Viet Nam Technology Catalogue for Power Generation

Danish Energy Agency

EREA
Electricity & Renewable Energy Authority

EMBASSY OF DENMARK

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Input for energy system modelling

FOREWORD

Today, innovations and technology improvements within energy generation, storage and renewable fuels are taking place at a very rapid pace, making long-term energy planning central to unlocking the potential of the new, renewable-based technologies. Long-term planning of energy systems is very dependent on cost, technical performance and environmental impacts of future energy technologies. Thus, the objective of this technology catalogue is to provide a robust review-based technical foundation for a range of power generation technologies, thereby constituting a key input to solid long-term energy planning in Viet Nam.

Through the multi-stakeholder involvement in the data collection process, as well as technology identification and prioritization, this 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), Viet Nam Electricity (EVN), independent power producers, local and international experts, other development partners organizations, energy branch associations and universities, among others. The stakeholder engagement is essential to ensure that the Technology Catalogue is well anchored and remains relevant among all stakeholders.

The aim for this Technology Catalogue is therefore that to assist long-term energy and power modelling in Viet Nam, thus supporting government institutions, private energy companies, think tanks and others through a common and broadly recognized set of data for current and future electricity producing technologies in Viet Nam.

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 Programme. The first Viet Nam Technology Catalogue for power generation and storage technologies was published in 2019, and subsequently updated in 2021. This new version includes all the technologies from the 2021 version, and new technologies have been added to expand the catalogue with new technologies relevant for power system analyses for Viet Nam. The focus of this update has been the addition of nuclear technologies with new technology descriptions and data sheets, and hydrogen-based power generation. Moreover, the chapters on wind turbines, carbon capture technologies, and coal-fired power plants have been updated, the latter to include lifetime extension, co-firing with biomass and ammonia. This present Technology Catalogue for power generation technologies, published along with the new Technology Catalogue for storage technologies and the new Technology Catalogue for renewable fuels technologies, constitutes substantial quantitative input to the Viet Nam Energy Outlook Report 2023.

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Contact information

Mr. Nguyen Hoang Linh, Senior Expert, Plan and Planning Department, Electricity and Renewable Energy Authority, Ministry of Industry and Trade, Email: linhnh@moit.gov.vn

Ms. Tran Hong Viet, Senior Programme Manager, Energy and Climate Change, Embassy of Denmark in Hanoi, Email: thviet@um.dk

Mr. Stefan Petrovic, Special Advisor, Centre for Global Cooperation, Danish Energy Agency, Email: snpc@ens.dk

AMENDMENT SHEET

Version	Date	Reference	Description
0005	Nov 2023	7 Solar Photovoltaics	Investment cost (M$/MWp) for utility-scale PV – updated Investment cost (M$/MWac) for utility-scale PV - updated
0004	Jul 2023	8 Wind Power Only for “Onshore Low-wind turbines” and “Offshore fixed” 6 Hydro Power	Fixed O&M ($/MWe/year) – updated Variable O&M ($/MWh) – updated Investment cost, small system (M$/MWe) - updated
0003	Mar 2023	1 Pulverized coal fired power	Biomass co-firing added Ammonia co-firing added Life-time extension added
0003	Mar 2023	3 Gas turbines	Hydrogen co-firing added
0003	Mar 2023	4 CO2 Capture and Storage (CCS) 8 Wind Power	Qualitative description updated
0003	Mar 2023	16 Nuclear Power Generation	Chapter added
0002	Aug 2021	2 CFB Coal Fired Power	Chapter added
0002	Aug 2021	4 CO2 Capture and Storage (CCS)	Chapter added
0002	Aug 2021	5 Industrial Co-generation	Chapter added
0002	Aug 2021	9 Tidal Power	Chapter added
0002	Aug 2021	10 Wave Power	Chapter added
0001	May 2019	Technology Catalogue Chapters 1-12	First version of the Viet Nam Technology Catalogue

CONTENT

Abbreviations

AFS	Axial Fuel Staging
BWR	Boiling Water Reactor
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon capture and storage
CEMS	Continuous Emission Monitoring System
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
CSP	Concentrated Solar Power
DLN	Dry Low NO_x (Combustion System)
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement and Construction
FGD	Flue Gas Desulphurization
FO	Fuel Oil
GHI	Global Horizontal Irradiation
HPP	Hydro Power Plant
ICE	Internal Combustion Engine
IGCC	Integrated Gasification Combined Cycle
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LTE	Lifetime Extension
MMV	Monitoring, Measurement and Verification
MSW	Municipal Solid Waste
OEM	Original Equipment Manufacturer
O&M	Operation and Maintenance Cost
PC	Pulverized Coal
PM	Particulate Matter
PTO	Power-take-off
PV	Photovoltaic
PWR	Pressurized Water Reactor
RE	Renewable Energy
R&D	Research & Development
SCGT	Simple Cycle Gas Turbine
SCR	Selective catalytic reduction
SMR	Small Modular Reactor
SNCR	Selective non-catalytic reduction
STC	Standard Test Conditions
TRL	Technology readiness level
WEC	Wave Energy Converter
WtE	Waste-to-Energy

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 include 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.

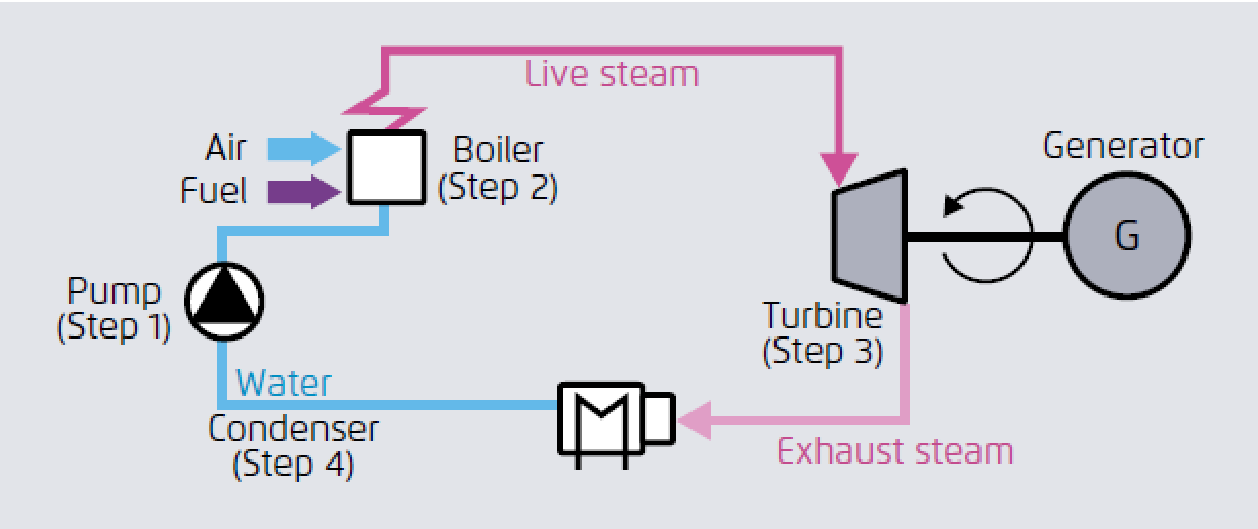

Figure 1: Schematic representation of operational flow of steam-based Rankine cycle in coal plants (ref. 3).

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 Viet Nam, a number of subcritical plants are operating but this catalogue focuses on supercritical and ultra-supercritical as no new subcritical plants are planned in Viet Nam 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).

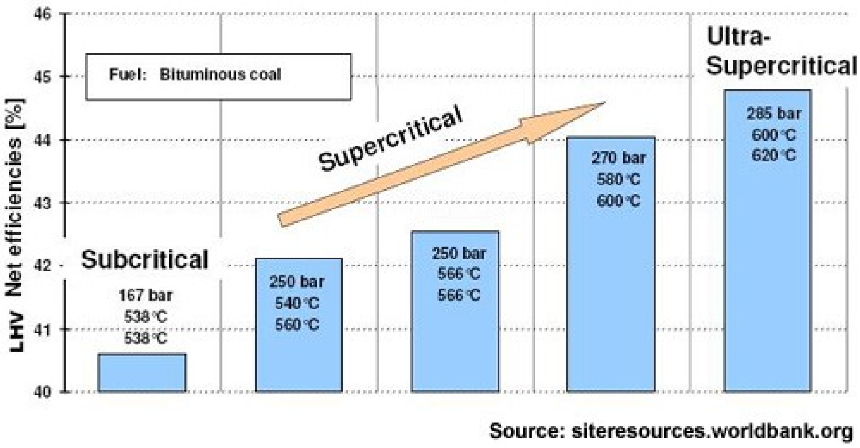

Figure 2: Definitions of sub-, super-, and ultra-supercritical plant (ref. 6). The same definitions apply to Anthracite coal.

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

[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.

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.

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

Advantages/disadvantages

Advantages:

- Mature and well-known technology.
- The efficiencies are not reduced as significantly at part load compared to full load as with combined cycle gas turbines.

Disadvantages:

- Coal fired power plants with no pollution control emit high concentrations of NO_x, SO_2 and particle matter (PM), which have high societal costs in terms of health problems. 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 Viet Nam 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 Viet Nam 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 SO2, (Some old thermal plants such as Pha Lai 1 and Ninh Binh have not yet applied)
- Selective Catalytic Reduction (SCR): Reduction of NOx (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 35.5%. 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, 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 °C; redrying steam temperature of 594.4 °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 Viet Nam 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 the World Bank's 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) Central	Vietnamese TC (2021)
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 World Bank's 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**	**2020**		
	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**	**2020**		
	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 Viet Nam 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 and 1.33) 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:

1. IEA and NEA, "Projected costs of generating electricity", 2015.
2. DEA, "Technology data for energy plants – Generation of electricity and district heating, energy storage and energy carrier generation and conversion", 2018.
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4. Mott MacDonald, "UK Electricity Generation Costs Update", 2010.
5. DEA, Flexibility in the Power System - Danish and European experiences, 2015. https://ens.dk/sites/ens.dk/files/Globalcooperation/flexibility_in_the_power_system_v23-lri.pdf, Assessed 9 September 2018.

[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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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, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity", 2017.

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 of Indonesia, 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 World Bank, Pollution Prevention and Abatement Handbook, 1998, https://doi.org/10.1596/0-8213-3638-X)

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, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity", 2017.

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 of Indonesia, 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 World Bank, Pollution Prevention and Abatement Handbook, 1998, https://doi.org/10.1596/0-8213-3638-X).

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

E Uncertainty Upper is fro1m 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.

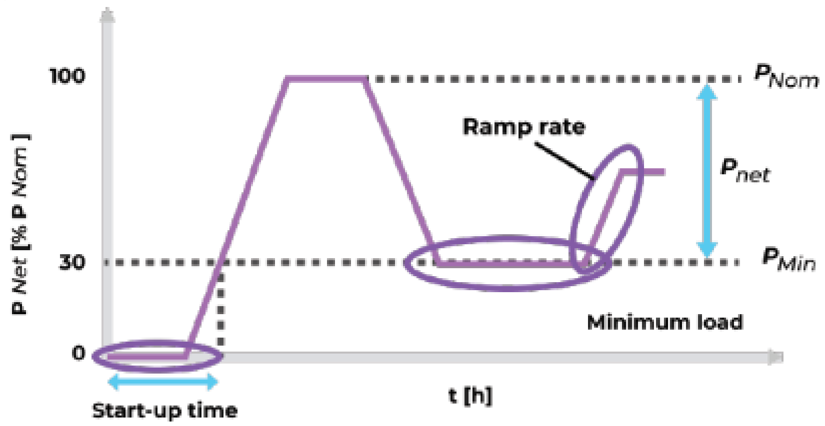

Figure 3: Key flexibility parameters of a power plant [3].

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 summarized 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 flexibility measures.

Table 5: Comparison of flexibility parameters before and after flexibility measures 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 pulverizers	 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
3) "prompt" NOx resulting from reaction between molecular nitrogen and hydrocarbon radicals. *(Ref. 1)*

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

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 N_2. 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]*.

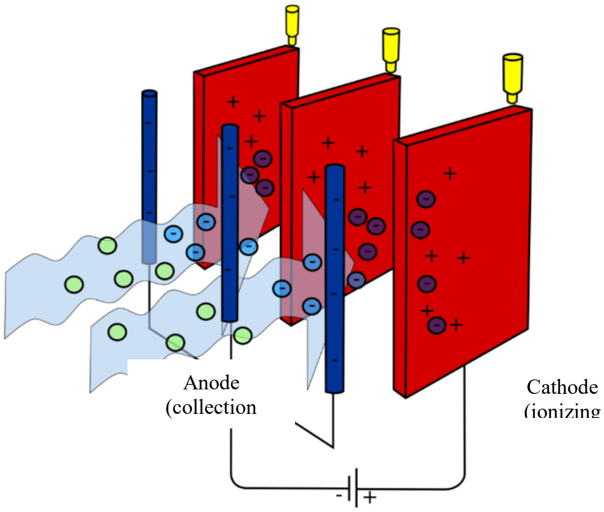

Figure 4: Principle behind electrostatic precipitator (ref.4).

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:

1. Coal cleaning
2. Wet scrubbing
3. 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:

1. Initial preparation,
2. Fine coal processing,
3. Coarse coal processing,
4. 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.

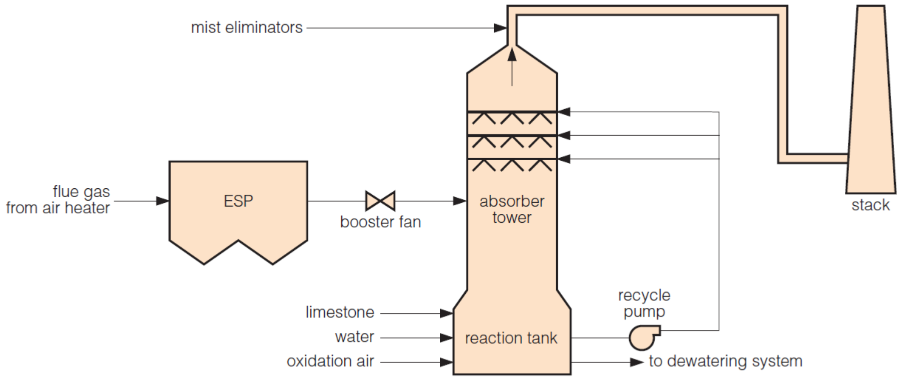

Figure 5. Wet scrubbing system (ref. 6)

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 through 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 Viet Nam, 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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Lifetime extension of existing coal plants

Brief technology description

Lifetime extension of existing large coal fired power plants offers a relatively quick and easy solution to keep existing capacity in operation, since the costs are typically several times lower than investments in new capacity.

Large coal power plants have been a major source in Viet Nam for the last decades. When a plant has been in operation for 30-35 years or more, the reliability of its components and systems will likely decrease leading to reduced availability and/or increased O&M costs. Therefore, based on experience, it will usually be necessary and beneficial to carry out a larger package of work that addresses repairs, renovation, and replacement of selected components and systems depending on their actual condition. Often also, improvement of environmental performance may be required, e.g. by improving the flue gas cleaning performance.

This 'Lifetime Extension' (LTE) is done with the purpose of restoring the plant to come close to its original conditions in terms of availability, efficiency, and O&M costs. The exact scope and extent of such a campaign though, shall be tailored to the actual plant in question and will depend on its design, previous records of operation, earlier major works carried out, etc. Also, the expected/desired future operation of the plant is taken into account. Whether or not to extend the life of a power plant is therefore not a simple decision but involves complex economic and technical factors [Ref. 5].

In this technology catalogue it is assumed that the lifetime extension:

- Takes place after approx. 30 years of normal operation, during which
- The maintenance of the plant has been carried out as planned, and
- Enables the plant to be operated with the availability rate close to that of the original new plant.
- Within the originally expected O&M budget,
- For an extended lifetime of approx. 20 years

Aging limit mechanisms: The life extension of a power plant usually requires replacing the existing components if they reach their technical lifetime. The aging limit can vary significantly, depending on the component design, operating conditions, and regular maintenance. In a coal power plant, the aging limit of component depends on many mechanisms including creep, fatigue, corrosion, erosion, spallation and obsolescence, each of which are explained below [2].

The typical failure mechanisms for major components in a power plant are shown in the following table.

Table 7. Typical component failure mechanisms [Ref. 2]

	Components	Creep	Low Cycle Fatigue	High Cycle Fatigue	Corrosion	Erosion	Concrete Spallation	Obsolescence
Boiler	HT components, headers, main steam pipework, steam chests HT bolts	X HT Pressure parts	X Drums and Headers		X Internal tubing	X Parts in air/gas path	X Support structures	
Steam turbine	HP and IP rotors and cylinders, casings, valves, steam chests	X HT Pressure parts	X	X	X Parts exposed to air/moisture/heat	X LP blades		
Balance of Plant	Airheaters, ID Fans, FD Fans, PA Fans, Milling Plant		X Fans, Mills, Airheaters		X ID Fans, Mills, Airheaters	X	X Mill Foundations	
Cooling and Feedwater	Condenser, air ejectors, pumps, motors,		X Pumps and	X Pumps and	X	X		

	Components	Creep	Low Cycle Fatigue	High Cycle Fatigue	Corrosion	Erosion	Concrete Spallation	Obsolescence
Systems	valves, cooling towers, feedwater heaters		Motors	Motors				
Electrical	Generators, transformers, switchyard, cabling breakers		X	X	X			
Civils	Roofs, Walls, Steel Structures, Foundations			X	X	X		
Others	Instrumentation, Digital Control systems, auxiliary control systems							

In connection with the LTE, the plant will be out of operation for a period, typically 6-9 months.

The LTE will typically involve considerable project costs for planning and management since it requires establishing a project organisation for engineering, purchase, construction management, test, and commissioning.

The distribution of works and costs involved with a LTE of an existing coal fired plant could typically be as follows, however depending widely on the actual scope [Ref. 5].

Main elements can be:

- Revision of electrical systems
- Instrumentation and control systems replacement
- Pulverizers upgrade or replacement (fuel supply and disposal)
- Boiler upgrade,
- Turbine refurbishment (possibly generator refurbishment)
- Water systems (heat exchanges for condensers and district heating)
- Buildings
- Flue gas cleaning.

In order to extend lifetime of coal-fired power plants, the components in the table below (Table 8) need to be periodical overhauled, replaced, upgraded or refurbishment.

Table 8. Main component life cycle for coal power plant [Ref. 2]

Area	Inspection	Activity	Frequency (year)	Year	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
Boiler	Major overhaul		4				x				x				x				x				x	
	Inert gas overhaul		2		x				x				x				x				x			
	HT Headers	Replace	28												x									
	Main steam pipework	Replace	40																					
Steam turbine	Major overhaul		12								x												x	
	Inert gas overhaul		4				x								x				x				x	

Area	Inspection	Activity	Frequency (year)	Year	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
	HP & IP Rotor	Refurb	16				x																x	
	LP Rotors	Refurb	28																					
	Steam chests	Replace	28																					
	Generators	Refurb	16				x																x	
Feed water system	Feed heaters	Refurb	30		x																			
	Condenser waterbox	Refurb	30		x																			
Electrical	Generator	Refurb	20												x									
	Transformers	Renew	30		x																			
	Motors	Refurb	10		x										x									
Control & Inst.	DCS	Upgrade	10		x										x									
		Upgrade	10		x										x									
	Man-machine interface																							
Coal and ash plant	Coal plant	Refurb	12								x												x	
	Ash plant	Refurb	12								x												x	
	Precipitors	Refurb	12								x												x	
Civil	Exposed steelwork	Repaint	25																					
	Roof & Cladding	Repair	25																					

For a typical coal power plant, the major overhaul frequency is shown in the following table (Table 9).

Table 9. Major overhaul frequency for coal power plant [Ref. 2]

Plant Area	Type	Frequency (years)	Duration (weeks)
Boiler	Major Overhaul	4	10 weeks
	Intermediate	2	4 weeks
Steam Turbine	Major Overhaul	12*	10 weeks
	Intermediate	4*	4 weeks

Lifetime extension of existing plants is also relevant when converting to other fuels e.g. biomass as discussed in the next section of co-firing of power plants.

Effect on efficiency and operation characteristic

Lifetime extension of coal-fired plants aims to maintain the performance of the existing plants, so the efficency will be the same of a little bit lower than the original one [Ref. 2].

The regulation abilities of coal fired power plants, e.g. start-up time and ramp rates may improve in connection with LTE due to implementation of better control systems [Ref. 2]. This effect is, however, not possible to quantify on a general level. In general, start-up times and -costs are not considered to change due to LTE.

Effect on emissions

The lifetime extension is not in itself expected to change the environmental performance characteristics beyond the maximum allowed emission values at the time of LTE, that probably are more stringent than the original requirements. If advantageous or required, such further improvements may be implemented in connection with LTE campaign.

Research and development perspectives

It is not anticipated that there will be a considerable further development in the technology relevant for lifetime extension of large coal fired power plants. However, with the large number of coal power plants running world-wide, it is expected that LTE methods will generally improve.

Examples of current projects

Ninh Binh Thermal Power Plant has been in operation since 1974 and consists of four medium-voltage generating with a total design capacity of 100 MW (4 x 25 MW). Traditional coal-fired (PC) steam boilers naturally circulate steam. After 48 years of commercial operation, the plant generates about 28.84 billion kWh of electricity to the national grid.

Boiler System: Updating UD nozzles (high density) in boilers have significantly improved boiler characteristics, increased efficiency by 1 ÷ 2%, no slag formation, extended furnace operating cycle, and reduced the percentage of residual carbon in the ash, reducing the concentration of NOx.

Turbine: The turbines No. 1, 2, and 3 after being replaced operate reliably, ensuring design capacity and efficiency from 30 ÷ 32%. Currently, turbine No. 4 has a long operating time, the impellers have corrosion, pitting affecting reliability and low efficiency 27% ÷ 28%, expected to be replaced in 2023.

No.	Specifications	Unit	Turbine 1	Turbine 2	Turbine 3	Turbine 4
1	Year of renewal	Year	2019	2018	2016	
2	Rated capacity	MW	25	25	27	25
3	Heat rate	kJ/kWh	11,243.9	11,207.9	11,246	13,100
4	Efficiency	%	32.02	32.12	32.01	27.48

Generator: The generators have been restored with new insulation and the excitation system has been replaced with a Unitrol 6080, which is stable and reliable. In 2007, replacing fuel oil used for starting the furnace and burning it with DO oil with the aim of reducing the amount of ash, SO_X, NO_X in production technology, and overcoming exhaust gas pollution. Replaced Siemens digital protection relay system for 04 groups of generator-transformer and electrical resistance in 2009 and 2010.

Transformers: The main transformers have been replaced: T1, T3 transformers in the years 2000 and 2013, transformers T2, T4 with large losses affecting the increase of self-consumption electricity, are expected to be replaced in the period of 2023-2025. 110 kV circuit breaker was replaced with SF6-110kV circuit breaker and 35 kV circuit breaker with vacuum circuit breaker cabinet manufactured by Siemens Germany in 2005.

Emissions treatment system: Upgrading ESP control system with EPIC-III and SIR4 of Alstom (2013-2014). The power plant does not have FGD, SCR systems to treat SO_x and NO_x emissions (expected to be installed from 2023-2026). Through the automatic online emission monitoring system, the concentrations of CO, SO2 and NOx all meet the permissible standards for emissions QCVN 22:2009.

Upgrading coal storage and supply system: install air cannon, renew water pump and cooled fan (2020-2021).

Cost estimate

An international study from [Ref. 2] calculated the cost of lifetime extension for 20 years from the year 30th to 50th of operations for a typical 1000 MW coal-fired power plant, shown that the total cost are estimated to be 257 million dollars, corresponding to **0.26 M$/MW** as show in the table below:

Table 10. Component cost of lifetime extension for coal-fired power plant [Ref. 2]

Area	Inspection	Activity	Frequency (year)	Cost per unit (mill USD)	30 31	32 33	34 35	36 37	38 39	40 41	42 43	44 45	46 47	48 49
Boiler	Major overhaul		4	20.1		1		1		1		1		1
	Inert gas overhaul		2	2.31	1		1		1		1		1	
	HT Headers	Replace	28	1.54										
	Main steam pipework	Replace	40	12.32						1				
Steam turbine	Major overhaul		12	12.32				1						1
	Inert gas overhaul		4	1.54		1				1		1		1
	HP & IP Rotor	Refurb	16	12.32		1								1
	LP Rotors	Refurb	28	9.24										
	Steam chests	Replace	28	3.08										
	Generators	Refurb	16	3.08		1								1
Feed water system	Feed heaters	Refurb	30	3.08	1									
	Condenser waterbox	Refurb	30	6.16	1									
Electrical	Generator	Refurb	20	7.7						1				
	Transformers	Renew	30	4.62	1									
	Motors	Refurb	10	3.08	1					1				
Control & Inst.	DCS	Upgrade	10	3.08	1					1				
	Man-machine interface	Upgrade	10	3.08	1					1				
Coal and ash plant	Coal plant	Refurb	12	7.7				1						1
	Ash plant	Refurb	12	3.08				1						1
	Precipitors	Refurb	12	4.62				1						1
Civil	Exposed steelwork	Repaint	25	3.08										
	Roof & Cladding	Repair	25	1.54										
Yearly cost (Mill USD)					25.4	37.0	2.3	47.8	2.3	50.9	2.3	21.6	2.3	64.8
Total cost (Mill USD)										256.8				

The Danish Technology Catalogue also mentions extending the life of coal-fired power plants for 15-20 years with the purpose of restoring the plant to come close to its original conditions. The total cost for lifetime extension given was 0.24 M€/MW corresponding to **0.26 M$/MW**.

As Ninh Binh TPP have not completed the lifetime extension of 20 years and the cost for the upgrading/replacing was not provided, the catalogue has a rough estimate for the cost of lifetime extension for whole 20 year period of about 620 billion Dong- corresponding to **0.27 MS/MW**, based on estimated cost for each component.

The O&M cost also aim to be maintained within the originally expected O&M budget, however the average fixed O&M cost may increase slightly for the extension period compared with the original lifetime to accommodate the necessary reinvestments during the extended lifetime.

Investment costs (MUSD/MW)		2020	2030	2050
Viet Nam data	Project: Ninh Bình TPP (roughly estimated)	0,27	0,27	0,27
International data	Danish technology catalogue	0,26	0,26	0,26
	WSP USA	0,26	0,26	0,26
Viet Nam Catalogue 2023		**0,26**	**0,26**	**0,26**
Projection	Learning curve – cost trend (%)	100%	100%	100%

Data sheet

Technology	Lifetime extension of coal power plant								
	2020	2030	2050	Uncertainty 2030		Uncertainty 2050		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	600	600	600	300	1000	300	1000		
Electricity efficiency. net (%-point). Name plate	-1	-1	-1	0	-3	0	-3	A	1,6,7
Electricity efficiency. Net (%-point). annual average	-1	-1	-1	0	-3	0	-3	A	1,6,7
Forced outage (%-point)	+0	+0	+0	+0	+1	+0	+1	A	6
Planned outage (weeks per year)	+0	+0	+0	+0	+1	+0	+1	A	6
Technical lifetime (years)	+20	+20	+20	+10	+20	+10	+20		
Construction time (years)									
Space requirement (1000m^2/MW)									
Regulation ability									
Ramping (%-point per minute)	+0	+0	+0	+0	+0	+0	+0	A	2
Minimum load (%-point of full load)	+0	+0	+0	+0	+0	+0	+0	A	2
Warm start-up time (hours)	+0	+0	+0	+0	+0	+0	+0	A	2
Cold start-up time (hours)	+0	+0	+0	+0	+0	+0	+0	A	2
Environment									
PM2.5 (% compared to 100% coal)	+0	+0	+0	+0	+0	+0	+0	A	6
SO2 (% compared to 100% coal)	+0	+0	+0	+0	+0	+0	+0	A	6
NO_X (% compared to 100% coal)	+0	+0	+0	+0	+0	+0	+0	A	6
Financial data (in 2019$)									
Nominal investment (M$/MWe)	0.26	0.26	0.26	0.1	0.3	0.1	0.3	AB	1,2,6,7
- of which equipment	-	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	+3%	+3%	+3%	+1%	+5%	+1%	+5%	A	1,6,7
Variable O&M (% compared to 100% coal)	0%	0%	0%	0%	+3%	0%	+3%	A	1,6,7

Notes:

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

B Values will depend on those of the plant prior to LTE, however the average fixed O&M cost may increase slightly for the extension period compared with the original lifetime to accommodate the necessary reinvestments during the extended lifetime

C It is assumed that plant emissions prior to the LTE are within the legal limits.

D Investment costs will vary largely, depending on the necessary scope of work. The indicated range represents typical cases where lifetime extended to obtain additional 20 years lifetime.

E Values will depend on those of the plant prior to LTE, however the average fixed O&M cost may increase slightly for the extension period compared with the original lifetime to accommodate the necessary reinvestments during the extended life time.

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Ammonia co-firing in coal power plants

Brief technology description

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

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

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

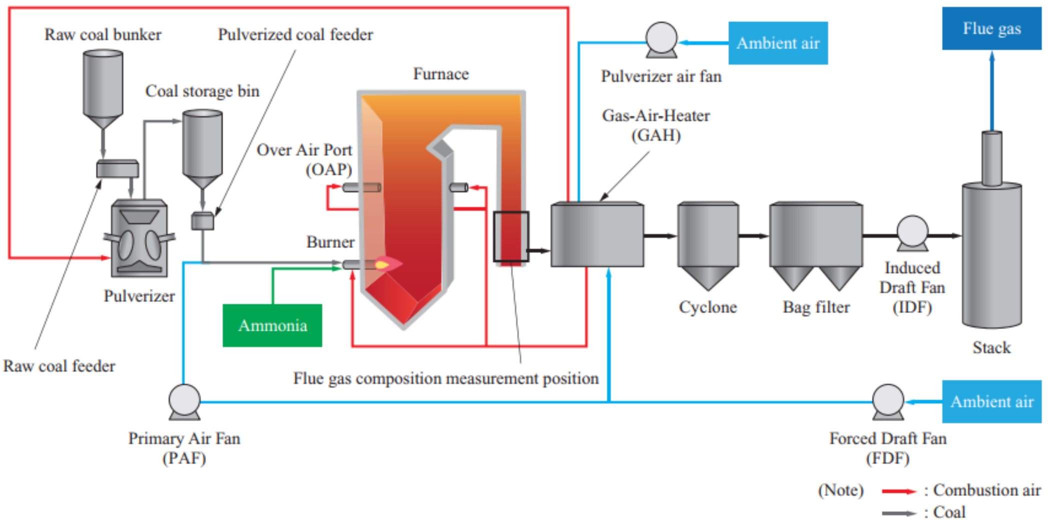

Figure 6. Diagram of ammonia co-firing in pulverized coal-fired power plants [1]

[Ref. 1] has examined modifications to the boiler system when co-firing ammonia in a pulverized coal as follows:

Heating surfaces of the boiler	As a result of numerical analysis that simulates a boiler, it was found that the heat recovery quantity is almost the same for coal firing and ammonia co-firing, and since the steam and gas temperatures throughout the system are not different from those that were designed, ammonia co-firing requires no modifications to the boiler heating surfaces.
Burner	Basically, burners designed for coal firing are also used for ammonia co-firing. However, it is necessary to add ammonia supply facilities, including equipment that injects ammonia gas into the burner and systems that address concerns arising from the use of ammonia.
Primary Air Fan (PAF)	The PAF is used to carry pulverized coal to the burner. During ammonia co-firing, some of the pulverized coal used as fuel is replaced by ammonia gas, and so the amount of air used to carry coal decreases; therefore, the PAF requires no modifications.
Forced Draft Fan (FDF)	The air required for combustion is supplied by the PAF and FDF. During ammonia co-firing, the amount of air supplied by the PAF decreases, and the FDF has to compensate for this in order to ensure the required amount of air for combustion. Hence, the flow rate on the FDF side tends to increase. There is some surplus capacity in the design specification of the FDF, and so no modification is necessary. However, depending on the design specification, such surplus capacity may not exist, and so careful consideration is required in order to determine whether modification is needed.
Induced Draft Fan (IDF)	As a result of material balance evaluation, the gas quantity tends to increase slightly for ammonia co-firing. As with the FDF, in the model plant used in this study, there is some surplus capacity in the design specification of the IDF, and so no modification is

	necessary. However, careful consideration is required, since modification may be needed depending on the setting in which surplus capacity is ensured.
Pulverizer	Because the amount of injected coal decreases for ammonia co-firing, the operation load of the pulverizer decreases. Therefore, no modification of the pulverizer is necessary. In addition, because the amount of injected coal decreases, the required temperature of the air for drying the coal decreases. As a result, some of the heat recovered by the GAH during coal firing remains in the flue gas during ammonia co-firing, and so the flue gas temperature during ammonia co-firing tends to be higher.
Gas Air Heater (GAH)	The flue gas temperature tends to increase because not all the heat from the gas side can be recovered due to a decrease in pulverizer inlet temperature, increase in gas flow rate, change in gas properties, etc. Flue gas temperature needs to be examined in detail, but since it increases by around 10 degrees Celsius, this level of increase can be absorbed by the surplus capacity available when the facility is newly installed, and so no modification of the GAH is required.
Environmental facilities (NOx removal equipment, removal equipment)	From the results of the test, under appropriate conditions of the two-stage combustion ratio, heat input, and coal fuel ratio, during ammonia co-firing NOx concentration is almost the same as during coal firing; and that CO2, SO2, and dust decrease as the amount of injected coal decreases. Although the environmental regulation values are satisfied, it was confirmed that there is an increase in the amount of gas and moisture content of the flue gas, so it is necessary to further evaluate modification and expansion of environmental facilities.

Modifying existing thermal plants for ammonia co-firing requires boiler modifications and investment in additional facilities like ammonia tanks and vaporizers. In general, the retrofits include [Ref. 2]:

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

This is illustrated in the figure below.

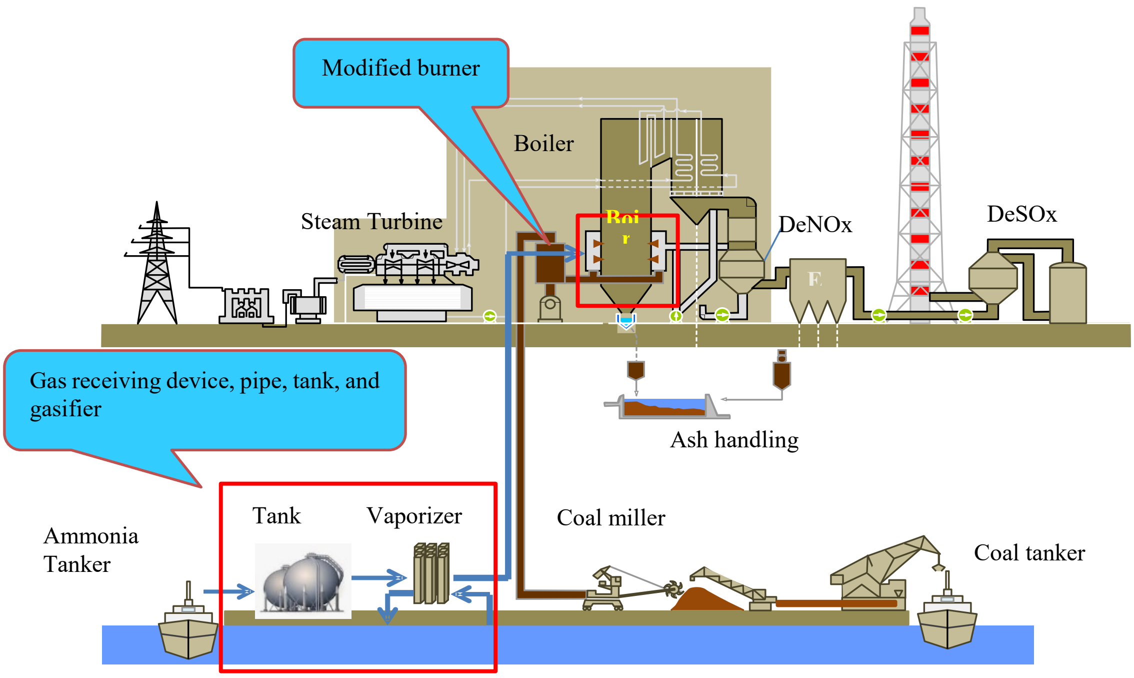

Figure 7. Facilities to be implemented and improved at a coal ammonia co-fired power plant

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

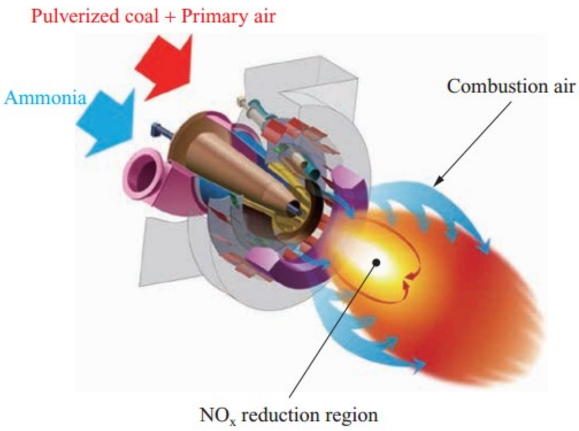

Figure 8. Schematic diagram of the modified burner to co-firing ammonia [Ref.1]

Advantages and Disadvantages

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

Advantages:

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

Disadvantages:

- Ammonia is a highly reactive and toxic gas, and proper safety measures must be in place to prevent accidents or releases.
- Ammonia co-firing requires modified burners and other facilities to retrieve, vaporize and transport ammonia. Moreover, additional NOx removal systems (selective catalytic reduction SCR) are also required, due to the significant amounts of NOx generated during combustion. Those modification and implementation can be costly.
- The price of ammonia is higher than that of coal, increasing fuel costs for the plant. An estimation of The Institute of Energy Economics, Japan projected that the fuel costs for a power plant that uses a 20% blend of ammonia will be significantly higher, more than double, than that of a power plant which uses coal alone. [Ref. 5].
- Currently, more than 90% of ammonia is synthesized from nitrogen in the air and hydrogen produced from fossil fuels, such as natural gas, coal, and oil without carbon capture and storage (grey ammonia). This process still emits large amount of CO_2. Other kinds of ammonia like blue ammonia (made via steam reforming of methane or gasification of coal couple with CO_2 capture and storage), or green ammonia (made via electrolysis of water using renewable energy electricity) release smaller volumes of CO_2 but are much more costly.
- Further research is needed to increase the NH3-to-coal ratio and improve the efficiency of the boiler**.**

Effect on boiler efficiency

A comparison is given of boiler performance for coal firing and ammonia co-firing 20% is verified in [Ref. 1]. The result shows that the boiler efficiency during ammonia co-firing is slightly lower than that during coal firing. This is presumably because, although ammonia co-firing reduces the loss due to unburned coal, burning ammonia increases the moisture content in the boiler flue gas, which increases the latent heat of the moisture discharged from the gas.

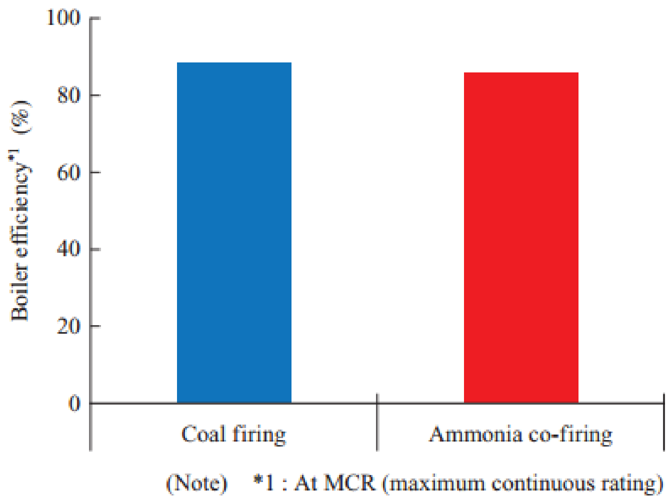

Figure 9. Comparison of boiler performance for coal firing and ammonia co-firing 20% [Ref.1]

Effect on operation characteristic

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

Effects on emissions

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

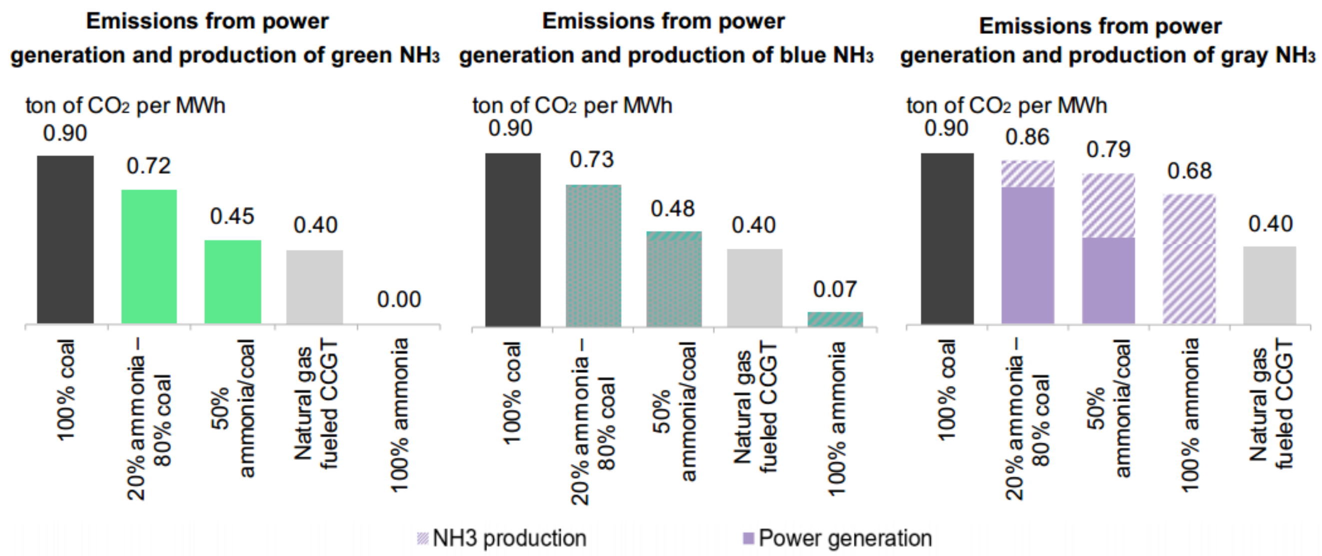

Figure 10. Emission reduction potential depending on the ammonia source [Ref.2]

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

The other emission of SO_2 and particle matter decrease when co-firing ammonia as the amount of injected coal decreases and NH_3 does not content of sulfur and dust [Ref. 1].

Studies point out that when co-firing ammonia at the rate of 20% in coal-fired power plants, it is possible to keep the NOx emission from increasing significantly compared to the case of 100% coal combustion by keeping the stable flame and adjust the two-stage combustion ratio and heat input [Ref. 1, 3]. [Ref. 4] shows that under the condition of 20% co-firing, equivalent NOx emission and unburnt carbon content than those of pure coal combustion can be achieved. This is probably caused by a combined effect of a high local equivalence ratio of

NH_3/air and the prominent denigration effect of NH_3 in the vicinity of the NH_3 downstream injection location.

Higher rates of ammonia co-firing will lead to higher emission of NOx, at 100% ammonia co-firing the NOx emission is estimated to increase about 30% compared to pure coal combustion [Ref. 2]. However, NOx removal systems using selective catalytic reduction (SCR) technology, which converts nitrogen oxides into diatomic nitrogen and water, could effectively solve the problem.

Examples of current projects

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

The co-firing technology also are adopted by South Korea, India, and several countries of Southeast Asia like Indonesia and Malaysia [Ref. 10]. However, in those countries, the technology is still in development phase.

Cost estimate

At the level of co-firing 20% ammonia in the pulverized coal-fired power plants, retrofit includes upgrading burners and additional balance of plant expenses to receive and store ammonia while additional NOx-reduction facilities are not necessary because NOx emissions do not increase significantly (see Effect on emission); these upgrades come at an estimated 11% premium in Capex [Ref. 2]. Considering using super-critical coal-fired power plants in Viet Nam (investment cost of 1.46 MUSD/MW – see Pulverized coal fired power/data sheet), the investment cost for co-firing 20% ammonia will be 0.16 MUSD/MW.

At higher ammonia co-firing ratio (e.g. 50% co-firing or 100% co-firing), storage tanks for ammonia would also need to be bigger and additional advanced equipment to capture NO_X emissions would be needed, and the boilers would require major upgrades or even replacement. At 100% firing of ammonia, the investment cost to retrofit coal-fired power plant is preliminary estimated at about 25% of CAPEX, equivalent to investment rate of 0.37 MUSD/MW.

O&M cost: Since new ammonia receiving device, pipe, tank and vaporizer and modified burner are needed when co-firing ammonia, the O&M cost will tend to slightly increase, from 5 – 10% depend on co-firing rate of ammonia [Ref. 2].

Data sheet

Technology	Pulverized coal – co-firing 20% ammonia								
	2020	2030	2050	Uncertainty 2030		Uncertainty 2050		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	600	600	600	300	1000	300	1000		
Electricity efficiency. net (%-point). name plate	-1	-1	-1	0	-2	0	-2	A, B	1
Electricity efficiency. net (%-point). annual average	-1	-1	-1	0	-2	0	-2	A, B	1
Forced outage (%-point)	+0	+0	+0	+0	+1	+0	+1	A	
Planned outage (weeks per year)	+0	+0	+0	+0	+0	+0	+0	A	
Technical lifetime (years)									
Construction time (years)									
Space requirement (1000m^2/MW)									
Regulation ability									
Ramping (% per minute)	+0	+0	+0	+0	+0	+0	+0	A	
Minimum load (% of full load)	+0	+0	+0	+0	+0	+0	+0	A	
Warm start-up time (hours)	+0	+0	+0	+0	+0	+0	+0	A	
Cold start-up time (hours)	+0	+0	+0	+0	+0	+0	+0	A	
Environment									
PM2.5 (% compared to 100% coal)	-20%	-20%	-20%	-10%	-20%	-10%	-20%	A	1
SO_2 (% compared to 100% coal)	-20%	-20%	-20%	-10%	-20%	-10%	-20%	A	1
NO_X (% compared to 100% coal)	+5%	+5%	+5%	+0%	+10%	+0%	+10%	A	1, 2, 3, 4
Financial data (in 2019$)									
Nominal investment (M$/MWe)	+0.16	+0.16	+0.16	+0.05	+0.3	+0.05	+0.3	A, C	2
- of which equipment	-	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	+5%	+5%	+5%	+3%	+8%	+3%	+8%	A	2
Variable O&M (% compared to 100% coal)	+5%	+5%	+5%	+3%	+8%	+3%	+8%	A	2

Notes:

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

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

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

Technology	Pulverized coal – co-firing 100% ammonia							
	2030	2050	Uncertainty 2030		Uncertainty 2050		Note	Ref
Energy/technical data			Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	600	600	300	1000	300	1000		
Electricity efficiency. net (%). name plate	-2	-2	-1	-3	-1	-3	A, B	1
Electricity efficiency. net (%). annual average	-2	-2	-1	-3	-1	-3	A, B	1
Forced outage (%)	+0	+0	+0	+1	+0	+1	A	
Planned outage (weeks per year)	+0	+0	+0	+0	+0	+0	A	
Technical lifetime (years)								
Construction time (years)								
Space requirement (1000m^2/MW)								
Regulation ability								
Ramping (% per minute)	+0	+0	+0	+0	+0	+0	A	
Minimum load (% of full load)	+0	+0	+0	+0	+0	+0	A	
Warm start-up time (hours)	+0	+0	+0	+0	+0	+0	A	
Cold start-up time (hours)	+0	+0	+0	+0	+0	+0	A	
Environment								
PM2.5 (% compared to 100% coal)	-100%	-100%	-70%	-100%	-70%	-100%	A	1
SO_2 (% compared to 100% coal)	-100%	-100%	-70%	-100%	-70%	-100%	A	1
NO_X (% compared to 100% coal)	+30%	+30%	+20%	+50%	+20%	+50%	A	1, 2, 3, 4
Financial data (in 2019$)								
Nominal investment (M$/MWe)	+0.37	+0.37	+0.20	+0.6	+0.20	+0.6	A, C	2
- of which equipment	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	+10%	+10%	+5%	+15%	+5%	+15%	A	2
Variable O&M (% compared to 100% coal)	+10%	+10%	+5%	+15%	+5%	+15%	A	2

Notes:

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

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

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

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Direct co-firing of biomass in existing power plants

Brief technology description

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

There are three main technologies: direct co-firing, indirect co-firing, and parallel co-firing [Ref. 2].

- Direct co-firing involves the simultaneous combustion of biomass and coal in the same furnace or boiler. This means that the fuel is fed into the same combustion chamber and burned together.
- Indirect co-firing, on the other hand, involves the combustion of biomass and coal in separate combustion chambers connected by heat exchangers. The hot gases from the combustion of coal are used to generate steam, which is then used to generate electricity, while the biomass is burned in a separate chamber to generate heat.
- Parallel co-firing involves the use of a separate combustion chamber or boiler solely dedicated to the combustion of biomass. The steam generated from the combustion of biomass is then used in conjunction with steam generated from the combustion of coal to generate electricity.

The three types are illustrated in the figure below.

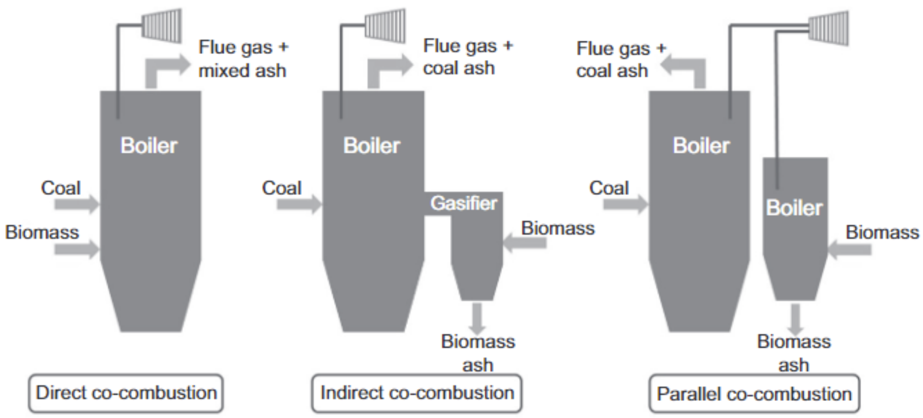

Figure 11. Schematic presentation of co-firing technology options [Ref. 4]

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

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

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

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

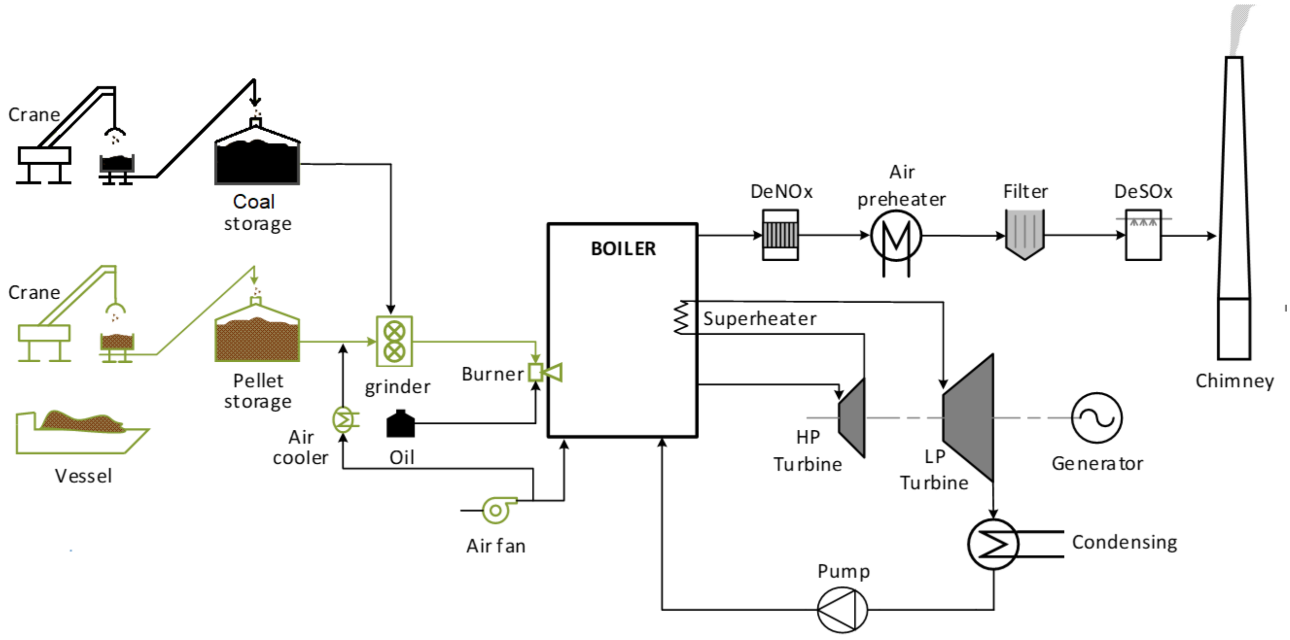

Figure 122. Sketch of a pulverized coal plant co-firing with wood pellets. The green elements indicate the equipment that needs to be added, replaced or refurbished.

Wood chips are a less homogeneous fuel than pellets, with large variations in quality and size. Its water content is high, typically from 20% and up to more than 50%, and it may as well contain fractions of soil. Therefore, in case of using wood chip for co-firing in pulverized coal plant, it is needed to install a plant for processing the chips into dry and fine-grained matter, i.e. comparable to the fuel obtained by grinding wood pellets, this will increase the retrofit cost of co-firing.

The circulating fluidized bed (CFB) coal-fired plant can use wood pellets, wood chips and other biomass for co-firing. Clearly, stoker and FBC boilers, which are designed to fully fire biomass, are much more suited for co-firing very high percentages of biomass than pulverized coal boilers. Due to no limitations of coal and biomass milling as in a pulverized coal boiler system, the CFB boiler can co-fire with 20% biomass with very small cost. The figure below shows a principal sketch of the CFB plant and which elements are expected to be added, replaced or refurbished to run on 100% biomass:

- New storage and transport systems for the wood chips
- Larger fans for pneumatic transport systems
- At high share of biomass, the steam pressure is often lower. Therefore, the high-pressure turbine may need to be replaced with a new one or be upgraded. Otherwise, the pressure drops over the high-pressure turbine and the steam will condensate the steam too much. In this case, the low-pressure turbine will get steam that is too “wet” and will eventually break faster than it should.
- Upgrading of or new flue gas system, filters and condensation scrubber and probably also SCR if needed.

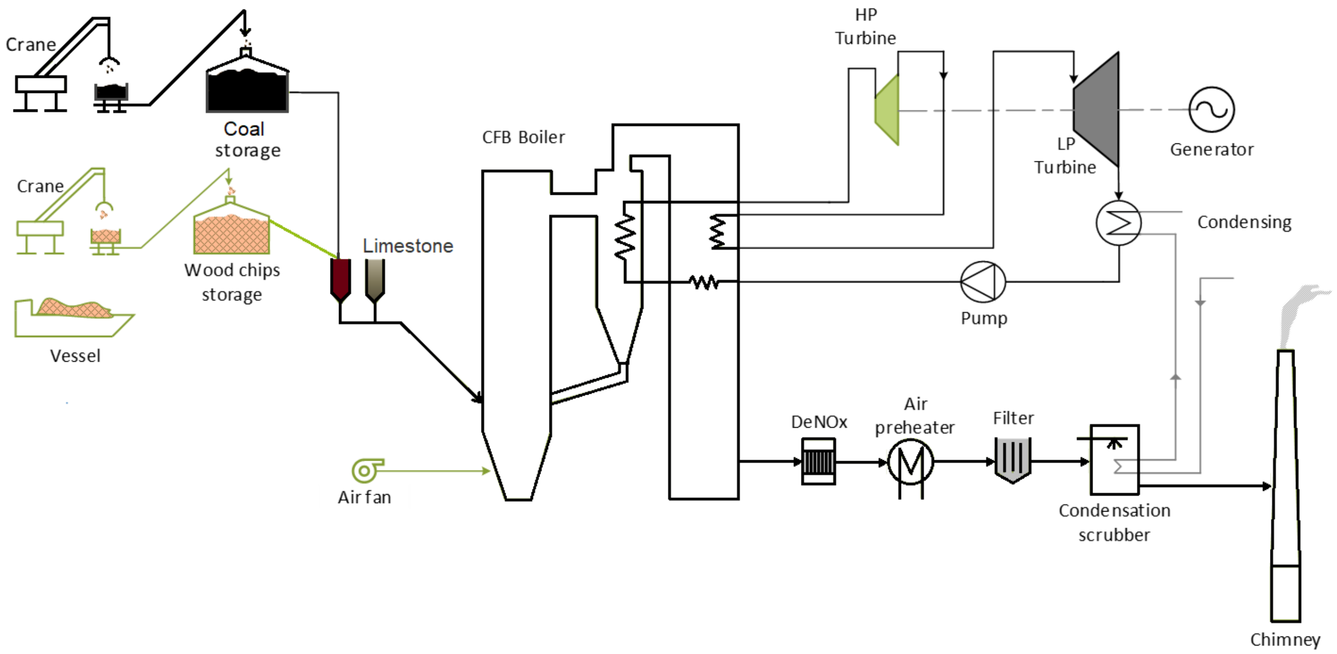

Figure 13. Sketch of a CFB coal plant co-firing with wood chip. The green elements indicate the equipment that needs to be added, replaced or refurbished.

The optimal mixing ratio of biomass fuel is determined based on factors such as cost and the operating requirements of each power plant. Currently, most power plants using co-firing technology of biomass and coal are applying mixing ratios of biomass fuel ranging from 5% to 10%.[Ref. 2]. In terms of technical feasibility, this ratio can reach over 50%, and may even be up to 100% depending on the conditions of the power plant.

The current trend in co-firing biomass and coal technology is to increase the biomass ratio in commercial projects and to eventually move towards using only biomass fuel as a replacement for coal. In some European countries like Denmark and the UK, there are power plants that started with mixing ratios of 3% to 10%, and some of them have already switched to using 100% biomass fuel [Ref. 8]. In Japan, there are currently some power plants that blend biomass with a ratio from 15% to 30% in existing coal-fired power plants, with plans to increase the biomass ratio to 50% to 100% after some plants undergo renovation from 2023 to 2035. In Viet Nam, Ninh Binh coal-fired plant of the pulverized coal type has tested co-firing with wood pellets at the highest share of biomass of 43% in 2020 [Ref. 11].

Table 11: Example of co-combustion ratio of biomass in coal-fired power plants [Ref. 3]

Power Plant/ Commissiong Time	Capacity of Coal-Fired Unit	Coupling Form	Biomass Fuel	Co-Combustion Ration of Heat	Technical Characteristics
Shiliquan/2005	400t/h high temperature and high pressure boiler	Direct co-firing	Wheat straw, corn stalk	18,6% (Design) 5% - 8% (Reality)	Adopt the independent burning system of BWE company in Denmark to achieve co-combustion. And the fuel entering the boiler needs to be pre-treated.
Baoji 2/2010	300 MW boiler	Direct co-firing	Straw, molding biomass	6,76 – 21,90%	Through a set of pulverizing system, biomass fuel is burned separately
British Tibury/2004	712 MW	Direct co-firing	Forest tree, wood pellet	100%	Using biomass to break in biomass burner
British Fiddlers Ferry/1995	4 x 500 MW	Direct co-firing	Pressed waste wood pellet fuel, olive core and other biomass	20%	After grinding, biomass particles are directly sent to the boiler for combustion

Fuel delivery, storage and handling: Biomass has a much lower bulk density, is generally moist, strongly hydrophilic and is non-friable. The lower heating values and much lower bulk densities mean that the overall fuel densities of biomass in MJ/m3 could be one tenth that of coal. Hence, co-firing biomass at 10% of thermal input requires comparable flows of biomass and coal. Co-firing higher percentages of biomass would require much higher flows of biomass than coal. Hence, the on-site delivery, storage and fuel handling demands of biomass are disproportionately high compared with coal. These issues will be particularly apparent when co-firing high biomass ratios. It may also be necessary to add extra flexibility in fuel storage and handling facilities to utilize multiple sources of biomass. The handling and flow properties of biomass are usually more problematical than coal due to the fuel size variation and high fiber and oversized particle content.

Slagging and fouling: Biomass fuels can contain a higher proportion of alkaline species compared with coal though the total ash content must also be considered. The constituents of the ash such as alkali metals, phosphorous, chlorine, silicon, aluminum and calcium affect ash melting behavior. Alkaline metals readily vaporize during combustion. A key reaction that needs to be considered is the release of volatile species, such as alkali metals and phosphate compounds and their subsequent deposition on boiler surfaces and on surfaces of ash particles and deposits. The major proportion of inorganic materials in biomass is in the form of salts or bound in organic matter, whereas in coal they are bound in silicates, which are more stable.

Corrosion and erosion: The majority of biomass fuels tend to be relatively rich in alkali metals, especially potassium and in some cases phosphates. They also have relatively low sulfur contents. Moreover, some types of biomass contain relatively high chlorine contents, up to 1%, which is released as HCl in the boiler flue gas, which can lead to the enrichment of chloride at the metal/oxide/ash deposit interface. Biomass ash deposits tend to have relatively high potassium contents and relatively high chloride to sulphate ratios. This can have a significant impact on corrosion, particularly at high metal temperatures on superheater surfaces.

Effect on boiler efficiency and operation characteristic

Compared to coal and other fossil fuels, biomass fuel typically has a lower heating value and a higher cost. Biomass co-firing could lead to the reduction of furnace's efficiency. Blending biomass with bituminous and lignite coal at a ratio of 30%, the efficiency of the plant can decrease from 35.2% to 34.61% and 34.081% to 33.798% respectively [Ref. 7].

The regulation abilities will in most cases not change much, in case existing boilers of coal-fired plants are co-firing with biomass.

Effect on emission

[Ref. 12]: The net emissions of CO_2 from the combustion of biomass are less than from coal if the biomass is grown in a sustainable manner. The measured stack emissions of CO_2 when biomass is cofired in a coal plant may increase slightly as the boiler is derated during cofiring. Even if the biomass that is cofired is not an energy crop, such as demolition wood, cofiring still reduces greenhouse gas emissions, as otherwise the waste wood would be left to decay and would produce methane, which is a far more potent greenhouse gas than CO_2.

SO_2 emissions invariably decrease, often in proportion to the amount of biomass used, as most types of biomasses contain less sulfur than coal. Further reductions are sometimes observed as biomass ash frequently contains higher levels of alkali and alkaline earth compounds than coal and can retain a greater fraction of sulfur in the ash. The proportion of sulfur retained in the ash typically increases from 10% in coal to 50% for pure biomass.

NOx emissions when cofiring biomass are more difficult to predict and may increase, decrease, or remain the same as compared to coal firing depending on the type of biomass, firing conditions and operating conditions. Some biomass fuels, such as woody fuels, have lower nitrogen contents, which result in lower NO_x emissions. Other fuels such as alfalfa stalks and rice hulls can contain higher nitrogen contents than typical coals. However, NO_x emissions are not determined purely by fuel nitrogen alone, but by the way the nitrogen is released.

[Ref. 5,6] estimated with a mixing ratio of around 16% to 20% biomass, CO_2 emissions can be reduced by approximately 20% and NO_x and SO_x emissions by about 10% compared to burning 100% coal.

Examples of current projects

[Ref. 19]: British Tibury power stations B began converting to burn 100% biomass from May 2011 with direct co-firing technology, the conversion would allow 750 MW of electricity to be generated from burning wood pellets imported from a pelleting plant in Georgia, USA, and other sources from Europe by the winter of 2011. This conversion made the station the biggest biomass generating site in the world.

[Ref. 20]: Ninh Binh Thermal Power Plant has been in operation since 1974 and consists of four medium-voltage generating with a total design capacity of 100 MW (4 x 25 MW). The plant has conducted 2 trials of biomass co-firing with main purpose to reduce SO_x emissions in 2020. The first time in October 2020, the plant purchased 30 tons of biomass in pellet form produced from forest by-products and mixed with coal at the depot at the rates of 15% and 20% are supplied to the coal crushing system and burned in the boiler. The second time in November 2020, the plant co-fired about 50 tons of biomass with coal through 3-level wind nozzles into the boiler with the rates: 18%, 28% and 43%. The results showed that SO_2 emission concentration decreased significantly from 408.4 mg/Nm3 at 0% biomass to 382.52 mg/Nm3 at 18%, 296.06 mg/Nm3 at 28% and 145.67 mg/Nm3 at 43%.

Cost

The investment cost of co-firing biomass in coal power plant largely depends on the plant capacity and service (i.e. power generation only or combined heat and power), as well as the type of the biomass fuel to be used, and the quality of the existing boiler.

At 20% of biomass co-firing on energy basis, PC boiler need to install new biomass storage and transport systems, retrofit burner and modified coal mill, or a new dedicated mill come with a retrofit cost of about 10% base CAPEX (corresponding to 0.15 MUSD/MW). While in CFB boiler, only biomass storage and transport systems are needed with low retrofit cost of about 3% Capex (corresponding to 0.05 MUSD/MW) [Ref. 1,11,12].

In pulverized coal plants 100% biomass firing will need larger biomass storage and transport systems. A larger dedicated mill and new burner is needed. There is a need for and modifying the reheater and superheater for larger spacing, using more corrosion resistant high alloy materials, increasing soot blowing and lowering the final temperature to reduce risk of the ash depositions and excessive slag. This comes with the higher retrofit cost of about 25% base CAPEX (corresponding to 0.37 MUSD/MW). With CFB boiler, the retrofit includes larger biomass storage and transport systems, larger fan and other related facilities. This comes with investment cost of about 15% of CAPEX (corresponding to 0.23 MUSD/MW) [Ref. 1,11,12].

O&M cost: Since there are modifications of some components when co-firing biomass (fuel delivery and storage, mill or burner), the O&M cost will tend to slightly increase, from 3 – 5% depend on co-firing rate of biomass.

Data sheet

Technology	Pulverized coal – co-firing 20% biomass (wood pellets)								
	2020	2030	2050	Uncertainty 2030		Uncertainty 2050		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	600	600	600	300	1000	300	1000		
Electricity efficiency. net (%). name plate	-1	-1	-1	0	-2	0	-2	A, B	1,12,13
Electricity efficiency. net (%). annual average	-1	-1	-1	0	-2	0	-2	A, B	1,12,13
Forced outage (%)	+0	+0	+0	+0	+1	+0	+1	A	1,12,13
Planned outage (weeks per year)	+0	+0	+0	+0	+0	+0	+0	A	1,12,13
Technical lifetime (years)									
Construction time (years)									
Space requirement (1000m^2/MW)	+0	+0	+0	+0	+0	+0	+0	A, C	1,12,13
Regulation ability									
Ramping (% per minute)	+0	+0	+0	+0	+0	+0	+0	A	1,12,13
Minimum load (% of full load)	+0	+0	+0	+0	+0	+0	+0	A	1,12,13
Warm start-up time (hours)	+0	+0	+0	+0	+0	+0	+0	A	1,12,13
Cold start-up time (hours)	+0	+0	+0	+0	+0	+0	+0	A	1,12,13
Environment									
PM2.5 (% compared to 100% coal)	-10%	-10%	-10%	-5%	-20%	-5%	-20%	A	1,6,12,13
SO_2 (% compared to 100% coal)	-10%	-10%	-10%	-5%	-20%	-5%	-20%	A	1,6,12,13
NO_X (% compared to 100% coal)	-5%	-5%	-5%	-0%	-10%	-0%	-10%	A	1,6,12,13
Financial data (in 2019$)									
Nominal investment (M$/MWe)	0.15	0.15	0.15	0.05	0.3	0.05	0.3	A,D	1,12,13
- of which equipment	-	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	+3%	+3%	+3%	+1%	+5%	+1%	+5%	A	1,12,13
Variable O&M (% compared to 100% coal)	+3%	+3%	+3%	+1%	+5%	+1%	+5%	A	1,12,13

Notes:

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

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

C Some additional under roof space (or silos) will be required for storage of pellets compared to coal (estimated 50%-100% extra m3 storage). But not more floor space (m^2).

D The nominal investment excludes investment for a general lifetime extension campaign.

Technology	Pulverized coal – co-firing 100% biomass (wood pellets)							
	2030	2050	Uncertainty 2030		Uncertainty 2050		Note	Ref
Energy/technical data			Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	600	600	300	1000	300	1000		
Electricity efficiency. net (%). name plate	-2	-2	-1	-3	-1	-3	A, B	1,12,13
Electricity efficiency. net (%). annual average	-2	-2	-1	-3	-1	-3	A, B	1,12,13
Forced outage (%)	+0	+0	+0	+1	+0	+1	A	1,12,13
Planned outage (weeks per year)	+0	+0	+0	+0	+0	+0	A	1,12,13
Technical lifetime (years)								
Construction time (years)								
Space requirement (1000m^2/MW)	+0	+0	+0	+0	+0	+0	A, C	1,12,13
Regulation ability								
Ramping (% per minute)	+0	+0	+0	+0	+0	+0	A	1,12,13
Minimum load (% of full load)	+0	+0	+0	+0	+0	+0	A	1,12,13
Warm start-up time (hours)	+0	+0	+0	+0	+0	+0	A	1,12,13
Cold start-up time (hours)	+0	+0	+0	+0	+0	+0	A	1,12,13
Environment								
PM2.5 (% compared to 100% coal)	-70%	-70%	-50%	-90%	-50%	-90%	A	1,6,12,13
SO_2 (% compared to 100% coal)	-70%	-70%	-50%	-90%	-50%	-90%	A	1,6,12,13
NO_X (% compared to 100% coal)	-30%	-30%	-5%	-40%	-5%	-40%	A	1,6,12,13
Financial data (in 2019$)								
Nominal investment (M$/MWe)	0.37	0.37	0.3	0.8	0.3	0.8	A, D	1,12,13
- of which equipment	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	+5%	+5%	+3%	+10%	+3%	+10%	A	1,12,13
Variable O&M (% compared to 100% coal)	+5%	+5%	+3%	+10%	+3%	+10%	A	1,12,13

Notes:

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

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

C Some additional under roof space (or silos) will be required for storage of pellets compared to coal (estimated 50%-100% extra m^3 storage). But not more floor space (m^2).

D The nominal investment assumes excludes investment for a general lifetime extension campaign.

Technology	CFB coal – co-firing 20% biomass (wood pellets, wood chips)								
	2020	2030	2050	Uncertainty 2030		Uncertainty 2050		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	300	300	300	150	600	150	600		
Electricity efficiency. net (%). name plate	0	0	0	0	-1	0	-1	A, B	1,12,13
Electricity efficiency. net (%). annual average	0	0	0	0	-1	0	-1	A, B	1,12,13
Forced outage (%)	+0	+0	+0	+0	+1	+0	+1	A	1,12,13
Planned outage (weeks per year)	+0	+0	+0	+0	+0	+0	+0	A	1,12,13
Technical lifetime (years)									
Construction time (years)									
Space requirement (1000m^2/MW)	+0	+0	+0	+0	+0	+0	+0	A, C	1,12,13
Regulation ability									
Ramping (% per minute)	+0	+0	+0	+0	+0	+0	+0	A	1,12,13
Minimum load (% of full load)	+0	+0	+0	+0	+0	+0	+0	A	1,12,13
Warm start-up time (hours)	+0	+0	+0	+0	+0	+0	+0	A	1,12,13
Cold start-up time (hours)	+0	+0	+0	+0	+0	+0	+0	A	1,12,13
Environment									
PM2.5 (% compared to 100% coal)	-10%	-10%	-10%	-5%	-20%	-5%	-20%	A	1,6,12,13
SO_2 (% compared to 100% coal)	-10%	-10%	-10%	-5%	-20%	-5%	-20%	A	1,6,12,13
NO_X (% compared to 100% coal)	-5%	-5%	-5%	0%	-10%	0%	-10%	A	1,6,12,13
Financial data (in 2019$)									
Nominal investment (M$/MWe)	0.05	0.05	0.05	0	0.2	0	0.2	A, D	1,12,13
- of which equipment	-	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	+3%	+3%	+3%	+1%	+5%	+1%	+5%	A	1,12,13
Variable O&M (% compared to 100% coal)	+3%	+3%	+3%	+1%	+5%	+1%	+5%	A	1,12,13

Notes:

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

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

C Some additional under roof space (or silos) will be required for storage of pellets compared to coal (estimated 50%-100% extra m^3 storage). But not more floor space (m^2).

D The nominal investment excludes investment for a general lifetime extension campaign.

Technology	CFB coal – co-firing 100% biomass (wood pellets, wood chips)							
	2030	2050	Uncertainty 2030		Uncertainty 2050		Note	Ref
Energy/technical data			Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	300	300	150	600	150	600		
Electricity efficiency. net (%). name plate	-1	-1	-1	-2	-1	-2	A, B	1,12,13
Electricity efficiency. net (%). annual average	-1	-1	-1	-2	-1	-2	A, B	1,12,13
Forced outage (%)	+0	+0	+0	+1	+0	+1	A	1,12,13
Planned outage (weeks per year)	+0	+0	+0	+0	+0	+0	A	1,12,13
Technical lifetime (years)								
Construction time (years)								
Space requirement (1000m^2/MW)	+0	+0	+0	+0	+0	+0	A, C	1,12,13
Regulation ability								
Ramping (% per minute)	+0	+0	+0	+0	+0	+0	A	1,12,13
Minimum load (% of full load)	+0	+0	+0	+0	+0	+0	A	1,12,13
Warm start-up time (hours)	+0	+0	+0	+0	+0	+0	A	1,12,13
Cold start-up time (hours)	+0	+0	+0	+0	+0	+0	A	1,12,13
Environment								
PM2.5 (% compared to 100% coal)	-70%	-70%	-50%	-90%	-50%	-90%	A	1,6,12,13
SO_2 (% compared to 100% coal)	-70%	-70%	-50%	-90%	-50%	-90%	A	1,6,12,13
NO_X (% compared to 100% coal)	-30%	-30%	-5%	-40%	-5%	-40%	A	1,6,12,13
Financial data (in 2019$)								
Nominal investment (M$/MWe)	0.23	0.23	0.15	0.5	0.15	0.5	A, D	1,12,13
- of which equipment	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	+5%	+5%	+3%	+10%	+3%	+10%	A	1,12,13
Variable O&M (% compared to 100% coal)	+5%	+5%	+3%	+10%	+3%	+10%	A	1,12,13

Notes:

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

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

C Some additional under roof space (or silos) will be required for storage of pellets compared to coal (estimated 50%-100% extra m^3 storage). But not more floor space (m^2).

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

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2. CIRCULATING FLUIDIZED BED (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.

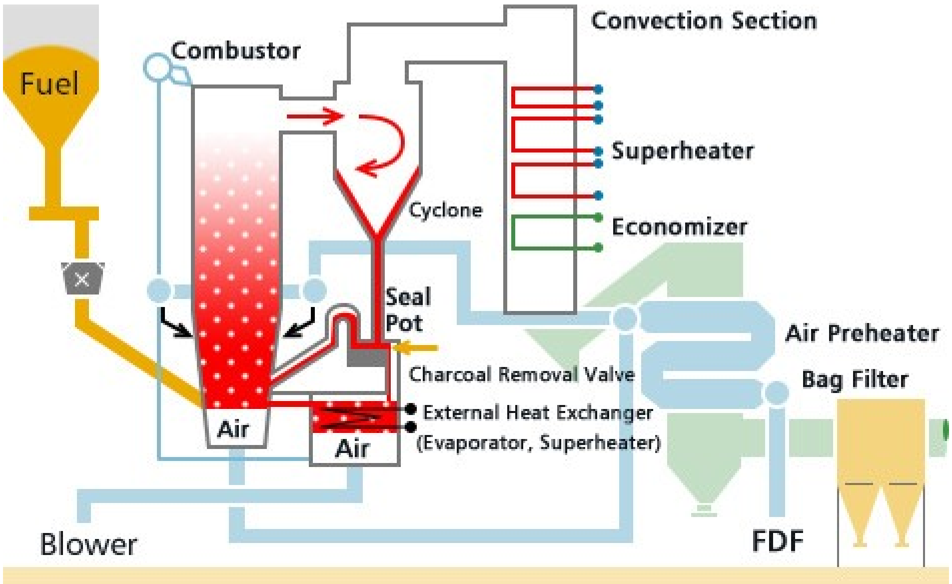

Figure 144: CFB boiler scheme (Ref. 2)

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 and disadvantages

Advantages

- CFB allows a wide range of fuels, including low-grade fuels and the option of co-firing.
- 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 Viet Nam 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 Viet Nam:

Thang Long power station
This is a 600 MW coal power plant in northern Viet Nam, 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/cm^2 (~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 Viet Nam:

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 12 for local cases.

Table 12. Data for selected CFB power plants in Viet Nam. 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 (MWe)	220	540	60	30	300
Generating capacity for total power plant (MWe)	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 PM2.5 (mg/Nm3)	118	102	-	-	-
SO_2 (mg/Nm3)	472	78	-	-	-
NO_X (g per GJ fuel)	315	8,3	-	-	-
Nominal investment (M$/MWe)	1,49	1,34	1,78	1,33	1,43
Fixed O&M ($/MWe/year)	45.700	39.200	45.300	-	-
Variable O&M ($/MWh)	1,34	0,97	1,12	-	-
Start-up costs ($/MWe/start-up)	240	299	309	262	-

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Data sheets

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

References:

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

2 IEA Clean Coal Centre, "The role of Circulating Fluidized Bed (CFB) Technology in Future Coal Power Generation", 2017.

3 IEA Clean Coal Centre, "Techno-economic analysis of PC versus CFB combustion technology", 2013.

4 Malgorzata Wiatros-Motyka, “The Lagisza Power Plant: The world’s First Supercritical CFB”, 2017.

5 Prabir Basu, “Circulating Fluidized Bed Boilers. Design Operation and Maintenance”, 2015.

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

7 Learning curve approach for the development of financial parameters.

8 Fuel Processing technology, “Gas emissions from a large scale circulating fluidized bed boilers burning lignite and biomass”, 2013.

9 IEA, Projected Costs of Generating Electricity, 2015.

10 IEA, World Energy Outlook, 2015.

11 Research Fund for Coal & Steel, “Utility scale CFB for competitive coal power”, 2008.

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

Notes:

A Assumed gradual improvement to international standard in 2050.

B Assumed no improvement for regulatory capability from 2030 to 2050

C Calculated from a max of 750 mg/Nm3 to g/GJ (conversion factor 0.35 from World Bank, Pollution Prevention and Abatement Handbook, 1998, https://doi.org/10.1596/0-8213-3638-X)

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 15 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 mixture of compressed air and gas (stream 3) is burnt and sent to the gas turbine (GT) where it is expanded. This makes the turbine shaft and hence the generator (G) rotate. The exhaust gas is released in stream 4.

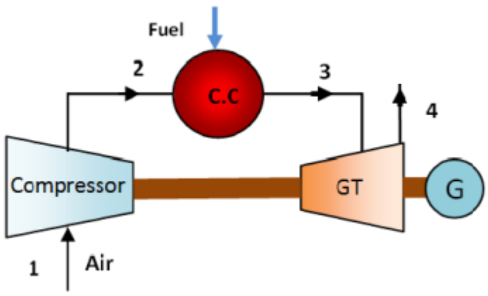

Figure 155: Process diagram of a Simple-Cycle Gas Turbine (SCGT) (ref. 1)

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 (GT), a steam turbine (ST), a gear (if needed), a generator (G), and a heat recovery steam generator (HRSG)/flue gas heat exchanger, see the diagram in Figure 16 below.

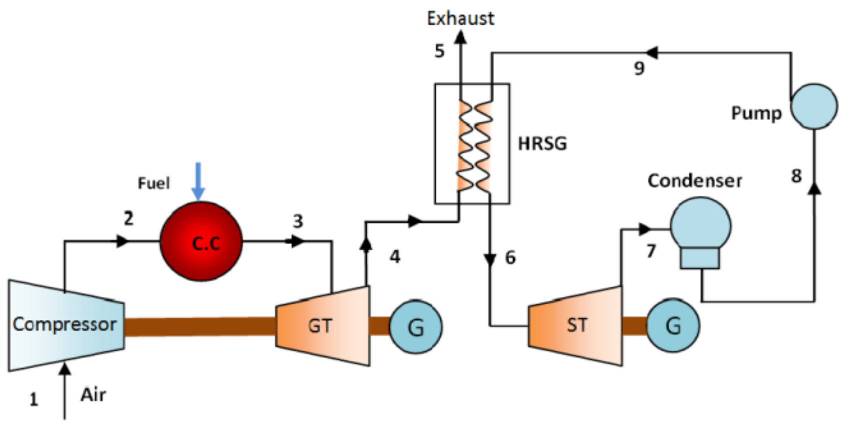

Figure 166: Process diagram of a CCGT (ref. 1)

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 slightly higher efficiency, the multi-shaft (separate) has a better availability parameter. Moreover, using a single-shaft generator reduces the need for individual components (generator, transformer). This results in a certain financial advantage over the multi-shaft generator. On the other hand, the multi-shaft generator has an advantage when it comes to operation and maintenance. The system can drive the two systems independently and use one generator when the other is maintained. It also gives more flexibility even in the construction phase and more layout option. (Ref. 6). The condenser is cooled by one-through river water, 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 52-62% whereas a single cycle gas turbine has an efficiency of 32-37%.

Input

Typical fuels are natural gas (including LNG) and light oil. Some gas turbines can be fueled with other fuels, such as LPG, biogas etc., and some gas turbines are available in dual-fuel versions (gas/oil).

Gas fired gas turbines need 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 – 600 MW range. Most CCGT units have an electric power rating of >15 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 if any.

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 gas 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 power production loss of several power plants (this can be compensated by using oil which is more expensive).

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 when the humidity is low.

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 Viet Nam 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 13. 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 Viet Nam 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 the World Bank's Pollution Prevention and Abatement Handbook, 1998.

Table 13: 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)			Viet Nam TC (2021)
	(Ref 5)	Number of plants	Central	Lower	Upper	
Generating capacity for one unit (MWe)	650	6	600	200	800	750
Generating capacity for total power plant (MWe)	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 Nm3)	30,1	1	30	30	30	30
SO2 (degree of desulphuring, %)	0[9]	1	-	-	-	-
NOX (g per GJ fuel)	57	1	86	20	86	57
Nominal investment (M$/MWe)	0,80	4	0,78	0,68	0,83	0,80
Fixed O&M ($/MWe/year)	30.500	4	24.100	18.100	30.100	30.500
Variable O&M ($/MWh)	0,47	6	0,14	0,10	0,17	0,47
Start-up costs ($/MWe/start-up)	73	4	83	62	104	73

In Table 14 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 Viet Nam. 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.

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[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 14: 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
Viet Nam 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 ($) 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, "Technology Catalogue on Power and Heat Generation", 2015.
4. Learning curve approach for the development of financial parameters.
5. Energy and Environmental Economics, "Capital Cost Review of Power Generation Technologies - Recommendations for WECC's 10- and 20-Year Studies", 2014.
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 of Indonesia, Regulation 21/2008.
8. Vuorinen, A., "Planning of Optimal Power Systems", 2008.
9. Soares, "Gas Turbines: A Handbook of Air, Land and Sea Applications", 2008.

Notes:

A. Assumed gradual improvement to international standard in 2050.
B. Uncertainty (Upper/Lower) is estimated as +/- 25%.
C. Assumed no improvement for regulatory capability.
D. Calculated from a max of 400 mg/Nm3 to g/GJ (conversion factor 0.27 from World Bank, Pollution Prevention and Abatement Handbook, 1998, https://doi.org/10.1596/0-8213-3638-X)
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								
$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	750	750	750	200	1050	200	1050		1
Generating capacity for total power plant (MWe)	1,500	1,500	1,500	200	1,600	200	1,600		1
Electricity efficiency. net (%). name plate	56	60	61	45	62	55	65		1,3,5,10
Electricity efficiency. net (%). annual average	52	59	60	39	61	54	64		
Forced outage (%)	5	5	5	3	10	3	10		1
Planned outage (weeks per year)	5	5	5	3	8	3	8		1
Technical lifetime (years)	25	25	25	20	30	20	30		1
Construction time (years)	2.5	2.5	2.5	2	3	2	3		1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non-thermal plants									
Capacity factor (%). theoretical	-	-	-	-	-	-	-		
Capacity factor (%). incl, outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	7	20	20	10	30	10	30	C	1,2
Minimum load (% of full load)	56	30	15	30	50	10	40	A	5
Warm start-up time (hours)	2	1	1	1	3	0.5	2	A	1,5
Cold start-up time (hours)	3	2	2	2	5	2	5		1,5
Environment									
PM 2,5 (mg per Nm^3)	30	30	30						
SO_2 (degree of desulphuring. %)	-	-	-	-	-	-	-	E	
NO_X (g per GJ fuel)	78	60	20	20	86	20	86	A,D	7,8
Financial data									
Nominal investment (M$/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 Danish Energy Agency, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity", 2017.

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3 IEA, World Energy Outlook, 2015.

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

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 of Indonesia, Regulation 21/2008.

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

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

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 World Bank, Pollution Prevention and Abatement Handbook, 1998, https://doi.org/10.1596/0-8213-3638-X)
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.

Hydrogen co-firing in Gas Turbines

Brief technology description

Hydrogen can be used as a fuel to partially replace (co-firing) or totally replace natural gas in gas turbines. Fundamentally, the challenges of using hydrogen-containing fuels for power generation with standard turbine technologies result from the differences in combustion characteristics of H_2 compared to CH_4. For example, the flame temperature (or reaction temperature) of H_2 is about 5-10% higher, potentially leading to higher thermal NOx production—and creating challenges related to degradation of materials and coatings. Due to the substantially lower volumetric energy density (i.e. lower heating value) of hydrogen compared to methane, fuel supply lines and other system components may need resized to account for the increased volume of fuel needed to maintain the same power output.

Another marked difference, and one of the most technically challenging, is the faster flame speed of hydrogen. For example, in a dry low NOx combustion system - DLN (today's state-of-the-art, high efficiency gas turbines use DLN combustors designed for burning NG with extremely low NOx and CO emissions), flow velocity would need to be nine times higher to prevent the flame from flashing back—the unintentional propagation of the flame upstream into the premixing combustion hardware. At about 95% H_2, the upper (flashback-driven) limit of a turbine's operating range experiences a relatively large decrease. This narrows the stable operating range, presenting one of the biggest challenges to designing high hydrogen capable pre-mixed DLN systems.

On the other hand, the LBO limit—the lower limit of a turbine's operating range—gradually decreases with increasing H_2 content, and CO production is not a concern. These properties potentially enable improved turndown capabilities (the ability to run at lower-than-rated power output) relative to current natural gas fired gas turbines. This potentially improved turndown capability is a flexibility advantage that can support a more integrated energy network. (ref. 4).

Table 15: Potential impacts and potential technical solutions of hydrogen co-firing in gas turbines.

Property	Properties of H_2 (relative to NG)	Potential impact	Potential technical solutions
Carbon monoxide production	100% reduction	CO production removed as a limitation to operating paratmers	N/A
Energy density	Vol: < 1/3 Mass: ~2,5 higher	More fuel by volume for same heat released	Increased flow velocity
Flame speed	9x higher	Increased flashback risk	Increased flow velocity New fuel injection designs (e.g., fuel staging/micromixers)
Flame temperature	~5-10% increase	Increased thermal NO_x production Increased materials/coating degradation	Larger selective catalytic reduction bed to compensate; fuel staging/new combustion designs New materials/coatings
Lean blowout (LBO) limits	~50% increase in LBO margin	Increased turndown capability	N/A
Lower flammability limit	20% lower	Safety – more flammable in event of leak More challenges to detection	New leak detection methods/gas sensors
Molecular size	8x lighter	Increased tendency to leak	More welded connections, new seals/tighter connections

Due to some specific characteristics of hydrogen gas such as flammability, easy leakage, etc., equipment maintenance and repair requirements are strict and need to be performed more continuously than using natural gas. For example, in addition to periodic equipment maintenance and repair services such as a conventional gas turbine plant, it is necessary to regularly check the fire alarm sensor system, check the welds in the pipelines and equipment, etc.

Combustion systems with diffusion flames and nitrogen or steam dilution can handle up to 100% vol. hydrogen. Nevertheless, these systems have several disadvantages, including reduced efficiency compared to systems without dilution, higher NOx level compared to lean-premixed technology, higher plant complexity and thereby higher capital and operational costs. Today's state-of-the-art, high efficiency gas turbines use premixed dry low NOx (DLN) combustors designed for burning NG with extremely low NOx and CO emissions.

To combat flashback concerns, these advanced designs incorporate new burner aerodynamics and fuel staging strategies. New burner designs that increase the axial velocity of premixed fuel/air stream into the combustion zone can help mitigate flashback concerns associated with hydrogen's high flame speed. One approach involves variations on micromixers—referred to as multi-tube mixers by GE (Figure below) and multi-cluster combustors by Mitsubishi Hitachi Power Systems (MHPS)—that rely on axial flow alone for flame stabilization, whereas conventional DLN designs employ a swirling flow component.

Figure 17: GE/DOE micromixer (ref. 4)

Another approach to utilizing high-H_2 fuels is axial fuel staging (AFS). This strategy relies on distributed fuel and/or air injection, modifying the conventional DLN designs that introduce air/fuel only at the beginning of the combustion chamber by also injecting air/fuel at various downstream locations. The resulting combustion occurs in multiple "zones", allowing for lower local flame temperature (mitigating NOx production) and a lower initial equivalence ratio, which locally decreases the flame speed (mitigating flashback risk).

For example, Ansaldo Energia, in partnership with PSM, has developed an AFS-based retrofit combustion system for hydrogen fuels called FlameSheet™ that is compatible with DLN turbines from major manufacturers. Ansaldo has also integrated sequential combustion technology into design of its GT26 and GT36 turbines. GE has also incorporated a combustor with AFS, called DLN 2.6+, into its HA line of turbines 13 for increased turndown capabilities and lower emissions (Ref. 4).

Operating range	Turbine speed (%)	Low ← Gas turbine load (%)	→ High
Fuel	Oil	Syngas	
Mode	Oil mode	Partial mode	Final mode
Operating burners	Oil spray nozzle	F1 + F2-1 + F2-2 + F3-1	F1 + F2-1 + F2-2 + F3-1 + F3-2
			

Figure 18 Axial fuel staging

Fuel transportation: When using hydrogen as fuel, it is of utmost importance to take into consideration the delivery pressure and temperature in order to avoid embrittlement in the pipelines and other auxiliaries. Existing piping and gas turbine valves shall be subject to retrofit when a gas turbine manifold running with natural gas is forecasted to run with H_2. Changes may include new valves design with a different sealing arrangement, and potentially new piping material.

Another point to consider is the incorrect purge of H_2 within the system. Indeed, the more components involved, the higher the likelihood for some H_2 to remain trapped within them, leading to explosion risks when doing maintenance or repair. On that basis, proper measurement apparatus for H_2 traces should be considered as part of any H_2 use with GTs. In addition, purge systems using CO_2 or nitrogen must be taken into consideration.

While hydrogen embrittlement does not occur in stainless steel equipment at 50 barg and 100°C, increasing the temperature to around 200°C may cause H_2 migration through the material. Indeed, H_2 embrittlement is a concern at temperatures above 200°C, although 316L grade stainless steel is considered quite suitable in reducing this effect. It is worth noting that hydrogen embrittlement is not only related to temperature, but also to the stress endured by the material which affects the permeation of H_2.

As hydrogen is flammable and explosive over very wide ranges of concentrations in air at standard atmospheric temperature (4 - 75% vol. and 15 - 59% vol. respectively), its handling becomes a major safety concern in comparison to methane or gasoline for instance. Gas dispersion is a key point to reduce the risk. Knowing this gas is lighter than methane, it may create accumulation at height, which is not expected when running natural gas. Refineries use dedicated gas detection devices for H_2.
Every machine must be evaluated on a case-by-case basis for hydrogen consumption, considering fuel skid, controls, and combustion system. As a general guideline, there are constraints to consider, namely [Ref. 1]:

- Low levels of hydrogen mixed with natural gas, to a level that does not require any changes to materials, designs and control and protection. These levels may be in the range of [0-10% vol.], depending on the system.
- Medium levels of hydrogen mixed with natural gas, to a level that does not require significant changes to materials, designs, control, and protection. These levels may be in the range of [10-30% vol.]
- Higher levels of hydrogen, which require a wider retrofit scope, and which probably then economically suggest that hydrogen fuel capability should be maximized given the assumption of fuel delivery, combustion module, control and protection retrofit [30-100% vol.]. A retrofit package is likely to include:
    - Core gas turbine combustion module replacement
    - Instrumentation and fuel control system modification
    - Plant fuel delivery system modification, including modified purge, metering, gas composition monitoring, safety systems (including package sensing and ventilation upgrades) and the provision of a start-up fuel supply.
    - It is likely that the economics of such a retrofit assume re-use of existing hot gas path designs of components.

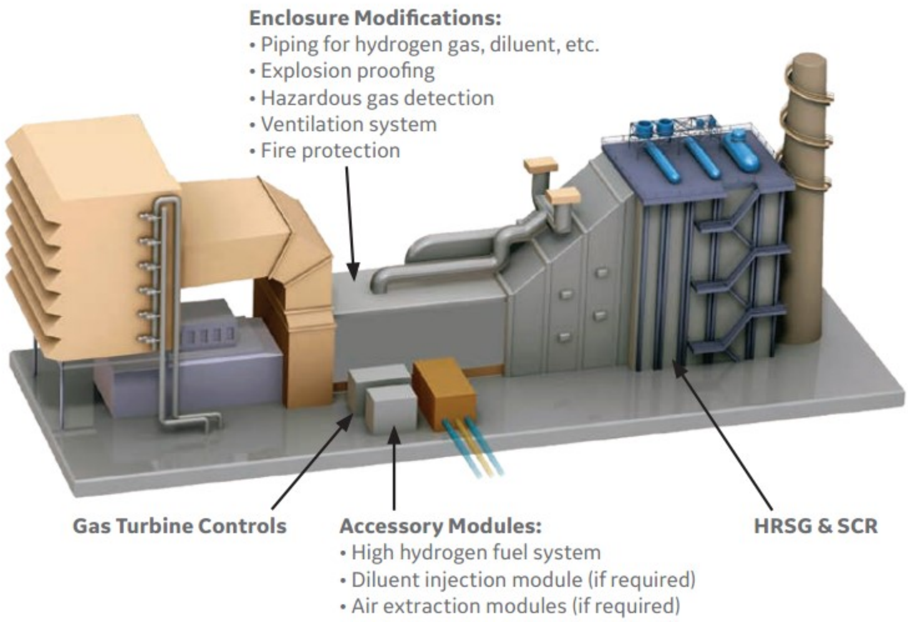

Figure 19: Example of a hydrogen gas turbine and its components

The corresponding volume and energy share for the different mixing ratios of hydrogen and natural gas is shown in the following table. In this report, the share of H_2 when co-firing in gas turbine plant is defined in terms of energy share. 20% share of energy of H_2 with natural gas is corresponding to approximate 45% share of volume of H_2.

Table 16: Corresponding volume and energy share for the different mixing ratios of hydrogen and natural gas [Ref. 2]

Volume share H_2 (%)	Energy share H_2 (%)
30	11
50	23
77	50
100	100

Impact on plant performance and flexibility

The research conducted so far suggests that gas turbine power output and performance should stay similar for natural gas-fired units subject to a combustion system replacement and high hydrogen firing rates [Ref. 1, 7].

The increased reactivity and higher flame speeds of hydrogen force new combustion and fuel injection designs to be adopted for high-rate hydrogen fueling. A likely problem will be the degree to which a plant capable of high hydrogen combustion rates will then be able to operate at high natural gas firing rates. It is probable that at some point during the natural-gas-to-hydrogen transition, compromises will have to be made on emissions, power output, or power output ramp rates. Due to the higher reactivity of hydrogen, the turndown is likely to be improved when operating at higher hydrogen concentrations as CO emissions will be reduced.

For grid support services that rely on high ramp rates (e.g. frequency response), it is likely that some short-term adaptation of the fueling mix and a more complex fuel delivery control system may be required. These solutions may differ between engine types so applicable regulations may need to reflect a range of engineering solutions.

Effect on emissions

Reduction in CO_2 emissions is the main advantage of hydrogen co-firing in a gas turbine power plant, the hydrogen should be produced by renewable energy (such as using wind/solar energy to electrolyze water), called green hydrogen. Fuel blends with higher H_2 content—typically expressed on a volumetric basis—result in lower CO_2 emissions per MWh, but the relationship is nonlinear as show in figure below, this relationship becomes linear when considering share of H_2 in term of energy.

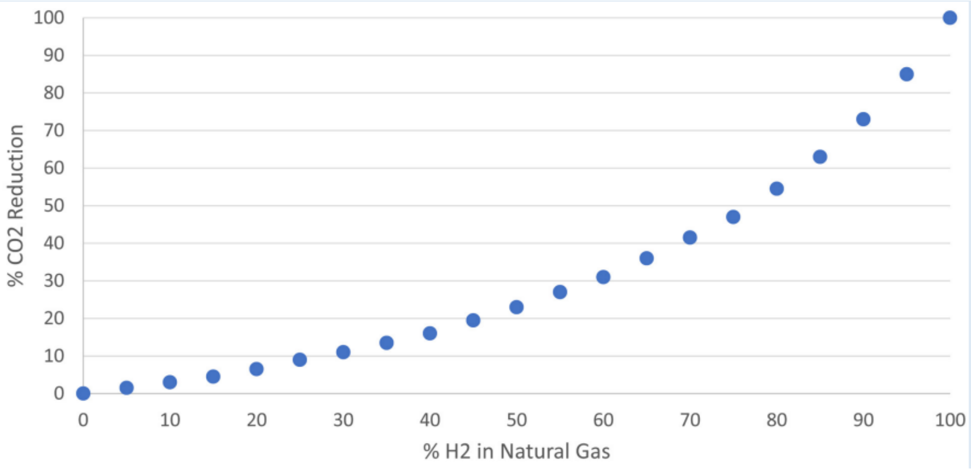

Figure 20. CO_2 Reduction for H2-NG blends by volume [Ref. 4]

Also, SO_2 emissions and particle matter decrease when co-firing ammonia as the amount of combustion natural gas decreases and hydrogen does not contain of sulfur and dust.

Since the flame temperature of H_2 is 5-10% higher than natural gas, co-firing H_2 in gas turbines will tend to release more NOx emission as show in below figure.

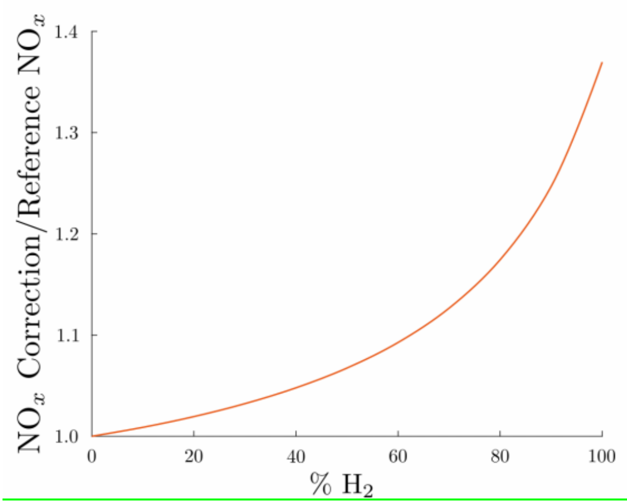

Figure 21. Increase of NO_x emission correspond to the H2 co-firing ratio according to [Ref. 9]

Georgia Tech's Institute of Strategic Energy [Reference 9] has conducted NOx emission assessments at gas turbine plants at 0-100% volume co-combustion rates, according to the results of this study when co-burning H_2 is at 20% of output (~45% by volume), NOx emissions increase by nearly 10% and when H_2 gas is completely burned, the amount is emitted NOx emissions increased to 40%. GE in its experimental studies [Reference 10] also showed that when co-combustion is 20% of production (~45% by volume), NOx emissions increase by about 30% with DLN technology. Thus, at 20% H_2 co-combustion, on average, NOx emissions increase to 20%, and at 100% co-combustion, NOx emissions increase to 40%.

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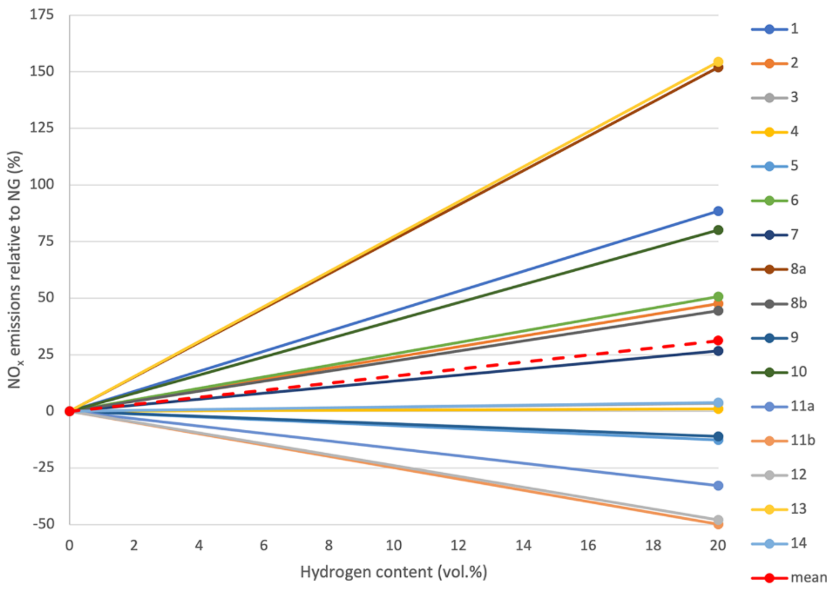

Figure 22. Increase of NO_x emission correspond to the H_2 co-firing ratio according to [Ref. 10]

Examples of current projects

Most major turbine engine manufacturers have made substantial progress in implementing hydrogen into their accepted fuel profiles. A summary of several commercial technologies produced by the original equipment manufacturers (OEMs) that allow gas turbines to achieve some level of commercially viable hydrogen combustion is shown in the following table. Notably, EU Turbines, an association of European turbine manufacturers that includes the three OEMs listed in the table as well as other major vendors, is committed to making gas turbines capable of operating with 100% H_2 commercially available by 2030.

Table 17: Hydrogen combustion technologies from the largest OEMs [4]

OEM	Type	Class	H_2 (%vol)
MHI	Diffusion	1200~1400	Up to 100%
	Pre-Mixed	1600	Up to 30%
	Multi-cluster	1650	Up to 100%
GE	DLE		Up to 5%
	SAC		30-85%
	SN	B, E class	90-100%
	MNQC	E, F class	90-100%
	DLN 1	B, E class	Up to 33%
	DLN 2.6+	F, H class	Up to 15%
	DLN2.6e	9HA class	Up to 50%
Siemens	DLE		2-15%
	WLE		15-100%
	DLE	E, F, H class	30%
	Diffusion	E, F, H class	Up to 100%
	DLE	E, F, H class	Up to 30%

By 2022, several new construction projects for gas turbine plants applying natural gas-hydrogen co-firing are being implemented such as: the plant in Hunter valley, Australia (capacity 2x330 MW, with mixed ratio of 15% hydrogen, expected to operate in 2023), Intermountain project, USA (replacing the 1800 MW coal-fired power plant with an 840 MW gas turbine plant, capable of mixing 30% hydrogen by 2025 and to 100% hydrogen by 2045). In addition, a 172 MW gas turbine renovation project with a 40% hydrogen mixing ratio at the Linden cogeneration power plant, USA is being implemented and is expected to come into operation in 2022 [5].

Cost

[Ref. 2] has proposed the capital cost increases as percentages of the costs for conventional gas turbines for different levels of hydrogen mixing capabilities, either for upgrading existing gas turbines or investing in new gas turbines based on discussions with industrial partners.

Hydrogen mix [vol-%]	Hydrogen mix [energy-%]	Hydrogen upgrade of existing gas turbines [% of base CAPEX]	New hydrogen gas turbines [% of base CAPEX]	Description of cost increase
30%	~11%	1	101	Fuel system
50%	~20%	7	103	Fuel system and burner tip
77%	~50%	10	105	Fuel system and burner
100%	100%	25	115	Combustion chamber

At the level of co-firing 20% hydrogen in term of energy (50% in terms of volume) the investment cost will increase about 7% regarding retrofit of fuel system and burner. Considering using CCGT power plants in Viet Nam (investment cost of 0.77 MUSD/MW – see Gas turbine/data sheet), the investment rate for co-firing 20% hydrogen would be 0.054 MUSD/MW. The investment cost for retrofit to firing 100% hydrogen will be estimated about 25% of base CAPEX, corresponding to 0.19 MUSD/MW.

O&M cost: since there are modifications of the fuel delivery system, metering, gas composition monitoring, safety system and burner when co-firing hydrogen, the O&M cost will tend to slightly increase, from 3 – 5% depend on co-firing rate of hydrogen.

Data sheets

The data for most data element is given as absolute difference compared to the original gas turbine that is retrofitted to co-fire hydrogen.

Technology	**CCGT – co-firing 20% hydrogen (in term of energy)**								
	2020	**2030**	**2050**	**Uncertainty 2030**		**Uncertainty 2050**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MW)	750	750	750	200	800	200	800		
Electricity efficiency. net (%-point). name plate	-0	-0	-0	0	-2	0	-2	A	1,7
Electricity efficiency. net (%-point). annual average	-0	-0	-0	0	-2	0	-2	A	1,7
Forced outage (%-point)	+0	+0	+0	+0	+1	+0	+1	A	
Planned outage (weeks per year)	+0	+0	+0	+0	+0	+0	+0	A	
Technical lifetime (years)									
Construction time (years)									
Space requirement (1000m^2/MW)									
Regulation ability									
Ramping (%-point per minute)	+0	+0	+0	+0	+0	+0	+0	A	1,4
Minimum load (%-point of full load)	-3	-3	-3	-1	-5	-1	-5	A	1,4
Warm start-up time (hours)	+0	+0	+0	+0	+0	+0	+0	A	1,4
Cold start-up time (hours)	+0	+0	+0	+0	+0	+0	+0	A	1,4
Environment									
PM2.5 (% compared to 100% natural gas)	-20%	-20%	-20%	-10%	-20%	-10%	-20%	A	4
SO_2 (% compared to 100% natural gas)	-20%	-20%	-20%	-10%	-20%	-10%	-20%	A	4
NO_X (% compared to 100% natural gas)	+20%	+20%	+20%	+10%	+60%	+10%	+60%	A	4,7,8,9,10
Financial data (in 2019$)									
Nominal investment (M$/MWe)	0.054	0.054	0.054	0.03	0.1	0.03	0.1	A,B	2
- of which equipment	-	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-	-		
Fixed O&M (% compared to 100% natural gas)	+3%	+3%	+3%	+1%	+5%	+1%	+5%	A	2
Variable O&M (% compared to 100% natural gas)	+3%	+3%	+3%	+1%	+5%	+1%	+5%	A	2

Notes:

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

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

Technology	CCGT – firing 100% hydrogen (in term of energy)							
	2030	2050	Uncertainty 2030		Uncertainty 2050		Note	Ref
Energy/technical data			Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	750	750	200	800	200	800		
Electricity efficiency. net (%-point). name plate	-0	-0	-0	-3	-0	-3	A	1,7
Electricity efficiency. net (%-point). annual average	-0	-0	-0	-3	-0	-3	A	1,7
Forced outage (%-point)	+0	+0	+0	+1	+0	+1	A	
Planned outage (weeks per year)	+0	+0	+0	+0	+0	+0	A	
Technical lifetime (years)								
Construction time (years)								
Space requirement (1000 m^2/MW)								
Regulation ability								
Ramping (%-point per minute)	+0	+0	+0	+0	+0	+0	A	1,4
Minimum load (%-point of full load)	-5	-5	-3	-10	-3	-10	A	1,4
Warm start-up time (hours)	+0	+0	+0	+0	+0	+0	A	1,4
Cold start-up time (hours)	+0	+0	+0	+0	+0	+0	A	1,4
Environment								
PM2.5 (% compared to 100% natural gas)	-100%	-100%	-100%	-100%	-100%	-100%	A	4
SO_2 (% compared to 100% natural gas)	-100%	-100%	-100%	-100%	-100%	-100%	A	4
NO_X (% compared to 100% natural gas)	+40%	+40%	+20%	+100%	+20%	+100%	A	4,7,8,9,10
Financial data (in 2019$)								
Nominal investment (M$/MWe)	0.19	0.19	0.1	0.3	0.1	0.3	A,B	2
- of which equipment	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-		
Fixed O&M (% compared to 100% natural gas)	+5%	+5%	+3%	+10%	+3%	+10%	A	2
Variable O&M (% compared to 100% natural gas)	+5%	+5%	+3%	+10%	+3%	+10%	A	2

Notes:

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

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

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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

Captured CO_2 can be injected for storage in deep geological formations (such as depleted oil and gas fields), deep coal seams that cannot be mined, and saline formations, both onshore and offshore. The former consists in injecting CO_2 as a dense phase supercritical fluid in declining oil, gas reserves so that pressure favors oil displacement and extra oil is extracted (Enhanced Oil Recovery – EOR) (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). Oil and gas fields are the leading storage options because of their ability to help offset storage cost with increased production of oil and gas. In addition, unlike saline aquifers and coal seams, oil and gas also have existing infrastructure that can be used toward CO_2 transportation. Additionally, the coal seams storage option has permeability concerns that might lead to risks of leakage.

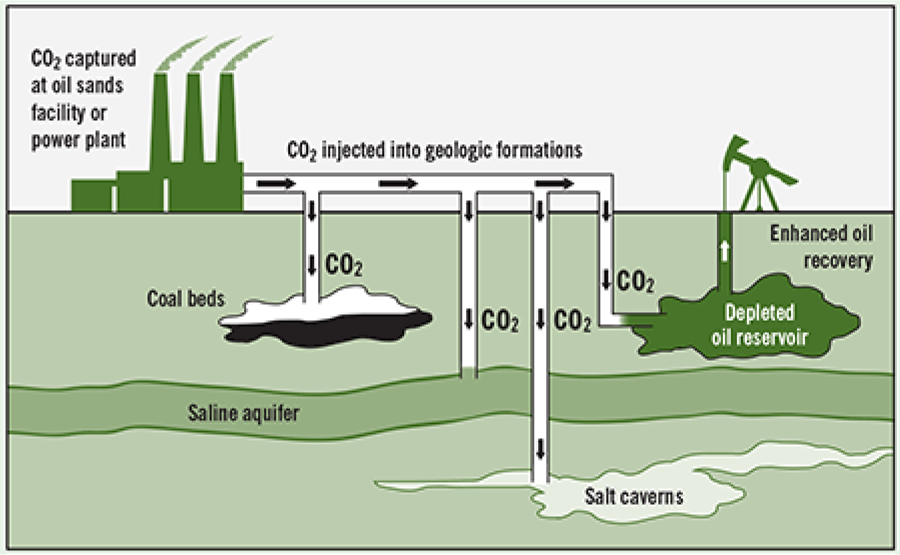

Figure 23. Post-capture treatment of CO_2. Source: Energywatch.

Viet Nam is one of the few countries in Southeast Asia that has promising CO_2 storage potential. A study of ADB (Ref. 20) identified 12 gigatons of theoretical CO_2 storage capacity in Viet Nam, which storage capacity was estimated for all saline aquifers, oil and gas fields and enhanced coal bed methane (ECBM) recovery, though much of this is concentrated in saline aquifers. The theoretical cumulative storage capacity of Viet Nam's saline aquifers exceeds 10 Gt of CO_2. It represents the storage capacity of the geological plays in six of the eight of Viet Nam's sedimentary basins: Song Hong, Phu Khanh, Cuu Long, Nam Con Son, Malay–Tho Chu, and Tu Chinh–Vung May. Song Hong and Phu Khanh offer the largest storage capacity at approximately 2.5 Gt of CO_2. The total theoretical CO_2 storage capacity of the coal in the eight blocks of the Ha Noi Trough was estimated at 458 Mt. This value represents the cumulative coal from 300 to 1,500 meters. A total of 34 oil and gas fields are in production or will be in the near future in the offshore Viet Nam area. These fields represent a key CO_2 storage potential. If only storage capacities of fields greater than 10 Mt CO_2 are considered, the effective storage capacity of the oil and gas fields in four of the eight Vietnamese sedimentary basins (Cuu Long, Malay–Tho Chu, Nam Con Son, Song Hong) is 1.15 Gt CO_2, with the largest field exceeding 300 Mt CO_2 capacity. This storage will be available when the fields are depleted or when CO_2-enhanced oil recovery (EOR) occurs.

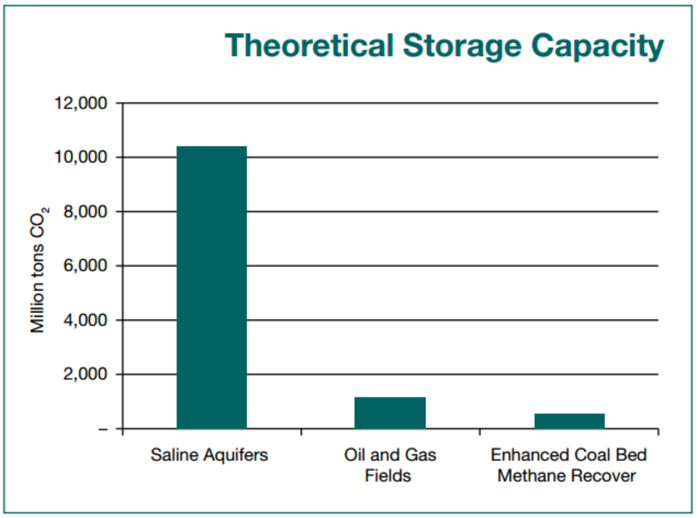

Figure 24. Theoretical CO_2 storage capacity in Viet Nam. Source: [Ref. 6, 20]

The study also ranked the prospective gas and oil fields based on storage suitability. The ranking methodology used a two-stage approach of qualifying and preferential criteria, as illustrated in the table below.

Table 18: qualifying and preferential criteria used as methodology for the study of (Ref. 20)

Qualifying criteria	
Capacity	Capacity > 10 Mt CO_2, with expections for satellite fields
Injection rate	Injection rate > 100 t of CO_2/day/well
Injectivity and capacity	Reservoir > 3 m thick
Confinement	Seal thickness > 7 m with no active faults
Preferential critieria	
Capacity	CO_2 storage
Injectivity	CO_2 storage per day per well Number of existing production/injection wells
Confinement: Depth	Seal thickness Number of abandoned wells Contamination of other resources
Economics	Cost recovery (enhanced oil recovery or other offset) Existing infrastructure Monitoring opportunity Availability (depletion rate) Willingness of operator

The Top 14 Oil and Gas Fields Offer 900 Megatons of CO_2 Storage Capacity. Fields CL01 and CL16 had the highest scores. Field CL16 offers the single largest storage capacity with over three times the capacity (357 Mt) of any other field.

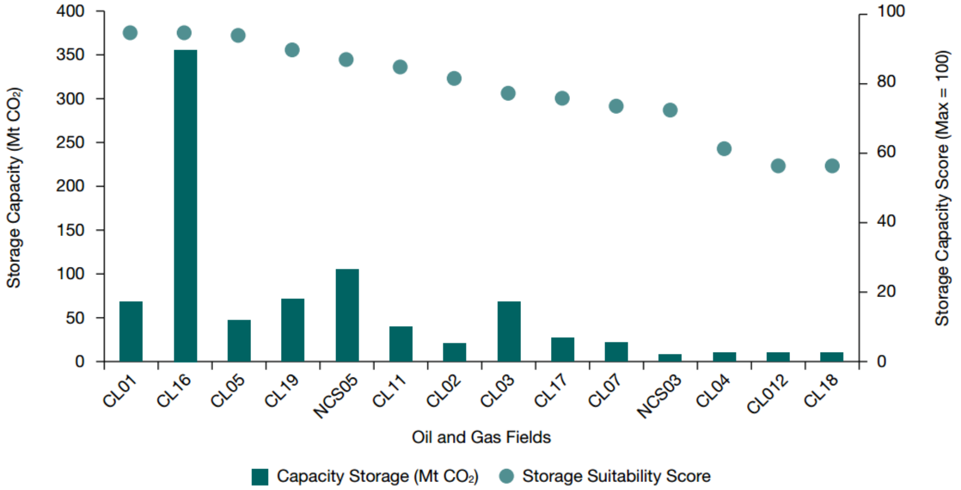

Figure 25. Oil and gas fields ranked by CO_2 storage suitability (Ref. 20).

Ranking of CO_2 storage capacity of oil and gas fields in details is shown in the table below.

Table 19. Detailed oil and gas fields ranked by CO_2 storage suitability (Ref. 20).

N.	Offshore fields	Year of first oil/gas	Year when CO_2-EOR may apply	N. of production wells	Storage capacity (Mt CO_2)	Score %	Ranking
1	CL01	2003	2006	23	69,17	94	1
2	CL02	2008	2016	4	23,10	81	6
3	CL03	2011			67,05	77	7
4	CL04	2013			11,55	61	11
5	CL05	1998	2007	43	48,09	93	2
6	CL07	1998	2005	24	23,52	73	9
7	CL11	2008	2013	3	42,14	84	5
8	CL12	N/A			10,85	56	12
9	CL16	1986	1988	200	357,06	94	1
10	CL17	1994	1995	35	29,12	75	8
11	CL18	2009		0	10,92	56	12
12	ML01	2003		33	51,74	-	N/A
13	ML03	2003		36	10,64	-	N/A
14	ML05	2008		32	48,70	-	N/A
15	NCS03	1994	1996	7	10,01	72	10
16	NCS04	2012			46,57	-	N/A
17	NCS05	2002	2011	5	107,33	87	4
18	NCS06	2012		0	28	-	N/A
19	CL19	2006	2010	7	74,47	89	3
20	NCS07	2013			55,37	-	N/A
21	NCS08	2013			31,24	-	N/A

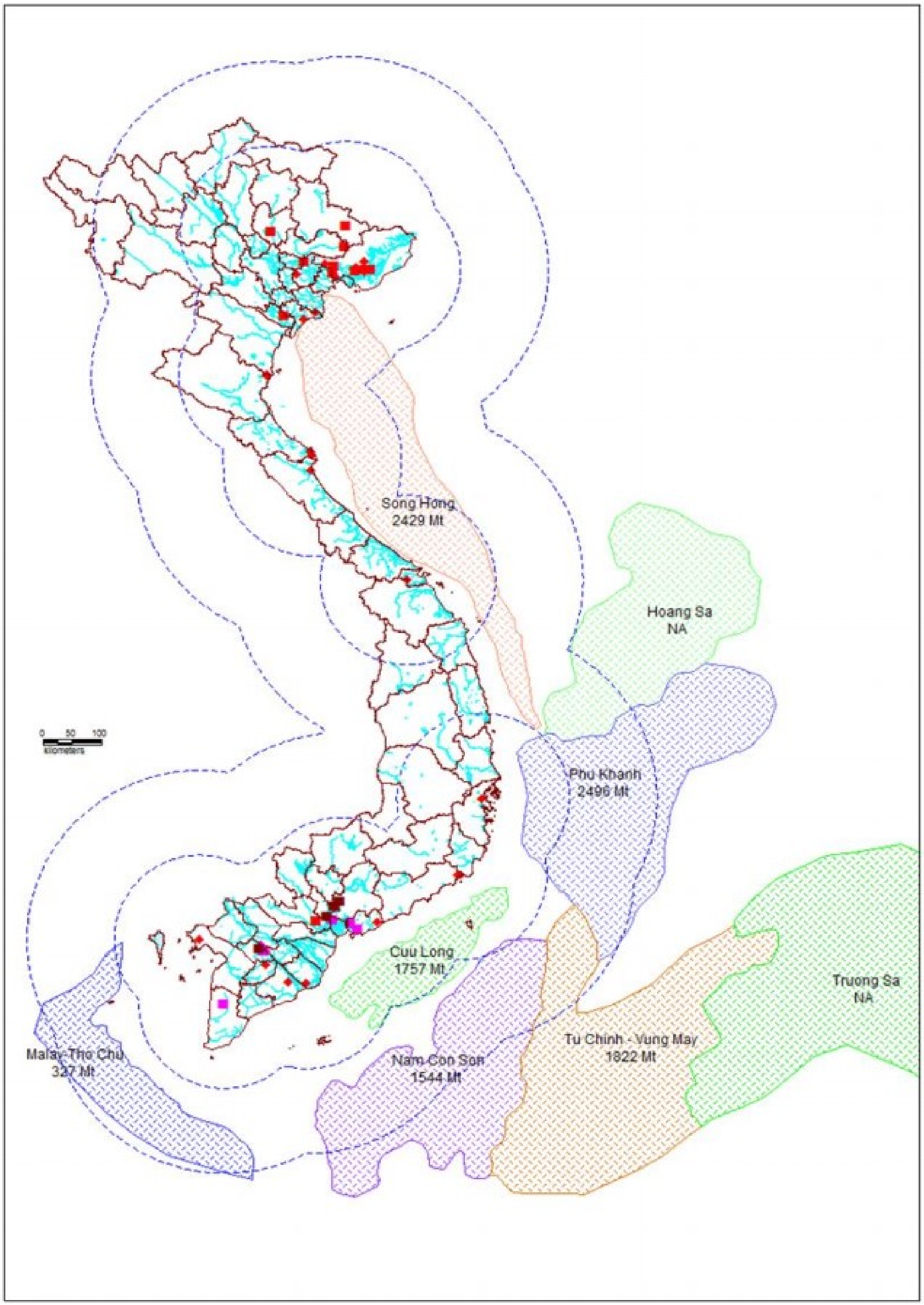

Figure 26: CO_2 storage potential in saline aquifers (150km and 300km circle around emission sources). The Paracel and Spratly Islands of Viet Nam are not shown in the map (Ref. 6, 20)

Measurement, monitoring, and verification (MMV)

Measurement, Monitoring, and Verification (MMV) is a process to accurately measure and track the injection and storage of carbon dioxide (CO_2) in a storage site. It involves continuous monitoring of the CO_2 plume at different depths in the geologic column: at the surface, the biosphere beneath the surface, the geosphere beneath the biosphere, and in the storage reservoir. The monitoring techniques at each of these depths are selected based on the parameters being monitored and the required frequency and timing of the monitoring measurements.

MMV is crucial in ensuring the secure storage of CO_2, providing confidence to the public and regulators, and earning CO_2 credits. It helps to identify and quantify the position of the CO_2 plume and detect any potential leakage, assess the movement of CO_2 over time, and evaluate short- and long-term risks associated with the storage.

In addition, a robust data management system is necessary to store, analyze, and ensure the long-term availability of the MMV data. This enables continuous evaluation of the performance of the storage site and identification of any issues that may arise.

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/disadvantages

Advantages

- **Post-combustion capture**. It can be applied to most of the existing coal-fired or thermal power plants.
- **Pre-combustion capture**. Syngas is concentrated in CO_2 and at high partial pressure, which extends the range of technologies available for separation and allows 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. NO_x 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 Viet Nam. 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.

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.

More studies are necessary concerning CCS potential in Viet Nam, 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 Viet Nam. Only two projects have been implemented:

Bach Ho project
Being the first commercial CCS project in Asia, the project has high demonstration value. The project is the result of cooperation between Mitsubishi Heavy Industry, Marubeni and Vietsovpetro. The project aims to capture CO_2 from a combined cycle natural gas power plant and pump it into the Bach Ho field to enhance oil recovery. CO_2 is transported through 144 km of undersea pipelines and stored at a depth of 4 km. The amount of carbon captured 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 million tonnes CO_2/year 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 Viet Nam on CCS are limited. [Ref 20,21] shows that a 546 MW-net Super Critical Coal power plant with CCS capturing approximately 4 Mt of CO_2 per year, with incremental capital costs for CCS of **$2,902/kW** and incremental annual operating costs of $117 million (for all part of capture, compression, transport and storage). For natural gas combined cycle plant with CCS, for a capacity of 482 MW-net, capturing approximately 1.4 Mt of CO_2 per year, there will be incremental capital costs for CCS of **$1,493/kW** and incremental annual operating costs of $20 million.

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.

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Data sheets

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)	2.90	2.66	2.11	1.66	3.26	1.22	2.61	F	2,5,9,10 11,12
- 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 ($/MWe/year)	+43,500	+42,100	+40,900	+13,500	+52,000	+13,500	+52,000	F	1,7,9
Variable O&M ($/MWh)	+3.22	+3.13	+3.03	+2.60	+8.52	+2.44	+8.02	F	1,5,9

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12 MOIT, ADB, GCCSI, Determining the potential for carbon capture and storage in Southeast Asia, Viet Nam Country Report, 2012.

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$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	-40	-40	-40					A	1
Generating capacity for total power plant (MWe)	-40	-40	-40					A	1
Electricity efficiency, net (%), name plate	-7	-7	-7						1
Electricity efficiency, net (%), annual average	-8	-8	-8						1
Forced outage (%)	+5	+5	+5						
Planned outage (weeks per year)									
Technical lifetime (years)	-								
Construction time (years)									
CO_2 emission reduction (%)	-87	-90	-90			-90	-99	B	1
Space requirement (1000 m^2/MWe)									
Ramping configurations									
Ramping (% per minute)	20	20	20					C	6
Minimum load (% of full load)	45	45	45					D	6
Warm start-up time (hours)	2.0	2.0	2.0					E	4
Cold start-up time (hours)	4.0	4.0	4.0					E	4
Environment									
PM 2.5 (mg per Nm^3)	30	30	30						3,6
SO_2 (degree of desulphuring, %)	99	99	99						3,6
NO_X (g per GJ fuel)	78	60	20						3,6
CH_4 (g per GJ fuel)	-	-	-						
N_2O (g per GJ fuel)	-	-	-						
Financial data									
Nominal investment (M$/MWe)	1.49	1.26	0.97	0.88	2.68	0.62	2.03	F	1,7,8,9,10
- 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., Carbon Dioxide Capture and Air Quality, 2011.
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10 MOIT, ADB, GCCSI, Determining the potential for carbon capture and storage in Southeast Asia, Viet Nam Country Report, 2012

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.

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

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 Viet Nam

Industry in Viet Nam 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 (2014 data, here and in the remainder of the paragraph). 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 Viet Nam 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.

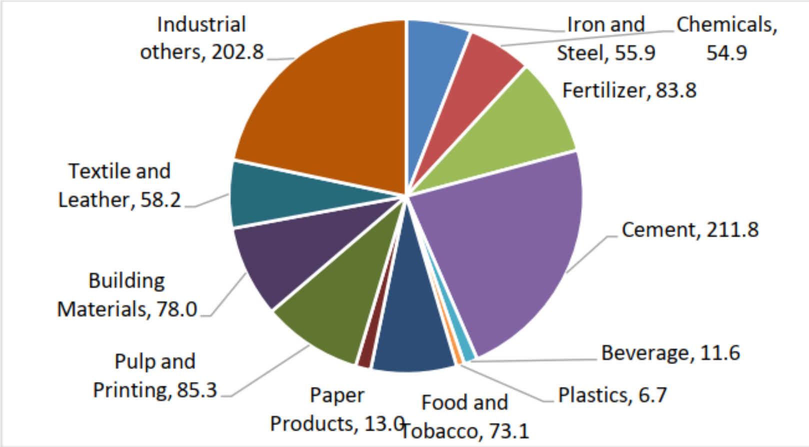

Figure 27: Breakdown of energy consumption in PJ by industry sector in Viet Nam 2014 (Institute of Energy, 2019)

As can be seen from the Figure 27 above, Viet Nam 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 Viet Nam, 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 Viet Nam, and even with improvements in technology that has been applied to the production of cement in later years [Ref. 11], 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. Viet Nam 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 Viet Nam 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.

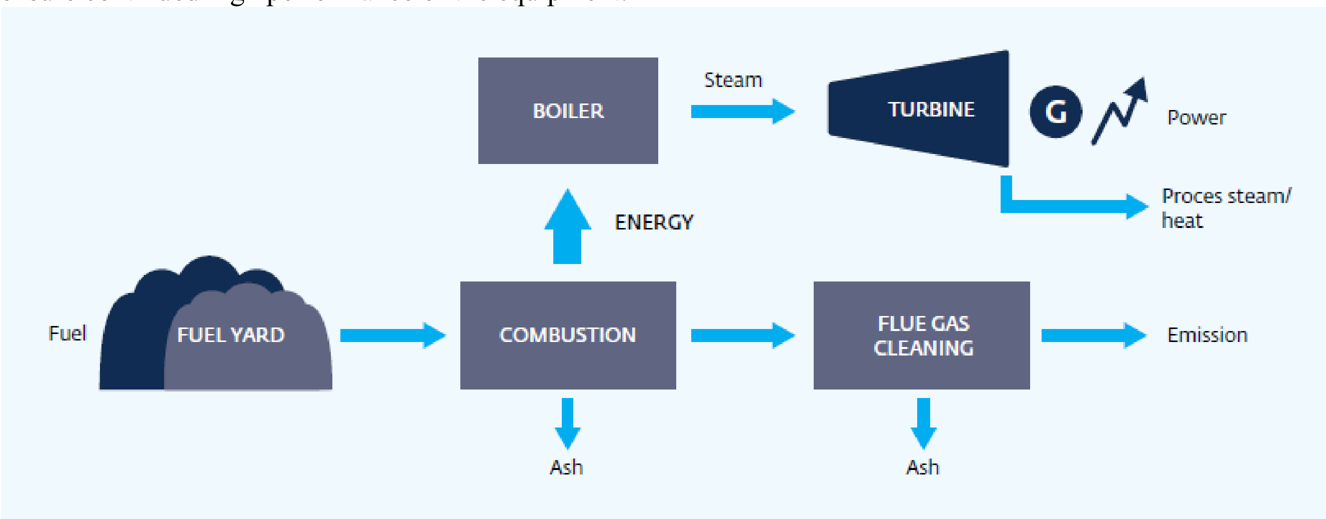

Figure 28: A schematic of a biomass fired co-generation plant (International Finance Corporation, 2017).

The Figure 28 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 [Ref. 9].

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 29 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.

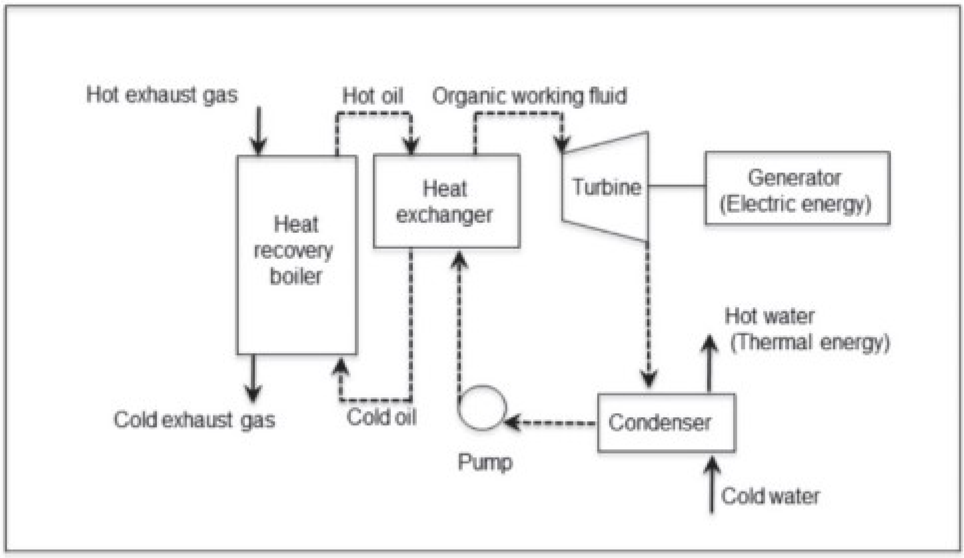

Figure 29: Schematic of cogeneration scheme in a Portland cement factory (Paredes-Sánchez, 2015).

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 20: 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 20 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^{0}C 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

Technology	Biomass-fired cogeneration (sugar mill)								
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)									

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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.

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, Energy balance and cogeneration for a cement plant. Appl. Therm. Eng., 2479-2489, 2006.

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

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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.

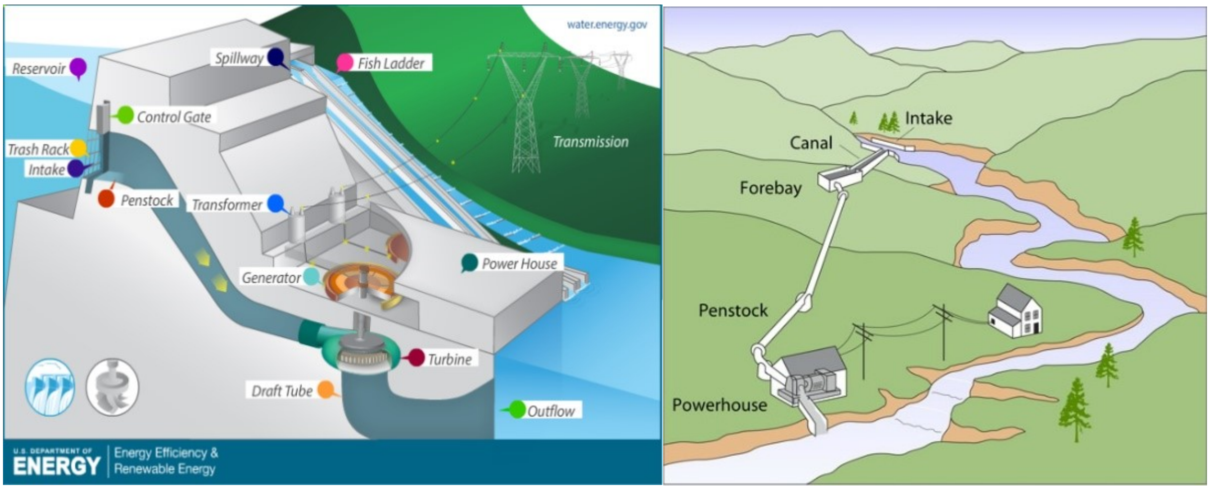

Figure 30: Reservoir and run-of-river hydropower plants (ref. 14)

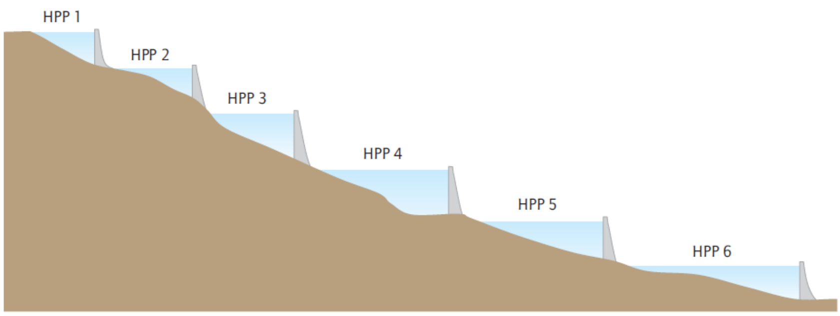

Figure 31: Cascading Systems (ref. 1)

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 21: Classification of hydropower 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.

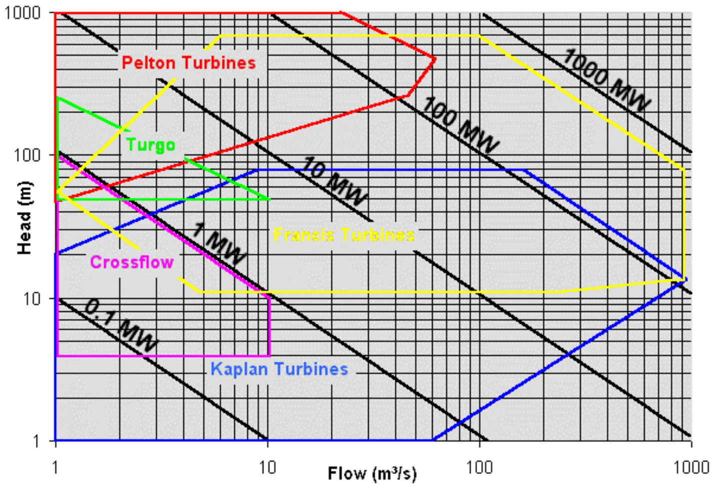

Figure 32: Hydropower turbine application chart (ref. 2)

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.

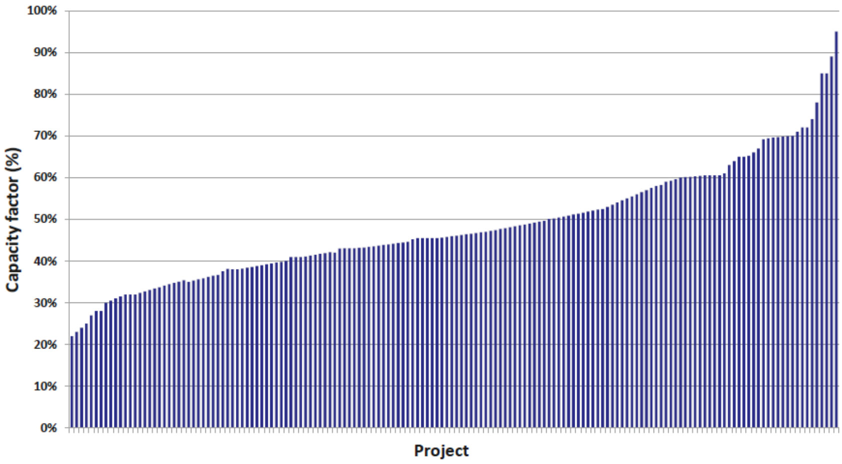

Figure 33: Capacity factors for 142 hydropower projects around the world (ref. 4)

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. Moreover, hydropower can prevent river sediments from flowing downstream, reducing the amount of sediment that can have beneficial effects on agricultural crops.

- 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).

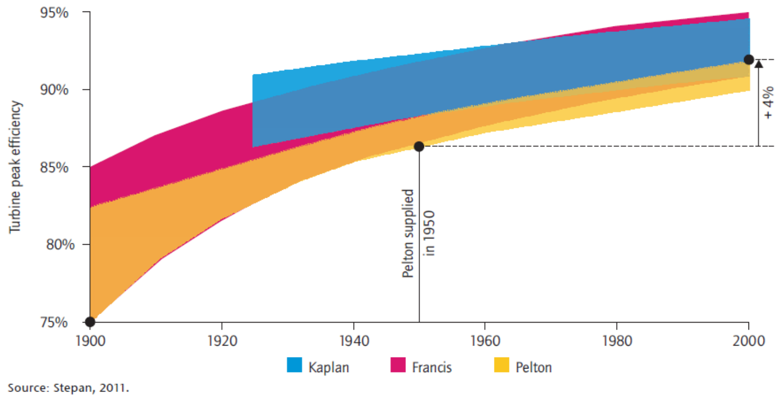

Figure 34: Improvement of hydraulic performance over time (ref. 7)

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 Viet Nam 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 Viet Nam of 15000 MW. More than 5,000 MW is installed today [Ref. 21].

Large hydropower plant (>30 MW): Lai Chau (ref 20)
Lai Chau is the first upper stream hydropower plant in Viet Nam 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 22: 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 23: 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 24: 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	40	40	40	30	50	30	50		8;9
Capacity factor (%), incl. outages	35	35	35	25	45	25	45		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$19/MWe)	1.3	1.3	1.3	0.8	4.0	0.8	4.0	C;D	4;5;6;7; 10
- of which equipment (%)	30	30	30	20	50	20	50		7
- of which installation (%)	70	70	70	50	80	50	80		7
Fixed O&M ($/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, Workshop on Rehabilitation of Hydropower, "The 3-Phase Approach", 2011.
2. Prayogo, "Teknologi Mikrohidro dalam Pemanfaatan Sumber Daya Air untuk Menunjang Pembangunan Pedesaan. Semiloka Produk-produk Penelitian Departement Kimpraswill Makassar", 2003.
3. Eurelectric, "Hydropower - Supporting a power system in transition", 2015.
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7. ASEAN, "Levelised cost of electricity of selected renewable technologies in the ASEAN member states", 2016.
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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	45	45	45	35	55	35	55		2;12
Capacity factor (%), incl. outages	40	40	40	30	50	30	50		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)	-	-	-	-	-	-	-		

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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 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.

Viet Nam had mechanism to encourage the development of solar power in Viet Nam: 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 Viet Nam 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).

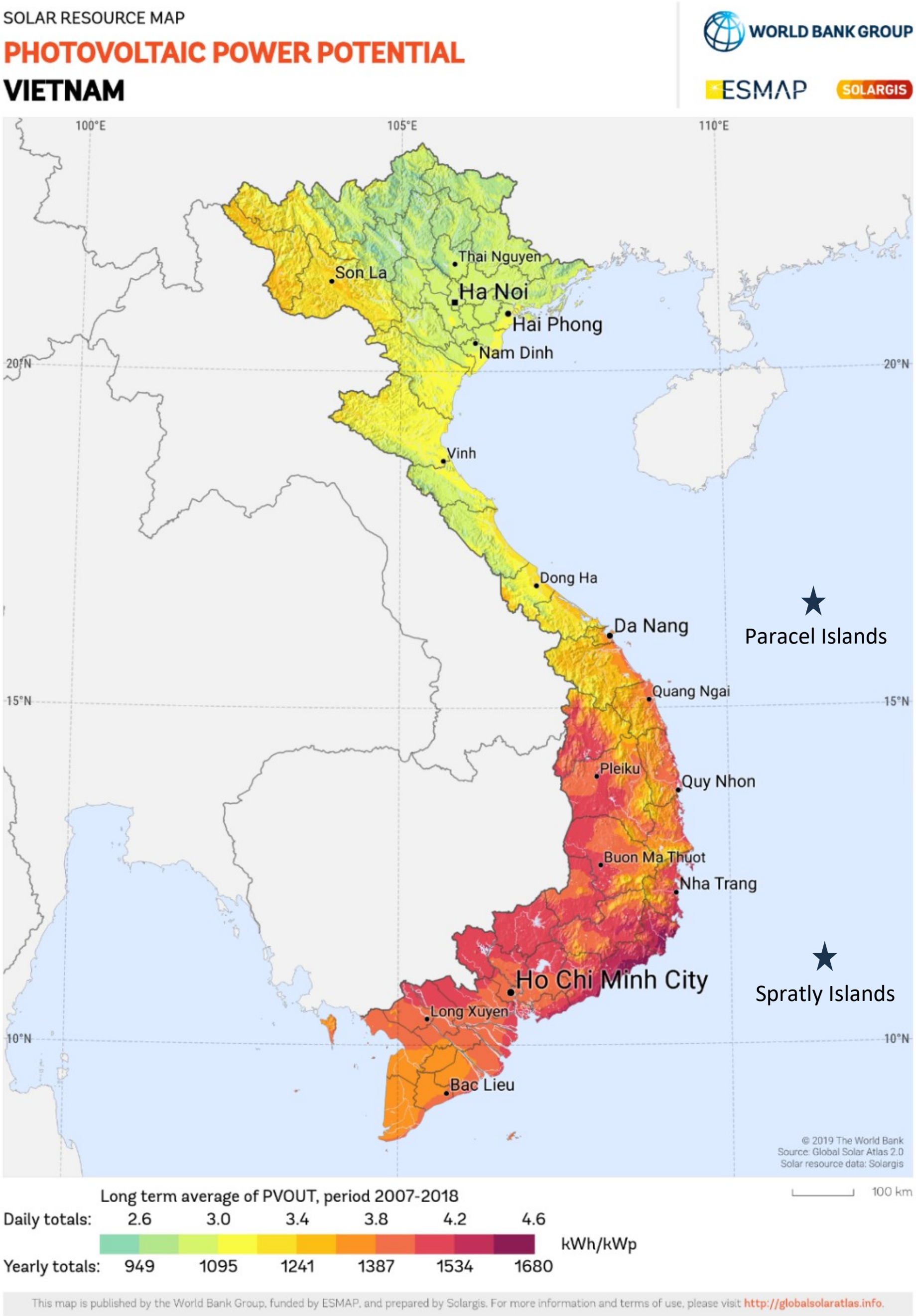

Figure 35: Full load hours (kWh/kWp) for PV in Viet Nam (Ref 7).

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

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 Viet Nam, 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 Viet Nam. 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.

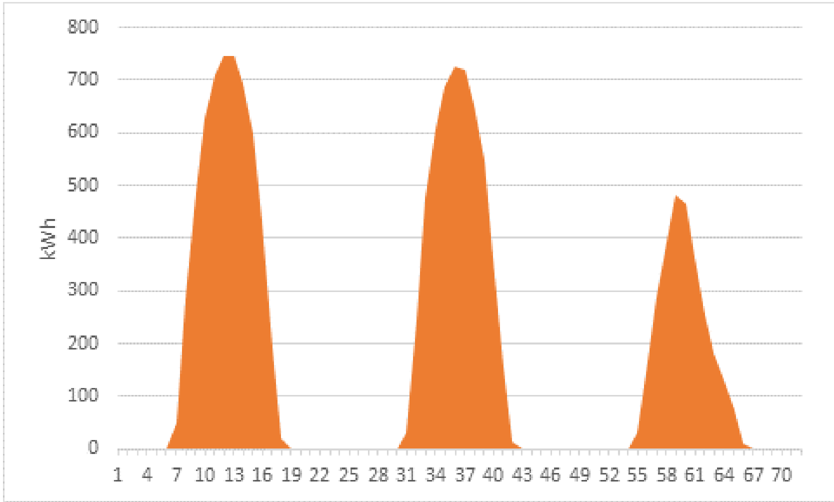

Figure 36: Generation for three days during summer season in Central Viet Nam. From: www.renewables.ninja

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.

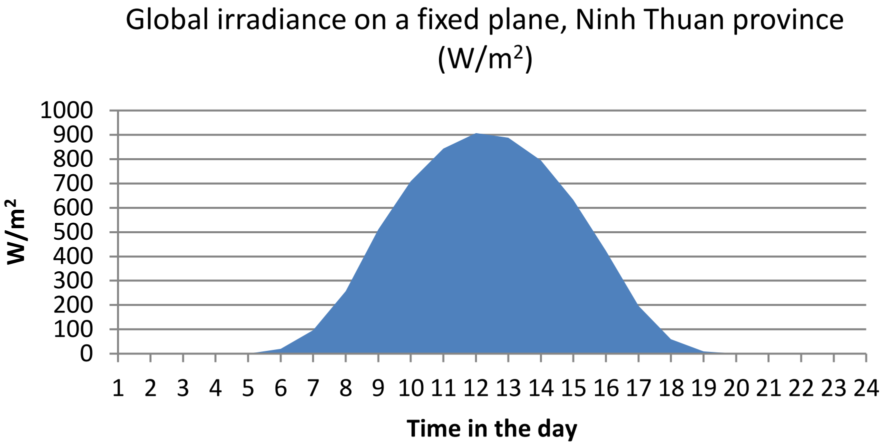

Figure 37: Global irradiance on a fixed plane (W/m^2) during the course of the day in the Ninh Thuan; average daily profile for September, the month with the best solar conditions. Source: Pvsyst Meteo data.

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.

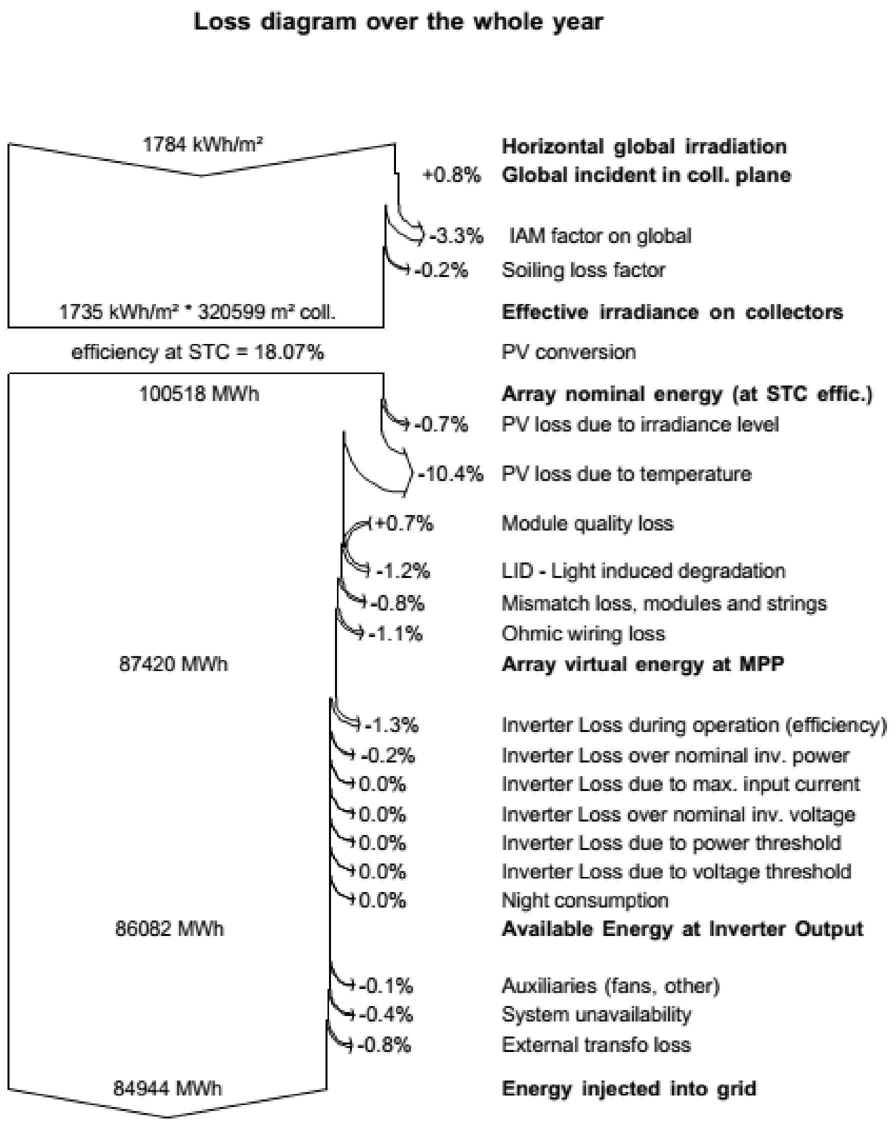

Figure 38: Yearly output calculation result of a 46 MW in Dak Lak province by PVsyst software version V6.67.

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 Viet Nam. 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 Viet Nam 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 Viet Nam.

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 Viet Nam (Ref. 19).

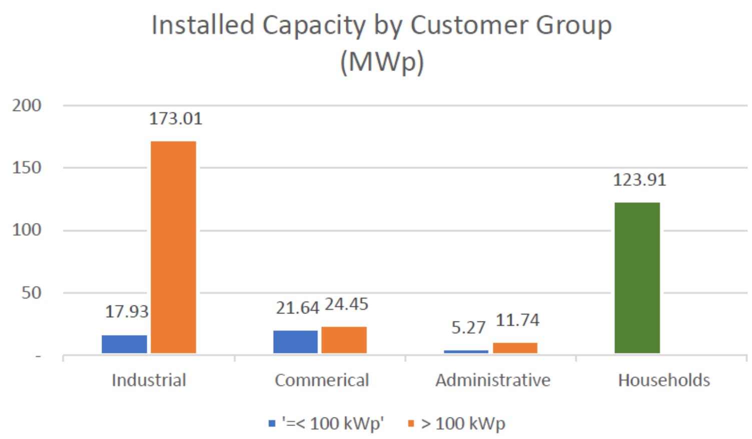

Figure 39: Rooftop solar installed capacity by customer group in Viet Nam (ref. 19)

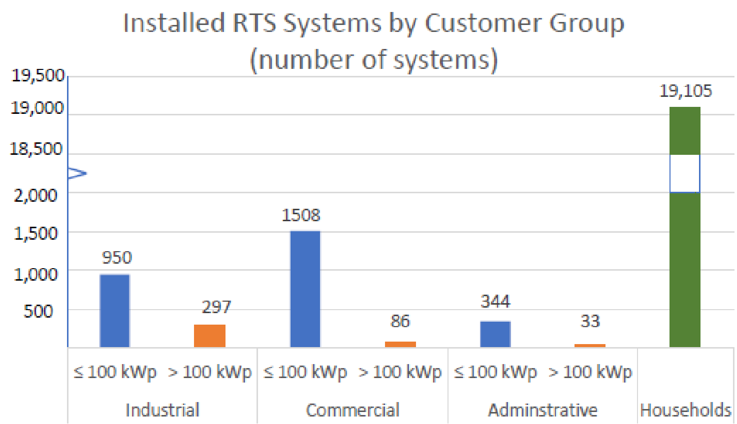

Figure 40: Rooftop solar number of projects by customer group in Viet Nam (ref. 19)

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.

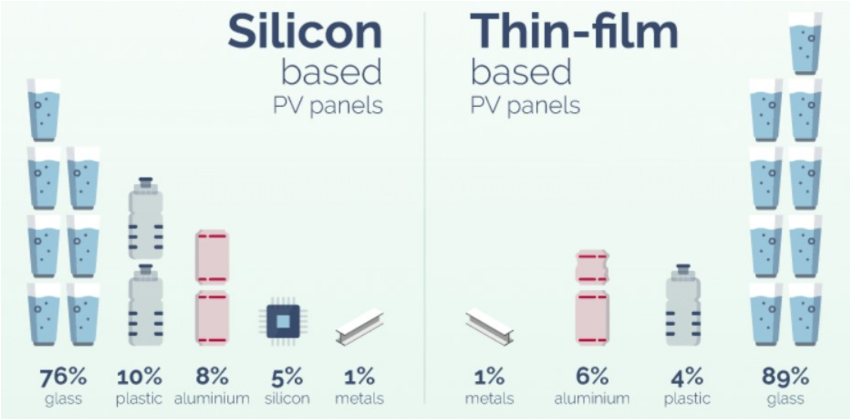

Figure 41: Main materials in a silicon based and thin film solar PV panel. (ref. 22)

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 42 below) (ref. 23). Additionally, improved panel quality would also lead to a reduction of failures and therefore creation of waste during the lifetime.

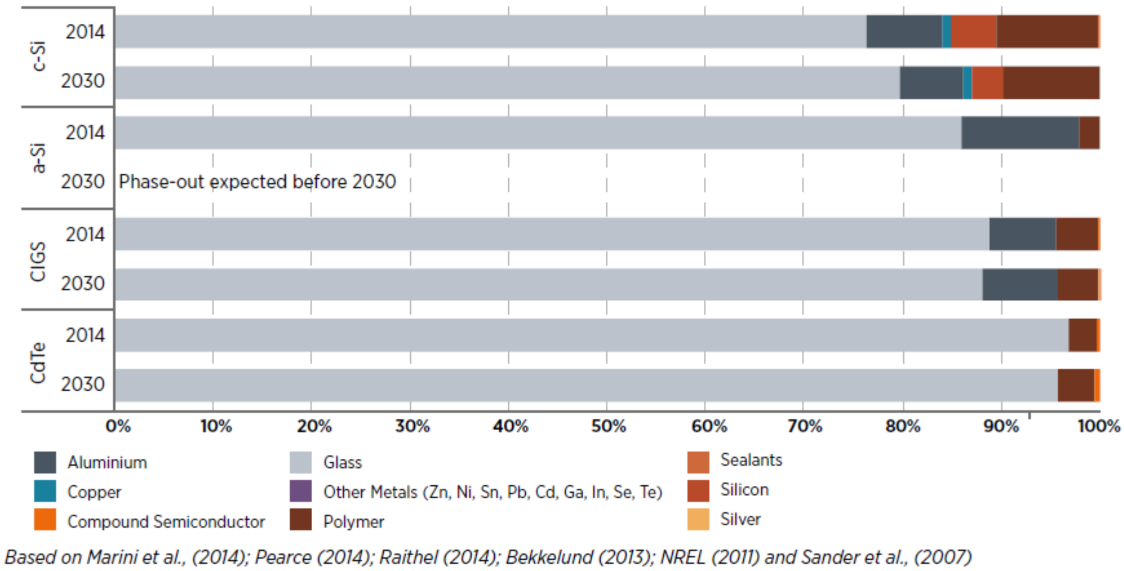

Figure 42: Evolution to 2030 of materials used for different PV panel technologies as a percentage of total panel mass (ref. 23)

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 43. 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/m^2 and much of this cost is from transporting (USD 3.3/m^2), while the actual recycling process (the cost of consumed materials, electricity or the investment for the recycling facilities) is very small (USD 0.3/m^2). Further, it was found that the external cost of PV end of life management is very similar to the private cost (USD 5.2/m^2). It estimated that the total economic value of the recycled materials from c-Si PV waste is USD 13.6/m^2. 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 m^2. (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.

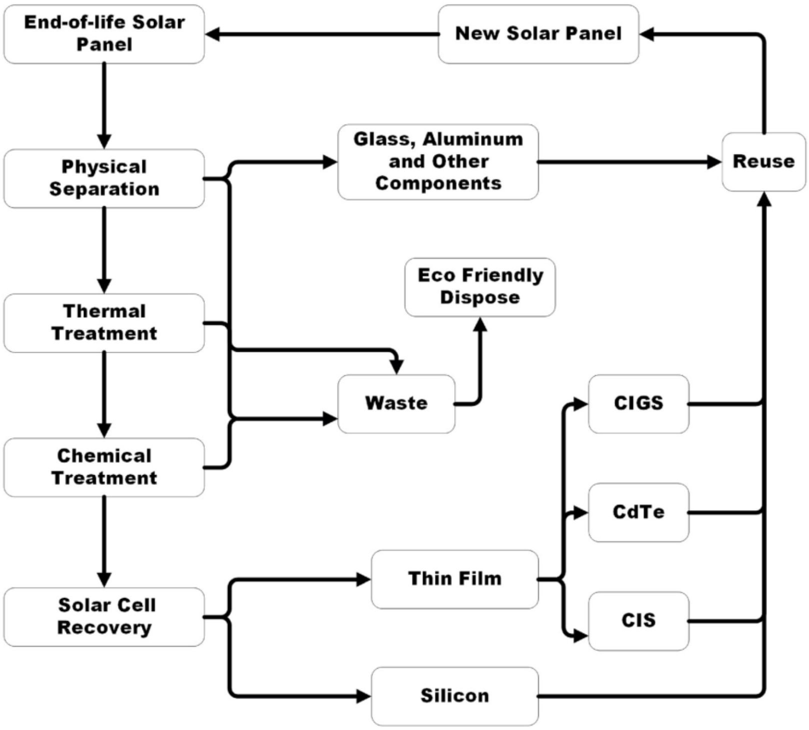

Figure 43: Different types of solar PV recycling processes. (ref. 24)

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. 15) 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 Viet Nam, 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 Viet Nam. Viet Nam 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 Viet Nam 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 Viet Nam 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 Viet Nam 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 Viet Nam 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 [MUSD2019/MW]		**2018-19**	**2020**	**2030**	**2050**
Catalogues	**This Technology Catalogue***		**0,81**	**0,57**	**0,42**
	Viet Nam Technology Catalogue (2021)		0,93	0,66	0,48
	Viet Nam Technology Catalogue (2019)		1,10	0,84	0,65
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%

** The data is based on references only from some solar power projects in Vietnam (Ref. 26)*

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 50 MW (61.8 MW_p) of installed capacity. The project 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.

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

The Gelex Ninh Thuan PV solar photovoltaic farm located in Thuan Nam district, Ninh Thuan province with installed capacity of 50 MW_p. The solar farm started construction in June 2018 and operated in June 2019. The fixed tilted plane technology is used with an angle of 11^0 and the azimuth is 180^0. The farm uses more than 150,000 multi-crystalline PV panel type 325 W_p, divided into 20 blocks, each block using 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.

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%.

Updated project: Rooftop PV

The rooftop PV solar system in District 9, Ho Chi Minh city with a capacity of 10.08 kWpwas installed 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.

Figure 44: 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 was installed 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 m^2 corresponding to 0.57 ha/MWe.

Figure 45: 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 was installed 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 m^2 corresponding to 0.68 ha/MWe.

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The description in this chapter is to a great extent from the Danish Technology Catalogue *"Technology Data on Energy Plants - Generation of Electricity and 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$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity, a typical power plant (MWe)	50	50	50					C	1
Electricity efficiency, net (%), name plate	-	-	-					A	
Electricity efficiency, net (%), annual average	-	-	-					A	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	35	40	40	25	40	35	45		1,6
Construction time (years)	0.7	0.5	0.5	0.3	1	0.25	1		5
Space requirement (1000 m^2/MWp)	11	11	11	10	11	10	11		5
Additional data for non-thermal plants									
Capacity factor (%), theoretical	21	24	24	14	23	14	24		1,2
Capacity factor (%), incl. outages	21	24	24	14	23	14	24		1,2
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-	B	
Cold start-up time (hours)	-	-	-	-	-	-	-	B	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWp)	0.65	0.46	0.34	0.54	0.73	0.25	0.57	D,R,S	1,3,4,5, 10
Nominal investment (M$/MWac)	0.81	0.57	0.42	0.68	0.91	0.31	0.71	D,R,S	1,3,4,5, 10
- of which equipment	39%	36%	25%						
- of which installation	61%	64%	75%						
Fixed O&M ($/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/m^2/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/m^2/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	

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 Data analyzed from www.renewables.ninja for multiple locations.
3 IEA, World Energy Outlook, 2019.
4 Learning curve approach for the development of financial parameters.
5 Local cases data.
6 The Danish Energy Agency, *Generation of electricity and district heating, 2020.*
7 Permasalahan penetrasi solar pv pada sistem grid nasional, Dewan Energi Nasional, Juni 2017 PT Len Industri (Persero)
8 PVGIS © Europeen Communitees 2001-2012.
9 Learning curve-based forecast of technology costs. Ea Energy Analyses, 2020.
10 Investment cost data from solar projects in Quang Tri, Quang Binh, Phu Yen, Ninh Thuan, Binh Phuoc, Ba Ria Vung Tau.

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

Decision No.39/2018/QD-TTg dated 10/9/2018 about incentive mechanism for developing wind power in Viet Nam defines onshore and offshore wind projects are projects that have wind turbines built and operated inside and outside of the lowest mean high water for many years (determined and announced according to the provisions of Decree No. 40/2016/ND-CP dated May 15, 2016 of the Government detailing the implementation of a number of articles of the Law on natural resources and environment of sea and islands), respectively. 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. (Real) offshore wind farm is defined as offshore wind farm with a minimum distance to shore of 6 nautical miles (~ 11 km) and in minimum sea depths of 10 m. When the seabed depth is smaller than 10 m or the distance is less than 6 nautical miles (Ref. 50, 51), the wind farm will be considered a nearshore wind farm; intertidal wind is considered a subcategory of nearshore 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.

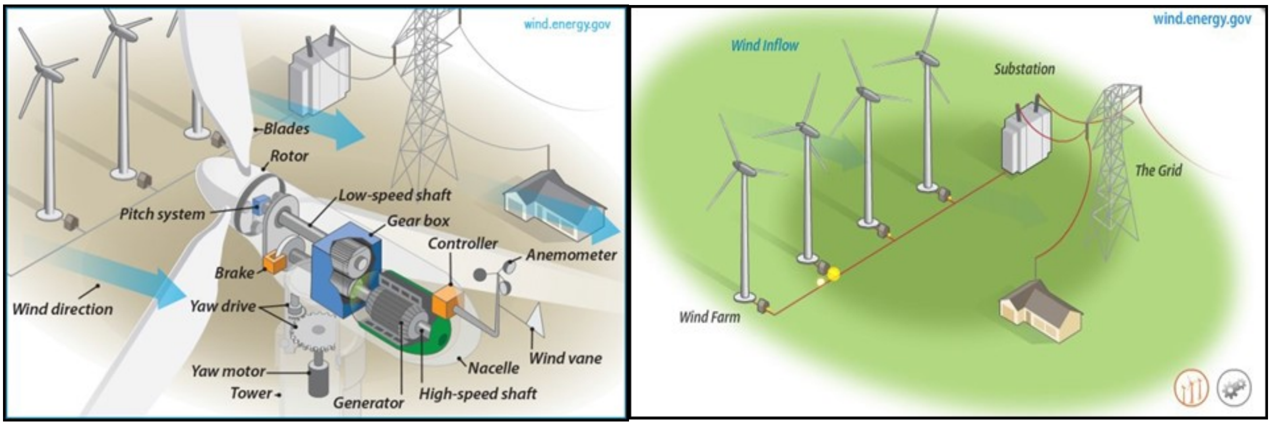


Figure 46: General turbine technology and electrical system (ref. 48)

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.

Table 25: Characteristics of wind classes as defined from the International Electrotechnical Commission

	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.

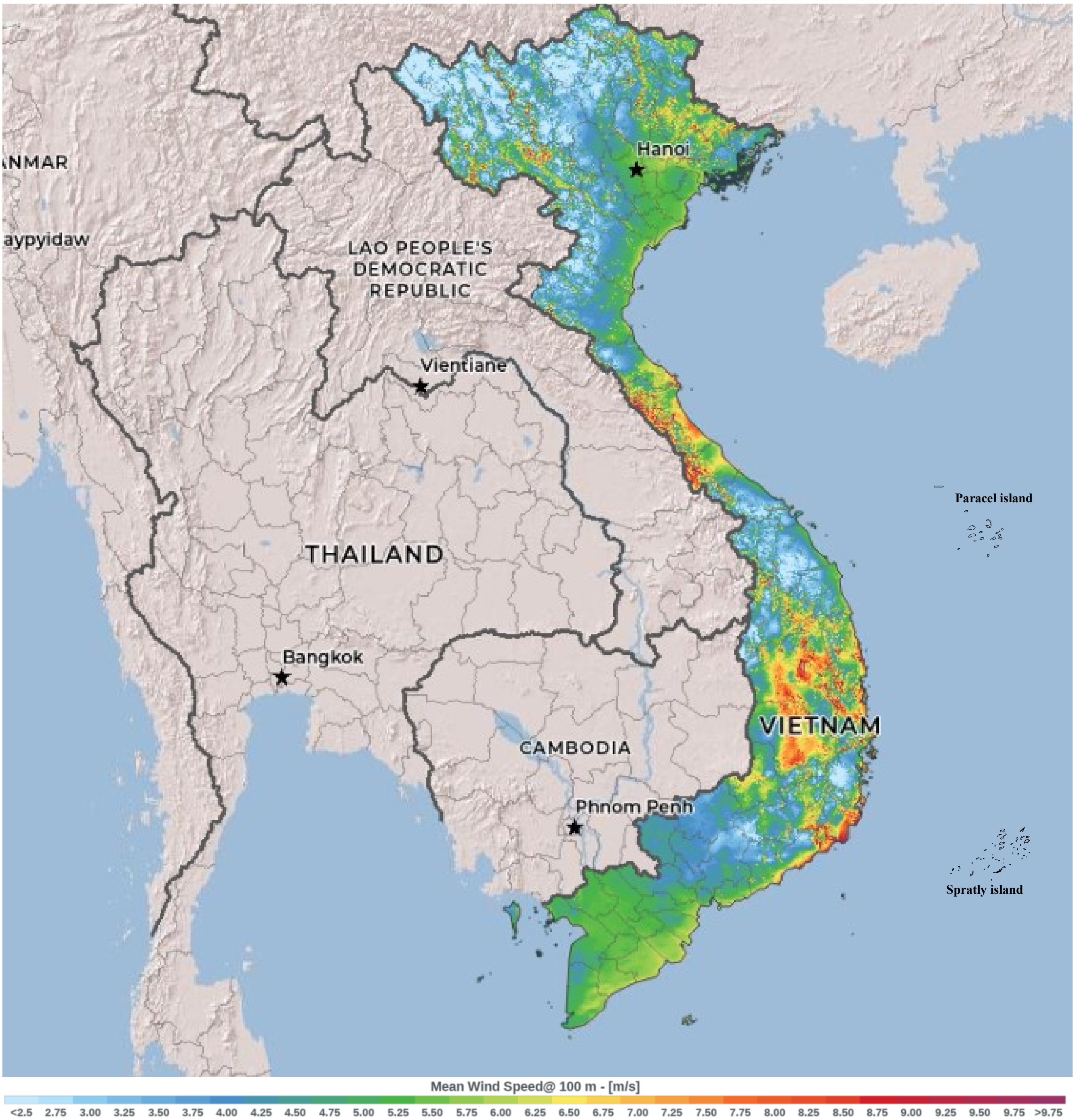


Figure 47. Wind resource in mainland Viet Nam – onshore, 100m above ground. Source: Global Wind Atlas.

Figure 47 shows an onshore wind resource map for Viet Nam. 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 221 GW, accounting for land and grid constraints (ref. 45).

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 Viet Nam is considered to be the best available in South-East Asia, for both onshore and offshore siting. However, Viet Nam 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 Viet Nam is deemed to be much higher than that, with estimates of over 600 GW (ref. 47).

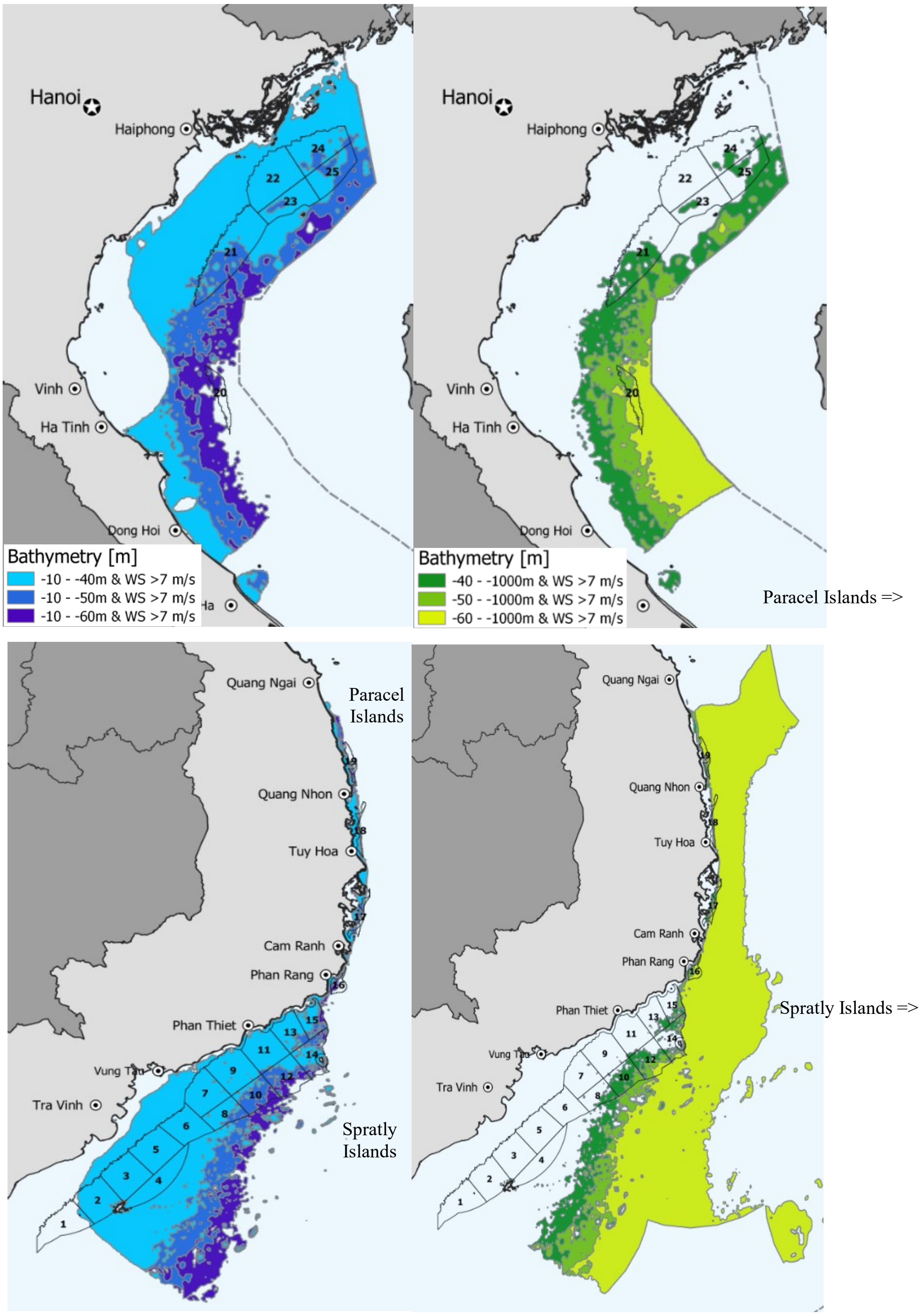


Figure 48: Overview of available sea area within 200nm from shore and wind speed above 7m/s with water depths greater than 10m (ref. 33).

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 49. 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
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 50: Investment costs scaling factor for distance to shore and water depth for Denmark. (ref. 38).

Currently, Viet Nam only has a general definition for offshore wind power according to Decision No. 39/2018 /QD-TTg dated September 10^{th}, 2018: wind projects that are built and operated outside of the lowest mean high water for many years. This is determined and announced according to the provisions of Decree No. 40/2016/ND-CP of the Government, dated May 15^{th}, 2016, detailing the implementation of a number of articles of the Law on natural resources and environment of sea and islands. However, as depth and distance greatly affect investment cost and turbine's technology, the division of offshore wind farm into nearshore and "real" offshore wind is necessary. (Real) offshore wind farm is defined as offshore wind with a minimum distance to shore of 6 nautical miles (~ 11 km) and in minimum sea depths of 10 m. When the seabed depth is smaller than 10 m or the distance to shore is less than 6 nautical miles (Ref. 50, 51), the wind farm will be considered a nearshore wind; intertidal wind farm is considered a subcategory of nearshore wind farm.

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).

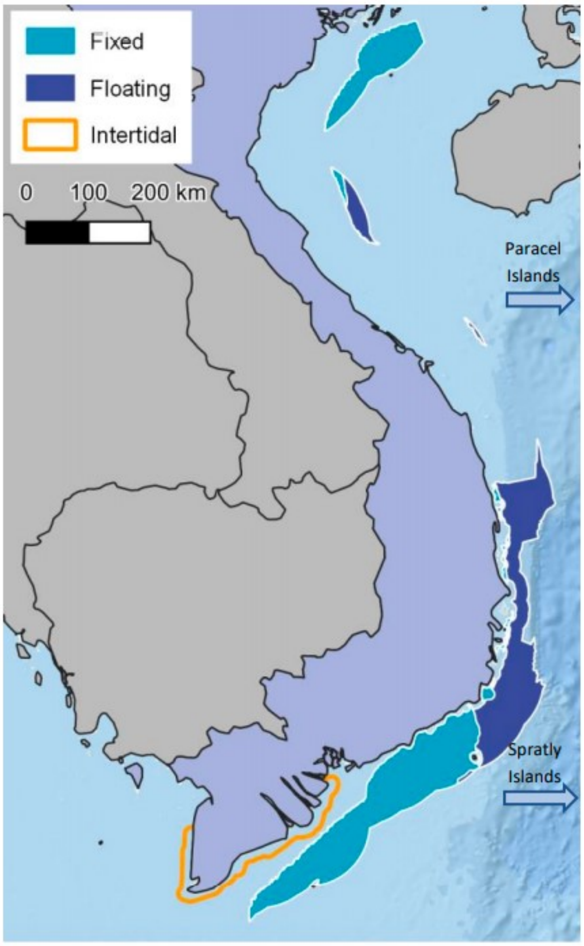


Figure 51. Potential sites for offshore wind turbines (Ref. 35). The potential for offshore wind is mainly along the coast of mainland Viet Nam and the Paracel and Spratly Islands are therefore not included in the map.

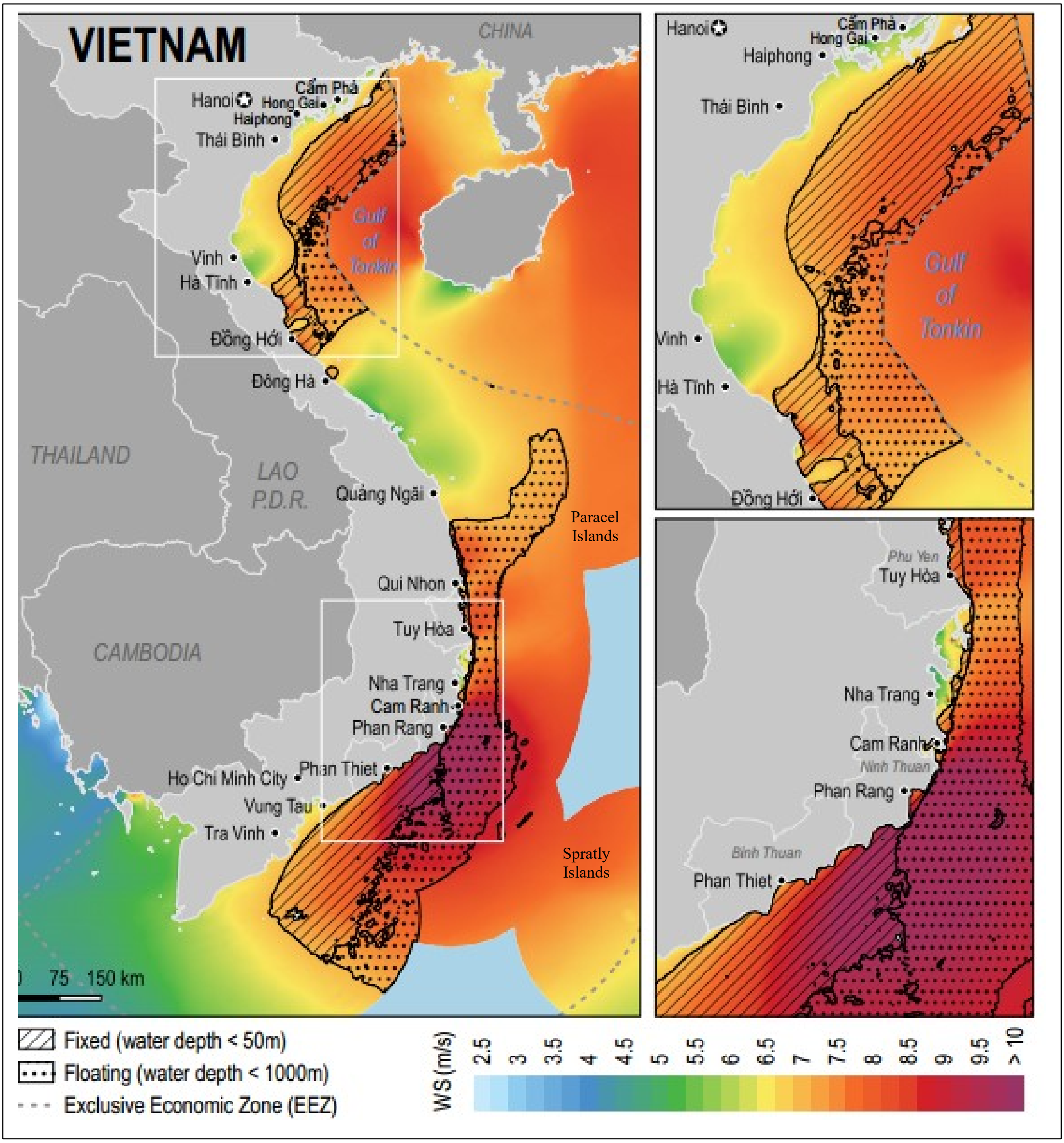


Figure 52. Map of potential offshore wind power locations in the form of floating and fixed foundations of Viet Nam according to ESMAP (Ref.47)

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[12] 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).

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

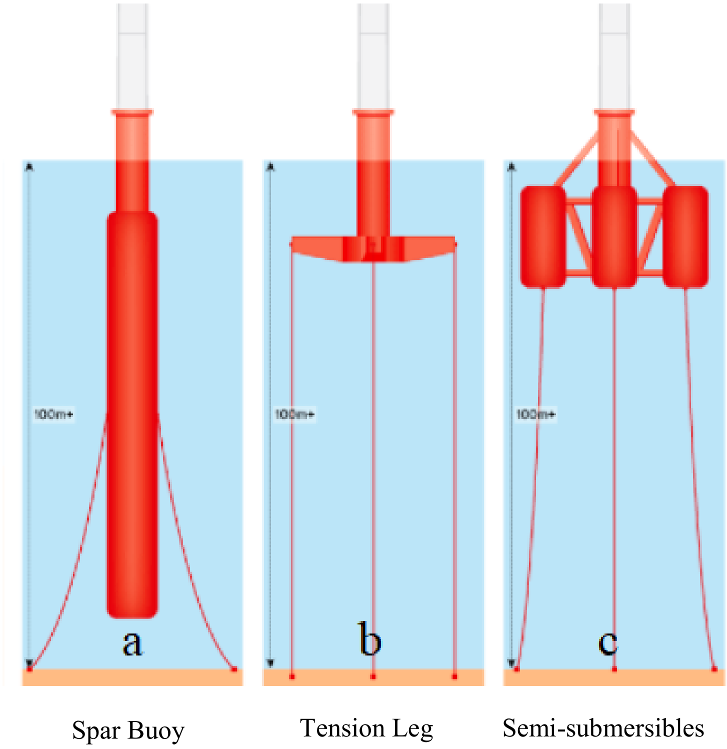


Figure 53. Different floating offshore foundations (Ref. 29).

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).

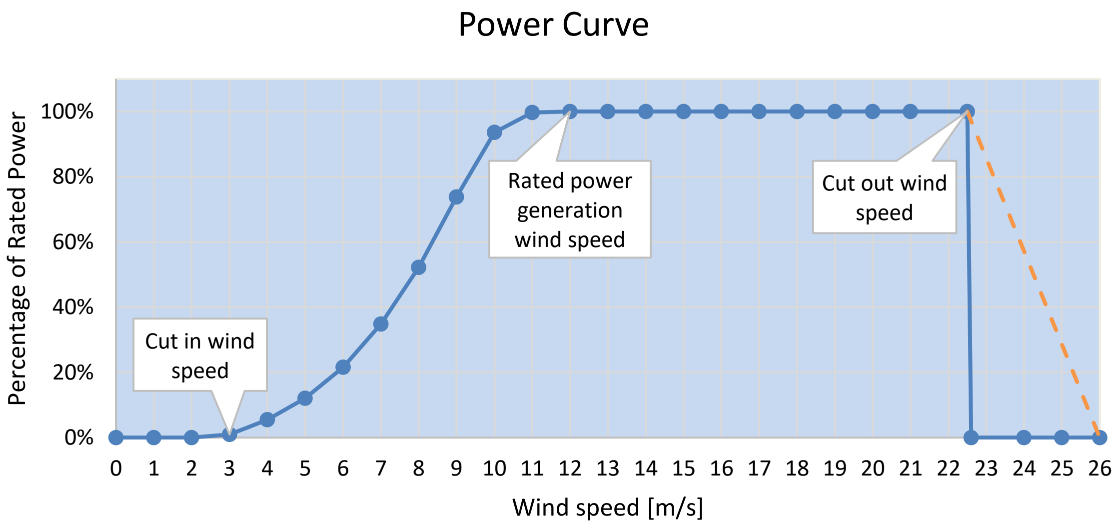


Figure 54: Power curve for a typical wind turbine (Ref. 48).

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.

Environment

Wind energy is a clean energy source. The environmental impact from the manufacturing of wind turbines is moderate and is in line with the impact of other normal industrial production. 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.

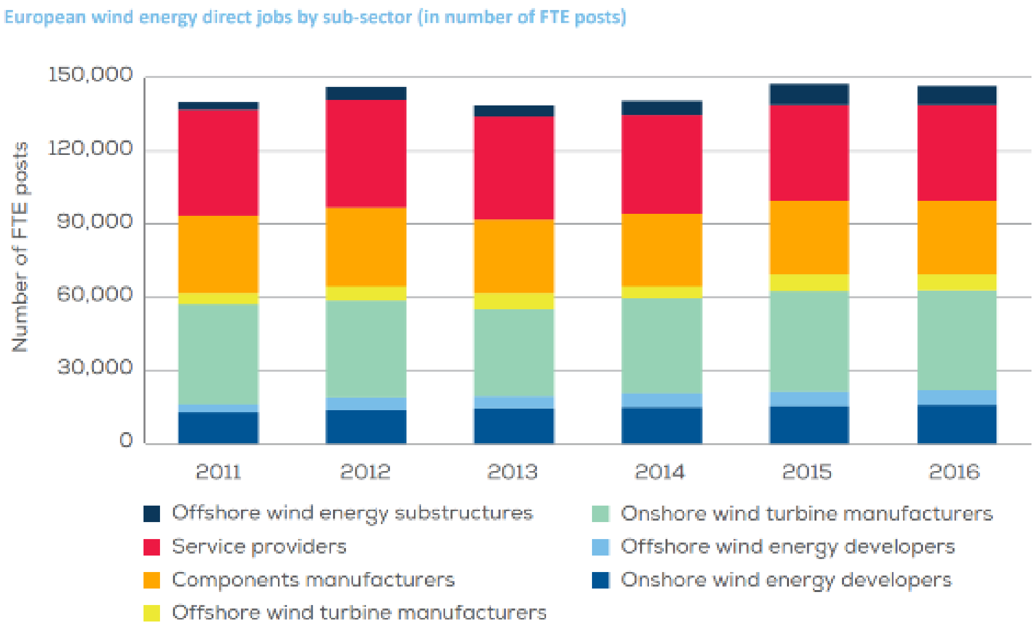


Figure 55: Direct employment (Full Time Employment) by company type related to the wind industry in Europe (Ref.6).

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[13]
- 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

In Vietnam, the median technology cost for an onshore project is 1.695 M$/MW (interquartile range 1.483 – 1.901). The median technology cost for a nearshore project is 2.011 M$/MW (interquartile range 1.800 – 2.207) (ref. 45).

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.

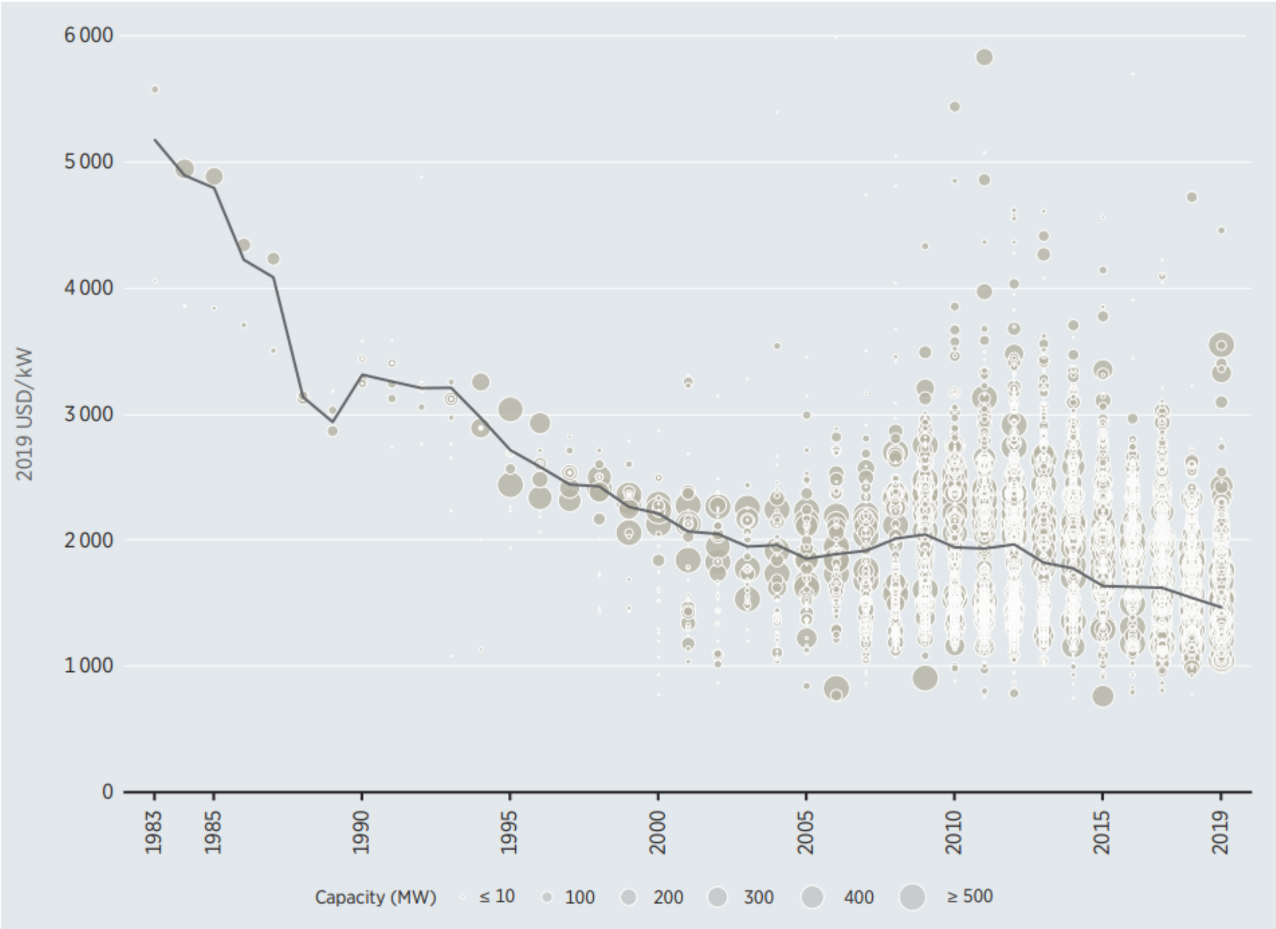
Data from IRENA (ref. 18) indicate total investment costs for onshore wind power of 1.5 M$/MW in 2019 – based on an extensive database.

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.

[13] 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 56: 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 Viet Nam 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 Viet Nam 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[14].

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 Viet Nam until 2020. The hub height 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 Viet Nam. 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:
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. The remaining phases will 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 Viet Nam. 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

[14] 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

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 26. 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

The tables below show reviewed investment cost figures for onshore and bottom-fixed offshore respectively, including projections to 2050. While onshore installations have gained momentum, with Viet Nam 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 Viet Nam 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 Viet Nam, 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 27: Investment cost figures for onshore projects, including projections.

Investment costs [$MUSD_{2019}$/MW]		2018-19	2020	2030	2050
Catalogues	Viet Nam Technology Catalogue 2021		1,50	1,28	1,08
	Viet Nam Technology Catalogue 2019		1,60	1,31	1,11
Viet Nam 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 28. Investment cost figures for offshore projects (fixed-bottom), including projections.

Investment costs [$MUSD_{2019}$/MW]		**2018-19**	**2020**	**2030**	**2050**
Catalogues	Viet Nam Technology Catalogue (2021)		3,15	2,15	1,70
	Viet Nam Technology Catalogue (2019)		2,36	2,25	1,93
Viet Nam 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%

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

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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), 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 ($/MWe/year)	42,475	38,475	32,704	36,975	45,075	24,704	34,704		4
Variable O&M ($/MWh)	0	0	0	0	0	0	0		4
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/m^2)	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, Renewable Power Generation Cost in 2014, 2015.

3 Danish Energy Agency, Technology Data - Generation of Electricity and District Heating, June 2022 update.
4 NREL (National Renewable Energy Laboratory), 2022 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory, 2022.
5 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(m^2)	260	242	236						1,5
Availability (%)	98%	98%	98%	95%	99%	95%	99%		1,5

References:

1 4C Offshore project database.

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, Viet Nam site LCOE screening, 2020.
5 IEA Wind Task 26, International technology catalogue for wind energy, 2020 (draft report).
6 Zhang S. Et al., Economy Comparison of Intertidal Zone Wind Farm and Normal Offshore Wind Farm, IEEE, 2011.

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 Viet Nam.

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 fixed foundation								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	5.7	10.0	14.0	1.6	15.0	4.0	20.0		1, 2
Generating capacity for total power plant (MWe)	100	500	1000	50	500	50	3000	D	1
Electricity efficiency, net (%), name plate									
Electricity efficiency, net (%), annual average									
Forced outage (%)	4.0	3.0	3.0	1.0	5.0	1.0	5.0		1
Planned outage (%)	0.3	0.3	0.3	0.1	0.5	0.1	0.5		1
Technical lifetime (years)	25	30	30	20	35	20	35		1
Construction time (years)	3.0	2.5	2.5	1.5	4	1.5	4		1
Space requirement (1000 m^2/MWe)	185	185	185	168	204	168	204		1
Additional data for non-thermal plants									
Capacity factor (%), theoretical	43%	48%	55%	-	-	-	-		
Capacity factor (%), incl. outages	41%	46%	53%	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (gram per Nm^3)	0	0	0	0	0	0	0		
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/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 ($/MWe/year)	111,162	86,050	70,096	80,000	140,000	50,000	100,000		3
Variable O&M ($/MWh)	0	0	0	0	0	0	0		3
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(m^2)	323	318	309						1
Availability (%)	97%	98%	98%	95%	99%	95%	99%		1

References:

1 Danish Energy Agency, Technology Data - Generation of Electricity and District Heating, June 2022 update.
2 Danish Energy Agency, Technology Data on Energy Plants - Generation of Electricity and District Heat, 2020.
3 NREL (National Renewable Energy Laboratory), 2022 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory, 2022.
4 AEGIR, Viet Nam 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. 2 and 4 above) have been used to calculate best estimates for Viet Nam.

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

Technology	Wind power - Floating offshore								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	7.0	12.0	15.0						1, 2, 5
Generating capacity for total wind farm (MWe)	35	500	1000						1, 5
Electricity efficiency, net (%), name plate									
Electricity efficiency, net (%), annual average									
Forced outage (%)	6.0	4.0	4.0						3
Planned outage (%)	0.6	0.6	0.6						3
Technical lifetime (years)	20	25	30						4
Construction time (years)	3.0	2.5	2.5						4
Space requirement (1000 m^2/MWe)	185	185	185						4
Additional data for non-thermal plants									
Capacity factor (%), theoretical	43%	48%	55%	-	-	-	-	D	
Capacity factor (%), incl. outages	40%	46%	52%	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (gram per Nm^3)	0	0	0	0	0	0	0		
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/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/m^2)	396	382	306						1
Availability (%)	94%	96%	96%						3

References:

1 Global Wind Energy Council, "Global Offshore Wind Report 2020", 2020.
2 BVG Associates, "Offshore wind roadmap for Viet Nam", 2020.
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 Viet Nam: Preliminary Findings,* 2020.
5 AEGIR, *Viet Nam site LCOE screening*, 2020.
6 M. Aquilina, "Cost Modelling of Floating Wind Farms with Upscaled Rotors in Maltese Waters", 2014.

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 Viet Nam, 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].

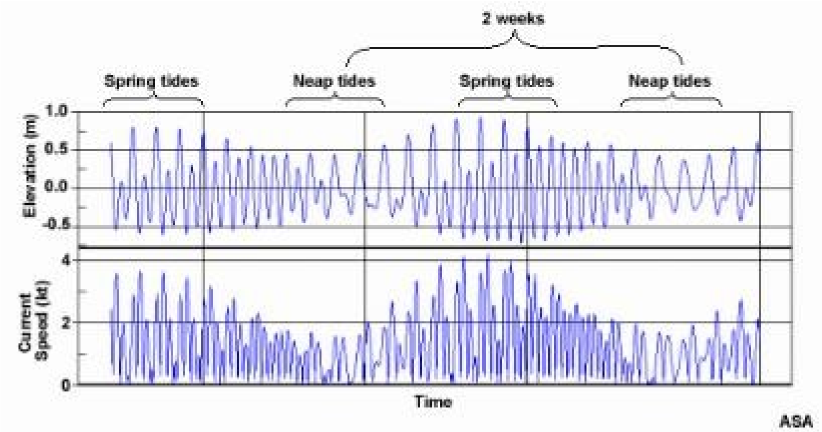


Figure 57: Time series representation of spring and neap tide along with correlation with tidal current speed variation.[3]

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.

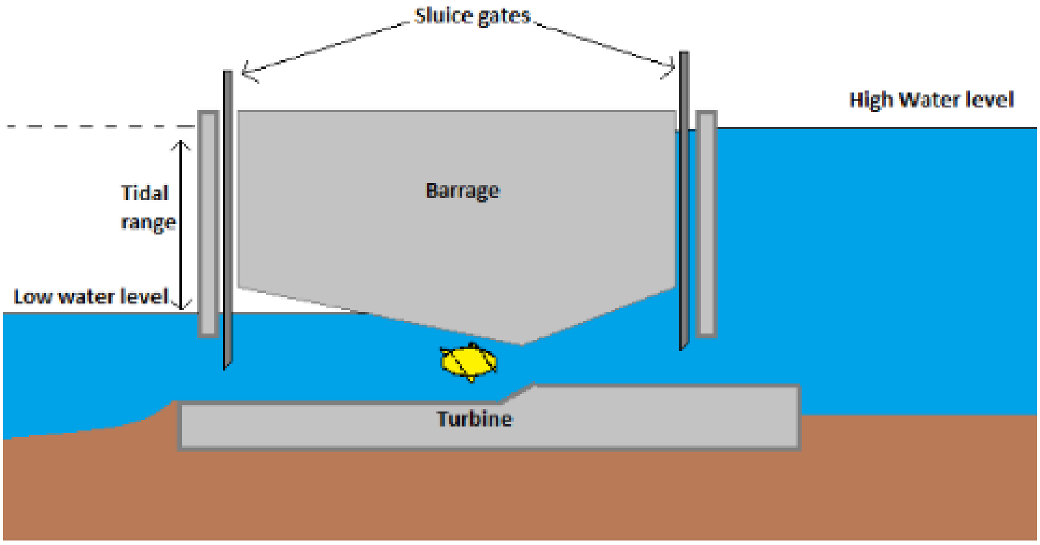


Figure 58: Schematic of tidal impoundment type plant.[4]

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

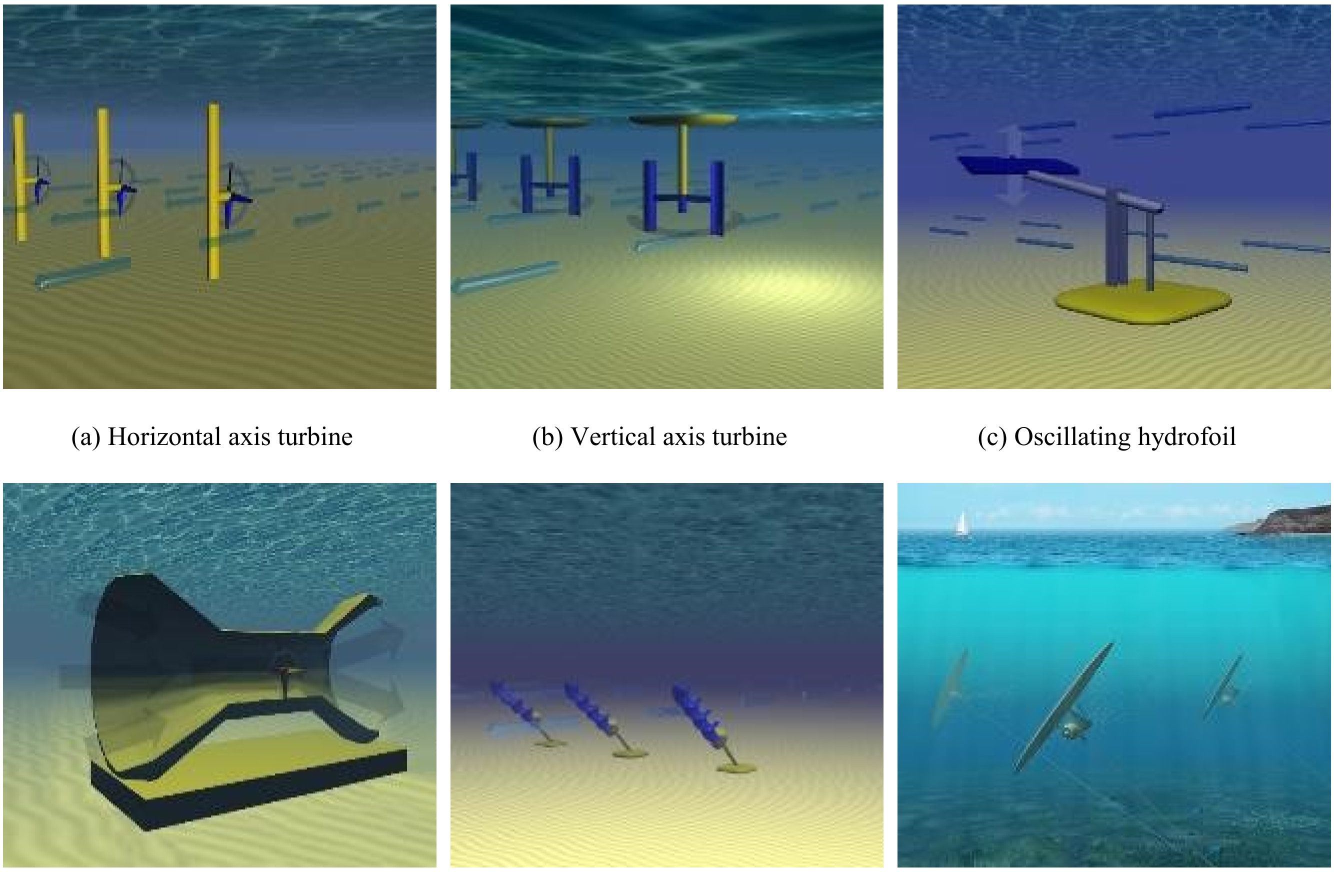
Figure 59: Tidal impoundment types [2]

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 60: 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:

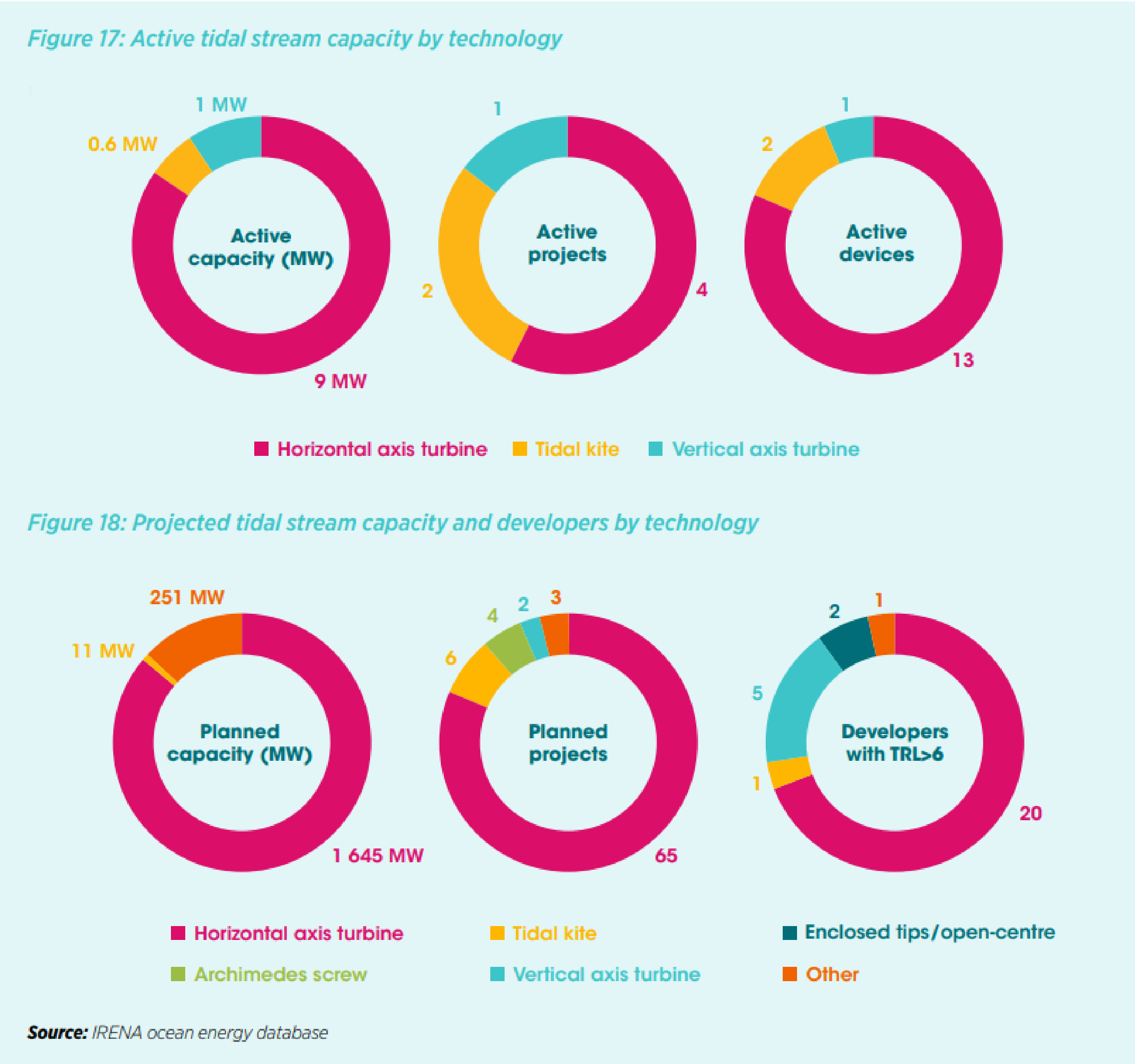


Figure 61: Active and project tidal stream capacity and technology [26]

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.

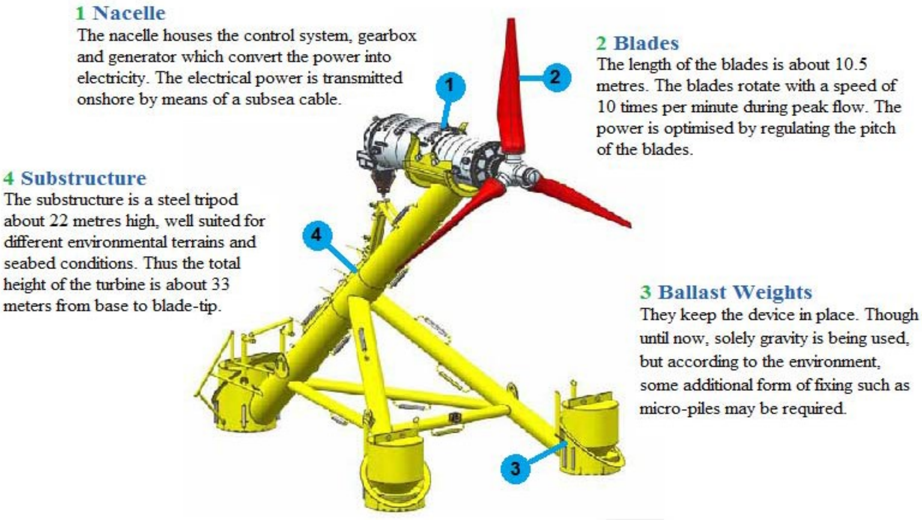


Figure 62: Early gravity based substructure design [8]

- *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.

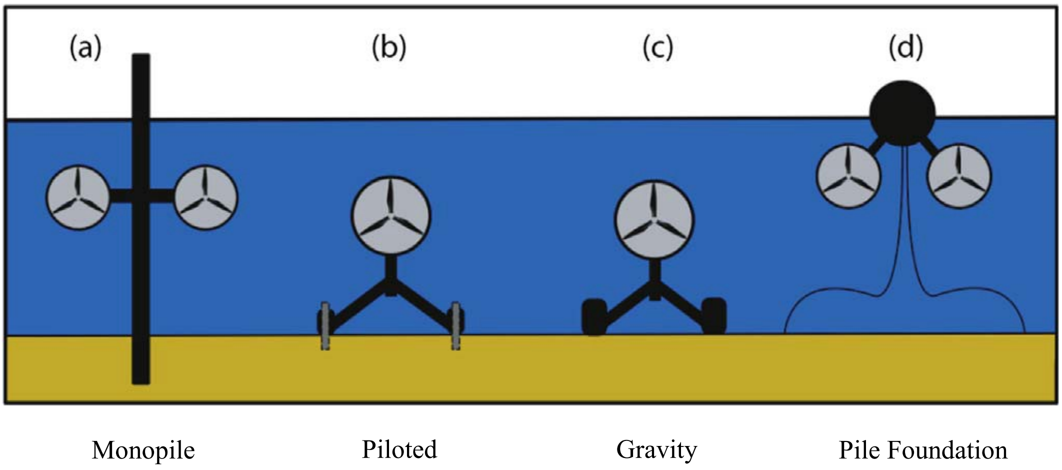


Figure 63: Foundation types: First generation devices [7]

Figure 64: 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.

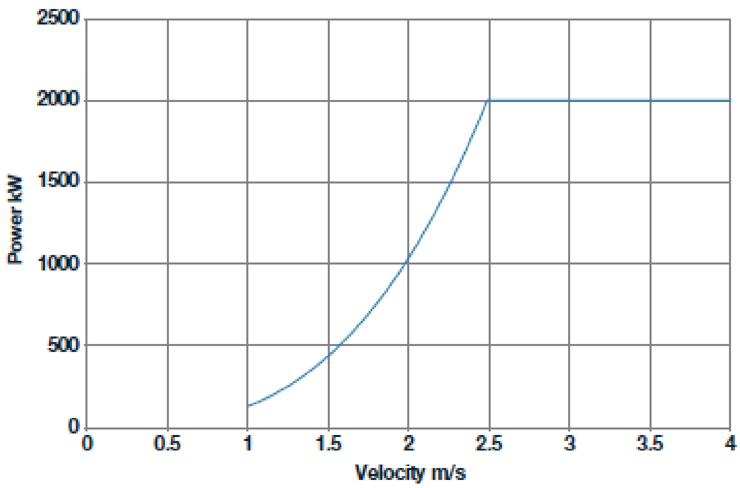


Figure 65: Sample power curve for tidal stream turbine.[9]

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 Viet Nam. 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 Viet Nam, 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.

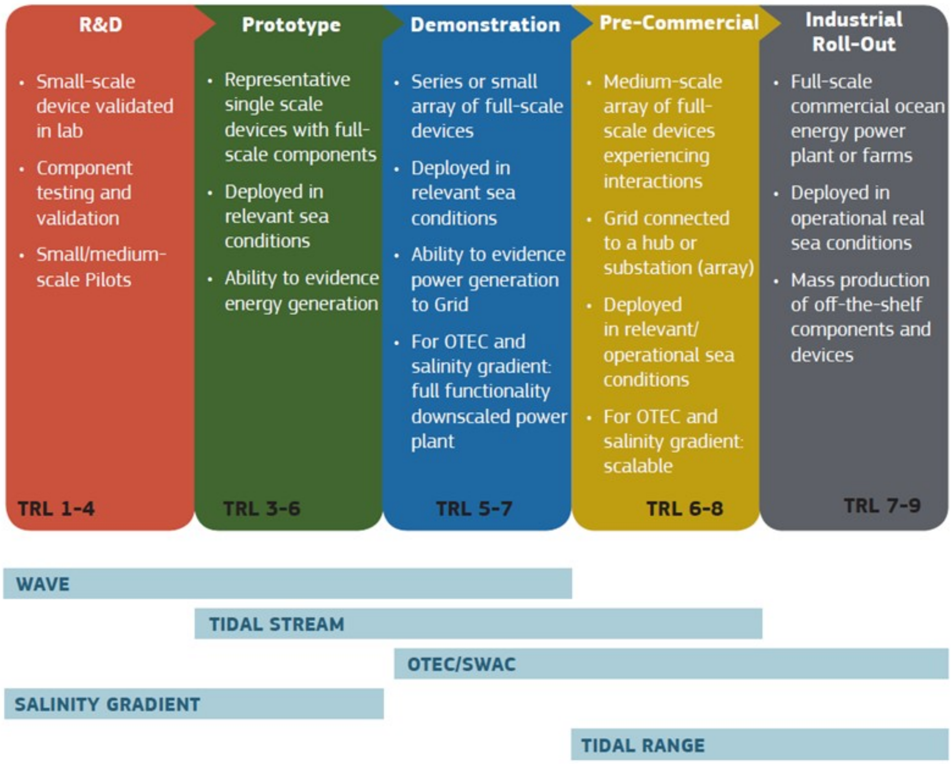


Figure 66: Where ocean energy technologies are in the stages of development [14]

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 67: 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.

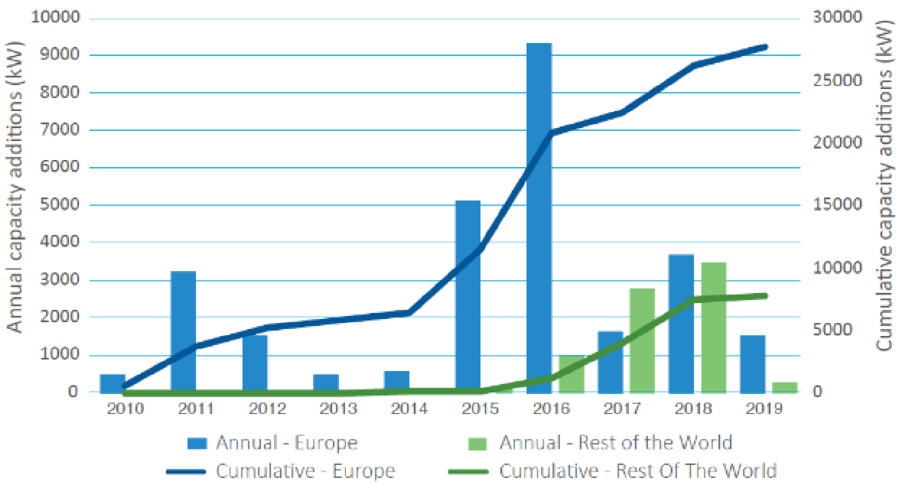


Figure 68: Installed and cumulative tidal stream energy capacity.[17]

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
Viet Nam Technology 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
Viet Nam Technology Catalogue 2021		5,7	4,6	3,4
IEA Report [21]	4,6 (3,4 – 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)									

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

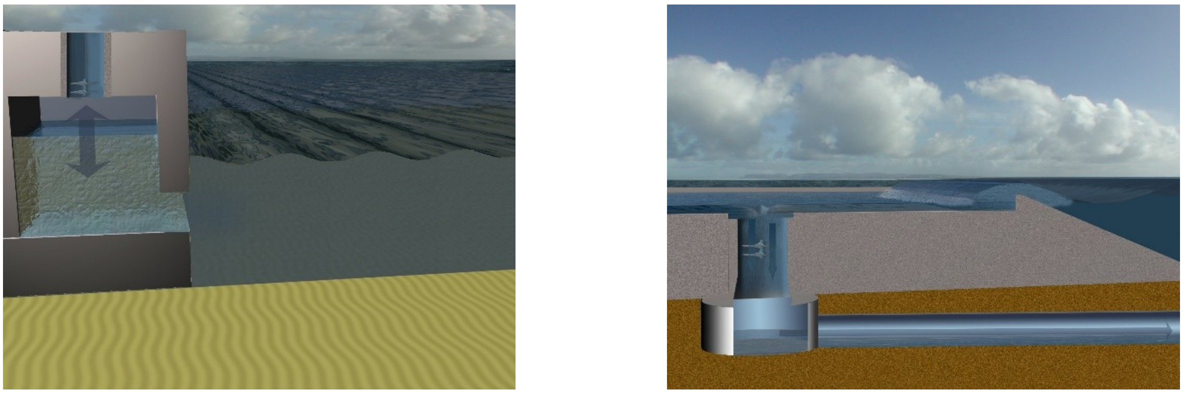
Under the marine energy umbrella, one of the technologies being explored is production of electricity from wave energy. These technologies aim to exploit the energy from the movement of waves.

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

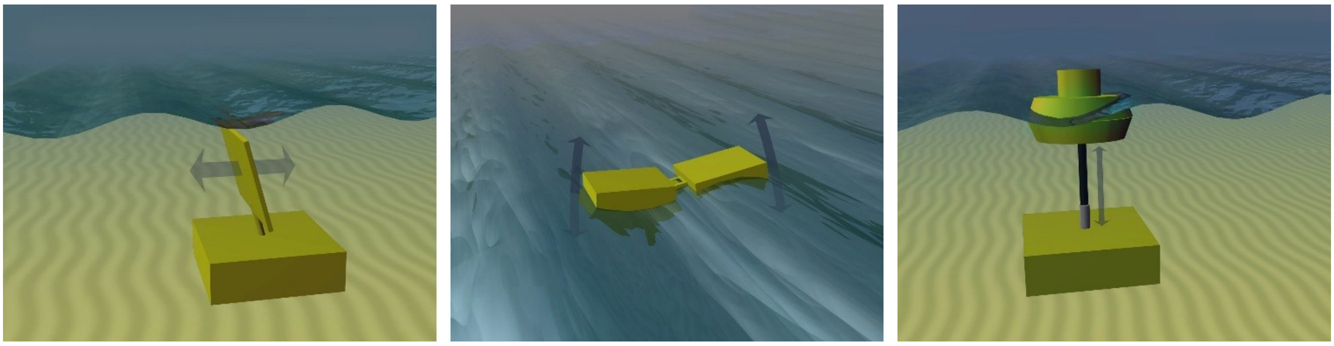
(b) Overtopping device

Figure 69: 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.



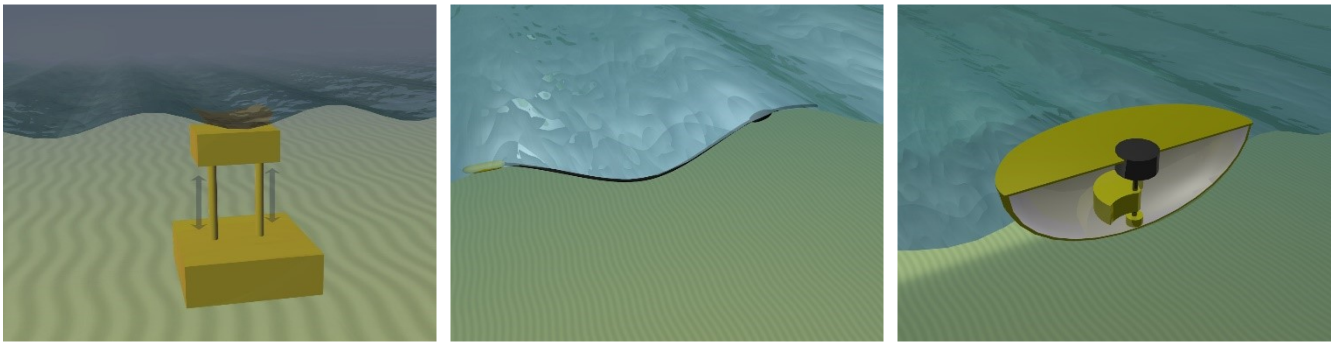
(c) Oscillating wave surge converters (d) Attenuator (e) Point absorber

Figure 70: 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 71: 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.

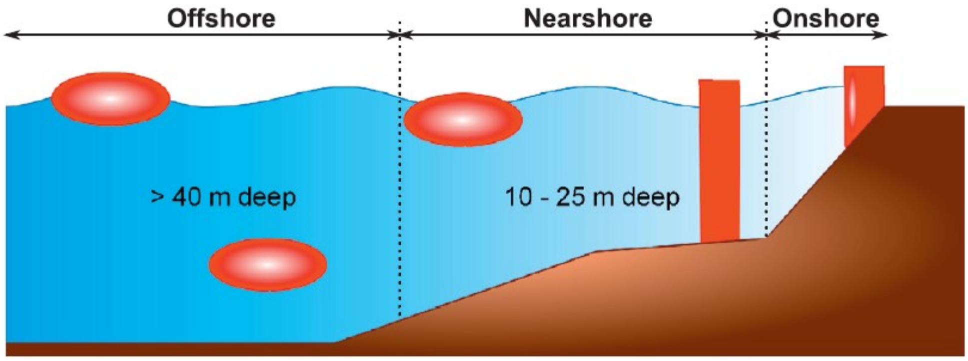


Figure 72: Location of wave energy converters [3]

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:

3. Passive mooring is only responsible for keeping the WEC in position.
4. Active mooring, in addition to keeping the WEC in position, also helps with optimising the energy capture.
5. 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.

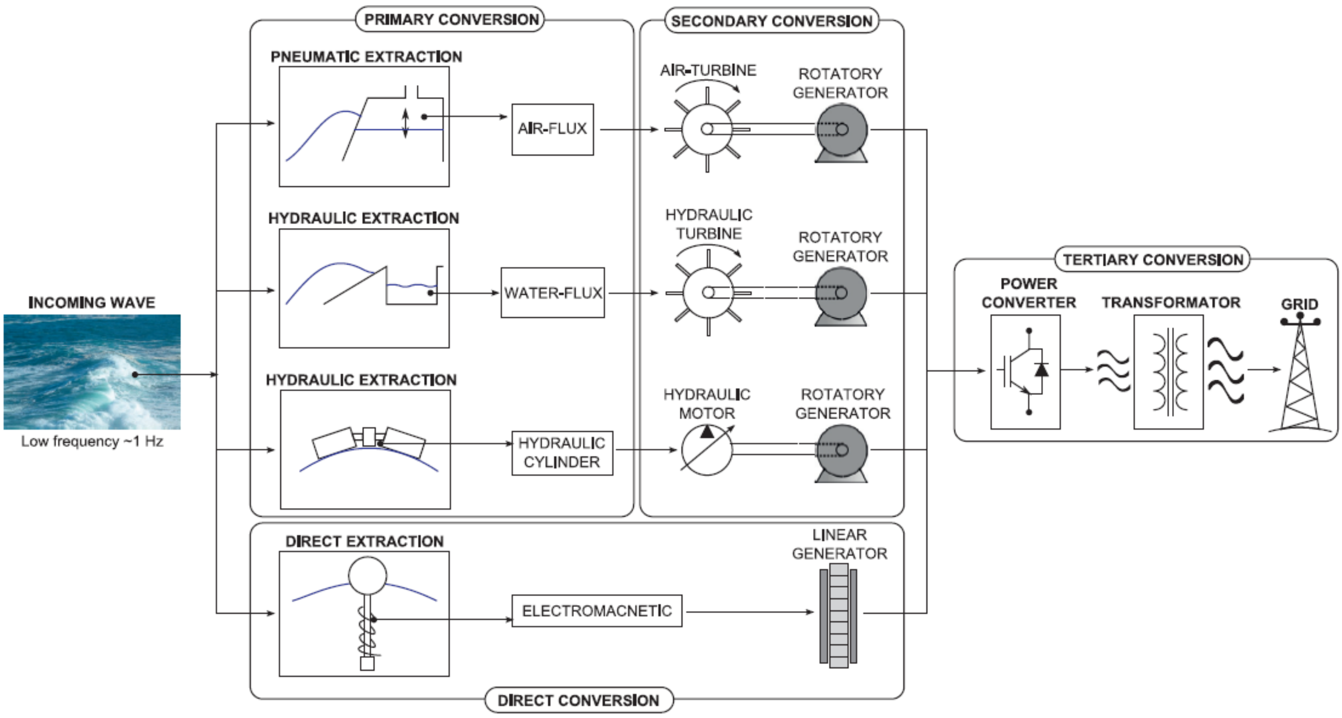


Figure 73: Wave energy conversion stages [3]

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.

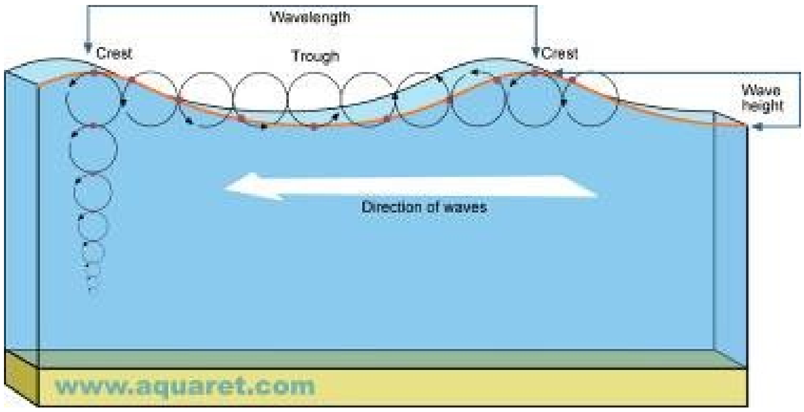
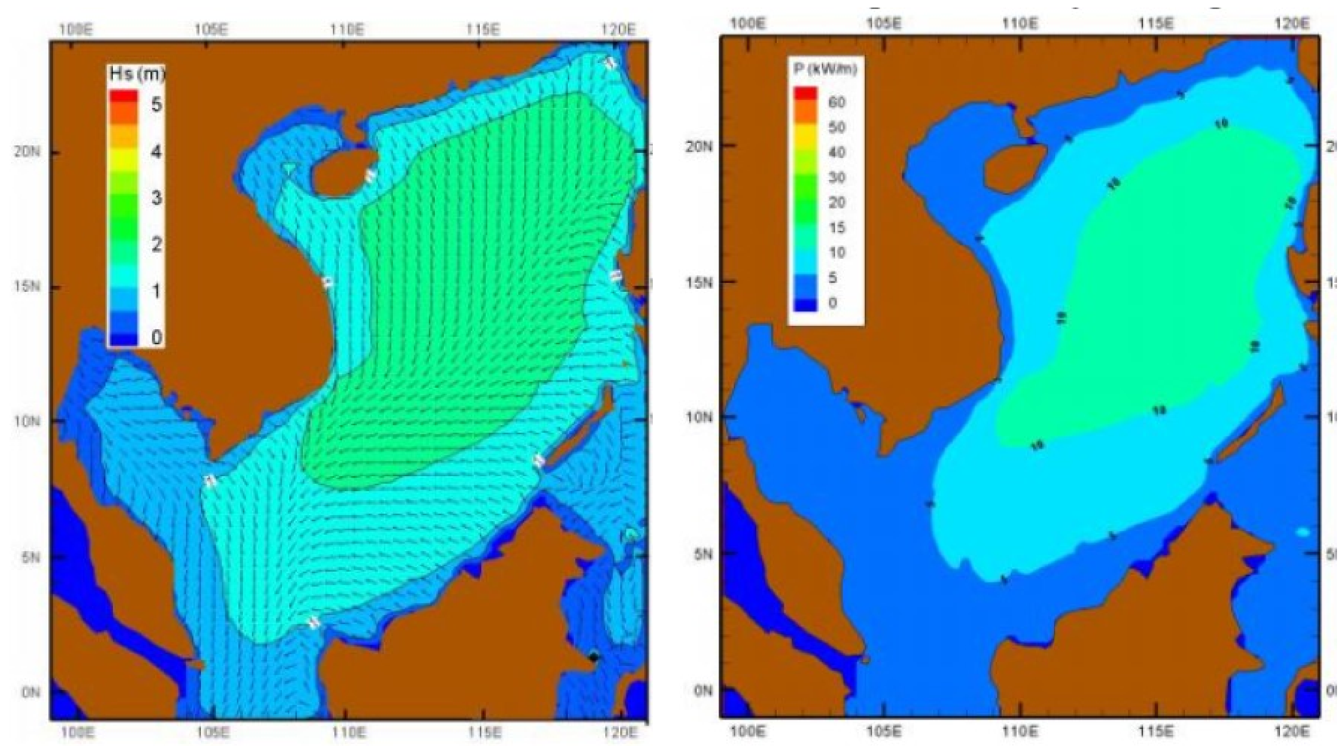


Figure 74: Wave characteristics [2]

The yearly average of wave height and wave energy flux for Viet Nam can be visualised from the figures below. Viet Nam, 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 75: Wave energy resource in Viet Nam [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]

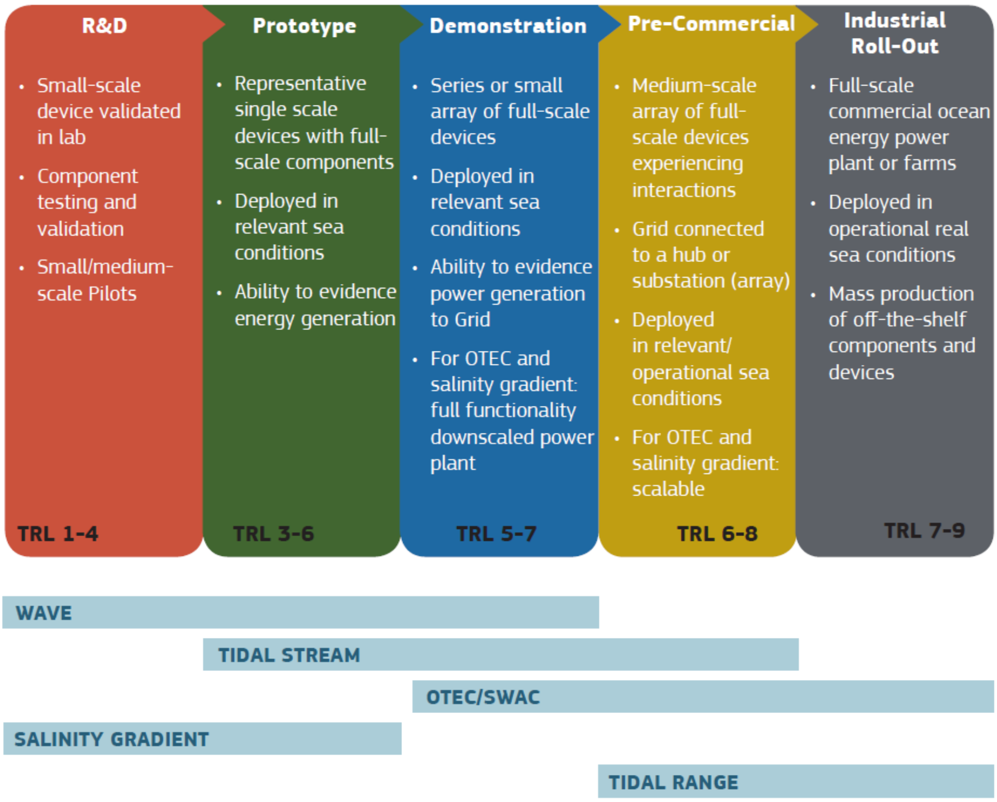


Figure 76: Where ocean energy technologies are in the stages of development [11]

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]

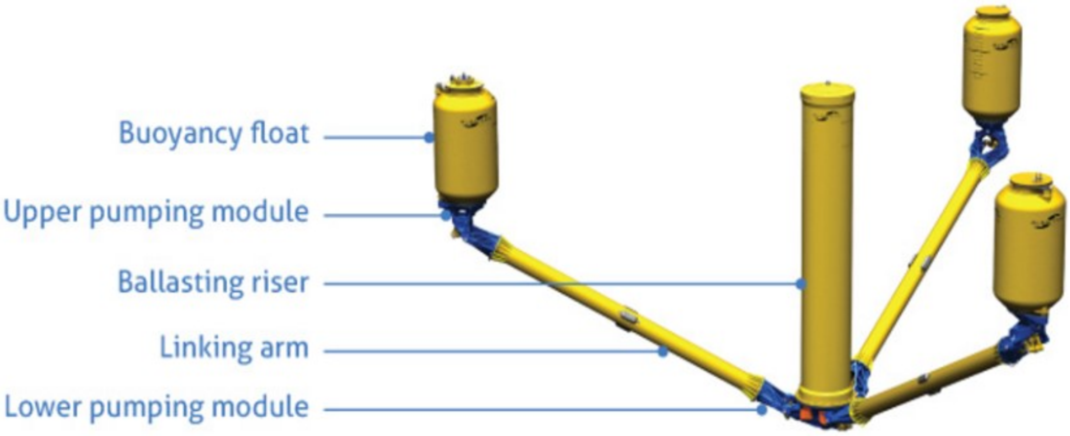


Figure 77: WaveNET [12]

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 78: 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.

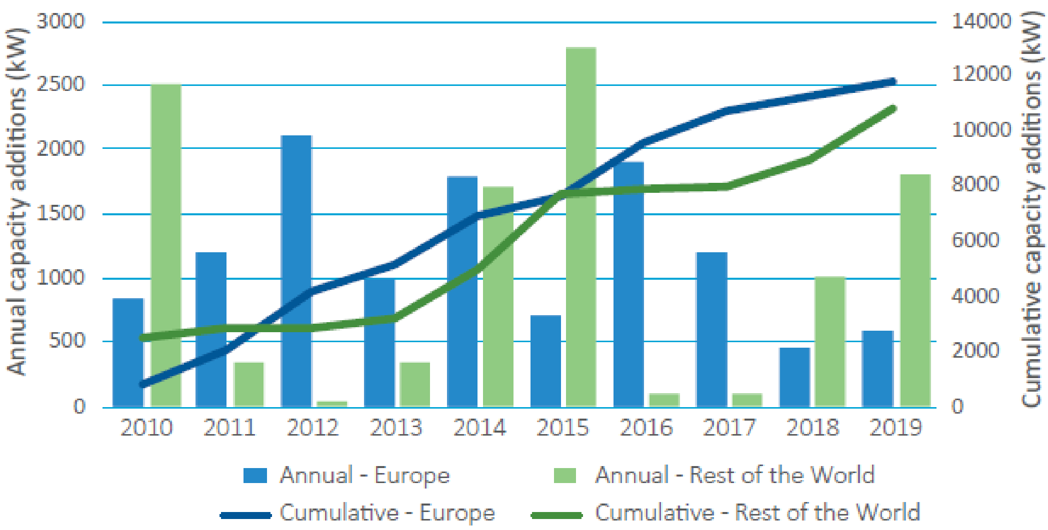


Figure 79: Installed and cumulative global wave energy capacity [10]

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 Viet Nam.

Investment cost for wave energy

Investment costs [MUSD2019/MW]		2020	2030	2050
Viet Nam Technology Catalogue 2021		10,8	8,6	5,5
IEA OES [13]	11,4 (1st Array) 9,7 (2nd Array) 6 (commercial)			
Viet Nam (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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1 : Power Sector Vision for the Greater Mekong Subregion," no. April, 2016.
[15] Seabased, "Sotenäs Wave Power Demonstration Project." https://seabased.com/projects.

Data sheets

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

References:

1 Ocean Energy Systems - OES (IEA), “International Levelised Cost of Energy for Ocean Energy Technologies”, 2015.
2 IRENA, "Wave Energy Technology Brief", 2014.
3 Aderinto and Li, Review on Power Performance and Efficiency of Wave Energy Converters, 2019.
4 Danish Energy Agency, Technology Data on Energy Plants - Generation of Electricity and District Heating, 2012.
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.

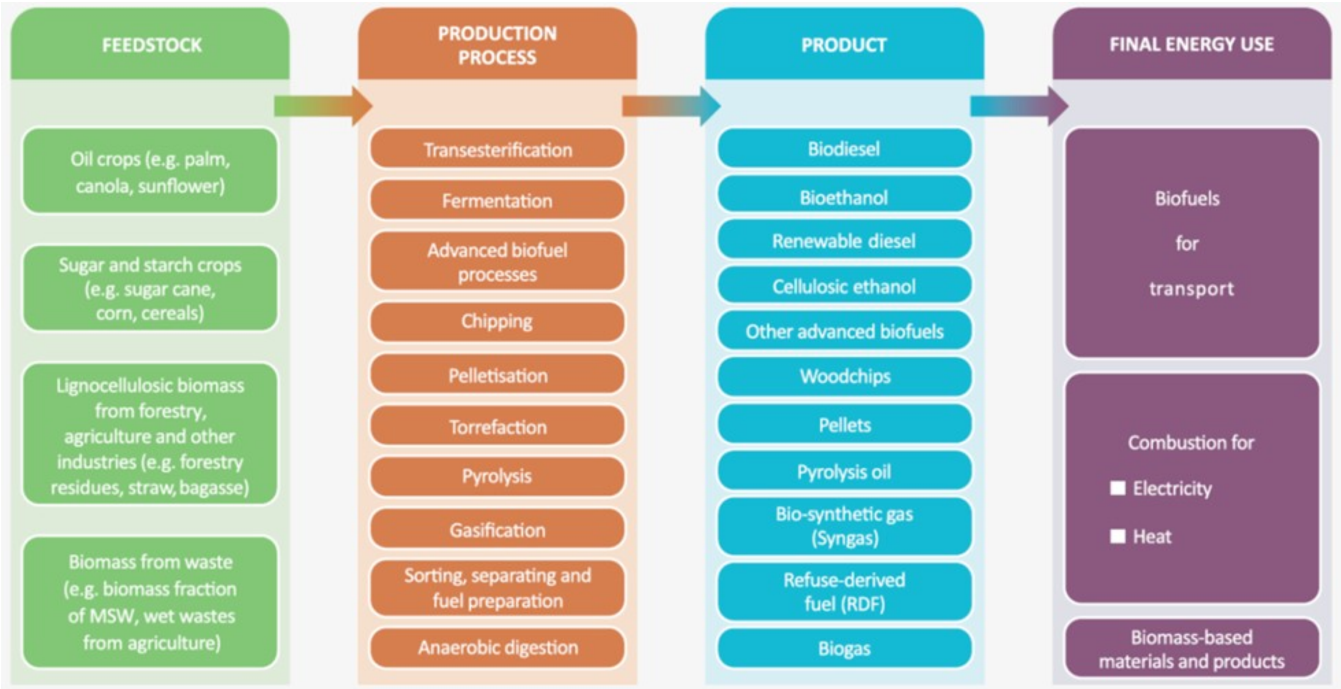

Figure 80: Biomass conversion paths (ref. 1)

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).

Viet Nam 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. According to PDP 8, the technical potential of biomass for electricity generation in Vietnam in the period up to 2030 is about 7.2 GW.

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

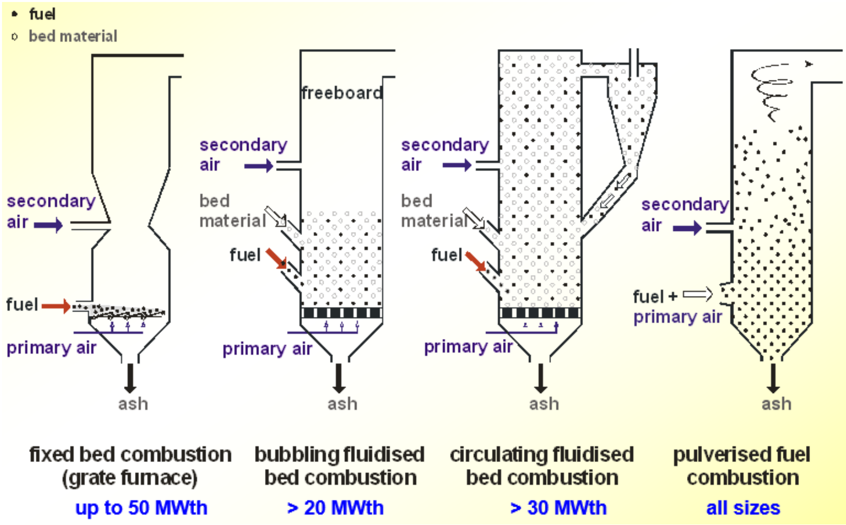

Figure 81: Technologies for industrial biomass combustion (ref. 4)

Table 29: 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).

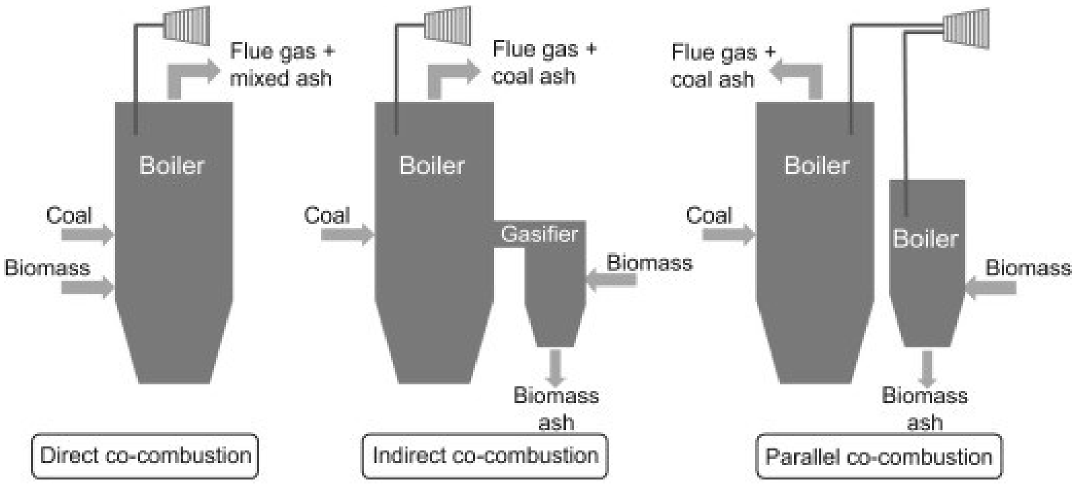

Figure 82: Different biomass co-firing configurations (ref. 15)

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 Viet Nam, using biomass for power generation is relatively new.

A significant share of biomass energy is consumed in Viet Nam 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 Viet Nam.

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 83 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.

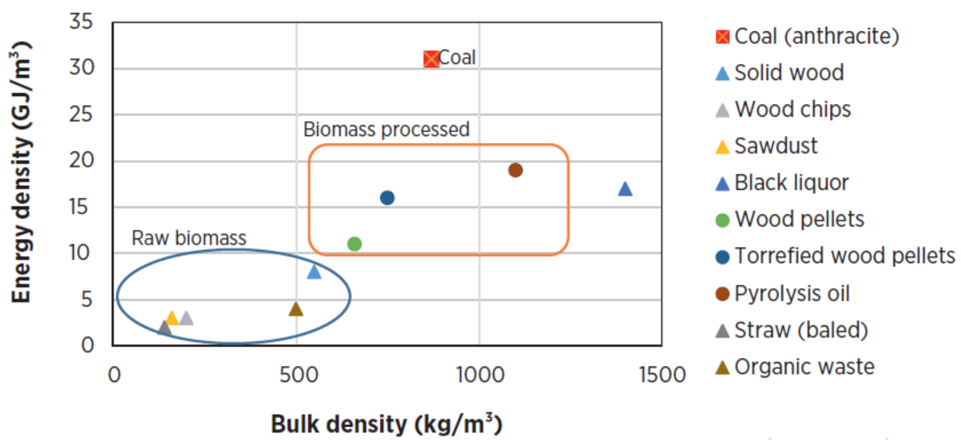

Figure 83: Energy density of biomass and coal (ref. 11).

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 84 gives an overview of the technology maturity of different biomass production technologies.

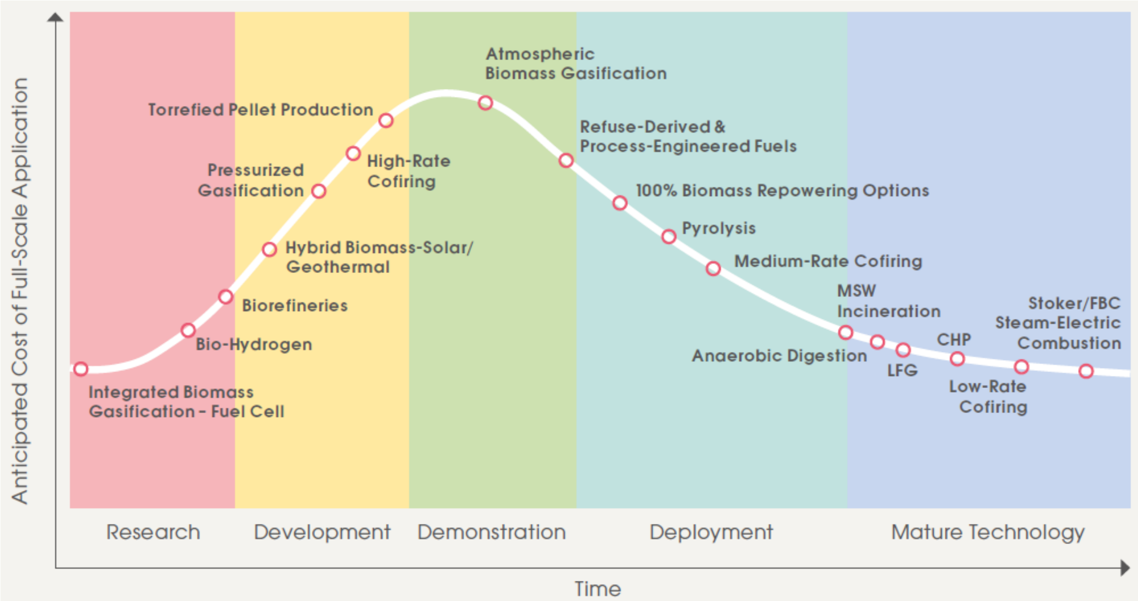

Figure 84: Biomass power generation technology maturity status (ref. 12)

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

Mode	Conditions	Composition		
		Liquid	Liquid	Liquid
Fast pyrolysis	Moderate temperature, short residence time	75%	Nhiệt phân nhanh	Nhiệt độ trung bình, thời gian lưu ngắn
Carbonization	Low temperature, very long residence time	30%	Các bon hóa	Nhiệt độ thấp, thời gian lưu rất dài
Gasification	High temperature, long residence time	5%	Khí hóa	Nhiệt độ cao, thời gian lưu dài

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

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

Investment cost estimation

Investment costs [MUSD2019/MW]		2020	2030	2050
Catalogues	**This Technology Catalogue**	1.80	1.60	1.40
	Viet Nam Technology Catalogue (2021)	1.80	1.60	1.40
	Viet Nam Technology Catalogue (2019)	1.70	1.60	1.40
International data	Danish Technology Catalogue	2.38	2.26	2.05
	Germany (Ref. 16)	2.35	2.21	1.95
	Indonesia (Ref. 17)	2.00	1.82	1.60
Projection	Learning curve – cost trend [%]	100%	91%	80%

Examples of current projects

The KCP Phu Yen Biomass Power Plant is located in the Hoa Son Sugar Factory land area. KCP Viet Nam 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.

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^{0}C 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)	-	-

References

The following sources are used:

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2. Loo, et.al., *Handbook of Biomass Combustion and Co-Firing*. Twente University Press: The Netherlands, 2003.
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17. DEA, Technology data for the Indonesian power sector, 2021.

Data sheets

The following page contains the data sheet 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 Viet Nam 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$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	25	25	25	1	50	1	50		1,5
Generating capacity for total power plant (MWe)	25	25	25	1	50	1	50		1,5
Electricity efficiency, net (%), name plate	32	32	32	25	35	25	35		1,3,7
Electricity efficiency, net (%), annual average	31	31	31	25	35	25	35		1,3,7
Forced outage (%)	7	7	7	5	9	5	9	A	1
Planned outage (weeks per year)	6	6	6	5	8	5	8	A	1
Technical lifetime (years)	25	25	25	19	31	19	31	A	7,8
Construction time (years)	2	2	2	2	3	2	3	A	7
Space requirement (1000 m^2/MWe)	35	35	35	26	44	26	44	A	1,9
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	10	10	10						3
Minimum load (% of full load)	30	30	30						3
Warm start-up time (hours)	0.5	0.5	0.5						3
Cold start-up time (hours)	10	10	10						3
Environment									
PM 2.5 (mg per Nm^3)	12.5	12.5	12.5						3
SO_2 (degree of desulphuring, %)	0.0	0.0	0.0						3
NO_X (g per GJ fuel)	125	125	125						3
Financial data									
Nominal investment (M$/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, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity", 2017.

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

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

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

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

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

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

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

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

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 31: 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.

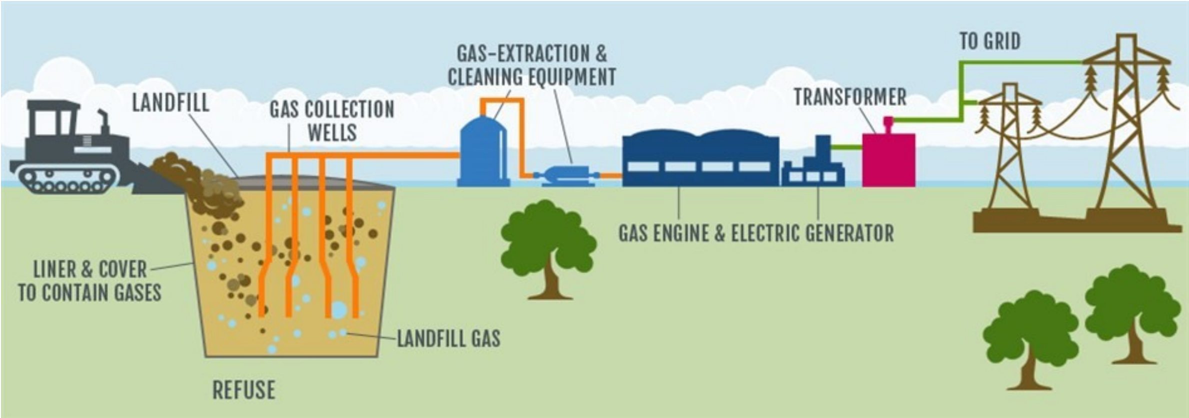

Figure 85: Land-fill gas to energy (ref. 5).

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	Directly suitable	Directly suitable	Likely to require pre-treatment	Likely to require pre-treatment	Likely to require pre-treatment
	Garden and park waste	Directly suitable	Directly suitable	Likely to require pre-treatment	Unsuitable	Unsuitable
	Dry recoverable waste	Unsuitable	Unsuitable	Directly suitable	Directly suitable	Directly suitable
	Refuse Derived Fuel	Unsuitable	Unsuitable	Directly suitable	Directly suitable	Directly suitable
	Inert	Unsuitable	Directly suitable	Unsuitable	Unsuitable	Unsuitable
	Hazardous	Unsuitable	Unsuitable	Likely to require pre-treatment	Unsuitable	Unsuitable
	Solid Recovered Fuel	Unsuitable	Unsuitable	Directly suitable	Directly suitable	Directly suitable
Agricultural	Biomass	Directly suitable	Directly suitable	Likely to require pre-treatment	Likely to require pre-treatment	Likely to require pre-treatment
	Animal waste	Directly suitable	Directly suitable	Likely to require pre-treatment	Likely to require pre-treatment	Likely to require pre-treatment
	Dry recoverable waste	Unsuitable	Unsuitable	Directly suitable	Directly suitable	Directly suitable
	Hazardous	Unsuitable	Unsuitable	Likely to require pre-treatment	Unsuitable	Unsuitable
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 86: 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 Viet Nam, 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 32: 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 33: 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

Investment cost estimation

Investment costs [MUSD2019/MW]		2019	2020	2030	2050
Catalogues	**This Technology Catalogue**		5.60	5.20	4.60
	Viet Nam Technology Catalogue (2021)		5.60	5.20	4.60
	Viet Nam Technology Catalogue (2019)	4.12-6.08 (Vietnam)	8.70	8.10	7.20
International data	Danish Technology Catalogue		8.58	8.11	7.07
	US (Ref. 15)	6.72 (2016)			
	Indonesia (Ref. 16)		2.60	2.60	2.60
Projection	Learning curve – cost trend [%]		100%	93%	82%

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 Viet Nam 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

Table 34: Data from local projects (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, "Reconsidering Municipal Solid Waste as a Renewable Energy Feedstock", *Issue Brief*, Environmental and Energy Study Institute (ESSI), Washington, USA, 2009.
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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	**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, "Clean Energy Handbook for Financial Service Institutions", Indonesia Financial Service Authority, Jakarta, Indonesia, 2014.

2 Renewables Academy" (RENAC) AG, "Biogas Technology and Biomass", Berlin, Germany, 2014.

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

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

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

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/m^3, 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 Viet Nam 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.

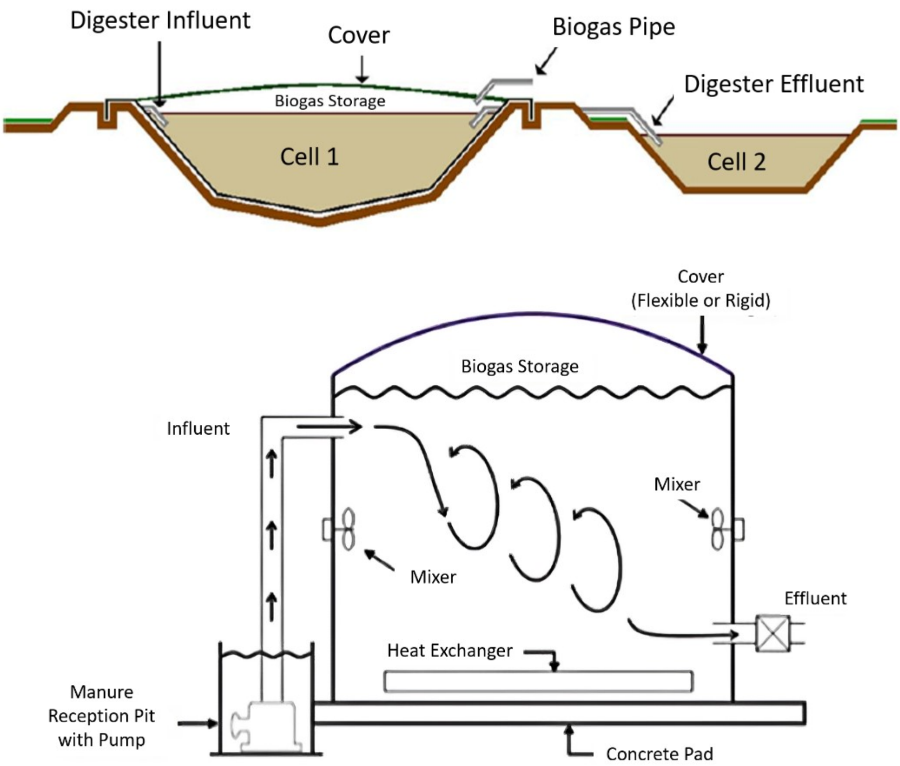


Figure 87: Covered lagoon and CSTR biogas plants (ref.3)

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).

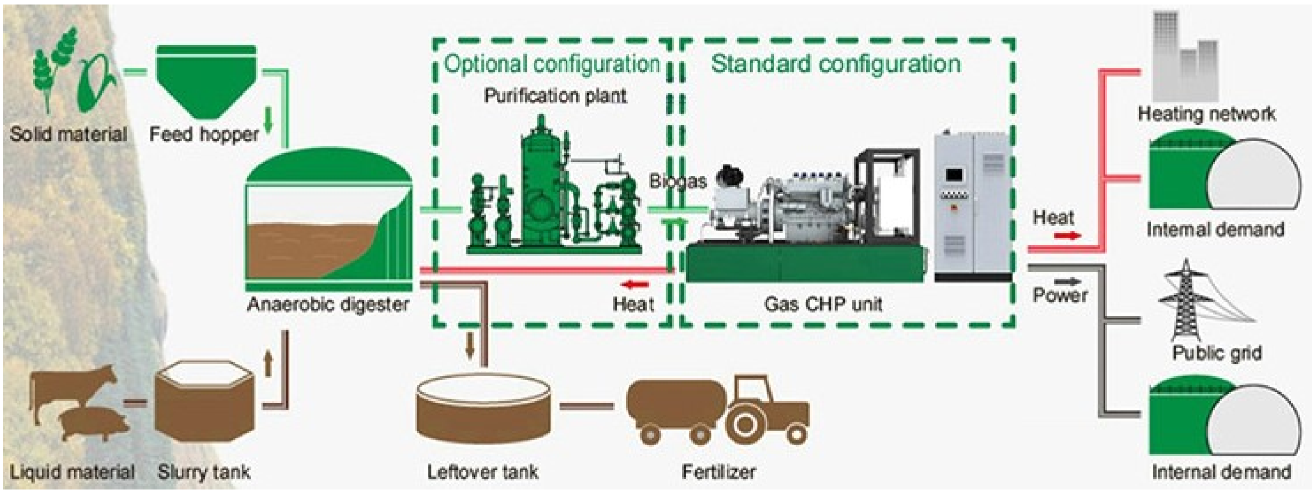


Figure 88: Biogas CHP working diagram (ref. 5).

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.

Investment cost estimation

Investment costs [MUSD2019/MW]		**2020**	**2030**	**2050**
Catalogues	**This Technology Catalogue**	2.90	2.70	2.30
	Viet Nam Technology Catalogue (2021)	2.90	2.70	2.30
	Viet Nam Technology Catalogue (2019)	2.80	2.60	2.20
International data	Danish Technology Catalogue	1.00	0.95	0.90
	Germany (Ref. 13)	2.40	2.40	2.39
	Indonesia (Ref. 14)	2.15	1.96	1.72
Projection	Learning curve – cost trend [%]	100%	93%	79%

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 Viet Nam, 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 Viet Nam.

References

The following sources are used:

1. Jorgensen, *Biogas – green energy*, Faculty of Agricultural Sciences, Aarhus University, 2nd edition, Denmark, 2009.
2. RENAC. *Biogas Technology and Biomass*, Renewables Academy (RENAC) AG, Berlin, Germany.
3. IIEE, "User guide for Bioenergy Sector", *Indonesia 2050 Pathway Calculator*, Jakarta, Indonesia, 2015.
4. DEA, *Technology Data for Energy Plants*, Danish Energy Agency, Copenhagen, Denmark, 2015.
5. Ettes Power Machinery, http://www.ettespower.com/Methane-Gas-Generator.html, Accessed: 10th August 2017.
6. Ministry of Environment, *Danish Climate Strategy*, Denmark, 2003.
7. Walker, "Stirling Engines", *Clarenden Press*, Oxford, London, England, 1980.
8. Cleanenergy, Stirling CHP Systems: Driving the future of biogas power, Cleanenergy AB, Sweden, 2014.
9. Makel Engineering, "Biogas-Fuelled Hcci Power Generation System For Distributed Generation", *Energy Research and Development Division*, *Final Project Report*, California, USA, 2014.
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, Renewable Power Generation Costs in 2017, International Renewable Energy Agency, Abu Dhabi, 2018.
13. DIW Berlin, Current and prospective costs of electricity generation until 2050, 2013.
14. DEA, Technology data for the Indonesian power sector, 2021.

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, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity", 2017

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

3 Winrock, "Buku Panduan Konversi POME Menjadi Biogas, Pengembangan Proyek di Indonesia", USAID – Winrock International, 2015.

4 RENAC, "Biogas Technology and Biomass, Renewables Academy (RENAC)", 2014.

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

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

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

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

9 Learning curve approach for the development of financial parameters.

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

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, "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", 2004.

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 (in the condition of being close to the gas sources) 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 NOx, SO2 emissions, and noise
- For gas-fired engines:
    - Need to develop fuel import infrastructure (LNG) for medium-sized power plants
    - Medium-sized and large-sized engines need to be close to the fuels supply to minimize fuel transportation costs, resulting in overall lower flexibility in selecting the location.

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.

References

The following sources are used:

1. BWSC, Hybrid power – integrated solutions with renewable power generation. Article viewed, 3rd August 2017 http://www.bwsc.com/Hybrid-power-solutions.aspx?ID=1341 , 2017
2. Danish Energy Agency, Technology Data for Energy Plants, August 2016, https://ens.dk/sites/ens.dk/files/Analyser/technology_data_catalogue_for_energy_plants_-_aug_2016._update_june_2017.pdf, 2016.
3. Danish Energy Agency, "Technology Data - Generation of Electricity and District Heating", 2020.

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$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	20	20	20						9
Generating capacity for total power plant (MWe)	100	100	100						
Electricity efficiency, net (%), name plate	46	47	48						9
Electricity efficiency, net (%), annual average	45	46	47	43	47	45	52		9
Forced outage (%)	3	3	3						
Planned outage (weeks per year)	1	1	1						1
Technical lifetime (years)	25	25	25						1
Construction time (years)	1.0	1.0	1.0						1
Space requirement (1000 m^2/MWe)	0.05	0.05	0.05						1
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-						
Capacity factor (%), incl. outages	-	-	-						
Ramping configurations									
Ramping (% per minute)	100	100	100						7,8,9
Minimum load (% of full load)	6.0	6.0	6.0					A	7,8,9
Warm start-up time (hours)	0.05	0.05	0.05						7,8,9
Cold start-up time (hours)	0.2	0.2	0.2						7,8,9
Environment									
PM 2.5 (gram per Nm^3)	20	20	20					B,C	2,3
SO_2 (degree of desulphuring, %)	0	0	0					C	2,3
NO_X (g per GJ fuel)	280	280	280					C	2,3
Financial data									
Nominal investment (M$/MWe)	0.60	0.58	0.55	0.55	0.70	0.50	0.65	D	5,6,8,9
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	10,000	9,500	9,000						1,8,9
Variable O&M ($/MWh)	6.5	6.0	5.5						1,8,9
Start-up costs ($/MWe/start-up)	-	-	-						

References:

1 Danish Energy Agency, "Technology Data for Energy Plants", 2016.
2 Minister of Environment of Indonesia, Regulation 21/2008.
3 The International Council on Combustion Engines, Guide to diesel exhaust emissions control of NOx, SOx, particles, smoke and CO_2, 2008.
4 http://www.bwsc.com/News---Press.aspx?ID=530&PID=2281&Action=1&NewsId=206
5 BWSC once again to deliver highly efficient power plant in the Faroe Islands.
6 Ea Energy Analyses and Danish Energy Agency, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity", 2017.
7 IRENA, Flexibility in Conventional Power Plants, 2019. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Flexibility_in_CPPs_2019
8 Danish Energy Agency, "Technology Data - Generation of Electricity and District Heating", 2020.
9 Wärtsila, "White paper Combustion engine power plants", Niklas Haga, General Manager, Marketing & Business Development Power Plants, 2011.

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 of Indonesia, 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$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	20	20	20						9
Generating capacity for total power plant (MWe)	100	100	100						
Electricity efficiency, net (%), name plate	47	48	49						8,9
Electricity efficiency, net (%), annual average	46	47	48	44	48	46	52		8,9
Forced outage (%)	3	3	3						
Planned outage (weeks per year)	1	1	1						1
Technical lifetime (years)	25	25	25						1
Construction time (years)	1.0	1.0	1.0						1
Space requirement (1000 m^2/MWe)	0.05	0.05	0.05						1
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-						
Capacity factor (%), incl. outages	-	-	-						
Ramping configurations									
Ramping (% per minute)	100	100	100						7,8,9
Minimum load (% of full load)	6.0	6.0	6.0					A	7,8,9
Warm start-up time (hours)	0.05	0.05	0.05						7,8,9
Cold start-up time (hours)	0.2	0.2	0.2						7,8,9
Environment									
PM 2.5 (gram per Nm^3)	7.5	7.5	7.5					B	2,3,8,9
SO_2 (degree of desulphuring, %)	0	0	0						2,3
NO_X (g per GJ fuel)	125	125	125						2,3,8,9
Financial data									
Nominal investment (M$/MWe)	0.60	0.58	0.55	0.55	0.70	0.50	0.65	C	5,6,8,9
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	10,000	9,500	9,000						1,8,9
Variable O&M ($/MWh)	6.5	6.0	5.5						1,8,9
Start-up costs ($/MWe/start-up)	-	-	-						

References:

1 Danish Energy Agency, "Technology Data for Energy Plants", 2016.

2 Minister of Environment of Indonesia, Regulation 21/2008.

3 The International Council on Combustion Engines, Guide to diesel exhaust emissions control of NOx, SOx, particles, smoke and CO_2, 2008.

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

5 BWSC once again to deliver highly efficient power plant in the Faroe Islands.

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

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

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

9 Wärtsila, "White paper Combustion engine power plants", Niklas Haga, General Manager, Marketing & Business Development Power Plants, 2011.

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.

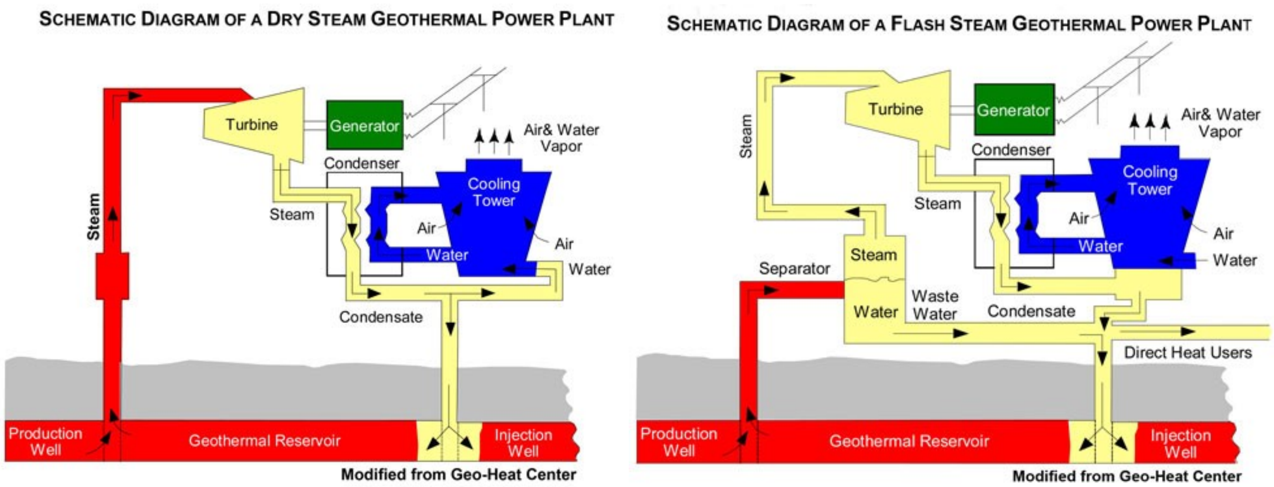


Figure 89: Direct and single flashed steam plants (ref. 7)

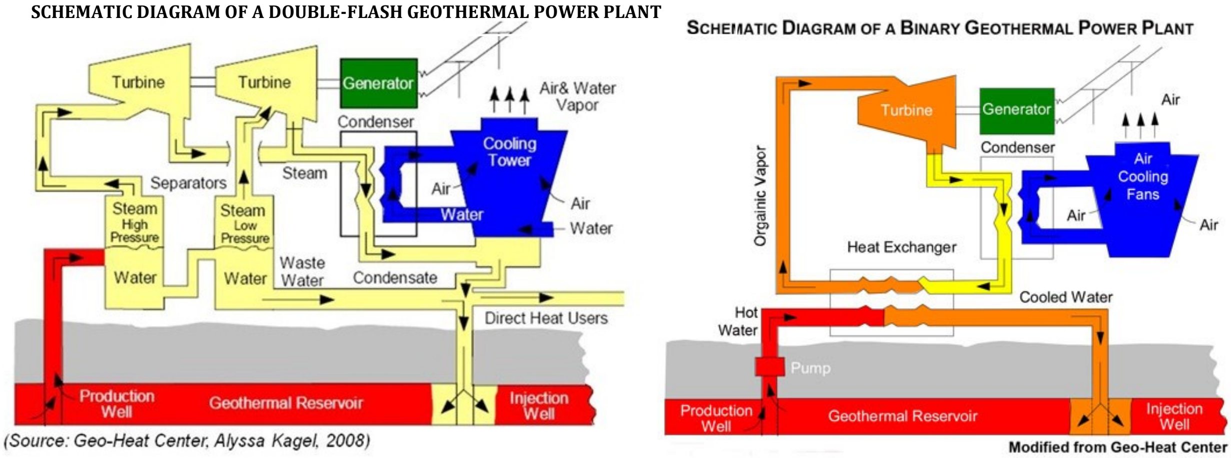


Figure 90: Double flashed (left) and binary (right) geothermal steam plants (ref. 7)

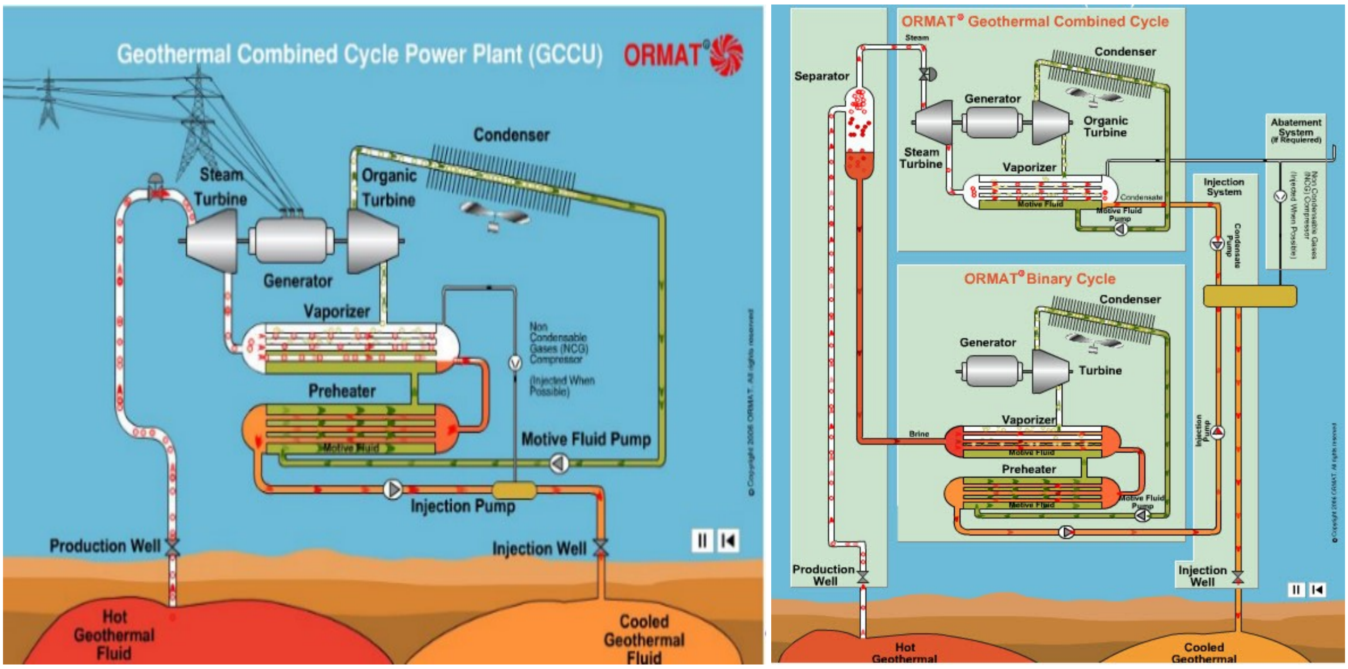


Figure 91: Hybrid/Combined Cycle plant (ref. 8)

The potential for geothermal energy in Viet Nam 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

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

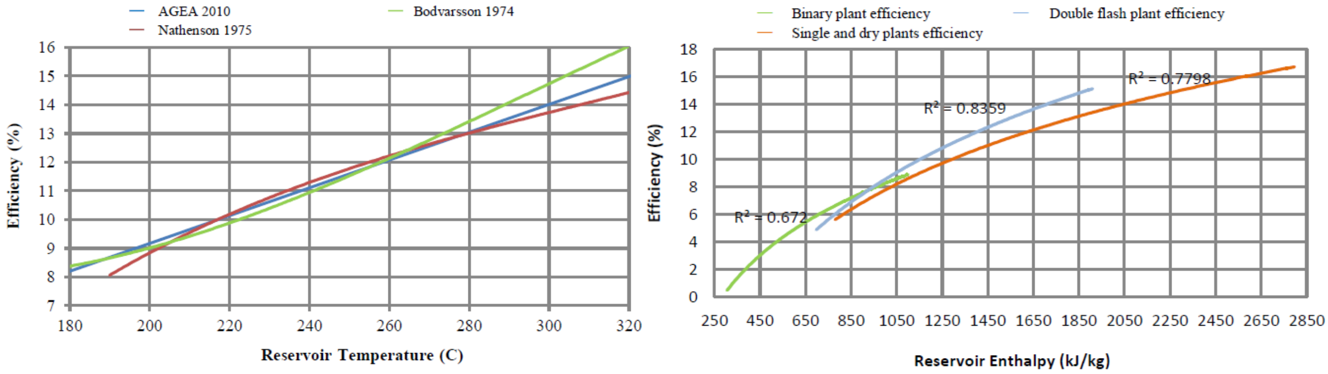


Figure 92: Geothermal plant efficiency as a function of temperature and enthalpy (ref. 5)

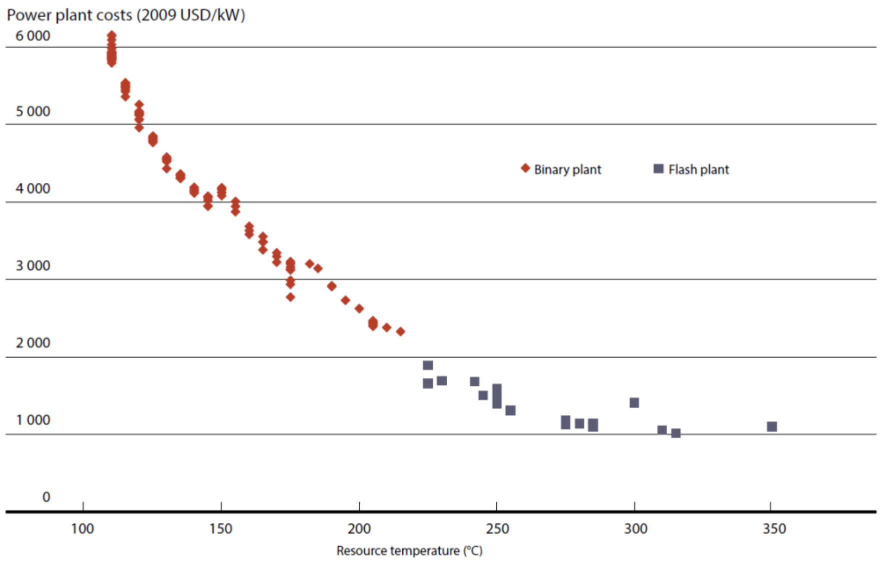


Figure 93: Indicative power plant only costs for geothermal projects by reservoir temperature (ref. 10). The power plant unit stands for around 40-50% of the total capital costs.

References

The following sources are used:

1. Hochstein, M.P., "Classification and assessment of geothermal resources" in: *Dickson MH and Fanelli M., Small geothermal resources*, UNITAEWNDP Centre for Small Energy Resources, Rome, Italy, 31-59, 1990.
2. Yuniarto, et. al., "Geothermal Power Plant Emissions in Indonesia", in *Proceedings World Geothermal Congress 2015*, Melbourne, Australia, 2015.
3. Moon & Zarrouk, "Efficiency Of Geothermal Power Plants: A Worldwide Review", in *New Zealand Geothermal Workshop 2012 Proceedings*, Auckland, New Zealand, 2012.
4. Colorado Geological Survey, www.coloradogeologicalsurvey.org, Accessed: 20th July 2017.
5. Ormat, Geothermal Power, www.ormat.com/geothermal-power, Accessed: 20th July 2017.
6. Sarulla Operation Ltd, Sarulla Geothermal Project, www.sarullaoperations.com/overview.html, Accessed: 20th July 2017.
7. IRENA, Renewable Power Generation Costs in 2014, 2015.
8. Geothermal Energy Association, 2006, "A Handbook on the Externalities, Employment, and Economics of Geothermal Energy", 2006.
9. Hoang Huu Quy, Overview of the geothermal potential of Viet Nam. Geothermics. Volume 27, Issue 1, February 1998, Pages 109-115, 1998.
10. IRENA, Renewable Power Generation Costs in 2017, International Renewable Energy Agency, Abu Dhabi, 2018.

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, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity", 2017.

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

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

4 Learning curve approach for the development of financial parameters.

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

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

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

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

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 of Indonesia, 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, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity", 2017.

2 IEA, World Energy Outlook, 2015.

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

4 Learning curve approach for the development of financial parameters.

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

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

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

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

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 of Indonesia, 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. NUCLEAR POWER GENERATION

Brief technology description

Nuclear energy has been used for civil purposes since the mid-1900s. In 2022, more than 400 nuclear reactors serving power generation in over 30 countries, with a total installed capacity of about 360 GW, have been put into operation. Electricity production from nuclear power plants in 2022 is about 2,487 TWh (Ref. 18). There are currently 55 new nuclear reactors under construction in 19 countries, with a total installed capacity of about 60 GW, and are expected to be operational in the period up to 2030. After 2030, about 100 new GW of nuclear power is planned to be built globally (Ref. 19). Nuclear power is a source of electricity with high capacity, stable and reliable operation without greenhouse gas emissions (Ref.).

Progress in nuclear engineering has brought about significant changes in the plant layout ever since. Different concepts have been tested and used around the world, building on national and regional research programs. Nuclear power plants are not standardized technology, as geopolitical reasons and historical legacy make nuclear research a national or regional matter.

In broad terms, nuclear energy can be obtained by:

- Splitting the nuclei of specific, heavy chemical elements (nuclear fission)
- Combining the nuclei of light chemical elements (nuclear fusion)

Nuclear power plants operating in the world are mainly fission type.

All fission power plants build on the same concept (Figure 94). Heavy atom nucleus' components (protons, neutrons) are tied together by nuclear forces. Elements with atomic number (Z) over 83 are unstable and decay naturally into elements with a higher binding energy. This occurs because the resulting elements have a higher stability than the original element.

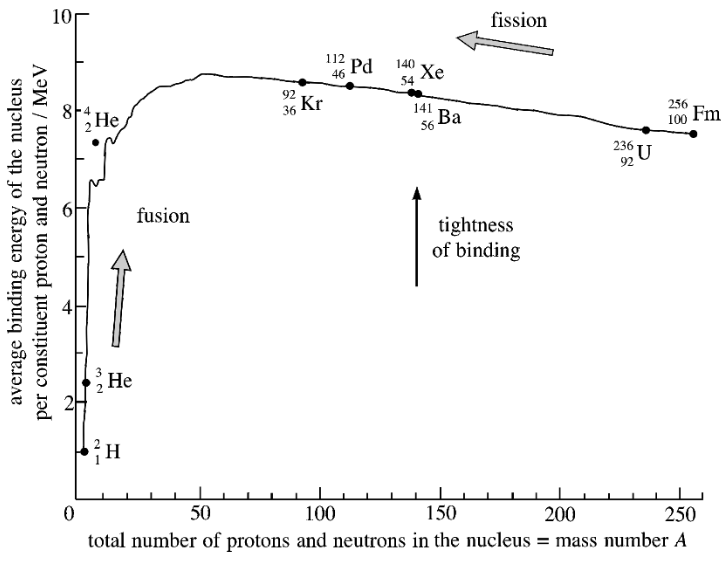


Figure 94: Nuclear energy binding graph (ref 1)

Fission can also be induced by supplying energy to such unstable elements, which in turn release an amount of energy equal to the binding energy of the original element. Induced fission is at the heart of nuclear power plant engineering. The activation energy, which is kinetic energy provided by mobile neutrons hitting the nuclei of selected heavy elements (such as uranium-235), catalyses a reaction such as the following:

$$^{1}_{0}n + {}^{235}_{92}U \rightarrow {}^{141}_{56}Ba + {}^{92}_{36}Kr + 3\,^{1}_{0}n + energy$$

Uranium-235 is one of the fissile elements, which can be used to sustain the chain reaction: for every uranium-235 atom splitting, about three mobile neutrons *n* are released, which in turn go on hitting other uranium-235 atoms. Energy is released in the form of heat, later used in the power cycle.

Nuclear reactors are designed to sustain and keep a stable reactivity. In the type of reactor that uses thermal energy neutrons, the core consists of the main components of the fuel, the moderator and the coolant. For this type of reactor, the light water acts both as a moderator and as a cooler for the reactor. In a fast breeder reactor, there is no moderator, only fuel and coolant. These components are briefly described below:

- The fissile material (e.g., uranium-235) is normally contained in rods, which need to be periodically replaced as the core gets short of fissile material (fuel cycle).
- The control elements, typically rods, can be lowered or lifted to regulate reactivity. Rods are made of a certain chemical element which inhibits reactivity by absorbing neutrons, usually high-boron steel and boron carbide.
- The moderator, which is only present in thermal reactors, is used to moderate-that is, to slow down neutrons produced during fission from the high energy band to the low energy band. Neutrons in the low energy range are called thermal neutrons. The newly born neutrons will interact with water molecules and lose energy. U-235 only interacts with thermal neutrons. Water, heavy water, and graphite (the common form of carbon) are often used as moderators.
- The coolant passes through the reactor core, which will take the heat generated by fission reactions, Water and heavy water used in the reactor uses thermal energy neutrons, it acts as both a coolant. slow as well as coolant. Liquid and gaseous sodium used in fast neutron reactors.
- The reactor pressure vessel is made of stainless steel material, resistant to high pressure and high heat. The reactor vessel is where the reactor core, control rod assemblies, retarder, and coolant are stored. The fuel rods are arranged according to the design of the country of manufacture and are fixed by the racks, the system of control rods, the automatic rod assemblies.

Fission power plants are usually classified by the core design, the general classification are as follow:

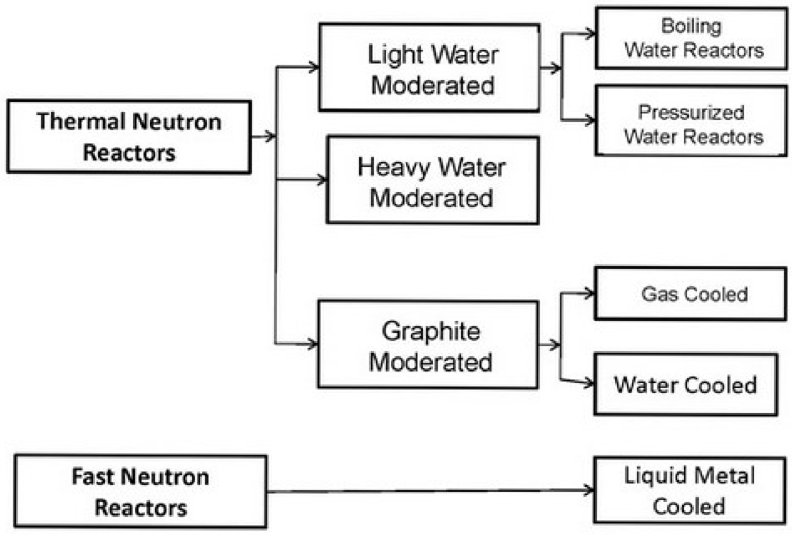


Figure 95: Classification of nuclear reactors

The most common reactors are: (i) Pressurized water reactors (PWRs), where the moderator is water kept at high-pressure to prevent vaporization (Figure 96). (ii) Boiling water reactors (BWRs), where the moderator is water turning into steam as it absorbs heat in the core (Figure 97). In both cases, water as a moderator can be either heavy or light, depending on the hydrogen isotope. Nowadays, most commercial reactors are of the types above (PWR or BWR), but PWR is most commonly applied. Nevertheless, other moderators and core designs have been used since the 1950s but have been progressively abandoned.

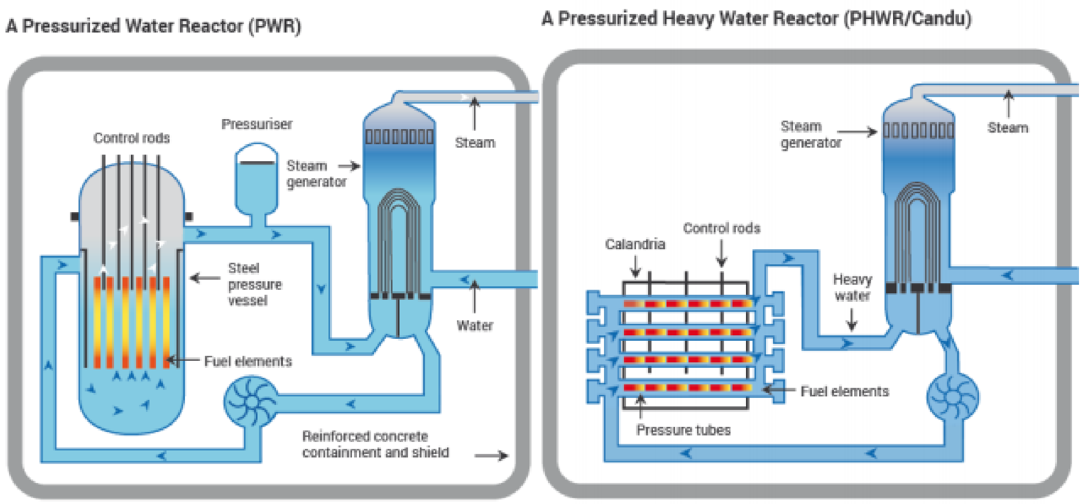


Figure 96: PWR schemes (ref. 2)

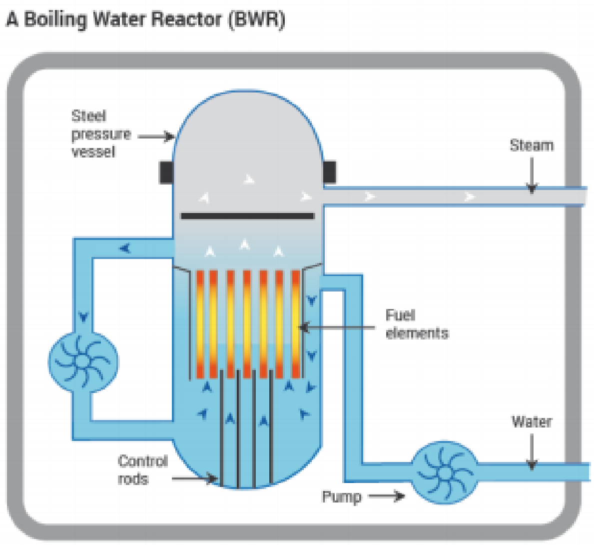


Figure 97: BWR schemes (ref. 2)

In PWRs, the primary loop water passes through the reactor core and collects heat, then enters the hot channel and passes through the U-tubes in the steam generator. Here, the water from the secondary loop in the steam generator takes heat from the water of the primary loop through the surface of the U-tube and boils to form steam, the steam is led by the pipe and enters the turbine, turning the turbine. bin and generate electricity. The water of the primary loop after losing heat goes to the other side of the steam generator and is pumped into the reactor tank through the cold channel (one cycle is over). Note that with the design of the PWR type, the water in the primary loop contains radiation, the water in the secondary loop does not (in the event that the U-tube break/break has not occurred); however, the water in the second loop de-irradiation is also carried out when there is a break/break of the U-tube.

Table 35 summarizes the reactor designs, which are being operated or are operable.

Table 35: Nuclear reactor types currently under operation or operable (ref 2).

Reactor type	Main countries	Number	GWe	Fuel	Coolant	Moderator
Pressurized water reactor (PWR)	USA, France, Japan, Russia, China, South Korea	301	286	Enriched UO_2	Water	Water
Boiling water reactor (BWR)	USA, Japan, Sweden	64	65	Enriched UO_2	Water	Water
Pressurized heavy water reactor (PHWR)	Canada, India	48	24	Natural UO_2	Heavy water	Heavy water
Advanced gas-cooled reactor (AGR)	UK	14	8	Natural U (metal), enriched UO_2	CO_2	Graphite
Light water graphite reactor (LWGR)	Russia	12	8,4	Enriched UO_2	Water	Graphite
Fast neutron reactor (FBR)	Russia	2	1,4	PuO_2 and UO_2	Liquid sodium	none
Total		441	393			

Nuclear power plants are also classified based on their performance, cost and safety. In this classification, nuclear power plants belong to a specific *generation*

- ***Generation I* reactors** (1950s - 1960s): were the first commercial reactors. The design differed from country to country and the reactor could be moderated in different manners (water, gas etc.). No Generation I reactor is still in operation.
- ***Generation II* reactors** (1970s - 2000s): are essentially water-cooled and moderated. They can be of the PWR/PHWR or BWR type. An exception is the AGR graphite-moderated reactor used in the UK. This generation of reactors are more efficient, reliable and safe than Generation I reactors.
- ***Generation III* reactors** (2000s - 2010s): Advanced designs (APWR, ABWR, AP600, EPR,…) feature safety and design improvements with respect to Generation II reactors and are characterized by an extended lifetime (up to 60 years). They are also conceived to have longer fuel cycles, minimizing downtime.
- ***Generation III+* reactors** (2010s - mid-2020s): Introduction of advanced passive safety features (e.g: in the event of an extreme incident, the reactor is designed with a core-catcher system, radioactive material is kept in the bottom of the furnace tank, not released into the environment), include Russia's VVER-1200/AES 2006; America's AP 1000; French EPR-1750, Advanced CANDU,...
- ***Generation IV* reactors** (mid-2020s onwards). The next generation of nuclear reactors under development by the GIF (Generation IV International Forum), increased efficiency, increased safety and reliability (see further in *Research and development* section).

The power cycle is normally a subcritical Rankine cycle. The efficiency of the cycle depends on the steam characteristics. Nuclear power plants use heat from nuclear fission reactions that produce steam to drive turbines to rotate and thereby generate electricity. In some cases, nuclear plants have also been used for heat production. However, given the high costs of nuclear energy, this is not common, as electricity is more valued as a commodity.

Currently, small modular reactors – SMR are becoming the new trend in nuclear power development. SMR offers a lower initial capital investment, greater scalability, shorter construction time and siting flexibility for locations unable to accommodate more traditional larger reactors. They also have the potential for enhanced safety and security compared to earlier designs.

Small modular reactors (**SMR**s) are a proposed class of nuclear fission reactors, smaller than conventional nuclear reactors, which can be built in one location (such as a factory), then shipped, commissioned, and operated at a separate site. The term SMR refers to the size, capacity and modular construction only, not to the reactor type and the nuclear process which is applied. Designs range from scaled down versions of existing designs to *G*eneration IV designs. Both thermal-neutron reactors and fast-neutron reactors have been proposed, along with molten salt and gas cooled reactor models (ref. 7). SMRs have a power capacity of up to 300 MW(e) per unit, which is about one-third of the generating capacity of traditional nuclear power reactors. SMRs are characterised by:

- **Small** – physically a fraction of the size of a conventional nuclear power reactor.
- **Modular –** making it possible for systems and components to be factory-assembled and transported as a unit to a location for installation.
- **Reactors –** harnessing nuclear fission to generate heat to produce energy.

Despite the loss of the advantages of economy-of-scale and considerably lesser power output, funding was expected to be easier thanks to the introduction of modular construction and projects with expected shorter timescales. The generic SMR proposal is to swap the economies of unit scale for the economies of unit mass production.

Currently, SMR have not been tested for commercial operation and the legal regulations have not yet been amended to apply.

Input

Nuclear fuel, main composition consists of Uranium, Plutonium, Thorium, etc

Output

Electricity.

Typical capacities

The International Atomic Energy Agency (IAEA) defines SMRs as "newer generation reactors designed to generate electric power up to 300 MW (ref. 8), medium-sized reactors as "reactors with an equivalent electric power between 300 and 700 MW" (ref. 9). Large reactors (conventional reactor) are generally considered reactors with an equivalent electric power higher than 700 MWe.

Ramping configurations

Nuclear power plants are characterized by high investment and high fixed operation and maintenance costs. However, variable operation costs are low. Therefore, they are usually run in base load mode. However, nuclear power plants are able to operate at a lower number of operating hours over wide ranges in many countries due to the increasing penetration of renewables. Modern reactors are able (and, in most cases, need) to adjust their operation to follow scheduled or unscheduled load changes, either directly on system operators' requests or via power price dynamics. In Europe, it is a requirement that nuclear power plants are capable of daily cycling between 50% and 100% of nominal load, with a ramping rate of 3-5% per minute. Most modern nuclear power plants (II+/III generation) can safely lower their production to 25% the nominal load.

SMRs are able to be added to the system in smaller increments, expanding flexibility for system planners. This comes in two ways—the reactors themselves have better capability to ramp up or down, and with multiple small reactors, it is easier to turn on/off one of several reactors to vary the output of the overall plant. Daily load follow of SMRs can be performed from 100% to as low as 20% power, at a linear power ramp rate of 5% - 10% per min (ref. 10).

Advantages/disadvantages

Advantage and disadvantage of nuclear power compared to other technologies [Ref 1, 2, 5]:

Advantages:
- Well-established technology (conventional reactors).
- Despite past accidents, nuclear power plants are a relatively safe technology.
- High energy density in terms of area required.
- Low carbon emissions. Does not emit greenhouse gases once operational.
- Lower operating cost compared to many other technologies.
- Consumes very small quantity of fuel.
- Large fuel storage facility is not required.

- Production level is usually not affected by weather conditions.
- Nuclear power plants are well suited to meet large power demands as they have a high efficiency and load factors (80 to 90%).

Disadvantages:

- Fissile materials (normally uranium) only available in selected countries on Earth.
- Environmental risks related to mining of the fuel.
- Operation patterns conditioned by refuelling (fuel cycles).
- Long construction time.
- Limited locations suited for power plant construction. Requirements: proximity to load centres, rivers or the sea to operate the condenser, away from seismic areas.
- Public acceptance issues.
- Geopolitical issues.
- During extreme events, safe operations have not always been guaranteed. Possibility of nuclear disaster.
- High initial capital cost.
- The maintenance cost is high (due to lack of standardisation and high salaries of the trained personnel in this field of specialisation).
- Handling of nuclear wastes and overall safety is a major concern.
- Decommissioning of nuclear power plants is a long and expensive process.

Advantage and disadvantage of SMR compared to large reactors [Ref 11-15]:

SMR advantages:

- **Enhanced safety and security:** Lower thermal power of the reactor core, compact architecture, and employment of passive concepts have the potential for enhanced safety and security compared to earlier designs and large commercial reactors. The passive safety systems are a very important safety feature in the SMR. Therefore, there is less reliance on active safety systems and additional pumps and AC power for accident mitigation. These passive safety systems can dissipate heat even after the loss of offsite power. The safety system incorporates an on-site water inventory that operates on natural forces (e.g., natural circulation). In reactor engineering, natural circulation is a very desired phenomenon since it can provide reactor core cooling without coolant pumps so that no moving parts could break down.
- **Modularity:** As was written, the term "modular" in SMRs refers to its scalability and the ability to fabricate major components of the nuclear steam supply system (NSSS) in a factory environment and then transport them to the site. This can help limit the on-site preparation and also reduce the construction time. This is very important since the lengthy construction times are one of the key problems of the larger units.
- **Construction time and financing:** Size, construction efficiency, and passive safety systems (requiring less redundancy) can reduce a nuclear plant owner's capital investment due to the lower plant capital cost. This, in turn, can lead to easier financing compared to larger plants
- **Reduced refueling needs:** SMRs use only a small amount of fuel and only need to be refueled every 3–7 years, compared to 1–2 years for conventional plants. Some SMRs are even designed to operate for up to 30 years without refueling.

SMR disadvantages:

- **Lost economies of unit scale:** Nuclear reactors grew bigger because manufacturers and operators gained commercial advantages from increasing size and output. SMR lost the advantages of economic of unit scale and only be cost-effective at high quantities, which require a large deployment.
- **Licensing:** One of the very important barriers is licensing of new reactor designs, the licensing process for new reactor as SMR designs is a lengthy and costly.

Environment

On a life-cycle basis, nuclear power emits just a few grams of CO_2-equivalent per kWh of electricity produced. A median value of 12 g CO2 equivalent/kWh has been estimated for nuclear, which is relatively low as compared to other power generation technologies (Figure 98). These emissions are based on a life cycle approach. In operation, a nuclear plant has no CO_2-emissions.

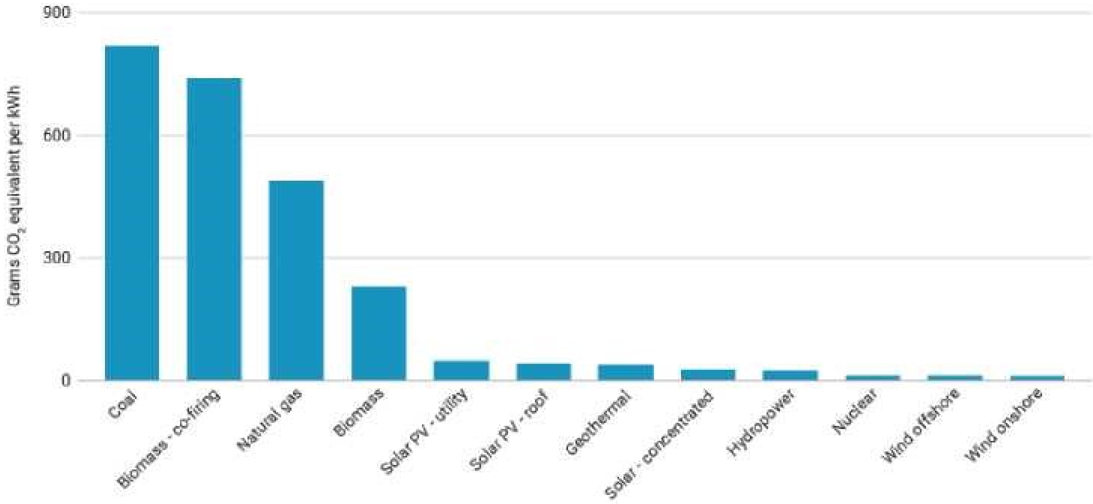


Figure 98: Average life-cycle CO_2 equivalent emissions (ref 2).

In terms of land use, nuclear power plants take up the least space compared to other technologies due to their high energy density. Another environmental aspect relevant to electricity production technologies is the use of water (depicted in Figure 99) which is becoming a scarce and valuable resource.

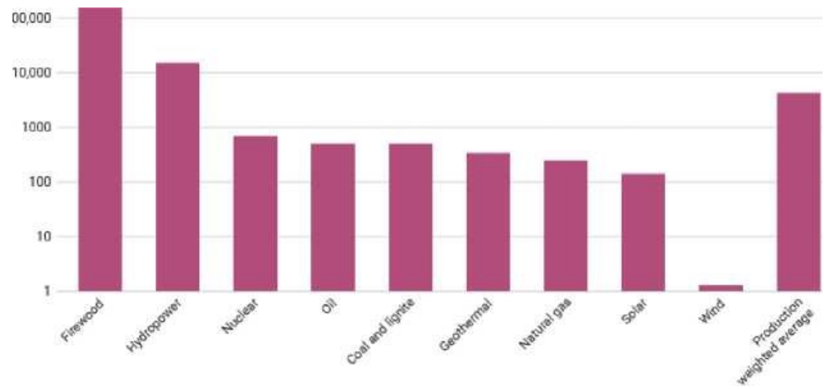


Figure 99: Water consumption per unit of electricity and heat produced (2008-2012) (ref 2).

Handling radioactive waste is one of the most significant environmental risks. Exposure to certain high levels of radiation, such as that from high level radioactive waste, can even cause death. Radiation exposure can also cause cancer, birth defects, and other abnormalities, depending on the duration of exposure, amount of radiation, and the decay mechanism. High-level radioactive waste from nuclear reactors can be hazardous for thousands of years.

Radioactive waste includes any material that is either intrinsically radioactive, or has been contaminated by radioactivity, and that is deemed to have no further use. Every radioactive particle has a half-life - the time taken for half of its atoms to decay, and thus for it to lose half of its radioactivity. Radioactive particles with long half-lives tend to be easier to handle. Eventually all radioactive waste decays into non-radioactive elements. The more radioactive an isotope is, the faster it decays.

Radioactive waste is produced at all stages of the nuclear fuel cycle. The fuel cycle involves the mining and milling of uranium ore, its processing and fabrication into nuclear fuel, its use in the reactor, its reprocessing, the treatment of the used fuel taken from the reactor, and finally, disposal of the waste. Whilst waste is produced during mining and milling and fuel fabrication, the majority (in terms of radioactivity) comes from the actual 'burning' of uranium to produce electricity. Radioactive waste is typically classified as either low-level (LLW), intermediate-level (ILW), or high level (HLW), dependent, primarily, on its level of radioactivity.

Currently, many radioactive waste treatment options have been researched and considered, including: Burying in the ground, nuclear waste recycling, taken into space, buried under the sea, buried in the subduction zone, buried under the glacier, stored in artificial stone, shorter half-life. The two options that are most used today are buried in the ground and recycling.

In waste burial approach, the waste can be temporarily treated/stored on-site (about 40 - 50 years) at the production facility using several methods, such as vitrification, ion exchange or synroc and then will be buried in a dedicated place in long term. In recycling approach, used fuel is processed to separate Plutonium and Uranium for reuse, the rest can be vitrified and buried.

On December 28, 2010, the Prime Minister issued Decision No. 2376/QD-TTg approving the orientation and planning of radioactive waste storage and burial sites until 2030, with a vision to 2050. The planning orientation clearly states that low and medium-active radioactive waste with a half-life of less than 100 days is stored in the storage facilities of the generating facility until it self-disintegrates. Low and medium activity radioactive waste with a half-life of more than 100 days to 30 years is transported to a national storage and burial depot for burial. As for radioactive waste, used radioactive sources with high activity and long half-life are centrally managed and stored in national warehouses. In particular, spent nuclear fuel is preserved, awaiting treatment at the cooling tank of the nuclear power plant for a period of 30-50 years, pending treatment according to the level of nuclear science and technology development in the world. and national radiation management policy.

Employment

A study on employment generated by the nuclear power sector, based on plants in OECD countries, suggested that a 1000 MWe plant leads to (ref. 3):

- Direct employment during a ten-year period of site preparation and construction of some 1200 professional and construction staff.
- Over a 50-year operating period, approximately 600 administrative, operation and maintenance, and permanently contracted staff are employed annually.
- Once the reactor is shut down, a further 500 people are employed annually over a ten-year period of decommissioning. In addition, over a period of about 40 years, 80 employees manage nuclear waste.

In addition, several jobs are created through indirect employment for the nuclear supply chain. Therefore, the total employment over the life cycle of a 1000 MWe nuclear power reactor is therefore estimated to be -3000 jobs.

About SMR, a study showed that the concepts GT-MHR SMR- 285 MW and GT-MGR SMR- 262 MW require operation staff of about 230 and 166 respectively (ref. 11).

Research and development

The next generation of nuclear reactors are categorized as Generation IV. Designs for Generation IV are not expected to be operational before the mid-2020s. There are seven designs being considered as Generation IV. These are under development by the GIF (Generation IV International Forum) an international collective representing governments of 13 countries where nuclear energy is significant now and seen as vital for the future. The different reactors are summarized in the table below.

Table 36: Generation IV reactors (ref. 2).

	Neutron spectrum (fast/ thermal)	Coolant	Temperature (°C)	Pressure	Fuel	Fuel cycle	Size (MWe)	Use
Gas-cooled fast reactors	Fast	Helium	850	High	U-238+	Closed, on site	1200	Electricity & hydrogen
Lead-cooled fast reactors	Fast	Lead or Pb-Bi	480-570	Low	U-238+	Closed, regional	20-180 300-1200 600-1000	Electricity & hydrogen
Molten salt fast reactors	Fast	Fluoride salts	700-800	Low	UF in salt	Closed	1000	Electricity & hydrogen
Molten salt reactor – Advanced high-temperature reactor	Thermal	Fluoride salts	750-1000		UO_2 particles in prism	Open	1000-1500	Hydrogen
Sodium-cooled fast reactors	Fast	Sodium	500-550	Low	U-238 & MOX	Closed	50-150 600-1500	Electricity
Supercritical water-cooled reactors	Thermal or fast	Water	510-625	Very high	UO_2	Open (thermal) Close (fast)	300-700 1000-1500	Electricity
Very high-temperature gas reactors	Thermal	Helium	900-1000	High	UO_2 prism or pebbles	Open	250-300	Electricity & hydrogen

Additionally, more than a dozen (Generation III) advanced reactor designs are in various stages of development. One of these is called Advanced Boiling Water Reactor, a few of which are now operating with others under construction. The best-known radical new design has the fuel as large 'pebbles' and uses helium as coolant, at very high temperature, possibly to drive a turbine directly. Considering the closed fuel cycle, Generation I-III reactors recycle plutonium (and possibly uranium), while Generation IV are expected to have full actinide recycle. Many advanced reactor designs are for small units - under 300 MWe - and in the category of small modular reactors (SMRs), since several of them together may comprise a large power plant, may be built progressively.

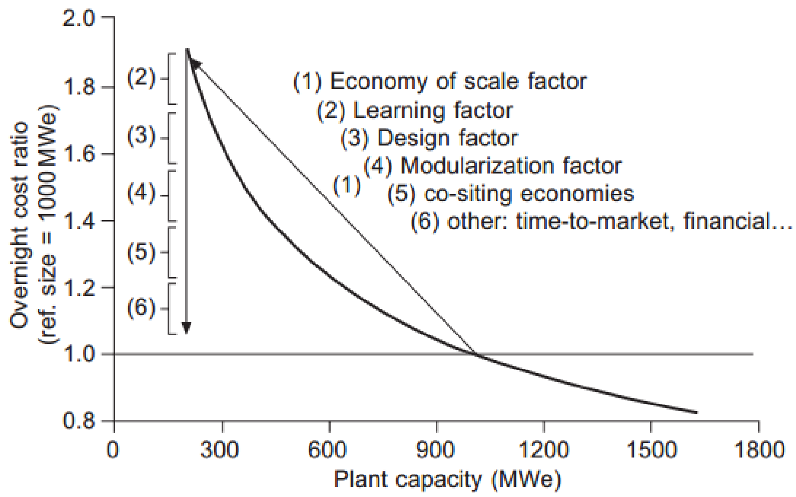
Investment cost estimate

<u>*Large reactor*</u>: The overnight capital cost for a nuclear plant is dependent on various factors ranging from plant design, equipment, labour, and construction. The value for 2020 is taking into account the global context, under the assumption that the plant to be set up would most likely be a PWR, since it is the most commonly used technology today as seen in table below. For the projected values until 2050, the learning curve approach is employed, which considers the global capacity development estimates as per the IEA's WEO19, as discussed in the appendix. The data are summarised in the table below.

Investment costs [MUSD$_{2019}$/MW]			2019	2020	2030	2050
Catalogues	This Technology Catalogue			5	4,8	4,45
Viet Nam	Ninh Thuan 1&2 NPP		5,06			
International data	Technology catalogue for Ethiopia (2021)			5	4,8	4,45
	NREL		6,3	6,18	5,9	5
	IEA WEO19 (Average of USA and EU)	(Average of USA and EU)	6			4,6 (2040)
		(Average of China and India)	2,7			2,7 *(2040)*
	IEA PCOG		3,4 (2,3 to 7)			
	EON		4,7 (PWR) 2,08 to 6 (Advanced)			
Projection	Learning curve – cost trend [%]			1,0	0,96	0,89

Note: Data of Ninh Thuan 1&2 nuclear power taken from Pre FS report of this project.

<u>*Small modular reactor SMR*</u>: With very few SMR projects under construction and no actual data on overnight actual costs available, cost estimation of SMRs is usually performed on a top-down basis, starting from available information on large, advanced pressurized water reactor (PWR) units, as a starting reference cost:



(Ref. 12 and ref. 13) considers four plant sizes (1600 MWe, 1200 MWe, 300 MWe, 150 MWe) to compare the "economy of scale" and the "economy of multiples" paradigms and two scenarios: NPPs deployed by a big utility and two minors and NPPs deployed by a single utility. The main results are:

- By considering only the "economy of scale," the overnight cost of the first SMR (300 MWe) would be 89% higher than a single LR (1600 MWe);
- By considering not only the "economy of scale" but the "economy of replication" too, the gap reduces to 13%.
- If the "IDC" is considered, the gap between SMRs (300 MWe) and LR (1600 MWe) reduces to 7% - 10%.

Since the investment cost in the TC does not consider IDC (see Appendix), the investment cost of SMR is calculated 13% higher than large reactors, corresponding to 5.65 MUSD/MW, consistent with the results in the study of Ref. 16.

Examples of current projects

SMR: KLT-40 in Russia (marine-based) (ref. 15)

The KLT-40S (Akademik Lomonosov) is a PWR developed for a floating nuclear power plant (FNPP) to provide capacity of 35 MWe per module. The design is based on third generation KLT-40 marine propulsion plant and is an advanced version of the reactor providing the long-term operation of nuclear icebreakers under more severe conditions as compared to stationary nuclear power plant (NPP).

Table 37: Parameters of SMR-type KLT-40S

MAJOR TECHNICAL PARAMETERS	
Parameter	**Value**
Technology developer, country of origin	JSC "Afrikantov OKBM", Rosatom, Russian Federation
Reactor type	PWR
Coolant/moderator	Light water/light water
Thermal/electrical capacity, MW(t)/ MW(e)	150/ 35
Primary circulation	Forced circulation
NSSS Operating pressure (primary/secondary), MPa	12.7
Core inlet/outlet coolant temperature ($°C$)	280/ 316
Fuel type/assembly array	UO_2 pellet in silumin matrix
Number of fuel assemblies in the core	121
Fuel enrichment (%)	18.6
Core discharge burnup (GWd/ton)	45.5
Refuelling cycle (months)	30-36
Reactivity control mechanism	Control rod driving mechanism
Approach to safety systems	Active (partially passive)
Design life (years)	40
Plant footprint (m^2)	4320 (Floating NPP)
RPV height/diameter (m)	4.8 / 2.0
RPV weight (metric ton)	N/A
Seismic design (SSE)	9 point on the MSK scale
Distinguishing features	Floating power unit for cogeneration of heat and electricity; no onsite refuelling; spent fuel take back.
Design status	Connected to the grid in Pevek in December 2019. Entered full commercial operation.

SMR: ACP-100 in China (land-based) (ref. 15)

The ACP100 is an integrated PWR design developed by China National Nuclear Corporation (CNNC) to generate an electric power of 125 MWe. The ACP100 is based on existing PWR technology adapting verified passive safety systems to cope with the consequences of accident events; in case of transients and postulated design basis accidents the natural convection cools down the reactor. The ACP100 integrated design of its reactor coolant system (RCS) enables the installation of the major primary circuit's components within the reactor pressure vessel (RPV).

Table 38: Parameters of SMR type ACP-100

MAJOR TECHNICAL PARAMETERS	
Parameter	**Value**
Technology developer, country of origin	CNNC(NPIC/CNPE) China
Reactor type	Integral PWR
Coolant/moderator	Light water / light water
Thermal/electrical capacity, MW(t)/MW(e)	385 / 125
Primary circulation	Forced circulation
NSSS Operating Pressure (primary/secondary), MPa	15 / 4.6
Core Inlet/Outlet Coolant Temperature (°C)	286.5 / 319.5
Fuel type/assembly array	UO_2/17x17 square pitch arrangement
Number of fuel assemblies in the core	57
Fuel enrichment (%)	<4.95
Core Discharge Burnup (GWd/ton)	<52 000
Refuelling Cycle (months)	24
Reactivity control mechanism	Control rod drive mechanism (CRDM), Gd_2O_3 solid burnable poison and soluble boron acid
Approach to safety systems	Passive
Design life (years)	60
Plant footprint (m^2)	200 000
RPV height/diameter (m)	10 / 3.35
RPV weight (metric ton)	300
Seismic Design (SSE)	0.3g
Fuel Cycle Requirements or Approach	Temporarily stored in spent fuel pools
Distinguishing features	Integrated reactor with tube-in-tube once through steam generator, nuclear island

SMR: Shidaowan HTR-PM in China (land-based) (ref. 17)

Shidaowan project located in Shidao Bay, Shandong province, China is the first land-based SMR, starting operation in December 2021. The plant uses gas-cooled HTR-PM- a Generation-IV reactor designed with twin reactor modules of 100 MW each driving a single 200-MW steam turbine. Its fuel is in the form of thousands of six-centimeter graphite pebbles containing uranium enriched to 8.9% uranium-235. Instead of cooling water, the reactor's graphite core is bathed in inert helium gas with an outlet temperature of up to 750°C. In line with the Generation-IV concept, the HTR-PM reactor can shut down safely in the event of an emergency without causing a core meltdown or significant leak of radioactive material.

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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 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.

Fuel costs are not included. It should finally be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Technology	**Nuclear power plant - PWR**								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	1000	1000	1000						
Generating capacity for total power plant (MWe)	2000	2000	2000					E	
Electricity efficiency, net (%), name plate	36	42	50					D	3
Electricity efficiency, net (%), annual average	33	38	45					D	3
Forced outage (%)	5%	4%	3%					C	2
Planned outage (weeks per year)	8	6	5						2
Technical lifetime (years)	60	60	80						3
Construction time (years)	7	6	6	4	10	4	10		3,4
Space requirement (1000 m^2/MWe)	2.62	2.62	2.62	2.0	3.4	2.0	3.4	E	8,9
Additional data for non-thermal plants									
Capacity factor (%), theoretical	85	87	90	75	93	75	93		3,4,6
Capacity factor (%), incl. outages	85	87	90	75	93	75	93		3,4,6
Ramping configurations									
Ramping (% per minute)	4	5	5					A	1
Minimum load (% of full load)	25	25	25					A	1
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (mg per Nm^3)	-	-	-						
SO_2 (degree of desulphuring, %)	-	-	-						
NO_x (g per GJ fuel)	-	-	-						
CH_4 (g per GJ fuel)	-	-	-						
N_2O(g per GJ fuel)	-	-	-						
Financial data									
Nominal investment (M$/MWe)	5.00	4.80	4.45	2	7	2	7	F	4,5,6,7, 10
- of which equipment	40%	40%	40%						3,7
- of which installation	60%	60%	60%						3,7
Fixed O&M ($/MWe/year)	127,000	122,000	113,000					G	4,5,6,7
Variable O&M ($/MWh)	2.4	2.3	2.2					G	4,5,6,7
Start-up costs ($/MWe/start-up)									

Technology	Nuclear power plant - SMR (Land based Water-cooled)								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	100	100	100	10	300	10	300		
Generating capacity for total power plant (MWe)	300	300	300					E	
Electricity efficiency, net (%), name plate	36	42	50					D	3
Electricity efficiency, net (%), annual average	33	38	45					D	3
Forced outage (%)	5%	4%	3%					C	2
Planned outage (weeks per year)	8	6	5						2
Technical lifetime (years)	60	60	80						3
Construction time (years)	3	3	3	2	5	2	5		10
Space requirement (1000 m^2/MWe)	0.64	0.64	0.64	0.042	1.6	0.042	1.6	E	11
Additional data for non-thermal plants									
Capacity factor (%), theoretical	85	87	90	75	93	75	93		3,4,6
Capacity factor (%), incl. outages	85	87	90	75	93	75	93		3,4,6
Ramping configurations									
Ramping (% per minute)	5	5	5	5	10	5	10	A	12
Minimum load (% of full load)	20	20	20					A	12
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (mg per Nm^3)	-	-	-						
SO_2 (degree of desulphuring, %)	-	-	-						
NO_x (g per GJ fuel)	-	-	-						
CH_4 (g per GJ fuel)	-	-	-						
N_2O(g per GJ fuel)	-	-	-						
Financial data									
Nominal investment (M$/MWe)	5.65	4.9	4.5	2	9.45	2	9.45	F	13,14
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	114,300	109,800	101,700					G	12
Variable O&M ($/MWh)	2.28	2.185	2.09					G	12
Start-up costs ($/MWe/start-up)									

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13. S. Boarin, M. Mancini, M. Ricotti, G. Locatelli, Economics and financing of small modular reactors (SMRs), Handbook of Small Modular Nuclear Reactors, 2021.
14. Giorgio Locatelli, Benito Mignacca, Small Modular Nuclear Reactors.

Notes:

A. Ramping and minimum load are constrained by the core stability'. Minimum requirements are usually set by the regulation.
B. A two-unit configuration is typical in nuclear power plants, but more units can be combined.
C. % of yearly hours with forced outage
D. Generation IV reactors are expected to achieve efficiencies well above 45%. In the future, nuclear reactors are likely' to run often at partial load - thus the gap between nameplate and net efficiency.
E. Nuclear power plants have a very high energy density in terms of area required. The values represented here are for the area needed for the plants. However, there can be a higher requirement based on government regulation and environmental concerns.
F. High variation in cost seen between US, EU, China and India. Moreover, this also depends on technology. Here the chosen values are estimated based on a mix of values available along with employing the learning curve approach used for financial parameters.

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, geothermal power plants and nuclear 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 Viet Nam.

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).

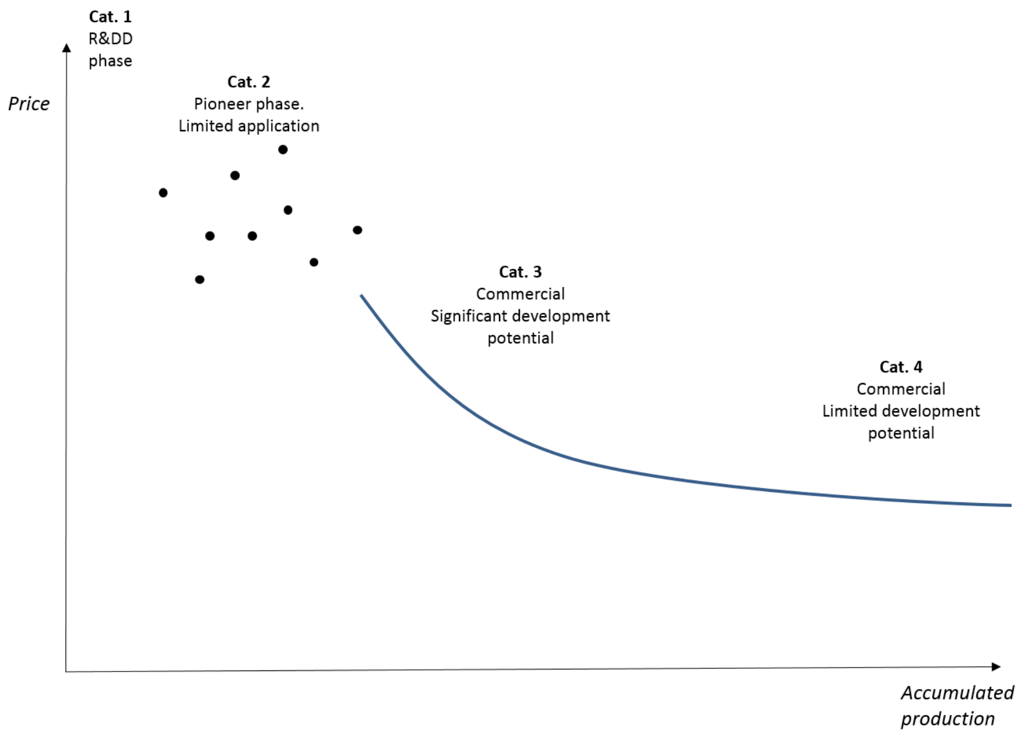


Figure 100: Technological development phases. Correlation between accumulated production volume (MW) and price.

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	This Technology Catalogue				
	Viet Nam Technology Catalogue (2021)				
Viet Nam 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 analyzed. 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. In addition, 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 39: The yearly average exchange rate between VND and USD (According to the exchange rate in June of the years of the State Bank of Viet Nam).

Year	VND to USD
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 40: 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	Produce 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 Viet Nam, 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 realized, assuming no planned or forced outages. The realized 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 Viet Nam 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. In addition, 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 cost per unit for larger power plants is 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 summarized below.

Table 41: 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.

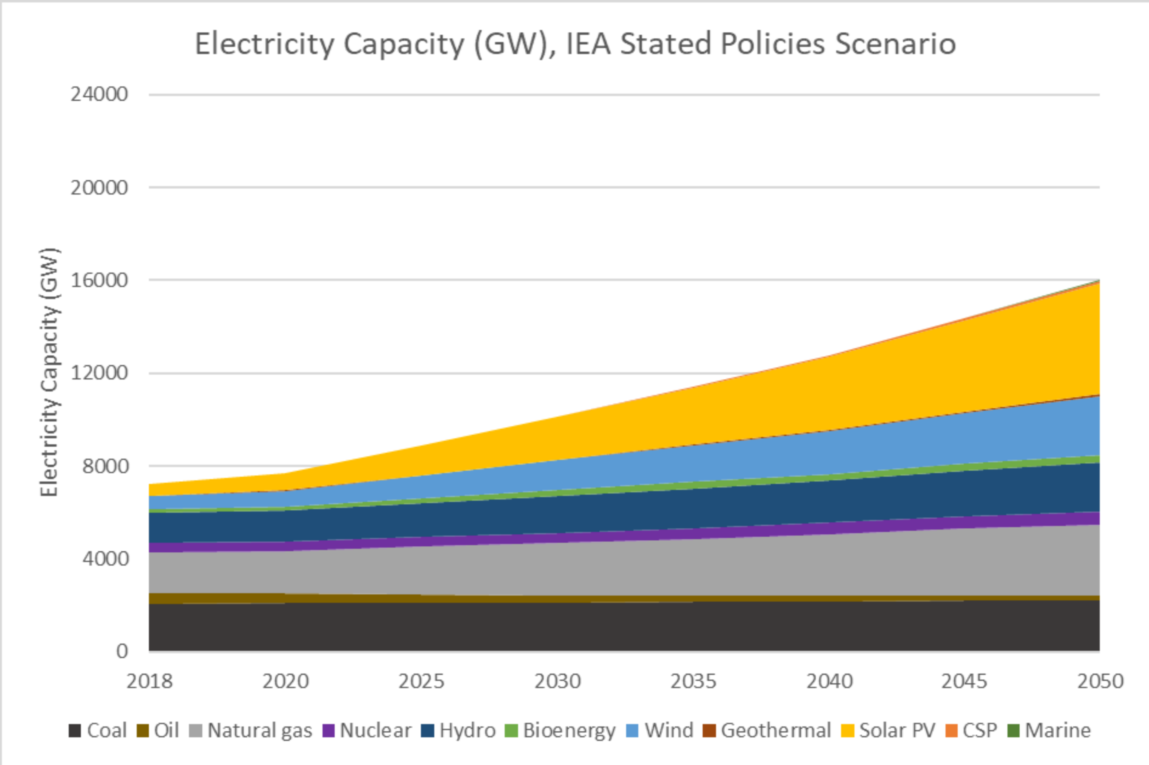
In its Energy Technology Perspectives 2020 and World Energy Outlook 2019, the IEA considers two reference global pathways, the Stated Policy scenario and the Sustainable Development scenario, with varying degree of climate policy commitment:

- 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.



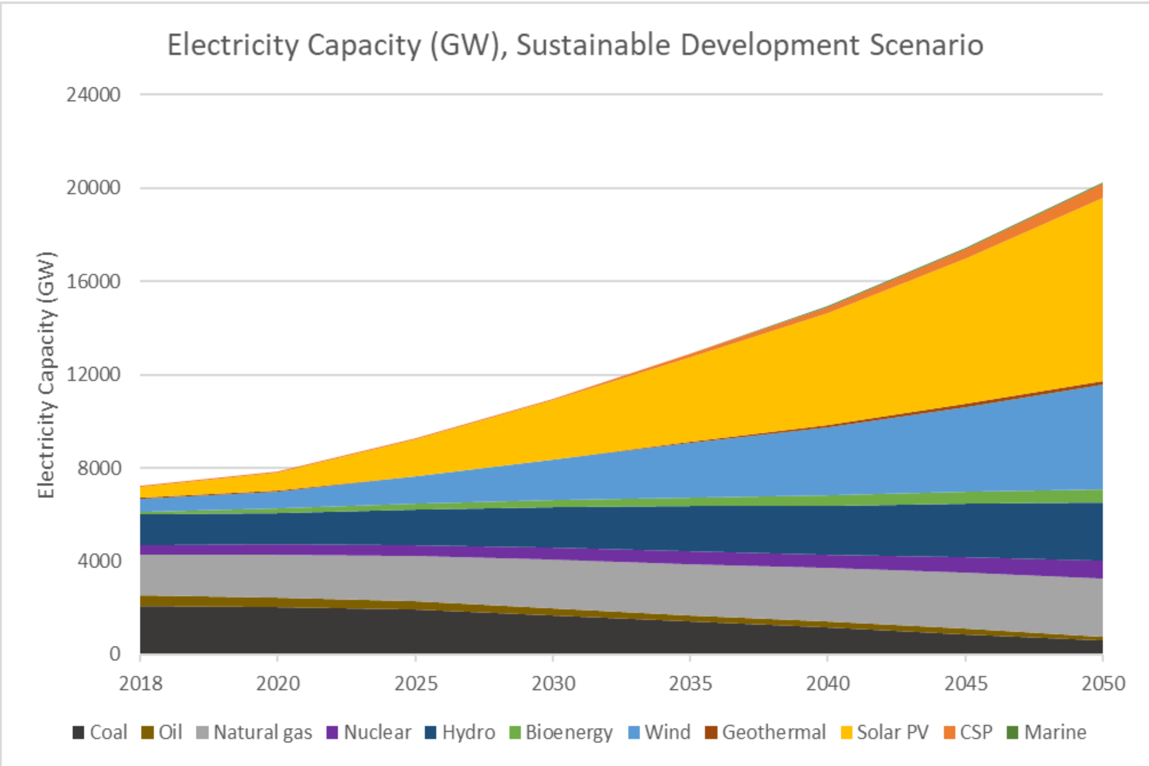


Figure 101: Electricity Capacity (GW) in the IEA's stated policies and sustainable development scenarios. IEA – World Energy Outlook 2019 [9].

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.

Table 42: 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

Table 43: 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.

Table 44: 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 (Large reactor)	12,50%	96%	93%	90%	96%	92%	88%	96%	92%	89%
Nuclear (SMR)	15%	87%	83%	80%	86%	82%	78%	87%	82%	79%
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[15]	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

[15] 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%.

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 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.

References

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