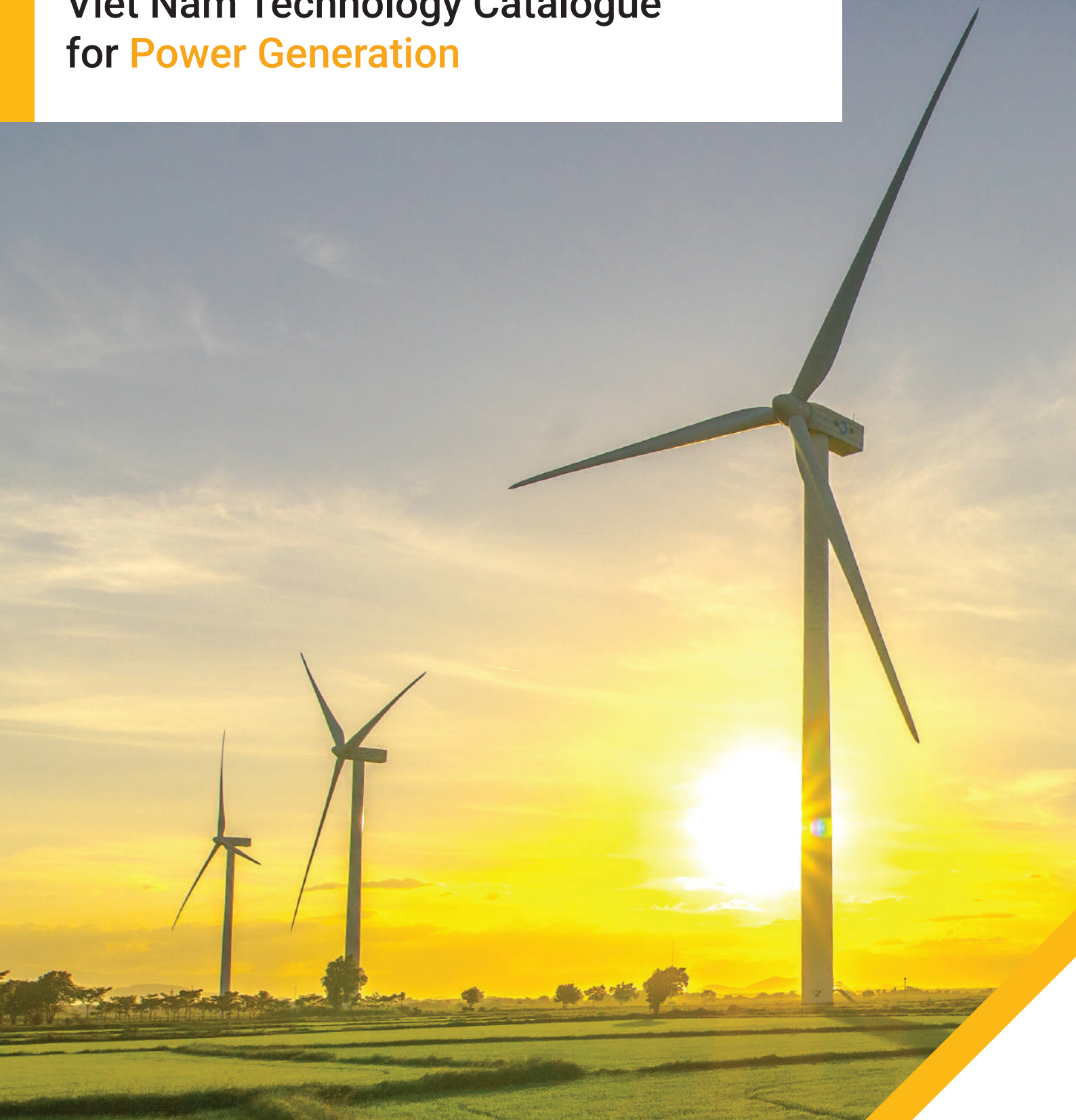


Viet Nam Technology Catalogue for **Power Generation**



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Danish Energy Agency



Input for energy
system modelling
May 2026

VIET NAM
TECHNOLOGY CATALOGUE
FOR POWER GENERATION
Input for energy system modelling

2026

FOREWORD

Today, innovations and technological improvements in energy generation, storage and renewable fuels are advancing at a very rapid pace. At the same time, the cost, technical performance and environmental impacts of energy technologies remain highly context dependent and continue to evolve over time. Reliable and transparent information on these characteristics is therefore essential for sound long-term energy planning.

This Technology Catalogue provides a review-based technical foundation for a wide range of power generation technologies. It aims at supporting evidence-based planning and analysis of Viet Nam's future power system. By presenting consistent data and assumptions on costs, performance and environmental impacts, the catalogue contributes to making energy system planning a central tool for unlocking the potential of new renewable-based technologies.

Through a multi-stakeholder involvement in the data and information collection process, all quantitative figures incorporated to this Technology Catalogue were thoroughly reviewed and scrutinized by a broad range of energy sector stakeholders in Vietnam, including Electricity Authority of Viet Nam (EAV), agencies under the Ministry of Industry and Trade (MOIT), Viet Nam Electricity (EVN), independent power producers, local and international experts, other development partners organizations, as well as energy branch associations and universities. This stakeholder engagement constitutes an essential element in the development process, to ensure that the Technology Catalogue is highly context specific, well anchored and legitimized by all relevant energy sector stakeholders.

The aim of this Technology Catalogue is therefore to serve as a key foundation for 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.

This Vietnamese Technology Catalogue builds on the approach of the Danish Technology Catalogues, which for many years have been developed by the Danish Energy Agency and Energinet through an open stakeholder process, serving as a key foundation for Denmark's long-term energy system planning

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 and 2023. This new version includes all the technologies from the 2023 version, with a particular focus on comprehensively updating the chapters on solar power, onshore wind power, offshore wind power, and nuclear power. All chapters across the catalogue have been revised to reflect the latest Vietnamese context. In addition, all technology datasheets have been fully updated, with particular emphasis on updating capital investment costs across technologies and converting all values to 2025 USD.

Acknowledgements

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Hanoi



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AMENDMENT SHEET

Under the Danish Energy Partnership Programme, the development of the Viet Nam Technology Catalogue has been a key activity since the first edition was published in 2019. From 2019 to the publication of the present edition in 2026, the catalogue has undergone a series of updates to incorporate new technologies, revised data and methodological improvements, thereby strengthening its relevance for long-term energy planning in Viet Nam. The main amendments introduced over time are summarized in the following amendment sheet.

Version	Date of update	Reference updated	Description
006	January 2026	Datasheet	All datasheets updated, converted to USD 2025
006	January 2026	Technology Catalogue Chapters 1-17	Water consumption added
006	January 2026	7 Solar Photovoltaics 8 Onshore wind power 9 Offshore wind power 17 Nuclear power generation	Full chapters updated Wind power chapter split into onshore and offshore wind power chapters
0005	Nov 2023	7 Solar Photovoltaics	Investment cost (M\$/MW _p) for utility-scale PV – updated Investment cost (M\$/MW _{ac}) 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 CO ₂ 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 CO ₂ 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

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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

This technology catalogue consists of 17 chapters describing different electricity generation technologies relevant to Viet Nam's energy sector. The first 6 chapters cover conventional generation technologies, followed by renewable, emerging and other low-carbon generation technologies. This introduction outlines the scope, methodological principles and structure of this Technology Catalogue. A detailed description of the approach and methodological principles can be found in Appendix 1 and 2 of this document.

Scope and purpose

Reliable information on the cost, performance and environmental characteristics of energy technologies is essential for sound long-term power system planning. As energy technologies continue to rapidly evolve, their technical and economic performance varies across countries depending on local conditions, regulatory frameworks and market maturity. Thus, consistent and transparent information is needed to support the assessment of electricity generation technologies in Viet Nam's evolving energy system. The purpose of this Technology Catalogue is therefore to provide a harmonized basis for assessing technologies, as well as support long-term energy planning.

This catalogue compiles technical and economic information for a wide range of electricity generation technologies based on Vietnamese experience where available, and international evidence where necessary. By presenting harmonized assumptions for technology costs, performance parameters and environmental characteristics, the catalogue enables more consistent comparisons across technologies and provides a common analytical foundation for planning and modelling.

System boundaries and technological maturity

The technologies in this catalogue consider the power production unit and its connection to the grid. This means that the presented cost and performance data refer to the generation assets plus the infrastructure required to deliver the energy to the main grid. For electricity generation technologies, 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. Similarly, presented efficiencies are also net efficiencies.

The catalogue reflects the Vietnamese context as far as possible. Technical parameters and investment costs are informed by Vietnamese project experience. At the same time, projections for mid- and long-term technology development (2030 and 2050) rely partly on international data, reflecting the increasingly global nature of energy technology supply chains and learning processes. Differences between Vietnamese and international cost levels may arise due to factors such as regulatory frameworks, supply chains, market maturity or local physical conditions.

Land use requirements are assessed for each technology. However, the cost of land is not included in the financial cost estimates, as land prices depend strongly on site-specific conditions. The technologies included in this catalogue range from very mature to emerging technologies. With a different maturity level, the cost and performance indicators incorporated to this document may be estimated with different levels of uncertainty. Comparably mature technologies might be subject to more robust estimates. Emerging technologies are projected to be subject to significant performance improvements and cost reductions over the coming decades, while their cost and performance are inherently subject to a higher uncertainty. All technologies have been grouped within one of four categories of technological development. This grouping is described in the section on research and development in Annex 1, which elaborates on technological progress, future development perspectives and the uncertainty levels related to the projections of cost and performance data.

Methodological principles and cost projections

To ensure comparability across technologies, all economic and technical data are reported using a common set of methodological assumptions.

Economic data are expressed in constant 2025 U.S. dollars, excluding taxes such as value-added tax (VAT), in order to reflect the socio-economic cost of electricity generation technologies. For most technologies, the catalogue provides cost and performance estimates for the years 2025, 2030, 2040 and 2050. Future cost developments are primarily based on the learning curve approach and estimated based on two key

inputs: technology learning rates derived from international literature, and projections of global technology deployment (see Appendix 2 for a detailed description of the projection methodology). Technologies are grouped into four categories of technological development, ranging from early research and demonstration technologies to fully commercial technologies with large-scale deployment. Technologies with higher maturity levels are associated with lower uncertainty in both current cost estimates and future projections.

Uncertainty ranges are provided for key parameters such as investment costs and efficiencies to reflect the variability observed across different sources and project conditions.

Structure of the technology sheets

Each technology is described in a standardized manner consisting of two main elements.

- **The qualitative descriptions** provide a concise explanation of the considered technology, including its operating principles, key inputs and outputs (electricity and other potential outputs e.g. process heat), advantages and disadvantages relative to alternatives, environmental characteristics including water consumption, and research and development perspectives. Examples of current projects are included, with Vietnamese examples provided for technologies already applied in Viet Nam and international examples for technologies that are new to the Vietnamese market.
- **The quantitative sections** present technical and economic parameters for each technology. Tables contain data for 2025, 2030, 2040 and 2050, including, among other, investment- and operation and maintenance costs, efficiencies, capacity factors, technical lifetimes, construction times and operational flexibility parameters such as ramping capability and minimum loads, as well as environmental data, including water consumption. To account for the inherent uncertainty related to projected data, tables also include *uncertainty* spans, evaluated on a case-by-case basis.

Together, the qualitative and quantitative sections provide a consistent basis for presenting electricity generation technologies included in this catalogue, and for assessing their potential role in Viet Nam's current and future energy system.

1. PULVERIZED COAL FIRED POWER

Brief technology description

A coal-fired power plant operates based on the Rankine thermal cycle, which includes the following main steps:

- (1) Feedwater supply and heating: Condensate from the condenser is pumped through the low-pressure heaters, the deaerator, and the high-pressure heaters to increase the feedwater temperature before entering the boiler.
- (2) Steam generation in the boiler: Coal is pulverized and combusted in the boiler furnace. The released heat converts water in the boiler tubes into steam, which is then further heated to become superheated steam at high temperature and pressure.
- (3) Power generation in the turbine: The superheated steam flows into the steam turbine, where it expands through multiple turbine stages, rotating the turbine shaft that drives the electric generator to produce electricity.
- (4) Condensation: After leaving the turbine, the exhaust steam enters the condenser, where it is cooled by circulating water and condensed back into liquid water. Cycle recirculation: The condensate is pumped back through the feedwater heating system and returned to the boiler, completing the closed thermal cycle of the power plant

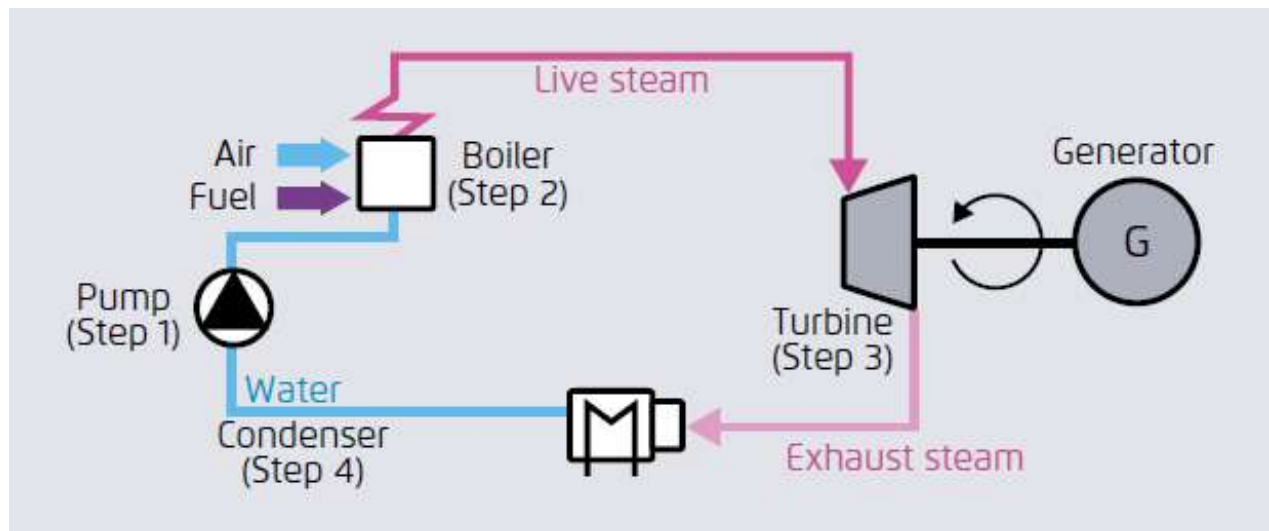


Figure 1: Schematic representation of operational flow of steam-based Rankine cycle in coal plants [3].

The major equipment of a coal-fired power plant includes the boiler, steam turbine, generator, condenser, coal handling and pulverizing system, feedwater supply and heating system, cooling system, flue gas treatment systems (such as SO₂ removal, NO_x reduction, and electrostatic precipitators), as well as transformers and power transmission systems. These components operate together to convert the chemical energy of coal into electrical energy and ensure stable and safe plant operation.

Pulverized coal technology uses coal that is finely ground and injected directly into the boiler furnace, where it combusts at high temperatures (approximately 1,300-1,500 °C). The heat generated is used to produce superheated steam that drives the steam turbine for power generation. This technology is suitable for large-capacity units and offers high efficiency, and it is widely applied in modern coal-fired power plants. However, it generally requires relatively stable coal quality and flue gas treatment systems such as SO₂ removal, NO_x reduction, and particulate control.

Pulverized coal (PC) power plants are capable of stable long-term operation with a high capacity factor, making them well suited to serve as baseload generation in the power system. Pulverized coal combustion technology has been widely commercialized and is highly reliable, enabling continuous operation at rated load for extended periods, thereby contributing to a stable electricity supply and enhancing energy security of the power system.

Coal-fired power plants are distinguished in three main types: 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 [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 [16].

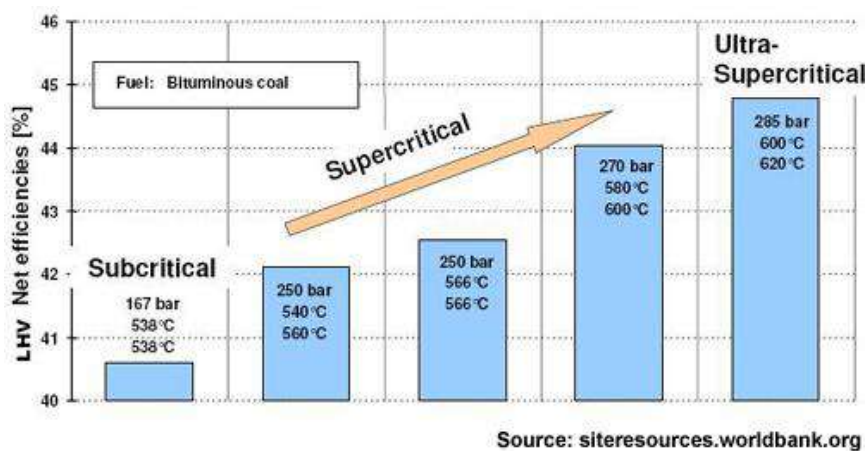


Figure 2: Definitions of sub-, super-, and ultra-supercritical plant [6]. The same definitions apply to Anthracite coal.

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. Some existing coal-fired power plants may consider partial conversion or deeper conversion to gaseous fuels (LNG), depending on the boiler configuration, equipment lifetime, and techno-economic performance. 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. [15]

Output

Power. The auxiliary power need for a 500 MW plant is typically 40-45 MW, and the net electrical efficiency¹ is thus 3.7-4.3 percentage points lower than the gross efficiency [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 [3].

Ramping configurations

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

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

Negative load adjustment is carried out through coordinated control between the fuel/air supply system (boiler) and the steam dispatch/control system (turbine).

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. [5,6].

Table 1: Examples of relevant areas for increased flexibility [6].

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

Advantages/disadvantages

Advantages:

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.

- 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, SO₂ and particle matter (PM), which have high societal costs in terms of health problems. According to several studies air pollution from coal-fired power plants is responsible for thousands of premature deaths each year globally.
- Coal firing results in a relatively high CO₂ 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.

Space requirement

The land required for coal plants ranges from 80 to 100 hectares.

Water consumption

Pulverised Coal Fired Power plants require a significant amount of demineralized water to generate high-pressure, high-temperature steam. The water used needs to be ultra-pure to avoid mineral deposits that could damage turbines and boilers.

Pulverised Coal Fired Power plants also require significant amounts of water for cooling, primarily in the condenser. The water consumption is mainly due to evaporation losses in the cooling system, which can be substantial.

Environment

The burning and combustion of coal creates the products CO₂, CO, H₂O, SO₂, NO₂, NO and particle matter (PM). CO, NO_x and SO₂ particles are unhealthy for the brain and lungs, causing headaches and shortness of breath, and in worst case, death. CO₂ causes global warming and thereby climate changes [3].

It is possible to implement filters for NO_x and SO₂. 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 Industrial Emission (QCVN 19:2024/BTNMT)
- National Technical Regulation on Air Quality (QCVN 05:2023/BTNMT)

Without applying technical solutions to control the emissions, the amount of pollutants such as dust, SO₂, NO_x and CO₂ 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 NO_x (Thermal plants using Circulating Fluidized Bed boiler do not apply)
- In addition, the chimneys of the plants are required to install a continuous emission monitoring system (CEMS)

Employment

In general, a 1,200 MW coal-fired plant needs 2,000-2,500 employees on average during construction and afterwards 300-900 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 [4].

For increased flexibility, see [5,6,8].

Examples of current projects

Subcritical: Quang Ninh coal-fired power plant [9].

Quang Ninh coal-fired power plant is in Cao Xanh Ward, 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/cm² (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/Nm³, the SO₂ and particle matter (PM_{2.5}) content do not exceed 400 and 150 mg/Nm³ respectively. According to actual measurement, the NO_x, SO₂ and PM_{2.5} emission of Quang Ninh thermal plant are 700 mg/Nm³, 394 mg/Nm³ and 136 mg/Nm³ 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: [10]

Hai Phong coal-fired plant located in Nam Trieu Ward, 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/cm³ and 541°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}, SO₂ and NO_x emission of plants are as follow: 35.8 mg/Nm³, 315.1 mg/Nm³ and 546.5 mg/Nm³ 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 [11]

General: Vinh Tan 4 coal-fired power plant is in the Vinh Tan Power Center, Vinh Hao Commune, Lam Dong 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 Nm³, the SO₂ is 181 mg per Nm³ and the PM_{2.5} emission is 27 mg per Nm³. 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 [12]

Vinh Tan 4 Ext coal-fired power plant is in the Vinh Tan Power Center, Vinh Hao Commune, Lam Dong 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°C, redrying steam temperature is 594.4°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 Nm³, the SO₂ is 93 mg per Nm³ and the PM_{2.5} emission is 11 mg per Nm³.

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 [11]

General: Vinh Tan I coal-fired power plant is in the Vinh Tan Power Center, Vinh Hao Commune, Lam Dong 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 Nm³, the SO₂ is 29 mg per Nm³ and the PM_{2.5} emission is 21 mg per Nm³. 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.

Investment cost estimation

The data from the different sources in the tables below is adjusted for inflation from their original price

years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - Supercritical						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		1.81	1.79		1.75	1.72
Technology Catalogue - Colombia 2025		1.85	1.83			1.75
Technology Catalogue - Indonesia 2024			1.64			1.58
Technology Catalogue - Vietnam 2023	1.85		1.84			1.80
IEA WEO 2025 - India*		1.20		1.2		1.2
IEA WEO 2025 - China*		0.7		0.7		0.7
*Stated policy scenario						

Investment cost [Million USD 2025 / MW] - Ultra-supercritical						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		2.01	1.99		1.95	1.91
Technology Catalogue - Colombia 2025						
Technology Catalogue - Indonesia 2024		1.83	1.77			1.72
Technology Catalogue - Vietnam 2023	2.06		2.04			2.03
IEA WEO 2025 - India*		1.40		1.4		1.4
IEA WEO 2025 - China*		0.8		0.8		0.8
*Stated policy scenario						

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.
- [3] Nag, “Power plant engineering”, 2009.
- [4] Mott MacDonald, “UK Electricity Generation Costs Update”, 2010.
- [5] DEA, Flexibility in the Power System - Danish and European experiences, 2015.
- [6] https://ens.dk/sites/ens.dk/files/Globalcooperation/flexibility_in_the_power_system_v23-lri.pdf, Assessed 9 September 2018.
- [7] 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.
- [8] Technical Design Report of Quang Ninh coal-fired plant.
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- [14] Munawar, M. E. (2018), Review article: Human health and environmental impacts of coal combustion and post-combustion wastes. Journal of Sustainable Mining. Volume 17, Issue 2, 2018, Pages 87-96. Open Access.
- [15] US Department of Energy, “Coal-To-Gas Plant Conversions in the U.S.”, 2020.
- [16] IEA Clean Coal Centre, “Status of advanced ultra-supercritical pulverised technology”, 2013.
- [17] International Energy Agency, World Energy Outlook, 2016.
- [18] 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 sheet

The following tables contain the data sheets of the technology. All costs are stated in U.S. dollars (\$), price year 2025. For explanation and definition of the parameters given in the table, see appendix 1. Uncertainty represents the variation in parameters.

Supercritical coal power plant											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Low er	Upp er	Low er	Upp er		
Energy/technical data											
Generating capacity for one unit	MW_e	600	600	600	600	300	800	300	800		1
Generating capacity for total power plant	MW_e	1200	1200	1200	1200	300	1800	300	1800		1
Electrical efficiency, net, name plate	%	37.7	38.8	39.4	39.9	33.0	40.0	35.0	42.0		1, 5, 6
Electrical efficiency, net, annual average	%	36.7	37.8	38.3	38.9	33.0	40.0	35.0	42.0		1, 6
Forced outage	%	7	6	5	3	5	15	2	7	A	1
Planned outage	%	13.5	9.6	7.7	5.8	5.8	15.4	3.8	7.7	A	1
Self-consumption	%	6	6	6	6	5	8	5	8		
Technical lifetime	years	30	30	30	30	25	40	25	40		1
Construction time	years	3.75	3	3	3	3	5	2	4	A	1
Space requirement	1000_m²/MW_e	1.85	1.85	1.85	1.85	1.00	2.75	1.00	2.75		6
Additional data for non-thermal plants											
Capacity factor, theoretical	%	-	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	2	4	4	4	1	4	3	4	B	1
Minimum load	% of full load	50	25	22.5	20	25	75	10	30	A	1
Warm start-up time	hours	6	4	4	4	2	8.5	2	5	B	1
Cold start-up time	hours	10	12	12	12	6	15	6	12	B	1
Minimum Up time	hours	6	6	6	6	-	-	-	-		7
Minimum Down time	hours	4	4	4	4	-	-	-	-		7
Environment											
PM 2.5	mg/Nm³	70	70	70	70	50	150	20	100	E	2, 3
SO₂ (degree of desulphuring)	%	86	86	86	95	73	95	73	95		2, 3
NOₓ	g/GJ_i	115	113	76	38	115	263	38	263	C	2, 3
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	1.81	1.79	1.75	1.72	1.35	2.44	1.29	2.15	D, F, G, H	1, 5, 6
- of which equipment	%	-	-	-	-	-	-	-	-		
- of which installation and other costs	%	-	-	-	-	-	-	-	-		
- of which equipment	MUSD/MW_e	-	-	-	-	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	-	-	-	-	-	-	-	-		
Fixed O&M	USD/MW_e/ye ar	49,301	48,810	47,843	46,895	36,976	66,557	35,171	58,618	F, H	1, 5, 6
Variable O&M	USD/MWh	1.40	1.40	1.39	1.36	1.05	1.89	1.02	1.70	F, H	1, 6
Start-up costs	USD/MW_e/sta rt-up	125	65	65	65	94	169	49	81	F, H	1, 4, 6
Technology specific data											
Water consumption	L/MWh	1870	1870	1870	1870	-		-	-	I, J	8, 9, 10, 11

Notes:

- A Assuming gradual improvement to international standard in 2050.
- B Assuming no improvement for regulatory capability.
- C Calculated from a max of 750 mg/Nm³ to g/GJ (conversion factor 0.35 from Pollution Prevention and Abatement Handbook, 1998).
- D For economy of scale a proportionality factor of 0.8 is suggested.
- E Uncertainty: Upper is from regulation, Lower is from current standards in Japan (2025) and South Korea (2050).
- F Uncertainty (Upper/Lower) is estimated as -25% (lower) and +35% (upper) for 2025 and +/- 25% for 2050.
- G Investment cost includes the engineering, procurement and construction (EPC) cost. See description under Methodology.
- H Assuming that costs fall 0.2 % each year.
- I Assuming a cooling tower is used. Pond- and once-through cooling generally result in lower water consumption.
- J Depending on the cooling method, the water consumption can range from around 10 L/MWh to around 2500 L/MWh.

References

- 1 Danish Energy Agency and Ea Energy Analyses, 2024 - Technology Data for the Indonesian Power Sector: Catalogue for Generation and Storage of Electricity
- 2 Platts Utility Data Institute (UDI) World Electric Power Plant Database (WEPP)
- 3 Maximum emission from Minister of Environment Regulation 21/2008
- 4 Deutsches Institut für Wirtschaftsforschung, On Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Fluctuating Renewables, 2016
- 5 IEA, World Energy Outlook, 2025
- 6 Danish Energy Agency, 2025 - Colombian Technology Catalogue for Generation and Storage of Electricity
- 7 Danish Energy Agency and Ea Energy Analyses, 2022 - Technology Data for the Indian Power Sector
- 8 International Energy Agency, 2016 - Water Energy Nexus
- 9 National Renewable Energy Laboratory, 2011 - A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies
- 10 U.S. Energy Information Administration, 2024 - Thermoelectric cooling water data
- 11 World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity

Coal ultra-supercritical											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	1,000	1,000	1,000	1,000	700	1,200	700	1,200		1
Generating capacity for total power plant	MW_e	1,000	1,000	1,000	1,000	700	1,200	700	1,200		1
Electrical efficiency, net, name plate	%	42.5	43.8	44.4	45.1	40.0	45.0	42.0	47.0		1, 5, 6
Electrical efficiency, net, annual average	%	41.5	42.7	43.4	44.0	40.0	45.0	42.0	47.0		1, 6
Forced outage	%	7	6	5	3	5	15	2	7	A	1
Planned outage	%	13.5	9.6	7.7	5.8	5.8	15.4	3.8	7.7	A	1
Self-consumption	%	6	6	6	6	5	8	5	8		
Technical lifetime	years	30	30	30	30	25	40	25	40		1
Construction time	years	4.33	3	3	3	3	5	2	4	A	1
Space requirement	1000_m ² /MW_e	-	-	-	-	-	-	-	-		6
Additional data for non-thermal plants											
Capacity factor, theoretical	%	-	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	5	5	5	5	4	5	4	5	B	1
Minimum load	% of full load	30	25	22.5	20	25	50	10	30	A	1
Warm start-up time	hours	4	4	4	4	2	5	2	5	B	1
Cold start-up time	hours	12	12	12	12	6	15	6	12	B	1
Minimum Up time	hours	-	-	-	-	-	-	-	-		7
Minimum Down time	hours	-	-	-	-	-	-	-	-		7
Environment											
PM 2.5	mg/Nm ³	70	70	70	70	50	150	20	100	E	2, 3
SO ₂ (degree of desulphuring)	%	86	86	90	95	73	95	73	95		2, 3
NO _x	g/GJ_i	152	150	100	38	152	263	38	263	C	2, 3
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	2.01	1.99	1.95	1.91	1.51	2.72	1.43	2.39	D, F, G, H	1, 5, 6
- of which equipment	%	-	-	-	-	-	-	-	-		
- of which installation and other costs	%	-	-	-	-	-	-	-	-		
- of which equipment	MUSD/MW_e	-	-	-	-	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	-	-	-	-	-	-	-	-		
Fixed O&M	USD/MW_e/year	75,311	74,561	73,083	71,634	56,483	101,670	53,726	89,543	F, H	1, 5, 6
Variable O&M	USD/MWh	1.30	1.29	1.26	1.24	0.98	1.76	0.93	1.55	F, H	1, 6
Start-up costs	USD/MW_e/start-up	67	67	67	67	50	91	50	84	F, H	1, 4, 6
Technology specific data											
Water consumption	L/MWh	1870	1870	1870	1870	-	-	-	-	I	8, 9, 10, 11

Notes:

- A Assuming gradual improvement to international standard in 2050.
- B Assuming no improvement for regulatory capability.
- C Calculated from a max of 750 mg/Nm³ to g/GJ (conversion factor 0.35 from Pollution Prevention and Abatement Handbook, 1998).
- D For economy of scale a proportionality factor of 0.8 is suggested.
- E Uncertainty: Upper is from regulation, Lower is from current standards in Japan (2025) and South Korea (2050).
- F Uncertainty (Upper/Lower) is estimated as -25% (lower) and +35% (higher) for 2025 and +/- 25% for 2050.
- G Investment cost includes the engineering, procurement and construction (EPC) cost. See description under Methodology.
- H Assuming that costs fall 0.2 % each year.
- I Ranges for supercritical coal are also valid for ultra-supercritical coal.

References

- 1 Danish Energy Agency and Ea Energy Analyses, 2024 - Technology Data for the Indonesian Power Sector: Catalogue for Generation and Storage of Electricity
- 2 Platts Utility Data Institute (UDI) World Electric Power Plant Database (WEPP)
- 3 Maximum emission from Minister of Environment Regulation 21/2008
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- 7 Danish Energy Agency and Ea Energy Analyses, 2022 - Technology Data for the Indian Power Sector
- 8 International Energy Agency, 2016 - Water Energy Nexus
- 9 National Renewable Energy Laboratory, 2011 - A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies
- 10 U.S. Energy Information Administration, 2024 - Thermoelectric cooling water data
- 11 World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity

1.1. 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. In the Vietnamese power system, improved flexibility of thermal power plants will play an increasingly important role for the integration of variable renewable energy (VRE). The country has already integrated significant shares of solar PV and wind power, and under the latest Power Development Plan a significant expansion of VRE expansion is envisioned. Flexible operation of coal-fired power plants can support system balancing during periods of high renewable generation.

Key parameters related to the flexibility of a thermal plant are:

- **Minimum Load (P_{min}):** The minimum or lowest power that can be stably 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-ups: **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.

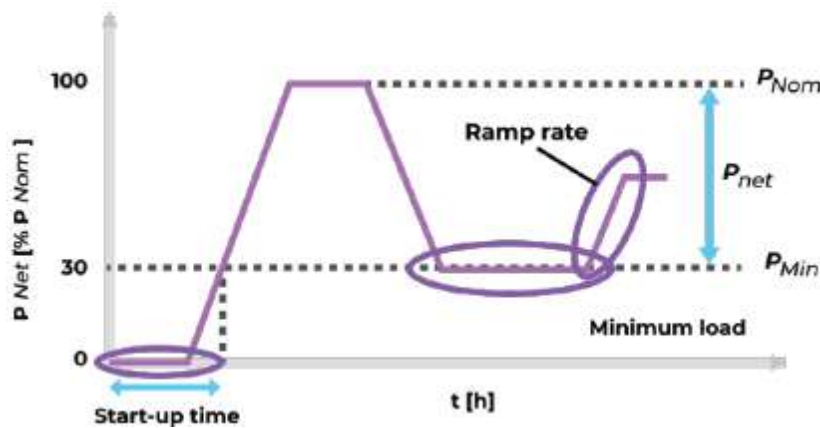


Figure 3: Key flexibility parameters of a power plant [3].

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. These parameters determine the ability of a coal-fired power plant to follow changes in system demand and renewable generation. Improved flexibility allows thermal plants to provide operational services such as load-following capability, reserve provision, and faster response to fluctuations in wind and solar generation.

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 2: Selected solutions for increasing the flexibility of coal-fired power plants [2], [4], [5], [[13]].

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	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.	Fire stability

Solutions	Objective	Description	Impact	Limitation
		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.	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 %.	
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	-

Solutions	Objective	Description	Impact	Limitation
			rate.	
Boiler turbine bypass system	Reduce start-up time and increase ramp rates	Use steam bypass systems at different turbine stages to rapidly regulate steam flow through the turbine, thereby adjusting power output.	Reduce start-up time by 5% and increase the ramp rate by 5% of nominal power per minute.	

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]. As outlined in Table 2 operation at low load levels and frequent ramping can reduce thermal efficiency and increase specific fuel consumption, including the need to co-fire oil in addition to coal to ensure stable combustion conditions in the burners and thereby reduce the risk of plant tripping when operating at minimum loads. At the same time, dedicated testing campaigns of low load operation in Vietnamese power plants show that the decrease in efficiency is smaller than the reduction of the output, meaning that operation at lower loads clearly leads to reduced fuel use and CO₂ emissions.

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

Flexibility Parameter	Average Plant	Post Flexibilization
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

Estimated costs for flexibility retrofitting and efficiency improvements by type of coal-fired boiler technology commonly used in Viet Nam are summarized in the following table:

Table 4: Summary of estimated costs for flexibility retrofitting and efficiency improvements by coal-fired boiler technology.

Circulating fluidized bed (CFB) boiler technology, subcritical, using anthracite coal (fines grades 6–7).		
Solutions	Estimated cost per 150 MW unit (million USD)	Flexibility improvements
Thermal energy storage	0.6	Reduce minimum load from 60–85% to approximately 40–60% of installed unit capacity; increase ramp rates from 0.5–1% to around 6% of nominal power per minute; shorten warm start-up time from 4–6 hours to approximately 3–5 hours, reducing start-up costs by about 30%.
Control system upgrade	1.3	
Boiler turbine bypass system	0.6	
Total	2.5	
Pulverized coal (PC) boiler technology, subcritical, firing anthracite coal.		
Solutions	Estimated cost per 300 MW unit (million USD)	Efficiency improvements
Thermal energy storage	1.1	Reduce minimum load from 60–80% to approximately 40–60% of installed unit capacity; increase ramp rates from 0.5–3% to around 6% of nominal power per minute; shorten warm start-up time from 5–10 hours to approximately 4–8 hours, reducing start-up costs by about 30–35%.
Control system upgrade	3.0	
Boiler turbine bypass system	1.0	
Total	5.1	
Pulverized coal (PC) boiler technology, firing imported coal.		
Solutions	Estimated cost per 600 MW unit (million USD)	Efficiency improvements
Thermal energy storage	2.0	Reduce minimum load from 35–50% to approximately 25–32% of installed unit capacity; increase ramp rates from 1–2% to around 6% of nominal power per minute; shorten warm start-up time from 4–6 hours to approximately 1.5–3 hours, reducing start-up costs by 35%.
Control system upgrade	5.4	
Boiler turbine bypass system	2.5	
Conversion from twin mills to a single mill	2.5	
Total	12.4	

While flexibility retrofits can improve the operational capability of coal-fired units, they should be assessed in the broader context of power system planning. Other options such as inter-alia grid expansion, electricity storage, demand-side flexibility may also contribute to balancing variable renewable energy. The optimal combination of measures depends on system conditions and should be evaluated by means of dedicated energy system modelling.

1.2. 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 NO_x emissions, emissions of fine particles and sulphur emissions. Here follows a brief description on control measures for each of these.

NO_x emission control

Nitrogen oxides (NO_x) 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 NO_x.

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

- 1) “thermal” NO_x resulting from oxidation of molecular nitrogen in the combustion air
- 2) “fuel” NO_x resulting from oxidation of chemically bound nitrogen in the fuel
- 3) “prompt” NO_x resulting from reaction between molecular nitrogen and hydrocarbon radicals. [1]

For pulverized coal combustion, roughly 20% of NO_x formation comes from thermal reactions. Thermal NO_x 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 NO_x emissions could include both mechanisms to reduce formation of NO_x during the combustion process (so called primary control technologies) and mechanisms to convert NO_x to less harmful compounds (so called secondary control technologies), for instance reducing NO_x back to N₂.

Formation of NO_x 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 [2]

To obtain this, the following technologies could be applied [2]:

Low NO _x burners (LNB)	A LNB limits NO _x 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 NO _x formation; (2) reduced flame temperature, which limits thermal NO _x formation; and (3) reduced residence time at peak temperature, which limits thermal NO _x formation. LNBs can reduce NO _x 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 NO _x formation. OFA reduction rates range from 20% to >60% depending on the initial NO _x 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 NO_x formation could in many cases not be enough to meet emission restriction from legal terms. (QCVN 19:2024/BTNMT, QCVN 05:2023/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 NO_x in the flue gas by converting NO_x have gained increased interest.

The three main technologies include:

- 1) Reburning
- 2) Selective noncatalytic reduction (SNCR) and

3) Selective catalytic reduction (SCR)

Re-burning:

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 NO_x 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% NO_x reduction on various coal-fired boiler types.

Selective Noncatalytic Reduction (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 NO_x 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 NO_x is actually formed. Therefore, the optimal amount for ammonia added can be quite complex to estimate. The removal can be up to 65% of NO_x . The scheme of the SNCR concept is shown in Fig.4. An SNCR facility consists of two operational units:

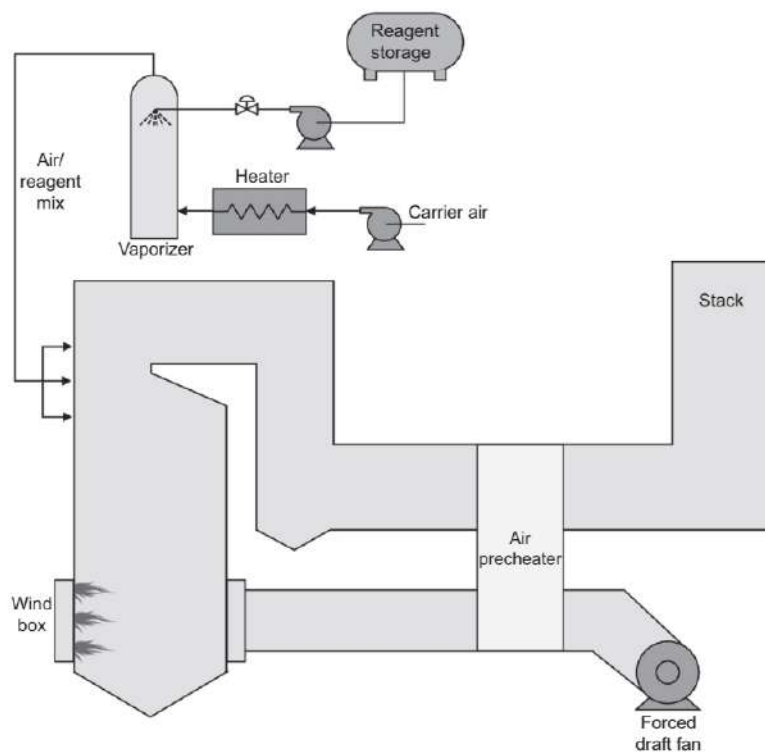


Figure 4: Selective Noncatalytic Reduction [12].

Selective catalytic reduction (SCR):

SCR technology needs to select an appropriate catalyst to make a reaction between reagents with NO_x on its surface (Fig. 5). The main advantage of this technique is that the temperature required is lower than in SNCR technology reactions. The most typical SCR catalyst used is a blend of titanium oxide and vanadium oxide. Noble metal blends of platinum and palladium have been developed during recent years, but they are not so widely used due to their high cost. Typical reagents are urea and ammonia. SCR can remove up to 80%-90% of NO_x and operates typically at low temperatures: 170-510 °C.

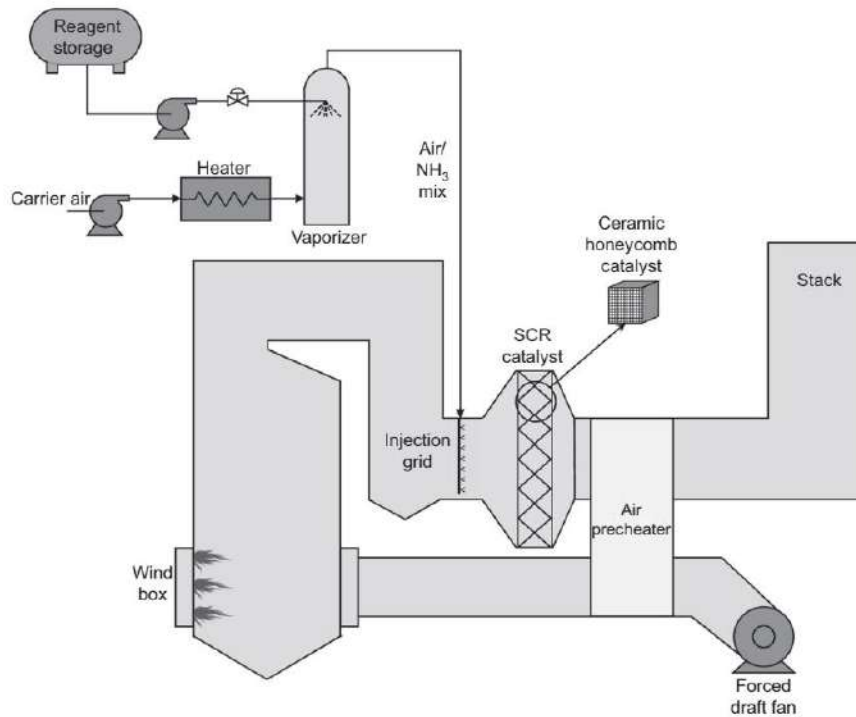


Figure 5: Selective catalytic reduction (SCR) [12].

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 $2.5\ \mu m$ 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 [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 nanometres, 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. [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 submicrometric 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].

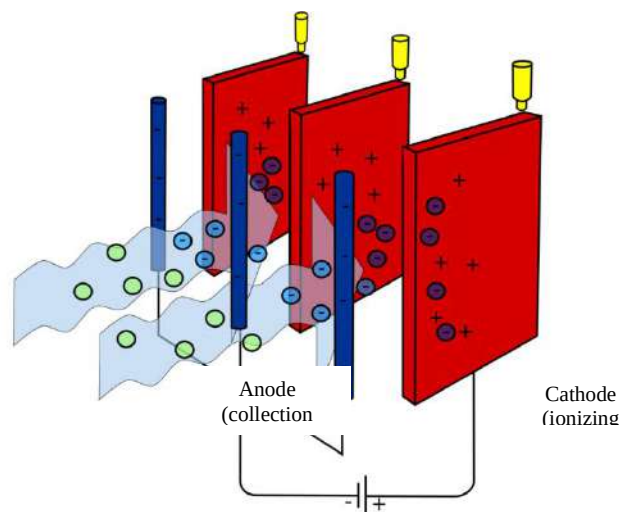


Figure 6: Principle behind electrostatic precipitator [4].

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 [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 [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 SO_3 . 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.

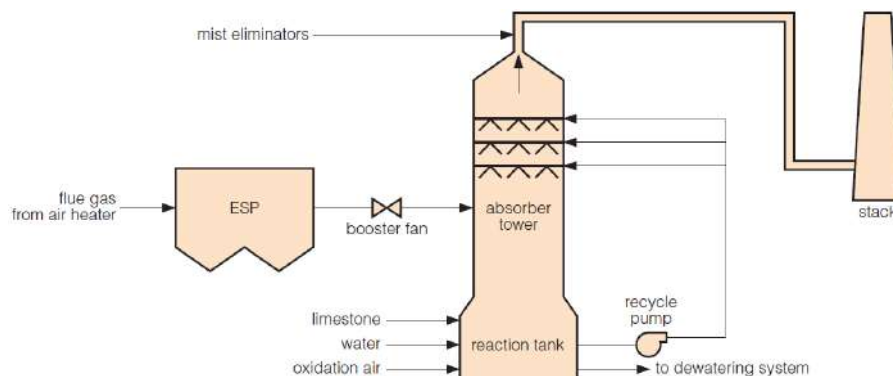


Figure 7: Wet scrubbing system [6]

The wet scrubbing system in Figure above 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. [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 (SO_x) in seawater is lower than that of limestone
- High seawater flowrate
- Large equipment size
- Corrosive absorbent, affecting the ocean ecosystem [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%. [10]

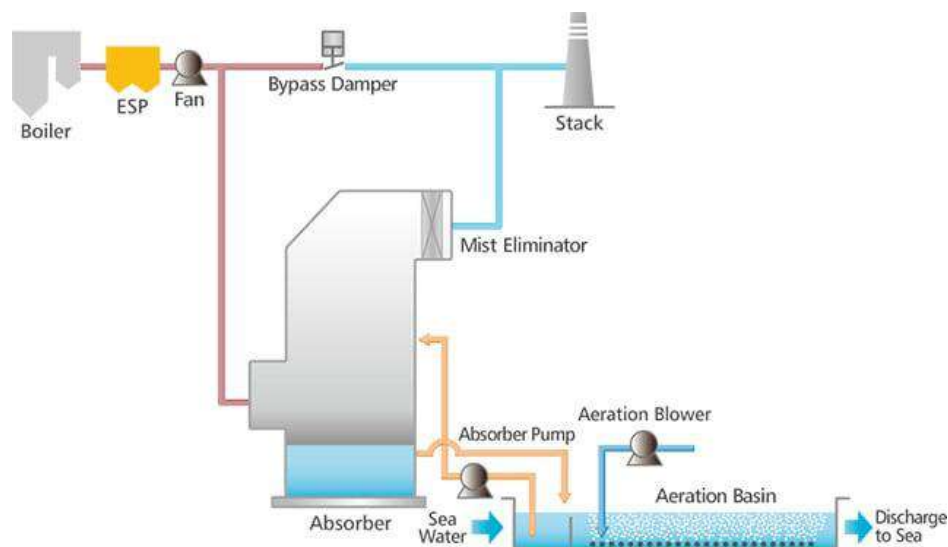


Figure 8: Seawater FGD Process [11]

The seawater FGD consists of two major components: grid tower scrubber and the aeration basin. In the grid tower scrubber, seawater absorbs SO_2 from the flue gas. In the aeration basin, the SO_2 rich seawater is treated to make it suitable for discharge to back to the sea.

Dry scrubbing

Dry scrubbing includes a dry sorbent, typically dry pulverized limestone. The sorbent needs to be grinded to fine parts (20-50 micrometre 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% [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-NO _x 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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1.3. 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 [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 5: Typical component failure mechanisms [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	Condenser, air ejectors,		X Pumps and	X Pumps and	X	X		

	Components	Creep	Low Cycle Fatigue	High Cycle Fatigue	Corrosion	Erosion	Concrete Spallation	Obsolescence
Feedwater Systems	pumps, motors, 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 [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 need to be periodical overhauled, replaced, upgraded or refurbishment.

Table 6: Main component life cycle for coal power plant [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																					

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
Steam turbine	Major overhaul		12								x													x
	Inert gas overhaul		4				x								x				x					x
	HP & IP Rotor	Refurb	16					x																x
	LP Rotors	Refurb	28																					
	Steam chests	Replace	28																					
	Generator s	Refurb	16					x																x
Feed water system	Feed heaters	Refurb	30			x																		
	Condenser waterbox	Refurb	30			x																		
Electric al	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
	Precipitator s	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 7: Major overhaul frequency for coal power plant [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 efficiency will be the same of a little bit lower than the original one [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 [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

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 NO_x.

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.

Table 8: Parameter of different turbine

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 NO_x 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 estimates

An international study from [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 9: Component cost of lifetime extension for coal-fired power plant [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 M\$/MW, based on estimated cost for each component.

Investment costs (MUSD/MW)		2020	2030	2050
Viet Nam data	Project: Ninh Binh 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 current		0.21	0.21	0.21
Projection	Learning curve – cost trend (%)	100%	100%	100%

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.

Data sheet

Coal lifetime extension											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	600	600	600	600	300	1,000	300	1,000		
Generating capacity for total power plant	MW_e	1,200	1,200	1,200	1,200	300	2,000	300	2,000		
Electrical efficiency, net, name plate	%	-1	-1	-1	-1	0	-3	-0	-3	A	1, 6, 7
Electrical efficiency, net, annual average	%	-1	-1	-1	-1	0	-3	-0	-3	A	1, 6, 7
Forced outage	%	+0	+0	+0	+0	+0	+1	+0	+1	A	6
Planned outage	%	+0	+0	+0	+0	+0	+1.9	+0	+1.9	A	6
Self-consumption	%	13.5	13.5	13.5	13.5	-	-	-	-		
Technical lifetime	years	+20	+20	+20	+20	+10	+20	+10	+20	A	
Construction time	years	-	-	-	-	-	-	-	-		
Space requirement (additional to existing plant)	1000_m²/MW_e	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	+0	+0	+0	+0	+0	+0	+0	+0	A	3
Minimum load	% of full load	+0	+0	+0	+0	+0	+0	+0	+0	A	3
Warm start-up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	3
Cold start-up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	3
Minimum Up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	3
Minimum Down time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	3
Environment											
PM 2.5 (compared to 100% coal)	%	+0	+0	+0	+0	+0	+0	+0	+0	A	8
SO ₂ (degree of desulphuring, compared to 100% coal)	%	+0	+0	+0	+0	+0	+0	+0	+0	A	8
NO _x (compared to 100% coal)	%	+0	+0	+0	+0	+0	+0	+0	+0	A	8
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	+0.21	+0.21	+0.21	+0.21	+0.1	+0.3	+0.1	+0.3	A, B, C	1, 2
- of which equipment	%	67	67	67	67	-	-	-	-		
- of which installation and other costs	%	33	33	33	33	-	-	-	-		
- of which equipment	MUSD/MW_e	0.14	0.14	0.14	0.14	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	0.07	0.07	0.07	0.07	-	-	-	-		
Fixed O&M (compared to 100% coal)	%	+3	+3	+3	+3	+1	+5	+1	+5	D	5, 7, 8
Variable O&M (compared to 100% coal)	%	+0	+0	+0	+0	+0	+3	+0	+3		5, 7, 8
Start-up costs	USD/MW_e /start-up	-	-	-	-	-	-	-	-		
Technology specific data											
Water consumption	L/MWh	+0	+0	+0	+0	-	-	-	-	E	

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 It is assumed that plant emissions prior to the LTE are within the legal limits.
- C Investment costs will vary largely, depending on the necessary scope of work. The indicated range represents typical cases where life time is extended to obtain additional 20 years life time.
- D Values 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 life time to accommodate the necessary reinvestments during the extended life time.
- E Assuming the same plant is used as stated the for Supercritical Coal Power Plant.

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1.4. 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 NO_x from ammonia is a concern. However, NO_x removal systems using selective catalytic reduction (SCR) technology, which converts nitrogen oxides into diatomic nitrogen, and water could effectively solve the problem [6].

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

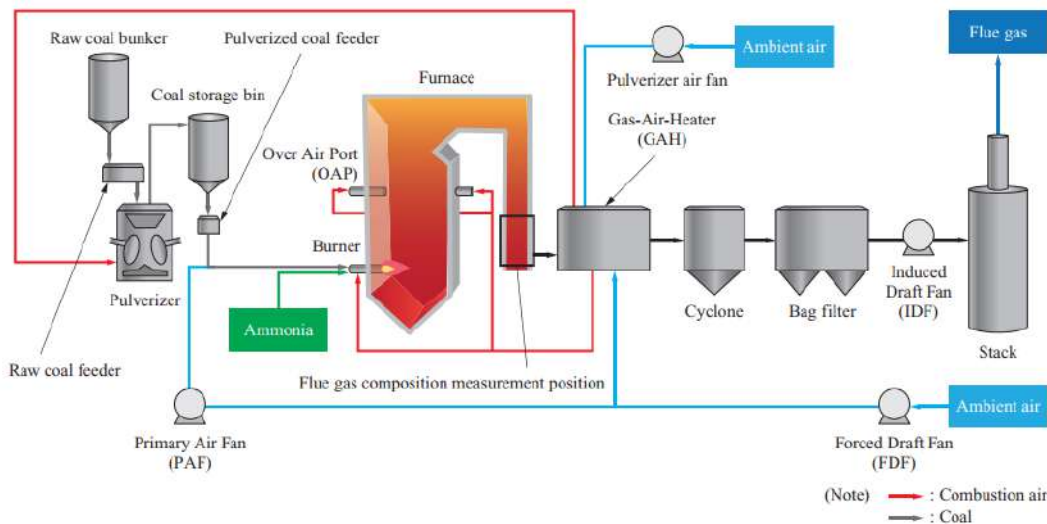


Figure 9: Diagram of ammonia co-firing in pulverized coal-fired power plants [1]

[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 (NO _x 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 NO _x concentration is almost the same as during coal firing; and that CO ₂ , SO ₂ , 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 [2]:

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

This is illustrated in the figure below.

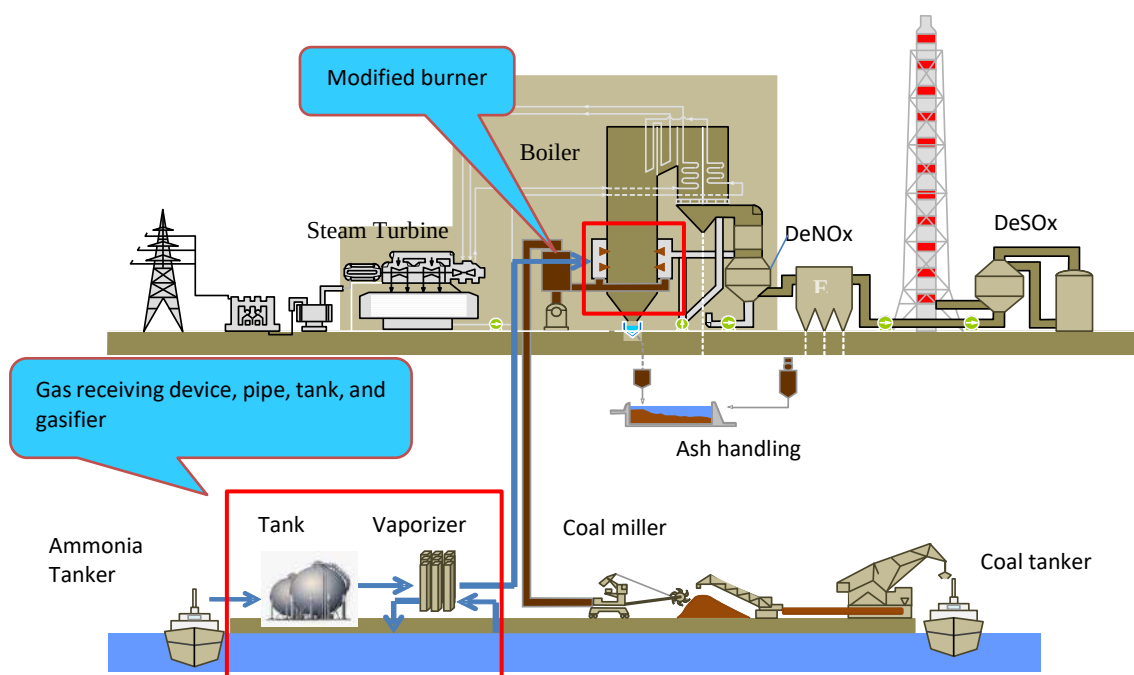


Figure 10: Facilities to be implemented and improved at a coal ammonia co-fired power plant

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 [1].

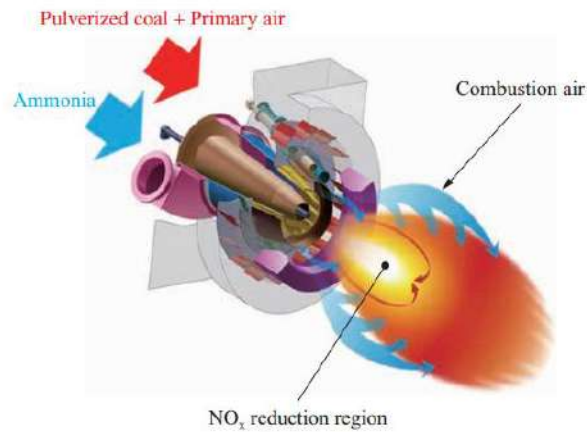


Figure 11: Schematic diagram of the modified burner to co-firing ammonia [1]

Effect on boiler efficiency

A comparison is given of boiler performance for coal firing and ammonia co-firing 20% is verified in [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.

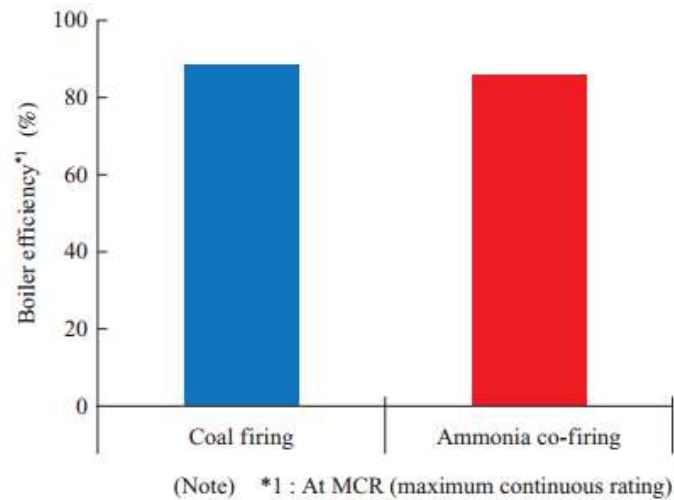


Figure 12: Comparison of boiler performance for coal firing and ammonia co-firing 20% [1]

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.

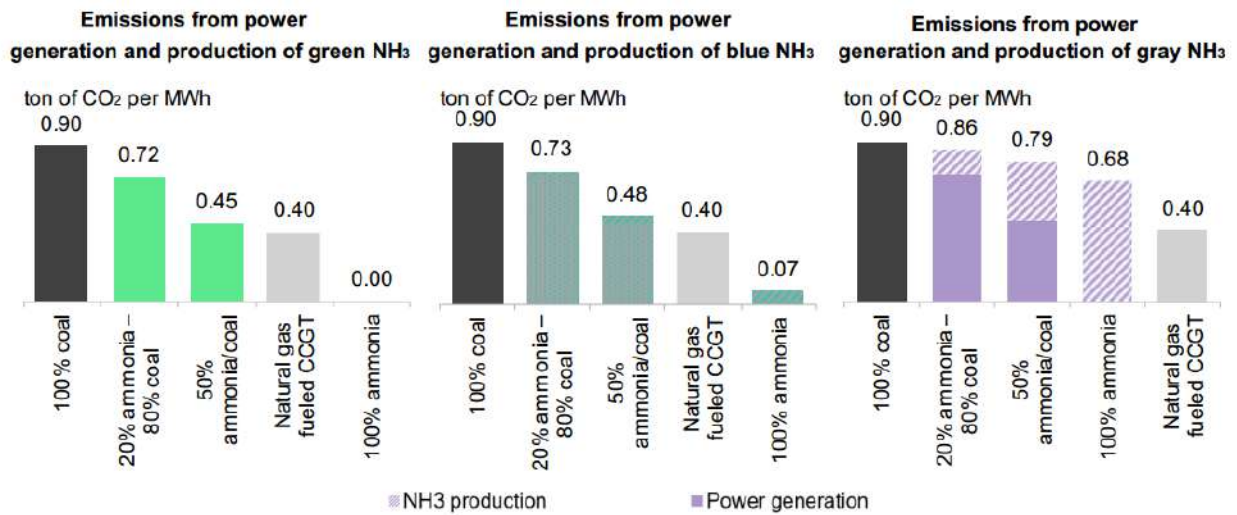


Figure 13: Emission reduction potential depending on the ammonia source [2]

Note: Emissions for power generation and ammonia production. Gray (unabated) ammonia production assumes 9kg of CO₂ emissions to produce 1kg of hydrogen. Blue ammonia production assumes 90% CO₂ capture rates of carbon capture and storage (CCS) technologies for unabated hydrogen production.

The other emission of SO₂ and particle matter decrease when co-firing ammonia as the amount of injected coal decreases and NH₃ does not contain sulfur and dust [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 NO_x 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 [1, 3]. [4] shows that under the condition of 20% co-firing, equivalent NO_x 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 NH₃/air and the prominent denigration effect of NH₃ in the vicinity of the NH₃ downstream injection location.

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

Based on technology development studies by Mitsubishi Heavy Industries (MHI) and IHI of Japan on ammonia co-firing in coal-fired power plants, the required equipment modifications or additions depend on the ammonia co-firing ratio.

At an approximately 20% co-firing level, most of the existing plant systems can continue to be utilized. However, additional systems are required, including ammonia receiving, storage, and supply systems, modification of burners, adjustment of the combustion air system, upgrades to the control and instrumentation systems, optimization of the flue gas treatment system, and installation of ammonia-related safety systems.

For 100% ammonia firing, more extensive modifications are required. These include the construction of a dedicated ammonia receiving port and large-scale storage systems, replacement with dedicated ammonia burners, major modification or redesign of the furnace, as well as upgrades to the electrical, control, and safety systems to ensure stable plant operation.

The specific modification requirements may vary between power plants depending on factors such as boiler type, unit capacity, and existing infrastructure conditions.

Table 10: Proposed equipment modifications for ammonia–coal co-firing

Plant System	20% Ammonia Co-firing	100% Ammonia Firing
Port and Fuel Receiving Facilities	Addition of medium-scale ammonia receiving facilities (small vessels, tank trucks, or rail transport).	Construction of a dedicated large-scale ammonia import terminal to supply the plant's primary fuel.
Fuel Storage System	Installation of medium-capacity ammonia storage tanks with associated safety systems.	Large-scale ammonia storage tanks designed similarly to chemical or LNG storage terminals.
Fuel Supply and Handling System	Installation of ammonia pumps, vaporizers, and pipelines to supply ammonia to the boiler area.	A complete ammonia fuel supply infrastructure with large capacity and redundancy.
Boiler and Furnace	Minor adjustments to the furnace to maintain stable combustion during co-firing operation.	Major modification or redesign of the furnace to accommodate the combustion characteristics of ammonia.
Burner System	Modification of existing coal burners to allow ammonia injection for co-firing.	Complete replacement with dedicated ammonia burners.
Air and Combustion System	Optimization of air distribution and overfire air (OFA) systems to stabilize combustion.	Significant modification of the air supply and air staging systems within the furnace.
Flue Gas Treatment System	Optimization of NO _x control systems (SCR/SNCR) to manage NO _x emissions and ammonia slip. However, according to the most recent tests conducted by IHI at the Hekinan Power Plant, air pollutant emissions did not increase compared to conventional coal combustion.	Advanced NO _x control systems and dedicated ammonia slip monitoring systems.
Coal Handling System	Existing coal handling system remains in operation.	Most coal handling systems are removed or decommissioned.
Electrical System	Additional electrical supply for ammonia pumps, vaporizers, and safety systems.	Expansion of auxiliary electrical systems to supply power for the full ammonia receiving, storage, and handling infrastructure.
Control and Instrumentation System	Upgrade of the distributed control system (DCS) to manage co-firing ratios and monitor ammonia leakage.	Redesign of combustion control strategies and full integration of ammonia fuel system controls.
Safety System	Installation of ammonia leak detection systems, ventilation, and emergency shutdown systems.	Comprehensive safety and risk management systems for ammonia-based plant operation.

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 CO₂ emission of coal-fired power plants. With the co-firing ratio of 50%, CO₂ emission of co-firing coal power plant will be equivalent level to gas-fired power generation.[2]
- Ammonia could be utilized directly as a fuel without cracking. Ammonia co-firing reduces the amount of soot and coal power particles in the furnace, leading to reduced ash deposition on heat transfer surfaces.
- Transmission of ammonia via pipelines is a mature technology. Ammonia is also well developed in terms of intercontinental transmission, relying on semi-refrigerated liquefied petroleum gas (LPG) tankers.

Disadvantages:

- Ammonia is a highly reactive and toxic gas, and proper safety measures must be in place to prevent accidents or releases.
- Ammonia co-firing requires modified burners and other facilities to retrieve, vaporize and transport ammonia. Moreover, additional NO_x removal systems (selective catalytic reduction SCR) are also required, due to the significant amounts of NO_x generated during combustion. Those modification and implementation can be costly.
- The price of ammonia is higher than that of coal, increasing fuel costs for the plant. An estimation of The Institute of Energy Economics, Japan projected that the fuel costs for a power plant that uses a 20% blend of ammonia will be significantly higher, more than double, than that of a power plant which uses coal alone. [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 CO₂. Other kinds of ammonia like blue ammonia (made via steam reforming of methane or gasification of coal couple with CO₂ capture and storage), or green ammonia (made via electrolysis of water using renewable energy electricity) release smaller volumes of CO₂ but are much more costly.
- Further research is needed to increase the NH₃-to-coal ratio and improve the efficiency of the boiler.

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 [7]. 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% [9].

In June 2025, JERA (Japan) completed a three-month trial of co-burning 20% ammonia with coal at Unit 1 GW of the Hekinan Thermal Power Plant, yielding positive results and considered the world's first trial of its kind on a large commercial power plant scale. The results showed that NO_x concentrations did not increase compared to coal-fired operation, SO_x decreased by approximately 20%, N₂O generation was below detection limits, and operational performance was comparable to coal-fired operation. Based on these results, JERA will begin work towards commercial operation with a high ammonia replacement rate at this plant [8].

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

Cost estimates

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 NO_x-reduction facilities are not necessary because NO_x emissions do not increase significantly (see Effect on emission); these upgrades come at an estimated 11% premium in Capex [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 [2].

Data sheet

Pulverized coal – co-firing 20% ammonia											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	600	600	600	600	300	1,000	300	1,000		
Generating capacity for total power plant	MW_e	1,200	1,200	1,200	1,200	300	2,000	300	2,000		
Electrical efficiency, net, name plate	%	-1	-1	-1	-1	0	-2	0	-2	A, B	5
Electrical efficiency, net, annual average	%	-1	-1	-1	-1	0	-2	0	-2	A, B	5
Forced outage	%	+0	+0	+0	+0	+0	+1	+0	+1	A	
Planned outage	%	+0	+0	+0	+0	+0	+0	+0	+0	A	
Self-consumption	%	8.6	8.6	8.6	8.6	-	-	-	-		
Technical lifetime	years	-	-	-	-	-	-	-	-		
Construction time	years	1	1	1	1	-	-	-	-		
Space requirement (additional to existing plant)	1000_m²/MW_e	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	+0	+0	+0	+0	+0	+0	+0	+0	A	
Minimum load	% of full load	+0	+0	+0	+0	+0	+0	+0	+0	A	
Warm start-up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	
Cold start-up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	
Minimum Up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	
Minimum Down time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	
Environment											
PM 2.5 (compared to 100% coal)	%	-20	-20	-20	-20	-10	-20	-10	-20	A, C	5
SO ₂ (degree of desulphuring, compared to 100% coal)	%	-20	-20	-20	-20	-10	-20	-10	-20	A, D	5
NO _x (compared to 100% coal)	%	+5	+5	+5	+5	+0	+10	+0	+10	A, E	3, 5, 6, 7
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	+0.15	+0.15	+0.15	+0.15	+0.10	+0.20	+0.10	+0.20	A, F, G	1, 2, 4
- of which equipment	%	-	-	-	-	-	-	-	-		
- of which installation and other costs	%	-	-	-	-	-	-	-	-		
- of which equipment	MUSD/MW_e	-	-	-	-	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	-	-	-	-	-	-	-	-		
Fixed O&M (compared to 100% coal)	%	+5	+5	+5	+5	+3	+8	+3	+8	A	3, 4
Variable O&M (compared to 100% coal)	%	+5	+5	+5	+5	+3	+8	+3	+8	A	3, 4
Start-up costs	USD/MW_e/start-up	-	-	-	-	-	-	-	-		
Technology specific data											
Water consumption	L/MWh	+0	+0	+0	+0	-	-	-	-	H	

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 electrical efficiency is 1-2 % point lower than that of the plant prior to conversion.
- C 100mg/Nm³ (at 6% O₂), 20% reduction compared to firing coal.
- D 500mg/Nm³ (at 6% O₂), 20% reduction compared to firing coal.
- E Assuming it remains the same as when firing coal.
- F The nominal investment assumes that investment for a general life time extension campaign is excluded.
- G The investment cost includes modifying existing coal plants for ammonia co-firing which requires boiler modifications and investment in additional facilities like ammonia tanks and vaporizers. In general, the retrofits include [3]: Modified burner; New ammonia receiving device, pipe, tank and vaporizer; Additional NO_x removal device. The cost of improving pipelines outside the plant-land plot is not included.
- H Assuming the same plant is used as stated the for Supercritical Coal Power Plant.

References

- 1 Fuel conversion project for Unit 2 of Pha lai thermal power plant, Institute of Energy, 2025
- 2 GFANZ, ClimateWorks Foundation and Institute of Energy, 2025 - Study on flexibility of coal thermal power plants to support the energy transition in Vietnam
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- 6 T. Ito, H.Ishii, J.Zhang, S..Ishihara, S.Toshiyuki (IHI Corporation), New technology of the Ammonia co-firing with pulverized coal to reduce the NO_x emission. AIChE meeting 2019
- 7 J.Tan, Y.He, R.Zhu, Y.Zhu, Z.Wang, Experimental study on co-firing characteristic of ammonia with pulverized coal in a staged combustion drop tube furnace, 2022

Pulverized coal – co-firing 100% ammonia										
Parameter	Unit	2030	2040	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW_e	600	600	600	300	1,000	300	1,000		
Generating capacity for total power plant	MW_e	1,200	1,200	1,200	300	2,000	300	2,000		
Electrical efficiency, net, name plate	%	-2	-2	-2	-1	-3	-1	-3	A, B	5
Electrical efficiency, net, annual average	%	-2	-2	-2	-1	-3	-1	-3	A, B	5
Forced outage	%	+0	+0	+0	+0	+1	+0	+1	A	
Planned outage	%	+0	+0	+0	+0	+0	+0	+0	A	
Self-consumption	%	8.6	8.6	8.6						
Technical lifetime	years									
Construction time	years	1	1	1						
Space requirement (additional to existing plant)	1000_m ² /MW_e									
Ramping ability										
Ramping	% of full load/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	
Minimum Up time	hours	+0	+0	+0	+0	+0	+0	+0	A	
Minimum Down time	hours	+0	+0	+0	+0	+0	+0	+0	A	
Environment										
PM 2.5 (compared to 100% coal)	%	-100	-100	-100	-70	-100	-70	-100	A, C	5
SO ₂ (degree of desulphuring, compared to 100% coal)	%	-100	-100	-100	-70	-100	-70	-100	A, D	5
NO _x (compared to 100% coal)	%	+30	+30	+30	+20	+50	+20	+50	A, E	3, 5, 6, 7
Economic data (in USD2025)										
Specific investment	MUSD/MW_e	+0.35	+0.35	+0.35	+0.20	+0.60	+0.20	+0.60	A, F, G	1, 2, 4
- of which equipment	%									
- of which installation and other costs	%									
- of which equipment	MUSD/MW_e									
- of which installation and other costs	MUSD/MW_e									
Fixed O&M (compared to 100% coal)	%	+10	+10	+10	+5	+15	+5	+15	A	3, 4
Variable O&M (compared to 100% coal)	%	+10	+10	+10	+5	+15	+5	+15	A	3, 4
Start-up costs	USD/MW_e/s tart-up									
Technology specific data										
Water consumption	L/MWh	+0	+0	+0	-	-	-	-	H	

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 electrical efficiency is 1-2 % point lower than that of the plant prior to conversion.
- C 100mg/Nm³ (at 6% O₂), 100% reduction compared to firing coal.

- D 500mg/Nm³ (at 6% O₂), 100% reduction compared to firing coal.
- E Assuming it remains the same as when firing coal.
- F The nominal investment assumes that investment for a general life time extension campaign is excluded.
- G The investment cost includes modifying existing coal plants for ammonia co-firing which requires boiler modifications and investment in additional facilities like ammonia tanks and vaporizers. In general, the retrofits include [3]: Modified burner; New ammonia receiving device, pipe, tank and vaporizer; Additional NO_x removal device. The cost of improving pipelines outside the plant-land plot is not included.
- H Assuming the same plant is used as stated the for Supercritical Coal Power Plant.

References

- 1 Fuel conversion project for Unit 2 of Pha lai thermal power plant, Institute of Energy, 2025
- 2 GFANZ, ClimateWorks Foundation and Institute of Energy, 2025 - Study on flexibility of coal thermal power plants to support the energy transition in Vietnam
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- 6 T. Ito, H.Ishii, J.Zhang, S..Ishihara, S.Toshiyuki (IHI Corporation), New technology of the Ammonia co-firing with pulverized coal to reduce the NO_x emission. AIChE meeting 2019
- 7 J.Tan, Y.He, R.Zhu, Y.Zhu, Z.Wang, Experimental study on co-firing characteristic of ammonia with pulverized coal in a staged combustion drop tube furnace, 2022

1.5. 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 CO₂, NO_x, and SO_x emissions [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 [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.

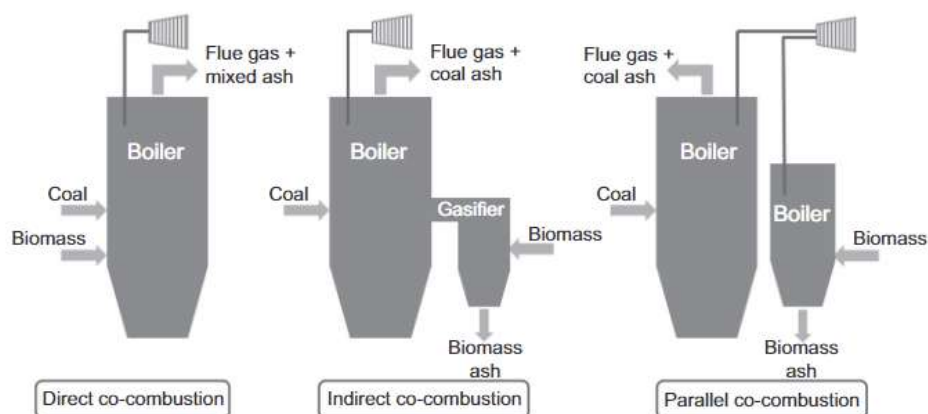


Figure 14: Schematic presentation of co-firing technology options [4]

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 [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% [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

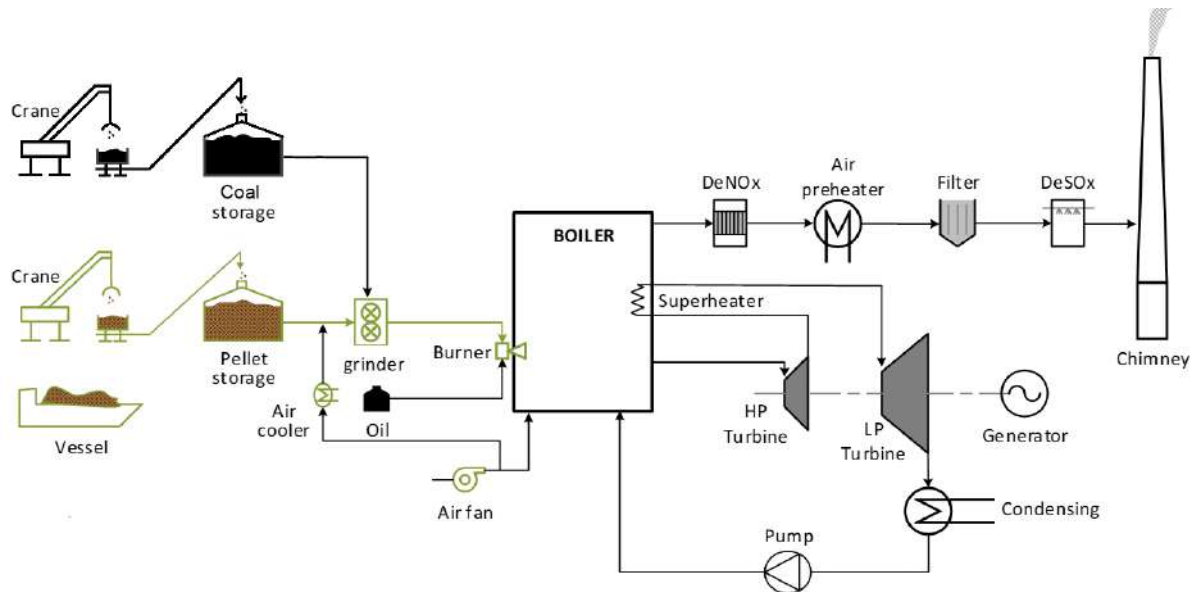


Figure 15: Sketch of a pulverized coal plant co-firing with wood pellets. The green elements indicate the equipment that needs to be added, replaced or refurbished.

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.

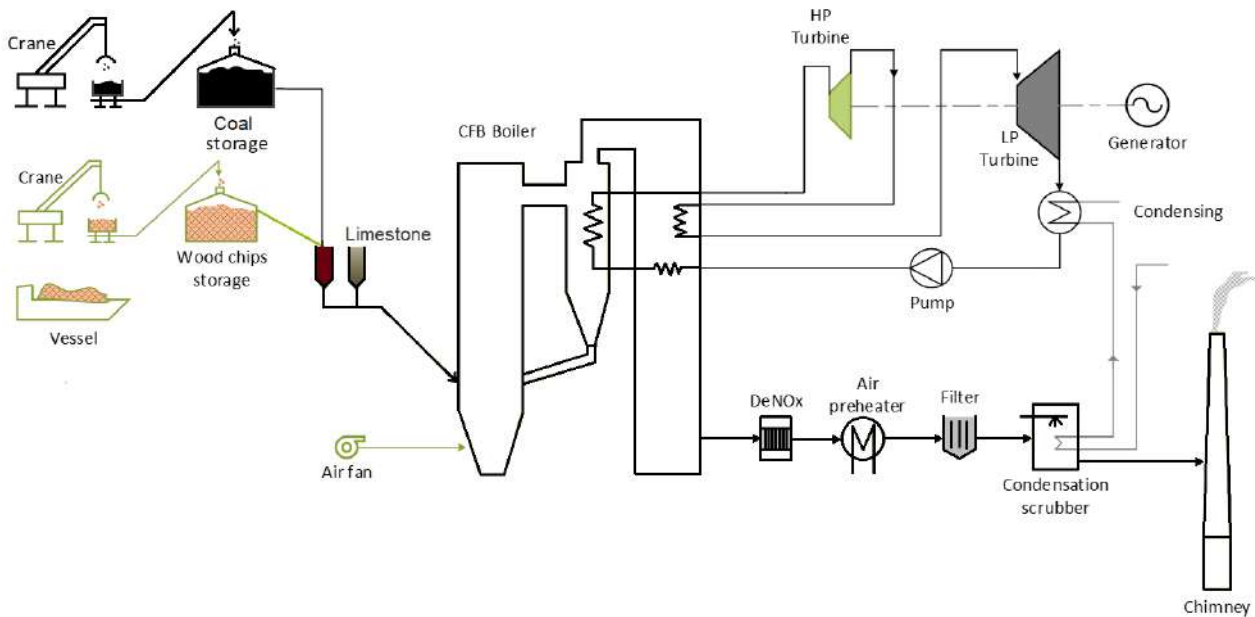


Figure 16: Sketch of a CFB coal plant co-firing with wood chip. The green elements indicate the equipment that needs to be added, replaced or refurbished.

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%.[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 [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 [11].

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

Power Plant/ Commissioning 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, aluminium and calcium affect ash melting behaviour. 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 [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

[12]: The net emissions of CO₂ from the combustion of biomass are less than from coal if the biomass is grown in a sustainable manner. The measured stack emissions of CO₂ 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 CO₂.

SO₂ 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.

NO_x 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.

[5,6] estimated with a mixing ratio of around 16% to 20% biomass, CO₂ 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

[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.

[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 SO₂ 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%.

[14]: From September to November 2025, the first wood chips co-firing trial in Vietnam was conducted at the Na Duong Power Plant (using CFB boiler), with a co-firing ratio of up to 20% using wood chips, the test gained significant knowledge on the efficient operation of related processes, such as biomass fuel transportation processes.

Cost estimates

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) [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) [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

Pulverized coal – co-firing 20% biomass (wood pellets)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	600	600	600	600	300	1,000	300	1,000		
Generating capacity for total power plant	MW_e	1,200	1,200	1,200	1,200	300	2,000	300	2,000		
Electrical efficiency, net, name plate	%	-1	-1	-1	-1	0	-2	0	-2	A, B	
Electrical efficiency, net, annual average	%	-1	-1	-1	-1	0	-2	0	-2	A, B	
Forced outage	%	+0	+0	+0	+0	+0	+1	+0	+1	A	
Planned outage	%	+0	+0	+0	+0	+0	+0	+0	+0	A	
Self-consumption	%	13.5	13.5	13.5	13.5	-	-	-	-		
Technical lifetime	years	-	-	-	-	-	-	-	-		
Construction time	years	1	1	1	1	-	-	-	-		
Space requirement (additional to existing plant)	1000_m ² /MW_e	+0	+0	+0	+0	-	-	-	-	A, C	
Ramping ability											
Ramping	% of full load/minute	+0	+0	+0	+0	+0	+0	+0	+0	A	2
Minimum load	% of full load	+0	+0	+0	+0	+0	+0	+0	+0	A	2
Warm start-up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	2
Cold start-up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	2
Minimum Up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	2
Minimum Down time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	2
Environment											
PM 2.5 (compared to 100% coal)	%	-10	-10	-10	-10	-5	-20	-5	-20	A	2
SO ₂ (degree of desulphuring, compared to 100% coal)	%	-10	-10	-10	-10	-5	-20	-5	-20	A	2
NO _x (compared to 100% coal)	%	-5	-5	-5	-5	-0	-10	-0	-10	A	2
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	+0.16	+0.16	+0.16	+0.16	+0.05	+0.30	+0.05	+0.30	A, D	1
- of which equipment	%	-	-	-	-	-	-	-	-		
- of which installation and other costs	%	-	-	-	-	-	-	-	-		
- of which equipment	MUSD/MW_e	-	-	-	-	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	-	-	-	-	-	-	-	-		
Fixed O&M (compared to 100% coal)	%	+3	+3	+3	+3	+1	+5	+1	+5	A	2
Variable O&M (compared to 100% coal)	%	+3	+3	+3	+3	+1	+5	+1	+5	A	2
Start-up costs	USD/MW_e/start-up	-	-	-	-	-	-	-	-		
Technology specific data											

Water consumption	L/MWh	+0	+0	+0	+0	-	-	-	-	E	

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 electrical efficiency is 1-2 % point lower than that of the plant prior to conversion.
- C Some additional under roof space (or silos) are required for storage of pellets compared to coal (estimated 50%-100% extra m3 storage). But not more floor space (m²).
- D The nominal investment is excluding investment for a general life time extension campaign.
- E Assuming the same plant is used as stated the for Supercritical Coal Power Plant.

References

- 1 Fuel conversion project for Unit 1 of Pha lai thermal power plant, Institute of Energy, 2025
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Pulverized coal – co-firing 100% biomass (wood pellets)										
Parameter	Unit	2030	2040	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW_e	600	600	600	300	1,000	300	1,000		
Generating capacity for total power plant	MW_e	1,200	1,200	1,200	300	2,000	300	2,000		
Electrical efficiency, net, name plate	%	-2	-2	-2	-1	-3	-1	-3	A, B	
Electrical efficiency, net, annual average	%	-2	-2	-2	-1	-3	-1	-3	A, B	
Forced outage	%	+0	+0	+0	+0	+1	+0	+1	A	
Planned outage	%	+0	+0	+0	+0	+0	+0	+0	A	
Self-consumption	%	8.6	8.6	8.6						
Technical lifetime	years									
Construction time	years	1	1	1						
Space requirement (additional to existing plant)	1000_m²/MW_e								A,C	
Ramping ability										
Ramping	% of full load/minute	+0	+0	+0	+0	+0	+0	+0	A	2
Minimum load	% of full load	+0	+0	+0	+0	+0	+0	+0	A	2
Warm start-up time	hours	+0	+0	+0	+0	+0	+0	+0	A	2
Cold start-up time	hours	+0	+0	+0	+0	+0	+0	+0	A	2
Minimum Up time	hours	+0	+0	+0	+0	+0	+0	+0	A	2
Minimum Down time	hours	+0	+0	+0	+0	+0	+0	+0	A	2
Environment										
PM 2.5 (compared to 100% coal)	%	-70	-70	-70	-50	-90	-50	-90	A	2
SO₂ (degree of desulphuring, compared to 100% coal)	%	-70	-70	-70	-50	-90	-50	-90	A	2
NOₓ (compared to 100% coal)	%	-30	-30	-30	-5	-40	-5	-40	A	2
Economic data (in USD2025)										
Specific investment	MUSD/MW_e	+0.36	+0.36	+0.36	+0.30	+0.80	+0.30	+0.80	A, D	1
- of which equipment	%									
- of which installation and other costs	%									
- of which equipment	MUSD/MW_e									
- of which installation and other costs	MUSD/MW_e									
Fixed O&M (compared to 100% coal)	%	+5	+5	+5	+3	+10	+3	+10	A	2
Variable O&M (compared to 100% coal)	%	+5	+5	+5	+3	+10	+3	+10	A	2
Start-up costs	USD/MW_e/start-up									
Technology specific data										
Water consumption	L/MWh	+0	+0	+0	-	-	-	-	E	

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 electrical efficiency is 1-2 % point lower than that of the plant prior to conversion.

- C Some additional under roof space (or silos) are required for storage of pellets compared to coal (estimated 50%-100% extra m3 storage). But not more floor space (m²).
- D The nominal investment is excluding investment for a general life time extension campaign.
- E Assuming the same plant is used as stated the for Supercritical Coal Power Plant.

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2. CIRCULATING FLUIDIZED BED (CFB) COAL FIRED POWER

Brief 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 SO₂ removal [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.

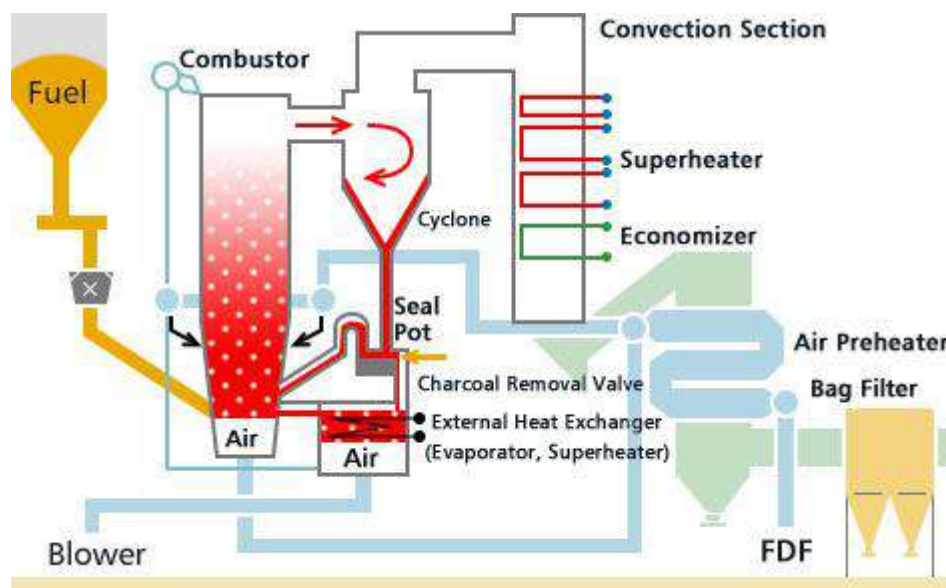


Figure 17: CFB boiler scheme [2]

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 [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. [4]

Auxiliary consumption is on average 9-10% of the generating capacity [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. [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 [6,7].

Disadvantages

- The auxiliary power consumption is higher than for pulverized plants due to the high fan power necessary for fluidization [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 [8].

Water consumption

The water consumption for CFB coal fired power is similar as for pulverized coal fired power described in the section Water consumption in the chapter Pulverized coal fired power.

Environment

As a result of the low combustion temperature and the amount of injected air, NO₂ 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 N₂O. The conversion of coal nitrogen in N₂O 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 N₂O.

The formation of Sulfur Dioxide mainly depends on gas residence time, temperature and excess air, but it is favoured by high temperature and high pressure. Thanks to the low combustion temperature, it is possible to use limestone to capture SO₂, thus most CFB power plants do not use SO₂ removal systems at post-combustion of the boiler. However, the efficiency and requirements for SO₂ removal depend directly on the sulfur content in the fuel. In cases of high sulfur content, additional investment in a SO₂ removal (FGD) system, similar to the solution currently being applied at Na Duong I, II Thermal Power Plant, may need to be considered.

CFB has lower primary emissions of SO_x and NO_x 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 CO₂.

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. [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. [9]

Research and development

The main research efforts are focused on capacity scale-up, auxiliary power reduction and improvements in SO₂ capture [10].

In addition, attaining higher and flexibility is also under research [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 [12].

Currently, coal-fired power plants using CFB technology are conducting test with biomass co-firing to assess their applicability under operating conditions in Vietnam. From September to November 2025, the first biomass co-burning trial in Vietnam was conducted at the Na Duong I Power Plant, with a co-firing ratio of up to 20% using wood chips, initial results show that CFB technology has the potential to gradually transition to using biomass fuel and gained significant knowledge on the efficient operation of related processes, such as biomass fuel transportation processes [23].

Examples of current projects

CFB boilers have been used in Viet Nam for years:

Na Duong power plant

This coal power plant produces 110 MW (2x55MW, configuration of 1 boiler – 1 turbine). It was completed in 2005 and it is a mine-to-mouth plant. [13]

Cao Ngan power plant

This coal power plant produces 115 MW (2x57.5MW, configuration of 1 boiler – 1 turbine) and was completed in 2007 with an investment cost of \$124 million. It uses Anthracite coal, and the boilers were provided by Alstom [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 [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, Quang 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 [16].

Mao Khe thermal plants [12]

General: Mao Khe coal-fired power plant is in 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 ($\sim 172 \text{ bar}$) 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 $\text{PM}_{2.5}$ 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, 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 ($\sim 241 \text{ bar}$), 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 $\text{PM}_{2.5}$ emissions are 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.

Nong Son power station

The Nong Son Thermal Power Plant commenced construction in 2006 in Nong Son Commune, Da Nang city with a designed capacity of 30 MW with configuration of 1 boiler – 1 turbine. The plant commenced commercial operation in 2015 [20].

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 Bac Ninh province and expect to commission in the period up to 2030. It will cost \$1 billion. It will use domestic anthracite coal.

Na Duong II power plant

The Na Duong II Thermal Power Plant is located in Na Duong commune, Lang Son province, with Vinacomin - Power Holding Corporation as the investor, it has a total investment of 4,089 billion VND, with a capacity of 110 MW, using a CFB boiler + 1 turbine + 1 generator. The main fuel for operating the plant is coal produced by Na Duong Coal Company. It is expected to become operational in 2026 [22].

Investment cost estimation

The data from the different sources in the table below is adjusted for inflation from their original price years

to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - CFB Coal Power Plant						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		1.9	1.88		1.85	1.81
Technology Catalogue - Vietnam 2023	1.94		1.92			1.90

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Data sheet

CFB boiler power plant ultra-supercritical											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	600	600	600	600	300	660	300	800		1
Generating capacity for total power plant	MW_e	1200	1200	1200	1200	300	1200	300	1800		1
Electrical efficiency, net, name plate	%	41	42	43	43	37	43	39	45		1, 5, 6
Electrical efficiency, net, annual average	%	40	41	42	42	37	43	39	45		1, 6
Forced outage	%	7	6	5	3	5	15	2	7	A	1
Planned outage	%	13	10	8	6	6	15	4	8	A	1
Self-consumption	%	-	-	-	-	-	-	-	-		
Technical lifetime	years	30	30	30	30	25	40	25	40		1
Construction time	years	3.75	3	3	3	3	5	2	4	A	1
Space requirement	1000_m ² /MW_e	-	-	-	-	-	-	-	-		6
Additional data for non-thermal plants											
Capacity factor, theoretical	%	-	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	4	4	4	4	2	4	3	4	B	1
Minimum load	% of full load	40	25	22.5	20	25	50	10	30	A	1
Warm start-up time	hours	8	4	4	4	2	8.5	2	5	B	1
Cold start-up time	hours	10	12	12	12	6	15	6	12	B	1
Minimum Up time	hours	6	6	6	6	-	-	-	-		7
Minimum Down time	hours	4	4	4	4	-	-	-	-		7
Environment											
PM 2.5	mg/Nm ³	70	70	70	70	50	150	20	100	E	2, 3
SO ₂ (degree of desulphuring)	%	90	90	90	95	90	95	90	99		2, 3
NO _x	g/GJ_i	108	105	72	38	108	263	38	263	C	2, 3
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	1.90	1.88	1.85	1.81	1.43	2.57	1.36	2.26	D, F, G, H	1, 5, 6
- of which equipment	%	-	-	-	-	-	-	-	-		
- of which installation and other costs	%	-	-	-	-	-	-	-	-		
- of which equipment	MUSD/MW_e	-	-	-	-	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	-	-	-	-	-	-	-	-		
Fixed O&M	USD/MW_e/year	50,920	50,413	49,413	48,434	38,190	68,742	36,326	60,543	F, H	1, 5, 6
Variable O&M	USD/MWh	1.30	1.39	1.36	1.33	0.98	1.76	1.00	1.66	F, H	1, 6
Start-up costs	USD/MW_e/start-up	65	65	65	65	49	87	49	81	F, H	1, 4, 6
Technology specific data											
Water consumption	L/MWh	+0	+0	+0	+0	-	-	-	-	I	

Notes:

- A Assuming gradual improvement to international standard in 2050.
- B Assuming no improvement for regulatory capability.
- C Calculated from a max of 750 mg/Nm³ to g/GJ (conversion factor 0.35 from Pollution Prevention and Abatement Handbook, 1998).
- D For economy of scale a proportionality factor of 0.8 is suggested.
- E Uncertainty: Upper is from regulation, Lower is from current standards in Japan (2025) and South Korea (2050).
- F Uncertainty (Upper/Lower) is estimated as -25% (lower) and +35% (higher) for 2025 and +/- 25% for 2050.
- G Investment cost includes the engineering, procurement and construction (EPC) cost. See description under Methodology.
- H Assuming that costs fall 0.2 % each year.
- I Assuming the same plant is used as stated the for Supercritical Coal Power Plant.

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CFB coal – co-firing 20% biomass (wood pellets, wood chips)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	300	300	300	300	150	600	150	600		
Generating capacity for total power plant	MW_e	600	600	600	600	300	1,200	300	1,200		
Electrical efficiency, net, name plate	%	+0	+0	+0	+0	+0	-1	+0	-1	A, B	3,14, 15
Electrical efficiency, net, annual average	%	+0	+0	+0	+0	+0	-1	+0	-1	A, B	3,14, 15
Forced outage	%	+0	+0	+0	+0	+0	+1	+0	+1	A	3,14, 15
Planned outage	%	+0	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Self-consumption	%	-	-	-	-	-	-	-	-		
Technical lifetime	years	-	-	-	-	-	-	-	-		
Construction time	years	1	1	1	1	-	-	-	-		
Space requirement (additional to existing plant)	1000_m ² /MW_e	+0	+0	+0	+0	-	-	-	-	A, C	3,14, 15
Ramping ability											
Ramping	% of full load/minute	+0	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Minimum load	% of full load	+0	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Warm start-up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Cold start-up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Minimum Up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Minimum Down time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Environment											
PM 2.5 (compared to 100% coal)	%	-10	-10	-10	-10	-5	-20	-5	-20	A	1,2
SO ₂ (degree of desulphuring, compared to 100% coal)	%	-10	-10	-10	-10	-5	-20	-5	-20	A	1,2
NO _x (compared to 100% coal)	%	-5	-5	-5	-5	-0	-10	-0	-10	A	1,2
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	+0.06	+0.06	+0.06	+0.06	+0.01	+0.20	+0.01	+0.20	A, D	1, 2
- of which equipment	%	-	-	-	-	-	-	-	-		
- of which installation and other costs	%	-	-	-	-	-	-	-	-		
- of which equipment	MUSD/MW_e	-	-	-	-	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	-	-	-	-	-	-	-	-		
Fixed O&M (compared to 100% coal)	%	+3	+3	+3	+3	+1	+5	+1	+5	A	3,14, 15
Variable O&M (compared to 100% coal)	%	+3	+3	+3	+3	+1	+5	+1	+5	A	3,14, 15
Start-up costs	USD/MW_e/start-up	-	-	-	-	-	-	-	-		
Technology specific data											
Water consumption	L/MWh	+0	+0	+0	+0	-	-	-	-	E	

Notes:

- A Value depends on the original plant. Value indicates the estimated change from the original value (unit is the same as for the parameter).
- B Typically, the electrical efficiency is 1-2 % point lower than that of the plant prior to conversion.
- C Some additional under roof space (or silos) will be required for storage of pellets compared to coal (estimated 50%-100% extra m3 storage). But not more floor space (m2).
- D The nominal investment is excluding investment for a general life time extension campaign.
- E Assuming the same plant is used as stated the for Supercritical Coal Power Plant.

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- 15 Danish Energy Agency and Energinet, "Technology Data - Energy Plants for Electricity and District heating generation", 2016

CFB coal – co-firing 100% biomass (wood pellets, wood chips)										
Parameter	Unit	2030	2040	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW_e	600	600	600	300	1,000	300	1,000		
Generating capacity for total power plant	MW_e	1,200	1,200	1,200	300	2,000	300	2,000		
Electrical efficiency, net, name plate	%	-1	-1	-1	-1	-2	-1	-2	A, B	3,14, 15
Electrical efficiency, net, annual average	%	-1	-1	-1	-1	-2	-1	-2	A, B	3,14, 15
Forced outage	%	+0	+0	+0	+0	+1	+0	+1	A	3,14, 15
Planned outage	%	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Self-consumption	%	8.6	8.6	8.6	-	-	-	-		
Technical lifetime	years	-	-	-	-	-	-	-		
Construction time	years	1	1	1	-	-	-	-		
Space requirement (additional to existing plant)	1000_m ² /MW_e	-	-	-	-	-	-	-	A, C	3,14, 15
Ramping ability										
Ramping	% of full load/minute	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Minimum load	% of full load	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Warm start-up time	hours	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Cold start-up time	hours	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Minimum Up time	hours	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Minimum Down time	hours	+0	+0	+0	+0	+0	+0	+0	A	3,14, 15
Environment										
PM 2.5 (compared to 100% coal)	%	-70	-70	-70	-50	-90	-50	-90	A	1,2
SO ₂ (degree of desulphuring, compared to 100% coal)	%	-70	-70	-70	-50	-90	-50	-90	A	1,2
NO _x (compared to 100% coal)	%	-30	-30	-30	-5	-40	-5	-40	A	1,2
Economic data (in USD2025)										
Specific investment	MUSD/MW_e	+0.29	+0.29	+0.29	+0.15	+0.50	+0.15	+0.50	A, D	1,2
- of which equipment	%	-	-	-	-	-	-	-		
- of which installation and other costs	%	-	-	-	-	-	-	-		
- of which equipment	MUSD/MW_e	-	-	-	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	-	-	-	-	-	-	-		
Fixed O&M (compared to 100% coal)	%	+5	+5	+5	+3	+10	+3	+10	A	3,14, 15
Variable O&M (compared to 100% coal)	%	+5	+5	+5	+3	+10	+3	+10	A	3,14, 15
Start-up costs	USD/MW_e/start-up	-	-	-	-	-	-	-		
Technology specific data										
Water consumption	L/MWh	+0	+0	+0	-	-	-	-	E	

Notes:

- A Value depends on the original plant. Value indicates the estimated change from the original value (unit is the same as for the parameter).
- B Typically, the electrical efficiency is 1-2 % point lower than that of the plant prior to conversion.
- C Some additional under roof space (or silos) will be required for storage of pellets compared to coal (estimated 50%-100% extra m3 storage). But not more floor space (m2).

- D The nominal investment is excluding investment for a general life time extension campaign.
- E Assuming the same plant is used as stated the for Supercritical Coal Power Plant.

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- 8 X. Wang et al., "Experimental investigation on biomass co-firing in a 300MW pulverized coal-fired utility furnace in China," *Proceedings of the Combustion Institute*, vol. 33, no. 2, pp. 2725–2733, 2011, doi: <https://doi.org/10.1016/j.proci.2010.06.055>.
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3. GAS TURBINES

Brief technology description

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

In a gas-fired power plant, electricity generation takes place through two energy cycles: (1) the gas turbine cycle, and (2) the steam turbine cycle. A combined cycle gas turbine (CCGT) power plant utilizes these two sequential energy cycles to achieve high efficiency (approximately 55–64%) and lower emissions than coal-fired power plants, as it recovers heat from the gas turbine cycle. The exhaust gas from the gas turbine still retains a very high temperature—typically around 500–600°C, which is used to generate steam for the steam turbine.

Simple Cycle (Gas Turbine Cycle)

- Air is drawn into the system and compressed by the gas turbine compressor.
- The gaseous fuel is injected into the combustion chamber, where it mixes with the compressed air.
- The mixture is combusted at high temperature, producing a high-pressure stream of hot gases.
- The hot gas expands through the gas turbine, causing it to rotate and drive the electric generator to produce electricity.

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 18 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.

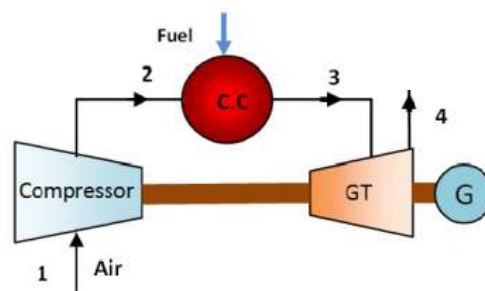


Figure 18: Process diagram of a Simple-Cycle Gas Turbine (SCGT) [1]

There are in general two types of gas turbines: 1) Industrial turbines (also called heavy duty) and 2) Aero-derivative turbine². Industrial gas turbines differ from aero-derivative turbines in the way that the frames, bearings and blading are of heavier construction. Additionally, industrial gas turbines have longer intervals between services compared to the aero-derivatives.

Aero-derivative turbines benefit from higher efficiency than industrial ones and the most service-demanding module of the aero-derivative gas turbine can normally be replaced in a couple of days, thus keeping a high availability.

Gas turbines can be equipped with compressor intercoolers where the compressed air is cooled to reduce the power needed for compression. The use of integrated recuperators (preheating of the combustion air) to increase efficiency can also be made by using air/air heat exchangers - at the expense of an increased exhaust pressure loss. Gas turbine plants can have direct steam injection in the burner to increase power output through expansion in the turbine section (Cheng Cycle).

Small (radial) gas turbines below 100 kW are now on the market, the so-called micro-turbines. These are

² An aero-derivative turbine is a type of power-generating turbine derived from the aerospace industry, originally serving as the main engine of aircraft. These turbines have been adapted for the power generation sector by removing the branching fans and adding a power-producing turbine in their exhaust section.

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 (Gas Turbine Cycle and Steam Turbine Cycle)

In a combined cycle power plant, the Brayton cycle (gas turbine cycle) is integrated with the Rankine cycle (steam turbine cycle). This integration utilizes the waste heat from the gas turbine exhaust, which still has a very high temperature—typically around 500–600°C.

The exhaust heat is recovered through a Heat Recovery Steam Generator (HRSG) to produce high-pressure steam, which is then supplied to the steam turbine. The steam turbine drives a separate generator, thereby producing additional electricity as illustrated in Figure below.

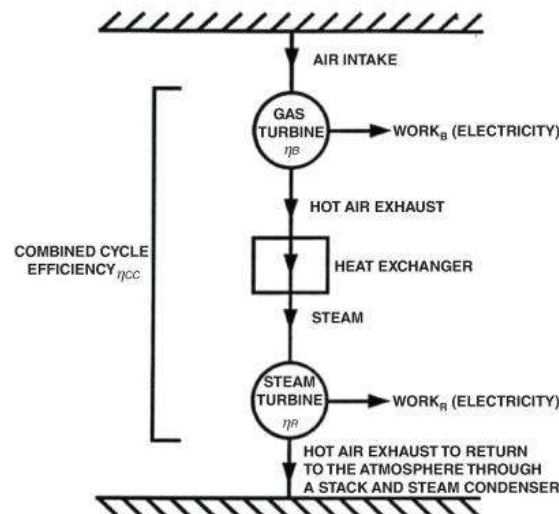


Figure 19: Process diagram of a CCGT [1].

Figure 20 illustrates the components of combined-cycle gas turbine (CCGT) plants, including: a gas turbine, a steam turbine, a gear (if needed), a generator, and a heat recovery steam generator (HRSG)/flue gas heat exchanger.

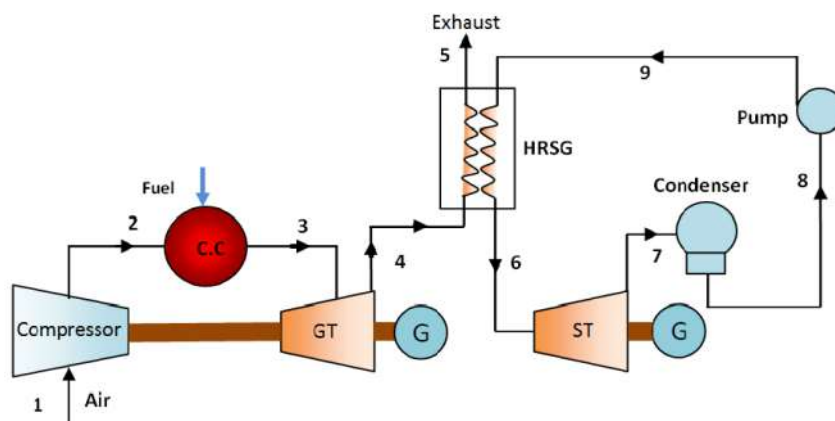


Figure 20: Process diagram of a CCGT [1]

In a combined cycle power plant, gas and steam turbines work together to maximize fuel efficiency and reduce emissions. The fuel first powers the gas turbine, and the exhaust heat then drives the steam turbine. This dual use of energy can achieve efficiency levels of 60 % or more, with lower emissions per unit of electricity produced.

Two configurations are possible: single-shaft and multi-shaft. A single-shaft design, where both turbines share a generator, enhances reliability with a simpler layout and fewer components. Meanwhile, a multi-shaft setup, where each turbine has its own generator, offers greater flexibility and slightly better performance by allowing independent operation of each turbine. This is shown in Figure 20.

A combined cycle gas-fired power plant typically consists of the following main systems:

- Fuel gas receiving and supply system: receives natural gas from a gas pipeline or from an LNG regasification terminal, and supplies it to the gas turbine.
- Gas turbine generator unit: comprising the compressor, combustion chamber, and gas turbine, coupled with an electric generator.
- Heat Recovery Steam Generator (HRSG): recovers heat from the gas turbine exhaust to produce steam.
- Steam turbine-generator unit: generates electricity from steam energy.
- Cooling system: uses cooling water to condense steam after it exits the steam turbine.
- Control and protection system: includes the central control system, as well as protection, safety, and operational monitoring systems.

Cooling, often by seawater or a cooling tower, is crucial for efficiency, as lower condenser temperatures improve steam turbine output. The gas turbine typically generates two to three times the power of the steam turbine, making it the primary power source, while the steam turbine uses waste heat for additional energy.

Overall, combined cycle systems achieve high efficiency and low emissions, with the choice of configuration depending on specific needs for reliability, flexibility, and performance.

Input

Gas turbines commonly use natural gas and light oil as fuels, though some are designed to operate with alternative fuels, like LPG or biogas. Certain models are also available in dual-fuel versions, allowing them to switch between gas and oil as needed. Gas-fired turbines generally require a fuel pressure of 20–60 bar, with aero-derivative turbines typically needing higher pressures compared to industrial ones.

In addition, steam from other sources can be fed into the steam turbine section to enhance overall efficiency and power output.

Output

Electricity.

Typical capacities

Simple-cycle gas turbines are available in the 30 kW – 570 MW range. The CCGT capacity for 1-on-1 configuration unit can reach up to 870 MW and 2-on-1 configuration can reach up to 1740 MW (At ISO conditions).

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 Nm³ of gas consumed. The increase in NO_x emissions with decreasing load places a regulatory limitation on the ramping ability. This can be solved in part by adding de- NO_x units.

CCGT units are to some extent able to operate at part load. This will reduce the electrical efficiency and often increase the NO_x emission. If the steam turbine is not running, the gas turbine can still be operated by directing the hot flue gasses through a boiler designed for high temperature or into a bypass stack.

The larger gas turbines for CCGT installations are usually equipped with variable inlet guide vanes, which will improve the part-load efficiencies in the 85-100 % load range, thus making the part-load efficiencies

comparable with conventional steam power plants in this load range. Another means to improve part-load efficiencies is to split the total generation capacity into several CCGTs. However, this will generally lead to a lower full load efficiency compared to one larger unit.

Advantages/disadvantages

Advantages:

- Simple-cycle gas turbine plants have short start-up/shut-down time, if needed. For normal operation, a hot start will take some 10-15 minutes.
- Large combined-cycle units have the highest electricity production efficiency among gas fuel-based power production.
- While it is true that gas turbines produce CO₂, their emissions per unit of electricity generated are lower compared to plants that use heavier fossil fuels, such as coal-fired power plants.
- Combined gas power plants require less space compared to coal or nuclear plants, making them easier to install in areas with limited land availability. Additionally, they can be located closer to urban or industrial centres where the demand for electricity is higher, reducing transmission losses and improving energy efficiency.
- Can provide reliability to the energy system by offering flexibility, stability and fast response capacity, ensuring a continuous and efficient supply in face of fluctuations in demand and support for renewable energy generation and supply.

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.
- 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.
- A significant disadvantage of gas turbines in terms of emissions is their production of carbon dioxide (CO₂) and other greenhouse gases. While gas turbines are more efficient and produce fewer emissions than coal-fired plants, they still rely on the combustion of natural gas. Additionally, gas turbines can emit nitrogen oxides (NO_x), which are harmful pollutants that contribute to smog formation and respiratory issues.
- Fuel price dependency: The gas turbine is dependent on the price and availability of fuels such as natural gas. In case of fuel price fluctuations, the profitability of the plant may be affected

Space requirement

The land area required for a combined cycle gas turbine (CCGT) power plant ranges from approximately 30 to 60 hectares for a capacity of 1,000–1,500 MW. If LNG receiving terminal infrastructure and storage facilities are included, the total land area may exceed 200 hectares.

Water consumption

Simple Cycle Gas Turbines (SCGTs) do not require water for their core operation because they use only a single phase of energy generation, directly converting fuel combustion into electricity. In SCGTs, air is compressed, mixed with fuel, and ignited, and the resulting high-temperature gases drive a turbine connected to an electric generator. This process does not involve a secondary steam cycle, which would require water to produce steam. The water consumption is used mostly for water-related systems and processes essential for the plant's internal operation but not directly involved in generating electricity for the grid. In the US, this is estimated at 0.08 l/kWh. For steam turbine power plants, water consumption factors (WCFs) are roughly 0.52 gallons per kilowatt-hour (gal/kWh) when using a pond for cooling and about 0.6 gal/kWh when using a cooling tower.

For steam turbine power plants, water consumption factors (WCFs) are roughly 1.97 litres per kilowatt-

hour (l/kWh) when using a pond for cooling and about 2.27 l/kWh when using a cooling tower. In contrast, combined cycle plants exhibit lower WCFs, approximately 0.91 l/kWh with pond cooling and 0.87 l/kWh with tower cooling, as shown in Figure below.

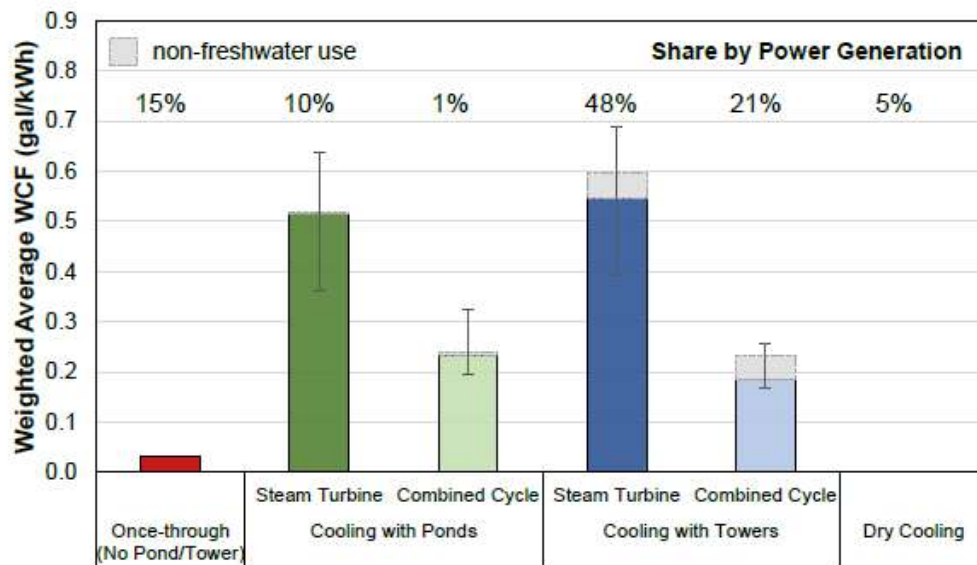


Figure 21: Water consumption factor for different thermal power generation

Environment

Gas turbines operate with continuous combustion and have combustion chambers with uncooled walls, allowing for very efficient combustion and low emission levels, excluding NO_x . Advances in combustor technology have achieved reduced NO_x emissions. Additionally, flue gas post-treatment options, such as SCR catalyst systems, can further minimize emissions.

Combined Cycle Gas Turbines (CCGTs) are environmentally preferable to Simple Cycle Gas Turbines (SCGTs) due to their higher efficiency, which allows them to generate more electricity using less fuel. This efficiency reduces carbon dioxide emissions per unit of power generated, lowering their overall carbon footprint.

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 [4].

Research and development

Gas turbines are a very well-known and mature technology – i.e. category 4.

Several technical developments have been increasing the efficiency for simple-cycle gas turbine configurations, including research into humidification air processes (HAT) and continuous development for less polluting combustion to reduce NO_x emissions.

Continuous research is done concerning higher inlet temperature at gas turbine blades to achieve higher electricity efficiency. This research is focused on materials and/or cooling of blades.

With respect to combined-cycle gas turbines (CCGTs), recent research and development are focused on boosting efficiency, reducing emissions, and supporting the transition to sustainable fuels like hydrogen alongside carbon capture technologies. Improvements are still being made primarily to the gas and steam turbines used. Developments for faster load response and dynamic capabilities are now also in focus. In [12] examples are given for a large ($>250 \text{ MW}_e$) CCGT plant with full GT power in less than 15 minutes and approx. 70 % power supply from the steam turbine. Full steam turbine power is achieved in less than one hour.

One major area of development is the use of hydrogen as a fuel. Leading manufacturers are developing

"hydrogen-ready" turbines that can initially operate on blends of natural gas and hydrogen. However, hydrogen presents combustion challenges due to its hotter and faster burn rate, which can lead to high NO_x emissions and stability issues.

Carbon capture and storage (CCS) technology is another critical area of innovation. Efforts are focused on post-combustion capture techniques, such as solvent-based capture and advanced amine scrubbing, which improve capture rates and reduce costs.

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

Examples of current projects

Nhon Trach 3 and Nhon Trach 4 are combined cycle gas turbine power plants in Ong Keo Industrial Zone in Phuoc Khanh commune, Nhon Trach district, Dong Nai province, Vietnam. The Project consists of two gas-fired power plants using liquefied natural gas (LNG) with total capacity of 2 x 812MW and will be located adjacent to the existing Nhon Trach 1 and Nhon Trach 2 CCGT. LNG will be sourced from Thi Vai LNG Terminal located approximately 24 kilometres (km) to the southeast of the Project.

The plant achieves an efficiency of 62-64% and electricity production: approximately 9 billion kWh/year. Main equipment gas turbine, steam turbine, generator, heat recovery unit, DCS control system supplied by GE (USA).

Data estimates

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.

In Vietnam, to date, only the Nhon Trach 3 and Nhon Trach 4 CCGT are operational. The remaining gas-fired power plants are in the feasibility study phase or have begun implementation. For flexibility parameters (Ramping, Minimum load, and start-up time) for CCGT, similar parameters as for local CCGT cases are assumed in recent projects in Vietnam. The financial parameters are covered separately below. Emission values have been converted from mg/Nm³ 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 12: Combined cycle gas turbine, 2020 data from existing local cases, the Indonesian TC and the central estimates for the Vietnamese TC.

Key parameter	Local cases data average		Indonesian TC (2020)			Viet Nam TC (2025)
		Number of plants	Central	Lower	Upper	
Generating capacity for one unit (MWe)	750	6	600	200	800	750
Generating capacity for total power plant (MWe)	1500	6				1.00
Electricity efficiency, net (%), name plate	60	5	57	45	62	58
Electricity efficiency, net (%), annual average	-	4	56	39	61	-
Ramping (% per minute)	11.7	5	20	10	30	11.7
Minimum load (% of full load)	33	5	45	30	50	33
Warm start-up time (hours)	0.5	5	2	1	3	1
Cold start-up time (hours)	-	5	4	2	5	2.5

Key parameter	Local cases data average		Indonesian TC (2020)			Viet Nam TC (2025)
PM 2.5 (mg per Nm ³)	≤ 15	1	30	30	30	15
SO ₂ (degree of desulphuring, %)	≤ 60	1	-	-	-	60
NO _x (g per GJ fuel)	≤ 70	1	86	20	86	78
Nominal investment (M\$/MWe)	1.18	4	0.78	0.68	0.83	1.15
Fixed O&M (\$/MWe/year)	42,326	4	24,100	18,100	30,100	42,300
Variable O&M (\$/MWh)	2.48	6	0,14	0,10	0,17	2.48
Start-up costs (\$/MWe/start-up)	-	4	83	62	104	87

In Vietnam, for CCGT using LNG, only the Nhon Trach 3 and Nhon Trach 4 power plants are in operation. Other LNG-fired power projects are currently at the feasibility study stage or have just begun implementation. For CCGT flexibility parameters (ramp-up/ramp-down rates, minimum load, and start-up time), recent projects in Vietnam generally assume values similar to those of existing domestic CCGT plants. Financial parameters are presented separately in the following section. Emission values have been converted from mg/Nm³ to g/GJ using a conversion factor of 0.027 for gas, according to the World Bank's Pollution Prevention and Abatement Handbook (1998).

Investment cost estimation

Gas turbine based combined cycle plants are a well-proven, widespread and available technology, making CCGT a category 4 technology. Improvements are still being made primarily to the gas and steam turbines used. Developments for faster load response and dynamic capabilities are now also in focus. In [12] examples are given for a large (>250 MW_e) CCGT plant with full GT power in less than 15 minutes and approx. 70 % power supply from the steam turbine. Full steam turbine power is achieved in less than one hour.

The main rotating parts (the gas turbine, steam turbine and the generator) tend to account for around 45-50 % of the investment costs (EPC price), the heat recovery steam generator, condenser and cooling system for around 20 %, the balance of plant components for around 15 %, the civil works for around 15 % and the remainder being miscellaneous other items [14].

The data from the different sources in the tables below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - SCGT						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		1.02	1.01		0.99	0.97
Technology Catalogue - Colombia 2025		1.00	0.98			0.94
Technology Catalogue - Indonesia 2024		1.18	1.12			1.05
Technology Catalogue - Vietnam 2023	0.77		0.75			0.71
IEA WEO 2025 -India	0.4			0.4		0.4
IEA WEO 2025 - China	0.35			0.35		0.35
NREL ATB 2024*		1.30	1.25	1.21	1.16	1.06
*Moderate scenario for Nominal 233 MW _{net} F-Frame simple cycle combustion turbine, Advanced Technology - NA						

Investment cost [Million USD 2025 / MW] - CCGT						
Sources	2020	2025	2030	2035	2040	2050

Technology Catalogue - Viet Nam Current		1.15	1.14		1.12	1.09
Technology Catalogue - Colombia 2025		1.13	1.12			1.08
Technology Catalogue - Indonesia 2024		1.15	1.10			1.01
Technology Catalogue - Vietnam 2023	0.97		0.87			0.86
IEA WEO 2025 -India		0.70		0.7		0.7
IEA WEO 2025 - China		0.56		0.56		0.56
NREL ATB 2024*		1.48	1.41	1.34	1.29	1.19
*Moderate scenario for NG 2-on-1 Combined Cycle (H-Frame)						

References

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

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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (\$) 2025.

Simple Cycle Gas Turbine - large system											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	510	510	510	510	250	750	250	750		1
Generating capacity for total power plant	MW_e	510	510	510	510	250	750	250	750		1
Electrical efficiency, net, name plate	%	42	43	45	46	35	45	39	49		1
Electrical efficiency, net, annual average	%	41	42	44	45	34	44	38	48		
Forced outage	%	2	2	2	2	1.5	10	1.5	10		1
Planned outage	%	3	3	3	3	2.5	10	2.5	10		1
Self-consumption	%	1.8	1.8	1.8	1.8	1.8	3	1.8	3		1
Technical lifetime	years	50	50	50	50	20	60	20	60		1
Construction time	years	3	3	3	3	2.5	4	2.5	4		1
Space requirement	1000_m²/MW_e	0.36	0.36	0.36	0.36	0.20	0.60	0.20	0.60		1
Additional data for non-thermal plants											
Capacity factor, theoretical	%	-	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	15	20	20	20	10	30	10	30		
Minimum load	% of full load	33	30	25	15	25	50	10	40		1
Warm start-up time	hours	0.35	0.2	0.2	0.2	0.1	0.5	0.1	0.4		
Cold start-up time	hours	0.75	0.5	0.5	0.5	0.4	1	0.4	1		
Minimum Up time	hours	4	4	4	4	-	-	-	-		
Minimum Down time	hours	3	3	3	3	-	-	-	-		
Environment											
PM 2.5	mg/Nm³	15	15	15	15	-	-	-	-		1
SO₂	mg/Nm³	60	60	60	60	-	-	-	-		1
NOₓ	g/GJ_i	78	60	40	20	20	86	20	86		
CH₄	mg/Nm³	-	-	-	-	-	-	-	-		
N₂O	mg/Nm³	51	51	51	51	-	-	-	-		1
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	1.02	1.01	0.99	0.97	0.77	1.38	0.73	1.21	A	2, 3, 4
- of which equipment	%	50	50	50	50	50	50	50	50		8
- of which installation and other costs	%	50	50	50	50	50	50	50	50		8
- of which equipment	MUSD/MW_e	0.51	0.50	0.49	0.49	0.38	0.69	0.36	0.61	A	8
- of which installation and other costs	MUSD/MW_e	0.51	0.50	0.49	0.49	0.38	0.69	0.36	0.61	A	8
Fixed O&M	USD/MW_e/year	30,004	29,705	29,116	28,539	22,503	40,506	21,405	35,674	A	2, 3, 4
Variable O&M	USD/MWh	4.58	4.53	4.44	4.36	3.44	6.18	3.27	6	A	

Simple Cycle Gas Turbine - large system											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Start-up costs	USD/MW_e/start-up	31.1	31.1	31.1	31.1	23.3	41.9	23.3	38.8	A	5
Technology specific data											
Water consumption	L/MWh	0	0	0	0	-	-	-	-	B	9, 10, 11

Notes:

A Uncertainty (Upper/Lower) is estimated as -25% (lower) and +35% (higher) for 2025 and +/- 25% for 2050.

B Since no cooling water is needed, the water consumption is negligible.

References

- 1 Based on projects from Vietnam
- 2 IEA, Projected Costs of Generating Electricity, 2020
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Combined Cycle Gas Turbine											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	750	750	750	750	200	800	200	800		1, 2
Generating capacity for total power plant	MW_e	1,500	1,500	1,500	1,500	200	1,600	200	1,600		1, 2
Electrical efficiency, net, name plate	%	58	60	61	61	45	62	55	65		1, 2, 4, 5, 10
Electrical efficiency, net, annual average	%	56	58	59	59	39	61	54	64		
Forced outage	%	2	2	2	2	1.5	10	1.5	10		1
Planned outage	%	3	3	3	3	2.5	10	2.5	10		1
Self-consumption	%	2.5	2.5	2.5	2.5	2	3	2	3		1
Technical lifetime	years	50	50	50	50	20	60	20	60		1
Construction time	years	3.5	3.5	3.5	3.5	2.5	4	2.5	4		1
Space requirement	1000_m ² /MW_e	0.36	0.36	0.36	0.36	0.20	0.60	0.20	0.60		1
Additional data for non-thermal plants											
Capacity factor, theoretical	%	-	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	11.7	20	20	20	10	30	10	30		1
Minimum load	% of full load	33	30	25	15	25	50	10	40		1
Warm start-up time	hours	1	1	1	1	0.5	1.5	1	1.5		1
Cold start-up time	hours	2.5	2.5	2.5	2.5	2	4	2	4		
Minimum Up time	hours	4	4	4	4	-	-	-	-		
Minimum Down time	hours	3	3	3	3	-	-	-	-		
Environment											
PM 2.5	mg/Nm ³	15	15	15	15	-	-	-	-		1
SO ₂	mg/Nm ³	60	60	60	60	-	-	-	-		1
NO _x	g/GJ_i	78	60	40	20	20	86	20	86		7, 8
CH ₄	mg/Nm ³	-	-	-	-	-	-	-	-		
N ₂ O	mg/Nm ³	51	51	51	51	-	-	-	-		1
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	1.15	1.14	1.12	1.09	0.86	1.55	0.82	1.37	A	1, 2, 4, 10
- of which equipment	%	50	50	50	50	50	50	50	50		1, 9
- of which installation and other costs	%	50	50	50	50	50	50	50	50		1, 9
- of which equipment	MUSD/MW_e	0.58	0.57	0.56	0.55	0.43	0.78	0.41	0.68	A	
- of which installation and other costs	MUSD/MW_e	0.58	0.57	0.56	0.55	0.43	0.78	0.41	0.68	A	
Fixed O&M	USD/MW_e/year	42,326	41,904	41,074	40,260	31,744	57,140	30,195	50,324	A	1, 2, 4
Variable O&M	USD/MWh	2.48	2.46	2.41	2.36	1.86	3.35	1.77	2.95	A	1
Start-up costs	USD/MW_e/start-up	87	87	87	87	65	117	65	108	A	

Combined Cycle Gas Turbine											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Technology specific data											
Water consumption	L/MWh	750	750	750	750	-	-	-	-	B	11, 12, 13

Notes:

- A Uncertainty (Upper/Lower) is estimated as -25% (lower) and +35% (higher) for 2025 and +/- 25% for 2050.
- B Assuming a cooling tower is used. Pond-cooling, once-through cooling and dry cooling can also be used. Dry cooling has the lowest water consumption, and the other methods are generally not very far from tower-cooling. The water consumption can vary in the range 100-1000 L/MWh.

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3.1. 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 H₂ compared to CH₄. For example, the flame temperature (or reaction temperature) of H₂ is about 5-10% higher, potentially leading to higher thermal NO_x production—and creating challenges related to degradation of materials and coatings. Due to the 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 NO_x combustion system - DLN (today's state-of-the-art, high efficiency gas turbines use DLN combustors designed for burning NG with extremely low NO_x and CO emissions), flow velocity would need to be 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% H₂, 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 H₂ 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. [4].

Table 13: Potential impacts and potential technical solutions of hydrogen co-firing in gas turbines.

Property	Properties of H ₂ (relative to NG)	Potential impact	Potential technical solutions
Carbon monoxide production	100% reduction	CO production removed as a limitation to operating parameters	N/A
Energy density	Vol: < 1/3 Mass: ~2,5 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 NO_x 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 NO_x (DLN) combustors designed for burning NG with extremely low NO_x 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 22: GE/DOE micromixer [4]

Another approach to utilizing high-H₂ 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 NO_x 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 [4].

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

Figure 23: 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 H₂. 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 H₂ within the system. Indeed, the more components involved, the higher the likelihood for some H₂ to remain trapped within them, leading to explosion risks when doing maintenance or repair. On that basis, proper measurement apparatus for H₂ traces should be considered as part of any H₂ use with GTs. In addition, purge systems using CO₂ 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 H₂ migration through the material. Indeed, H₂ 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 H₂.

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 H₂.

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 [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.

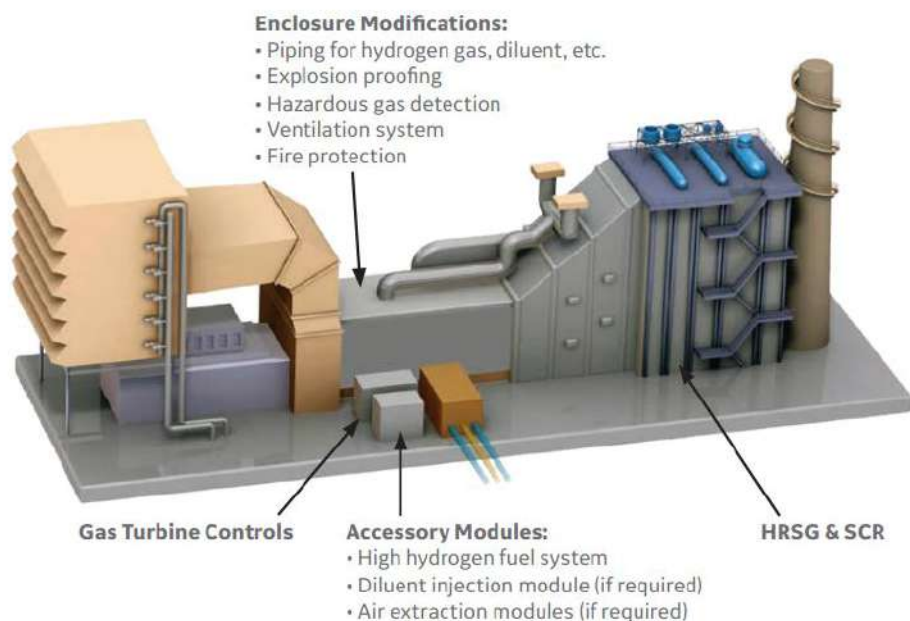


Figure 24: Example of a hydrogen gas turbine and its components

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 H₂ when co-firing in gas turbine plant is defined in terms of energy share. 20% share of energy of H₂ with natural gas is corresponding to approximate 45% share of volume of H₂.

Table 14: Corresponding volume and energy share for the different mixing ratios of hydrogen and natural gas [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 [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 fuelling. 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 fuelling 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 CO₂ 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 H₂ content—typically expressed on a volumetric basis—result in lower CO₂ emissions per MWh, but the relationship is nonlinear as show in figure below, this relationship becomes linear when considering share of H₂ in term of energy.

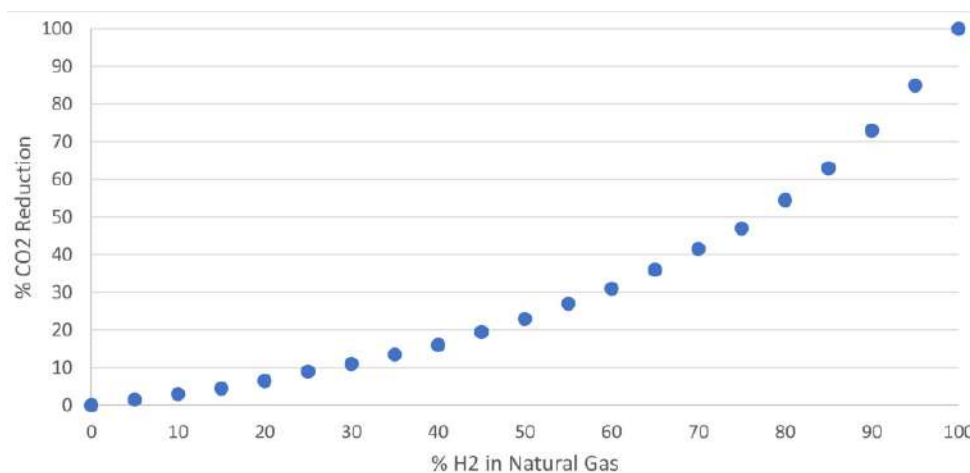


Figure 25: CO₂ Reduction for H₂-NG blends by volume [4]

Also, SO₂ emissions and particle matter decrease when co-firing ammonia as the amount of combustion

natural gas decreases and hydrogen does not contain 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 NO_x emission as show in below figure.

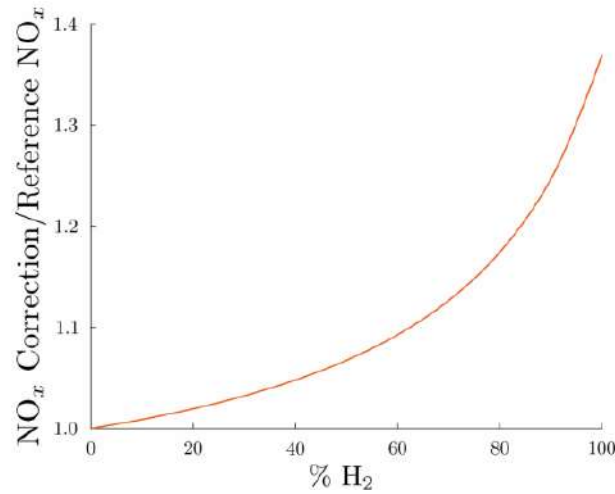


Figure 26: Increase of NO_x emission correspond to the H_2 co-firing ratio according to [9]

Georgia Tech's Institute of Strategic Energy [9] has conducted NO_x 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 ($\sim 45\%$ by volume), NO_x emissions increase by nearly 10% and when H_2 gas is completely burned, the amount is emitted NO_x emissions increased to 40%. GE in its experimental studies [10] also showed that when co-combustion is 20% of production ($\sim 45\%$ by volume), NO_x emissions increase by about 30% with DLN technology. Thus, at 20% H_2 co-combustion, on average, NO_x emissions increase to 20%, and at 100% co-combustion, NO_x emissions increase to 40%.

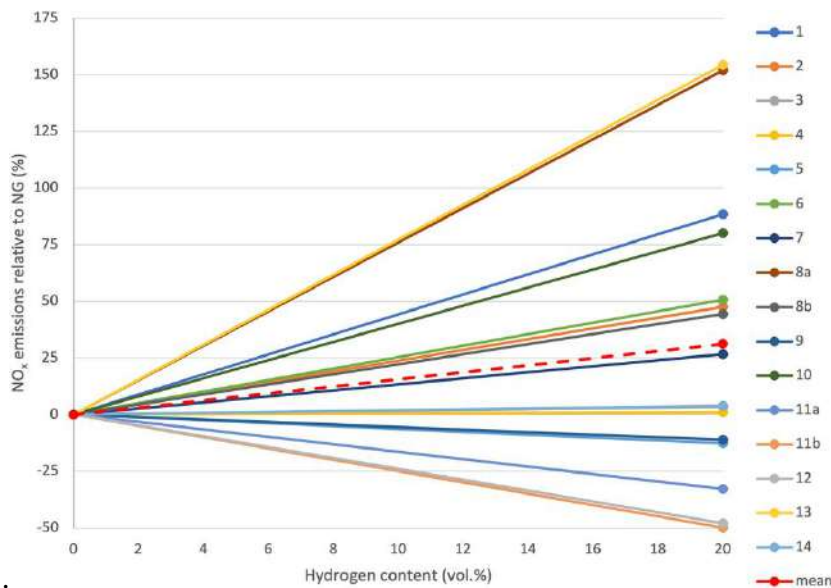


Figure 27: Increase of NO_x emission correspond to the H_2 co-firing ratio according to [10]

Examples of current projects

The term “hydrogen-ready” typically refers to gas turbines that are designed or modified to operate on a hydrogen–natural gas blend, with a transition pathway toward higher hydrogen concentrations over time. Most current commercial applications involve hydrogen blending ratios ranging from 5% to 30% by volume, depending on the turbine design, combustion system, and operating conditions. Original Equipment Manufacturers (OEMs) emphasize that hydrogen readiness is not defined by a single technical specification, but rather by a combination of design features. As noted above, these include advanced combustion chambers capable of managing hydrogen’s higher flame propagation velocity, control systems

that adjust the fuel–air mixture in real time, and materials capable of withstanding higher temperatures and combustion dynamics.

As of 2025, some turbine models are being marketed as capable of operating with higher hydrogen blending ratios with minimal hardware modifications, while other platforms require phased upgrades as hydrogen supply increases. Full conversion to 100% hydrogen combustion technology remains largely limited to demonstration projects and pilot installations. Operating on hydrogen from the outset requires investors to secure a stable hydrogen supply at very large volumes.

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% H₂ commercially available by 2030.

Table 15: 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%

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, operated in 2025), 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 came into operation in 2023 [5].

Cost estimates

[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

Some studies indicate that retrofitting Combined Cycle Gas Turbine (CCGT) power plants to enable the use of low-carbon fuels, either individually or in blended form, increases the Levelized Cost of Electricity (LCOE) by approximately 6–12.7 €/MWh (~6.5–14 USD/MWh) [1].

This highlights the need for coordinated development of energy infrastructure. National and regional energy planning authorities should identify suitable fuel storage locations and invest in the necessary infrastructure to ensure cost-effective storage and transportation of fuels. Policy design should also take into account proximity to fuel supply sources and storage facilities as part of the decision-making process for plant retrofitting.

Study [1] also indicates that the marginal cost of electricity generation when using hydrogen, ammonia, or biomethane exceeds 120 €/MWh (~130 USD/MWh) even under the most favourable conditions, and in most cases surpasses 150 €/MWh (~165 USD/MWh). By comparison, natural gas remains the lowest-cost option under currently foreseeable carbon pricing scenarios. However, natural gas price volatility and carbon price risks suggest that low-emission gaseous fuels may still play a role in the future as energy systems move toward deep decarbonization targets.

Some research findings suggest that although a hydrogen-ready (H₂-ready) design option typically results in a relatively modest increase in initial capital expenditure (CAPEX)—generally around 3% to 10% of the gas turbine procurement cost for a low readiness level (approximately 6% H₂ by heat input)—if the plant is not optimally designed from the outset to minimize major hardware modifications, upgrading the plant to operate on 100% hydrogen in the future could require additional investment of up to 20% of the total plant construction cost [2].

Cumulative cost risk: These retrofit costs are cumulative in nature. If the retrofit pathway is not carefully planned, the total cost (initial CAPEX plus subsequent retrofit costs) may be significantly higher than the cost of constructing a new plant designed for 100% hydrogen operation from the beginning. In practice, retrofitting a conventional gas-fired power plant (without an H₂-ready design) to operate on 100% hydrogen may require 25% to 72% of the original asset value, depending on the turbine type and the extent of modifications to the fuel supply system [2].

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.

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.

Some international codes and standards include:

- ASME B31.12 (Hydrogen Piping and Pipelines): This is one of the most important standards governing the design, materials, fabrication, installation, and inspection of hydrogen piping and pipeline systems.
- NFPA 2 (Hydrogen Technologies Code): This code establishes comprehensive fire protection and safety requirements, as well as design criteria for applications and equipment involving hydrogen, in both gaseous and liquid forms.
- ISO 21789: This standard specifies safety requirements for industrial gas turbine applications and gas-driven engines using liquid or gaseous fuels.

ISO/TR 15916: This technical report provides guidance on the use of hydrogen in both gaseous and liquid forms, as well as on the storage of hydrogen in these or other forms.

Data sheet

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

CCGT – co-firing 20% hydrogen (in terms of energy)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	750	750	750	750	200	800	200	800		
Generating capacity for total power plant	MW_e	1500	1500	1500	1500	200	1600	200	1600		
Electrical efficiency, net, name plate	%	-0	-0	-0	-0	-0	-2	-0	-2	A	3, 9
Electrical efficiency, net, annual average	%	-0	-0	-0	-0	-0	-2	-0	-2	A	3, 9
Forced outage	%	+0	+0	+0	+0	+0	+1	+0	+1	A	
Planned outage	%	+0	+0	+0	+0	+0	+0	+0	+0	A	
Self-consumption	%	-	-	-	-	-	-	-	-		
Technical lifetime	years	-	-	-	-	-	-	-	-		
Construction time	years	-	-	-	-	-	-	-	-		
Space requirement (additional to existing plant)	1000_m²/MW_e	+0	+0	+0	+0	+0	+0	+0	+0		
Additional data for non-thermal plants											
Capacity factor, theoretical	%	-	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	+0	+0	+0	+0	+0	+0	+0	+0	A	1, 2, 3, 6
Minimum load	% of full load	-3	-3	-3	-3	-1	-5	-1	-5	A	1, 2, 3, 6
Warm start-up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	1, 2, 3, 6
Cold start-up time	hours	+0	+0	+0	+0	+0	+0	+0	+0	A	1, 2, 3, 6
Minimum Up time	hours	-	-	-	-	-	-	-	-		
Minimum Down time	hours	-	-	-	-	-	-	-	-		
Environment											
PM 2.5 (compared to 100% coal)	%	-20	-20	-20	-20	-10	-20	-10	-20	A	1, 2, 6
SO ₂ (degree of desulphuring, compared to 100% coal)	%	-20	-20	-20	-20	-10	-20	-10	-20	A	1, 2, 6
NO _x (compared to 100% coal)	%	+20	+20	+20	+20	+10	+60	+10	+60	A	1, 2, 6, 9, 10, 11, 12
CH ₄	%	-	-	-	-	-	-	-	-		
N ₂ O	%	-	-	-	-	-	-	-	-		
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	0.07	0.07	0.07	0.07	0.04	0.12	0.04	0.12	A, B	1, 2, 4
- of which equipment	%	-	-	-	-	-	-	-	-		
- of which installation and other costs	%	-	-	-	-	-	-	-	-		
- of which equipment	MUSD/MW_e	-	-	-	-	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	-	-	-	-	-	-	-	-		
Fixed O&M	USD/MW_e/year	+3	+3	+3	+3	+1	+5	+1	+5	A	1, 2, 4
Variable O&M	USD/MWh	+3	+3	+3	+3	+1	+5	+1	+5	A	1, 2, 4
Start-up costs	USD/MW_e/start-up	-	-	-	-	-	-	-	-		
Technology specific data											
Water consumption	L/MWh	0	0	0	0	-	-	-	-	C	

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.
- C Assuming that the same plant is used as for Combined Cycle Gas Turbine.

References

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- 10 L.Wright, C.Lewis, “Emission of NO_x from blending of hydrogen and natural gas in space heating boilers”, 2022
- 11 Georgia Tech/Strategic Energy Institute, “NO_x emission from Hydrogen_Methane fuel blends”, 2022
- 12 GE, “Powering to a cleaner energy future with hydrogen”, 2022

CCGT – co-firing 100% hydrogen (in terms of energy)										
Parameter	Unit	2030	2040	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW_e	750	750	750	200	800	200	800		
Generating capacity for total power plant	MW_e	1500	1500	1500	200	1600	200	1600		
Electrical efficiency, net, name plate	%	-0	-0	-0	-0	-3	-0	-3	A	3, 9
Electrical efficiency, net, annual average	%	-0	-0	-0	-0	-3	-0	-3	A	3, 9
Forced outage	%	+0	+0	+0	+0	+1	+0	+1	A	
Planned outage	%	+0	+0	+0	+0	+0	+0	+0	A	
Self-consumption	%	-	-	-	-	-	-	-		
Technical lifetime	years	-	-	-	-	-	-	-		
Construction time	years	-	-	-	-	-	-	-		
Space requirement (additional to existing plant)	1000_m²/MW_e	+0	+0	+0	+0	+0	+0	+0		
Additional data for non-thermal plants										
Capacity factor, theoretical	%	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-		
Ramping ability										
Ramping	% of full load/minute	+0	+0	+0	+0	+0	+0	+0	A	1, 2, 3, 6
Minimum load	% of full load	-5	-5	-5	-3	-10	-3	-10	A	1, 2, 3, 6
Warm start-up time	hours	+0	+0	+0	+0	+0	+0	+0	A	1, 2, 3, 6
Cold start-up time	hours	+0	+0	+0	+0	+0	+0	+0	A	1, 2, 3, 6
Minimum Up time	hours	-	-	-	-	-	-	-		
Minimum Down time	hours	-	-	-	-	-	-	-		
Environment										
PM 2.5 (compared to 100% coal)	%	-100	-100	-100	-100	-100	-100	-100	A	1, 2, 6
SO₂ (degree of desulphuring, compared to 100% coal)	%	-100	-100	-100	-100	-100	-100	-100	A	1, 2, 6
NOx (compared to 100% coal)	%	+40	+40	+40	+20	+100	+20	+100	A	1, 2, 6, 9, 10, 11, 12
CH₄	%	-	-	-	-	-	-	-		
N₂O	%	-	-	-	-	-	-	-		
Economic data (in USD2025)										
Specific investment	MUSD/MW_e	0.24	0.24	0.24	0.18	0.30	0.18	0.30	A, B	1, 2, 4
- of which equipment	%	-	-	-	-	-	-	-		
- of which installation and other costs	%	-	-	-	-	-	-	-		
- of which equipment	MUSD/MW_e	-	-	-	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	-	-	-	-	-	-	-		
Fixed O&M	USD/MW_e/year	+5	+5	+5	+3	+10	+3	+10	A	1, 2, 4
Variable O&M	USD/MWh	+5	+5	+5	+3	+10	+3	+10	A	1, 2, 4
Start-up costs	USD/MW_e/start-up	-	-	-	-	-	-	-		
Technology specific data										
Water consumption	L/MWh	0	0	0	-	-	-	-	C	

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.
- C Assuming that the same plant is used as for Combined Cycle Gas Turbine.

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4. CO₂ CAPTURE, UTILIZATION AND STORAGE (CCUS)

Brief technology description

The increase of atmospheric CO₂ 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, Utilization and Storage (CCUS) may be the technology that will allow the presence of fossil fuels in a CO₂-constrained future. In addition, CCUS 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. CCUS can be divided into Capture, Compression, Transport, Utilization and Storage, which are described in the following sections.

CO₂ Capture

The CO₂ 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 [1].

1. Post-Combustion Capture

In post-combustion capture, the CO₂ is separated from the flue gas. The dominant post-combustion technology is absorption or scrubbing of CO₂ in chemical solvents like amine solutions, which are commercially available for industrial purposes, but not for power plants yet. The CO₂ is stripped from the solvent by raising the temperature [2].

2. Pre-Combustion Capture

In pre-combustion capture, the CO₂ 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 CO₂ is removed [1]. The most common separation technology are solvents, which scrub the CO₂ 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 technology solutions [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 CO₂. 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 CO₂, where the water vapor can be condensed easily, giving a highly concentrated CO₂ stream [4].

In all three methods, once the CO₂ is captured, it later needs to be compressed and transported to storage.

CO₂ compression and liquefaction

The major barrier for extensive use of CO₂ removal technology are the high costs of separating and compressing the CO₂. The additional energy required for this process typically reduces the efficiency by 10%. To transport the CO₂ by pipeline, a suitable pressure for transport is 10 to 20 MPa, whereas to be transported by ship, it needs to be liquified.

CO₂ transportation

It is necessary to transport the captured CO₂ 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 costs 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.

CO₂ Utilization

In the Utilization stage of the Carbon Capture, Utilization and Storage (CCUS) chain, the captured CO₂ is reused as a feedstock for various industrial processes, contributing to the development of a circular carbon

economy. Specifically, CO₂ can be converted into synthetic fuels (e-fuels, methanol, methane), chemical feedstocks (such as urea and polycarbonate), or mineralized into construction materials like carbonated concrete and bricks. In addition, CO₂ is injected into depleted oil and gas reservoirs to enhance oil recovery (EOR – Enhanced Oil Recovery), with a portion of it being permanently stored in geological formations [21], [22]. This reuse not only helps reduce CO₂ emissions to the atmosphere but also generates new economic value; however, the overall energy efficiency and life-cycle emissions must be carefully assessed to ensure genuine climate benefits. Therefore, although Utilization is an important element of the CCUS chain, it is generally regarded as a complementary measure to CO₂ storage rather than a full substitute for it, as in conventional CCS systems.

CO₂ storage

Captured CO₂ 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 CO₂ as a dense phase supercritical fluid in declining oil, gas reserves so that pressure favours oil displacement and extra oil is extracted (Enhanced Oil Recovery – EOR) [5]. The latter is the most widespread storage method for long term CO₂ storage, and saline aquifers have a large potential volume and are common [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 CO₂ transportation. Additionally, the coal seams storage option has permeability concerns that might lead to risks of leakage.

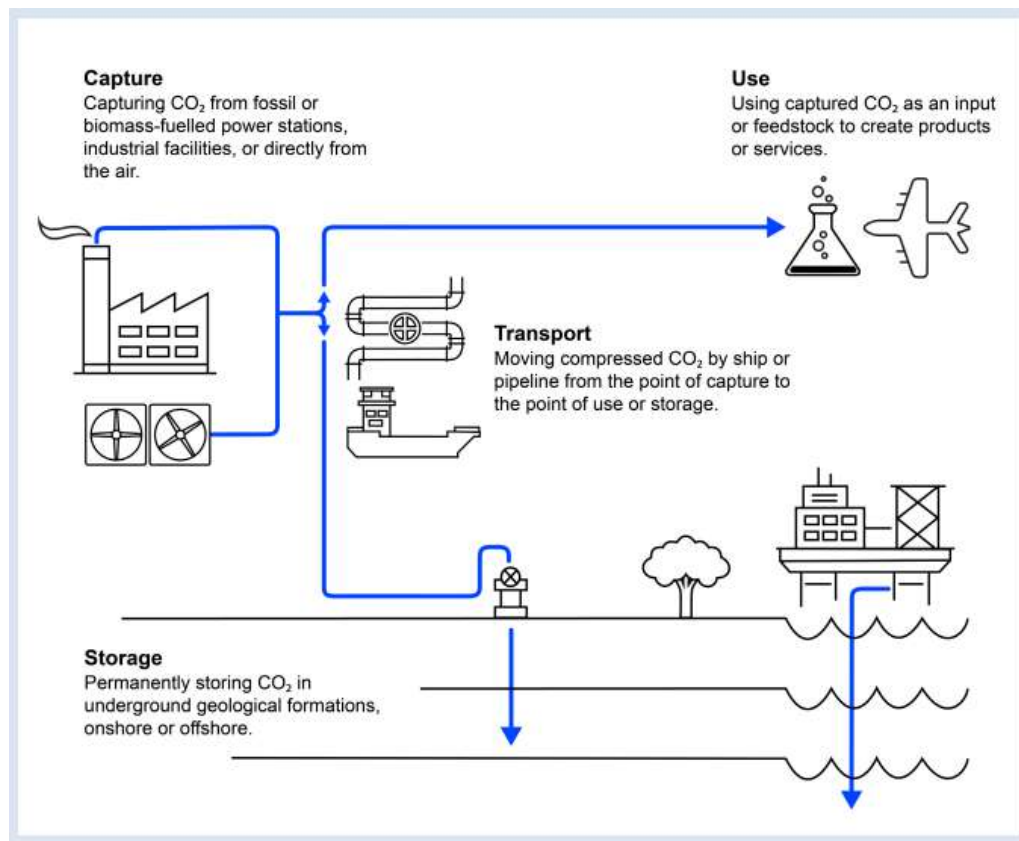


Figure 28: Schematic of CCUS [22]

Viet Nam is one of the few countries in Southeast Asia that has promising CO₂ storage potential. A study of ADB [20] identified 12 gigatons of theoretical CO₂ 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 CO₂. 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 CO₂. The total theoretical CO₂ 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 CO₂ storage potential. If only storage capacities of fields greater than 10 Mt CO₂ 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 CO₂, with the largest field exceeding 300 Mt CO₂ capacity. This storage will be available when the fields are depleted or when CO₂-enhanced oil recovery (EOR) occurs.

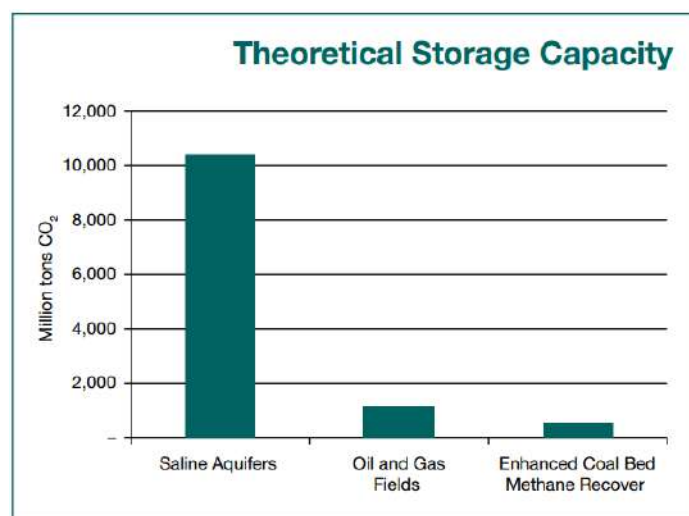


Figure 29: Theoretical CO₂ storage capacity in Viet Nam. Source: [6, 20]

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 16: Qualifying and preferential criteria used as methodology for the study of [20]

Qualifying criteria	
Capacity	Capacity > 10 Mt CO ₂ , with exception 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 criteria	
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 CO₂ 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.

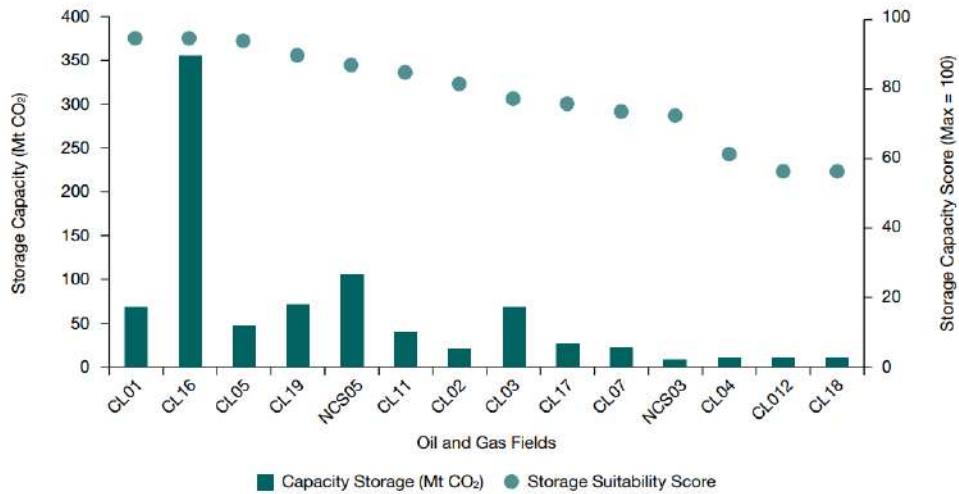


Figure 30: Oil and gas fields ranked by CO₂ storage suitability [20].

Ranking of CO₂ storage capacity of oil and gas fields in details is shown in the table below.

Table 17: Detailed oil and gas fields ranked by CO₂ storage suitability [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

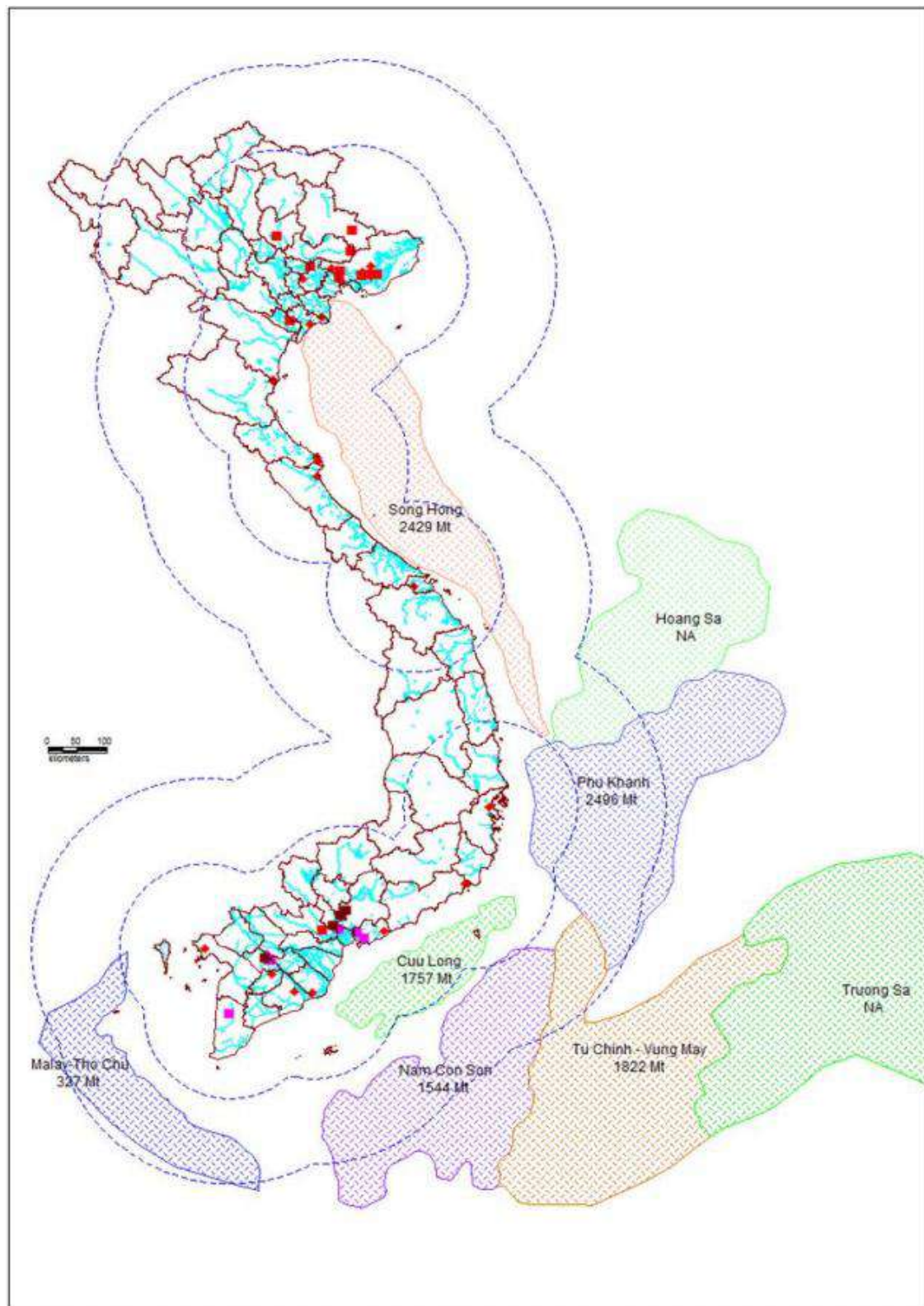


Figure 31: CO₂ storage potential in saline aquifers (150km and 300km circle around emission sources).
The Paracel and Spratly Islands of Viet Nam are not shown in the map [6, 20]

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 (CO₂) in a storage site. It involves continuous monitoring of the CO₂ 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 CO₂, providing confidence to the public and regulators, and earning CO₂ credits. It helps to identify and quantify the position of the CO₂ plume and detect any potential leakage, assess the movement of CO₂ over time, and evaluate short- and long-term risks associated with the storage.

In addition, a robust data management system is necessary to store, analyse, 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 H₂, CO and CO₂).
- In post-combustion capture, CO₂ in flue gas from power plant combustion.
- In the oxy-fuel combustion, a stream of CO₂ and H₂O where CO₂ is found at relatively high concentrations.

Output

The main outputs are stored CO₂ and CO₂-lean flue gas, but if it is not stored, CO₂ can be converted into value-added products for the food and drink industry or for manufacturing chemical products [4].

Ramping configurations

The ability to regulate a power plant is not influenced by adding post-combustion capture. However, the CO₂ 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 CCUS 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 CO₂ 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 CO₂ concentrations in the flue gas, so complex post-combustion separation can be avoided; CO₂ is obtained by getting rid of the water through simple condensation. Power plants can also be retrofitted in order to include oxy-fuel combustion [7].

Disadvantages

- **Post-combustion capture.** The CO₂ is diluted in the flue gas and at ambient pressure, which makes it harder to sequester the CO₂. 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 O₂ production is expensive. Recycling the cooled CO₂ is necessary to maintain temperature within combustor materials, which decreases efficiency and adds auxiliary load [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 [8]. Cost of CCUS and lack of a CO₂ economy have been identified as the major challenges preventing the widespread adoption of this technology [9].

Water consumption

CO₂ capture, utilization and storage (CCUS) processes require significant amounts of water, primarily for the capture step. The amount of water used varies depending on the capture technology employed, with post-combustion capture typically requiring more water than pre-combustion capture.

In post-combustion capture, water is used to regenerate the solvent used to absorb CO₂ from the flue gas, resulting in significant water consumption. Additionally, water may be used for cooling and other auxiliary systems.

In contrast, pre-combustion capture, such as integrated gasification combined cycle (IGCC), may require less water, as the CO₂ is captured before combustion. However, water is still used in the gasification process and for cooling.

The storage step of CCUS, which involves injecting CO₂ into geological formations, does not require significant amounts of water. However, some water may be used for monitoring and verification activities, such as injecting tracers to track CO₂ migration.

Overall, the water footprint of CCUS is largely determined by the capture technology and process design employed, with post-combustion capture typically having a higher water demand than pre-combustion capture.

Environment

CCUS 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 (SO₂).** SO₂ emissions in coal fired plants fall when CO₂ is captured, plants with CCS are normally equipped with improved Flue Gas Desulfurization (FGD). IGCC plants already have low SO₂ 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 CCUS. 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 [10].
- **Ammonia (NH₃).** It is the only pollutant for which a significant increase in emissions is expected, due to the degradation of amine-based solvents [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 [11], which is the main source of CO₂ emissions [12].

Even though the energy sector in Viet Nam still relies primarily on coal, there have not yet been any focused or in-depth research initiatives on CCUS technologies and potential in the country. CCUS is not a current priority in Southeast Asia; governmental efforts are mainly directed toward developing renewable energy and natural gas to transition to a low-carbon economy rather than emphasizing CCUS.

One advantage of implementing CCUS is that Viet Nam would not need to change the existing structure of its energy system. The Asian Development Bank (ADB) has suggested that emission reduction through CCUS could become economically feasible in Southeast Asia as carbon prices rise toward 2050.

However, further research is needed on CCUS potential in Viet Nam, not only regarding storage capacity but also technical and economic aspects. Since the current cost of CCUS remains high, the implementation of CCUS projects in Viet Nam is still challenging. Therefore, under Viet Nam's conditions, reducing costs, establishing a comprehensive legal framework, and developing an appropriate carbon market policy will be crucial for the successful deployment of CCUS projects.

Examples of current projects

The existing CCUS 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 CO₂ from a combined cycle natural gas power plant and pump it into the Bach Ho field to enhance

oil recovery. CO₂ 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 [13].

The Rang Dong project

A small CO₂-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 [14].

Petra Nova Carbon Capture

This power plant located in Texas has the world's largest post-combustion CO₂ capture system. It has been operating since 2017, when it was retrofitted with a 1.4 million tonnes CO₂/year capture facility [15]. CO₂ 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 [16]. It can capture 60,000 CO₂ tonnes/year from the flue gas, which is utilized for baking soda and ash. The technology is running without subsidy due to a new CO₂ stripping chemical, which is slightly more efficient than amine [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 CO₂ is sold for commercial use [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. CO₂ is sold for EOR purposes [19].

The CCUS project at the Taizhou Coal-fired Power Plant (Jiangsu Province, China)

The CCUS project at the Taizhou Coal-fired Power Plant (Jiangsu Province, China), implemented by China Energy Investment Corporation, officially began commercial operation in June 2023. The system is capable of capturing approximately 500,000 tons of CO₂ per year from the flue gas of Unit 4, with a recovery rate exceeding 90%. The captured CO₂, compressed and purified to about 99% purity, is supplied to enterprises producing dry ice, industrial gases, and refrigerated food products. This is currently the largest CCUS project in Asia in the coal power sector, marking an important milestone in China's application of carbon emission reduction technologies [23].

The Greensand project (Denmark)

The Greensand project in Denmark is the world's first CO₂ storage facility to receive imported emissions, officially operating from March 8 and storing CO₂ at a depth of 1.8 km under the North Sea. CO₂ is liquefied in Belgium, transported by ship in specialized containers to the Nini West field, and then injected into geological storage reservoirs, with plans to expand to the Siri field after the pilot phase. The project, implemented by Ineos (UK) and Wintershall Dea (Germany), aims to store 8 million tons of CO₂ per year by 2030, contributing to Denmark's goal of achieving carbon neutrality by 2045 [24].

Investment cost estimation

The cost figures are presented as incremental costs relative to the same technologies without carbon capture (CCS). The data reflect the addition of post-combustion capture technology. Performance and energy data are expressed as differences compared to technologies without CCS, since CCS cannot operate as a standalone technology. The estimates for 2020 are based on several international data sources and the Danish Technology Catalogue, as Vietnam's experience with CCS deployment remains limited. References [6, 20] indicate that a supercritical coal-fired power plant with a net capacity of 546 MW equipped with CCS can capture approximately 4 million tonnes of CO₂ per year, with incremental capital costs for CCS of USD 2,902/kW and additional annual operating costs of USD 117 million (covering capture, compression, transport, and storage). For a natural gas combined cycle plant with CCS, with an actual capacity of 482 MW, approximately 1.4 million tonnes of CO₂ can be captured annually, with incremental capital costs of USD 1,493/kW and additional annual operating costs of USD 20 million.

In the 2026 Technology Catalogue, the cost estimates for 2020 have been adjusted for inflation from the original price year to 2025 USD.

Projections follow a learning curve approach, consistent with the learning rates applied to coal- and gas-fired power plants. See Appendix 1 for a description of the learning curves.

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Data sheet

Supercritical coal power plant with CCS - Retrofit post-combustion										
Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW _e	-60	-60	-60					A	1
Generating capacity for total power plant	MW _e	-60	-60	-60					A	1
Electricity efficiency, net, name plate	%	-7	-7	-7						1
Electricity efficiency, net, annual average	%	-8	-8	-8						1
Forced outage	%	+7	+7	+7						
Planned outage	weeks per year									
Technical lifetime	years									
Construction time	years									
CO ₂ emission reduction	%	-89	-90	-90			-90	-99	B	1
Space requirement	1000 m ² /MW _e									
Ramping configurations										
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	g/Nm ³	81	81	81						3, 7
SO ₂ (degree of desulphuring,)	%	97	97	97						3, 7
NO _x	g/GJ fuel	152	150	38						3, 7
CH ₄	g/GJ fuel									
N ₂ O	g/GJ fuel									
Economic data (in USD2025)										
Nominal investment	M\$/MW _e	+3.61	+3.32	+2.63	+2.07	+4.05	+1.51	+3.25	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	\$/MW _e /year	+54,157	+52,414	+50,920	+16,807	+64,739	+16,807	+64,739	F	1, 7, 9
Variable O&M	\$/MWh	+4.01	+3.90	+3.77	+3.24	+10.61	+3.04	+9.98	F	1, 5, 9
Technology specific data										
Water consumption	L/MWh	3200	3200	3200	-	-	-	-	G	13, 14

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 CO₂ more efficiently in the future. CO₂ can be already captured at higher rates, but costs to marginally increase capture rates beyond the reported values are relatively high.
- C In principle, ramping is not affected by the presence/absence of CCS.
- D Minimum load is not affected by CCS. However, the CO₂ compressor requires higher loads for smooth operability.

- E The regeneration in the post-combustion unit has a start-up time comparable to that of the power plant.
- F Compression, transport and storage are not included in the figures.
- G Assuming a cooling tower is used.

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Natural Gas Combined Cycle with CCS - Retrofit post-combustion										
Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW_e	-40	-40	-40					A	1
Generating capacity for total power plant	MW_e	-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									
CO2 emission reduction	%	-87	-90	-90			-90	-99	B	1
Space requirement	1000 m²/MW_e									
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	g/Nm³	30	30	30						3, 6
SO₂ (degree of desulphuring,)	%	99	99	99						3, 6
NOx	g/GJ fuel	78	60	20						3, 6
CH₄	g/GJ fuel	-	-	-						
N₂O	g/GJ fuel	-	-	-						
Economic data (in USD2025)										
Nominal investment	M\$/MW_e	+1.86	+1.57	+1.21	+1.10	+3.33	+0.78	+2.53	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	+11,703	11,205	10,956	9,088	18,177	8,590	18,177	F	1, 7, 8
Variable O&M	\$/MWh	+1.55	+1.50	+1.46	+0.78	+5.18	+0.78	+5.18	F	1, 7, 8
Technology specific data										
Water consumption	L/MWh	1500	1500	1500	-	-	-	-	G	11, 12

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 CO₂ more efficiently in the future. CO₂ can be already captured at higher rates, but costs to marginally increase capture rates beyond the reported values are relatively high.
- C In principle, ramping is not affected by the presence/absence of CCS.
- D Minimum load is not affected by CCS. However, the CO₂ compressor requires higher loads for smooth operability.
- E The regeneration in the post-combustion unit has a start-up time comparable to that of the power plant.
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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

Vietnam's industrial sector is diverse and encompasses several different industries. Total energy consumption in the industrial sector in 2024 is estimated at around 20,600 ktoe, of which coal consumption accounts for approximately 14,700 ktoe (71%), while oil and petroleum products account for about 5,900

ktoe (29%). The metal and fabricated metal products industry, together with the non-metallic mineral products industry, represent the largest share, accounting for roughly 55% of total energy consumption. This clearly reflects the energy-intensive nature of processes such as firing, smelting, and construction material production. In contrast, light and consumer industries—including textiles, chemicals, and food processing—maintain relatively modest energy consumption levels, remaining stable at around 7–8% for each subsector. High-tech manufacturing industries, such as machinery and equipment production and motor vehicle manufacturing, fall into the lowest consumption group (only about 2–3%), indicating significantly lower energy intensity compared to basic material production industries.

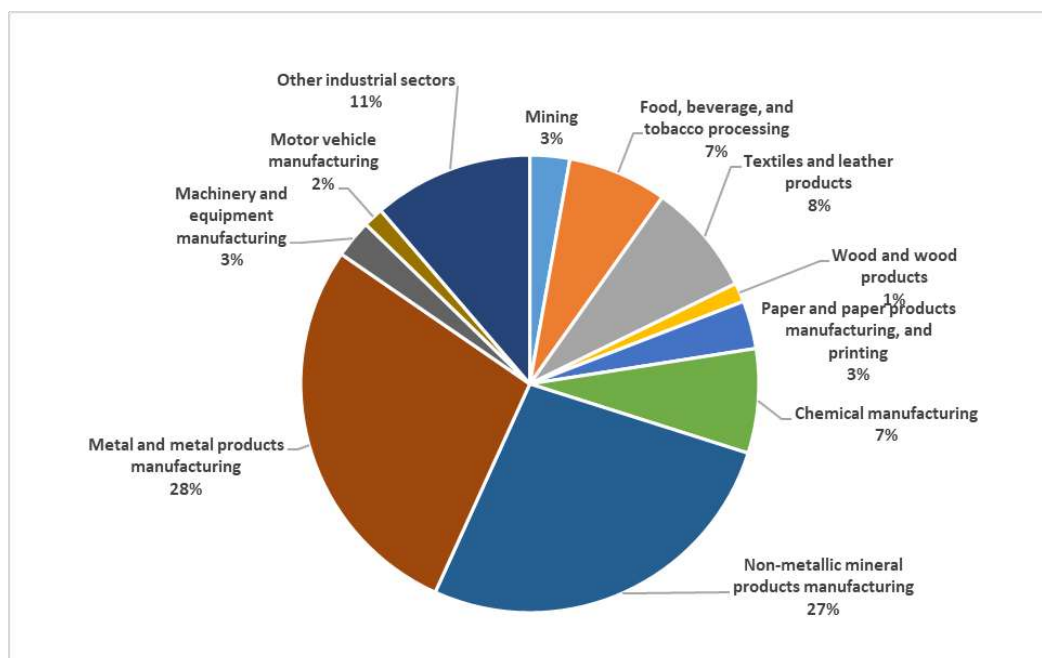


Figure 32: Structure of energy consumption in industry sector in Viet Nam 2014 [7]

As can be seen from the Figure 32 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 [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.

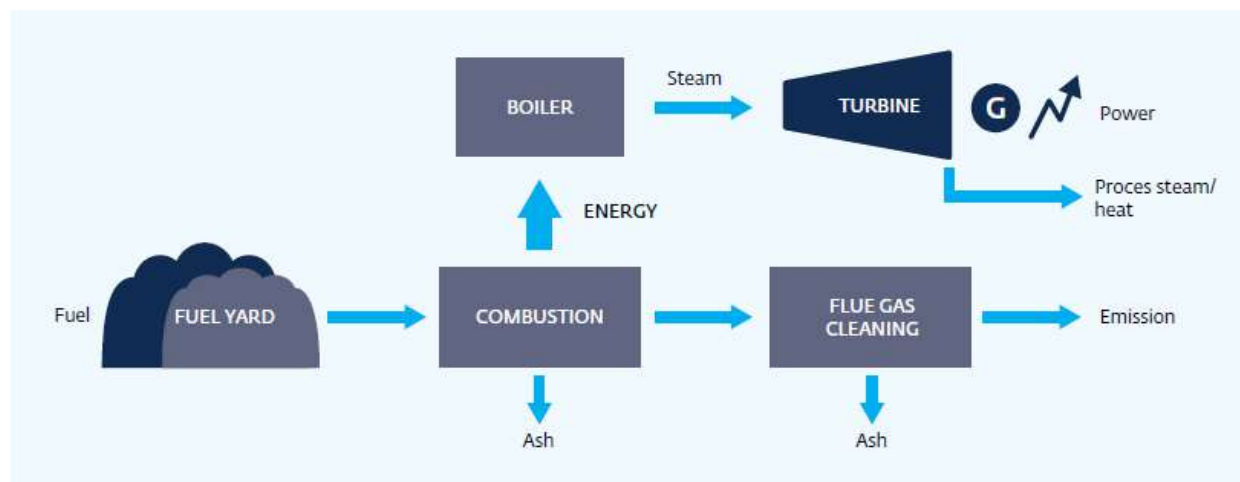


Figure 33: A schematic of a biomass fired co-generation plant [9]

The Figure 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 [9].

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 [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 34 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.

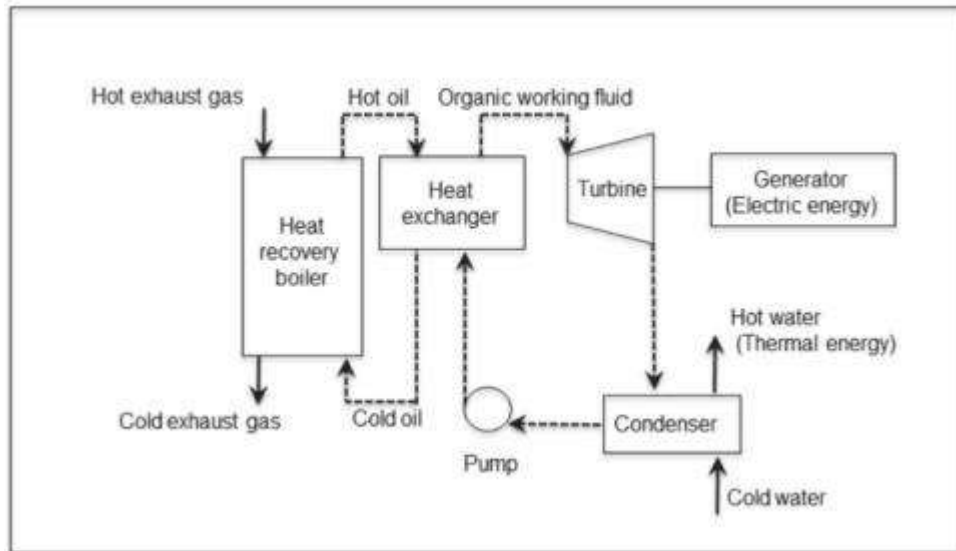


Figure 34: Schematic of cogeneration scheme in a Portland cement factory [15]

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 [15].

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

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

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

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

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

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 18: Typical capacities of biomass CHP boiler systems [3]

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 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 [12].

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 [13].

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.

Water consumption

Industrial co-generation systems, also known as combined heat and power (CHP) systems, typically require water for cooling and other auxiliary systems. The amount of water used varies depending on the specific system design and configuration.

In general, co-generation systems use water for cooling the exhaust gases and condensing the steam, which can result in significant water consumption. However, some systems may use alternative cooling methods, such as air-cooled or dry cooling, which can reduce water usage.

Additionally, water may be used in other auxiliary systems, such as boiler feedwater treatment and chemical dosing. However, these uses are typically relatively small compared to the cooling water requirements.

The overall water footprint of industrial co-generation systems is largely determined by the cooling system design and the specific application. Systems that use water-cooled condensers or other water-intensive cooling methods will tend to have higher water consumption than those that use alternative cooling methods.

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 CO₂-equivalent greenhouse-gas emissions of this thermal energy assuming coal as the input is around 8,000 tons per year [15].

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 [9].

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).

Examples of current projects

Biomass-fired CHP boiler:

An Khe Factory is 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°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, T°C: 380; Boiler 3: Q2: 80T/h, P = 67bar, T°C: 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 m³ 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 340⁰ 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.

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 [7].

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Data sheet

Biomass-fired cogeneration										
Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW_e	25	25	25	4	200	4	200		1, 5, 12
Generating capacity for total power plant	MW_e	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 m²/MW_e	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	g/Nm³	12.5	12.5	12.5						3
SO₂ (degree of desulphuring,)	%	0.0	0.0	0.0						3
NOₓ	g/GJ fuel	125	125	125						3
Economic data (in USD2025)										
Nominal investment	M\$/MW_e	2.2	2.0	1.8	1.7	3.1	1.3	2.2	B	4, 5, 6, 7, 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	61,627	56,647	49,301	46,220	83,196	36,976	61,627	A	4, 5, 8, 10
Variable O&M	\$/MWh	3.9	3.6	3.2	3.0	5.3	2.4	3.9	A	5, 10
Start-up costs	\$/MW_e/start-up									
Technology specific data										
Water consumption	L/MWh	-	-	-	-	-	-	-		

Notes:

- A Lower and upper uncertainties are for 2025 -25% (lower) and +35% (higher) and for 2050 -/+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.

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CHP in a cement factory										
Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW_e	8	8	8	2	20	2	20		1, 2, 3
Generating capacity for total power plant	MW_e									
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 m²/MW_e									
Additional data for non-thermal plants										
Capacity factor, theoretical	%									
Capacity factor, incl. outages	%									
Ramping configurations										
Ramping	% per minute									
Minimum load	% of full load									
Warm start-up time	hours									
Cold start-up time	hours									
Environment										
PM 2.5	g/Nm³									
SO₂ (degree of desulphuring,)	%									
NOx	g/GJ fuel									
Economic data (in USD2025)										
Nominal investment	M\$/MW_e	3.11	3.11	3.11	3.11	3.11	3.11	3.11		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	15.56	15.56	15.56	6.22	24.90	6.22	24.90		2
Start-up costs	\$/MW_e/start-up									
Technology specific data										
Water consumption	L/MWh	-	-	-	-	-	-	-		

Notes:

A Estimated.

References

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6. HYDRO POWER

Brief technology description

Hydropower is a method of generating electricity by using the flow of water (rivers, reservoirs, or dams) to rotate turbines, thereby converting hydraulic energy into mechanical energy and subsequently into electrical energy. The operation process and working principle of a hydropower plant consist of five main stages:

- **Water conveyance:** The operation of a hydropower plant begins when high-pressure water flows through large steel pipes known as penstocks. These pipes are specially designed to withstand high pressure and convey water from the reservoir to the powerhouse. As the water flows through the penstocks, it creates large water columns with significant pressure, ready for energy conversion.
- **Turbine rotation:** When water flows forcefully into the powerhouse, it strikes the turbine connected to the generator. The force of the water causes the turbine to rotate, converting mechanical energy into electrical energy. The turbine acts as the central machine and plays a decisive role in electricity generation. This process occurs continuously, ensuring that the energy from water is utilized efficiently.
- **Generation of high-voltage electricity:** The electrical energy generated from the rotation of the turbine is transmitted through a transformer. Here, alternating current (AC) is stepped up to a higher voltage level. Increasing the voltage is necessary to minimize power losses during transmission, ensuring that sufficient electricity reaches the points of consumption.
- **Power transmission:** The high-voltage electricity is connected to the power grid, delivering energy to consumption areas.
- **Water discharge:** After passing through the turbine, the water is released back into the river, continuing its natural cycle.

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.

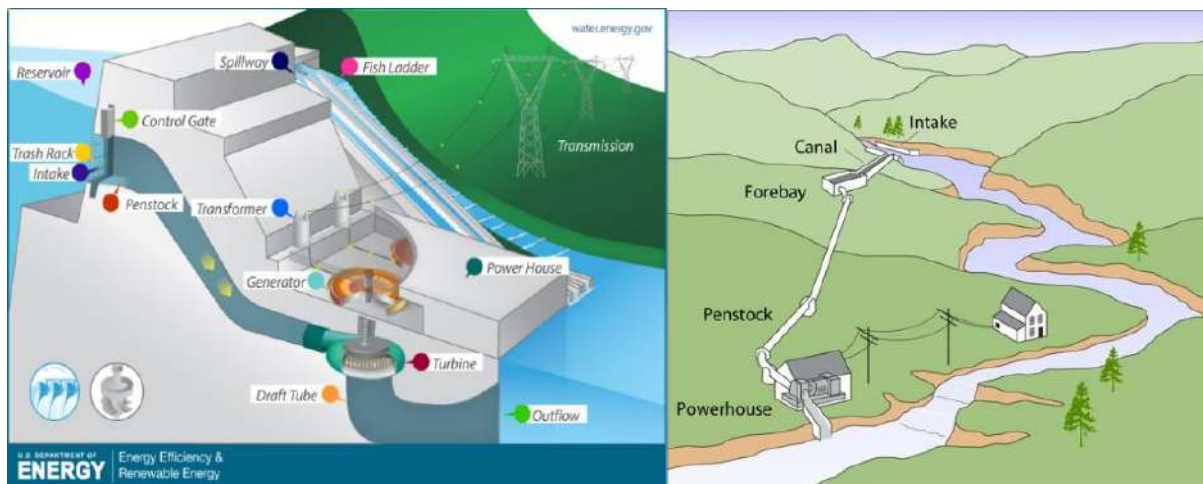


Figure 35: Reservoir and run-of-river hydropower plants [14]

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.

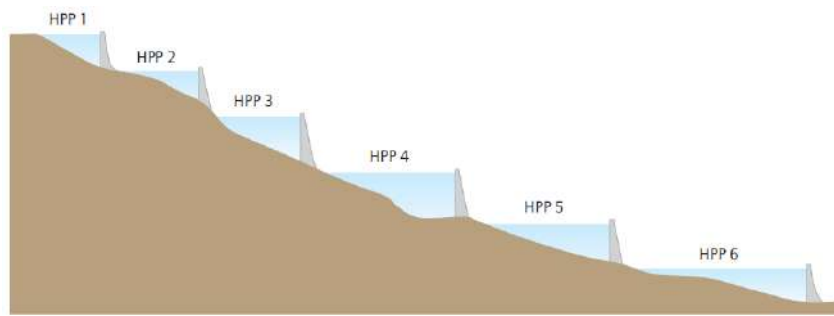


Figure 36: Cascading Systems [1]

In Vietnam, hydropower plants must operate in accordance with the regulations specified in the operating procedures for both single reservoirs and cascade reservoirs. Coordinated operation of hydropower reservoir cascades plays a key role in reducing flood peaks, mitigating downstream flooding, and storing water appropriately to supply water and control salinity intrusion during the dry season. This coordination helps optimize flood control storage, ensure dam safety, and enable synchronized operation in accordance with established procedures to respond to climate change.

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

Table 19: 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 almost always 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.

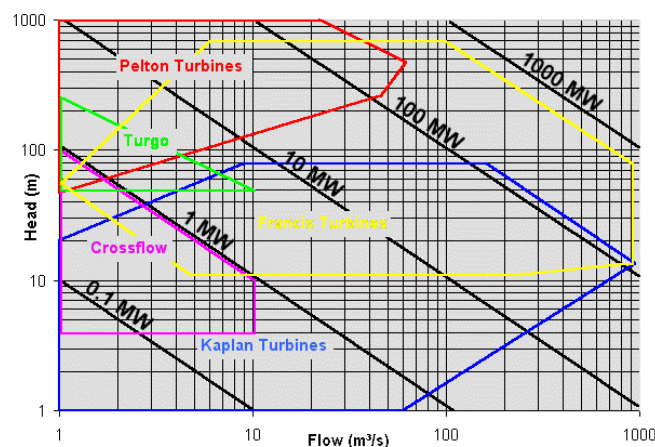


Figure 37: Hydropower turbine application chart [2]

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.

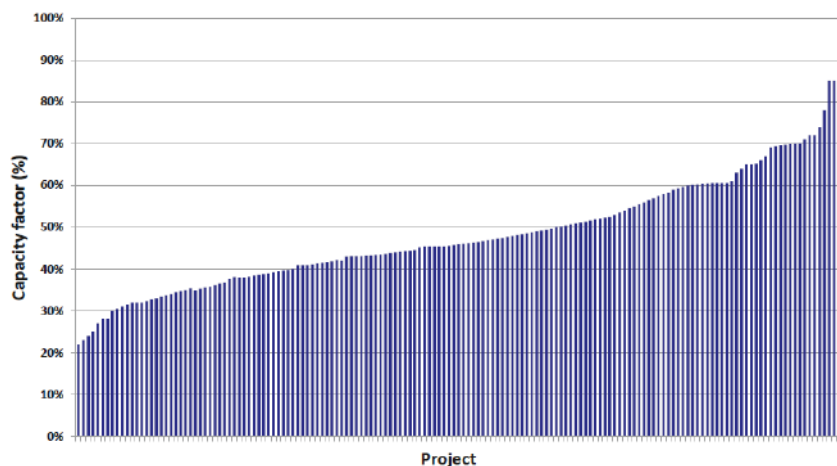


Figure 38: Capacity factors for 142 hydropower projects around the world [4]

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 800 MW per unit can be considered [15].

At present, the largest hydropower plant in Vietnam is the Son La Hydropower Plant, with a total installed capacity of 2,400 MW, consisting of six generating units of 400 MW each.

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.

In Vietnam, hydropower remains a power source with stable generation capacity. With its ability to rapidly increase or decrease output, it serves as an important peak-shaving source in the load profile. Hydropower can provide primary and secondary frequency regulation as well as black-start capability, playing a key role in maintaining system frequency and voltage stability when the share of variable renewable energy (wind and solar power) is high.

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.

Space requirement

Reservoirs require the construction of a dam that creates a large artificial lake, necessitating extensive land acquisition, which can significantly alter local ecosystems and often requires relocating communities and wildlife. However, the necessary space varies significantly as it is very dependent on the local topography and particular geographical conditions.

On the other hand, run-of-river hydro projects have a much smaller footprint. As they not require large reservoirs but instead use the natural flow of the river to generate electricity, run-of-river systems typically require a small portion on land for intake and powerhouse structures, causing marginal disruptions to the surrounding landscape and habitats. Less than 0,3 hectares per MW are needed for this type of project according to data from the Colombian Technology Catalogue for Power Generation and Storage Technologies 2025.

Water consumption

For hydropower plants, water is not consumed in the same way as in thermal power plants. Water is the primary input for hydropower generation, and the amount of water used depends on the specific project. However, hydropower does not consume water during the generation process; it is regulated and returned downstream, with losses mainly due to evaporation and seepage. Reservoirs also alter the flow regime over time. While water is returned to the river after power generation, flow rates in certain river sections may be reduced. In addition, some water may be lost due to evaporation from reservoirs.

In some areas with hydropower projects that include reservoirs, the same volume of water can be used for multiple purposes—first for electricity generation, and subsequently to meet local water demand. This approach helps optimize resource management and reduce the overall water footprint of energy production, making it a highly effective strategy in regions where water conservation is a critical concern.

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 CO₂ 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.

In Vietnam, several hydropower plants with reservoirs are designated as multipurpose hydropower facilities, serving both electricity generation and flood regulation functions. Therefore, these hydropower plants must operate in compliance with reservoir and cascade reservoir operating procedures to ensure minimum downstream flows, maintain inland waterway transportation, and provide water supply for downstream areas. In addition to generating electricity to ensure the security of power supply for the national power system, hydropower reservoirs must also balance other economic, environmental, and social objectives. These include maintaining minimum downstream flows; coordinating with irrigation reservoirs to supply water for domestic use, agriculture, and production needs of downstream communities during the dry season; ensuring the safety of hydraulic structures; and contributing to flood mitigation for downstream areas during the flood season.

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. [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).

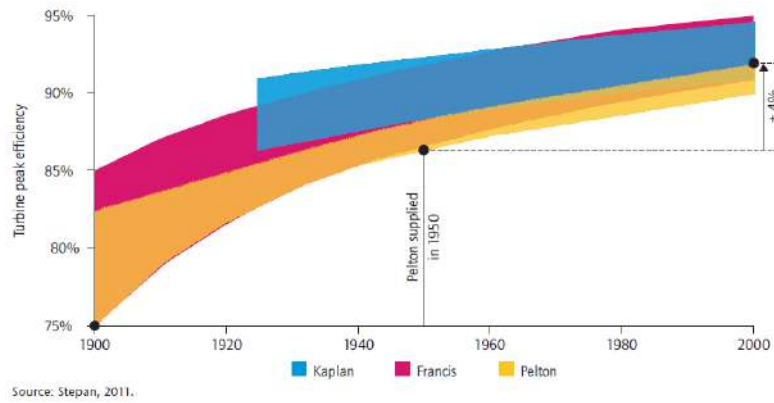


Figure 39: Improvement of hydraulic performance over time [7]

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 [13]. A roller-compacted concrete (RCC) dam is built using much drier concrete than traditional concrete gravity dams, allowing speedier and lower cost construction.
- Upgrade or redevelop old plants to increase efficiency and environmental performance.
- Add hydropower plant units to existing dams or water flows.

Examples of current projects

[19] indicates an economic potential for small hydro (<30 MW) in Viet Nam of 15000 MW. More than 5,000 MW is installed today [21].

Large hydropower plant (>30 MW): Lai Chau [20]

Lai Chau is the first upper stream hydropower plant in Viet Nam on the Da River hydropower cascade. The plant is located in 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 km², the reservoir volume is 1.21 billion m³ and the useful volume is 800 million m³. The normal rising water level is 295 m, and the dead water level is 265m, the maximum water flow through the turbine is 1664.2 m³/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 m³/s. The volume of the reservoir is 3.29 million m³ 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 [21,22]

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. The project is implemented on the same site as the existing Hoa Binh Hydropower Plant - a key facility of the national power system - therefore, all construction activities have been carefully planned and strictly monitored to ensure absolute safety for the existing structures and to minimize vibration and environmental impacts on the surrounding area.

Unit No. 1 of the project was synchronized with the national grid on August 19, 2025. Unit No. 2 of the project was synchronized with the national grid in November, 2025.

According to the design, once in operation, the Hoa Binh Hydropower Plant Expansion Project will supply approximately 500 million kWh of electricity annually, thereby enhancing power generation capacity for the northern region. The project also makes optimal use of excess discharge water during the flood season from the existing plant for power generation, helping to reduce the operational load on the existing units.

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 m³/s, increasing the total water flow to 3000 m³/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 (including 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.

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. 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.

The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - Hydro power plant Large (Reservoir)						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		2.00	2.00		1.99	1.98
Technology Catalogue - Colombia 2025		2.57	2.57			2.54
Technology Catalogue - Indonesia 2024		2.32	2.23			2.07
Technology Catalogue - Vietnam 2023	1.90		1.90			1.90
IRENA 2024*	2.25	2.33				
IEA WEO 2025 – India**		2		2		2
IEA WEO 2025 – China**		1.6		1.6		1.6
*Global weighted average of total installed cost of large hydro power plants						
**Capital cost of large-scale hydro power plants under stated policy scenario						

Investment cost [Million USD 2025 / MW] - Hydro power plant Small						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		1.80	1.80		1.79	1.79
Technology Catalogue - Indonesia 2024		2.64	2.54			2.36
Technology Catalogue - Vietnam 2023	1.65		1.65			1.65
IRENA 2024*	2.97	1.82				
IEA WEO 2025 – India**		3.05		3.05		3.05
IEA WEO 2025 – China**		2.00		2.00		2.00
*Global weighted average of total installed cost of small hydro power plants						
**Capital cost of small-scale hydro power plants under stated policy scenario						

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Data sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (\$), price year 2025.

Hydro power plant - small system											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW _e	10	10	10	10	1	30	1	30		
Generating capacity for total power plant	MW _e	20	20	20	20	1	30	1	30		
Electrical efficiency, net, name plate	%	95	95	95	95	85	97	85	97		5
Electrical efficiency, net, annual average	%	95	95	95	95	85	97	85	97		5
Forced outage	%	4	4	4	4	2	10	2	10		5
Planned outage	%	10.6	10.6	10.6	10.6	5.8	19.2	5.8	19.2		7
Self-consumption	%	0.7	0.7	0.7	0.7	0.4	1.3	0.4	1.3		
Technical lifetime	years	50	50	50	50	40	90	40	90		5
Construction time	years	3	4	4	4	2	6	2	6		5
Space requirement	1000_m ² /MW _e	32	32	32	32	11	69	11	69		
Additional data for non-thermal plants											
Capacity factor, theoretical	%	59	59	59	59	57	70	57	70		
Capacity factor, incl. outages	%	50	50	50	50	40	65	40	65		
Ramping ability											
Ramping	% of full load/minute	50	50	50	50	30	100	30	100		6
Minimum load	% of full load	0	0	0	0	0	0	0	0		6
Warm start-up time	hours	0.1	0.1	0.1	0.1	0.0	0.3	0.0	0.3		6
Cold start-up time	hours	0.1	0.1	0.1	0.1	0.0	0.3	0.0	0.3		6
Minimum Up time	hours	0.5	0.5	0.5	0.5	0.3	1.0	0.3	1.0		
Minimum Down time	hours	0.5	0.5	0.5	0.5	0.3	1.0	0.3	1.0		
Economic data (in USD2025)											
Specific investment	MUSD/MW _e	1.80	1.80	1.79	1.79	0.80	4.40	0.79	4.36	A	
- of which equipment	%	40	40	40	40	40	40	40	40		1
- of which installation and other costs	%	60	60	60	60	60	60	60	60	B	1
- of which equipment	MUSD/MW _e	0.72	0.72	0.72	0.71	-	-	-	-	A	
- of which installation and other costs	MUSD/MW _e	1.08	1.08	1.07	1.07	-	-	-	-	A	
Fixed O&M	USD/MW _e /year	39,600	39,503	39,365	39,280	16,000	110,000	15,871	109,110	A, C	
Variable O&M	USD/MWh	0.5	0.5	0.5	0.5	0.38	0.63	0.37	0.62	D	
Start-up costs	USD/MW _e /start-up										
Technology specific data											
Water Consumption	L/MWh	~1000	~1000	~1000	~1000	-	-	-	-	E	2, 3, 4

Notes:

- A Costs are very site sensitive. Costs are projected with a learning rate approach assuming a 1% learning rate for based on IEA's assumptions in their Global Energy and Climate Model, including capacity projections of the IEA's World Energy Outlook 2025, with Stated Policies for the central values.
- B For hydropower plants the civil works and earthworks often make up a significant share of the costs which are included as installation as described in the overall methodology for the Technology Catalogue.
- C O&M corresponding to 2.2% of CAPEX/year according to IEA with an uncertainty range of 2% to 2.5% for large-scale plants according to IRENA.
- D Uncertainty (Upper/Lower) is estimated as +/- 25%.
- E The water consumption can vary a lot. It is based on evaporation losses which depend on the reservoir size. If there is no reservoir, the water consumption can be very low.

References

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- 6 Eurelectric, "Hydropower - Supporting a power system in transition", 2015
- 7 Based on projects in Vietnam

Hydro power plant - large system											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	150	150	150	150	30	400	0	0		5, 6, 7
Generating capacity for total power plant	MW_e	150	150	150	150	30	2,000	30	2,000		5, 6, 7
Electrical efficiency, net, name plate	%	95	95	95	95	85	97	85	97		8
Electrical efficiency, net, annual average	%	95	95	95	95	85	97	85	97		8
Forced outage	%	4	4	4	4	2	10	2	10		5
Planned outage	%	11.5	11.5	11.5	11.5	5.8	19.2	5.8	19.2		9
Self-consumption	%	0.9	0.9	0.9	0.9	0.5	1.5	0.5	1.5		
Technical lifetime	years	50	50	50	50	40	90	40	90		9, 5
Construction time	years	4	4	4	4	2	6	2	6		9, 5
Space requirement	1000_m ² /MW_e	100	100	100	100	47	143	47	143		
Additional data for non-thermal plants											
Capacity factor, theoretical	%	53	53	53	53	49	60	49	60		
Capacity factor, incl. outages	%	45	45	45	45	35	55	35	55		
Ramping ability											
Ramping	% of full load/minute	50	50	50	50	30	100	30	100		10
Minimum load	% of full load	0	0	0	0	0	0	0	0		10
Warm start-up time	hours	0.1	0.1	0.1	0.1	0.00	0.3	0.0	0.3		10
Cold start-up time	hours	0.1	0.1	0.1	0.1	0.00	0.3	0.0	0.3		10
Minimum Up time	hours	0.5	0.5	0.5	0.5	0.3	1.0	0.3	1.0		
Minimum Down time	hours	0.5	0.5	0.5	0.5	0.3	1.0	0.3	1.0		
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	2.00	2.00	1.99	1.98	0.75	8.80	0.74	8.73	A	
- of which equipment	%	30	30	30	30	20	50	20	50		1
- of which installation and other costs	%	70	70	70	70	50	80	50	80	B	1
- of which equipment	MUSD/MW_e	0.60	0.60	0.60	0.60	-	-	-	-	A	
- of which installation and other costs	MUSD/MW_e	1.40	1.40	1.39	1.39	-	-	-	-	A	
Fixed O&M	USD/MW_e/year	44,000	43,893	43,739	43,644	15,000	220,000	14,879	218,220	A, C	
Variable O&M	USD/MWh	0.75	0.75	0.75	0.74	0.56	0.94	0.56	0.93	D	
Start-up costs	USD/MW_e/start-up										
Technology specific data											
Water consumption	L/MWh	19000	19000	19000	19000	-	-	-	-	E	2, 3, 4

Notes:

- A Costs are projected with a learning rate approach assuming a 1% learning rate for based on IEA's assumptions in their Global Energy and Climate Model, including capacity projections of the IEA's World Energy Outlook 2025, with Stated Policies for the central values.
- B For large hydropower plants the civil works and earthworks to establish tunnelling and dams are often the biggest share of the costs (around 50% according to IEA). These costs are included as installation costs as described in the overall methodology for the Technology Catalogue.
- C O&M corresponding to 2.2% of CAPEX/year according to IEA with an uncertainty range of 2% to 2.5% for large-scale plants according to IRENA.
- D Uncertainty (Upper/Lower) is estimated as +/- 25%.
- E The water consumption can vary a lot. It is based on evaporation losses which depend on the reservoir size. If there is no reservoir, the water consumption can be very low. On the contrary, if the reservoir is big, the evaporation losses can be substantial.

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7. SOLAR PHOTOVOLTAICS

Brief technology description

A solar cell is a semiconductor component that generates electricity when exposed to light. When sunlight strikes the cell, photons excite electrons, separating them from atoms in the semiconductor material (silicon) and creating electron-hole pairs. Each solar cell contains an electric field formed by the junction of two different types of silicon (n-type and p-type). This electric field drives the excited electrons toward the n-type layer and the holes toward the p-type layer, generating an electric current. The movement of electrons occurs in a single direction (from the n-type layer to the p-type layer), producing direct current (DC). This direct current is then converted by an inverter into alternating current (AC), which can be used by household electrical devices or fed into the power grid. For practical reasons, several solar cells are typically interconnected and laminated to (or deposited on) a glass pane to obtain a mechanical ridged and weathering-protected solar module.

PV modules consist of multiple interconnected solar cells that are characterized according to the type of absorber material used including crystalline silicon, thin film, perovskite, and monolithic derivatives. Crystalline silicon (c-si) stands for the most exploited substrate material and often comes in the form of wafers. Mono- and multicrystalline dominate the market and the trend is expected to be sustained in the future given its cost-competitiveness and performance [1,2,3,4]. While monocrystalline experience higher efficiencies compared to multicrystalline equivalents, these may experience higher efficiencies in the future. Thin solar films are made from other composites such as cadmium telluride or copper indium gallium, among others. Monolithic cells are made from compounds of group III and V elements (Ga, As, In, P), and are typically deposited on a Ge substrate. Such highly efficient multi-junction cells are primarily used in space applications or concentrated photovoltaic (CPV) systems, which perform best in climates with abundant direct sunlight. Eventually, perovskite cells show promising efficiency but face serious issues with toxicity, stability, and large-scale scalability. While not yet commercially viable, they may serve as top layers in tandem cells with c-Si substrates that enable absorbing a broad spectrum of sunlight efficiently. Copper zinc tin sulphide (CZTS) is another stable candidate for future tandem designs.

Manufacturing process - Crystal growth method

The multicrystalline casting method has been the dominating crystallization technology since the early 2000's due to the flexibility in utilization of any kind of purified silicon no matter form (broken wafers, tops and tails from monocrystalline growth) and residual contamination. However, as indicated in Figure 40, over the last few years almost all major PV companies have been in the process of converting to a full monocrystalline focus by adding only new manufacturing capacity based on Mono-solutions due to their slightly higher efficiency, and since further scale-up has made mono-Si cells cheaper and therefore more cost-competitive. There are other factors such as lower degradation and improved aesthetics which might play a role for residential customers, which play a part in the overall shift. In 2023, over 95% of the global solar market was based on monocrystalline products [5]. The market share is expected to increase further.

Furthermore, other macro-trends are poised to reshape the silicon product landscape in the coming years, with larger wafer sizes and n-type products expected to become mainstream. These changes are progressing so rapidly that current market reports and statistics have yet to fully capture their impact. The shift toward larger wafer sizes is driven by the need to optimize wafer-to-cell-to-module processing costs. Some subprocesses incur costs that scale with wafer area (and thus do not benefit from increased wafer size), whereas others - such as batch processes - have costs that scale with the number of units, leading to cost reductions as wafer size increases. The shift from p-type to n-type represents a change of main doping (from Boron or Gallium to Phosphorous) and thereby a change of the electrical charge of the major electricity carrier in the wafer from positive (holes) to negative (electrons) which results in a longer minority carrier lifetime – which is a key cell design optimization parameter as understood in terms of semiconductor physics [5].

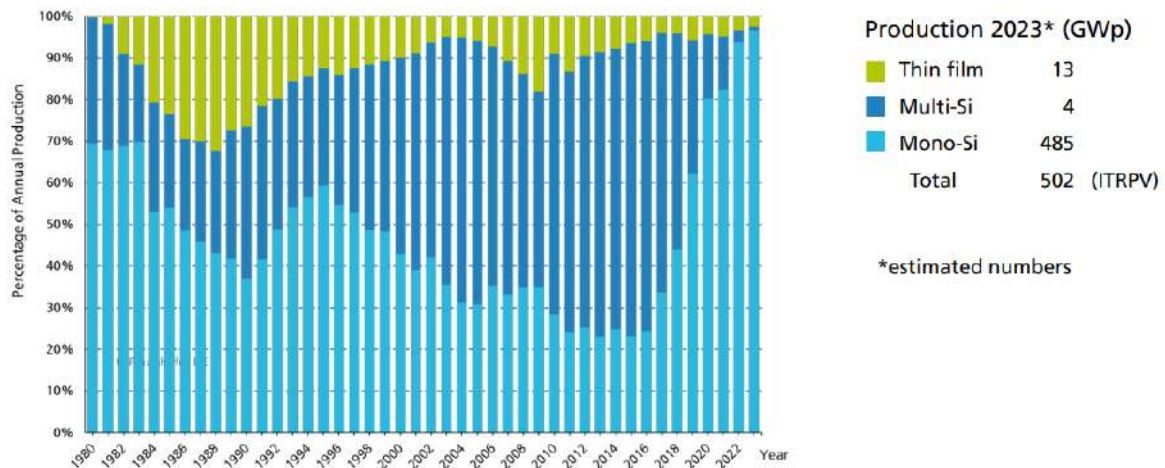


Figure 40: Historical global market shares of different cell technologies [5].

Manufacturing process - Wafer slicing method

The active silicon substrate that constitutes the solar cell is sliced from the ingot or block with a wire-saw. Since the technology was invented in the 1990's, hard silicon carbide particles in a slurry of glycol have been the preferred abrasion material. However, during the last few years, this solution has almost entirely been replaced by diamond coated wires and regular cooling water. This method has demonstrated to be cheaper in operation, as it eliminates the slurry recycling operation, provides a potential to cut thinner wafers and provides a wafer surface better suited for post-cleaning structuring into micro-pyramids or other anti-reflecting surface treatments by etching [6].

Solar cell architecture

The most dominating is the PERC (Passivated Emitter and Rear Cell), where an extra processing step has been added to reduce carrier recombination at the surface by “passivating” these surfaces (typically by a nanometre thin layer of silicon dioxide, aluminium-oxide or oxy-nitrides). Also, alternatives including PERT (passivated emitter rear totally diffused), HJT (Heterojunction Technology) or TopCON (Tunnel-Oxide Passivated Contact) are also now being introduced at large-scale manufacturing facilities all due to the higher efficiency potential that can be obtained (by up to 24-25% compared to the Al-BSF maximum around 20-21%) [7].

Solar module

The encapsulation of cells into a PV module has undergone several changes over the last few years. Whereas the front protection is still made by a 2.2 – 3.2 mm thick antireflective coated semi-toughened microstructured glass, more and more modules have the backsheets polymer foil replaced by another glass pane, whereby a more mechanically rigid and better-protected structure is obtained. This also opens for an optional elimination of the aluminium frame. Additionally, more transparent encapsulation materials known as polyolefins are now in use and anti-soiling surface coatings have been introduced [7].

Bifacial PV-panels and half-cut cells

Bifacial solar panels capture light from both the front and back. This setup has experienced significant momentum during the last few years, especially in utility-scale ground-mounted systems and commercial rooftops, where modules are mounted on flat roofs with similar structures as for ground-mounted plants. They take advantage of reflected light from surfaces like grass, snow, or white roofs, and any other surface with an albedo sufficiently high to reflect light and energy back. Additionally, half-cut cell technology, where cells inside the module are split in two to increase efficiency by decreasing resistance losses, has rapidly gained traction. The Thuan Nam solar power project in Vietnam is one of the first large-scale projects to adopt Tiger bifacial half-cell modules supplied by JinkoSolar (611 MW_p). This technology enhances power generation efficiency and reduces system costs compared with conventional modules [37]. The Tiger modules, featuring 163 mm wafer size, can generate 20–25 W more power than the 166 mm models and help further reduce Balance of System (BOS) costs. By 2026, as suggested in Figure 41, silicon-

based bifacial modules are projected to dominate 90 % of the global market due to their efficiency and low additional cost, as well as standardisation advantages of the growing solar module production industry [8] [9].

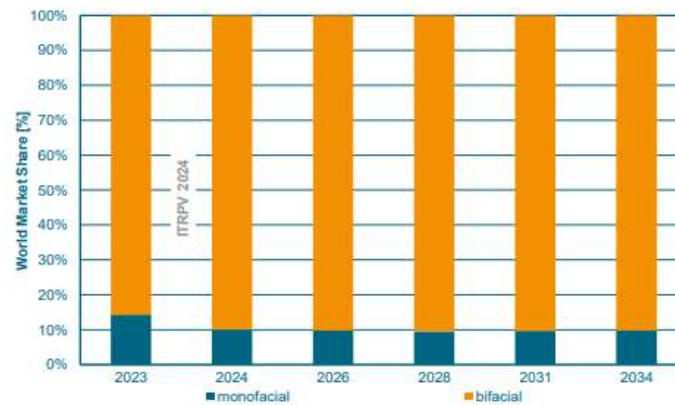


Figure 41: Forecasted global market share of bifacial vs. monofacial PV panels [8].

Perovskite PV cells

Perovskite PV cells are an emerging thin-film technology based on hybrid organic-inorganic lead (or tin) halide materials in a perovskite crystal structure. The absorber can be deposited as a micrometre-thin layer on glass or flexible substrates using low-temperature processes and therefore in principle offers low material use and potentially low manufacturing costs. Laboratory single-junction perovskite cells have already reached conversion efficiencies above 25 %, and perovskite-silicon tandem cells have surpassed 30 %, indicating a long-term potential for module efficiencies above today's crystalline silicon products [24]. Methylammonium lead triiodide ($\text{CH}_3\text{NH}_3\text{PbI}_3$), or MAPbI_3 , is one of the perovskite materials currently under research.

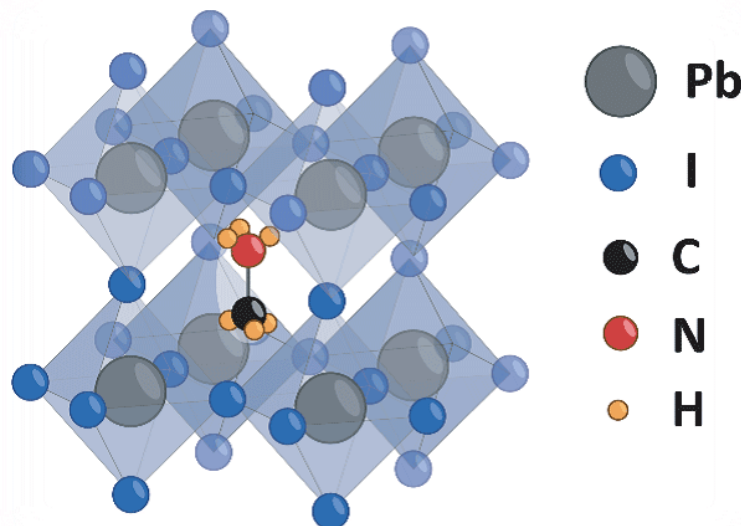


Figure 42: The structure of a perovskite solar cell.

Perovskite materials exhibit exceptional light absorption, high charge carrier mobility, and long carrier lifetimes, resulting in high device efficiencies and opening the possibility of realizing a low-cost technology that can be scaled to industrial production. To achieve this potential, challenges related to stability and environmental compatibility must be overcome; however, if these issues are resolved, perovskite-based technology could have a transformative impact on the rapid deployment of solar power at the terawatt scale. The fundamental material properties have also stimulated interest in using hybrid perovskite semiconductors across a broader range of energy applications, including conventional electronic and optical systems.

Currently, NREL is developing thin-film dual-junction tandem photovoltaic modules using low-cost

polycrystalline halide perovskites (e.g., $\text{CH}_3\text{NH}_3\text{PbI}_3$) for both the top and bottom cells. Halide perovskites have demonstrated remarkable progress in photovoltaic (PV) efficiency — increasing from 3.8% in 2009 to a certified 22% in 2016. Notably, such high-efficiency perovskite solar cells can be fabricated from polycrystalline materials using solution-processing methods.

The greatest potential is presently recognized in perovskite–silicon tandem structures, where a perovskite cell is integrated onto a conventional crystalline silicon cell to more effectively utilize the solar spectrum. However, this technology is still at an early stage of commercialization: challenges related to long-term stability, large-scale manufacturing, and the use of soluble lead compounds have not yet been fully resolved and remain subjects of ongoing research and experimentation.

PV system applications

Photovoltaic (PV) systems are versatile solutions to manage solar energy across a wide variety of applications, from small-scale setups to large-scale utility projects.

The photovoltaic (PV) modules are divided into two distinct classes by application, where residential panels typically are 1.5 – 2.1 m², whereas the panels for utility-scale projects are 2-3 m². The modules for both applications will have similar power rates in the range of 190-220 W_p pr. m² and may be made from diverse absorber materials. They are sold with a product warranty of typically ten to twelve years, a power warranty of a minimum of 25 years and an expected lifetime of more than 30-35 years, depending on the type of cells and encapsulation method.

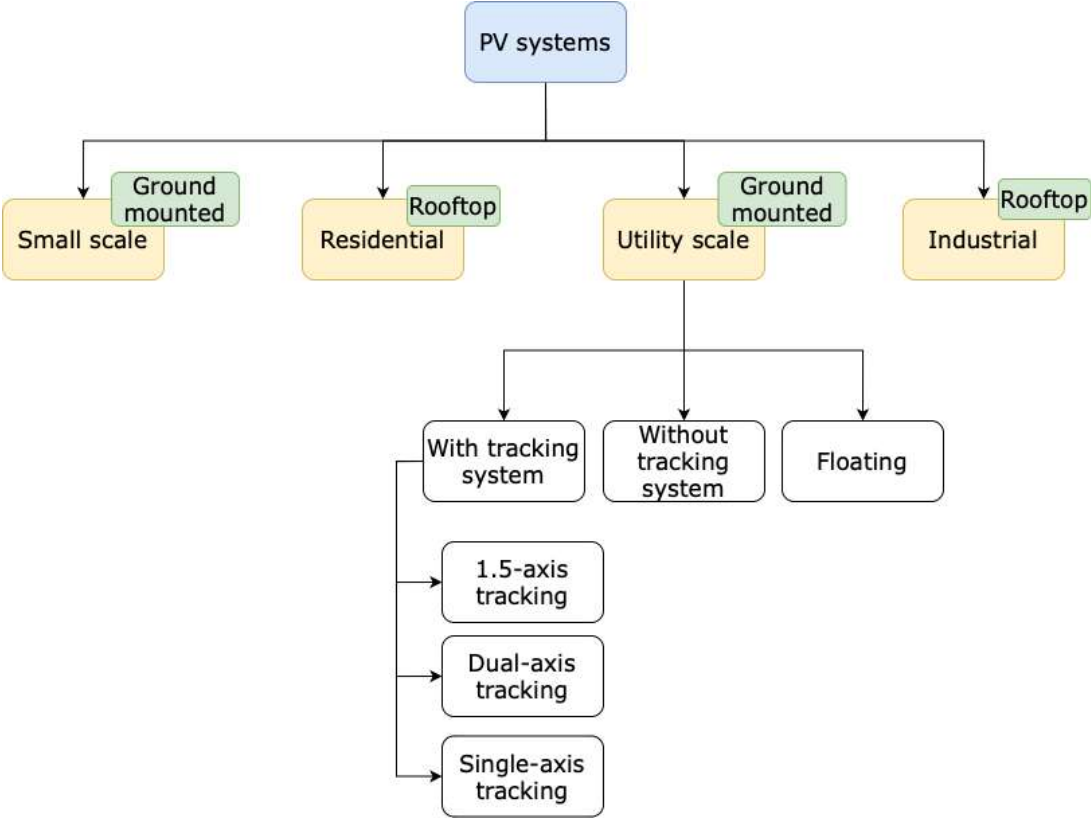


Figure 43: Classification of a PV system applications depending on the scale. Disclaimer: Not all the sub-categories have been considered for the quantitative analysis of this study, only the ones with a major current or upcoming role in Vietnam

Regarding the smallest applications, PV systems often power individual homes, bringing about clean energy to end-consumers.

As we scale up, industrial scale setups can cover bigger energy demands to cope with demand requirements of buildings, factories, and infrastructures. That contributes significantly to accomplishing sustainable and cost-effective energy production. When it comes to large scale deployments, utility-scale projects that are typically ground-mounted deliver large power requirements by exploiting economies of scales as well as technical benefits on increased power generation provided by tracking systems. This additional performance ability for tracking systems depends on geographical location, type of PV-module, type of

control system, time horizon for measurements and inclination angle applied. Figure 43 summarizes all the above stated.

In Vietnam, solar power is categorized into three types: ground-mounted solar, floating solar, and rooftop solar. For ground-mounted projects, PV panels are installed on open land areas, which generally require substantial space. Floating solar systems, on the other hand, utilize water surfaces - typically hydropower reservoirs - for panel installation, thereby saving land area but involving higher investment, operation, and maintenance costs compared to ground-mounted systems. Both ground-mounted and floating solar projects are usually of large capacity, ranging from several tens to several hundreds of megawatts, and are directly connected to the national power grid. Rooftop solar includes systems installed on industrial parks, public buildings, and households. These systems are smaller in capacity and mainly serve on-site electricity consumption, with or without grid connection.

PV module power (capacity)

The power generation capacity of a solar module depends on the intensity of the irradiation the module receives, incidence angle, spectral distribution of the solar radiation as well as module temperature. For practical reasons the module power is therefore referenced to a set of laboratory Standard Test Conditions³ (STC) which corresponds to an irradiation of 1000 W/m² with an AM1.5⁴ spectral distribution perpendicular to the module surface and a cell temperature of 25 °C. This STC capacity is referred to as the peak capacity.

In TCVN 7447-7-712:2019, the standard test conditions for PV modules are referenced from the international standard IEC 61215. Accordingly: a) PV cell temperature: 25 °C; b) Solar irradiance on the plane of the PV cell or module: 1000 W/m²; c) Light spectrum corresponding to an air mass of 1.5.

Losses and corrections

As the actual operating conditions will always be different from those established by the STC the average capacity of the module over the year will therefore differ from the peak capacity.

PV power production is reduced in reality and compared to laboratory conditions because of suboptimal setups regarding the inclination angle and the outdoor temperature that increases to above 25 °C.

For practical reasons, the various losses are often compiled into a single factor, called the performance ratio, which describes the energy yield of the actual system relative to a reference system operating under ideal Standard Test Conditions. This factor describes all energy losses components in the real system, which include optical losses related (light reflections from the glass surface), electrical losses (electrical string mismatch loss, dc- and ac-resistive losses), performance losses as compared to datasheet STC-values (while operating at temperatures different from 25 °C, light intensities different from 1000 W/m² and spectral conditions different from AM1.5 etc.) as well as inverter- and transformer losses, snow- and soiling loss etc. The uplift from bifaciality, albeit not part of the STC P_p measurement, is typically included in the performance ratio or presented separately.

Inverter capacity and sizing factor

The capacity of the inverter, also known as the rated power, defines the upper limit for power that can be delivered from the plant. The plant capacity is defined as the minimum capacity between this inverter capacity and the grid capacity as agreed with the utility, i.e. the minimum capacity the plant can feed into the grid. The relationship between the DC peak capacity and the plant capacity is called the sizing factor or the Inverter Load Ratio (ILR). A high sizing factor leads to energy “clipping” during peak hours, but at the same time reduces cost for inverters and grid connection. The sizing factor is optimized differently whether the limiting factor of the installation is availability of area, availability of grid capacity, subsidy scheme, imposed constraints on the allowed nominal power, daily self-consumption profile, fixed physical orientation or tilt angle of the modules etc.

There is no single inverter that is optimal for all situations. Different PV module technologies and system configurations may be suited to different types of inverters. When selecting a PV inverter, two main

³ Although the modules are specified under STC conditions, they operate under NOC conditions, whose parameters are specified in the technical datasheets of each photovoltaic solar panel: irradiance of 800 [W/m²], surface temperature of 45 [°C], spectral value of 1.5 [AM], and wind speed of 1 [m/s] at 20 [°C].

⁴ The air mass coefficient defines the optical path length of solar irradiation when travelling through the Earth's atmosphere, relative to a vertical path.

approaches can be considered: a distributed solution (using multiple smaller inverters of several tens of kVA each, placed across the site) or a centralized solution (using a few large inverters rated at ≥ 500 kVA, located in a central position). Choosing the most efficient inverter requires analysing both technical and financial factors. The DC–AC conversion efficiency directly affects the annual revenue of a solar power system and varies with DC input voltage and load. In Vietnam, the sizing factor of operational ground-mounted solar power plants is typically around 1.2. However, according to some experts, in regions with lower solar irradiation such as the northern provinces, a higher sizing factor - around 1.4 - should be adopted to ensure better system performance.

Wear and degradation

In general, a PV installation is very robust and only requires a minimum of component replacement over the course of its lifetime. Some inverter technologies typically need to be replaced every 10-15 years [10]. For the PV module only limited physical degradation will occur. It is common to assign a constant yearly degradation rate of 0.3 – 0.5 % to the overall production output of the installation. The performance degradation rate varies depending on the type of solar cell technology. For crystalline silicon (c-Si) modules, the degradation rate is usually higher in the first year of operation as the panels are first exposed to sunlight. This effect then stabilizes over time and is referred to as Light Induced Degradation (LID). Depending on the quality of the crystalline silicon panels, the LID rate can range from 0.5% to 2%. On average, photovoltaic panels degrade at a rate of 0.3–1% per year. For crystalline silicon modules, the typical degradation rate is around 0.4% per year, with some manufacturers offering panels with lower degradation rates. For amorphous silicon and CIGS modules, the average degradation rate is around 0.7–1% per year. Meanwhile, CdTe panels typically degrade at a rate of 0.4–0.6% per year. This degradation rate does not represent an actual physical degradation mechanism, but 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 [12]. Failures in the PV system is typically related to soldering, cell crack, hot spots, yellowing or delamination of the encapsulant foil, junction box failures, loose cables, hailstorm and lightning [12]. Degradation is difficult to assess on a project level, as the magnitude of degradation easily can be offset or overwhelmed by other factors influencing the individual system’s efficiency [2].

Orientation

In practice, there are two basic installation methods commonly applied for solar panels: fixed mounting and solar tracking systems that adjust the panel orientation according to the sun’s movement.

Tracking system installation is typically applied on flat ground to facilitate the movement mechanism. It requires larger spacing between panels/arrays depending on the rotation angle, and a large installation area to avoid internal shading. This option is generally applied to small- and medium-scale projects due to its high investment cost in mechanical and automatic control systems. The rotation direction usually follows the East–West path of the sun. This method allows for higher energy yields, with the increase depending on the tilt angle, but it requires more land and limits the total installed capacity.

Fixed mounting installation can be applied on various types of terrain, requires less spacing between panels/arrays, has lower investment costs, and demands less land area. However, the energy yield is lower compared to the tracking system. For floating solar power projects, since the platform is not fixed and is affected by waves, wind, and water flow, making the movement mechanism difficult, the fixed mounting method is typically used. For fixed mounting systems, the panels are tilted at an angle relative to the horizontal plane to maximize solar radiation intake. Theoretically, to optimize solar energy capture, panels should be tilted at an angle equal to the site’s latitude and oriented toward true South (azimuth angle)⁵. However, in practice, the tilt angle is adjusted depending on specific site conditions and other factors. A large tilt angle increases the spacing between panel rows, thus requiring more land area per installed capacity and stronger structural support to withstand wind loads. A small tilt angle, on the other hand, reduces the self-cleaning effect from rainfall. Given that Vietnam is located between latitudes 9° and 23°, the optimal tilt angle for fixed mounting systems typically corresponds to the local latitude.

Input

Solar radiation is the input of a PV panel. The irradiation, which the module receives, depends on the solar

⁵ Duffie, J.A. & Beckman, W.A. (2013). *Solar Engineering of Thermal Processes*. 4th Edition. John Wiley & Sons.

energy resource potential at the location, including shading conditions and the orientation of the module.

Potential in Vietnam

An indicator for the potential is the 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).

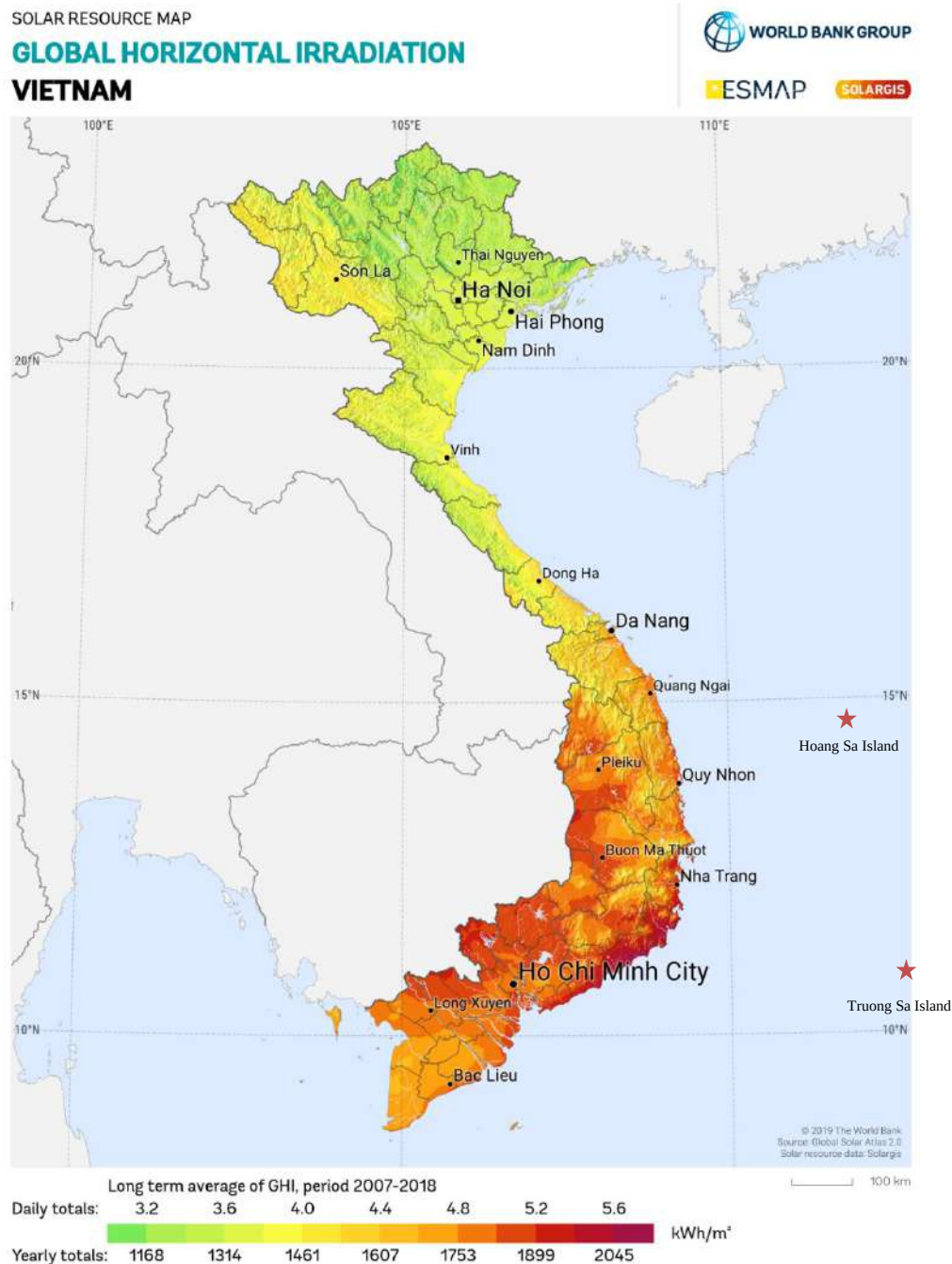


Figure 44. Horizontal irradiation potential in Viet Nam[13]

The average annual solar energy received on a horizontal surface (Global Horizontal Irradiance, GHI) in Viet Nam varies between approximately 1200 kWh and 2000 kWh per m². In Viet Nam, solar power potential is concentrated in the Central Highland, Southern Central and the South with latitude from 9° (Ca Mau province) to 14° (Gia Lai province).

The estimated potential for solar power development by region is determined based on updated reviews of available land funds in line with national land-use planning and land-use plans under National Assembly Resolution No. 39/2021/QH15 and Prime Minister Decision No. 326/QĐ-TTg, as follows:

Table 20: Estimated solar power potential based on available land area

Unit: MW

Region	Land solar	Floating solar	Rooftop solar in industrial zones	Rooftop solar on public buildings	Residential rooftop solar	Total
North	22.345	16.859	20.692	12.650	11.147	83.692
North Central	3.952	8.895	5.150	3.121	5.542	26.660
Center Central	4.815	11.323	3.756	2.027	3.521	25.442
Highlands	16.418	9.124	1.496	1.506	2.448	30.993
South Central	15.391	10.872	3.091	2.207	4.164	35.726
South	17.579	20.403	24.815	8.245	22.092	93.133
Whole country	80.500	77.476	59.000	29.756	48.914	295.646

Output

PV modules generate DC electricity, which must be converted to AC through inverters. Some modules, called AC modules, have integrated inverters, providing advantages like easier installation, flexibility in orientation, improved shade resistance, and safer shutdowns during emergencies. Nevertheless, these are more expensive and mostly used in residential settings. Alternatively, power optimizers are often used for arrays that are strongly affected by shading. Such a solution is cheaper than using microinverters but still brings about similar safety and operational benefits.

The final power generation 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.
- The type of inverter used (on-grid, off-grid, or hybrid).
- 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.
- Weather patterns.

Typical capacities

In Vietnam, the capacity of rooftop solar power systems varies widely depending on the purpose of use and available rooftop area. For households, systems typically range from 3 to 10 kW_p, which is sufficient to meet most daily electricity needs. In contrast, rooftop systems installed on factory or warehouse roofs in industrial zones are generally larger, commonly ranging from 50 kW_p to over 1 MW_p, and in some large industrial parks with extensive roof areas, the capacity can reach several MW_p. The system size is determined by rooftop space, electricity consumption, and the owner's investment capacity.

In Vietnam, rooftop solar systems can be deployed under two main configurations: grid-connected and off-grid. Grid-connected systems allow connection to the national power grid, enabling the use of solar energy when available and grid electricity when needed, while also selling excess electricity to Electricity of Vietnam (EVN) under the current policy framework. Off-grid systems are typically used in areas without grid access or for applications requiring independent power supply. Both types can be integrated with energy storage systems (battery storage) to enhance power reliability, particularly at night or during grid outages. According to regulatory documents such as Decree 135/2024/NĐ-CP [15] and Decree 58/2025/NĐ-CP [16], choosing an appropriate system model is encouraged to support sustainable energy development and energy self-sufficiency in residential, commercial, and industrial areas.

Large-scale (utility-scale) solar power plants are typically installed on the ground or floating on water, with capacities starting from 1 MW. Ground-mounted solar projects in Vietnam have reached significant scales,

typically ranging from tens to several hundred MW_p. Notable operating ground-mounted solar farms include Xuan Thien Easup solar power plant (600 MW) and Trung Nam Thuan Nam solar power plant (450 MW). For floating solar, a representative project is Da Mi solar power plant with a design capacity of 47.5 MW_p, using approximately 143,940 PV modules over 50 hectares of water surface, and generating around 70 million kWh/year. Ground-mounted projects can more easily achieve large capacities thanks to lower construction and transmission infrastructure costs and larger available land areas. Floating solar, while benefiting from natural cooling effects (reducing module temperature) and saving land use, is typically developed at small to medium scales (tens of MW_p) due to site limitations, higher floating installation costs, and additional requirements for environmental and structural considerations.

Ramping configurations

Utility-scale solar energy presents significant challenges for the energy grid, particularly in managing its effects on key electrical parameters. One major issue is the variability and intermittency of solar power, which can cause fluctuations in voltage and frequency stability. As solar output varies with cloud cover and time of day, rapid changes in power generation can lead to imbalances between supply and demand, affecting the grid's ability to maintain consistent voltage levels. Additionally, solar farms can impact grid inertia and short circuit capabilities, which are crucial for maintaining grid stability, especially during sudden changes in power load or supply. This reduced inertia makes the grid more susceptible to frequency deviations, potentially leading to power outages or the need for backup generation. To mitigate these effects, grid operators must invest in advanced grid management technologies such as synchronous compensators, energy storage systems, and fast-responding conventional power plants to ensure stability in the face of large-scale solar integration.

In Vietnam, the National Power System and Market Operator Company (NSMO) plays a crucial role in managing and operating the national power grid, including exercising control over large-scale solar power plants. To ensure system stability and security, NSMO can coordinate the adjustment of solar power output, either increasing or curtailing generation when necessary to balance supply and demand and maintain technical parameters such as voltage and frequency within permissible limits. This centralized control helps mitigate the variability and intermittency of renewable energy sources and supports the grid in operating more efficiently and reliably, especially as the share of solar power continues to rise rapidly in Vietnam.

According to Circular No. 05/2025/TT-BCT issued on February 1, 2025, on regulations for transmission, distribution, and metering systems, solar power plants connected to the transmission grid or those with an installed capacity of over 30 MW connected to the distribution grid must be capable of active and reactive power control as required by the power system operator. Specifically, they must be able to reduce active power output within no more than 2 seconds when the frequency exceeds 50.5 Hz and complete the response within 15 seconds; and be able to adjust reactive power within a power factor range of -0.95 to 0.95⁶.

Currently, rooftop solar systems account for a significant portion of Vietnam's total installed solar capacity, but they mainly operate under self-consumption models and are not centrally controlled by the grid operator. This poses major challenges for maintaining grid stability since their output depends on weather conditions and cannot be flexibly adjusted according to system needs. However, a mechanism for centralized power control of these systems is still lacking, creating potential risks to grid quality and stability.

To ensure the ability to regulate solar power output in line with the load curve, the Revised Power Development Plan VIII requires that new utility-scale solar projects install battery storage systems with a minimum capacity equal to 10% of the project's installed capacity, with a storage duration of 2 hours.

Advantages/disadvantages

Advantages

- PV does not use any fuel or other consumable.
- PV is noiseless (except for fan-noise from inverters and transformers).
- PV systems are modular and easy to install.

⁶ MOIT, Circular No. 05/2025/TT-BCT issued on February 1, 2025, on regulations for transmission, distribution, and metering systems

- Operation & Maintenance (O&M) of PV plants is simple and limited as there are no moving parts, except for tracker systems, and no wear and tear. Inverters need only be replaced once or twice during the operational life of the installation.
- Solar systems can be easily developed as hybrid systems with batteries as a strategy to mitigate impacts on variability, complementarity, and grid strength.
- PV systems integrated into buildings require no incremental ground space.
- Affordable aesthetic panels are expected to become available for building integration in the coming years.

Disadvantages

- PV systems are highly intermittent due to uncertain weather conditions, generating significant variability in energy generation on an intrahourly scale.
- Solar generation is concentrated around midday, and this typically does not align with peak consumption times. The PV system can generate ramps at peak hours because of the “duck curve” and energy spillovers during peak generation hours.
- Aesthetic concerns may limit the use of PV in certain urban environments and in the open space when the visual impact is unacceptable.
- PV installations can only provide ancillary services in specific situations as generation usually follows the daily and yearly variations in solar irradiation.
- Materials abundance (In, Ga, Te) is of concern for large-scale deployment of some thin-film technologies (CIGS, CdTe).
- Some thin-film technologies do contain small amounts of toxic 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.
- PV systems are quite area intensive as the MW_p/ha factor is typically around 0.8 – 1 ha/MW_p for Fixed Tilt installations and down to 0.6 – 0.7 for Horizontal Single Axis Trackers, including additional areas required for internal roads, compounds and transformer stations.

Space requirement

According to Circular No. 18/2020/TT-BCT issued by Ministry of Industry and Trade of Vietnam (MOIT), which provides regulations on project development and standard power purchase agreements for solar power projects, the land and water surface area with a fixed term for grid-connected solar power projects includes the total area for constructing project facilities (including the power plant and substations, excluding transmission lines and access roads).

The Circular stipulates that the land and water surface area for solar power plants must not exceed 1.2 ha per MW [17]. In practice, ground-mounted solar power projects in Vietnam typically require around 0.8–1 ha per MW, while floating solar projects tend to use about 10–15% less land area compared to ground-mounted solar installations. With technological advancements, the land and water use requirements for large-scale solar power projects are expected to decrease in the near future, improving land-use efficiency and enabling the deployment of higher capacities on the same footprint.

For rooftop solar power systems, it is estimated that approximately 6–8 m^2 of free rooftop area is required to install 1 kW_p of capacity [18]. Accordingly, a household installing a 3–6 kW_p system would need around 18–36 m^2 of rooftop space. For households with higher electricity demand or for medium-sized factory roofs, the required area can increase to about 60–70 m^2 for systems of 10–12 kW_p .

Water consumption

The typical solar PV (photovoltaic) installations do not require water for electricity generation itself; they mainly need water for occasional cleaning of the solar panels to remove dust and other residues that could block sunlight. The frequency of cleaning PV panels may vary depending on environmental conditions. In areas with high levels of dust, leaves, bird droppings or pollution (e.g., nearby factories, construction sites, or roads), panels may need to be cleaned more frequently — about every 3 to 6 months. In contrast, in clean environments with regular rainfall, cleaning may only be required every 6 to 12 months. On average, cleaning one solar panel requires approximately 1 litre of water.

Environment

The environmental impacts from manufacturing, installation and operation of PV systems are limited.

Thin film modules may contain small amounts of cadmium and arsenic. In Europe PV modules as well as inverters are covered by the European Union “Waste from Electrical and Electronic Equipment” (WEEE) directive, whereby appropriate treatment of the products by end-of-life is organized. The exact methodology to be used when larger amounts of PV panels shall be decommissioned and recycled in 15-20 years from now may not be identified, but several projects are working on optimizing solutions and preparing large scale facilities for this purpose, in a recent study 15 companies have been identified to be currently active in the PV reuse sector in Europe [19].

At present, the collection and recycling of PV modules after their end of life are not yet common in Vietnam. Certain components, such as lead and cadmium, may cause soil and groundwater contamination if they leak. Vietnam also lacks specific regulations or a coordinated collection–recycling system for solar waste, posing potential environmental risks in the future. In addition, solar power projects require large areas of land and water, which can impact natural habitats - particularly in agricultural zones or production forest areas.

End-of-life Recycling Technology

The treatment of photovoltaic (PV) panels after the end of their service life has been identified as an issue that requires attention and resolution alongside the development of this renewable energy technology. In the Environmental Protection Plan for the Industry and Trade Sector for the period 2020–2025 (approved by the Prime Minister under Decision No. 1375/QĐ-TTg dated 8 September 2020) identifies the assessment of environmental and social impacts of energy projects in general, and solar power projects in particular, as a key priority task.

Proposed solutions for the management of solar PV panels include: waste classification and the development of guidelines for dismantling PV panels; limiting landfill disposal and incineration of solar waste; establishing support channels to direct waste streams to appropriate treatment facilities to ensure material recovery, minimize transportation, and utilize existing technologies; and encouraging the development of recycling technologies to recover strategic materials contained in solar power plants.

Among these solutions, promoting recycling technologies for photovoltaic panels is considered a key and urgent measure to ensure the “clean” criterion within the renewable energy value chain in line with the circular economy approach. The combined weight of glass, frames, and photovoltaic cells accounts for approximately 91–93% of the total weight of a solar panel. Therefore, most materials in a solar panel can be recycled and recovered for reuse in manufacturing. This not only reduces costs but also contributes to environmental protection. Many technologies have been developed from research on recycling solar photovoltaic (PV) panels. Among them, some emerging recycling technologies are capable of recovering more than 90% of silicon⁷—the main material used in PV modules (according to IRENA)., with future targets aiming for even higher efficiency. Current solar panel treatment and recycling technologies combine physical, thermal, and chemical processes. First, physical processes are used to separate panel components such as aluminium frames, junction boxes, and electrical cables. The aluminium is then remelted for reuse. The remaining components can be crushed for further analysis and appropriate processing. Next, thermal processes are applied by heating or annealing the panel components in furnaces, melting materials such as EVA encapsulants to recover solder wires, glass sheets, and silicon for reuse. Finally, chemical processes—using solvents, corrosive agents, and reduction reactions—are applied to treat and recover the remaining materials from the solar panels.

Research and development

Research and development (R&D) in photovoltaic (PV) technology has evolved substantially over time. From 2005 to 2010, the focus was mainly manufacturing challenges and scaling up production. Right after, between 2010 and 2013, efforts moved towards reducing costs to make PV more competitive. Afterwards, the emphasis has been on developing high-efficiency solutions and addressing issues related to system durability and lifespan. As PV plants are expected to play a critical role in future power generation, R&D

⁷ By combining mechanical recycling, thermal treatment, and chemical processing methods, the material recovery rate can be significantly improved.

will increasingly put efforts on maximizing power generation. These activities are mainly concentrated in key manufacturing countries such as Germany, China, the USA, Taiwan, and Japan [20]. Building integrated PV (BIPV) and coloration of solar modules lead the pack regarding the most recent applications in the market.

BIPV applications are tailored mainly to incorporate solar cells into facades and windows, and they still experience a significant upfront cost compared to conventional setups. However, they can replace typical investments as they form part of the building's envelope. Furthermore, regarding the savings on building materials (such as cladding or roofing), the marginal cost of choosing BIPV over traditional PV is much lower than the initial higher price might suggest. Figure 45 illustrates an instance on these setups. Regarding coloration applications, solar modules can be coloured by adding a layer in front of the solar cells that reflects specific wavelengths, reducing system's efficiency as reflected light doesn't contribute to power generation. Theoretical studies show that most RAL⁸ colours can be achieved through coloration with less than a 20% efficiency loss, even though white tones have higher losses [21] [22]. However, practical realization on a large scale of these idealized filters has still to be proved. Commercially, two main coloration methods exist: pigment-based, that absorbs light and reduces efficiency by over 20 % but offers consistent colours as is often angle independent [23]. Other techniques like optical fibres, diffuse, and sanitized glass can reduce glare and colour variability.



Figure 45: Solar Facade at the International School, Copenhagen [24].

Perovskite PV cells

The NREL applied perovskite program aims to make perovskite solar cells a viable technology by removing commercialization barriers through improving efficiency, controlling stability, and enabling scalability.

Within a few years, NREL has made significant technical contributions to perovskite research, reflected in leading scientific publications and strong interest from industry. NREL's impact has been supported by short-term funding from the Laboratory Directed Research and Development (LDRD) program and early investments from the U.S. Department of Energy focused on photovoltaics (PV).

The areas of perovskite photovoltaic research currently pursued at NREL include [38]:

- Development of tandem photovoltaic modules to increase efficiency.
- Transitioning from small laboratory-scale photovoltaic devices to large-area modules.
- Investigation of new materials to replace the commonly used methylammonium lead halide perovskite ($\text{CH}_3\text{NH}_3\text{PbI}_3$) in order to improve perovskite film performance by enhancing both stability and conversion efficiency, while reducing the use of toxic materials such as lead.

⁸ RAL is a standardized colour coding system widely used in the industry to define specific colours in a uniform and consistent manner.

- Research on thin-film deposition methods, chemical improvements, and engineering of the perovskite active layer and device architecture to enhance the performance of commercial perovskite devices.
- Design of new perovskite solar cell architectures, such as interdigitated back-contact perovskite solar cells, that exploit the unique properties of perovskite layers to produce low-cost devices with improved efficiency and reliability.

Research and development of PV technology in Vietnam

The prospects for solar power research and development in Vietnam are increasingly being driven by advanced technology projects and collaborations between domestic enterprises and major corporations. A notable example is the pilot project for manufacturing thin-film solar cells using Air Pressure Chemical Vapor Deposition (APP-CVD) technology, implemented by the Vietnam Oil and Gas Group (Petrovietnam) in cooperation with the Petroleum Automation, Information, and Telecommunication Technology Joint Stock Company (PAIC) [25]. This project is expected to create a significant breakthrough in energy security and open opportunities for commercializing domestically produced solar cells, contributing to enhancing Vietnam's technological self-reliance and promoting sustainable development in the renewable energy sector. In addition, domestic companies such as IREX, under SolarBK, have established industrial-scale production lines for solar panels, supplying high-efficiency products that meet international standards and have already been commercialized and widely applied in real-world projects across the country [26]. Red Sun Energy Joint Stock Company is another prominent example in the field of solar panel and rooftop solar system manufacturing, although on a smaller scale. The company's main products are solar panels with capacities ranging from 3 Wp to 280 Wp, designed to capture and convert solar energy into electricity. The combination of scientific research and domestic manufacturing provides a crucial foundation for Vietnam to enhance technological capabilities, reduce dependence on imports, and accelerate the green energy transition in the near future. The integration of scientific research and domestic manufacturing will provide a crucial foundation for Vietnam to strengthen its technological capabilities, reduce dependence on imports, and accelerate its green energy transition in the near future.

Examples of current projects

The installed capacity of solar power in Vietnam as of the end of 2024 is illustrated in the figure below:

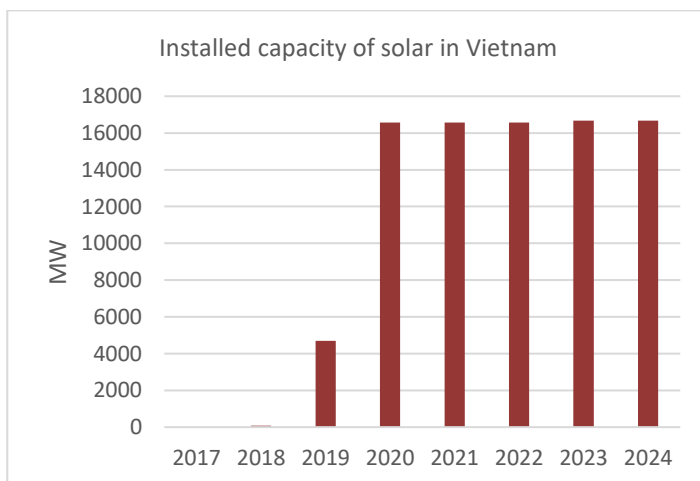


Figure 46: Solar installed capacity in Vietnam in the period 2017 - 2024⁹

The first commercially operated solar power project in Vietnam began in 2018, supported by the government's Feed-in Tariff (FIT) incentive mechanism [27]. In just two years (2019–2020), nearly 17 GW of new solar capacity was installed nationwide. By the end of 2024, solar power accounted for 11% of the country's total installed electricity capacity. Among solar sources, large-scale solar projects represent over 53%, with the remainder being rooftop solar systems.

With the rapid increase in variable renewable energy capacity, in addition to leveraging the flexibility of regional hydropower resources to coordinate operation in line with the load profile, it is necessary to further

⁹ Excluding the unregistered rooftop solar capacity, the actual total solar power capacity in Vietnam may be significantly higher than the official figures

deploy energy storage resources such as battery energy storage systems and pumped storage hydropower. Under the development orientation for utility-scale solar power set out in Decision No. 768/QĐ-TTg dated 15 April 2025 approving the revised Power Development Plan VIII, solar power projects are required to install battery energy storage system (BESS) with a minimum capacity equal to 10% of the project's installed capacity, with a storage duration of two hours. As a result, most solar power projects currently under development are designed with integrated BESS. The price framework for solar power projects combined with BESS is approximately 11-15% higher than that of standalone solar power projects.

The Trung Nam – Thuan Nam 450 MW Solar Power Plant is a large-scale renewable energy project in Thuan Nam District, formerly part of Ninh Thuan Province (now Khanh Hoa Province). The project has a capacity of 450 MW, an estimated annual generation of 1,200,000 kWh, and covers an area of 557 ha with more than 1,300,000 solar panels.

Alongside the solar plant, project also invested in a 220/500 kV substation and transmission lines to fully evacuate the plant's output and enhance the renewable energy integration capacity in the Ninh Thuan – Binh Thuan region. The total investment for the entire complex - including the solar plant, substation, and transmission system - is approximately VND 12,000 billion.

Construction began on May 15, 2020, and the project was commissioned on October 12, 2020, completed in just under five months. This is Vietnam's first renewable energy complex integrated with transmission infrastructure and was, at the time of commissioning, the largest solar power project in Southeast Asia, making a significant contribution to the country's green and sustainable energy development goals [28].



Figure 47: Trung Nam Thuan Nam solar power plant – 450 MW

The Da Mi 47.5 MW_p Floating Solar Power Plant was constructed on the surface of the Da Mi Hydropower Reservoir, formerly in Binh Thuan Province (now Lam Dong Province). This is the first floating solar project in Vietnam, with a capacity of 47.5 MW_p and an estimated annual generation of approximately 70 million kWh. The project utilizes 143,940 solar panels installed on 50 ha of the reservoir within a total area of 56.65 ha, without requiring resettlement. The system is mounted on HDPE floating structures and connected directly to the Da Mi solar power plant 110 kV substation.

The total investment for the project is nearly VND 1,500 billion. Construction began in November 2018, and commercial operation started in May 2019, making Da Mi the first floating solar project to be connected to the national grid in Vietnam and opening a new development model combining hydropower and solar energy in the country [29].



Figure 48: Da Mi solar power plant – 47.5 MW_p

Rooftop solar power in Vietnam has developed rapidly in large industrial parks since 2019–2021, particularly in the southern provinces where solar irradiation potential is high and industrial electricity demand is large. At VSIP I Industrial Park (Binh Duong Province), a 51 kW_p rooftop solar system was installed and commissioned in 2020 on the administration building [30]. In the same province, completing a nearly 2 MW_p rooftop solar project in December 2020, invested and operated by Sembcorp Smart Energy Solutions [31].

For residential rooftop solar, provinces with the largest total installed capacity include Binh Duong, Dong Nai, Ho Chi Minh City, and Ninh Thuan, where households, schools, and commercial-service facilities utilize rooftop space to install systems typically ranging from 3 to 20 kW_p.

Investment cost estimation

The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - Solar PV – Utility scale ground-mounted						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		0.73	0.52		0.40	0.36
Technology Catalogue - Vietnam 2023	1.02		0.72			0.53
Technology Catalogue - Vietnam 2021	1.17		0.83			0.61
Technology Catalogue - Vietnam 2019	1.39		1.06			0.82
Technology Catalogue – Denmark 2022*	0.70		0.47			0.36
Technology Catalogue – Colombia 2024**		1.06	0.73			0.49
Technology Catalogue – India 2023	0.72		0.52			0.31
IEA WEO 2025 – India***		0.54		0.36		0.29
IEA WEO 2025 – China***		0.61		0.32		0.26
Fraunhofer 2025 – China		0.64				
Fraunhofer 2025 – India		0.57				

* Data for ground-mounted, fixed

** Data for ground-mounted, tracking

*** Projections from Stated Policy scenario

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Data sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (\$), price year 2025

Rooftop solar											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	kW_e										
Generating capacity for a typical power plant	kW_e	10	10	10	10	2	20	2	20		1
Forced outage	%	0	0	0	0	-	-	-	-		
Planned outage	%	0	0	0	0	-	-	-	-		
Technical lifetime	years	30	32	35	40	25	35	35	45		2, 3
Construction time	years	0.08	0.08	0.08	0.08	0.01	0.13	0.01	0.13		1
Space requirement	1000 m ² /MW_p	6.5	6.1	5.7	5.4	4.9	8.1	4.0	6.7		1, 2, 3
Additional data for non-thermal plants											
Capacity factor, theoretical	%	17.2	17.7	18.1	18.7	11.0	24.0	12.0	26.1	A	
Capacity factor, incl. outages	%	17.2	17.7	18.1	18.7	11.0	24.0	12.0	26.1	A	
Economic data (in USD2025)											
Specific investment, total system	MUSD/MW_e	0.85	0.61	0.47	0.42	0.74	0.99	0.36	0.44	B, C	1
- of which equipment	%	48	47	46	45	-	-	-	-		1, 2, 4, 5
- of which installation and other costs	%	52	53	54	55	-	-	-	-		1, 2, 4, 5
PV module cost	MUSD/MW_e	0.28	0.19	0.13	0.12	0.24	0.33	0.10	0.13	C	1, 2, 4, 5
PV inverter cost	MUSD/MW_e	0.13	0.10	0.08	0.07	0.12	0.15	0.06	0.07	C	1, 2, 4, 5
Balance Of Plant cost	MUSD/MW_e	0.23	0.17	0.13	0.12	0.20	0.27	0.11	0.13	C	1, 2, 4, 5
Installation cost	MUSD/MW_e	0.21	0.16	0.12	0.11	0.18	0.24	0.10	0.12	C	1, 2, 4, 5
Fixed O&M	USD/MW_e/year	12,800	11,105	9,875	9,425	12,043	14,428	8,868	9,658	C	1, 6
Variable O&M	USD/MWh	0	0	0	0	0	0	0	0		
Technology specific data											
Full load hours	kWh/kW	1,511	1,547	1,584	1,638	966	2,105	1,047	2,283	A, D	
Peak full load hours	kWh/kW_p	1,314	1,345	1,377	1,425	920	1,754	998	1,902	A, D	
Global horizontal irradiance	kWh/m ² /y	1,550	1,550	1,550	1,550	1,150	2,000	1,150	2,000	E	7
DC/AC sizing factor	W_p/W	1.15	1.15	1.15	1.15	1.05	1.2	1.05	1.2	F	1, 3
Transposition Factor		1.02	1.02	1.02	1.02	1.00	1.02	1.00	1.02	G	7
Performance ratio		0.83	0.85	0.87	0.90	0.80	0.86	0.87	0.93	H	1, 2, 3
PV module conversion efficiency	%	21.5	23.0	24.5	26.0	20.0	23.0	24.2	27.8	I	1, 3
Inverter lifetime	years	15	15	15	15	12.5	16	12.5	16		1
Average annual degradation of FLH	%	0.4	0.4	0.4	0.4	0.3	0.8	0.3	0.8	J	2
Water consumption		< 100	< 100	< 100	< 100	-	-	-	-	K	8, 9, 10, 11

Rooftop solar											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Economic data - per DC peak cap.											
Nominal investment	MUSD/MW _{p(DC)}	0.74	0.53	0.41	0.36	0.70	0.82	0.35	0.37		
PV module cost	MUSD/MW _{p(DC)}	0.24	0.16	0.12	0.10	0.22	0.27	0.09	0.11		
PV inverter cost	MUSD/MW _{p(DC)}	0.11	0.09	0.07	0.06	0.11	0.13	0.06	0.06		
Balance Of Plant cost	MUSD/MW _{p(DC)}	0.20	0.15	0.12	0.10	0.19	0.22	0.10	0.11		
Installation cost	MUSD/MW _{p(DC)}	0.18	0.14	0.11	0.10	0.18	0.20	0.09	0.10		
Fixed O&M	USD/MW _{p(DC)} /year	11,130	9,656	8,587	8,195	11,470	12,023	8,445	8,048		
Variable O&M	USD/MWh _{p(DC)}	0	0	0	0	0	0	0	0		

Notes:

- A The capacity factor or full load hours depend greatly on the global horizontal irradiance at the specific plant site. For sites significantly different from the 1550 kWh/m²/year solar irradiation mentioned here, the capacity factors should be adjusted accordingly.
- B Investment cost includes the engineering, procurement and construction (EPC) cost. See description under Methodology.
- C Costs are projected with a learning rate approach assuming a 25.7% learning rate for modules based on Fraunhofer [5], 19% learning rate for inverters based on the Danish Technology Catalogue for Generation of Electricity and District Heating [2], and 20% as per other components based on IEA, and 10% for O&M, including capacity projections of the IEA's World Energy Outlook 2025, with the scenario Stated Policies for the central values and the scenarios Current Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.
- D The number of full load hours is calculated based on other values in the table. The formula is: Full load hours = DC/AC sizing factor * peak full load hours. The formula used to calculate Peak full load hours is: Peak full load hours = Global horizontal irradiance * transposition factor * performance ratio.
- E The central value is the average annual solar irradiance received on a horizontal surface in Vietnam. Hanoi receives 1330 kWh/m²/year and Ho Chi Mich City receives 1800 kWh/m²/year. Minimum and maximum value correspond to The Global Solar Atlas's s Global Horizontal Irradiation distribution for Vietnam.
- F 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.
- G 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.
- H 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%.
- I The efficiency is a market average of commercial modules. Modules with above 21 % efficiency are commercially available. The market development towards 2030 is projected to shift to back contact n-type mono- Si cells and silicon HJT n-type mono-Si cells which both have higher efficiencies.
- J Annual degradation of full load hours is not included in the above figures of full-load hours and capacity factors.
- K Solar PVs do not need water for cooling, however water can be used for cleaning.

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- U.S. Energy Information Administration, 2023 - U.S. electric power sector continues water efficiency gains
- World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity

Utility Scale Solar PV (fixed)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e										
Generating capacity for a typical power plant	MW_e	100	100	100	100	70	200	70	200		1
Forced outage	%	0	0	0	0	-	-	-	-		
Planned outage	%	0	0	0	0	-	-	-	-		
Technical lifetime	years	30	32	35	40	25	35	35	45		2, 3
Construction time	years	0.7	0.7	0.5	0.5	0.3	1	0.2	0.7		1
Space requirement	1000 m ² /MW_p	11.0	10.3	9.7	9.1	9.0	12.0	7.4	9.9		1, 2, 3
Additional data for non-thermal plants											
Capacity factor, theoretical	%	19.5	20.0	20.4	21.1	11.7	26.0	12.7	28.2	A	
Capacity factor, incl. outages	%	19.5	20.0	20.4	21.1	11.7	26.0	12.7	28.2	A	
Economic data (in USD2025)											
Specific investment, total system	MUSD/MW_e	0.73	0.52	0.40	0.36	0.63	0.85	0.31	0.38	B, C	1
- of which equipment	%	44	42	41	40	-	-	-	-		1, 2, 4, 5
- of which installation and other costs	%	56	58	59	60	-	-	-	-		1, 2, 4, 5
PV module cost	MUSD/MW_e	0.25	0.17	0.12	0.11	0.21	0.29	0.09	0.11	C	1, 2, 4, 5
PV inverter cost	MUSD/MW_e	0.07	0.05	0.04	0.04	0.06	0.08	0.03	0.04	C	1, 2, 4, 5
Balance Of Plant cost	MUSD/MW_e	0.24	0.18	0.14	0.13	0.21	0.28	0.11	0.13	C	1, 2, 4, 5
Installation cost	MUSD/MW_e	0.17	0.13	0.10	0.09	0.15	0.20	0.08	0.09	C	1, 2, 4, 5
Fixed O&M	USD/MW_e/year	10,000	8,676	7,715	7,363	9,409	11,272	6,928	7,545	C	1, 6
Variable O&M	USD/MWh	0	0	0	0	0	0	0	0		
Technology specific data											
Full load hours	kWh/kW	1,708	1,749	1,790	1,852	1,025	2,281	1,111	2,473	A, D	
Peak full load hours	kWh/kW_p	1,314	1,345	1,377	1,425	932	1,754	1,010	1,902	A, D	
Global horizontal irradiance	kWh/m ² /y	1,550	1,550	1,550	1,550	1,150	2,000	1,150	2,000	E	7
DC/AC sizing factor	W_p/W	1.3	1.3	1.3	1.3	1.1	1.3	1.1	1.3	F	1, 3
Transposition Factor		1.02	1.02	1.02	1.02	1.00	1.02	1.00	1.02	G	7
Performance ratio		0.83	0.85	0.87	0.90	0.81	0.86	0.88	0.93	H	1, 2, 3
PV module conversion efficiency	%	21.5	23.0	24.5	26.0	20.0	23.0	24.2	27.8		1, 3
Inverter lifetime	years	15	15	15	15	12.5	16	12.5	16		1
Average annual degradation of FLH	%	2	2	2	2	0.5	3.0	0.5	3.0	J	1
Water consumption		< 100	< 100	< 100	< 100	-	-	-	-	K	8, 9, 10, 11
Economic data - per DC peak cap.											
Nominal investment	MUSD/MW_p(DC)	0.56	0.40	0.31	0.28	0.58	0.65	0.28	0.29		
PV module cost	MUSD/MW_p(DC)	0.19	0.13	0.09	0.08	0.19	0.23	0.08	0.09		

Utility Scale Solar PV (fixed)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
PV inverter cost	MUSD/MW _p (DC)	0.05	0.04	0.03	0.03	0.06	0.06	0.03	0.03		
Balance Of Plant cost	MUSD/MW _p (DC)	0.18	0.14	0.11	0.10	0.19	0.21	0.10	0.10		
Installation cost	MUSD/MW _p (DC)	0.13	0.10	0.08	0.07	0.14	0.15	0.07	0.07		
Fixed O&M	USD/MW _p (DC)/year	7,692	6,674	5,935	5,664	8,554	8,671	6,298	5,804		
Variable O&M	USD/MWh _p (DC)	0	0	0	0	0	0	0	0		

Notes:

- A The capacity factor or full load hours depend greatly on the global horizontal irradiance at the specific plant site. For sites significantly different from the 1550 kWh/m²/year solar irradiation mentioned here, the capacity factors should be adjusted accordingly.
- B Investment cost includes the engineering, procurement and construction (EPC) cost. See description under Methodology.
- C Costs are projected with a learning rate approach assuming a 25.7% learning rate for modules based on Fraunhofer [5], 19% learning rate for inverters based on the Danish Technology Catalogue for Generation of Electricity and District Heating [2], and 20% as per other components based on IEA, and 10% for O&M, including capacity projections of the IEA's World Energy Outlook 2025, with the scenario Stated Policies for the central values and the scenarios Current Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.
- D The number of full load hours is calculated based on other values in the table. The formula is: Full load hours = DC/AC sizing factor * peak full load hours. The formula used to calculate Peak full load hours is: Peak full load hours = Global horizontal irradiance * transposition factor * performance ratio.
- E The central value is the average annual solar irradiance received on a horizontal surface in Vietnam. Hanoi receives 1330 kWh/m²/year and Ho Chi Mich City receives 1800 kWh/m²/year. Minimum and maximum value correspond to The Global Solar Atlas's s Global Horizontal Irradiation distribution for Vietnam.
- F 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.
- G 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.
- H 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%.
- I The efficiency is a market average of commercial modules. Modules with above 21 % efficiency are commercially available. The market development towards 2030 is projected to shift to back contact n-type mono- Si cells and silicon HJT n-type mono-Si cells which both have higher efficiencies.
- J Annual degradation of full load hours is not included in the above figures of full-load hours and capacity factors.
- K Solar PVs do not need water for cooling, however water can be used for cleaning.

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- U.S. Energy Information Administration, 2023 - U.S. electric power sector continues water efficiency gains
- World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity

Floating PV											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e										
Generating capacity for a typical power plant	MW_e	40	70	80	100						1
Forced outage	%	0	0	0	0	-	-	-	-		
Planned outage	%	0	0	0	0	-	-	-	-		
Technical lifetime	years	30	32	35	40	25	35	35	45		2, 3
Construction time	years	0.7	0.7	0.5	0.5	0.3	1.0	0.2	0.7		1, 2, 3
Space requirement	1000 m ² /MW_p	10	9.3	8.8	8.3	8.5	12.0	7.0	9.9		1, 2, 3
Additional data for non-thermal plants											
Capacity factor, theoretical	%	20.5	21.0	21.5	22.2	12.3	27.3	13.3	29.6	A	
Capacity factor, incl. outages	%	20.5	21.0	21.5	22.2	12.3	27.3	13.3	29.6	A	
Economic data (in USD2025)											
Specific investment, total system	MUSD/MW_e	1.04	0.75	0.58	0.52	0.95	1.65	0.25	0.65	B, C, D	1
- of which equipment	%	35	33.6	32.3	31.8	-	-	-	-		1, 2, 4, 5
- of which installation and other costs	%	65	66.4	67.7	68.2	-	-	-	-		1, 2, 4, 5
PV module cost	MUSD/MW_e	0.29	0.19	0.14	0.12	0.24	0.45	0.10	0.13	D	1, 2, 4, 5
PV inverter cost	MUSD/MW_e	0.08	0.06	0.05	0.04	0.07	0.13	0.04	0.05	D	1, 2, 4, 5
Balance Of Plant cost	MUSD/MW_e	0.40	0.29	0.23	0.21	0.35	0.63	0.18	0.22	D	1, 2, 4, 5
Installation cost	MUSD/MW_e	0.28	0.21	0.16	0.15	0.25	0.44	0.13	0.15	D	1, 2, 4, 5
Fixed O&M	USD/MW_e/year	15,000	13,013	11,573	11,045	14,113	16,908	10,392	11,317	D	1, 6
Variable O&M	USD/MWh	0	0	0	0	0	0	0	0		
Technology specific data											
Full load hours	kWh/kW	1,793	1,836	1,880	1,944	1,076	2,395	1,167	2,597	A, E	
Peak full load hours	kWh/kW_p	1,379	1,413	1,446	1,496	978	1,842	1,061	1,997	A, E	
Global horizontal irradiance	kWh/m ² /y	1,550	1,550	1,550	1,550	1,150	2,000	1,150	2,000	F	7
DC/AC sizing factor	W_p/W	1.3	1.3	1.3	1.3	1.1	1.3	1.1	1.3	G	1, 3
Transposition Factor		1.02	1.02	1.02	1.02	1.00	1.02	1.00	1.02	H	7
Performance ratio		0.87	0.89	0.91	0.95	0.85	0.90	0.92	0.98	I, J	1, 2, 3
PV module conversion efficiency	%	21.5	23.0	24.5	26.0	20.0	23.0	24.2	27.8	K	1, 3
Inverter lifetime	years	15	15	15	15	12.5	16	12.5	16		1
Average annual degradation of FLH	%	2	2	2	2	0.5	3	0.5	3	L	2
Water consumption		< 100	< 100	< 100	< 100	-	-	-	-		
Economic data - per DC peak cap.											
Nominal investment	MUSD/MW_p(DC)	0.80	0.58	0.44	0.40	0.86	1.27	0.23	0.50		
PV module cost	MUSD/MW_p(DC)	0.22	0.15	0.11	0.09	0.22	0.35	0.09	0.10		
PV inverter cost	MUSD/MW_p(DC)	0.06	0.05	0.04	0.03	0.06	0.10	0.04	0.04		
Balance Of Plant cost	MUSD/MW_p(DC)	0.30	0.23	0.18	0.16	0.32	0.48	0.17	0.17		

Floating PV											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Installation cost	MUSD/MW _p (DC)	0.22	0.16	0.12	0.11	0.22	0.34	0.12	0.12		
Fixed O&M	USD/MW _p (DC)/year	11,538	10,010	8,902	8,496	12,830	13,006	9,447	8,706		
Variable O&M	USD/MWh _p (DC)	0	0	0	0	0	0	0	0		

Notes:

- A The capacity factor or full load hours depend greatly on the global horizontal irradiance at the specific plant site. For sites significantly different from the 1550 kWh/m²/year solar irradiance mentioned here, the capacity factors should be adjusted accordingly.
- B Investment cost includes the engineering, procurement and construction (EPC) cost. See description under Methodology.
- C Overall cost estimation based on utility-scale datasheet, considering that floating PV plants are expected to be approx. 25% more expensive than ground-mounted utility-scale plants, with the mark-up apparent in installation and other cost incl. balance of plant.
- D Costs are projected with a learning rate approach assuming a 25.7% learning rate for modules based on Fraunhofer [5], 19% learning rate for inverters based on the Danish Technology Catalogue for Generation of Electricity and District Heating [2], and 20% as per other components based on IEA, and 10% for O&M, including capacity projections of the IEA's World Energy Outlook 2025, with the scenario Stated Policies for the central values and the scenarios Current Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.
- E The number of full load hours is calculated based on other values in the table. The formula is: Full load hours = DC/AC sizing factor * peak full load hours. The formula used to calculate Peak full load hours is: Peak full load hours = Global horizontal irradiance * transposition factor * performance ratio.
- F The central value is the average annual solar irradiance received on a horizontal surface in Vietnam. Hanoi receives 1330 kWh/m²/year and Ho Chi Mich City receives 1800 kWh/m²/year. Minimum and maximum value correspond to The Global Solar Atlas's s Global Horizontal Irradiation distribution for Vietnam.
- 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.
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- 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 surrounding water can have an effect on the performance ratio in terms of its cooling and reflective properties, which typically lies 5% above comparable ground-mounted onshore PV plants.
- K The efficiency is a market average of commercial modules. Modules with above 21 % efficiency are commercially available. The market development towards 2030 is projected to shift to back contact n-type mono- Si cells and silicon HJT n-type mono-Si cells which both have higher efficiencies.
- L Annual degradation of full load hours is not included in the above figures of full-load hours and capacity factors.

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8. ONSHORE WIND POWER

Brief technology description

The contemporary large onshore wind turbine typically adopts a horizontal-axis design with three blades, positioned upwind and connected to the grid. These turbines utilize active pitch, variable speed, and yaw control mechanisms to optimize electricity generation across a spectrum of wind speeds. Wind turbines function by harnessing the kinetic energy present in the wind through their rotor blades, subsequently transferring this energy to the drive shaft. This drive shaft is linked either to a speed-boosting gearbox in conjunction with a medium- or high-speed generator, or to a low-speed, direct-drive generator. The generator then converts the rotational energy of the shaft into electrical power.

In modern wind turbines, blade pitch control plays a pivotal role in maximizing power output at low wind speeds. Simultaneously, it ensures a consistent power output while limiting mechanical stress and loads on the turbine during high wind speeds. Figure below offers a comprehensive depiction of the turbine technology and electrical system, illustrating the example of a geared turbine.

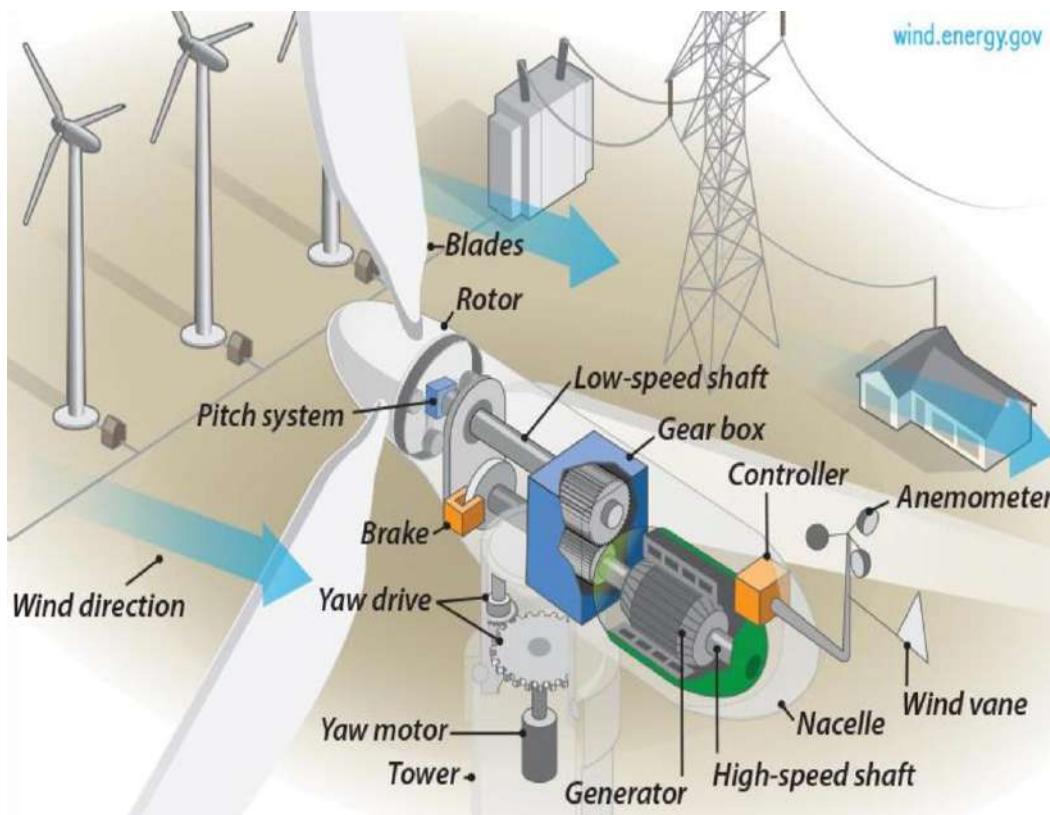


Figure 49: General turbine technology and electrical system [1].

The wind power equation calculates the amount of power that can be extracted from the wind by a wind turbine. The equation is:

$$P = \frac{1}{2} \rho A v^3$$

Where:

- **P** is the power (in watts) extracted from the wind.
- **ρ** (rho) is the air density (in kilograms per cubic meter, kg/m³), typically around 1.225 kg/m³ at sea level under standard conditions.
- **A** is the swept area of the wind turbine rotor (in square meters, m²), which is proportional to the square of the rotor radius.
- **v** is the wind speed (in meters per second, m/s) at the location of the turbine.

It is worth noticing that wind speed has the biggest influence on the power output because the power is proportional to the cube of the wind speed. This means that even small increases in wind speed led to significant increases in power output. For example, doubling the wind speed results in an eightfold increase in power.

No wind turbine can capture more than 59.3 % of the kinetic energy in the wind, a concept known as the Betz's Limit. This is because some wind must pass through the rotor to maintain airflow. The actual power produced by a turbine will always be less than the theoretical value calculated by the wind power equation due to various losses (mechanical, electrical, and aerodynamic).

Wind turbines are engineered to function within a specific wind speed spectrum delimited by a low "cut-in" wind speed and a high "cut-out" wind speed. Below the cut-in speed, the wind lacks sufficient energy to be effectively harnessed. Once the wind speed surpasses the cut-in threshold, the turbine initiates operations and begins generating electricity. With rising wind speeds, the turbine's power output increases, hitting its rated power output at a particular wind speed. To sustain this rated power output at higher wind speeds, the blade pitch is regulated. Upon reaching the cut-out speed, the turbine undergoes shutdown or operates in a reduced power mode to prevent mechanical damage.

Onshore wind turbines can be installed individually, in clusters, or as part of larger wind farms. Commercial wind turbines operate autonomously and are overseen and managed via a Supervisory Control and Data Acquisition (SCADA) system.

Wind turbines operate across a range of wind speeds to optimize power generation. As illustrated in Figure 50, the cut-in wind speed, typically between 2 to 4 m/s, is the minimum speed at which a turbine begins to produce electricity. As wind speeds increase, turbines reach their rated power generation, usually around 10 to 12 m/s, depending on the specific power, which is the ratio of the rated power to the swept rotor area. At wind speeds of 25 m/s, turbines either shut down or transition to reduced power operation to prevent mechanical damage. However, manufacturers are increasingly incorporating soft cut-out mechanisms, allowing turbines to continue operating at high wind speeds, with a final cut-out expected to be around 30 m/s in future models – this is shown in Figure 50 with a dashed-red curve. This approach maximizes power output while ensuring turbine safety [2].

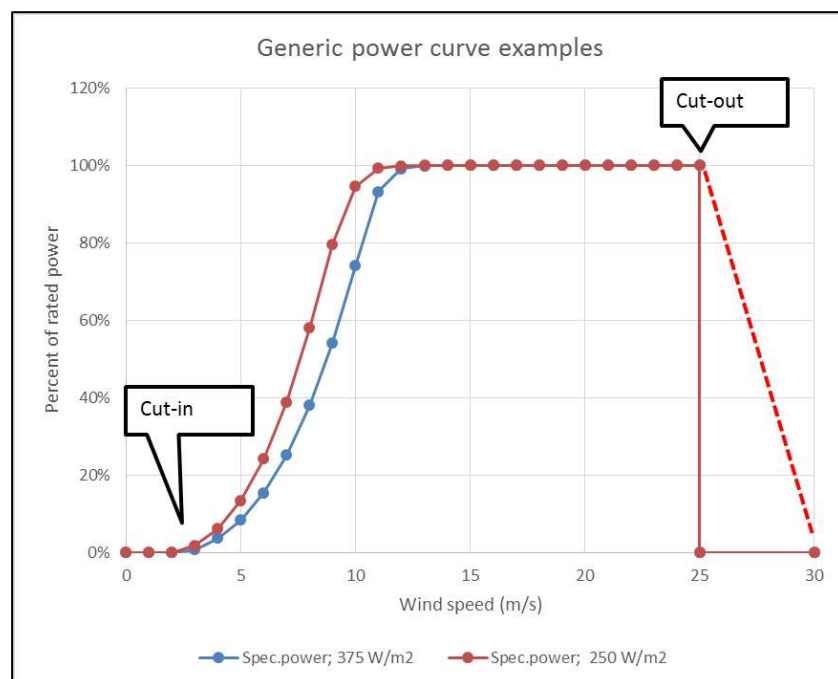


Figure 50: Turbine power curves (Information's from expert workshop held by the Danish Energy Agency). Specific power values refer to e.g. 3 MW with 124m rotor diameter (250 W/m²) and 3 MW with 101 m rotor diameter (375 W/m²).

Capacity factors and wind speed

The annual energy yield of a wind turbine is significantly influenced by the average wind speed at its

between the rotor diameter that the turbine uses to convert the wind resource into power.

The capacity factor of operational wind power projects in Vietnam ranges from around 20% to 40% (equivalent to 1,700–3,500 full load hours per year), depending on the region. Among them, some provinces with high wind project capacity factors include Quang Tri, Gia Lai, Bac Lieu, and Tra Vinh.

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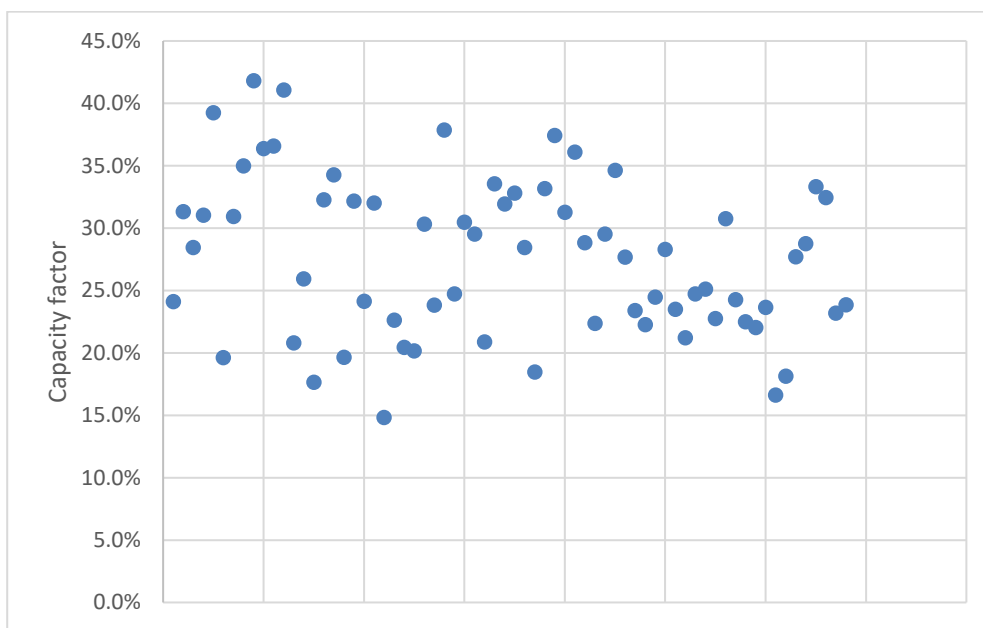


Figure 51: Capacity factor of existing wind power project in Vietnam

Surface roughness, a critical factor, is commonly categorized using Table 20. The roughness length is the height above ground level, where average wind speed is considered 0, due to the barriers the uneven surface creates for a stable wind flow. The more ragged the terrain is, the higher the roughness length is, shown by Table 21 below. The wind speed variation with height is governed by the roughness length.

Table 21: Description of surface roughness classification.

Roughness class	Roughness Length (m)	Description
0	0.0002	Water
1	0.03	Open farmland
2	0.1	Partly open farmland with some settlements and trees
3	0.4	Forest, cities, farmland with many windbreaks

In Vietnam, most operational wind power projects feature turbine heights of around 130–140 m. Priority wind power development areas are those with wind speeds greater than 6 m/s. Regions with high wind speeds (> 6 m/s) and significant development potential include the Central Highlands, the South-Central Coast, and the Southwest. However, in the Northern region, where electricity demand is high, wind power development may be considered in areas with lower wind speeds (4.5–5.5 m/s). This, however, results in higher investment costs for wind power in the North, making it less competitive compared to the Central and Southern regions.

There is a correlation between the annual mean wind speed and the specific power for annual energy production (AEP). Notably, the increase in AEP demonstrates an almost linear relationship with the mean

wind speed, especially within the range of 6 m/s and 9 m/s, as depicted in Figure 52. The examples in Figure 52 are for:

- 3 MW turbines with 90 m rotor diameter, with specific power of 472 W/m² (called “high specific power”);
- 3.3 MW turbines with 112 m with specific power of 335 W/m² (called “medium specific power”);
- 3.3 MW turbines with 126 m rotor diameters, with specific power of 265 W/m² (called “low specific power”).

Projections indicate that future turbines will likely feature even lower specific power compared to the “low specific power” example depicted in Figure 52 [2].

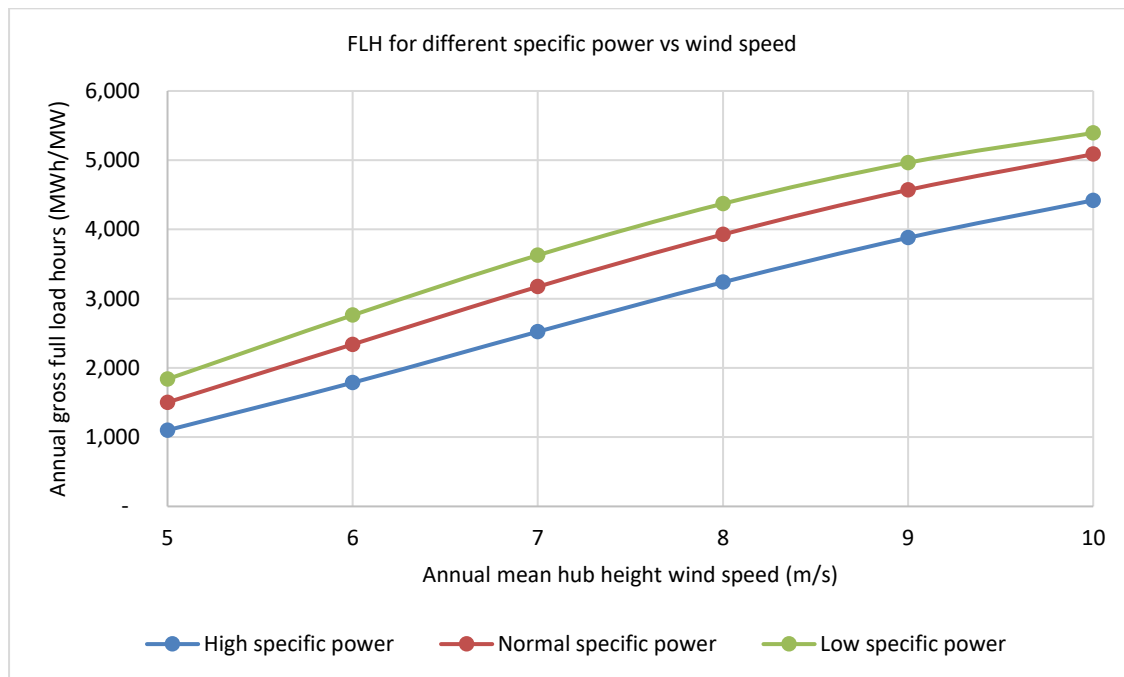


Figure 52: Annual full load hours as a function of mean wind speed at hub height [2].

Wind Power Potential in Vietnam

Figure 53 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.

Theoretical Potential

According to Circular No. 06/2013/TT-BCT [3] issued by the Ministry of Industry and Trade, “theoretical wind power potential” refers to the potential determined with wind speeds of 6.0 m/s or higher at a height of 80 m. Most of these areas are coastal lands along the South-Central Coast, the Southern region, the Central Highlands, the North Central region, and a small portion in the Northern region. To estimate the installable capacity based on the theoretical potential area, a 4.0 MW wind turbine with a rotor diameter of 150 m has been applied. The spacing between turbine rows (perpendicular to the prevailing wind direction) has been set at 7 rotor diameters, while the spacing between turbines in the same row is 5 rotor diameters. Under this configuration, the installable density would be around 5.1 MW/km², with a total estimated theoretical wind power capacity of 320.1 GW. If applying Circular No. 06/2013/TT-BCT (wind speed $\geq$ 6 m/s), Vietnam’s onshore theoretical wind potential is lower, at about 179.8 GW [4].

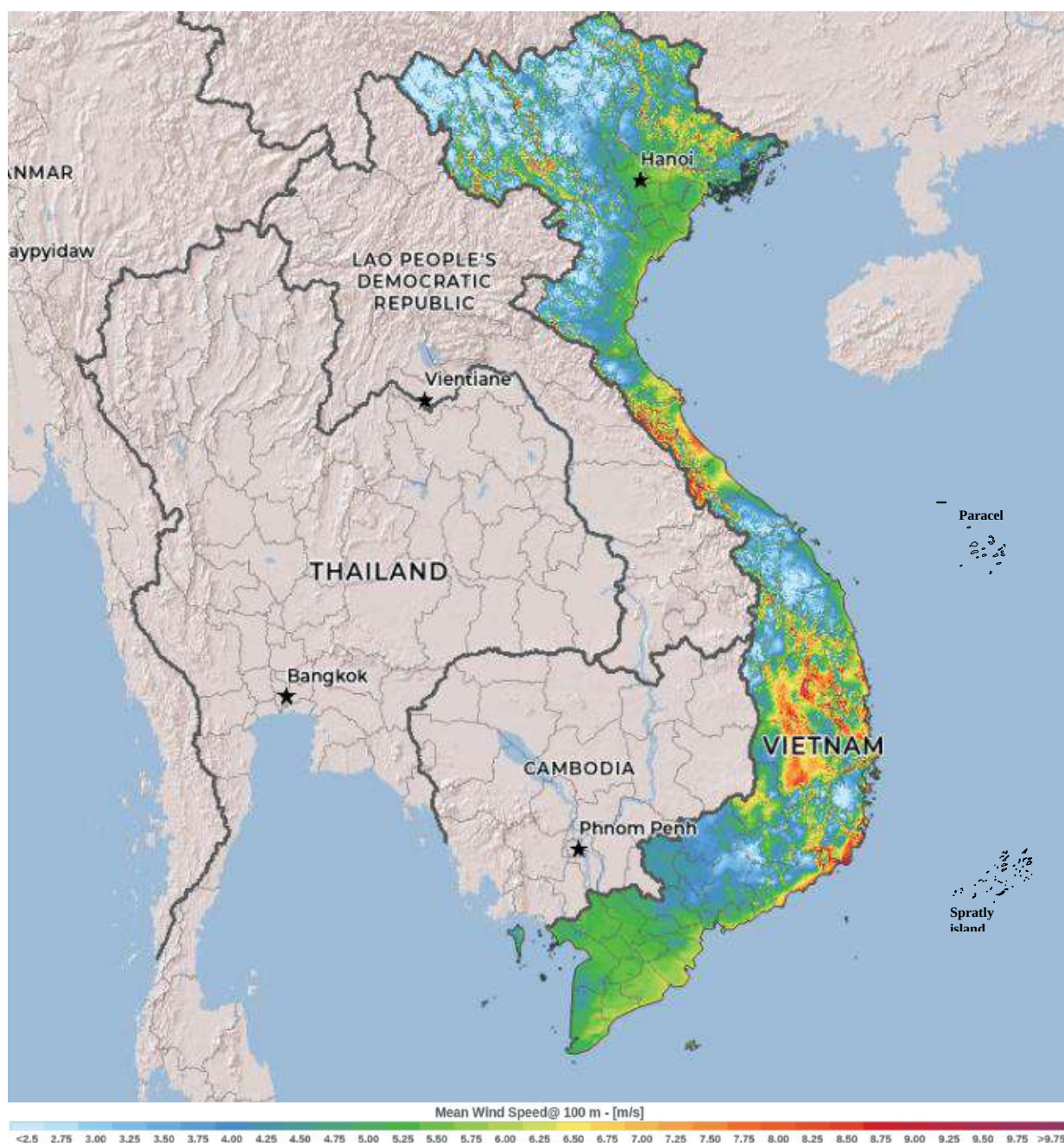


Figure 53: Wind resource in mainland Viet Nam – onshore, 100m above ground. Source: Global Wind Atlas.

Technical Potential

Technical potential is derived from the theoretical potential, adjusted for actual and planned land use. The methodology for calculating wind power potential is to review wind speed data and update land availability based on the National Assembly's Resolution No. 39/2021/QH15 and the Prime Minister's Decision No. 326/QĐ-TTg on national land use planning. By overlaying mapping layers to exclude areas with theoretical potential but unsuitable for wind power development, the total national technical potential at about 130,000 MW, with the largest shares located in the Southern region (44,700 MW) and the Central Highlands (42,700 MW).

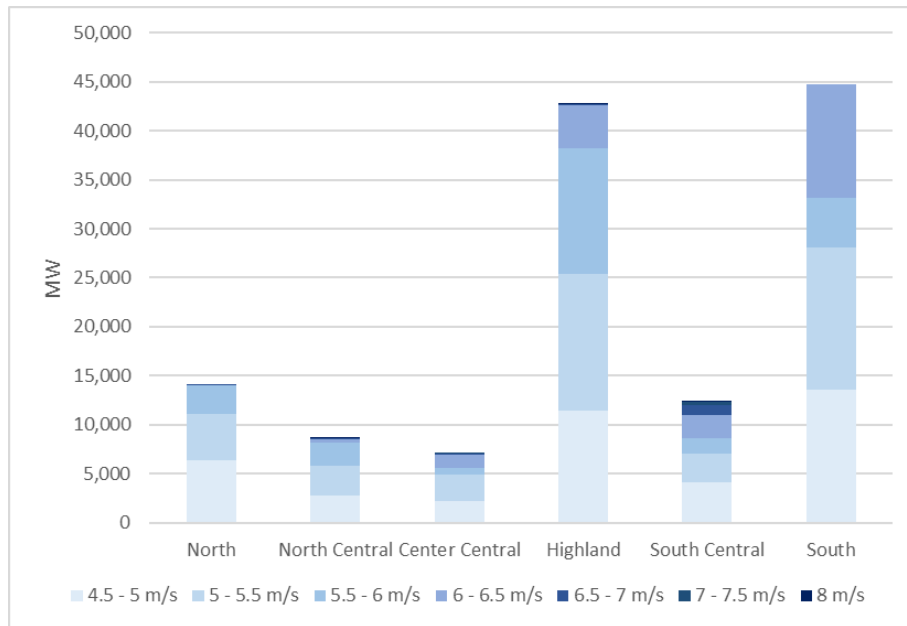


Figure 54: Technical potential of onshore wind in Vietnam

Input

A wind turbine harnesses wind energy.

Output

The output is electricity.

Typical capacities

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 22: 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

Utility scale onshore wind turbines currently installed in the capacity range of 3 to 6 megawatts (MW) in

various markets worldwide, are generally categorized based on their nameplate capacity. Lower utility-scale turbines are not available on the market any longer due to technical development. Smaller variants and micro turbines, between 1 to 25 kilowatts (kW), are classified as domestic wind turbines.

In the global market and as depicted in Figure 55, the size of wind turbines has steadily increased over time. This growth is attributed to larger generators, taller hub heights, and expanded rotor sizes, collectively enhancing electricity generation. The adoption of lower specific power - increasing the rotor area more than proportionally to the generator rating - enhances the capacity factor, particularly as power output at wind speeds below rated power scales directly with the rotor's swept area. Additionally, taller hub heights associated with larger turbines generally offer higher wind resources.



Figure 55: Increasing yields of onshore wind turbines [5].

The average rated power of onshore wind turbines in the global market has escalated from around 1 MW since the year 2000 to approximately 5.3 MW in 2021, and it is expected to reach almost 6 MW by 2035. Rotor diameters (RD) have followed a similar trend, which started at 50.17 m in 2000 and reached 158 m by 2021. It is projected that turbines will feature a rotor diameter of above 180 m by 2035. There is a considerable range of capacity around the average values that is deployed, as turbines of the size of 6 MW also are installed currently, but also older turbines with lower capacity of 2 MW are still used in projects.

According to REN21 [6] statistics, the average turbine delivered to the market in 2024 had a capacity of 5.5 MW, representing a 9% increase over 2023; turbines announced for future installation were significantly larger, with the largest onshore prototypes reaching 15 MW.

As of 2025, the world's largest onshore wind turbine, with a capacity of 16.2 MW, was installed in Jiangsu Province, China. The turbine stands 155 meters tall - equivalent to a 50-story building- with a rotor diameter of 266 meters and a swept area of 55,500 square meters, nearly the size of eight soccer fields. Each blade measures 130 meters in length [7].

In Vietnam, thanks to the preferential FIT scheme, many wind power projects were commissioned in 2021. At that time, most operational projects in the country employed turbines with capacities of around 3–4 MW and rotor diameters of 140–150 m. Keeping pace with global trends, newly developed projects in Vietnam are designed with larger turbines and rotor diameters. Some projects are planning to use 6 MW turbines with rotor diameters of up to 175 m.

Ramping configurations

Wind-generated electricity is inherently variable due to its reliance on prevailing wind conditions. Consequently, frequency regulation capability of wind turbines is contingent upon the prevailing weather. During periods of low wind (speed less than 4-6 m/s), turbines have limited capacity to provide regulation, except potentially for voltage regulation. While modern turbines, equipped with inverters and advanced control systems, aid in stabilizing the grid by supplying reactive power, their regulation ability is weather-dependent.

In conditions where there is adequate wind resource available (speed higher than 4-6 m/s but lower than

25-30 m/s), wind turbines can consistently offer downward frequency regulation and, in many instances, upward frequency regulation provided the turbine operates in a power-curtailed mode, deliberately maintaining an output below its potential based on available wind. Although technically possible, the practice of operating turbines at a reduced power level to facilitate up regulation is infrequent. This is due to the typical requirement for system operators to compensate owners for the reduced revenue, leading to limited utilization of this feature in many countries [9].

Wind power impacts the reliable power system operation depending on its penetration level, power system size, generation capacity mix, load variation and the interconnection with neighbouring power systems. The intermittent nature of wind power may lead to power balancing problems in a highly wind power integrated power system, as it can deviate the system frequency from its nominal level and the tie line power exchange from planned and cost-effective generation schedule. The large-scale integration of wind power therefore challenges the system operators to maintain a close balance between production and consumption in their individual power systems and the tie line interchange at its schedule.

Wind power forecast plays an important role in this regard, as for example in a current Danish power system, a single 1 m/s increase or decrease in a wind speed will generate a power imbalance of approximate 350 MW [10].

The developed control methods and the available reserves are suitable to deal with the variable wind power supply in the existing power systems. However, operation and control methods need to be reviewed for future integration of wind power as wind power plants will be replacing the conventional power plants in modern power system.

Dispatchable power plants participate in up or down active power regulation, whereas the Automatic Generation Control (AGC) down regulates the active power production from the wind power plant (WPP) only in case of generation excess and when the dispatchable power plants operate at their minimum limits. The AGC strategy integrates the WPP efficiently in secondary control by downregulating their production only in case of generation excess and utilizes the available wind power in case of generation deficiency. The remaining power imbalance after the AGC response is minimized by the programmed activation [11].

According to Circular No. 05/2025/TT-BCT dated February 1, 2025, on regulations for the power transmission system, power distribution system, and electricity metering, wind power plants connected to the transmission grid or with an installed capacity above 30 MW connected to the distribution grid are required to be capable of reducing active power within no later than 2 seconds when the frequency exceeds 50.5 Hz, and the reduction must be completed within 15 seconds. In addition, wind power sources must also be capable of adjusting reactive power within a power factor range of -0.95 to 0.95 [12].

Advantages/disadvantages

Advantages

- Wind turbines produce no emissions during operation.
- Operating wind turbines do not emit greenhouse gases, contributing to a cleaner environment.
- Due to low operational costs and the absence of fuel expenses, wind power offers predictable and stable cost structures.
- The modular nature of wind technology facilitates scalable capacity expansion, ensuring flexibility to align with demand, thus preventing unnecessary overbuilds and associated stranded costs.
- Wind energy projects generally have shorter lead times compared to various alternative energy technologies, enabling quicker implementation.
- Wind resource complements hydro power availability as the generic annual generation profile is different [13].
- Wind systems can be easily developed as hybrid systems with batteries as a strategy to mitigate impacts on variability, complementarity, and grid strength.
- Utilizing wind energy for power generation will help reduce dependence on imported fuels.

Disadvantages

- Wind power is typically intermittent, weather-dependent, and seasonal, requiring the power system to maintain reserve capacity. For example, in Vietnam, there have been periods when wind turbines generate little or no power, which can last up to a month.
- Wind energy is capital-intensive initially, requiring significant investment for installation.
- Dependence on wind as an energy resource introduces variability in energy production, impacting consistency.
- Compared to traditional thermal power plants, wind power offers a moderate contribution to ensuring continuous capacity adequacy.
- The intermittent nature of wind energy requires complementary regulating power to manage fluctuations and grid stability.
- Wind turbines may pose visual impact concerns and produce noise, affecting nearby communities.
- High wind resources are often located far from load centre, requiring grid infrastructure to connect.

Space requirement

According to Circular No. 02/2019/TT-BCT dated January 15, 2019, issued by the Ministry of Industry and Trade, the land and water surface areas used for wind power projects are classified into two categories: permanent land use area and temporary land use area.

Permanent land use area of a wind power project refers to the total area of wind turbine foundations, including the protection zone around the foundations; areas for auxiliary equipment at the turbine base; medium-voltage underground cables connecting the wind turbines; foundations for overhead transmission line towers; substations; internal road systems; and operation and management buildings. The permanent land use area is allocated to the project investor by the competent authority for the entire lifetime of the project.

Temporary land use area of a wind power project refers to the area permitted for temporary use during project construction, including temporary access roads, equipment and material storage yards, construction sites, temporary worker camps, and other auxiliary facilities. Upon completion and commissioning of the project, the temporary land use area that does not fall within the permanent land allocation will be reclaimed by the competent authority for other purposes.

Circular No. 02/2019/TT-BCT stipulates that the permanent land use area shall not exceed 0.35 ha/MW, and the temporary land use area shall not exceed 0.30 ha/MW [8]. In practice, wind power projects in Vietnam generally require a combined permanent and temporary land use area of about 0.4–0.6 ha/MW.

Currently in Vietnam, the spacing of onshore wind turbines is typically designed with a distance of 8D to 9D between turbine rows and 2D to 3D between two turbines within the same row (where D is the rotor diameter of the wind turbine). However, the layout of onshore wind farms depends greatly on actual terrain conditions, requiring avoidance of steep mountainous areas, protected forests, or locations with limited land availability. Due to complex topography, onshore turbines cannot be arranged in straight and uniform rows as commonly seen offshore, and instead must be flexibly adjusted according to natural terrain and prevailing wind directions to ensure power generation efficiency and safe operation.

Water consumption

Onshore wind farms typically do not use freshwater in the energy generation process itself. There is a marginal water consumption in buildings during the operation stage and by some processes during the construction stage.

Environment

Wind energy is a clean energy source. Environmental concerns include land-use and siting of farms, as well as visual impact if close to population, including flickering from rapid shifts between shadow and light when turbine is between sun and settlement, noise and the risk of bat or bird collisions.

The visual impact of wind turbines is a controversial issue, especially as onshore wind turbines have become larger.

Flickering is generally managed through a combination of prediction tools and turbine control. Turbines

may in some cases need to be shut down for brief periods when flickering effect could occur at neighbouring residences.

Wind power plants generate two types of noise: (i) Mechanical noise – produced during the operation of mechanical components. Typically, offshore wind turbines emit noise levels of around 90–100 dB; (ii) Aerodynamic noise – generated by the interaction of the turbine blades with the wind. Near the hub of large-capacity wind turbines, noise levels can reach 100 dB. Thereby, the operational noise of wind turbines does not affect human activities beyond a distance of 100 meters.

In 2013, the Danish Environmental Agency investigated how wind turbines and especially noise from wind turbines influence human health. The report presented several findings [14]:

- No conclusive evidence was found of a correlation between short-term and long-term exposure to wind turbine noise and the occurrence of blood clots in the heart and stroke.
- The results of the study do not support a link between long-term exposure to wind turbine noise and newly emerging diabetes or between exposure to wind turbine noise during pregnancy and negative birth defects.
- For first-time redemption of prescriptions for sleep medication and antidepressant medicine, the researchers found a connection with high levels of outdoor wind turbine noise among the elderly over the age of 65 and weak indications of similar findings for first-time intake of prescriptions for medicines for the treatment of high blood pressure.
- The study generally includes few illnesses among the groups exposed to the highest noise levels. The findings are not considered valid by the researchers unless reproduced by other researchers.

A Canadian literature study concludes that wind turbines might cause annoyance for the neighbours, but no causal relation could be established between noise from wind turbines and the neighbour's health [15].

The risk of bird collisions has been of concern in Denmark due to the proximity of wind turbines to bird migration routes. In general, it turns out that birds can navigate around turbines, and studies report low overall bird mortality but with some regional variations [16].

The environmental impact from the manufacturing of wind turbines is moderate and is in line with the impact of other normal industrial production. The mining and refinement of rare earth metals used in permanent magnets is an area of concern [1, [17], [18]. The energy payback time of an onshore wind turbine is in several studies calculated to be in the order of 3-9 months [19], [20].

Life-cycle assessment (LCA) studies of wind farms have concluded that environmental impacts come from three main sources:

- bulk waste from the tower and foundations, even though a high percentage of the steel is recycled
- hazardous waste from components in the nacelle
- greenhouse gases (e.g. CO₂ from steel manufacturing and solvents from surface coatings)

Approximately 96 % of a wind turbine is made from recyclable materials, including steel, copper, aluminium, and plastics in its outer shell and components. With over 8,000 parts, turbines are typically designed (guaranteed) to operate up to 25 years but empirically often operate longer [21], and most of their materials can be recycled at the end of their life. However, the blades, typically made of fiberglass, are not fully recyclable and often end up in landfills or incinerated. Innovative methods are emerging to repurpose them, such as using fiberglass in cement production or reusing whole blades in structures like bike sheds, noise barriers, and bridges. With an increased supply of end-of-life blades caused by the expanding global wind market, further methods to reuse and recycle the components are expected to emerge.

Modern wind turbines are generally very tall, often exceeding 150 m (around 300 m for 18 MW turbines), which can affect aviation. Before construction, investors must coordinate with the relevant authorities from the Civil Aviation Authority and the Ministry of National Defense. It is also necessary to install signalling systems (aviation obstruction lights) on the turbines.

Besides concerns related to clearance height, wind turbines can interfere with aviation communication systems. Wind farms with multiple turbines installed close together can create significant shadowing and may affect the long-range visibility of radar, as radar waves are disturbed. When the turbine blades rotate, radar reflections can be affected, potentially generating inaccurate signals. Therefore, wind turbines should

not be installed near radar systems, especially those used for airspace protection or air traffic control.

End-of-life Recycling Technology

Recycling technology for wind turbines at the end of their lifecycle currently focuses on the treatment of components that are difficult to decompose, particularly blades made of composite materials. While approximately 80–90% of the turbine's mass (such as steel towers, copper generators, and aluminium components) can be easily recycled using conventional metallurgical methods, recycling turbine blades remains the greatest challenge.

Wind turbine blades are made from composite materials such as fiberglass, carbon fiber, and epoxy resins, which make them lightweight, strong, and highly resistant to weather conditions. However, these very characteristics make the blades difficult to recycle or result in high recycling costs. Currently, there is no effective and scalable method worldwide for recycling these materials. The global energy industry is continuously seeking solutions. Many companies have begun repurposing old blades into useful products such as materials for cement production, asphalt mixtures, or even pedestrian bridges and highway noise barriers. Some companies also reuse entire blades as roofs for electric vehicle charging stations, bus shelters, or bicycle parking structures [22].

In recent years, a research group at the Lanzhou Institute of Chemical Physics under the Chinese Academy of Sciences has introduced a solution to recycle wind turbine blades into asphalt materials. The research team addressed the challenge by utilizing the unique characteristics of decommissioned blades, including their light weight, high strength, and corrosion resistance. Through a combination of crushing and chemical treatment processes, the team successfully modified the blades for incorporation into asphalt mixtures and cement concrete. The researchers collaborated with a domestic road construction company to test the improved asphalt mixture containing decommissioned turbine blades on a section of highway in Lanzhou, Gansu Province, Northwest China, in September 2024. After more than five months of operation, the road surface showed no cracks, subsidence, or peeling, demonstrating the feasibility of this recycling method [23].

Research and development

Future research will focus on reducing investment costs through improved design and load reduction technologies. More efficient methods for determining wind resources, including external design conditions, will be developed, along with enhanced aerodynamic performance. Efforts will aim to lower operational and maintenance costs by improving turbine component reliability. There will be advancements in ancillary services, better integration with energy systems, and improved tools for wind power forecasting. Research will also explore ways to enhance power quality, reduce noise, optimize repowering strategies, and explore storage solutions to increase wind power's value [5].

Research and development in Vietnam

The prospects for onshore wind power technology development in Vietnam in the coming years are considered very positive, especially in the field of domestic equipment manufacturing. Currently, Vietnam is not yet able to produce complete wind turbines but has become an important link in the global supply chain. Notably, CS Wind Vietnam (a South Korean company with a large factory in Ba Ria – Vung Tau) is now the world's largest wind turbine tower manufacturer, having exported thousands of towers for onshore wind projects in the United States, South Korea, and Europe. In addition, several domestic mechanical engineering companies are gradually participating in the fabrication and assembly of steel structures, helping to reduce import costs and increase the localization rate in wind power projects. Although high-tech components such as composite blades, gearboxes, and generators still need to be imported, the development of the domestic manufacturing sector indicates potential to eventually master more complex equipment clusters in the future. With supportive policies on research, technology transfer, and investment incentives, Vietnam has the potential to build a competitive onshore wind power supply chain in the region while promoting sustainable growth of the domestic mechanical engineering industry.

Examples of current projects

Current Onshore Wind Turbine Offerings in Vietnam:

Before 2021, onshore wind power projects in Vietnam mainly used 3–4 MW turbines from manufacturers such as Envision, Vestas, and Goldwind, primarily due to supplier availability. However, future trends

indicate the use of larger-capacity turbines with bigger rotor diameters to reduce LCOE, improve wind utilization, lower operational costs, and align with global technological trends.

Some technical specifications of operational onshore wind power projects in Vietnam are as follows:

Ea Nam Wind Power Project

The Ea Nam Wind Power Project, located in Ea H'leo District, Dak Lak Province, has a capacity of 400 MW, making it the largest onshore wind project in Vietnam to date. The project uses 84 Enercon turbines (models E-138 EP3 and E-160 EP5) with individual capacities of 4.2–5.5 MW, tower heights of 130–150 m, and rotor diameters of 138–160 m. The total investment is approximately VND 16,500 billion (~USD 713 million), with land and associated infrastructure needs estimated at over 600 ha. In addition to the plant, the project includes a 500 kV transmission line of about 1.2 km to connect to the national grid. All 84 turbines were completed and commissioned on October 31, 2021, with an expected annual electricity output of around 1.1 billion kWh.

Kosy Bac Lieu Wind Power Project

The Kosy Bac Lieu Wind Power Project has a capacity of 40.5 MW and is located in Vinh Thinh Commune, Hoa Binh District (formerly Bac Lieu Province, now part of Ca Mau Province). The turbines are fully supplied by Goldwind International Renewable, one of the top three global wind turbine manufacturers. This is the latest 4.5 MW smart turbine series, suitable for local wind conditions, with a rotor diameter of 155 m and a tower height of 130 m to increase power generation. The Goldwind turbines use permanent magnet direct-drive technology without a gearbox, reducing operational losses and enhancing efficiency. The total investment is approximately VND 1,600 billion (~USD 69 million). The project officially began commercial operation in October 2021.

Lac Hoa 2 Wind Power Project

The Lac Hoa 2 Wind Power Project is located in Vinh Tan and Lac Hoa Communes, Vinh Chau Town (formerly Soc Trang Province, now under Can Tho City). The project has a capacity of 130 MW. In August 2023, 38 out of 40 turbines had been commissioned, each with a capacity of 3.3 MW. The turbines are manufactured by Envision, the world's second-largest turbine manufacturer, with towers made of special stainless steel, 140 m high, rotor diameters of 156 m, and three blades per turbine, each over 76 m long made of special composite materials. The total investment is approximately VND 5,700 billion (~USD 238 million). This project is one of the few wind power projects completed after the FIT period in Vietnam.

Investment cost estimation

The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - Onshore wind – High Wind Turbines						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Vietnam Current		1.37	1.32		1.28	1.26
Technology Catalogue - Vietnam 2023	1.89		1.61			1.36
Technology Catalogue - Vietnam 2021	1.89		1.61			1.36
Technology Catalogue - Vietnam 2019	2.01		1.65			1.40
Technology Catalogue – Denmark 2022	1.38	1.47	1.43			1.36
Technology Catalogue – Colombia 2024		1.41	1.33			1.26
Local data - Project: Khanh Hoa Province 2021	1.18					
Local data - Project: Gia Lai Province 2025		1.47				
Local data - Project: Lam Dong Province 2025		1.13				
IEA WEO 2025 – India		1.14		1.07		1.04
IEA WEO 2025 – China		0.88		0.82		0.81

Additional remarks

Advancements in technology and ongoing improvements in maintenance and materials have extended the anticipated technical lifespan of wind turbines. While the traditional assumption was a 20-year lifecycle, current studies and practical observations suggest that turbines installed soon might well have a projected lifespan of 25 years [26-28]. Looking further ahead, between 2030 and 2050, it is plausible that wind turbines could endure for up to 30 years, given ongoing enhancements and refinements in turbine design, materials, and operational strategies.

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Data sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (\$), price year 2025

Onshore Wind – High turbine											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW _e	5.0	6.0	6.2	6.5	3.5	7	5.5	9		1
Generating capacity for a typical power plant	MW _e	100	100	100	100	30	300	30	300		1, 2
Forced outage	%	2.5	2.0	2.0	2.0	-	-	-	-		1, 2, 3
Planned outage	%	0.3	0.3	0.3	0.3	-	-	-	-		1, 2, 3
Technical lifetime	years	27	30	30	30	25	35	25	40		1, 2, 3
Construction time	years	1.5	1.5	1.5	1.5	-	-	-	-		1, 2, 3
Space requirement	1000 m ² /MW _e	14	14	14	14	-	-	-	-		2, 4
Additional data for non-thermal plants											
Capacity factor, theoretical	%	35.0	35.3	36.3	36.9	26.2	43.7	27.6	46.1	A	
Capacity factor, incl. outages	%	34.0	34.5	35.5	36.0	25.5	42.5	27.0	45.0	A	1, 2
Economic data (in USD2025)											
Specific investment, total system	MUSD/MW _e	1.37	1.32	1.28	1.26	1.16	1.78	1.07	1.64	B, C, F	1, 5, 6
- of which equipment	%	65	65	65	65	-	-	-	-	D	1, 2, 4
- of which installation and other costs	%	35	35	35	35	-	-	-	-	D	1, 2, 4
- of which equipment	MUSD/MW _e	0.89	0.86	0.83	0.82	0.76	1.16	0.66	1.08	D	1, 2, 4
- of which installation and other costs	MUSD/MW _e	0.48	0.46	0.45	0.44	0.41	0.62	0.36	0.58	D	1, 2, 4
Fixed O&M	USD/MW _e /year	34,250	32,787	31,541	31,075	29,113	44,525	26,857	41,075	B, E	1
Variable O&M	USD/MWh	-	-	-	-	-	-	-	-	E	
Technology specific data											
Average annual full-load hours	MWh _e /MW _e	2,978	3,022	3,110	3,154	2,234	3,723	2,365	3,942		1
Hub Height	m	130	130	140	150	-	-	-	-		1
Rotor Diameter	m	145	160	165	180	-	-	-	-		1
Specific Power	W/m ²	303	298	290	286	-	-	-	-		1, 3
Availability	%	97.2	97.7	97.7	97.7	-	-	-	-		
Water consumption		0	0	0	0	-	-	-	-		7, 8

Notes:

- A Lower and upper uncertainties are +/- 25%.
- B Costs are projected with a learning rate approach assuming a 5% learning rate based on [6], and 6 % learning rate for OPEX based on [3]. Learning is linked to the capacity projections of the IEA's World Energy Outlook 2025, with the scenario Stated Policies for the central values and the scenarios Current Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.
- C Lower and upper uncertainties are -15% and +30%.
- D 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. Central value assumes a 65/35 distribution.
- E O&M corresponding to 2.5 % of CAPEX/year. All O&M assumed as fixed cost. In reality, some O&M will be variable, but given the high spread in possible capacity factors, all O&M is for simplicity accrued under fixed O&M.

- F This cost estimate represents a general standard onshore wind project in Vietnam. Depending on varying factors like region, terrain, grid connection, transport difficulty, etc. the cost can vary significantly.

References

- 1 Existing projects in Vietnam
- 2 Danish Energy Agency, 2025 - Colombian Technology Catalogue for Generation and Storage of Electricity
- 3 Danish Energy Agency, 2024 - Danish Technology Catalogue for Generation of Electricity and District Heating
- 4 Danish Energy Agency and Ea Energy Analyses, 2024 - Technology Data for the Indonesian Power Sector: Catalogue for Generation and Storage of Electricity
- 5 Stakeholder dialogue
- 6 IEA, 2025 - World Energy Outlook 2025
- 7 World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity
- 8 U.S. Energy Information Administration, 2023 - U.S. electric power sector continues water efficiency gains

Onshore Wind – Medium turbine											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	4.5	4.5	5.0	5.2	3.5	6.0	4.0	7.0		1
Generating capacity for a typical power plant	MW_e	50	70	80	100	30	70	50	150		1, 2
Forced outage	%	2.5	2.0	2.0	2.0	-	-	-	-		1, 2, 3
Planned outage	%	0.3	0.3	0.3	0.3	-	-	-	-		1, 2, 3
Technical lifetime	years	27	30	30	30	25	35	25	40		1, 2, 3
Construction time	years	1.5	1.5	1.5	1.5	-	-	-	-		1, 2, 3
Space requirement	1000 m²/MW_e	14	14	14	14	-	-	-	-		2, 4
Additional data for non-thermal plants											
Capacity factor, theoretical	%	36.0	36.3	36.9	37.9	27.0	45.0	28.4	47.3	A	
Capacity factor, incl. outages	%	35.0	35.5	36.0	37.0	26.3	43.8	27.8	46.3	A	1, 2
Economic data (in USD2025)											
Specific investment, total system	MUSD/MW_e	1.50	1.45	1.40	1.38	1.28	1.95	1.18	1.80	B, C, F	1, 5, 6
- of which equipment	%	65	65	65	65	-	-	-	-	D	1, 2, 4
- of which installation and other costs	%	35	35	35	35	-	-	-	-	D	1, 2, 4
- of which equipment	MUSD/MW_e	0.98	0.94	0.91	0.90	0.83	1.27	0.73	1.18	D	1, 2, 4
- of which installation and other costs	MUSD/MW_e	0.53	0.51	0.49	0.48	0.45	0.68	0.39	0.63	D	1, 2, 4
Fixed O&M	USD/MW_e/year	37,500	35,898	34,534	34,024	31,875	48,750	29,405	44,973	B, E	1
Variable O&M	USD/MWh	-	-	-	-	-	-	-	-	E	
Technology specific data											
Average annual full-load hours	MWh_e/MW_e	3,066	3,110	3,154	3,241	2,300	3,833	2,431	4,052		1
Hub Height	meter	130	140	160	170	-	-	-	-		1
Rotor Diameter	meter	155	155	165	170	-	-	-	-		1
Specific Power	W/m²	238	238	234	229	-	-	-	-		1, 3
Availability	%	97.2	97.7	97.7	97.7	-	-	-	-		
Water consumption		0	0	0	0	-	-	-	-		7, 8

Notes:

- A Lower and upper uncertainties are +/- 25%.
- B Costs are projected with a learning rate approach assuming a 5% learning rate based on [6], and 6 % learning rate for OPEX based on [3]. Learning is linked to the capacity projections of the IEA's World Energy Outlook 2025, with the scenario Stated Policies for the central values and the scenarios Current Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.
- C Lower and upper uncertainties are -15% and +30%.
- D 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. Central value assumes a 65/35 distribution.
- E O&M corresponding to 2.5 % of CAPEX/year. All O&M assumed as fixed cost. In reality, some O&M will be variable, but given the high spread in possible capacity factors, all O&M is for simplicity accrued under fixed O&M.
- F This cost estimate represents a general standard onshore wind project in Vietnam. Depending on varying factors like region, terrain, grid connection, transport difficulty, etc. the cost can vary significantly.

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- 5 Stakeholder dialogue
- 6 IEA, 2025 - World Energy Outlook 2025
- 7 World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity
- 8 U.S. Energy Information Administration, 2023 - U.S. electric power sector continues water efficiency gains

Onshore Wind – Low turbine											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	3.0	3.5	4.0	4.5	2.5	5.0	4.0	6.5		1
Generating capacity for a typical power plant	MW_e	50	70	80	100	30	70	50	150		1, 2
Forced outage	%	2.5	2.0	2.0	2.0	-	-	-	-		1, 2, 3
Planned outage	%	0.3	0.3	0.3	0.3	-	-	-	-		1, 2, 3
Technical lifetime	years	27	30	30	30	25	35	25	40		1, 2, 3
Construction time	years	1.5	1.5	1.5	1.5	-	-	-	-		1, 2, 3
Space requirement	1000 m²/MW_e	14	14	14	14	-	-	-	-		2, 4
Additional data for non-thermal plants											
Capacity factor, theoretical	%	38.1	38.9	39.9	40.9	28.6	47.6	30.7	51.2	A	
Capacity factor, incl. outages	%	37.0	38.0	39.0	40.0	27.8	46.3	30.0	50.0	A	1, 2
Economic data (in USD2025)											
Specific investment, total system	MUSD/MW_e	1.65	1.59	1.54	1.52	1.40	2.06	1.23	1.77	B, C, F	1, 5, 6
- of which equipment	%	65	65	65	65	-	-	-	-	D	1, 2, 4
- of which installation and other costs	%	35	35	35	35	-	-	-	-	D	1, 2, 4
- of which equipment	MUSD/MW_e	1.07	1.03	1.00	0.99	0.91	1.34	0.80	1.15	D	1, 2, 4
- of which installation and other costs	MUSD/MW_e	0.58	0.56	0.54	0.53	0.49	0.72	0.43	0.62	D	1, 2, 4
Fixed O&M	USD/MW_e/year	41,250	35,898	34,534	34,024	35,063	51,563	30,720	44,128	B, E	1
Variable O&M	USD/MWh	-	-	-	-	-	-	-	-	E	
Technology specific data											
Average annual full-load hours	MWh_e/MW_e	3,241	3,329	3,416	3,504	2,431	4,052	2,628	4,380		1
Hub Height	meter	130	140	150	170	-	-	-	-		1
Rotor Diameter	meter	150	160	175	190	-	-	-	-		1
Specific Power	W/m²	170	174	166	167	-	-	-	-		1, 3
Availability	%	97.2	97.7	97.7	97.7	-	-	-	-		
Water consumption		0	0	0	0	-	-	-	-		7, 8

Notes:

- A Lower and upper uncertainties are +/- 25%.
- B Costs are projected with a learning rate approach assuming a 5% learning rate based on [6], and 6 % learning rate for OPEX based on [3]. Learning is linked to the capacity projections of the IEA's World Energy Outlook 2025, with the scenario Stated Policies for the central values and the scenarios Current Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.
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- F This cost estimate represents a general standard onshore wind project in Vietnam. Depending on varying factors like region, terrain, grid connection, transport difficulty, etc. the cost can vary significantly.

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9. OFFSHORE WIND POWER

Brief technology description

Wind power sources can be divided into two categories: onshore wind and offshore wind. According to the Law on Electricity No. 61/2024/QH15 dated November 30, 2024, an offshore wind project includes all wind turbines constructed in Vietnam's sea areas and located seaward of the mean low-water line of the mainland over multiple years. Offshore wind projects are classified into the following types: a) Nearshore wind projects, in which all turbines are constructed within 6 nautical miles from the mean low-water line of the mainland; b) Offshore wind projects, in which all turbines are constructed beyond 6 nautical miles from the mean low-water line of the mainland.

The cost and technology of offshore wind depend significantly on seabed depth and distance to shore. Certain sea areas in Vietnam, although geographically close to shore, have deep waters — such as the coasts of Binh Dinh (old), Phu Yen (old), and Khanh Hoa provinces. Although these are classified as nearshore wind areas under the Law on Electricity No. 61/2024/QH15, their costs should be considered equivalent to offshore wind. The Vietnam Technology Catalogue for Power Generation (2023 edition) [[1]]¹⁰ proposed classifying offshore wind according to seabed depth and distance to shore, reflecting differences in investment costs. Accordingly, a real offshore wind farm is defined as one located at least 6 nautical miles (≈ 11 km) from shore and in water depths of at least 10 m. When the seabed depth is less than 10 m or the distance is under 6 nautical miles [[2]]¹¹, the wind farm is considered nearshore, with intertidal wind regarded as a subcategory of nearshore wind. In this Technology Catalogue, parameters for offshore and nearshore wind are determined based on seabed depth and distance to shore, consistent with the 2023 edition.

Offshore wind turbines

The basic operating principles of offshore wind turbines, most of the subsystems (electrical, hydraulic, pitching, emergency braking, cooling, ventilation, etc.) and software components are the same as for onshore wind turbines. However, as offshore wind turbines have to withstand higher wind speeds and more stable wind profiles, the configuration of the wind turbine setup parameters differs slightly from onshore wind turbines in order to make the wind turbines suitable for offshore use. The corrosive offshore environment due to the high salt content and increased humidity in the air places additional demands on the electrical and mechanical components. Since the world's first offshore wind project at Vindeby in Denmark, many offshore turbines have been fitted with air conditioning to protect the sensitive electronics inside the units, active corrosion protection systems in the foundations and North Sea-grade paint to protect the external steel structures.

Although no offshore wind projects have yet entered operation, Vietnam is continuing to develop a comprehensive set of standards for the design of offshore wind turbines suitable for harsh marine environments, with stringent requirements for safety, reliability, and international compatibility. In particular, the development of offshore wind projects in the Gulf of Tonkin, North Central, and Central Coast regions must ensure typhoon-resistant designs, as these areas are frequently affected by tropical storms in Vietnam. Large rotor structures, blades, and towers are reinforced to withstand high loads and use corrosion-resistant materials and coatings to endure saltwater, salt spray, and high humidity conditions.

Turbine foundations

Offshore wind turbine foundations are subject to more complex loading conditions than onshore wind turbine foundations, and the design and concept of offshore wind turbine foundations are therefore very different from onshore wind turbine foundations. They must be designed to withstand the harsh marine environment and the effects of large waves and, in some locations, ice. These factors and the complexity of installation result in offshore foundations being more expensive than onshore wind foundations for turbines of a similar size.

To date, offshore wind turbines have been installed on four different types of fixed foundations: gravity, monopile, jacket and tripod structures. Today, monopiles are the most common and cost-effective foundation type, followed by jackets. The choice of foundation type depends on local seabed conditions,

¹⁰ DEA-EREA, Vietnam Technology Catalogue for Power Generation, 2023

¹¹ COWI, Research on criteria and regulatory establishment for an efficient and sustainable offshore wind power market in Viet Nam, 2021

wind turbine size and water depth. Today, with the latest technological innovations, fixed foundations can be used in water depths of up to 70 metres.

Meanwhile, floating substructure technology is also being investigated and may have the potential to reduce the overall cost of offshore wind in the future. At the same time, as floating substructures are the only solution for deep waters, it will dramatically increase the possible exploitation of the global resource potential of offshore wind, allowing installation in areas that were previously infeasible. In sea areas with depths greater than 50–60 meters, the use of floating foundations can be considered.

One potential advantage of floating offshore wind turbines is that they can be assembled and maintained in port rather than at sea, as they can be towed (due to their floating nature), which could reduce both installation and maintenance costs in the future compared to bottom-fixed offshore turbines. While initial towing out to sea for installation has proven successful, towing to shore for maintenance has shown mixed results and logistical obstacles, but having the necessary tools and a well-prepared maintenance platform seems to reduce downtime and therefore lost production during maintenance [[3],[4]]. Even though the increasing cost of labour, towing vessels and supply vessels is a negative factor for floating offshore wind, a towed maintenance strategy could be beneficial for floating offshore wind farms [[3]]. Despite these advantages for floating offshore wind, the cost level of the foundation structures is expected to remain significantly higher than that of monopiles for the foreseeable future.

Floating offshore wind technology has been developed over the last 20 years to meet three fundamental requirements:

- Stable and cost-effective foundation structures.
- Control systems that can accommodate the natural motion of the floating structure.
- Sufficient reliability and availability to make floating wind an integral part of the energy grid.

Since 2009, floating wind structures have been introduced to the market, as shown in Figure 56, and floating wind farms have been demonstrated since 2017. At present, proposed offshore wind projects in Vietnam primarily focus on areas suitable for fixed-bottom foundations. No studies have yet been conducted on floating foundation structures appropriate for Vietnamese sea conditions.

The wind turbines used in floating offshore wind farms are the same wind turbines as for any other offshore wind farm, but configured specifically for the floating environment. This could be special configuration parameters for pitching, tower damping system, safety circuit, yaw system, etc.

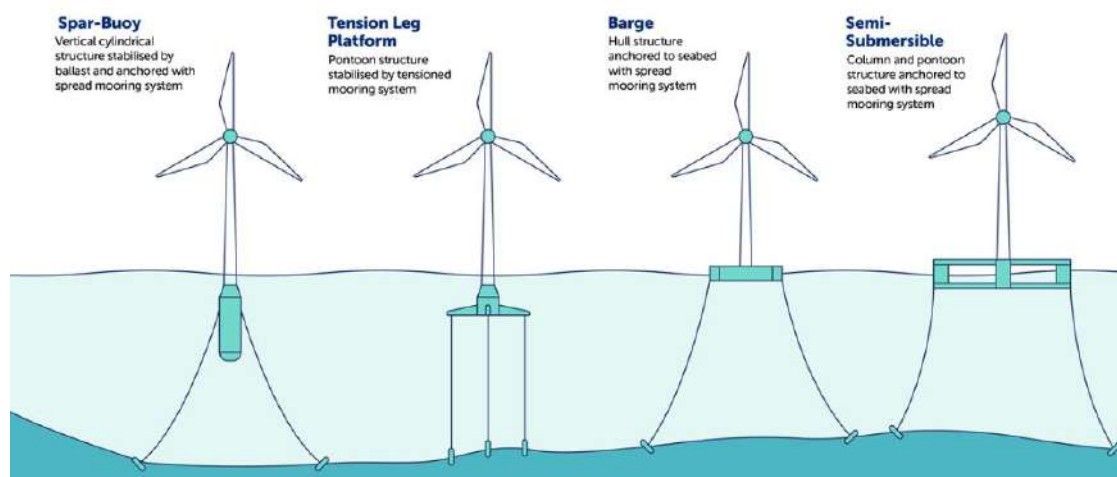


Figure 56: Floating foundation structures – dominant types [5], [6]

Electrical systems

While early offshore wind was based on 33 kV level components, today's offshore wind turbines have built-in transformers that provide a standard voltage level of 66 kV to the array cable system in the wind turbine. Solutions based on a 132 kV voltage level are being investigated. The higher voltage level will reduce specific cable costs and losses, as well as overall life cycle costs, and may therefore reduce energy costs, provided that the additional costs associated with increased safety clearances, etc. at the higher voltage level do not outweigh the benefits [[7]].

In traditional offshore wind farms, the array cables are connected to an offshore substation at the wind farm. Here the voltage is transformed to a higher voltage level for export to the onshore grid. As wind farms today are often built further offshore, and as the feed-in points for exported offshore wind power become more centralised, HVDC solutions are becoming increasingly important.

In Vietnam, offshore wind power collection and transmission to shore, as proposed by project developers, typically use 35 kV, 66 kV, or 220 kV cables. Due to the relatively high cost of constructing offshore substations, many projects prefer to collect power through individual cables directly to shore, where the voltage is then stepped up for connection to the national grid. For offshore wind projects located farther from the coast, power transmission to shore using HVDC systems may be considered.

Vietnam Offshore Wind Potential

To estimate offshore wind potential, several different factors should be considered: Wind resources, protected areas, critical habitats, fishing, indigenous people, heavy trafficked shipping routes and environmentally sensitive zones.

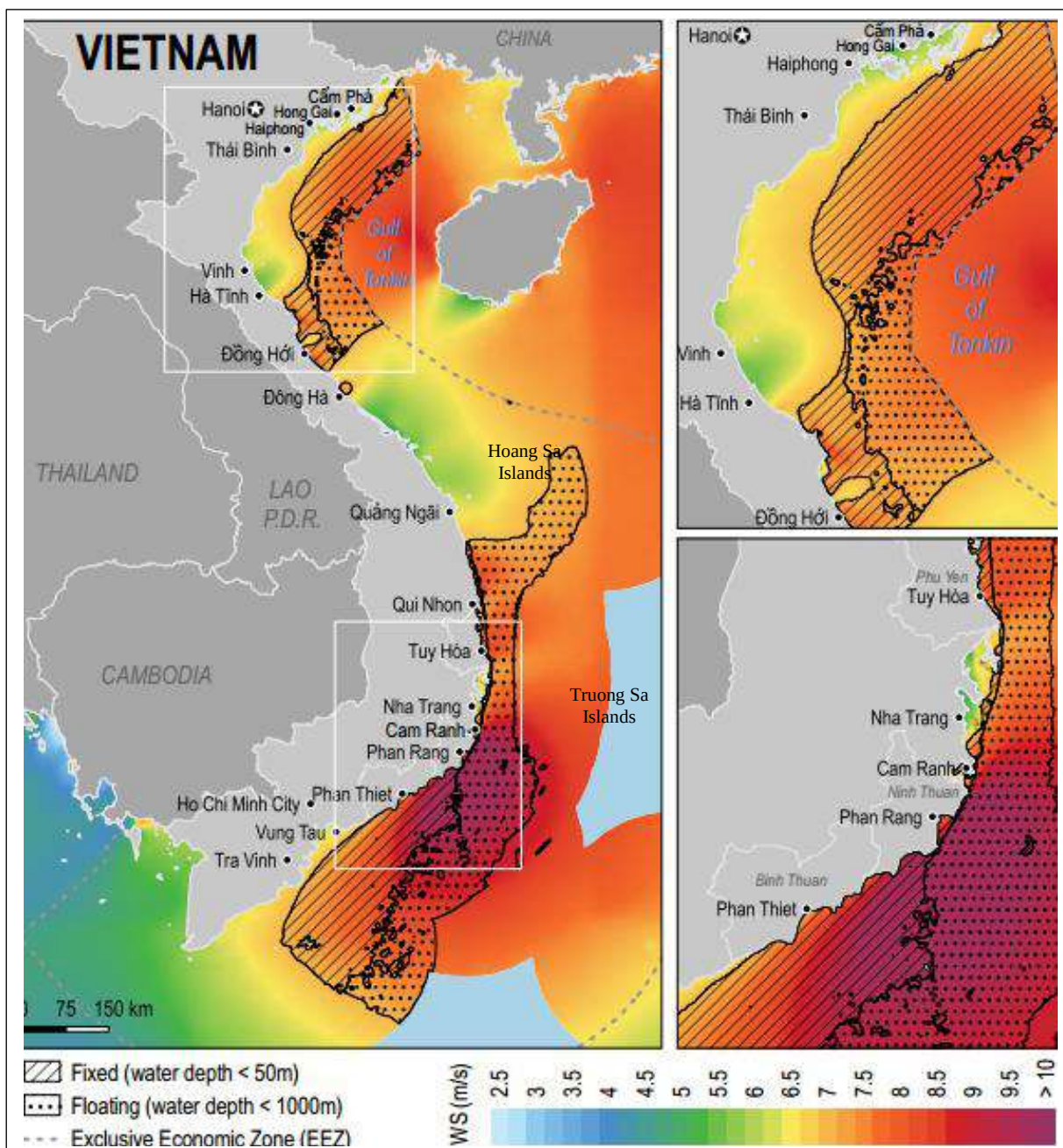


Figure 57: Map of potential offshore wind power locations in the form of floating and fixed foundations of Viet Nam according to ESMAP [8]

According to the World Bank's (WB – ESMAP) technical potential assessment, based on the global wind map at 100 m height and within 200 km from the coastline, along with seabed topography data from GEBCO, the total potential capacity is estimated at 600 GW, including 261 GW for fixed-bottom foundations and approximately 338 GW for floating foundations. The identified technical potential area includes sea zones under Vietnam's sovereignty, located within 200 km from the shore, where wind speeds exceed 7 m/s at 100 m height — these conditions were used to determine the offshore wind technical potential. This surveyed area does not yet cover the entire Exclusive Economic Zone (EEZ) of Vietnam (200 nautical miles from the baseline) as defined by the 1982 United Nations Convention on the Law of the Sea.

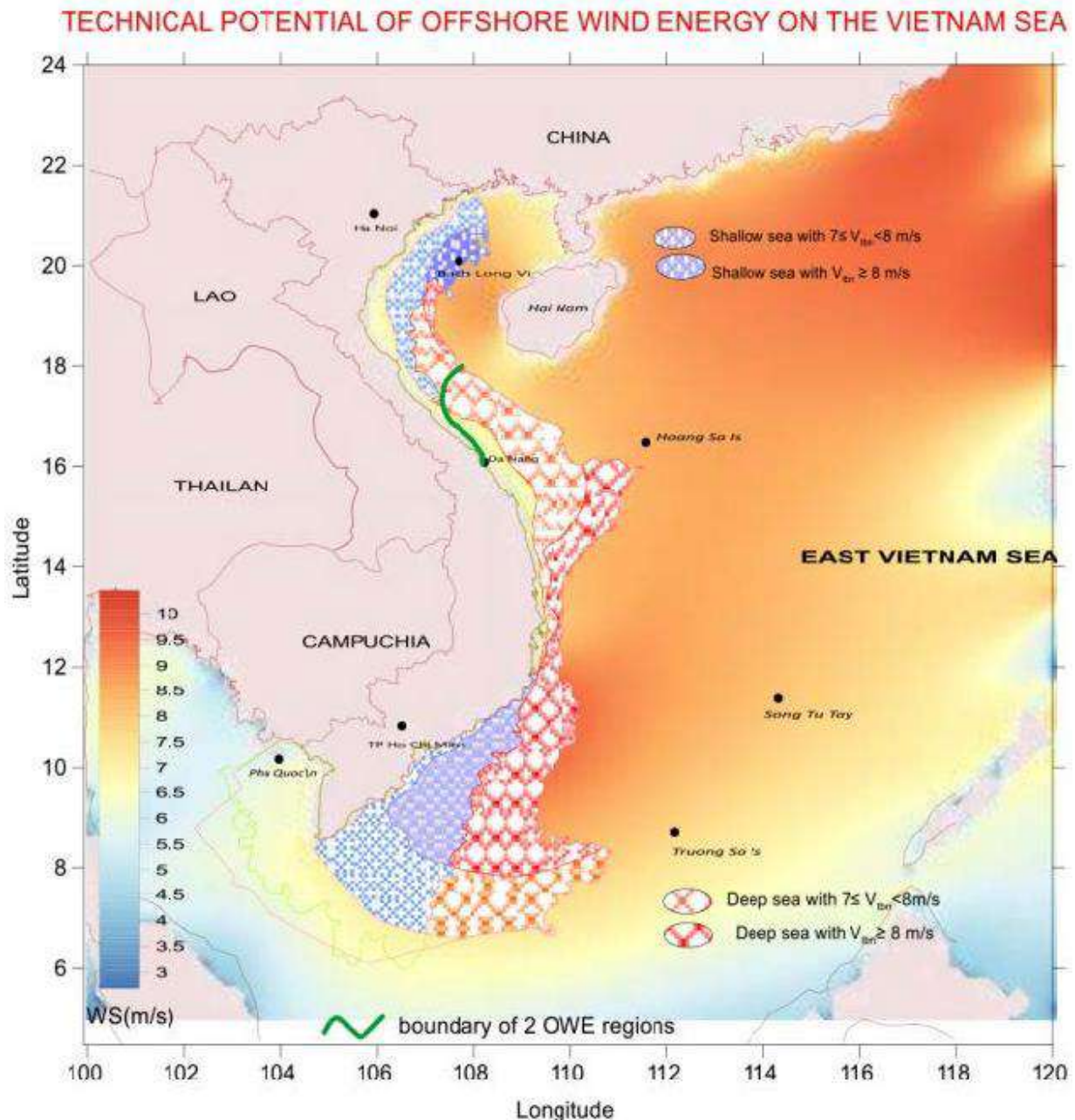


Figure 58: Technical potential of offshore wind energy on the Vietnam sea [9]

The techno-economic potential of offshore wind will be continuously updated and is expected to increase over time as advancements in science and technology improve project feasibility, particularly for sites located farther offshore. In the near and medium term, development should focus on nearshore sites with good wind resources and moderate seabed depths; in the longer term, as technological progress ensures project economic viability, more distant offshore areas can be considered for exploitation.

According to the “Task on Detailed Assessment of Wind Energy Potential in Coastal (within 6 nautical

miles) and Offshore Areas of Vietnam and Proposal for Long-term Support for the Power Sector” implemented by the United Nations Development Programme (UNDP) Vietnam in collaboration with the Norwegian Embassy in Vietnam, supporting the National Center for Hydro-Meteorological Forecasting under the General Department of Meteorology and Hydrology [[9]], the total exploitable potential within Vietnam’s EEZ is approximately 1,068 GW. This figure is higher than the World Bank’s (WB) 2021–2022 estimate (around 600 GW) due to two main reasons: (1) the EEZ-based assessment area (extending up to 200 nautical miles, about 322 km) is broader than the WB’s 200 km range; and (2) the area with average wind speeds exceeding 7 m/s (used to determine technical potential) is larger than that in the WB’s study. In the same report, the nearshore area is defined as the sea zone extending from the coastline up to 6 nautical miles offshore (approximately 11 km), which lies within the national territorial waters.

The assessment of wind energy potential in nearshore areas indicates that the Southern region has the highest technical potential, followed by the South-Central Coast, while the Red River Delta has the lowest potential. Specifically: Red River Delta (0.169 GW), North Central Coast (1.345 GW), Central Coast (2.244 GW), South Central Coast (25.899 GW), and Southern region (28.372 GW).

Input

The input of offshore wind is wind. The kinetic energy of the wind is converted into electrical energy.

A power curve shows the power output as a function of wind speed at hub height. Figure 59 shows a generic power curve for a soft cut-off wind turbine. The performance of a wind turbine is usually expressed in terms of three specific wind speed ranges, depending on the turbine model (specific operating conditions may result in deviations from these ranges). The cut-in wind speed is the minimum wind speed at which the turbine will start operating. The rated wind speed is where the turbine reaches its rated power, and the cut-out wind speed is where the turbine will stop operating for safety reasons. In Table 23, the three wind speed ranges are shown for two different turbines.

Table 23: Design wind speed ranges for two Wind Turbine types [10, 11].

WT type	Cut-in [m/s]	Rated [m/s]	Cut-out [m/s]
V236-15 MW	3	11.1	31
SG 14-236 DD	4	12	32

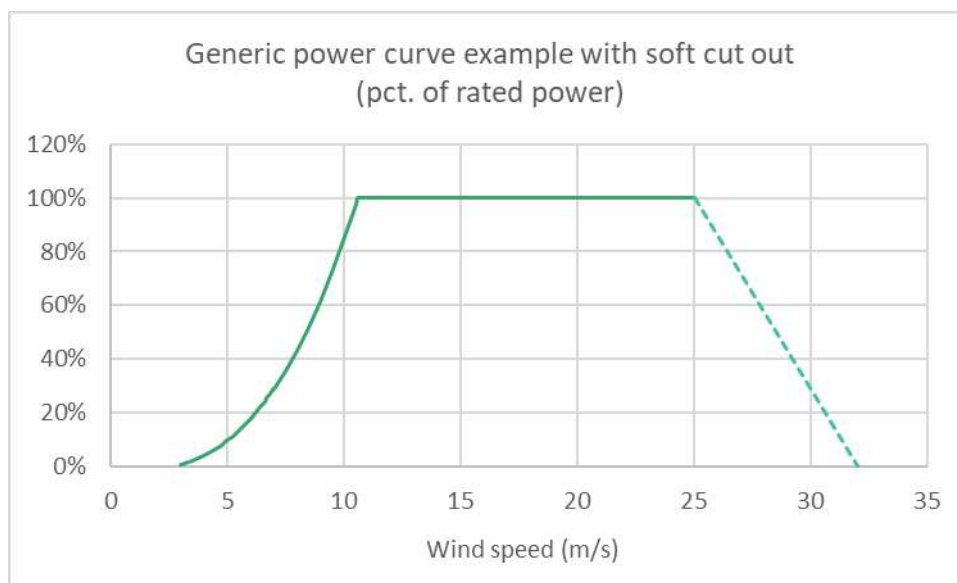


Figure 59: Generic power curve example with soft cut out. Source: IEA 15MW reference turbine.

The quality of the offshore wind resource tends to increase with distance from the coast, so that wind farms far from the coast will generally have higher annual production than those close to the coast (nearshore), with all other things being equal at each site.

Output

The output of offshore wind turbines is electric power.

Typical capacities

The rated capacity of commercially available wind turbines in the Northern European offshore market is in the range of 14-15 MW. These turbines are expected to be installed and operational from 2025 [[12]] [[13]]. The first commercial wind farm with 14 MW turbines was commissioned in the UK in late 2024 [[14]].

Rotor diameters are increasing, as are hub heights and overall heights. Globally, the weighted average rotor diameter of wind turbines used in commissioned offshore wind projects increased by 84% between 2010 and 2023, and by 16% between 2022 and 2023. In Europe, the weighted average rotor diameter was 141 metres in 2017, increasing by 35% to 190 metres in 2023. In China, the diameter increased by 33% over the same period, from 171 metres to 227 metres. The difference in rotor diameter between China and Europe is mainly due to the difference in wind speed, as the average wind speed of projects in China is lower than in Europe. The site distribution of wind speed has a significant impact on energy production, with manufacturers adjusting rotor and turbine sizes to optimise energy production in different wind conditions [[15]].

As depicted in Figure 60 and Figure 61, the historic growth rate of turbine capacities by their first year of commercial installation on a given site has followed an exponential trend from 2000 to 2020 with a doubling time of approximately 8-9 years, as indicated [[15]]. The latest turbine generations in the 14-15 MW range will extend this trend in the next years. At the same time, one might expect a decreasing long-term growth rate as the industry further matures and consolidates possibly through standardization of equipment and components. Market competition might play a role in at what time and thus at which capacity level a stronger standardization will take place.

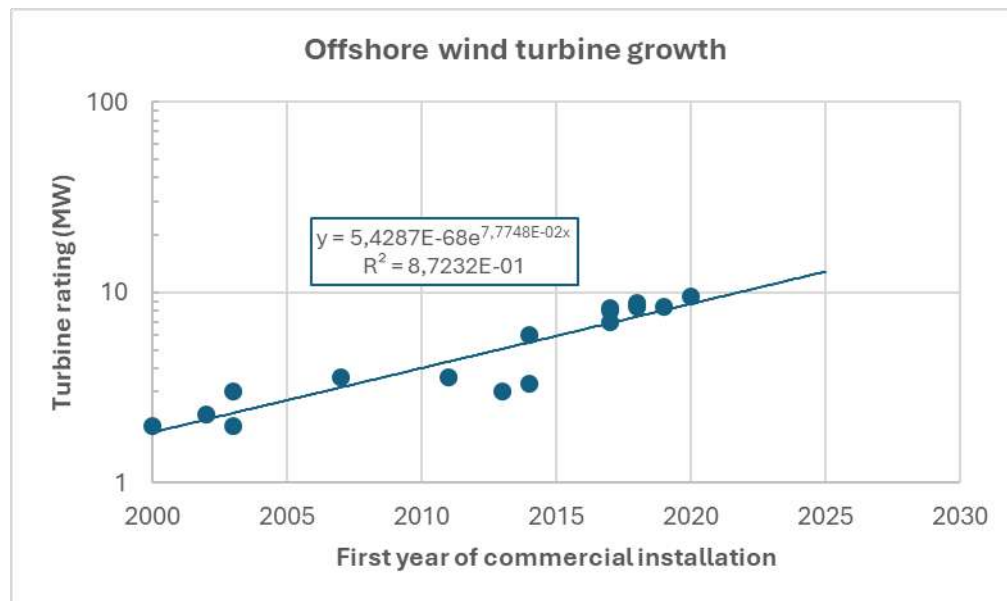


Figure 60: Growth rate for commissioned offshore wind turbines (first year of commercial installation of a given turbine) [[15]].

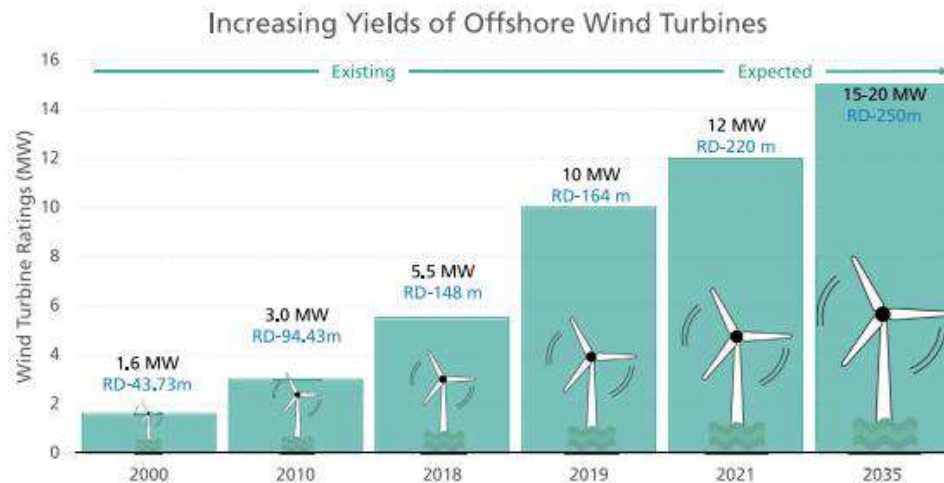


Figure 61: Increasing yield of offshore wind turbines [9].

It is assumed that the historic and current growth rate will sustain up until 2030. This results in 20 MW turbines in this year, whereafter the growth rate is assumed to decrease, possibly towards a plateau in the future. With current technology, rotor diameters of 300 m are deemed feasible by the industry [[3]]. With a constant average specific power of 350 W/m^2 , this results in generator capacities of ca. 25 MW and thereby exceeding the extrapolated capacity level in 2030. It is expected that technology improvements will lead to a further increase in capacity [[10]], however at a slower pace and with slower growth rate.

The 26 MW offshore wind turbine developed by Dongfang Electric (China) is currently considered the largest wind turbine in the world, marking a groundbreaking milestone for the global wind power industry. With a rotor diameter of over 310 meters and a hub height of approximately 185 meters, this giant turbine can efficiently harness offshore wind resources, thereby increasing electricity generation and reducing the levelized cost of energy per unit capacity. Notably, the turbine's design allows stable operation under harsh conditions, including regions frequently affected by strong winds and typhoons. In September 2025, the 26 MW prototype was installed for testing at the Dongying Test Center (Shandong Province, China), but it remains in the testing phase and has not yet entered commercial operation [[16]].

In Vietnam, offshore wind projects are expected to begin operation around 2030. Wind turbines with capacities of 18 MW or higher are still under testing, and no commercial project has yet deployed such large turbines. However, several manufacturers are planning to commercialize turbines above 18 MW in the near future. Therefore, most preliminary project designs tend to select turbines in the capacity range of approximately 16–20 MW.

Wind resource and capacity factors

One of the major drivers for developing wind farms offshore rather than onshore is the better wind resource, which can justify some of the additional investment and O&M costs.

At present, no offshore wind projects have been commissioned in Vietnam; therefore, the capacity factor for offshore wind in the country has yet to be verified. According to satellite data, the offshore areas of Khanh Hoa and Lam Dong provinces have the highest wind speeds, with estimated capacity factors of around 51–57%. Meanwhile, offshore areas in the northern region of Vietnam have lower capacity factors, ranging from approximately 36–40%.

Ramping configurations

Offshore wind turbines have similar regulation and ancillary service capabilities to onshore turbines. See the descriptions in the chapter, *Onshore Wind Power*. The ability to adjust active and reactive power of offshore wind farms must comply with Circular No. 05/TT-BCT dated February 1, 2025, on regulations for transmission, distribution, and electricity metering systems. Vietnam has not yet issued separate regulations specifically for offshore wind power sources.

Due to the long distances between the wind farm and the point of electrical connection to the grid, the reactive compensation provided by the wind turbines in the wind farm is very low, if any. Voltage regulation

is a local phenomenon and therefore offshore wind farms are not normally required to provide any kind of voltage regulation or voltage stabilisation. The reactive compensation of the export cable is usually implemented at the substation or close to the grid connection point. The grid connection agreement specifies who is responsible for what part of the reactive compensation for the export cable and voltage aspects such as on-load tap-changer settings.

Thanks to modern power electronic converters, offshore wind sources are capable of near-instantaneous power control, providing a high degree of flexibility to the power system:

- Ramp-up/ramp-down capability: A large-scale offshore wind farm can change its output from minimum to maximum (or vice versa) within a matter of minutes, rather than taking several hours as is typical for coal-fired power plants.
- Fast Frequency Response: At the millisecond level, turbines equipped with grid-forming technology can instantaneously adjust their power output to compensate for frequency deviations, providing a form of “virtual inertia” to the system. This capability enables offshore wind farms to participate in high-value ancillary service markets, contributing to national grid stability.
- Black-start capability: Following a widespread power outage (blackout), offshore wind farms integrated with grid-forming technology can self-start and generate voltage to support grid restoration without relying on external power sources. For example, pilot projects in the North Sea (such as those by Siemens Gamesa) have demonstrated that offshore wind turbines can help restore regional grids within a relatively short time frame (approximately 20–30 minutes).
- Power curtailment: In cases of grid congestion, offshore wind power can reduce output from 100% to 0% almost instantaneously through blade pitch control, without causing damage to the equipment.

Advantages/disadvantages

Offshore wind turbines have similar general advantages and disadvantages to onshore turbines. See the chapter, *Onshore Wind Power*.

The main advantages of offshore wind over onshore wind are the better wind resource offshore, the reduced visual and noise impact, and the ability to build much larger turbines than onshore. In addition, with open sea construction areas and low land occupation (mainly for onshore substations), offshore wind projects are more convenient for increasing capacity scale, avoiding the prolonged timelines associated with land clearance procedures.

On the negative side, offshore wind farms have more complex and expensive foundations and more complex grid connection and logistics than onshore wind farms. In addition, offshore wind farms require vessels, tools and equipment that can be used in an offshore environment, which are more expensive, resulting in higher capital and operating costs for offshore wind farms. Furthermore, the limited availability of ports and vessels compared to the demand for offshore wind construction and maintenance may be a temporary bottleneck in the further development of offshore wind. Looking at floating offshore wind, the wind turbines are complex to operate and maintain and require further development.

These additional costs may be offset by the higher returns from the projects, as the wind resource is better offshore than onshore.

Other advantages and disadvantages of offshore wind power could be listed as follows:

Advantages:

- Wind turbines produce no greenhouse gas emissions during their operation.
- With low operating costs and no fuel costs, wind power offers predictable and stable cost structures.
- The modular nature of wind power technology facilitates scalable capacity expansion, ensuring flexibility to meet demand and avoiding unnecessary overbuilding and associated stranded costs.
- Wind power projects generally have shorter lead times compared to various alternative energy technologies, allowing them to be implemented more quickly.

Disadvantages:

- Wind energy is initially capital intensive, requiring significant investment in turbines, foundations, grid connection, logistics, and machinery.
- Dependence on wind as an energy resource introduces variability in energy production, which impacts the balancing philosophy and forecasting methodology of the grid system operator.
- The variable nature of wind power generation may require ancillary services to ensure grid stability and security of supply-
- Nearshore wind can raise concerns about visual impact and may result in claims for compensation from neighbouring communities for loss of property value.
- Noise can be a nuisance for neighbours of both onshore and offshore wind turbines.

Space requirement

In theory, the layout of offshore wind turbines is easier to implement than onshore turbines because it is less constrained by terrain. However, offshore wind turbines need to be spaced appropriately to reduce wake losses and increase electricity production. Typically, the minimum distance between turbines is set at approximately six times the rotor diameter.

According to Decree No. 58/2025/ND-CP dated March 3, 2025, detailing certain provisions of the Electricity Law on the development of renewable and new energy, the maximum sea area for offshore wind surveys is 20 ha per MW, and the maximum sea area for implementing an offshore wind project is 5 ha per MW [[18]].

Water consumption

Offshore wind farms, by their nature, are situated in marine environments, so they typically do not use freshwater in the energy generation process itself. There is a marginal water consumption in buildings during the operation stage and by some processes during the construction stage.

Environment

Some disturbance to marine life is to be expected during the construction phase of offshore wind farms. For decades, developers have developed measures to ensure sustainability and protect the marine environment during construction and operation. New technology using patented jetting technology attached to the monopile is used to reduce the resistance of the sandy bottom, further reducing noise during installation.

Before, during and after the construction of the two Danish wind farms Horns Rev I and Nysted Havmøllepark (Rødsand I), extensive monitoring programmes were initiated to investigate and document the environmental impact of these two wind farms. The monitoring programmes have shown that, under the right conditions, large wind farms pose a low risk to birds, mammals and fish. Species diversity actually tends to increase due to the increased habitat heterogeneity created by the foundations, which act as miniature reefs, and because fishing is prohibited in the wind farm area, the conditions for fish breeding have improved [[19], [20], [21], [22]].

The results of the monitoring programmes show that it is possible to develop offshore wind farms in an environmentally sustainable way that causes negligible damage to the marine environment. However, each offshore wind farm under development is subject to a separate environmental impact assessment to ensure compliance and to identify mitigation measures where necessary.

For near-shore projects, the relative proximity of the wind farms to the coast has an impact on the reaction of people living in the vicinity. Offshore wind projects can impact marine tourism, which is one of Vietnam's strengths. Conflicts may arise between wind power developers and fishermen due to effects on fishing areas.

Offshore wind farms occupy large areas at sea, limiting the navigation space for vessels. In adverse weather conditions (fog, storms), ships may lose orientation and collide with turbines. Small boats and fishing vessels may inadvertently enter restricted areas, posing risks to both the vessels and the wind power system.

Several life cycle assessment (LCA) studies of wind turbines have concluded that environmental impacts arise from three main sources:

- Bulk waste from the tower, gearboxes, transformers, blades and foundations, although a high percentage of the steel and blades can be recycled.
- Hazardous waste from nacelle components - air conditioning coolant, hydraulic oil, coating of electronic circuits, electrical cables, etc.
- Greenhouse gases (e.g. CO₂ from steel production and solvents from surface coatings).

Research and development

Besides the R&D potential described in the chapter *Onshore Wind Power*, offshore technology development is expected to include the following:

- Further upscaling of wind turbine capacities and hub heights, but also industrialisation of current wind turbine capacities and their expected benefits.
- New or improved types of fixed and floating foundations suitable for industrialisation,
- Development of compact offshore substations, including HVDC converter stations, circuit switches and cables. HVDC systems are commercially available today, but are assumed to be economically viable only at grid connection distances above ~100km,
- Multi-terminal HVDC to integrate large amounts of offshore wind power into a future offshore meshed grid system,
- Improvement of design methods in planning and plant layout by reducing wake losses, operation and maintenance costs, e.g. improvements in monitoring and control strategy through the use of AI technologies and maintenance strategy through the use of robots and drones.
- Improved methods of dealing with different seabed conditions, thereby reducing foundation costs and associated risks.
- Improved availability and reliability by incorporating the capability for fault tolerant subsystems through advanced built-in monitoring and control functions to ensure the operation of the entire wind farm.
- Development of offshore wind turbines combined with integrated hydrogen production capability and a battery storage system for direct connection to the future hydrogen network.
- Improvements in mesoscale wake phenomena - modelling and analysis of mesoscale wake losses to better understand the impact of multi-GW wind farms on regional wind speeds.

Fixed-bottom offshore wind projects in Europe and China have achieved availability levels of 95–98% thanks to optimized operation and maintenance (O&M) processes. The application of remote monitoring technologies has significantly reduced unplanned downtime, bringing availability close to ideal levels despite harsh marine conditions. Major developers such as Ørsted, Equinor, and Vattenfall have already integrated Digital Twin technology into standard operating procedures for offshore wind farms in the North Sea and Asia. Digital Twins go beyond simple parameter visualization and are now capable of automated diagnostics. For example, these systems can detect micro-cracks in turbine blades or corrosion at foundation structures before they are visible to the naked eye, helping to reduce maintenance costs by 20–30%. At the wind-farm level, Digital Twins enable the optimization of yaw angles of upstream turbines to mitigate wake effects on downstream turbines, thereby increasing total project energy output by an additional 1–2% [41]. In 2025, entities such as PTSC and international joint ventures are studying the application of Digital Twin technology to offshore substations and pilot projects. This has become a mandatory requirement in international tenders to ensure transparency and safety throughout the project lifecycle, which typically spans 25–30 years.

Currently, Vietnam does not yet fully manufacture offshore wind turbines, but some domestic companies have begun participating in the supply chain for equipment and structures serving this sector. PTSC (PetroVietnam Technical Services Corporation) is one of the pioneering companies in offshore structural fabrication. Specifically, in May 2023, PTSC won a bid and signed a contract with Ørsted Group to manufacture and supply 33 wind turbine foundations for the CHW2204 offshore wind farm project in Taiwan (China), with a total capacity of 920 MW. PTSC has also signed and is executing contracts for the design and fabrication of nine offshore substations (OSS) for offshore wind projects in Taiwan (China) and Europe (Baltic Sea region) [[23]]. In addition, Doosan Vina – a subsidiary of Doosan Enerbility,

headquartered in the Dung Quat Economic Zone (Quang Ngai) – signed a memorandum of understanding with Ørsted to develop the supply chain for monopile foundations and offshore components for wind projects in Southeast Asia, the Asia-Pacific region, and Europe. With over 15 years of experience manufacturing equipment for power plants, chemical plants, and port infrastructure, Doosan Vina has the potential to become a leading manufacturer of foundations and mechanical structures in the regional offshore wind supply chain [[24]].

Examples of current projects

Currently, offshore wind projects in Vietnam are expected to come into operation around 2030. Projects under study tend to select wind turbines with a capacity of approximately 16–20 MW, rotor diameters of about 240–280 m, and hub heights of around 140–180 m. Turbines with capacities of 18 MW or higher are still under testing, and no real projects have yet used these turbines. However, some manufacturers are planning to commercialize 18 MW turbines in the near future, so larger-capacity turbines are expected to be launched soon. Wind speeds in offshore areas with high potential for wind power development in Vietnam, such as the South-Central Coast, are around 8–9 m/s, suitable for the latest-generation offshore wind turbines with high capacity.

Since these projects are still at the research stage, the specific choice of offshore wind turbines will be finalized after surveys and measurements are conducted in potential sea areas.

Future demand offshore

In the future, it is expected that the offshore wind technologies face the following challenges:

- More focus on biodiversity and other environmental issues due to larger and more numerous projects.
- More demands on participation in grid regulation and grid expansion in general.
- New solutions for storing the produced power, like Power-to-X solutions.
- Sustainability requirements will also play a large role going forward.

Floating offshore wind

Floating offshore wind is in rapid development. While the application of bottom-fixed offshore wind is currently limited to water depths of 60 m or less, floating technologies can in principle be applied at any water depth above 30–40 m. Practical applications are likely to be limited to water depths less than 1,000–1,500 m due to the cost of mooring systems, but even so IEA has estimated that the commercially viable floating offshore wind resource may exceed the world's total electricity consumption by up to a factor of 10 [[36]].

Three main concepts of floating substructures are available, differing in the way they obtain the floating stability that is required to keep the turbine upright under all wind and wave conditions. The spar buoy concept relies on ballast for stability, having the centre of gravity of the total assembly below the centre of buoyancy. The semisubmersible concept relies on buoyancy for stability. It has lateral columns that penetrate the waterplane and are submerged to a varying degree when the turbine heels over due to bending moments caused by wind and wave loads, and the differences in buoyancy as a function of the submersion of the columns creates the restoring moment. The tension leg platform (TLP) concept relies on the mooring system for stability. It has vertical or near-vertical mooring lines that are kept taut by the buoyancy on the substructure, and bending moments caused by wind and wave loads are countered by a restoring moment arising out of differences in line tension [[39]].

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

In floating wind, the wind turbines are typically installed on the floating substructures at the quayside using land-based cranes. Towing of the fully assembled structure and hook-up to the pre-laid mooring system at the installation site can be carried out with large tugs, anchor handlers or similar vessels of a few thousand tons displacement, thereby eliminating the need for large and expensive installation vessels. A wide range

of mooring systems are available, most commonly three or more drag anchors are connected to the floating substructure with a combination of chains and wire ropes. So-called dynamic cables are used as array cables; they are ordinary subsea cables fitted with additional steel wire reinforcement ensuring that bending resulting from substructure movement is kept within a range that minimizes fatigue loading on the cable conductors.

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

At the present time, only a limited number of floating substructures have been demonstrated. The first demonstrators were installed around 2010 by Equinor (a spar buoy concept) and Principle Power (a semisubmersible concept), and both of these parties have subsequently demonstrated their technologies in small wind farms. A barge-type variant of the semisubmersible concept was installed by the French company Ideol in 2017, and a spar buoy was installed by the Danish company Stiesdal Offshore Technologies in 2021 [[39]].

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

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

Floating Power Plant has developed the FPP Platform, a substructure integrating wind and wave power. A first full-scale demonstration project may be installed at the PLOCAN test site of the Canary Islands as early as 2024.



Figure 62: The Stiesdal TetraSpar full-scale demonstration project in 2021 [[40]].

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Data sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (\$), price year 2025

Offshore Wind (fixed bottom)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW _e		15	20	25	12	18	20	35		1, 2, 5
Generating capacity for a typical power plant	MW _e		500	1000	1500	100	1000	100	2000		1, 2, 5
Forced outage	%		4.0	3.0	2.5	1.0	5.0	1.0	5.0	A	2
Planned outage	%		0.3	0.3	0.3	0.1	0.5	0.1	0.5	A	2
Technical lifetime	years		27	30	30	25	40	25	40	B	
Construction time	years		3	3	2.5	2.5	4	2	3.5	C	2, 3
Space requirement	1000 m ² /MW _e		200	167	125	182	222	91	111	D	1
Additional data for non-thermal plants											
Capacity factor, theoretical	%		46.5	47.2	47.0	41.7	53.7	47.0	57.5	E	
Capacity factor, incl. outages	%		44.5	45.7	45.7	40.0	51.4	45.7	55.9	E	
Economic data (in USD2025)											
Specific investment, total system	MUSD/MW _e		4.30	3.69	3.45	3.70	5.50	2.56	4.55	F, G, H, I	1, 2, 4, 5, 6
- of which equipment	%		55	55	55	-	-	-	-	G, J	2, 5
- of which installation	%		30	30	30	-	-	-	-	G, J	2, 5
- of which grid connection	%		15	15	15	-	-	-	-	G, J	2, 5
- of which equipment	MUSD/MW _e		2.37	2.03	1.90	2.04	3.03	1.41	2.50	G, H, I	
- of which installation	MUSD/MW _e		1.29	1.11	1.03	1.11	1.65	0.77	1.36	G, H, I	
- of which grid connection	MUSD/MW _e		0.65	0.55	0.52	0.56	0.83	0.38	0.68	G, H, I	
Fixed O&M	USD/MW _e /year		150,500	133,245	128,736	129,500	192,500	100,000	175,000	H, K	5
Variable O&M	USD/MW _h		-	-	-	-	-	-	-	K	
Technology specific data											
Average annual full-load hours	MWh _e /MW _e		3,900	4,000	4,000	3,500	4,500	4,000	4,900	E	2, 5
Hub Height	m		150	170	190	-	-	-	-		1, 2
Rotor Diameter	m		236	280	320	-	-	-	-		1, 2
Specific Power	W/m ²		343	325	311	-	-	-	-		1, 2
Availability	%		95.7	96.7	97.2	-	-	-	-		
Avg. water depth	m		30	30	30	20	40	20	40		4, 5
Export cable length, per circuit	km		80	80	80	50	150	50	150		4, 5
Distance to O&M Port	km		65	65	65	45	75	45	75		4, 5
Water consumption			0	0	0	-	-	-	-		7, 8

Notes:

General: The datasheet represents a project using AC and monopile as foundation. Data is presented as FID years and 2025 has not been included as the first offshore wind projects will be installed after 2030 with FID close to 2030.

A Offshore turbines have typically higher forced outage than onshore due to access problems in harsh weather.

B The life time depends on the wind conditions; average annual speed and turbulence, relative to the design class of the turbine

- C Calculated based on average spacing of 8 RD between turbines and a square layout. Space requirement is highly depending on site size, layout and chosen distance between turbines.
- D Construction time is from FID to commercial production.
- E Capacity factor and average annual full load hours depend greatly on the specific project site and can vary a lot. For sites with different wind conditions than 3,900 average annual full load hours mentioned here (for 2030), the capacity factor should be adjusted accordingly.
- F The specific investment cost includes all physical equipment and installation of the turbines (EPC), foundations (monopile), grid connection (excl. grid reinforcements), inter-array cables, offshore substation and export cables to the point of connection at the coastline as well. It excludes VAT and other taxes, financing costs, costs related to renting or buying of land, costs incurred before FID e.g. predevelopment costs (administration, consultancy, project management, site preparations, approvals/permits, etc.), onshore cables and decommissioning costs.
- G Equipment: Cost of turbines, foundations, including transportation. Installation: Electrical infrastructure of turbine, array- and export cables, substation, civil works, planning and management. Grid connection: Cost of export cables and substation. The split of cost may vary considerably from project to project.
- H Cost are projected with a learning rate approach assuming a region-specific learning rate on 10% learning rate from 2030 to 2040, which is lower than the global 15% from IEA WEO 2025 and the 18.3% from [6]. From 2040 to 2050 a learning rate of 15% from IEA WEO 2025 have been applied. The learning rate for OPEX is set at 8% for all years. A lower learning rate was chosen for 2030 to 2040, because the offshore sector in Vietnam is still in early stages of development. There is high uncertainty given the nascent market stage, which could result in higher learnings after the first of a kind (FOAK) project than the 10% included from 2030 to 2040. Learning is linked to the capacity projections of the IEA's World Energy Outlook 2025, with the scenario Stated Policies for the central values and the scenarios Current Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.
- I Lower uncertainties for 2050 are calculated by using the added capacities from the Net Zero Emissions by 2050 scenario from [9] with a learning rate of 15% from 2030-2050 and the upper uncertainties are calculated by using the added capacities from the Current Policies scenario from [9] with a learning rate of 10% from 2030-2050.
- J The cost breakdown of 55%, 30% and 15% is based on local and regional information, but it can vary significantly based on site characteristics.
- K O&M corresponding to 3.5% of CAPEX/year. All O&M assumed as fixed cost. In reality, some O&M will be variable, but given the high spread in possible capacity factors, all O&M is for simplicity accrued under fixed O&M.

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Offshore Wind (floating)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e		6	8	10	8	15	15	25		1, 2
Generating capacity for a typical power plant	MW_e		200	500	1000	50	500	50	3,000		1
Forced outage	%		3.0	2.5	2.0	1	5	1	5		1, 2, 3
Planned outage	%		0.3	0.3	0.3	0.1	0.5	0.1	0.5		1, 2, 3
Technical lifetime	years		30	30	30	20	35	20	35	A	2, 3
Construction time	years		2.5	2.5	2.5	1.5	4.0	1.5	4.0		1, 3
Space requirement	1000 m²/MW_e		279	209	167	251	313	125	200	B	
Additional data for non-thermal plants											
Capacity factor, theoretical	%		35.4	36.5	36.5	-	-	-	-		1
Capacity factor, incl. outages	%		34.3	35.6	35.8	-	-	-	-		
Economic data (in USD2025)											
Specific investment, total system	MUSD/MW_e		5.59	4.79	4.59	5.03	6.71	2.98	6.19	C, D, E, F	3, 4
- of which equipment	%		60	60	60	-	-	-	-	G	
- of which installation	%		30	30	30	-	-	-	-	G	
- of which grid connection	%		10	10	10	-	-	-	-	G	
- of which equipment	MUSD/MW_e		3.35	2.88	2.75	3.02	4.02	1.79	3.72	E, F	
- of which installation	MUSD/MW_e		1.68	1.44	1.38	1.51	2.01	0.89	1.86	E, F	
- of which grid connection	MUSD/MW_e		0.56	0.48	0.46	0.50	0.67	0.30	0.62	E, F	
Fixed O&M	USD/MW_e/year		195,650	167,747	160,607	176,085	234,780	104,394	216,819	C, E, H	2, 3, 4
Variable O&M	USD/MWh		-	-	-	-	-	-	-	H	
Technology specific data											
Average annual full-load hours	MWh_e/MW_e		3,007	3,120	3,136	-	-	-	-		
Hub height	m		120	130	140	-	-	-	-		
Rotor diameter	m		164	220	250	-	-	-	-		
Specific power	W/m²		284	210	204	-	-	-	-		
Availability	%		97.0	97.5	98.0	-	-	-	-		
Water consumption			0	0	0	-	-	-	-	-	6, 7

Notes:

- A The life time depends on the wind conditions; average annual speed and turbulence, relative to the design class of the turbine.
- B Calculated based on average spacing of 8 RD between turbines and a square layout. Space requirement is highly depending on site size, layout and chosen distance between turbines.
- C For the initial cost CAPEX and OPEX assessments, it is assumed that Floating offshore is 30% more expensive than fixed bottom offshore.
- D 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.

- E Costs are projected with a learning rate approach assuming a 10% learning rate based on IEA, and 8% learning rate for OPEX. There is high uncertainty given the nascent market stage, which could result in higher learnings after the first of a kind project. Learning is linked to the capacity projections of the IEA's World Energy Outlook 2025, with the scenario Stated Policies for the central values and the scenarios Current Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.
- F Lower and upper uncertainties are -10% (lower) and +20% (higher) for 2025 and +/-35% for 2050.
- G Cost breakdown can vary significantly based on site characteristics. Here it is assumed to be the same split as for nearshore wind: 60%, 30% and 10% for equipment based on local (nearshore wind) projects, installation and grid connection are assumed for modelling purposes only.
- H O&M corresponding to 3.5% of CAPEX/year. All O&M assumed as fixed cost. In reality, some O&M will be variable, but given the high spread in possible capacity factors, all O&M is for simplicity accrued under fixed O&M.

References

- 1 Danish Energy Agency and Ea Energy Analyses, 2023 - Viet Nam Technology Catalogue for Power Generation
- 2 Danish Energy Agency, 2025 - Colombian Technology Catalogue for Generation and Storage of Electricity
- 3 Danish Energy Agency, 2024 - Danish Technology Catalogue for Generation of Electricity and District Heating
- 4 IEA, World Energy Outlook, 2025
- 5 Danish Energy Agency and Ea Energy Analyses, 2024 - Technology Data for the Indonesian Power Sector: Catalogue for Generation and Storage of Electricity
- 6 World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity
- 7 U.S. Energy Information Administration, 2023 - U.S. electric power sector continues water efficiency gains

Offshore Wind (nearshore)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW _e	5	6	8	10	4	8	6	15		1
Generating capacity for a typical power plant	MW _e	150	200	300	500	50	500	50	3,000		1
Forced outage	%	4.0	3.0	2.5	2.0	1.0	5.0	1.0	5.0	A	
Planned outage	%	0.3	0.3	0.3	0.3	0.1	0.5	0.1	0.5	A	
Technical lifetime	years	27	30	30	30	20	35	20	35	A, B	1, 2
Construction time	years	2.5	2.0	2.0	1.5	1.5	4.0	1.5	4.0		1
Space requirement	1000 m ² /MW _e	334	279	209	167	300	375	125	200	C	2
Additional data for non-thermal plants											
Capacity factor, theoretical	%	34.2	35.4	36.5	36.5	28.5	40.0	32.0	45.7		1
Capacity factor, incl. outages	%	32.8	34.3	35.6	35.8	28.3	38.0	31.6	43.4		1
Economic data (in USD2025)											
Specific investment, total system	MUSD/MW _e	2.70	2.38	2.11	2.04	2.43	3.24	1.32	2.75	D, E, H	1, 3
- of which equipment	%	60	60	60	60	-	-	-	-	F	1
- of which installation	%	30	30	30	30	-	-	-	-	F	1
- of which grid connection	%	10	10	10	10	-	-	-	-	F	1
- of which equipment	MUSD/MW _e	1.62	1.43	1.27	1.22	1.46	1.94	1.12	1.24		
- of which installation	MUSD/MW _e	0.81	0.71	0.63	0.61	0.73	0.97	0.56	0.62		
- of which grid connection	MUSD/MW _e	0.27	0.24	0.21	0.20	0.24	0.32	0.19	0.21		
Fixed O&M	USD/MW _e /year	94,500	86,102	78,662	76,678	40,000	100,000	25,000	45,000	G, H	
Variable O&M	USD/MWh	-	-	-	-	-	-	-	-	G	
Technology specific data											
Average annual full-load hours	MWh _e /MW _e	3,000	3,100	3,200	3,200	2,500	3,500	2,800	4,000		1
Hub Height	m	110	120	130	140	-	-	-	-		1
Rotor Diameter	m	145	164	220	250	-	-	-	-		1
Specific Power	W/m ²	303	284	210	204	-	-	-	-		1
Availability	%	95.7%	97.0%	97.5%	98.0%	-	-	-	-		
Water consumption		0	0	0	0	-	-	-	-		4, 5

Notes:

- A There is no substantial difference between intertidal and offshore wind outage and lifetime. However, towing is a less lengthy process.
- B The life time depends on the wind conditions; average annual speed and turbulence, relative to the design class of the turbine.
- C Calculated based on average spacing of 8 RD between turbines and a square layout. Space requirement is highly depending on site size, layout and chosen distance between turbines.
- D 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.
- E Lower and upper uncertainties are -10% (lower) and +20% (higher) for 2025 and -/+35% for 2050.

- F Cost breakdown can vary significantly based on site characteristics. Here 60%, 30% and 10% for equipment based on local projects, installation and grid connection are assumed for modelling purposes only.
- G O&M corresponding to 3.5% of CAPEX/year. All O&M assumed as fixed cost. In reality, some O&M will be variable, but given the high spread in possible capacity factors, all O&M is for simplicity accrued under fixed O&M.
- H Costs are projected with a learning rate approach assuming an 8% learning rate and 6% learning rate for OPEX. There is high uncertainty given the nascent market stage, which could result in higher learnings after the first of a kind project. Learning is linked to the capacity projections of the IEA's World Energy Outlook 2025, with the scenario Stated Policies for the central values and the scenarios Current Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.

References

- 1 Existing projects in Vietnam
- 2 Danish Energy Agency, 2024 - Danish Technology Catalogue for Generation of Electricity and District Heating
- 3 Stakeholder dialogue
- 4 World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity
- 5 U.S. Energy Information Administration, 2023 - U.S. electric power sector continues water efficiency gains

10. 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 2024, 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].

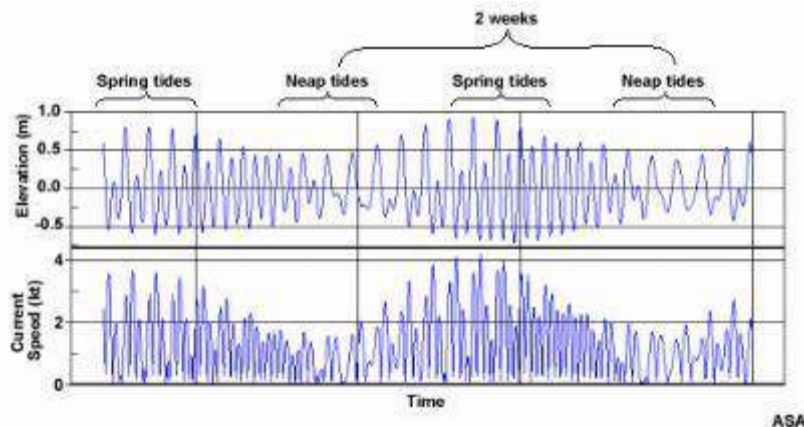


Figure 63: Time series representation of spring and neap tide along with correlation with tidal current speed variation.[3]

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.

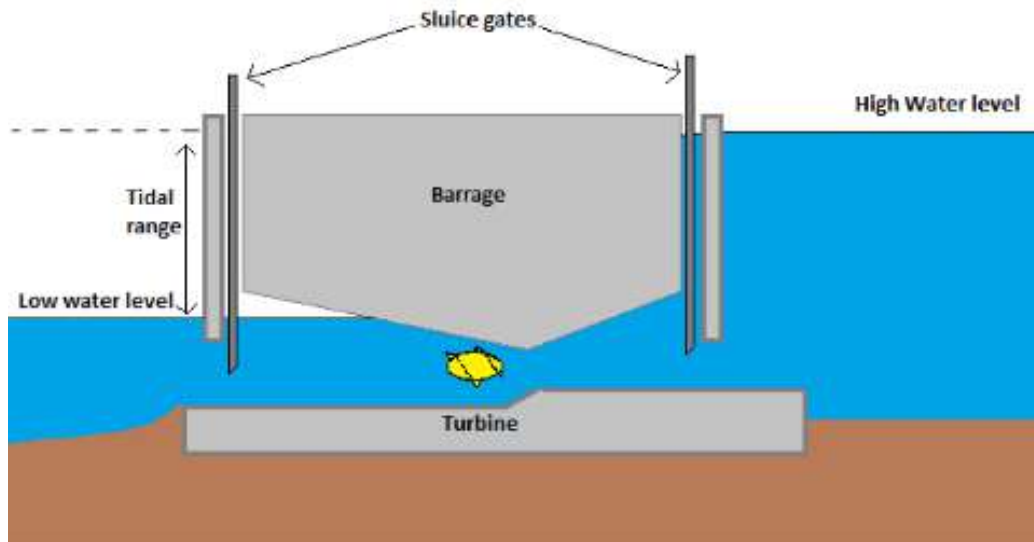


Figure 64: Schematic of tidal impoundment type plant.[4]

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.

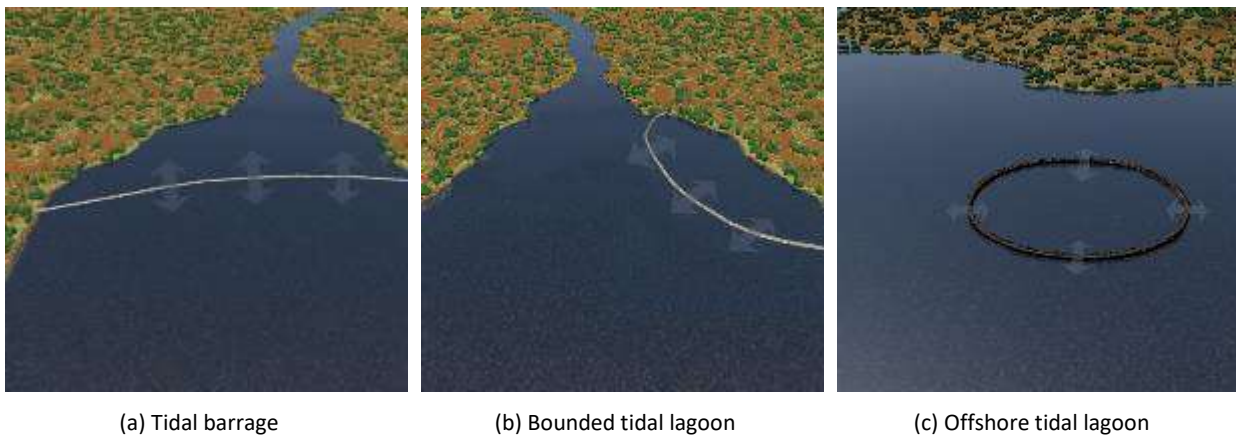


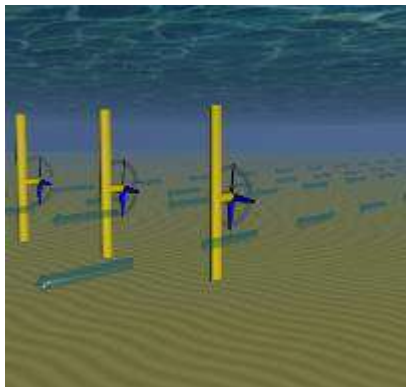
Figure 65: Tidal impoundment types [2]

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.

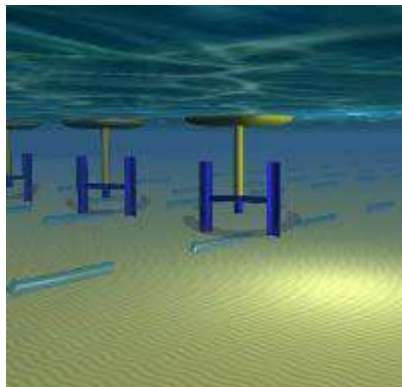
The types of turbine technologies for tidal stream plants are [2][5]:

- *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.

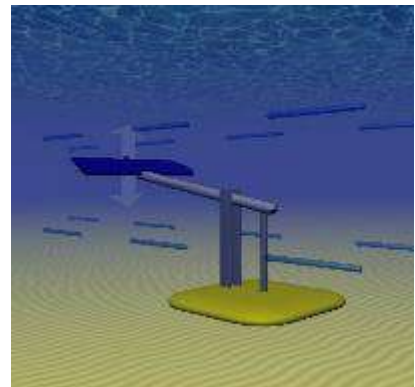
Most horizontal and vertical axis turbine use blades that are connected to a central rotor shaft, which through a gearbox, is connected to a generator shaft. Another type, called open-centre turbines, have a different design with the blades mounted on an inner, open centred shaft, housed in a static 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].



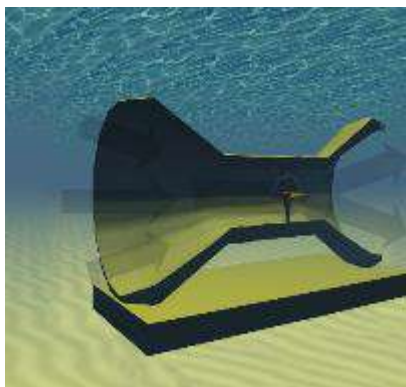
(a) Horizontal axis turbine



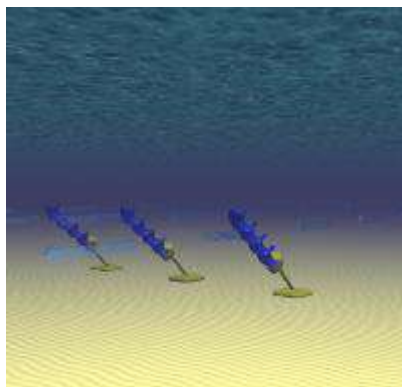
(b) Vertical axis turbine



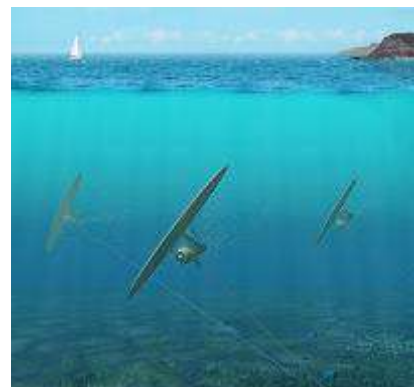
(c) Oscillating hydrofoil



(d) Enclosed Tips (Venturi effect device)



(e) Archimedes screw



(f) Tidal kite

Figure 66: 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.

As of the end of 2024, the total global installed capacity of tidal power (ocean power, focusing on tidal technologies) was estimated at around 513 MW, with an additional 1.6 MW commissioned in 2024. Of this capacity, two tidal range (barrage) systems — the La Rance Tidal Power Station in France (240 MW) and the Sihwa Lake Tidal Power Station in South Korea (254 MW) — account for the majority of operational capacity, underscoring that tidal barrage remains the leading technology that has achieved commercial-scale deployment.

Alongside large-scale tidal barrage systems, tidal stream (in-stream turbine) technology is emerging as the main development pathway, particularly in Europe and in countries with significant tidal resources, as it helps address site constraints and high upfront costs associated with barrage technology. In Europe, over the next five years, 11 tidal stream projects with a total capacity of 152 MW are expected to be deployed at pre-commercial sites, most of which receive public funding and revenue-support mechanisms [26]. The United Kingdom, the global leader in tidal energy, has an estimated 11 GW of tidal power potential—enough to meet 11% of national electricity demand if fully exploited. This potential is being advanced through the Contracts for Difference (CfD) scheme, which guarantees a fixed strike price for renewable power generators; although tidal energy has competed in CfD auctions since 2014, the sector only began receiving dedicated public financial support in 2021. By the end of 2024, six new tidal energy projects had been awarded, bringing the UK’s total project pipeline to roughly 130 MW expected to come online by 2029 [27].

Beyond Europe, research and development of tidal stream technologies is expanding in North America and the Asia-Pacific region, supported by public programmes, funding and R&D initiatives in Canada, the United States and China, although operational capacity remains very limited. Despite substantial global resource potential, tidal power still accounts for only a very small share of total renewable energy capacity, and the prospects for scaling up depend heavily on the effectiveness of policy support, financial investment and technological progress in the coming years.

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)).

Piled: 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.

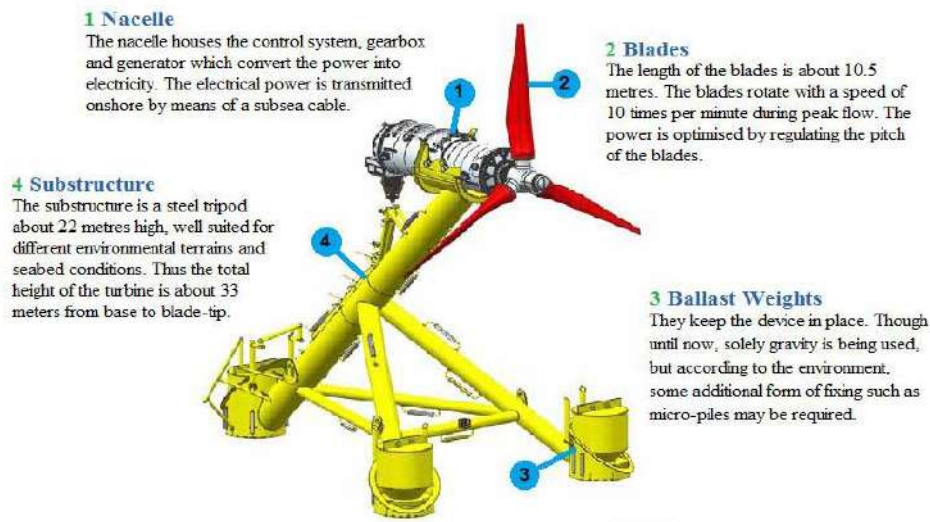


Figure 67: Early gravity based substructure design [8]

- *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.

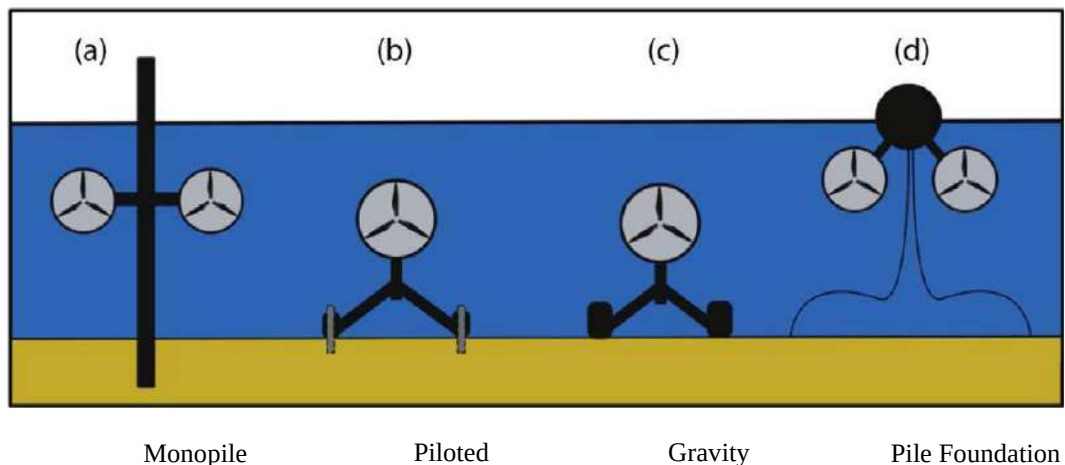


Figure 68: Foundation types: First generation devices [7]



Figure 69: 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.

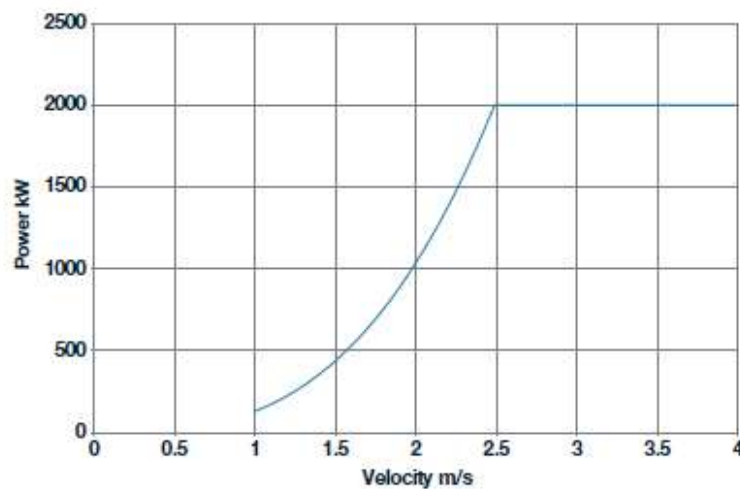


Figure 70: Sample power curve for tidal stream turbine.[9]

Globally most 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.

Water consumption

The turbines or other conversion technologies used to generate electricity are typically submerged in the water and do not consume water in the process.

However, some water may be used in auxiliary systems, such as cooling systems for the electrical equipment or for maintenance and cleaning of the turbines. Additionally, water may be used in the manufacturing process of the tidal power equipment, but this is not directly related to the operation of the tidal power plant.

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 are possible due to tidal impoundment projects .
- 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 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.

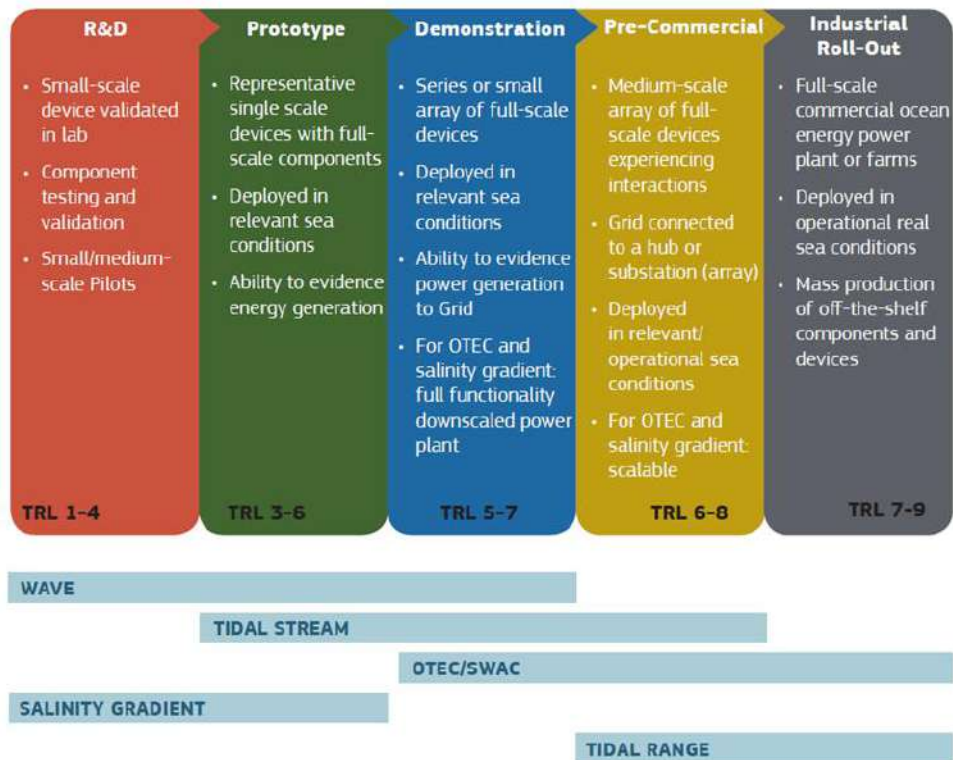


Figure 71: Where ocean energy technologies are in the stages of development [14]

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 72: 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 is bound to reduce costs, lesser outage periods and increase plant lifetimes.

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 Quoy, 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 Sihwa Lake Tidal Power Station (South Korea) is currently the largest tidal power plant in the world in terms of installed capacity, at 254 MW. The project began commercial operation in November 2011 and employs ten horizontal-axis bulb-type turbine generators, each rated at 25.4 MW. The facility harnesses an average tidal range of approximately 5.6 metres in Gyeonggi Bay through a 12.7-kilometre seawall. The reservoir covers a surface area of about 43.8 km², with an operational water level designed to vary between –4.0 metres and +4.0 metres relative to sea level. Its estimated annual renewable electricity production is approximately 552.7 GWh [25].

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.

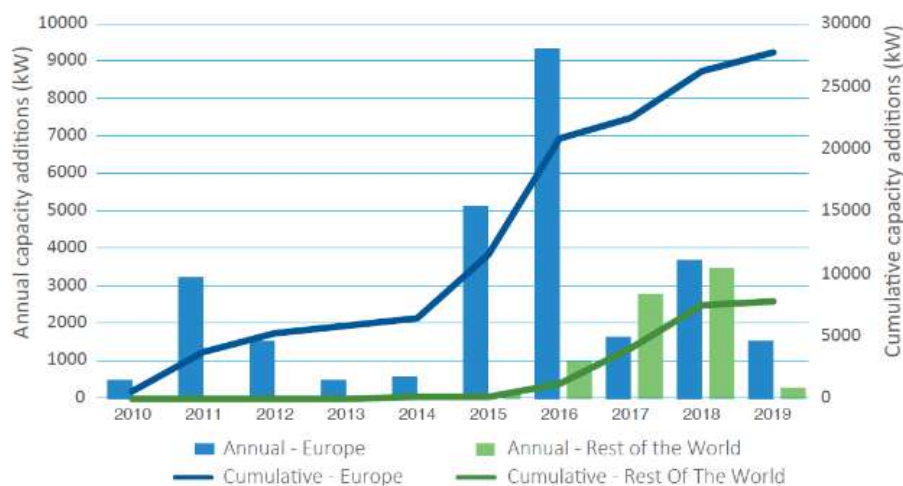


Figure 73: Installed and cumulative tidal stream energy capacity.[17]

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 2025 US dollars and applicable inflation.

Investment Cost for Tidal Impoundment:

The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - Tidal power Impoundment type						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		6.8	6.4			6.3
Technology Catalogue - Indonesia 2024		6.13	5.70			5.70
Technology Catalogue - Vietnam 2023	6.96		6.46			6.46
IEA WEO 2025 – India*		6.5		4.25		2.8
IEA WEO 2025 – China*		6.6		4.25		2.8
*Capital cost for the Marine (tidal & wave) power generation						

The recommended values for 2025 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 cost [Million USD 2025 / MW] - Tidal power stream type						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		7.1	5.7			4.2
Technology Catalogue - Indonesia 2024		5.92	5.18			3.80
Technology Catalogue - Vietnam 2023	7.22		5.82			4.30
IEA WEO 2025 – India*		6.5		4.25		2.8
IEA WEO 2025 – China*		6.6		4.25		2.8
*Capital cost for the Marine (tidal & wave) power generation						

The recommended cost for tidal stream in 2025 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.

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Data sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2025.

Tidal power - Impoundment Type										
Parameter	Unit	2025	2030	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW_e	1	10	25	1	25	1	25	A	3
Generating capacity for total power plant	MW_e	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 m²/MW_e	0.2	0.2	0.2	0.1	0.3	0.1	0.3	D	
Additional data for non-thermal plants										
Capacity factor, theoretical	%	35	35	40	35	40	35	40	E	
Capacity factor, incl. outages	%									
Ramping configurations										
Ramping	% per minute	50	50	50	30	100	30	100	G	
Minimum load	% of full load	0	0	0	0	0	0	0	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	g/Nm³	0	0	0						
SO₂ (degree of desulphuring,)	%	0	0	0						
NOx	g/GJ fuel	0	0	0						
CH₄	g/GJ fuel	0	0	0						
N₂O	g/GJ fuel	0	0	0						
Economic data (in USD2025)										
Nominal investment	M\$/MW_e	6.8	6.4	6.3	3.6	9.3	3.6	9.3	E	1, 2, 4
- of which equipment	%									
- of which installation	%									
Fixed O&M	\$/MWe/year	88,145	77,811	44,446	29,133	89,639	29,133	89,639	E	1, 2, 3, 4
Variable O&M	\$/MWh	0	0	0						
Start-up costs	\$/MW_e/start-up									
Technology specific data										
Water consumption	L/MWh	0	0	0	-	-	-	-		

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.

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

Tidal power - Stream Type										
Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW_e	1	2	2	0.1	6	1	6	A	3, 5
Generating capacity for total power plant	MW_e	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 /MW_e									
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	g/Nm ³	0	0	0						
SO ₂ (degree of desulphuring,)	%	0	0	0						
NO _x	g/GJ fuel	0	0	0						
CH ₄	g/GJ fuel	0	0	0						
N ₂ O	g/GJ fuel	0	0	0						
Economic data (in USD2025)										
Nominal investment	M\$/MW_e	7.1	5.7	4.2	3.7	8.8	2.5	8.8	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	353,105	286,716	142,821	115,410	512,933	115,410	512,933	B	1, 2
Variable O&M	\$/MWh	15	11	9						4
Start-up costs	\$/MW_e/start-up									
Technology specific data										
Water consumption	L/MWh	0	0	0	-	-	-	-		

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.

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

11. WAVE POWER

Brief technology description

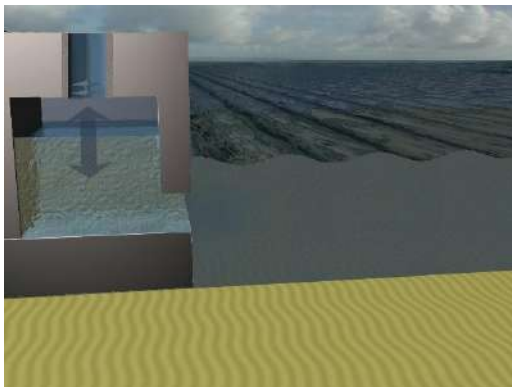
Under the marine energy umbrella, one of the technologies being explored is production of electricity from wave energy. These technologies aim to exploit the energy from the movement of waves.

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.

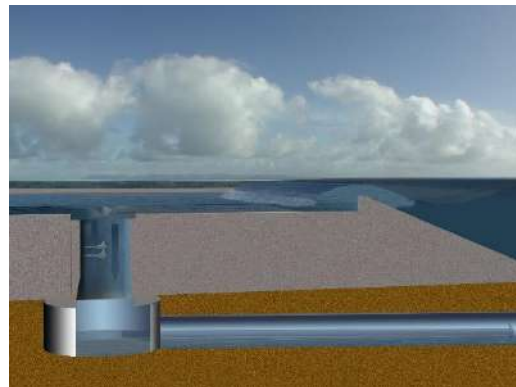
As this technology is still in the early stages of development, there are various types of wave energy devices being explored. The following are some of the first generation wave energy converters (WECs) being developed globally [1], [2]:

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 74: 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.

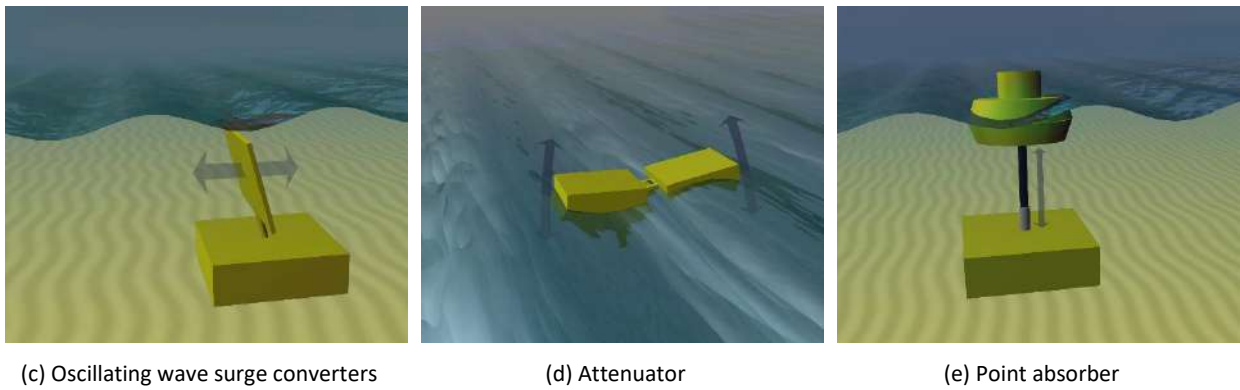


Figure 75: Wave energy collectors/convertors [2]

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.

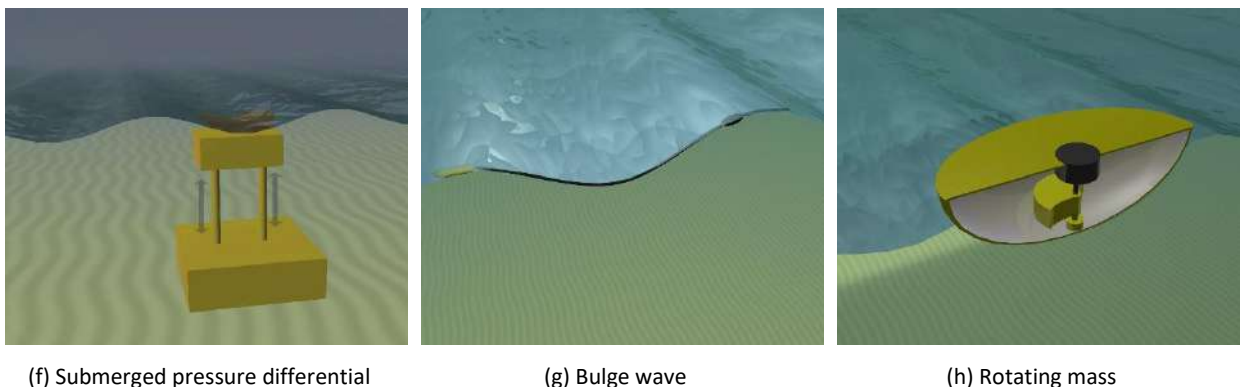


Figure 76: Wave energy collectors/convertors [2]

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.

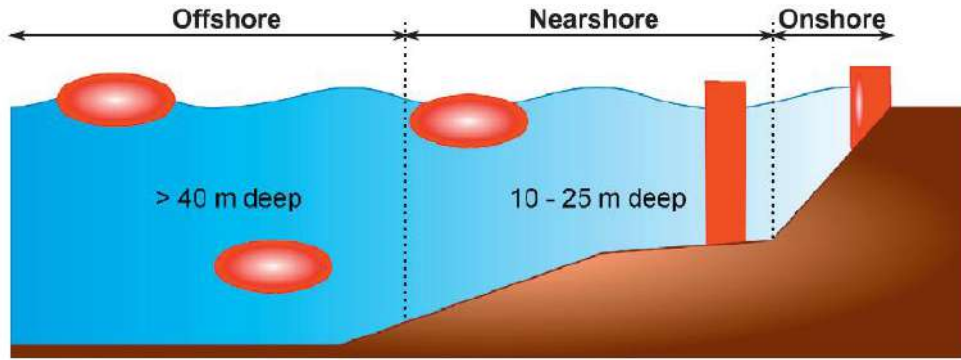


Figure 77: Location of wave energy converters [3]

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 the 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.

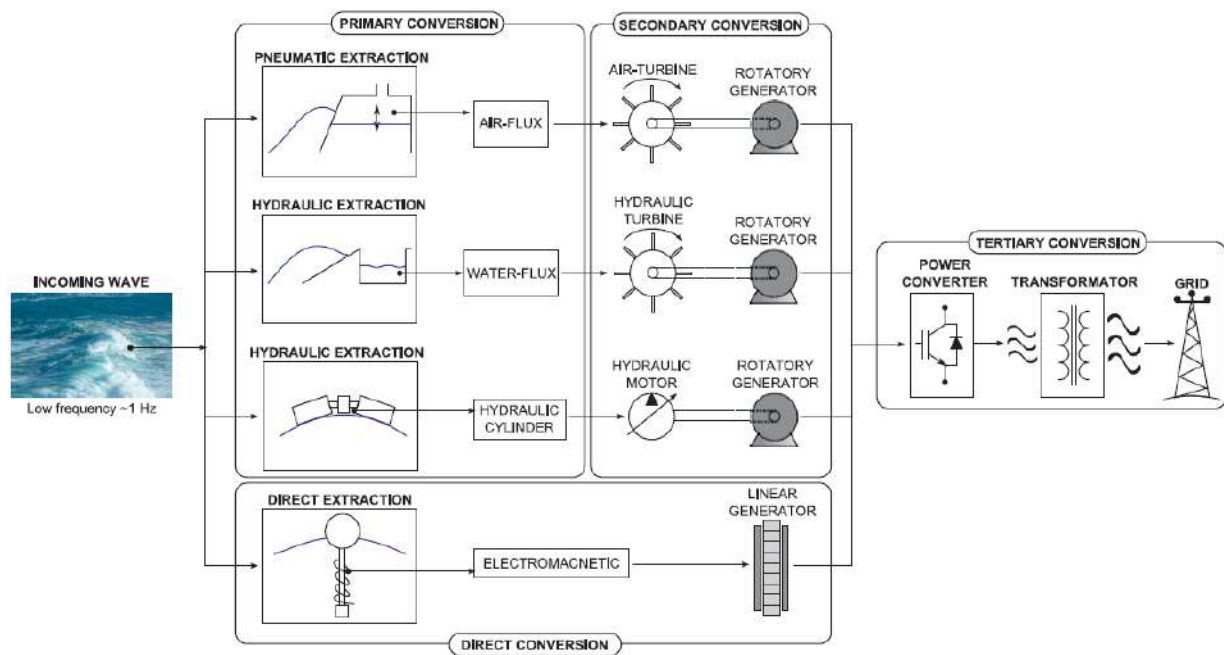


Figure 78: Wave energy conversion stages [3]

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.

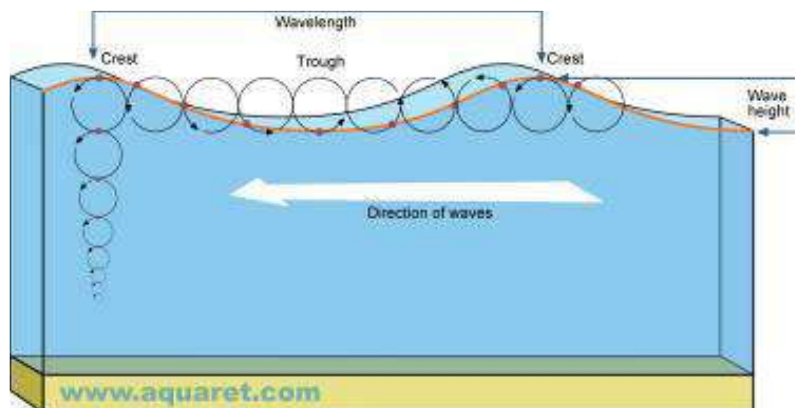


Figure 79: Wave characteristics [2]

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.

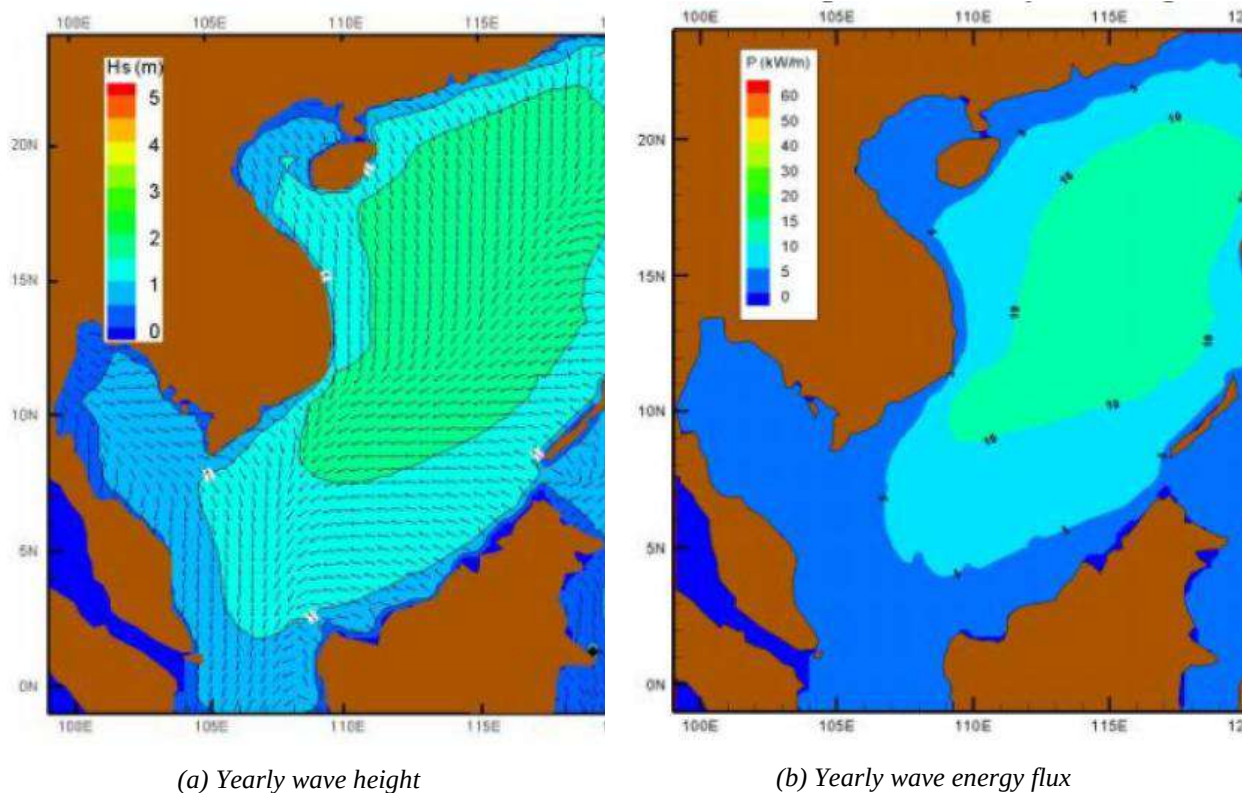


Figure 80: Wave energy resource in Viet Nam [7]

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 coastal 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.

Water consumption

The devices or systems used to convert wave energy into electricity are typically submerged in the water and do not consume water in the process.

Similar to tidal power, some water may be used in auxiliary systems, such as cooling systems for the electrical equipment or for maintenance and cleaning of the devices. However, these uses are minimal and do not contribute significantly to the overall water footprint.

The manufacturing process of wave power equipment may require some water, but this is not directly related to the operation of the wave power plant. Overall, the water footprint of wave power generation is negligible.

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]

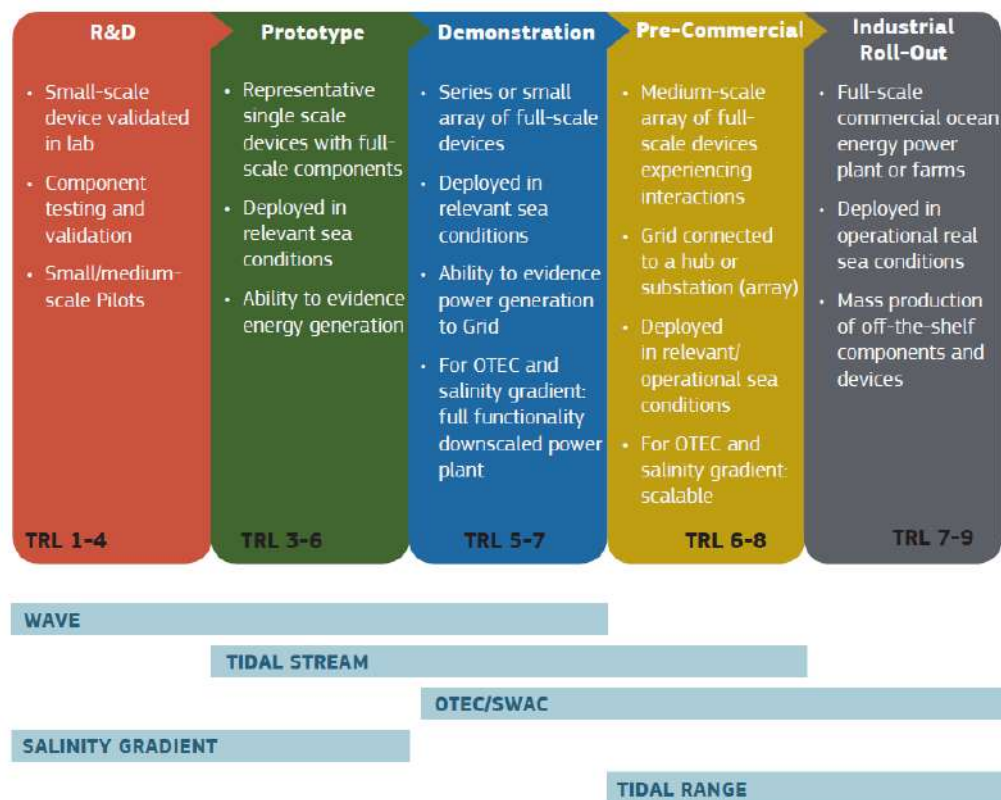


Figure 81: Where ocean energy technologies are in the stages of development [11]

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]

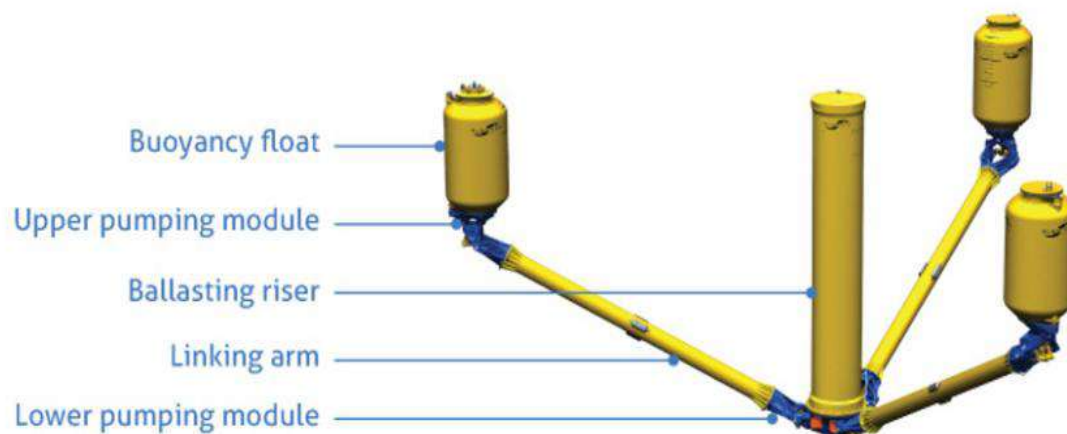


Figure 82: WaveNET [12]

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 83: 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.

Examples of current 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]

Investment cost estimation

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 84: 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

The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - Wave power						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		13.4	10.6			6.8
Technology Catalogue - Vietnam 2023	13.67		10.89			6.96
IEA WEO 2025 – India*		6.5		4.25		2.8
IEA WEO 2025 – China*		6.6		4.25		2.8
*Capital cost for the Marine (tidal & wave) power generation						

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.

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Data sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), year 2025.

Wave power										
Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Generating capacity for one unit	MW_e	0.2	0.2	0.2	0.1	0.5	0.1	0.5	A	4
Generating capacity for total power plant	MW_e	<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 m²/MW_e									
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	g/Nm³	0	0	0						
SO₂ (degree of desulphuring,)	%	0	0	0						
NOₓ	g/GJ fuel	0	0	0						
CH₄	g/GJ fuel	0	0	0						
N₂O	g/GJ fuel	0	0	0						
Economic data (in USD2025)										
Nominal investment	M\$/MW_e	13.4	10.6	6.8	5.1	23.2	3.4	11.6		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	615,022	384,700	288,836	179,278	1,052,011	89,639	486,788		1, 5
Variable O&M	\$/MWh									
Start-up costs	\$/MW_e/start-up									
Technology specific data										
Water consumption	L/MWh	0	0	0	-	-	-	-		

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.

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12. 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.

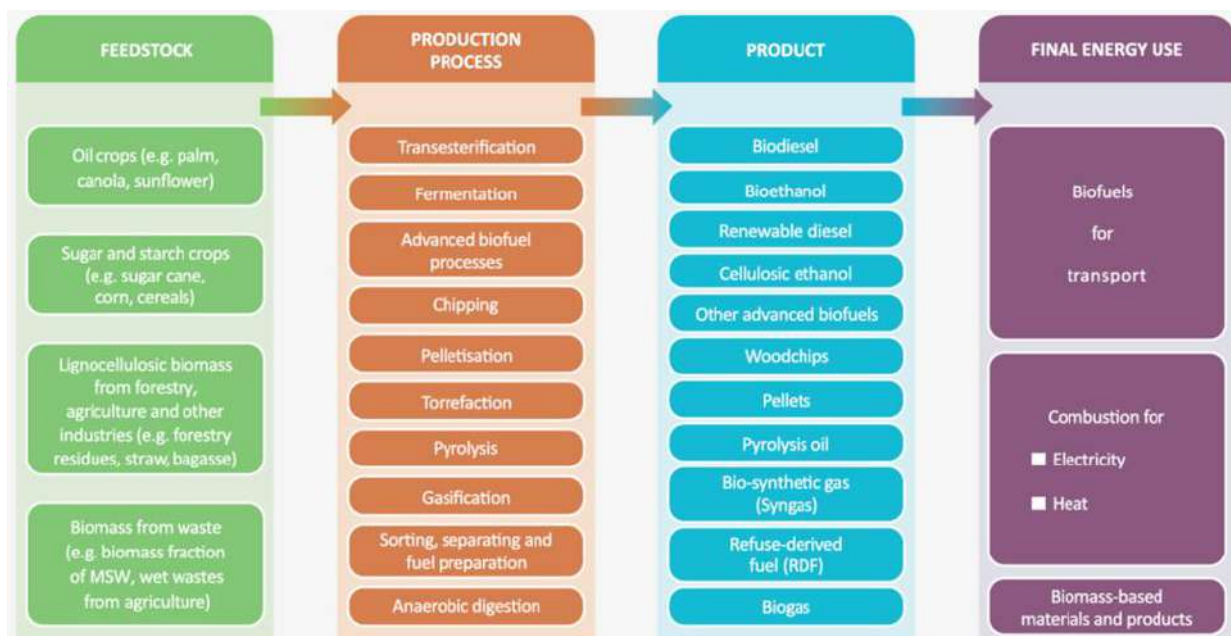


Figure 85: Biomass conversion paths [1]

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 to the mineral contents of the ash, the electric efficiency is lower – typically 15-35% [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 [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. The technical potential of biomass for electricity generation in Vietnam in the period up to 2030 is estimated more than 7 GW.

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

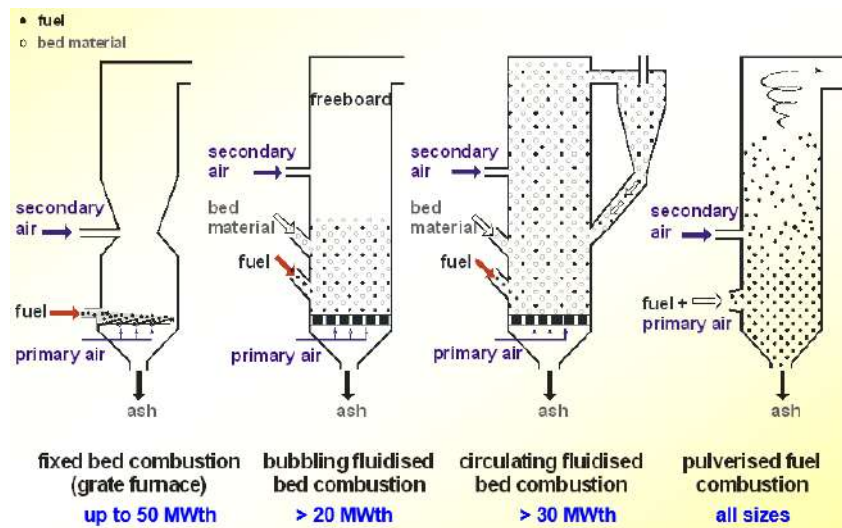


Figure 86: Technologies for industrial biomass combustion [4]

Table 24: Heating values of different biomass fuel types [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. [5].

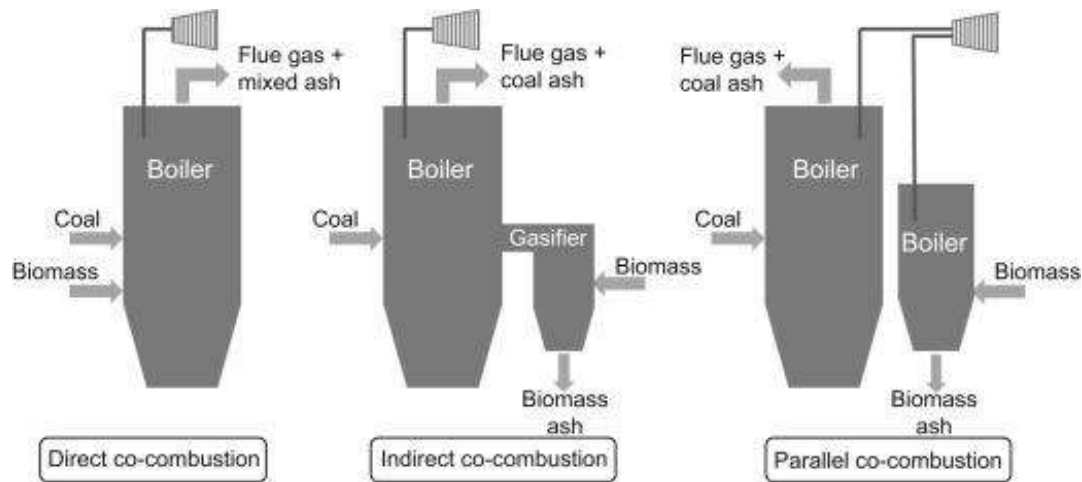


Figure 87: Different biomass co-firing configurations [15]

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 configurations

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 CO₂ 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 SO₂, NO_x and particles.

Water consumption

Water consumption varies significantly across different biomass-based power generation methods. According to a life-cycle analysis by Chinese researchers, a typical biomass direct-combustion power system in East Asia requires approximately 42.2 litres per kilowatt-hour (l/kWh). Notably, about 85% of this water usage occurs during the agricultural stage, emphasizing the significant water footprint of crop cultivation. The remaining 15 % is attributed to the operation and maintenance of the power plant itself. In contrast, a recent North American study reported much higher life-cycle water demands, ranging from 260 to 1,289 l/kWh, depending on the specific technology and regional factors.

Environment

The main ecological footprints from biomass combustion are persistent toxicity, climate change, and acidification. However, the footprints are small [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 88 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.

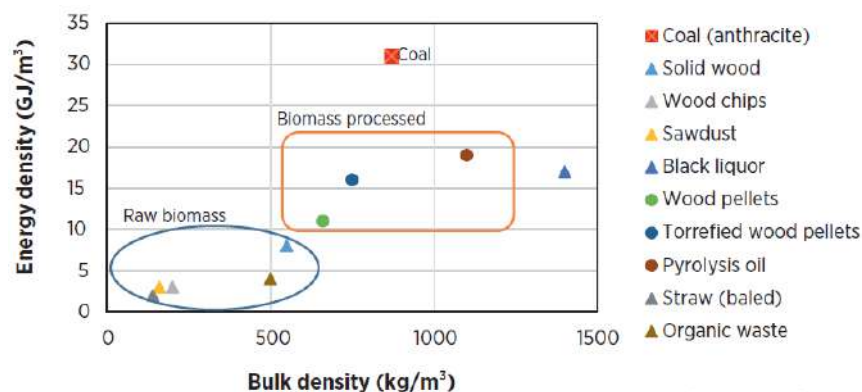


Figure 88: Energy density of biomass and coal [11].

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

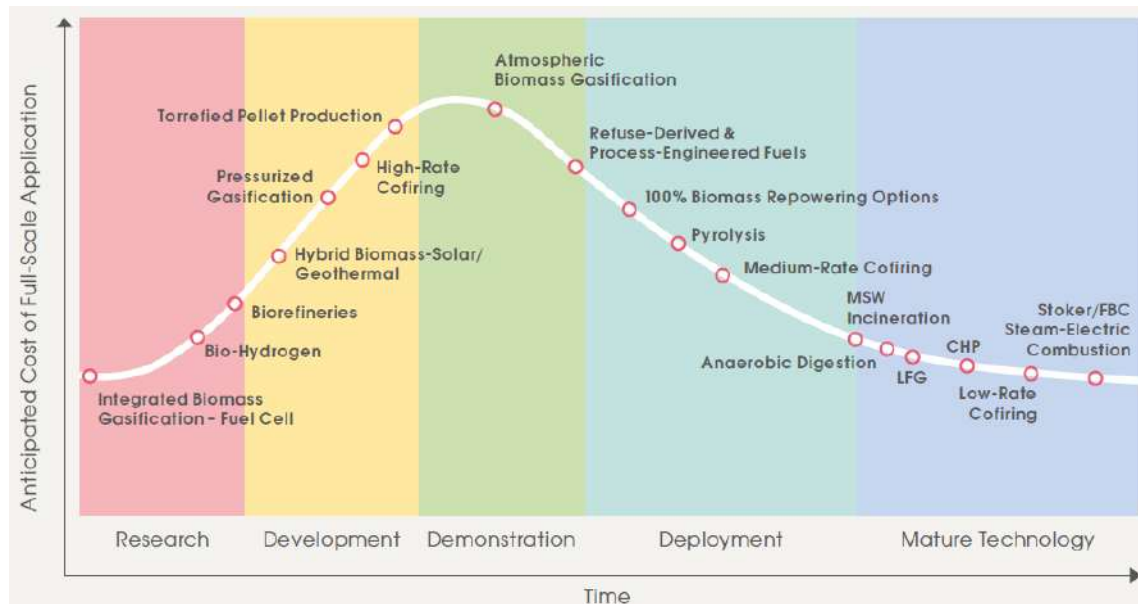


Figure 89: Biomass power generation technology maturity status [12]

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 25: Phase makeup of biomass pyrolysis products for different operational modes [13]

Mode	Conditions	Composition		
		Liquid	Liquid	Liquid
Fast pyrolysis	Moderate temperature, short residence time	75%	Fast pyrolysis	Medium temperature, short residence time
Carbonization	Low temperature, very long residence time	30%	Carbonization	Low temperature, very long retention time
Gasification	High temperature, long residence time	5%	Gasification	High temperature, long retention time

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

According to the draft National Biomass Power Development Report prepared by the Institute of Energy

in 2018, it is estimated that by 2025, the total energy theory of biomass resources will reach 130.59 million tons (equivalent to 454.89 million MWh) and in 2030 will reach 138.41 million tons (equivalent to 483.16 million MWh). Source agriculture still uses a large proportion of about 67%, followed by solar wood with about 30%, the rest is waste wood with about 3%.

Examples of current projects

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

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)	-	-

An Khe Factory is 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°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.

The table above shows some key data for two examples of biomass-fired plants in \$2019.

Investment cost estimation

The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - Biomass Power Plant						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		2.23	2.19		2.14	2.12
Technology Catalogue - Colombia 2025*		2.63	2.53			2.38
Technology Catalogue - Indonesia 2024**		2.41	2.19			1.92
Technology Catalogue - Vietnam 2023**	2.28		2.03			1.77
IEA WEO 2025 -India***		2.15		2.1		2.05
IEA WEO 2025 – China***		1.6		1.55		1.55
NREL ATB 2024****		4.91	4.69	4.53	4.38	4.06
*Palm oil / sugar cane / rice husk-based biomass power plant						
**Small power plant based on palm oil or rice husk						
***Bioenergy large scale units, stated policy scenarios						
****Dedicated biopower/biomass plant, moderate scenario						

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Data sheet

The following page contains the data sheet of the technology. All costs are stated in U.S. dollars (\$), price year 2025.

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.

Biomass power plant											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	25	25	25	25	1	50	1	50		1,5
Generating capacity for total power plant	MW_e	25	25	25	25	1	50	1	50		1,5
Electrical efficiency, net, name plate	%	32	32	32	32	25	35	25	35		1, 3, 7
Electrical efficiency, net, annual average	%	31	31	31	31	25	35	25	35		1, 3, 7
Forced outage	%	7	7	7	7	5.25	8.75	5.25	8.75		1
Planned outage	weeks per year	6	6	6	6	4.5	7.5	4.5	7.5		1
Self-consumption	%										
Technical lifetime	years	25	25	25	25	18.75	31.25	18.75	31.25		7, 8
Construction time	years	2	2	2	2	1.5	2.5	1.5	2.5		7
Space requirement	1000_m²/MW_e	35	35	35	35	26.25	43.75	26.25	43.75		1, 9
Additional data for non-thermal plants											
Capacity factor, theoretical	%										
Capacity factor, incl. outages	%										
Ramping ability											
Ramping	% of full load/minute	10	10	10	10						3
Minimum load	% of full load	30	30	30	30						3
Warm start-up time	hours	0.5	0.5	0.5	0.5						3
Cold start-up time	hours	10	10	10	10						3
Minimum Up time	hours										
Minimum Down time	hours										
Environment											
PM 2.5	g/GJ_i	125									3
SO₂ (degree of desulphuring)	%	0									3
NOx	g/GJ_i	125									3
CH₄	g/GJ_i										
N₂O	g/GJ_i										
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	2.23	2.19	2.14	2.12	1.67	3.01	1.59	2.65	A	4, 5, 6, 7, 8

Biomass power plant											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
- of which equipment	%	65	65	65	65	50	85	50	85		
- of which installation and other costs	%	35	35	35	35	15	50	15	50		1, 2
- of which equipment	MUSD/M _{W_e}	1.45	1.43	1.39	1.38	0.83	2.55	0.80	2.25		1, 2
- of which installation and other costs	MUSD/M _{W_e}	0.78	0.77	0.75	0.74	0.25	1.50	0.24	1.33		
Fixed O&M	USD/MW _e /year	61,627	60,745	59,371	58,744	46,220	83,196	44,058	73,430	A	4, 5, 8
Variable O&M	USD/MW _h	3.98	3.93	3.84	3.80	2.99	5.38	2.85	4.75	A	5
Start-up costs	USD/MW _e /start-up										
Technology specific data											
Water consumption	L/MWh	2100	2100	2100	2100	-	-	-	-	B, C	10, 11, 12, 13

Notes:

- A Uncertainty (Upper/Lower) is estimated as -25% (lower) and +35% (higher) for 2025 and +/- 25% for 2050.
- B Assuming a cooling tower is used. Pond- and once-through cooling result in lower water consumption.
- C Depending on the cooling method and the assumptions in different references, the water consumption can vary between ~1400 and 42200 L/MWh.

References

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13. 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 [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 26: Average heat values of MSW components [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 m³/day.

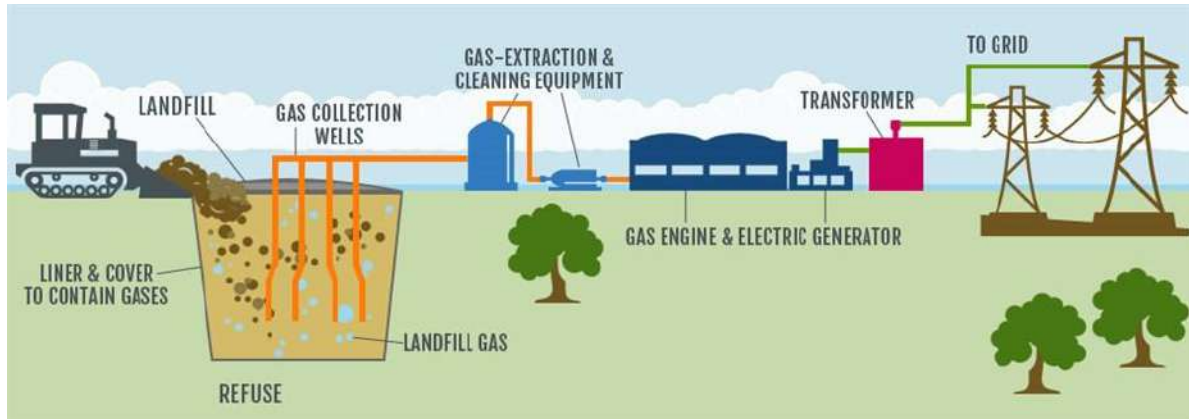


Figure 90: Land-fill gas to energy [5].

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

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

Key: ● Directly suitable ● Likely to require pre-treatment ● Unsuitable

Figure 91: Summary of waste to energy technologies' suitability per waste stream and potential output [4]

In Vietnam, the development of waste-to-energy projects in localities - especially in provinces, cities, and major urban centres - is urgently needed to address environmental issues and to treat municipal and industrial waste, while supplying a low-carbon and sustainable source of electricity for socio-economic development. The total capacity registered by localities for such projects across Vietnam is approximately 3,000 MW. All proposed projects are encouraged to be developed in the period up to 2030.

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 ($> 110\text{ }^{\circ}\text{C}$) or warm ($<110\text{ }^{\circ}\text{C}$) water, bottom ash (slag), residues from flue gas treatment, including fly ash. If the flue gas is treated by wet methods, there may also be an output of treated or untreated process wastewater (the untreated wastewater originates from the SO_2 -step, when gypsum is not produced).

For land-fill gas systems, the outputs are electricity and heat. The land-fill gas which has been cleaned (from sulphur and carbon dioxide contents) can be sold as commercial gas through natural gas pipeline networks.

Typical capacities

Medium: 10 – 50 MW.

Small: 1 – 10 MW.

Ramping configurations

The plants that 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.

Water consumption

Waste incineration requires water use primarily for cooling, bottom ash quenching, and flue gas wet scrubbing, typically provided by municipal water supplies. For WtE plants, the specific water consumption ranges from 0.30 to 0.50 m³ per ton of municipal solid waste (tMSW) when water is not used for flue gas wet scrubbing. However, if water is used for this purpose, consumption can rise significantly, ranging from 1.80 to 2.00 m³ per ton of MSW.

Landfill gas have similar water requirements as simple cycle gas turbines, ranging from 0.52 gallons per kilowatt-hour (gal/kWh) when using a pond for cooling and about 0.60 gal/kWh when using a cooling tower.

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. [1]

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

Table 27: Efficiency of Energy Conversion Technologies [9,10]

Technology	Efficiency (kWh/ton of waste)
Land-fill gas	41 – 84
Combustion (Incinerator)	470 – 930
Pyrolysis	450 – 530
Gasification	400 – 650

Table 28: Expected Landfill Diversion [11,12]

Technology	Land diversion (% weight)
Land-fill gas	0
Combustion (Incinerator)	75*
Pyrolysis	72 – 95
Gasification	94 – 100

* 90% by volume

Examples of current projects

Nam Son waste incineration power plant (Ha Noi)

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

Can Tho waste incineration power plant (Can Tho city)

Can Tho waste incineration power plant is located in Truong Xuan commune, Thoi Lai district, Can Tho city, and 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 USD₂₀₁₉ / MW.

Soc Son Waste-to-Energy Plant (Ha Noi city)

The Soc Son Waste-to-Energy Plant began construction in August 2019 and reached full operation with a capacity of 90 MW in 2025. The plant can process 5,000 tons of waste per day. It is the largest waste-to-energy plant in Vietnam, the second largest in the world, and the largest in Southeast Asia. The Soc Son Waste-to-Energy Plant applies advanced and modern waste treatment technology (mechanical grate furnace technology — Waterleau, Belgium) that meets the most stringent environmental standards based on both European and Vietnamese regulations. The operation of the plant is expected to fundamentally address the issue of municipal solid waste, converting waste into clean energy and reducing reliance on landfilling. The total investment of the project is approximately USD 320 million, equivalent to an investment cost of about USD 3.6 million per MW.

Seraphin Waste-to-Energy Plant (Ha Noi city)

The Seraphin Waste-to-Energy Plant began construction in March 2022 at the Xuan Son Solid Waste Treatment Area, Son Tay Town, Hanoi. In September 2025, the plant commenced operation, with a capacity to process 2,250 tons of waste per day and generate 37 MW of electricity per hour, enough to supply tens of thousands of households. The total investment of the project is approximately USD 198 million, equivalent to an investment cost of about USD 5.35 million per 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.

Investment cost estimation

The data from the different sources in the tables below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - MSW Incineration						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		27.7	27.7		27.7	27.7
Technology Catalogue - Colombia 2025		5.52	5.45			5.23
Technology Catalogue - Indonesia 2024		6.31	5.83			5.22
Technology Catalogue - Vietnam 2023	7.09		6.58			5.82

Investment cost [Million USD 2025 / MW] - MSW Landfill Gas						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		3.24	3.2		3.14	3.08
Technology Catalogue - Indonesia 2024		3.06	3.06			3.06
Technology Catalogue - Vietnam 2023	3.29		3.29			3.29

Data estimates

Table 29: Data from local projects [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

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Data sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (\$), price year 2025.

Incineration Power Plant - Municipal Solid Waste											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW _e	22	22	22	23						
Generating capacity for total power plant	MW _e	22	22	22	23						
Electrical efficiency, net, name plate	%	29	30	30	31	28	32	30	33		1
Electrical efficiency, net, annual average	%	28	29	29	29	26	30	28	31		1
Forced outage	%	1	1	1	1						1
Planned outage	%	6	6	6	6						1
Self-consumption	%										1
Technical lifetime	years	25	25	25	25						1
Construction time	years	2.5	2.5	2.5	2.5						1
Space requirement	1000 _m ² /MW _e	1.5	1.5	1.5	1.5						
Additional data for non-thermal plants											
Capacity factor, theoretical	%										
Capacity factor, incl. outages	%										
Ramping ability											
Ramping	% of full load/minute	10	10	10	10	7.5	12.5	7.5	12.5		1
Minimum load	% of full load	20	20	20	20	15.0	25.0	15.0	25.0		1
Warm start-up time	hours	50	50	50	50	0.4	0.6	0.4	0.6		1
Cold start-up time	hours	200	200	200	200	1.5	2.5	1.5	2.5		1
Minimum Up time	hours										
Minimum Down time	hours										
Environment											
PM 2.5	g/GJ _i										
SO ₂ (degree of desulphuring)	%										
NO _x	g/GJ _i										
CH ₄	g/GJ _i										
N ₂ O	g/GJ _i										
Economic data (in USD2025)											
Specific investment	MUSD/MW _e	6.97	6.47	6.10	5.73	5.23	9.41	4.30	7.16	A	1
- of which equipment	%	60	60	60	60	45	75	45	75		1
- of which installation and other costs	%	40	40	40	40	30	50	30	50		1
- of which equipment	MUSD/MW _e	4.18	4.14	4.06	3.98	3.14	5.65	2.98	4.97	A	1
- of which installation and other costs	MUSD/MW _e	2.79	2.76	2.71	2.65	2.09	3.76	1.99	3.32	A	1
Fixed O&M	USD/MW _e /year	315,479	312,337	306,146	300,078	236,609	425,896	225,058	375,097	A	1
Variable O&M	USD/MWh	31.25	30.94	30.32	29.72	23.44	42.19	22.29	37.15	A	1
Start-up costs	USD/MW _e /start-up										
Technology specific data											

Incineration Power Plant - Municipal Solid Waste											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Waste treatment capacity	tonnes/h	27.7	27.7	27.7	27.7						
Calorific content	GJ/ton										
Investment cost (waste)	\$/ton										
Water Consumption	L/MWh	600	600	600	600	-	-	-	-	B, C	2

Notes:

- A Uncertainty (Upper/Lower) is estimated as -25% (lower) and +35% (higher) for 2025 and +/- 25% for 2050.
- B Assuming the energy value for MSW is 10 MJ/kg and the plant efficiency is 30%.
- C Flue gas wet scrubbing not included. If it is included, the water consumption can be higher.

References

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- 2 MME, UPME, DEA & Emergente, 2025 - Colombian Technology Catalogue for Power Generation and Storage Technologies 2025

Landfill Gas Power Plant - Municipal Solid Waste											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	1	1	1	1	0.5	10	0.5	10		1
Generating capacity for total power plant	MW_e	1	1	1	1	0.5	10	0.5	10		1
Electrical efficiency, net, name plate	%	35	35	35	35	25	37	25	37		2
Electrical efficiency, net, annual average	%	34	34	34	34	25	37	25	37		2
Forced outage	%	5	5	5	5	2	15	2	15		4
Planned outage	%	9.6	9.6	9.6	9.6	2	15	2	15		4
Self-consumption	%										
Technical lifetime	years	25	25	25	25	20	30	20	30		3
Construction time	years	1.5	1.5	1.5	1.5	1	3	1	3		3
Space requirement	1000_m ² /MW_e										
Additional data for non-thermal plants											
Capacity factor, theoretical	%										
Capacity factor, incl. outages	%										
Ramping ability											
Ramping	% of full load/minute										
Minimum load	% of full load										
Warm start-up time	hours										
Cold start-up time	hours										
Minimum Up time	hours										
Minimum Down time	hours										
Environment											
PM 2.5	g/GJ_i										
SO ₂ (degree of desulphuring)	%										
NO _x	g/GJ_i										
CH ₄	g/GJ_i										
N ₂ O	g/GJ_i										
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	3.24	3.20	3.14	3.08	2.43	4.37	2.80	3.54		3
- of which equipment	%	70	70	70	70	64	77	64	81		5
- of which installation and other costs	%	30	30	30	30	27	33	27	35		5

Landfill Gas Power Plant - Municipal Solid Waste											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
- of which equipment	MUSD/MW _e	2.27	2.24	2.20	2.16	1.54	3.36	1.47	2.96		5
- of which installation and other costs	MUSD/MW _e	0.97	0.96	0.94	0.92	0.66	1.44	0.63	1.27		5
Fixed O&M	USD/MW _e /year	161,848	160,236	157,060	153,947	121,386	218,495	139,952	177,039		3
Variable O&M	USD/MWh	0	0	0	0						
Start-up costs	USD/MW _e /start-up										
Technology specific data											
Water consumption	L/MWh	2270	2270	2270	2270	-	-	-	-	A	6

Notes:

A Assuming a cooling tower is used. For pond-cooling, it is a bit lower, around 1970 L/MWh.

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", 2024
- 5 MEMR, "Waste to Energy Guidebook", Jakarta, Indonesia, 2015
- 6 MME, UPME, DEA & Emergente, 2025 - Colombian Technology Catalogue for Power Generation and Storage Technologies 2025

14. BIOGAS POWER

Brief technology description

Biogas produced by anaerobic digestion is a mixture of several gases. The most important part of the biogas is methane. Biogas has a caloric value between 23.3 – 35.9 MJ/m³, depending on the methane content. The percentage of volume of methane in biogas varies between 50 to 72% depending on the type of substrate and its digestible substances, such as carbohydrates, fats and proteins. If the material consists of mainly carbohydrates, the methane production is low. However, if the fat content is high, the methane production is likewise high. For the operation of power generation or CHP units with biogas, a minimum concentration of methane of 40 to 45% is needed. The second main component of biogas is carbon dioxide. Its composition in biogas reaches between 25 and 50% of volume. Other gases present in biogas are hydrogen sulphide, nitrogen, hydrogen and steam [1,2].

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 13.

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 [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.

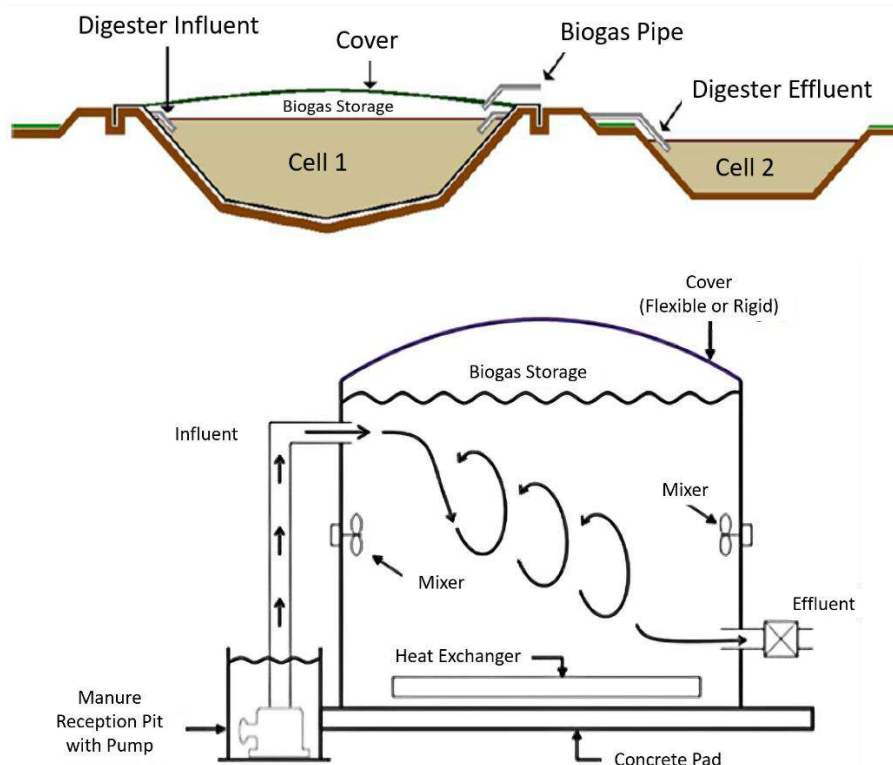


Figure 92: Covered lagoon and CSTR biogas plants [3]

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 ($\geq 12\%$) continuously.

The output of biogas depends much on the amount and quality of supplied organic waste. For manure the gas output is typically 14 – 14.5 m³ methane per tonne, while the gas output typically is 30 – 130 m³ methane per tonne for industrial waste [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).

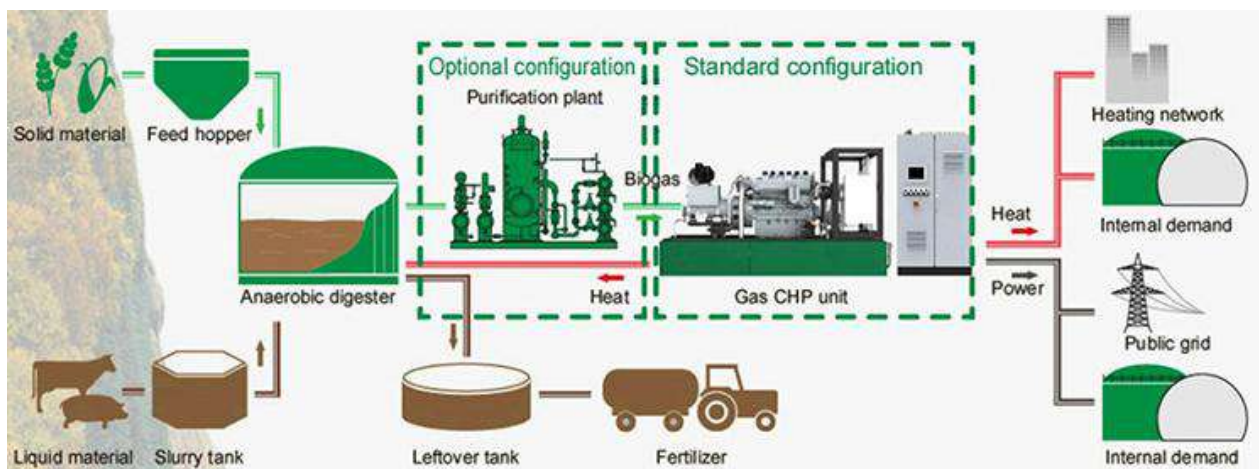


Figure 93: Biogas CHP working diagram [5].

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 CO₂ 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.

Water consumption

Bioenergy production is water-intensive, and its consumption varies significantly across different biomass-based power generation methods. For more detailed information, refer to the section Water consumption in the Biomass chapter.

Environment

Biogas is a CO₂-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 CO₂ mitigation cost has been determined to approx. 5 € per tonne CO₂-equivalent [6].

Research and development

Makel Engineering, Inc. (MEI), Sacramento Municipal Utility District, and the University of California, Berkeley developed a homogenous charge compression ignition (HCCI) engine-generator (genset) that efficiently produces electricity from biogas. The design of the HCCI engine-generator set, or “genset,” is based on a combination of spark ignition and compression ignition engine concepts, which enables the use of fuels with very low energy content (such as biogas from digesters) to achieve high thermal efficiency while producing low emissions. Field demonstrations at a dairy south of Sacramento, California show that this low-cost, low-emission energy conversion system can produce up to 100 kilowatts (kW) of electricity while maintaining emission levels that meet the California Air Resources Board’s (ARB) strict regulations (ref. 9). This type of engine is still under development.

Examples of current projects

The largest biogas power plant in the world is located in Finland. It has an installed capacity of 140 MW. Fuelled mainly with wood residue from Finland's large forestry sector, the plant is expected to reduce carbon-dioxide emissions by 230,000 tons per year while providing both heating and electricity for Vaasa's approximately 61,000 residents. [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.

Investment cost estimation

The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - Biogas power plant						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		3.6	3.6		3.5	3.4
Technology Catalogue - Colombia 2025		4.47	4.32			4.06
Technology Catalogue - Indonesia 2024		2.59	2.20			1.94
Technology Catalogue - Vietnam 2023	3.67		3.42			2.91

References

- [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.
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- [5] Ettes Power Machinery, <http://www.ettespower.com/Methane-Gas-Generator.html>, Accessed: 10th August 2017.
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- [7] Walker, "Stirling Engines", *Clarendon Press*, Oxford, London, England, 1980.
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- [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 sheet

The follow pages contain the data sheets of the technology. All costs are stated in U.S. dollars (\$), price year 2025.

Biogas power plant											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	1	1	1	1						3
Generating capacity for total power plant	MW_e	1	1	1	1						3
Electrical efficiency, net, name plate	%	35	35	35	35						4
Electrical efficiency, net, annual average	%	34	34	34	34						4
Forced outage	%	5	5	5	5						1
Planned outage	%	9.6	9.6	9.6	9.6						1
Self-consumption	%										
Technical lifetime	years	25	25	25	25						7
Construction time	years	1.5	1.5	1.5	1.5						7
Space requirement	1000_m ² /MW_e	70	70	70	70						12
Additional data for non-thermal plants											
Capacity factor, theoretical	%										
Capacity factor, incl. outages	%										
Ramping ability											
Ramping	% of full load/minute	20	20	20	20	10	30	10	30		11, 13
Minimum load	% of full load	40	30	23	15	30	50	10	20		10, 13
Warm start-up time	hours										
Cold start-up time	hours										
Minimum Up time	hours										
Minimum Down time	hours										
Environment											
PM 2.5	g/GJ_i										
SO ₂ (degree of desulphuring)	%										
NO _x	g/GJ_i										
CH ₄	g/GJ_i		0	0	0			0	0		
N ₂ O	g/GJ_i		0	0	0			0	0		
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	3.6	3.6	3.5	3.4	2.71	4.87	2.58	4.30	A	3, 5, 8, 9
- of which equipment	%	65	65	65	65	50	85	50	85		
- of which installation and other costs	%	35	35	35	35	15	50	15	50		
- of which equipment	MUSD/MW_e	2.35	2.31	2.26	2.24	1.35	4.14	1.29	3.66		
- of which installation and other costs	MUSD/MW_e	1.26	1.25	1.22	1.20	0.41	2.44	0.39	2.15		

Fixed O&M	USD/MW _e/year	125,494	123,699	120,900	119,625	94,121	169,41 7	89,718	149,531	A	5, 7, 9
Variable O&M	USD/MW h	0.12	0.12	0.12	0.12	0.09	0.17	0.09	0.15	A	6, 9
Start-up costs	USD/MW _e/start-up										
Technology specific data											
Water consumption	L/MWh	2100	2100	2100	2100	-	-	-	-	B	14, 15

Notes:

A Uncertainty (Upper/Lower) is estimated as -25% (lower) and +35% (higher) for 2025 and +/- 25% for 2050.

B Assuming a cooling tower is used.

References

- 1 Ea Energy Analyses and Danish Energy Agency, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity", 2024
- 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
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- 15 World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity

15. 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 liquid fuel such as crude oil, biofuel, LFO, HFO, especially LFO or diesel (popularly known as diesel engine). However, in recent years gas such as natural gas/LNG, LPG, synthetic methane 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 a RICE, 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 (closed-loop) 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 to produce hot water, steam, chilled water or a combination of these in industrial applications such as combined heat and power (CHP), district cooling and power (DCAP) and trigeneration. A combined cycle solution utilizing steam turbine generator can also be applied to boost the plant output and efficiency.

Due to relatively high fuel costs, internal combustion engines using liquid fuels such as diesel are mainly used in power plants which are remote without access to natural gas or use natural gas as the main fuel while using liquid fuels as backup only (dual-fuel model). 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 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.

There are two main types of internal combustion engines used for power generation: Internal Combustion Engines (RICE) and aeroderivative gas turbines (Aero GT), also known as aero gas turbines. According to Circular No. 54/2025/TT-BCT, internal combustion engine (RICE) power plants, together with aeroderivative gas turbines (Aero GT), are defined as flexible power plants. These power sources feature fast start-up capability and a flexible modular design for power generation to balance capacity and maintain the stability of the power system.

Input

Internal combustion engines may use a wide range of fuels including crude oil, heavy fuel oil, diesel oil and biodiesel fuel.

Typical capacities

From 10 MW_e up to approx. 500 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.

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.

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 have a lower capability of producing high-pressure steam (as turbines). Approx. 50% of the waste heat is released at lower temperatures.
- For oil/diesel fired engines:
 - Expensive fuel (for oil-fired engines)
 - High operational costs, especially for large engines
 - High environmental impact from NO_x, 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.

Water consumption

Combustion engines used for power generation require water for cooling, primarily in the engine's cooling system and heat rejection systems. The amount of water used varies depending on the engine design, size, and application, as well as the cooling system configuration.

In general, combustion engines used for power generation use water to cool the engine block, cylinder head, and other components, as well as to condense the exhaust heat in the heat rejection system. The water is typically circulated through a cooling tower or heat exchanger to dissipate heat.

The water footprint of combustion engines used for power generation can be significant, particularly for larger engines or those operating at high capacities. However, the actual water consumption can vary widely depending on factors such as engine efficiency, load factor, and cooling.

Environment

Emissions highly depend on the fuels applied, fuel type and its content of sulphur etc. Modern large-scale internal combustion engines 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.

Research and development

Internal combustion engines are a very well-known and mature technology – i.e. category 4.

Short start-up, fast ramp rate 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.

Internal combustion engine power plants are a mature technology and only gradual improvements are expected. Internal combustion engines can also run on natural gas and their advantageous fast start and 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.

Examples of current projects

The Ninh Binh Flexible Power Plant Project is planned as a replacement for the existing Ninh Binh Thermal Power Plant, with the plant relocated to Kim Dong Commune to address environmental pollution and support urban redevelopment. The project has a total planned capacity of 1,500 MW, of which Phase I, with a capacity of 300 MW, has been approved in principle, and will adopt LNG-fired reciprocating internal combustion engine technology. As a flexible power source, the project is expected to enhance supply-demand balancing and facilitate the integration of variable renewable energy into the power system. According to the implementation schedule, the plant targets commissioning of approximately 50% of its capacity by late 2027–early 2028 and full operation by 2029, after which the existing Ninh Binh Thermal Power Plant will be shut down and relocated.

In addition to the Ninh Binh project, several existing thermal power plants are also studying conversion options to flexible thermal power sources upon reaching the end of their economic lifetime, such as the Pha Lai Thermal Power Plant.

Investment cost estimation

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.

A recent 37 MW project on the Faeroe Island has been announced to cost 0.86 mill. \$/MW_e. 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.

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.

Below, costs from different Technology Catalogues and projects are listed in tables to compare. The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - ICE Natural Gas						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		0.85	0.84		0.82	0.81
Technology Catalogue - Vietnam 2023	0.76		0.73			0.70

Investment cost [Million USD 2025 / MW] - ICE Diesel/Fuel oil						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		0.8	0.79		0.78	0.76
Technology Catalogue - Indonesia 2024		0.96	0.96			0.94
Technology Catalogue - Vietnam 2023	0.76		0.73			0.70

Technology Catalogue - Ethiopia 2021	0.76		0.72			0.67

References

- [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 sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (\$), price year 2025. 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.

Internal combustion engine – dual fuel (diesel & gas)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW _e	20	20	20	20	-	-	-	-		9
Generating capacity for total power plant	MW _e	100	100	100	100	-	-	-	-		
Electrical efficiency, net, name plate (gas mode)	%	45.5	46.5	47.5	47.5	43.5	47.5	45.5	52.5		9, 10
Electrical efficiency, net, annual average (gas mode)	%	44.5	45.5	46.5	46.5	42.5	46.5	44.5	51.5		9, 10
Electrical efficiency, net, name plate	%	44	45	46	46	42	46	44	51		9, 10
Electrical efficiency, net, annual average	%	43	44	45	45	41	45	43	50		9, 10
Forced outage	%	3	3	3	3	-	-	-	-		
Planned outage	%	1.9	1.9	1.9	1.9	-	-	-	-		1
Self-consumption	%	1.5	1.5	1.5	1.5	-	-	-	-		10
Technical lifetime	years	50	50	50	50	-	-	-	-		10
Construction time	years	1.5	1.5	1.5	1.5	-	-	-	-		10
Space requirement	1000_m²/MW _e	0.05	0.05	0.05	0.05	-	-	-	-		1
Additional data for non-thermal plants											
Capacity factor, theoretical	%	-	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	100	100	100	100	-	-	-	-		7, 8, 9
Minimum load	% of full load	2	2	2	2	-	-	-	-	A	10
Warm start-up time	hours	0.03	0.03	0.03	0.03	-	-	-	-		7, 8, 9, 10
Cold start-up time	hours	0.2	0.2	0.2	0.2	-	-	-	-		7, 8, 9
Environment											
PM 2.5	g/Nm³	20	20	20	20	-	-	-	-		2, 3
SO ₂ (degree of desulphuring)	%	0	0	0	0	-	-	-	-		2, 3
NO _x	g/GJ _i	280	280	280	280	-	-	-	-		2, 3
CH ₄	g/GJ _i	-	-	-	-	-	-	-	-		
N ₂ O	g/GJ _i	-	-	-	-	-	-	-	-		
Economic data (in USD2025)											
Specific investment	MUSD/MW _e	0.91	0.90	0.88	0.87	0.83	1.17	0.79	1.11		5, 6, 8, 9, 10
- of which equipment	%	65	65	65	65	-	-	-	-		
- of which installation and other costs	%	35	35	35	35	-	-	-	-		
- of which equipment	MUSD/MW _e	0.59	0.58	0.57	0.56	-	-	-	-		10
- of which installation and other costs	MUSD/MW _e	0.32	0.32	0.31	0.30	-	-	-	-		10
Fixed O&M	USD/MW _e /year	10,000	9,900	9,704	9,512	-	-	-	-		1, 8, 9

Variable O&M	USD/MWh	8.89	8.80	8.63	8.46	-	-	-	-		1, 8, 9, 10
Start-up costs	USD/MW_e/start-up	-	-	-	-	-	-	-	-		
Technology specific data											
Water consumption	L/MWh	0	0	0	0	0	0	0	0	B	

Notes:

- A Minimum load for a single unit is 10 % - corresponds to 2 % for total plant when consisting of 5 units.
- B Since cooling system is closed-looped, the water consumption is negligible.

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 NO_x, SO_x, particles, smoke and CO₂, 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", 2024
- 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", 2024
- 9 Wärtsilä, "White paper Combustion engine power plants", Niklas Haga, General Manager, Marketing & Business Development Power Plants, 2011.
- 10 Stakeholder input

Internal combustion engine (natural gas only)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	20	20	20	20	-	-	-	-		9
Generating capacity for total power plant	MW_e	100	100	100	100	-	-	-	-		
Electrical efficiency, net, name plate	%	45.5	46.5	47.5	47.5	43.5	47.5	45.5	52.5		8, 9, 10
Electrical efficiency, net, annual average	%	44.5	45.5	46.5	46.5	42.5	46.5	44.5	51.5		8, 9, 10
Forced outage	%	3	3	3	3	-	-	-	-		
Planned outage	%	1.9	1.9	1.9	1.9	-	-	-	-		1
Self-consumption	%	1.5	1.5	1.5	1.5	-	-	-	-		10
Technical lifetime	years	50	50	50	50	-	-	-	-		10
Construction time	years	2	1.5	1.5	1.5	-	-	-	-		10
Space requirement	1000_m ² /MW_e	0.16	0.16	0.16	0.16	-	-	-	-		
Additional data for non-thermal plants											
Capacity factor, theoretical	%	-	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	100	100	100	100	-	-	-	-		7, 8, 9
Minimum load	% of full load	2	2	2	2	-	-	-	-	A	10
Warm start-up time	hours	0.03	0.03	0.03	0.03	-	-	-	-		7, 8, 9, 10
Cold start-up time	hours	0.0	0.0	0.0	0.0	-	-	-	-		
Environment											
PM 2.5	g/Nm ³	7.5	7.5	7.5	7.5	-	-	-	-		2, 3, 8, 9
SO ₂ (degree of desulphuring)	%	0	0	0	0	-	-	-	-		2, 3
NO _x	g/GJ_i	125	125	125	125	-	-	-	-		2, 3, 8, 9
CH ₄	g/GJ_i	-	-	-	-	-	-	-	-		
N ₂ O	g/GJ_i	-	-	-	-	-	-	-	-		
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	0.85	0.84	0.82	0.81	0.78	1.20	0.74	1.14		5, 6, 8, 9, 10
- of which equipment	%	65	65	65	65	-	-	-	-		
- of which installation and other costs	%	35	35	35	35	-	-	-	-		
- of which equipment	MUSD/MW_e	0.55	0.54	0.53	0.52	-	-	-	-		10
- of which installation and other costs	MUSD/MW_e	0.30	0.30	0.29	0.29	-	-	-	-		10
Fixed O&M	USD/MW_e/year	10,000	9,900	9,704	9,512	-	-	-	-		1, 8, 9
Variable O&M	USD/MW_h	8.09	8.01	7.85	7.70	-	-	-	-		1, 8, 9, 10

Internal combustion engine (natural gas only)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Start-up costs	USD/MW_e/start-up	-	-	-	-	-	-	-	-		
Technology specific data											
Water consumption	L/MWh	0	0	0	0	0	0	0	0	B	

Notes:

- A Minimum load for a single unit is 10 % - corresponds to 2 % for total plant when consisting of 5 units.
- B Since cooling system is closed-looped, the water consumption is negligible.

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 CO₂, 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 Wärtsilä, "White paper Combustion engine power plants", Niklas Haga, General Manager, Marketing & Business Development Power Plants, 2011
- 10 Stakeholder input

Diesel engine (using fuel oil)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	20	20	20	20	-	-	-	-		9
Generating capacity for total power plant	MW_e	100	100	100	100	-	-	-	-		
Electrical efficiency, net, name plate	%	44	45	46	46	42	46	44	51		9, 10
Electrical efficiency, net, annual average	%	43	44	45	45	41	45	43	50		9, 10
Forced outage	%	3	3	3	3	-	-	-	-		
Planned outage	%	1.9	1.9	1.9	1.9	-	-	-	-		1
Self-consumption	%	1.5	1.5	1.5	1.5	-	-	-	-		10
Technical lifetime	years	50	50	50	50	-	-	-	-		10
Construction time	years	2	1.5	1.5	1.5	-	-	-	-		10
Space requirement	1000_m ² /MW_e	0.05	0.05	0.05	0.05	-	-	-	-		1
Additional data for non-thermal plants											
Capacity factor, theoretical	%	-	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	100	100	100	100	-	-	-	-		7, 8, 9
Minimum load	% of full load	2	2	2	2	-	-	-	-	A	10
Warm start-up time	hours	0.03	0.03	0.03	0.03	-	-	-	-		7, 8, 9, 10
Cold start-up time	hours	0.2	0.2	0.2	0.2	-	-	-	-		7, 8, 9
Environment											
PM 2.5	g/Nm ³	20	20	20	20	-	-	-	-		2, 3
SO ₂ (degree of desulphuring)	%	0	0	0	0	-	-	-	-		2, 3
NO _x	g/GJ_i	280	280	280	280	-	-	-	-		2, 3
CH ₄	g/GJ_i	-	-	-	-	-	-	-	-		
N ₂ O	g/GJ_i	-	-	-	-	-	-	-	-		
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	0.80	0.79	0.78	0.76	0.73	1.13	0.70	1.07		5, 6, 7, 8, 10
- of which equipment	%	65	65	65	65	-	-	-	-		
- of which installation and other costs	%	35	35	35	35	-	-	-	-		
- of which equipment	MUSD/MW_e	0.52	0.51	0.50	0.49	-	-	-	-		
- of which installation and other costs	MUSD/MW_e	0.28	0.28	0.27	0.27	-	-	-	-		
Fixed O&M	USD/MW_e/year	10000	9900	9704	9512	-	-	-	-		1, 8, 9
Variable O&M	USD/MWh	8.09	8.01	7.85	7.70	-	-	-	-		1, 8, 9, 10
Start-up costs	USD/MW_e/start-up	-	-	-	-	-	-	-	-		
Technology specific data											

Water consumption	l/MWh	-	-	-	-	-	-	-	-	B	

Notes:

- A Minimum load for a single unit is 10 % - corresponds to 2 % for total plant when consisting of 5 units.
- B Since cooling system is closed-looped, the water consumption is negligible.

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 CO₂, 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 Wärtsilä, "White paper Combustion engine power plants", Niklas Haga, General Manager, Marketing & Business Development Power Plants, 2011.
- 10 Stakeholder input

16. 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 [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.

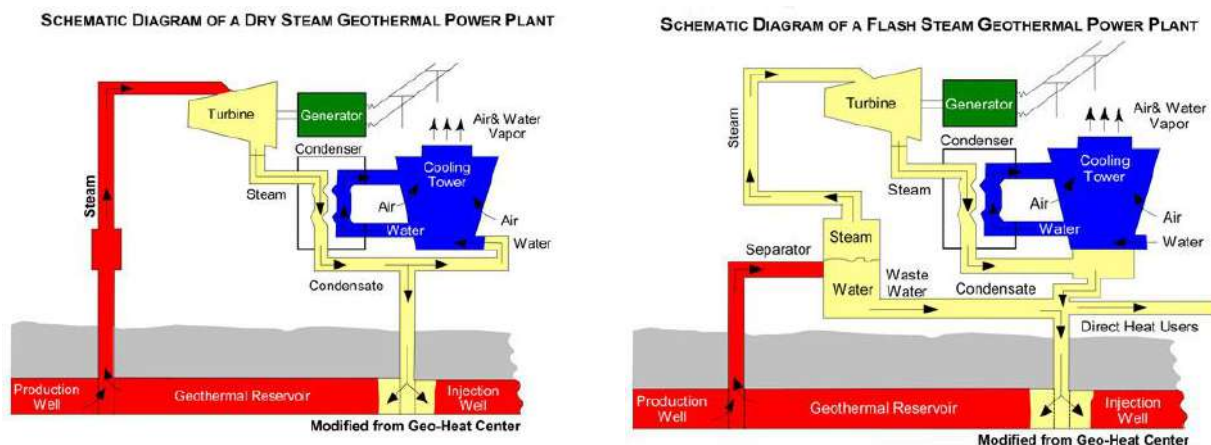
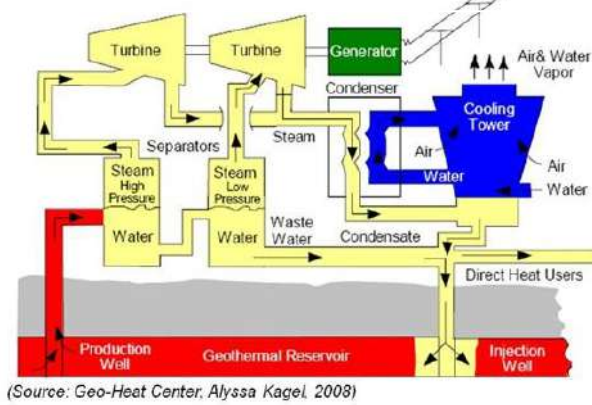


Figure 94: Direct and single flashed steam plants [7]

SCHEMATIC DIAGRAM OF A DOUBLE-FLASH GEOTHERMAL POWER



SCHEMATIC DIAGRAM OF A BINARY GEOTHERMAL POWER PLANT

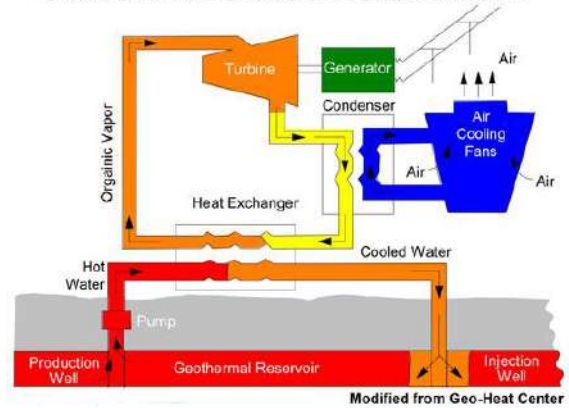


Figure 95: Double flashed (left) and binary (right) geothermal steam plants [7]

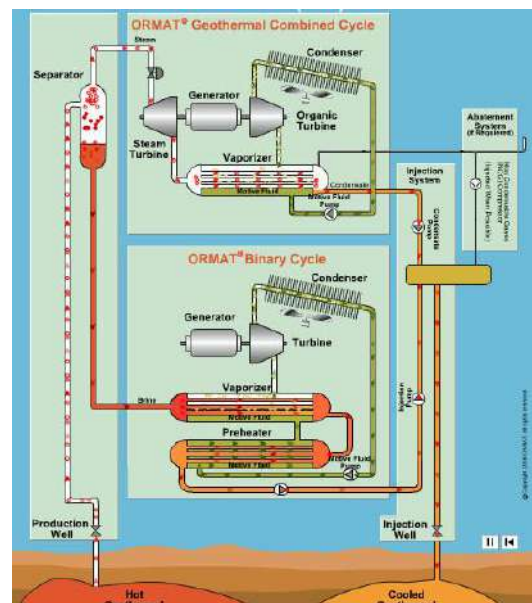
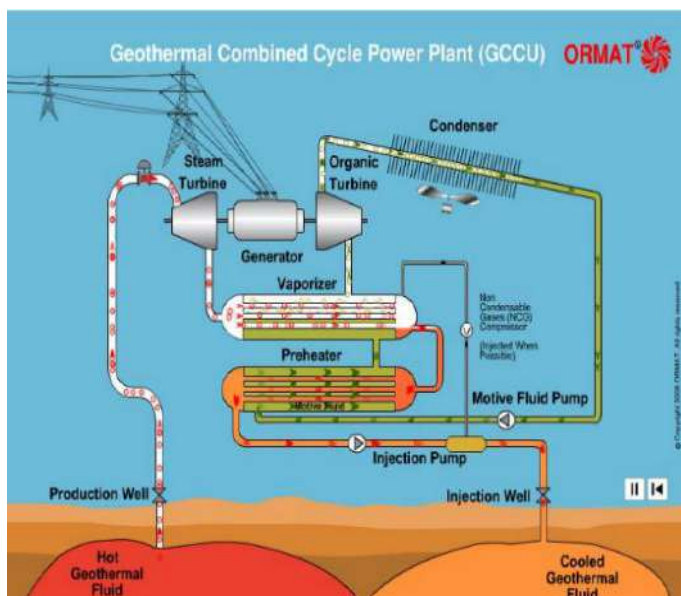


Figure 96: Hybrid/Combined Cycle plant [8]

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 CO₂ 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.

Space requirement

Geothermal energy is highlighted as the least land-intensive renewable energy source, using less area per TWh than alternatives like solar or wind power. A U.S. government report shows geothermal energy's efficiency, requiring 7.5 square kilometres per TWh, much less than solar PV and wind, which use up to 10 times more land. This low land use positions geothermal as a highly sustainable energy option, minimizing its environmental footprint [11].

Water consumption

Geothermal power's water usage is an important consideration, though it varies significantly depending on the type of technology employed. Closed-loop systems, such as binary cycle power plants, use minimal water because the working fluid (typically an organic compound with a low boiling point) is recondensed and continuously recycled within the system. This type of plant has very low water consumption relative to other methods of power generation. On the other hand, open-loop systems, which directly use geothermal steam from underground reservoirs, may require more water. These systems often need additional water for cooling and condensing the steam back into water, which can be partially mitigated by using air-cooled condensers, albeit at a cost to efficiency. Water used is often sourced from the geothermal reservoir itself, which can reduce the impact on local freshwater resources.

It is important to note that recent advancements in geothermal power plant designs increasingly focus on optimizing water consumption and improving efficiency, rather than relying on technologies with high freshwater demand.

Flash plants, which use higher temperature geofluid, are more thermodynamically efficient, resulting in lower water consumption (0.7 to 3.8 gal/kWh). Binary plants, however, consume more water (as they require high-quality external water for cooling).

This type of cooling system significantly impacts operational water consumption in geothermal power plants. This analysis focuses on dry-cooled binary systems and wet-cooled flash systems using condensed geofluid, while also discussing wet and hybrid systems. Cooling system selection affects both lifetime water consumption and power generation efficiency. Dry cooling systems greatly reduce water usage but sacrifice

efficiency, particularly during hot summer days when energy demand is highest. This is evidenced in Figure 97.

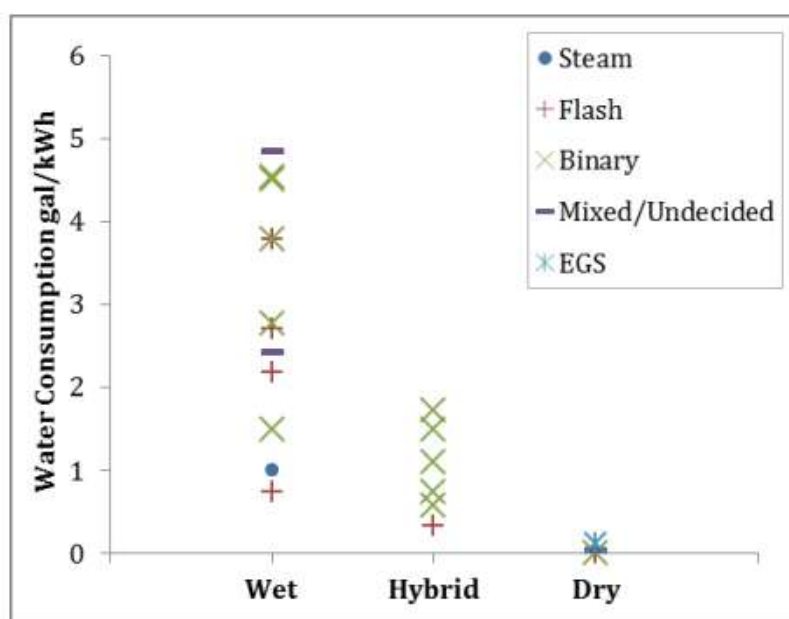


Figure 97: Operational water consumption for geothermal technologies

Environment

Steam from geothermal fields contains Non-Condensable Gas (NCG) such as Carbon Dioxide (CO₂), Hydrogen Sulphide (H₂S), Ammonia (NH₃), Nitrogen (N₂), Methane (CH₄) and Hydrogen (H₂). Among them, CO₂ is the largest element within the NCG's discharged. CO₂ constitutes up to 95 to 98% of the total gases, H₂S constitutes only 2 to 3%, and the other gasses are even less abundant.

H₂S 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 H₂S 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.

Investment cost estimation

The data from the different sources in the tables below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW] - Geothermal power plant Large						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		4.5	4.34		4.15	4.03
Technology Catalogue - Colombia 2025		4.84	4.56			4.21
Technology Catalogue - Indonesia 2024		4.65	4.65			4.18

Investment cost [Million USD 2025 / MW] - Geothermal power plant Large						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Vietnam 2023	4.56		4.30			3.92
IRENA 2024*	4.41	4.12				
NREL ATB 2024**		5.12	4.85	4.65	4.54	4.32
IEA WEO 2025 – India***		3.60		3.40		3.20
IEA WEO 2025 – China***		2.30		2.15		2.05
*Weighted average total installed costs **Hydro/flash Geothermal power plant, moderate scenario, overnight capital cost ***Generic geothermal power plant capital cost under stated policy scenario, no further specifications of geothermal plant are provided.						

Investment cost [Million USD 2025 / MW] - Geothermal power plant Small						
Sources	2020	2025	2030	2035	2040	2050
Technology Catalogue - Viet Nam Current		5.85	5.67		5.42	5.26
Technology Catalogue - Colombia 2025		6.16	5.81			5.36
Technology Catalogue - Indonesia 2024		5.81	5.81			5.23
Technology Catalogue - Vietnam 2023	5.95		5.57			5.06
IRENA 2024*	4.41	4.12				
NREL ATB 2024**		6.70	6.25	5.94	5.80	5.52
IEA WEO 2025 – India***		3.60		3.40		3.20
IEA WEO 2025 – China***		2.30		2.15		2.05
*Weighted average total installed costs **Hydro/binary Geothermal power plant, moderate scenario, overnight capital cost ***Generic geothermal power plant capital cost under stated policy scenario, no further specifications of geothermal plant are provided.						

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. [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.

Currently, only one geothermal power project with an installed capacity of about 15 MW has been proposed for development in Gia Lai Province. However, this project has not yet conducted extensive studies or in-depth surveys.

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.

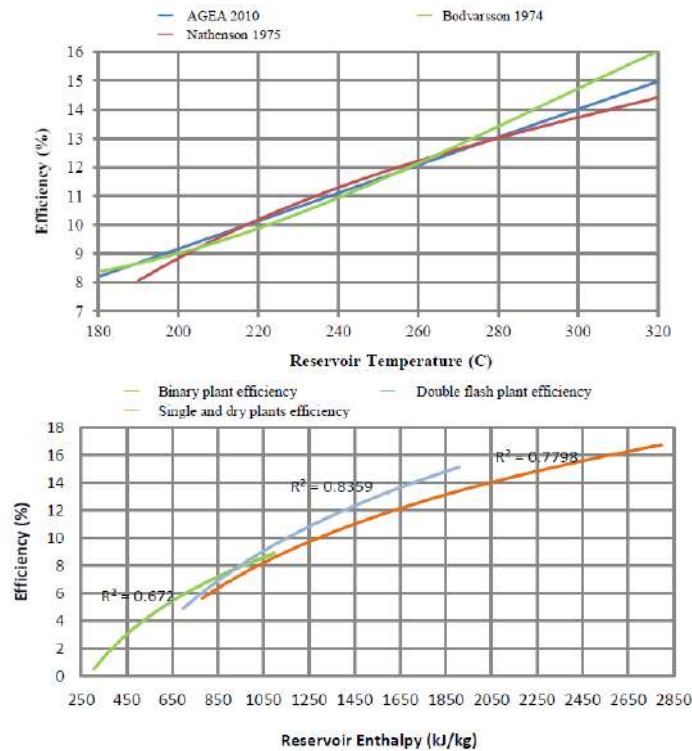


Figure 98: Geothermal plant efficiency as a function of temperature and enthalpy [5]

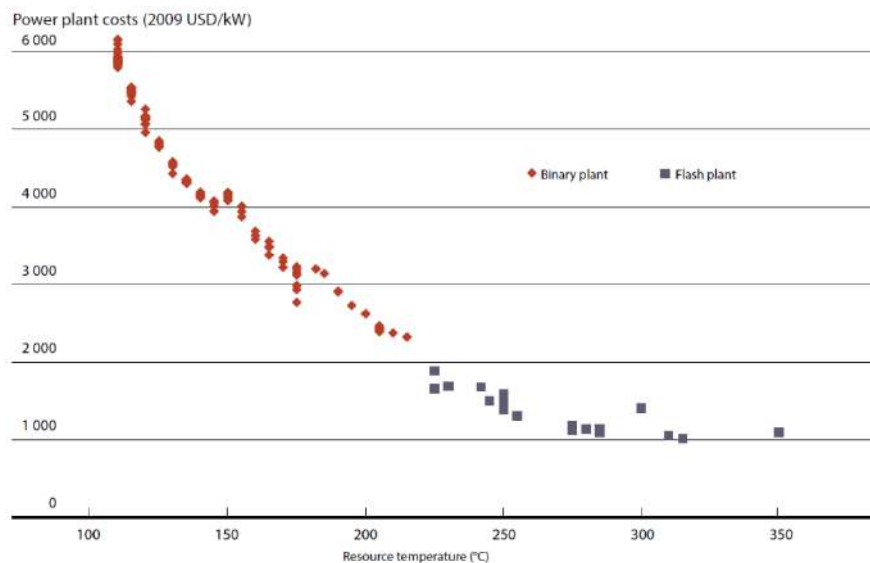


Figure 99: Indicative power plant only costs for geothermal projects by reservoir temperature [10]. The power plant unit stands for around 40-50% of the total capital costs.

References

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- [10] IRENA, Renewable Power Generation Costs in 2017, International Renewable Energy Agency, Abu Dhabi, 2018.
- [11] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014. Climate Change Impacts in the United States: The Third National Climate Assessment. U.S. Global Change Research Program, 841 pp. doi:10.7930/J0Z31WJ2.

Data sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (\$), price year 2025.

Geothermal Small (binary/condensing)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW_e	10	10	10	10	0.3	30	0.3	30		5, 11
Generating capacity for total power plant	MW_e	20	20	20	20	5	30	5	30		5
Electrical efficiency, net, name plate	%	10	11	12	12	6	12	8	14		8
Electrical efficiency, net, annual average	%	10	11	12	12	6	12	8	14		8
Forced outage	%	10	10	10	10	5	30	5	30		5
Planned outage	%	7.7	7.7	7.7	7.7	4	12	4	12		5
Self-consumption	%							0	0		5
Technical lifetime	years	30	30	30	30	20	50	20	50		5
Construction time	years	2	2	2	2	1.5	3	1.5	3		5
Space requirement	1000_m ² /MW_e	30	30	30	30	20	40	20	40		5
Additional data for non-thermal plants											
Capacity factor, theoretical	%	90	90	90	90	70	100	70	100		5
Capacity factor, incl. outages	%	80	80	80	80	70	100	70	100		5
Ramping ability											
Ramping	% of full load/minute										
Minimum load	% of full load										
Warm start-up time	hours										
Cold start-up time	hours										
Minimum Up time	hours										
Minimum Down time	hours										
Environment											
PM 2.5	g/GJ_i										
SO ₂ (degree of desulphuring)	%										
NO _x	g/GJ_i										
CH ₄	g/GJ_i										
N ₂ O	g/GJ_i										
Economic data (in USD2025)											
Specific investment	MUSD/MW_e	5.85	5.67	5.42	5.26	4.39	7.90	3.95	6,58	A	5, 6, 7, 11
- of which equipment	%	60	60	60	60	40	70	40	70		6
- of which installation and other costs	%	40	40	40	40	30	50	30	50		6
- of which equipment	MUSD/MW_e	3.51	3.40	3.25	3.16	1.76	5.53	1.58	4.97		6
- of which installation and other costs	MUSD/MW_e	2.34	2.27	2.17	2.11	1.32	3.95	1.18	3.55		6

Geothermal Small (binary/condensing)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Fixed O&M	USD/MW _e /year	25,896	25,095	23,986	23,296	19,422	34,959	17,472	29,120	A	5, 7
Variable O&M	USD/MWh	0.47	0.46	0.44	0.43	0.35	0.64	0.32	0.53	A	5, 7
Technology specific data											
Exploration cost	MUSD/MW _e	0.19	0.19	0.19	0.19	0.14	0.25	0.14	0.23		10
Confirmation cost	MUSD/MW _e	0.19	0.19	0.19	0.19	0.14	0.25	0.14	0.23		10
Capacity expansion cost of nominal investment	%										
Water consumption	L/MWh	9770	9770	9770	9770	-	-	-	-	B	1, 2, 3

Notes:

- A Uncertainty (Upper/Lower) is estimated as -25% (lower) and +35% (higher) for 2025 and +/- 25% for 2050.
- B Assuming a cooling tower is used, binary. Different ranges can be found.

References

- 1 International Energy Agency, 2016 - Water Energy Nexus
- 2 National Renewable Energy Laboratory, 2011 - A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies
- 3 World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity
- 4 Budisulistyo & Krumdieck, "Thermodynamic and economic analysis for the pre- feasibility study of a binary geothermal power plant", 2014
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- 6 IRENA, Renewable Power Generation Costs in 2014, 2015
- 7 Learning curve approach for the development of financial parameters
- 8 Moon & Zarrouk, "Efficiency Of Geothermal Power Plants: A Worldwide Review", 2012
- 9 Yuniarto, et. al. "Geothermal Power Plant Emissions in Indonesia", 2015
- 10 Geothermal Energy Association, "A Handbook on the Externalities, Employment, and Economics of Geothermal Energy", 2006
- 11 Climate Policy Initiative, Using Private Finance to Accelerate Geothermal Deployment: Sarulla Geothermal Power Plant, Indonesia, 2015

Geothermal Large (flash/dry)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW _e	55	55	55	55	30	500	30	500		4
Generating capacity for total power plant	MW _e	110	110	110	110	30	500	30	500		4
Electrical efficiency, net, name plate	%	16	16	16	16	8	18	10	20		8
Electrical efficiency, net, annual average	%	15	15	15	15	8	18	10	20		8
Forced outage	%	10	10	10	10	5	30	5	30		4
Planned outage	%	7.7	7.7	7.7	7.7	2	6	2	6		4
Self-consumption	%										
Technical lifetime	years	30	30	30	30	20	50	20	50		4
Construction time	years	2	2	2	2	1.5	3	1.5	3		4
Space requirement	1000_m ² /MW _e	30	30	30	30	20	40	20	40		4
Additional data for non-thermal plants											
Capacity factor, theoretical	%	90	90	90	90	70	100	70	100		4
Capacity factor, incl. outages	%	80	80	80	80	45	93	45	93		4
Ramping ability											
Ramping	% of full load/minute	3	10	15	20						11
Minimum load	% of full load										
Warm start-up time	hours										
Cold start-up time	hours										
Minimum Up time	hours										
Minimum Down time	hours										
Environment											
PM 2.5	g/GJ _i										
SO ₂ (degree of desulphuring)	%										
NO _x	g/GJ _i										
CH ₄	g/GJ _i										
N ₂ O	g/GJ _i										
Economic data (in USD2025)											
Specific investment	MUSD/MW _e	4.5	4.34	4.15	4.03	3.36	6.05	3.02	5.04	A	4, 5, 6, 7
- of which equipment	%	60	60	60	60	40	70	40	70		6
- of which installation and other costs	%	40	40	40	40	30	50	30	50		6
- of which equipment	MUSD/MW _e	2.69	2.61	2.49	2.42	1.34	4.24	1.21	3.53		6
- of which installation and other costs	MUSD/MW _e	1.79	1.74	1.66	1.61	1.01	3.03	0.91	2.52		6
Fixed O&M	USD/MW _e /year	23,281	22,561	21,564	20,944	17,461	31,430	15,707	26,179	A	4, 7
Variable O&M	USD/MWh	0.32	0.31	0.30	0.29	0.24	0.44	0.22	0.36	A	4, 7

Geothermal Large (flash/dry)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Technology specific data											
Exploration cost	MUSD/M W _e	0.19	0.19	0.19	0.19	0.14	0.23	0.14	0.23		10
Confirmation cost	MUSD/M W _e	0.19	0.19	0.19	0.19	0.14	0.23	0.14	0.23		10
Capacity expansion cost of nominal investment	%										
Water consumption	L/MWh	13,620	13,620	13,620	13,620	-	-	-	-	B	1, 2, 3

Notes:

- A Uncertainty (Upper/Lower) is estimated as -25% (lower) and +35% (higher) for 2025 and +/- 25% for 2050.
- B Assuming a cooling tower is used, flash (geothermal fluid). Flash (freshwater) results in lower water consumption. Different ranges can be found

References

- 1 International Energy Agency, 2016 - Water Energy Nexus
- 2 National Renewable Energy Laboratory, 2011 - A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies
- 3 World resources institute, 2020 - Guidance for calculating water use embedded in purchased electricity
- 4 Ea Energy Analyses and Danish Energy Agency, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity", 2024
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- 8 Moon & Zarrouk, "Efficiency Of Geothermal Power Plants: A Worldwide Review", 2012
- 9 Yuniarto, et. al. "Geothermal Power Plant Emissions in Indonesia", 2015
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17. NUCLEAR POWER GENERATION

Brief technology description

Nuclear energy is a form of energy released from the nucleus, the core of atoms, made up of protons and neutrons. This source of energy can be used in electricity generation in two ways: fission – when nuclei of atoms split into several parts – or fusion – when nuclei fuse together. The nuclear energy harnessed around the world today to produce electricity is through nuclear fission, while technology to generate electricity from fusion is at the R&D phase. All fission power plants are built on the same concept. Heavy atom nucleus' components (protons, neutrons) are tied together by nuclear forces. Elements with atomic number (Z) over 83 are unstable and decay naturally into elements with a higher binding energy. This occurs because the resulting elements have a higher stability than the original element.

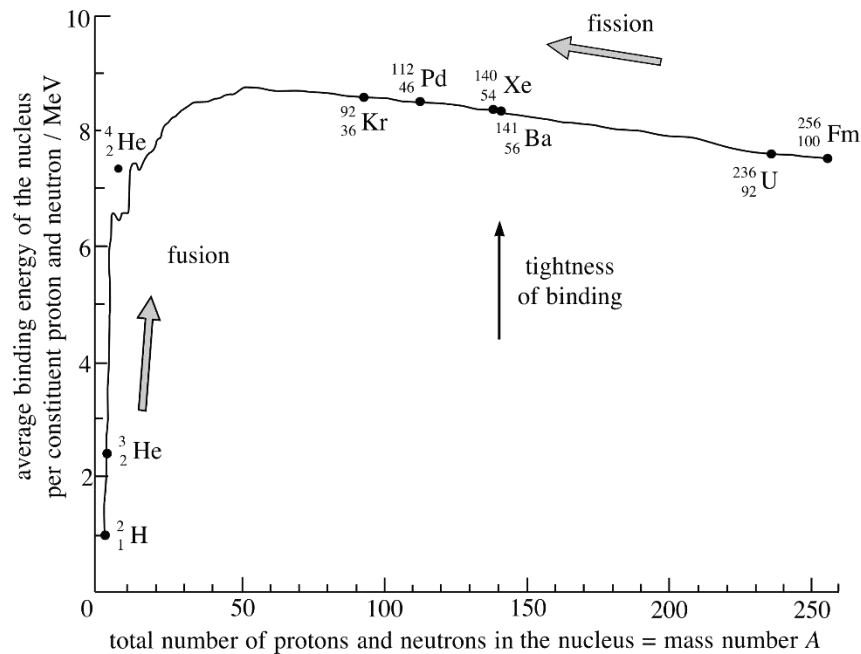
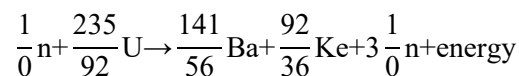


Figure 100. Nuclear energy binding graph [1].

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 fission¹² is central for nuclear power plant (NPP) engineering. The activation energy, which is kinetic energy provided by mobile neutrons hitting the nuclei of selected heavy elements (such as ²³⁵U), catalyses a reaction such as the following:



²³⁵U is one of the fissile elements, since it sustains the chain reaction: for every ²³⁵U atom splitting, on average two to three mobile neutrons *n* are released, which in turn go on hitting other ²³⁵U atoms. Energy is released in the form of heat, later used in the power cycle.

Nuclear reactors are designed to sustain and keep a stable reactivity. The central region of a reactor is called the *core*. In a thermal neutron reactor¹³, the core contains the fuel, the moderator, and a coolant. In a fast neutron reactor¹⁴, there is no moderator, only fuel and coolant. These components are briefly described below:

- The fissile material (e.g., ²³⁵U). It is contained in rods, which need to be periodically replaced as the core gets short of fissile material (fuel cycle).

¹² Induced fission is a type of nuclear fission that is initiated artificially, meaning it is caused by human intervention rather than occurring naturally.

¹³ A thermal neutron reactor (or thermal reactor) is a type of nuclear reactor in which the fission chain reaction is sustained primarily by thermal neutrons — neutrons that have been moderated (slowed down) until they reach thermal equilibrium with their surroundings, having an average energy of about 0.025 eV at room temperature.

¹⁴ A fast neutron reactor (or fast reactor, or fast breeder reactor) is a type of nuclear reactor in which the fission chain reaction is sustained by fast neutrons — neutrons that have not been slowed down, with typical energies around 1–2 MeV.

- The control elements, typically rods, can be lowered or lifted to regulate reactivity. Rods are made of a certain chemical element which inhibits reactivity by absorbing neutrons, usually high-boron steel and boron carbide.
- The coolant is a fluid circulating through the core, responsible for transferring the heat from it. Water, heavy water and various gases are the most commonly used coolants for thermal reactors. In the case of water and heavy water, these coolants also frequently serve as the moderator. With fast reactors, liquid sodium and gases are most used for coolant.
- The reactor pressure vessel is usually a robust steel vessel containing the reactor core and moderator/coolant. It may also be a series of pressure tubes holding the fuel and conveying the coolant through the surrounding moderator.

Nuclear energy has been used for civil purposes since the mid-1900s. Progress in nuclear engineering has brought about significant changes in the plant layout ever since. While there are international guidelines on nuclear safety, NPPs are not a standardized technology, as there are many diverse functional designs. Geopolitical factors and historical legacy have made nuclear research a primarily national or regional matter [41].

Fission power plants are usually classified by the core design, the general classification is depicted in Figure below.

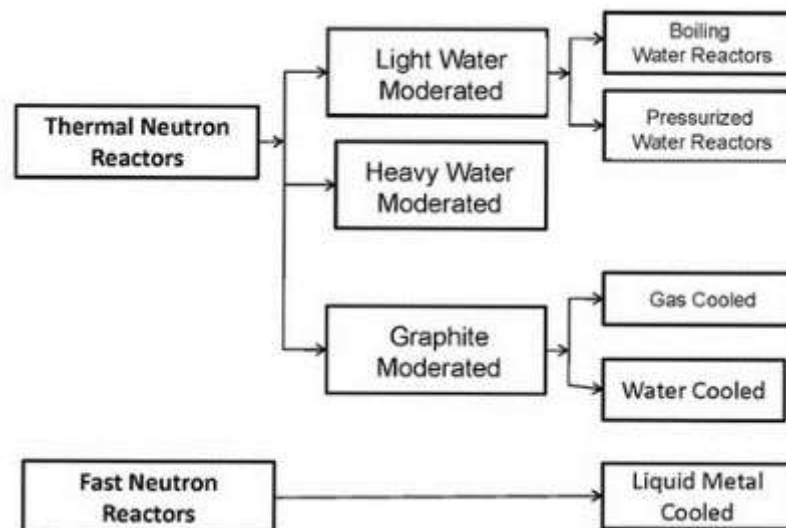


Figure 101. Classification of nuclear reactors [36].

Nuclear reactors can be classified based on various criteria, including core design, type of moderator used, fuel type, and technological generation. Understanding these classifications is crucial for comprehending the diverse technologies employed in nuclear power generation and identifying the specific advantages and challenges associated with each reactor type.

Classification by Core Design and Moderator Type

Nuclear reactors are primarily classified by the design of the core and the type of moderator used:

- Pressurized Water Reactors (PWRs): PWRs are the most common type of nuclear reactor in the world. They utilize light water as both a moderator and coolant, maintaining the water under high pressure to prevent it from boiling. The heat generated in the reactor core is transferred to a secondary circuit via a steam generator, where steam is produced to drive the turbines for electricity generation [2].
- Boiling Water Reactors (BWRs) (see Figure 102): BWRs also use light water as a moderator, but unlike PWRs, the water boils directly within the reactor core to produce steam that drives the turbine generators. This design is simpler but involves handling radioactive steam, making the operation and maintenance more complex [3].

A Boiling Water Reactor (BWR)

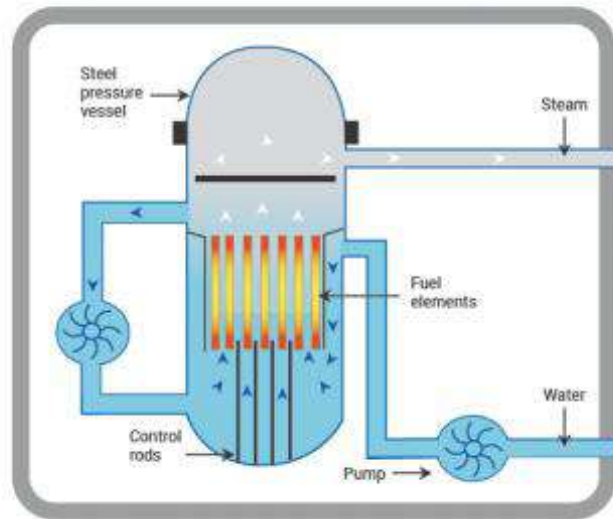
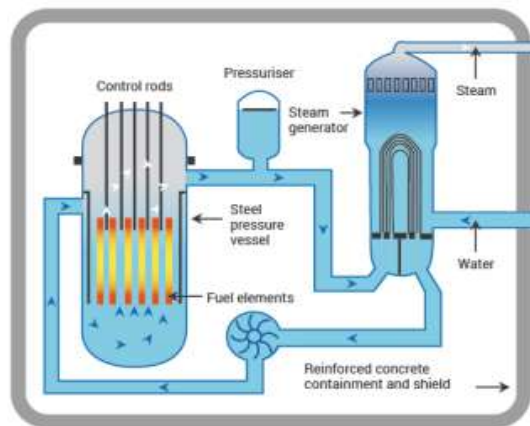


Figure 102. BWR schemes [5].

- Pressurized Heavy Water Reactors (PHWRs) (see Figure 103): PHWRs, such as the CANDU reactors developed in Canada, use heavy water (D_2O) as a moderator and coolant. Heavy water reactors (HWRs) use "enriched" water, whose molecules contain hydrogen atoms composed of more than 99 % deuterium, an isotope of hydrogen that is heavier than tritium. The use of heavy water as a moderator improves the overall neutron economy, allowing the use of natural uranium as fuel and reducing the need for its enrichment [3].

A Pressurized Water Reactor (PWR)



A Pressurized Heavy Water Reactor (PHWR/Candu)

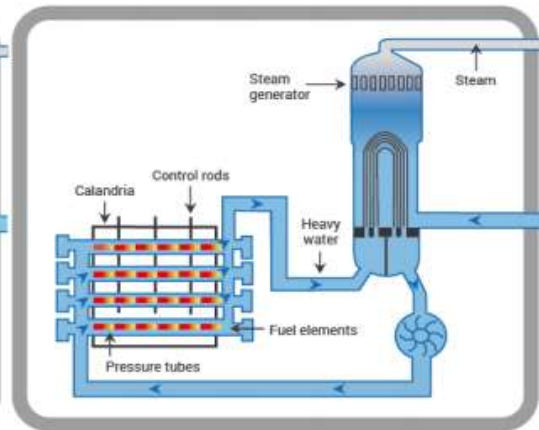


Figure 103. PWR and PHWR schemes [5].

- Gas-Cooled Reactors (GCRs): GCRs use graphite as a moderator and a gas, such as CO_2 or helium, as a coolant. These reactors were initially developed in the UK (AGR, Magnox) and the former Soviet Union (RBMK¹⁵). The use of graphite as a moderator allows for higher operating temperatures, increasing thermal efficiency [2].
- Fast Breeder Reactors (FBRs): Unlike thermal reactors, FBRs do not use a moderator, allowing the neutrons to remain at higher (fast) energies. These reactors can generate more fissile material

¹⁵ The Soviet Union did not develop true Gas-Cooled Reactors (GCRs) like the UK's Magnox or AGR designs, which use CO_2 or helium gas as coolants. However, the RBMK design shares some similarities with GCRs: it uses graphite as the moderator; it can operate at higher temperatures than PWRs; and it has a channel-type structure instead of a single pressure vessel. For this reason, RBMKs are sometimes grouped with GCR types, but technically, they are not gas-cooled reactors (GCRs) but rather reactors that use water as the coolant and graphite as the moderator.

(usually plutonium) than they consume, making them crucial for sustaining long-term nuclear fuel supplies [2].

Water-cooled reactors (WCRs) which include PWR, BWR, and PHWR, have played a fundamental role in the history of the commercial nuclear industry and currently account for more than 95 % of all the 442 operating civilian power reactors in the world. In addition, most nuclear reactors under development and under construction are water-cooled reactors. Originally, many of these plants were granted a 40-year operating license; Thanks to advances in technology, however, the life of these plants is now being extended to 60 years, with the possibility of continuing to operate for longer. WCRs are expected to continue to play an important role in the twenty-first century.

Many of the lessons learned over the past 50 years of WCR operation and technical development, continue to apply to the design and operation of existing and advanced WCRs. The latest advances in WCR technology include improvements to current models and the development of new concepts, which share the common goals of improved safety, passive safety, more efficient use of resources and improvements in economic terms. Another key aspect is the development, testing, and factory construction of small integrated modular reactors, while innovations in safety, construction, and economic efficiency continue to advance within WCR technology.

Safety systems designed in today's advanced WCRs incorporate passive features that do not require power and include larger water inventories, so that in the event of unforeseen conditions, as a prolonged plant blackout, the situation could be dealt with for days instead of hours to cool the reactor core through this controlled inventory of water.

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

Table 30: Examples of nuclear reactor types currently under operation or operable [5].

Reactor type	Main countries	Number	GW _e	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			

Classification by Technological Generation

Nuclear reactors are also classified by their technological generation, reflecting advancements in design, safety, and efficiency:

- **Generation I:** These are the earliest reactors developed in the 1950s and 1960s. They were less efficient and varied significantly in design across different countries. No Generation I reactors are in commercial operation today [2].
- **Generation II:** Developed between the 1970s and 1990s, Generation II reactors include most of the reactors in operation today, such as water cooled and moderated reactors like PWRs, BWRs, and PHWRs. These reactors are more efficient and safer compared to Generation I designs [2].
- **Generation III and III+:** Introduced in the 2000s, these reactors feature significant safety enhancements, such as passive safety systems that do not require human intervention in emergencies. Examples include the AP1000, EPR, and VVER-1200 [3]. These reactors also have

longer operational lifespans and improved fuel efficiency, reducing the frequency of refuelling outages [4].

- **Generation IV:** Currently under development, Generation IV reactors aim to improve safety, efficiency, and sustainability further. These reactors include designs such as Lead-Cooled Fast Reactor (LFR), Very-High-Temperature Reactor (VHTR), Supercritical-Water-Cooled Reactor (SCWR), Gas-Cooled Fast Reactors (GFRs), Molten Salt Reactors (MSRs), and Sodium-Cooled Fast Reactors (SFRs). Generation IV reactors are expected to be operational by the mid-2030s and are designed to minimize nuclear waste and maximize fuel efficiency through closed fuel cycles [3]. (See further in Research and development section).

Small Modular Reactors (SMRs)

Small Modular Reactors (SMRs) represent a significant advancement in nuclear technology, with capacities of up to 300 MW_e. SMRs are characterized by their modular design, which allows for factory fabrication and on-site assembly. This modularity not only reduces construction time and costs but also enhances safety by incorporating advanced passive safety features [6]. SMRs are characterised by:

- **Small Size:** They occupy less space compared to conventional nuclear reactors.
- **Modular Design:** This feature allows for components and systems to be pre-assembled in factories and then transported as a complete unit to the installation site.
- **Reactor Functionality:** SMRs employ nuclear fission to produce heat and, subsequently, energy.

SMRs are designed to be flexible, capable of providing power to small grids or remote locations, and can be scaled up by adding more modules as needed. Additionally, SMRs offer the potential for broader deployment of nuclear power by lowering the financial barriers associated with traditional large-scale NPPs [4]. Despite these advantages, challenges such as regulatory approval and economic competitiveness remain significant hurdles to widespread SMR adoption [6].

SMRs have a power capacity of up to 300 MW_e per unit, which is about one-third of the generating capacity of traditional nuclear power reactors. The micro modular reactors are characterized by the smallest capacities and are expected to reach the minimum capacity of 1.5 MW_e. This expectation is based on the capacity for the Aurora power plant, in USA, which still is at the conceptual design phase and currently is designed in 15 MW - 50 MW capacity modules [7]. Most of the adopted designs of SMR include advanced or inherent safety features and can be delivered as a single or multi-module plant.

The development of SMRs is targeted to achieve some of the characteristics that larger plants are not capable of offering. SMRs could play a role within the flexibility of power generation, and provide cogeneration in areas with small electricity grids, remote and off grid areas. The newer SMRs aim at safety performance that is comparable or improved compared to traditional designs [7].

However, several technical challenges remain to be addressed in terms of developing new codes and standards. Multi-module SMR plants bring the challenge of control room staffing and human factor engineering. Moreover, the economic viability of the SMR plants remains to be demonstrated, as most units are slated for future deployment and current projects such as NuScale SMR, are expensive.

Classification of SMRs

SMRs can be classified into five large groups:

- i) Fast Neutron SMR reactors
- ii) Micro Modular Reactor (MMR)
- iii) MSR Molten Salt Reactor
- iv) High Temperature Reactor (HTR) and High Temperature Gas Cooled (HTGR) reactors
- v) Water Cooled Reactors (WCR) among which the pressurized water reactor "Pressurized Water Reactor (PWR)" and the boiling water reactor "Boiling Water Reactor (BWR)" stand out.

Fast Neutron SMR reactor or Fast Reactor (FR) (see Figure 104) do not have water as a moderator, which reduces the speed of neutrons to sustain the fission chain reaction. These reactors, if they operate in a closed fuel cycle where fuel is reused and recycled, have the potential to increase the nuclear energy extracted, that is, between 60 and 70 times more energy can be extracted from uranium than existing thermal reactors

[8]. This helps to reduce the required reserves of plutonium and will minimize the thermal load, volume and isolation time required for high-level radioactive waste. They will also have higher efficiency and the innovative concepts promise to have improved safety features over evolutionary reactors (a feature not yet proven). Another advantage of liquid metal-cooled fast reactors (FRs) is that they operate at very low pressure.

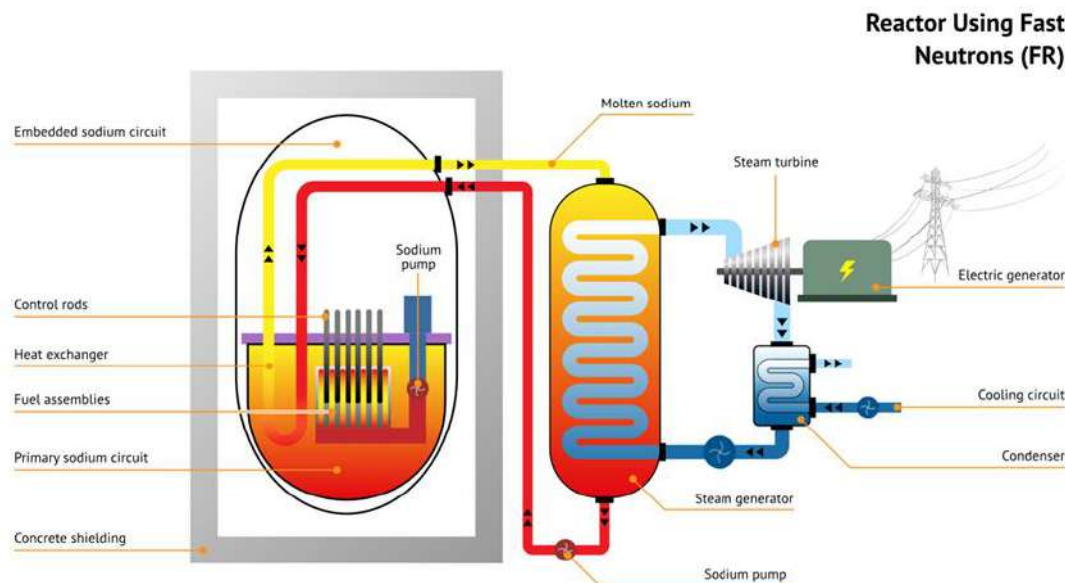


Figure 104: Fast Neutron SMR Reactor, or Fast Reactor (FR) [34].

Due to their particular physics, FRs are very flexible and can be designed as breeders, burners or general-purpose reactors. When designed as breeders, FRs produce more fuel than they consume. As burners, they are specifically designed to minimize the volume, thermal load, and lifespan of the most hazardous nuclear waste, thus drastically reducing geological repository requirements. In both cases, to be effective, the technology requires a closed fuel cycle, including fuel reprocessing.

General purpose FRs have higher fuel burn, a longer fuel cycle, and/or higher coolant temperatures. They are particularly suitable for producing electricity more efficiently or for non-electrical applications (e.g. hydrogen production). However, operation and maintenance are more challenging than in the case of WCR [9].

Thanks to their flexibility, fast reactors can be adapted to different national nuclear policies and needs. If the objective is to preserve natural uranium (for example, in countries that plan to exploit a large fleet of NPPs), fast reactors can function as breeders. If the goal is to minimize plutonium reserves and/or reduce the number and requirements of geological deposits, FRs can function as burners. Even from a strategic point of view, the motivation for developing an FR program can be very different in different countries. For example, Japan is developing a FR program due to the lack of traditional energy resources. The Russian Federation has sufficient fossil fuel resources, but is fully committed to the development and deployment of FR to achieve future strategic objectives (including export) and maintain technological leadership [9].

Micro Modular Reactors (MMR) seek to generate power up to 10 MW_e. This advanced technology, usually included as a subcategory of SMRs, is being developed especially in Canada, China, the Russian Federation, the United States and several Member States in Europe. MMRs are typically charged throughout the reactor's lifespan and have some unique features: to a greater extent than other SMRs, they can be manufactured entirely in a factory, transported more easily to sites, and connected to the electrical power and heat end-user.

Incorporating the passive safety features of fourth-generation SMR designs, these microreactors can also be self-regulating, based on inherent and passive safety systems, and thus achieve a high level of control and safety with minimal operator actions. They are also not limited to a specific type of moderator, coolant, or neutron energy range, and exhibit very different characteristics. For example, refrigerants can include helium, lead, air, water, liquid metal, and heat pipes. For deployment to become a reality, these small power

plants would also need to have adequate safety and positive proliferation resistance characteristics. The principle diagram of a helium gas-cooled MMR is illustrated in Figure below.

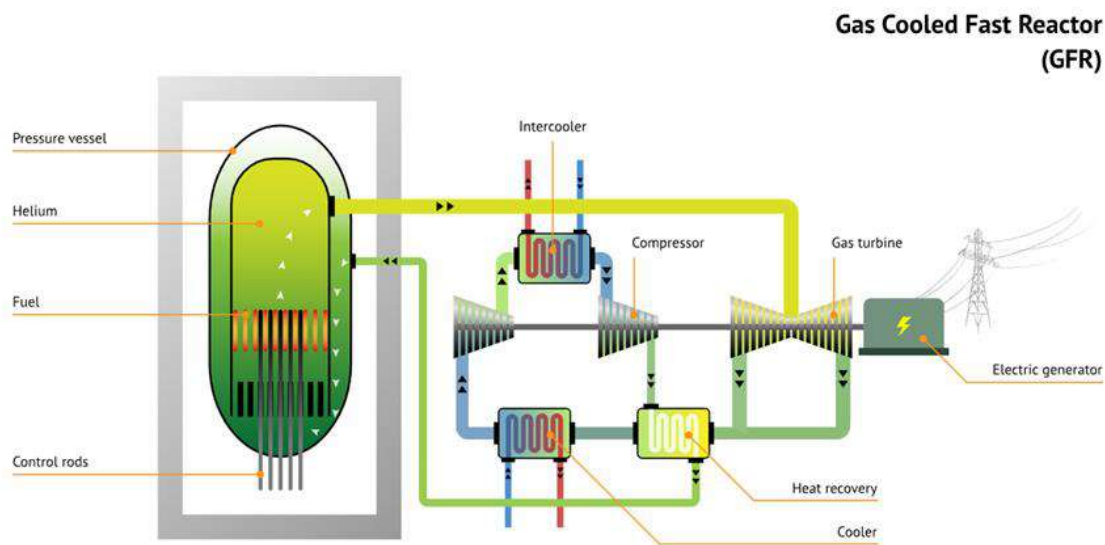


Figure 105: Gas-cooled Micro Modular Reactor (MMR) [10].

Molten Salt Reactor (MSR): The MSR depicted in Figure 106 is distinguished by its fuel dissolved in molten salt, although some designs use solid fuel and molten salt as coolant. It is interesting in terms of efficiency (higher temperatures), safety (low pressure and melt-state fuel), sustainability (e.g. through a closed fuel cycle with in-line reprocessing) and waste reduction.

The technology was developed and demonstrated in part in the experimental molten salt reactor at Oak Ridge National Laboratory in the United States of America (1965-1969). However, there is still a need to evaluate their technical feasibility, especially the long-term performance of structural materials in molten salts. MSR designers focus their efforts on solving material issues, improving safety conditions, developing optimal core design methods, and evaluating economic models [11].

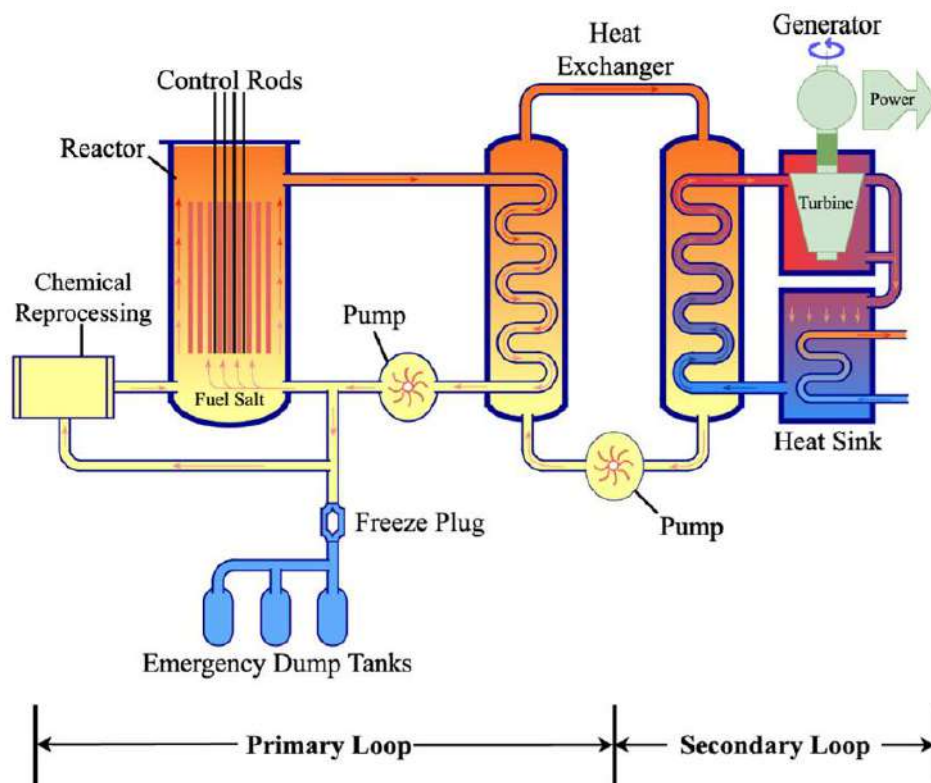


Figure 106: Molten Salt Reactor [35].

Other challenges include the acceptance of its security features in licensing and also some problems of weapons proliferation. While some of the proliferation-related aspects (e.g. inline reprocessing) could be technically resolved, it is politically possible that it may only be allowed to be deployed in countries that allow reprocessing. Some companies with new designs already offer specific MSRs on the market, but large-scale commercial deployment is not anticipated before 2030, although demonstration reactors could be operational during this timeframe (a molten salt test reactor is currently being developed in China) [12].

High-Temperature Gas-Cooled Reactor (HTGR): The HTGR illustrated in Figure 107 is a helium-cooled, graphite-moderated fission nuclear reactor technology that uses all-ceramic fuels. It has inherent safety features and excellent retention of fission products in fuel and graphite compared to conventional nuclear reactor technology [13].

The reactor's outlet temperature, typically between 750 °C and 950 °C, is significantly higher than that of conventional nuclear reactors (the standard outlet temperature for pressurized water reactors is around 320 °C). This high output temperature not only increases the conversion efficiencies of electrical power generation, but it also expands the opportunities to use the increased heat as industrial process heat in a higher temperature range that is difficult to achieve with conventional nuclear reactors. In subsequent deployments, the operating temperature could reach more than 950 °C. However, these reactors will require the use of new structural materials.

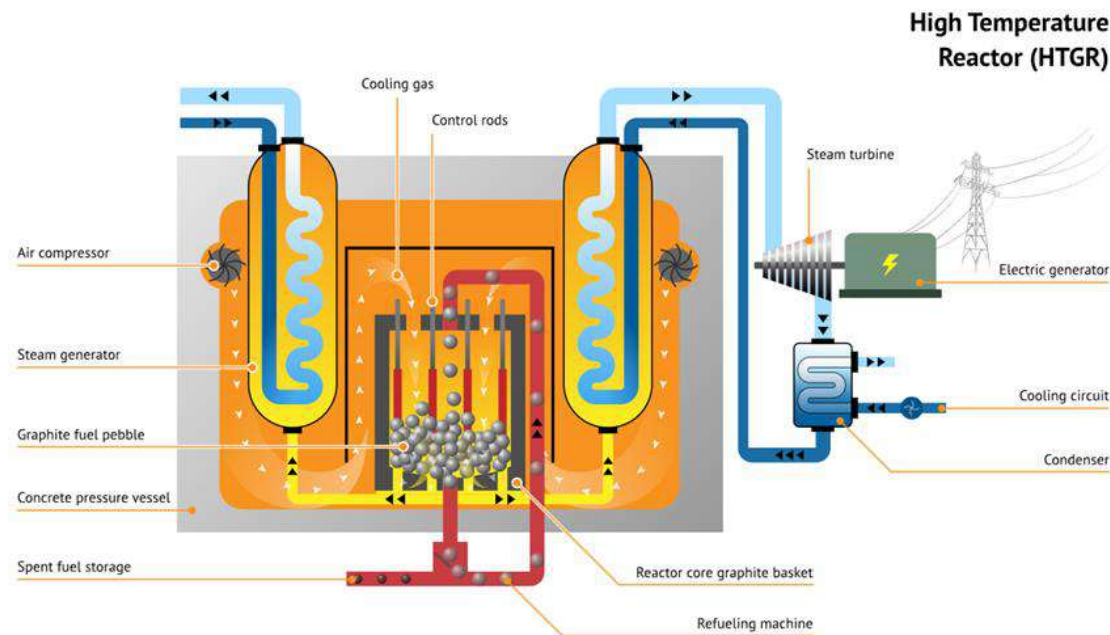


Figure 107: Schematic of a high-temperature gas-cooled reactor (HTGR) [13].

The first HTGR was proposed in a 1945 design study in the United States. In the 1960s, experimental HTGRs emerged in the United Kingdom, the United States, and Germany, followed by commercial-scale pilots in the United States and Germany, reactors that operated from the mid-1970s to the early 1990s. Operational experiences and design improvements are reflected in the two experimental HTGRs current operating in Japan and the People's Republic of China. These reactors have demonstrated stable operation and system safety performance without any significant technical issues [13] [14].

Water-Cooled Reactors (WCRs) are reactors that use the PWR, LWR and PHWR technologies described earlier in the *Classification by Core Design and Moderator Type* subsection. In order to improve the thermal performance and economics of the plant, research and development activities for supercritical water-cooled reactors (SCWRs) are underway. Supercritical water exists at temperatures and pressures above its critical point, at which the liquid and gaseous states are indistinguishable. This water is often used in advanced coal, oil and gas-fired power plants. SCWRs are projected to be around 1.3 times more efficient than conventional WCRs.

Small Modular Reactors in Operation

Currently, there are two SMR power plants in operation, one in Russia (marine-based) and one in China (land-based demonstration reactor):

- In the Russian Federation, the Akademik Lomonosov floating NPP, with two KLT-40S reactors of 35 MW_e each, was refuelled for the first time in 2023. This floating NPP has been in commercial operation since May 2020, supplying heat and power to the town of Pevek in the Chukotka region.
- In China, the demonstration HTR-PM at the Shidaowan site started commercial operation during December 2023. It generates 200 MW_e at full power, from two reactors linked to a single power turbine.

Some details about the two plants are given below:

KLT-40 in Russia (marine-based) [7]: The KLT-40S (Akademik Lomonosov) is a PWR developed for a floating nuclear power plant (FNPP) to provide a capacity of 35 MW_e per module. The design is based on third generation KLT-40 marine propulsion plant and is an advanced version of the reactor providing the long-term operation of nuclear icebreakers under more severe conditions as compared to stationary nuclear power plant (NPP). The reactor's technical parameters are shown in Table below.

Table 31: KLT-40: Major technical parameters [7].

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

HTR-PM in China (land-based demonstration reactor) [43]: The High Temperature Gas Cooled Reactor - Pebble-bed Module (HTR-PM) is a modular High Temperature Gas Cooled Reactor (HTGR) demonstration power plant which is designed by the Institute of Nuclear and New Energy Technology (INET), Tsinghua University of China. The current HTR-PM design falls into the category of innovative small sized reactors, featuring 200MW electrical output by two reactor modules. In January 2006 the project named “Large Advanced Pressurized Water Reactor and High-Temperature Gas-cooled Reactor Nuclear Power Plants” became one of the 16 top priority projects of the “Chinese Science and Technology Plan” for the period 2006 - 2020. By February 2008 the implementation plan and the budget for the HTR-PM project was approved by the State Council of China. The demonstration nuclear power plant is being constructed in Rongcheng, Shandong Province, China.

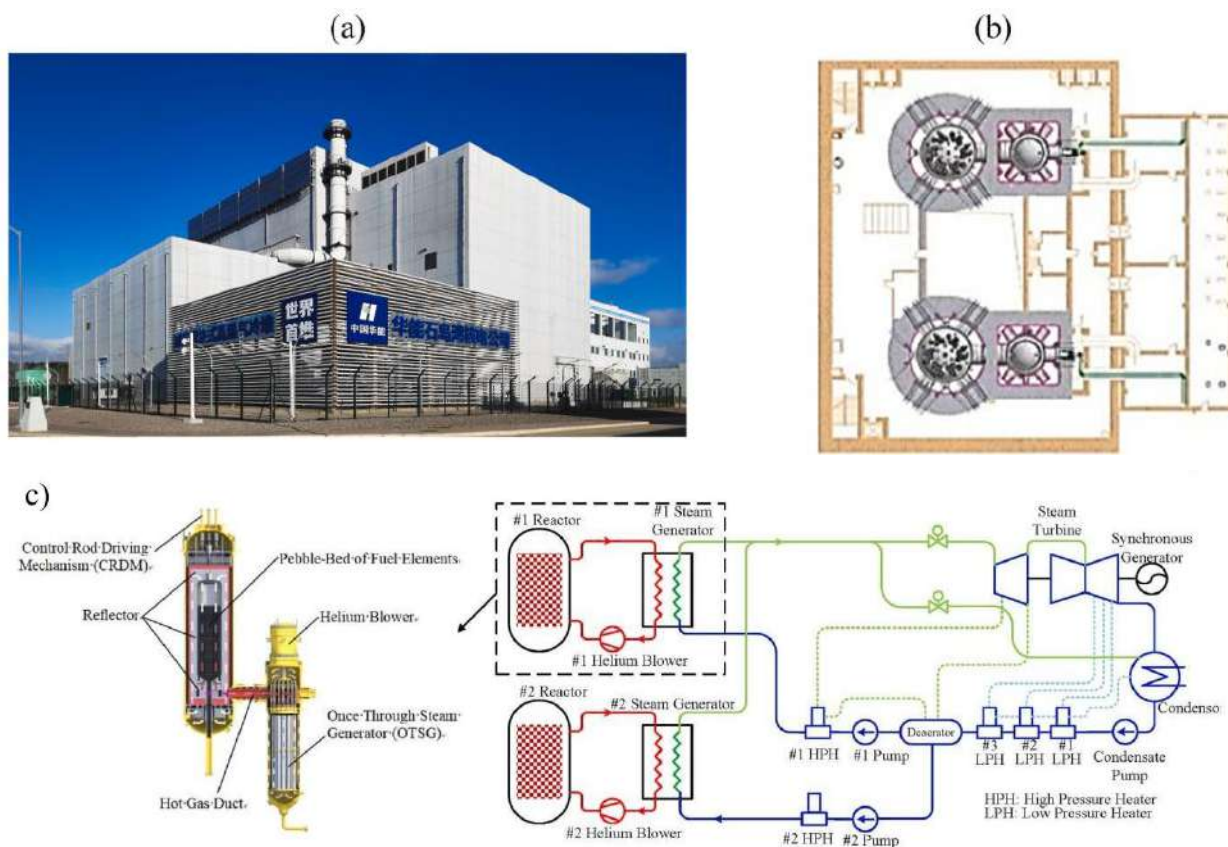


Figure 108: The HTR-PM nuclear power plant: (a) outside view of plant building, (b) layout of the nuclear island, (c) schematic diagram for power generation process of HTR-PM plant [44].

Table 32: HTR-PM: Major technical parameters [45].

HTR-PM: Major technical parameters	
Parameter	Value
Reactor thermal power (MW)	458
Designed operational life time (year)	60
Expected load factor (%)	85
Fuel elements	
Diameter of fuel elements (mm)	60
Nuclear fuel	UO ₂
U-235 enrichment of fresh fuel (%)	8.5
Heavy metal loading per fuel element (g)	7
Number of fuel balls	520,000
Number of graphite balls	225,530
Average discharge burn-up (MW _d /tU)	80,000
Fuel loading scheme	Multi-pass (six times)
Average time of fuel elements in core (EFPD)	647
Number of fuel balls discharged each day	4,821
Number of fresh fuel balls required each day	804
Number of graphite balls discharged each day	2,091
Nuclear design parameters	

HTR-PM: Major technical parameters	
Diameter of central graphite column (cm)	220
Inner/outer diameter of fuel zone (cm)	220 / 400
Average height of active core (cm)	1,100
Average power density of fuel zone (MW/m ³)	4.75
Maximum power density of fuel zone (MW/m ³)	12.85
Average output power per fuel ball (kW)	0.881
Neutron leakage from the core (%)	15.08
Reactivity control	
Number of control rods	18
Number of absorber ball units	18
Worth of control rods (%)	5.25
Worth of absorb ball units (%)	11.32
Worth of control rods and absorb ball units (%)	14.08
Coolant	
Primary helium pressure (MPa)	7.0
Helium temperature at reactor outlet (°C)	750
Helium temperature at reactor inlet (°C)	250
Primary helium flow rate (kg/s)	176
Maximum fuel temperature under normal operation (°C)	1,055
Maximum fuel temperature under accidents (°C)	1,620
Reactor pressure vessel	
Inner diameter (m)	6.7
Height (m)	24
Wall thickness (mm)	146–250
Steam cycle	
Main steam flow rate (kg/s)	155.4
Feed water temperature (°C)	205.3
Main steam pressure at turbine inlet (MPa)	13.5
Main steam temperature at turbine inlet (°C)	538
Generator power (MW)	195

Other projects [46]:

- In Canada, construction of the GE Hitachi Nuclear Energy BWRX-300 reactor that uses natural circulation is planned to be built in the Darlington site, and connection to the grid is expected by the end of 2028. This would be the first commercial SMR project to begin construction in North America.
- France is pursuing and encouraging developments of SMRs through the France Relance 2030 funds, including the EDF-NUWARD SMR (which is also a PWR) and nine other advanced designs: NAAREA (Nuclear Abundant Affordable Resourceful Energy for All), Newcleo, Jimmy Energy, Otrera, Calogena, Blue Capsule Technology, Hexana, Stellaria and Thorizon.
- In Japan, six SMR designs developed by private sector stakeholders are under discussion. The High Temperature Engineering Test Reactor (HTTR) at the Japan Atomic Energy Agency, with a

thermal power of 30 MW, is operational and is planned to be utilized for a hydrogen production demonstration project.

- The Republic of Korea has two notable SMR designs. The first, called the System-integrated Modular Advanced Reactor (SMART) and developed by KAERI with Saudi Arabia, is a PWR capable of generating 100 MW_e. It was granted standard design approval in September 2024 by the regulatory body of the Republic of Korea while a new partnership with Canada has been announced, with a licensing application to be submitted for the potential deployment at Chalk River Laboratories in Canada. The second, called i-SMR, is an integral PWR designed to generate 170 MW_e and is being developed by a national consortium.
- In the United Kingdom, Rolls-Royce is developing a PWR of 470 MW_e capacity.
- Numerous SMR designs are under development in the USA. The licensing and demonstration of the NuScale VOYGR design, which could comprise six modules that generate 77 MW_e each, has shifted from Idaho Falls, Idaho to other potential users in the USA and Europe, including Romania. Westinghouse has submitted a pre-application for design certification for its AP300 SMR, and Holtec International is developing its SMR-300. Generation IV reactor technologies include the X-energy Xe-100, which uses HTGR technology and the Oklo Aurora Powerhouse and Westinghouse eVinci microreactors. The Microreactors Applications, Research, Validation and Evaluation (MARVEL) project is also ongoing at the Idaho National Laboratory.

Notable Floating NPP Developments: Several countries are engaged in the design development of marine-based SMRs for floating NPPs for on shore and offshore applications. A reactor design start-up company, Seaborg Technologies in Denmark, is developing a compact molten salt reactor to produce 100 MW_e. The KEPCO E&C (Republic of Korea) continues the development of BANDI, a PWR-based floating power unit to generate 60 MW_e. The Russian Federation has adopted the RITM-200M design (already used in icebreakers) for upcoming floating NPPs, while the China National Nuclear Corporation (China) is developing a floating NPP design, the ACP100S.

Technology Readiness Level (TRL) of SMR

In addition to analyses of capital costs and operational performance when assessing small modular reactor (SMR) designs, it is necessary to consider their level of technological maturity, measured by the Technology Readiness Level (TRL). At present, most SMR designs worldwide remain at the stages of conceptual design, detailed design finalization, safety assessment, or licensing review, corresponding approximately to TRL 4–7. While some designs have progressed to first-of-a-kind (FOAK) project deployment, they have not yet achieved widespread commercial deployment nor established stable, industrial-scale supply chains.

The fact that the technology has not yet reached higher TRL levels (TRL 8–9) implies the persistence of risks related to licensing schedules, actual capital costs (including FOAK premium effects), module standardization capability, and the degree of supply chain localization. Therefore, at the pre-feasibility stage, TRL should be considered an important parameter in the assessment of technological and financial risks associated with the SMR design option under consideration.

Input

Nuclear reactors require a variety of inputs to generate electricity, with the most critical being nuclear fuel. The primary fuels used in nuclear reactors include uranium, plutonium, and thorium. These elements undergo nuclear fission, where the nucleus of an atom splits into smaller parts, releasing a significant amount of energy in the form of heat.

Uranium: Uranium is the most commonly used fuel in nuclear reactors. It is primarily used in the form of uranium dioxide (UO₂), a ceramic material that is stable at high temperatures. Natural uranium consists mostly of uranium-238 (U-238), with about 0.7 % being uranium-235 (U-235), the isotope necessary for sustaining a fission chain reaction. To be used in most nuclear reactors, uranium must be enriched, increasing the concentration of U-235 to between 3 % and 5 % [2].

Plutonium: Plutonium-239 (Pu-239) is another fissile material used as nuclear fuel, particularly in fast breeder reactors (FBRs). Plutonium is produced in reactors from U-238 and can be extracted through the reprocessing of spent nuclear fuel. Plutonium fuels are often used in a mixed oxide (MOX) form, which combines plutonium dioxide with uranium dioxide [3].

Thorium: Thorium-232 (Th-232) is a fertile material that can be converted into fissile uranium-233 (U-233) within a reactor. Thorium is considered a promising alternative to uranium due to its greater abundance and reduced long-term radioactivity. However, the technology for using thorium in reactors is still under development and has not been widely adopted [4].

In addition to nuclear fuel, other inputs required for reactor operation include:

Coolant: A coolant is necessary to transfer the heat generated by nuclear fission from the reactor core to the steam generators or directly to the turbines. Common coolants include light water (H₂O), heavy water (D₂O), carbon dioxide (CO₂), and liquid metals such as sodium (Na).

Moderator: In thermal reactors, a moderator is used to slow down neutrons to increase the probability of fission. Light water, heavy water, and graphite are typical moderators used in various reactor designs.

Control Rods: These are made of materials that absorb neutrons, such as boron, hafnium, or cadmium. Control rods are inserted into or withdrawn from the reactor core to control the rate of the nuclear reaction.

Output

The primary output of a nuclear reactor is electricity. Additionally, nuclear reactors can produce other valuable outputs:

Radioisotopes: Many reactors are capable of producing radioisotopes used in medicine, industry, and scientific research. For example, reactors produce isotopes like Cobalt-60 (Co-60) for cancer treatment.

Heat: Some reactors are designed for cogeneration, producing both electricity and heat. The heat can be used for district heating, desalination, or industrial processes.

Spent Nuclear Fuel: After its use in the reactor, nuclear fuel becomes highly radioactive and is considered spent nuclear fuel. It contains a mixture of fission products, uranium, and plutonium, which must be carefully managed and stored due to its long-lived radioactivity. Some of this material can be reprocessed and recycled as new fuel.

Typical capacities

Large reactors (conventional reactors) are generally considered reactors with an equivalent electric power higher than 700 MW_e. Medium-sized reactors are defined as “reactors with an equivalent electric power between 300 and 700 MW” [19]. The International Atomic Energy Agency (IAEA) defines SMRs as “newer generation reactors designed to generate electric power up to 300 MW” and SMR plants’ capacity can be as small as few MW, the smallest registered (in conceptual design phase) is 1.5 MW_e [7].

Ramping configurations

Nuclear energy is a cornerstone for baseload power generation due to its ability to provide a constant and reliable source of electricity, regardless of weather conditions or time of day. Unlike variable renewable energy sources like wind or solar, NPPs operate at a high capacity factor, typically over 90 %, that is to say, they produce near their maximum power output almost continuously. This steady output is crucial for maintaining the stability of the power grid. Nuclear reactors produce electricity through the process of nuclear fission, where atomic nuclei split and release energy in the form of heat. This heat is used to generate steam, which drives turbines connected to generators. Because NPPs can run uninterrupted for long periods - often between refuelling cycles that can span 18 to 24 months - they provide a dependable foundation upon which other, more intermittent sources of energy can be added, ensuring a continuous supply of electricity to meet the base demand of an energy grid. The potential benefits can be seen in Table 33.

SMRs offer a wide range of configurations and some designs use a multi-module approach to achieve scalability and adaptability to growing energy demand. Some SMRs, particularly microreactors, are designed for use in remote or non-interconnected areas, small isolated networks, as well as for emergency response. SMRs can also be suitable for densely populated areas and industrial clusters [25].

Table 33: Flexibility attributes and potential benefits of SMR [25].

Attribute	Sub-Attribute	Benefits
Operational flexibility	Manoeuvrability	Load following
	Compatibility with hybrid energy system and polygeneration	Economic operation with increasing penetration of intermittent generation, alternative missions
	Diversified fuel use	Economics and security of supply
	Island operation	System resiliency, remote power, micro-grid, emergency power applications
Deployment flexibility	Scalability	Ability to deploy at the scale needed
	Siting	Ability to deploy where needed
	Constructability	Ability to deploy on schedule and budget
Product flexibility	Electricity	Reliable, dispatchable power supply
	Process heat	Reliable, dispatchable process heat
	Radioisotopes	Unique or high demand isotopes supply

Ramping configurations

Modern reactors are able to adjust their operation to follow scheduled or unscheduled load changes. Many modern NPPs (III/III+ generation) can safely operate at 25 % of the nominal load and ramp up to full output at a ramping rate of 2.5 % per minute up to 60 % output and then at a ramping rate of 5 % per minute to full rated power. It means that the power plants can change from 25 % to 100 % nominal rated output in less than 30 minutes [26]. However, NPPs characterized by high investment, high fixed operation and maintenance (O&M) costs and low variable operation costs, therefore it is typically assumed that they will run in base load mode (meaning more than 8000 h/year).

The new SMRs have capability to ramp up or down, and daily load of SMRs can be performed from 100 % to as low as 20 % power. If in a setup with multiple SMRs forming a plant, one or more modules could be turned on/off to vary the output of the overall plant.

In Europe, flexibility is a requirement for a NPP: the plants must be capable of daily cycling between 50 % and 100 % of their nominal load, maintaining a ramping rate of 3-5 % per minute.

The European Utility Requirements (EUR) since 2001 specify that new reactor designs must be capable of load-following between 50 % and 100 % of capacity. Although most French reactors operate in this mode, the European Pressurised Reactor (EPR) design has enhanced capabilities. It can maintain its output at 25 % and then gradually increase to full production at a rate of 2.5 % of nominal power per minute up to 60 % of production, and at 5 % of nominal power per minute up to full nominal power [27]. This means that the unit can potentially change its output from 25 % to 100 % in less than 30 minutes, although this may come at the cost of some wear and tear [28].

Advantages/disadvantages

Advantages

- Well-established technology (conventional reactors).
- NPPs are a safe technology due to advancements that have significantly reduced the risks associated with past accidents.
- High energy density, meaning they require less land area compared to other sources like solar or wind.
- Low carbon emissions compared to fossil fuel plants. They do not emit greenhouse gases during operation, and the emissions associated with their life cycle are minimal compared to other sources.

- Large fuel storage facilities are not needed due to the high efficiency and compactness of nuclear material. Production levels are usually not affected by weather conditions. NPPs are well-suited to meet large energy demands, as they have high performance and capacity factors (80 to 90%).
- Ongoing advances in recycling and the development of alternative fuel cycles are expanding the availability of nuclear fuel.

Disadvantages

- Prolonged construction time, with uncertainty in timeline predictions due to technical and logistical factors.
- NPPs lack international standardization due to national security and strategy concerns.
- Suitable locations for nuclear power plant construction are limited, as they must be near load centres and water sources (such as rivers or the sea) and away from seismic zones.
- Geopolitical issues, such as disruptions in the supply chain and the risk of nuclear proliferation, complicate international collaboration on safety standards and regulations.
- High initial capital cost compared to other alternatives.
- There is significant uncertainty in predicting investment costs. However, recent improvements in project management and modular techniques have enhanced the reliability of timelines.
- Maintenance costs are high due to the lack of standardization and the high salaries of highly specialized personnel.
- The decommissioning of NPPs requires long and expensive processes, posing a financial challenge.
- It is expected that the start-up cost of the SMR supply chain will be very high.
- Managing spent nuclear fuel waste is costly and usually accounts for about 5% of the total electricity generation cost [38].
- Nuclear energy generates radioactive waste from spent fuel, which requires special handling due to its impact on human health. This issue is further described in the

Advantages and disadvantages of SMR compared to large reactors

SMR advantages

- **Enhanced safety and security:** Lower thermal power of the reactor core, compact architecture, and employment of passive concepts have the potential for enhanced safety and security compared to earlier designs and large commercial reactors. The passive safety systems are an important safety feature in the SMR. The safety system incorporates an on-site water inventory that operates on natural forces (e.g., natural circulation, convection, gravity and self-pressurization) [28]. 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. These higher safety margins lower or even eliminate the potential for releases of radioactivity to the environment and the public in case of accident.
- **Modularity:** The term 'modular' in SMRs signifies scalability and the ability to fabricate major components of the nuclear steam supply system (NSSS) in a factory setting before transport to the site. This can help limit the on-site preparation and reduce the construction time. Factory fabrication allows working in a better-controlled environment determining a quality improvement, reducing construction schedule, reducing maintenance cost because of a reduction of the probability of failure of components, and having a safer construction process. It also improves workers' safety on-site because they handle a smaller number of components. Factory fabrication could determine a cost-saving in labour and construction.
- **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 can lead to easier financing compared to larger plants [16].

- Reduced refuelling needs: SMRs use only a small amount of fuel and only need to be refuelled 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 refuelling.

SMR disadvantages

- Lack of development: only a few SMRs are currently in operation for power generation. It is therefore difficult to have confidence in production times, learning rates and cost reductions proposed by the industry
- Lost economies of unit scale: nuclear reactors grew bigger because manufacturers and operators gained commercial advantages from increasing size and output. SMRs lose the advantages of economies of unit-scale and may only be cost-effective in high quantities, which require a large deployment of SMR modules.
- Licensing: One of the important barriers is licensing of new reactor designs. The licensing process for a new reactor as SMR designs is lengthy and costly, and expected to be longer than for conventional reactors.

Technology life-cycle management

For nuclear power plants, the assessment of techno-economic performance should be conducted using a full life-cycle approach, including: (i) capital investment; (ii) operation and maintenance; (iii) fuel supply; (iv) decommissioning; and (v) management of spent nuclear fuel and radioactive waste.

1. Capital Investment (CAPEX)

Capital investment represents the largest cost component over the life cycle of a nuclear power plant and typically constitutes the dominant share of the Levelized Cost of Electricity (LCOE). This component includes: design, review, and licensing costs; construction of nuclear and auxiliary facilities; procurement of major equipment (reactor, turbine, safety systems); project management, insurance, and contingencies; interest during construction (IDC); and other related expenditures.

A distinctive feature of nuclear power projects is their long construction period, stringent safety standards, and rigorous quality control requirements, which may lead to schedule delays and cost overruns if project management is ineffective. Therefore, within a life-cycle approach, effective management of CAPEX risks and financing costs is critical to the overall economic performance of the project.

2. Operation and Maintenance (O&M)

Operation and maintenance costs include: operational, technical, and safety personnel; routine maintenance and major overhauls; spare parts and materials management; radiation protection and nuclear security measures; as well as insurance and other legal obligations.

For large-scale nuclear power plants, economies of scale generally result in relatively stable and competitive O&M costs per kWh compared to other baseload generation sources. However, safety upgrades following major international events (e.g., the Fukushima accident in Japan in 2011), long-term operation (LTO) programmes, or replacement of major components may increase O&M costs during the mid- and late-life phases of the plant.

3. Fuel Supply

Nuclear fuel costs include: uranium mining and milling; conversion and enrichment; fuel assembly fabrication; transportation and insurance; and spent fuel management.

Compared with coal- or gas-fired power plants, nuclear fuel costs typically account for a smaller share of LCOE due to the high energy density of nuclear fuel and relatively long refuelling cycles (12–24 months). Nevertheless, supply security considerations and fluctuations in enrichment service prices may affect long-term fuel costs.

Under a life-cycle approach, fuel costs should be evaluated in conjunction with long-term contracting strategies, supplier diversification, and strategic fuel stockpiling policies in order to ensure financial stability and energy security.

4. Decommissioning

Decommissioning is a mandatory legal obligation upon the end of a plant's operational lifetime (typically 40–60 years, with possible extensions). This process includes dismantling contaminated systems and components, treatment and classification of resulting radioactive waste, decontamination of structures, and site restoration. International practice requires plant owners to establish a dedicated decommissioning fund during the operational phase, typically through accrual mechanisms linked to electricity generation. Decommissioning costs are generally estimated at several percent of the initial capital investment; however, in absolute terms, they are substantial due to the large plant capacity and stringent safety requirements.

5. Spent Fuel Management

For large-scale reactors, a significant volume of spent fuel is generated over the plant's lifetime. Common management strategies include: initial storage in spent fuel pools at the plant site; interim dry storage; and, in the long term, either reprocessing or deep geological disposal. Costs associated with spent fuel management include long-term interim storage, transportation, packaging, and final disposal. These represent long-term financial obligations that must be calculated and funded progressively throughout the operational life of the plant.

6. Radioactive Waste Management

Radioactive waste generated during operation and decommissioning is classified according to activity levels (low, intermediate, and high level). Waste management involves classification, treatment and conditioning, packaging, interim storage, and final disposal. For high-level waste or spent nuclear fuel, deep geological disposal is widely regarded under international practice as a sustainable long-term solution.

Space requirement

A NPP typically occupies a compact area, needing approximately 3.4 km² for every 1,000 megawatts of installed capacity. This estimate reflects the median land area for the 59 nuclear plant sites across the United States [20].

To calculate the direct land use intensity of energy, one must divide the area occupied by the power generation facility, in this case, a nuclear reactor, by the amount of energy generated over a year. It is important to note that the area dedicated to uranium mining, conversion, and enrichment is referred to as indirect land use. The use of this variable distinguishes the exclusive use of land for operation, which, if analysed in isolation, may create a bias in data interpretation. In fact, the total land use intensity of energy is the sum of both direct and indirect land use. When comparing different energy sources, nuclear energy is the most efficient in terms of land use as depicted in table below [21].

Table 34: Land-use intensity of energy [21].

Source of energy	Land Use Intensity of Energy total (ha/TWh/y) – Mean
Hydroelectric	15,000
Ground-mounted PV	2,100
Natural gas	410
Wind	170
Nuclear LR	15

For Vietnam [47]: On June 26, 2025, at the 27th Session of the 11th People's Council of Ninh Thuan Province for the 2021–2026 term, the Council approved the Resolution on the Adjustment of the Ninh Thuan Provincial Master Plan for the period 2021–2030, with a vision to 2050. This adjustment focuses on 11 major areas, including 8 items directly or indirectly related to the Ninh Thuan NPP Project (*note: the former Ninh Thuan Province has now been merged into the new Khanh Hoa Province*). Accordingly:

- Ninh Thuan 1 NPP has a total planned area of approximately 883.68 hectares, including 443.11 ha on land and 440.57 ha at sea.
- Ninh Thuan 2 NPP has a total planned area of approximately 758.54 hectares (including 380.91 ha on land and 377.63 ha at sea).

Since the two Vietnamese NPPs have not yet been constructed, the projected design capacity values published in official documents are used for analysis. Each plant is planned to include four reactor units, with an individual unit capacity ranging from 1,000 to 1,600 MW.

Input data for calculation:

Table 35: Estimated space requirement of project in Vietnam

Information	Ninh Thuan 1 NPP	Ninh Thuan 2 NPP
Total area (ha)	883.68	758.54
Land area (ha)	443.11	380.91
Sea area (ha)	440.57	377.63
Number of units	4	4
Capacity per unit (MW _e)	1,000–1,600	1,000–1,600
Total capacity (MW _e)	4,000–6,400	4,000–6,400

Modern NPPs typically operate with a capacity factor of around 90%. With 8,760 hours per year, the annual electricity generation for a 4,000 MW plant is 31.54 TWh/year, and for 6,400 MW, it is 50.46 TWh/year. When considering the total area (land + sea), the land-use intensity for Ninh Thuan 1 NPP ranges from 28.0 to 17.5 ha/TWh/year, and for Ninh Thuan 2 NPP from 24.1 to 15.0 ha/TWh/year. If only land area is considered, the land-use intensity for Ninh Thuan 1 NPP is 14.1–8.8 ha/TWh/year, and for Ninh Thuan 2 NPP is 12.1–7.6 ha/TWh/year.

Therefore, when accounting for the entire area (land + sea), the land-use intensity of Vietnam's two NPPs is 15–28 ha/TWh/year, slightly higher than the global average, due to inclusion of sea areas and auxiliary infrastructure. However, when only onshore land area is considered, the result of 7.6–14.1 ha/TWh/year is comparable to or even lower than the global average (~15 ha/TWh/year).

Thus, it can be seen that Ninh Thuan 1 and 2 NPPs demonstrate good land-use efficiency, particularly when considering the actual onshore area occupied.

Water consumption

In terms of water usage per megawatt-hour, nuclear energy slightly exceeds that of comparable fossil fuel plants, whether using once-through or closed-cycle cooling methods. While nuclear power utilizes more water than certain renewable sources like wind and photovoltaic solar, it typically consumes less than other renewable technologies such as geothermal [22].

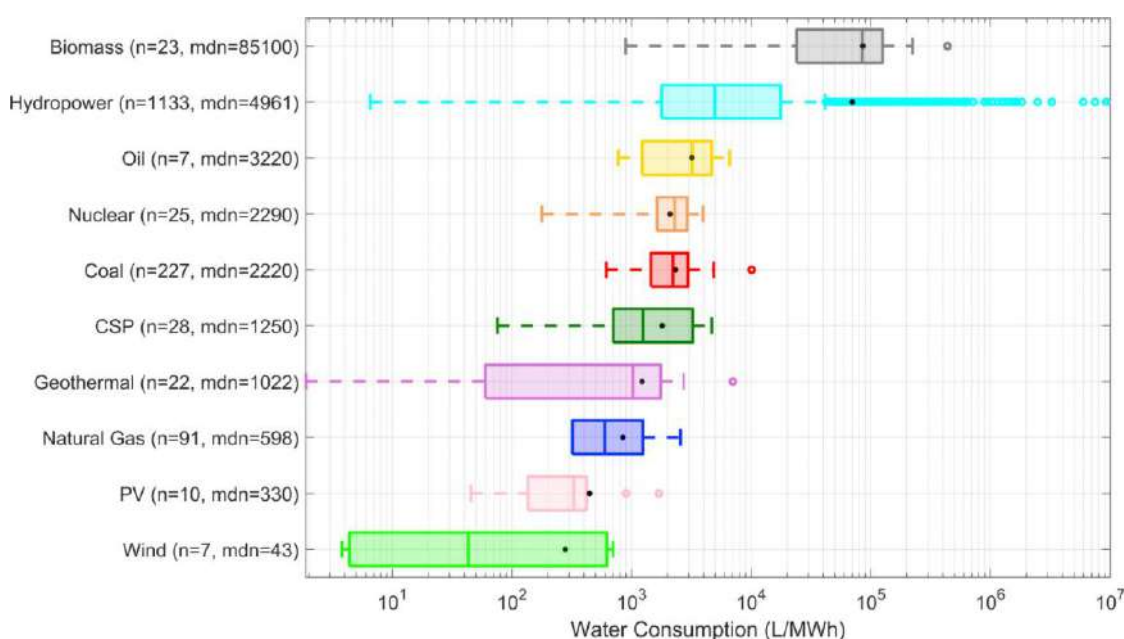


Figure 109: Water use comparison between energy sources [24].

The most common nuclear reactors, such as Pressurized Water Reactors (PWR) and Boiling Water Reactors (BWR), use water both for cooling the core and for producing steam that drives the turbines. Water consumption can vary, but it typically ranges from 2000 to 3000 litres per megawatt-hour (l/MWh) of electricity produced [23]. This water is primarily used in the condenser cooling systems, where steam is condensed back into water after passing through the turbines.

On the other hand, gas-cooled reactors (GCR) or liquid metal-cooled reactors (such as sodium in sodium-cooled fast reactors, SFR) have much lower or even zero water consumption in some cases. In these systems, the primary coolant is not water, so water use is limited to the secondary steam generation system and condenser cooling. In such cases, water consumption can be significantly lower, often in the range of 500 to 1000 l/MWh. The global median in 2019 was 2290 l/MWh [24], as shown in Figure 109: Water use comparison between energy sources [24]..

Environment

Figure 110 shows that nuclear power emits 9 g CO₂ equivalent/kWh of direct emissions; this value being significantly lower as compared to other combustion-based power generation technologies. These emissions are based on a life cycle approach, assuming 60 years of lifetime and the hours of operation between a minimum of 3700 and 7400 h per year [29].

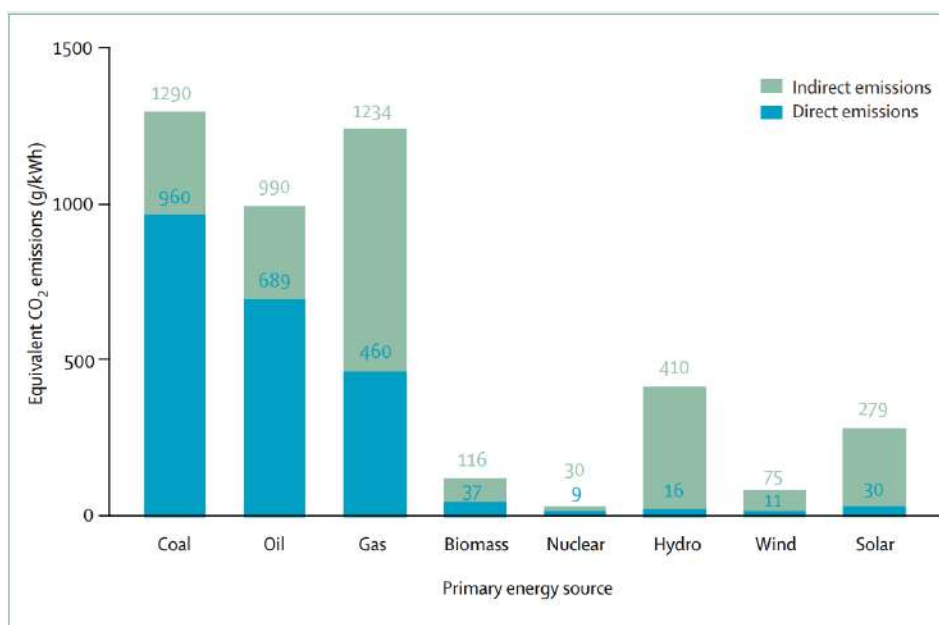


Figure 110: Average life-cycle CO₂ equivalent emissions from different power generation sources [29].

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. However, it is important to highlight that the nuclear industry is the only energy sector with structured long-term plans for managing its waste.

Radioactive waste includes any material that is either intrinsically radioactive, or has been contaminated by radioactivity, and that is deemed to have no further use. Every radioactive particle has a half-life - the time taken for half of its atoms to decay, and thus for it to lose half of its radioactivity. Radioactive particles with long half-lives tend to be easier to handle. Eventually all radioactive waste decays into non-radioactive elements. The more radioactive an isotope is, the faster it decays. The radioactive materials produced by nuclear fission of uranium are divided in short-term, medium-lived, and long-lived fission products. A typical short-term product is the isotope Iodine-131 (¹³¹I), with a half-life of 8 days, while medium-lived fission product has half-lives of about 30 years. Only seven fission products have half-lives much longer than 30 years, in the range of 200.000 to 16 million years. They are called the long-lived fission products, such as Caesium-135 (¹³⁵Cs) or Selenium-79 (⁷⁹Se).

Radioactive waste is produced at all stages of the nuclear fuel cycle. The fuel cycle involves the mining and milling of uranium ore, its processing and fabrication into nuclear fuel, its use in the reactor, its

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

Currently, many radioactive waste treatment options have been researched and considered, including: burying in the ground, nuclear waste recycling, taken into space, buried under the sea, buried in the subduction zone, buried under the glacier, stored in artificial stone. The two options that are most used today are buried in the ground and recycling. In the 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 the recycling approach, used fuel is processed to separate Plutonium and Uranium for reuse, the rest can be vitrified and buried.

Nuclear waste management has significantly advanced over the past decades, with innovative technologies such as vitrification and deep geological storage offering safe and long-term solutions. Additionally, ongoing research is focused on further reducing the environmental impact through recycling and reusing nuclear materials. Compared to other energy sources, such as coal and oil, nuclear energy has a much lower environmental impact in terms of greenhouse gas emissions and air pollution.

Nuclear waste management remains a contentious issue despite the existing and proven technical capabilities for safe storage and disposal. The controversy primarily stems from the long-lived radioactivity of nuclear waste, which poses potential risks to human health and the environment for thousands of years. Communities near proposed storage sites often express strong opposition due to fears of contamination, accidents, and adverse impacts on property values. Additionally, the political and logistical challenges of establishing and maintaining secure, long-term disposal facilities, such as deep geological repositories, further complicate the situation.

Safety issues and Concerns

Nuclear accidents like Chernobyl and Fukushima have significantly contributed to an unfavourable environment for nuclear energy by amplifying public fears and scepticism about the safety and reliability of nuclear power. This resulted in challenges for policymakers and energy companies in securing public support and investment for nuclear energy initiatives.

In the last few years, public perception of nuclear energy has evolved positively, driven by the growing awareness of the need to reduce carbon emissions and combat climate change. Nuclear energy is increasingly seen as a viable and necessary solution to complement other renewable energy sources, ensuring a stable and continuous supply of electricity.

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 six 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 [5].

Reactor Type	Neutron Spectrum	Coolant	Temperature (°C)	Pressure	Fuel Cycle	Size (MW _e)	Energy Use
Gas-cooled fast reactors	fast	helium	850	high	closed, on site	1200 & 1800+	electricity & hydrogen
Lead-cooled fast reactors	fast	lead or Pb-Bi	480-570	low	closed, regional	20-1800+	electricity & hydrogen
Molten salt fast reactors	fast	fluoride salts	700-800	low	closed	1000	electricity & hydrogen

Molten salt reactor - advanced high-temperature reactors	thermal	fluoride salts	750-1000	low	open	1000-1500	hydrogen
Sodium-cooled fast reactors	fast	sodium	500-550	low	closed	50-1500	electricity
Very high temperature gas reactors	thermal	helium	900-1000	high	open	250-300	hydrogen & electricity

Additionally, more than a dozen (Generation III) advanced reactor designs are in various stages of development. One of these is called Advanced Boiling Water Reactor, a few of which are now operating and others are under construction. The best-known radical new design is the High-Temperature Gas-Cooled Reactor Pebble-Bed Module Reactor (HTGR-PBM), an advanced nuclear reactor design utilizing helium gas as a coolant and spherical pebble-shaped fuel elements. This configuration allows the reactor to operate at high temperatures, around 750 °C to 950 °C, which enhances its thermal efficiency and expands its potential applications beyond electricity generation, such as in industrial processes and hydrogen production. The pebble-bed design incorporates passive safety features and a modular approach, meaning reactors can be scaled up by adding more modules as needed, making it flexible and adaptable for various energy needs.

Considering the closed fuel cycle, Generation I-III reactors recycle plutonium and uranium while Generation IV are expected to have full actinide recycling. 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, and may be built progressively.

Example of current projects

Currently, two main development trends are being pursued in the global nuclear power sector: large-scale nuclear power plants and small modular reactors (SMRs). Large nuclear power plants continue to play a dominant role in the global nuclear power system, typically with unit capacities ranging from about 1,000 to 1,600 MWe per reactor. Representative projects that are currently in operation or under construction include the Taishan Nuclear Power Plant in China, which uses the EPR technology with a capacity of approximately 1,600 MWe per unit; the Hinkley Point C project in the United Kingdom featuring two EPR-1600 reactors; the Barakah Nuclear Power Plant in the United Arab Emirates employing the APR-1400 technology developed in the Republic of Korea; the Rooppur Nuclear Power Plant in Bangladesh and the El-Dabaa Nuclear Power Plant in Egypt, both based on the Russian VVER-1200 technology; as well as AP1000 projects in China and the United States. These Generation III/III+ reactors are designed with advanced passive safety systems, long operational lifetimes, and improved efficiency, thereby enhancing the safety and economic performance of nuclear power generation.

In parallel, small modular reactors (SMRs) are being actively developed in many countries to provide more flexible power supply options, reduce upfront capital investment, and shorten construction schedules. Typical SMR designs have electrical capacities ranging from about 50 to 300 MWe per module, and multiple modules can be combined to achieve larger plant capacities. Notable examples include the ACP100 (Linglong One) reactor with a capacity of about 125 MWe currently under construction in China; the BWRX-300 reactor with a capacity of about 300 MWe developed by GE Hitachi and planned for deployment in Canada and Poland; the NuScale VOYGR design from the United States with a capacity of approximately 77 MWe per module; and the KLT-40S reactors used on Russia's floating nuclear power plant Akademik Lomonosov. In addition, several next-generation SMR designs such as the Rolls-Royce SMR (United Kingdom), SMART (Republic of Korea), and CAREM (Argentina) are also under development and moving toward commercial deployment. The parallel development of large nuclear power plants and SMRs is expected to create a more flexible nuclear energy system capable of meeting diverse grid conditions and supporting the global energy transition in the future.

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Data sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (\$), price year 2025.

Nuclear PWR											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW _e	1200	1200	1200	1200					F	
Generating capacity for total power plant	MW _e	2400	2400	2400	2400					A	
Electrical efficiency, net, name plate	%	36	38	40	42					B	1
Electrical efficiency, net, annual average	%	34	36	38	40					B	1
Forced outage	%	2	2	2	2					C	1
Planned outage	%	9	8	7	6						1
Self-consumption	%	7	7	6	5					N	14
Technical lifetime	years	60	60	60	60	40	80				1, 2
Construction time	years	7.4	7.4	7.4	7.4	4	10			D	1, 2
Space requirement	1000_m ² /MW _e	2.6	2.6	2.6	2.6	2.0	3.4	2.0	3.4	E	3, 4
Additional data for non-thermal plants											
Capacity factor, theoretical	%	85	87	88	90	75	93				5, 6, 7
Capacity factor, incl. outages	%	76	78	80	83	67	83				5, 6, 7
Ramping ability											
Ramping	% of full load/min ute	4	4	3	3	3	5			F, G	1, 8
Minimum load	% of full load	40	40	40	40	30	50			G	8
Warm start-up time	hours	2	2	1	1	2	6				8
Cold start-up time	hours	30	30	30	30	24	48				1
Environment											
PM 2.5	g/GJ _i	-									
SO ₂ (degree of desulphuring)	%	-									
NO _x	g/GJ _i	-									
CH ₄	g/GJ _i	-									
N ₂ O	g/GJ _i	-									
Economic data (in USD2025)											
Specific investment	MUSD/MW _e	6.50	6.00	5.50	5.00	5.00	10.00	4.50	8.00	H, I, J, K	6, 7, 9, 10, 11
- of which equipment	%	40	40	40	40	-	-	-	-	I	
- of which installation and other costs	%	60	60	60	60	-	-	-	-	I	
- of which equipment	MUSD/MW _e	2.60	2.40	2.20	2.00	2.00	4.00	1.80	3.20	I	

Nuclear PWR											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
- of which installation and other costs	MUSD/MW _e	3.90	3.60	3.30	3.00	3.00	6.00	2.70	4.80	I	
Fixed O&M	USD/MW _e /year	127,000	122,000	118,000	113,000	50,000	180,000	50,000	180,000		9, 10
Variable O&M	USD/MWh	2.4	2.3	2.2	2.1	1.8	3.0	1.6	2.6	L	
Start-up costs	USD/MW _e /start-up	9,750	9,750	9,750	9,750	7,500	15,000	6,750	12,000	M	
Technology specific data											
Water consumption	L/MWh	2540	2540	2540	2540	-	-	-	-		15, 16, 17, 18, 19

Notes:

- A A two-unit configuration is typical in nuclear power plants, but more units can be combined.
- B Generation IV reactors are expected to achieve efficiencies well above 45 %. In the future, nuclear reactors are likely to run often at partial load - thus the gap between nameplate and net efficiency.
- C % of yearly hours with forced outage.
- D The construction time refers solely to the period from when the final investment decision (FID) is taken and until commercial operation. It does not include project preparation stages such as feasibility studies, site selection, licensing, or pre-construction activities, unless explicitly stated otherwise.
- 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 The Russian VVER-1200-technology is used as a reference.
- G Ramping and minimum load are constrained by the core stability'. Minimum requirements are usually set by the regulation.
- H Decommissioning costs are usually 15% of the total investment cost, it is not included in the investment cost.
- I The specific investment breakdown is composed by 40% share of direct cost (i.e., Equipment, Labour, Construction, Materials and Building), 45% of Indirect cost (i.e., Design services, Construction and Supervision and project management, Commissioning and start-up costs), 12% of Owner's cost. Financial costs are excluded (would add around 20% to the investment cost).
- J The development of the overnight cost is based on NREL ATB 2024.
- K CAPEX shall reflect a potential first of a kind plant according to [9]. As limited data is available for these, specific cost information of recently and currently developed plants in various markets is consulted, spanning France, UK, China and the UAE [13], excluding data for Russia, South Korea and USA not being representative due to maturity of market, political and macroeconomic situations.
- L Uncertainty (Upper/Lower) is estimated as +/- 25 %.
- M Start-up costs are assumed to be 0.15% of CAPEX.
- N Based on Russian reactor technologies.

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Nuclear SMR											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Generating capacity for one unit	MW _e	100	100	100	100	80	125				1, 2, 3, 4
Generating capacity for total power plant	MW _e	300	300	300	300						1, 3, 4
Electrical efficiency, net, name plate	%	33	34	35	36					A	1, 2
Electrical efficiency, net, annual average	%	30	31	32	34					A	1, 2, 4, 5
Forced outage	%	3	3	3	3					B	1, 4
Planned outage	%	6.5	6.0	5.5	5.0	3	7				2
Self-consumption	%	29	25	22	20	20	30			I	12
Technical lifetime	years	40	45	50	55	30	60				2, 3
Construction time	years	9	8	6	4	8	12			C	2, 3, 6
Space requirement	1000_m ² /MW _e	0.64	0.64	0.64	0.64	0.05	1.60	0.05	1.60	D	1, 7
Additional data for non-thermal plants											
Capacity factor, theoretical	%	-	-	-	-	-	-	-	-		
Capacity factor, incl. outages	%	-	-	-	-	-	-	-	-		
Ramping ability											
Ramping	% of full load/minute	1.2	1.2	1.2	1.2					E	
Minimum load	% of full load	25	25	25	25					E	
Warm start-up time	hours	1.5	1.5	1.5	1.5						
Cold start-up time	hours	24	24	24	24						
Environment											
PM 2.5	g/GJ _i	-									
SO ₂ (degree of desulphuring)	%	-									
NO _x	g/GJ _i	-									
CH ₄	g/GJ _i	-									
N ₂ O	g/GJ _i	-									
Economic data (in USD2025)											
Specific investment	MUSD/MW _e	-	7.50	6.00	5.00	5.00	15.00	4.00	10.00	F, G	6, 9, 10, 11
- of which equipment	%	-	33	33	33	-	-	-	-	G	
- of which installation and other costs	%	-	67	67	67	-	-	-	-	G	
- of which equipment	MUSD/MW _e	-	2.50	2.00	1.67	1.67	5.00	1.33	3.33	G	
- of which installation and other costs	MUSD/MW _e	-	5.00	4.00	3.33	3.33	10.00	2.67	6.67	G	
Fixed O&M	USD/MW _e /year	-	110,000	105,000	102,000	-	-	-	-		
Variable O&M	USD/MW _h	-	2.20	2.15	2.10	-	-	-	-	H	2, 3, 8

Nuclear SMR											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Start-up costs	USD/MW_e/start-up	-	0	0	0	0	0	0	0		
Technology specific data											
Water consumption	L/MWh	-	-	-	-	-	-	-	-		

Notes:

- A 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.
- B % of yearly hours with forced outage.
- C = 109 months: China managed to connect its first SMR, one of two 100 MW HTR-PM reactors, to the grid on 20 December 2021. Construction began in 2012, and by then the time estimate for construction had increased to '50 months'. In reality, the first unit took almost 109 months from first concrete to mains connection, more than twice as long as expected.
- D Nuclear power plants have a 'high energy density' in terms of area required. The values represented here are for the area needed for the plants. However, there can be a higher requirement based on government regulation and environmental concerns.
- E Ramping and minimum load are constrained by the core stability'. Minimum requirements are usually set by the regulation.
- F Decommissioning costs usually are the 15% of the total investment cost.
- G The specific investment breakdown is composed by 40% share of direct cost (i.e., Equipment, Labour, Construction, Materials and Building), 45% of Indirect cost (i.e., Design services, Construction and Supervision and project management, Commissioning and start-up costs), 12% of Owner's cost. Financial costs are excluded (would add around 20% to the investment cost).
- H The main characteristics are taken from CAREM-25.
- I Based on reactor type HTR-PM. Other reactor types like ACP100, RITM-200N and NuScale all have a self-consumption rate around 20%.

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APPENDIX 1: METHODOLOGY

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

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

Unless otherwise stated, the thermal technologies in the catalogue are assumed to be designed for and operating for approx. 6000 full-load hours of generation annually (capacity factor of just below 70%). 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 presents the key characteristics of the technology as concisely as possible. The following paragraphs are included where relevant for the technology.

Brief 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

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

This section provides a description of specific advantages and disadvantages relative to equivalent technologies. Generic advantages are ignored; for example, benefits such as mitigating climate risks or enhancing security of supply are not included.

Space requirements

Description of the area required to produce with the given technology. Space requirements are generally expressed in 1000 m² per MW. The value presented only refers to the area occupied by the facilities needed

to produce energy. In case the area refers to the overall land use necessary to install a specific amount of capacity, or if a certain minimum distance from dwellings is required, this is specified in the notes. The space requirements may for example be used to calculate the rent of land, which is not included in the financial cost, since this cost item depends on the specific location of the plant.

Water consumption

Water consumption is expressed in l/MWh and includes the water used directly in the operation of the power plant, such as that required for cooling or the energy generation process. This value does not account for the water used in the manufacturing or construction of the plant's equipment and infrastructure, which is typically addressed in life cycle analyses.

However, where relevant, the qualitative description may also include a life-cycle water consumption to allow for a comparison between technologies.

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).

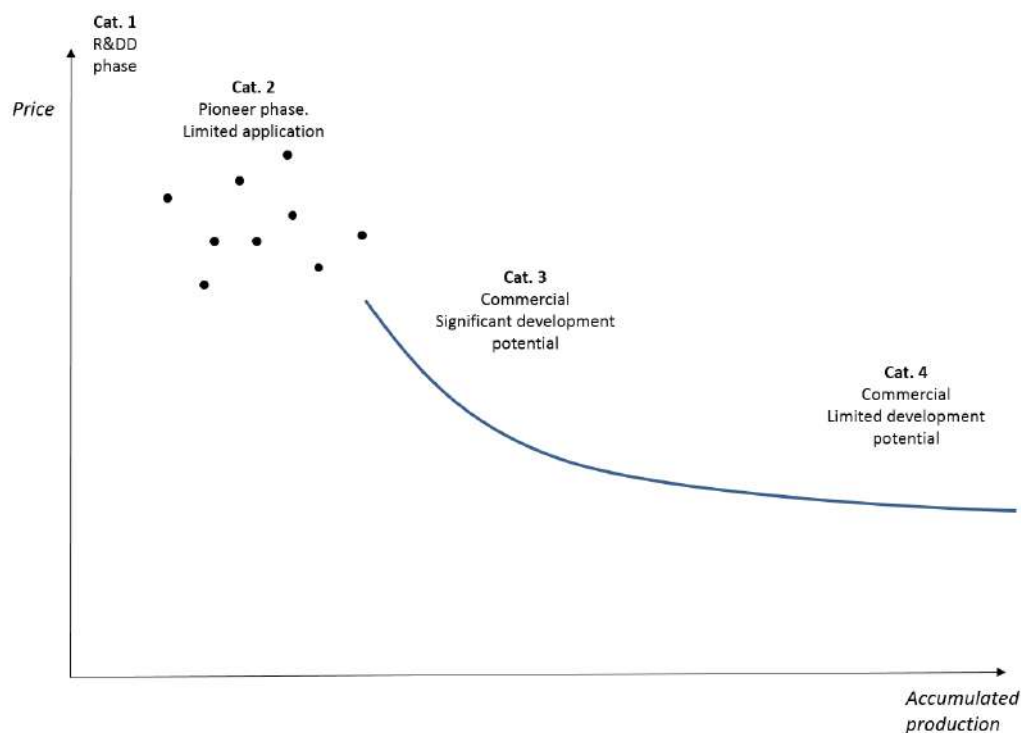


Figure 111: Technological development phases. Correlation between accumulated production volume (MW) and price.

Examples of current projects

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

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.

For technologies where no market standard has yet been established, reference is made to the best available technology among R&D projects.

Investment cost estimation

In this section investment cost estimates 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.

Cost reductions and improvements of performance can be expected for most technologies in the future.

Cost projections based on the learning curve approach are performed to estimate the costs for the years 2030 (2040) and 2050. Technological learning is based on a certain learning rate and on a capacity deployment defined from the IEA's Stated Policies Scenario (STEPS). The single technology is given a normalized cost of 100% in 2025 (base year); values smaller than 100% for 2030 and 2050 represent the technological learning, thus the relative cost reduction against the base year. For a comprehensive explanation of the methods used and to gain a deeper understanding of the assumptions underlying the projections, please refer to Appendix 2.

As for the uncertainty of investment cost data, the following approach was followed: for 2025 the lower and upper bound of uncertainty are derived from the cost span in the various sources analysed (usually it is set at +/- 25% but vary depending on the technology). For 2050, the central estimate is based on a learning

rate as defined in Appendix 2 and an average capacity deployment from the CPS, STEPS and NZE scenarios of the World Energy Outlook 2025 (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.

Additional remarks

This section includes other information, for example links to web sites that describe the technology further or give key figures on it.

References

References are numbered in the text in squared brackets and bibliographical details are listed in this section.

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 2025 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 2025. When converting costs from a year X to \$2025 the following approach is recommended:

1. If the cost is stated in VND, convert to \$ using the exchange rate.
2. Then convert from \$ in year X to \$ in 2025 using the relationship between the US Producer Price Index for “Engine, Turbine, and Power Transmission Equipment Manufacturing” of year X and 2025.

Table 37: World bank US Producer Price Index

Year	Index (2020=1)
2019	0.98
2020	1.00
2021	1.01
2022	1.06
2023	1.14
2024	1.19
2025	1.22

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

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 2025/2030 and 2050. The level of uncertainty is illustrated by providing a lower and higher bound. 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 2025, 2030, 2040 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 other units can be 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 and planned outage are both given in per cent.

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 was 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 2025-time horizon.

CO₂ 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:

Table 38: SO_x emissions

	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 NO₂ and NO, where NO is converted to NO₂ in weight-equivalents. NO_x emissions are also stated in grams per GJ fuel.

Emissions of methane (CH₄) and Nitrous oxide (N₂O) are generally not included in the catalogue. However, these are both potent greenhouse gases, 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.

Economic data

Economic data are all in \$ fixed prices, price-level 2025 and exclude value added taxes (VAT) or other taxes.

For projection of future economic 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, does not lose its value. It can therefore be sold again after the power plant has fulfilled its purpose and been decommissioned.

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

Cost of grid expansion

As mentioned, the 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.

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 39: 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.

The World Energy Outlook 2025 include three scenarios: the Current Policies Scenario (CPS), the Stated Policies Scenario (STEPS) and the Net Zero Emissions by 2050 scenario (NZE), which all represent global pathways with varying degree of climate policy commitment. For this study, the capacity development from the STEPS scenario is used as reference for renewable energy technologies, whose values falls in between the other two scenarios.

Table below shows the development of accumulated capacities of different electricity generation technologies toward 2050, using primo 2025 as the starting point.

Table 40: Development of accumulated capacities of different electricity generation technologies toward 2050

Accumulated generation capacity relative to 2025 (=1)		CPS			STEPS			NZE		
Technology	Installed capacity 2025 [GW]	2035	2040	2050	2035	2040	2050	2035	2040	2050
Coal	2259	1.1	1.1	0.9	1.1	1.0	0.8	0.5	0.3	0.1
Oil	401	0.7	0.6	0.4	0.7	0.6	0.3	0.4	0.2	0.1
Natural gas	2049	1.2	1.3	1.5	1.2	1.2	1.3	0.8	0.6	0.4
Nuclear	420	1.3	1.5	1.7	1.4	1.6	1.9	1.7	2.1	2.6
Hydro	1437	1.4	1.5	1.7	1.4	1.5	1.8	1.6	1.8	2.0
Bioenergy	181	1.4	1.5	1.8	1.4	1.7	1.9	2.3	2.9	3.7
Wind	1131	2.3	2.6	3.1	2.4	2.9	3.5	4.0	5.3	7.1
Geothermal	15	1.9	2.6	3.9	2.1	2.8	4.2	3.7	5.2	7.8
Solar PV	2164	3.7	4.8	6.4	4.1	5.5	7.5	5.8	8.2	11.2
CSP	8	2.6	4.5	8.6	2.7	4.6	8.9	12.1	24.8	43.8
Marine	1	11.4	27.0	58.4	11.6	27.9	60.8	19.5	38.5	78.3

For this study, the forecasting years are 2030, 2040 and 2050. To find a forecasted installed capacity for 2030, a linear interpolation between 2025 installed capacities and 2035 capacities in the IEA scenarios have been done.

As seen in the table, wind energy has not been separated in onshore and offshore in the WEO 2025. As both technical and economic parameters differs significantly for the two technologies, this study separates wind energy in onshore and offshore. To estimate the future capacities of onshore and offshore wind individually, the 2025 installed capacities have been found from IRENA capacity statistics 2025, while the forecasted capacities are based on the WEO 2025 scenarios, with relative shares following the WEO 2021 which is the most recent year where onshore and offshore wind was separated. The relative share is approximately 80% onshore and 20% offshore over the years.

Learning rates

The World Energy Outlook, perform yearly updates of learning rates for the renewable technologies based on their global tracking of technology costs. This study uses the learning rates from WEO 2025, which can be seen in the following table:

Table 41: Learning rates for the renewable technologies

Technology	WEO 2025 learning rate
Solar PV	20%
Wind, Onshore	5%
Wind, Offshore	15%
Hydropower	1%
Bioenergy (Biomass and Biogas)	5%
Geothermal	5%
Concentrated Solar power (CSP)	10%
Marine Energy	14%
Fossil fuels with CCS	10%

Solar PV, CSP and marine technologies are expected to see the strongest cost reductions. For solar PV, it is based on what have been observed historically. There is an uncertainty as to whether the technology will continue to experience drastic cost reductions. It should also 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. Offshore wind is also projected for significant cost reductions, which can be due to the high price levels we are experiencing now and the high complexity of the technology which allows room for innovation and development.

For O&M, a 10% learning rate has been applied for solar PV based on the Danish Technology Catalogue. The learning rate for battery storage is likewise based on the Danish Technology Catalogue which has been updated in 2025. The learning rates for batteries which have been applied in this study are 17% for the energy component and 10% for the power component as well as other costs.

For conventional thermal power plants, no learning rate have been applied in this study (0,4%) due to the maturity level of the technologies. For nuclear energy, there is a very high uncertainty on the cost development of the technology and very little literature can be found on the topic. Due to the uncertainty, no learning rate has been applied for nuclear. 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.

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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APPENDIX 3: METHODOLOGY FOR CALCULATION OF LEVELISED COST OF ELECTRICITY (LCOE)

This appendix describes a methodology for calculating the levelised cost of electricity (LCoE) for the power-generating technologies included in the Technology Catalogue. The purpose is to enable users to derive comparable generation costs on the basis of the techno-economic information provided in the technology datasheets.

The methodology is intended for simple techno-economic LCoE calculations. It is therefore based on the technical and economic assumptions contained in the datasheets and does not constitute a full project-finance model. In particular, the methodology does not include detailed modelling of financing structure, taxation, depreciation, debt repayment profile, or other project-specific financial conditions unless such elements are added explicitly by the user.

This appendix applies to power-generating technologies only. It does not apply to storage technologies, for which LCoE is generally not the most appropriate indicator.

For methodological purposes, the technologies are divided into two categories:

- Non-thermal generation technologies, such as wind and solar PV, for which electricity generation is derived primarily from installed capacity and capacity factor or full-load hours.
- Thermal generation technologies, such as coal- and gas-fired power plants, for which electricity generation cost depends additionally on fuel price and net electrical efficiency.

Definition of LCoE

The levelised cost of electricity expresses the discounted average cost of generating one unit of electricity over the technical lifetime of a plant. It may be interpreted as the constant electricity price that would set discounted lifetime revenues equal to discounted lifetime costs.

The general expression for LCoE is:

$$LCoE = \frac{\sum_{t=0}^N \frac{C_t}{(1+r)^t}}{\sum_{t=0}^N \frac{E_t}{(1+r)^t}}$$

where:

- C_t is the cost incurred in year t
- E_t is the electricity generated in year t
- r is the discount rate
- N is the total project horizon, including construction and operation as relevant

In this formulation, the numerator includes all relevant discounted lifetime costs, while the denominator includes discounted lifetime electricity generation.

For the purposes of the Technology Catalogue, the relevant cost components will normally include:

- Investment cost
- Fixed O&M cost
- Variable O&M cost
- Fuel cost, where relevant
- Emission cost, where relevant
- Optional decommissioning cost or residual value, if included by the user

General calculation approach

The technology datasheets provide a substantial part of the information required for a simple techno-economic LCoE calculation. In particular, the datasheets generally include values for:

- Generating capacity
- Technical lifetime
- Construction time
- Specific investment
- Fixed O&M cost
- Variable O&M cost
- Output-related parameters such as capacity factor, full-load hours, or annual average net electrical efficiency

However, the datasheets do not in all cases provide a complete set of inputs for LCoE calculation. Users will therefore normally need to supplement the datasheet information with additional assumptions, in particular regarding:

- Discount rate or weighted average cost of capital
- Inflation, if a nominal LCoE is to be calculated
- Fuel prices for thermal technologies
- Emission costs, if such costs are to be included
- Utilisation assumptions for thermal technologies where annual output is not given directly

The recommended approach is to use the datasheet values directly wherever available and to supplement them only where necessary with transparent and well-documented external assumptions.

Datasheet parameters used in the LCoE calculation

Parameters common to all generation technologies

For most generation technologies, the following datasheet parameters are directly relevant for LCoE calculation.

- Generating capacity for one unit and/or generating capacity for a typical power plant define the reference plant size.
- Technical lifetime defines the operating period over which costs and electricity generation are assessed.
- Construction time defines the period between investment decision and start of operation and is relevant where investment expenditure is distributed over the construction period.
- Specific investment or specific investment, total system defines the investment cost per unit of installed electrical capacity.
- Fixed O&M defines annual fixed operation and maintenance cost per unit of installed capacity.
- Variable O&M defines operation and maintenance cost per unit of electricity generated.
- Forced outage and planned outage may be used either directly or indirectly in the generation estimate, depending on how the output-related parameters are defined in the datasheet.

The notes to the datasheets should always be consulted, as they may clarify the assumed cost boundary, the derivation of O&M costs, and whether capacity factors or full-load hours already include outages, losses, or other adjustments.

Additional parameters for non-thermal generation technologies

For non-thermal technologies such as wind and solar PV, the principal additional output-related parameters are typically:

- Capacity factor, theoretical
- Capacity factor, incl. outages
- Average annual full-load hours or full-load hours
- Average annual degradation, where relevant

These parameters form the basis for estimating annual electricity generation.

If both parameters capacity factor and annual full-load hours are provided, the user should apply only one of them as the primary generation input and ensure that they are not used simultaneously to represent the same output.

For some technologies, the datasheets may also contain supporting technical parameters such as hub height, rotor diameter, specific power, transposition factor, performance ratio, DC/AC sizing factor, or PV module conversion efficiency. These may be useful for interpretation or validation, but they are not generally required in a simple LCoE calculation if capacity factor or full-load hours are already provided.

Additional parameters for thermal generation technologies

For thermal technologies, the key additional parameter is normally electrical efficiency, net, annual average. This parameter is required in order to convert fuel price into fuel cost per unit of electricity generated.

If fuel price is expressed per unit of fuel energy input, the fuel cost per unit of electricity may be expressed as:

$$Fuel\ cost_{MWh} = \frac{Fuel\ price_{input\ energy}}{\eta_{net}}$$

where:

- Fuel price_{input energy} is the fuel price expressed per unit of fuel energy input, for example USD/GJ
- η_{net} is the annual average net electrical efficiency, expressed as a fraction

Annual fuel cost is then calculated as:

$$Fuel\ cost_{annual} = E_{annual} \times Fuel\ cost_{MWh}$$

Thermal datasheets may also contain information on start-up cost, minimum load, ramping capability, minimum up-time, minimum down-time, and start-up time. These parameters are relevant for detailed dispatch modelling, but they are not normally required in a simple base-case LCoE calculation.

Similarly, environmental indicators such as SO₂, NO_x, or particulate emissions are not direct LCoE inputs unless the user applies explicit cost assumptions related to emissions or environmental compliance.

Estimation of annual electricity generation

Non-thermal generation technologies

For non-thermal technologies, annual electricity generation is normally estimated from installed capacity and either capacity factor or full-load hours.

If capacity factor including outages is provided, annual generation is calculated as:

$$E_{annual} = P \times 8760 \times CF$$

If average annual full-load hours are provided, annual generation is calculated as:

$$E_{annual} = P \times FLH$$

If annual degradation is specified, electricity generation in later years may be reduced accordingly. If degradation is not specified, annual generation may be assumed constant over the operating lifetime.

Thermal generation technologies

For thermal technologies, annual electricity generation is typically estimated from installed capacity and a user-defined utilisation assumption unless more specific operating information is available.

Annual generation may be expressed as:

$$E_{annual} = P \times 8760 \times U$$

where:

- P is installed electrical capacity
- U is annual utilisation or capacity factor

If the user wishes to reflect planned and forced outages explicitly, the utilisation assumption should be chosen so that it is consistent with the outage assumptions in the datasheet.

Calculation of cost components

Investment cost

Total investment cost is normally calculated as:

$$CAPEX = \text{Specific investment} \times \text{Installed capacity}$$

If construction time is modelled explicitly, the investment cost should be distributed across the construction period according to an assumed expenditure profile and discounted accordingly.

Fixed operation and maintenance cost

Annual fixed operation and maintenance cost is calculated as:

$$FOM_{annual} = \text{Fixed O\&M} \times \text{Installed capacity}$$

Variable operation and maintenance cost

Annual variable operation and maintenance cost is calculated as:

$$VOM_{annual} = \text{Variable O\&M} \times E_{annual}$$

Fuel cost for thermal technologies

For thermal technologies, annual fuel cost is calculated from electricity generation, annual average net electrical efficiency, and fuel price. If fuel price is expressed per unit of fuel energy input, the fuel cost per unit of electricity is:

$$\text{Fuel cost}_{MWh} = \frac{\text{Fuel price}_{input}}{\eta_{net}}$$

Annual fuel cost is then:

$$\text{Fuel cost}_{annual} = E_{annual} \times \text{Fuel cost}_{MWh}$$

The user must ensure full consistency of units. If fuel price is given in USD/GJ and electricity generation is measured in MWh, appropriate conversion between energy units is required.

Emission cost

Where emission cost is included, it may be expressed either as a cost per unit of electricity generated or as a cost derived from fuel input and an emission factor. The chosen method should be consistent with the available external data.

Additional user-supplied inputs

Inputs required for all technologies

The following inputs are generally not fully specified in the datasheets and must therefore be supplied by the user.

Discount rate or WACC

A discount rate is required to discount future costs and electricity generation to present values. This may be specified either in real terms or in nominal terms, depending on the price basis of the calculation.

Inflation

Inflation is required if a nominal LCoE is to be calculated. If the calculation is performed in constant prices, a real discount rate should be used instead.

Construction expenditure profile

The datasheets provide construction time, but not necessarily the distribution of investment expenditure across the construction period. Users may therefore need to assume, for example, equal annual expenditure or another suitable expenditure profile.

Additional inputs required for thermal technologies

For thermal technologies, users will normally also need to provide:

Fuel price

The datasheets provide technical efficiency, but not the fuel price itself. Fuel price assumptions must therefore be supplied externally and expressed in a unit consistent with the efficiency definition.

Plant utilisation assumption

Where no directly usable annual output assumption is provided, the user must specify a plant utilisation factor, capacity factor, or annual operating hours.

Emission cost, where relevant

If the user wishes to include carbon cost or other emission-related cost components, these must be specified separately.

Optional additional assumptions

Depending on the purpose of the analysis, the user may also choose to include:

- Decommissioning cost
- Residual or salvage value
- Site-specific output adjustments
- Grid connection costs beyond the datasheet boundary
- Technology-specific degradation assumptions where not already reflected in the datasheet values

Such assumptions are optional in a simple techno-economic LCoE calculation and should only be included where justified by the intended use of the analysis.

Treatment of construction time

The datasheets provide construction time, which should be reflected in the LCoE calculation. This is particularly important for technologies with long lead times and substantial upfront investment.

In a simplified approach, the entire investment may be treated as occurring at the beginning of the construction period. In a more detailed approach, the investment may be distributed over the construction years according to an assumed expenditure profile.

Where construction time is included explicitly, discounting begins in the first year in which expenditure occurs, while electricity generation begins only after commissioning.

Real and nominal LCoE

The cost values in the Technology Catalogue are generally presented in a constant price basis. Users should therefore distinguish clearly between real and nominal LCoE calculations.

A real LCoE is appropriate when:

- Costs are expressed in constant prices
- No inflation is applied to future cost streams
- A real discount rate is used

A nominal LCoE is appropriate when:

- Future costs are escalated with inflation or other nominal price assumptions
- A nominal discount rate is used

The discount rate and the cost streams must always be expressed in the same price basis. A nominal discount rate should not be applied to constant-price cash flows unless those cash flows are first escalated consistently. Likewise, a real discount rate should not be applied to nominal cash flows.

For most catalogue applications, a real LCoE based on constant-price inputs will provide the most transparent basis for comparison.

Limitations of the method

The methodology described in this appendix is intended as a practical and consistent tool for comparing the average lifetime cost of electricity generation across technologies under a defined set of assumptions. It is suitable for techno-economic comparison, but it does not capture all dimensions relevant to system planning or investment appraisal.

In particular, LCoE does not reflect:

- Dispatchability
- System integration cost
- Balancing and reserve requirements
- Locational value
- Timing of generation
- Detailed financing structure
- Tax treatment
- Market revenues

For many non-thermal technologies, the datasheets provide most of the core inputs required for a simple LCoE calculation. For thermal technologies, the datasheets generally need to be supplemented with fuel-price assumptions, utilisation assumptions, and, where relevant, emission-cost assumptions.

The resulting LCoE should therefore be interpreted as a technology cost indicator under the chosen assumptions, rather than as a complete measure of system value or project profitability.

