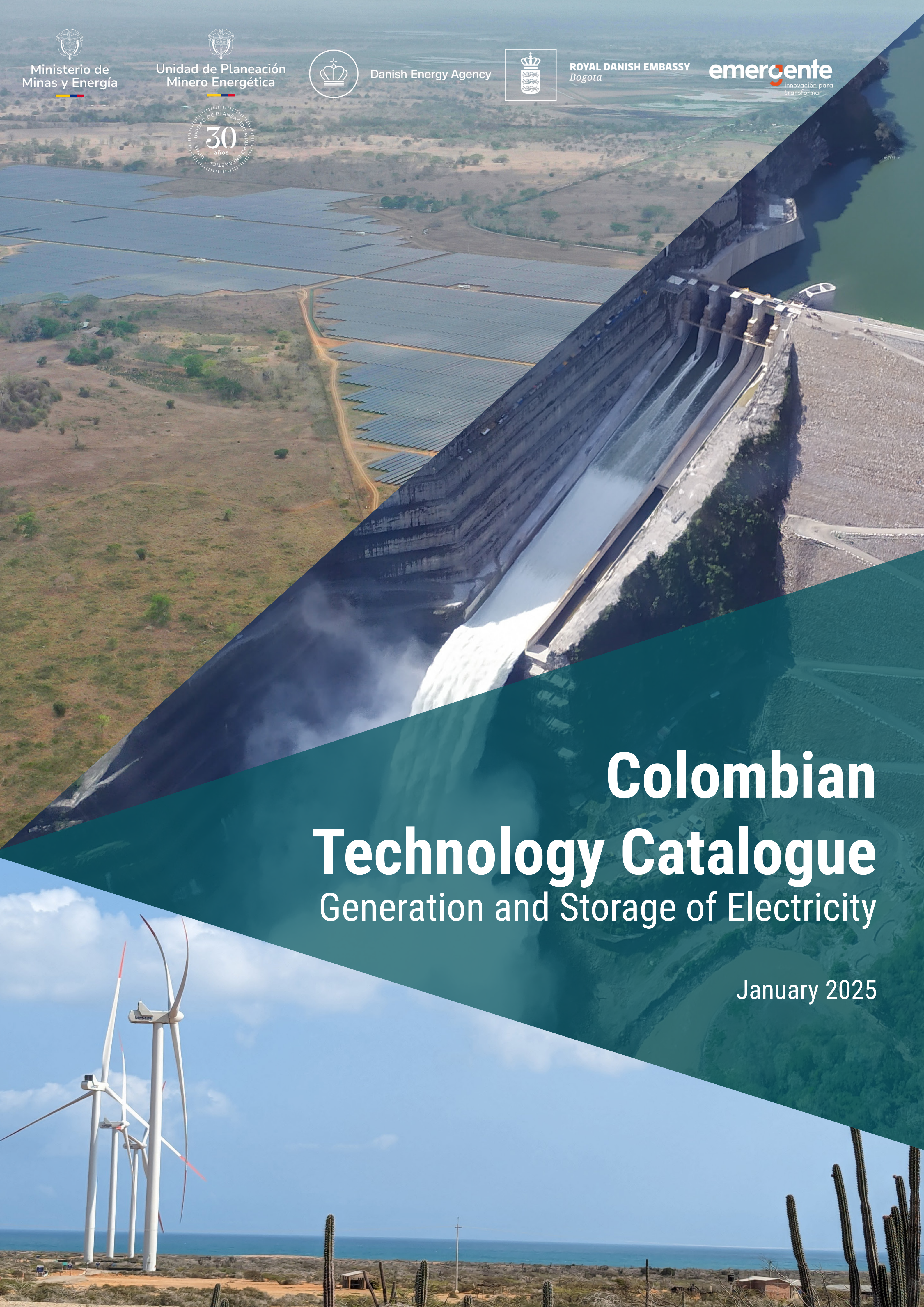
Ministerio de Minas y Energía

Unidad de Planeación Minero Energética

Danish Energy Agency

ROYAL DANISH EMBASSY
Bogota

emergente
innovación para transformar



Colombian Technology Catalogue

Generation and Storage of Electricity

January 2025

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Acknowledgements

This technology catalogue is prepared by the Ministry of Mines and Energy (MME), the Mining and-Energy Planning Unit (UPME), the Danish Energy Agency (DEA), Emergente and the Royal Danish Embassy in Colombia (RDE) under the Colombia-Denmark Strategic Sector Cooperation. We would like to acknowledge all the stakeholders in Colombia and abroad who contributed to this technology catalogue by providing technical data, reviewing chapters and participating in workshops. Without these contributions, it would not be possible to produce this publication.

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Abbreviations

AD	Anaerobic digestion
AEP	Annual energy production
AEP	Annual energy production
AGC	Automatic generation control
APS	Announced Pledges Scenario
ARB	Air Resources Board
BOP	Balance of plant
BWR	Boiling water reactor
CAPEX	Capital expenditures
CARDER	Risaralda Regional Autonomous Corporation
CCGT	Combined-cycle gas turbines
CCS/U	Carbon capture and storage or utilization
CHP	Combined heat and power
CNNC	China National Nuclear Corporation
COP	Production costs
CORTOLIMA	Tolima Regional Autonomous Corporation
C_p	Power coefficient
CRQ	Quindío Regional Autonomous Corporation
CSP	Concentrated solar power
CSTR	Continuous stirred-tank reactor
DEA	Danish Energy Agency
DST	Dynamic Stress Test
EFB	Empty fruit bunches
EGS	Enhanced geothermal systems
EIA	Environmental Impact Assessment
EMS	Energy Management System
ENFICC	Firm Energy for Reliability Charge
ENSO	El Niño Southern Oscillation
EPM	Empresas Públicas de Medellín
EPR	European Pressurised Reactor
EUR	European Utility Requirements
FBR	Fast Breeder Reactors
FENAVI	Federal Association of Poultry Framers
FFB	Fresh fruit bunches
FGT	Flue gas treatment
FID	Final investment decision
FR	Fast reactors
GCR	Gas-cooled reactor
GFR	Gas-cooled fast reactor
GHG	Greenhouse gas
GIF	Generation IV International Forum
HAT	Humidification of intake air processes
HCCI	Homogenous charge compression ignition
HJT	Heterojunction
HLW	High-level waste (nuclear)

HPS	Hydro pumped storage
HRSG	Heat recovery steam generator
HRT	Hydraulic retention time
HTGR	High-temperature gas-cooled reactor
HTGR-PBM	High-Temperature Gas-Cooled Reactor Pebble-Bed Module Reactor
HTR	High Temperature Reactor
HWRs	Heavy water reactors
IAEA	International Atomic Energy Agency
IAM	Incident Angle Modifier
IEA	International Energy Agency
ILW	Intermediate-level waste (nuclear)
IRR	Internal rate of return
ITCZ	Intertropical Convergence Zone
LCA	Life-cycle assessment
LHV	Lower heating value
LIB	Li-ion battery
LIB BESS	Battery Energy Storage System
LLW	Low-level waste (nuclear)
MEI	Makel Engineering, Inc.
MME	Ministry of Mines and Energy
MMR	Micro Modular Reactor
MOX	Mixed oxide
MPPT	Maximum Power Point Tracking
MSR	Molten Salt Reactor
MSW	Municipal solid waste
MW_e	Megawatt electric
MWh	Megawatt hour
NAA	Neutron activation analysis technique
NCG	Non-Condensable Gas
NCRE	Non-Conventional Renewable Energy
NDC	Nationally Determined Contribution
NPV	Net present value
NSSS	Nuclear steam supply system
NZE	Net Zero Emissions by 2050 (scenario)
OPEX	Operational Expenditures
ORC	Organic Rankine Cycles
PCS	Power conversion system
PHS	Pumped hydro storage
PHWR	Pressurized Heavy Water Reactors
PKS	Palm kernel shells
PM	Particulate Matter
POME	Palm Oil Mill Effluent
PPA	Power Purchase Agreements
PV	Photovoltaic
PWR	Pressurized Water Reactor
R&D	Research and development
RCS	Reactor coolant system

RD	Rotor diameters
RDE	Royal Danish Embassy in Colombia
RO	Reverse osmosis
RPV	Reactor pressure vessel
SCADA	Supervisory control and data acquisition
SCGT	Simple-Cycle Gas Turbines
SCR	Selective Catalytic Reduction
SCWR	Supercritical water-cooled reactors
SDG	UN Sustainable Development Goals
SIN	National Interconnected System
SMR	Small Modular Reactors
SNCR	Systems as ammonia injection
SoC	State of Charge
SSC	Strategic Sector Cooperation
SSP	Shared Socioeconomic Pathways
STC	Standard Test Conditions
STEPS	Stated Policies Scenario
TLP	Tension leg platform
TSO	Transmission System Operators
UNAL	National University of Colombia
UPME	Mining and-Energy Planning Unit in Colombia
VOC	Volatile organic compounds
WCFs	Water consumption factors
WCR	Water Cooled Reactors
WEEE	Waste from Electrical and Electronic Equipment
WMF	Watershed Modelling Framework
WPP	Wind power plant
WtE	Waste to energy

1. Methodology

1.1. Objective of the technology catalogue

The present technology catalogue publication is a result of the Colombian-Danish government-to-government cooperation on energy transition. It summarises technical and economic data for the most important power generation and storage technologies in Colombia. In doing so, it aims to establish a uniform, commonly accepted and up-to-date basis for energy planning.

The technology catalogue is based on the best available, up-to-date data on the technical and economic characteristics of the technologies considered. This includes a variety of public and non-public datasets on Colombian power generation and storage projects. These have been supplemented with international data from commonly accepted sources, e.g. from the International Energy Agency's World Energy Outlook report [1], where relevant. Furthermore, the datasets have been reviewed and verified by representatives from industry, academic, government, and the third sector, both during a series of dedicated workshops and a public hearing process.

Three distinct categories of plants are included:

- Thermal electricity generation: plants producing electricity with thermal processes (for example steam cycle or internal combustion engines), including nuclear.
- Non-thermal electricity generation: technologies producing electricity without thermal processes, such as wind power, solar power or hydroelectric power plants.
- Electricity storage: plants consuming and producing electricity without thermal processes such as lithium-ion batteries and pumped storage.

The information summarised in this report can inform future power sector outlooks, evaluations of security of supply, studies on environmental and climate change impacts and other technical and economic studies, e.g., on the framework conditions for the development and deployment of certain classes of technologies.

Technology catalogues are valuable resources that compile technical and economic data. However, these catalogues have inherent limitations and uncertainties. The information they contain often relies on available data and on projections and estimates about technology costs, efficiencies, and environmental impacts. Since these metrics can evolve rapidly and not as foreseen as technologies advance and market conditions shift, catalogues can quickly become outdated. Moreover, uncertainties stem from factors like unforeseen policy changes, fluctuating material costs, and technological breakthroughs, all of which impact the reliability of the data. Therefore, to maintain relevance and accuracy, it is essential to regularly update these catalogues to sustain confidence in the catalogue's projections and to support informed decision-making within the energy sector.

1.2. General assumptions

This section contains a brief description of the base assumption for all technologies, marking how the boundaries for the technologies are defined. Therefore, this study limits the cost and performance data to the generation assets plus the infrastructure required to deliver the energy to the main grid. For power plants generating electricity, this is the nearest land-based substation of the transmission/distribution grid. In other words, the technologies are described as they are perceived by the electricity grid. Consequently, stated capacities are net capacities, which are calculated as the gross generation capacity minus the auxiliary power consumption "capacity" at the plant. Similarly, efficiencies are also net efficiencies.

Another general assumption is the number of full load hours[1] which should correspond with the expectations in the specific country. Unless otherwise stated, the thermal technologies in the Colombian technology catalogue are assumed to be designed and operated for approximately 4000-5000 full load hours annually. 75 % of generation is expected to take place in full load and the remaining 25 % in part load. Some of the exceptions are municipal solid waste incineration facilities and stand-alone biogas plants, which are designed for continuous operation, i.e. approximately 8000 full load hours annually. The assumed numbers of full load hours are summarized in Table 1-1.

For electricity-production technologies dependent on wind and solar resources, estimates of annual full load hours of production are made for each technology.

Table 1-1. General assumption for number of full load hours for thermal technologies.

Thermal technology	Representative annual full load hours
Supercritical coal power plants	4000-5000
Combined-cycle gas turbine	4000-5000
Simple-cycle gas turbine	4000-5000
Municipal solid waste incineration / biogas standalone	8000

1.3. Dialogue with Colombian stakeholders during the process

To best achieve the above-mentioned objectives and general assumptions of a technology catalogue for Colombia, two series of stakeholder consultation workshops –and more than 50 subsequent bilateral interviews– were conducted in Bogotá and Medellín during 2024, with the first series in May and the second in August. These workshops, which included both in-person and online formats, aimed to gather expert feedback and facilitate collaboration for the development of a comprehensive technology catalogue relevant to Colombia's power sector. Holding the workshops in both Bogotá and Medellín, along with the online consultations, allowed for broader participation across regions and sectors. This approach attracted over 500 registered participants, with more than 150 experts from Colombia's energy sector attending in person.

[1] Full load hours refer to the time for which a plant would have to be operated at nominal power in order to convert the same amount of electrical work as the plant has actually converted within a defined period of time.

The initial series focused on reviewing and refining the qualitative sections of the technology catalogue, while the subsequent series in August concentrated on discussing the quantitative datasheets for each technology.

Stakeholder engagement was instrumental in securing essential knowledge and data contributions, supporting the catalogue's depth and relevance. Key outcomes included:

- **Identification of representative projects** and pilot research initiatives in Colombia, providing localized data and insights into technological applications.
- **Insights into technical and financial parameters** for widely adopted technologies, enriching the catalogue's accuracy and applicability.
- **Connections with stakeholders** open to bilateral follow-ups, enabling continued data provision and support for catalogue updates. This enabled the team to set up bilateral consultations with over 50 different project developers, academics, and public officials.

In addition to gathering data, the inclusive approach of these consultations—both online and in-person—served to provide a meeting platform for stakeholders, promoting the catalogue and showcasing the value of industry-government knowledge exchange. This collaborative effort, modelled on the Danish "Teknologikatalog" [2], highlighted the strategic importance of cross-sector engagement in advancing the Colombian energy sector.

1.4. Qualitative description

The qualitative description provides a concise summary of the key characteristics of the technology and consists of the following sections.

1.4.1. Brief technology description

This section provides a brief description of the basic principles of the technology for non-engineers, including an illustration of the technology's main components.

1.4.2. Input

This section describes the main raw materials and primarily fuels consumed by the technology.

1.4.3. Output

This section outlines the forms of generated energy, i.e. electricity and heat, and any relevant by-products.

1.4.4. Typical capacities

The stated capacities are for a single unit capable of producing energy (e.g. a single wind turbine or a single gas turbine), not a power plant consisting of multiple units, such as a wind farm.

In the case of modular technology such as PV or solar heating, a typical size of a solar power plant based on the market standard is chosen as a unit. Different sizes may be specified in separated tables, e.g., distinguishing small PV, medium PV, and large PV.

1.4.5. Space requirement

Space requirements are expressed in 1000 m^2 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.

1.4.6. Water consumption

Water usage is expressed in l/MWh. This differs from water usage related to the construction of equipment needed for a given generation plant, e.g., in a life-cycle perspective. This perspective often also considers water usage outside Colombia.

However, where relevant, the qualitative description may also include a life-cycle water consumption to allow for a comparison of between technologies.

1.4.7. Regulation ability and other power system services

Regulation abilities are particularly relevant for electricity generating technologies. This includes the part-load characteristics, start-up time and how quickly a technology is able to change its production when already running on part-load.

If relevant, the qualitative description includes the technology's capability for delivering the following power system services:

- Inertia
- Short circuit power
- Black start
- Voltage control
- Damping of system oscillations (PSS)
- Frequency regulation

1.4.8. Advantages/disadvantages

This section describes the specific advantages and disadvantages relative to similar technologies. Generic advantages are ignored, such as the role of renewable energy technologies in mitigating climate risks.

In terms of disadvantages, the section explains possible barriers for accelerating the development of the technologies and reasons for high installation and operation costs in the Colombian context.

1.4.9. Environment

This section highlights relevant environmental characteristics, for example, special emissions or ecological footprints.

CO_2 emission values are not explicitly provided, but readers of the catalogue can calculate them by combining fuel data with technological efficiency data.

Particulate emissions are expressed as PM2.5, measured in grams per gigajoule (GJ) of fuel.

SO_2 emissions are also expressed in grams per GJ of fuel.

For technologies that use desulphurisation equipment (typically in large power plants), the degree of desulphurisation is indicated as a percentage.

NO_x emissions include both NO_2 and NO, with NO converted to NO_2 in weight equivalents. These emissions are expressed in grams per GJ of fuel.

Methane (CH_4) and nitrous oxide (N_2O) emissions are likewise expressed in grams per GJ of fuel.

The primary sources for the values presented include the National Greenhouse Gas Inventory Report 1990–2018 and Black Carbon 2010–2018 of Colombia - Third Biennial Update Report on Climate Change of Colombia, prepared by IDEAM; the 2006 IPCC Guidelines for National Greenhouse Gas Inventories; and values from existing projects available in the Sinergox database.

1.4.10. Research and development perspectives

This section lists the most important challenges to further development of the technology. Also, the potential for technological development in terms of costs and efficiency are mentioned and quantified if possible. Colombian research and development perspectives are highlighted where relevant.

1.4.11. Examples of market standard technology

This section describes recent full-scale commercial projects, which can be considered market standard, preferably with links to further information. A description of what is meant by "market standard" is given in the introduction to the quantitative description section. For technologies where no market standard has yet been established, reference is made to the best available technology among R&D projects.

1.4.12. Prediction of performance and cost

Cost reductions and improvements of performance can be expected for most technologies in the future. This section accounts for the assumptions underlying the *cost* and technical *performance* in 2024 as well as the improvements assumed for the years 2030 and 2050. For a comprehensive explanation of the methods used and to gain a deeper understanding of the assumptions underlying the projections, please refer to Appendix. Forecasting the Cost of Electricity Production Technologies.

The specific technology is identified and classified into one of four categories of technological maturity, indicating its current commercial and technological progress, and the assumptions for the projections are described in detail.

Performance predictions are based on technical data from established international sources

Cost predictions are based on the following information, with any given year in the datasheet corresponding to Final Investment Decision (FID) year when all permits and financing are at hand, followed by the technical construction time as stated in the datasheets:

Data for the base year 2024

If available, local projects are included along with international projections from credible sources (e.g. IRENA, IEA, etc.). Local investment cost figures are reported directly if available; otherwise, they are derived from the result of Power Purchase Agreements (PPA), auctions and/or support mechanisms.

If consistent data is not available, or if no suitable market standard has yet emerged for new technologies, the base year costs may be estimated using an engineering bottom-up assessment applying a decomposition of manufacturing and installation costs into raw materials, labour costs, financial costs, etc. International references such as the IEA, NREL etc. are preferred for such estimates.

Assumptions for projecting costs into future years

Where applicable, cost projections following a learning-rate approach are aligned with capacity deployment outlined in the World Energy Model scenarios from the IEA's *World Energy Outlook 2023* [1]. For a detailed explanation of the methods and assumptions behind these projections, please refer to Appendix. Forecasting the Cost of Electricity Production Technologies. According to the IEA:

"*Innovation theory describes technological innovation through two approaches: the technology-push model, in which new technologies evolve and push themselves into the marketplace; and the market-pull model, in which a market opportunity leads to investment in R&D and, eventually, to an innovation*" [3].

"The process of innovation involves a wide range of participants: governments, researchers, investors, entrepreneurs, corporations and civil society all play important roles in generating ideas for new or improved technologies and in improving and financing them right through to market entry and deployment. Innovation systems are complex and rest on four pillars: resource push, knowledge management, market pull and socio-political support" [4].

The level of "market-pull" is to a high degree dependent on the global climate and energy policies. Hence, in a future with strong climate policies, demand for renewable energy technologies will be higher, while innovation is expected to take place faster than in a potential future with less ambitious policies. This is expected to lead to both more efficient technologies and cost reductions among others due to economy-of-scale effects. Therefore, for technologies where large cost reductions are expected, it is important to account for assumptions about global future demand.

The **IEA's Announced Pledges Scenario (APS)** is used as a central estimate for projections in this study, wherever applicable. The IEA describes the Announced Pledges Scenario in their World Energy Outlook 2023 [1] version as follows:

"This scenario assumes that governments will meet, in full and on time, all of the climate-related commitments that they have announced, including longer term net zero emissions targets and pledges in Nationally Determined Contributions (NDCs), as well as commitments in related areas such as energy access. Pledges made by businesses and other stakeholders are also taken into account where they add to the ambition set out by governments."

According to the IEA [1], the less ambitious **Stated Policies Scenario (STEPS)** *"(...) is designed to provide a sense of the prevailing direction of energy system progression, based on a detailed review of the current policy landscape. Whereas the APS reflects what governments say they will achieve, the STEPS looks in detail at what they are actually doing to reach their targets and objectives across the energy economy."*

The STEPS Scenario may be viewed as a lower bound for future technological development based on a frozen-policy approach.

As a more ambitious projection, the **Net Zero Emissions by 2050 Scenario (NZE)** may be used as an upper bound for the technology development. According to the IEA [1], the NZE is a *"(...) normative scenario [that] portrays a pathway for the energy sector to help limit the global temperature rise to 1.5 °C above preindustrial levels in 2100 (with at least a 50 % probability)* *with limited overshoot.* (...) *The NZE Scenario also meets the key energy-related UN Sustainable Development Goals (SDGs): universal access to reliable modern energy services is reached by 2030, and major improvements in air quality are secured.”*

By using this approach, the quantitative data used in the technology catalogue is consistent with the IEA’s Global Energy and Climate Model [1], encompassing relevant outcomes for policy assessments of technologies as well as technology developments in compliance with national targets and international treaties.

Learning curves and technological maturity

As outlined in the Appendix. Forecasting the Cost of Electricity Production Technologies, there are several approaches to projecting the future financial costs of power generation technologies. One method involves an engineering bottom-up assessment, as previously discussed when deriving 2024 data. This approach breaks down the technology's costs into categories such as labour and materials, for which future projections are available. Alternatively, learning curves can be used, based on the principle that with each additional unit produced or deployed, cumulative learning occurs. This learning drives improvements in products and processes, resulting in lower costs for subsequent units. A third option is the Delphi survey, which gathers insights from a large group of international experts to assess expected cost developments and key drivers of cost reductions.

The potential for improving technologies is linked to the level of technological maturity. The technologies are categorized within one of the following four levels of technological maturity, also illustrated in Figure 1. This approach follows the methodology presented in the report Technology Data – Generation of Electricity and District Heating, published by the Danish Energy Agency [2].

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 high (e.g. wave energy converters, solid oxide fuel cells).

Category 2. Technologies in the *pioneer phase*. The technology has been proven to work through demonstration facilities or semi-commercial plants. Due to the limited application, the price and performance is still subject to high uncertainty, and further development and customization is still needed. The technology still has a significant development potential (e.g., gasification of biomass).

Category 3. *Commercial technologies with moderate deployment*. The price and performance of the technology is known. These technologies are deemed to have a specific development potential and, therefore, there is some uncertainty related to future price and performance (e.g., offshore wind turbines).

Category 4. *Commercial technologies, with large deployment*. The price and performance of the technology today is well established and normally only incremental improvements would be expected. Therefore, the future price and performance may also be projected with a relatively high level of certainty (e.g. coal power, gas turbines).

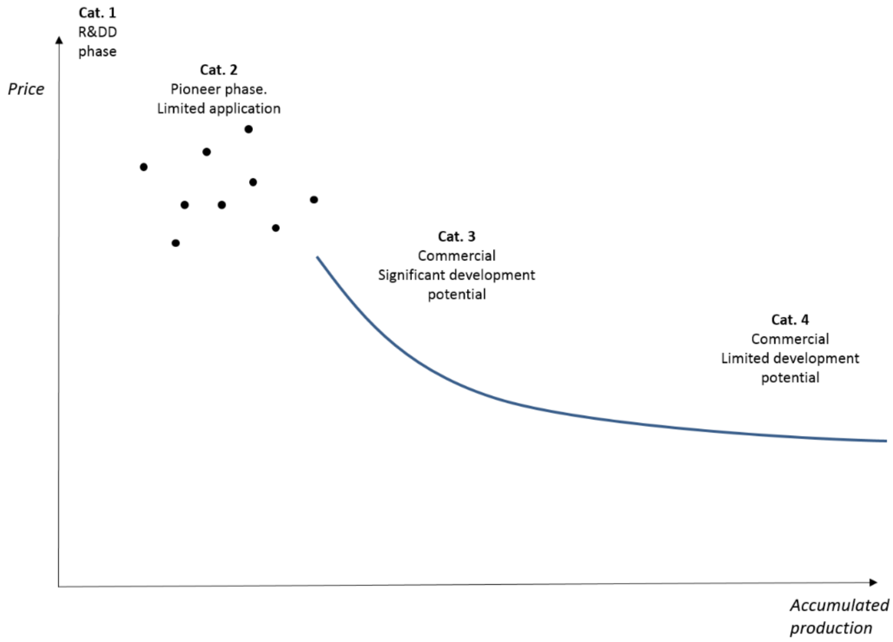

Figure 1. Technological development phases. Correlation between accumulated production volume (MW) and price [2].

1.4.13. Additional remarks

This section includes other relevant information not included in any of the previous sections, for example, links to websites describing the technology further.

1.4.14. References

References are numbered in the text in squared brackets and bibliographical details are listed in this section.

1.5. Quantitative description

As detailed in the Appendix. Forecasting the Cost of Electricity Production Technologies, the selected *one-factor* and *multi-factor* learning curve approaches are deemed the most appropriate methods for projecting the financial costs of technologies in this study. The choice between one-factor and multi-factor approaches depends on the significance of specific technology components and the availability of financial data for each component. This section provides an explanation of the structure of the tables presenting the quantitative data generated from this study.

To enable comparative analyses between technologies, it is imperative that the data presented is in fact comparable: **all cost data are stated in fixed 2024 USD prices excluding value added taxes (VAT) and other taxes**. The information in the tables relates to the development status of the technology at the point of final investment decision (FID) in the given year (2024, 2030 and 2050 where applicable). FID is assumed to be taken when financing of a project is secured, and all permits are at hand. The year of commissioning will depend on the construction time of the individual technologies.

A typical table of quantitative data is shown in Table 1-2, Table 1-3 and Table 1-4, containing all parameters used to describe the technologies. The table consists of a generic part, which is identical for groups of similar technologies (thermal power plants, non-thermal power plants) and a technology-specific part. The generic part is made to allow for easy comparison across technologies.

Each cell in the table contains only one number, which is the central estimate for the market-standard technology, i.e. no ranges should be used. Uncertainties related to the figures are stated in the columns named *Uncertainty*. To keep the table simple, the level of uncertainty is only specified for the years 2024 and 2050.

Understanding Uncertainty in Technology Projections

The catalogue addresses both well-established technologies and those still under development, each with varying degrees of uncertainty in terms of future cost and performance improvements (see *Learning curves and technological maturity* for more details). The qualitative description highlights the key factors contributing to the uncertainty ranges outlined in the quantitative analyses of the catalogue. These factors may be related to specific technological or market dynamics, the level of industry expertise, or potential raw material constraints. They are also influenced by the stage of technological maturity.

To illustrate the uncertainty, a lower and upper bound is provided alongside a central estimate in the datasheets. It is important to note that long-term cost projections involve significant uncertainty. The degree of uncertainty is linked to the technology's maturity level and the time horizon considered; hence, the gap between lower and upper bounds may vary substantially. The uncertainty assessment is tailored to each technology based on the best available projections and does not account for variations in product efficiency or pricing across different models.

Uncertainty levels are specified for the most critical metrics, such as investment costs and efficiency rates, with other figures included where relevant.

All data in the tables are referenced by a number in the right-most column *Ref*, referring to source specifics below the table. The column *Note* includes additional information on how the data are obtained as well as assumptions and potential calculations behind the figures. Before using the data, please be aware that essential information may be found in the notes below the table.

The generic parts of the tables for thermal power plants, non-thermal power plants and storage technologies are presented below:

Table 1-2. Reference datasheet for thermal power plants.

Technology	**Thermal electricity generation**										
	2024	**2030**	**2035**	**2040**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
						Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data											
Generating capacity for one unit (MW_e)											

Electricity efficiency, net (%), name plate											
Electricity efficiency, net (%), annual average											
Forced outage (%)											
Planned outage (weeks per year)											
Technical lifetime (years)											
Construction time (years)											
Space requirement (1000 m^2/MW_e)											
Regulation ability											
Ramping rate (% 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 of input fuel)											
SO_2 (g/ GJ of input fuel)											
NO_X (g/GJ of input fuel)											
CH_4 (g/GJ of input fuel)											
N_2O (g/GJ of input fuel)											
Financial data											
Specific investment (million USD/MW)											
- of which equipment (%)											
- of which installation (%)											
Fixed O&M (USD/MW_e/year)											
Variable O&M (USD/MWh)											
Start-up cost (USD /MW_e/start-up)											

Table 1-3. Reference datasheet for non-thermal power plants.

Technology	**Non-thermal electricity generation**										
	2024	**2030**	**2035**	**2040**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
						Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data											
Generating capacity for one unit (MW_e)											
Generating capacity for total power plant (MW_e)											
Average annual full-load hours (MWh_e/MW_e)											
Forced outage (%)											
Planned outage (weeks per year)											
Technical lifetime (years)											
Construction time (years)											
Space requirement (1000 m^2/MW_e)											
Additional data for non-thermal plants											
Capacity factor (%), theoretical											
Capacity factor (%), incl. outages											
Regulation ability											
Ramping rate (% of Full Load/Minute)											
Minimum load (% of full load)											
Warm start-up time (hours)											
Cold start-up time (hours)											
Financial data											
Specific investment (million USD/MW)											
- of which equipment (%)											
- of which installation (%)											
Fixed O&M (USD/MW_e/year)											
Variable O&M (USD/MWh)											
Start-up costs (USD/MW_e/start-up)											

Table 1-4. Reference datasheet for storage technologies.

Technology	Storage technologies										
	2024	2030	2035	2040	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Energy/technical data											
Energy storage capacity for one unit (MWh)											
Input capacity for one unit (MW)											
Output capacity for one unit (MW)											
Round trip efficiency (%)											
Forced outage (%)											
Planned outage (weeks per year)											
Technical lifetime (years)											
Construction time (years)											
Space requirement (1000 m^2/MW_e)											
Regulation ability (only for electricity storage)											
Response time from idle to full-rated discharge (sec)											
Response time from full-rated charge to full-rated discharge (sec)											
Financial data											
Total investment cost (million USD per MWh)											
- energy component (million USD/MWh)											
- capacity component (million USD/MW)											
- other project costs (million USD)											
Fixed O&M (USD/MW/year)											
Variable O&M (USD/MWh)											

1.6. References

[1] IEA (2023), World Energy Outlook 2023, IEA, Paris https://www.iea.org/reports/world-energy-outlook-2023, Licence: CC BY 4.0 (report); CC BY NC SA 4.0 (Annex A)

[2] Danish Energy Agency (2023), Technology Data - Energy Plants for Electricity and District heating generation https://ens.dk/en/our-services/technology-catalogues/technology-data-generation-electricity-and-district-heating

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2. Photovoltaics

2.1. Brief technology description

A solar cell is a semiconductor component that generates electricity when exposed to light. For practical reasons, several solar cells are typically interconnected and laminated to (or deposited on) a glass pane 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 derivates. 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 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 cadmium telluride or copper indium gallium, among others. Monolitic 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 2, 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 in 2025.

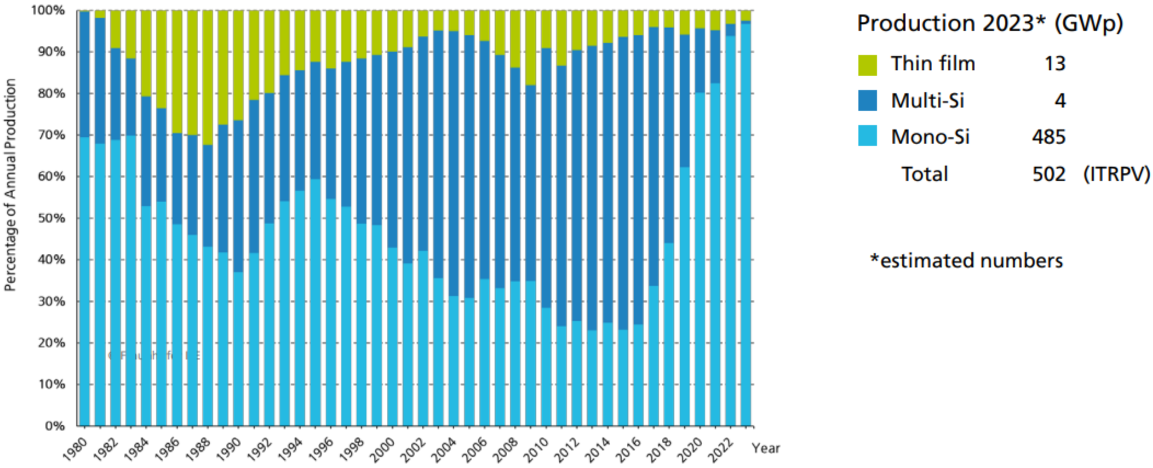

Figure 2. Historical global market shares of different cell technologies [5].

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 majority 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].

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 [39].

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 nanometer 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%) [6].

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 backsheet 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 [6].

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. State-of-the-art large-format bifacial panels with half-cut cells (600 W_p) are being deployed in Colombia and are expected to become the standard. By 2026, as suggested in Figure 3, 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 [7, 8].

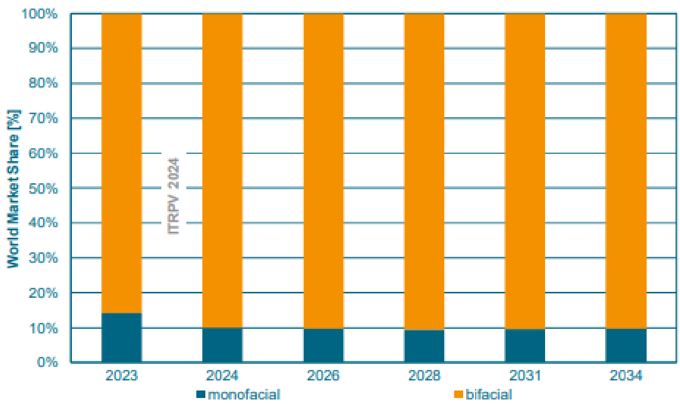

Figure 3. Forecasted global market share of bifacial vs. monofacial PV panels [8].

2.1.1. 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 m^2, whereas the panels for utility-scale projects are 2-3 m^2. The modules for both applications will have similar power rates in the range of 190-220 W_p pr. m^2 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.

Regarding the smallest applications, PV systems often power individual homes, bringing about clean and 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 4 summarizes all the above stated. Additionally, the reader can refer to the following manuscripts to grasp better every case including residential [52], industrial [54], utility-scale (with tracking systems [50, 51] and floating layouts [53]).

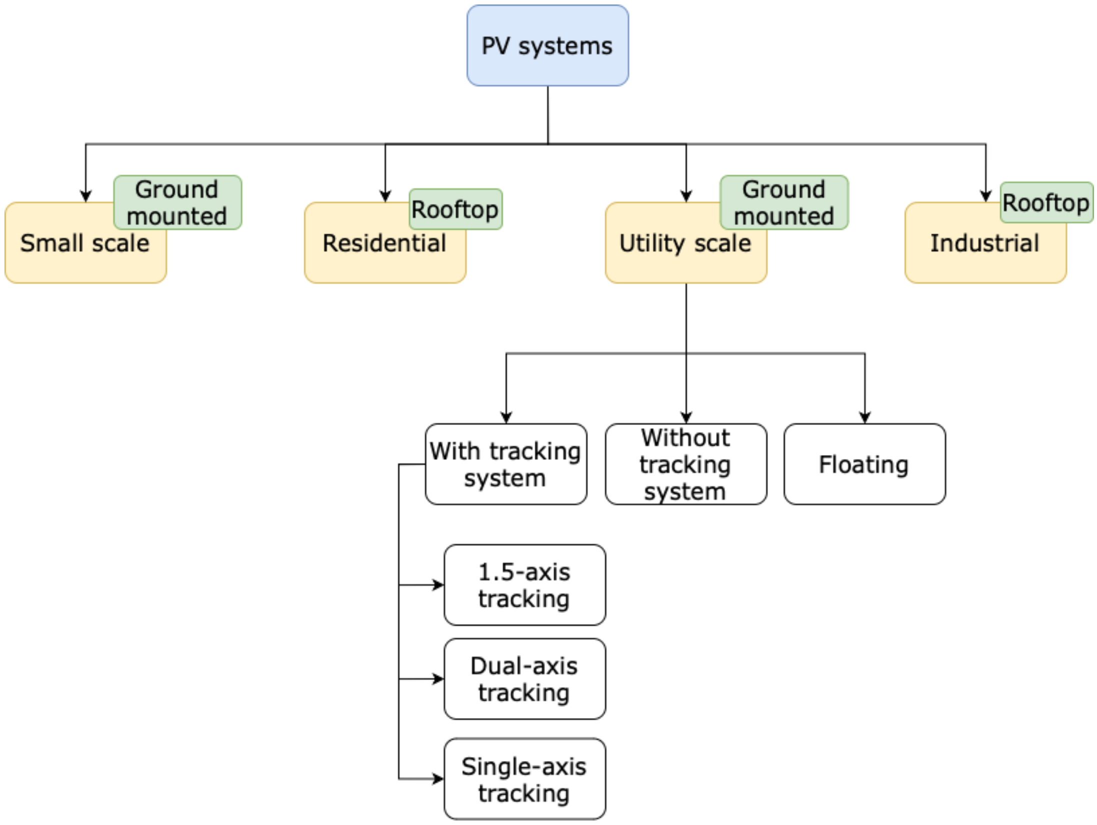

Figure 4. Classification of a PV system applications depending on the scale. Disclaimer: Not all the sub-categories have been considered for the quantitative analysis of this study, only the ones with a major current or upcoming role in Colombia.

2.1.2. 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 Conditions (STC) which corresponds to an irradiation of 1000 W/m^2

with an AM1.5[2] spectral distribution perpendicular to the module surface and a cell temperature of 25 °C. This STC capacity is referred to as the peak capacity.

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 outdoor temperature increases by over 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/m^2 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 Pp 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. 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.

According to stakeholders, the typical sizing factor in Colombia is at ca. 1.3 on average for ground-mounted plants and is a parameter that is sensible to regulation and the developer’s plant design optimization. In the coming years, the sizing factor might change again among others as a possible reaction to the planned introduction of connection fees that solar PV developers can face, and the induced possible relocation of some projects and consequential changes on a project level in terms of the limiting factors mentioned above. The rationale for the introduction of these fees is to incentivize solar PV development with the lowest total grid connection cost. The range of different sizing factors is expected to remain around the same level as is observed as of today.

In summary, both the extent to which tracker systems may become commercially attractive in Colombia and the framework conditions (capacity payments and network code requirements) under which utility scale projects may be connected to the grid (DSO and TSO), will influence the

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

sizing factor. How the utility scale PV sizing factor will develop in the coming years is therefore associated with uncertainty.

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 [36]. 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. 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 [15]. 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 [11]. 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

Both direct light (beam) and diffuse components of the light can be utilized. This implies a high degree of freedom in orienting the PV modules, both with respect to inclination and orientation East-West.

For a fixed tilt system, where modules are installed in an inclination angle typically up to 15 degrees, the available energy received in the plane of the PV module (glass surface) is increased compared to horizontal by a so-called transposition factor, which however is low at ca. 1.01 at Colombian latitudes. Being close to the Equator, the optimal orientation of the panels would be closer to horizontal plane with ca. 7 degrees but in practice, according to information from stakeholders, many utility scale PV plants are typically installed with a 15 degrees tilt angle to allow water to drain off the panels more effectively, preventing pooling and the accumulation of dirt and debris which can decrease the efficiency of solar energy production. This tilt also optimizes the angle of incidence between the solar panels and the sun's rays, enhancing energy capture during peak solar hours. Residential and commercial tilt angles usually follow the inclination of the existing roof. Panels facing other directions than south receive less energy than panels facing directly towards south, this is reflected by transposition factors as well.

2.2. Input

Solar radiation is the input of a PV panel. The irradiation, which the module receives, depends on the solar energy resource potential at the location, including shading conditions and the orientation of the module.

2.2.1. Potential in Colombia

Due to its geographical location, as seen in Figure 5, Colombia enjoys a high availability of solar resources. The average annual solar irradiance received on a horizontal surface in Colombia is 4.5 kWh/m^2/day [16]. Solar radiation variation in terms of Colombia is influenced by its diverse topography and hydroclimatic settings.

The areas receiving the highest levels of global solar radiation, exceeding the San Andrés and Providencia islands, large parts of the Caribbean region, and the inter-Andean valley. The highest values, exceeding 5.5 kWh/m^2 per day, occur in small areas in the central and north of La Guajira. Areas with lower levels of global solar radiation in Colombia, averaging below 3 kWh/m^2 per day, are found in parts of the west of Chocó and the higher altitudes areas of the cordilleras, mainly because of the high precipitation and cloud coverage present.

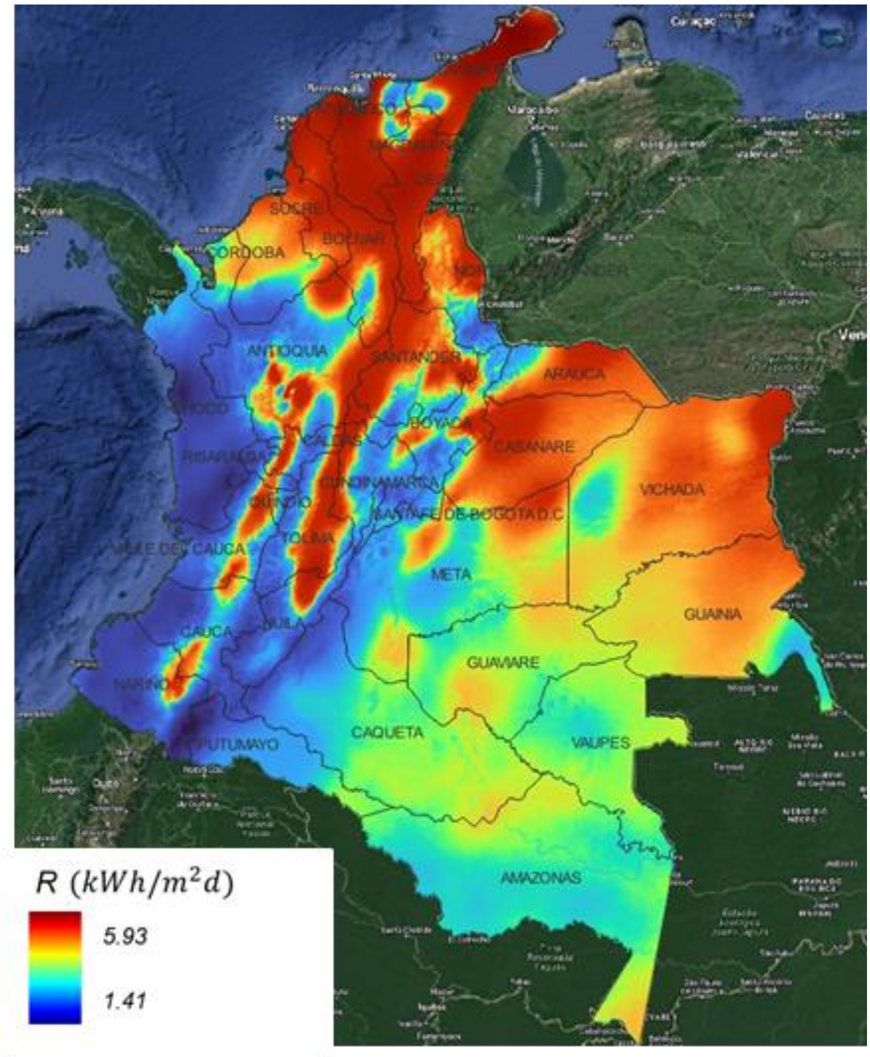

Figure 5. Solar Radiation Map for Colombia by Emergente [16].

Colombia's tropical location plays a significant role in the consistency of its solar radiation throughout the year. This consistent position leads to relatively stable solar radiation levels across seasons, which is different from regions further from the equator where the sun's angle changes more drastically with the seasons.

However, the main variations in solar radiation in Colombia are influenced by the movement of the Intertropical Convergence Zone (ITCZ). The ITCZ is a region where the northeast and southeast trade winds converge, and it is characterized by a band of clouds and precipitation that shifts north and south of the equator depending on the season. As the ITCZ moves over different parts of Colombia, it can increase cloud cover, which reduces the amount of solar radiation reaching the surface [38].

Numerous regions across Colombia are well-suited for the efficient development and operation of photovoltaic solar farms. However, large areas of the country have slopes too high for development of large-scale farms, and there could be conflicts with land use and ecosystem presents, with costly environmental management. In this sense, the most attractive projects for developers are expected to be the most profitable and those that require the least environmental management. Hence, researchers in [17] classified environmental criticalities and the LCOE of projects into 3 groups: low, medium, high. The highest suitability is associated with scores of 1, and the poorest is associated with scores of 9. Projects under development with a capacity of 20 MW or higher are shown overlayed in Figure 6.

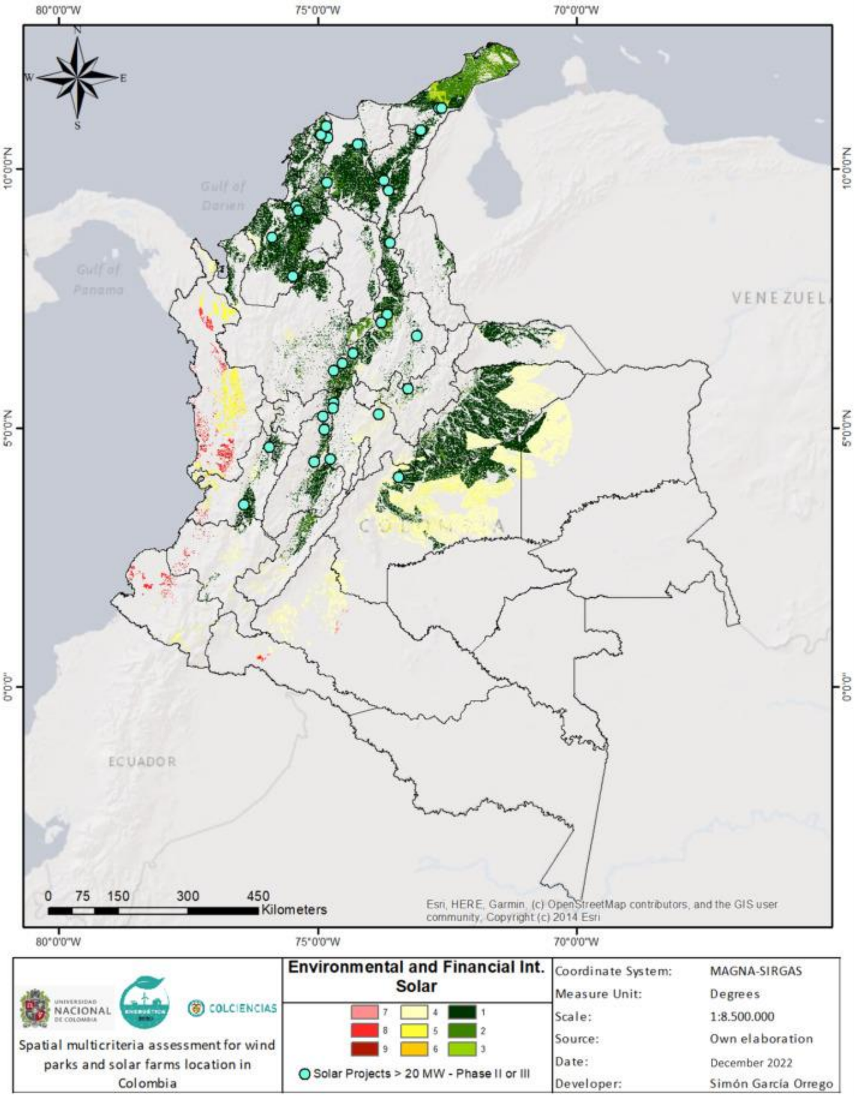

Figure 6. Integration of the financial performance and environmental criticalities for solar farms in Colombia [17].

Notably, the northern coastal departments such as La Guajira, Córdoba, Sucre, Bolívar, Atlántico, Magdalena, and Cesar are distinguished by their rich and consistent solar resources, augmented by advantageous environmental conditions. Additionally, central Colombia's inter-Andean valleys, particularly the segment of the Cauca River Valley stretching between Valle del Cauca and Quindío, and the Magdalena River Valley from Huila to the Caribbean, are prime areas for solar energy development. The eastern plains, especially in the departments of Meta and Casanare, also offer optimal conditions for large-scale solar energy capture, with easy access to the national grid. Collectively, projects in the country could achieve an installed capacity exceeding 8 TW, with a potential output of more than 11,000 TWh per year [17].

2.3. 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.
- 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.

2.4. Typical capacities

PV systems range from a few Watts to Gigawatts, but for practical purposes, systems from a few hundred Watts to a few hundred MW are relevant. These systems are modular, with typical module sizes between 450 W_p and 600 W_p, though some new models reach up to 670 W_p.

In Colombia, residential PV systems typically range from 2 to 6 kW_p, covering 15-40 m², and are designed to meet 100% of household energy consumption due to the net-metering policy. In non-interconnected areas, these systems can be paired with small batteries, with a 5-kWh battery costing USD 2,000-USD3,000 for a 6.7 kW_p system including VAT (2024 prices) [19].

Commercial and industrial PV systems, usually installed on buildings, range from 20 to 1,000 kW_p and are designed mainly for self-consumption purposes. They will typically have a sizing factor around 1 to 1.2 and may deliver non-self-consumed power to a transformer in the low voltage distribution grid.

Utility scale systems or PV power plants will normally be ground mounted and typically range in size from 1 MW and beyond. New utility scale plants in Colombia respond to regulatory limits: Distributed generation plans are just below 1 MW, non-centrally dispatched plants range from 5 to 19.9 MW. Over 20 MW, the typical development size 70 MW is but larger plants up to 300 MW_p are also now under development [20]. They are typically operated by independent power producers that by use of transformers deliver power to either the medium voltage distribution grid or directly to the high voltage transmission grid.

2.5. Space requirement

The module area needed to deliver 1 kW of peak generation capacity can be calculated as $1/\eta_{mod}$[3], and equals 4.9 m^2 by today's standard PV modules. According to the stakeholder consultation, for modules on tilted roofs, 1.2 m^2 of roof area is needed per m^2 of module area to account for service areas for installation and maintenance. Modules on flat roofs and modules on ground will typically need more roof and land area than the area of the modules itself, to avoid too much shadowing from the other modules. The following table shows typical ratios (according to stakeholders) of the area of the module to the ground surface required for the installation, so-called ground coverage ratios. For residential installations, the table shows the ratio between module area and roof area (assuming tilted roof installation) (see Table 2-1).

Table 2-1. Ground coverage ratio and installed power density for different PV segments.

	Residential (rooftop)	Commercial (flat rooftop)	Utility (fixed tilt)	Utility (tracker)
Ground coverage ratio	0.8	0.8		
Area requirement [ha/MW_p]			1.2	1.5

2.6. Water consumption

In Colombia, 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. Given Colombia's frequent rainfalls, natural precipitation can often fulfil this cleaning role, reducing the need for manual washing and thus minimizing water usage. According to Colombia project developers, usual maintenance operation includes 2 washes per year, where approximately 1 litre of water per module is used.

2.7. Regulation ability and other power system services

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

[3] η_{mod} represents the efficiency of the photovoltaic module, meaning the proportion of incident solar energy that the module converts into usable electricity.

synchronous compensators, energy storage systems, and fast-responding conventional power plants to ensure stability in the face of large-scale solar integration.

The generation from a PV system reflects the yearly and daily variation in solar irradiation. When connecting PV systems to the grid, a set of grid codes describing required functionality and communication protocol as set by the TSO and DSO must be respected. The detailed technical requirements depend on the system size and do not impose any specific technical demand that cannot be fulfilled by any modern PV inverter. However, for systems above 125 kW, a park controller which interfaces the grid operator is required to ensure system level remote control of all individual inverters, which then enables the system to deliver ancillary grid services like frequency response, reactive power, variable voltage output, or power fault ride-through functionality to the grid. Besides the park controller, a simulation model must be delivered to the utility for verification of the technical capability, and the development and delivery of this model can be quite complicated and troublesome for smaller installers. Utility scale PV plants may provide downregulation if generating or upregulation if not generating at maximum capacity, but today most PV systems supply the full amount of available energy to the consumer/grid.

At a DSO scale, the inverters of residential and commercial/industrial roof systems will follow the local grid characteristics and deliver their output according to the defined network codes. This also implies that the inverter must reduce its output in case the observed frequency or voltage conditions get outside predefined limits. However, a massification of distributed generation can create challenges for the grid such as the “duck curve.” In a nutshell, the duck curve shows the difference in electricity demand and the amount of available solar energy throughout the day. It creates serious challenges for conventional power sources (thermal and hydro) to compensate for such sudden changes. Figure 7 illustrates this phenomenon forecasted by 2030 in Colombia. Mitigation measures are among other incentives for a more flexible operation of the existing thermal power capacity, or the inclusion of batteries in connection to solar plants for peak shaving, if economically feasible.

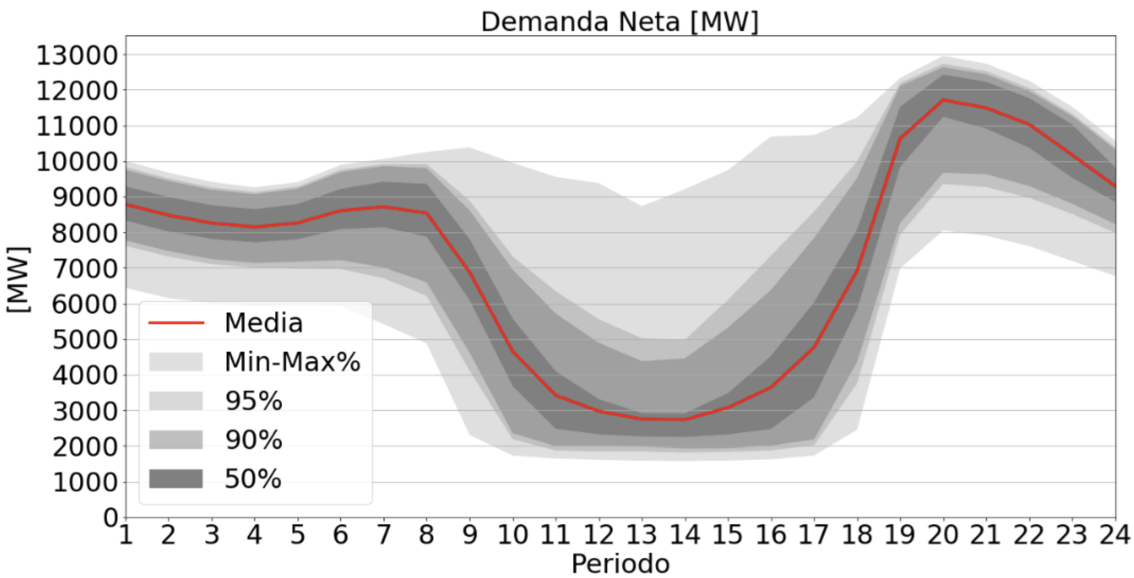

Figure 7. Projected “duck curve” hourly energy net demand for Colombia in 2030 [40].

Projected "duck curve" hourly energy net demand for Colombia in 2030 [40]. Despite this, solar energy resources in Colombia could effectively complement the country's hydropower generation both during dry seasons caused by the natural variability of the resources, that includes the Madden-Julian Oscillations, the dry seasons of the annual weather cycle and the warm phase of El Niño Southern Oscillation (ENSO). During these times, when there is less rainfall and consequently fewer clouds, solar energy installations can achieve higher yields. This increase in solar radiation capture is crucial because hydropower, which depends on water flow, may decrease due to lower precipitation levels. By harnessing more solar energy during these periods, Colombia can offset potential energy deficits caused by reduced hydropower generation, ensuring a more stable and reliable energy supply throughout the year.

2.8. Advantages/disadvantages

2.8.1. Advantages

- PV does not use any fuel or other consumable.
- PV is noiseless (except for fan-noise from inverters and transformers).
- PV complements wind power as the generic seasonal/daily generation profile is different.
- PV modules have a long lifetime of more than 30 years and PV modules can be recycled to a high degree [21] [22].
- PV systems are modular and easy to install.
- Operation & Maintenance (O&M) of PV plants is simple and limited as there are no moving parts, except for tracker systems, and no wear and tear. Inverters need only be replaced once or twice during the operational life of the installation.
- Large PV power plants can be installed on land that otherwise are of no or limited commercial use (water collection/pesticide-free areas, landfills, low-lands, areas of restricted access or chemically polluted areas).
- PV systems integrated into buildings require no incremental ground space, and the electrical inter-connection and export capacity is readily available at no or small additional cost.
- Affordable aesthetic panels are expected to become available for building integration in the coming years.

2.8.2. Disadvantages

- PV systems are highly intermittent due to uncertain weather conditions. PV system can generate ramps at peak hours because of the "duck curve".
- 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 – 0.9 MW_p/ha for Fixed Tilt installations and down to 0.6 – 0.7 for Horizontal Single Axis

Trackers, including additional areas (25 ± 10 %) required for internal roads, compounds and transformer stations [36].

2.9. 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, but all 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 [23].

In Colombia, researchers estimated the number of solar panels residues present in the country, for different scenarios. The results show that in the 2040 decade, from 20,000 to 80,000 tons of solar waste will be generated each year. The difference in the numbers Is explained by different assumption of solar power adoption in Colombia and recycling goals and public policy [21].

2.10. Research and development perspectives

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 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 [31]. 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, 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 8 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 RAL[4] colours can be achieved through coloration with less than a 20% efficiency loss, even though white tones have higher losses [26,27]. However, practical realization on a large scale of these idealized filters has still to be proved. Commercially, two main coloration

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

methods exist: pigment-based, that absorbs light and reduces efficiency by over 20 % but offers consistent colours as is often angle independent [28]. Other techniques like optical fibres, diffuse, and sanitized glass can reduce glare and colour variability.

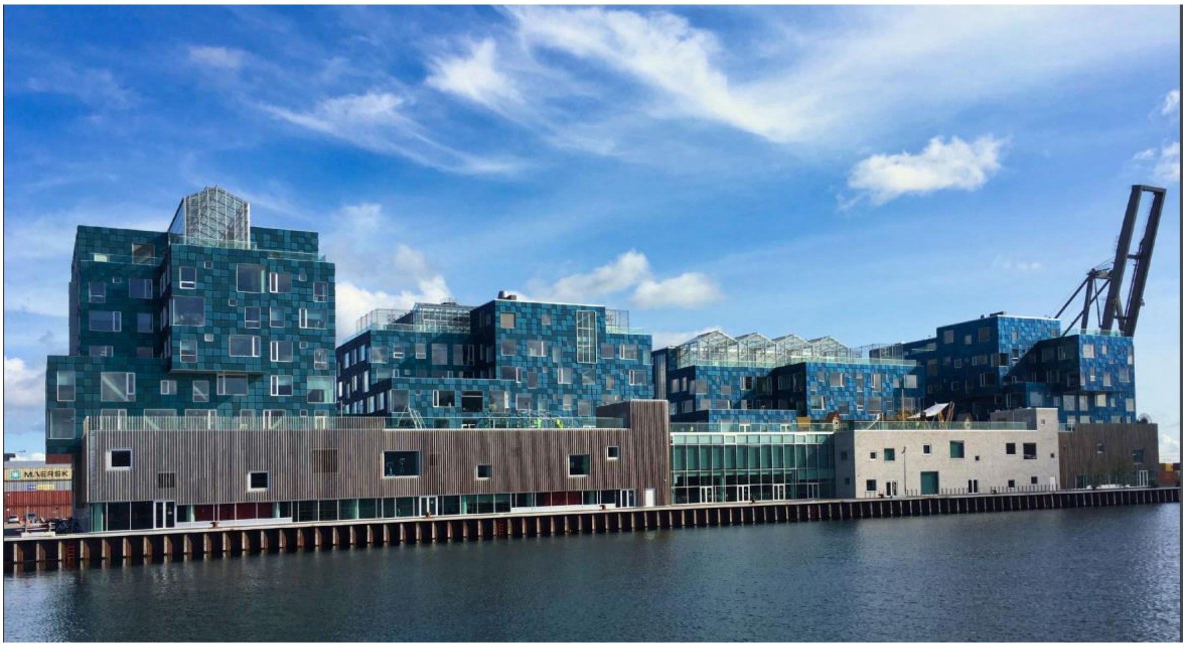

Figure 8. Solar Facade at the International School, Copenhagen [24].

2.10.1. Research and Development of PV technology in Colombia

The Colombian company Solenium developed and patented a tracker technology called Zentrack. This system, created in 2017 and illustrated in Figure 9, enables solar panels to automatically track the sun's path, increasing energy production by up to 25 %, and it is designed to be used in small-scale projects. It operates using an astronomical algorithm and integrates with meteorological data to monitor key variables such as wind speed, solar radiation, and rain, optimizing panel positioning. Solenium has already exported 60 units to various regions in Brazil [12].

Figure 9. Solenium Zentrack Technology [12].

Researchers from EAFIT University have been developing a local BIPV solution, a solar brick (see Figure 10). This system integrates photovoltaic elements into building construction, suitable for vertical surfaces such as building facades. This solution allows often underutilized spaces to be used for energy generation, offering a practical alternative for both urban and rural settings. The system includes masonry units and specially designed covers that house photovoltaic modules, electronics, and storage components. Benefits include energy independence, optimized solar capture by 10 %, recyclability, and seismic resistance, making it a practical, eco-friendly solution for sustainable energy in building designs [29].

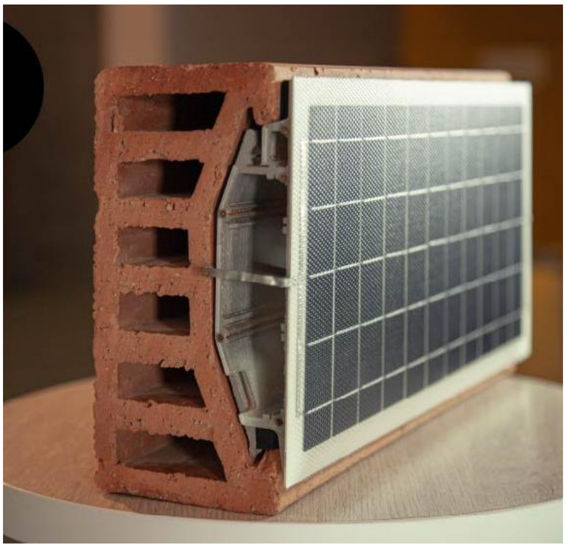

Figure 10. EAFIT – Solar Brick [29].

Thermowire is a Colombian solar PV manufacturer that established an automated production line in Sogamoso, Boyacá, using German technology and 100 % Colombian manufacturing. This facility, as seen in Figure 11, allows the company to design solar modules tailored to customer specifications while ensuring high-quality standards. Thermowire has the country's first automated laboratory for testing solar cell efficiency, which allows the company to guarantee the energy performance of its products. The local production plant eliminates the need for solar module imports, reducing storage time, and ensuring each module is produced per order, providing a true lifespan. Additionally, the company offers a 25-year real warranty, underscoring its confidence in the durability and performance of its products [30].

Figure 11. Thermowire – PV manufacturing [30].

2.11. Examples of standard market technology

Data from the market operator in Figure 12 shows that the installed and registered PV capacity in Colombia has been growing in the recent years. The additional installation capacity in 2024 does not contain data of the full year [20].

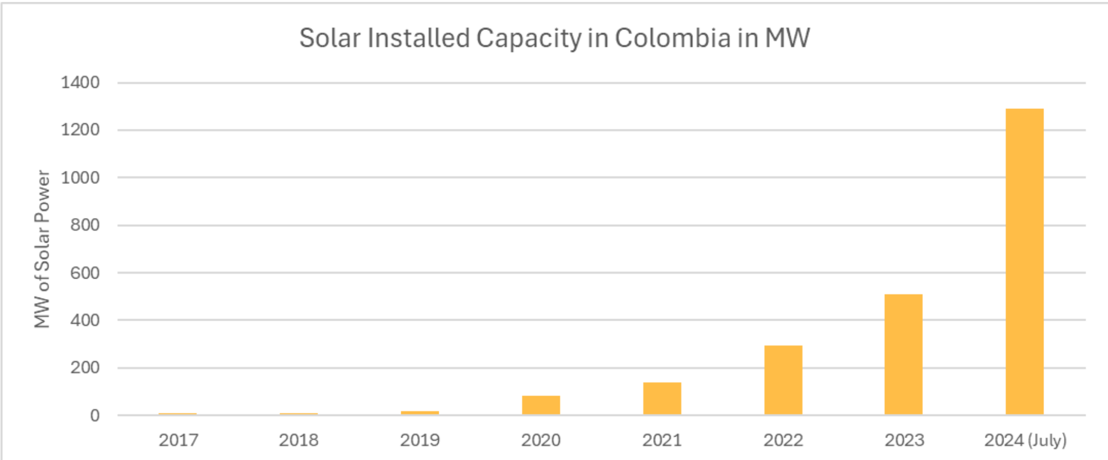

Figure 12. Yearly solar installed capacity in Colombia. Data from [20].

According to data from XM in Figure 13, utility-scale solar dominates the country's installed solar capacity with 53 % (673 MW) of the total capacity utilizing solar trackers. Fixed-tilt utility-scale solar with less than 20 MW of capacity makes up 41 % (514 MW), further contributing to large-scale generation efforts. Rooftop solar installations account for a smaller portion, representing just 5 % (60 MW) of the total capacity, while distributed generation, which involves small-scale localized systems up to 1 MW, contributes only 1 % (14 MW). This distribution highlights the country's focus on utility-scale projects as the primary driver of solar energy development.

However, it is worth noticing that many rooftop solar are not registered before the nationwide market operator, and the number may be higher than it is actually presented [20].

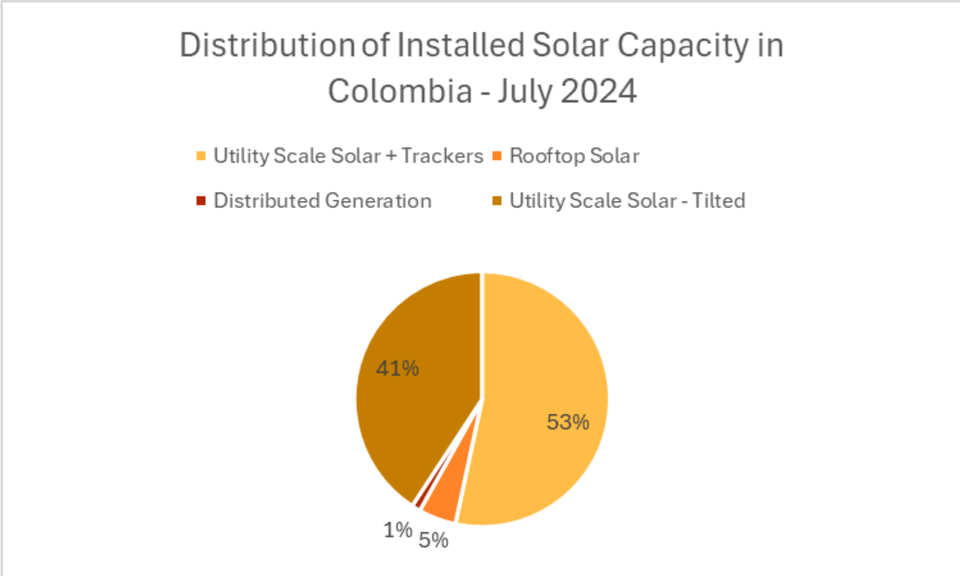

Figure 13. Distribution of solar installed capacity in Colombia by type of project. Data from [20].

La Loma Solar Plant, developed by ENEL and located in the Colombian department of Cesar, is the largest photovoltaic park ever built in the country. With 400,000 solar panels distributed across an area of 437 hectares, it has an installed capacity of 187 MW peak (150 MW grid-connected), and it can generate 420 GWh of renewable energy per year (see Figure 14).

Figure 14. Aerial view of La Loma Solar Plant [30].

According to XM Data, by mid-2024 there were over 68 MW of large-scale self-generation industrial rooftop projects in Colombia [20], and this number is expected to rise in the following years. One of the first iconic projects in Colombia, depicted in Figure 15, was installed by Celsia at Compañía Nacional de Chocolates in 2017. The installed capacity of the system is 2,132 kW and it produces 3,150,964 kWh/year of clean energy.

Figure 15. Aerial view of Solar Plant at Compañía Nacional de Chocolates [37].

2.12. Prediction of performance and cost

Table 2-2 compares different investment cost estimates from various sources for photovoltaics. The data focuses on solar PV with cost per grid-connected AC capacity. If expressed in module-based DC capacity as often done in the solar PV industry, the values will be lower scaled by the applicable ratio between DC and AC capacity.

Table 2-2. Investment cost comparison across regions for different solar PV projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	1.36 (residential PV) 1.18 (industrial PV) 1.12 (small scale PV) 1.03 (utility scale PV)	2024
	International data	
Technology Catalogue Denmark (2023)	1.55 (residential PV) 1.09 (industrial PV) 0.81 (utility scale PV)	2022
Technology Catalogue Indonesia (2024)	1.35 (residential PV) 1.21 (industrial PV) 1.08 (utility scale PV)	2023
Technology Catalogue Vietnam (2023)	1.21 (residential PV) 0.79 (utility scale PV) (not tracking)	2022
IEA GEC Model, Brazil region (2021)	0.65 (residential PV) 0.65 (industrial PV) 0.84 (utility scale PV)	2021
NREL ATB (2023)	3.35 (residential PV) 2.1 (industrial PV)	2023

	1.52 (utility scale PV)	

Table 2-2 shows a considerable range between the specific investment costs in the various references, which can be explained by the various capacity sizes that are considered standard. As solar PV cost is prone to economies of scales also on a single-plant perspective (larger solar PV plants usually, and all else equal, have lower specific investment cost), it is difficult to compare references solely on their specific investment cost.

Predictions about the future investments costs of PV panels can be made by looking at the past development in prices and global capacity. Learning rates describe the cost reductions achieved when the accumulated capacity is doubled. For most technologies, learning rates vary between 5 and 25 % meaning that a doubling of accumulated capacity results in a 5 to 25 % cost reduction. The precise learning rates of PV components such as inverter, substructure, EPC, transformer, cables and other grid related costs are difficult to estimate as these components have been on the market for many decades and global production records are thereby hard to come by. However, it is reasonable to assume a lower learning rate for these components. The learning rate of PV modules however was on average 39.9 % from 2006 to 2023, shown in Figure 16.

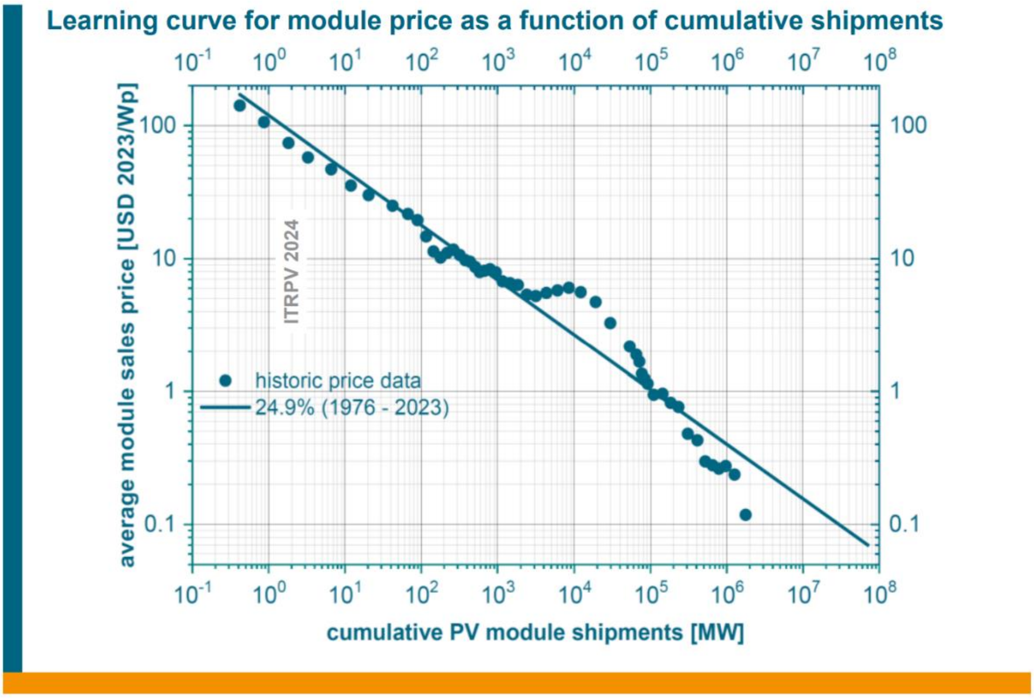

Figure 16. Historic learning rate of PV modules [8].

Figure 16 shows that he module price has decreased from 24-26 USD per W_p in 1980 to about 0.1 USD per W_p in 2020 in a global perspective. Such a trend shows a strong correlation between cumulative production and price reductions. This tendency is projected to continue in the future.

The typical component shares of the total investment cost for a utility scale plant are shown in Table 2-3, representing the utility-scale datasheet including tracker systems.

Table 2-3. Component cost shares of utility-scale PV systems.

Component	Share of total cost
Module	41%
Inverter	13%
Tracker-related cost	5%
Installation	22%
Other balance of plant cost	18%
Total	100%

Module and inverter prices, which together see the most significant cost declines as also presented above, account together for 54% of the total investment costs, and are projected with a learning rate of 24 % [34]. Tracker systems, other balance of plant cost and installation cost are 46 % of the total costs and are projected with a slightly more moderate learning rate of 20 % [31].

In 2023, the global cumulative capacity of photovoltaic (PV) systems increased to 1.6 terawatts (TW), up from 1.2 TW in 2022. This growth was driven by the commissioning of new PV systems, rising from 407.3 gigawatts (GW) to 446 GW, and an estimated 150 GW of modules in global inventories. Despite several years of high material and transport costs, module prices fell dramatically due to an oversupplied market. This price drop helped maintain the competitiveness of PV technology, even as electricity prices decreased from their historic highs in 2022 [31].

Using the capacity projections of the Announced Pledges Scenario 2021 [31], the future component costs can be calculated with respective learning rates (see Table 2-4).

Table 2-4. Future component costs based on the global solar PV capacity projections of IEA's Announced Pledges Scenario 2021 [32].

$MUSD_{2024}/MW_p$	2024	2030	2050
PV module*	0.33	0.22	0.18
Inverter*	0.11	0.07	0.05
Tracker-related cost**	0.04	0.03	0.02
Installation**	0.18	0.13	0.09
Other balance-of-plant costs**	0.15	0.11	0.07
Total investment	0.79	0.55	0.37

*Learning rate for PV module and inverter: 24 %.
**Learning rate other components: 20 %.

With IEA's Net Zero Emissions by 2050 Scenario projection, the cost reductions become somewhat more poignant, resulting in a lower overall cost by 2050. As seen in Table 2-5, the main difference is lower PV module prices due to higher cumulative global installation. The prices projections start with the central estimate in 2024.

Table 2-5. Future component costs based on the global solar PV capacity projections of IEA's Net Zero Emissions by 2050 [32].

$MUSD_{2024}/MW_p$	2024	2050
PV module	0.33	0.13
Inverter	0.11	0.04
Tracker-related cost	0.04	0.02
Installation	0.18	0.08
Balance of plant cost	0.15	0.07
Total investment	0.79	0.20

Both projections suggest that the price development in the future may not be as radical as the historic development in a global perspective, meaning that PV technology can currently, according to the Technology Catalogue guidelines, be classified as a category 3 technology with a large deployment while presumably approaching category 4 around 2030 in terms of price development.

2.12.1. Efficiency perspectives

Current PERC p-type mono-Si modules are projected to reach 21.6 % efficiency in 2024, with potential growth up to 22 % in the next 10 years. Further advancements in p-type PERC are not expected beyond an average of 22 %. In contrast, n-type modules with tunnel oxide passivation are anticipated to outperform p-type PERC, starting at 22.8 % efficiency in 2024 and reaching up to 24 % within a decade. SHJ modules are predicted to hit 23 % in 2024 and increase to 24.3 % by 2034 [8].

Back-contact cells on n-type technology are forecast to achieve around 23.2 % efficiency in 2024, eventually growing to 24.7 % by 2034 (see Figure 17). The development of back-contact concepts combined with passivated contacts is advancing, enhancing both performance and market share. Si-based tandem modules are expected to emerge post-2026, with efficiencies reaching 27 % by 2028 and close to 30 % by 2034, surpassing silicon's practical efficiency limits. Tandem technologies using perovskite remain a significant research focus, but progress will need to be carefully monitored. Perovskite-perovskite tandems are viewed as a more challenging technology, likely achievable only after successful silicon-perovskite tandem development [8].

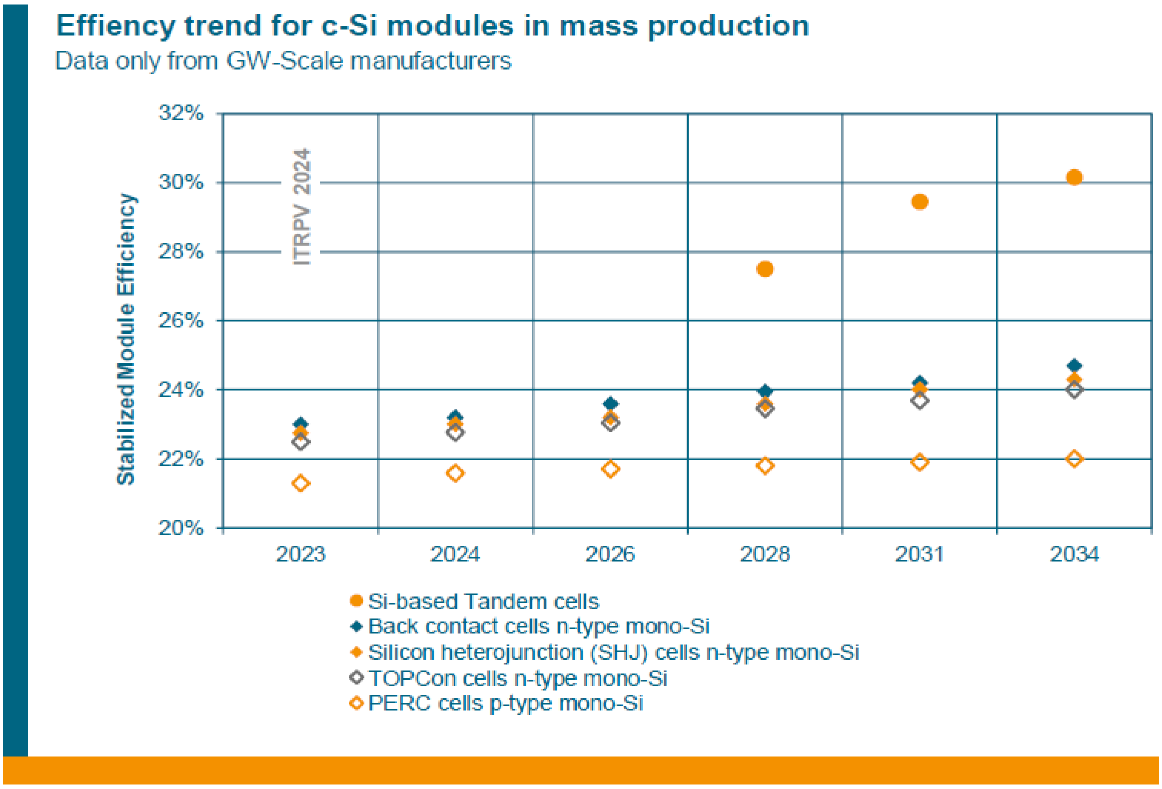

Figure 17. Efficiency trends for different cell types [8].

2.12.2. Uncertainty

As future PV module price projections show further price reductions, there are uncertainties associated with the magnitude and timing of these reductions. Many different factors can influence the future price development such as the raw material cost of different cell types, new structural innovations, national policies and competition with other renewable technologies.

As for silicon-based cell types, the global silicon reserve is estimated to be abundant and thereby able to supply the current demand for many decades [18].

An additional uncertainty is with respect to which cell type will be the dominant one in the future market, as the effect of new near-future production methods for monocrystalline cells are yet to be determined. In addition, there is always the possibility that a new cell type emerges and becomes dominant.

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2.14. Datasheet

2.14.1. Residential scale

Technology	**PV residential scale, rooftop - grid connected**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Not e**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for total power plant ($kW_{e(AC)}$)	6	6	6	2	20	2	20	I	8
Forced outage (%)	0	0	0						2
Planned outage (weeks/year)	0	0	0						2
Technical lifetime (years)	27	30	35	25	30	30	40		2,5

Construction time (years)	0.1	0.1	0.1	0.1	0.5				5
Space requirement ($m^2/kW_{e(AC)}$)	5.1	4.8	4.1	4.4	6.0	3.5	5.2		5
Additional data for non-thermal plants									
Capacity factor (%), theoretical	18.0	18.5	19.6	12.3	25.4	12.7	27.5	C, D	5
Capacity factor (%), incl. outages	18.0	18.5	19.6	12.3	25.4	12.7	27.5	C, D, E	5
Ramping configurations									
Ramping (% of full load/minute)	4 %	4 %	4 %	3 %	4 %	3 %	4 %	J	2.4
Minimum load (% of full load)	47 %	25 %	20 %	39 %	55 %	20 %	40 %	F	4
Warm start-up time (hours)	4	4	4	2	5	2	5	D	4
Cold start-up time (hours)	12	12	12	6	15	6	15	D	4
Environment									
PM 2.5 (g/GJ of fuel input)	0	0	0	-	-	-	-		
SO_2 (g/GJ of fuel input)	0	0	0	-	-	-	-		
NO_X (g/GJ of fuel input)	0	0	0	-	-	-	-		
CH_4 (g/GJ of fuel input)	0	0	0	-	-	-	-		
N_2O (g/GJ of fuel input)	0	0	0	-	-	-	-		
Output									
Full load hours (kWh/kW)	1,574	1,622	1,717	1,077	2,225	1,116	2,413	D,K	
Peak power full load hours (kWh/kW_p)	1,369	1,410	1,493	979	1,854	1,015	2,010	D,E, K	
Financial data									
Specific investment, total system (million USD/MW_e)	1.36	0.94	0.63	1.29	1.48	0.60	0.69	A,B, C	1,2,3,4
Specific investment, total system, per DC (million USD/MW_p)	1.18	0.82	0.55	1.17	1.24	0.5	0.6	A,B, C	1,2,3,4
PV module cost ($USD/W_{e(AC)}$)	0.47	0.32	0.20	0.45	0.52	0.19	0.22	A,B, C	1,2,3,4
PV inverter cost ($USD/W_{e(AC)}$)	0.28	0.18	0.12	0.26	0.30	0.11	0.13	A,B, C	1,2,3,4
Balance Of Plant cost ($USD/W_{e(AC)}$)	0.35	0.25	0.18	0.33	0.38	0.17	0.19	A,B, C	1, 3, 4
Installation cost ($USD/W_{e(AC)}$)	0.26	0.19	0.13	0.25	0.28	0.13	0.14	A,B, C	1,2,3,4
Fixed O&M (USD/MW_e/year)	17,000	14,600	12,300	16,700	17,700	12,100	12,800	C	2,5,6,7,10
Variable O&M (USD/MWh)	0	0	0	0	0	0	0		
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Global horizontal irradiance (kWh/m^2/year)	1,643	1,643	1,643	1,194	2,190	1,194	2,190	H	9,11
DC/AC sizing factor (W_p/W)	1.15	1.15	1.15	1.10	1.20	1.10	1.20		10
Transposition factor	1.01	1.01	1.01	1	1.02	1	1.02		
Performance ratio	0.825	0.85	0.90	0.82	0.83	0.85	0.90	G	2,3,10
PV module conversion efficiency (%)	21.5	23	25					F	2,3
Inverter lifetime (years)	12.50	15	15						2
Average annual degradation of full-load hours (%)	0.4	0.3	0.3					N	2
Financial data - per DC peak capacity									
Nominal investment (million USD/MW_p)	1.18	0.82	0.55	1.17	1.24	0.54	0.57	A,B, C	1,2,3,4
PV module cost ($USD/W_{p(DC)}$)	0.41	0.27	0.18	0.41	0.44	0.17	0.19	A,B, C	1,2,3,4
PV inverter cost ($USD/W_{p(DC)}$)	0.24	0.16	0.10	0.23	0.25	0.10	0.11	A,B, C	1,2,3,4
Balance of plant cost ($USD/W_{p(DC)}$)	0.30	0.22	0.15	0.30	0.31	0.15	0.16	A,B, C	1, 3, 4
Installation cost ($USD/W_{p(DC)}$)	0.23	0.17	0.12	0.23	0.24	0.12	0.12	A,B, C	1,2,3,4

Fixed O&M (USD/MW$_{p(DC)}$/year)	14,783	12,696	10,696	13,917	16,091	10,083	11,636	C	2,5,6,7,10
Variable O&M (USD/MWh$_{p(DC)}$)	0	0	0	0	0	0	0		

Notes

A Aggregated data of Colombian projects receiving incentives/support, in alignment with further international sources

B Cost are projected with a learning rate approach assuming a 24 % learning rate for modules and inverters based on Fraunhofer, and 20 % as per other components based on IEA, and 10 % for O&M, including capacity projections of the IEA's World Energy Outlook 2023, with Announced Pledges for the central values and Stated Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.

C Uncertainty in the short term assumes the same spread as the long-term uncertainty.

D Capacity factor = Full load hours / 8760.

E 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 1643 kWh/m^2/year solar irradiation mentioned here, the capacity factors should be adjusted accordingly.

F Yearly outage time is assumed to be 0,5 % equal approximately 2 hours.

G 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 heterojunction (HJT) n-type mono-Si cells which both have higher efficiencies.

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 is assumed to be standard for ground-mounted plants in 2050.

I The central value is the average annual solar irradiance received on a horizontal surface in Colombia. The areas receiving the highest levels of global solar radiation, exceeding the San Andrés and Providencia islands, large parts of the Caribbean region, and the inter-Andean valley. Minimum and maximum value correspond to The Global Solar Atlas's s Global Horizontal Irradiation distribution for Colombia

J The capacity range is continuous across the different datasheets with a representative value selected through database processing and stakeholder consultation

K The full-load hours are a result of global horizontal radiation, transposition factor and performance ratio.

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[9] Emergente Energía Sostenible - Radiation Map for Colombia

[10] Discussion with Technology Catalogue stakeholder group

[11] World Bank, Global Solar Atlas

2.14.2. Industrial scale

Technology	**PV Industrial scale, rooftop - grid connected**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for total power plant (kW$_e$)	100	100	100	20	1000	20	1000	I	7
Forced outage (%)	0	0	0						2
Planned outage (weeks/year)	0	0	0						2
Technical lifetime (years)	27	30	35	25	30	30	40		2,5
Construction time (years)	0.5	0.5	0.5	0.5	1.5	0.5	1.5		5
Space requirement (1000 m^2/MW$_e$)	5.1	4.8	4.1	4.4	6.0	3.5	5.2		5
Additional data for non-thermal plants									
Capacity factor (%), theoretical	18.7	19.3	20.5	12.3	27.5	12.7	30.5	C, D	5

Capacity factor (%), incl. outages	18.7	19.3	20.5	12.3	27.5	12.7	30.5	C, D, E	5
Ramping configurations									
Ramping (% of full load/minute)	-	-	-	-	-	-	-		
Minimum load (% of full load)	-	-	-	-	-	-	-		
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (g/GJ of fuel input)	0	0	0	-	-	-	-		
SO_2 (g/GJ of fuel input)	0	0	0	-	-	-	-		
NO_X (g/GJ of fuel input)	0	0	0	-	-	-	-		
CH_4 (g/GJ of fuel input)	0	0	0	-	-	-	-		
N_2O (g/GJ of fuel input)	0	0	0	-	-	-	-		
Output									
Full load hours (kWh/kW)	1,642	1,692	1,792	1,077	2,410	1,116	2,672	C,D,K	
Peak power full load hours (kWh/kW$_p$)	1,369	1,410	1,493	979	1,854	1,015	2,055	C,D,E,K	
Financial data									
Specific investment, total system (million USD/MW$_e$)	1.18	0.81	0.55	1.11	1.29	0.52	0.59	A,B,B1	1,2
Specific investment, total system, per DC (million USD /MW$_p$)	0.98	0.68	0.45	1.01	0.99	0.47	0.46	A,B,B1	1,2
PV module cost (USD/W$_{e(AC)}$)	0.46	0.31	0.20	0.44	0.51	0.19	0.22	A,B,B1	1,2
PV inverter cost (USD/W$_{e(AC)}$)	0.20	0.13	0.09	0.19	0.22	0.08	0.10	A,B,B1	1,2
Balance Of Plant cost (USD/W$_{e(AC)}$)	0.23	0.17	0.12	0.22	0.25	0.11	0.13	A,B,B1	1
Installation cost (USD/W$_{e(AC)}$)	0.28	0.21	0.14	0.27	0.31	0.14	0.16	A,B,B1	1,2
Fixed O&M (USD/MW$_e$/year)	15,000	12,900	10,900	14,600	15,600	10,600	11,300	B1	4,5,6,9
Variable O&M (USD/MWh)	0	0	0	0	0	0	0		
Start-up costs (USD/MW$_e$/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Global horizontal irradiance (kWh/m^2/year)	1,643	1,643	1,643	1,194	2,190	1,194	2,190	H	8,10
DC/AC sizing factor (W$_p$/W)	1.20	1.20	1.20	1.10	1.30	1.10	1.30		9
Transposition factor	1.01	1.01	1.01	1	1.02	1	1.02		10
Performance ratio	0.825	0.85	0.90	0.82	0.83	0.85	0.92	G	2,3,9
PV module conversion efficiency (%)	21.5	23	25					F	2,3
Inverter lifetime (years)	12.5	15	15						2
Average annual degradation of full-load hours (%)	0.4	0.3	0.3					J	2
Financial data - per DC peak capacity									
Nominal investment (million USD/MW$_p$)	0.98	0.68	0.45	1.01	0.99	0.47	0.46	A,B,B1	1,2
PV module cost (USD/W$_{p(DC)}$)	0.39	0.26	0.17	0.40	0.39	0.17	0.17	A,B,B1	1,2
PV inverter cost (USD/W$_{p(DC)}$)	0.17	0.11	0.07	0.17	0.17	0.07	0.07	A,B,B1	1,2
Balance of plant cost (USD/W$_{p(DC)}$)	0.19	0.14	0.10	0.20	0.19	0.10	0.10	A,B,B1	1
Installation cost (USD/W$_{p(DC)}$)	0.24	0.17	0.12	0.25	0.24	0.12	0.12	A,B,B1	1,2
Fixed O&M (USD/MW$_{p(DC)}$/year)	12,500	10,750	9,083	11,231	14,182	8,154	10,273	B1	4,5,6,9
Variable O&M (USD/MWh$_{p(DC)}$)	0	0	0	0	0	0	0		

Notes

A Aggregated data of Colombian projects receiving incentives/support, in alignment with further international sources

B Cost are projected with a learning rate approach assuming a 24 % learning rate for modules and inverters based on Fraunhofer, and 20 % as per other components based on IEA, and 10 % for O&M, including capacity projections of the IEA's World Energy Outlook 2023, with Announced Pledges for the central values and Stated Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.

B1 Uncertainty in the short term assumes the same spread as the long-term uncertainty.

C Capacity factor = Full load hours / 8760.

D 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 1643 kWh/m²/year solar irradiation mentioned here, the capacity factors should be adjusted accordingly.

E Yearly outage time is assumed to be 0,5 % equal approximately 2 hours.

F 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.

G 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 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 MPPT efficiency and is averaged over typical load levels. An addition to the ratio is the added benefit of having bifacial modules, which is assumed to be standard for ground-mounted plants in 2050.

H The central value is the average annual solar irradiance received on a horizontal surface in Colombia. The areas receiving the highest levels of global solar radiation, exceeding the San Andrés and Providencia islands, large parts of the Caribbean region, and the inter-Andean valley. Minimum and maximum value correspond to The Global Solar Atlas's s Global Horizontal Irradiation distribution for Colombia

I The capacity range is continuous across the different datasheets with a representative value selected through database processing and stakeholder consultation

J Annual degradation of full load hours is not included in the above figures of full-load hours and capacity factors

K The full-load hours are a result of global horizontal radiation, transposition factor and performance ratio.

References

[1] UPME, “Incentivos tributarios para las FNCER” database, 2024
[2] Danish Energy Agency, Technology Catalogue for generation of electricity and District Heating, 2024
[3] Fraunhofer, 2024, Photovoltaics report 2024
[4] IEA, 2023, World Energy Outlook Global Energy and Climate Model input data
[5] Danish Energy Agency, Ea Energy Analyses, Technology Data for the Indonesian Power Sector, 2024
[6] Danish Energy Agency, Ea Energy Analyses, Viet Nam Technology Catalogue for Power Generation, 2023
[7] XM, Data from Paratec
[8] Emergente Energía Sostenible - Radiation Map for Colombia
[9] Discussion with Technology Catalogue stakeholder group
[10] World Bank, Global Solar Atlas

2.14.3. Small scale

Technology	PV small scale, ground-mounted - grid connected								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for a typical power plant (MW_e)	10	10	10	1	20	1	20	L	5
Forced outage (%)	0	0	0						2
Planned outage (weeks/year)	1	1	1						
Technical lifetime (years)	27	30	35	25	30	30	40		2,7
Construction time (years)	0.5	0.5	0.5	0.5	1.5	0.5	1.5		7
Space requirement (1000 m^2/MW_e)	12.5	11.7	10.0	6.0	13.0	6.0	13.0	M	8
Additional data for non-thermal plants									
Capacity factor (%), theoretical	20.3	20.9	22.6	12.3	33.9	12.7	37.5	E, F	7
Capacity factor (%), incl. outages	19.9	20.5	22.2	12.3	33.9	12.7	37.5	E, F, G	7
Ramping configurations									
Ramping (% of full load/minute)	-	-	-	-	-	-	-		

Minimum load (% of full load)	-	-	-	-	-	-	-		
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (g/GJ of fuel input)	0	0	0	-	-	-	-		
SO_2 (g/GJ of fuel input)	0	0	0	-	-	-	-		
NO_X (g/GJ of fuel input)	0	0	0	-	-	-	-		
CH_4 (g/GJ of fuel input)	0	0	0	-	-	-	-		
N_2O (g/GJ of fuel input)	0	0	0	-	-	-	-		
Output									
Full load hours (kWh/kW)	1,779	1,833	1,984	1,077	2,966	1,116	3,288	E,F,O	
Peak power full load hours (kWh/kW$_p$)	1,369	1,410	1,526	979	1,854	1,015	2,055	E,F,G,O	
Financial data									
Specific investment, total system (million USD/MW$_e$)	1.12	0.77	0.52	1.06	1.22	0.49	0.57	A,B,B1	1,2,12
Specific investment, total system, per DC (million USD/MW$_p$)	0.86	0.59	0.40	0.96	0.76	0.45	0.35	A,B,B1,C	1,2
PV module cost (USD/W$_{e(AC)}$)	0.46	0.31	0.20	0.44	0.51	0.19	0.22	A,B,B1	1,2
PV inverter cost (USD/W$_{e(AC)}$)	0.14	0.09	0.06	0.13	0.15	0.06	0.07	A,B,B1	1,2
Balance Of Plant cost (USD/W$_{e(AC)}$)	0.29	0.21	0.14	0.27	0.31	0.14	0.16	A,B,B1	1
Installation cost (USD/W$_{e(AC)}$)	0.23	0.17	0.12	0.22	0.25	0.11	0.13	A,B,B1	1,2
Fixed O&M (USD/MW$_e$/year)	11,000	9,400	8,000	10,700	11,400	7,800	8,300	B1,D	6
Variable O&M (USD/MWh)	0	0	0	0	0	0	0		
Start-up costs (USD/MW$_e$/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Global horizontal irradiance (kWh/m^2/year)	1,643	1,643	1,643	1,194	2,190	1,194	2,190	K	4,9
DC/AC sizing factor (W$_p$/W)	1.30	1.30	1.30	1.1	1.6	1.1	1.6	C	10
Transposition factor	1.01	1.01	1.01	1	1.02	1	1.02		9
Performance ratio	0.825	0.85	0.92	0.82	0.83	0.85	0.92	J	2,3,8
PV module conversion efficiency (%)	21.5	23	25					I	2,3
Inverter lifetime (years)	12.50	15	15						2
Average annual degradation of full-load hours (%)	0.4	0.3	0.3					N	2
Financial data - per DC peak capacity									
Nominal investment (million USD/MW$_p$)	0.86	0.59	0.40	0.96	0.76	0.45	0.35	A,B,B1,C	1,2
PV module cost (USD/W$_{p(DC)}$)	0.36	0.24	0.15	0.40	0.32	0.17	0.14	A,B,B1	1,2
PV inverter cost (USD/W$_{p(DC)}$)	0.11	0.07	0.05	0.12	0.10	0.05	0.04	A,B,B1	1,2
Balance of plant cost (USD/W$_{p(DC)}$)	0.22	0.16	0.11	0.25	0.19	0.13	0.10	A,B,B1	1
Installation cost (USD/W$_{p(DC)}$)	0.18	0.13	0.09	0.20	0.16	0.10	0.08	A,B,B1	1,2
Fixed O&M (USD/MW$_{p(DC)}$/year)	8,462	7,231	6,154	6,688	10,364	4,875	7,545	B1,D	6
Variable O&M (USD/MWh$_{p(DC)}$)	0	0	0	0	0	0	0		

Notes

A Aggregated data of Colombian projects receiving incentives/support, supplemented with further international sources

B Cost are projected with a learning rate approach assuming a 24 % learning rate for modules and inverters based on Fraunhofer, and 20 % as per other components based on IEA, and 10 % for O&M, including capacity projections of the IEA's World Energy Outlook 2023, with

Announced Pledges for the central values and Stated Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.

B1 Uncertainty in the short term assumes the same spread as the long-term uncertainty

C The typical sizing factor is based on operational projects, expressed in their average for the central value and minimum and maximum for the lower and higher bound. Most projects are designed around the central value for both small-scale and large-scale plants.

D IRENA data representative for utility-scale plants converted to smaller scale plants

E Capacity factor = Full load hours / 8760.

F 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 1643 kWh/m^2/year solar irradiation mentioned here, the capacity factors should be adjusted accordingly.

G Yearly outage time is assumed to be 0,5 % equal approximately 2 hours.

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 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 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 MPPT efficiency and is averaged over typical load levels. An addition to the ratio is the added benefit of having bifacial modules, which is assumed to be standard for ground-mounted plants in 2050.

K The central value is the average annual solar irradiance received on a horizontal surface in Colombia. The areas receiving the highest levels of global solar radiation, exceeding the San Andrés and Providencia islands, large parts of the Caribbean region, and the inter-Andean valley. Minimum and maximum value correspond to The Global Solar Atlas's s Global Horizontal Irradiation distribution for Colombia

L The capacity range is continuous across the different datasheets with a representative value selected through database processing and stakeholder consultation

M Typical size identified through stakeholder consultation, and projected as per assumed efficiency gain of modules. Typically, tracking projects use 20 % more land compared to fixed-tilt projects based on stakeholder consultation.

N Annual degradation of full load hours is not included in the above figures of full-load hours and capacity factors

O The full-load hours are a result of global horizontal radiation, transposition factor and performance ratio.

References

[1] UPME, “Incentivos tributarios para las FNCER” database, 2024
[2] Danish Energy Agency, Technology Catalogue for generation of electricity and District Heating, 2024
[3] Fraunhofer, 2024, Photovoltaics report 2024
[4] Emergente Energía Sostenible - Radiation Map for Colombia
[5] XM, Data from Paratec
[6] IRENA, 2023, Renewable Power Generation Costs in 2022
[7] Danish Energy Agency, Ea Energy Analyses, Technology Data for the Indonesian Power Sector, 2024
[8] Discussion with Technology Catalogue stakeholder group
[9] World Bank, Global Solar Atlas
[10] Bloomberg New Energy Finance, Power Asset Database

2.14.4. Utility scale

Technology	**PV utility-scale, ground-mounted - grid connected**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for a typical power plant (MWe)	70	70	70	20	150	20	150	I	6
Forced outage (%)	0	0	0						2
Planned outage (weeks/year)	1	1	1						
Technical lifetime (years)	27	30	35	25	30	30	40		2,7
Construction time (years)	0.5	0.5	0.5	0.5	1.5	0.5	1.5		7
Space requirement (1000 m^2/MW$_p$)	15.0	14.6	13.1	7.2	15.6	7.2	15.6	J	8
Additional data for non-thermal plants									
Capacity factor (%), theoretical	25.4	26.2	28.3	17.5	39.7	18.1	44.0	E	7
Capacity factor (%), incl. outages	24.9	25.7	27.8	17.5	39.7	18.1	44.0	E	7
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/GJ of fuel input)	0	0	0	-	-	-	-		
SO_2 (g/GJ of fuel input)	0	0	0	-	-	-	-		
NO_X (g/GJ of fuel input)	0	0	0	-	-	-	-		
CH_4 (g/GJ of fuel input)	0	0	0	-	-	-	-		
N_2O (g/GJ of fuel input)	0	0	0	-	-	-	-		
Output									
Full load hours (kWh/kW)	2,224	2,291	2,480	1,530	3,476	1,586	3,853	E,L	
Peak power full load hours (kWh/kW_p)	1,711	1,763	1,908	1,224	2,318	1,269	2,569	E,L	
Financial data									
Specific investment, total system (million USD/MW_e)	1.03	0.71	0.48	0.98	1.13	0.45	0.52	A,B,B1	1,2
Specific investment, total system, per DC (million USD/MW_p)	0.79	0.55	0.37	0.78	0.75	0.36	0.35	A,B,B1,D	1,2
PV module cost (USD/$W_{e(AC)}$)	0.42	0.28	0.18	0.40	0.47	0.17	0.20	A,B,B1	1,2
PV inverter cost (USD/$W_{e(AC)}$)	0.14	0.09	0.06	0.13	0.15	0.06	0.06	A,B,B1	1,2
Nominal investment (tracker related costs) (USD/$W_{e(AC)}$)	0.05	0.04	0.03	0.05	0.05	0.02	0.03	A,B,B1,C	1,2
Balance Of Plant cost (USD/$W_{e(AC)}$)	0.23	0.17	0.12	0.22	0.25	0.11	0.13	A,B,B1	1
Installation cost (USD/W_p)	0.19	0.14	0.10	0.18	0.21	0.09	0.10	A,B,B1	1,2
Fixed O&M (USD/MW_e/year)	7,400	6,300	5,400	7,100	7,700	5,200	5,600	B,B1	5
Variable O&M (USD/MWh)	0	0	0	0	0	0	0		
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Global horizontal irradiance (kWh/m^2/y)	1,643	1,643	1,643	1,194	2,190	1,194	2,190	H	4,9
DC/AC sizing factor (W_p/W)	1.30	1.30	1.30	1.25	1.5	1.25	1.5	D	10
Transposition Factor	1.26	1.26	1.26	1	1.28	1	1.28		9
Performance ratio [-]	0.825	0.85	0.92	0.82	0.83	0.85	0.92	G	2,3,8
PV module conversion efficiency (%)	21.5	23	25					F	2,3
Inverter lifetime (years)	12.5	15	15						2
Average annual degradation of full-load hours (%)	0.4	0.3	0.3					K	2
Financial data - ONLY REFERENCES									
Nominal investment (million USD/MW_p)	0.79	0.28	0.18	0.40	0.47	0.17	0.20	A,B,B1,D	1,2
PV module cost (USD/$W_{p(DC)}$)	0.33	0.22	0.14	0.32	0.31	0.14	0.13	A,B,B1	1,2
PV inverter cost (USD/$W_{p(DC)}$)	0.11	0.07	0.05	0.10	0.10	0.04	0.04	A,B,B1	1,2
Nominal investment (tracker related costs) (USD/$W_{p(DC)}$)	0.04	0.03	0.02	0.04	0.04	0.02	0.02	A,B,B1,C	1,2
Installation cost (USD/$W_{p(DC)}$)	0.18	0.13	0.09	0.17	0.17	0.09	0.08	A,B,B1	1
Balance Of Plant cost (USD/$W_{p(DC)}$)	0.15	0.11	0.07	0.15	0.14	0.07	0.07	A,B,B1	1,2
Fixed O&M (USD/$MW_{p(DC)}$/year)	5,692	4,846	4,154	4,733	6,160	3,467	4,480	B,B1	5
Variable O&M (USD/$MWh_{p(DC)}$)	0	0	0	0	0	0	0		

Notes

A Aggregated data of Colombian projects receiving incentives/support, supplemented with further international sources

B Cost are projected with a learning rate approach assuming a 24 % learning rate for modules and inverters based on Fraunhofer, and 20 % as per other components based on IEA, and 10 % for O&M, including capacity projections of the IEA's World Energy Outlook 2023, with Announced Pledges for the central values and Stated Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.

B1 Uncertainty in the short term assumes the same spread as the long-term uncertainty

C Tracker-related cost usually amounts to 10 – 15 % of the cost, including its installation

D The typical sizing factor is based on operational projects, expressed in their average for the central value and minimum and maximum for the lower and higher bound. Most projects are designed around the central value for both small-scale and large-scale plants.

E 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 1643 kWh/m²/year solar irradiation mentioned here, the capacity factors should be adjusted accordingly.

F 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 HJ) n-type mono-Si cells which both have higher efficiencies.

G 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 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 MPPT efficiency and is averaged over typical load levels. An addition to the ratio is the added benefit of having bifacial modules, which is assumed to be standard for ground-mounted plants in 2050.

H The central value is the average annual solar irradiance received on a horizontal surface in Colombia. The areas receiving the highest levels of global solar radiation, exceeding the San Andrés and Providencia islands, large parts of the Caribbean region, and the inter-Andean valley. Minimum and maximum value correspond to The Global Solar Atlas's s Global Horizontal Irradiation distribution for Colombia

I The capacity range is continuous across the different datasheets with a representative value selected through database processing and stakeholder consultation. The upper range corresponds to the largest PV plant in operation in Colombia as of September 2024.

J Typical size identified through stakeholder consultation, and projected as per assumed efficiency gain of modules. Typically, tracking projects use 20% more land compared to fixed-tilt projects based on stakeholder consultation.

K Annual degradation of full load hours is not included in the above figures of full-load hours and capacity factors

L The full-load hours are a result of global horizontal radiation, transposition factor and performance ratio.

References

[1] UPME, "Incentivos tributarios para las FNCER" database, 2024

[2] Danish Energy Agency, Technology Catalogue for generation of electricity and District Heating, 2024

[3] Fraunhofer, 2024, Photovoltaics report 2024

[4] Emergente Energía Sostenible - Radiation Map for Colombia

[5] IRENA, 2023, Renewable Power Generation Costs in 2022

[6] XM, Data from Paratec

[7] Danish Energy Agency, Ea Energy Analyses, Technology Data for the Indonesian Power Sector, 2024

[8] Discussion with Technology Catalogue stakeholder group

[9] World Bank, Global Solar Atlas

[10] Bloomberg New Energy Finance, Power Asset Database

2.14.5. Floating

Technology	**PV Floating, utility-scale, grid connected**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for total power plant (MW_e)	10	10	10	1	20	1	20	G	
Forced outage (%)	0	0	0						2,6
Planned outage (weeks/year)	1	1	1						2,6
Technical lifetime (years)	27	30	35	25	30	30	40		2,6
Construction time (years)	0.5	0.5	0.5	0.5	1.5	0.5	1.5		2,6
Space requirement (1000 m^2/MW_e)	12.5	11.7	10.0	6.0	13.0	6.0	13.0		2,6
Additional data for non-thermal plants									
Capacity factor (%), theoretical	21.3	21.4	22.6	14.0	33.3	14.5	35.2	J	2
Capacity factor (%), incl. outages	20.9	21.0	22.2	14.0	33.3	14.5	35.2	J	2
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/GJ of fuel input)	0	0	0	-	-	-	-		
SO_2 (g/GJ of fuel input)	0	0	0	-	-	-	-		
NO_X (g/GJ of fuel input)	0	0	0	-	-	-	-		
CH_4 (g/GJ of fuel input)	0	0	0	-	-	-	-		
N_2O (g/GJ of fuel input)	0	0	0	-	-	-	-		
Output									
Full load hours (kWh/kW)	1,865	1,876	1,984	1,224	2,920	1,269	3,083	J	
Peak power full load hours (kWh/kW$_p$)	1,435	1,443	1,526	979	1,947	1,015	2,055	J	
Financial data									
Specific investment, total system (million USD/MW$_e$)	1.38	0.96	0.65	1.30	1.50	0.61	0.71	A,B,B1	1,2
Specific investment, total system, per DC (million USD/MW$_p$)	1.06	0.74	0.50	1.04	1.00	0.49	0.47	A,B,B1,C	1,2
PV module cost (USD/W$_{e(AC)}$)	0.46	0.31	0.20	0.44	0.51	0.19	0.22	A,B,B1	1,2
PV inverter cost (USD/W$_{e(AC)}$)	0.14	0.09	0.06	0.13	0.15	0.06	0.07	A,B,B1	1,2
Balance Of Plant cost (USD/W$_{e(AC)}$)	0.43	0.31	0.22	0.41	0.46	0.21	0.23	A,B,B1	1,2
Installation cost (USD/W$_{e(AC)}$)	0.35	0.25	0.18	0.33	0.37	0.17	0.19	A,B,B1	1,2
Fixed O&M (USD/MW$_e$/year)	13,750	11,800	10,000	13,300	14,200	9,700	10,300	A,B1	1,2
Variable O&M (USD/MWh)	0	0	0	0	0	0	0		
Start-up costs (USD/MW$_e$/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Global horizontal irradiance (kWh/m^2/y)	1,643	1,643	1,643	1,194	2,190	1,194	2,190	F	4,7
DC/AC sizing factor (W$_p$/W)	1.30	1.30	1.30	1.25	1.5	1.25	1.5	C	8
Transposition Factor	1.01	1.01	1.01	1	1.02	1	1.02		7
Performance ratio	0.865	0.87	0.92	0.82	0.87	0.85	0.92	E, H	2,3,5
PV module conversion efficiency (%)	21.5	23	25					D	2,3
Inverter lifetime (years)	12.5	15	15						2
Average annual degradation of full-load hours (%)	0.4	0.3	0.3					I	6
Financial data - per DC peak capacity									
Nominal investment (million USD/MW$_p$)	1.06	0.74	0.50	1.04	1.00	0.49	0.47	A,B,B1,C	1,2
PV module cost (USD/W$_{p(DC)}$)	0.36	0.24	0.15	0.35	0.34	0.15	0.15	A,B,B1	1,2
PV inverter cost (USD/W$_{p(DC)}$)	0.11	0.07	0.05	0.11	0.10	0.04	0.04	A,B,B1	1,2
Balance Of Plant cost (USD/W$_{p(DC)}$)	0.33	0.24	0.17	0.33	0.31	0.17	0.16	A,B,B1	1,2
Installation cost (USD/W$_{p(DC)}$)	0.27	0.19	0.13	0.26	0.25	0.13	0.13	A,B,B1	1,2
Fixed O&M (USD/MW$_{p(DC)}$/year)	10,577	9,077	7,692	8,867	11,360	6,467	8,240	A,B1	1,2
Variable O&M (USD/MWh$_{p(DC)}$)	0	0	0	0	0	0	0		

Notes

- A Overall cost estimation based on utility-scale datasheet, considering that floating PV plants are expected ca. 25 % more expensive than ground-mounted utility-scale plants, with the mark-up apparent in installation and other cost incl. balance of plant
- B Cost are projected with a learning rate approach assuming a 24 % learning rate for modules and inverters based on Fraunhofer, and 20% as per other components based on IEA, and 10 % for O&M, including capacity projections of the IEA's World Energy Outlook 2023, with Announced Pledges for the central values and Stated Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.
- B1 Uncertainty in the short term assumes the same spread as the long-term uncertainty
- C The typical sizing factor is based on operational projects (both floating and ground-mounted plants), expressed in their average for the central value and minimum and maximum for the lower and higher bound.
- D 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.
- E 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 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 MPPT efficiency and is averaged over typical load levels.

F The central value is the average annual solar irradiance received on a horizontal surface in Colombia. The areas receiving the highest levels of global solar radiation, exceeding the San Andrés and Providencia islands, large parts of the Caribbean region, and the inter-Andean valley. Minimum and maximum value correspond to The Global Solar Atlas's s Global Horizontal Irradiation distribution for Colombia

G The capacity range equals the size for small-scale ground-mounted PV plants for easier comparison between the datasheets. As of 2024, there are no floating PV plants of that size commissioned in Colombia and global experience on this scale is sparse.

H 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.

I Annual degradation of full load hours is not included in the above figures of full-load hours and capacity factors

J The full-load hours are a result of global horizontal radiation, transposition factor and performance ratio.

References

[1] UPME, “Incentivos tributarios para las FNCER” database, 2024

[2] Danish Energy Agency, Ea Energy Analyses, Technology Data for the Indonesian Power Sector, 2024

[3] Fraunhofer, 2024, Photovoltaics report 2024

[4] Emergente Energía Sostenible - Radiation Map for Colombia

[5] Discussion with Technology Catalogue stakeholder group

[6] Danish Energy Agency, Technology Catalogue for generation of electricity and District Heating, 2024

[7] World Bank, Global Solar Atlas

[8] Bloomberg New Energy Finance, Power Asset Database

3. Wind Turbines - Onshore

3.1. 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 18 offers a comprehensive depiction of the turbine technology and electrical system, illustrating the example of a geared turbine.

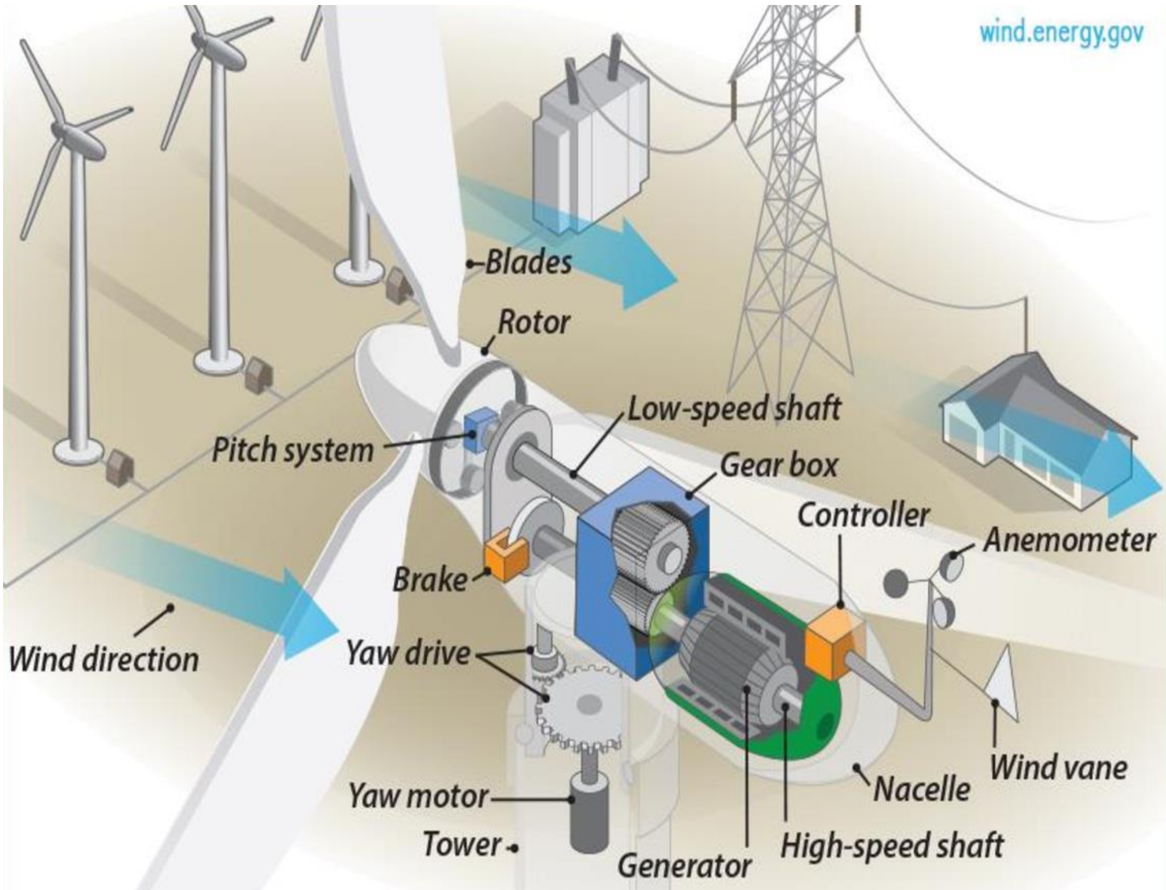

Figure 18. General turbine technology and electrical system [1].

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/m^3), typically around 1.225 kg/m^3 at sea level under standard conditions.
- **A** is the swept area of the wind turbine rotor (in square meters, m^2), 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 19, 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 19 with a dashed-red curve. This approach maximizes power output while ensuring turbine safety [30].

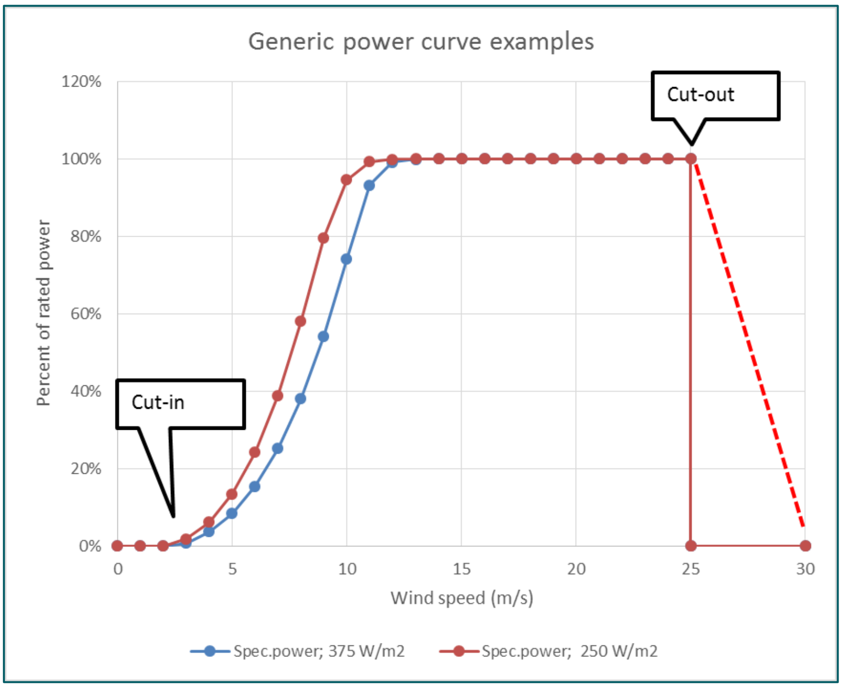

Figure 19. Turbine power curves (Information's from expert workshop held by the Danish Energy Agency). Specific power values refer to e.g. 3 MW with 124m rotor diameter (250 W/m²) and 3 MW with 101 m rotor diameter (375 W/m²).

3.1.1. Capacity factors and wind speed

The annual energy yield of a wind turbine is significantly influenced by the average wind speed at its location. This average wind speed is contingent upon various factors such as geographical positioning, the turbine's hub height, and the surface roughness of the area. Additionally, localized obstructions like forests, buildings (especially for smaller turbines), hedges, and the wake effects from neighbouring turbines all contribute to reductions in wind speed. Lastly the turbine design plays a considerable role in how many full load hours to expect at a given site. Part of the turbine design is expressed as specific power in W/m², which is the ration between the generator capacity of a turbine and the swept area of the rotor, i.e. the circular area between the rotor diameter that the turbine uses to convert the wind resource into power.

Modern onshore turbines commonly found in Denmark exhibit capacity factors within the range of 35 %, equating to approximately 3100 annual full load hours. Graphical representations outlining typical duration curves are provided in the Figure 20.

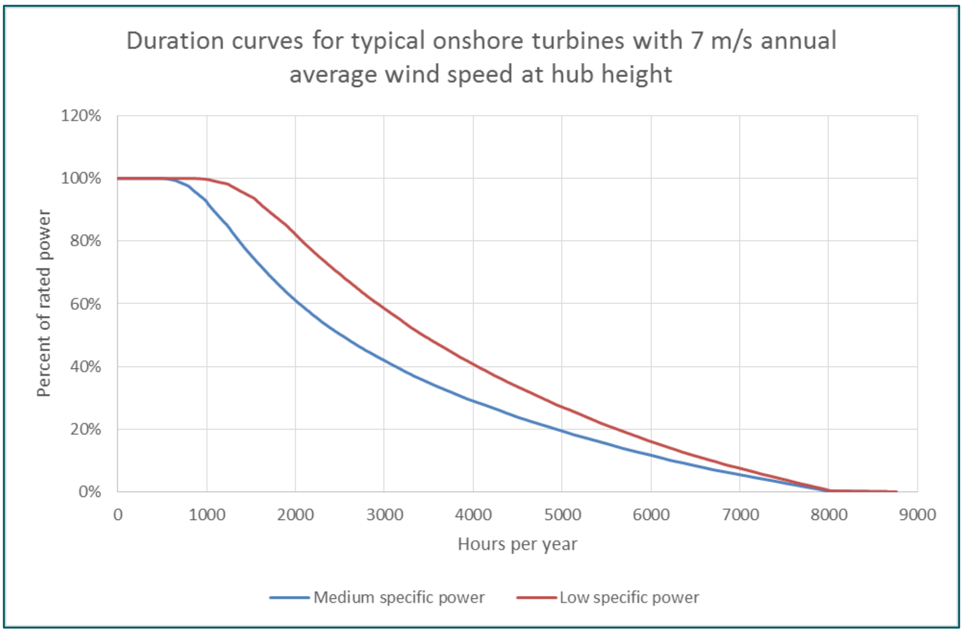

Figure 20. Duration curves based on the V117 3.3 MW (307 W/m²) and V126 3.3 MW (265 W/m²) onshore wind turbines located in Denmark [2]. Empirical data for Colombia is missing due to no representative operational figures as of 2024.

Surface roughness, a critical factor, is commonly categorized using Table 3-1. 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 3-1 below. The wind speed variation with height is governed by the roughness length.

Table 3-1. 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

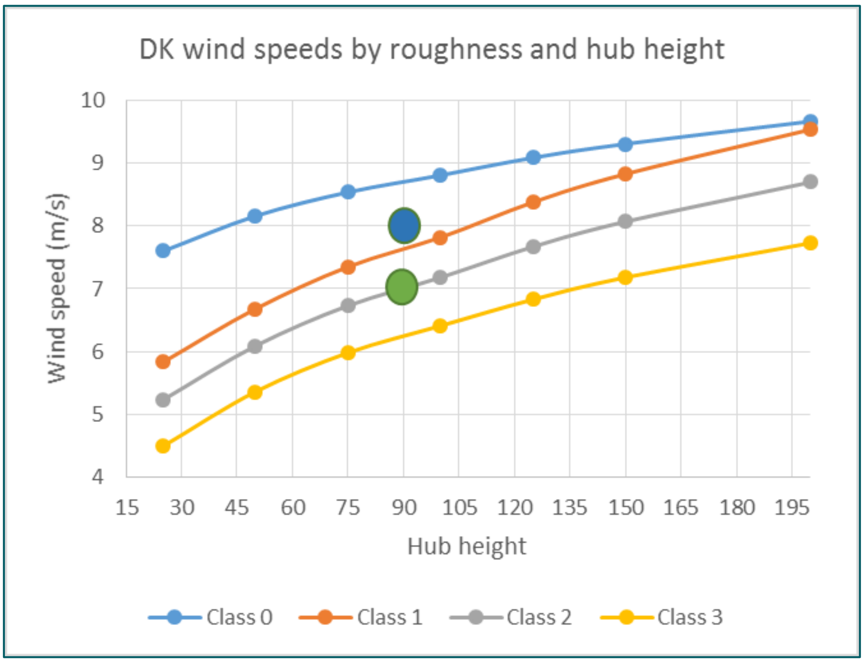

Figure 21. Annual average wind speeds as a function of hub height and roughness class for flat terrain in Denmark. The green dot represents a typical modern inland site; the blue dot represents a typical coastal site [30].

Figure 21 is a depiction of average wind speeds categorized by hub height and surface roughness for flat terrain. Presently, onshore wind turbines installed in Europe commonly feature hub heights ranging between 85-90 m. For the projects to be installed in La Guajira, heights are close to 121 m. For a standard inland site in Europe, the average wind speed hovers around 7 m/s, whereas on a typical coastal site, the average wind speed elevates to approximately 8 m/s. Notably, an incremental rise in the average wind speed from 7 to 8 m/s yields a substantial 25 % increase in annual energy production. Although there are no published studies about typical load duration curves for Colombia, similar wind speeds as in the image above can be found in parts of the Departments of Cesar and La Guajira. For higher average wind speeds such as the case of the northern part of La Guajira, the duration curves will be shifted to the right with a longer range of 100 % output of the turbines, as the turbines will be producing for a longer time under nominal load of the turbine power curve.

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 22. The examples in Figure 22 are for:

- 3 MW turbines with 90 m rotor diameter, with specific power of 472 W/m^2 (called “high specific power”);
- 3.3 MW turbines with 112 m with specific power of 335 W/m^2 (called “medium specific power”);
- 3.3 MW turbines with 126 m rotor diameters, with specific power of 265 W/m^2 (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 22 [30].

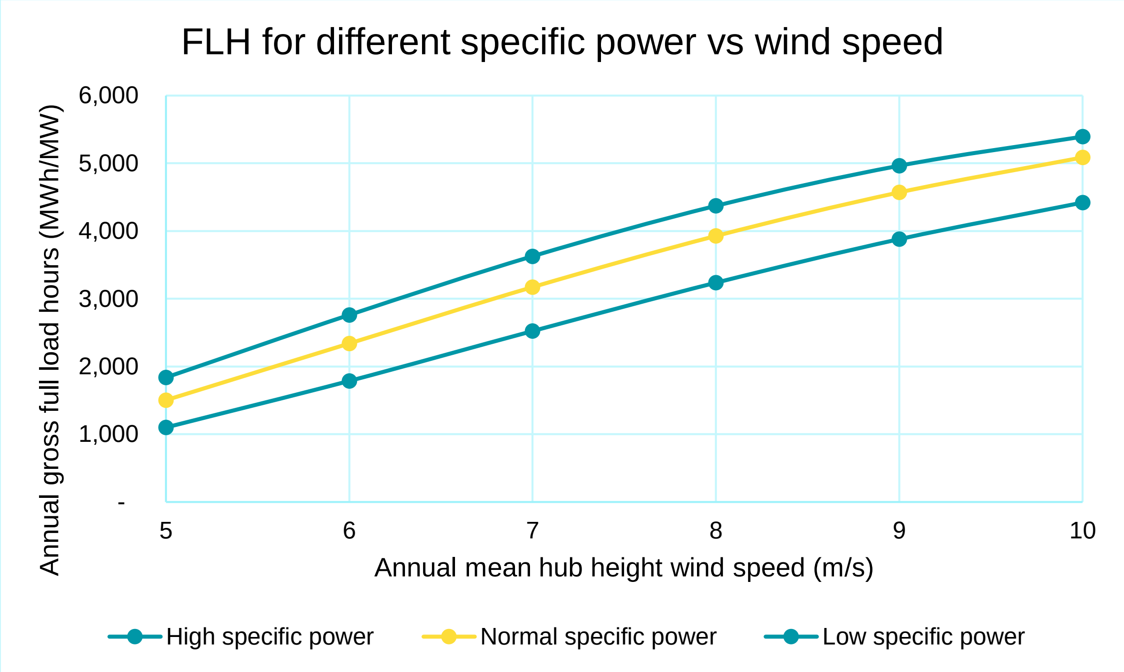

Figure 22. Annual full load hours as a function of mean wind speed at hub height [30].

3.1.2. Wind Power Potential in Colombia

The wind resource map for Colombia in Figure 23, effectively highlights the regional disparities in wind potential. Notably, the northern coast of the Country, particularly in La Guajira, where the prevailing wind directions from the east and east-northeast trade winds, exhibit the highest wind resources (9-10 m/s) [3]. The rest of Colombia have significantly lower wind speeds, due to the topographic sheltering of the Andes Mountain range.

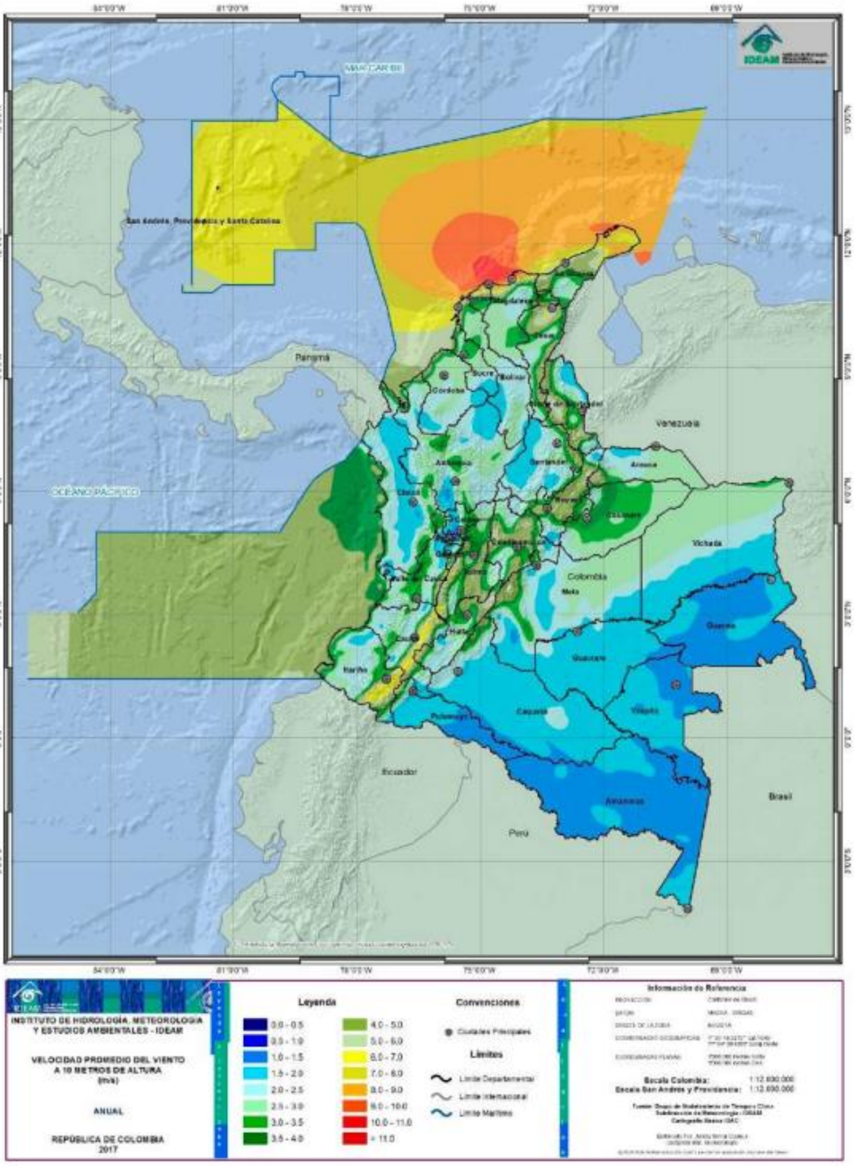

Figure 23. Wind Atlas for Colombia [3].

Taking this into account, onshore wind harnessing considering more than single sites is only possible at a large scale in La Guajira and Atlántico Departments. La Guajira has by far the largest wind power potential, but it is also home to the Wayuu and other indigenous communities, which pose a challenge for project development in relation to prolonged and complex negotiations.

To account for this situation, researchers from Energética 2030 analysed the financial and environmental performance of wind parks. The most attractive projects for developers are expected to be the most profitable and those that require the least environmental management. Hence, environmental criticalities and the LCOE of projects were classified into 3 groups: low, medium, and high. The highest suitability is associated with a score of 1, and the poorest is associated with scores of 9 (see Figure 24). Current projects under development with a capacity of 20 MW or higher are shown overlayed.

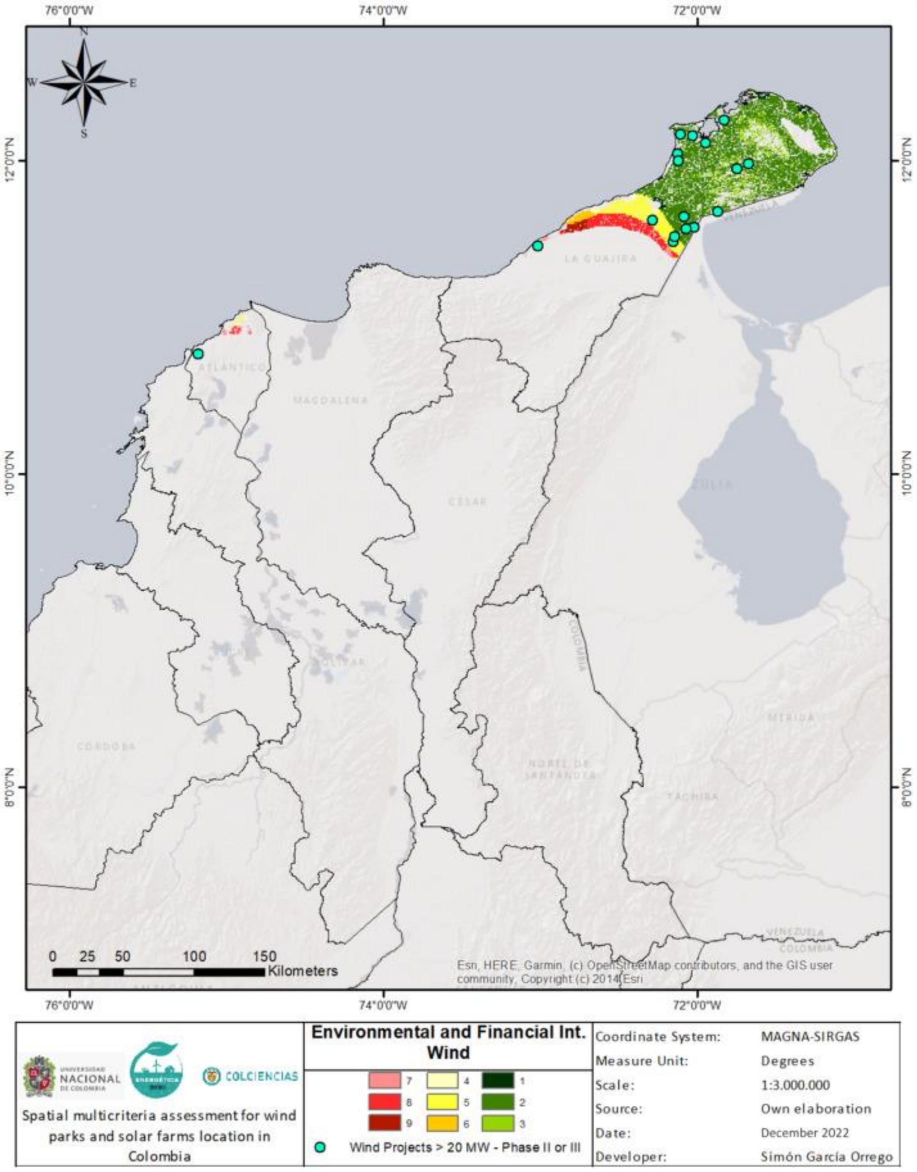

Figure 24. Integration of the financial performance and environmental criticalities for wind farms in Colombia [4].

As shown in Figure 24, exploitable wind resources are concentrated primarily in the northern part of the Caribbean region, particularly in the municipalities of Uribia, Maicao, and Manaure in the department of La Guajira, as well as Puerto Colombia, Barranquilla, Tubará, and Galapa in the department of Atlántico along the northern coast. Despite the limited availability of wind in other regions of the country, wind energy projects face significant restrictions due to environmental factors. Safety setbacks from populated areas, roads, and rivers considerably reduce the land available for wind energy development. Nevertheless, if all potential wind farms were constructed, Colombia could add approximately 35 GW of installed capacity to its energy grid and generate 176 TWh annually by leveraging this non-conventional energy source [*4].*

3.2. Input

A wind turbine harnesses wind energy.

3.3. Output

Electricity.

3.4. Typical capacities and development statistics

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 25, 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.

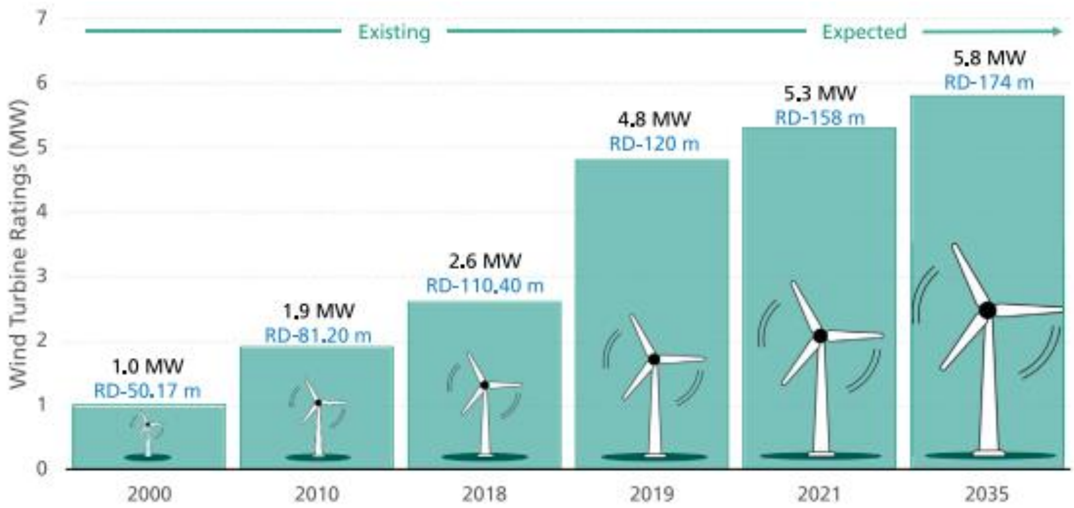

Figure 25. Increasing yields of onshore wind turbines [5].

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 174 meters 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.

On average, capacity factors for onshore turbines installed in Denmark before 2000 lingered below 25 % (equivalent to approximately 2200 full load hours). In contrast, onshore turbines installed post-2010 exhibit average capacity factors typically ranging from 30 % to 35 % (equating to 2,600-3,100 full load hours). This trend towards larger rotor sizes and diminished specific power is not exclusive to Denmark but is evident globally [31].

3.5. Space requirement

Wind farms have two types of land impacts: total land area and direct impact area. Large wind facilities use between 10 and 50 hectares per megawatt of output, mostly for spacing between turbines. On average, wind farms require 24 hectares per megawatt, depending on the measurement and consideration what area the wind farm consists of. This is because despite high land demands, wind farms often coexist with agricultural activities, although construction and buildings near turbines are restricted [6]. When used together with agriculture, the area in between turbines can fully be used apart from marginal deductions of maintenance access roads.

3.6. 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.

3.7. Regulation ability and other power system services

Wind-generated electricity is inherently variable due to its reliance on prevailing wind conditions. Consequently, the 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's adequate wind resource available (speed higher than 4-6 m/s but lower than 25-30 m/s), wind turbines can consistently offer downward regulation and, in many instances, upward 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 [7]. Wind turbine generation can swiftly adjust down for grid balancing purposes. The start-up time from no production to full operation depends on the prevailing wind conditions.

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 energy resources along the Caribbean Coast could effectively complement the country's hydropower generation both during the dry seasons of the annual weather cycle and during ENSO events. This relationship is characterized by an inverse correlation between the water supply to the national power system and the availability of non-conventional renewable energies like solar and wind; as water levels drop, solar and wind resources tend to increase, and vice versa. The synergy between these two specific resources is not constant but varies throughout the year and in response to changes in ENSO conditions [8-9].

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

In Colombia, the introduction of wind systems forces a modernization of XM, the market operator, as it needs to activate the dispatch power with reduced planning horizon to decrease the real time regulating burden. Especially if it is planned as a backup to the predictable inefficiency of hydroelectric plants during El Niño, the warm phase of ENSO. Various European countries have introduced market dispatch as part of the European power market that operate on an hour-ahead dispatch plan to manage the power imbalances in a highly wind power integrated power system, supplemented by intra-day market and balancing market to account for irregulations on a time-scale below an hour

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].

3.8. Advantages/disadvantages

3.8.1. 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.

3.8.2. Disadvantages

- 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.

3.9. 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.

Noise can be dealt with in the planning phase, if relevant for a given wind farm. Allowable sound emission levels are calculated based on allowable sound pressure levels at neighbours. In some cases, it is necessary to operate turbines at reduced rotational speed and/or less aggressive pitch setting to meet the noise requirements. Noise reduced operation may cause a reduction in annual energy production of 5-10 % due to increased manual shutdown despite ability to operate, based on Danish experience where noise reduced operation has been in place for some relevant wind farms. Despite meeting the required noise emission levels turbines sometimes give rise to noise complaints from neighbours. In 2013, the Danish Environmental Agency investigated how wind turbines and especially noise from wind turbines influence human health. The report presented several findings [12]:

- 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 [13].

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 [14].

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, 15, 16]. The energy payback time of an onshore wind turbine is in several studies calculated to be in the order of 3-9 months [17, 18].

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

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

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 [30], 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.

3.10. Research and development perspectives

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].

3.10.1. Research Perspectives in Colombia

Researchers from Energética 2030 engaged in design and construct a small wind turbine, for rural and isolated areas. The turbine features a horizontal axis, fixed-pitch rotor, and passive orientation system. It generates power in winds between 2.5 m/s and 25 m/s, with a power coefficient of 0.43. This innovative turbine uses composite materials to improve efficiency and adaptability, and is expected to enhance distributed energy generation in Colombia [19].

Parsons Kinetics is a Colombian company that develops small scale wind turbines as depicted in Figure 26, the bio-inspired wind turbine achieves high efficiency at low wind speeds of 3.5 m/s, making it suitable for many geographical areas. Unlike large commercial turbines that require over 10 m/s, this design offers near-ideal wind utilization with a power coefficient (C_p) close to 60 %. Additionally, it reduces energy costs by 55 % per kWh compared to other turbines in this capacity segment, providing a competitive solution for green energy generation [21].

Figure 26. Parsons Kinetics's Small Scale Turbine [21].

3.10.2. Social Research for project acceptance

The primary social difficulties for wind project development in La Guajira, revolve around high social conflict rooted in concerns about equity and justice. La Guajira is home to the Wayuu, the most populous indigenous group in Colombia, which is organized into about 30 clans, each comprising numerous scattered communities. Historically, La Guajira's natural resources such as coal, natural gas, and salt shaped a primarily extractive regional economy heavily dependent on mining. Paradoxically, the abundance of natural resources and their economic potential has not translated into greater well-being for its inhabitants, which is reflected in the high poverty rates in the region, which is higher compared to other departments [22].

Such issues have led to various blockages and protests, causing delays in project advancement. While there is not an outright opposition to the projects themselves, the primary contention arises from the way these projects are introduced and managed within the communities, particularly through the prior consultation processes, and through the final decision-making process. This requires project developers to focus resources and energy in the management of social and cultural impacts, fair distribution of benefits, land use conflicts, and the legitimacy of consultation processes, and has caused very extensive delays in project execution [22].

3.11. Examples of market standard technology

Current Onshore Wind Turbine Offerings in Denmark:

At present, the Danish onshore wind market predominantly features commercially approved turbines offered by Siemens Gamesa and Vestas. These turbines typically encompass rated power within the 4.5–7 MW range, accompanied by rotor diameters spanning 100 to 150 m. However, hub heights are frequently constrained, primarily due to visual impact concerns and neighbouring distance stipulations. There is no such regulation in Colombia. Current Colombian projects that have secured financing are on average developed with turbines averaging 4.3 MW and lying between 2–5.6 MW [29].

Notably, hub heights beyond 125 meters have not been observed outside of dedicated test sites, as existing projects navigate limitations imposed by visual impact considerations and prescribed distance requirements from neighbouring areas.

3.12. Prediction of performance and cost

Table 3-2 compares different investment cost estimates from various sources. The data focuses on utility-scale onshore wind.

Table 3-2. Investment cost comparison across regions for utility-scale onshore wind projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	1.37	2024
	National data	
Stakeholder group discussions	1.1 - 1.5	2024
	International data	
Technology Catalogue Denmark (2023)	1.28	2022
Technology Catalogue Indonesia (2024)	1.85	2023
Technology Catalogue Vietnam (2023)	1.82	2022
IEA GEC Model, Brazil region (2021)	1.18	2021
IRENA (LATAM excl. Brazil)	1.47	2023
NREL ATB (2023)	1.36 - 2.00	2023
Lazard, LCoE, 2024	N/A	

Onshore wind power development in Colombia includes a variety of capacity sizes of wind farms with some, but minor economy of scale in between them. Given the stage of development with current generation utility-scale turbines, there is agreement on cost figures among the industry, but little experienced on realized figures based on fully developed and commissioned plants. While several sites have obtained permits or have secured financing followed by the construction phase, many farms are yet to be commissioned.

O&M cost are derived from investment cost (CAPEX) by assuming 2.5 % per CAPEX per year.

In this catalogue, the prediction of cost for small-scale turbines and related wind farms is derived by economy of scale deriving from utility-scale farms, as few robust inputs have been available for small-scale turbines. The comparison is done by using the typical turbine sizes of each datasheet and convert the investment cost with a proportionality factor of 0.85. Although the engineering slightly differs for typical turbine models as presented above, the same proportionality has been observed for other technologies in this catalogue as well.

3.13. 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. Domestic wind turbines, classified as micro or small wind turbines with capacities up to 25 kW, have specific regulations in Denmark. They're typically situated in close proximity to buildings, within 20 m [17], and are subject to similar noise requirements as larger turbines [17].

3.14. References

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3.15. Datasheet

3.15.1. Utility scale

Technology	Wind power - Onshore								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MW_e)	4.5	6.2	7.0	2.0	5.6	5.5	9.0		2,3,9
Generating capacity for total power plant (MW_e)	100	100	100	10	300	10	300		9,11
Forced outage (%)	2.5	2	2						3
Planned outage (weeks/year)	0.16	0.16	0.16						3
Technical lifetime (years)	27	30	30	25	35	25	40		2,3
Construction time (years)	1.5	1.5	1.5						2
Space requirement (1000 m^2/MW_e)	14	14	14						3
Average annual full-load hours ($MWhe/MW_e$)	3,066	3,300	3,700						10
Additional data for non-thermal plants									
Capacity factor (%), theoretical	37	39	44					E	
Capacity factor (%), incl. outages	35	38	42	24	46	24	46	E	8
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/GJ of fuel input)	0	0	0	0	0	0	0		
SO_2 (g/GJ of fuel input)	0	0	0	0	0	0	0		
NO_X (g/GJ of fuel input)	0	0	0	0	0	0	0		
CH_4 (g/GJ of fuel input)	0	0	0	0	0	0	0		
N_2O (g/GJ of fuel input)	0	0	0	0	0	0	0		
Financial data									
Specific investment, total system (MUSD/MW)	1.37	1.30	1.23	1.10	1.50	1.20	1.26	A,D	1,2,3,4,5,6,9
- of which equipment	0.96	0.91	0.86	0.77	1.05	0.84	0.89	B,D	2,3,4,9
- of which installation	0.41	0.39	0.37	0.33	0.45	0.36	0.38	B,D	2,3,4,9
Fixed O&M (USD/MW_e/year)	27,400	26,000	24,600	22,000	30,000	24,000	25,500	C,D	1,2,3,4,5,6,9
Variable O&M (USD/MWh)	0	0	0	0	0	0	0		
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		
Technology-specific data									
Hub Height (m)	85	130	150	85	120	85	150		2,3,9

Rotor Diameter (m)	135	162	190						9
Specific Power (W/m²)	314	301	247						2,3,9

Notes

- A Given the early stage onshore wind market in Colombia, the values are an aggregated assessment on literature supplemented by data aggregation of data of the register of UPME
- B Equipment: Cost of turbines including transportation. Installation: Electrical infrastructure of turbine, civil works, grid connection, planning and management. The split of cost may vary considerably from project to project. Central value assumes a 70/30 distribution.
- C O&M corresponding to 2 % 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 accrued under fixed for simplicity
- D Cost are projected with a learning rate approach assuming a 5% learning rate based on [1] and [2], and 6 % learning rate for OPEX based on [2]. Learning is linked to the capacity projections of the IEA's World Energy Outlook 2023, with Announced Pledges for the central values and Stated Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.
- E This data is from Jepirachi, the only project in Colombia that went in commercial operation
- F The average project size is done in discussion with stakeholders, and is aligned with the average size of Colombian projects for which financing is secured. The uncertainty range shows the wide spread of these projects.

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3.15.2. Small scale

Technology	**Wind power - Small onshore wind turbines < 1 MW**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MW_e)	0.01	0.01	0.01	0.005	0.025	0.005	0.025		1,2
Generating capacity for total power plant (MW_e)	1	5	10	1	10	1	10		3
Forced outage (%)	2	1.5	1.5	0	8	0	8		1,2,3
Planned outage (weeks/year)	0.16	0.16	0.16						1,2,3
Technical lifetime (years)	27	30	30	25	35	25	40		1,2
Construction time (years)	1	1	1						1,2,3
Space requirement (1000 m^2/MW_e)	11	11	11						2,3
Additional data for non-thermal plants									
Capacity factor (%), theoretical	26	26	26	20	33	20	33		3
Capacity factor (%), incl. outages	25	25	25	20	30	20	30		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/GJ of fuel input)	0	0	0	0	0	0	0		
SO_2 (g/GJ of fuel input)	0	0	0	0	0	0	0		
NO_X (g/GJ of fuel input)	0	0	0	0	0	0	0		
CH_4 (g/GJ of fuel input)	0	0	0	0	0	0	0		
N_2O (g/GJ of fuel input)	0	0	0	0	0	0	0		
Financial data									
Specific investment, total system (million USD/MW)	3.4	3.3	3.1	3.0	3.8	3.0	3.2	A,D	1
- of which equipment	2.4	2.3	2.2	2.1	2.7	2.1	2.2	B,D	1
- of which installation	1.0	1.0	0.9	0.9	1.1	0.9	0.9	B,D	1
Fixed O&M (USD/MW_e/year)	68,500	64,300	60,200	51,375	85,625	45,150	75,250	C,D	1,2
Variable O&M (USD/MWh)	0	0	0	0	0	0	0		
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		

Notes

A Values are in line with [1] and [2], expressing the small-scale wind turbines with a 0.8 proportionality factor compared to the large-scale turbines. The cost varies significantly based on different designs and types of small-scale wind

B Uncertainty of investment cost for the base year is assumed to scale with the proportionality factor depending on capacity sizes, with lower cost due to higher capacity rating employed

C The fixed O&M corresponds to 2.7 % of CAPEX/year given the same proportionality factor between large-scale and small-scale wind. Uncertainty values assumed to be +/-25 %

D Cost are projected with a learning rate approach assuming a 5% learning rate based on [1] and [2], and 6% learning rate for OPEX based on [2]. Learning is linked to the capacity projections of the IEA's World Energy Outlook 2023, with Announced Pledges for the central values and Stated Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.

E A proportionality factor α of 0.85 is used to convert the presented cost from the utility-scale datasheet to small-scale, in accordance with economy of scale found in literature and in line with input given by stakeholders

F Uncertainty for O&M is based on a +/- 25 % spread in line with [2]

References

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4. Wind Turbines - Offshore

4.1. Brief technology description

The basic operating principles of offshore wind turbines are the same as for onshore turbines, although modifications are required to make the turbines suitable for deployment offshore. For a detailed technical description, see the previous chapter on wind turbines onshore. However, there are specific issues for offshore wind turbines, presented as follows:

The corrosive offshore environment resulting from the high levels of salt and moisture in the air leads to additional requirements for electrical and mechanical components. Since the world's first offshore wind project at Vindeby in Denmark, many offshore turbines have been equipped with air conditioning systems to protect the sensitive electronics inside the units, and with North Sea-grade protective paint to protect the external steel structures [28].

Foundations for offshore turbines are subject to more complex load conditions than onshore foundations and the design and concept of offshore foundations are therefore very different from onshore foundations. They must be designed to survive the harsh marine environment and the impact of large waves and tropical storms, which contribute to them being costlier than their onshore counterparts.

Until now, offshore wind farms have been installed on four different types of foundation: monopile, gravity, jacket, and tripod structures. Today, monopiles and jackets are the most common foundation types and are still under development. The choice of which foundation type to use depends on the local sea-bed conditions and the water depth (see Figure 27). Nowadays, fixed bottom foundations are investigated to be deployed up to 70 m with the latest technology. Suction bucket foundations have been investigated for different applications. Suction bucket foundations are mainly suitable when the seabed is sand but may have the advantage of lower decommissioning cost as well as of noiseless installation compared to monopiles, but there is limited experience in deployment, and consequentially bigger risk. Suction buckets can be used as "anchors" for jacket foundations at large water depths, where the suction effect is easier to attain due to the higher water pressure on the buckets. Technological innovations such as floating substructures may have the potential to reduce the overall cost in the future. Floating substructures can be designed to be well-suited for large serial production, and they are the only solution for deep waters, in which monopiles and jackets come to their limits [28].

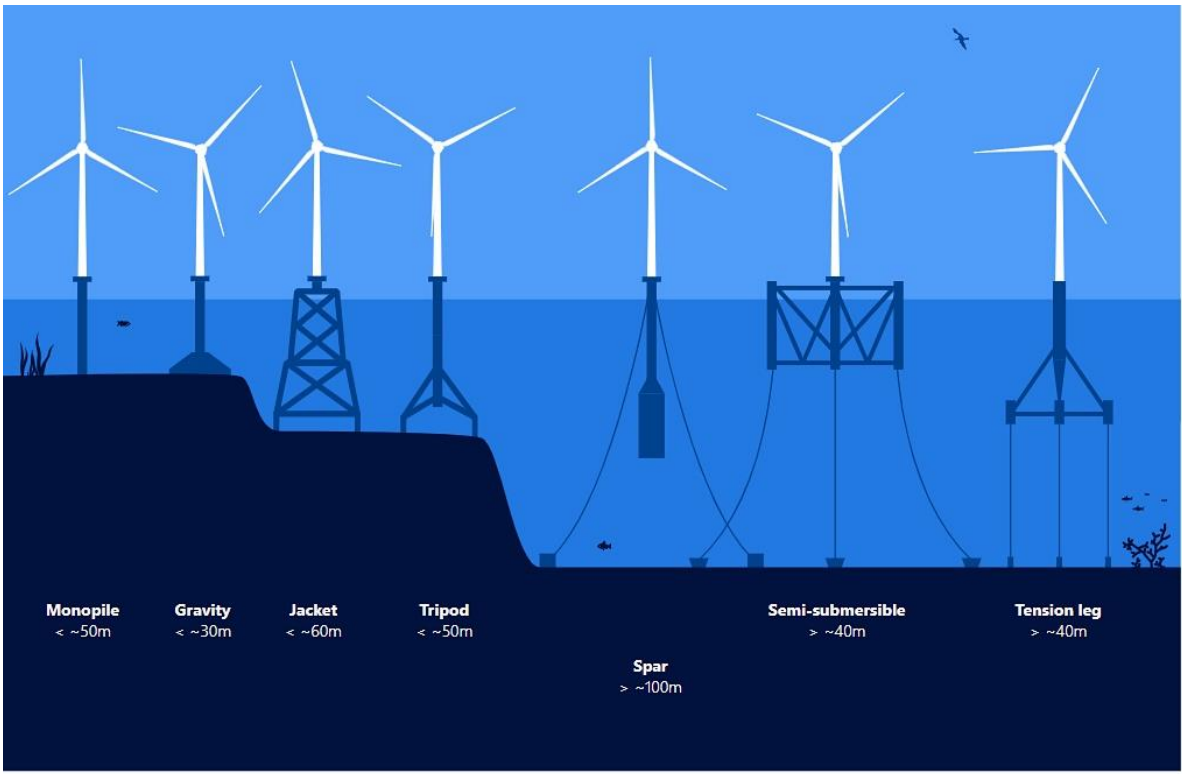

Figure 27. Types of offshore wind foundations [1].

Offshore wind farms are typically built with large turbines in considerable numbers. The most recent offshore wind farms developed in Denmark have capacities of 800-1,000 MW as agreed in the Energy agreement from 2018. The latest concluded Danish tender is Thor, for which the utility and offshore wind developer RWE from Germany obtained the rights to develop the project further. This will be followed by Hesselø that is expected to have 1,000 MW of capacity plus up to 200 MW capacity behind the meter for potential storage or Power to X applications. The Danish parliament agreed in 2021 on further capacities of 2 GW with the aim of being erected before 2030. With the energy hubs (energy islands) in the North Sea and Baltic Sea being added onto this, expectedly supplying both Denmark and neighbouring countries with power, the groundwork towards a more integrated supply system offshore is being laid. In UK, Netherlands and German waters, offshore wind farms of several thousand MW are being developed currently. It is likely that this technology will also be deployed in developing nations in the following years.

Nowadays, offshore wind turbines in Europe have built-in transformers delivering 66 kV to the array cable system in the wind farm as a standard size. Solutions of 132 kV are being investigated. The higher voltage level will reduce specific cable costs and losses and the total lifecycle costs and thereby reduce the cost of energy. In traditional offshore wind farms, the array cables are connected to a transformer station in the wind farm. Here, the voltage is transformed to 150 kV, 220 kV or 320 kV for export to the onshore grid. With higher capacities further offshore, HVDC solutions are becoming increasingly important.

The offshore wind resource increases with the distance to the shore [2] and as a result wind farms far from shore will generally have higher capacity factors than Nearshore wind farms. However, due to the simplified grid arrangement with no offshore substation as well as shallow waters and shorter distances to service hubs, nearshore wind farms have lower cost levels for both investment and O&M.

4.1.1. Colombia Offshore Wind Potential

As illustrated in Figure 28, Colombia's Caribbean coastline has substantial, energetic offshore wind resources with a technical potential estimated at 109 GW. Wind speeds, especially in the La Guajira region, consistently exceed 10 meters per second with estimated net capacity factors for representative projects – the amount of electricity they could produce compared to their theoretical full potential – approaching 70 %, among the highest globally [3].

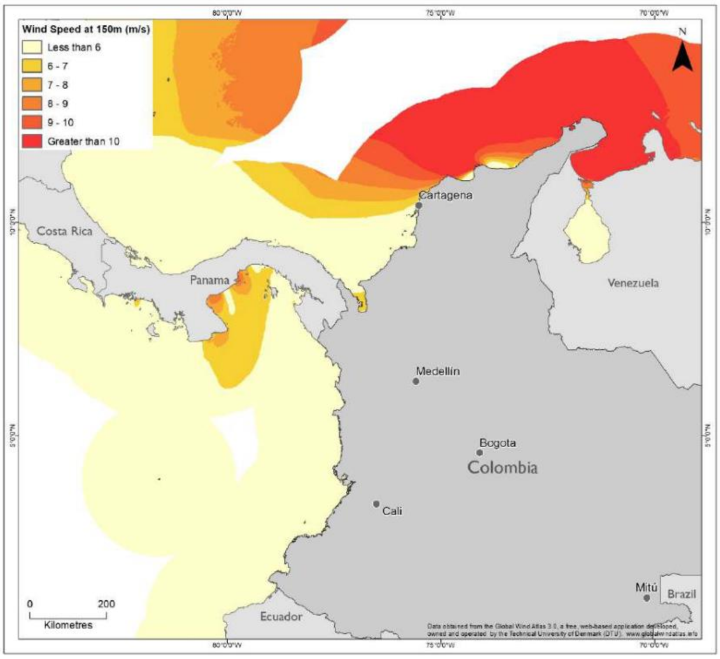

Figure 28. Colombia offshore wind speeds [3].

The Colombian coastline features numerous protected areas, critical habitats, and environmental sensitivities. The waters are used by commercial and artisanal fisheries, and the onshore lands hold significance for indigenous communities. Additionally, there are areas designated for hydrocarbon activities and heavily trafficked shipping routes. To build the offshore roadmap, the Ministry of Mines and Energy utilized existing spatial data to further characterize Colombia’s offshore wind resources and potential constraints to development. It evaluated a wide range of environmental, social, and technical issues to identify technically attractive initial exploration areas that, based on the available data, are likely to have lower negative impacts associated with development. Considering environmental, social, and technical constraints, the potential development is estimated at about 50 GW, equivalent to 2.8 times the total existing generation capacity in the country [3].

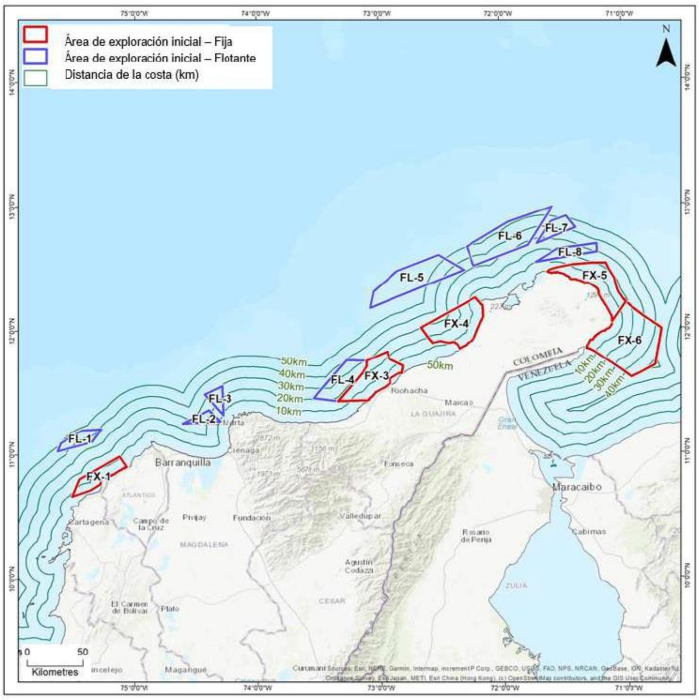

Figure 29. Initial exploration areas for offshore wind in Colombia [3].

Of the 13 initial exploration areas shown in Figure 29, five are located in shallow waters (less than 70 meters), making them suitable for fixed foundations. These areas represent over 27 GW of potential across 6,800 km². The remaining eight areas are in deeper waters (more than 70 meters), ideal for floating foundation offshore wind projects, with a potential of 21 GW across 5,400 km². Table 4-1 shows the reference capacity values for the major Colombian offshore areas.

Table 4-1. Offshore wind development potential in the initial exploration areas [3].

Site ID	Area (km²)	Nominal Reference Capacity (MW)
FX-1	550	2,200
FX-3	1,150	4,600
FX-4	1,400	5,600
FX-5	1,200	4,800
FX-6	2,500	10,000
Fixed Foundation Wind Potential	6,800	27,200
FL-1	350	1,400
FL-2	200	800
FL-3	200	800
FL-4	800	3,200
FL-5	1,550	6,200
FL-6	1,550	6,200
FL-7	350	1,400
FL-8	400	1,600

Floating Foundation Wind Potential	5,400	21,600
Reference Capacity Potential (MW)		~50,000

The Caribbean Sea experiences extreme weather, with winds exceeding 120 km/h (over 33 m/s) during the June to November hurricane season and cold fronts from higher latitudes between December and March. These weather events cause significant negative socioeconomic and environmental impacts. Cold fronts in the Colombian Caribbean are particularly impactful, damaging coastal infrastructure and altering ocean-atmospheric conditions. These changes include pressure gradients, temperature drops, increased wind intensity, cloud cover, and wave height. On average, six cold fronts occur annually, most frequently in January and February (64% of occurrences) [4].

The hurricane season peaks from mid-August to late October, with severe hurricanes possible at any time during these months. Local oceanographic features influence storm severity, leading to large spatial variations in extreme climate conditions. Most storms occur or persist in the northern Caribbean basin, where warm ocean temperatures fuel hurricanes. Conversely, coastal upwelling off northern South America brings cold surface waters that inhibit storm formation near the shore. Nonetheless, severe weather from tropical storms has impacted the offshore basins of Colombia and Venezuela in the past [4].

4.2. Input

Input is wind.

As depicted in Figure 30, the minimum required wind speed is 3-5 m/s, also named “cut in” wind speed. The rated power generation reached around 12 m/s wind speed. The cut-out or transition to reduced power operation at wind speed: 25-30 m/s. Most turbine manufacturers apply a soft cut-out for high wind speeds (in resulting in a final cut-out wind speed around 30 m/s [5, 6].

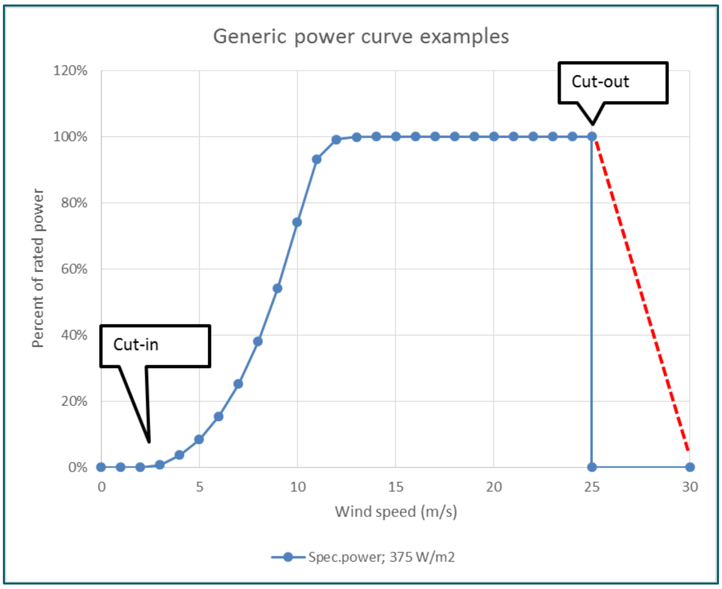

Figure 30. Power curve example. Soft cut-out is indicated with dashed red curve. Specific power values refer to e.g. 7 MW with 154 m rotor diameter [6].

4.3. Output

The output is electricity.

Modern commissioned offshore turbines located in the North Sea have capacity factors of the order of 50 %, corresponding to 4,400 annual full load hours, in waters with an average annual wind speed of 10 m/s. A typical duration curve for a wind farm in the North Sea is presented in Figure 31 below, and can be used as reference for sites off the Caribbean coast with similar wind speeds. Due to the relation between wind resource and power output, sites with higher average annual wind speeds will see power curves shifted to the right, and vice versa.

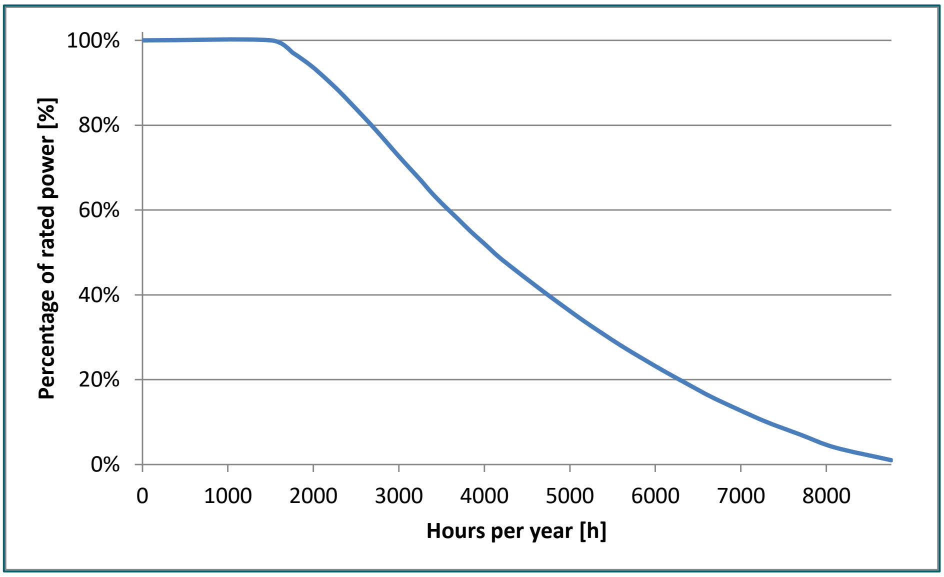

Figure 31. Example of a duration curve for a North Sea offshore wind farm [23].

4.4. Typical capacities and development statistics

As depicted in Figure 32 and Figure 33, 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 [7]. 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.

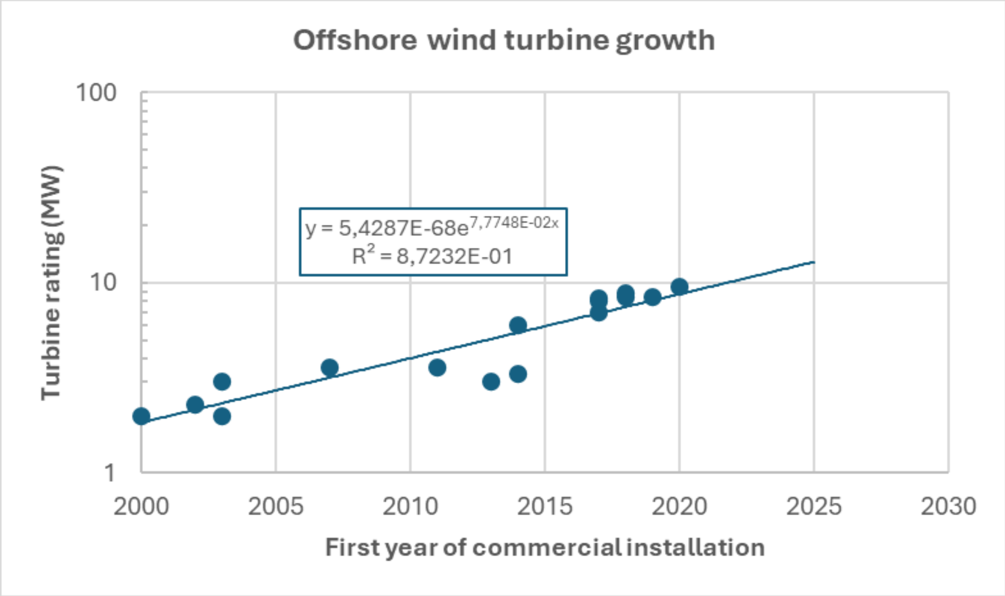

Figure 32. Growth rate for commissioned offshore wind turbines (first year of commercial installation of a given turbine) [7].

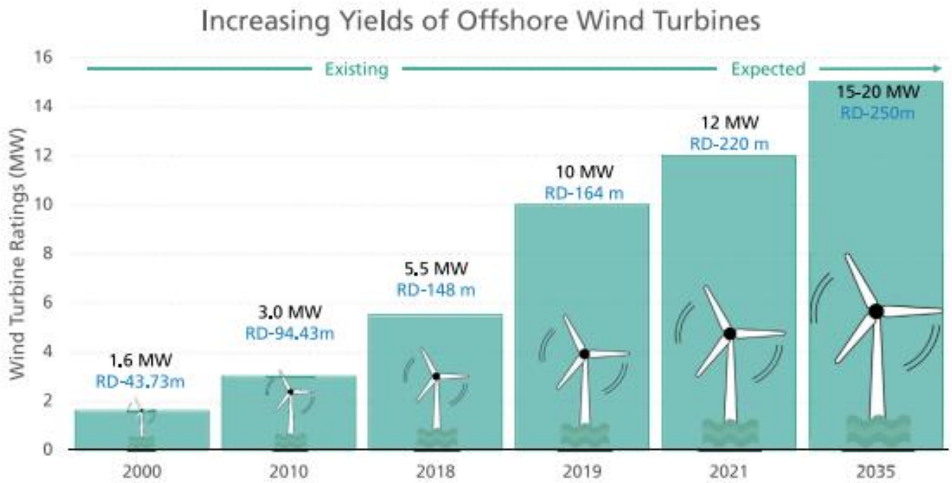

Figure 33. Increasing yield of offshore wind turbines [9].

It is assumed that the historic and current growth rate will sustain up until 2030. This results in 20 MW turbines in this year, where after 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 [10]. With a constant average specific power of 350 W/m², 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 [11], however at a slower pace and with slower growth rate. For Colombia it is expected that there will be a time delay between the biggest turbines on the market at a given time and their deployment in Colombian waters. In consequence, the turbine sizes are assumed to increase to the following capacities as shown in Table 4-2.

Table 4-2. Assumptions for WTG size for future representative Colombian projects.

Year	Assumed WTG size for future projects (MW)
2024	8
2030	15
2050	20

4.4.1. 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. There is no official available data for wind capacity factors in Colombia, but there are approximations using the ERA 5 Climate Reanalysis calibrated with data from Jepírachi, that used to be Colombia's only wind farm [12].

Offshore wind farms installed in Denmark 2009-2013 have a weighted average capacity factor of 48 %,As seen in Figure 34. For comparison, onshore wind turbines installed in Denmark 2011-2013 have an average capacity factor of 33 %. The following graph compares the capacity factors of existing Danish offshore wind projects (represented by blue bars) with approximations for onshore wind capacity factors in Colombia (represented by orange bars). The Danish offshore projects, such as Horns Rev I, Rødsand I, Samsø, Horns Rev II, Sprogø, Rødsand II, and Anholt, have capacity factors ranging between 37 % and 50 %. In contrast, the estimated capacity factors estimations onshore wind projects in Colombia, including Pto. Estrella, Pto. Bolivar, Ballenas, Sta. Marta, and Pto. Velero, show much higher values, ranging from 47 % to 86 %, with Pto. Estrella and Pto. Bolívar having the highest approximations at 86 % [12]. This illustrates the significant wind energy potential of Colombian onshore wind projects, particularly in comparison to established offshore wind farms in the North Sea.

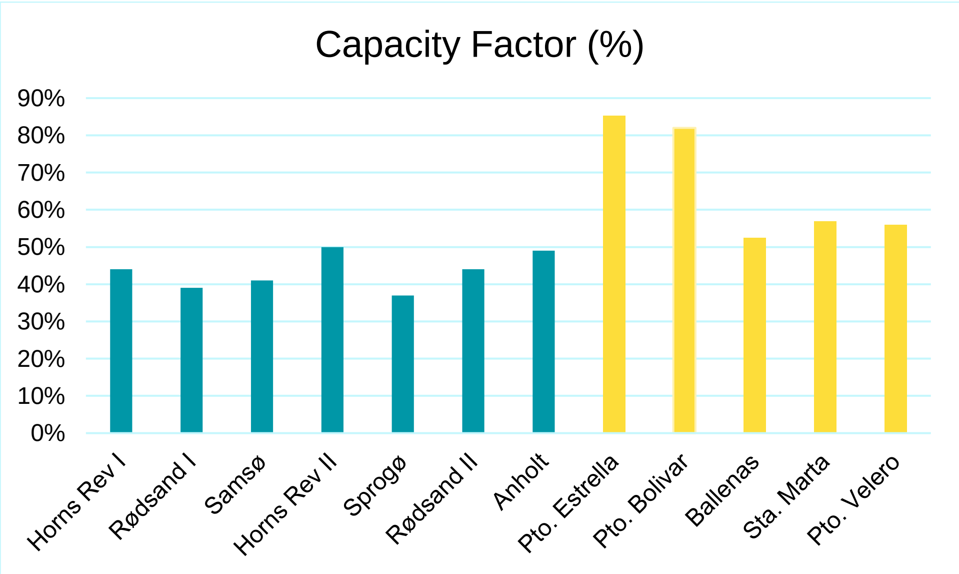

Figure 34. Comparison of capacity factors between existing Danish offshore wind farms and estimations for onshore wind sites in Colombia [12, 13].

However, it is important to recognize that the Colombian wind capacity factors are based on climate reanalysis wind data estimations, which can be less reliable compared to actual measurements from operating wind farms, like those in Denmark. Climate reanalysis data are generated by combining historical weather observations with modern numerical weather prediction models. While this approach can provide a broad estimation of wind potential over time and space, it has quality limitations as it is not real wind measurement.

Finally, evidence from the Danish projects shows that both the location and the specific power are key drivers of the capacity factor (see Figure 35). Two projects with similar location and wind source can have different capacity factor due to differences in the specific power.

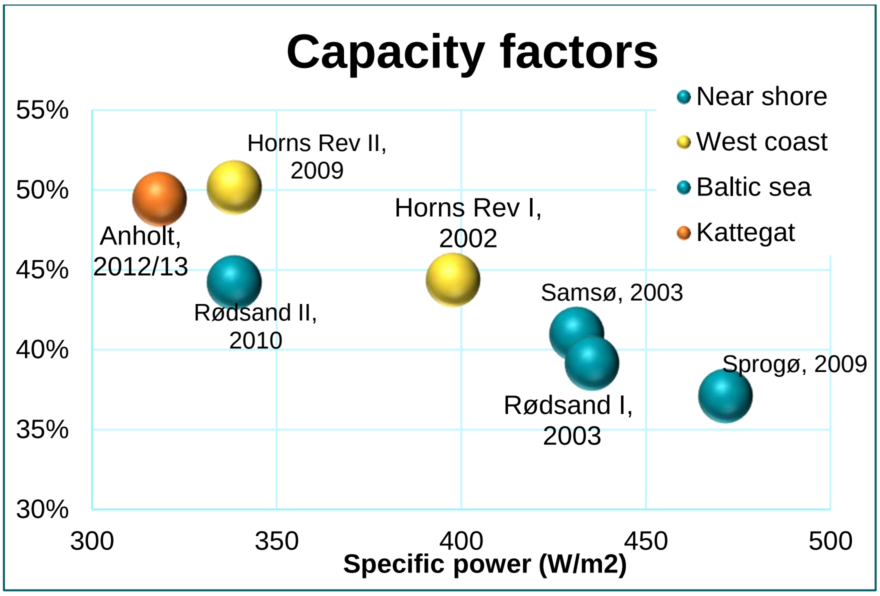

Figure 35. Capacity Factor shown as function of the Specific Power (W/m²) for Danish Offshore wind turbine projects. The three projects most left are the latest ones among the sample. (Figure from a previous version of Technology Catalogue [28]).

4.5. Space requirement

Offshore wind turbines are typically spaced further apart within wind farms, with an average installed power density of 7.2 MW per square kilometre, ranging from 3.3 to 20.2 MW/km². This spacing is necessary to minimize wake effects and optimize power generation efficiency. However, the large area required for offshore wind farms can lead to competition for space with other economic activities in the marine environment, such as fisheries, shipping routes, and recreational activities [14].

4.6. 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.

4.7. Regulation ability and other power system services

Offshore wind turbines have similar regulation and ancillary service capabilities to onshore turbines. See the descriptions in the chapter, *Wind Turbines - Onshore*.

Because of the large distances between the wind farm and the point of connection to the power grid, the regulation of voltage and reactive power in the main power grid is more challenging for offshore wind farms than for their onshore counterparts. A larger distance will result in an increased impedance and loss. An offshore wind farm will be able to compensate for reactive power created by itself; however, their contribution to further compensation of reactive power in the main power grid is limited and depends on the distance to point of connection. Onshore wind turbines, which in general are closer to the grid, have better possibilities for contributing to regulation of voltage and reactive power. Due to the difference in sizes between typical offshore and onshore wind farms, respectively, the potential for regulation abilities however is bigger for offshore wind farms than onshore wind farms.

Wind energy resources along the Colombian Caribbean Coast could effectively complement the country's hydropower generation both during the dry seasons of the annual weather cycle and during ENSO events. This relationship is characterized by an inverse correlation between the water supply to the national power system and the availability of non-conventional renewable energies like solar and wind; as water levels drop, solar and wind resources tend to increase, and vice versa. The synergy between these two specific resources is not constant but varies throughout the year and in response to changes in ENSO conditions [15-16].

4.8. Advantages/disadvantages

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

The major advantages of offshore wind turbines, relative to onshore wind turbines, are the better wind resources offshore, the reduction of the visual and noise impacts and reduction of space requirement from turbines which has become a major barrier for onshore deployment, and the possibility of building much larger wind farms than onshore.

There are, however, more logistical considerations associated with building wind turbines offshore than onshore and needs for more expensive equipment, resulting in higher capital costs for offshore wind farms. Those costs, however, can pay off when considering the bigger scale of the projects and better wind resource.

4.9. Environment

As is the case with all big infrastructure projects, some disturbance to sea-life must be anticipated during the construction phase for offshore wind turbines. There are no operating projects in Colombia but some experiences can be learned from the Danish case.

Before, during, and after the construction of the two Danish wind farms Horns Rev I and Rødsand I, comprehensive monitoring programmes were launched to investigate and document the environmental impact of these two wind farms [17]. The monitoring programmes showed that, under the right conditions, large wind farms pose low risks to birds, mammals and fish. Species diversity even tends to increase due to the increase in habitat heterogeneity resulting from the foundations, which act as miniature reefs.

However, as environmental impacts are context dependant, specific tropical ecosystems in Colombia could be affected by offshore wind projects and a special evaluation must be undertaken to assess the impacts of projects. In this sense Colombia has a wide range of coastal marine habitats and ecosystems, including lagoons, wetlands, coral reefs, algae, mangroves, rocky and sandy beaches, upwelling areas, and various types of seabed. Also, the Colombian Caribbean hosts a high diversity of marine mammals such as dolphins, whales, and manatees, with 29 species recorded, representing 83 % of the marine mammal species found in Colombia and 24 % of those worldwide [3].

The installation of wind turbines and underwater cables can disturb the seabed and increase sediment suspension, reducing water quality and affecting species like corals, sponges, and seagrasses. Offshore structures may cause localized seabed erosion due to water movement changes. The turbines can also disrupt the daily circulation of birds and bats, creating barriers for migratory species [3]. Offshore projects developed in Colombia should account for this and other specific impacts.

4.10. Research and development perspectives

Besides the R&D potential described in the chapter *Wind Turbines - Onshore*, offshore technology development is expected to include [18, 19]:

- Further upscaling of wind turbines,
- New foundation types suitable for genuine industrialization, among which floating substructures,
- Development of higher electrical wind farm systems of 132 kV and up as alternative to present 66 kV,
- Development of compact offshore substations, including high-voltage direct current (HVDC) converter stations and cables. HVDC equipment is available today, but only assumed economically feasible at more than ~100km to shore,
- Multi terminal HVDC with power flow in both directions to integrate large quantities of offshore wind power in a future meshed offshore grid
- Improvement of design methods in planning and operation phase, e.g., reduction of wake losses, O&M costs by e.g. improved control strategies, more optimized tower/foundation structure by integrated design,
- Logistic issues, e.g. more dedicated vessels in installation and maintenance phase,
- Improved methods for handling of different seabed conditions, lowering foundation costs,
- Improved reliability and fault tolerance, among others due to monitoring, in operational phase for lowering availability losses and securing optimal operation.

Currently, the pace of product development and competition is high. Consequently, projects are often planned and developed with turbines that are not yet in serial production.

4.11. Examples of market standard technology

For Hollandse Kust Zuid 1-4 in the Netherlands, as depicted in Figure 36, Vattenfall are now constructing 1.5 GW wind farm based on 11 MW Siemens turbines with 200 m rotor diameter. For the next project Northfolk at UK east coast to be commissioned in 2027, Vattenfall expect 15 MW Siemens with 236 m rotor diameter. This is a project with an expected 3.6 GW to be installed. At Testcenter Østerild, Siemens has established a 15 MW turbine with 236 m rotor diameter.

Figure 36. Hollandse Kust Zuid Wind Farm [30].

4.12. Prediction of performance and cost

Table 4-3 compares different investment cost estimates from various sources. The data focuses on fixed-bottom offshore wind.

Table 4-3. Investment cost comparison across regions for different offshore wind projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	4.3 (fixed bottom) 5.4 (floating in 2030)	2024
National data		
Bilateral meetings with local stakeholders	4.5 – 5.0	2024
International data		
Technology Catalogue Indonesia (2024)	4.6 (fixed bottom) 6.17 (floating)	2023

Technology Catalogue Vietnam (2023)	3.83 (fixed bottom) 6.68 (floating)	2022
IEA GEC Model, Brazil region (2021)	4.98 (fixed bottom)	2021
Technology Catalogue Denmark (2024)	2.65 (fixed bottom)	2020

Given the early stage of development of offshore wind in the country, there is high uncertainty regarding initial cost estimations of offshore wind against future finalized realization cost. This is evident by the considerable range of input from various stakeholders. Localized investment cost data is limited as there is e.g. no specific data for offshore wind in Latin America excluding Brazil, as IRENA presents for other renewable energy technology.

O&M cost are derived from investment cost (CAPEX) by assuming 2.5 % per CAPEX per year.

Floating offshore wind is not as technologically mature as fixed-bottom offshore wind, and there are few operational plants world-wide. Many sites are used as prototypes for further testing of the technologies, and there is no complex large-scale operational site commissioned globally, as of now. Electrical connections and mooring are among the complexities of a commercial large-scale floating offshore wind farm. In order to emphasize this, it is assumed that the development of floating lacks behind fixed-bottom offshore wind with the first available information in the datasheet in 2030 instead of 2024. Furthermore, it is assumed that costs are 25% higher than fixed-bottom offshore wind reflecting the higher complexities of the sites. This considers both investment cost and more complex installation and equipment requirements, as well as costlier maintenance of the farms, due to the more complex equipment employed and the typically longer distance to maintenance harbours of the far offshore sites in deeper waters.

4.12.1. Uncertainty

There are several uncertainties, not just in cost and improvement of performance of the technology, but also on supply chain and service opportunities. The cost reductions related to supply chain and service are dependent on the international level of deployment of wind power as well as the national availability of services, which are dependent on the continuity and level of national deployment of offshore wind power. Another highly volatile uncertainty is the raw material cost development. In this context it is assumed that changes in raw material prices will balance off in the longer run, while possible short-term effects are neither predicted nor accounted for. Especially the availability of more rare or limited materials like copper or rare earth metals used for permanent magnets could potentially create larger fluctuations on raw material markets.

Future demands 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 [24].

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 [28].

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 is 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 (see Figure 37) [28].

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 37. The Stiesdal TetraSpar full-scale demonstration project in 2021 [29].

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4.14. Datasheet

4.14.1. Fixed bottom

Technology	**Wind power - Offshore**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MW_e)	8	15	20						1,3,4
Generating capacity for total power plant (MW_e)	200	500	1000						1,3,4,10
Hub Height (m)	100	135	155						1
Specific Power (W/m^2)	379	343	349						1
Forced outage (%)	0.04	0.03	0.02						1,3,4
Planned outage (weeks/year)	0.50	0.50	0.50	0.50	0.50	0.50	0.50		1,3,4
Technical lifetime (years)	27	30	30	25	30	25	35		1
Construction time (years)	3.0	2.5	2.5	1.5	4.0	1.5	4.0		1,3,4
Space requirement (1000 m^2/MW_e)	137.7	178.2	168.0					G	
Average annual full-load hours (MWh_e/MW_e)	3500	4800	4900						1,3,9,10
Additional data for non-thermal plants									
Capacity factor (%), theoretical	42.0	57.1	57.6	35	45	35	60	F	1,3,9,10
Capacity factor (%), incl. outages	39.9	54.8	56.0					F	
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	E	1,3,4
Minimum load (% of full load)	-	-	-	-	-	-	-		
Warm start-up time (hours)	-	-	-	-	-	-	-		

Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (g/GJ of fuel input)	0	0	0	0	0	0	0		
SO_2 (g/GJ of fuel input)	0	0	0	0	0	0	0		
NO_X (g/GJ of fuel input)	0	0	0	0	0	0	0		
CH_4 (g/GJ of fuel input)	0	0	0	0	0	0	0		
N_2O (g/GJ of fuel input)	0	0	0	0	0	0	0		
Financial data									
Specific investment, total system (million USD/MW)	4.3	3.2	2.3	4.0	5.0	2.2	2.6	A,D	2,3,6,8
- of which equipment	2.2	1.6	1.1	2.0	2.5	1.1	1.3	B,D	6
- of which installation	1.3	1.0	0.7	1.2	1.5	0.7	0.8	B,D	6
- of which grid connection	0.9	0.6	0.5	0.8	1.0	0.4	0.5	B,D	6
Fixed O&M (USD/MW_e/year)	108,500	81,000	56,500	100,000	125,000	56,000	65,000	C,D	2,3,6,7
Variable O&M (USD/MWh)	0	0	0	0	0	0	0	C	
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Rotor diameter (m)	164	236	270						1
Hub height (m)	100	135	155						1
Specific power (W/m^2)	379	343	349						1
Availability (%)	95.1	96.1	97.1						1,3,9

Notes

A Given the nascent offshore wind market in Colombia, the values are an aggregated assessment on literature supplemented by data aggregation of data of the register of UPME. There is large uncertainty on these values

B Cost breakdown can vary significantly based on site characteristics. Here 50 %, 30 %, and 20 % for equipment, installation and grid connection are assumed for modelling purposes only, consulting global IRENA data

C 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

D Cost are projected with a learning rate approach assuming a 15 % 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 2023, with Announced Pledges for the central values and Stated Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.

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

F Capacity factors are highly dependent on the wind climate. For 2024, wind speeds of 8-9 m/s are chosen representing the favourable conditions for fixed bottom offshore wind off the coast between Cartagena and Barranquilla. From 2030 onwards, the wind climate conditions around La Guajira are chosen, assuming the availability for offtake following the commissioning of HVDC line to the region as per UPME's transmission expansion plans.

G 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.

References

[1] Danish Energy Agency, Technology Catalogue for generation of electricity and District Heating, 2024
[2] UPME, "Registro de Proyectos de Generación" database
[3] Danish Energy Agency, Ea Energy Analyses, Technology Data for the Indonesian Power Sector, 2024
[4] Danish Energy Agency, Ea Energy Analyses, Viet Nam Technology Catalogue for Power Generation, 2023
[5] Danish Energy Agency, Indian Technology Catalogue Generation and Storage of Electricity, 2022
[6] IEA, 2023, World Energy Outlook Global Energy and Climate Model input data
[7] IRENA, 2023, Renewable Power Generation Costs in 2022
[8] Discussion with Technology Catalogue stakeholder group
[9] World Bank, Global Wind Atlas
[10] AFRY, Offshore Wind Roadmap Study, Hoja de ruta para el despliegue de la energía eólica costa afuera en Colombia, 2024

4.14.2. Floating

Technology	Wind power - Floating offshore								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MW_e)	-	15	20	-	-				1,2,3
Generating capacity for total wind farm (MW_e)	-	150	1000	-	-				1,2,3,6
Forced outage (%)	-	0.03	0.02	-	-				1,2,3
Planned outage (%)	-	0.5	0.5	-	-				1,2,3
Technical lifetime (years)	-	30	30	-	-				1,2,3
Construction time (years)	-	2.5	2.5	-	-				1,2,3
Space requirement (1000 m^2/MW_e)	-	95.1	168.0	-	-			C	
Average annual full-load hours [MWh_e/MW_e]	-	4800	4900	-	-				1,3,5
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	57.1	57.6	-	-	45	60	D	1,3,5,6
Capacity factor (%), incl. outages	-	54.8	56.0	-	-			D	
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/GJ of fuel input)	-	0	0	-	-	0	0		
SO_2 (g/GJ of fuel input)	-	0	0	-	-	0	0		
NO_X (g/GJ of fuel input)	-	0	0	-	-	0	0		
CH_4 (g/GJ of fuel input)	-	0	0	-	-	0	0		
N_2O (g/GJ of fuel input)	-	0	0	-	-	0	0		
Financial data									
Specific investment, total system (million USD/MW)	-	5.4	2.8	-	-	2.8	3.3	B	2,3,4
- of which equipment	-	2.7	1.4	-	-	1.4	1.6	B	2,3,4
- of which installation	-	1.6	0.9	-	-	0.8	1.0	B	2,3,4
- of which grid connection	-	1.1	0.6	-	-	0.6	0.7	B	2,3,4
Fixed O&M (USD/MWe/year)	-	135,625	70,625	-	-	70,000	81,250	B,E	2,3,4
Variable O&M (USD/MWh)	-	0	0	-	-	0	0		
Start-up costs (USD/MW_e/start-up)	-	0	0	-	-	0	0		
Technology specific data									
Rotor diameter (m)	-	236	270	-	-				1
Hub height (m)	-	135	155	-	-				1
Specific power (W/m^2)	-	343	349	-	-				1
Availability (%)	-	96.1	97.1	-	-				1,3,9

Notes

A Floating offshore is not assumed earlier than 2030, with commercialisation planned for 2035 as mentioned in [6]

B For the initial cost CAPEX and OPEX assessments, it is assumed that Floating offshore is 25% more expensive than fixed bottom offshore. For the initial year 2030, the comparison is against 2024 fixed bottom costs. Results are in line with [2] and [3]

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 Capacity factors are highly dependent on the wind climate. Assumptions for the central value are based on the wind climate off the coast of La Guajira.

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

References

[1] Danish Energy Agency, Technology Catalogue for Generation of Electricity and District Heating, 2024

[2] Danish Energy Agency, Ea Energy Analyses, Technology Data for the Indonesian Power Sector, 2024

[3] Danish Energy Agency, Ea Energy Analyses, Viet Nam Technology Catalogue for Power Generation, 2023

[4] IEA, 2023, World Energy Outlook Global Energy and Climate Model input data

[5] World Bank, Global Wind Atlas

[6] AFRY, Offshore Wind Roadmap Study, Hoja de ruta para el despliegue de la energía eólica costa afuera en Colombia, 2024

5. Hydro Power Plant

5.1. Brief technology description

Hydropower is a method of generating electricity that converts the kinetic energy of flowing water into mechanical and then electrical energy. The efficiency of this process is determined by two crucial factors: flow and head. The 'flow' refers to the volume of water moving per unit of time, typically measured in cubic meters per second. This flow is what propels the turbine, the central component of a hydropower system. The 'head' is the term used to describe the height difference between the water's source and the turbine.

In a hydropower plant, water is channelled from a higher elevation (often stored in a reservoir) to a lower elevation where the turbines are located. As the water descends, it gains speed and pressure due to the gravitational pull associated with the head. This pressurized water is directed through turbines, where the flow's kinetic energy is harnessed to rotate the turbine blades. The rotating turbines drive a generator, which converts mechanical energy into electrical energy for use. The greater the head and the stronger the flow, the more energy can be generated, making these factors critical in the design and location of a hydropower plant.

The output of a hydropower plant can be estimated using a simple equation that considers the flow of water, the height from which the water falls, and the efficiency of the turbine and generator. The basic equation to calculate the power output from a hydropower plant is:

$$P = \rho \times g \times Q \times H \times \eta \mathrm{P}$$

Where:

- P is the power output in watts (W).
- ρ (rho) is the density of water (approximately 1000 kg/m³ for fresh water).
- g is the acceleration due to gravity (approximately 9.81 m/s²).
- Q is the volumetric flow rate of water in cubic meters per second (m³/s).
- H is the head, or the height difference in meters (m) between the load pond and the axis of the generating unit
- η (eta) is the overall efficiency of the turbine and generator system, expressed as a decimal (e.g., 0.90 for 90 % efficiency).
- This equation gives a theoretical estimation of the electrical power that can be generated under ideal conditions

Types of hydropower plants

There are three main 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 (see Figure 38). Typically, a run-of-river project will have little or no storage facility.
- **Storage/reservoir.** Uses a dam to store water in a reservoir (see Figure 39). Electricity is produced by releasing water from the reservoir through a turbine, which activates a generator.

- **Pumped storage.** Providing peak-load supply, harnessing water which is cycled between a lower and upper reservoir by pumps which use surplus energy from the system at times of low demand (This technology is explained in a separated chapter).

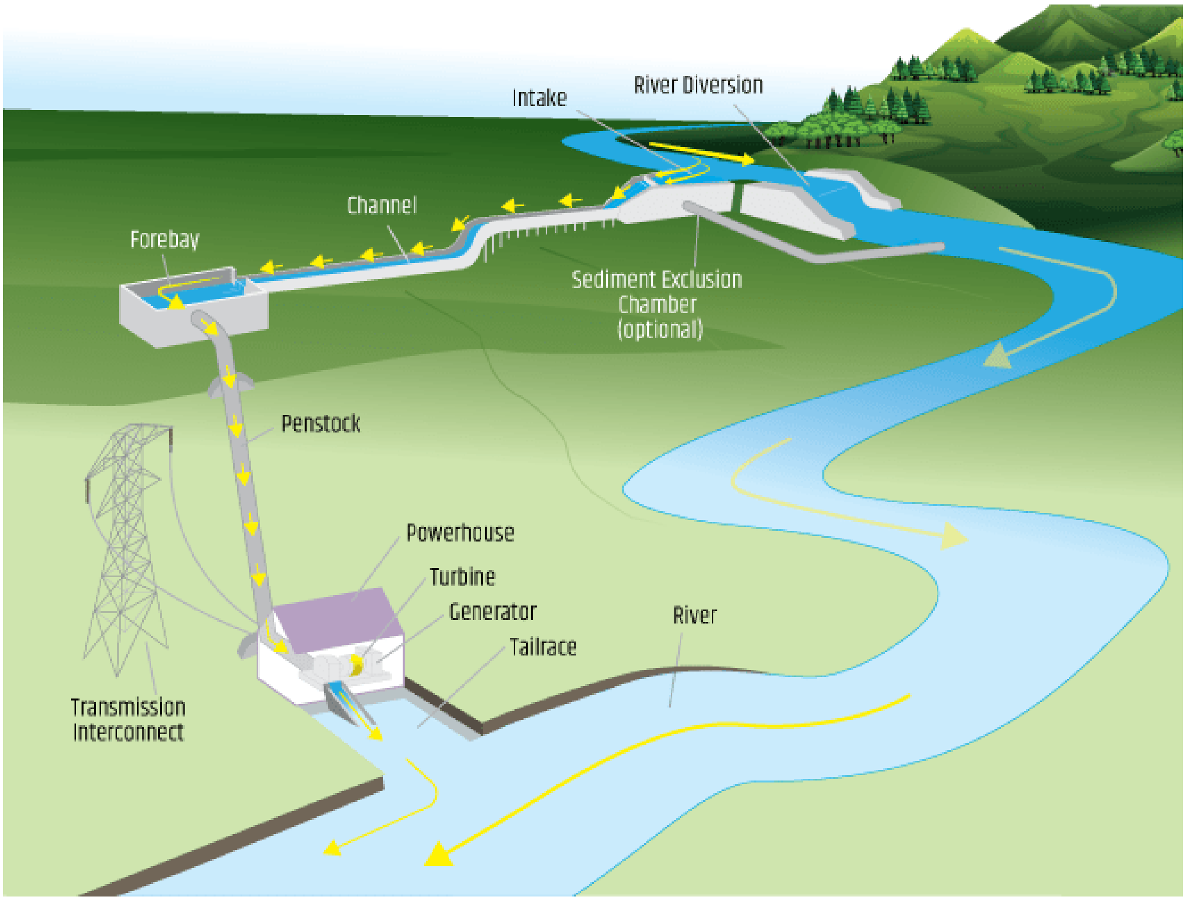

Figure 38. Schematics of a run-of-river hydropower plant [1].

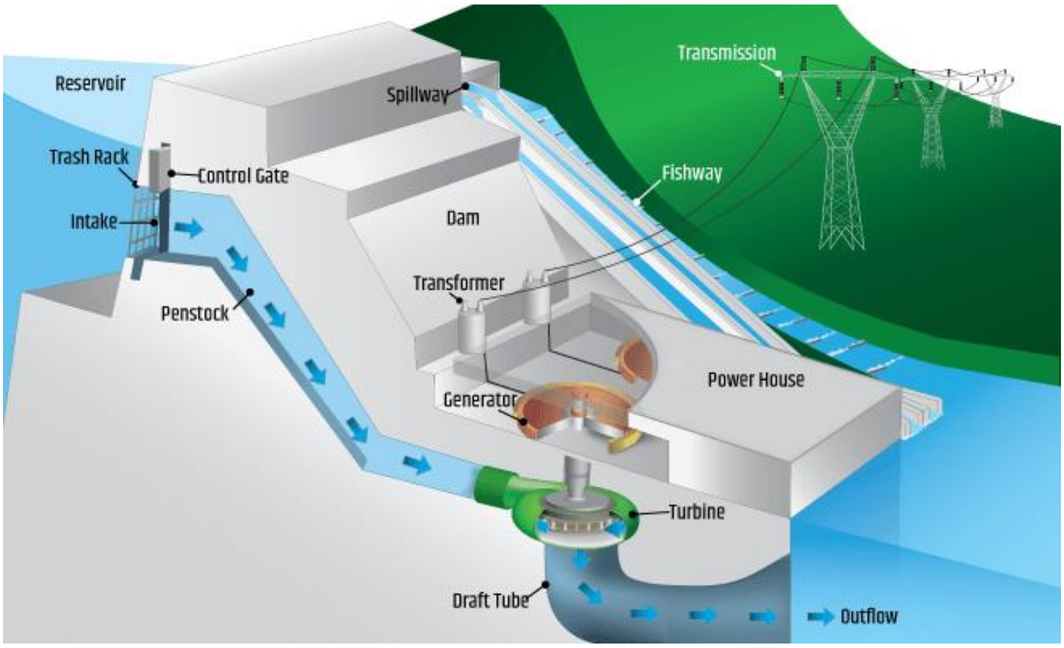

Figure 39. Schematics of a reservoir hydropower plant [1].

Run-of-river systems do not require the construction of reservoirs. Consequently, they cannot store water or regulate flow rates. This type of hydropower system typically has a lower impact on the landscape than reservoirs, maintaining much of the natural environment intact. However, as the water is taken directly from the river, control structures as silting tanks or desanders are needed to avoid the sediments to reach and damage the turbine.

In contrast, reservoir systems do not need sediment settling structures because they can store water and managing flow rates, allowing for a more controlled generation of electricity. However, these systems often have a significant impact on the landscape, altering natural habitats and potentially displacing communities, due to the large-scale water storage and the physical presence of the dam.

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 and can potentially disrupt ecosystems because of the interruption of nutrient flow and species migration.

In Colombia, the largest cascading systems can be found in the Nare-Guatapé Hydropower Chain, in the eastern region of the Antioquia Department, that includes Guatapé (560 MW), Jaguas (170 MW), Playas (200 MW), Calderas (20 MW) and San Carlos (1,240 MW) power plants (see Figure 40). Other Reservoir Chains include the Porce III Hydraulic Chain that includes La Tasajera (306 MW), Gualadupe -Troneras-Guatrón, (512 MW), Porce II (405 MW) and Porce III (700 MW) power plants.

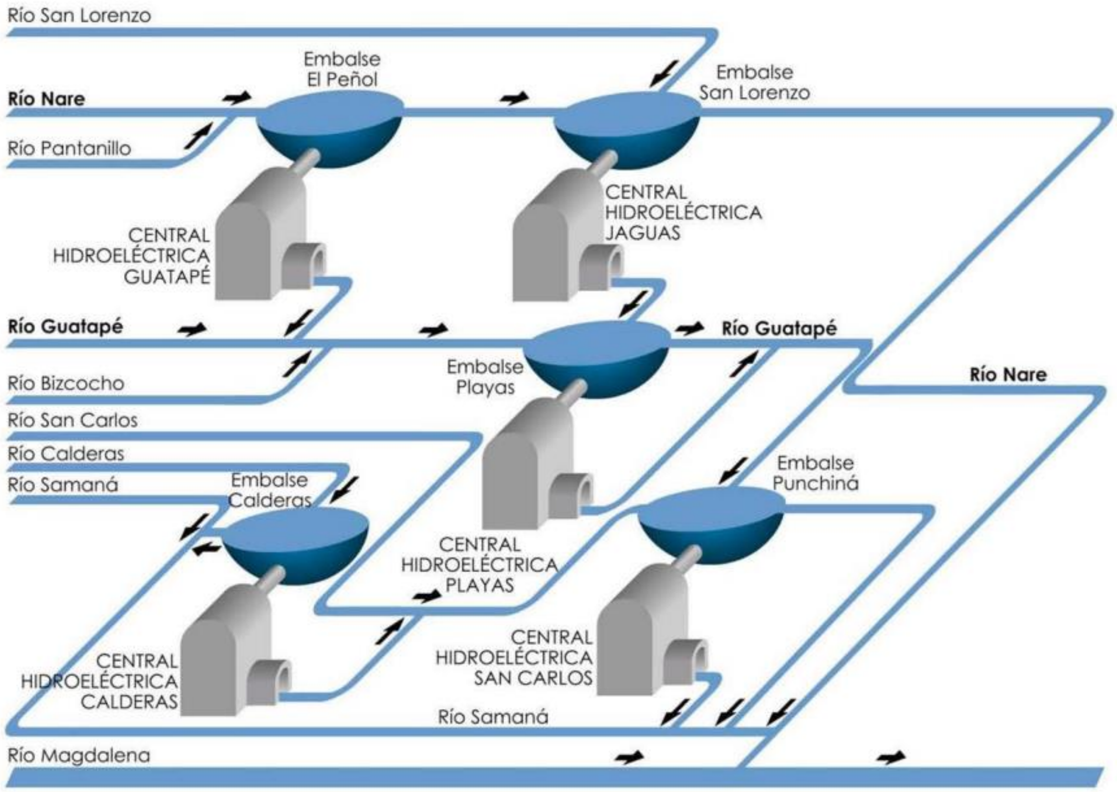

Figure 40. Schematics of the Nare-Guatapé hydropower chain [2].

5.1.1. Classification by installed capacity

Hydropower systems' installed capacities can range from tens of Watts to hundreds of MW. A classification based on the size of hydropower plants in Colombia is presented in Table 5-1. However, there is no internationally recognized standard definition for hydropower sizes, so definitions can vary from one country to another. In Colombia, the definition of hydropower size usually follows the dispatch rules from the market operator:

Table 5-1. Classification of hydro-power size [3].

Type	Capacity
Centrally dispatched - Large hydro power	> 20 MW
Non Centrally Dispatched - Small hydropower	1 MW – 20 MW
Distributed Generation - Mini and micro hydropower	1 - 1000 kW

5.1.2. Types of Turbines

Pelton, Francis, and Kaplan turbines are most used types of water turbines for hydroelectric power plants, each suited to different hydraulic conditions (see Figure 41 and Table 5-2):

- **Pelton Turbine**: Ideal for high head and low flow situations, the Pelton turbine is an impulse turbine where water jets strike spoon-shaped buckets mounted around the edge of a wheel. The impact of the water on the buckets turns the wheel, generating energy.
- **Kaplan Turbine:** Suitable for low head and high flow scenarios, the Kaplan turbine is also a reaction type but features adjustable blades. It has a propeller-like design with blades that can be pitched to optimize efficiency as water flow and hydraulic conditions change. This feature makes it highly adaptable and efficient in locations where water flow varies.
- **Francis Turbine:** A reaction turbine that operates in medium to high head and medium flow conditions, the Francis turbine has a spiral-shaped casing that directs the water through vanes on a runner. This process converts the pressure energy of water into mechanical energy. The water enters radially and exits axially, pushing against the turbine blades as it passes through, which spins the turbine.

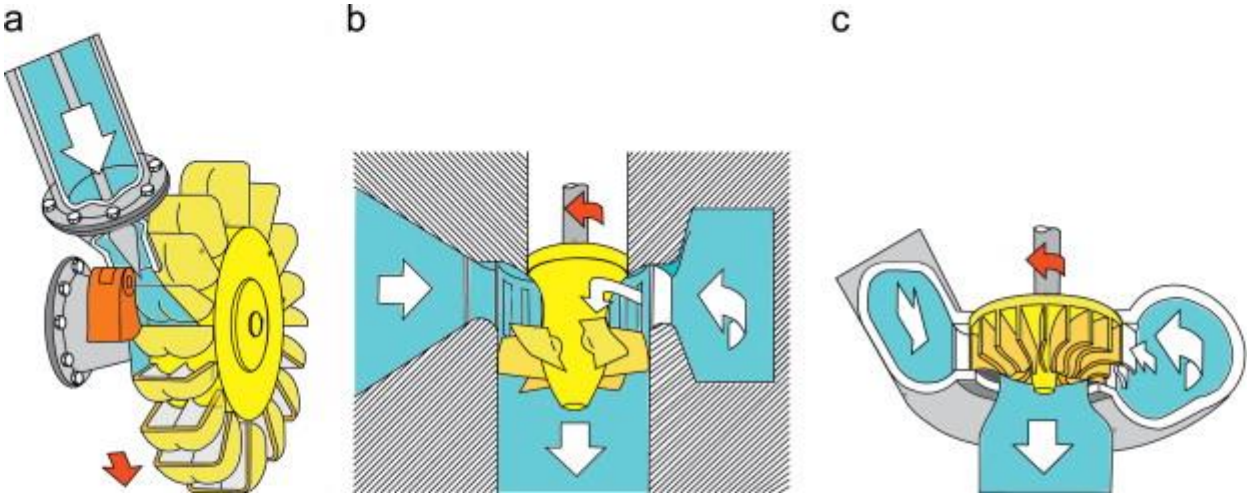

Figure 41. Pelton (a), Kaplan (b) and Francis (c) Turbines [4].

Table 5-2. Classification of hydropower turbines per type.

Feature	Pelton Turbine	Francis Turbine	Kaplan Turbine
Type	Impulse	Reaction	Reaction
Head	High	Medium to High	Low
Water Flow	Low	Medium	High
Efficiency	High at very specific conditions	High across a range of conditions	High and adjustable
Design	Bucketed wheel, nozzles direct water jets	Spiral casing, water passes radially and axially	Propeller with adjustable blades
Application	Mountainous areas with steep river drop	Wide range of applications including dam-based plants	Best for flat terrains with large rivers

Choosing a type of hydropower turbine is a function of two paraments: flow rate and head. For high-head systems, Pelton turbines are most suitable due to their ability to handle high pressure with low flow rates. In contrast, for medium-head systems, Francis turbines are typically chosen, as they can efficiently manage a combination of moderate head and flow. For low-head systems Kaplan turbines are ideal, as they are designed for high flow rates with lower pressure. Turbine manufacturers present different application charts such as Figure 42 to choose the right technology according to the flow/head combination.

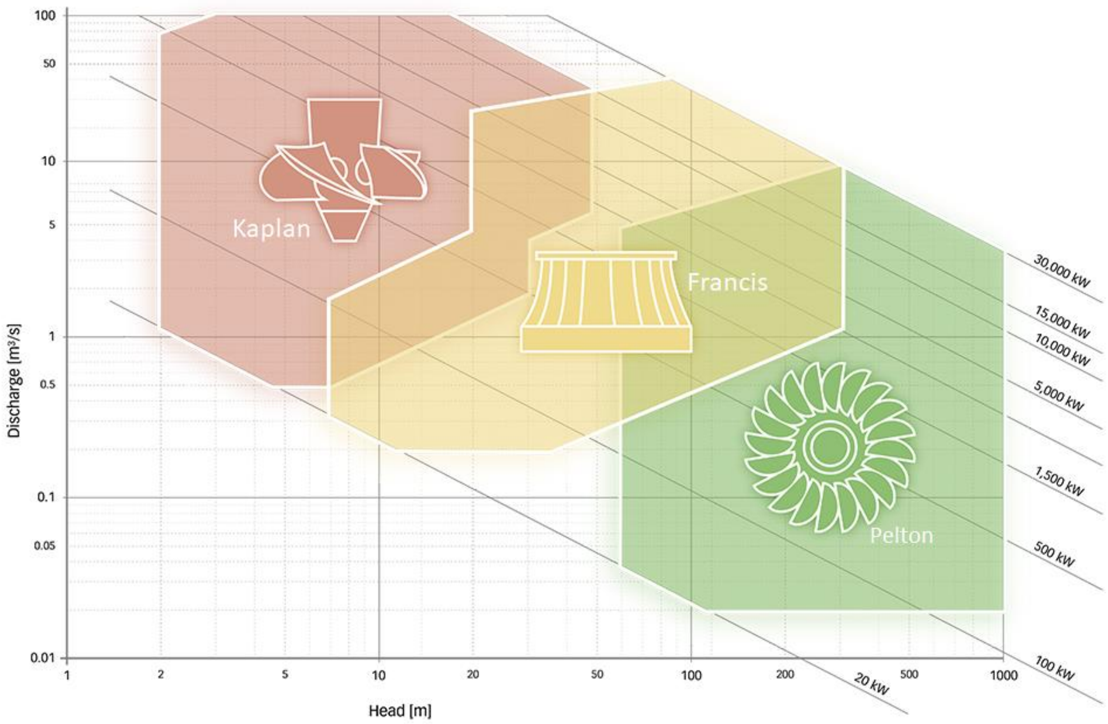

Figure 42. Hydropower turbine application chart [5].

There is a branch of technologies for smaller heads, that include several other turbine technologies like overshot and undershot water wheels, Bulb Turgo and Crossflow turbines and Archimedean screws, among others. The selection principle using a combination of head and flow applies for these turbines too.

A brief description of these technologies presented below, and the flow and head ranges for their application are shown in Figure 43:

- **Overshoot Water Wheel**: Water flows over the top of the wheel, making it turn as the weight of the water causes the wheel to rotate.
- **Undershoot Water Wheel**: Water strikes the bottom part of the wheel, causing it to rotate.
- **Bulb Turbine**: This turbine is fully submerged in the water and is used in low-head, high-flow applications. The generator is housed in a bulb-shaped casing, hence the name.
- **Turgo Turbine**: A variant of the Pelton turbine, it is an impulse turbine where water strikes the turbine blades at an angle, enabling higher rotational speeds than a Pelton, making it more efficient for certain head ranges.

- **Crossflow Turbine**: A simple, robust turbine where water flows through the blades twice, maximizing the energy capture. These turbines are known for their ability to handle debris without significant damage.
- **Archimedean Screw**: The screw rotates as water flows through it, generating mechanical energy. It is efficient at low speeds and is often used in small, eco-friendly hydropower installations due to its fish-friendly design.

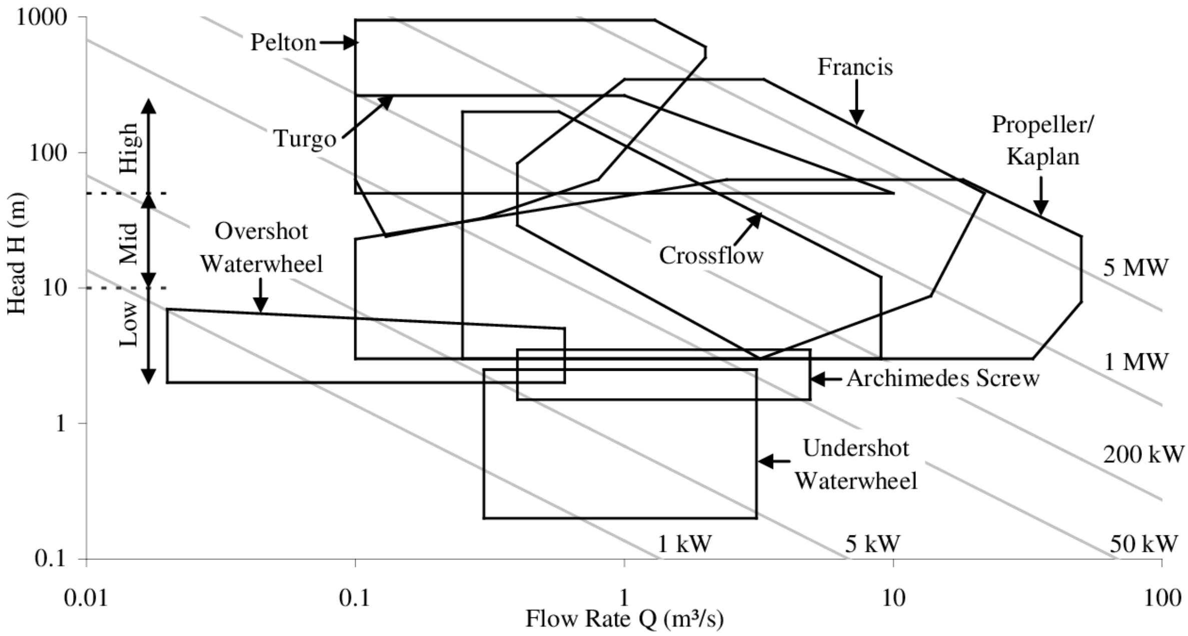

Figure 43. Other hydropower technologies application chart [6].

5.1.3. Hydropower Potential in Colombia

In 2015, the UPME (Unidad de Planeación Minero Energética) published the "Atlas of Hydropower Potential of Colombia," focusing on the utilization through run-of-river power plants with varying conduit lengths (200 m, 1000 m, and 5000 m). The results, as depicted in Figure 44 and Table 5-3, were presented for sub-hydrographic zones corresponding to different hydrographic areas of the national territory.

Table 5-3. Hydropower Potential in Colombia [7].

Capacity Range	Potential Capacity (MW)
Less than 5 kW	2 MW
Less than 50 kW	15 MW
Less than 500 kW	143 MW
10 - 20 MW	4786 MW
20 - 100 MW	8113 MW
Greater than 100 MW	43,129 MW

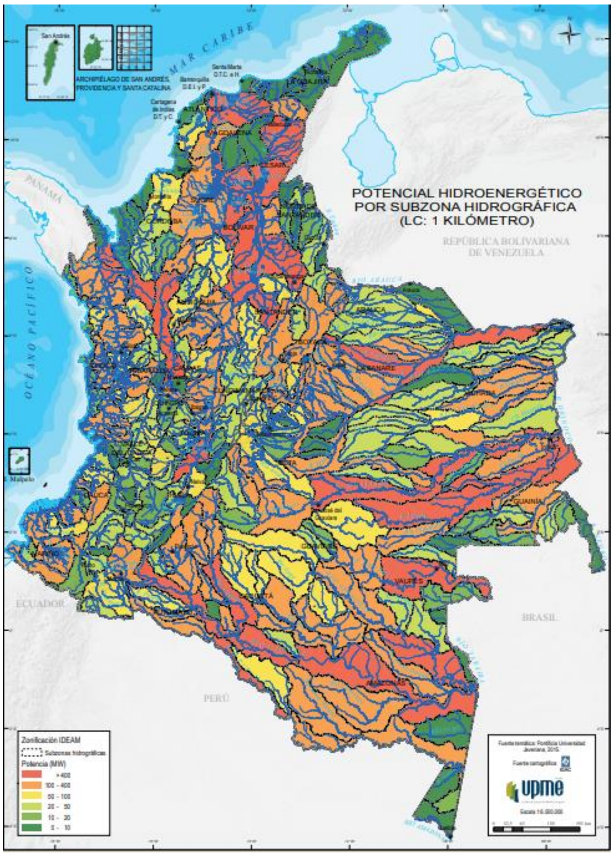

Figure 44. Hydropower potential by sub-hydrographic zone in Colombia [7].

Generally, the Colombian territory has a well-distributed hydropower potential, particularly abundant in the Andean Region of the country, where there is a combination of large river flows and very steep elevation differences.

In 2024 the total capacity of hydropower plants installed in Colombia was 13.206 MW [3], which is the majority (63 %) of the installed capacity in the country. This makes Colombia very sensitive to ENSO, as it significantly influences hydropower generation in Colombia due to its impact on the country's rainfall patterns. During El Niño phases, Colombia typically experiences reduced rainfall, which leads to lower river flows and diminished reservoir levels. Since hydropower in Colombia largely depends on the availability of surface water, such conditions can result in substantial reductions in electricity generation capacity. Conversely, the La Niña phase is associated with increased rainfall, which can enhance hydropower output by raising river flows and reservoir levels. In an ENSO neutral year, around 85 % of Colombia’s energy can come from hydropower, whereas during El Niño that percentage can drop to 50 %.

5.2. Input

Pressure water in a conduction, with an established flow and head.

5.3. Output

Electricity.

5.4. Typical capacities

Hydropower systems can range from tens of Watts to hundreds of MW. The largest hydropower plant turbine which will be installed in Colombia is the Hidroituango power plant with 2400 MW, divided in 8 turbines with a capacity of 300 MW each.

5.5. 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, as shown in Table 5-4 [8].

Table 5-4. Land Use of Reservoir Hydropower in Colombia. Modified from [8].

Land Use - Reservoir Hydropower	Ha/MW	MW
Playas	35,3	207
Prado	83,3	51
Urra	21,7	338
El Quimbo	20,8	400
Calima	14,7	132
Betania	13,7	540
Guatron	12,5	512
Guatape	11,1	560
Sogamoso	8,5	819
Salvajina	6,5	315
Jaguas	6,3	170
San Francisco/Santo Domingo	5,2	135
La tasajera	3,6	306
Miel I	3,5	396
Porce II	2,7	405
Chivor	1,3	1000
Guavio	1,1	1250
Porce III	0,7	700
San Carlos	0,3	1240
Alto y bajo Anchicayá	0,2	429
Hidroituango	2,9	2400
Esmeralda	41,7	30
Average	14,0	
Lower	0,2	
Upper	83,3	

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 as seen in Table 5-5.

Table 5-5. Land Use of Run-of-River Hydropower in Colombia [8].

Hydropower Project	ha/MW	MW
San Miguel	0,1	52
Amoya la esperanza	0,3	80
Carlos Lleras	0,3	60

5.6. Water consumption

Water is the main input for hydropower generation and the amount of water used depends on any project. However, the water is not lost as it is returned to the river after generating power, but it may diminish the water flow in a particular section of the river. Also, water may be lost to evaporation in reservoirs.

In some locations of hydropower facilities with water reservoirs, the same volume of water can serve dual purposes, first in energy generation and then in meeting local water demands. This method of utilizing water optimizes resource management and reduces the overall water footprint of energy production, making it a highly efficient strategy in regions where water conservation is critical.

According to data from XM, Colombia's Electric System Market operator, on average 31 MW of power can be provided by each cubic meter per second of water in the power plant of the system [3].

5.7. Regulation ability and other power system services

Hydropower plays a crucial role in enhancing the flexibility of energy systems, thanks to its ability to quickly adjust power output in response to fluctuating electricity demands. Unlike fossil fuel plants which may take hours to ramp up, reservoir hydropower facilities can increase or decrease electricity production almost instantaneously [24]. This makes them ideal for balancing the grid when integrating intermittent renewable sources like wind and solar, which are subject to variations in output based on weather conditions. This capability not only provides a stable and reliable power supply but also enhances the overall efficiency and resilience of power systems, helping to mitigate issues related to the variability and unpredictability of other renewable energy sources. Hydropower helps to maintain the power frequency by continuous modulation of active power, and to meet moment-to-moment fluctuations in power requirements [24]. 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.

Reservoir hydropower plants store water during periods of high availability, allowing for power generation even when natural water flows are low. This enables flexible energy production over extended periods, from weeks to a full year, regardless of current river discharge levels. As a result, reservoir hydropower is the dominant renewable source for providing both short-term and long-term energy flexibility. In contrast, run-of-river hydropower relies directly on natural water flows without large reservoirs for storage, making it less flexible. While run-of-river systems are environmentally friendlier due to their lower impact on ecosystems and lower water storage, they are more susceptible to seasonal and weather variations. Therefore, they offer less control over energy production and are better suited for constant, predictable flows but not for addressing large fluctuations in energy demand. Reservoir hydropower provides superior energy management over varying timeframes compared to run-of-river systems, which are more limited in responding to grid demands due to their dependence on real-time water availability [9]. However, it is important to acknowledge that sedimentation can affect regulation ability in the long term, this is further discussed in the Environment section.

The flexibility provided by hydropower reservoirs is particularly important for the future of the electric sector. Scenarios studies in the country have shown that, under a business-as-usual growth in electricity demand, half of the electricity generated in Colombia by 2050 could still come from the existing large reservoir hydropower plants (see Figure 45) [10] [11]. Under an energy transition scenario with larger electrification of final uses, an expansion in hydropower capacity will be needed [25]. Under any scenario, the proper management of reservoirs will be crucial to complement the expected increase in solar and wind power capacity in the country.

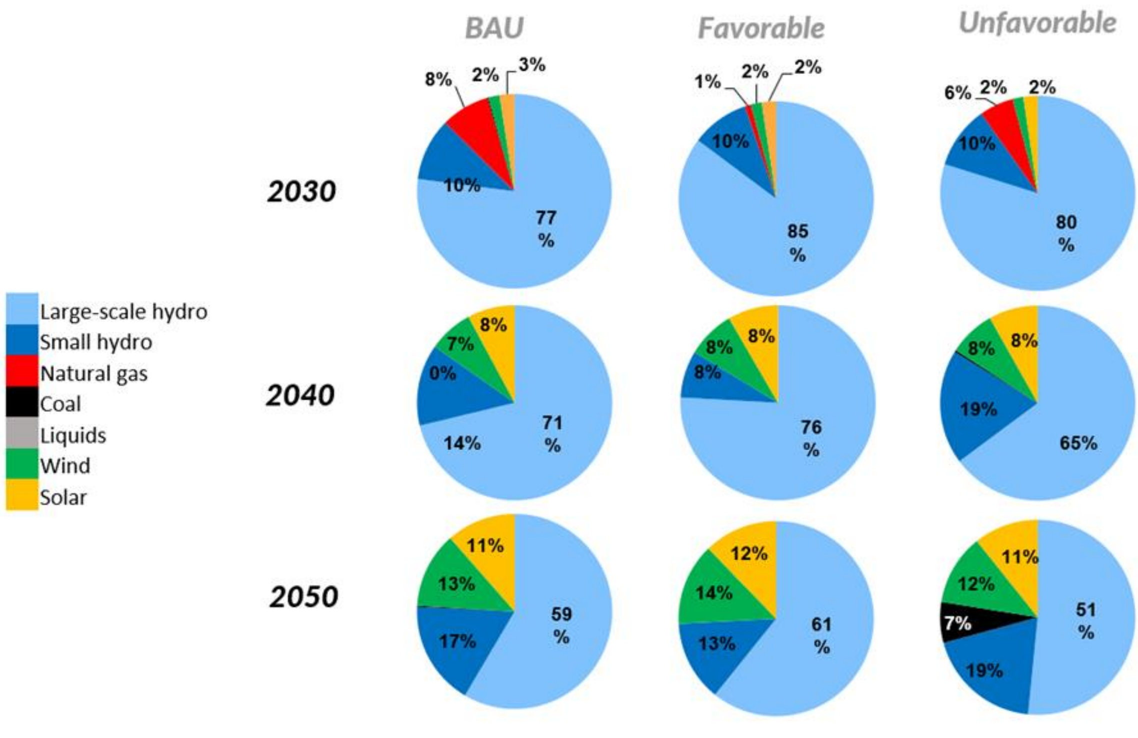

Figure 45. Share of large-scale hydropower in the Colombian electric energy generation, for different scenarios and timeline [11].

5.8. Advantages/disadvantages

5.8.1. Advantages

- Hydropower is the most efficient renewable energy. The water to wire efficiency can reach 90%
- Hydropower facilities have a very long service life, which can be extended indefinitely, and further improved. Some operating facilities in certain countries are 100 years and old. This translates into long-lasting, affordable electricity.
- Water flow short-term variability (hourly, daily) is usually lower that wind or solar, making it more predictable for energy dispatch

Specific Advantages for Reservoirs

- Reservoirs can store energy in form of water to be used as needed; engineers can control the flow of water through the turbines to produce electricity on demand.
- Hydropower reservoirs can be used jointly in other uses such as water supply, irrigation and flood control
- Cascading hydropower projects can be managed to achieve an optimal use of the water resources

Specific Advantages for Run of River Projects

- Run of river hydro does not flood large extensions of land, having a minimal landscape or land use impact.
- Run-of-rive hydro does not affect the natural regulation of the water resource
- Run of rive hydro can be scaled down and become solutions for distributed generation or non-grid-connected populations

5.8.2. Disadvantages

- Hydropower facilities impact the local environment and may compete with other uses for the land and water. Those alternative uses may be more highly valued than electricity generation
- 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 are impacted by climate variability, i.e. seasonal droughts. When water is not available, the hydropower plants cannot produce electricity. This is particularly critical for Colombia and the influence of El Niño Phenomenon.

Specific Disadvantages for Reservoirs

- Reservoirs have very significant social impacts as building a dam modifies the economic vocations of territories, and may include the relocation of population, this can create loss of social capital
- 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.

- Reservoirs plants are impacted by sedimentation. Sedimentation affects the safety of dams and reduces energy production, storage, discharge capacity, regulation ability and flood attenuation capabilities, as also detailed in section *Environment*. It increases loads on the dam and gates, damages mechanical equipment and creates a wide range of environmental impacts.

Specific Disadvantages for Run of River Projects

- Run-of-river projects re unable to store water, so they have no regulation ability over the water resource
- Run-of-river project are subject to flash flooding risks that could potentially damage intake structures
- Run-of-rive projects may need additional equipment to remove obstacles from the water intake structures

5.9. Environment

Environmental issues identified in the development of hydropower include:

- **Safety issues:** Modern hydropower is considered a safe energy source, with dam failures[5] causing loss of life being relatively rare in the last three decades. The population at risk has been significantly reduced through the routing and mitigation of extreme flood events. There have been observed improvements in dam safety over time. The International Commission on Large Dams (ICOLD) notes a fourfold reduction in failure rates over the past 40 years [29]. For dams built before 1950, the failure rate was 2.2%, whereas for those constructed after 1950, the rate decreased to less than 0.5% [30]. However, recent incidents like the Brumadinho dam disaster, the Derna dam disaster, and the Koshi Barrage breach underscore the need for continued safety precautions [31].
- **Water use and water quality impacts:** The impact of hydropower plants on water quality is 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 [26].
- **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.
- **Reservoir sedimentation and debris**: Dam construction may change geomorphology and sedimentation or erosion patterns of the river and affect the reservoir, the dam/power plant and the downstream environment [27]. Sedimentation in reservoirs impacts hydraulic regulation by reducing storage capacity, which limits the ability to control water flow for electricity generation and flood management. Accumulated sediment decreases the effective water volume and can obstruct control structures, reducing operational efficiency and safety. Sedimentation prevention methods include reforestation in the watershed, which stabilizes soil and minimizes erosion; sustainable

[5] Failure or inadequate capacity of the flood discharge structure is the most common cause of dam failure, which is typically a design flaw rather than a consequence of inadequate O&M [29].

agricultural practices, which reduce soil loss and sediment flow from farmland; and constructing upstream sediment barriers, which capture sediment before it reaches the main reservoir [28].

- **Reservoir greenhouse gas emissions**. Greenhouse gases like carbon dioxide and methane are generated through the natural breakdown of organic matter in most aquatic environments, including reservoirs. These emissions are significant in human-made reservoirs, which are typically created for purposes like hydroelectricity generation or water storage by dam construction. Since reservoirs are artificial, the greenhouse gases they release are considered to have anthropogenic origin [12].

5.10. Research and development perspectives

Hydropower is a very mature and well-known technology. While hydropower is the most efficient power generation technology, with a high energy payback ratio and conversion efficiency, there are still room for small but important improvements in technological development.

5.10.1. 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). Some improvements aim directly at reducing the environmental impacts of hydropower by developing fish-friendly turbines. aerating turbines and oil-free turbines.

5.10.2. Hydrokinetic turbines

Kinetic flow turbines as illustrated in Figure 46 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.

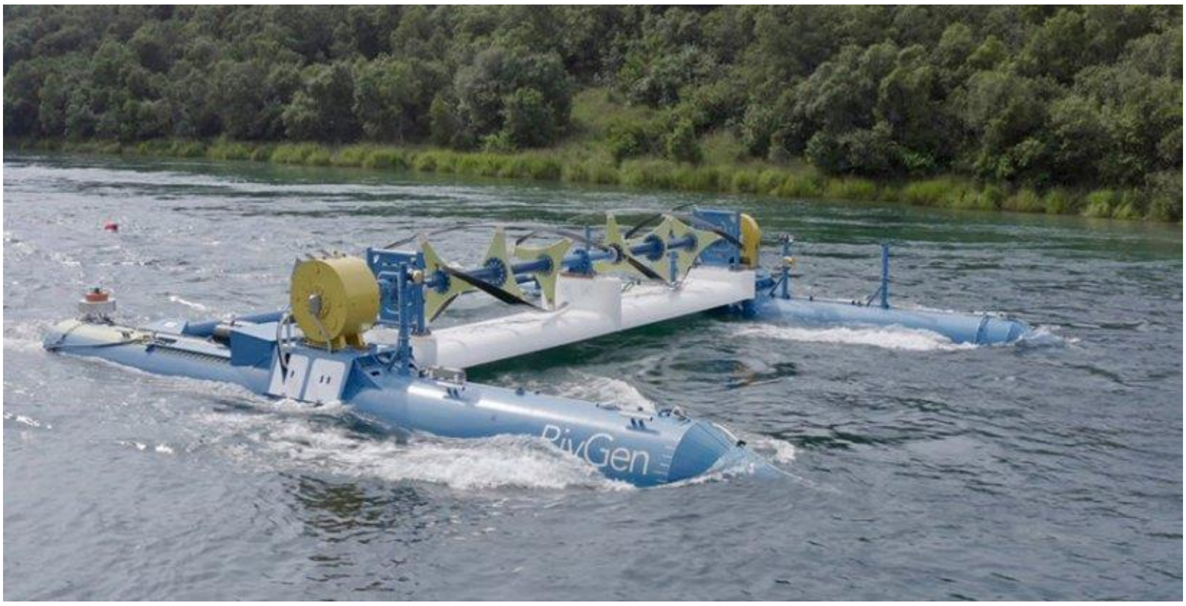

Figure 46. RivGen Power System – Hydokinetic turbine deployed in Alaska [14].

5.10.3. Archimedean screws

Originally conceived as a method for lifting water, have found a modern application in generating renewable energy. These devices, shown in Figure 47, consist of a large helical screw encased in a cylindrical tube that is partially submerged in water. As water flows into the lower end of the screw, the force of the water's weight and the flow itself cause the screw to rotate. This rotation is then harnessed to drive a generator, producing electricity. Archimedean screws are particularly effective in low-head hydropower sites where traditional turbines might not be as efficient. They offer several advantages, including low installation and maintenance costs, high efficiency across a range of flow conditions, and an inherent fish-friendliness that minimizes environmental impact. These characteristics make Archimedean screws an attractive option for small-scale hydropower projects, contributing to the diversification of renewable energy sources while supporting ecological conservation efforts. In Colombia, Archimedean screws have been used to provide water for non-grid connected relocation areas of former ex-combatants.

Figure 47. Pico hydropower with Archimedean screw in Miravalle, Meta [15].

5.10.4. Climate change adaptation

To adapt hydropower systems to climate change, research focuses on understanding the impacts of changing water availability and extreme weather events. Climate change will cause both water scarcity and increased flooding due to more frequent and intense precipitation events. Hydropower plants, especially those without upstream flow control, may face challenges with seasonal water variations and increased flood risks, potentially leading to operational issues and reduced efficiency.

Key areas of research include developing high-resolution climate and hydro-meteorological scenarios for each dam site to predict future water flows and extreme weather events. This data will help optimize plant operations, maintenance, and infrastructural adaptations. For example, flood management systems such as spillways, gated systems, and fuse plugs need to be evaluated for their compatibility with existing dams and surrounding geography. In some cases, infrastructural adaptation, like building larger dams, may be necessary where significant water runoff is expected [16].

There is existing research aimed to use high-resolution hydrological modelling to assess the impact of climate change on the river's flow. Using future precipitation projections from climate models, and spatial downscaling and bias correction it is possible daily precipitation series reflecting climate change signals, which were then used to drive the hydrological model to assess potential changes in flow regimes (see Figure 48) [17].

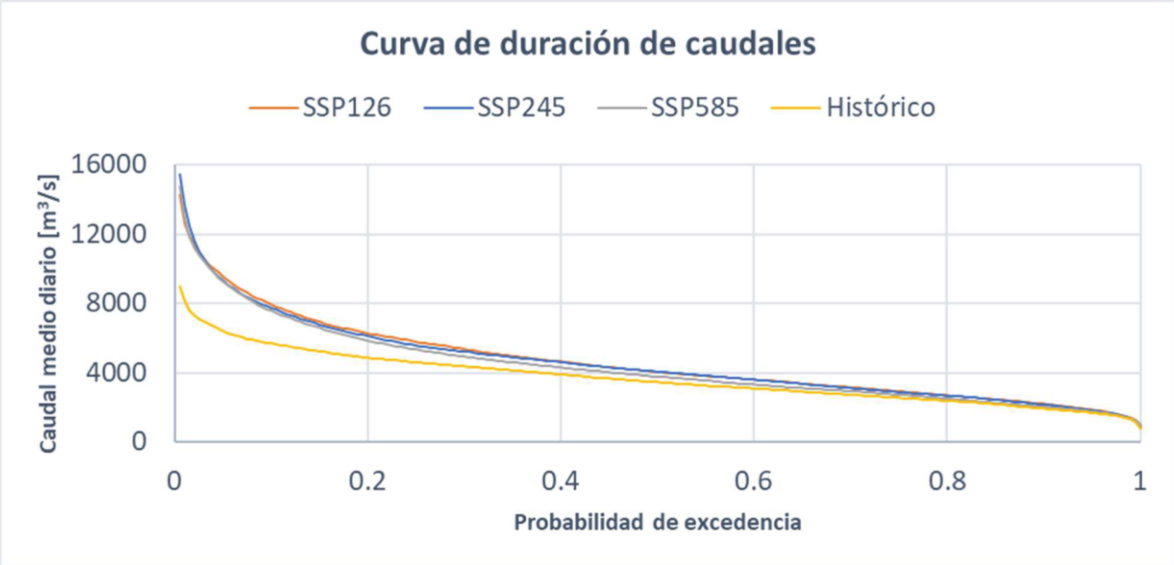

Figure 48. Flow duration curves for the Magdalena River in Colombia under climate change scenario represented by Shared Socioeconomic Pathways (SSPs): SSP1-2.6, SSP2-4.5, and SSP5-8.5 [17].

5.10.5. Watershed Management

Hydropower differs from other renewables like wind and solar due to its unique ability to manage and influence watershed resources. This management of watersheds in terms of land use, forest cover, reservoir construction and others, allows hydropower systems to further adapt to changing climate conditions, such as shifts in precipitation patterns and water. This capability to actively manage and adapt to watershed changes can provide a significant advantage in mitigating and responding to climate change impacts.

One of the existing tools to understand this is the Watershed Modelling Framework (WMF) [19]. WMF uses modular Python-based platform designed for efficient, distributed modelling of hydrological processes at the watershed scale. The WMF facilitates applications in flood prediction, water resource management, and climate change impact assessment, providing a robust foundation for informed decision-making. This adaptability is particularly beneficial for developing countries facing challenges like resource constraints and inadequate infrastructure. By offering a deeper understanding of hydrological processes, the WMF supports the creation of more effective and sustainable water management policies, including the hydropower sector [20].

5.11. Examples of market standard technology

Hidroituango

The Hidroituango project in Colombia, depicted in Figure 49, features a large dam that is 225 meters high and has a volume of 20 million cubic meters, harnessing Cauca River with a flow of 1,010 cubic meters per second. The project includes plans for an underground power station with an installed capacity of 2,400 MW and an average annual energy output of 13,930 GWh. The machine hall, resembling a 17-story building, will house eight 300 MW Francis turbines [21].

Additional facilities at the plant include electromechanical and control equipment, a control room, assembly room, and office buildings. The transformer cavern upstream houses three single-phase transformer banks per generating unit. Downstream, two surge chamber caverns collect water post-turbine, returning it to the Cauca River via discharge tunnels located about 1,400 meters downstream.

The generation units are fed by a supply tunnel beginning on the right bank of the river, equipped with gates for flow control. An intermediate discharge tunnel, modified to handle a flow of up to 750 m^3/s, manages reservoir filling and controlled water release downstream of the dam. The spillway, an open-channel controlled by four gates, can handle up to 22,600 m^3/s of water, about the size of four soccer fields. Externally, the main 500 kV encapsulated substation receives power from the transformer cavern. The reservoir itself is 78 km long and holds up to 2.8 billion cubic meters of water at maximum operating level. Additional infrastructure includes access roads, campsites, a transmission line, and a construction substation.

Figure 49. Hidroituango Hydropower Project [21].

Miel

The Miel I Hydroelectric Power Plant shown in Figure 50 is located in the municipality of Norcasia and forms part of the water potential of eastern Caldas, a region comprised by the basins of the rivers Guarinó, La Miel, Moro, Manso, Samaná Sur and secondary tributaries such as the rivers Pensilvania and Tenerife. It began commercial operation in December 2002. The power plant has a Net Effective Capacity of 396 MW. The Patángoras dam, which is 188 m high, is built on the La Miel River, creating the Amaní reservoir, which covers 1,220 hectares and has a storage capacity of 571 million m^3 [22].

Figure 50. Miel I Hydropower Project [21].

Agua Fresca

In its first stage, Agua Fresca it is a hydroelectric run-of river power generation project, with a design flow of 2.7 m^3/s, an installed capacity of 7.49 MW and an annual production of 63.3 GWh. The connection of the Project to the National Electrical Grid is done in the Municipality of Fredonia, in the Fredonia Substation of Empresas Públicas de Medellín - EPM. For this, a 44 kV transmission line with a length of 15 km was built. It is estimated that the project will displace yearly 11,577 tCO_2e, by displacing the power generation of the thermal plants in the Colombian Electric Sector. The project, depicted in Figure 51, reuses the water from the discharge of Rio Piedras Hydroelectric Plant. In case this plant is not operating or operating with a flow less than 2.7 m^3 /s, Agua Fresca Power Plant counts with a secondary intake structure that takes water directly from the river. In this way, Agua Fresca project is independent and has an increased reliance in its operation [23].

Figure 51. Agua Fresca hydropower project [32].

5.12. Prediction of performance and costs

5.12.1. Investment cost overview

The overnight capital cost of hydropower plants strongly depends on the site where the plant is located and observed costs therefore have very large variations. 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. Table 5-6 shows differences in investment costs across regions.

Table 5-6. Investment cost comparison across regions for different hydropower projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	2.5 (large RoR) 3.0 (small RoR) 4.3 (mini RoR) 2.5 (large hydro reservoir)	2024
	National data	
Stakeholder workshop	3-5 (large RoR)	2024
	International data	
Technology Catalogue Indonesia (2024)	2.47 (large RoR) 2.81 (small RoR) 3.03 (mini RoR)	2023
Technology Catalogue Vietnam (2023)	1.58 (large RoR) 1.08 (large hydro reservoir)	2022
Technology Catalogue India (2021)	1.76 (large hydro) 1.37 (large hydro reservoir	2021
IEA GEC Model, Brazil region (2021)	2.36 (large RoR) 3.76 (small RoR)	2021

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5.14. Datasheet

5.14.1. Hydro run-of-river – large scale

Technology	Hydro power plant - large system								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MW_e)	35	35	35	20	50	20	50	A	1,6,11
Electricity efficiency, net (%), name plate	95	95	95	85	97	85	97		8
Electricity efficiency, net (%), annual average	95	95	95	85	97	85	97		8
Forced outage (%)	4	4	4	2	7	2	7		9
Planned outage (weeks/year)	3	3	3	2	6	2	6		9
Technical lifetime (years)	50	50	50	40	90	40	90		8
Construction time (years)	4	4	4	2	6	2	6		3,11
Space requirement (1000 m^2/MW_e)	2,4	2,4	2,4	1,4	3,2	1,4	3,2	G	10,11
Additional data for non-thermal plants									
Capacity factor (%), theoretical	53	53	53	38	66	38	66	H	
Capacity factor (%), incl. outages	48	48	48	31	62	31	62	H	6,7
Ramping configurations									
Ramping (% per minute)	55	55	55	0	100	0	100	H	6,12
Minimum load (% of full load)	0	0	0	0	0	0	0		12
Warm start-up time (hours)	0.3	0.3	0.3	0	0.5	0	0.5		6
Cold start-up time (hours)	0.3	0.3	0.3	0	0.5	0	0.5		6
Environment									
PM 2.5 (g/GJ of fuel input)	0	0	0	0	0	0	0		
SO_2 (g/GJ of fuel input)	0	0	0	0	0	0	0		
NO_X (g/GJ of fuel input)	0	0	0	0	0	0	0		
CH_4 (g/GJ of fuel input)	0	0	0	0	0	0	0		
N_2O (g/GJ of fuel input)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (millon USD/MW_e)	2.50	2.50	2.48	2.2	3.0	2.18	2.98	B,E,I	2,3,4,5,11
- of which equipment	0.90	0.90	0.89	0.79	1.08	0.79	1.07	C,E,I	2,3,4,11
- of which installation	1.60	1.60	1.59	1.41	1.92	1.40	1.91	C,E,I	2,3,4,11
Fixed O&M (USD/MW_e/year)	55,000	54,900	54,600	44,000	75,000	43,500	74,500	D,E	4,5
Variable O&M (USD/MWh)	0	0	0	0	0	0	0		
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		

Notes

A Large Run of River hydro plants are assessed representative between 20MW and 50MW, based on operational projects in Colombia. The central value corresponds to the average value.

B Aggregated data and fitted curve of Colombian projects in the register by UPME, supplemented with further international sources

C Assuming ca. 36% share of cost amounting equipment and 64% amounting installation for large scale RoR based on stakeholder input

D O&M corresponding to 2.2% of CAPEX/year acc. to IEA with an uncertainty range of 2% to 2.5% for large-scale plants according to IRENA

E Cost 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 2023, with Announced Pledges for the central values.

F This is the efficiency of the utilization of the water's potential energy.

G Space requirements for new sites is highly uncertain given the geographical dependency. Stakeholder input has resulted in the range that is presented here.

H Numbers are based on historical operation, but dispatchable hydro plants are not bound by the numbers presented. The theoretical capacity factor is derived by accounting for lower outage times for the upper capacity factor and vice versa.

I Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the limited general technology improvement potential.

J The baseline cost is derived by economy of scale effects with a proportionality factor of 0.85 based on the cost for large-scale RoR Hydro

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5.14.1. Hydro run-of-river – medium/small scale

Technology	**Hydro power plant - Medium/small system**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MW_e)	10	10	10	1	20	1	20	A	1,6,11
Electricity efficiency, net (%), name plate	95	95	95	85	97	85	97	F	8
Electricity efficiency, net (%), annual average	95	95	95	85	97	85	97	F	8
Forced outage (%)	4	4	4	2	7	2	7		9
Planned outage (weeks/year)	3	3	3	2	6	2	6		9
Technical lifetime (years)	50	50	50	40	90	40	90		8
Construction time (years)	3	3	3	2	6	2	6		3,11
Space requirement (1000 m^2/MW_e)	2,4	2,4	2,4	1,4	3,2	1,4	3,2	G	10,11
Additional data for non-thermal plants									
Capacity factor (%), theoretical	70	70	70	56	76	56	76	H	
Capacity factor (%), incl. outages	63	63	63	46	72	46	72	H	6,7
Ramping configurations									
Ramping (% per minute)	55	55	55	0	100	0	100	H	6,12
Minimum load (% of full load)	0	0	0	0	0	0	0		12
Warm start-up time (hours)	0.3	0.3	0.3	0	0.5	0	0.5		6
Cold start-up time (hours)	0.3	0.3	0.3	0	0.5	0	0.5		6

Environment									
PM 2.5 (g/GJ of fuel input)	0	0	0	0	0	0	0		
SO_2 (g/GJ of fuel input)	0	0	0	0	0	0	0		
NO_X (g/GJ of fuel input)	0	0	0	0	0	0	0		
CH_4 (g/GJ of fuel input)	0	0	0	0	0	0	0		
N_2O (g/GJ of fuel input)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (million USD/MW_e)	3.02	3.01	3.00	2.1	3.8	2.09	3.77	B,E,I,J	2,3,4,5,11
- of which equipment	1.00	0.99	0.99	0.69	1.25	0.69	1.24	C,E,I	2,3,4,11
- of which installation	2.02	2.02	2.01	1.41	2.54	1.40	2.53	C,E,I	2,3,4,11
Fixed O&M (USD/MW_e/year)	66,500	66,400	66,000	46,200	75,000	45,900	83,000	D,E	4,5
Variable O&M (USD/MWh)	0	0.0	0.0	0.0	0.0	0.0	0.0		
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		

Notes

A Small Run of River hydro plants are assessed representative between 1MW and 20MW, based on operational projects in Colombia. The central value corresponds to the rounded average value.

B Aggregated data and fitted curve of Colombian projects in the register by UPME, supplemented with further international sources

C Assuming ca. 36% share of cost amounting equipment and 64% amounting installation for large scale RoR based on stakeholder input

D O&M corresponding to 2.2% of CAPEX/year acc. to IEA with an uncertainty range of 2% to 2.5% for small-scale plants according to IRENA

E Cost 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 2023, with Announced Pledges for the central values.

F This is the efficiency of the utilization of the water's potential energy.

G Space requirements for new sites is highly uncertain given the geographical dependency. Stakeholder input has resulted in the range that is presented here.

H Numbers are based on historical operation, but dispatchable hydro plants are not bound by the numbers presented. The theoretical capacity factor is derived by accounting for lower outage times for the upper capacity factor and vice versa.

I Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the limited general technology improvement potential.

J The baseline cost is derived by economy of scale effects with a proportionality factor of 0.85 based on the cost for large-scale RoR Hydro

References

[1] Bloomberg New Energy Finance, Power Asset Database

[2] UPME, "Registro de Proyectos de Generación" database

[3] Danish Energy Agency, Ea Energy Analyses, Viet Nam Technology Catalogue for Power Generation, 2023

[4] IRENA, 2023, Renewable Power Generation Costs in 2022

[5] IEA, 2010, Projected Cost of Generating Electricity

[6] Paratec - Projects that started operation after 2010

[7] Calculation from Sinergox - Data Provided by MME

[8] Stepan, 2011, Workshop on Rehabilitation of Hydropower, "The 3-Phase Approach".

[9] U.S. Department of Energy, 2015, "Hydropower Market Report".

[10] Ramirez-Tovar el al 2022 Land-use in the Electric Colombian System: Hidden Impacts and Risks of Large-scale Renewable Projects. International Journal of Energy Economics and Policy, 12(2),

[11] Discussion with Technology Catalogue stakeholder group

[12] Eurelectric, 2015, "Hydropower - Supporting a power system in transition".

5.14.1. Hydro run-of-river – mini/micro scale

Technology	**Hydro power plant - Mini/micro system**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MW_e)	1	1	1	0.1	1	0.1	1	A	1,6,11
Electricity efficiency, net (%), name plate	95	95	95	85	97	85	97		8

Electricity efficiency, net (%), annual average	95	95	95	85	97	85	97		8
Forced outage (%)	4	4	4	2	7	2	7		9
Planned outage (weeks/year)	3	3	3	2	6	2	6		6
Technical lifetime (years)	50	50	50	40	90	40	90		6
Construction time (years)	2	2	2	1.5	3	1.5	3		3,11
Space requirement (1000 m^2/MW_e)	2,4	2,4	2,4	1,4	3,2	1,4	3,2		10,11
Additional data for non-thermal plants									
Capacity factor (%), theoretical	56	56	56	24	83	24	83	H	
Capacity factor (%), incl. outages	51	51	51	20	78	20	78	H	6,7
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	F	
Minimum load (% of full load)	-	-	-	-	-	-	-	F	
Warm start-up time (hours)	0.3	0.3	0.3	0.0	0.5	0.0	0.5		6
Cold start-up time (hours)	0.3	0.3	0.3	0.0	0.5	0.0	0.5		6
Environment									
PM 2.5 (g/GJ of fuel input)	0	0	0	0	0	0	0		
SO_2 (g/GJ of fuel input)	0	0	0	0	0	0	0		
NO_X (g/GJ of fuel input)	0	0	0	0	0	0	0		
CH_4 (g/GJ of fuel input)	0	0	0	0	0	0	0		
N_2O (g/GJ of fuel input)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (million USD/MW_e)	4.3	4.25	4.23	4.0	5.0	3.97	4.96	B,E,I,J	2,3,4,5,11
- of which equipment	1.41	1.40	1.40	1.32	1.65	1.31	1.64	C,E,I	2,3,4,11
- of which installation	2.86	2.85	2.84	2.68	3.35	2.66	3.33	C,E,I	2,3,4,11
Fixed O&M (USD/MW_e/year)	94,000	93,600	93,100	80,000	125,000	79,400	124,100	D,E	4.5
Variable O&M (USD/MWh)	0	0	0	0	0	0	0		
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		

Notes

A Mini Run of River hydro plants are assessed representative up to 1MW and below, based on operational projects in Colombia. Mini Run of River hydro plants represent plants suitable for energy communities.

B Aggregated data and fitted curve of Colombian projects in the register by UPME, supplemented with further international sources

C Assuming ca. 36% share of cost amounting equipment and 64% amounting installation for large scale RoR based on stakeholder input

D O&M corresponding to 2.2% of CAPEX/year acc. to IEA with an uncertainty range of 2% to 2.5% for mini-scale plants according to IRENA

E Cost 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 2023, with Announced Pledges for the central values.

F It is assumed that micro and mini hydro are not capable of regulation. The possibility of a turbine bypass could give the possibility of down regulation.

G Space requirements for new sites is highly uncertain given the geographical dependency. Stakeholder input has resulted in the range that is presented here.

H Numbers are based on historical operation, but dispatchable hydro plants are not bound by the numbers presented. The theoretical capacity factor is derived by accounting for lower outage times for the upper capacity factor and vice versa.

I Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the limited general technology improvement potential.

J The baseline cost is derived by economy of scale effects with a proportionality factor of 0.85 based on the cost for large-scale RoR Hydro

References

[1] Bloomberg New Energy Finance, Power Asset Database
[2] UPME, "Registro de Proyectos de Generación" database
[3] Danish Energy Agency, Ea Energy Analyses, Technology Data for the Indonesian Power Sector, 2024
[4] IRENA, 2023, Renewable Power Generation Costs in 2022
[5] IEA, 2010, Projected Cost of Generating Electricity
[6] Paratec - Projects that started operation after 2010
[7] Calculation from Sinergox - Data Provided by MME

[8] Stepan, 2011, Workshop on Rehabilitation of Hydropower, "The 3-Phase Approach".
[9] U.S. Department of Energy, 2015, "Hydropower Market Report".
[10] Ramirez-Tovar el al 2022 Land-use in the Electric Colombian System: Hidden Impacts and Risks of Large-scale Renewable Projects. International Journal of Energy Economics and Policy, 12(2),
[11] Discussion with Technology Catalogue stakeholder group
[12] Eurelectric, 2015, "Hydropower - Supporting a power system in transition".

5.14.2. Hydro with reservoir

Technology	**Reservoir hydro power plant**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MW_e)	200	200	200	50	600	50	600		1,6,11
Generating capacity for total power plant (MW_e)	800	800	800	50	1250	50	2400		1,6,11
Electricity efficiency, net (%), name plate	95	95	95	85	97	85	97	F	8
Electricity efficiency, net (%), annual average	95	95	95	85	97	85	97	F	8
Forced outage (%)	4	4	4	2	7	2	7		9
Planned outage (weeks/year)	3	3	3	2	6	2	6		9
Technical lifetime (years)	50	50	50	40	90	40	90		8
Construction time (years)	5	5	5	4	6	4	6		3,11
Space requirement (1000 m^2/MW_e)	135,2	135,2	135,2	2,4	833,3	2,4	833,3	G	10
Additional data for non-thermal plants									
Capacity factor (%), theoretical	57	57	57	55	63	55	63	H	
Capacity factor (%), incl. outages	52	52	52	45	59	45	59	H	6,7
Ramping configurations									
Ramping (% per minute)	12	12	12	6	23	6	23		6,12
Minimum load (% of full load)	48	48	48	44	51	44	51		12
Warm start-up time (hours)	0.3	0.3	0.3	0	0.5	0	0.5		6
Cold start-up time (hours)	2	2	2	0.1	7	0.1	7		6
Environment									
PM 2.5 (g/GJ of fuel input)	0	0	0	0	0	0	0		
SO_2 (g/GJ of fuel input)	0	0	0	0	0	0	0		
NO_X (g/GJ of fuel input)	0	0	0	0	0	0	0		
CH_4 (g/GJ of fuel input)	0	0	0	0	0	0	0		
N_2O (g/GJ of fuel input)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (million USD/MW_e)	2.50	2.50	2.48	1.85	3.20	1.84	3.18	B,E,I,J	2,3,4,5,11
- of which equipment	1.25	1.25	1.24	0.93	1.60	0.92	1.59	C,E,I	2,3,4,11
- of which installation	1.25	1.25	1.24	0.93	1.60	0.92	1.59	C,E,I	2,3,4,11
Fixed O&M (USD/MW_e/year)	55,000	54,900	54,600	37,000	80,000	36,700	79,500	D,E	4,5
Variable O&M (USD/MWh)	0	0	0	0	0	0	0		
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		

Notes

A Capacity corresponds to the median, lower and higher bound of the operational hydro reservoir power plants in Colombia. The higher uncertainty interval in 2050 corresponds to the largest reservoir plant currently in planning phase.

B Aggregated data and fitted curve of Colombian projects in the register by UPME, supplemented with further international sources

C Assuming ca. 50 % share of cost amounting equipment and 50% amounting installation for large scale reservoir plants according to IRENA Renewable Power Generation Cost in 2022

D O&M corresponding to 2.2 % of CAPEX/year acc. to IEA with an uncertainty range of 2 % to 2.5 % for large-scale plants according to IRENA

E Cost 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 2023, with Announced Pledges for the central values.

F This is the efficiency of the utilization of the water's potential energy

G Space requirements for new sites is highly uncertain given the geographical dependency.

H Numbers are based on historical operation, but dispatchable hydro plants are not bound by the numbers presented. The theoretical capacity factor is derived by accounting for lower outage times for the upper capacity factor and vice versa.

I Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the limited general technology improvement potential.

J The baseline cost corresponds to stakeholder consultation and the presented international benchmark data

References

[1] Bloomberg New Energy Finance, Power Asset Database

[2] UPME, "Registro de Proyectos de Generación" database

[3] Danish Energy Agency, Ea Energy Analyses, Viet Nam Technology Catalogue for Power Generation, 2023

[4] IRENA, 2023, Renewable Power Generation Costs in 2022

[5] IEA, 2010, Projected Cost of Generating Electricity

[6] Paratec - Projects that started operation after 2010

[7] Calculation from Sinergox - Data Provided by MME

[8] Stepan, 2011, Workshop on Rehabilitation of Hydropower, "The 3-Phase Approach".

[9] U.S. Department of Energy, 2015, "Hydropower Market Report".

[10] Ramirez-Tovar el al 2022 Land-use in the Electric Colombian System: Hidden Impacts and Risks of Large-scale Renewable Projects. International Journal of Energy Economics and Policy, 12(2),

[11] Discussion with Technology Catalogue stakeholder group

[12] Eurelectric, 2015, "Hydropower - Supporting a power system in transition".

6. Geothermal

6.1. Brief technology description

Geothermal power plants harness underground geothermal reservoirs, which contain water at high temperatures and pressures with dissolved mineral salts and gases. Through drilling, deep wells are constructed in the geothermal reservoir to extract geothermal fluid (hot brine and/or steam), separating the water from the mineral salts. The steam at relatively high temperatures is then used to operate various Rankine cycles. The geothermal fluid is extracted from a production well which can be characterized by its average enthalpy (and thus pressure and temperature). In 1990, Hochstein proposed the following categorization of geothermal reservoirs [1]

- Low-temperature (enthalpy) geothermal wells with reservoir temperatures below 125°C
- Medium-temperature (enthalpy) geothermal wells with reservoir temperatures between 125°C and 225°C
- High-temperature (enthalpy) geothermal wells whose temperatures exceed 225°C.

In Colombia, geothermal resources are mainly classified as hydrothermal geothermal systems with high temperatures (> 225°C). Only a few geothermal resources have lower temperatures and can be considered as medium enthalpy, but this is significant as there is interest in Colombia to harness them for energy efficiency in the oil industry.

The plant configuration at the geothermal site depends on the application and on the type of geothermal fluid available in the underground, which is its thermodynamic and chemical properties. Geothermal to electrical power conversion systems in use in the world today may be divided into four major energy conversion systems:

- Dry steam plants (found in high-temperature geothermal fields) are used at vapor-dominated reservoirs. The geothermal fluid must be predominantly composed of steam to avoid fast wearing and corrosion of the plant’s components. These plants, depicted in Figure 52, usually make use of saturated or slightly superheated steam.

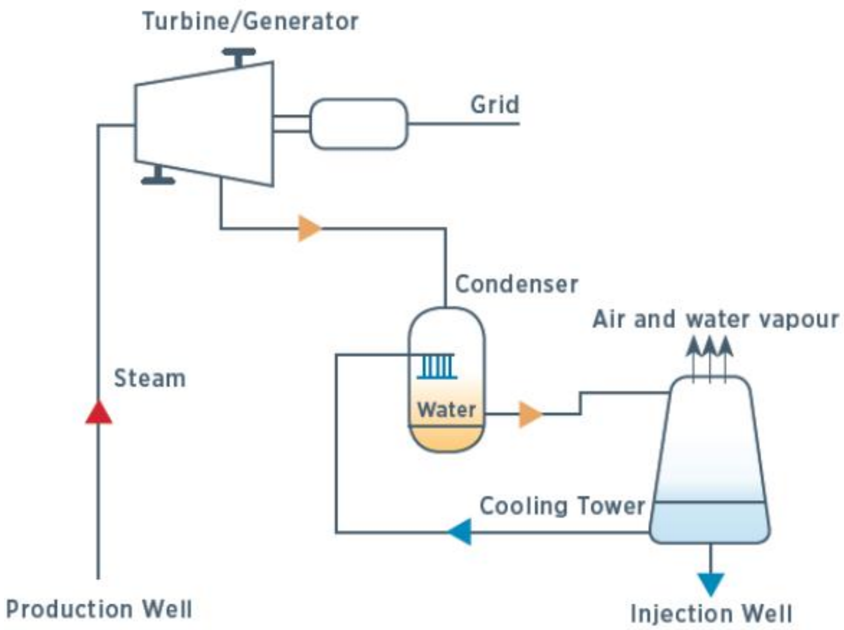


Figure 52. Schematic of a dry-steam geothermal plant [2].

- Flashed steam[6] plants (found in high-temperature geothermal fields), illustrated in Figure 53 and Figure 54, used at both vapor and water-dominated reservoirs and more specifically:
    - Single flash plants (only for high-pressure flash steam).
    - Double flash plants (for both low and high-pressure flash steam).

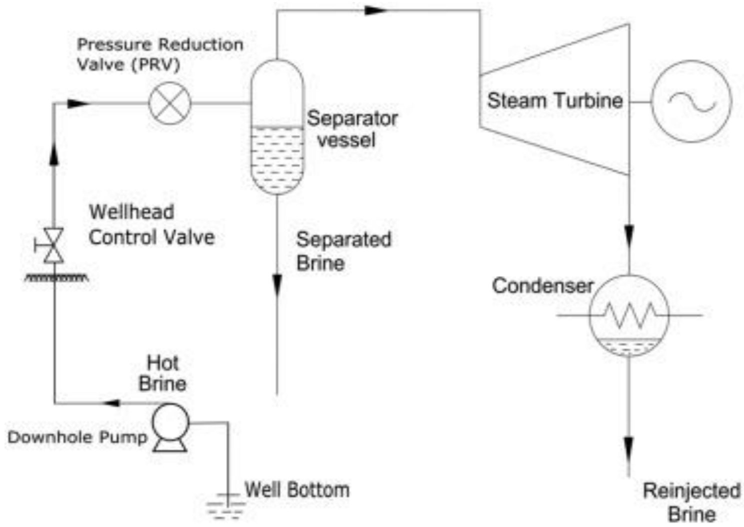


Figure 53. Schematic of a single-flash geothermal plant [16].

Double-flash geothermal power plants are more efficient because they optimally harness the energy of geothermal fluid by generating steam in two stages, as shown in Figure 54. First, the

[6] Flash steam refers to the phenomenon in which a hot geothermal fluid (usually water) undergoes a rapid pressure drop upon entering a separator or expander, causing part of the liquid to instantly transform into steam.

fluid undergoes high-pressure separation, and the resulting steam drives the turbine in the first stage. Then, the remaining liquid is reduced to a lower pressure in a second separator, producing additional steam that is also used in the turbine.

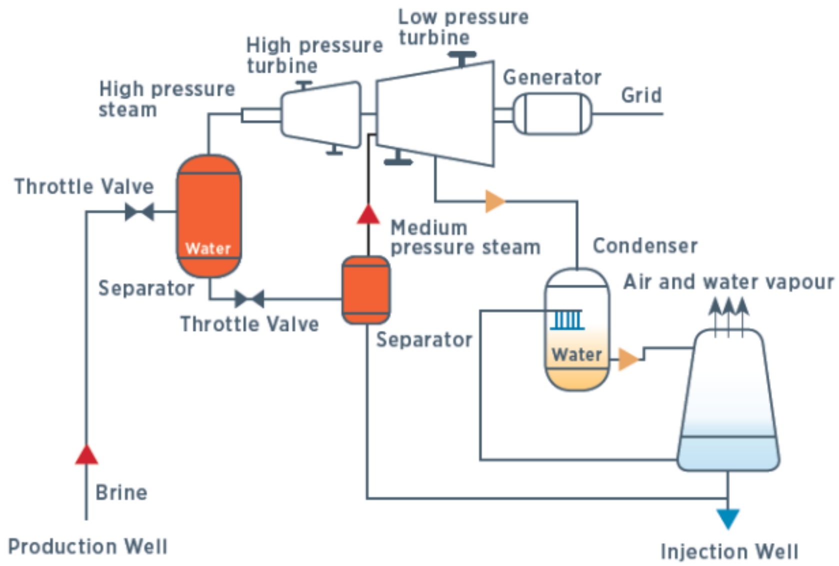
- 

Figure 54. Schematic of a double-flash geothermal plant [2].

- Binary or twin-fluid system are found in low and medium-temperature geothermal fields, based upon Kalina or Organic Rankine Cycles (ORC). The schematic in Figure 55 illustrates how hot brine from the Earth's subsurface is extracted through a production well and passes through a heat exchanger, transferring its heat to a secondary working fluid with a lower boiling point. The working fluid vaporizes, driving a turbine connected to a generator, and is then condensed and cooled in a cooling tower before being recirculated, while the cooled brine is reinjected into the earth through an injection well. With new ORC technologies, it is possible to harness resources even at temperatures below 100°C [15].

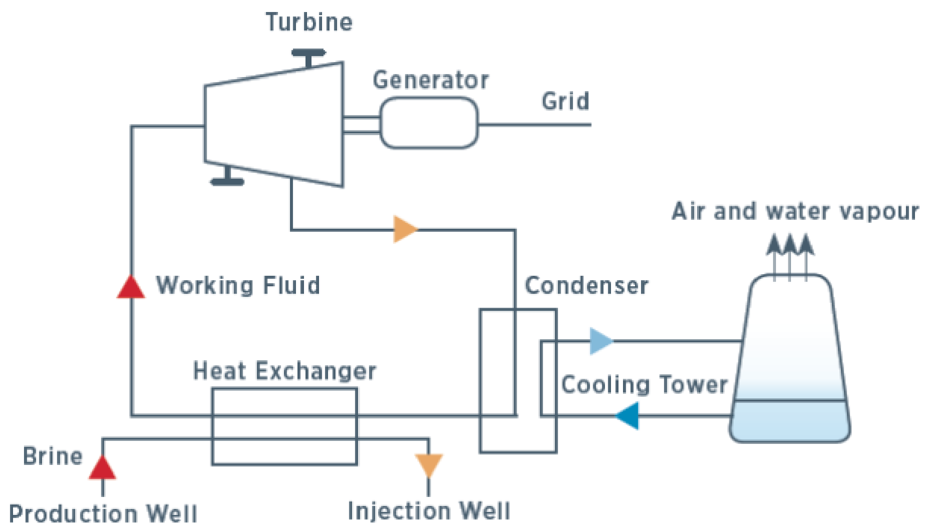


Figure 55. Schematic of a binary geothermal plant [2].

- Hybrid/Combined Cycle, which is a combined system comprising two or more of the above basic types in series and/or in parallel, as shown in Figure 56. Typically, binary plants can be used as bottoming cycles to exploit residual heat from a topping (flash) plant or other heat production systems can be incorporated to boost the plant efficiency, such as Concentrated Solar Power (CSP).

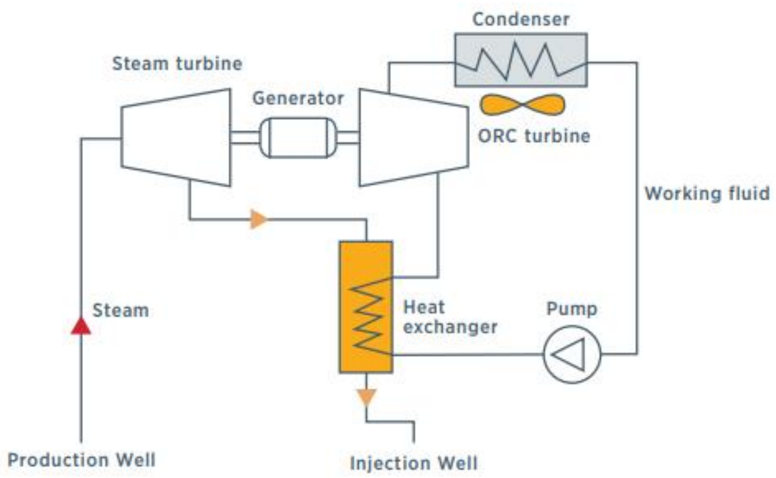


Figure 56. Schematic of a hybrid geothermal plant [2].

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 of system is the most common type of power conversion system in use today. Depending on the geothermal fluid characteristics, plant type and system frequency, geothermal turbines are manufactured in different sizes, up to 120 MW. Binary type low/medium temperature units, such as the Kalina cycles or ORCs, are typically manufactured in smaller sizes, i.e., ranging between 100 kW and 10 MW nominal output. Larger units tailored to specific uses are, however, available at higher prices.

Geothermal power plants generally have lower conversion efficiency than conventional thermal power plants due to the lower temperature and pressure of geothermal fluids. The efficiency of geothermal plants varies depending on the type of system and the enthalpy of the reservoir. As shown in Figure 57, binary plants tend to have lower efficiency at higher enthalpy ranges but are more efficient at lower enthalpies (750–850 kJ/kg), with an efficiency of around 8 %.

On the other hand, double flash plants can achieve higher efficiencies, reaching up to 15 % with reservoir enthalpy above 1800 kJ/kg. Single flash and dry steam plants perform best at the highest enthalpy levels, achieving efficiencies of up to 17 % [3].

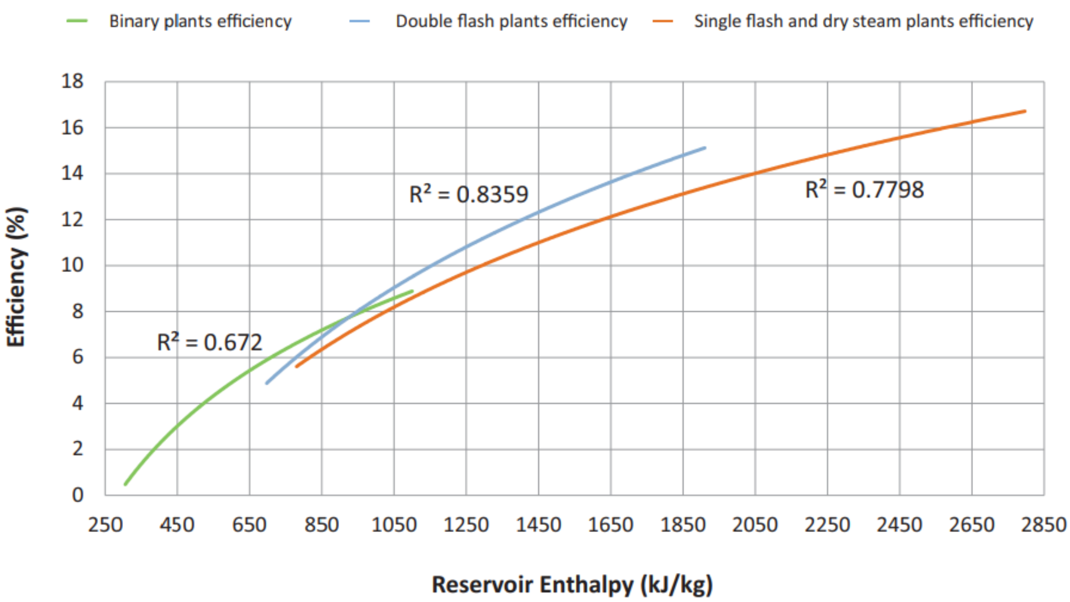


Figure 57. Geothermal power plant efficiency summary [3].

6.1.1. Geothermal Potential in Colombia

In 2020, as seen in Table 6-1, the Colombian Geological Service estimated the country potential at 1170.20 MW_e with a stored heat of 138.60 EJ, in 21 geothermal areas distributed in 80 clusters [4]. It is worth noticing that this is a preliminary study that only considers hydrothermal reservoirs and does not include reservoirs associated to sedimentary basins nor that may be exploited in co-generation in the hydrocarbon industry.

Table 6-1. Heats and estimated electric power in the Geothermal areas of Colombia [4].

Geothermal Area	Hot springs	Clusters	Heat (EJ)	90 % Confidence Interval (EJ)	Recoverable Heat (EJ)	Power (MW_e)	90 % Confidence Interval (MW_e)
Paipa	14	4	4.31	3.41 a 5.22	0.5	21.5	10.96 a 32.04
Paipa*	14	0	2.87	--	0.0	20.89	--
Iza	4	3	2.72	2.27 a 3.14	0.3	12.09	6.45 a 178.73

San Diego	15	6	12.51	11.45 a 13.6	1.15	141.85	118 a 165
Volcán Cerro Bravo	8	4	7.94	6.96 a 8.92	0.88	79.73	63.49 a 95.98
Villamarí a-Termales	9	3	4.83	4.03 a 5.62	0.51	38.5	27.39 a 49.71
Nereidas -Botero Londoño	14	5	12.19	10.55 a 13.83	1.31	100.72	71.60 a 129.85
Hacienda Granates	19	9	11.57	10.39 a 12.76	1.36	67.24	52.04 a 82.43
Volcán de Santa Rosa	20	3	10.66	9.27 a 12.05	1.07	137.24	105.6 a 168.9
Laguna Otún	1	1	0.63	0.3 a 0.95	0.08	0.08	0.03 a 0.13
Nevado del Tolima	18	4	8.66	7.5 a 9.82	1.17	82.7	60.70 a 104.71
Volcán Cerro Machín	14	2	10.05	8.29 a 11.81	1.14	129.94	93.65 a 166.23
Volcán del Huila	4	1	0.76	0.37 a 1.14	0.09	0.1	0.03 a 0.16
Caldera Gabriel López	8	4	5.15	4.55 a 5.75	0.57	24.78	19.69 a 29.83
Caldera del Paletará	21	8	14.27	12.86 a 15.67	1.48	117.96	96.13 a 139.78
Volcanes de Sotará - Sucubún	2	2	2.82	2.37 a 3.27	0.3	17.43	12.06 a 22.62
Volcanes Doña Juana-Las Ánimas	6	3	5.3	4.62 a 5.99	0.55	37.84	29.82 a 45.86
Volcanes Galeras-Morasur co	8	4	4.87	4.22 a 5.51	0.68	29.49	20.68 a 38.29

Volcán de Sibundoy	4	3	3.09	2.66 a 3.52	0.33	9.8	5.52 a 12.83
Volcán Azufral	8	6	9.6	8.69 a 10.52	0.91	81.9	67.41 a 96.36
Volcán Cumbal	1	2	2.56	1.59 a 3.51	0.25	15.66	5.41 a 25.90
Complejo Volcánico Chiles - Cerro Negro	5	3	4.14	3.58 a 4.8	0.48	23.77	16.98 a 30.55
TOTAL	203	80	138.6	136.76 a 140.43	15.11	1170.2	1138.81 a 1201.58

The 21 geothermal areas associated with active and inactive volcanic systems are grouped into five surrounding areas located in the Cordillera Oriental (Paipa - Iza) (see Figure 58). These are located to the north (San Diego and Cerro Bravo - Cerro Machín) and south (Huila - Sucubún and Las Ánimas - Chiles) of the Cordillera Central, with some areas on the eastern flank of the Cordillera Occidental (Azufral, Cumbal and Chiles - Cerro Negro).

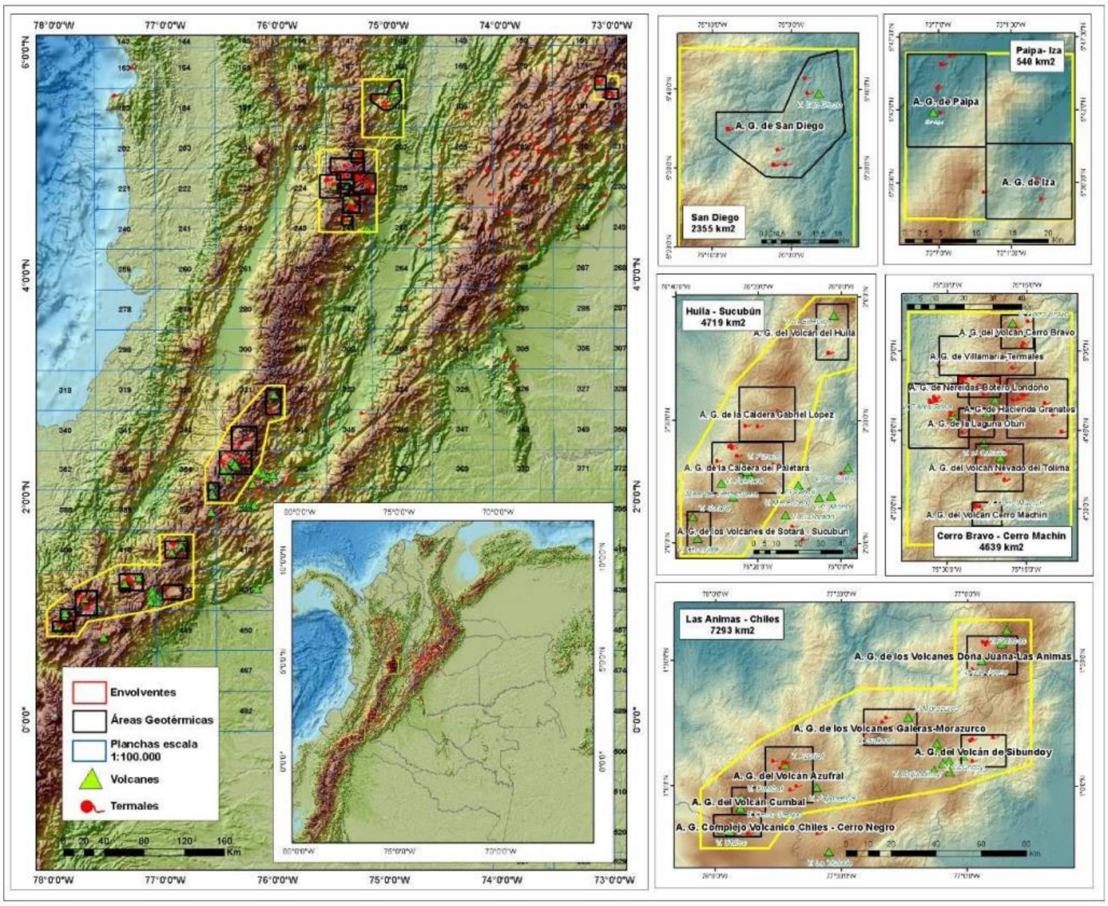


Figure 58. Location of geothermal areas (black polygons) and geothermal blocks (yellow polygons) in Colombia [5].

The most attractive locations for high-enthalpy geothermal resources (> 200°C), include Nereidas - Botero Londoño, Cerro Machín, Cerro Bravo, Paramillo de Santa Rosa, San Diego, Caldera del Paletará, Chiles Cerro Negro, Azufral, and Paipa, have a total stored heat of 85.6 EJ and a total electrical power of 834.6 MW_e. This represents 70% of the potential calculated for the entire territory.

It is worth noting that the SGC studied and estimated the geothermal potential solely using geochemical data from thermal waters. The preliminary estimation of Colombia's geothermal potential corresponds to the implementation of a widely validated methodology for regional geothermal potential assessment in areas lacking information from geothermal exploratory or production wells. Colombia requires reliable information about reservoirs and their potential in volcanic areas [5] to adequately and accurately quantify this potential.

For lower enthalpy geothermal systems not related to volcanoes, a stored heat of 49.56 EJ and an electrical power of 24.95 MW_e were calculated. These systems are located in 16 departments across the Caribbean, Pacific, Orinoquía, and primarily the Andean regions. The highest concentration of stored heat and electrical power corresponds to the department of Huila, with values of 7.08 EJ and 12.09 MW_e, respectively [4]. These resources are associated with thermal springs likely controlled by fracture systems.

6.2. Input

Heat extracted from the thermal fluid, whose characteristics vary depending on the type of reservoir and the geological conditions of the region, although in most cases it consists of high-temperature brine[7] extracted from underground deposits.

6.3. Output

Electricity (heat can be recovered in cogeneration systems).

6.4. Typical capacities

Generation units for geothermal power plants typically range in capacity from small-scale installations generating a few MW to larger facilities producing several hundred megawatts. The capacity depends on factors such as the resource quality, the technology used, and the size of the geothermal reservoir. Smaller plants, often located in regions with low-enthalpy reservoirs, may generate around 2.5–20 MW, serving local communities or industrial needs. On the other hand, larger geothermal units, found in areas with significant geothermal potential, can produce from 50 MW to over 100 MW, enough to supply power to tens of thousands or even millions of homes.

6.5. 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

[7] Brine is saline water with concentrations of dissolved minerals and gases (such as silica, hydrogen sulfide, or carbon dioxide).

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 [6].

6.6. 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.

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 [7].

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 59.

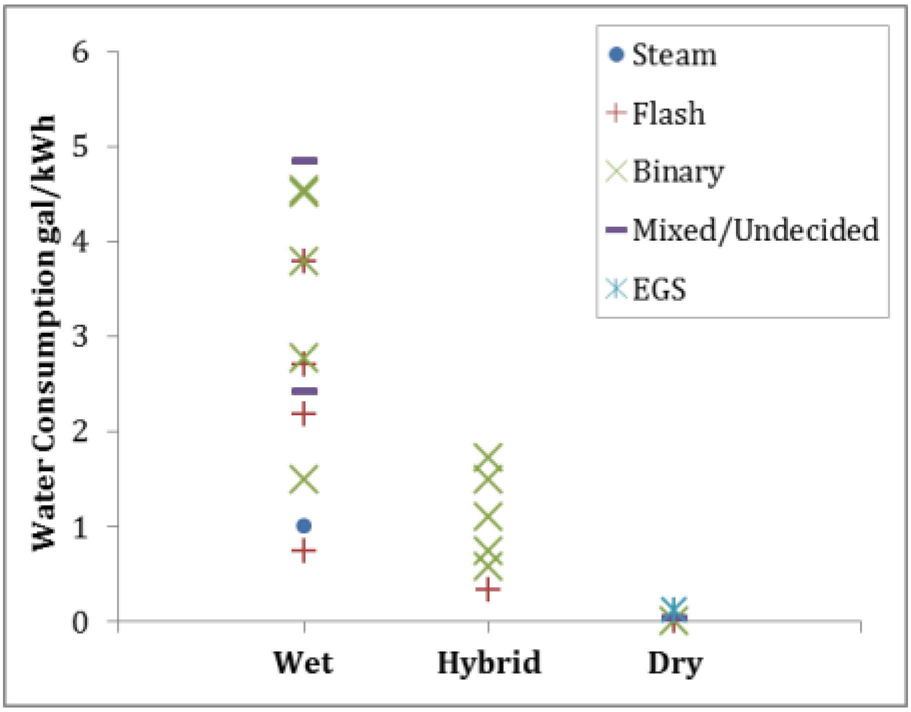


Figure 59. Operational water consumption for geothermal technologies [7].

6.7. Regulation ability and other power system services

Geothermal power can provide the grid with reliable, continuous power, making it an ideal source of baseload energy. Due to its reliance on the Earth's internal heat, which is consistent and inexhaustible over human timescales, geothermal power plants can operate around the clock, being only marginally external weather conditions, day-night cycles, or large-scale climate variability like the ENSO. This constant operation ensures a stable flow of electricity, maintaining grid stability and reliability. Furthermore, geothermal plants typically exhibit high-capacity factors, indicating that they operate at near full capacity most of the time.

Geothermal energy can offer both reliable baseload power and flexible operations. Recent advancements in enhanced geothermal systems (EGS) have further improved this flexibility by allowing plants to store energy underground and adjust output based on grid demand. This makes geothermal energy a valuable complement to variable renewable sources like wind and solar, helping to balance supply and demand in real-time. By shifting energy production to periods when renewable sources are less available, geothermal can support grid stability and maximize economic returns for operators. Enhanced geothermal systems can act like a "built-in battery," storing heat underground when demand is low and generating electricity when it's most needed. This ability to ramp up or down increases the value of geothermal in energy markets and makes it an essential component of future decarbonized grids [8].

6.7.1. Ramping configurations

The general experience is that geothermal energy should be used as a 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.

6.8. Advantages/disadvantages

6.8.1. Advantages:

- High degree of availability (>98 % and 7500 operating hours/annum is common).
- Small ecological footprints.
- Almost zero liquid pollution with re-injection of liquid effluents.
- Insignificant dependence on weather conditions.
- Comparatively low visual impact.
- Established technology for electricity production.
- Renewable energy sources and environmentally friendly technology with low CO_2 emission.
- High operation stability and long lifetime.
- Potential for combination with heat storage and/or other process heat applications.

6.8.2. Disadvantages:

- High initial costs for the exploration stages
- A high risk exists in the first phases of the geothermal project (exploration, tests, etc.) No certainty of success before the first well is drilled and the reservoir has been tested [9].
- Successful projects are very location sensitive. Adequate geothermal reservoirs are not always located near energy demand areas.

- The pipelines to transport the geothermal fluids will have an impact on the surrounding area.
- Geothermal resource depletion if the withdrawal rate from the reservoir is too high.

6.9. Environment

Steam from geothermal fields contains Non-Condensable Gas (NCG) such as Carbon Dioxide (CO_2), Hydrogen Sulphide (H_2S), Ammonia (NH_3), Nitrogen (N_2), Methane (CH_4) and Hydrogen (H_2). Among them, CO_2 is the largest element within the NCG's discharge. CO_2 constitutes up to 95 to 98 % of the total gases, hydrogen sulphide (H_2S) constitutes only 2 to 3 %, and the other gasses are even less abundant.

H_2S is a colourless, flammable, and extremely hazardous gas. It causes a wide range of health effects, depending on concentration. Low concentrations of the gas irritate the eyes, nose, throat, and respiratory system (e.g., burning/tearing of eyes, cough, shortness of breath). The safety threshold for H_2S in humans can range from 0.0005 to 0.3 ppm.

CO_2 and H_2S are the dominant chemical compounds in geothermal steam, thus this catalogue delivers data on CO_2 and H_2S emissions from geothermal power plants in Indonesia. NCG concentrations from each geothermal field are different.

6.10. Research and development perspectives

Geothermal power plants are considered as a category 3 – i.e. commercial technologies, with potential for improvement. Research and development (R&D) in geothermal technologies has been advancing significantly in recent years, driven by the need to diversify renewable energy sources and improve efficiency. The most important trends include [9].

- Enhanced Geothermal Systems (EGS): EGS technology is a major focus, as it expands geothermal potential beyond naturally occurring hydrothermal resources. EGS involves creating or enhancing permeability in deep rock formations by injecting fluid to stimulate geothermal heat extraction. This method can be applied in more geographic locations, providing broader geothermal access. Advances in drilling and reservoir engineering are central to this trend.
- Supercritical Geothermal Fluids: Research is being conducted on using supercritical geothermal fluids, which exist at extremely high temperatures and pressures. These fluids can provide much higher energy output per well compared to conventional geothermal systems. Experiments in areas like Iceland are focusing on accessing these deep, supercritical reservoirs, potentially revolutionizing geothermal energy production
- Cost Reduction via Improved Drilling Technologies: Drilling is one of the most expensive aspects of geothermal projects, accounting for up to 50 % of total costs. R&D efforts are focused on reducing these costs by improving drilling technologies, including faster and more accurate drilling methods and the use of advanced materials. Technologies like thermal spallation and plasma drilling are being tested to significantly lower costs.
- Digitalisation and Monitoring: The integration of digital tools such as advanced simulation models, real-time monitoring systems, and artificial intelligence is another key trend. These technologies allow for better management of geothermal reservoirs,

optimize plant performance, and predict potential failures, increasing efficiency and lifespan.

The production of geothermal energy is influenced by the temperature differential between the air and the geothermal fluid. The temperature of the geothermal fluid is relatively stable over time, meaning that variations in power output are primarily driven by changes in local atmospheric conditions. Researchers from EIA University found that the Climate change trends in the higher altitudes of the tropical Colombian Andes, predict increases in near-surface air temperatures could surpass current levels, potentially impacting geothermal plants in these areas by decreasing their energy production. Climate change forecasts suggest that air temperatures in the Ruiz-Tolima Massif may experience increases between +1.27 ºC and +3.47 ºC, averaging around +2.18 ºC. Under such scenarios, the annual energy production from geothermal sources is estimated to decrease by approximately 1 % for each degree of rise in near-surface air temperature. Developing method for climate change assessment and temperature projections are crucial for assessing the viability and planning of geothermal projects in the mountainous areas [11].

6.11. Examples of market standard technology

The most advanced geothermal project for energy generation in Colombia is in Nereidas Valley, in the Ruiz-Tolima Massif in the Caldas Department. The project has been under study since the 1980s, and has an environmental license granted by the Ministry of Environment. In 2019, CHEC carried out updates to the project's studies to examine what was happening beneath the surface and the promising potential that could allow for the construction of a plant with a capacity of up to 65 MW, with very good prospects for electric power generation. In 2023, CHEC, Ecopetrol and Baker Hughes signed an MOU to structure feasibility studies for the project and will conduct technical studies, subsoil analysis, and structuring of financing sourcing. This would lead to the execution of a pilot project in the department of Caldas [12].

It is worth noticing that in Colombia, potential areas for geothermal energy are in remote and inaccessible places, with extreme climatic conditions, where machines and vehicles may require special adjustments due to power losses and project personnel requires special equipment, training for working at heights, and preparation prior to starting work [14].

These areas are also defined as high-risk zones due to volcanic eruptions and mudflows; this aspect must be carefully assessed for the location of thermal gradient wells, exploration wells, production or reinjection wells, the plant, connection line, and fluid conduction lines. Large-scale, high-resolution, and up-to-date maps and aerial photographs must be available for such assessment and to properly build the hydrogeological model [14].

As for non-conventional geothermal, Parex Resources Colombia, in partnership with the National University of Colombia (UNAL) Medellín Campus, developed pilot projects for the co-production of hydrocarbons and electric power from geothermal resources in the Maracas Block in San Luis de Palenque and the Rumba Field, in the municipality of Aguazul, Casanare . This innovative project primarily seeks to: (i) utilize the temperatures and volumes of water produced in hydrocarbon extraction to generate electricity by using specialized equipment installed at the surface; (ii) produce approximately 100 kW effectively, replacing 5 % of the energy generated from fossil fuels with geothermal energy, thereby reducing up to 550 tons of CO_2e annually [12].

In addition to these projects, Ecopetrol has two permits granted by the Colombian government in April 2024 for the exploitation of the geothermal resource for the generation of electrical energy in co-production mode with hydrocarbons, in the areas called “Apiay” and “Cubarral”. The area called “Apiay” is located in the municipalities of Acacías, Restrepo and Villavicencio – Meta. And the area called “Cubarral” is located in the municipalities of Acacías, Castilla La Nueva and Guamal–Meta. A projected electrical energy generation capacity is estimated, between 300 and 350 KW, for each of the projects, with the possibility of extending to 5-20 MW, thanks to temperatures greater than 100ºC. Enough energy to impact production costs, by being able to supply the energy demand of several assets in this region of the country.

6.12. Prediction of performance and cost

6.12.1. Investment cost overview

The investment costs of a geothermal project are heavily influenced by the exploration and drilling phases and by the type of geothermal power plant (flash or binary). Site selection and preparation are associated with a certain risk in the development of the geothermal project, thereby increasing the plant’s cost of capital. Figure 60 illustrates the relationship between risk and cumulative costs in a geothermal project.

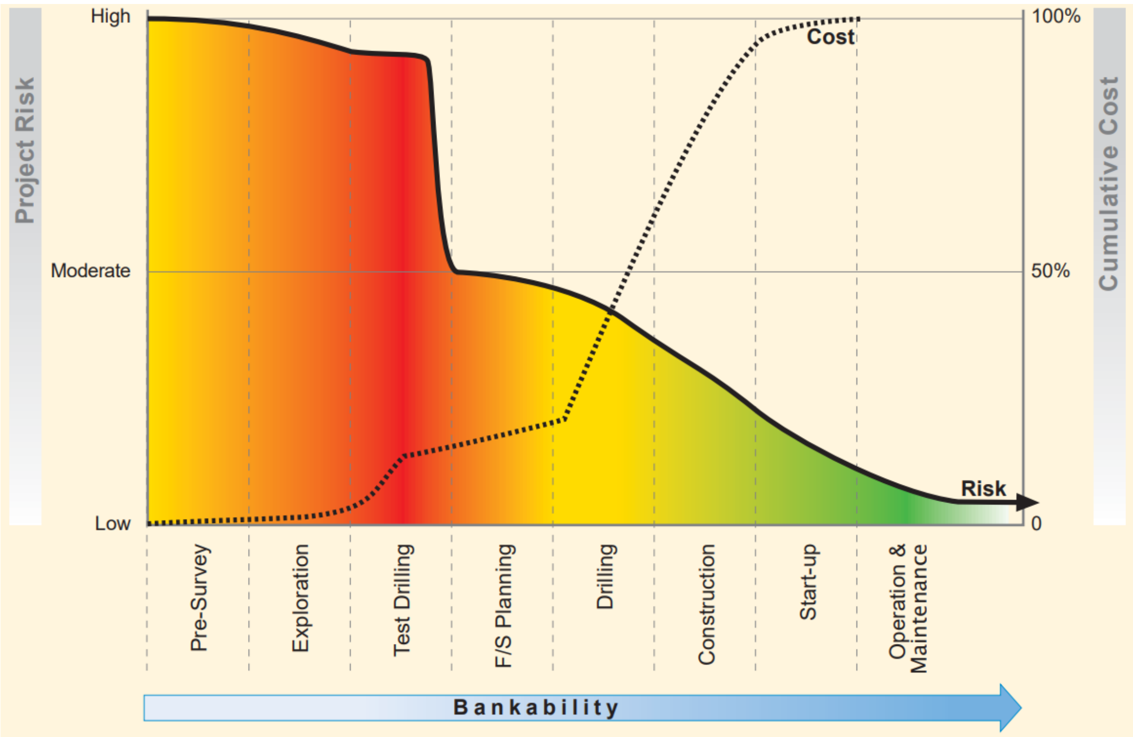


Figure 60. Project cost and risk profile at various stages of development for a geothermal project [13].

Cost figures can therefore span over wide ranges. Flash plants are more economical because of an overall lower need for equipment, while the presence of an ORC (binary plants) increases project costs. Generally, the costs between projects vary a lot and IRENA reports estimated costs ranging from below 2 million USD/MW to above 8 million USD/MW during the last 15 years due to site-specific factors. Cost data from relevant sources are reported in Table 6-2, along with the recommended values for the investment costs.

Geothermal projects also have significant costs related to the continued management of the site to maintain the capacity output and performance throughout the lifetime. These costs are included in the fixed O&M category, estimated at around 110.000-145.000 USD/MW depending on plant type to cover makeup and re-injection of two wells throughout the lifetime.

Table 6-2. Investment cost comparison across regions for geothermal projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	4.72 (large – flash or dry) 6.00 (small – binary or condensing)	2024
National data		
K&M Advisors, 2020, "Reporte del Modelo Económico Financiero (Geotermia)"	4.67 (large – flash or dry) 11.07 (small – binary or condensing)	2020
International data		
Technology Catalogue Indonesia (2024)	4.77 (large – flash or dry) 6.00 (small – binary or condensing)	2023
Technology Catalogue Vietnam (2023)	4.18 (large – flash or dry) 5.52 (small – binary or condensing)	2022

6.13. Additional remarks

6.13.1. Technology specific data, exploration cost

Calculating the exploration cost for geothermal energy involves several steps and various factors that reflect the complexity and uncertainty of geothermal exploration. The total exploration cost is the sum of these costs.

- **Preliminary Survey Costs:** This includes the cost of geological, geochemical, and geophysical surveys. Each survey requires different equipment, expertise, and time, and the costs can vary significantly based on these factors.
- **Adaptation costs, road works, platform design and planning:** Includes the preliminary expenses for the development of the project, the road improvements required for the movement of the equipment and the adaptation of the exploration platform.
- **Exploratory Drilling Costs:** The costliest part of the exploration phase is exploratory drilling, which provides direct information about the site's geothermal potential. The drilling costs depend on the site's geology, the depth of the resource, and the number and depth of the wells drilled.

- **Environmental Impact Assessment (EIA) Costs:** This includes the costs of conducting environmental studies to understand the potential environmental impact of a geothermal project, which is a legal requirement in many jurisdictions.
- **Administrative Costs:** This includes overheads such as project management, permitting, legal and consultation fees.
- **Contingency Costs:** Given the inherent uncertainty in exploration, a contingency cost is often added to the budget to account for unforeseen expenses.

The actual exploration costs vary significantly depending on the site's characteristics, regulatory requirements, and market conditions. Therefore, a generic value found in international literature was included in the technical data within the Datasheets section. It has been explicitly noted that this value varies significantly and should be considered at the plant level.

6.13.2. Technology-specific data, confirmation cost

Confirmation cost for geothermal energy refers to the expenses associated with validating the results obtained during the exploration phase. After identifying a potential geothermal reservoir, the next step is to confirm the site's productivity, the reservoir characteristics, and the feasibility of power production. This phase is crucial as it reduces risks and uncertainties before significant financial commitments are made for development. Here is a framework for calculating the confirmation cost, the total confirmation cost is the sum of all these costs:

- **Confirmatory Drilling Costs:** This includes the cost of drilling additional wells to confirm the results from the exploratory drilling. Costs will depend on factors such as the depth and number of wells, and the site's geology.
- **Reservoir Testing and Modelling Costs:** These costs cover testing the drilled wells and modelling the reservoir to assess its size, temperature, pressure, and other properties.
- **Feasibility Study Costs**: This includes the costs of preparing a detailed technical and financial feasibility study based on the results of confirmatory drilling and reservoir testing.
- **Administrative Costs:** This consists of overheads like project management, legal fees, and permit applications.
- **Contingency Costs:** Given the uncertainties in confirming geothermal resources, a contingency cost is often added to account for potential unforeseen expenses.

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6.15. Datasheets

6.15.1. Flash

Technology	Geothermal power plant (flash or dry)								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MW_e)	50	50	50	30	500	30	500	A	1,4,5,9
Generating capacity for total power plant (MW_e)	100	100	100	30	500	30	500	A	1,4,5,9
Electricity efficiency, net (%), name plate	16%	17%	18%	8%	18%	10%	20%		6
Electricity efficiency, net (%), annual average	15%	16%	17%	8%	18%	10%	20%		6
Forced outage (%)	10%	10%	10%	5%	30%	5%	30%		4
Planned outage (weeks/year)	4	4	4	2	6	2	6		4
Technical lifetime (years)	30	30	30	20	50	20	50		4,7,9
Construction time (years)	2	2	2	1.5	3	1.5	3	E	4,7,9
Space requirement (1000 m^2/MW_e)	30	30	30	20	40	20	40		4
Additional data for non-thermal plants									
Capacity factor (%), theoretical	88%	88%	88%	70%	100%	70%	100%	J,K	4,9
Capacity factor (%), incl. outages	73.1%	73.1%	73.1%	43%	91.3%	43%	91.3%	J,K	4
Ramping configurations									
Ramping (% per minute)	3%	10%	20%	-	-	-	-		8
Minimum load (% of full load)	-	-	-	-	-	-	-		
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (g/GJ of fuel input)	-	-	-	-	-	-	-	F	
SO_2 (g/GJ of fuel input)	-	-	-	-	-	-	-	F	
NO_X (g/GJ of fuel input)	-	-	-	-	-	-	-	F	
CH_4 (g/GJ of fuel input)	-	-	-	-	-	-	-	F	
N_2O (g/GJ of fuel input)	-	-	-	-	-	-	-	F	
Financial data									
Nominal investment (million USD/MW_e)	4.72	4.44	4.10	3.28	6.15	2.85	5.35	B,C,M,P	2,3,4,9
- of which equipment (%)	60%	60%	60%	40%	70%	40%	70%	G,M	2,4
- of which installation (%)	40%	40%	40%	30%	50%	30%	50%	G,M	2,4
Fixed O&M (USD/MW_e/year)	89,800	84,600	78,100	45,900	137,600	39,900	119,700	L,M,N,P	2,4,9
Variable O&M (USD/MWh)	0.30	0.29	0.26	0.22	0.38	0.20	0.33	M,P	4
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Exploration costs (million USD/MW_e)	0.66	0.66	0.61	0.46	0.85	0.43	0.80	H,O	4,9
Capacity expansion cost of nominal investment (%)	82%	82%	82%	91%	73%	91%	73%	I	9

Notes

A Geothermal plants (flash or dry) are assessed representative between 30 MW and 500 MW in 2024, based on operational projects in Colombia and in alignment with further international sources.

B Investment cost are excluding Exploration costs (see under Technology specific data).

C Investment cost include project review and planning, field development, construction, start-up and commissioning and other unforeseen costs.

D The efficiency is the thermal efficiency - meaning the utilization of heat from the ground. Since the geothermal heat is renewable and considered free, then an increase in efficiency will give a lower investment cost per MW. These large units are assumed to be flash units at high source temperatures.

E Refers to construction of the steam cycle power plant itself. Preparation of the geothermal site includes surveying, exploration, drilling, resource confirmation, which can take 4-5 years in total.

F Geothermal do emit H_2S.

G Assumed 60 % equipment, 40 % installation based on international data.

H Exploration cost includes preliminary survey, exploratory studies, exploratory drilling and unforeseen costs in exploratory phases for 50 MW projects in Colombia. This cost varies significantly as it depends on the site's characteristics, regulatory requirements, and market conditions and should therefore be considered on plant level.

I Installing new capacity (MW) in a new phase for an existing project.

J Based on operational data from Colombia.

K Assumed the same theoretical capacity factor for 2030 and 2050 and calculated the capacity factor incl. outages based on the reduction of outages.

L Based on the base scenario (scenario 2) in reference [9].

M Cost are projected with a learning rate approach assuming a 5% learning rate for both equipment and installation based on IEA's World Energy Outlook 2023, and 5% for O&M, including capacity projections of the IEA's World Energy Outlook 2023, with Announced Pledges used for the central values.

N Total O&M cost from reference [9] excluding cost for variable O&M from reference [4].

O Uncertainty (Upper/Lower) is estimated as +/- 30 %

P Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the general technology improvement potential.

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6.15.2. Binary

Technology	**Geothermal power plant (binary or condensing)**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MW_e)	10	10	10	1	50	1	50	A	1,4,5,9
Generating capacity for total power plant (MW_e)	20	20	20	5	50	5	130	A	1,4,5,9
Electricity efficiency, net (%), name plate	10%	11%	12%	6%	12%	8%	14%	D	6
Electricity efficiency, net (%), annual average	10%	11%	12%	6%	12%	8%	14%	D	6
Forced outage (%)	10%	10%	10%	5%	30%	5%	30%		4
Planned outage (weeks/year)	4	4	4	2	6	2	6		4
Technical lifetime (years)	30	30	30	20	50	20	50		4,7,9
Construction time (years)	2	2	2	1.5	3	1.5	3	E	4,7,9
Space requirement (1000 m^2/MW_e)	30	31	32	20	40	20	40		4
Additional data for non-thermal plants									
Capacity factor (%), theoretical	88%	88%	88%	70%	100%	70%	100%	J,K	4,9
Capacity factor (%), incl. outages	73.1%	73.1%	73.1%	43%	91.3%	43%	91.3%	J,K	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/GJ of fuel input)	-	-	-	-	-	-	-	F	
SO_2 (g/GJ of fuel input)	-	-	-	-	-	-	-	F	

NO_X (g/GJ of fuel input)	-	-	-	-	-	-	-	F	
CH_4 (g/GJ of fuel input)	-	-	-	-	-	-	-	F	
N_2O (g/GJ of fuel input)	-	-	-	-	-	-	-	F	
Financial data									
Nominal investment (million USD/MW_e)	6.00	5.66	5.22	4.60	7.63	4.00	6.64	B,C,M,P	2,3,4,9
- of which equipment (%)	60%	60%	60%	40%	70%	40%	70%	G,M	2,4
- of which installation (%)	40%	40%	40%	30%	50%	30%	50%	G,M	2,4
Fixed O&M (USD/MW_e/year)	88,900	83,700	77,300	45,900	137,600	39,900	119,600	L,M,N,P	2,4,9
Variable O&M (USD/MWh)	0.44	0.41	0.38	0.33	0.55	0.29	0.48	M,P	4
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Exploration costs (million USD/MW_e)	2.98	2.98	2.79	2.09	3.87	1.96	3.63	H,O	4,9
Capacity expansion cost of nominal investment (%)	69%	69%	69%	77%	62%	77%	62%	I,Q	9

Notes

A Geothermal plants (binary or condensing) are assessed representative between 1 MW and 50 MW in 2024, based on operational projects in Colombia and in alignment with further international sources.

B Investment cost are excluding Exploration costs (see under Technology specific data).

C Investment cost include project review and planning, field development, construction, start-up and commissioning and other unforeseen costs.

D The efficiency is the thermal efficiency - meaning the utilization of heat from the ground. Since the geothermal heat is renewable and considered free, then an increase in efficiency will give a lower investment cost per MW. These smaller units are assumed to be binary units at medium source temperatures.

E Refers to construction of the steam cycle power plant itself. Preparation of the geothermal site includes surveying, exploration, drilling, resource confirmation, which can take 4-5 years in total.

F Geothermal do emit H_2S.

G Assumed 60 % equipment, 40 % installation based on international data

H Exploration cost includes preliminary survey, exploratory studies, exploratory drilling and unforeseen costs in exploratory phases for a 11 MW project in Colombia. This cost varies significantly as it depends on the site's characteristics, regulatory requirements, and market conditions and should therefore be considered on plant level.

I Installing new capacity (MW) in a new phase for an existing project.

J Based on operational data from Colombia.

K Assumed the same theoretical capacity factor for 2030 and 2050, and calculated the capacity factor “incl. outages” based on the impact of outages themselves.

L Based on the base scenario (scenario 2) in reference 9.

M Cost are projected with a learning rate approach assuming a 5% learning rate for both equipment and installation based on IEA's World Energy Outlook 2023, and 5% for O&M, including capacity projections of the IEA's World Energy Outlook 2023, with Announced Pledges used for the central values.

N Total O&M cost [9] excluding cost for variable O&M.

O Uncertainty (Upper/Lower) is estimated as +/- 30 %

P Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the general technology improvement potential.

Q Assumed same percentage for uncertainty as geothermal flash.

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7. Biomass Power Plant

7.1. Brief technology description

Biomass is a very versatile source for energy production, and it can be harnessed in three primary conversion processes: biochemical, hydrothermal, and thermochemical. In biochemical conversion, biomass undergoes pre-treatment and hydrolysis, followed by fermentation to produce biofuels like bioalcohols, biohydrogen, and biogas. The hydrothermal conversion process focuses on gasification, producing syngas that can be further processed into bioethanol via Fischer-Tropsch catalysis. Lastly, thermochemical conversion involves gasification, liquefaction, and pyrolysis. Gasification generates syngas, which can be used for heat and power, while liquefaction yields tar and bio-oil, and pyrolysis produces gas, bio-oil, and char – all of which contribute to combined heat and power generation. Each process utilizes biomass efficiently, offering multiple avenues for renewable energy production. These types of harnessing options are shown in Figure 61. With these options in mind, this chapter looks at the solid biomass combustion for power generation.

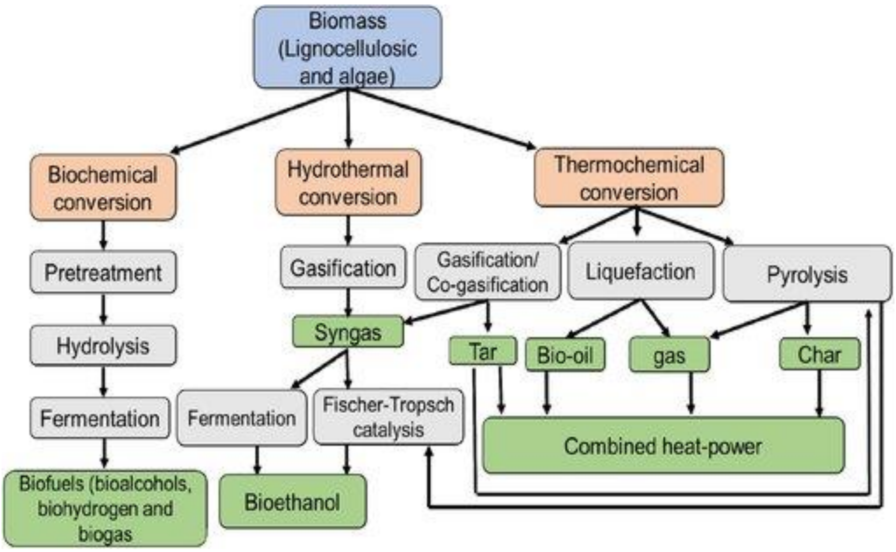

Figure 61. Biomass conversion paths work [1].

The technology used to produce electricity in biomass power plants depends on the biomass resources. The efficiency of biomass combustion for power generation is lower than coal because of a lower calorific value of biomass compared to coal and the limitations in steam temperature and pressure due to the mineral contents of the ash. These efficiencies range typically from 15-35 % [2].

Direct combustion of biomass is generally based on the Rankine cycle, where a steam turbine is employed to drive the generator, like 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 (see Figure 62). In dust combustion, the biomass is pulverized or chopped and blown into the furnace, possibly in combination with a fossil fuel.

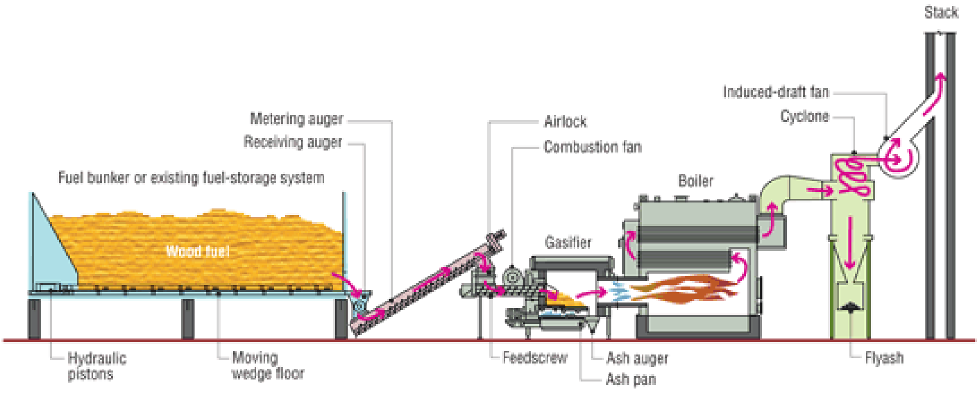

Figure 62. Fixed bed biomass boiler [4].

Calculation of biomass raw materials from plantation products can be done using the mass balance approach. The mass balance is of course different for each raw material. Different crops provide varying levels of efficiency in converting their biomass into usable energy, depending on factors such as the fraction of the biomass used and its lower heating value (LHV). data in Table 7-1 highlight the potential of some common biomass crops in energy generation.

Table 7-1. Percentage of the biomass used and calorific values for different crops in Colombia [22].

Crop	Lower heating value (LHV) (MJ/kg)
Sugar Cane bagasse	14,7
Forest Residues	16.9
Rice Husk	14.9
Coffee grounds	24.5
Coffee husk	17.9
Palm Fibers	16.6
Palm Kernel	16.7
Palm Rachis	18.3

7.1.1. Sugar Cane Cogeneration

Biomass energy production using sugarcane bagasse involves converting the fibrous residue left after sugar extraction into a renewable energy source. Sugarcane bagasse is typically burned in high-efficiency boilers to produce steam, which drives turbines to generate electricity. This process, depicted in Figure 63, is often used in sugar mills, where the energy produced can power both the mill's operations and contribute excess electricity to the grid [7]. Sugar cane is a fast-growing crop, providing a consistent and renewable supply of bagasse in regions where sugarcane cultivation is prevalent, such as Brazil, India and Colombia.

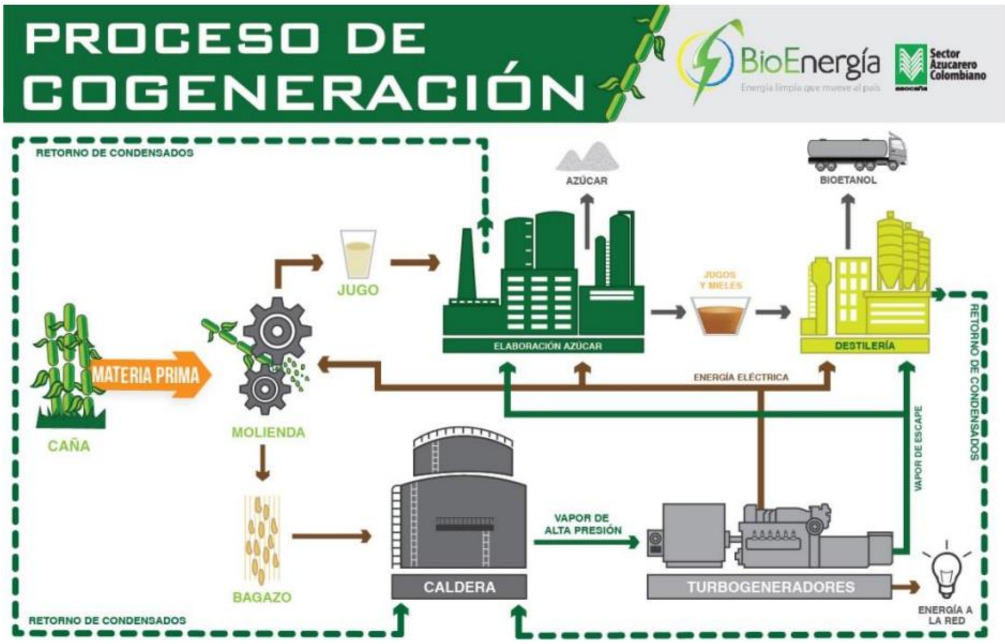

Figure 63. Sugar cane bagasse cogeneration process [7].

7.1.2. Palm oil residue-based feedstock

In a typical palm oil mill, crude palm oil is extracted from fresh fruit bunches (FFB) through a mechanical process. This process, illustrated in Figure 64, generates a waste stream comprising 22 % empty fruit bunches (EFB), 5 % palm kernel shells (PKS), and 13 % mesocarp fibres. Commonly, palm kernel shells and mesocarp fibres are used as fuel to produce steam for sterilizers and electricity to power the mill.

The EFB are usually recycled in plantations or used as fuel in other energy plants, such as those serving palm oil refineries, where steam and power are also required for chemical processes. A key challenge has been ensuring a stable and reliable energy supply during oil processing.

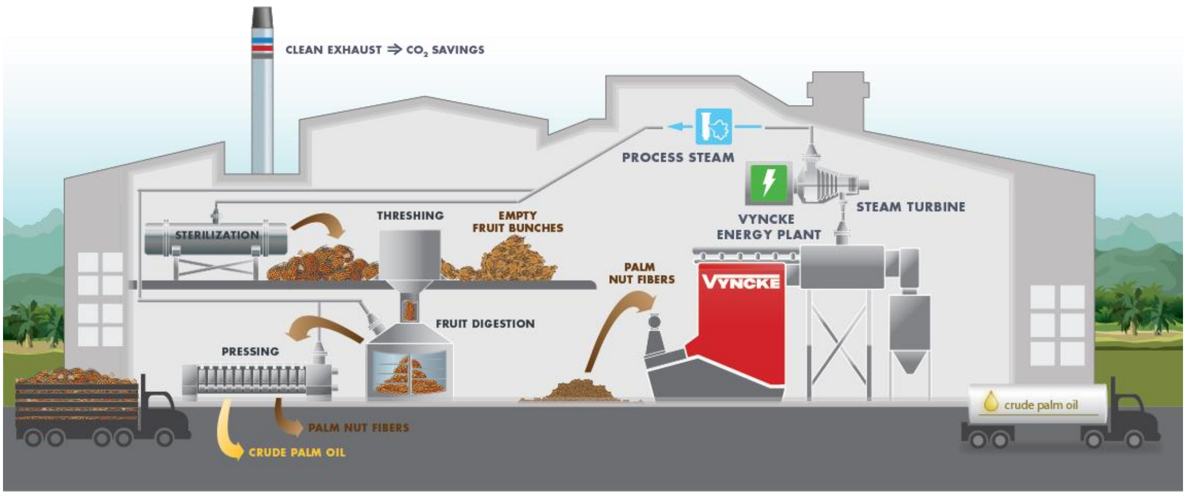

Figure 64. Typical combined heat and power from palm oil solid waste [8].

7.1.3. Biomass potential in Colombia

Colombia has prominent biomass resources which have potential for generation of electricity through direct combustion as shown in Figure 65. The sources include palm oil, sugar cane, coffee, corn, rice husk, banana, and plantain. According to the Mines-and-Energy planning Unit (UPME) and the MME, the total biomass energy potential amounts to almost 347,639 TJ/year which is widely spread over the country *[9].*

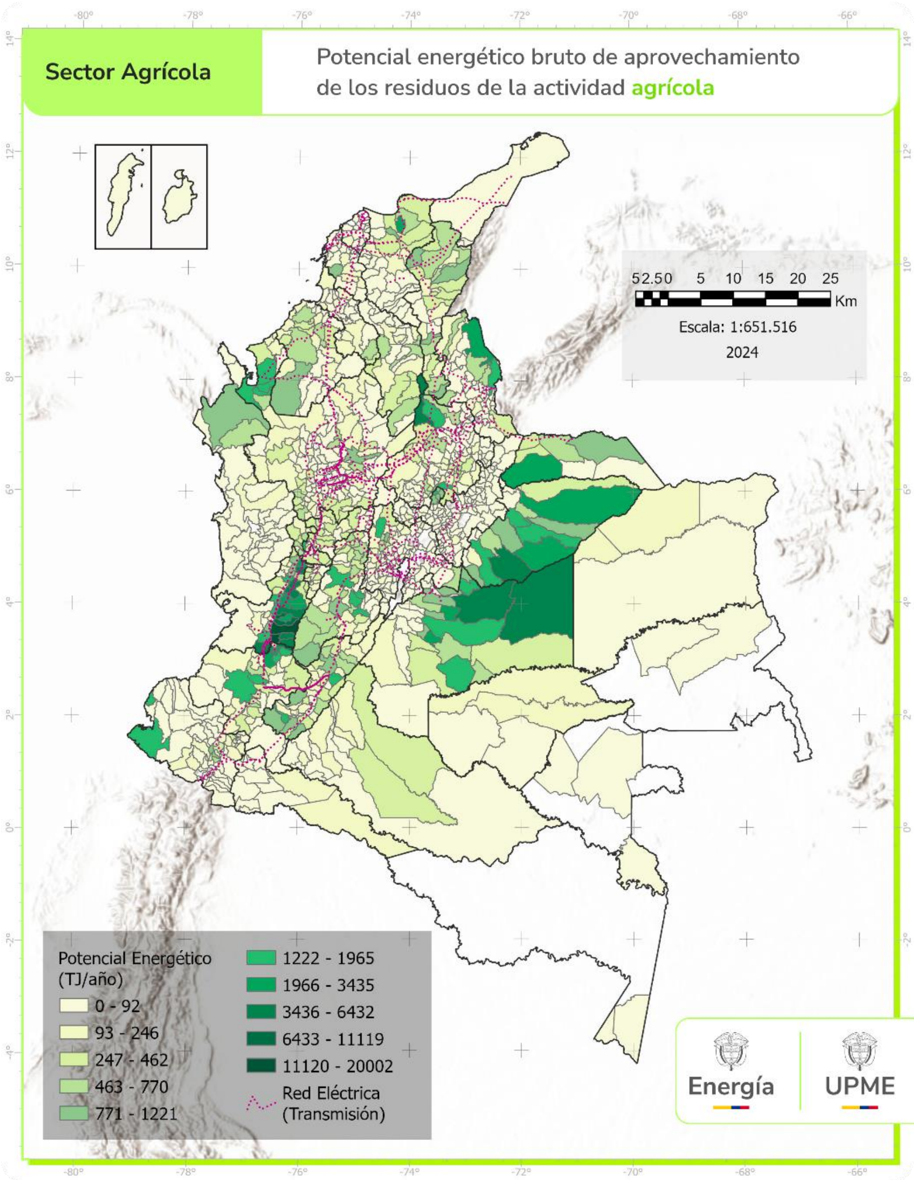

Figure 65. Agricultural Residual Biomass Energy Potential [9].

Agricultural residues volumes vary across various departments in Colombia. As shown in Table 7-2, the departments with the highest biomass energy potential are Valle del Cauca, leading with 108,126.23 TJ/year, followed by Meta with 29,542.55 TJ/year. Quindío, despite its smaller area, stands out with an energy potential of 2,089.76 TJ/year. Other departments with significant contributions include Cauca (27,453.85 TJ/year), Santander (19,121.47 TJ/year), and Tolima (19,716,58 TJ/year) *[9]*.

Table 7-2. Agricultural residual biomass energy potential by department [9].

Department	Energy potential from agriculture (TJ/year)
AMAZONAS	17,75
ANTIOQUIA	19857,07
ARAUCA	4359,22
ARCHIPIÉLAGO DE SAN ANDRÉS, PROVIDENCIA Y SANTA CATALINA	0,38
ATLÁNTICO	269,81
BOLÍVAR	6821,70
BOYACÁ	7343,50
CALDAS	6747,65
CAQUETÁ	1645,79
CASANARE	18250,35
CAUCA	27453,85
CESAR	10471,30
CHOCÓ	2640,99
CÓRDOBA	5940,73
CUNDINAMARCA	9928,99
GUAINÍA	8,80
GUAVIARE	400,84
HUILA	15531,55
LA GUAJIRA	124,88
MAGDALENA	7078,48
META	29542,55
NARIÑO	7878,11
NORTE DE SANTANDER	8326,91
PUTUMAYO	514,13
QUINDIO	2089,76
RISARALDA	4271,93
SANTANDER	19121,47
SUCRE	2667,25
TOLIMA	19716,58
VALLE DEL CAUCA	108126,23
VAUPÉS	7,10
VICHADA	484,35
Total Nacional	347639,99

7.2. Input

Biomass, e.g. residues from industries (wood waste, sugar cane bagasse, empty fruit bunches, coconut shell, etc.), wood chips (from pulpwood, logging residues etc.), 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, $DeNO_x$ catalysts etc. can be applied for further reductions of emissions.

7.3. Output

Electricity (and heat if there is demand for it).

7.4. Typical capacities

Projects in Colombia range from 1 MW to 60 MW of installed capacity *[19].*

7.5. Space requirement

There is not an established figure for the space requirement for agricultural residue as biomass share the space for food productions, and the actual requirement can vary depending on crop yield, climate conditions, and crop type. The power generation facility, including fuel storage, biomass conversion, and emission control systems, typically requires about 0.1 to 0.4 hectares per MW of capacity, depending on the plant design and technology (e.g., direct combustion or gasification). A mid-sized biomass plant might need several hectares for both equipment and operations [10].

7.6. 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) [11]. 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 [28].

7.7. Regulation ability and other power system services

Biomass plants, particularly medium and small-sized facilities equipped with drum-type boilers, can be adjusted to operate within a range of 15 % to 100 % of their nominal load. This operational flexibility allows plants to ramp up or down according to demand fluctuations [25]. Many of these plants are also fitted with heat accumulators, enabling them to be stopped daily without significant loss of efficiency or operational performance.

Unlike other renewables, which depend on weather conditions, biomass power generation can occur continuously, day and night, regardless of weather, because the combustion is not influenced by external environmental factors. Biomass plants can serve as a reliable baseload energy source because they produce a steady and controllable output of energy [24].

While biomass power plants can run continuously in theory, the availability of feedstock can fluctuate based on agricultural cycles, logistical issues, and competing demands. Hence, biomass energy generation may experience variations not due to weather, but because of resource availability tied to these factors. The key to mitigate this is to ensure diverse and reliable feedstock sources and efficient supply chain management [24].

7.8. Advantages/disadvantages

7.8.1. Advantages

- Mature and well-known technology.
- CO_2 emissions are considered neutral[8] when biomass is sourced sustainably as described in the Environment section.
- Biomass power generation is an alternative for agricultural waste management.
- Biomass can be a renewable alternative for heat intensive industrial processes.
- Biomass can support the transition away from fossil fuels by repurposing existing thermal power plants.

7.8.2. Disadvantages

- The availability of biomass feedstock is location dependent.
- Use of biomass from dedicated energy crops can have negative indirect consequences e.g. in competition with food production, nature/biodiversity, depending on regional conditions [26].
- In the low-capacity range (less than 10 MW) the economies-of-scale affect the costs and competitiveness of projects.
- 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 % to keep the boiler from being damaged [12].
- Combustion of biomass results in emissions of SO_2, NO_x and particles.
- Biomass feedstock volume can be affected by agricultural cycles.
- Biomass feedstock collection, stockpiling and transportation can create supply chain issues that can generate cost overruns in power generation [27].

7.9. Environment

The main ecological footprints from biomass combustion are persistent toxicity, and acidification. However, the footprints are small, particularly when only biomass residues, are used for combustion [13]. The combustion of biomass from dedicated plantations can only be considered *carbon neutral* if the energy crops harvested to supply the bioenergy grow back and keep that carbon sequestered in biomass and soils. Also, it is important consider the water footprint when irrigation systems are needed for energy crops.

[8] **Carbon Neutral** refers to a state where an individual, organization, or activity produces no net carbon dioxide (CO_2) emissions. Achieving carbon neutrality involves balancing the amount of carbon emitted with an equivalent amount of carbon offset or removed from the atmosphere.

7.10. Research and development perspectives

Worldwide, biomass power plants are a mature and commercial technology. However, in Colombia, using biomass for power generation is not common practice in the energy generation industry, as it is concentrated in co-generation in agro-industrial settings. Most of the biomass projects in the country involve sugar cane bagasse to co-generate heat and power for the sugar mills and selling surplus electric energy to the grid.

Direct, traditional uses of biomass for heating and cooking applications rely on a wide range of feedstock and simple devices, but the energy efficiency of these applications is very low because of biomass moisture content, low energy density, and the heterogeneity of the basic input. A range of pre-treatment and upgrading technologies have been developed to improve biomass characteristics and make handling, transport, and conversion processes more efficient and cost effective. A comparison of the energy and bulk densities of raw and processed biomass is shown in Figure 66. Most common forms of pre-treatment include drying, palletisation and briquetting, torrefaction and pyrolysis, where the first two are by far the most used.

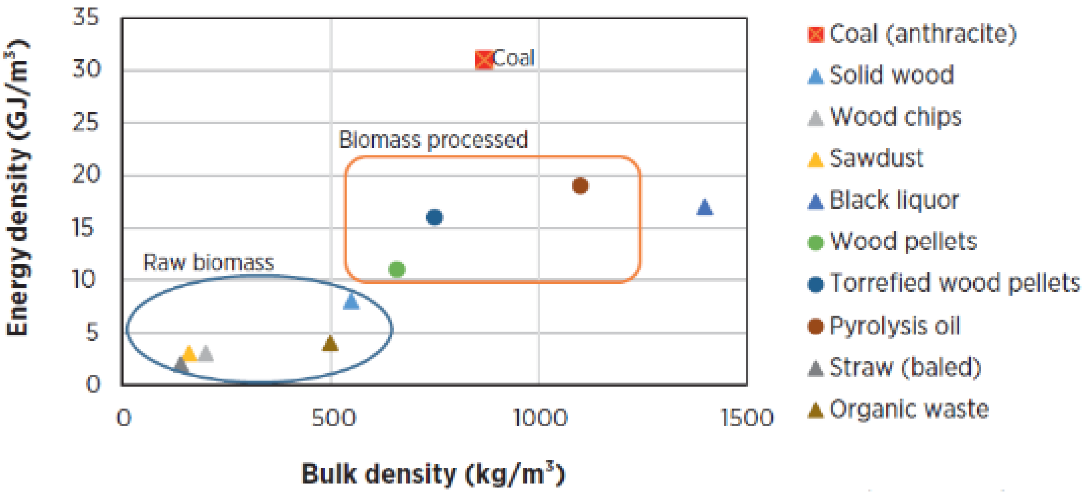

Figure 66. Energy density of biomass and coal [14].

Gasifier technologies offer the possibility of converting biomass into producer gas[9], 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 some gasification technologies are commercially available, there are still ongoing efforts done in terms of R&D and demonstration to promote the commercial use of gasification technologies. Figure 67 shows the status of different types of gasification alternatives.

[9]Producer gas is the substance that is produced by burning biomass with an air deficit and a regulated amount of humidity. Producer gas is a mixture of gases such as hydrogen carbon monoxide, carbon dioxide, and nitrogen.

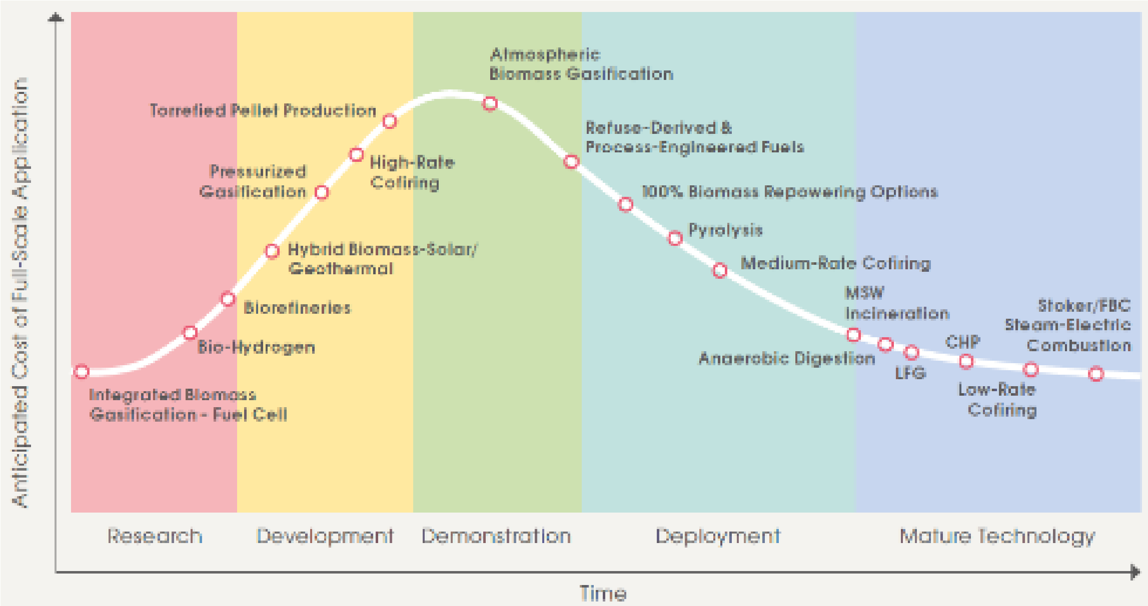

Figure 67. Biomass power generation technology maturity status [15].

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 Table 7-3.

Table 7-3. Phase makeup of biomass pyrolysis products for different operational modes [16].

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

Although biomass combustion systems across all capacity ranges are considered mature technologies, ongoing research and development efforts continue to address new challenges and opportunities brought by the evolving energy landscape [17]. Carbon emissions reduction remains a priority, particularly for small-scale residential heating systems that typically lack secondary pollution control measures, as well as for medium- and large-scale combustion plants. Cost-effective solutions to lower emissions of particulate matter and organic compounds in small-scale systems hold significant market potential, especially given the high sales volume of residential stoves and boilers and the tightening of emission regulations in many countries. For larger applications, such as district heating systems, where organic emissions are largely controlled through complete combustion, the reduction of NO_x emissions remains a key challenge [17].

One of the most promising future markets for biomass combustion technologies is the transition away from fossil fuels in industry, particularly for high-temperature heat applications. While electrification is a growing trend across many industries, it may not be suitable for all processes, creating opportunities for tailored biomass-based energy solutions. As global energy systems rapidly evolve to meet climate change mitigation goals, biomass combustion technologies offer unique opportunities. Increasing shares of wind and solar power are improving the greenhouse gas (GHG) balance but also heightening the need for grid balancing. Biomass combustion technologies provide the operational flexibility required to meet this demand. Additionally, biomass-based carbon capture and storage or utilization (CCS/U) can help achieve net-negative GHG emissions, contributing to the goals of the Paris Agreement.

Some manufacturers are working on developing efficient small- and micro-scale combined heat and power (CHP) solutions, aiming to downsize power plants to fit into residential buildings. These systems often use wood pellets or wood chips, combined with power units like Stirling engines, micro-steam engines, or Organic Rankine Cycles (ORC). While only a few products have entered the market due to technological and economic challenges, the concept of cost-effective residential CHP systems remains attractive, especially as they complement solar systems by providing energy during periods of low sunlight.

7.10.1. Biomass energy research in Colombia

One notable initiative is the first hybrid laboratory for energy generation in La Guajira, inaugurated in 2022 and depicted in Figure 68 [18]. This project focuses on integrating different renewable energy sources, including biomass, to develop sustainable solutions for power generation. The laboratory serves as a research hub for exploring the potential of biomass in combination with other renewable sources, like solar and wind, to provide energy to isolated regions. This initiative underscores Colombia’s commitment to leveraging biomass as part of its broader strategy to promote renewable energy in remote areas. The lab is part of Energética 2030, a research alliance by universities and companies in Colombia. This project aims to develop technologies that can produce multiple forms of energy from biomass, such as electricity, heat, and biogas, making the process more efficient and sustainable. The research is focused on optimizing the use of agricultural and forestry residues to improve energy production while reducing environmental impact [18].

Figure 68. Hybrid Biomass Laboratory at University of La Guajira [18].

7.11. Examples of market standard technology

According to the market operator, in 2024 there were 192 MW of installed capacity in Biomass co-generation, most of these plants are sugar mills in Valle del Cauca Region (see Table 7-4).

Table 7-4. Biomass Co-generation in the Colombian Interconnected System. Data in MW [19].

Generator	Power (MW)
BIOENERGY	19,9
CENTRAL CASTILLA 1	3
COGENERADOR MANUELITA 2	12
COGENERADOR PROENCA	19,9
INCAUCA 1	60
INGENIO PROVIDENCIA 2	19,9
INGENIO RIOPAILA 1	16
INGENIO RISARALDA 1	19,9
INGENIO SAN CARLOS 1	2
MAYAGUEZ 1	19,9
Total	192,5

7.11.1. Palm Oil

As depicted in Table 7-5, Cenipalma consolidated the degree of implementation of cogeneration and energy generation processes in the palm oil extraction plants. It was found that 25 % of these plants cogenerate energy for internal use, 7 % generate it from biogas, and only 3 % supply excess energy to the grid *[20].* Using data provided by seven extraction plants in the Northern Zone, the operability of the cogeneration module was validated. It was confirmed that the biomass available in the extraction plants meets the energy requirements of the process and can additionally generate a surplus of energy. For plants with capacities between 21 - 41 tons of fresh fruit bunches (FFB) per hour, a generation potential between 1.7 and 8.9 MW was determined *[20].*

Table 7-5. Palm oil processing plants that have implemented cogeneration/electric power generation projects in Colombia in 2020 [20].

Zones	Number of benefit plants	Cogeneration with biomass	Methane capture	Generate electricity from biogas	Export excess electricity to the grid
Eastern	32	9	5	4	1
Northern	14	2	1	1	1
Central	17	6	1	-	-
Southwestern	5	-	-	-	-
Total	68	17	7	5	2

7.11.2. Energy Crops

Since November 13, 2021, Refoenergy Bita, a biomass-based power plant, has been operational in Puerto Carreño, (see Figure 69) [21]. providing 100 % renewable and sustainable energy to the capital of the Vichada department. This plant, operated by Refocosta, supplies clean energy to over 18,000 residents. Prior to the plant's operation, the area faced energy shortages and rationing due to the lack of connection to the national grid, relying intermittently on energy from Venezuela. To address this issue, the national government, Valorem, and Refocosta collaborated to establish the Refoenergy Bita plant, which generates 4.5 megawatt-hours of electricity for Puerto Carreño from forest biomass. This project also prevents 50,000 tons of carbon dioxide emissions annually. The trees used for energy production are cultivated specifically for this purpose, avoiding deforestation of Colombian forests [21].

Figure 69. Refoenergy Bita forest biomass power generation [21].

Building upon from this experience, EDF Colombia has partnered with Refocosta to establish the country's largest eucalyptus-based biomass power generation plant, Refoenergy Villanueva. This facility, which will be situated in the Villanueva municipality of Casanare, will boast a net total installed capacity of 25 MW. All the energy produced will be supplied exclusively to the Ecopetrol Group under an agreement with Gecelca S.A. This plant started its construction in 2023 and was the first biomass plant to be selected in the reliability charge auction in 2024 *[23].*

7.12. Prediction of performance and cost

7.12.1. Investment cost overview

Table 7-6 presents a comparison of investment costs for power projects, expressed in millions of USD per megawatt ($MUSD_{2024}$/MW), based on different data sources and regions. The investment costs of biomass power plants largely depend on the type of feedstock – size, calorific value, chemical composition etc., as this affects the pre-treatment processes. Economy of scale also plays an important role, as biomass plants in Colombia are relatively small.

Table 7-6. Investment cost comparison across regions for biomass projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	2.56	2024
International data		
Technology Catalogue Indonesia (2024)	2.56	2024

Technology Catalogue Vietnam (2023)	2.17	2023
IEA GEC Model, Brazil region (2021)	2.47	2021
NREL ATB (2023)	5.28	2023

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7.14. Datasheet

Technology	Biomass power plant (palm oil / sugar cane / rice husk)								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MW_e)	25	25	25	1	50	1	50		1,4,9

Generating capacity for total power plant (MW_e)	25	25	25	1	50	1	50		1,4,9
Electricity efficiency, net (%), name plate	32 %	32 %	32 %	25 %	35 %	25 %	35 %		1,5,6
Electricity efficiency, net (%), annual average	31 %	31 %	31 %	25 %	35 %	25 %	35 %		1,5,6
Forced outage (%)	7 %	7 %	7 %	5 %	9 %	5 %	9 %	B	1
Planned outage (weeks/year)	6	6	6	4.5	7.5	4.5	7.5	B	1
Technical lifetime (years)	25	25	25	18.8	31.3	18.8	31.3	B	1,6
Construction time (years)	2	2	2	1.5	2.5	1.5	2.5	B	6
Space requirement (1000 m^2/MW_e)	35	35	35	26.3	43.8	26.3	43.8	B	1,7
Additional data for thermal plants									
Capacity factor (%), theoretical	52.6 %	52.6 %	52.6 %	7.4 %	83.3 %	7.4 %	83.3 %	D,E	2,3
Capacity factor (%), incl. outages	43.3 %	43.3 %	43.3 %	5.8 %	72.1 %	5.8 %	72.1 %	D,E	2,3
Ramping configurations									
Ramping (% per minute)	10 %	10 %	10 %						5
Minimum load (% of full load)	30 %	30 %	30 %						5
Warm start-up time (hours)	0.5	0.5	0.5						5
Cold start-up time (hours)	10	10	10						5
Environment									
PM 2.5 (mg per Nm^3)	12.5	12.5	12.5						5
SO_2 (degree of desulphurisation, %)	0	0	0						5
NO_X (g/GJ of fuel input)	125	125	125						5
CH_4 (g/GJ of fuel input)	30	30	30	10	100	10	100	H	10
N_2O (g/GJ of fuel input)	4.0	4.0	4.0	1.5	15.0	1.5	15.0	I	10
Financial data									
Nominal investment ($MUSD/MW_e$)	2.56	2.47	2.32	1.66	2.89	1.51	2.61	A,C,F,G,J	1
- of which equipment (%)	65 %	65 %	65 %	50 %	85 %	50 %	85 %	A	1
- of which installation (%)	35 %	35 %	35 %	15 %	50 %	15 %	50 %	A	1
Fixed O&M (USD/MW_e/year)	60,700	58,400	54,900	48,300	80,900	43,700	73,200	A,F,G,J	1
Variable O&M (USD/MWh)	3.82	3.68	3.46	2.87	4.78	2.59	4.32	A,F,G,J	1
Start-up costs (USD/MW_e/start-up)	-	-	-	-	-	-	-		

Notes

A Based on prices from countries with similar biomass input

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

C Land cost for planting biomass is not included

D The capacity factor is calculated with available information.

E Assumed the same theoretical capacity factor for 2030 and 2050 and changed the capacity factor incl. outages based on the reduction of outages.

F The values for the Stated Policies Scenario (lower scenario normally used as estimate for lower uncertainty) and Announced Pledges Scenario (median scenario normally used as central estimate) from IEA has been switched around because of the way IEA projects bioenergy and the values for the median scenario (central estimate) is lower than the values for the lower scenario (lower uncertainty).

G Cost are projected with a learning rate approach assuming a 5% learning rate for both equipment and installation based on IEA's World Energy Outlook 2023, and 5% for O&M, including capacity projections of the IEA's World Energy Outlook 2023, with Announced Pledges used for the central values.

H Data from existing projects in Colombia [3] shows much higher numbers with a central estimate at 600 g/GJ and a range between 130 - 2809 g/GJ.

I Data from existing projects in Colombia [3] shows much higher numbers with a central estimate at 79.9 g/GJ and a range between 17.2 - 374.5 g/GJ.

J Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the general technology improvement potential.

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8. Biogas Power Plant

8.1. Brief technology description

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.

Mesophilic and thermophilic processes in biogas production are distinguished by the temperature ranges that favour each type of bacteria. Mesophilic bacteria thrive at moderate temperatures, typically fermenting optimally at up to 30 °C (90 °F). In contrast, thermophilic bacteria prefer higher temperatures, fermenting most effectively above this range. Each process has unique advantages, with mesophilic digestion generally requiring less energy for heating, while thermophilic digestion can offer faster reaction rates and higher pathogen destruction. 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][10].

Biogas produced by anaerobic digestion is a mixture of several gases. The most important part of the biogas is methane (CH_4). Biogas has a calorific value between 23.3 – 35.9 MJ/m^3, depending on the methane content. The volume percentage of methane in biogas varies from 50 % to 72 % depending on the type of substrate and its digestible substances, such as carbohydrates, fats and proteins. For the operation of power generation or combined heat and power (CHP) units with biogas, a minimum concentration of methane of 40 % to 45 % is needed. The second main component of biogas is carbon dioxide (CO_2). 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].

Biogas systems come in various types and sizes, including household biogas digesters, covered lagoon systems, and Continuous Stirred-Tank Reactors (CSTR). The latter two are widely used in commercial Combined Heat and Power (CHP) plants to generate heat and/or electricity, both for internal use and for sale to customers on an industrial scale. Below is an explanation of these systems:

8.1.1. Covered Lagoons

Covered lagoon systems are applied when biogas feedstocks are mostly liquid waste like Palm Oil Mill Effluent (POME). The system consists of a lagoon—essentially an open-air pond—lined with impermeable material to prevent leakage, which is then covered with a flexible, impermeable membrane. The cover traps the gases generated by the anaerobic breakdown of organic matter (such as manure or agricultural residues), primarily methane (CH_4) and carbon

[10] Mesophilic and thermophilic processes in biogas production are distinguished by the temperature ranges that favour each type of bacteria. Mesophilic bacteria thrive at moderate temperatures, typically fermenting optimally at up to 30°C (90°F). In contrast, thermophilic bacteria prefer higher temperatures, fermenting most effectively above this range. Each process has unique advantages, with mesophilic digestion generally requiring less energy for heating, while thermophilic digestion can offer faster reaction rates and higher pathogen destruction.

dioxide (CO_2), which can then be captured and used as biogas for energy production. A scheme for the covered lagoons and a picture of the technology are presented in Figure 70 and Figure 71.

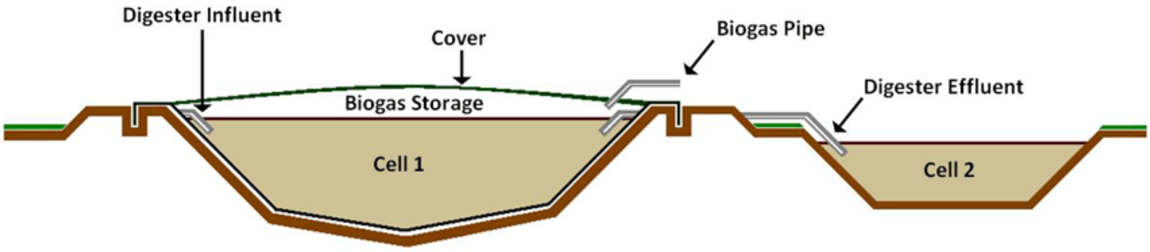

Figure 70. Scheme of a covered-lagoon biogas plant [3].

Figure 71. Picture of a covered-lagoon cell for manure feedstock [4].

8.1.2. Continuous Stirred Tank Reactors (CSTR)

Continuous Stirred-Tank Reactor (CSTR) technology is a widely used method in biogas production, designed to process organic materials in a fully mixed environment. In a CSTR system, the feedstock (such as animal manure, food waste, or agricultural residues) is continuously fed into the reactor, where it undergoes anaerobic digestion by microorganisms. The reactor is equipped with a mechanical stirring mechanism that ensures uniform mixing of the material, promoting efficient microbial action and maximizing biogas production. In CSTR systems, liquid waste is stored in tanks to capture biogas during the anaerobic biological conversion process. In general, this type of technology has several stirrers in the tank that serves to stir the material that has higher solids content (≥12 %) continuously.

One of the key advantages of CSTR technology is its flexibility in handling various types of organic matter with different compositions. The stirring mechanism ensures that the microorganisms are evenly distributed, preventing the formation of dense zones that could hinder the digestion process. Additionally, CSTR systems can maintain a constant temperature, making them highly effective for large-scale biogas operations. The schematics of a CSTR is depicted in Figure 72. A real-world photograph of a CSTR systems in shown in Figure 73.

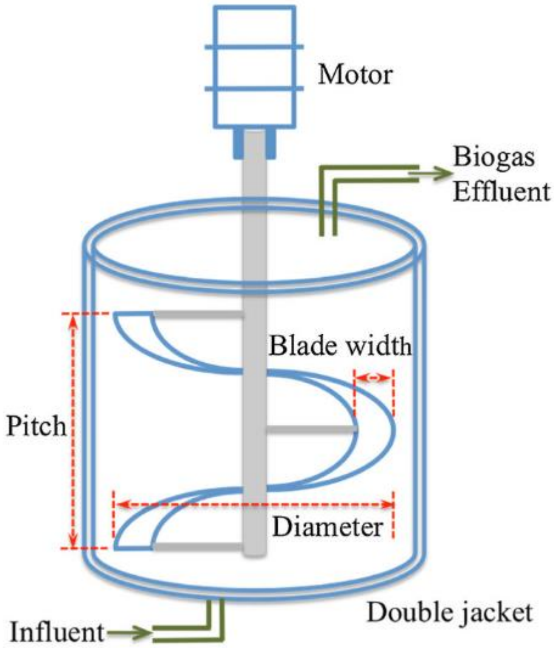

Figure 72. Schematics of a Continuous Stirred-Tank Reactors CSTR [5].

Figure 73. Continuous Stirred-Tank Reactors CSTR [6].

Summarizing the information presented in this section a comparison between Covered Lagoons and CSTR is presented in Table 8-1.

Table 8-1. Comparison between covered lagoons and CSTR.

Feature	Covered Lagoon Systems	Continuous Stirred-Tank Reactors (CSTR)
Feedstock	Low-solids liquid waste (e.g., POME)	High-solids organic materials (≥12 %)
Structure	Lagoon with impermeable lining and flexible cover	Enclosed tank with mechanical stirring
Mixing	None (passive system)	Mechanical stirring for uniform mixing
Temperature Control	Ambient temperature, no active control	Maintains constant temperature for microbial efficiency
Advantages	Cost-effective, low maintenance	High efficiency, flexible feedstock handling, controlled
Limitations	Limited to low-solids waste, less process control	Higher cost, requires mechanical maintenance
Ideal Application	Agricultural or manure-based biogas systems	Large-scale biogas production with diverse feedstocks

8.1.3. Electricity and Heat Generation from Biogas

After production in a biodigester, the biogas is purified by introducing a small amount of fresh air (0-3 % relative to biogas production) into the exhaust pipes as it moves from the primary to the secondary fermenter. The fresh air provides the necessary oxygen for sulphur bacteria to convert hydrogen sulphide (H_2S) into elemental sulphur, thus helping to clean the biogas of harmful sulphur compounds. The exact amount of air required is determined by measuring H_2S levels with a gas analyser. The maximum allowable air supply is capped at 10 % of the produced biogas to ensure efficiency and safety [7].

Biogas utilization involves cogeneration, where biogas is converted into both electricity and heat. The electricity is fed into the power grid, while thermal energy can be used to heat the fermenters and nearby facilities, such as farms and greenhouses. Excess heat can also be used for drying agricultural products, heating buildings, water heating or even process steam covering industrial steam loads. An emergency gas flare is available to burn excess biogas during overproduction or maintenance shutdowns. Biogas is stored in a low-pressure tank to balance production fluctuations, and the remaining fermentation by-products are separated into liquid and solid fractions for agricultural use, with the liquid fraction stored in open tanks before being used as fertilizer [7]. The efficiency of a biogas power plant is about 35 % if it is just used for electricity production. The efficiency can increase to 80 % if the plant is operated as combined heat and power (CHP). An example of a CHP system is provided in Figure 74.

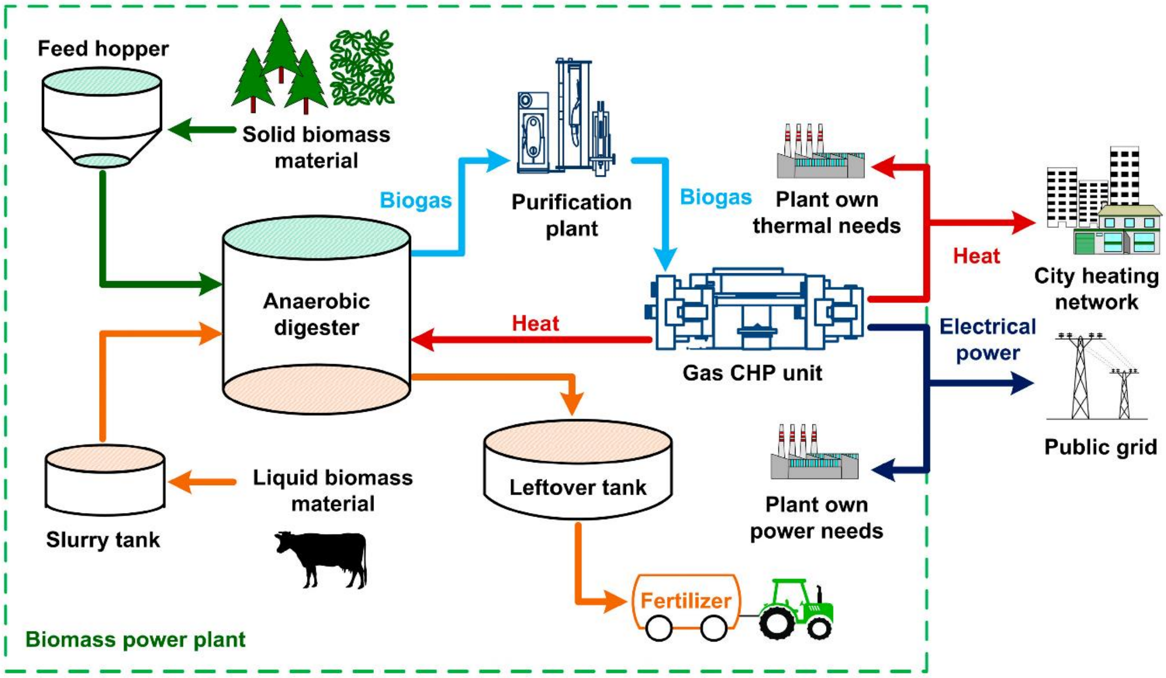

Figure 74. Biogas combined heat and power (CHP) system diagram [7].

8.1.4. Biogas production depends on the biomass feedstock

The output of biogas depends much on the amount and quality of supplied organic waste, Table 8-2 shows the gas yields of different feedstock. For manure the gas output is typically 14 – 14.5 m^3 methane per tonne, while the gas output typically is 30 – 130 m^3 methane per tonne for industrial waste [8]. 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.

Table 8-2. Biogas yield from different feedstock [9].

Seedstocks	Total Waste (fresh)	Gas Yield (m^3/kg of dry matter)
Cattle	10–15 kg/day/head	0.34
Poultry	0.75 kg/day/head	0.46
Sheep	0.75 kg/day/head	0.37
Pig	1.3 kg/day/head	0.39
Kitchen	0.25 kg/day/head	0.3
Rice straw	1.2 tonnes/ha	0.61
Wheat straw	3.5 tonnes/ha	0.41
Water hyacinth	5 tonnes/ha	0.40

8.2. Input

Bio-degradable organic waste without environmentally harmful components such as, animal manure, solid and liquid organic waste from industry or agricultural residues. Sludge from sewage treatment plants and the organic fraction of household waste may also be used.

8.3. Output

Electricity and heat.

The data presented in this technology sheet assumes that the biogas is used as fuel in an engine, which produces electricity and/or heat, or sold to a third party. However, the gas may also be injected into the natural gas grid or used as fuel for vehicles. The digested biomass can be used as fertilizer in crop production.

8.4. Typical capacities

Biogas plants vary in scale, with small-scale systems (10–100 kW) commonly serving farms or rural areas for self-sustained energy, medium-scale plants (100 kW–1 MW) supporting small industries, municipalities, or large farms, and large-scale facilities (over 1 MW) centralized to process urban or industrial waste.

'Biogas plants are expanding in renewable energy portfolios, supported by technological advancements, policies, and circular economy goals. Upgrading biogas to biomethane enhances its use in vehicles and gas grids.

8.5. Space requirement

The space requirements for a biogas plant can vary depending on the configuration and components of the system. Based on the provided data by Colombian stakeholders, a biogas plant typically requires space for containers, digestion tanks, and additional safety measures such as distance from the flare. For instance, two containers for the power equipment, each occupying 30 m², would require a total of 60 m². The space needed for anaerobic digesters depends on their diameter, with tank diameters ranging from 20 to 30 m², leading to an area of between 314 m² to 707 m². Additionally, a safety buffer of 79 m² is typically reserved as the distance from the flare. In total, the biogas plant would require a space ranging from 453 m² to 845 m² for a 1 MW of installed capacity.

8.6. Water consumption

Bioenergy production is water-intensive, and its consumption varies significantly across different biomass-based power generation methods [10, 16]. For more detailed information, refer to the section Water consumption in the Biomass chapter.

8.7. Regulation ability and other power system services

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.

Unlike other renewables, which depend on weather conditions, biogas production can occur continuously, day and night, regardless of weather, because the digestion process is not influenced by external environmental factors. Biogas plants can serve as a reliable baseload energy source because they produce a steady and controllable output of energy.

If there is a consistent supply of feedstock, such as agricultural waste, manure, or organic industrial waste, biogas production can be continuous.

8.8. Advantages/disadvantages

8.8.1. Advantages

- The CO_2 abatement cost is quite low, since methane emission is mitigated.
- Saved expenses in manure handling and storage; provided separation is included and externalities are monetized.
- Environmentally critical nutrients, primarily nitrogen and phosphorus, can be redistributed from overloaded farmlands to other areas.
- The fertilizer value of the digested biomass is better than the raw materials. The fertilizer value is better known, making it easier to spread the right amount on the farmlands.
- Compared to other forms of waste treatment, biogas digestion of solid biomass has the advantage of recycling nutrients to the farmland in an economically and environmentally sound way.

8.8.2. Disadvantages

- Production Scale: Biogas production requires significant upfront investment in digestion facilities and might not be cost-effective on a small scale.
- Feedstock Requirements: Consistent and sufficient supply of organic waste materials is necessary, which can be challenging to manage.
- Energy Density: Biogas has a lower energy density compared to natural gas, so more of it is needed to produce the same amount of energy.
- Environmental Concerns: While cleaner than fossil fuels, biogas plants can still produce odors and potentially harmful byproducts if not managed properly.

8.9. Environment

Biogas is a CO_2-neutral fuel. Also, without biogas fermentation, significant amounts of the greenhouse gas methane will be emitted to the atmosphere. The anaerobically treated organic waste product is almost free compared to raw organic waste; however, methane slips are possible during the anaerobic digestion.

Moreover, Biogas power generation is a highly effective circular economy strategy because it transforms organic waste into renewable energy and valuable byproducts, creating a closed-loop system. his process reduces the need for fossil fuels and mitigates methane emissions, a potent greenhouse gas, from decomposing organic waste. The byproducts of biogas production—liquid digestate and solid residues—are rich in nutrients and can be used as organic fertilizers. This recycles nutrients back into the soil, reducing reliance on chemical fertilizers and closing the waste loop.

8.10. Research and development perspectives

Stirling engines create opportunities to produce electricity (and heat) using biogas of any type and quality. A Stirling engine is a heat engine that operates by cyclic compression and expansion of air or other gases (the working fluid) at different temperatures, such that there is a net conversion of heat energy to mechanical work [11]. More specifically, the Stirling engine is a closed-cycle regenerative heat engine with a permanently gaseous working fluid.

Stirling engines have a high efficiency compared to steam engines, being able to reach 50 % efficiency. They are also capable of quiet operation and can use almost any heat source. The heat energy source is generated externally to the Stirling engine rather than by internal combustion as with Otto cycle or Diesel cycle engines. Because the Stirling engine is compatible with alternative and renewable energy sources it could become increasingly significant as the price of conventional fuels rises, and considering concerns such as depletion of oil supplies and climate change.

The current Stirling combined heat and power system [12]. can produce both electricity and heat from a methane gas concentration as low as 18 % – with multiple applications from biogas and landfill sites to wastewater treatment.

Makel Engineering, Inc. (MEI), Sacramento Municipal Utility District, and the University of California, Berkeley developed a homogenous charge compression ignition (HCCI) engine-generator (genset) that efficiently produces electricity from biogas. The design of the HCCI engine-generator set, is based on a combination of spark ignition and compression ignition engine concepts, which enables the use of fuels with very low energy content (such as biogas from digesters) to achieve high thermal efficiency while producing low emissions. Field demonstrations at a dairy south of Sacramento, California show that this low-cost, low-emission energy conversion system can produce up to 100 kW of electricity while maintaining emission levels that meet the California Air Resources Board’s (ARB) strict regulations [13].

8.11. Examples of market standard technology

Feedstocks biogas production in Colombia are mainly from animal manure and agricultural waste including agriculture industries like palm oil mill effluent (POME) [14]. These are described as follows:

8.11.1. Palm Oil Mill Effluent (POME)

In October 2020, the National Federation of Oil Palm Growers (FEDEPALMA) and the Oil Palm Research Center Corporation (CENIPALMA) presented the report "Diagnosis of Biogas Production and Use in the Colombian Palm Oil Sector" to the national biogas committee, from which the following information is extracted: oil palm is present in 21 Departments and 161 Municipalities, with 560,000 hectares cultivated by more than 6,000 producers [14].

Biogas in the palm oil agroindustry is produced from the anaerobic digestion (AD) of wastewater from palm oil extraction plants produced in the extraction process. This biogas is characterized by its high methane content (50 to 60 %), allowing it to be used as a source for generating thermal or electrical energy. As 2021, Biogas production in Colombia was 133 million cubic meters per year for an electrical energy generation of 60 MW [14]. Out of 68 extraction plants in the country, 7 have covered ponds for methane capture, and 5 of them generate electrical energy. Of these, 2 supply surplus to the National Interconnected System (SIN), and 1 participated in the 2019 Firm Energy for Reliability Charge (ENFICC) auction, being successful.

8.11.2. Pork Production

The Colombian Pork Producers Association (Porkcolombia-FNP), in collaboration with international governments, academia, the Ministry of Environment and Sustainable Development (MADS), the private sector, and environmental authorities such as the Tolima Regional Autonomous Corporation (CORTOLIMA), the Risaralda Regional Autonomous Corporation (CARDER), and the Quindío Regional Autonomous Corporation (CRQ), is advancing in the energy utilization of its organic waste [14]. This is achieved through various agreements aimed at information exchange, promoting technical and institutional strengthening, and implementing pilot projects in Non-Conventional Renewable Energy (NCRE) and cleaner production. Notable initiatives include:

- Installation of UASB biodigesters as prototypes for the pig farming sector.
- Development of educational materials for biodigester management.
- Creation of the Biogas Guide for the pig farming sector in Colombia [15].
- Consultancy studies to characterize pig manure, estimate the real potential of methane production, evaluate process efficiency, design a filter to reduce H2S concentration in biogas, and train producers interested in biodigester installation.

Many small and medium-sized pig farms have installed bag-type or Taiwanese biodigesters throughout the country. One example of a large company in the sector is in Puerto Gaitán, Meta: La Fazenda inaugurated in March 2021, its plant for generating electricity from the biogas generated from pig excrement. They currently treat 1200 t/day of swine effluent, with a production of 600 m^3/h of biogas at 63 % methane for a generation of 576,000 kW/month. At the same time, the plant generates 1200 m^3/h of biodigestate [14].

8.11.3. Poultry Farming

The Colombian Federal Association of Poultry Framers (FENAVI) participates in the Biogas Committee and the National Committee for the Utilization of Residual Biomass. However, not many biogas projects have been implemented in the sector mainly due to the current use of poultry manure as organic fertilizer or soil amendment, which is well commercialized and has much lower production costs compared to biogas generation. Additionally, the sector primarily consists of small farms that sell untreated poultry manure. Medium and large companies have wastewater treatment systems, some with aerobic technology.

In Caloto, Cauca, the company Huevos Kikes in 2017 inaugurated its electric power generation plant with an installed capacity of 0.8 MW, from the biogas generated from the treatment of 164 m^3/day of water with chicken manure, effluents from the poultry farm process.

8.12. Prediction of performance and costs

8.12.1. Investment cost overview

Table 8-3 presents a comparison of investment costs for power projects, expressed in millions of USD per megawatt ($MUSD_{2024}$/MW), based on different data sources and regions. The results of this study are derived from the values shared by stakeholder, 4.38 MUSD/MW with a base year for final investment decision (FID) set in 2024. In contrast, international data sources provide varied costs: Indonesia at 2.75 MUSD/MW (2024 FID), Vietnam at 3.52 MUSD/MW (2023 FID), and Denmark at a significantly lower 1.33 MUSD/MW (2016 FID).

Table 8-3. Investment cost comparison across regions for biogas projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	4.38	2024
National data		
Bilateral meetings with local stakeholders	4.38	2024
International data		
Technology Catalogue Indonesia (2024)	2.75	2024
Technology Catalogue Vietnam (2023)	3.52	2023
Technology Catalogue Denmark (2021)	1.33	2016

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8.14. Datasheet

Technology	**Biogas power plant**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MW_e)	0.88	0.88	0.88	0.25	1.9	0.25	1.9		10
Generating capacity for total power plant (MW_e)	0.88	0.88	0.88	0.25	1.9	0.25	1.9		10
Electricity efficiency, net (%), name plate	42 %	42 %	42 %	41 %	42.5 %	41 %	42.5 %		10
Electricity efficiency, net (%), annual average	40 %	40 %	40 %	35 %	41 %	35 %	41 %	E	1,2,3
Forced outage (%)	10 %	10 %	10 %	9 %	12 %	9 %	12 %		9
Planned outage (weeks/year)	3	3	3	1	5	1	5		9
Technical lifetime (years)	25	25	25	20	50	20	50		9
Construction time (years)	1.5	1.5	1.5	0.5	2.0	0.5	2.0		9
Space requirement (1000 m^2/MW_e)	0.649	0.649	0.649	0.453	0.845	0.453	0.845		9
Additional data for thermal plants									
Capacity factor (%), theoretical	8.2 %	8.2 %	8.2 %	2.7 %	13. 1%	2. 7%	13.1 %	A,B	8
Capacity factor (%), incl. outages	6.9 %	6.9 %	6.9 %	2.2 %	11.7 %	2.2 %	11.7 %	A	8
Ramping configurations									
Ramping (% per minute)	20 %	20 %	20 %	10 %	30 %	10 %	30 %		5
Minimum load (% of full load)	40 %	30 %	15 %	30 %	50 %	10 %	20 %		6
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
CH_4 (g/GJ of fuel input)	1	1	1	0,3	3	0,3	3		11
N_2O (g/GJ of fuel input)	0,1	0,1	0,1	0,03	0,3	0,03	0,3		11
Financial data									
Nominal investment ($MUSD/MW_e$)	4.38	4.21	3.96	3.12	5.01	2.82	4.53	C,D,F	10
- of which equipment (%)	81 %	81 %	81 %	79 %	87 %	79 %	87 %	D	10
- of which installation (%)	19 %	19 %	19 %	13 %	21 %	13 %	21 %	D	10
Fixed O&M (USD/MW_e/year)	46,200	44,400	41,800	42,700	53,800	38,600	48,700	C,D,F	10
Variable O&M (USD/MWh)	0.018	0.017	0.016	0.016	0.019	0.014	0.017	C,D,F	10
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		10

Notes

A The capacity factor is calculated with available information.

B Assumed the same theoretical capacity factor for 2030 and 2050

C The values for the Stated Policies Scenario (lower scenario normally used as estimate for lower uncertainty) and Announced Pledges Scenario (median scenario normally used as central estimate) from IEA has been switched around because of the way IEA project bioenergy.

D Cost are projected with a learning rate approach assuming a 5 % learning rate for both equipment and installation based on IEA's World Energy Outlook 2023, and 5 % for O&M, including capacity projections of the IEA's World Energy Outlook 2023, with Announced Pledges used for the central values.

E Assumed same percental difference to Electricity efficiency (net, name plate) as international TC's

F Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the general technology improvement potential.

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9. Supercritical Pulverized Coal Power Plant

9.1. Brief Technology Description

Coal-fired plants run on a steam-based Rankine cycle, as depicted in Figure 75. In the first step the operating fluid (water) is compressed to high pressure using a pump. The next step, the boiler heats the compressed fluid to its boiling point converting it to steam, still at a high pressure. In the third step the steam is allowed to expand in the turbine, thus rotating it. This in turn rotates the generator to produce electricity. The final step in the cycle involves the condensation of the steam in the condenser.

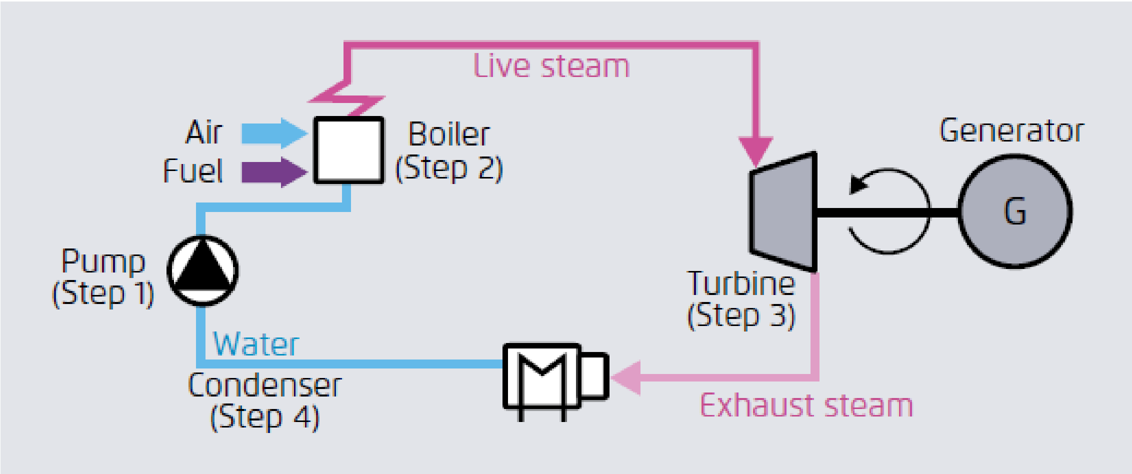

Figure 75. Schematic representation of operational flow of steam-based Rankine cycle in coal plants [1].

We distinguish between three types of coal fired power plants: subcritical, supercritical and ultra-supercritical. The names refer to the state (temperature and pressure) of the steam during the evaporation phase. Besides the technical variations in the plant layout, from an energy modelling perspective the main differences lie in the plant's cost and in its cycle efficiency, as described in Table 9-1. Supercritical and ultra-supercritical power plants have been the most deployed coal technologies in the last 20 years, even though subcritical power plants maintain the largest capacity worldwide, as shown in Figure 76.

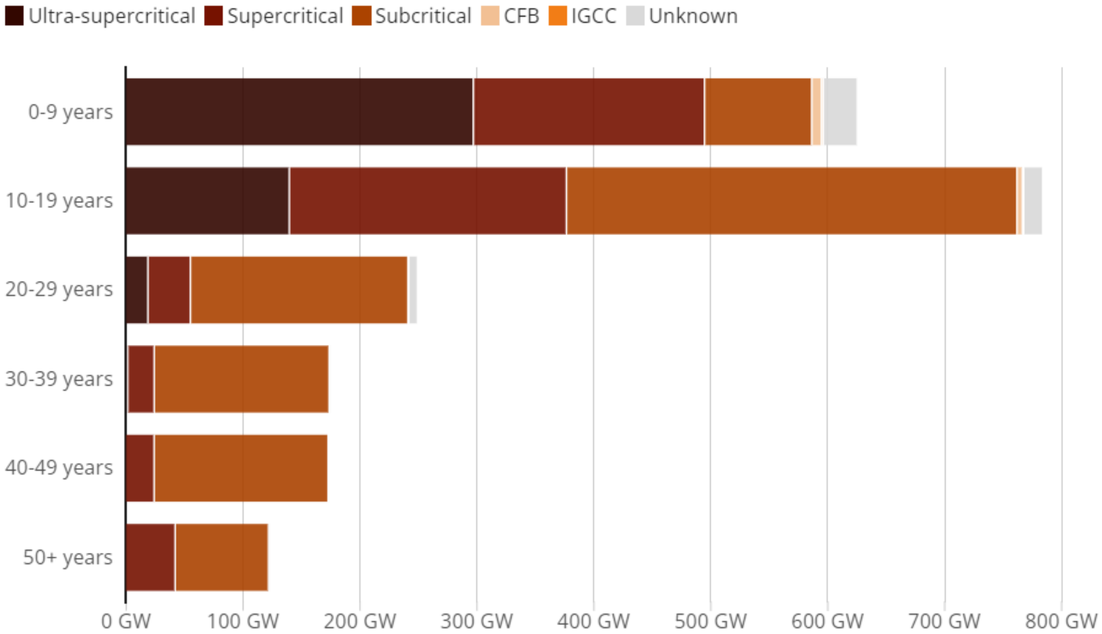

Figure 76. Operating coal-fired power capacity, by unit age group and technology type [5].

As shown in Figure 77, subcritical is below 200 bars and 540 °C. Both supercritical and ultra-supercritical plants operate above the water-steam critical point, which requires pressures of more than 221 bars (by comparison, a subcritical plant will generally operate at a pressure of around 165 bars) [15]. 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 [2, 15].

Table 9-1. Comparison of characteristics of coal plant technologies [3].

Type of Coal Plant	Description	Efficiency	Technology	Pollution
Subcritical	Uses coal to boil water, producing steam that drives a turbine and generates electricity. Energy loss occurs when water turns to steam.	Lower efficiency due to energy loss.	Standard technology.	Higher pollution due to more coal usage.

Supercritical	Utilizes specialized equipment to convert water into a supercritical fluid, with properties of both gas and liquid, reducing energy loss and improving efficiency.	Higher efficiency than subcritical.	Maintains water at specific high temperature and pressure.	Lower pollution due to less coal usage.
Ultra-supercritical	Operates at even higher temperatures and pressures than supercritical plants, reducing energy loss further and increasing efficiency.	Higher efficiency than supercritical.	Advanced equipment for even higher temperature and pressure.	Lower pollution than supercritical plants.

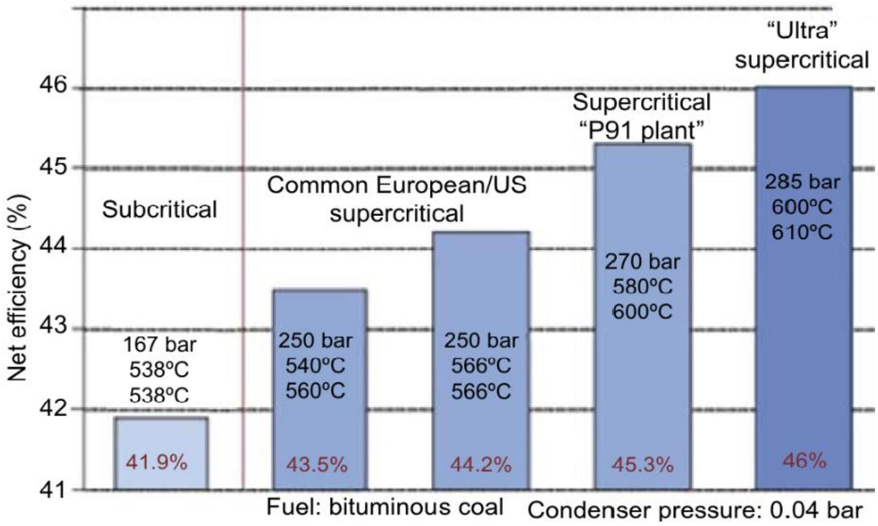

Figure 77. Efficiency differences between sub-, super-, and ultra-supercritical plant, derived from [15].

9.2. Input

Pulverized Coal: High-quality, finely ground coal is used as the primary fuel input to achieve efficient and complete combustion. Typically, coal used has a high calorific value with low sulphur and ash content, such as bituminous coal.

9.3. Output

Power and Heat. It is worth noticing that the auxiliary power need for a 500 MW plant is 40-45 MW, and the net electricity efficiency is thus 3.7 - 4.3 percentage points lower than the gross efficiency [6].

9.4. Typical capacities

In Colombia there are coal power plant with capacities from 5 MW for cogeneration, up to 273 MW for grid power generation [16].

9.5. Space requirement

The land required for coal plants ranges from 80 to 100 hectares, based on these higher estimates for coal plans, the total land used by coal plants in the US was approximately 43,700 hectares in 2015, which equates to roughly 0.28 hectares per megawatt of electricity generated [7].

9.6. Water consumption

Supercritical 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. Pulverized coal supercritical coal plants consume 4,114 l/MWh (1,087 gal/MWh), most of them corresponding of cooling tower losses, as shown in the far-right column in Figure 78.

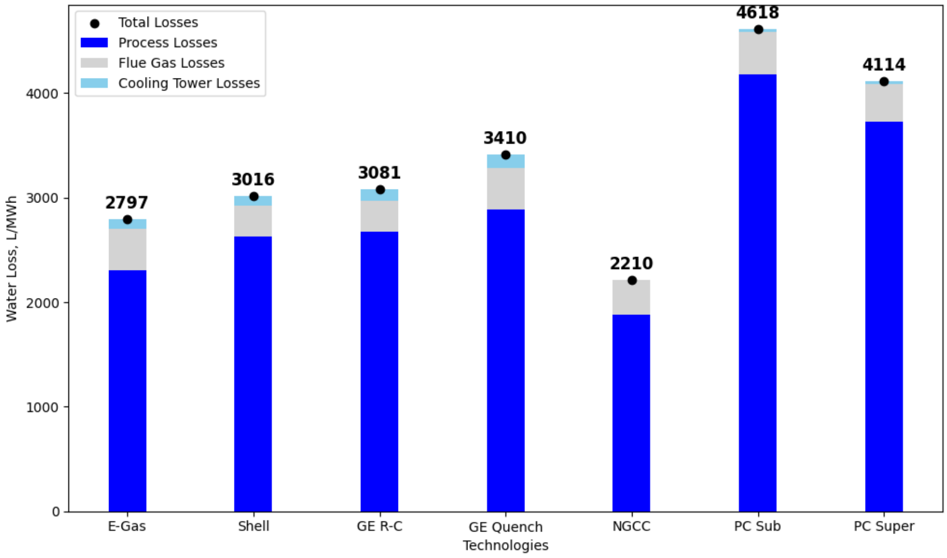

Figure 78. Comparison of water loss for various fossil plants, derived from [8].

9.7. Regulation ability and other power system services

Pulverized fuel power plants can deliver both frequency control and load support. Advanced units are in general able to deliver 5 % of their nominal capacity as frequency control within 30 seconds at loads between 50 % and 90 %. This fast load control is achieved by utilizing certain water/steam buffers within the unit. The load support control takes over after approximately 5 minutes, when the frequency control function has utilized its water/steam buffers. The load support control can sustain the 5 % load rise achieved by the frequency load control and even further to increase the load (if not already at maximum load) by running up the boiler load. Negative load changes can also be achieved by bypassing steam (past the turbine) or by closure of the turbine steam valves and subsequent reduction of boiler load.

With the increase in variable sources of electricity like solar and wind, coal-fired plants need to be more flexible to balance the power grid. Key parameters related to the flexibility of a thermal plant are depicted in Figure 79. Their definition is as follow:

- **Minimum Load (P_{min})**: Is the minimum or lowest power that can be produced by the plant.
- **Maximum Load (P_{nom})**: It is the nominal capacity of a plant.
- **Start-up time**: It is the time needed for the plant to go from start of operation to the generation of power at minimum load. There are three types of start-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**: It refers to the change in net power produced by the plant per unit time. Normally, the unit for ramp rate is MW/min or as a percentage of the nominal load per minute. Usually there is a ramp up rate for increase in power and ramp down rate for a decrease in power produced.
- **Minimum up and down time**: The up time refers to the minimum time the plant needs to be in an operational state once turned on. The down time refers to the minimum time after shutdown that the plant is out of operation, before it can be turned on again.

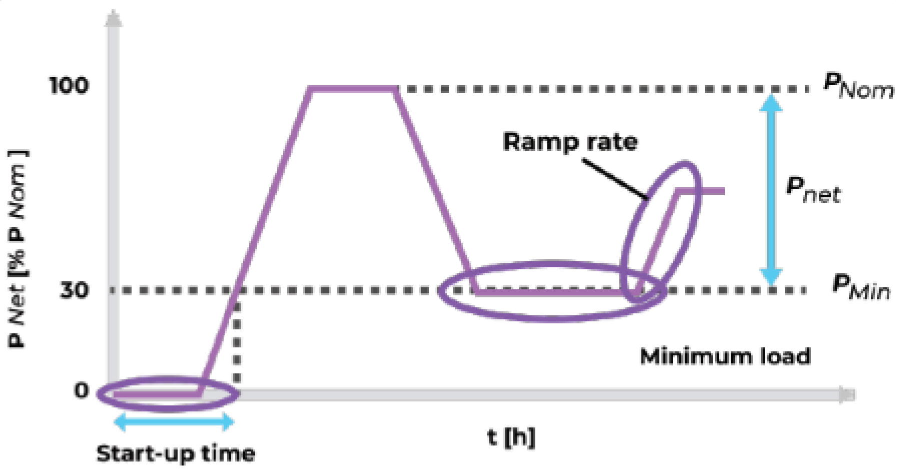

Figure 79. Key flexibility parameters of a power plant [6].

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. Accordingly, there are various retrofit solutions that can be added on to existing plants or considered when building new plants. These solutions have been summarised in Table 9-2.

Table 9-2. Solutions for increasing the flexibility of coal-fired power plants [1, 8].

Solutions	Objective	Description	Impact	Limitation

Indirect Firing	Lower minimum load, increased ramp rate and better part load efficiency	Milling is decoupled from load dynamics. Involves setting up a dust bunker between the coal mill and the burner to store pulverized coal. During periods of low load, auxiliary power can be used for coal milling, thereby reducing total power injected into the grid. Plus this reduces the minimum load in high load periods as the required coal is already stored in the bunker and can be used flexibly.	Indirect firing can decrease the minimum stable firing rate. Firing rate and net power are proportional. A reduction of the firing rate therefore leads to a similar reduction of minimum load. Another advantage of reaching a low stable fire is that the need for ignition fuels, such as oil or gas, can be reduced by 95 %.	Fire stability
Switching from two-mill to single-mill operation	Lower minimum load	Switching to a single mill operation results in boiler operation with fewer burning stages. In this operation, heat is released only at the highest burner stage, ensuring operational stability.	Switching to a single mill operation has resulted in reducing minimum load to 12.5 % P_{nom} in experiments conducted in hard coal-fired thermal plants at Bexbach and Heilbronn in Germany.	Water-steam circuit

Control system optimization and plant engineering upgrade	Lower minimum load, higher ramp rate, shorter start-up time	Upgrading control systems can improve plant reliability and help operate different components of the plant close to their design limits.	Control system and engineering upgrades resulted in the reduction of minimum load from nearly 67 % P_{nom} to 48 % P_{nom} at two units in the Weisweiler lignite-fired plant in Germany.	Fire stability/thermal stress
		Software systems that enable dynamic optimization of key components such as boilers can reduce the start-up time and increase ramp rate.	Boiler control system software have been developed that allow plant operators to choose between different start-up options based on market requirements.	
Auxiliary firing for stabilizing fire in boiler	Lower minimum load, higher ramp rate	This involves using auxiliary fuel such as heavy oil or gas to stabilize fire in the boiler. This ensures a lower stable firing rate in the boiler. Auxiliary firing can also be used for rapid increases to the firing rate, thereby enabling a higher ramp rate.	Since fire stability in the boiler usually limits the minimum load, auxiliary firing can support the minimum load reduction. As part of Jänschwalde research project, ignition burners were used for auxiliary firing using dried lignite, which reduced the minimum load from 36 % P_{nom} to 26 % P_{nom}.	Fire stability and boiler design

"New" turbine start	Shorter start-up time	This option involves starting up the steam turbine as the boiler ramps up by allowing "cold" steam to enter the turbine quickly after shutdown.	The start-up time can be reduced by 15 minutes using this approach.	Turbine design
Thin-walled components/special turbine design	Shorter start-up time, higher ramp rate	Using high-grade steel, thinner-walled components can be built to ensure quicker start-up and higher ramp rates compared to traditional thick-walled components.	Not known.	Mechanical and thermal stresses
Thermal energy storage for feed water preheating	Lower minimum load	Heat from the steam turbine can be absorbed by feed water, thereby reducing net power. Thermal energy stored in the feed water can be discharged to increase net power during periods of high demand.	Using a hot water storage system that can operate for 2–8 hours can reduce minimum load by 5–10 %, and during discharge the hot water system can be used to increase net power by 5 % without increasing the firing rate.	-

It is important to mention here that, while improved flexibility can allow for better operation of the plant, there are certain drawbacks to frequent plant start-ups and fast load swings that occur under such operation. Flexible operation causes thermal and mechanical fatigue stress on some of the components. When combined with normal plant degradation this can reduce the expected life of some pressure parts. In this regard, the critical parts that need to be given more attention to are the boiler and steam turbine systems [10].

The improvement in flexibility of plants is dependent on various factors like age of plant, existing technology, type of coal and some 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 9-3 provides a summary and comparison of potential improvement in relevant parameters for a hard coal-fired power plant before and after flexibilization.

Table 9-3. Comparison of flexibility parameters before and after flexibilization initiatives in a hard coal power plant [1] [9].

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

The estimation of the cost for flexibility improvement solutions can vary on a case-by-case basis. A rough estimate suggests costs between 120,000 and 600,000 USD/MW [1] [9]. Furthermore, a study conducted by IEA Clean Coal Centre, investigated the cost of various flexibility improvements for coal plants. The investment cost estimates from this study are summarized in Table 9-4 below[11].

Table 9-4. Investment cost estimated for specific flexibility improvement solutions based on a study for a 600 MW hard coal power plant [4].

Solution	Investment estimate (in USD for a 600 MW hard coal power plant)
Increase maximum load (Includes: 3-way valve and optionally bypass piping)	558,265
Lower minimum load (from 40% to 25%) (Includes: boiler circulation pump, connecting pipe work, control and stop valves, standby heating, electrical, instrumentation and programming of the DCS system)	1,898,101

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

Increased ramping speed (from 1% to 2% per min.) **Upgrade of DCS-system** **Refurbishment of pulverizes**	156,314 424,281

9.8. Advantages/disadvantages

9.8.1. Advantages:

- Mature and well-known technology.
- The efficiencies are not reduced as significantly at part load compared to full load as with combined cycle-plants.
- High reliability to uncertainties.

9.8.2. Disadvantages:

- Coal fired power plants emit high concentrations of NO_x, SO_2 and particle matter (PM), which have high societal costs in terms of health problems and in the worst-case death.
- The burning of coal is the biggest emitter per CO_2 emission per energy unit output, even for a supercritical power plant.
- Coal fired power plants using the advanced steam cycle (supercritical) possess the same fuel flexibility as the conventional boiler technology. However, supercritical plants have higher requirements concerning fuel quality. Inexpensive heavy fuel oil cannot be burned due to materials like vanadium, without the steam temperature (and hence efficiency) is being reduced, and biomass fuels may cause corrosion and scaling, if not handled properly.
- Coal fired power plants have a relatively high maintenance periodicity (around every 4 months). This is a major concern because during the El Niño, when hydropower is not able to deliver power in Colombia, predictive O&M scheduled planning should be carefully carried out to guarantee national energy security.

9.9. Environment

The main ecological footprints from coal-fired AD plants are bulk waste (disposal of earth, cinder, and rejects from mining), climate change and acidification. The fly ash can be utilized 100 % in cement and concrete.

Coal is comprised of a variety of chemicals including carbon, hydrogen, sulphur, and even metals. When coal is burned, these substances are released into the atmosphere as either gases or as PM 2.5 particles. They then travel with the wind and react with other atmospheric chemicals. Thus, individuals living downwind from a coal plant are exposed to a complex mixture of airborne chemicals, each carrying potential health impacts. A study in Science found that coal-burning power stations emit fine particulates (PM2.5) containing sulphur dioxide that are associated with higher mortality than other types of PM2.5 [11].

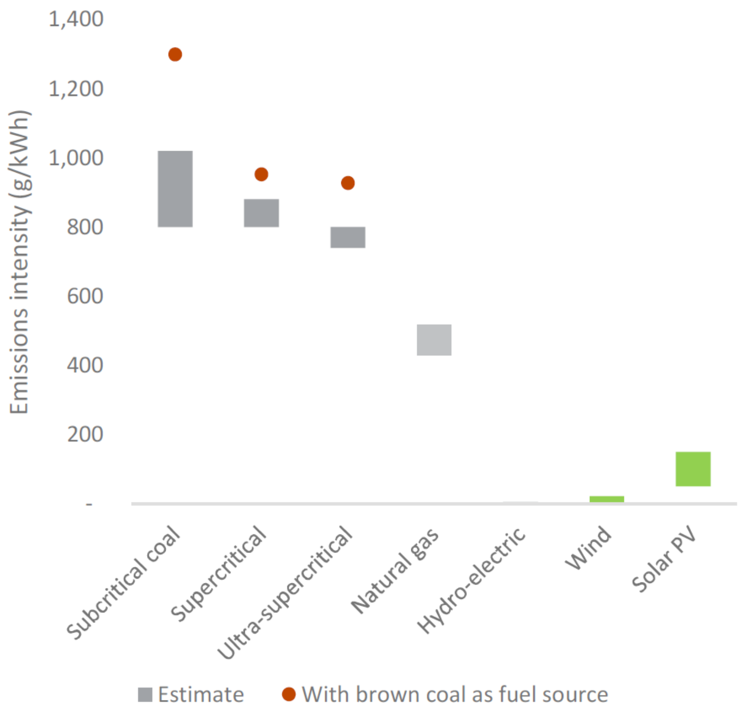

Figure 80. Comparison emissions of coal plant technologies [3].

The most efficient coal technology available today, "ultra-supercritical," still produces over 740 grams of CO_2 per kWh of electricity generated. This exceeds the typical emissions range for natural gas, which is between 430 and 517 grams of CO_2 per kWh. As illustrated by the brown dots in Figure 80, switching the fuel source from black coal to brown coal increases emissions intensity across different technologies. According to available research, an "ultra-supercritical" plant using brown coal would emit 928 grams of CO_2 per kWh [3].

9.10. Research and development perspectives

Conventional super critical coal technology is fairly well established and so there appear to be no major breakthroughs ahead. There is very limited scope to improve the cycle thermodynamically. It is more likely that the application of new materials will allow higher efficiencies, though this is unlikely to come at a significantly lower cost [4]. Best-available-technology plants today operate at up to 600 °C. An electricity efficiency of 55 % requires steam at 700 °C and the use of nickel-based alloys [1]. Further RD&D in such alloy steels is required in order to obtain increased strength, lower costs and thereby cheaper and more flexible plants.

Existing coal power plants may be rebuilt for biomass combustion, mainly in order to reduce CO_2 emissions without discarding existing generating capacity. The conversion to biomass in existing pulverized coal fired power plants may be done partly by co-firing a fraction of biomass together with the coal, or by converting the plant fully to biomass. The power plants for rebuilding should be at an age so that a lifetime extension will be necessary in any case.

9.11. Examples of market standard technology

As depicted in Figure 81, Colombia has 19 coal power plants and 4 cogeneration power plants (bagasse and coal), which sum up to 1,658 MW of installed capacity. None of them use the supercritical coal technology [12].

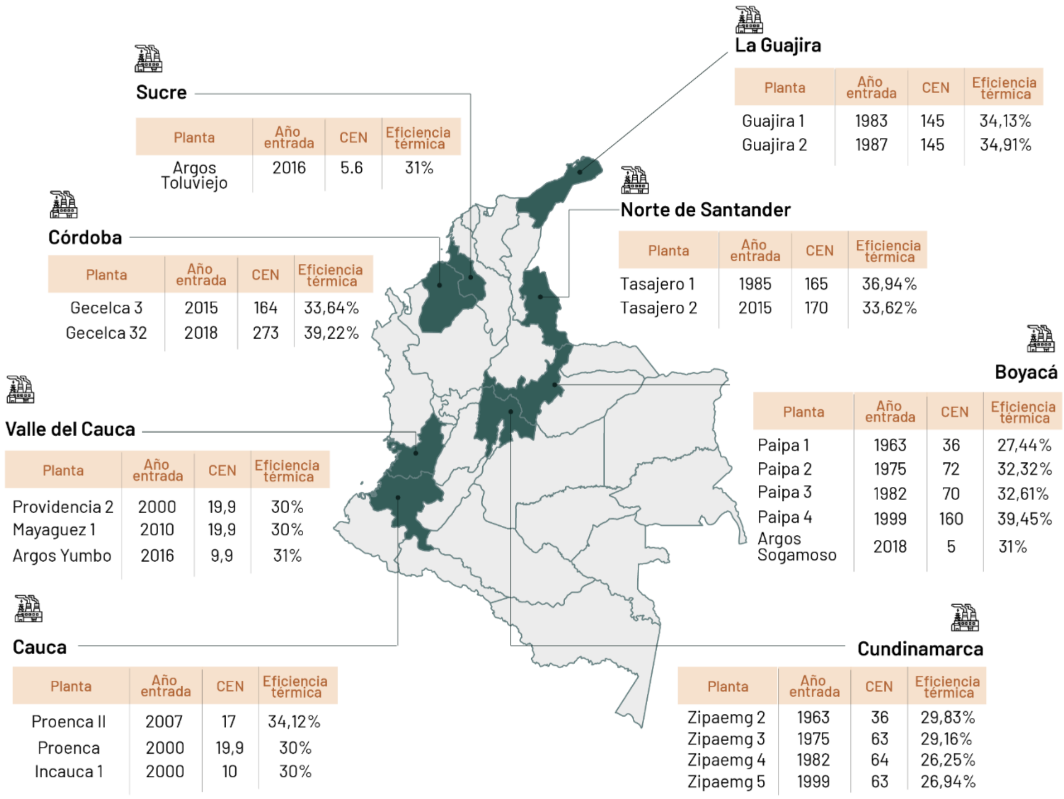

Figure 81. Location, year and installed capacity of coal power plants in Colombia [12].

9.12. Prediction of performance and cost

9.12.1. CAPEX and OPEX costs for new coal fired power plants

Investment costs for coal power plants are very sensitive to the plant's design. Supercritical power plants use once-through boilers which contribute to cost increases; in state-of-the-art plants, efficiency gains in the order of a few percent are obtained through a well-thought design of machines and feedwater preheating. This remarkably increases overnight expenses.

Another important factor that greatly affect costs is the presence of sophisticated control systems, which are needed to optimize the functioning at partial load. Additional equipment for fault prediction also increases costs. Plants designed for base-load electricity supply are less expensive on average, and so are units forced to comply with very stringent environmental regulations.

The typical coal power plant in Colombia operates in condensing mode, with no district heat production. Compared to other international figures (e.g. Denmark's), this indicates a less complicated design and therefore lower costs.

It is therefore complicated to draw a comparison with other international values; all in all, coal power plants in Indonesia are found to be cheaper than the international average on a per-MW basis. The data in Table 9-5 refers to supercritical power plants.

Table 9-5. Investment cost comparison for coal (supercritical). The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [MUSD2024/MW]	Base year FID (final investment decision)
This study	1.79	2024
International data		
Technology Catalogue Indonesia (2024)	1.80	2024
Technology Catalogue Vietnam (2023)	1.77	2023
Technology Catalogue Denmark (2024)	3.0	2017
IEA GEC Model, Brazil region (2021)	1.80	2021
NREL ATB (2023)	3.35	2023

9.12.2. Prediction of the cost in 2030 and 2050

To predict the costs in 2030 and 2050, it is assumed that the cost is falling by 0.2 % p.a. This is based on an assumption of accumulation of capacity commissioned from 2020 to 2050 deduced from predictions of the future global installed electricity capacity in the 4D scenario in the Energy Technology Perspectives [13], and an assumed learning rate of app. 8 % for coal technologies [12].

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9.14. Datasheet

Technology	**Supercritical coal power plant**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MW_e)	201	201	201	164	270	164	270		4
Generating capacity for total power plant (MW_e)	201	201	201	170	434	170	434		4
Electricity efficiency, net (%), name plate	38 %	39 %	40 %	33 %	40 %	35 %	42 %		2
Electricity efficiency, net (%), annual average	37 %	38 %	39 %	33 %	40 %	35 %	42 %		2
Forced outage (%)	7 %	6 %	3 %	5 %	15 %	2 %	7 %	F	2
Planned outage (weeks/year)	7	5	3	3	8	2	4	F	2
Technical lifetime (years)	30	30	30	25	40	25	40		2
Construction time (years)	4	3	3	3	5	2	4	F	2
Space requirement (1000 m^2/MW_e)	1.83	1.83	1.83	0.95	2.7	0.95	2.7		6
Additional data for thermal plants									
Capacity factor (%), theoretical	44.5 %	44.5 %	44.5 %	26.5 %	60.0 %	26.5 %	60.0 %	C,H,I	5
Capacity factor (%), incl. outages	35.8 %	37.8 %	40.7 %	19.0 %	53.7 %	22.7 %	56.6 %	C,H	5
Ramping configurations									
Ramping (% of Full Load/Minute)	4 %	4 %	4 %	3 %	4 %	3 %	4 %	J	2.4
Minimum load (% of full load)	47 %	25 %	20 %	39 %	55 %	20 %	40 %	F	4
Warm start-up time (hours)	4	4	4	2	5	2	5	D	4
Cold start-up time (hours)	12	12	12	6	15	6	15	D	4
Minimum Up time (hours)	6	6	6					K,L	9
Minimum Down time (hours)	4	4	4					K,L	9
Environment									
PM 2.5 (g/GJ of fuel input)	3.4	3.4	3.4						8
SO_2 (g/GJ of fuel input)	3102	3102	3102						8
NO_X (g/GJ of fuel input)	209	209	209	209	209	209	209		8
CH_4 (g/GJ of fuel input)	3.27	3.27	3.27	1.83	7.06	1.83	7.06		5
N_2O (g/GJ of fuel input)	4.91	4.91	4.91	2.75	10.60	2.75	10.60		5
Financial data									

Nominal investment (MUSD/MW$_e$)	1.80	1.78	1.71	1.12	2.23	1.06	2.11	A,B,M	1,2,3,10
- of which equipment (%)									
- of which installation (%)									
Fixed O&M (USD/MW$_e$/year)	50,500	49,900	47,900	37,900	63,100	35,900	59,900	A,B,G	1,2,3
Variable O&M (USD/MWh)	1.26	1.25	1.20	0.95	1.58	0.90	1.50	A,B,G	1,2,3
Start-up costs (USD/MW$_e$/start-up)	64.1	64.1	64.1	48.06	80.10	48.06	80.10	A,B,G	2

Notes

A Based on international data.

B Assuming that cost fall 0.2 % each year.

C The capacity factor in 2024 is calculated from 2017-2024 for each plant with available information.

D Estimation based on international data for the capability of the machine. An average of the operational data in Colombia [4] shows that hot start-up time is 8 hours, warm start-up time is 36 hours and cold start-up time is 65 hours. The operational data from Colombia is higher than international data because of the design of the Colombian energy system.

E This is for programmed stops, for non-programmed stops the time ranges between 0 and 1 h.

F Assumed gradual improvement to international standard in 2050.

G Uncertainty (Upper/Lower) is estimated as +/- 25 % in this case, to account for the variability and uncertainties inherent in its estimation.

H Assumed the same theoretical capacity factor for 2030 and 2050 and changed the capacity factor incl. outages based on the reduction of outages.

I Uncertainties for 2050 have been assumed to be the same as in 2030.

J Assumed no improvement for regulatory capability.

K Estimation based on international data for the capability of the machine. An average of the operational data in Colombia [4] shows that minimum up time is 48 hours and minimum down time is 18,67 hours (for programmed stops, for non-programmed stops the time for down time ranges between 0 and 1 hours). The operational data from Colombia is a lot higher than international data because of the design of the Colombian energy system.

L Coal is less flexible than gas regarding minimum up/down time.

M Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the general technology improvement potential.

References

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[4] XM: Data From Paratec - Projects from 2010 on (3 units for Coal)

[5] Data from Sinergox - calculation provided by Emergente

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10. Combined-Cycle Gas Turbine

10.1. Brief technology description

The core concept of a combined cycle plant lies in integrating a Brayton cycle (gas turbine) with a Rankine cycle (steam turbine). In this setup, the gas turbine's exhaust heat is harnessed to produce steam, which then drives a steam turbine, boosting the system's overall efficiency.

A combined cycle plant operates by recovering the thermal energy in the exhaust gases as they exit the gas turbine, essentially extending the open Brayton cycle. This recovered heat is then used in the Rankine cycle, where water is heated to produce steam that powers a steam turbine, generating additional electricity, as shown in Figure 82.

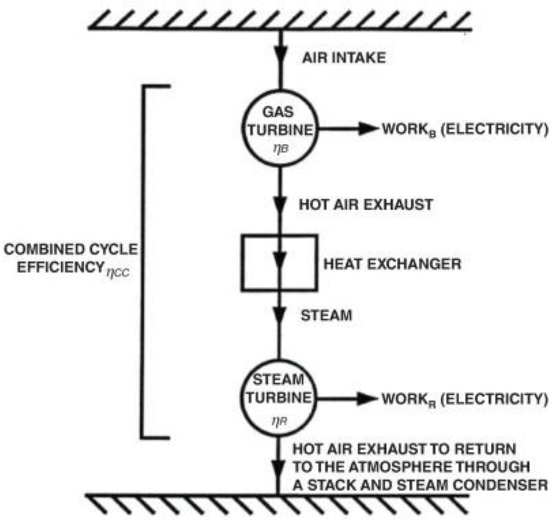

Figure 82. Process diagram of a CCGT [1].

Figure 83 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.

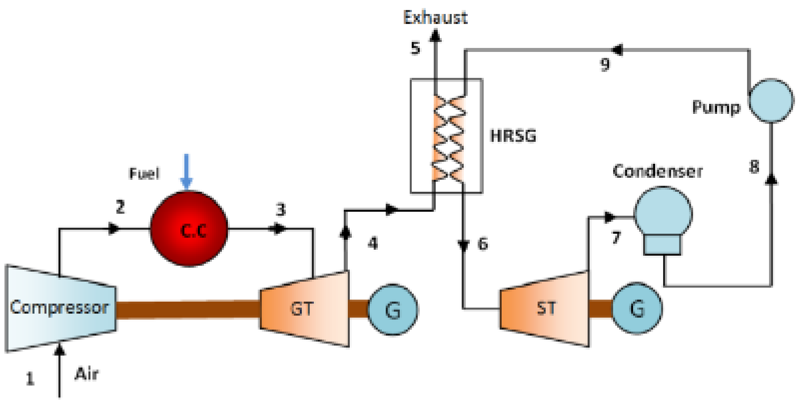

Figure 83. Process diagram of a CCGT [2].

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 83.

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.

10.1.1. Gas Turbines

In general, there two types of gas turbines for power generation: Industrial turbines (also called heavy-duty) and aero-derivative turbines. These are described in the Chapter Simple-Cycle. For combined cycle, gas turbines are used jointly with steam turbines.

10.1.2. Steam Turbines

After combustion in the gas turbine generates electricity, the exhaust gases, which are still extremely hot, are directed to a heat recovery steam generator (HRSG). This system captures the heat to produce steam. This steam is then directed through nozzles into the turbine, where it strikes rows of blades attached to a rotor. As the steam expands across the blades, its pressure and temperature drop, creating a force that causes the blades and rotor to spin. This rotational energy is transferred to a generator via a connected shaft, which converts the mechanical energy into electrical power. After passing through the turbine's stages, the steam, now at a lower pressure, is exhausted into a condenser, where it cools and condenses back into water. This water can then be reused in the steam cycle, making the process highly efficient. Steam turbines often feature multiple stages—high-pressure, intermediate-pressure, and low-pressure sections—to maximize energy extraction as the steam progresses through the system. An example is illustrated in Figure 84.

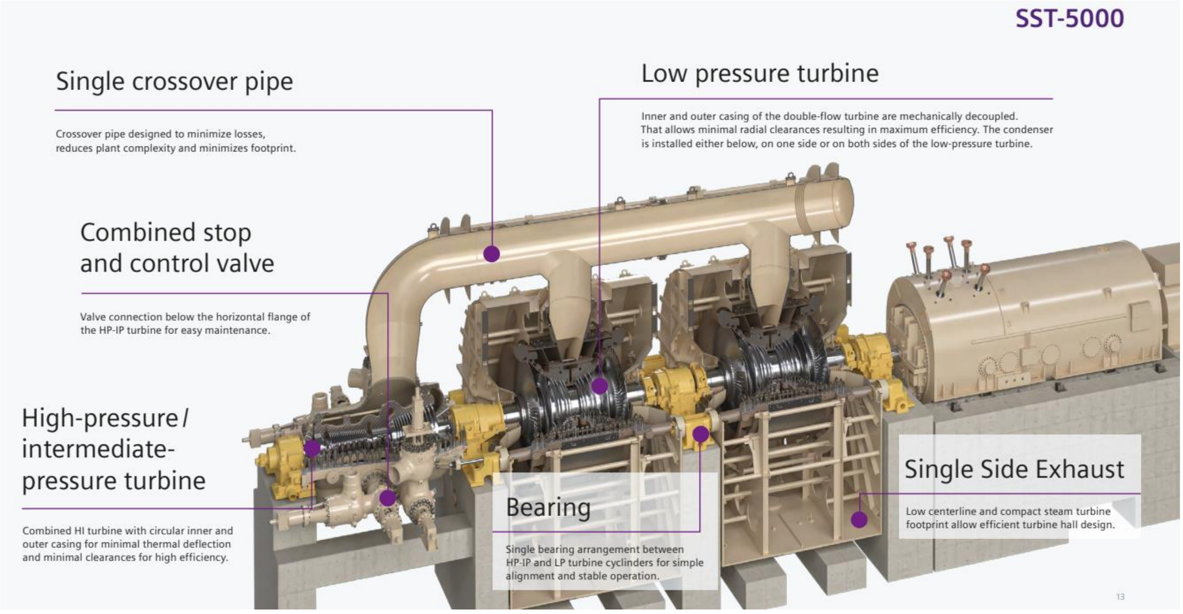

Figure 84. Illustration with the main components of steam turbines [4].

10.2. Input

As described in the chapter Simple-Cycle, 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.

10.3. Output

Electricity.

10.4. Typical capacities

The enclosed datasheets cover large scale combined-cycle gas turbines (CCGT) (100 – 400 MW_e with extraction steam turbine) and medium scale (10 – 100 MW with back pressure steam turbine).

Most CCGT units have an electric power of > 40 MW_e.

10.5. Space requirement

In 2015, the U.S. housed 1,740 natural gas power plants. According to the Natural Gas Supply Association, the average natural gas plant requires between 8 and 16 hectares of land. Using a median value of 12 hectares as the standard, these plants collectively occupied approximately 21,088 hectares of land in 2015, equating to about 0.14 hectares per megawatt produced [5].

This corresponds to Colombian data in Table 10-1, where space requirements for projects combines cycle projects range between 0.12 and 0.14 hectares per MW [6].

Table 10-1. Land Use of Combined-Cycle Gas Power Plants in Colombia [6].

Land Use Gas CC	Ha/MW
Tebsab	**0,12**
Flores 4b	**0,12**
Termocentro cc	**0,14**
Termocandelaria 1, 2	**0,14**

10.6. Water consumption

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 85 [7].

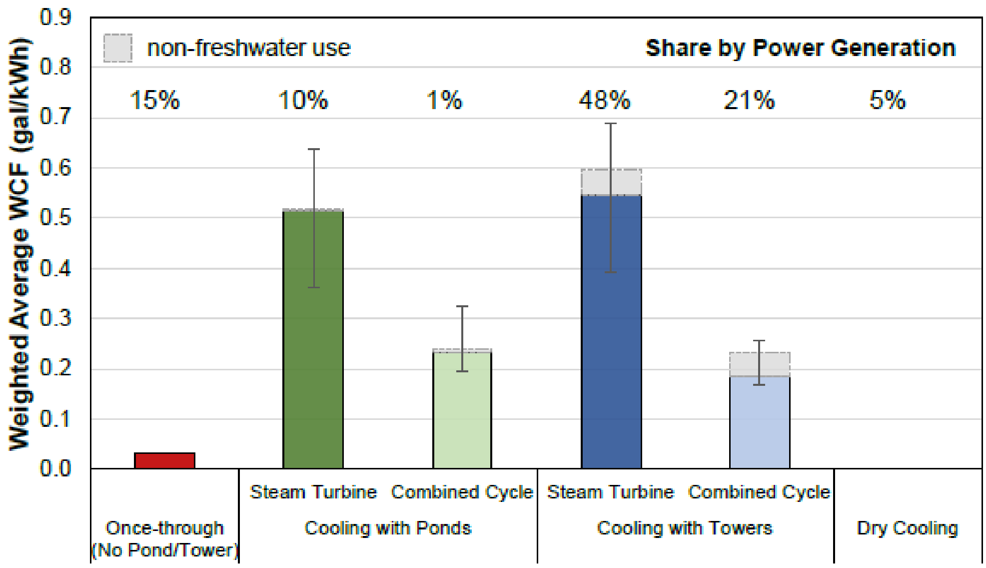

Figure 85. Water consumption factor for different thermal power generation [7].

10.7. Regulation ability and other power system services

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.

10.8. Advantages/disadvantages

10.8.1. Advantages

- CCGT Provide Highest possible efficiency in thermal power generation.
- Large gas turbine based combined-cycle units are world leading regarding electricity production efficiency among fuel-based power production.
- Existing gas or steam turbines can be converted to combined cycle power plants at any time.
- While it is true that gas turbines produce CO_2, 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

10.8.2. Disadvantages

- Smaller CCGT units have lower electrical efficiencies compared to larger units. Units below 20 MW_e are few and will face close competition with single-cycle gas turbines and reciprocating engines.
- The economies of scale are substantial, i.e. the specific cost of plants below 200 MW_e increases as capacity decreases.
- The high air/fuel ratio for gas turbines leads to lower overall efficiency for a given flue gas cooling temperature compared to steam cycles and cogeneration based on internal combustion engines.
- A significant disadvantage of gas turbines in terms of emissions is their production of carbon dioxide (CO_2) 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.

10.9. 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. CCGTs capture exhaust heat to generate additional electricity through a steam turbine, minimizing waste heat and reducing nitrogen oxide (NO_x) emissions, a major air pollutant.

10.10. Research and development perspectives

As mentioned in the Chapter Simple-Cycle, 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 [8].

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 [9].

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.

One major area of development is the use of hydrogen as a fuel. Leading manufacturers such as GE, Siemens, and Mitsubishi Power are developing "hydrogen-ready" turbines that can initially operate on blends of natural gas and hydrogen [16]. However, hydrogen presents combustion challenges due to its hotter and faster burn rate, which can lead to high NO_x emissions and stability issues [16].

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 [17].

10.11. Examples of market standard technology

Large CCGT units have demonstrated an electrical efficiency of 60 % (LHV reference). Systems are now being offered and built with an electrical efficiency close to 62 %. The units are large units with an output in the 500 – 600 MW_e [10].

The most recent combined cycle project in Colombia is the Termocandelaria expansion project, shown in Figure 86 where an existing single cycle plant was capacity from 314 MW to 566 MW, by upgrading from two simple-cycle units to three combined-cycle units, boosting generation capacity by 80 % without increasing CO_2 emissions. This USUSD 258 million expansion improves fuel efficiency and reduces energy production costs by 40 %. As 2023, Termocandelaria could cover 7 % of the national energy demand, 25 % of the Caribbean coast, and 121 % of Bolívar's, contributing 252 MW of additional capacity [11].

Figure 86. Termocandelaria Combined Cycle Power Plant [15].

10.12. Prediction of performance and costs

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.

In Colombia, thermal power plants represent 30.2 % of the total net effective installed capacity, of which approximately half corresponds to machinery working with CCGT technology. Although the efficiency of the system is limited to 60 % according to the literature, there is an optimal heat rate in each individual system that reduces the production costs (COP) per MBTU/MWh, however the parameters that define it must be unique for each thermal unit, type of fuel and turbine [10].

Colombia has abundant natural gas resources in the Caribbean region and in the past years, wellhead gas power plants have been developed. By generating power directly at the wellhead, where natural gas is extracted, energy companies can harness the fuel more efficiently. This proximity reduces logistical expenses and losses in transporting gas to distant power plants or processing facilities. These savings in transportation and improved efficiency not only reduce operational costs but also can result in more competitive electricity pricing.

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].

Table 10-2 compares different investment cost estimates from various sources.

Table 10-2. Investment cost comparison across regions for CCGT projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	1.10	2024
International data		
Technology Catalogue Indonesia (2024)	1.22	2024
Technology Catalogue Vietnam (2023)	0.93	2023
Technology Catalogue Denmark (2024)	1.31	2017
IEA GEC Model, Brazil region (2021)	0.79	2021
NREL ATB (2023)	1.30	2023

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10.14. Datasheet

Technology	**Combined Cycle Gas Turbine**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MW_e)	377	377	377	239	555	239	555		5
Generating capacity for total power plant (MW_e)	377	377	377	239	555	239	555		5
Electricity efficiency, net (%), name plate	57 %	60 %	61 %	45 %	62 %	55 %	65 %		3.6
Electricity efficiency, net (%), annual average	56 %	59 %	60 %	39 %	61 %	54 %	64 %		3
Forced outage (%)	5 %	5 %	5 %	3 %	10 %	3 %	10 %		3
Planned outage (weeks/year)	5	5	5	3	8	3	8		3
Technical lifetime (years)	25	25	25	20	30	20	30		3
Construction time (years)	2.5	2.5	2.5	2	3	2	3		3
Space requirement (1000 m^2/MW_e)	1.3	1.3	1.3	1.16	1.41	1.16	1.41		8
Additional data for thermal plants									
Capacity factor (%), theoretical	34.2 %	34.2 %	34.2 %	1.9 %	55.3 %	1.9 %	55.3 %	C	7
Capacity factor (%), incl. outages	29.3 %	29.3 %	29.3 %	1.5 %	50.6 %	1.5 %	50.6 %	D	7
Ramping configurations									
Ramping (% per minute)	20 %	20 %	20 %	10 %	30 %	10 %	30 %	G	3
Minimum load (% of full load)	45 %	30 %	15 %	24 %	70 %	10 %	40 %	I	3,5,6
Warm start-up time (hours)	2	1	1	1	3	0.5	2	E,I	1,3,6
Cold start-up time (hours)	4	4	4	2	5	2	5	E	1,3,6
Minimum Up time (hours)	4	4	4					K,L	11
Minimum Down time (hours)	3	3	3					K,L	11

Environment									
PM 2.5 (g/GJ of fuel input)	0.89	0.89	0.89	0.89	0.89	0.89	0.89		10
SO_2 (g/GJ of fuel input)	0.28	0.28	0.28					J	10
NO_X (g/GJ of fuel input)	89	60	20	20	89	20	89	I	3,4,10
CH_4 (g/GJ of fuel input)	1.79	1.79	1.79	0.53	2.34	0.53	2.34		7
N_2O (g/GJ of fuel input)	0.18	0.18	0.18	0.05	0.24	0.05	0.24		7
Financial data									
Nominal investment (MUSD/MW_e)	1.10	1.09	1.05	0.64	1.36	0.61	1.29	A,B,M	1,2,3,4
- of which equipment (%)	50 %	50 %	50 %	50 %	50 %	50 %	50 %	A,B	1,3,4
- of which installation (%)	50 %	50 %	50 %	50 %	50 %	50 %	50 %	A,B	1,3,4
Fixed O&M (USD/MW_e/year)	32,900	32,500	31,200	24,700	41,100	23,400	39,000	A,B,H	1,3,4
Variable O&M (USD/MWh)	1.74	1.71	1.65	1.30	2.17	1.24	2.06	A,B,H	1,3,4
Start-up costs (USD/MW_e/start-up)	92.8	92.8	92.8	69.6	116.1	69.6	116.1	H	3,4

Notes

A Based on aggregated data of Colombian projects in the register database by UPME (projects from 2018 and forward), supplemented with further prices from international sources.

B Assuming that cost fall 0.2 % each year.

C Calculated based on the parameters: Capacity factor incl. outages, Forced outage and Planned outage.

D The capacity factor is calculated from 2017-2024 for each plant with available information.

E Estimation based on international data for the capability of the machine. An average of the operational data in Colombia [5] shows that hot start-up time is 16,5 hours, warm start-up time is 28 hours and cold start-up time is 46,5 hours. The operational data from Colombia is higher than international data because of the design of the Colombian energy system.

F This is for programmed stops, for non-programmed stops the time ranges between 0 and 1 hour.

G Assumed no improvement for regulatory capability.

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

I Assumed gradual improvement to international standard in 2050.

J Commercialised natural gas is practically sulphur free and produces virtually no sulphur dioxide

K Estimation based on international data for the capability of the machine. An average of the operational data in Colombia [5] shows that minimum up time is 9,08 hours and minimum down time is 4 hours (for programmed stops, for non-programmed stops the time for down time ranges between 0 and 1 hours). The operational data from Colombia is higher than international data because of the design of the Colombian energy system.

L Gas is more flexible than coal regarding minimum up/down time

M Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the general technology improvement potential.

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11. Simple-Cycle Gas Turbine

11.1. Brief technology description

Most simple-cycle gas turbine (SCGT) power plants operate in open circuit with an internal combustion system. As shown in Figure 87,The fuel air flows through the single control surface into the compressor and combustion chamber, respectively, and the combustion products leave the control surface after expanding through the turbine. If the gases are not involved in combustion, it is possible to work in a closed cycle, in which case a boiler is needed to heat the gas and an exchanger to cool it.

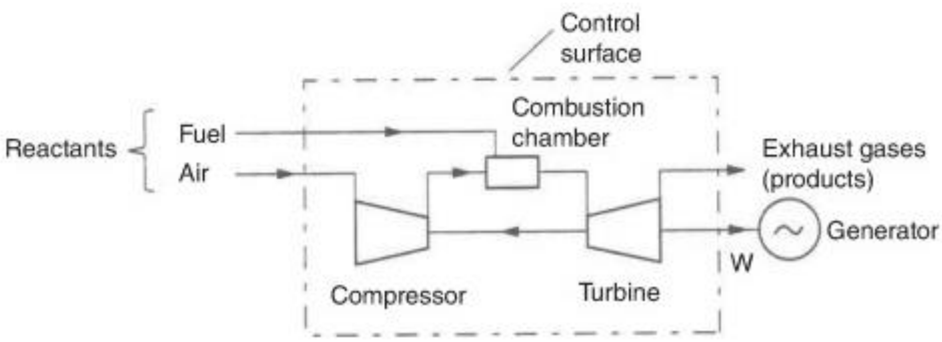

Figure 87. Process diagram of a simple-cycle gas turbine (SCGT) [1].

The major components of a simple-cycle (or open-cycle) gas turbine power unit are a gas turbine, a gear (when needed) and a generator. In this process there are several energy losses:

- Combustion efficiency: The combustion process in a gas turbine is not 100 % efficient, resulting in energy losses. Some of the fuel energy is lost as heat lost in the exhaust gases.
- Turbine blade efficiency: Turbine blades play a crucial role in extracting energy from the hot gases and converting it into mechanical work. However, due to factors such as aerodynamic losses and material limitations, turbine blades cannot convert all available energy efficiently.
- Compressor efficiency: Gas turbines use compressors to compress incoming air prior to combustion. Compressor efficiency affects the overall efficiency of the gas turbine. Factors such as pressure losses and mechanical inefficiencies can reduce compressor efficiency.
- Turbine cooling: Gas turbines operate at high temperatures, and it is necessary to cool the turbine blades to avoid damage. However, the cooling process consumes energy, which reduces the overall efficiency of the turbine.

In general, there are two types of gas turbines for power generation:

Industrial turbines (also called heavy-duty) (Figure 88)

These range from small units to complex large-scale designs. When used solely for electrical power generation, their efficiency ranges from 30 % to 40 % [13]. Because it is more efficient to use both the electricity and the heat generated, many of these turbines are used in combined heat and power plants (CHP), reaching capacities of up to 500 MW. Gas turbines can achieve an efficiency of up to 57 % when the exhaust gas energy is harnessed in heat recovery systems in steam turbine plants [12]. In these configurations, the exhaust gases are used to heat water or cool the inlet air, thereby increasing power output. Another advantage is that they can be switched on and off in a matter of minutes and can supply unscheduled peaks in energy demand.

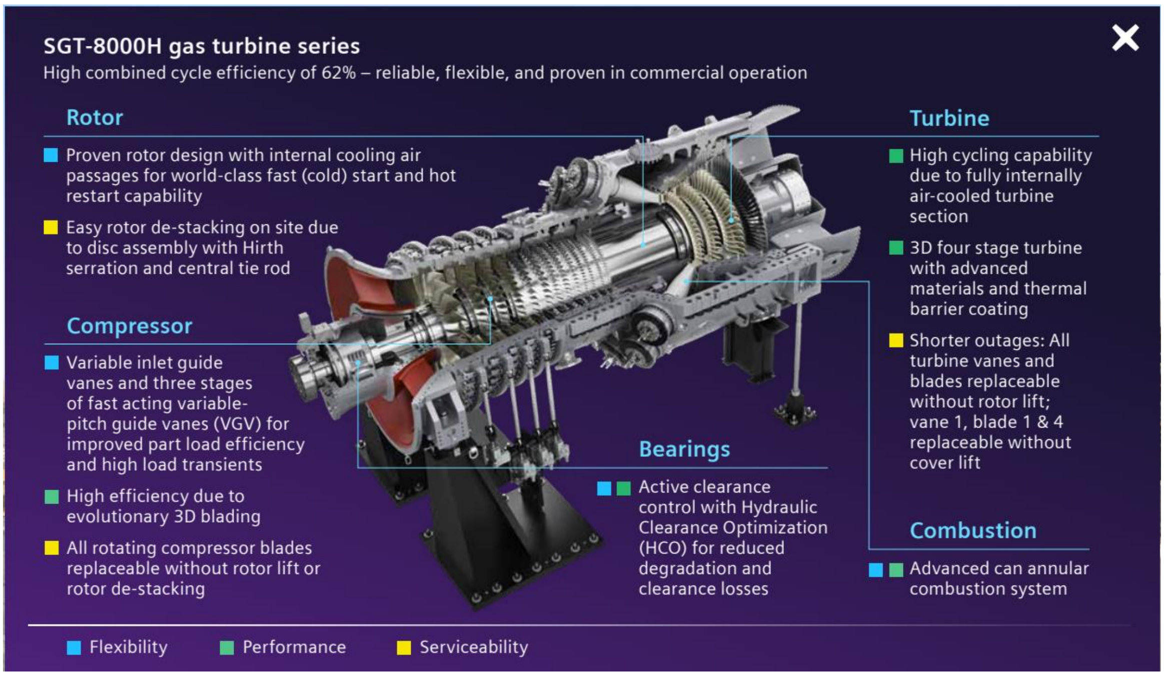

Figure 88. Illustration with the main components of industrial gas turbines [2].

Aero-derivative turbines (Figure 89)

Compared with industrial gas turbines, Aeroderivative gas turbines on the other hand are lightweight and compact designs adapted from aircraft jet engines. They are used to generate thrust through the reaction effect of a jet of gases a jet of gases expelled at high speed. They operate at higher compression ratios and efficiencies but have lower power outputs. The most important aircraft engines are single-flow engine: The air flow enters through the diffuser into the compressor, where it increases in pressure. It is then combusted in the combustion chamber, flows through the turbine generating Finally, it is accelerated in the nozzle to generate a high-speed jet of gases that provides the full thrust of the engine.

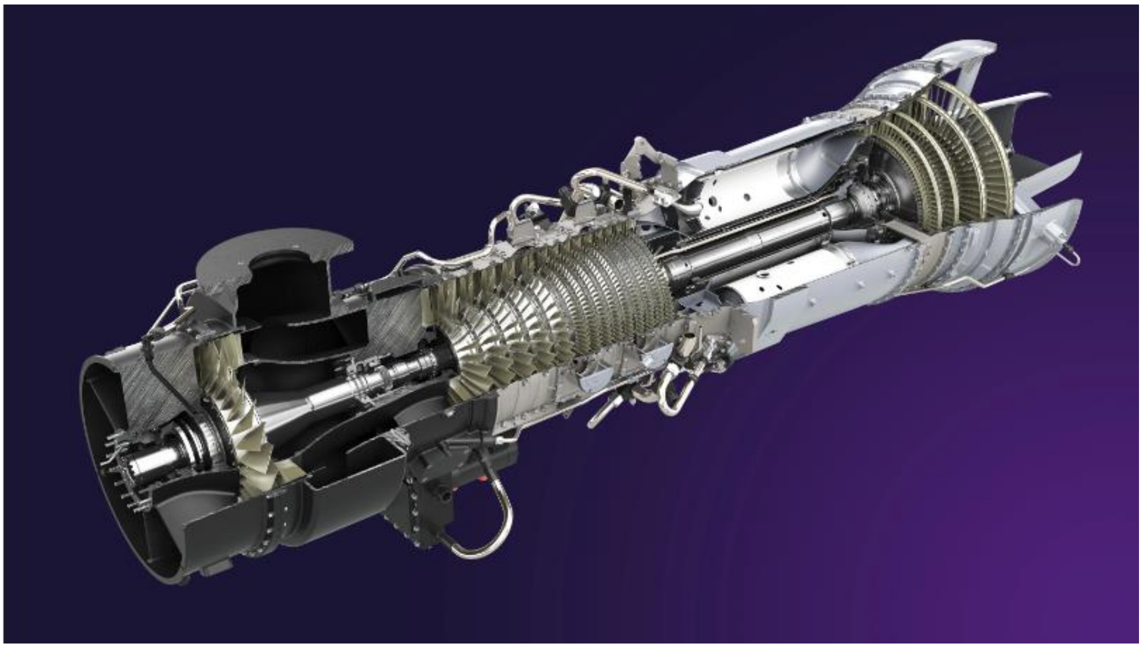

Figure 89. Aero-derivative gas turbines [2].

Industrial gas turbines are distinct from aero-derivative turbines in that they have heavier construction in frames, bearings, and blading. Additionally, they typically require longer intervals between services compared to aeroderivative. Aero-derivative turbines are known for their higher efficiency compared to industrial turbines. The most service-demanding module of an aero-derivative gas turbine can usually be replaced within a couple of days, ensuring 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 gas turbines, specifically those below 100 kW known as micro-turbines, often feature combustion air preheating using heat from the gas turbine exhaust (integrated recuperator) to achieve reasonable electrical efficiency, typically between 25-30 %.

Gas Engines (Figure 90)

Besides turbines, there are also alternatives to generate power using gas through internal combustion gas. These engine engines operate by burning an air-fuel mixture, which causes the rapid expansion of high-pressure gases. This expansion pushes the piston down the cylinder during the power stroke, transferring rotational energy to the crankshaft. Unlike gas turbines, where combustion is continuous, in these engines combustion only occurs intermittently during the power stroke. As the piston moves back up the cylinder during the exhaust stroke, exhaust gases are expelled through an exhaust valve. Multiple cylinders are connected to the crankshaft, with some pistons powering the crankshaft during their power stroke while others return to the top during their exhaust stroke.

Figure 90. Gas engines for power generation [3].

11.2. Input

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

Gas-fired gas turbines need an input pressure of the fuel (gas) of 20-60 bar, dependent on the gas turbine compression ratio, i.e. the entry pressure in the combustion chamber. Typically, aero derivative gas turbines need higher fuel (gas) pressure than industrial types.

11.3. Output

Electricity and heat.

11.4. Typical capacities

Simple-cycle gas turbines are available in the 30 kW_e – 450 MW_e range [4]. Advances in technology have improved efficiency and environmental performance, with typical development focusing on higher firing temperatures, advanced materials and improved turbine aerodynamics.

11.5. Space requirement

In 2015, the U.S. housed 1,740 natural gas power plants. According to the Natural Gas Supply Association, the average natural gas plant requires between 8 and 16 hectares of land. Using a median value of 12 hectares as the standard, these plants collectively occupied approximately 21,088 hectares of land in 2015, equating to about 0.14 hectares per megawatt produced [5].

This corresponds to Colombian data in Table 11-1, where space requirements for simple cycle projects range between 0.1 and 0.3 hectares per MW [6].

Table 11-1. Land Use of Simple-Cycle Gas Power Plants in Colombia [6].

Power plant	Ha/MW
Flores 1	0,2
Proelectrica 1, 2	0,1

Merilectrica 1	0,1
TEBSA 3 y 4	0,3
Termoyopal	0,3

11.6. 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 [7]. 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.

11.7. Regulation ability and other power system services

A simple-cycle gas turbine can start and stop within minutes, making it suitable for supplying power during peak demand. Although less power-efficient than combined cycle plants, they are typically used as peak or reserve power plants, operating from several hours per day to a few dozen hours per year.

The state-of-the-art projects in Colombia use multiple smaller gas engines instead of a single large turbine to increase operational flexibility. This approach offers several advantages [3]:

- Load Adjustment: With multiple motors, plant operators can turn individual units on or off depending on the demand, allowing for more precise control over energy output. This makes the plant more adaptable to fluctuating energy demand, which is particularly important when integrating renewable sources like wind and solar that have variable generation.
- Efficiency at Partial Loads: Running a single large turbine at partial load can be inefficient. In contrast, a plant with several smaller motors can optimize performance by operating only the necessary number of units, maintaining higher efficiency even at lower loads.
- Reduced Downtime: When maintenance is required, only one or a few motors need to be taken offline, while the rest of the system continues to operate. This reduces downtime and enhances overall reliability.
- Faster Response: Smaller motors typically have quicker start-up times compared to large turbines. This allows gas power plants to ramp up production more rapidly, improving their ability to respond to sudden changes in electricity demand or to back up intermittent renewable energy sources.

11.8. Advantages/disadvantages

11.8.1. Advantages

- Simple-cycle gas power plants have short start-up/shut-down time, if needed. For normal operation, a hot start will take some 10-15 minutes [8, 9]. Construction times for gas turbine based simple cycle plants are shorter than steam turbine plants [9].
- Simple 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.

11.8.2. Disadvantages

- High initial cost: The initial investment for the construction of a gas turbine power plant is high due to the complexity of the technology.
- 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.
- Limitations in power generation: The gas turbine has limitations in terms of electricity generation compared to other technologies such as hydropower or nuclear power.
- A significant disadvantage of gas turbines in terms of emissions is their production of carbon dioxide (CO_2) 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.

11.9. Environment

Gas turbines operate with continuous combustion, and their combustion chambers have non-cooled walls, which promotes very complete fuel combustion and helps maintain low emission levels (with the exception of NO_x emissions). Advances in combustor design have significantly reduced NO_x emissions, making modern gas turbines cleaner and more efficient. To further cut emissions, especially NO_x, flue gas post-treatment systems like Selective Catalytic Reduction (SCR) catalysts can be used. These systems treat the exhaust gases after combustion, ensuring that emission levels are kept as low as possible.

11.10. Research and development perspectives

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

Additionally, continuous development for less polluting combustion is taking place. Low-NO_x combustion technology is assumed. Water or steam injection in the burner section may reduce the NO_x emission, but also the total efficiency and thereby possibly the financial viability. The trend is more towards dry low-NO_x combustion, which increases the specific cost of the gas turbine [10].

11.11. Examples of market standard technology

One of the most recent simple gas cycle projects in Colombia is El Tesorito, inaugurated by Celsia in 2022 [11]. El Tesorito generation plant project had a capacity of 200 MW and represented an investment of USD 190 million. This gas power plant uses 11 state-of-the-art internal combustion engines, more efficient than other technologies, ensuring a quick operational start-up time, even within minutes. The Sahagún Substation (500kV) serves as the connection point with El Tesorito, from where energy is transmitted to the National Interconnected System (SIN) and then distributed to Colombian households [11].

Figure 91. El Tesorito Power Plant, Sahagún, Colombia [11].

11.12. Prediction of performance and costs

Gas turbine technology is a well-proven commercial technology with numerous power-generating installations worldwide. Technological improvements are continuously being made; new materials, new surface treatments or improved production methods can lead to higher electrical efficiency, improved lifetime and less service needs.

Developments now also focus on broader gas quality acceptance during operation and improved dynamic performance.

The efficiency of the simple-cycle turbine can be increased, if inlet temperatures to the turbine section can be increased. Therefore, development of ceramic materials that can withstand high temperatures used in the hot parts of the gas turbine is taking place.

Colombia has abundant natural gas resources in the Caribbean region and in the past years, Wellhead gas power plants have been developed. By generating power directly at the wellhead, where natural gas is extracted, energy companies can harness the fuel more efficiently. This proximity reduces logistical expenses and losses in transporting gas to distant power plants or processing facilities *[14].* These savings in transportation and improved efficiency not only reduce operational costs but also can result in more competitive electricity pricing.

Table 11-2 presents a comparison of investment costs for power projects, expressed in millions of USD per megawatt ($MUSD_{2024}$/MW), based on different data sources and regions.

Table 11-2. Investment cost comparison across regions for SCGT projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	0.97	2024
	International data	
Technology Catalogue Indonesia (2024)	1.26	2024
Technology Catalogue Vietnam (2023)	0.74	2023
Technology Catalogue Denmark (2024)	0.88	2017
IEA GEC Model, Brazil region (2021)	0.45	2021
NREL ATB (2023)	1.17	2023

11.13. References

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11.14. Datasheet

Technology	Simple Cycle Gas Turbine - large system								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MW_e)	65.5	65.5	65.5	8	200	8	200		6
Generating capacity for total power plant (MW_e)	131	131	131	50	200	50	200		6
Electricity efficiency, net (%), name plate	34 %	36 %	40 %	27 %	37 %	36 %	43 %	J	3.8
Electricity efficiency, net (%), annual average	33 %	35 %	39 %	23 %	38 %	35 %	42 %	J	3
Forced outage (%)	2 %	2 %	2 %	1 %	3 %	1 %	3 %	K	1.3
Planned outage (weeks/year)	3	3	3	1.5	5	1.5	5	K	1.3
Technical lifetime (years)	25	25	25	20	30	20	30	I	3
Construction time (years)	1.5	1.5	1.5	1.1	1.9	1.1	1.9	F	1, 3
Space requirement (1000 m^2/MW_e)	2.01	2.01	2.01	1.13	3.5	1.13	3.5		7
Additional data for thermal plants									
Capacity factor (%), theoretical	57.0 %	57.0 %	57.0 %	6.6 %	100 %	6.6 %	100 %	H	5
Capacity factor (%), incl. outages	52.7 %	52.7 %	52.7 %	5.8 %	96.2 %	5.8 %	96.2 %	C	5
Ramping configurations									
Ramping (% per minute)	20 %	20 %	20 %	10 %	30 %	10 %	30 %	G	1,3,9
Minimum load (% of full load)	55 %	30 %	15 %	24 %	78 %	10 %	40 %	L	3,4,6
Warm start-up time (hours)	0.23	0.2	0.2	0.1	0.5	0.1	0.4	D	1,3,4
Cold start-up time (hours)	0,5	0,5	0,5	0.4	1	0.4	1	D	1,3,4
Minimum Up time (hours)	4	4	4					E,N	11
Minimum Down time (hours)	3	3	3					E,N	11
Environment									
PM 2.5 (g/GJ of fuel input)	0.89	0.89	0.89	0.89	0.89	0.89	0.89		10
SO_2 (g/GJ of fuel input)	0.28	0.28	0.28					M	10
NO_X (g/GJ of fuel input)	89	60	20	20	89	20	89	L	3,4,10
CH_4 (g/GJ of fuel input)	2.35	2.35	2.35	0.00	4.76	0.00	4.76		5
N_2O (g/GJ of fuel input)	0.25	0.25	0.25	0.00	0.47	0.00	0.47		5
Financial data									
Nominal investment ($MUSD/MW_e$)	0.97	0.96	0.92	0.71	1.54	0.67	1.46	A,B,O	1,2,3,4

- of which equipment (%)	50 %	50 %	50 %	50 %	50 %	50 %	50 %	A,B	1,2,3,4
- of which installation (%)	50 %	50 %	50 %	50 %	50 %	50 %	50 %	A,B	1,2,3,4
Fixed O&M (USD/MW$_e$/year)	29,400	29,000	27,900	22,100	36,800	20,900	34,900	A,B,F	1,3,4,8
Variable O&M (USD/MWh)	5.52	5.45	5.24	4.14	6.90	3.93	6.55	A,B,F	1,3,4,8
Start-up costs (USD/MW$_e$/start-up)	29.2	29.2	29.2	21.9	36.5	21.9	36.5	F	3,4

Notes

A Based on aggregated data of Colombian projects in the register database by UPME, supplemented with further international sources prices from international sources

B Assuming that cost fall 0.2 % each year

C The capacity factor is calculated from 2017-2024 for each plant with available information.

D Estimation based on international data for the capability of the machine. An average of the operational data in Colombia [6] shows that hot start-up time is 5,35 hours, warm start-up time is 11,25 hours and cold start-up time is 17 hours. The operational data from Colombia is higher than international data because of the design of the Colombian energy system.

E Gas is more flexible than coal regarding minimum up/down time

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

G Assumed no improvement for regulatory capability.

H Calculated based on the parameters: Capacity factor incl. outages, Forced outage and Planned outage.

I Assumed same uncertainty as for CCGT.

J Assumed same percentage for uncertainty as CCGT.

K Lower uncertainty for 2030 and 2050 are calculated based on available information for capacity factor incl. outages.

L Assumed gradual improvement to international standard in 2050.

M Commercialised natural gas is practically sulphur free and produces virtually no sulphur dioxide

N Estimation based on international data for the capability of the machine. An average of the operational data in Colombia [6] shows that minimum up time is 4,65 hours and minimum down time is 1,34 hours (for programmed stops, for non-programmed stops the time for down time ranges between 0 and 2 hours).

O Cost uncertainties in the short term indicate the spread of current projects under operation and in development known to the authors. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the general technology improvement potential.

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12. Waste-to-Energy Power Plant

12.1. Brief technology description

Municipal solid waste (MSW) is a waste type consisting of everyday items that are discarded by the public. The composition of MSW varies greatly from municipality to municipality, and it changes significantly with time. The MSW industry has four components: recycling, composting, disposal, and waste-to-energy. MSW can be used to generate energy. Several technologies have been developed that make the processing of MSW for energy generation cleaner and more economically viable than ever before, including landfill gas capture, combustion, pyrolysis, gasification, and plasma arc gasification [1]. While older waste incineration plants emitted a lot of pollutants new technologies have significantly reduced this concern. This chapter concentrates on incineration plants and landfill gas power plants.

12.1.1. Incineration power plants

The major components of waste to energy (WtE) incineration power plants are a waste reception area, a feeding system, a grate fired furnace interconnected with a steam boiler, a steam turbine, a generator, an extensive flue gas cleaning system and systems for handling of combustion and flue gas treatment residues (see Figure 92).

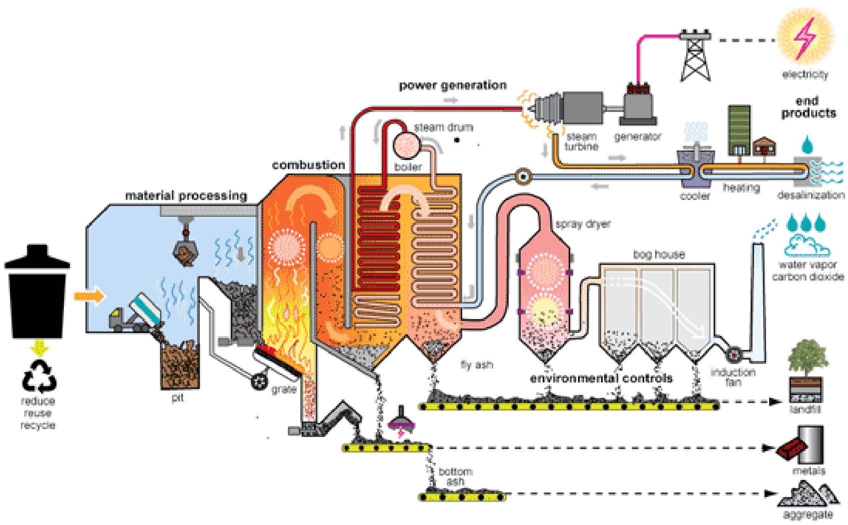

Figure 92. Typical WtE Plant [2].

The method of using incineration to convert municipal solid WtE is a relatively old method of WtE production. The waste is delivered by trucks and is normally incinerated in the state and condition in which it arrives. Only bulky items are shredded before being fed into the waste bunker. Incineration generally entails burning waste (residual MSW, commercial, industrial, and refuse-derived fuel) to boil water, which powers steam generators that make electric energy and heat to be used in homes, businesses, institutions and industries. One problem associated with incinerating MSW to make electrical energy is the potential for pollutants to enter the atmosphere with the flue gases from the boiler.

These pollutants can be acidic and were in the 1980s reported to cause environmental damage by turning rain into acid rain. Since then, the industry has removed this problem using 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 potential to use waste in WtE plants is influenced by the density of the waste, its moisture and ash content, its heating value and particle size distribution. Thermal WtE technology feedstock is dependent on its chemical content (carbon, hydrogen, oxygen, nitrogen, sulphur and phosphorous) and its volatile content.

Table 12-1. Average heating values of MSW components [3].

Component	Heating Value (GJ/ton)
Food Waste	4.7
Paper	16.8
Cardboard	16.3
Plastics	32.6
Textiles	17.5
Rubber	23.3
Leather	1.7
Garden trimmings	6.5
Wood	18.6
Glass	0.1
Metals	0.7

Typical electric efficiencies of WtE plants using combustion technologies are about 14 % – 28 % [3]. To avoid losing the rest of the energy, it can be used for e.g. district heating (cogeneration), wherever there is a demand for it. The total efficiencies of cogeneration incinerators are typically higher than 80 % (based on the lower heating value of the waste) [3].

12.1.2. Landfill gas (LFG) power plants

Landfill gas is created through the decomposition of organic waste materials in landfills. Organic waste such as food scraps, yard trimmings, paper, and wood, which are buried in landfills, begin to decompose over time. This decomposition occurs through the action of microorganisms that break down the organic matter. In a landfill, the decomposition process often takes place in an anaerobic (low-oxygen) environment. This is because the organic waste is buried under layers of soil and other materials, limiting the amount of oxygen available. As microorganisms break down the organic waste anaerobically, they produce gases as by-products. The primary components of landfill gas are methane (CH_4) and carbon dioxide (CO_2), but it can also contain trace amounts of other gases such as hydrogen sulphide (H_2S) and volatile organic compounds (VOCs) [4].

Figure 93 shows landfill gas composition over time in four phases [4]:

1. **Phase I (Aerobic)**: Oxygen is high initially but drops quickly. CO_2 rises as aerobic bacteria decompose waste.

2. **Phase II (Anaerobic, Non-methanogenic)**: Oxygen is depleted. CO_2 peaks, while CH_4 starts forming slowly.
3. **Phase III (Anaerobic, Methanogenic Unsteady)**: CH_4 production increases significantly, reaching 45-50 %, while carbon dioxide stabilizes around 50-55 %.
4. **Phase IV (Anaerobic, Methanogenic Steady)**: CH_4 and CO_2 levels stabilize, while nitrogen levels remain low. This phase can last 10 to 30 years.

The overall trend shows a transition from aerobic to stable anaerobic conditions, with methane as a key by-product.

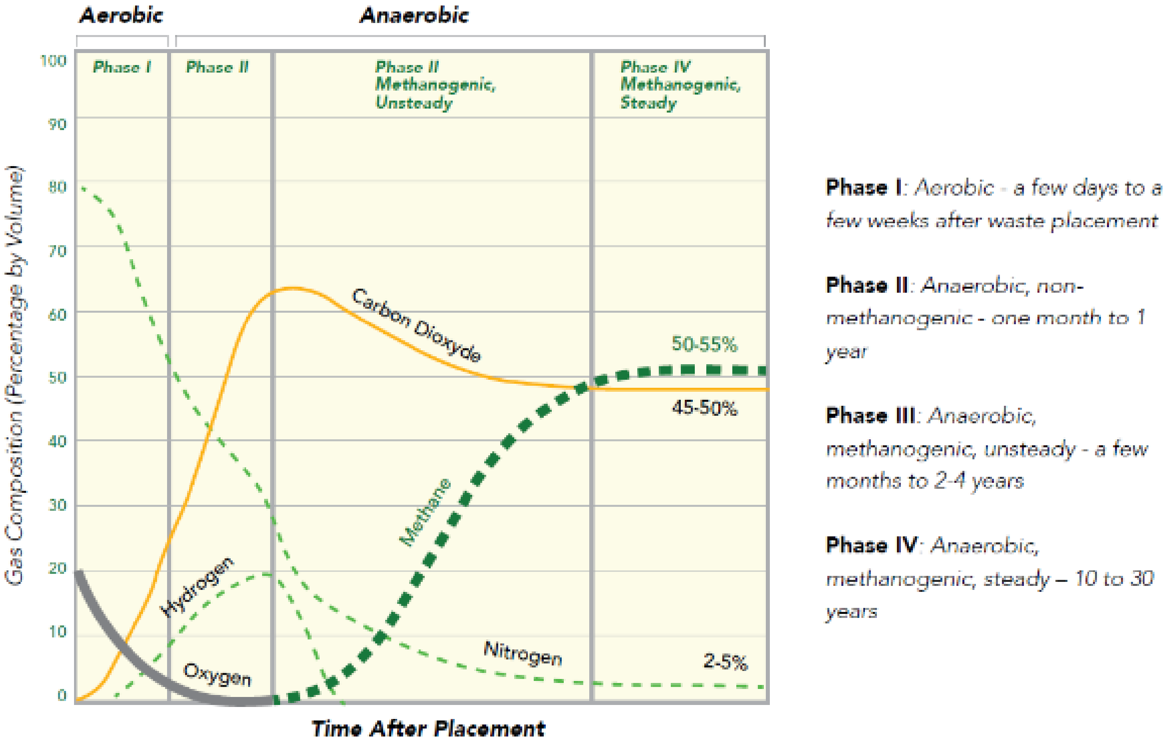

Figure 93. LFG generation and changes over time [4].

Landfills can be equipped with gas collection systems to capture the methane and other gases produced. This is important for several reasons: methane is a potent greenhouse gas, and capturing it can prevent its release into the atmosphere. Additionally, collected methane can be used as a renewable energy source for generating electricity or heating. After collection, landfill gas is either flared off (burned) to reduce its environmental impact or processed to recover methane for use as energy. Proper management and treatment of landfill gas are crucial for minimizing its impact on air quality and climate change. Figure 94 shows a landfill gas-to-energy scheme. Using gas engines, landfill gas can be used as fuel feedstock to produce electricity. According to information received from Colombian stakeholders, the production volume of landfill gas in Colombia can range from 80 to 100 m^3 of gas per ton of waste.

Figure 94. Landfill gas to energy scheme [5].

Not every waste stream is appropriate for the same WtE treatments. Table 12-2 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.

Table 12-2. Summary of WtE technologies' suitability per waste stream and potential output [4].

	Anaerobic digestion	Landfill gas recovery	Incineration	Gasification	Pyrolysis
Food waste	🟢	🟢	🟡	🟡	🟡
Garden and park waste	🟢	🟢	🟡	🔴	🔴
Dry recoverable waste	🔴	🔴	🟢	🟢	🟢
Refuse Derived Fuel	🔴	🔴	🟢	🟢	🟢
Inert	🔴	🟢	🔴	🔴	🔴
Hazardous	🔴	🔴	🟡	🔴	🔴
Solid Recovered Fuel	🔴	🔴	🟢	🟢	🟢
Biomass	🟢	🟢	🟡	🟡	🟡
Animal waste	🟢	🟢	🟡	🟡	🟡
Dry recoverable waste	🔴	🔴	🟢	🟢	🟢
Hazardous	🔴	🔴	🟡	🔴	🔴
Outputs					
Electricity	X	X	X	X	X
Heat	X	X	X	X	
Biogas	X	X			
Digestate	X				
Syngas				X	X

Other commercial solids					X

Directly Suitable · Likely to require pre-treatment · Unsuitable

12.1.3. Waste Characteristics in Colombia

There are no consolidated numbers for WtE potential in Colombia. The Mining and Energy Planning Unit (UPME) Atlas of Residual Biomass Energy Potential in Colombia was developed in 2011 [6] and calculated the power potential of municipal biomass in 25.3 GWh/year. This atlas consolidates maps of residual biomass availability and its energy potential from marketplace waste and green area pruning in 12 municipal capitals, sometimes including associated metropolitan municipalities. However, this estimate likely understates the true WtE energy potential because the study only considered 1.38 % of the total waste generated nationwide [7].

This underestimation is confirmed by the finding of a 2020 study that was conducted in three capital cities—Bogotá D.C., Cartagena, and Manizales—that represent varying conditions and characteristics of municipal solid waste (MSW) [8]. Data on MSW production volumes was collected from reports provided by public sanitation service providers, while the lower calorific value was estimated using a predictive model referenced in literature. The results indicate that developing these technologies in the three mentioned cities could generate 2,309 GWh per year, corresponding to approximately 3,3 % of the electricity demand in Colombia.

Composition

In terms of composition of Municipal Solid Waste in Colombia, and depicted in Table 12-3, the largest portion is represented by organic waste, which is over 50 % of the composition of largest Colombian cities. This is followed by paper, plastic, textile, glass, wood, metal, and other materials [9].

Table 12-3. Waste composition (%) of several Colombian cities [9].

Fraction (%)	Bogota	Medellin	Cali	Barranquilla	Cartagena	Bucaramanga	Sincelejo
Organic	51.3	55.4	52.6	52.6	52.5	33.3	61.5
Paper[a]	13.7	5.5	4.8	9.0	10.3	9.4	6.0
Textile	4.5	4.2	0.0	7.3	3.4	4.5	4.2
Wood	1.6	0.7	0.0	4.8	1.1	3.5	0.0
Glass	3.7	3.7	2.3	3.0	5.0	3.4	0.8
Plastic	16.9	8.6	10.1	11.8	14.7	8.8	19.8
Metal	1.1	1.4	0.8	0.9	1.8	2.4	0.5
Other	7.2	20.6	29.3	10.5	11.2	35.0	7.1
DMSW[b]	71.1	65.8	57.4	73.8	67.3	50.7	71.7

a. Paper fraction includes cardboard.
b. DMSW is the sum of organic, paper and cardboard, textile, and wood fractions of MSW.

12.1.4. Flow of municipal waste

The flow of municipal solid waste (MSW) in Colombia is shown in Figure 95: The largest portion is organic waste, followed by paper, plastic, textile, glass, wood, metal, and other materials. In terms of disposal, 77 % of waste is directed to landfill. Recycling (14 %) and composting (8 %)

are also significant methods of disposal, with smaller amounts going to incineration and open dumps [9].

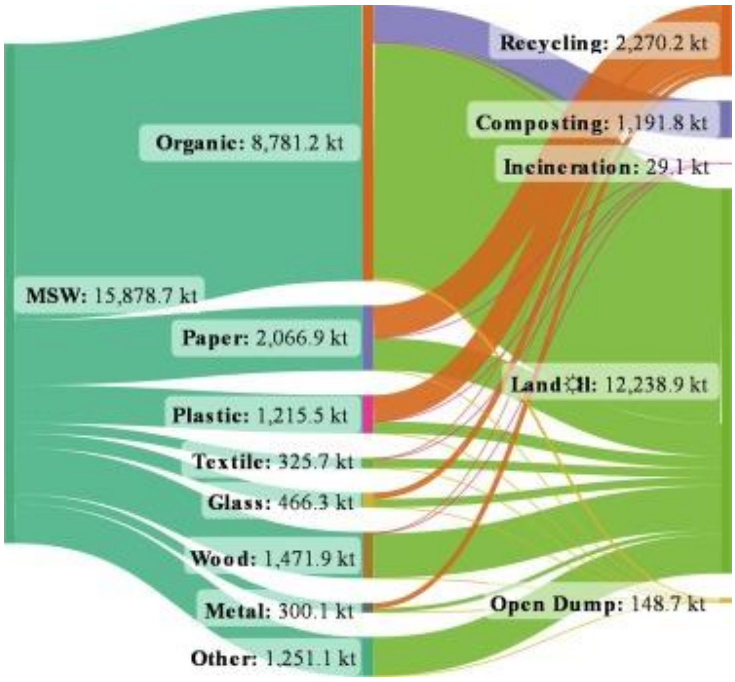

Figure 95. Sankey Diagram of creation and disposal of municipal solid waste in Colombia [9].

In 2022, an average of 11.938.709 tons of solid waste per year were disposed of through the public cleaning service across the national territory, representing a 0.26 % increase over 2021 (see Figure 96). Of the total daily disposed waste, 43.78 % was accounted for by the eight most populated cities: Bogotá D.C., Medellín, Cali, Barranquilla, Cartagena, Cúcuta, Soacha, and Soledad [10].

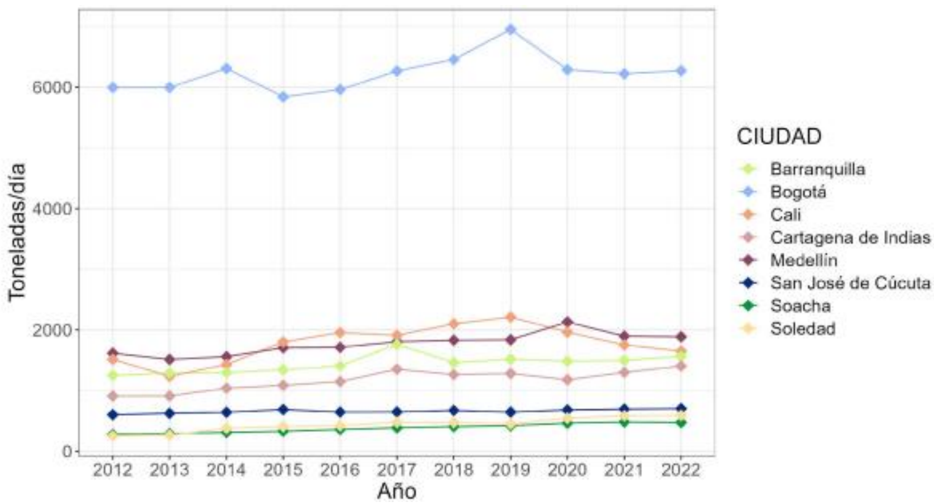

Figure 96. Tons of Waste for the 8 municipalities with largest population in Colombia.

As shown in Table 12-4 Bogotá D.C., Antioquia, Valle del Cauca, Atlántico, Bolívar, and Cundinamarca are the departments with the highest number of disposed tons of waste.

Additionally, these departments also have the largest populations and economic activities, according to reports and figures released by DANE [10].

Table 12-4. Final Disposal at a department level [10].

DEPARTAMENT	AVERAGE TON/DAY 2021	AVERAGE TON/DAY 2022
BOGOTÁ, D.C.	6 221,42	6 270,48
ANTIOQUIA	4 236,12	4 194,92
VALLE DEL CAUCA	3 501,93	3 374,75
ATLÁNTICO	2 669,14	2 715,81
BOLÍVAR	1 921,34	2 026,30
CUNDINAMARCA	2 004,15	2 010,02
MAGDALENA	972,22	1 527,18
SANTANDER	1 637,65	1 448,42
NORTE DE SANTANDER	1 095,45	1 094,74
CÓRDOBA	966,45	1 011,25
TOLIMA	866,54	919,28
CESAR	885,18	861,04
RISARALDA	796,35	815,60
CALDAS	666,41	719,28
NARIÑO	693,50	663,20
META	679,47	645,83
BOYACÁ	529,60	601,73
HUILA	602,27	572,33
LA GUAJIRA	553,07	510,83
SUCRE	461,84	473,93
CAUCA	441,83	446,46
QUINDÍO	397,84	394,00
CHOCÓ	199,74	369,33
CASANARE	225,14	249,30
CAQUETÁ	178,84	175,21
PUTUMAYO	156,18	150,49
ARAUCA	162,00	118,41
SAN ANDRÉS, PROVIDENCIA Y SANTA CATALINA	117,31	95,05
GUAVIARE	45,35	41,78
AMAZONAS	10,01	23,01
VICHADA	23,23	21,07
GUAINÍA	16,35	17,03

As seen in Table 12-5, The disposal of waste by land filling or land spreading is the current most common fate of solid waste in Colombia. For the 2021 period, 262 final disposal sites were identified, four less sites than 2021. The distribution of sites in 2021 is as follows: 1.690 sanitary landfills, 79 open-air dumps, 13 contingency cells, and 10 temporary cells [10]. The geographical distribution of the sites across Colombia is shown in Figure 97.

Table 12-5. Disposed waste tons per type of system [10].

SYSTEM	ANNUAL TONS DISPOSED	%
Burning	-	0.0 %
Body of water	-	0.0 %
Burial	-	0.0 %
Treatment plant	-	0.0 %
Transitional cell	23,163.72	0.2 %
Contingency cell	163,807.99	1.4 %
Open-air dump	211,526.81	1.8 %
Sanitary landfill	11,585,211.19	96.7 %

Figure 97. Final disposal sites in Colombia [10].

Landfill WtE Potential in Colombia

A study from Universidad de la Costa published in 2023 aimed to calculate the Colombian potential of landfill gas energy generation in seven cities [9]. The results are shown in Figure 98, where different acronyms correspond to the different technologies that were considered, as follows:

- *TUR - Standard Gas Turbine-Generator Set*
- *CHPT - Combined Heat and Power Standard Gas Turbine Generator Set*
- *ENG - Reciprocating Internal Combustion Engine-Generator Set*
- *CHPE - Combined Heat and Power Reciprocating Internal Combustion Engine-Generator Set*

The scenarios consider using gas turbines, reciprocating internal combustion engines, and cogenerating electricity and heat. The economic performance is assessed through various metrics: the net present value (NPV), the internal rate of return (IRR), the profitability index, and the benefits-cost ratio, alongside an economic sensitivity analysis. Environmental performance is evaluated by calculating the greenhouse gas (GHG) emissions reduction potential and avoidance potential. The results indicate an electric power generation potential ranging from 1.6 MW_e to 47.5 MW_e [9].

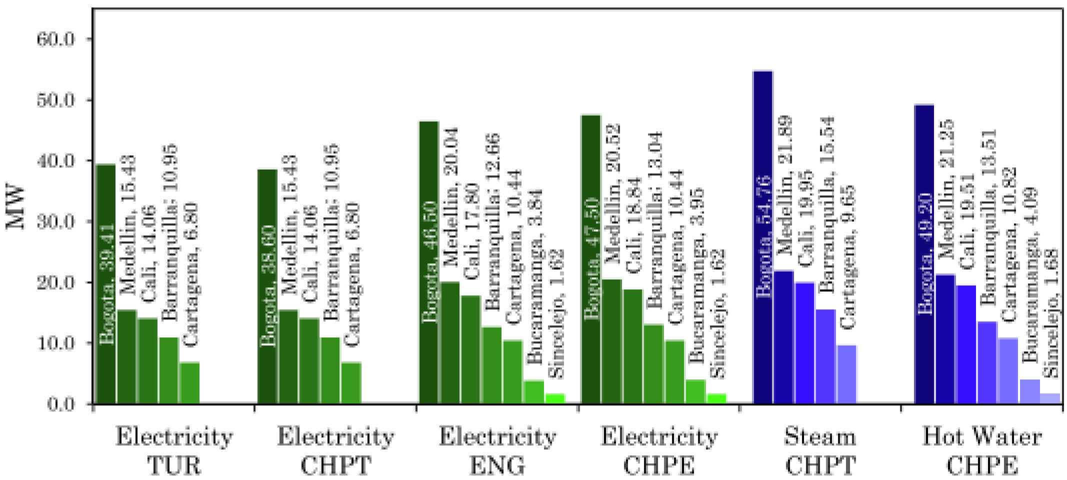

Figure 98. Maximum power and heat installed capacity of different technologies in several Colombian cities [9].

12.2. Input

WtE plants use MSW and other combustible wastes, water and chemicals for flue gas treatment, gasoil or natural gas for auxiliary burners (if installed), and in some cases biomass for starting and closing.

Landfill gas is the fuel feedstock for the landfill-gas power plants. Internal combustion engines have generally been used at landfills where gas quantity can produce 500 kW to 10 MW, or where sustainable LFG flow rates to the engines are approximately 0.2 to 1.6 million CFD at 50 % methane. Multiple engines can be combined for projects larger than 1 MW [4]. Table 12-6 provides examples of commonly available sizes of internal combustion engines.

Table 12-6. Landfill gas flow rates and power output figures for internal combustion engines [4].

Output (kW)	Gas Flow (m^3/hr at 50% CH_4)
325 kW	195
540 kW	324
633 kW	380
800 kW	480
1.2 MW	720

The capacity and required feedstock is different depending on the WtE technology. Table 12-7 shows the require feedstock for different capacities and technologies.

Table 12-7. Required feedstock for several different capacities and WtE technologies [11].

Type	Capacity (MW)	Required Feedstock (ton/day)
Incinerator (direct combustion)	50	1645.82
	35	1152.07
	20	658.33
Gasification (indirect combustion)	50	1278.14
	35	894.70
	20	511.25
Pyrolysis (indirect combustion)	50	3501.74
	35	2451.22
	20	1400.70

12.3. Output

For combustion systems, the outputs are electricity and if demand for it the heat as hot (> 110 ºC) or warm (< 110 ºC) water, bottom ash (slag), residues from flue gas treatment, including fly ash. If the flue gas is treated by wet methods, there may also be an output of treated or untreated process wastewater (the untreated wastewater originates from the SO_2-step, when gypsum is not produced).

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

12.4. Typical capacities

Medium: 10–50 MW capacity; Small: 1–10 MW capacity.

12.5. Space requirement

A landfill gas power plant makes efficient use of land already allocated for waste management, eliminating the need for additional land acquisition. The landfill itself functions as the primary source of raw material—landfill gas, which is a by-product of organic waste decomposition. Therefore, the plant is strategically situated to collect this gas directly from the landfill, reducing infrastructure needs related to gas transportation.

An incineration plant can reduce land use from landfills by decreasing the volume of waste that would otherwise need to be buried. Through the process of combustion, incineration facilities reduce the mass of waste by up to 90 %, converting it into ash that occupies less space than the original garbage. As a result, the ash can be stored in landfills that are a fraction of the size required for the untreated waste. Additionally, by diverting waste to incineration facilities instead of directly to landfills, the demand for new landfill space diminishes. This approach also prolongs the lifespan of existing landfills, which are often challenging to site and manage due to environmental and community concerns.

12.6. 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 m^3 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 m^3 per ton of MSW [12].

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 [13].

12.7. Regulation ability and other power system services

The plants that using combustion technologies can be down regulated to about 50 % of the nominal capacity, under which limit the boiler may not be capable of providing adequate steam quality and environmental performance. For emission control reasons and due to high initial investments, they should be operated as base load.

Landfill gas to energy plants can also be ramped up or down depending on the availability of the landfill gas in a storage. Unlike other renewables, which depend on weather conditions, WtE production can occur continuously, day and night, regardless of weather, because the process is not influenced by external environmental factors. WtE plants can serve as a reliable baseload energy source because they produce a steady and controllable output of energy. If there is a consistent supply of feedstock, energy generation can be continuous.

However, considering the sizes and potential in Colombia, a 50 MW WtE would have marginal flexibility in the current 20 GW energy system due to its relatively small size, accounting for only 0.25 % of the total capacity. Its limited impact on grid stability and demand management is compounded by slower ramp-up and ramp-down times compared to larger or more flexible energy sources. However, it could provide local energy services to the distribution system operator.

12.8. Advantages/disadvantages

12.8.1. Advantages

- **Significant Waste Reduction**: Waste volumes can be reduced by approximately 80-95 %.
- **Greenhouse Gas Mitigation**: Helps offset greenhouse gas emissions that would otherwise come from fossil-fuel-based power generation.

- **Reliable Energy Source**: Provides a consistent, baseload electricity supply.
- **Decreased Landfill Usage**: Reduces the amount of waste sent to landfills, minimizing pollution risks to nearby environments.
- **Lower Disposal Costs**: Avoids landfill taxes and associated disposal fees.
- **Valuable By-products**: Produces by-products that can be used as fertilizers.
- **Methane Emission Control**: Helps prevent methane emissions from landfills, or can capture and utilize them as an energy source.
- **Energy Security**: Supports domestic energy production, reducing dependence on imported fuels.
- **Recyclable Ash**: The ash produced can be repurposed in the construction industry.
  Leachate Prevention: Eliminates the issue of leachate generation, a common problem with landfills.

12.8.2. Disadvantages

- **High Costs**: Incineration facilities are costly to construct, operate, and maintain. As a result, they are often developed for their environmental benefits rather than for efficient power generation.
- **Air Pollution**: Emissions from incinerator chimneys can release harmful pollutants such as acid gases, nitrogen oxides, heavy metals, particulates, and dioxins—a known carcinogen. Even with advanced control systems, some dioxins still enter the atmosphere.
- **Incentivizes Waste Production**: Incinerators require a consistent supply of waste to operate effectively. This may encourage increased waste generation and disincentivize recycling and waste reduction efforts by local authorities.
- **Limited Suitability in Developing Countries**: In developing nations, like Colombia, waste incineration may be less practical due to the high moisture content (40-70 %) of organic waste, primarily from kitchen scraps, making it harder to burn effectively compared to the lower moisture content (20-40 %) of waste in industrialized countries.

12.8.3. Controversy with recycling

Recycling is estimated to save 3-5 times more energy compared to waste-to-energy (WtE) generation. This is because producing goods from recycled materials requires significantly less energy than manufacturing them from raw, virgin resources [23].

Incineration could discourage waste reduction and recycling efforts by providing a seemingly convenient disposal option. This stands in contrast to circular economy approaches that prioritize waste minimization, material recovery, and recycling, aiming to keep resources in use for as long as possible and reduce the overall environmental footprint, and finally send the materials for incineration when circularity is not feasible nor possible.

12.9. Environment

Municipal solid waste (MSW) incinerators require effective flue gas treatment (FGT) to meet stringent environmental regulations. However, this in turn generates additional environmental costs through the impacts of materials and energy used in the treatment. A total of eight technologies: electrostatic precipitators and fabric filters for removal of particulate matter; dry, semi-dry and wet scrubbers for acid gases; selective non-catalytic and catalytic reduction of nitrogen oxides (NO_x); and activated carbon for removal of dioxins and heavy metals, are now commercially available in the market [14].

The incineration process produces two types of ash. Bottom ash comes from the furnace and is mixed with slag, while fly ash comes from the stack and contains components that are more hazardous. In municipal waste incinerators, bottom ash is approximately 10 % by volume and approximately 20 to 35 % by weight of the solid waste input. Fly ash quantities are much lower, generally only a few percent of the 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 [14].

By using waste as fuel, WtE plants can inadvertently discourage waste reduction and recycling efforts. This reliance may lead to more materials being disposed of than necessary, depleting valuable resources that could be reused or repurposed. Moreover, many materials burned in incinerators could otherwise be recycled or composted, such as metals, plastics, or organics. Incineration of these materials means losing the opportunity to reclaim and reintroduce them into production cycles, which is counter to circular principles. Investment in WtE plants requires a steady supply of waste to remain economically viable. This can create a "lock-in" effect where municipalities continue to send waste to incinerators rather than investing in more sustainable practices like waste reduction and comprehensive recycling programs [22].

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 might 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 (see Figure 99) [23].

Figure 99. Leachate collection and treatment pond at Doña Juana Landfill [15].

12.10. Research and development perspectives

Waste incineration plants is a mature technology, whereas landfill gas is commercialised, but still being gradually improved. There are, however, several other new and emerging technologies that 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 (see Table 12-8 and Table 12-9). 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 290 to 704 ^oC. 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 [1].
- *Gasification* — MSW is heated in a chamber with a small amount of oxygen present at temperatures ranging from 400 to 1650 ^oC. 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].
- *Plasma Arc Gasification* — Superheated plasma technology is used to gasify MSW at temperatures of 5500 ^oC or higher - an environment comparable to the surface of the sun. The resulting process incinerates nearly all the solid waste while producing from two to ten times the energy of conventional combustion [1].

Table 12-8. Efficiency of Energy Conversion Technologies [16,17].

Technology	Efficiency (kWh/ton of waste)
Landfill gas	41 – 84
Combustion (incinerator)	470 – 930
Pyrolysis	450 – 530
Gasification	400 – 650
Plasma arc gasification	400 – 1250

Table 12-9. Expected Landfill Diversion [18,19].

Technology	Land diversion (% weight)
Landfill gas	0
Combustion (incinerator)	75*
Pyrolysis	72 – 95
Gasification	94 – 100
Plasma arc gasification	95 – 100

* 90% by volume

12.11. Examples of market standard technology

Doña Juana Power project, run by Biogás Colombia S.A.S. E.S.P., involves harnessing biogas from the Doña Juana Landfill that serves the city of Bogotá [20]. This project, which can be seen in Figure 100, captures biogas produced from decomposing waste and converts it into electricity, reducing over 800.000 CO_2 ton_{eq} each year. The project is structured into three plants:

- Doña Juana I Central: Phase I (1.7 MW) began operations on April 29, 2016.
- Phase II (3.3 additional MW) will start operations in January 2024.
- Doña Juana II Central: (9.8 MW) will start operations in the second half of 2024.
- Doña Juana III Central: (9.88 MW) will start operations in the first half of 2025.

Figure 100. Doña Juana Landfill gas plant [20].

In February 2021, the country's first WtE recovery plant was inaugurated in the Magic Garden landfill in the Island of San Andrés. The plant, which is depicted in Figure 101, which cost 24,356 million pesos and was funded by the national government, the municipality, and the Department of the Archipelago of San Andrés, Providencia, and Santa Catalina, will process 80 tons of solid waste daily [21]. This facility will benefit the 103,955 inhabitants of San Andrés Island. In this plant, the company INTERASEO will manage the separation, processing, and incineration of waste. The resulting energy will then be used to supply at least 80 % of the plant's own consumption needs.

Figure 101. MSW plant in San Andrés Island [21].

12.12. Prediction of performance and cost

12.12.1. Investment cost overview

Table 12-10 presents a comparison of investment costs for power projects, expressed in millions of USD per megawatt (MUSD/MW), based on different data sources and regions. It incorporates various data sources, each with a specific base year for Final Investment Decision (FID). These sources include a study on Colombia by Adriana Patricia Agudelo Montoya et al. (2023), international data from Nickolas J. Themelis et al. (2013), and technology catalogues from Indonesia (2024), Vietnam (2023), and Denmark (2021). The investment costs presented reflect regional and temporal differences, offering valuable insights into the global landscape of renewable energy investment.

Table 12-10. Investment cost comparison across regions for WtE projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	5.38	2024
National data		
Adriana Patricia Agudelo Montoya et al., Uniminuto, 2023	5.62	2023
International data		
Nickolas J. Themelis et al., EED/IDB, 2013	8.57	2013
Technology Catalogue – Indonesia (2024)	6.7	2024

Technology Catalogue – Vietnam (2023)	6.8	2023
Technology Catalogue – Denmark (2021)	12.33	2020

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12.14. Datasheet

Technology	**Incineration Power Plant - Municipal Solid Waste**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MW_e)	15.4	16.0	16.2	10	50	10	50	M	5.6
Generating capacity for total power plant (MW_e)	15.4	16.0	16.2	10	50	10	50	M	5.6
Electricity efficiency, net (%), name plate	29.5 %	30.5 %	31.1 %	28.0 %	31.5 %	29.5 %	32.5 %		2,3,6
Electricity efficiency, net (%), annual average	28 %	29 %	29.5 %	26.6 %	29.9 %	28.0 %	30.9 %		2,3,6
Forced outage (%)	1 %	1 %	1 %	1 %	1 %	1 %	1 %		1
Planned outage (weeks/year)	2.9	2.6	2.1	2.4	3.3	1.6	2.6		1
Technical lifetime (years)	25	25	25	20	35	20	35		1,4,6
Construction time (years)	3.0	2.5	2.5	2.5	3.5	2.0	3.0		4,6
Space requirement (1000 m^2/MW_e)	2.5	2.5	2.5	2.0	3.0	2.0	3.0	I	4.6
Additional data for thermal plants									
Capacity factor (%), theoretical	96.2 %	96.2 %	96.2 %					H	5.6
Capacity factor (%), incl. outages	90.0 %	90.5 %	91.4 %					L	5.6
Ramping configurations									
Ramping (% per minute)	10 %	10 %	10 %	7.5 %	12.5 %	7.5 %	12.5 %	C	1
Minimum load (% of full load)	20 %	20 %	20 %	15 %	25 %	15 %	25 %	C	1
Warm start-up time (hours)	0.50	0.50	0.50	0.38	0.63	0.38	0.63	C	1
Cold start-up time (hours)	2.0	2.0	2.0	1.5	2.5	1.5	2.5	C	1

Environment									
SO_2 (degree of desulphurisation, %)	99.8 %	99.8 %	99.8 %	99.0 %	99.9 %	99.0 %	99.9 %		1
NO_X (g/GJ of fuel input)	60	40	10	10	60	10	60		1
CH_4 (g/GJ of fuel input)	0.10	0.10	0.10	0.00	0.10	0.00	0.10		1
N_2O (g/GJ of fuel input)	1.0	1.0	1.0	1.0	3.0	1.0	3.0		1
Financial data									
Nominal investment (million USD/MW_e)	5.38	5.31	5.10	3.07	7.68	2.92	7.29	A,B,D,E,J,K,N	5,6
- of which equipment (%)	59 %	54 %	50 %	44 %	74 %	38 %	63 %	A,B,C,E	1,2,3
- of which installation (%)	41 %	46 %	50 %	31 %	51 %	38 %	63 %	A,B,F	1,2,3
Fixed O&M (USD/MW_e/year)	432,000	427,000	410,000	324,000	540,000	307,500	512,500	A,B,C,G	6
Variable O&M (USD/MWh)	36.54	36.1	34.7	27.4	45.7	26.0	43.4	A,B,C	6
Start-up costs (USD/MW_e/start-up)									
Technology specific data									
Waste treatment capacity (tonnes/h)	20.0	20.0	20.0					D	4.6
Calorific content (GJ/ton)	11.0	11.0	11.0	10.0	12.0	10.0	12.0	D	4,5,6

Notes

A Based on prices from countries with similar MSW compositions

B Assuming that cost fall 0.2% each year

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

D Assumed a waste treatment of 20 tonnes/hour [6] and an energy content of 11 GJ/ton [5][6].

E Assuming LOT-based tendering of electromechanical equipment. EPC contracting is expected at unchanged or slightly higher cost (0-10%), provided only construction is included in the EPC contract.

F Installation includes civils works (including waste bunker) and project cost considering LOT-based tendering.

G Fixed O&M include amongst other things the major part of staffing and maintenance, analyses, research and development, accounting, insurances, fees, memberships, office. Not included are finance cost, depreciation and amortisation.

H 2024 estimate is calculated based on the capacity incl. outages, forced outages and planned outages. 2030 and 2050 estimates are assumed to be the same as 2024.

I Space requirements have been calculated based on plants in North and South America.

J Central estimate for 2024 is based on 525 USD/ton waste treated/year. Uncertainty (Upper/Lower) in 2024 is based on 300 USD/ton waste treated/year and 750 USD/ton waste treated/year. Cost uncertainty in the long term follows the relative spread of short-term uncertainty, while also expressing the general technology improvement potential.

K The estimates shown do not take into account the local conditions and are subject to many factors, such as the price of steel. Hence, they are considered to be within a plus or minus 20% accuracy [6].

L The increasing capacity factor incl. outages in 2030 and 2050 is calculated based on the reduction of forced and planned outages.

M The installed capacity is based on several parameters such as the calorific content in the waste, the electricity efficiency, the amount of waste treated per hour and the capacity factor incl. outages [6]. The result has also been compared to plants with similar conditions in South America.

N Investment costs includes: Site preparation, access, landscaping; buildings, stack; grate, boiler, air supply, ash handling, electrical and mechanical systems; turbine generator; air pollution control system; contingency.

References

[1] Danish Energy Agency, Technology Catalogue for Generation of Electricity and District Heating, 2024

[2] Danish Energy Agency, Ea Energy Analyses, Technology Data for the Indonesian Power Sector, 2024

[3] Danish Energy Agency, Ea Energy Analyses, Viet Nam Technology Catalogue for Power Generation, 2023

[4] Bilateral meetings with stakeholders

[5] Adriana Patricia Agudelo Montoya et al., Uniminuto, 2023, Análisis de la capacidad de generación de energía eléctrica de los RSU de Medellín y viabilidad económica de la implementación de una planta WTE de los RSU estudiados

[6] Nickolas J. Themelis et al., EEC/IDB, 2013, Guidebook for the application of waste to energy technologies in Latin America and the Caribbean

13. Nuclear Power Generation

13.1. 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 (see Figure 102).

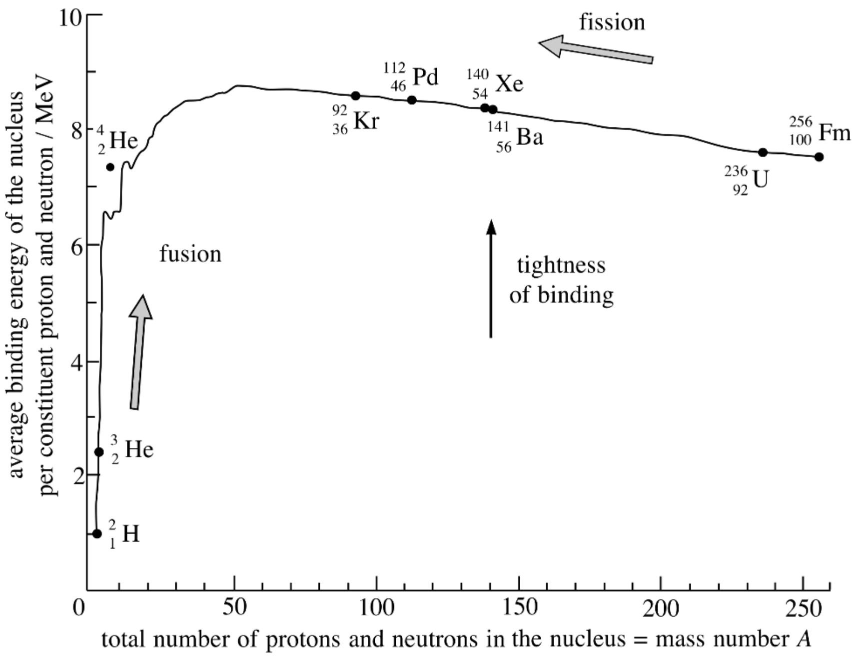

Figure 102. Nuclear energy binding graph [1].

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 fission is central for nuclear power plant engineering. The activation energy, which is kinetic energy provided by mobile neutrons hitting the nuclei of selected heavy elements (such as ^{235}U), catalyses a reaction such as the following:

$$\frac{1}{0}n + \frac{235}{92}U \rightarrow \frac{141}{56}Ba + \frac{92}{36}Ke + 3\frac{1}{0}n + energy$$

^{235}U is one of the fissile elements, since it sustains the chain reaction: for every ^{235}U atom splitting, three mobile neutrons *n* are released, which in turn go on hitting other ^{235}U 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 reactor, the core contains the fuel, the moderator, and a coolant. In a fast breeder reactor, there is no moderator, only fuel and coolant. These components are briefly described below:

- The fissile material (e.g., ^{235}U). It is contained in rods, which need to be periodically replaced as the core gets short of fissile material (fuel cycle).
- The control elements, typically rods, can be lowered or lifted to regulate reactivity. Rods are made of a certain chemical element which inhibits reactivity by absorbing neutrons, usually high-boron steel and boron carbide.
- The 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, 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. Nuclear power plants are not standardized technology, because geopolitical reasons and historical legacy make nuclear research a national or regional matter. Fission power plants are usually classified by the core design, the general classification is depicted in Figure 103.

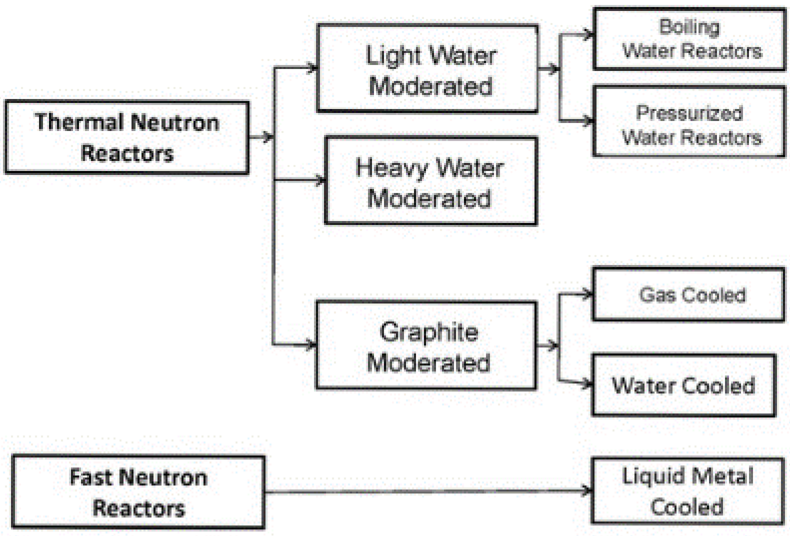

Figure 103. Classification of nuclear reactors [36].

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.

13.1.1. 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 104): 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].

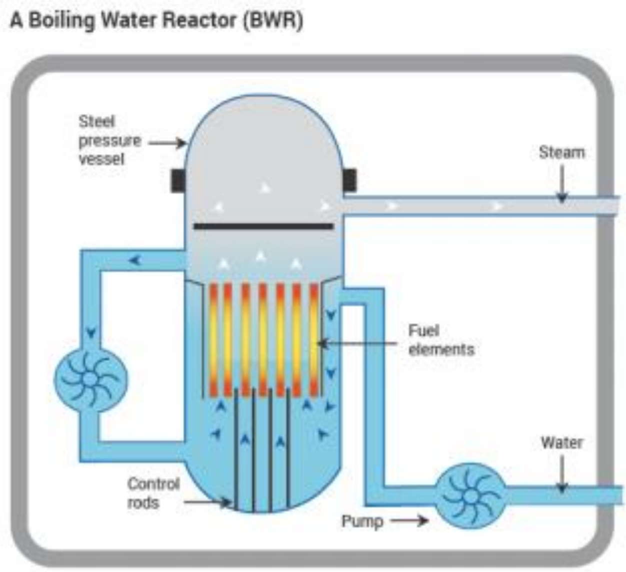

Figure 104. BWR schemes [5].

- Pressurized Heavy Water Reactors (PHWRs) (see Figure 105): 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].

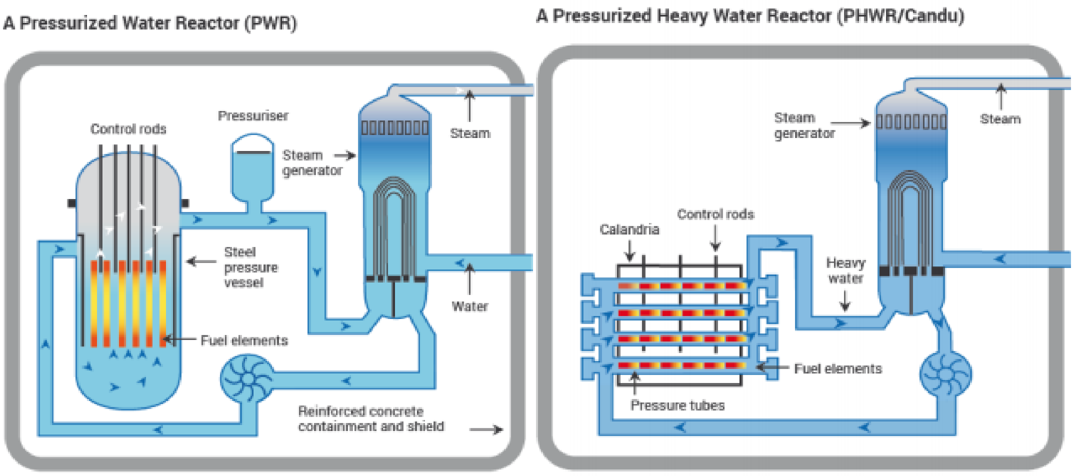

Figure 105. PWR and PHWR schemes [5].

- 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) and the former Soviet Union (RBMK). 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 (usually plutonium) than they consume, making them crucial for sustaining long-term nuclear fuel supplies [2].

Water-cooled reactors (WCR) 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 13-1 below summarizes the reactor designs, which are being operated or are operable.

Table 13-1. 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 UO2	water	water
Boiling water reactor (BWR)	USA, Japan, Sweden	64	65	enriched UO2	water	water
Pressurized heavy water reactor (PHWR)	Canada, India	48	24	natural UO2	heavy water	heavy water
Advanced gas-cooled reactor (AGR)	UK	14	8	natural U (metal), enriched UO2	CO_2	graphite
Light water graphite reactor (LWGR)	Russia	12	8.4	enriched UO2	water	graphite
Fast neutron reactor (FBR)	Russia	2	1.4	PuO_2 and UO2	liquid sodium	none
Total		441	393			

13.1.2. 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 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 perspectives section).

13.1.3. 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].

- 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 nuclear plants [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 brings 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.

13.1.4. 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 or FR (see Figure 106*)* They 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.

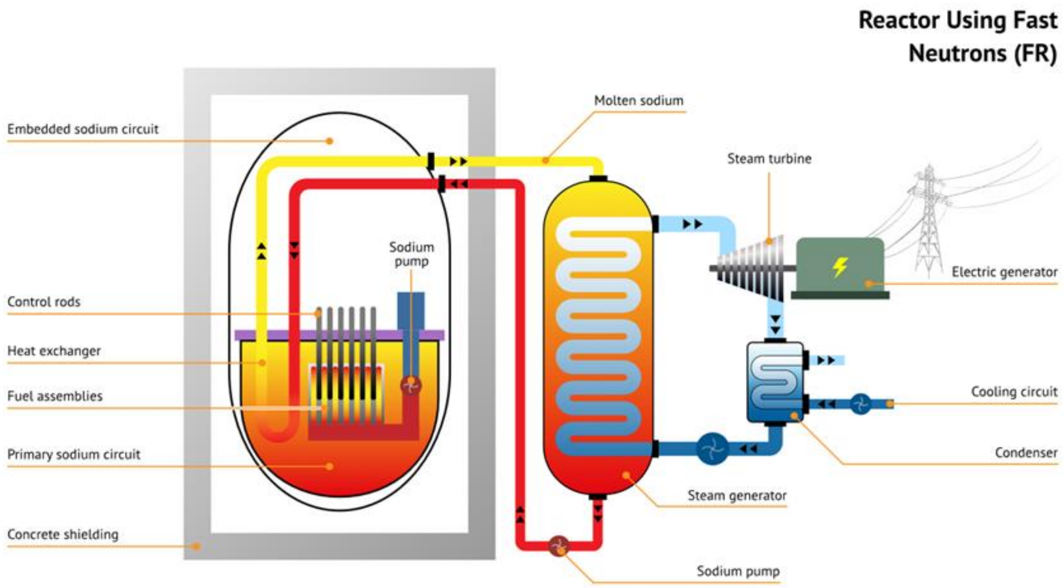

Figure 106. Fast Neutron SMR o FR [34].

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, nuclear 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 nuclear power plants), nuclear 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 an 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) They 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 diagram of a helium gas-cooled MMR is illustrated in Figure 107.

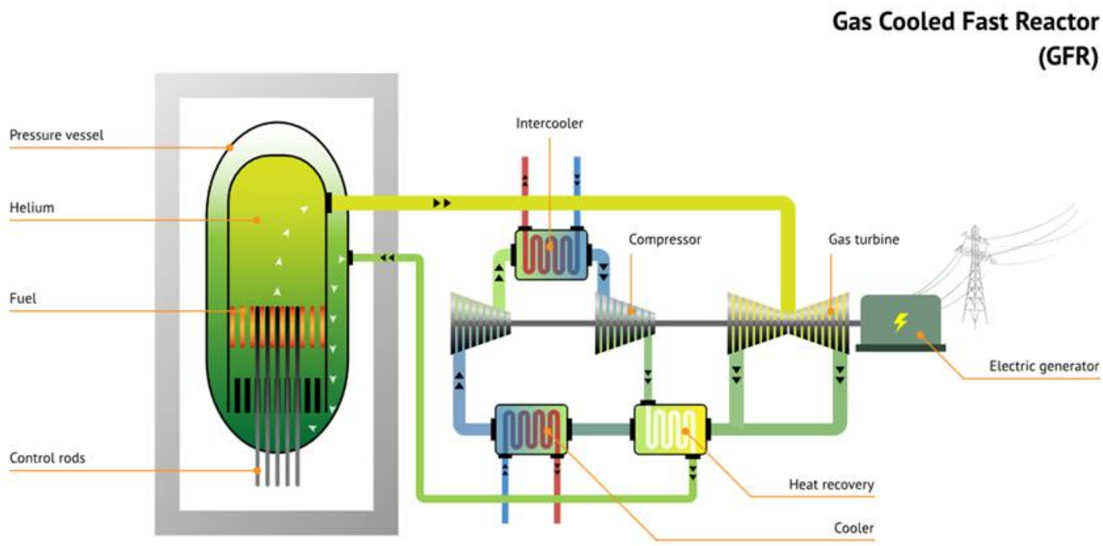

Figure 107. Gas-cooled Micro Modular Reactors (MMR) [10].

Molten Salt Reactor (MSR) The MSR depicted in Figure 108 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].

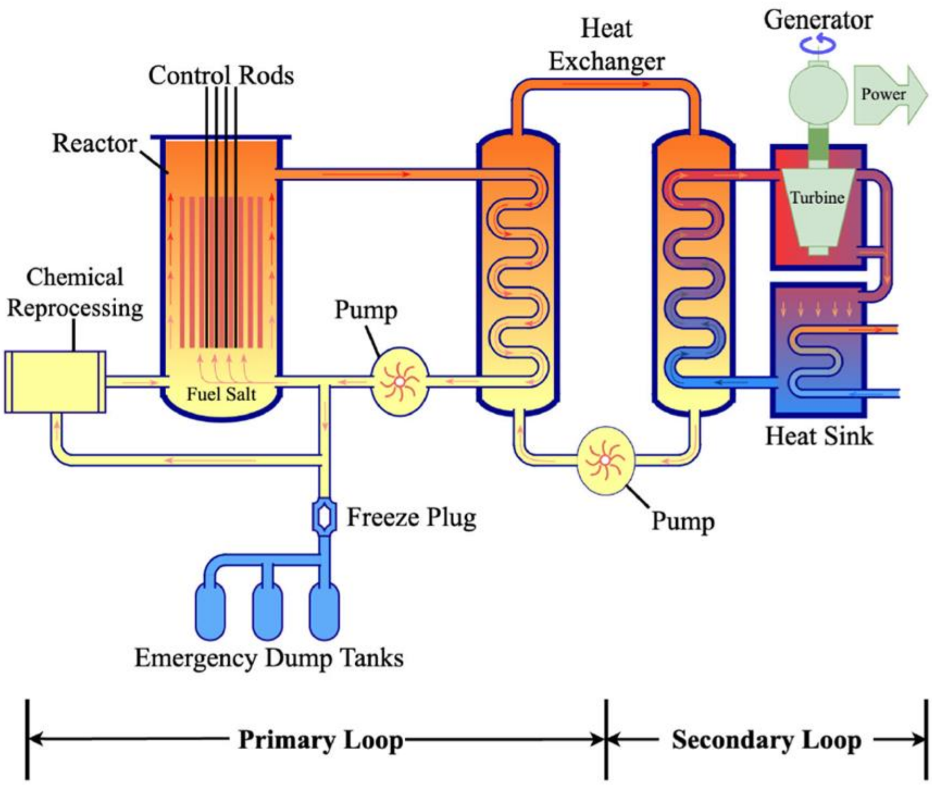

Figure 108. Molten Salt Reactor [35].

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. online 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 109 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.

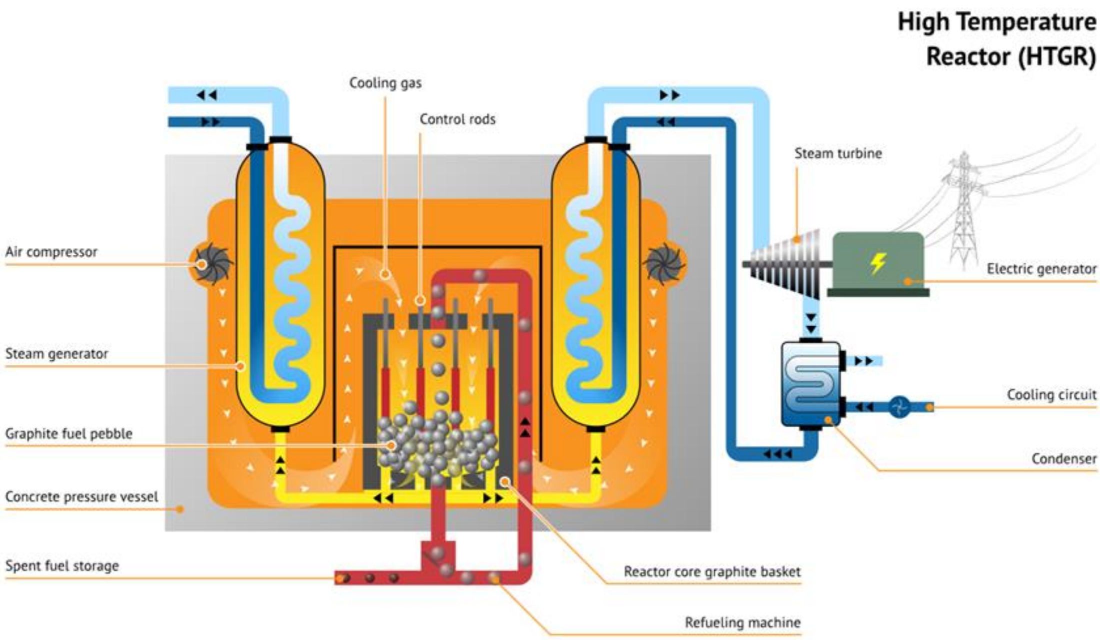

Figure 109. Schematic of a high-temperature gas-cooled reactor (HTGR) [13].

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.

13.1.5. Small Modular Reactors in Operation

Currently, there are two SMR power plants in operation, one in Russia and one in China. 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 13-2.

Table 13-2. 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	UO2 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.

ACP-100 in China (land-based) [7]: The ACP100 seen in Figure 110 is an integrated PWR design developed by China National Nuclear Corporation (CNNC) to generate an electric power of 125 MW_e. The ACP100 is based on existing PWR technology adapting verified passive safety systems to cope with the consequences of accident events; in case of transients and postulated design basis accidents the natural convection cools down the reactor. The ACP100 integrated design of its reactor coolant system (RCS) enables the installation of the major primary circuit's components within the reactor pressure vessel (RPV).

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

Figure 110. ACP-100 illustration and technical parameters.

In China one of two HTR-PM reactors of 100 MW, started generating electricity to the grid 20 December 2021.The construction of the first of the two HTR-PMs was originally planned to happen before 2010, while a study claimed that the cost would not exceed a conventional pressurized water reactor by more than 20 %. However, construction only 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 [7].

Other projects: A small modular reactor (SMR) project in Idaho, USA, consisting of six 77 MW reactors. The development of this project began in 2000. In 2013, it was decided that NuScale should build these six SMRs in Idaho. In 2022, the U.S. Nuclear Regulatory Commission approved the construction of NuScale's reactor design. NuScale announced that the six reactors, with a total capacity of 462 MW, would be operational by 2030. However, in November 2023, the project was stopped due to rising costs [15 - 18]. In mid-2021, the target price for power was estimated at USD 58/MWh. By January 2023, this target price had increased to USD 89/MWh, despite a USD 1.4 billion contribution from the U.S. Department of Energy through the Inflation Reduction Act, which aimed to reduce the power target price by USD30/MWh. The higher target price is attributed to a 75 % increase in the estimated construction cost of the project, from USD 5.3 billion to USD 9.3 billion, raising the investment cost from USD 11.5 million per MW to USD 20.1 million per MW. This cost increase is primarily due to inflationary pressures on the energy supply chain, particularly increases in the Producer Price Index for steel, electrical equipment, and copper wire and cable. The Producer Price Index for All Commodities increased by 45 % indicating that 30 % of the 75 % increase in capital expenditures cannot be solely explained by the rise in the Producer Price Index.

13.2. 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 (UO_2), 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 (MO_X) 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 (H_2O), heavy water (D_2O), carbon dioxide (CO_2), 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.

13.3. 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.

13.4. 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].

13.5. Space requirement

A nuclear power plant typically occupies a compact area, needing approximately 3.4 km^2 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 13-3 [21].

Table 13-3. Land-use intensity of energy [21].

Source of energy	Land Use Intensity of Energy total (ha/TWh/y) – Mean
Hydroelectric	15000
Ground-mounted PV	2100
Natural gas	410
Wind	170
Nuclear LR	15

13.6. 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].

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.

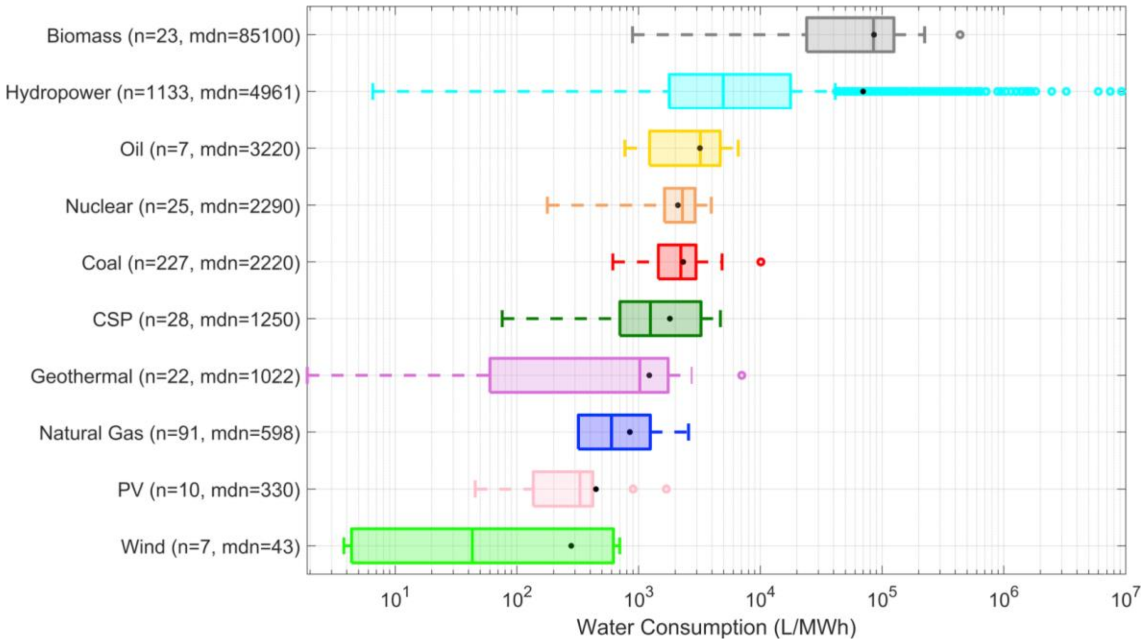

Figure 111. Water use comparison between energy sources [24].

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 111.

13.7. Regulation ability and other power system services

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, nuclear power plants 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 nuclear plants 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 13-4.

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 13-4. 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

13.7.1. Ramping configurations

Modern reactors are able to adjust their operation to follow scheduled or unscheduled load changes. Many modern nuclear power plants (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, nuclear power plants characterized by high investment, high fixed operation and maintenance 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 SMR have capability to ramp up or down, 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 nuclear power plant: 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].

13.8. Advantages/disadvantages

13.8.1. Advantages

- Well-established technology (conventional reactors).
- Nuclear power plants 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. Nuclear power plants 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.

13.8.2. Disadvantages

- Prolonged construction time, with uncertainty in timeline predictions due to technical and logistical factors. Nuclear power plants 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 nuclear power plants 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 *Environment* section.

13.8.3. 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.

13.9. Environment

Figure 112 shows that nuclear power emits 9 g CO_2 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].

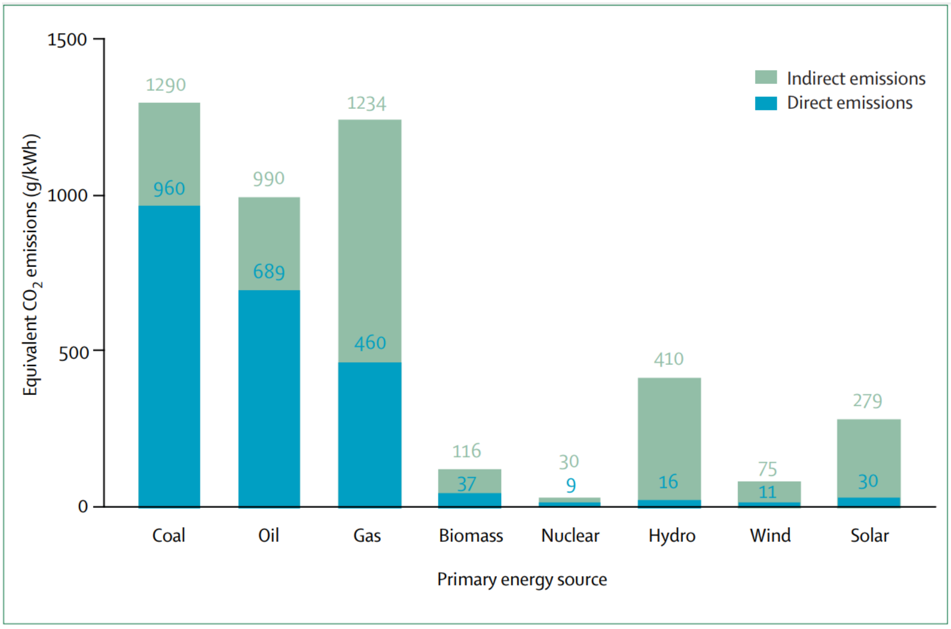

Figure 112. Average life-cycle CO2 equivalent emissions from different power generation sources [29].

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.

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(^{131}I), 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 (^{135}Cs) or Selenium-79 (^{79}Se).

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

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.

13.9.1. 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.

13.10. Research and development perspectives

The next generation of nuclear reactors are categorized as Generation IV. Designs for Generation IV are not expected to be operational before the mid-2020s. There are seven designs being considered as Generation IV. These are under development by the GIF (Generation IV International Forum), an international collective representing governments of 13 countries where nuclear energy is significant now and seen as vital for the future. The different reactors are summarized in the Table 13-5.

Table 13-5. 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 MW_e - and in the category of small modular reactors (SMRs), since several of them together may comprise a large power plant, may be built progressively.

13.11. Examples of market standard technology

There are no commercial nuclear reactors in Colombia, but the country has been operating a research reactor, with some shutdown periods, which is called "Reactor Nuclear de Investigación IAN-R1", hereinafter IAN-R1 reactor. Its first criticality was on January 20, 1965. From that time to date, it has always operated safely and in accordance with the requirements established by the Regulatory Authority [31].

The IAN-R1 Reactor depicted in Figure 113 is an open pool type nuclear research reactor, with TRIGA fuel elements and 19.7 % U-235 enrichment. Maximum neutron flux $8x10^{11}$ n/cm^2/s, thermal power 30 kW, with coolant and moderator light water and reflected by graphite.

The main purpose of the reactor has been research in fundamental areas such as neutron and reactor physics, thermohydraulics and shielding, instrumentation, nuclear safety and chemistry. It was also used for the production of radioisotopes Au-198, Br-82, La-140, Na-24, and included demonstration scale production of Mo-99.

Figure 113. IAN-R1 Reactor at the Colombian Geological Service [32].

The main application of the IAN-R1 Reactor has been the development of the neutron activation analysis technique (NAA), with the purpose of quantifying elemental compositions of samples for rock characterization, environmental contamination, detection of heavy metals or toxics. Other techniques have been explored such as fission fingerprint dating, which provides information about the probability of the presence of hydrocarbons in the extraction site of the sample.

In addition to the IAN-R1 Reactor, an ecosystem has been forming in Colombia with the participation of academia and industry. From academia, universities such as the University of Antioquia and the National University of Colombia have opened diploma courses and chairs with curricular content on basic and applied concepts of nuclear energy, design concepts, operation and management of nuclear reactors. From the industry, companies such as Ecopetrol and EPM have shown their interest in exploring the applications of nuclear power plants.

In Latin America, there are just seven nuclear power reactors in operation: three in Argentina, two in Brazil and two in Mexico. The most advanced nuclear power plant in the region is Atucha II (see Figure 114), officially named Central Nuclear Néstor Kirchner, located in Lima, Zárate District, approximately 100 kilometres from Buenos Aires, Argentina. Construction began in 1982 but was halted in 1994, resuming in 2006. The plant achieved its first criticality on June 3, 2014, and was synchronized with the National Interconnected System on June 27, 2014. Atucha II operates a pressurized heavy-water reactor (PHWR) with a thermal power of 2,175 MWt and a gross electrical output of 745 MW_e, utilizing natural uranium as fuel and heavy water (D_2O) as both moderator and coolant [33].

Figure 114. Atucha II Nuclear Power Plant [33].

13.12. Prediction of performance and cost

13.12.1. Investment cost overview

Large nuclear plants are seen as a category 3 or 4 technology, while the SMR should be seen as a category 2-3 meaning the estimates for SMR are made with high uncertainty.

Large reactor: The overnight capital cost for a nuclear plant is dependent on various factors ranging from plant design, equipment, labour, and construction. The value for 2023 is considering the global context, under the assumption that the plant to be set up would most likely be a PWR. The estimate lies in the conservative end accounting for latest project delays and cost reconsiderations in mature markets and to reflect the local market situation. The data is shown Table 13-6, and compared with other international sources.

Small modular reactor SMR: With very few SMR projects under construction and no actual data on overnight actual costs available, cost estimation of SMRs is usually performed on a top-down basis, as shown in Figure 115. This entails starting from available information on large, advanced pressurized water reactor (PWR) units as a starting reference cost.

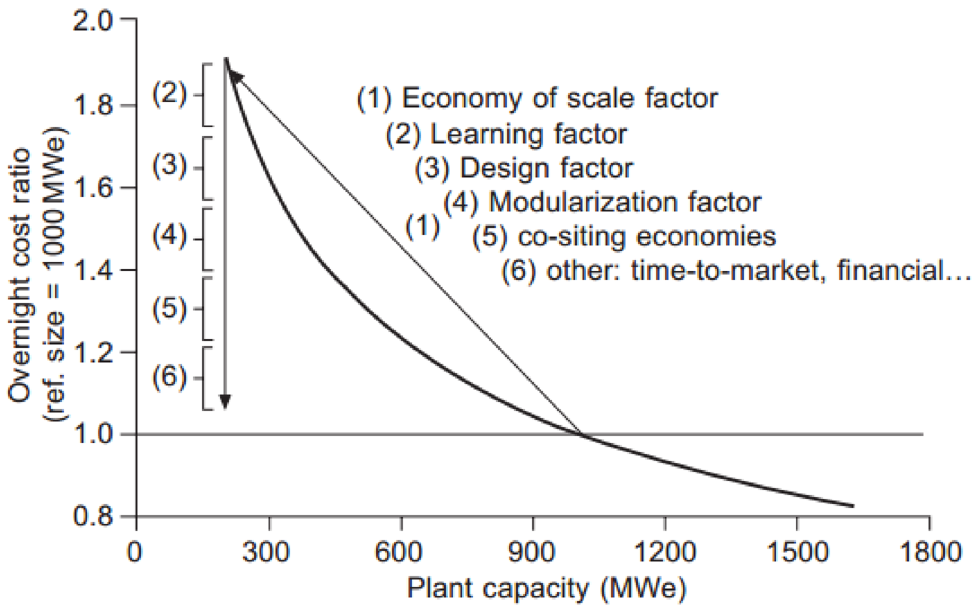

Figure 115. Six top-down estimation of overnight construction costs of SMR: qualitative trend [37].

Some studies [4] [30] consider four plant sizes (1600 MW_e, 1200 MW_e, 300 MW_e, 150 MW_e) to compare the "economy of scale" and the "economy of multiples" paradigms and two scenarios: NPPs deployed by a big utility and two minors and NPPs deployed by a single utility. The main results are:

- By considering only the "economy of scale," the overnight cost of the first SMR (300 MW_e) would be 89 % higher than a single LR (1600 MW_e);
- By considering not only the "economy of scale" but the "economy of replication" too, the gap reduces to 13 %;
- If the Interest During Construction (IDC) is considered, the gap between SMRs (300 MW_e) and LR (1600 MW_e) reduces to 7 % - 10 %. Since the investment cost in the TC does not consider IDC the investment cost of SMR is calculated 13 % higher than large reactors.

With the introduction of Small Modular Reactors (SMRs), construction costs and implementation times are expected to be significantly reduced. SMRs allow for faster and more flexible construction, tailored to the specific needs of each region. These technological advancements have also made financing nuclear projects more accessible, fostering greater adoption of nuclear energy worldwide.

Table 13-6 presents a comparison of investment costs for power projects, expressed in millions of USD per megawatt ($MUSD_{2024}/MW$), based on different data sources and regions.

Table 13-6. Investment cost comparison across regions for PWR and SMR nuclear projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	9.0 (PWR) 9.6 (SMR in 2030)	2024
International data		
Technology Catalogue Indonesia (2024)	10.1 (PWR) 9.6 (SMR in 2030)	2024
Technology Catalogue Vietnam (2023)	6.07 (PWR) 6.86 (SMR)	2023
IEA GEC Model, Brazil region (2021)	4.49 (PWR)	2021
NREL ATB (2023)	8.21 (PWR) 8.82 (SMR)	2023

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13.14. Datasheet

13.14.1. Conventional (PWR)

Technology	Nuclear power plant - PWR								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MW_e)	1000	1000	1000						
Generating capacity for total power plant (MW_e)	2000	2000	2000					B	
Electricity efficiency, net (%), name plate	37	38	42					C	4
Electricity efficiency, net (%), annual average	34	36	40					C	4
Forced outage (%)	2	2	2						4
Planned outage (%)	9	8	6						4
Auxiliary Power Consumption (%)									
Technical lifetime (years)	60	60	60						1,4
Construction time (years)	7.4	7.4	7.4	4.0	10.0				1,4
Space requirement (1000 m^2/MW_e)	2.6	2.6	2.6	2.0	3.4	2.0	3.4	D	8,9
Additional data for thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	4	4	3	3	5			A	5,4
Minimum load (% of full load)	25	25	25					A	5
Warm start-up time (hours)	2	2	1	2	6				5
Cold start-up time (hours)	30	30	30	24	48				4
Primary regulation (% per 30 seconds)									
Secondary regulation (% per minute)									
Ramp Down Rate (% of Full Load/Minute)									
Minimum Up time (hours)									
Minimum Down time (hours)									
Hot Start-up fuel consumption (Mcal/MW)									
Warm Start-up fuel consumption (Mcal/MW)									
Cold Start-up fuel consumption (Mcal/MW)									
Environment									
PM 2.5 (mg/GJ of fuel input)	-	-	-	-	-	-	-		
SO_2 (g/GJ of fuel input)	-	-	-	-	-	-	-		
NO_x (g/GJ of fuel input)	-	-	-	-	-	-	-		
CH_4 (g/GJ of fuel input)	-	-	-	-	-	-	-		
N_2O (g/GJ of fuel input)	-	-	-	-	-	-	-		
Financial data									
Nominal investment ($MUSD/MW_e$)	9.00	7.90	6.80	7.00	12.00	5.00	10.00	E,F,G,H	2,3,7,10
- of which equipment	3.00	2.63	2.27					F	
- of which installation	6.00	5.27	4.53					F	
Fixed O&M (USD/MW_e/year)	127,000	120,000	113,000	20,000	180,000	20,000	180,000		2,3
Variable O&M (USD/MWh)	2.40	2.30	2.20	1.80	3.00	1.65	2.75	I	2,3,7
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		

Notes

A Ramping and minimum load are constrained by the core stability'. Minimum requirements are usually set by the regulation.

B A two-unit configuration is typical in nuclear power plants, but more units can be combined.

C 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

D Nuclear power plants have a very' high energy' density' in terms of area required. The values represented here are for the area needed for the plants. However, there can be a higher requirement based on government regulation and environmental concerns F High variation in cost seen between US. EU costs and China. India costs. Moreover, this also depends on technology'. Here the chosen values are estimated based on a mix of values available along with employing the learning curve approach used for financial parameters.

E Decommissioning costs usually are the 15% of the total investment cost, is not included in the investment cost

F The CAPEX breakdown is composed by 33% share of direct cost (i.e., Equipment, Labour, Construction, Materials and Building), 37% of Indirect cost (i.e., Design services, Construction and Supervision and project management, Commissioning and start-up costs), 17% of Financial costs, 10% of Owner's cost.

G The development of the overnight cost is based on NREL ATB 2023

H CAPEX shall reflect a potential first of a kind plant according to [2]. 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 [11], excluding data for Russia, South Korea and USA not being representative due to maturity of market, political and macroeconomic situations.

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

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13.14.2. Small modular reactors

Technology	Nuclear power plant - SMR (Land based Water-cooled)								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MW_e)	80	80	80						2,3,4
Generating capacity for total power plant (MW_e)	300	300	300	10	300	10	300		2,3,4
Electricity efficiency, net (%), name plate	27	27	30					B	2
Electricity efficiency, net (%), annual average	27	27	30					B	2,1,4
Forced outage (%)	3	3	3						2,1
Planned outage (%)	6.5	6.0	5.0	3.0	7.0				2
Technical lifetime (years)	30	40	50						2,3
Construction time (years)	9	8	4	8	12	4	12	G	2,3, 13
Space requirement (1000 m^2/MW_e)	0.64	0.64	0.64	0.04	1.60	0.04	1.60	C	11
Additional data for thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		

Ramping configurations									
Ramping (% per minute)	1.2	1.2	1.2					A	2.5
Minimum load (% of full load)	25	25	20					A	1,2,5
Warm start-up time (hours)	1.5	1.5	1.5						2.5
Cold start-up time (hours)	24	24	24						
Primary regulation (% per 30 seconds)									
Secondary regulation (% per minute)									
Ramp Down Rate (% of Full Load/Minute)									
Minimum Up time (hours)									
Minimum Down time (hours)									
Hot Start-up fuel consumption (Mcal/MW)									
Warm Start-up fuel consumption (Mcal/MW)									
Cold Start-up fuel consumption (Mcal/MW)									
Environment									
PM 2.5 (g/GJ of fuel input)	-	-	-	-	-	-	-		
SO_2 (g/GJ of fuel input)	-	-	-	-	-	-	-		
NO_x (g/GJ of fuel input)	-	-	-	-	-	-	-		
CH_4 (g/GJ of fuel input)	-	-	-	-	-	-	-		
N_2O (g/GJ of fuel input)	-	-	-	-	-	-	-		
Financial data									
Nominal investment (MUSD/MW_e)	-	9.60	7.30	5.60	20.00	5.00	10.00	D,E	8,10,12,13
- of which equipment	-	3.20	2.43						2,3,6
- of which installation	-	6.40	4.87						2,3,6
Fixed O&M (USD/MW_e/year)	-	110,000	102,000						2,3,6
Variable O&M (USD/MWh)	-	2.20	2.10					F	2,3,6
Start-up costs (USD/MW_e/start-up)	-	0	0	0	0	0	0		

Notes

A Ramping and minimum load are constrained by the core stability'. Minimum requirements are usually set by the regulation.

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 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 F High variation in cost seen between US. EU costs and China. India costs. Moreover, this also depends on technology'. Here the chosen values are estimated based on a mix of values available along with employing the learning curve approach used for financial parameters.

D Decommissioning costs usually are the 15% of the total investment cost

E The CAPEX breakdown is composed by 33 % share of direct cost (i.e., Equipment, Labour, Construction, Materials and Building), 37 % of Indirect cost (i.e., Design services, Construction and Supervision and project management, Commissioning and start-up costs), 17 % of Financial costs, 10 % of Owner's cost.

F The main characteristic are taken from CAREM-25

G +109 mdr: China, however, managed to connect its first SMR, one of two 100 MW HTR-PM reactors, to the grid on 20 December 2021.Construction only 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

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14. Lithium-ion batteries for grid-scale storage

14.1. Brief technology description

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

A LIB, depicted in Figure 116, contains two porous electrodes separated by a porous membrane. A liquid electrolyte fills the pores in the electrodes and membrane. Lithium salt (e.g. $LiPF_6$) is disolved in the electrolyte to form Li^+ and PF_6^- ions. The ions can move from one electrode to the other via the pores in the electrolyte and membrane. Both the positive and negative electrode materials can react with the Li^+ ions. The negative electrode in a LIB is typically made of carbon and the positive of a Lithium metal oxide. By convention, the negative and the positive electrode are also called the anode and the cathode respectively. Electrons cannot migrate through the electrolyte and the membrane physically separates the two electrodes to avoid electrons crossing from the negative to the positive electrode and thereby internally short circuiting the battery.

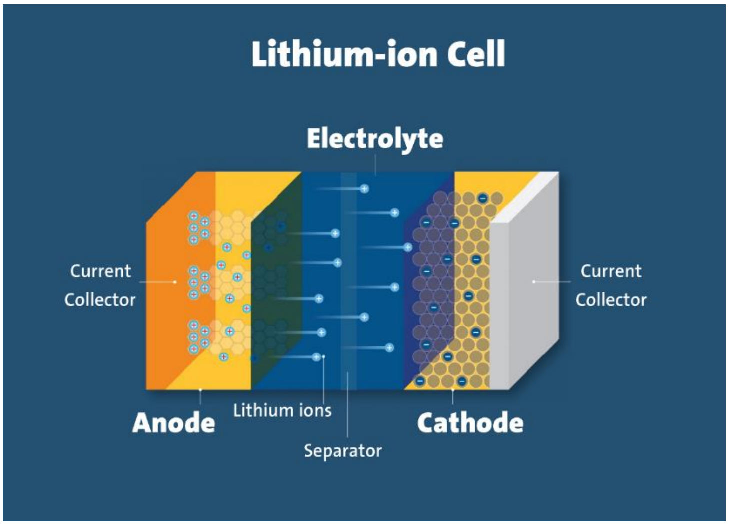


Figure 116. Schematic diagram of a typical battery [1].

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

The energy released by having one Li^+ ion, and one electron, leaving the negative electrode and entering the positive electrode is measured as the battery voltage times the charge of the electron. In other words the battery voltage - also known as the *electromotive force*: *EMF* - measures the energy per electron released during the discharge process. *EMF* is typically a around 3-4 Volts and depends on the LIB cell chemistry, the temperature and the state of charge (SOC – see below). When e.g. a light bulb is inserted in the external circuit the voltage primarily drops across the light bulb and therefore the energy released in the LIB is dissipated in the light bulb. If the light bulb is substituted with a voltage source (e.g. a power supply) the process in the battery can be reversed and thereby electric energy can be stored in the battery.

As seen in Figure 117, the battery is fully discharged when nearly all the lithium have left the negative electrode and reacted with the positive electrode. If the battery is discharged beyond this point the electrode chemistries become unstable and start degrading. When the LIB is fully discharged the *EMF* is low compared to when it is fully charged. Each LIB chemistry has a safe voltage range for the *EMF* and the endpoints of the range typically define 0 % and 100 % state of charge (SOC), and the safe voltage range prevents complete Lithium removal. However, a 20 %-80 % SOC is often recommended to balance performance and lifespan limiting the chemical stress on the system, and in situations where maximizing available capacity is not necessary. The discharge capacity is measured in units of Ampere times hours [Ah], and depends on the type and amount of material in the electrodes. Overcharging, or prolonged storage at high SOC also accelerates degradation.

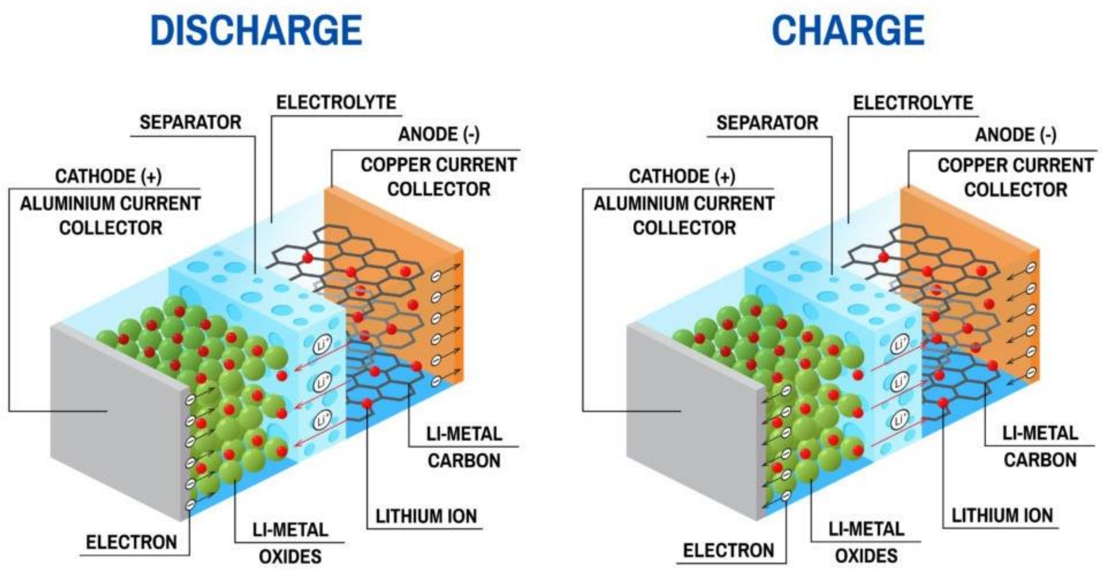


Figure 117. Schematic diagram of a LIB system in charge and discharge mode. During discharge the Li+ ions move from the negative electrode (left side) to the positive electrode. The process is reversed during charge mode (right side) [2].

The first lithium batteries were developed in the early 1970s, and Sony released the first commercial lithium-ion battery in 1991. During the '90s and early 2000s the LIBs gradually matured via the pull from the cell-phone market. The Tesla Roadster was released to customers in 2008 and was the first highway legal serial production all-electric car to use lithium-ion battery cells. Further, around 2010 the LIBs expanded into the energy storage sector with first applications, even though a future commercialization in utility-scale storage is made possible also through wider implementation of batteries in electric vehicles and a continued decline in cost through adoption, production expansion and learning.

14.1.1. Lithium-ion chemistries

The three most widely used LIB chemistries for grid-connected LIB systems and the major manufactures are (see Table 14-1):

- NMC - Lithium Nickel Manganese Cobalt Oxide
- LFP -Lithium Iron Phosphate
- LTO - Lithium Titanate

NMC (Lithium Nickel Cobalt Manganese Oxide ($LiNiCoMnO_2$)) is the most widely used of the three chemistries due to the increased production volume and lower prices lead by the automotive sector. The NMC battery has a high energy density but uses cobalt. The environmental challenges in using cobalt are described in the section: “Environment”. The LFP (Lithium Iron Phosphate ($LiFePO_4/C$)) battery do not use cobalt in the cathode, but are not as widely used as NMC, and are therefore generally higher priced, primarily due to the lower production volumes.

Both NMC and LFP batteries have graphite anodes. The main cause for degradation of NMC and LFP LIBs is graphite exfoliation and electrolyte degradation which particularly occur during deep cycling when the SOC is decreased below 10 %. LTO LIBs are the most expensive cell chemistry of the three. In LTOs the graphite anode is replaced with a Lithium Titanate anode. The cathode of a LTO battery can be NMC, LFP or other battery cathode chemistries. The LTO battery is characterized by long calendar lifetime and high number of cycles

Table 14-1. Comparison of three widely used LIB chemistries.

Short name	Name	Anode	Cathode	Energy density Wh/kg	Cycles	Calendar life	Major manufactures	References
NMC	Lithium Nickel Manganese Cobalt Oxide	Graphite	Li $Ni_{0.6}Co_{0.2}Mn_{0.2}O_2$	120-300	3000-10000	10-20 years	Samsung SDI LG Chem SK Innovation Leclanche Kokam	[2–7]
LFP	Lithium Iron Phosphate	Graphite	$LiFePO_4$	50-130	6000-8000	10-20 years	BYD/Fenecon Fronius/Sony	[8,9]
LTO	Lithium Titanate	$LiTO_2$	$LiFePO_4$ or Li $Ni_{0.6}Co_{0.2}Mn_{0.2}O_2$	70-80	15000-20000	25 years	Leclanche Kokam Altairnano	[3,5,6,9]

There are other available LIB chemistries such as LCO (Lithium Cobalt Oxide ($LiCoO_2$), LNMO (Lithium Nickel Manganese Spinel ($LiNi_{0.5}Mn_{1.5}O_4$)) and NCA (Lithium Nickel Cobalt Aluminium Oxide ($LiNiCoAlO_2$)) are generally not used for first life grid electricity storage and are therefore not included in the table.

14.1.2. Lithium-ion battery packaging

There are different ways of battery packing (see Figure 118 and Figure 119). Cylindrical cells find widespread applications ranging from laptops and power tools to utility scale battery packs, Coin cells are usually used as primary cells in portable consumer electronics, watches and hearing aids. Prismatic LIB cells are often used in industrial applications and grid-connected LIB Battery Energy Storage Systems. Pouch LIB cells are also used in electric vehicles.

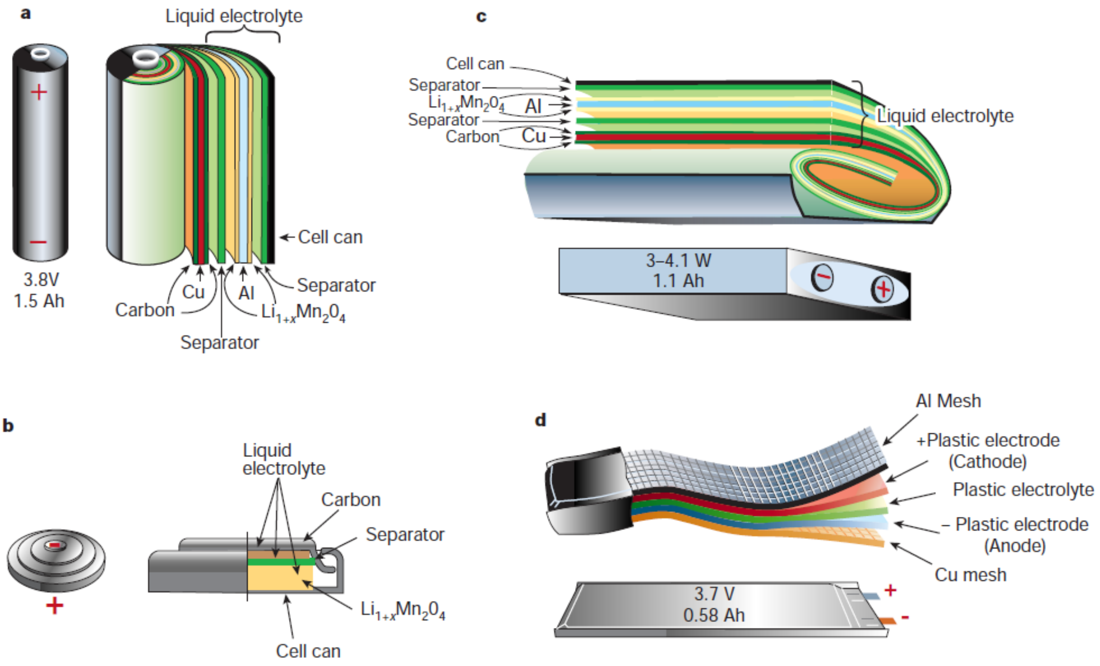


Figure 118. Schematic drawing showing the shape, packaging and components of various Li-ion battery configurations [10]. (a) Cylindrical; (b) coin; (c) prismatic; and (d) pouch.

Figure 119. Examples of commercial LIB cells. (a) Tesla 21700 cylindrical NMC LIB cell (b) Samsung SDI prismatic LIB cells (c) LG Chem pouch NMC LIB cell.

14.1.3. Components in a lithium-ion battery energy storage system

In LIB storage systems battery cells are assembled into modules that are assembled into packs. The battery packs include a Battery Management System (BMS). The BMS is an electronic system that monitors the battery conditions such as voltage, current, and temperature and protects the cells from operating outside the safe operating area.

Further an Energy Management System (EMS) controls the charge/discharge of the grid-connected LIB storage from a system perspective. Depending on the application and power configuration the power conversion system may consist of one or multiple power converter units (DC/AC link).

14.1.4. Lithium-ion grid integration

For system coupling a transformer may be needed for integration with higher grid voltage levels. The grid integration, as depicted in Figure 120, provides services to the grid such as increased reliability, load shifting, frequency regulation etc. The services are described further below in the section "Regulation ability and other system services". Value generation and profit is created by selling the services to grid Transmission System Operators (TSOs). Battery capacity may be sold to the TSOs in full or partially, allowing for alternate use of the remaining capacity, for example local load management, energy trading or DSO services. Appropriate sizing of the battery and power conversion systems is essential to maximize the revenue.

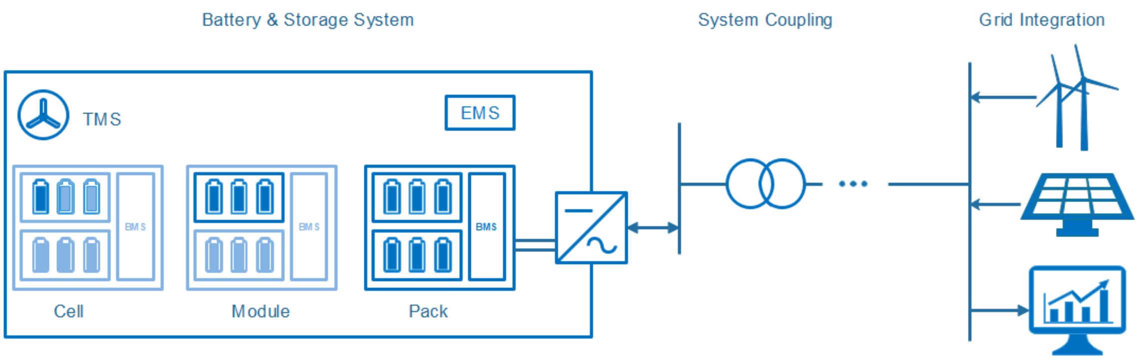


Figure 120. Schematic drawing of a battery storage system, power system coupling and grid interface components. Keywords highlight technically, and economically relevant aspects [11].

14.2. Input/Output

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

14.2.1. Energy efficiency and losses

The losses in a LIB can be divided in operational and standby losses.

14.2.2. Operational losses

The operational losses occur when energy is discharged or charged to/from the grid. It includes the conversion losses in the battery and the power electronics.
When the LIB is not operated its voltage equals the electromotive force. However, during discharge or charge the battery voltage changes due to current passing through the internal resistance in the LIB. The voltage changes are typically described using Ohms law, and the loss in the internal resistance is dependent on the current squared.

The LIB provides a DC current during discharge and needs a DC current input for charging. Before the electricity is sent to the grid the inverter converts the DC current to AC. The inverter loss typically increases gradually from around 1 % to 2 % when increasing the relative conversion power from 0 % to 100 % [12].

14.2.3. Standby losses

Unwanted chemical reactions cause internal current leakage in the LIB. The current leakage leads to a gradual self-discharge during standby. The self-discharge rate increases with temperature and depicted in Figure 121 below shows the remaining charge capacity as a function of time and temperature for a LIB. The discharge rate is the slope of the curve and is around 0.1 % per day at ambient temperature.

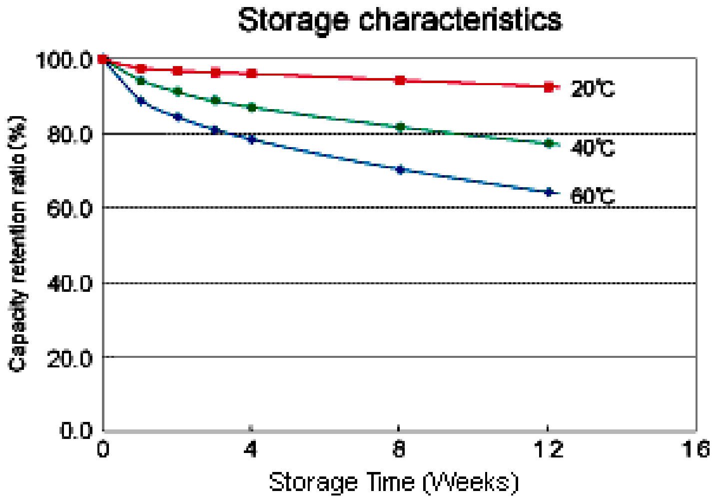


Figure 121. Remaining charge capacity for a typical LIB as function of storage time [13].

Besides the self-discharge in the cell, a LIB electricity storage system requires power to operate the auxiliary balance of plant (BOP) components. Figure 5 outlines the BOP components which include the inverter, BMS, EMS and TMS. The relative energy loss to the BOP components depends on the application, and a careful operation strategy is important to minimize their power consumption [12]. The standby loss E_{stb} is the sum of the energy losses during standby due to self-discharge and power consumption in the BOP components.

14.2.4. Energy Efficiency

The conversion roundtrip efficiency of the LIB cell is the discharged energy divided with the charged energy. The battery conversion efficiency decreases with increasing current since the P_{loss} increases. An example of a LIB cell conversion efficiency is shown in Figure 122. The C-rate is the inverse of the time it takes to discharge a fully charged battery with nominal power. At a C-rate of 2 it approximately takes ½ hour and at a C-rate of 6 approximately takes 10 minutes.

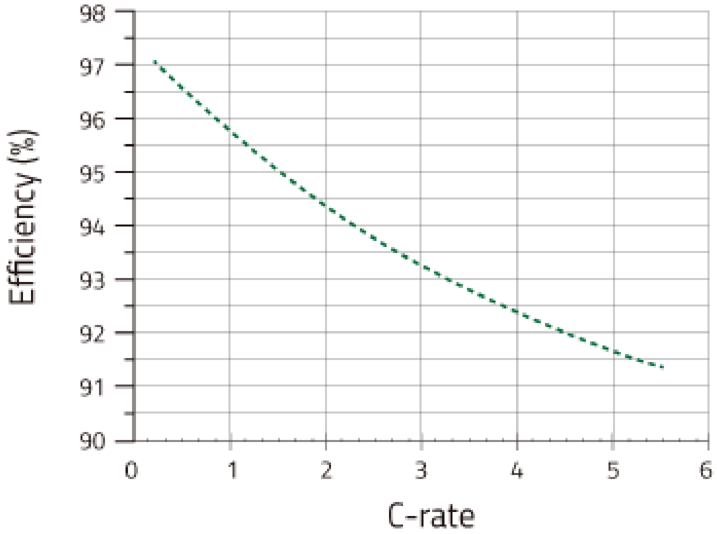


Figure 122. Conversion round trip efficiency vs. C-rate for NMC-based lithium polymer batteries [14].

The system conversion roundtrip efficiency $\eta_{\text{Conversion}}$ considers losses which occur on the conversion path from the energy charged $E_{\text{Charge,AC}}$ and the energy discharged $E_{\text{Discharge,AC}}$ from/to the grid.

The total roundtrip efficiency η_{Total} further includes the standby losses. E_{stb} The various types η_{Total} make the total roundtrip efficiency heavily dependent on the application. As an example, an 11 MW/4.4 MWh LIB system was installed in Maui, Hawaii for wind ramp management, essentially smoothing the output of a 21 MW wind farm [15]. The total roundtrip efficiency for this system is around 80 % [16]. Lazard uses an estimate of 85 % [17]. To summarize, the total roundtrip loss typically consists of 2-5 % related to the cell, 2-4 % to the power electronics and the rest to standby losses.

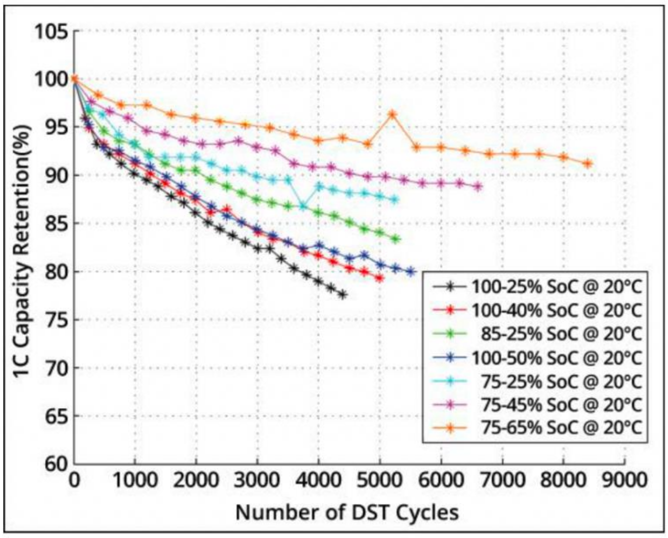


Figure 123. Capacity retention curves under different charge/discharge habits [43].

Figure 123 illustrates the relationship between the number of DST (Dynamic Stress Test) cycles and the 1C capacity retention (%) of a battery, as influenced by various state-of-charge (SoC) ranges. Battery retention degrades more significantly with wider SoC ranges (e.g., 100–25 %) compared to narrower ranges (e.g., 75–65 %), with the steepest decline occurring early in the cycle life. Usage patterns with smaller charge-discharge ranges, such as 75–65 % SoC, retain higher capacity over more cycles, indicating that limiting the depth of discharge prolongs battery life.

14.3. Typical storage period

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

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

LIB systems have been deployed to provide frequency response with a response time ranging from seconds to minutes [19], and the systems are increasingly used for renewables time shifting with typical storage periods of a few hours [11, 18].

14.4. Space requirement

The racks and battery packs are typically assembled in containers and the energy per 40 feet container is 4-6 MWh for NMC batteries [4,20]. The footprint of a 40-feet container is 29.7 m^2. This gives a space requirement around 5-7.5 m^2/MWh.

14.5. Water consumption

Utility-scale lithium-ion energy systems typically do not require external water for their electrochemical operations. Some BESS advanced liquid cooling technologies that operate in a closed cycle, where water or another coolant circulates within a sealed system to transfer heat away from the battery cells efficiently. This method enhances system efficiency and longevity by maintaining optimal operating temperatures without the need for constant water replenishment.

14.6. Regulation ability and other power system services

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

LIB BESS (Battery Energy Storage System) suitable for a broad range of applications in the electric sector [18]. These applications include:

- Peak Load Shaving: to provide or receive energy to reduce peaks in the power system.
- Renewable Integration: to support renewable integration by time or load shifting (e.g. storing photovoltaic energy generated during the day for use at night).
- Transmission Congestion Relief: to reduce the load on transmission and distribution systems, helping to defer expensive upgrades.
- Frequency Regulation: to alleviate deviations in AC frequency. Today, frequency regulation is the main application of stationary BESS systems deployed worldwide
- Reliability: to improve network reliability by responding immediately after a contingency, maintaining stability until generation can be re-dispatched.
- Voltage Deviations: to enhance power quality by reducing voltage deviations in distribution networks.
- Spinning Reserves: to provide spinning reserves, ensuring power availability during disruptions.
- Active and Reactive Power: to regulate active and reactive power, improving the network voltage profile and enhancing renewable energy integration.

Batteries have important regulation capabilities and can provide services to the energy systems an shown in Table 14-2. Key applications include Arbitrage, Firm Capacity, and different types of Operating Reserves such as Primary Frequency Response and Regulation. Service durations vary from seconds to hours, with arbitrage and firm capacity focusing on peak demand management, while operating reserves ensure quick responses to demand fluctuations and contingencies. [21].

Table 14-2. Applications of Utility Scale Energy Storage [21].

Application	Description	Duration of Service Provision
Arbitrage	Purchasing low-cost off-peak energy and selling it during periods of high prices.	Hours
Firm Capacity	Provide reliable capacity to meet peak system demand.	4+ hours
Operating Reserves		
- Primary Frequency Response	Very fast response to unpredictable variations in demand and generation.	Seconds
- Regulation	Fast response to random, unpredictable variations in demand and generation.	15 minutes to 1 hour
- Contingency Spinning	Fast response to a contingency such as a generator failure.	30 minutes to 2 hours

- Replacement/Supplemental	Units brought online to replace spinning units.	Hours
- Ramping/Load Following	Follow longer-term (hourly) changes in electricity demand.	30 minutes to hours
Transmission and Distribution Replacement and Deferral	Reduce loading on T&D system during peak times.	Hours
Black-Start	Units brought online to start system after a system-wide failure (blackout).	Hours

14.6.1. Frequency regulation and renewable energy integration cost examples

The aim with this technology catalogue is to provide a brief insight into the technical aspects, current status, and forecasted price level of the LIB BESS technology. In relation to this, and to help the reader obtaining realistic prices indications, we provide two simple installation cost calculation examples below. One for frequency regulation in 2024 and one for energy integration in 2030. The examples are based on the data in the Data sheet. For simplicity neither O&M expenses nor interest rates are included in the calculations.

Frequency regulation in 2020: 4C-rate, 2 MWh BESS system.

Cost items:

- 2 MWh "energy component", year 2024
- 2 MWh "other project costs", year 2024
- 8 MW PCS "capacity component", year 2024
- CAPEX in total cost: 2 · (0.35 MUSD + 0.04 MUSD) + 8 · 0.33 MUSD = 3.42 MUSD
- Same CAPEX in specific cost per MWh and per MW, respectively:
- Per MWh: 3.42 MUSD / 2 MWh = 1.72 MUSD/MWh
- Per MW: 3.42 MUSD / 8 MW = 0.43 MUSD/MW

Energy integration in 2030: ¼C-rate, 16 MWh BESS system.

Cost items:

- 16 MWh "energy component", year 2030
- 16 MWh "other project costs", year 2030
- 4 MW PCS "capacity component", year 2030
- CAPEX in total cost: 16 · (0.2 MUSD + 0.03 MUSD) + 4 · 0.24 MUSD = 4.64 MUSD
- Same CAPEX in specific cost per MWh and per MW, respectively:
- Per MWh: 4.64 MUSD / 16 MWh = 0.29 MUSD/MWh
- Per MW: 4.64 MUSD / 4 MW = 1.16 MUSD/MW

When applying these dynamics over different discharge times (i.e. 1 divided by C-rate), there is an inverse behaviour in specific costs per capacity (in MUSD/MW) compared to specific cost per energy storage (in MUSD/MWh), as visualized in Figure 124 below that is based on the 2024-values of the utility-scale datasheet cost components.

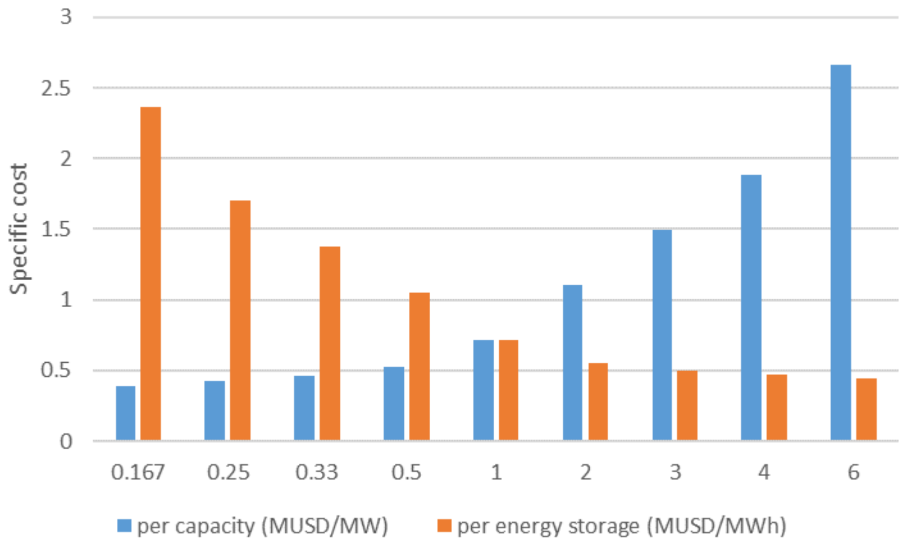


Figure 124. Specific cost for utility-scale battery in 2024, expressed in cost per capacity (MW) and per energy storage (MWh). Source: Authors' own elaboration.

Naturally, the absolute cost level and price expressed in MUSD depends on the overall size of the battery storage system. For example, a battery system of 4 MWh/2 MW is costlier than a 2 MWh/1 MW battery, despite having the same C-rate of 1/2.

14.7. Advantages/disadvantages

14.7.1. Advantages

Proven Technology: Lithium-ion technology is mature and well-understood, reducing risks associated

- Lithium-ion can store large amounts of energy in a small space, making them ideal for applications with space constraints
- Lithium-ion batteries have high charge and discharge efficiency, with minimal energy loss during the process
- Lithium-ion batteries have a long cycle life, meaning they can endure many charge-discharge cycles, making them cost-effective over time
- Fast Response Time. This makes them highly effective for grid services like frequency regulation, voltage control, and spinning reserves
- Stand-alone technology with little maintenance requirements

14.7.2. Disadvantages

- The upfront cost of lithium-ion battery systems remains high, although prices are gradually declining
- There is a risk of overheating and fires, requiring sophisticated battery management systems to prevent issues like thermal runaway
- Lithium-ion batteries experience a decline in performance over time, especially after repeated charge-discharge cycles

- End-of-life management and recycling can be challenging due to the materials used, such as cobalt and nickel

14.8. Environment

A US-EPA report stated in 2013 that across battery chemistries, the global warming potential impact attributable to LIB production including mining is substantial [22]. More specifically a recent review on life-cycle analysis (LCA) of Li-Ion battery production estimates that “on average, producing 1 Wh of storage capacity is associated with a cumulative energy demand of 328 Wh and causes greenhouse gas (GHG) emissions of 110 g $CO_{2\,eq}$“ [3].

The LIB cathode material NMC contains toxic cobalt and nickel oxides. About 60 % of the global production of cobalt comes from DR Congo and the environmental health risks and work conditions in relation to the cobalt mining raises ethical concerns [24]. Visual Capitalist believes the cobalt content in NMC could decrease to 10 % already in 2020 [25] from 20 % today by changing from a 6-2-2 ratio to an 8-1-1 ratio.

Starting about two years ago, fears of a lithium shortage almost tripled prices for the metal [26], and the demand for lithium will not fall anytime soon. According to Bloomberg New Energy Finance the electric car production alone is expected to increase more than thirtyfold by 2030. However, the next dozen years will drain less than 1 percent of the reserves in the ground, according to BNEF. One should be sceptic of this statement as battery makers are likely going to rapidly increase mining capacity to meet the demand.

14.9. Research and development perspectives

Currently a wide range of government and industry-sponsored LIB material, cell, and system level research is taking place. Some of the ongoing material research to further increase the energy density of LIB cells includes high-voltage electrolytes allowing charging voltages of up to 5 volts [27] and silicon nanoparticle-based anodes to boost the charge capacity [28]. Several research and development activities focus on improving the cycle lifetime of LMO cells [29–31].

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

Several non-lithium-based battery chemistries are being investigated. Aluminium Sulphur batteries may reach up to 1000 Wh/kg with relatively abundant electrode materials but are still in the very early development phase [32]. Besides the materials research, improved cell design, BMS, TMS and EMS technology and operation strategy can improve storage efficiency considerably.

Although LIB systems for electricity storage are now commercially available, the R&D is still in its relatively early phase and is expected to contribute to future cost reductions and efficiency improvements.

14.9.1. Research and development perspectives in Colombia

In Colombia, innovation and development of Li-on batteries has been focused on addressing the environmental impacts at the end of life of these systems. Two companies, Batex and Recobatt, are actively involved in giving second life to lithium-ion batteries. The concept of "second life" for batteries refers to repurposing used lithium-ion batteries, typically from electric vehicles, for less demanding applications once their efficiency for high-performance use declines. These batteries still retain a significant portion of their original capacity, making them suitable for energy storage systems, especially in residential, commercial, or grid-support applications. This approach helps reduce environmental impact by extending the lifecycle of the batteries and minimizing electronic waste, while also offering a more affordable energy storage solution.

Alttero, a company based in Medellin, has developed battery recycling process stands out for its mechanical crushing of lithium-ion, polymer lithium, and nickel metal hydride batteries without prior discharge or chemical treatment. The technology operates in a controlled environment with gases and does not require nitrogen, resulting in a dry recycling method that produces zero emissions and no environmental discharges. The batteries are transformed into two material streams: one rich in cobalt, lithium, and nickel for the international market, and another containing laminated metals like copper and aluminium for local sale. The process is energy-efficient and housed in a maritime container [33].

14.10. Examples of market standard technology

As March 2024, Colombia has one utility scale BESS, in the Termozipa thermal power plant, owned by ENEL (see Table 14-3). This system allows Termozipa increase its generation capacity by storing 7 MW of power and 3.9 MWh of energy, and to engage in primary frequency regulation when the thermal units are shut down.

Table 14-3. Example of market standard technology for grid-connected LIB systems in Colombia.

Image	Location	Primary usage	Year	Power capacity	Ref.
	Tocancipá, Cundinamarca Colombia	Frequency Regulation	2021	7 MW 3.9 MWh NMC	[34].

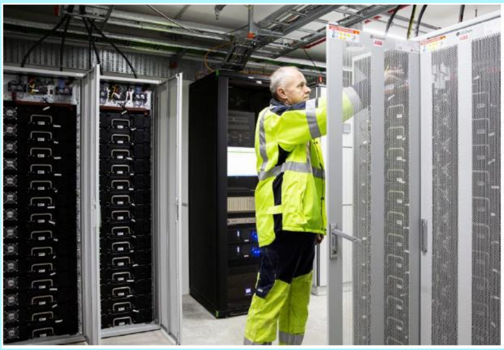
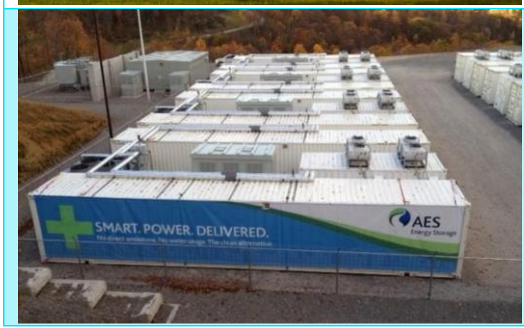
Grid scale turn-key LIB systems are commercially available from a wide range of suppliers (see Table 14-4). Two larger grid-connected LIB systems are installed in Denmark:

- In Nordhavn, Copenhagen, Denmark a 630 kW/460 kWh was installed by ABB for Radius Elnet and Ørsted in 2017. This set the scene for Ørsted's first steps into commercial battery storage. For Ørsted the following energy storage projects are under development: a 20 MW battery storage near Liverpool in UK and a 1 MW storage pilot project in Taiwan [35].
- Lem Kær Wind Farm was Vesta's pilot project for energy storage which participates in the DK frequency regulation market. Vestas is working on Kennedy Power Plant that integrates wind and solar with grid-scale energy storage and will feature a 2 MW / 4 MWh grid-scale LIB storage system to provide ancillary services, test energy arbitrage and reduce curtailment.

Globally the two largest grid-scale LIB storage systems are the Mira Loma Substation in California which features 20 MW/80 MWh using 400 Tesla Powerpack 2 [36,37] and the Neoen's Hornsdale Wind Farm which features 100 MW/129 MWh [37], both systems provide peak shaving.

The Laurel Mountain, West Virginia, USA grid-scale LIB storage system at 32 MW/8 MWh [38] is designed for frequency regulation and with high power to energy ratio compared to the Tesla grid-scale LIB storage systems which are designed for peak shaving with a lower power to energy ratio.

Table 14-4. Example of market standard technology for grid-connected LIB systems around the world.

Image	Location	Primary usage	Year	Power capacity	Techn. provider	Ref.
	Energylab Nordhavn, Copenhagen, Denmark	Frequency Regulation Peak Shaving Voltage Regulation Harmonic Filtering	2017	630 kW 460 kWh NMC	ABB for Radius Elnet / Ørsted	[35]
	Lem Kær Wind Farm, Denmark	Frequency regulation	2014	400 kW LFP and 1.2MW LTO	Altairnano and A123 for Vestas	[35]
	Mira Loma Substation, California, USA	Peak Shaving	2016	20 MW 80 MWh	Tesla	[36,37]
	Neoen's Hornsdale Wind Farm, South Australia	Peak Shaving	2017	100 MW 129 MWh	Tesla	[37]
	Laurel Mountain, Belington, West Virginia, USA	Frequency Regulation and Renewable Energy Integration	2011	32 MW 8 MWh	AES and A123	[38]

14.11. Prediction of cost and capacity

The current (2024) LIB price is close to 139 USD/kWh [39] and the forecast predicts a battery price of 70 USD/kWh by 2030 [41]. Furthermore, the lowering prices have been systematically overperformed the previous forecasts as seen in Figure 125.

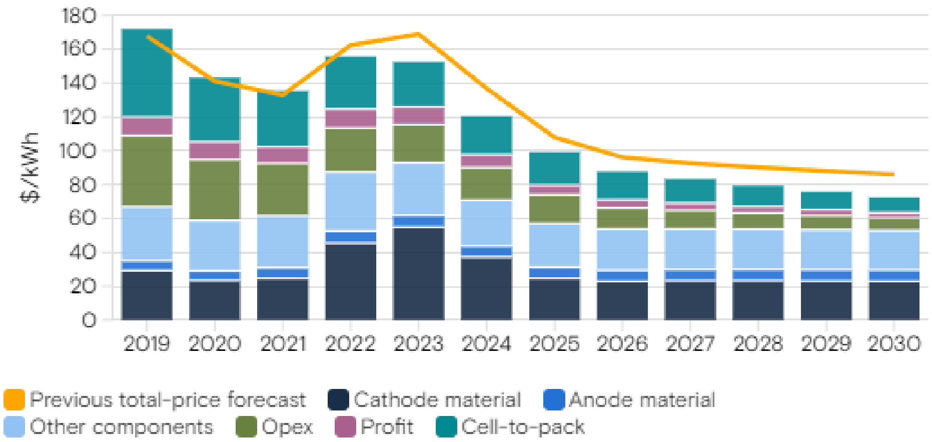


Figure 125. Example of market standard technology for grid-connected LIB systems around the world [40].

The cost reductions are backed up by a rapid increase in the LIB production capacity. The capacity is expected to grow from 1,163 GWh in 2022 to 8,945 GWh by 2027 representing an impressive eight-fold growth in five years (see Figure 126). The manufacturing capacity is concentrated in China, which is expected to hold approximately 70 % of the market [41].

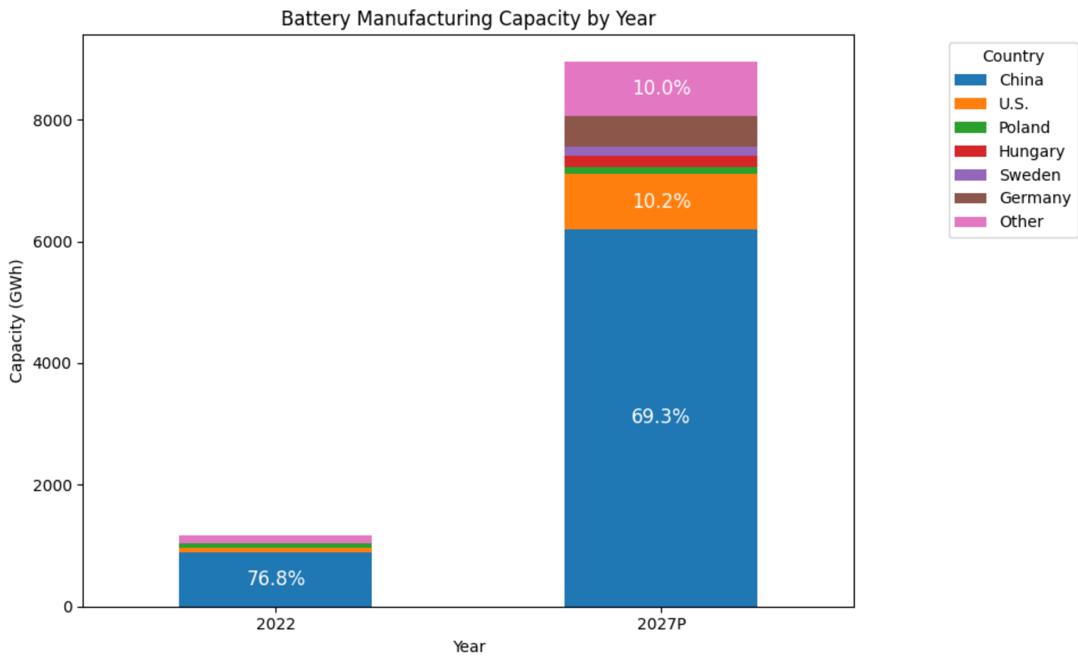


Figure 126. Projected growth in LIB manufacturing capacity over next few years, total and divided on technology producers, derived from [41].

The forecasted decrease in battery pack cost and increase in production capacity aligns with a forecasted steep growth rate of the utility-scale application market. The installed capacity is estimated to reach almost 7 TWh in 2030 as illustrated in Figure 127 [42].

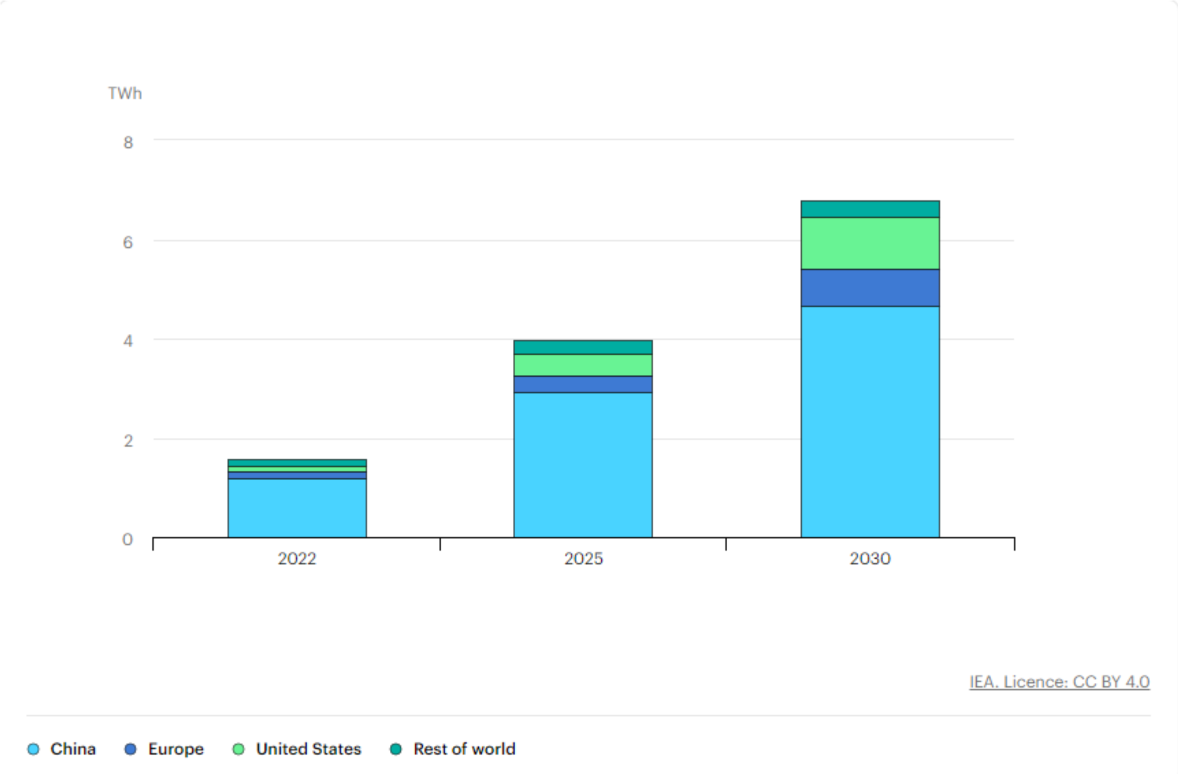


Figure 127. Worldwide forecast of battery storage capacity (TWh) [42].

14.11.1. Investment cost overview

Table 14-5 presents a comparison of investment costs for power projects, expressed in millions of USD per megawatt ($MUSD_{2024}$/MW), based on different data sources and regions.

Table 14-5. Investment cost comparison across regions for LIB projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)
This study	1.89 (large) 5.3 (small)	0.47 (large) 1.3 (small)
International data		
Technology Catalogue Indonesia (2023)	1.50 (large)	0.53 (large)
Technology Catalogue India (2023)	1.11 (large)	0.39 (large)
NREL ATB 2023	1.72 (large) 1.86(small)	0.43 (large) 0.46 (small)
This study	1.89 (large) 5.3 (small)	0.47 (large) 1.3 (small)

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14.13. Datasheet

14.13.1. Utility scale

Technology	Batteries - Lithium-ion (utility-scale)								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		

Energy/technical data									
Energy storage capacity for one unit (MWh)	4	4	4	4	4	4	4	A, B	
Input capacity for one unit (MW)	1	1	1	1	1	1	1	A, B	
Output capacity for one unit (MW)	1	1	1	1	1	1	1	A, B	
Discharge time (hours)	4	4	4	4	4	4	4	A, B	
Round-trip efficiency (%) AC	90	92	92					C	1
Round-trip efficiency (%) DC	95	96	96					C	1
Self-discharge rate (%/day)	0.10	0.10	0.10						2
Forced outage (%)	0.38	0.35	0.25					M	
Planned outage (weeks/year)	0.20	0.10	0.10					L	
Technical lifetime (cycles)	7,500	10,000	15,000					M	3
Technical lifetime (years)	15	20	25					D	3
Construction time (years)	0.20	0.20	0.20						
Energy density (Wh/kg)	150	200	300						
Ramping configurations									
Response time from idle to full-rated discharge (ms)	50	50	50						4
Response time from full-rated charge to discharge (sec)	<0.08	<0.08	<0.08	<0.08	<0.08	<0.08	<0.08	O	7
Financial data									
Total investment (MUSD/MWh)	0.47	0.28	0.20	0.35	0.54	0.19	0.22	G	1,5,6,10
- energy component (MUSD/MWh)	0.35	0.20	0.13	0.26	0.38	0.12	0.14	P	1,5,6,9,11
- power component (MUSD/MW)	0.33	0.24	0.19	0.24	0.35	0.18	0.20	C, P	1,5,6,9,11
- other project costs (MUSD/MWh)	0.04	0.03	0.02	0.03	0.07	0.02	0.03	N, P	5,6,9
Fixed O&M (USD/MW/year)	15000	10830	8674	5,000	50,000	8292	9055	O	6,9,10
Variable O&M (USD/MWh)	2.00	1.44	1.16	2.00	2.60	1.11	1.21	I	7,10
Technology specific data									
Energy storage expansion cost (MUSD/MWh)	0.39	0.23	0.16	0.29	0.45	0.14	0.17	F	
Output capacity expansion cost (MUSD/MW)	0.33	0.24	0.19	0.24	0.35	0.18	0.20	F	
Total investment (MUSD/MW)	1.89	1.14	0.81	1.40	2.14	0.76	0.87		

Notes

A A 4-hour battery has been picked as a reference, as there is more data available for this power-to-energy ratio in the references listed.

B Power and energy output can be scaled linearly by utilizing many modules (up to 250 MW has been demonstrated, https://www.pv-magazine-australia.com/2023/08/10/battery-capacity-overtakes-pumped-hydro-in-nem/). Output capacity expansion can be done reprograming the management unit without any new battery module. For Utility batteries the ratio between energy storage and capacity is in general between 1 and 10 (C-rate between 1/10 and 1) only rarely the ration will be below 1.

C The gradual change towards lower C-rates following the transition from frequency regulation to renewable integration promotes lower C-rates. Therefore, the average DC roundtrip efficiency is expected to increase slightly. The RT eff. vs. C-rate is exemplified in Figure 122 [3]. The AC roundtrip efficiency includes losses in the power electronics and is 2-4 % lower than the DC roundtrip efficiency. The total roundtrip efficiency further includes standby losses making the total roundtrip efficiency typically ranging between 80 % and 90 % [21,22].

D Samsung SDI 2016 whitepaper on ESS solutions provide 15-year lifetime for current modules operating at C =1/2 to C=3. Steady improvement in battery lifetime due to better materials and battery management expected. Number of cycles can be a more meaningful lifetime indicator.

E The discharge time is the number of hours the battery can discharge at rated output capacity. It equals the Energy/Power ratio corrected for the discharge efficiency.

F Since multi-MWh LIB systems are scalar, the energy and output capacity expansion costs are here estimated to be equal to the energy and "other cost" for energy storage expansion, and power components for output capacity expansion cost, with the other equipment and cost remaining constant respectively

G Power conversion cost is strongly dependent on scalability and application.

I Cost per MWh of energy discharged from the battery

L It is expected not to have any outage during lifetime of the grid-connected LIB. Only a few days during the e.g. 15 years life time is needed for service and exchanging fans and blowers for thermal management system and power conversion system. Forced outage is expected to drop with increasing robustness following the learning rate and cumulated production. Planned outage is expected to decrease after 2020 due to increased automation.

M Cycle life specified as the number of cycles at 1C/1C to 80 % state-of-health. Samsung SDI 2016 whitepaper on ESS solutions provide 15-year lifetime for current modules operating at C/2 to 3C [14]. Steady improvement in battery lifetime due to better materials and battery management is expected. Kokam ESS solutions are also rated at more than 8000-20000 cycles (80-90 % DOD) based on chemistry [3]. Thus, for daily full charge-discharge cycles, the batteries are designed to last for 15-50 years if supporting units are well functioning. Lifetimes are given for both graphite and LTO anode based commercial batteries from Kokam.

N Other costs include construction costs and entrepreneur work. These costs heavily dependent on location, substrate and site access. Power cables to the site and entrepreneur work for installation of the containers are included in other costs. Therefore, other costs are assumed to – roughly – correlate with the system size. Automation is expected to decrease other costs from 2030 and onwards.

O The response time is obtained from simulated response time experiments with hardware in the loop.

P A learning rate of 17 % is assumed for the energy components, and 10 % for power component and other costs, according to IEA and BNEF

References

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14.13.2. Small scale

Technology	**Batteries - Lithium-ion (small-scale)**								
	2024	**2030**	**2050**	**Uncertainty (2024)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Energy storage capacity for one unit (MWh)	0.004	0.004	0.004	0.004	0.004	0.004	0.004	A, B	
Input capacity for one unit (MW)	0.001	0.001	0.001	0.001	0.001	0.001	0.001	A, B	
Output capacity for one unit (MW)	0.001	0.001	0.001	0.001	0.001	0.001	0.001	A, B	
Discharge time (hours)	4	4	4	4	4	4	4	A, B	
Round-trip efficiency (%) AC	90	92	92					C	1
Round-trip efficiency (%) DC	95	96	96					C	1
Self-discharge rate (%/day)	0.1	0.1	0.1						2
Forced outage (%)	0.38	0.35	0.25					M	
Planned outage (weeks/year)								L	
Technical lifetime (cycles)	7500	10000	15000					M	3
Technical lifetime (years)	15	20	25					D	3
Construction time (years)	0.2	0.2	0.2						
Energy density (W_h/kg)	150	200	300						
Ramping configurations									
Response time from idle to full-rated discharge (ms)	50	50	50						4
Response time from full-rated charge to discharge (sec)	<0.08	<0.08	<0.08	<0.08	<0.08	<0.08	<0.08	O	7
Financial data									
Total investment (MUSD/MWh)	1.3	0.8	0.6	1.0	1.5	0.5	0.6	G	1,5,6,10
- energy component (MUSD/MWh)	1.0	0.5	0.4	0.7	1.1	0.3	0.4	P, Q	1,5,6,9,11
- power component (MUSD/MW)	0.9	0.7	0.5	0.7	1.0	0.5	0.6	H, P, Q	1,5,6,9,11
- other project costs (MUSD/MWh)	0.1	0.1	0.1	0.1	0.2	0.1	0.1	N, P, Q	5,6,9
Fixed O&M (USD/MW/year)	42,276	30,522	24,447	14,092	140,919	23,369	25,521	O, Q	6,9,10
Variable O&M (USD/MWh)	5.6	4.1	3.3	5.6	7.3	3.1	3.4	I, Q	7,10
Technology specific data									

Energy storage expansion cost (MUSD/MWh)	1.1	0.6	0.4	0.8	1.3	0.4	0.5	F	
Output capacity expansion cost (MUSD/MW)	0.9	0.7	0.5	0.7	1.0	0.5	0.6	F	
Total investment (MUSD/MW)	5.3	3.2	2.3	4.0	6.0	2.1	2.4		

Notes

A A 4-hour battery has been picked as a reference, as there is more data available for this power-to-energy ratio in the references listed.

B Power and energy output can be scaled linearly by utilizing many modules. Output capacity expansion can be done reprogramming the management unit without any new battery module. For smaller scale batteries the ratio between energy storage and capacity is in general between 1 and 10 with a tendency towards higher numbers (C-rate between 1/10 and 1); only rarely the ration will be below 1.

C The gradual change towards lower C-rates following the transition from frequency regulation to renewable integration promotes lower C-rates. Therefore, the average DC roundtrip efficiency is expected to increase slightly. The RT eff. vs. C-rate is exemplified in Figure 7 [3,51]. The AC roundtrip efficiency includes losses in the power electronics and is 2-4 % lower than the DC roundtrip efficiency. The total roundtrip efficiency further includes standby losses making the total roundtrip efficiency typically ranging between 80 % and 90 % [21,22].

D Samsung SDI 2016 whitepaper on ESS solutions provide 15-year lifetime for current modules operating at C =1/2 to C=3. Steady improvement in battery lifetime due to better materials and battery management expected. Number of cycles can be a more meaningful lifetime indicator.

E The discharge time is the number of hours the battery can discharge at rated output capacity. It equals the Energy/Power ratio corrected for the discharge efficiency.

F Since multi-MWh LIB systems are scalar, the energy and output capacity expansion costs are here estimated to be equal to the energy and "other cost" for energy storage expansion, and power components for output capacity expansion cost, with the other equipment and cost remaining constant respectively

G Power conversion cost is strongly dependent on scalability and application.

H The gradual change towards lower C-rates following the transition from frequency regulation to renewable integration promotes lower C-rates. Therefore, the average DC roundtrip efficiency is expected to increase slightly. The RT eff. vs. C-rate is exemplified in Figure 7 [3]. The AC roundtrip efficiency includes losses in the power electronics and is 2-4 % lower than the DC roundtrip efficiency. The total roundtrip efficiency further includes standby losses making the total roundtrip efficiency typically ranging between 80 % and 90 %

I Cost per MWh of energy discharged from the battery

L It is expected not to have any outage during lifetime of the grid-connected LIB. Only a few days during the e.g. 15 years life time is needed for service and exchanging fans and blowers for thermal management system and power conversion system. Forced outage is expected to drop with increasing robustness following the learning rate and cumulated production. Planned outage is expected to decrease after 2020 due to increased automation.

M Cycle life specified as the number of cycles at 1C/1C to 80 % state-of-health. Samsung SDI 2016 whitepaper on ESS solutions provide 15-year lifetime for current modules operating at C/2 to 3C [14]. Steady improvement in battery lifetime due to better materials and battery management is expected. Kokam ESS solutions are also rated at more than 8000-20000 cycles (80-90 % DOD) based on chemistry [3]. Thus, for daily full charge-discharge cycles, the batteries are designed to last for 15-50 years if supporting units are well functioning. Lifetimes are given for both graphite and LTO anode based commercial batteries from Kokam.

N Other costs include construction costs and entrepreneur work. These costs heavily dependent on location, substrate and site access. Power cables to the site and entrepreneur work for installation of the containers are included in other costs. Therefore, other costs are assumed to – roughly – correlate with the system size. Automation is expected to decrease other costs from 2030 and onwards.

O The response time is obtained from simulated response time experiments with hardware in the loop.

P A learning rate of 17 % is assumed for the energy components, and 10 % for power component and other costs, according to IEA and BNEF

Q A proportionality factor α of 0.85 is suggested to convert the presented cost from the utility-scale datasheet to small-scale, in accordance with economy of scale found in literature

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15. Pumped Hydro Storage

15.1. Brief technology description

A typical pumped hydro storage (PHS) consists of two water reservoirs (lakes), tunnels that convey water from one reservoir to another, a reversible pump-turbine, a motor-generator, transformers, and transmission connection [1]. The amount of stored electricity is proportional to the product of the volume of water and the height between the reservoirs. For bulk electricity storage in utility grids, pumped hydro power plants dominate, with approximately 100 GW in service around the globe [2].

There are two main types of PHS facilities explained in Figure 128: off-stream PHS (closed cycle) uses water that was pumped to the upper reservoir, while hybrid PHS (combined) uses both the pumped water and natural flow water to generate electricity.

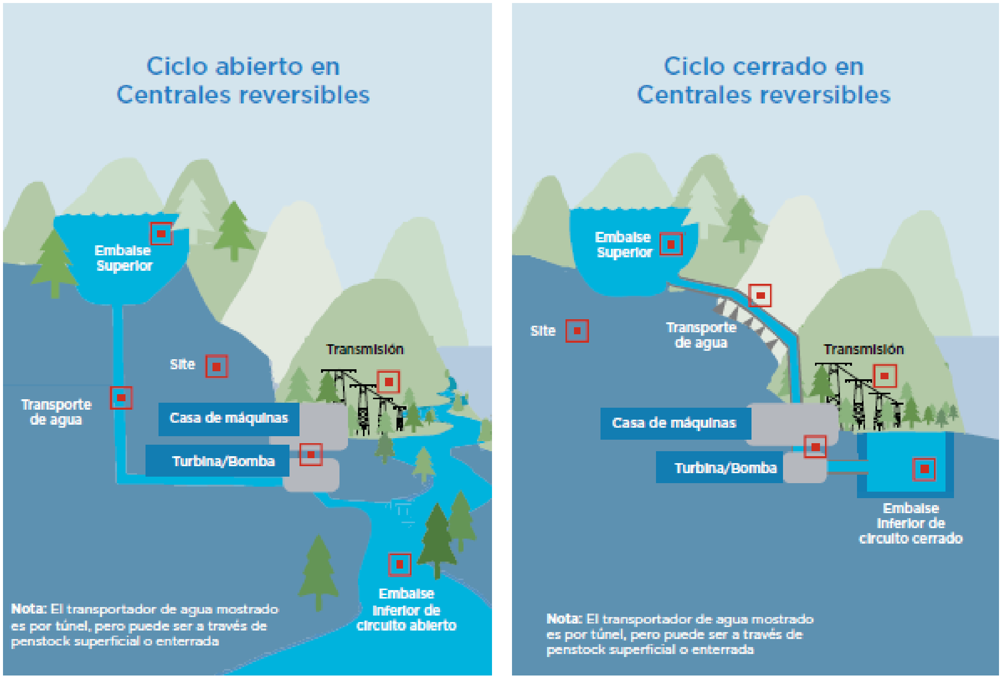

Figure 128. Main features of HPS installations for open cycle configurations (left) and closed cycle configurations (right) [1].

Greenfield PHS, including dams, have high capital expenditures and a long construction time. If an existing hydro plant is extended to also be a PHS, the investment per installed MW is significantly lower and the construction time varies between 2 and 3 years.

As seen in Figure 129, pumped hydro storage involves a two-step process: pumping water to a higher elevation during periods of low electricity demand and releasing it to generate power during peak demand. This process inherently introduces energy losses. The efficiency of PHS systems typically ranges from 70-85 %, meaning that some energy is lost during the pumping phase and additional losses occur during the generation phase [1]. Despite these losses, PHS remains one of the most efficient large-scale energy storage methods available.

Figure 129. Pumped Hydro cycle efficiency [1].

The primary advantage of PHS lies not in its raw efficiency but in its ability to store excess energy and provide grid stability. By storing energy during off-peak times and releasing it when demand is high, PHS helps balance supply and demand, integrate renewable energy sources, and enhance grid reliability. While less efficient than regular hydropower, PHS provides essential energy storage and flexibility benefits that are crucial for modern energy systems.

15.2. Input

The main energy input for a pumped hydro storage plant is electricity, typically drawn from the grid during off-peak periods when electricity is cheap or abundant (e.g., excess from wind, solar, or nuclear).

15.3. Output

Electricity.

15.4. Typical capacities

PHS facilities are dependent on local geography and currently have capacities up to 1,000 MW. In addition to large variations in capacities PHS is also very diverse regarding characteristics such as the discharge time, which is ranging from several hours to a few days.

15.5. Space requirement

Pumped hydropower storage systems offer a significant advantage in terms of spatial efficiency because they can be integrated into existing reservoir infrastructure without the need for additional space. This approach not only optimizes the use of available land but also reduces the ecological and social impacts of developing new large-scale infrastructure.

However, is the construction of an additional reservoir is required, the space requirement will be dependent on the topography and the desired storage level. The construction of a new reservoir could have adverse social and environmental impact and take up productive land use, as is the case of large-scale hydro.

15.6. Water consumption

Even as pumped hydropower storage systems do not require additional water to that used by the existing hydropower plant they are integrated with, they can pose challenges to downstream water flows, particularly regarding ecological flows.

These systems often manipulate water levels in reservoirs to optimize electricity generation, which can lead to significant fluctuations in water release schedules. Such alterations can disrupt the natural flow regimes that are critical for habitats, aquatic life, and nutrient cycling downstream. Operation of these systems must maintain the ecological flows essential to support the health and biodiversity of riverine environments. These flows ensure that sufficient water remains in rivers to sustain fish populations, riparian vegetation, and overall ecosystem functions.

Furthermore, during periods of high electricity demand or low natural inflow, the water held in upper reservoirs may not be released in adequate amounts, exacerbating water scarcity issues downstream. These impacts require careful management and potentially the integration of adaptive strategies that balance energy production needs with the ecological and water-use requirements of downstream communities and ecosystems.

15.7. Regulation ability and other power system services

The primary intent of PHS is to provide peaking energy each day. However, their duty can be expanded to include ancillary service functions, such as frequency regulation in the generation mode. A variable-speed system design allows providing ancillary service capability in the pumping mode as well, which increases overall plant efficiency [2].

As Hydro Pumped Storage (HPS) installations offer greater flexibility than fixed-speed units, these plants provide additional services within the electrical grid beyond their primary purpose of energy storage, such as:

Peak levelling: An HPS system can be used for peak levelling to meet the highest demands in a short period of time.

Load balancing: Load levelling typically involves storing energy during light load periods (off-peak hours) in the system and delivering it during periods of high demand.

Frequency regulation: It allows maintaining the frequency within given margins through continuous modulation of active power.

Backup reserve, spinning reserve: Reversible plants can provide an additional energy source that can be made available to the transmission system within seconds in case of unexpected load changes on the network.

Flexible and rapid ramps: Advances such as variable-speed turbines can provide flexible ramping capacity, allowing the generator to increase or decrease its output based on changes in net load forecasts. This is how some HPS can reach full load in less than 30 seconds.

Black start capability: These plants can operate with zero loads. When loads increase, additional energy can be rapidly charged.

Voltage support: These plants can control reactive power, thus ensuring that energy flows from generation to load.

It is worth noticing that these services are provided by conventional reservoir hydroelectric plants. However, HPS can additionally absorb energy surpluses (for example, from variable renewable energy - VRE) to meet demand peaks and fluctuations.

15.8. Advantages/disadvantages

The advantage of PHS is the large volumes compared to other storages e.g. various batteries. In addition, PHS does not use fossil fuel such as e.g. compressed-air energy storage.

A disadvantage with PHS is the need for differences in height between the two reservoirs. When a new PHS is not built in connection with an existing hydropower plant there are also environmental concerns in flooding large areas.

PHS are significantly constrained by geographical requirements. These systems necessitate a specific topography characterized by the presence of two large reservoirs at different elevations; this allows for the movement of water between these elevations to generate or store energy.

15.9. Environment

The possible environmental impacts of pumped storage plants have not been systematically assessed but are expected to be small. The water is largely reused, limiting extraction from external water bodies to a minimum. Using existing dams for pumped storage may result in political opportunities and funding for retrofitting devices and new operating rules that reduce previous ecological and social impacts [7]. PHS projects require small land areas, as their reservoirs will in most cases be designed to provide only hours or days of generating capacities.

15.10. Research and development perspectives

In the 1890's PHS was first used in Italy and Switzerland. After over 100 years of development PHS is a mature technology, but there are several developments around the world [1]:

- **Variable speed PHS**: Most existing systems are equipped with fixed-speed pumping turbines and can provide large-scale storage but can only offer frequency regulation during the discharge mode. New variable-speed technology allows facilities to regulate frequency during the pumping process. Japan has been a pioneer in the commercial use of this technology.

- **Saltwater PHS**: Japan was also a pioneer in this system in Okinawa. This plant uses the open sea as the lower reservoir. New projects have been proposed related to this technology, including the project by the Dutch consulting firm (DNV KEMA) that plans to use the sea as the upper reservoir and build a lower one by dredging and constructing a ring of dikes 50 meters below sea level.
- **Underground PHS**: Researchers have proposed the possibility of using underground caverns as lower reservoirs, but so far none have been built.
- **Compressed air PHS**: An innovative design plans to replace the upper reservoir with a pressurized water container. Instead of storing potential energy in elevated water, the proposed system stores energy in compressed air.
- **Submarine PHS**: Another innovative concept is to use the water pressure at the bottom of the sea to store electricity from offshore wind turbines. The system places pressure vessels submerged at the bottom of the sea.

A new (2009) Danish concept is storing electricity as potential energy by elevating sand. The sand is lifted by pumping water into a balloon underneath the sand, and then lowered by taking the water out through the pump, now acting as a turbine.

15.11. Examples of market standard technology

Currently, there are no existing large-scale hydropower storage facilities in Colombia.

However, there is a project under development for non-grid connected communities of La Sierpe and Unión Málaga in Timbiquí, Cauca. The project will use a hydraulic tank storage system integrated with photovoltaic (PV) generation, designed by the company STEPSol- The PV system, with a capacity of 30 kW_p and a daily production of 395 kWh, will supply power directly while also driving a pump to store excess energy in an elevated reservoir with a storage capacity of 160 kWh. The system will operate through a bidirectional, closed-loop hydraulic circuit with a round-trip efficiency of 56 % [6].

15.12. Prediction of performance and cost

According to an analysis for 19 countries where PHS plants were installed between 2003 and 2019 [3], investment costs range from 617 USD/kW to 2,465 USD/kW. Likewise, according to various bibliographic sources [4] the specific costs vary between 500 USD/kW and 1,333 USD/kW for reversible plants with an installed capacity between 58 MW and 2400 MW.

A 2020 study [5] undertook a technical analysis using available data from HPS project licensing applications was conducted. This included high-level analysis based on historical data from various HPS projects, ongoing project cost data, and other global information based on a typical closed-cycle HPS project which resulted in Figure 130. In all project development categories, the upper and lower reservoirs (civil works), along with the generation unit components (equipment) and water transport systems (civil works), account for the largest proportions of the total capital costs. Similarly, the components of the upper and lower reservoirs, water conduits, and transmission interconnections (civil works) require the most time and have the highest potential risk of negatively impacting project completion by causing unexpected cost increases or delays in scheduling.

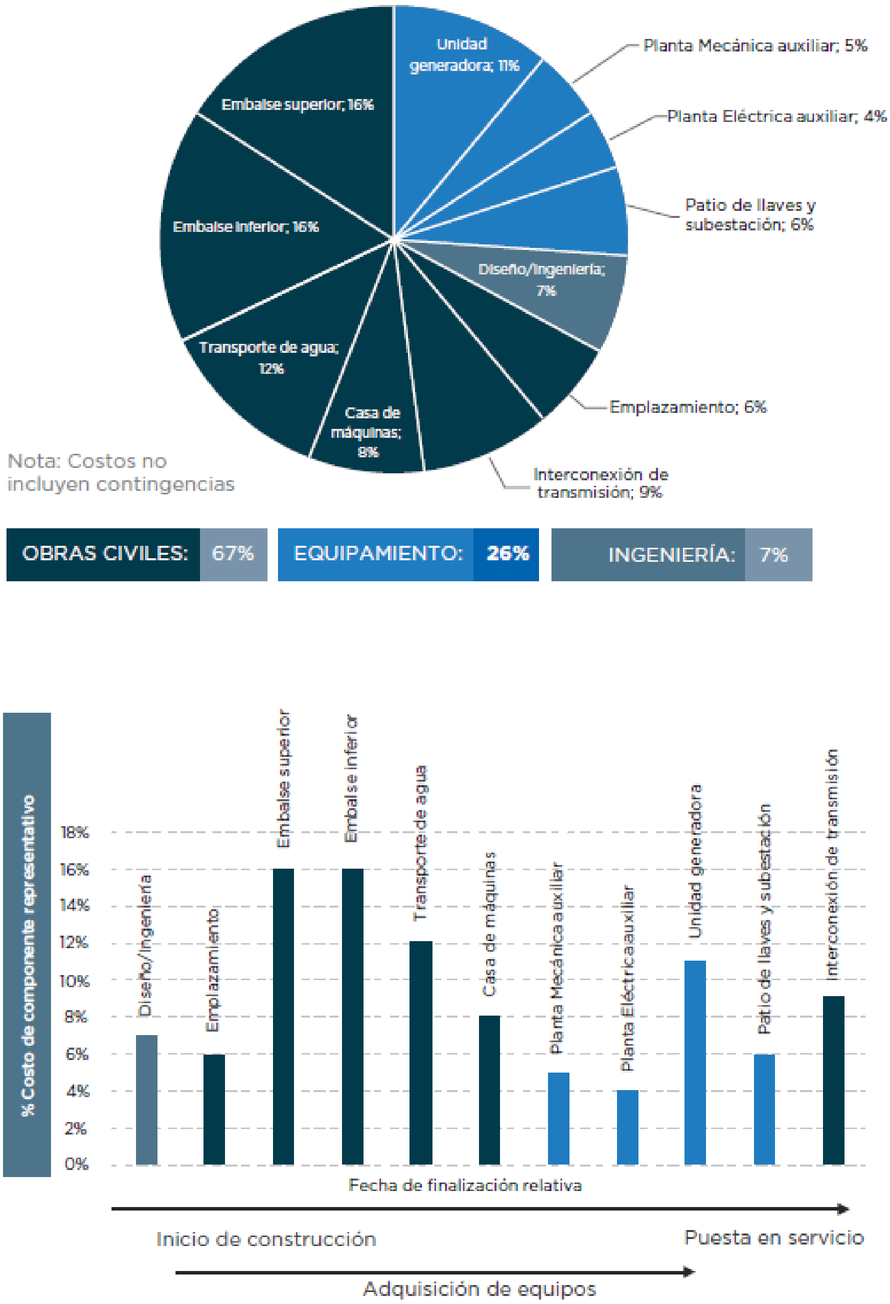

Figure 130. Representative breakdown of the total capital cost for an example of an HPS project (closed cycle) [5].

Table 15-1 presents a comparison of investment costs for power projects, expressed in millions of USD per megawatt ($MUSD_{2024}$/MW), based on different data sources and regions.

Table 15-1. Investment cost comparison across regions for pumped hydro storage projects. The base year for the investment cost is the year the final investment decision (FID) was taken. The values presented in this table have been adjusted for inflation to 2024 values.

Data source	Investment cost [$MUSD_{2024}$/MW]	Base year FID (final investment decision)

This study	1.2	2024
International data		
Technology Catalogue Indonesia (2024)	1.35	2023
Technology Catalogue India (2021)	0.63	2020
Technology Catalogue Vietnam (2023)	1.08	2022

15.13. Additional remarks

There are frequently several hydro power plants on the same river, and the operation of these plants is to some degree interlinked. The benefits of a new PHS therefore depend also on the existing hydropower infrastructure.

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15.15. Datasheet

Technology	Hydro pumped storage - natural reservoirs								
	2024	2030	2050	Uncertainty (2024)		Uncertainty (2050)		Note	Ref
				Lower	Upper	Lower	Upper		

Energy/technical data									
Generating capacity for one unit (MW_e)	250	250	250	100	500	100	500	A	5
Generating capacity for total power plant (MW_e)	1000	1000	1000	100	4000	100	4000		5
Electricity efficiency, net (%), name plate	80	80	80	75	82	75	82		1, 7, 8
Electricity efficiency, net (%), annual average	80	80	80	75	82	75	82		1, 7, 8
Forced outage (%)	4	4	4	2	7	2	7		8
Planned outage (weeks/year)	3	3	3	2	6	2	6		8
Technical lifetime (years)	50	50	50	40	90	40	90		1
Construction time (years)	5	5	5	4	6	4	6	F,G	1
Space requirement (1000 m^2/MW_e)	30	30	30	15	45	15	45	F,G	1
Ramping configurations									
Ramping (% per minute)	50	50	50	10	100	100	100		8, 9
Minimum load (% of full load)	0	0	0	0	0	0	0		9
Warm start-up time (hours)	0.1	0.1	0.1	0	0.3	0.3	0.3		9
Cold start-up time (hours)	0.1	0.1	0.1	0	0.3	0.3	0.3		9
Environment									
PM 2.5 (g/GJ of fuel input)	0	0	0	0	0	0	0		
SO_2 (g/GJ of fuel input)	0	0	0	0	0	0	0		
NO_X (g/GJ of fuel input)	0	0	0	0	0	0	0		
CH_4 (g/GJ of fuel input)	0	0	0	0	0	0	0		
N_2O (g/GJ of fuel input)	0	0	0	0	0	0	0		
Financial data									
Nominal investment ($MUSD/MW_e$)	1.20	1.20	1.19	1.00	1.35	0.99	1.34	B,E,H	1,2
- of which equipment	0.36	0.36	0.36	0.30	0.40	0.30	0.40	B,E,I	1,2,3
- of which installation	0.84	0.84	0.83	0.70	0.94	0.70	0.94	B,E.I	1,2,3
Fixed O&M (USD/MW_e/year)	24,000	24,000	23,800	15,000	33,700	14,900	33,500	C,E	1,4
Variable O&M (USD/MWh)	0	0	0	0.00	0.00	0.00	0.00		
Start-up costs (USD/MW_e/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Size of reservoir (MWh)	10,000	10,000	10,000	3,000	20,000	3,000	20,000	D	1,5,6
Load/unload time (hours)	10	10	10	4	12	4	12	D	1,5,6

Notes

A Size per turbine.

B Numbers are very site sensitive to geographical characteristics. There will be a limited improvement by learning curve development, but best, i.e. cheap locations will be utilized first. The investment largely depends on civil work.

C O&M assumed to be between 1.5% and 2.5%/year in line with [1] with NREL with the central value to be at 2%

D Size of the total plant, not per unit

E Cost 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 2023, with Announced Pledges for the central values and Stated Policies and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.

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

G Space requirements for new sites is highly uncertain given the geographical dependency. Stakeholder input has resulted in the range that is presented here.

H Cost uncertainties in the short and long term indicate the spread of cost based on the examined cases. Cost are highly uncertain given the geographical characteristics.

I Assuming ca. 30% share of cost amounting equipment and 70% amounting installation for large-scale RoR based on stakeholder input

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Appendix. Forecasting the Cost of Electricity Production Technologies

This section replicates the structure used in Appendix 2 of the EREA-DEA Vietnamese Technology Catalogue for power generation technologies 2023 [1], adapting its contents to this study.

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 considered 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 in Table 0-1.

Table 0-1. Advantages and disadvantages of different methodologies for forecasting technology costs [1].

	Advantages	Disadvantages
Engineering bottom-up	• Gives a good understanding of underlying cost-drivers. • Provides insight into 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 overarching logic of learning	• 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

	rates has proved correct for many technologies and sectors. • Data available to perform learning curves for most important technologies.	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 and multi-factor learning curve approaches [2] are 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.

Learning-curve-based cost projections are dependent on two key inputs, once a cost baseline is established: a projection of the technological deployment and an estimated learning rate [2]. 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 this study relies 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 WEO 23 presents three different scenarios, the STEPS, APS and the NZE [3]. For this study, the capacity development from the Announced Pledges Scenario (APS) is used as reference for renewable energy technologies, whose values falls in between the other two IEA scenarios, described in the section *Assumptions for projecting costs into future years*.

Table 0-2 shows the development of accumulated capacities of different electricity generation technologies toward 2050, using 2024 as the starting point (=1).

Table 0-2. Accumulated generation capacities relative to 2024, in the STEPS, APS and NZE scenarios [3].

Accumulated generation capacity relative to 2024 (2024 = 1)	STEPS		APS		NZE	
Technology	2030	2050	2030	2050	2030	2050
Solar PV	2,4	6,5	2,8	8,2	3,1	9,6

Wind onshore	1,7	2,9	2,0	4,2	2,3	5,8
Wind offshore	3,0	8,8	3,5	15,9	4,1	16,8
Hydro	1,1	1,4	1,1	1,6	1,2	1,8
Bioenergy	1,3	2,2	1,7	4,0	1,7	3,9
CSP	2,4	12,3	4,2	42,5	7,0	61,6
Geothermal	1,8	4,2	2,2	6,6	3,2	8,6
Battery storage	6,5	27,7	8,5	36,7	12,0	49,4

Learning rates

Learning rates typically range between 5 and 25 %. Literature studies give an indication of the level of learning rates, which may be expected [2, 3, 4]. Solar PV is associated with higher learning rates, while nuclear and coal power fall on the lower end—or may even show no future learning [2, 3, 4]. The low or negligible learning rates for nuclear and other traditional thermal plants are likely due to increasing external requirements, such as stricter safety standards for nuclear energy and tighter emissions regulations for coal, both of which drive up investment costs.

Considering the uncertainties related to the estimation of learning rates, Table 0-3 outlines learning rates for various energy technologies [3], [5], [6], [7]. For technologies where learning rates were specified for multiple components (e.g., Solar PV, Onshore Wind, Offshore Wind, Battery Energy Storage), a multi-factor learning curve approach was used. For technologies without explicit component breakdowns (e.g., Hydropower, Geothermal, Biomass, Coal, Natural Gas, Waste-to-Energy, and Nuclear), a one-factor learning curve methodology was applied.

When the abovementioned learning rates are combined with the future deployment of the technologies projected in the IEA scenarios, an estimate of the cost development over time can be deduced.

Table 0-3. Learning rates applied in this study based on [3], [5], [6], [7].

One-factor and multi-factor learning rates applied in this study		
Technology	**Component**	**Learning rate**
Solar PV	PV module cost	24 %
	Inverter cost	24 %
	Other costs (Balance of plant)	20 %
	Installation	20 %
	Fixed O&M	10 %
Onshore Wind	Equipment	5 %
	Installation	5 %
	Fixed O&M	6 %
	Variable O&M	6 %
Offshore Wind	Equipment	15 %
	Installation	15 %
	Grid connection	15 %

	Fixed O&M	8 %
	Variable O&M	8 %
Hydropower	-	1 %
Battery Energy Storage	CAPEX - energy component (MUSD/MWh)	17 %
	CAPEX - power component (MUSD/MW)	10 %
	CAPEX - other project costs (MUSD/MWh)	10 %
	Fixed O&M	10 %
	Variable O&M	10 %
Geothermal	-	5 %
Biomass	-	5 %
Coal	-	-
Natural Gas	-	-
Waste-to-Energy	-	-
Nuclear (Large Reactor)	-	-

For traditional thermal technologies, including coal, natural gas, nuclear, and waste-to-energy that are mature technologies without further significant learning potential and no expected significant increase in capacity, a simpler approach is used, typically with a minor improvement rate over time. The specific approach is elaborated in the respective chapter. In contrast, renewable-energy thermal plants such as geothermal and biomass are expected to see moderate cost decreases, with a general learning rate of 5 %. This reflects their established deployment but still allows for some cost improvements over time.

Onshore wind power also has moderate projected cost reductions due to its widespread deployment. Almost all the learning curve studies for wind power focus only on the development of the capital cost of the wind turbines (USD per MW) [4]. At the same time, focus from manufacturers has been dedicated to increasing the capacity of wind turbines (higher full load hours per MW) and therefore the effective cost reduction expressed as levelized cost of electricity (LCOE) generation, is likely to be higher. This trend is likely to prevail in the future.

In some cases, cross-technology learning effects occur. For example, coal and biomass technologies share core components, such as boilers and steam turbines, allowing learning spill-over effects between them. However, because these technologies are already so widely deployed, their accumulated generation capacity has a limited impact on further cost reductions.

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 2024 perspective Colombian prices of some technologies may be higher (or in some cases lower) than international reference values because local expertise is limited. However, as Colombian know-how is built up and technologies are adapted to the Colombian context within the next decade, it is reasonable to assume that cost for these technologies may approach the international level of currently more advanced markets.

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