Università degli Studi di Padova

Dipartimento di Ingegneria Industriale

COMPARATIVE TECHNO-ECONOMIC EVALUATION OF NUCLEAR AND HIGH ENTHALPY GEOTHERMAL ENERGY

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1. Introduction

With the increasing demands of climate change mitigation, energy production has become an important area. Nuclear and geothermal energy can really help the world switch to a future with less pollution.

Nuclear energy comes from inside heavy atoms. When it's working, it doesn't emit a lot of greenhouse gases. That's why it's so important for decreasing carbon emissions and dealing with climate change. Since countries are trying to achieve their decarbonization goals, nuclear power's stability works well with the up-and-down nature of renewable energy like wind and solar.

On the other hand, geothermal energy utilizes heat from under the Earth's surface. People think of it as an energy source that can be kept for a long time. Its low carbon footprint and steady energy production assist the world get away from fossil fuels. Geothermal projects help diversify energy sources, and they also boost the economy and create jobs locally.

Together, geothermal and nuclear energy offer ways to meet energy needs and cut emissions. These two can actually work together.

1.1. Nuclear Energy

Nuclear energy is a non-renewable energy source. It is based on finite resources such as Uranium (U) or Plutonium (Pu). The main isotope used for nuclear reactions is U-235, which is not naturally replenished at the same rate as it is consumed. This is the reason why it is not considered as a renewable resource.

Nuclear energy is energy released form a heavy atom by a process called nuclear fission. In this process, large amounts of energy are released in the form of heat when the nuclei of these atoms split into smaller parts.

The main function of nuclear energy is the generation of electricity. However, it is also used in other fields, for example in medicine for radiotherapy treatments, in laboratories for research or scientific studies, and in submarines or warships where nuclear propulsion reactors are used.

History and current status of nuclear energy

Nuclear energy has improved a lot over last decades. Now, it's a key part of the world's energy supply.

Today there are approximately 439 nuclear reactors in operation in over 30 countries around the world. They produce about 9% of the world's electricity.

As can be seen in Figure 1, the country with the largest number of operational nuclear reactors is the United States, with 94 in operation (connected to the grid). It is followed by China and France, with 58.

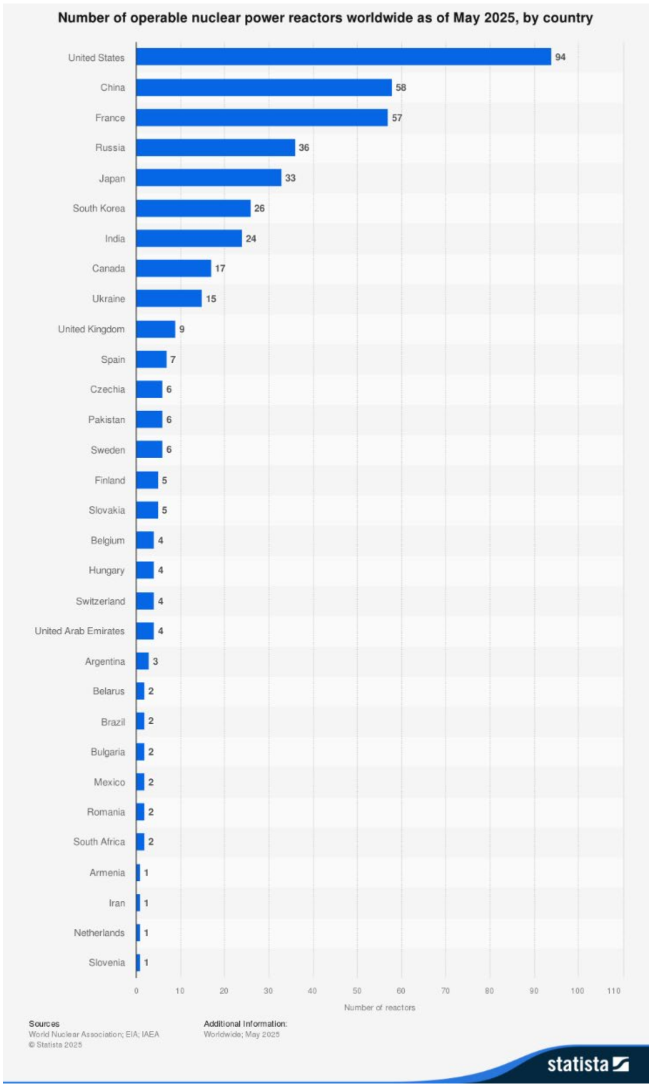

Figure 1. Number of operative nuclear reactors in 2025. Source: Statics

In 1954, they made nuclear fission a commercial product and the first nuclear power plant started up in Obninsk, Russia. The new power was a super steady energy source. As nuclear power plants are only switched off for refuelling every two years approximately, they constitute a permanent “baseload” source of electricity.

This energy source has generated renewed interest in recent years due to de need to reduce carbon emissions and increase energy security. China, India, South Korea, Russia, and Turkey are the leaders in nuclear new build, with 58 units under construction across 18 countries.

In Europe, nuclear energy produces approximately 26% of the European Union's electricity.

However, the continent is divided over its use. While France still wants nuclear power as a key part of its energy plan, other countries like Germany have decided to shut down their nuclear plants, joining Italy and Lithuania in phasing out this energy source.

In 2022, France had issues because of maintenance and weather that affected the reactors, cutting how much they could operate to 40% for about a month.

Italy, on the other hand, has had a complicated history with nuclear energy. In 1987, after the Chernobyl accident, the country decided to abandon nuclear power by referendum, closing the four nuclear plants operating at the time. The last of these plants ceased operation in 1990, and since then, Italy has remained without nuclear power production.

This decision has left the country heavily dependent on energy imports and fossil fuel reserves, which means people pay a lot for energy. In comparison, other countries such as Spain have managed to stabilise energy prices thanks to their use of renewable energy. Because of this situation, there's a lot of talk in Italy about whether they should think about using nuclear energy again to have more energy options and not be so dependent on other countries.

Besides, the war in Ukraine has generated an energy crisis affecting Europe. This is due to the continent's heavy dependence on natural gas from Russia. Sanctions on Russia and the restriction of supply have drastically increased energy prices and highlighted the need to find more secure and sustainable sources. This has highlighted the urgent need to diversify energy sources and accelerate the transition to renewable energy.

In this regard, Italy is rethinking the use of nuclear energy after more than three decades of abandonment. The possible reintroduction of nuclear power is being considered, driven by the need to reduce reliance on fossil fuels, enhance energy security, and achieve climate targets set by the European Union. Although no official decision has been made, political and technical discussions are underway regarding the possibility of reintroducing nuclear energy. They're talking about using newer, safer technology, like Generation III+ reactors and small modular reactors (SMRs), but those are not yet commercially available.

This reconsideration is happening in other parts of Europe too, where several countries are changing their energy plans because of the energy crisis caused by political problems and the need to reduce emissions. But nuclear power is still something people disagree about. Some countries, like France and Finland, still support using it to meet climate and security goals. Other countries, like Germany and Austria, want to stop using nuclear energy because people are worried about it, it's hard to deal with the waste, and there have been accidents in the past. Italy's debate is similar, as they consider energy independence, safety for the planet, and what the public thinks.

NUCLEAR TECHNOLOGIES

The main nuclear technologies currently in commercial operation are Generation III and Generation III+ reactors. Small Modular Reactors (SMRs) are under development and not yet deployed at commercial scale.

The characteristics are the following:

- Generation III and Generation III + reactors:

These are the most advanced nuclear reactor designs currently in commercial operation. Generation III reactors are improvements over earlier Generation II designs, offering enhanced safety, higher efficiency, and longer operating lifespans. Generation III+ reactors further incorporate additional passive safety systems and improved accident resistance.

The main characteristics are:

- Increased safety and efficiency compared to previous generation reactors.
- Incorporate passive safety systems that do not require human intervention or external energy supply.
- Lifetimes of up to 60 years, with the possibility of extension.
- Example of Generation III: ABWR (Advanced Boiling Water Reactor)
- Examples of Generation III+: EPR (European Pressurised Reactor), AP1000 (Westinghouse), VVER-1200 (Rosatom).

This type of Reactors includes Pressurized Water Reactors (PWR) and Boiling Water Reactors (BWR) advanced.

- PWR:

A PWR (Pressurized Water Reactor) is a common type of nuclear plant used for electricity generation. It consists in three different circuits. In the primary circuit is closed and is where are the reactor and the pressurizer. The secondary circuit is also a closed circuit where it can be found the turbines that turn the alternator. The tertiary circuit is opened. Here is where the water is taken from a source (river, sea…) then is pumped to the condensator and then it is returned to the atmosphere (in the form of water vapour).

The purposes of pressurized water in a PWR are:

- Cooling the reactor core
- Transmitting heat to the turbine
- Moderating neutron reactions

The temperatures in a PWR are limited to prevent the coolant from reaching its boiling point. This is the main function of the pressurizer, avoid the primary coolant to boil.

The power is controlled by adjusting the position of the control roads for fast control and changing the concentration of boron into the coolant for slow control.

The function of control roads is to absorb neutrons and to control the reaction rate

The steam generator in the secondary circuit is the responsible od transferring heat from the reactor to the turbine.

The meaning of the burn-up is the total energy released during reactor operations and considering it, the effects due to the formation of fissile material from fertile and the presence of still fissile nuclei in the spent fuel are almost equivalent.

In this circuit:

- The fuel commonly used is Uranium-235.
- The moderator is light water.
- The coolant is pressurized light water.
- The efficiency is 33%.
- The burn up is between 40,000 – 60,000 MWd/tU
- The pressure in the primary circuit is around the 160bars (320ºC)
- The pressure in the secondary circuit is around 65 bars (290ºC)
- The pressures are higher than in BWR because PWR needs avoid boiling water
- The critical temperature of water is 374ºC

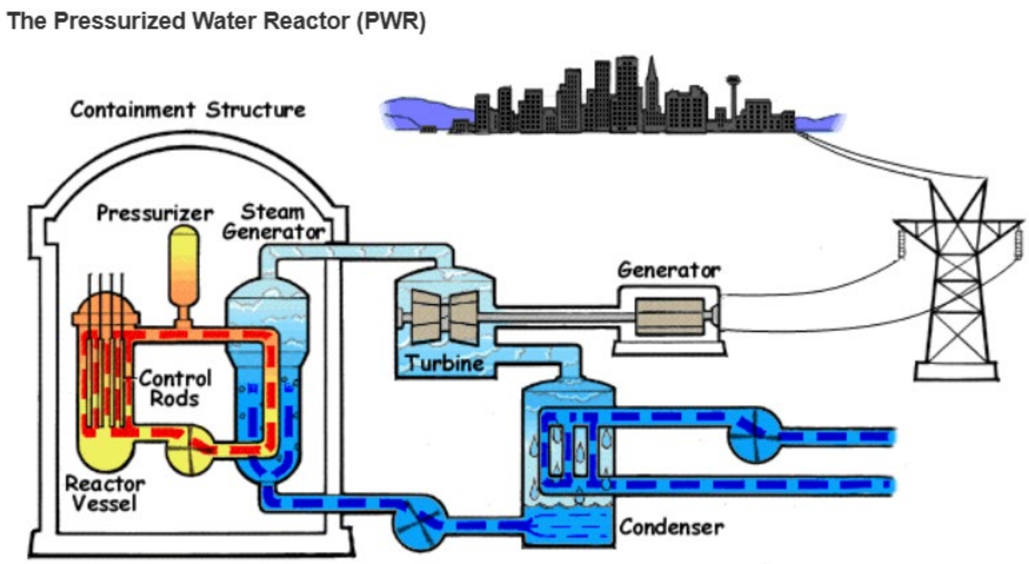

Figure 2. Scheme PWR. Source: U.S.NRC

- BWR:

A BWR (Boiling Water Reactor) is a type of nuclear plant. It is composed by two independent circuits (and a recirculation).

In BWR, the water vapour used in the turbine is generated directly inside the reactor core. For this reason, unlike the PWR, BWR doesn't need a steam generator and a pressurizer. The moderator and the coolant is water.

The steam produced in the reactor core is used to drive the turbine to generate electricity, cool the reactor core and act as a moderator.

The power is controlled with the control rods or with the recirculation flow control.

In this circuit:

- The fuel commonly used is Uranium-235.
- The moderator is light water.
- The coolant is boiling light water.
- The efficiency is 33%.
- The burn-up is between 35,000 – 50,000 MWd/tU
- The reactor pressure is around the 65 bars (285ºC)
- The pressures are lower than in PWR because BWR has boiling water.

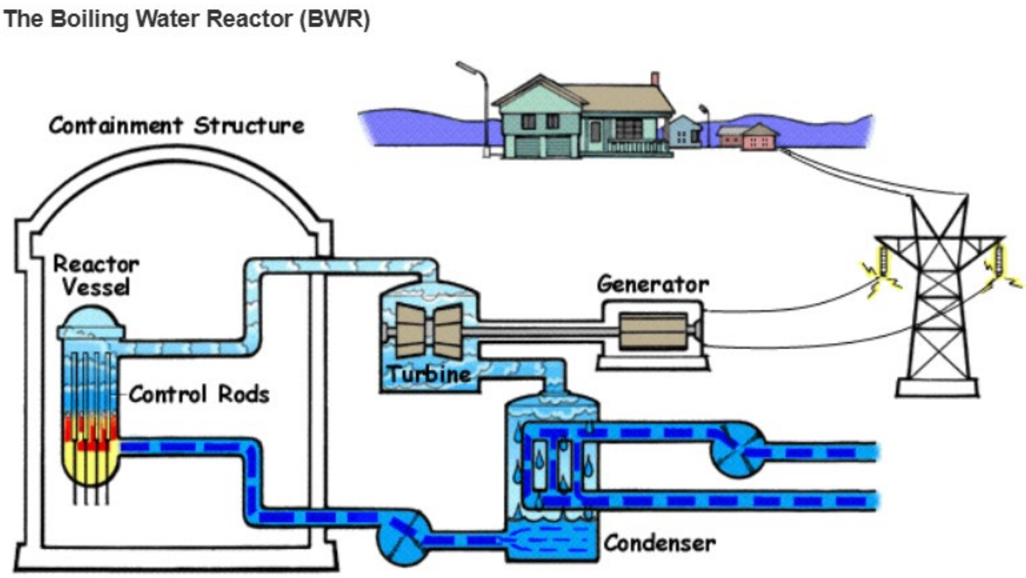

Figure 3.Scheme BWR. Source: U.S.NRC

- Small Modular Reactors (SMR):
  - Generating power <300 MW per unit.
  - Compact and modular design, which allows for faster and more flexible construction.
  - Ideal for remote areas or as a complement to renewables.
  - Example: NuScale SMR (USA).

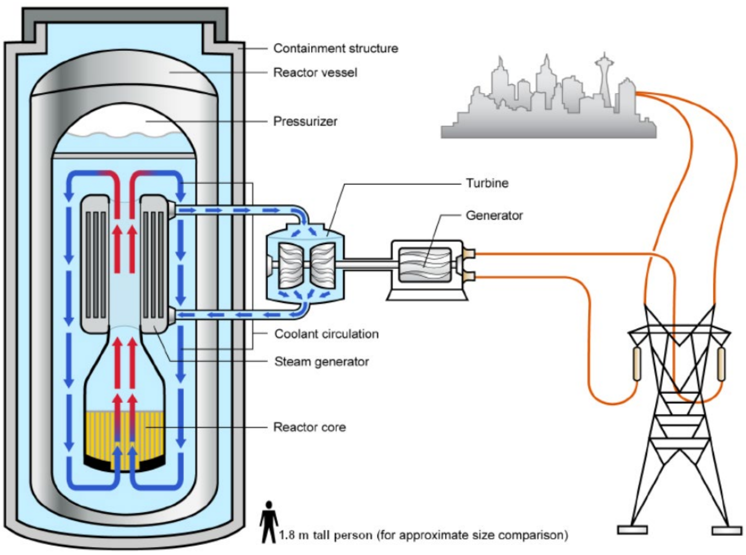

Figure 4. Scheme SMR. Source Wikipedia.

1.1.1. Advantages and disadvantages of Nuclear Energy

1.1.1.1. Advantages of nuclear energy

- Low CO_2 emissions (much less than fossil fuels).
- High energy density (1 kg of uranium generates as much energy as 1,500 tons of coal, making it highly efficient).
- Stable baseload electricity generation (Nuclear plants have a high capacity factor, ensuring reliable electricity supply).
- Reduced dependence on fossil fuels (improving energy security).
- Long plant lifespan (in the reality during 40-60 years, with possible extensions up to 80 years).
- Improved safety measures (Generation III+ and SMR reactors have passive safety systems and improved accident resistance).
- Lower land use compared to other technologies (Requires less land per MWh generated compared to solar or wind power).

1.1.1.2. Disadvantages of nuclear energy

- Radioactive waste management. (The waste remains radioactive for thousands of years, which makes a disposal difficult).
- High capital costs (CapEx). (Building a nuclear plant requires significant investment).
- Long construction time (around 7-15 years to build and commission).
- Potential nuclear accidents. (Though rare, events like Chernobyl and Fukushima have caused public distrust and environmental damage).
- Significant water use for cooling. (For cooling, impacting local ecosystems).
- Public opposition and acceptance challenges. (Many communities oppose new plants due to safety and environmental concerns).
- Risk of nuclear proliferation (Uranium enrichment for civilian use can be misused for weapons, raising geopolitical concerns).

1.1.1.3. Solutions to nuclear energy challenges

- Deep geological waste storage. (Projects like Onkalo in Finland ensure the safe confinement of nuclear waste in stable geological formations).

- New reactor designs with lower waste production. (Fast reactors and molten salt reactors can recycle nuclear fuel, reducing high-level waste).
- Development of Small Modular Reactors (SMRs). (Have lower initial costs, shorter construction times, and enhanced safety features).
- Enhanced passive safety systems. (Generation III+ reactors feature passive safety mechanisms that work without power in emergencies).
- Air-Cooled reactors or coastal locations. (Building plants near oceans or using air cooling reduces freshwater usage).
- Public education and transparency campaigns. (Raising awareness about safety improvements can reduce public opposition).

1.2. Geothermal Energy

Geothermal energy is a form of renewable energy that is obtained from the internal heat of the Earth. This heat is generated mainly by the decay of radioactive elements present within the planet and by the residual heat from the formation of the Earth millions of years ago.

History and present of geothermal energy

Geothermal energy has been used by humans for centuries. The Chinese, Romans and Native Americans are among the civilisations that used hot springs for heating, bathing and cooking. But its application to produce electricity is relatively new.

The first geothermal experiment to generate electricity took place in 1904 in Larderello, Italy, where Prince Piero Ginori Conti powered a light bulb with steam from hot springs. This was the beginning of geothermal energy as an electricity generator. In 1911, the first commercial geothermal power plant was built on the same site, making Italy a pioneer in this technology.

Figure 5. Piero Ginori Conti and his experiment in 1904.

Throughout the 20th century, geothermal energy spread to other countries with developments in Iceland, New Zealand, the United States, Mexico and Japan. Technologies improved to such an extent that many types of geothermal power plants such as dry steam, flash steam and binary cycle plants became viable, allowing conversion to many of the Earth's geothermal resources.

Today, geothermal electricity is a steady and stable source of electricity in most regions of the world. As is can be seen in the Figure 6, in 2024, installed geothermal capacity worldwide exceeded 16 GW, with the United States, Indonesia, the Philippines, Turkey and New Zealand leading the way.

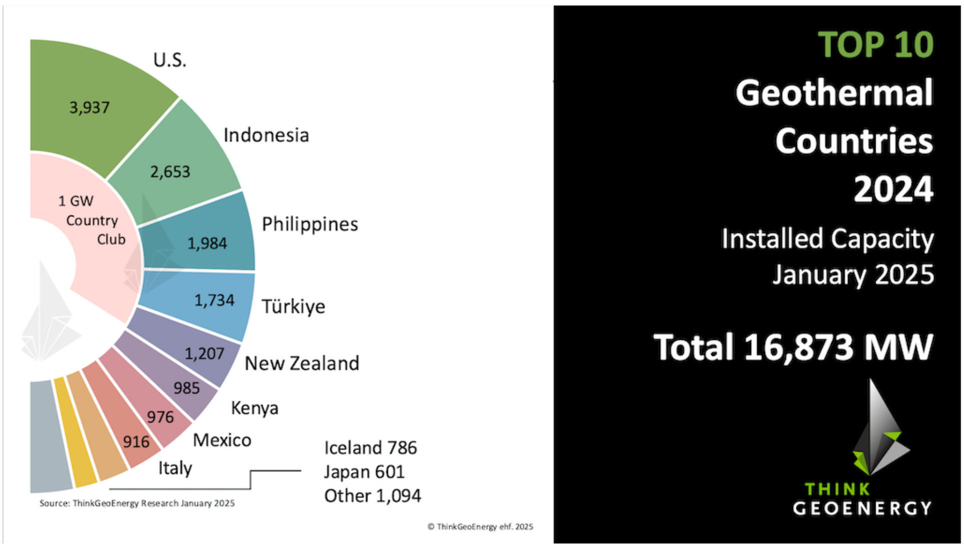

Figure 6. Top 10 leading countries in geothermal energy in 2024. Source Think Geoenergy.

In Europe, geothermal energy is progressively emerging. Iceland is a world leader in that it gets about 30% of its electricity from geothermal and uses geothermal heat for more than 90% of its residential homes. France, Germany and Hungary are promoting deep geothermal proposals for electricity and heat.

The growth of geothermal energy has been boosted by technological advances, such as deep drilling and Enhanced Geothermal Systems (EGS), to utilise the resources of lower natural geothermal areas.

Italy is still very important in terms of geothermal energy, as it was the pioneer country in using this technology for electricity generation. Larderello is still in operation today and remains one of the largest geothermal electricity producing regions in Europe. Geothermal energy accounts for approximately 2% of electricity generation in Italy, with more than 900 MW of installed capacity.

The Italian government is interested in increasing its geothermal capacity to reduce dependence on energy imports and make its electricity system more sustainable. Strict environmental regulations and investments in new technologies are holding back the sector's growth.

Europe, and in particular Italy, has an important historical and current role with geothermal energy. As nations seek clean and stable energy sources, geothermal energy could play a central role in the global energy transformation.

How geothermal energy works:

The heat from the Earth's interior is transferred to the surface through the Earth's crust. In some locations, this heat accumulates, forming geothermal reservoirs that can be exploited for electricity generation or direct thermal uses, such as heating and cooling.

To exploit these reservoirs, wells are drilled into the ground, sometimes over 1.6 kilometres deep, to extract steam or hot water found within the Earth.

Depending on the temperature of the geothermal fluids, there are different types of applications:

- Low-Temperature Geothermal Energy: Fluids below 70°C, utilized in geothermal heat pumps for heating and cooling.
- Medium-Temperature Geothermal Energy: Fluids between 70-150°C, used for heating and industrial processes.
- High-Temperature Geothermal Energy: Fluids above 150°C, primarily used for electricity generation.

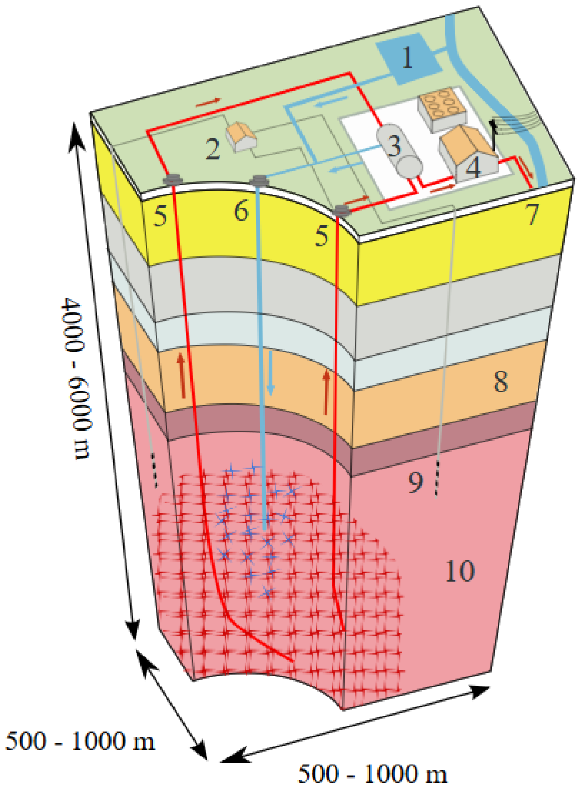

Figure 7. Layers of the Earth.

1. **Surface:** The outermost layer where the geothermal energy access structures are located.
2. **Buildings/Facilities:** Represents installations that use geothermal energy, such as houses or factories.
3. **Piping system:** Piping that transports heat transfer fluid, such as water or steam.

4. **Electricity generator:** Equipment where thermal energy is converted into electrical energy.
5. **Injection zone:** Place where cold water is injected into the ground to be heated.
6. **Hot rock layer:** Stratum where the geothermal heat is located.
7. **Insulation layer:** Material that minimises heat loss.
8. **Cold rock layer:** Less hot stratum that acts as a barrier to heat.
9. **Geothermal reservoir:** Underground area where heat accumulates.
10. **Geothermal heat source:** Deep level where mineral heat is generated.

<u>GEOTHERMAL TECHNOLOGIES</u>

There are some different types of geothermal energy because it is classified according to the temperature of the resource and its application type. There are four main categories:

High-Enthalpy Geothermal Energy

This type of energy comes from resources with temperatures above 150 °C, mainly used for large-scale electricity generation. High-enthalpy reservoirs are typically found in volcanic zones or tectonically active areas, such as Iceland, Italy, or Indonesia.

This are the three main types of high enthalpy geothermal plants.

1. Dry Steam Plants.

These are the oldest geothermal plants and use steam directly from a geothermal reservoir to spin turbines that generate electricity.

This type of plant was the first to be used, starting in Larderello, Italy, in 1904.

One important example is The Geysers in California, which is the largest generator of geothermal electricity generator in the world.

2. Flash Steam Plants

Nowadays this type of plant is the most common. Converts high-pressure geothermal water into steam to power the turbines.

It uses hot water from a geothermal reservoir that, when brought to a lower pressure, "flashes" or rapidly converts to steam. This steam is used to drive a turbine and generate electricity. Flash steam plants are efficient and can extract more energy from the remaining water in a second process.

3. Binary Cycle Plants

Binary cycle plants use a working fluid that is heated through heat exchange with geothermal water. This fluid vaporizes and is used to drive a turbine. This type of plant is especially useful for low-temperature geothermal resources, as it allows for electricity generation without directly releasing steam into the environment.

Medium-Enthalpy Geothermal Energy

Medium-enthalpy resources have temperatures between 90 °C and 150 °C. They are used for electricity generation through binary cycle technology and direct applications such as district heating and industrial processes.

Binary Cycle Plants are the most common technology in this range, using a low-boiling-point fluid to efficiently produce electricity. These resources are more accessible than high-enthalpy ones, as they require less depth.

For example, geothermal plants in Turkey and Japan utilize these resources for both power generation and local heating systems.

Low-Enthalpy Geothermal Energy

Low-enthalpy resources have temperatures below 90 °C. Although they are not suitable for electricity generation, they are ideal for direct applications, such as:

- Heating buildings and district heating networks.
- Greenhouse and fish farm heating.

- Use in spas and thermal baths.

For example, district heating systems in Nordic countries widely use this type of energy to reduce fossil fuel consumption.

Shallow Geothermal Energy (Very Low Enthalpy)

Shallow geothermal energy takes advantage of the constant temperature of the shallow subsurface, which ranges between 10 °C and 30 °C.

It is used with Ground Source Heat Pumps (GSHP) for building climate control, providing heating in winter and cooling in summer.

This type of energy is available almost everywhere, making it a popular option to improve the energy efficiency of residential and commercial buildings.

For example, ground source heat pump systems are common in Central and Northern Europe, where they help reduce conventional energy consumption for heating and cooling.

In the following Table 1 it is possible to see a summary of the types of geothermal energy.

Type	Temperature Range	Applications	Technology Examples	Example Locations
High-Enthalpy	> 150 °C	Large-scale electricity generation	Dry Steam, Flash Steam, Binary Cycle	Italy (Larderello), Iceland, Indonesia
Medium-Enthalpy	90 – 150 °C	Electricity generation, district heating, industrial processes	Binary Cycle	Turkey, Japan
Low-Enthalpy	< 90 °C	Heating, greenhouse and fish farm heating, thermal baths	Direct use (district heating)	Nordic countries
Shallow Geothermal (Very Low)	10 – 30 °C	Building climate control (heating and cooling)	Ground Source Heat Pumps (GSHP)	Central and Northern Europe

Table 1. Types of geothermal energy

In order to achieve a successful geothermal installation, a number of factors need to be met, which will be discussed below:

- High geothermal gradient.

This refers to the rate at which temperature increases with depth. On a global average, it is usually 25-30°C/km. However, to achieve efficient geothermal energy, areas with more than 40°C/km are needed.

A high geothermal gradient allows useful temperatures of 150-300°C to be reached at accessible depths (1-4 km).

These high velocities occur in volcanic regions, tectonic plate boundaries and hot spots.

- Underground heat source.

Ideally, there is recent volcanic activity, near-surface magma or active radiogenesis (a process by which heat is generated in the Earth's interior due to the radioactive decay of elements such as uranium (U), thorium (Th) and potassium-40 (K^{40}) in the rocks of the Earth's mantle and crust).

- Adequate geothermal reservoir.

This refers to the presence of natural aquifers or, if not present, that the ground is permeable rock such as sandstone or limestone, so that Enhanced Geothermal Systems (EGS) can be created.

- Access and drillability.

The ground must be drillable, in other words, it must be rock that is not too hard or abrasive.

Unstable or protected seismic zones may impede development.

- Nearby energy demand.

To minimise energy transport losses and make it economically viable, proximity to centres of consumption is necessary.

- Regulation, social acceptance and financing.

In Europe, many countries have administrative obstacles, little knowledge of the technology, or social rejection due to seismic risk. This is why favourable legislation and support from the local community is necessary.

1.2.1. Advantages and Disadvantages of Geothermal Energy

1.2.1.1. Advantages of geothermal energy

- Renewable and sustainable energy source. (Earth's internal heat is virtually inexhaustible on a human timescale.
- Low CO_2 Emissions. (Much lower than coal or natural gas).
- High efficiency and baseload capability. (Geothermal systems have capacity factors of 75-95%, ensuring continuous power supply).
- Versatile applications. (Can be used for electricity generation, heating, and cooling).
- Minimal land footprint. (Requires less space compared to solar or wind energy per unit of generated electricity).
- Energy independence. (Doesn't rely on fossil fuel imports, enhancing energy security).
- Lower impact on wildlife. (Unlike wind or hydropower, geothermal plants have a lesser effect on local wildlife).

1.2.1.2. Disadvantages of geothermal energy

- Limited geographical availability. (Only viable in areas with high geothermal activity, such as the Pacific Ring of Fire or Iceland).
- High initial investment costs. (Drilling and exploration can account for up to 50% of total project costs).
- Resource depletion risk. (If not managed properly, a geothermal field may lose efficiency over time).
- Emission of Non-Condensable gases. (Some plants release small amounts of hydrogen sulfide (H_2S), methane, and other gases).
- Risk of induced seismicity. (Fluid injection into the subsurface can trigger minor earthquakes in some areas).

- Challenges in large-scale expansion. (Unlike solar or wind, increasing geothermal capacity requires additional drilling, which is costly).
- Potential groundwater contamination. (Without proper management, geothermal fluids may affect nearby aquifers).

1.2.1.3. Solutions to geothermal energy challenges

- Development of Enhanced Geothermal Systems (EGS). (Allows geothermal energy generation in non-traditional locations, expanding feasibility).
- Optimization of drilling techniques. (Directional drilling and advanced materials help lower costs and improve efficiency).
- Reinjection of geothermal fluids. (Maintains reservoir pressure and minimizes resource depletion).
- Capture and treatment of non-condensable gases. (Advanced technologies enable CO_2 and H_2S capture and reuse to reduce emissions).
- Seismic monitoring and careful planning. (Implementing early warning systems and fluid injection management reduces the risk of induced seismicity).
- Expansion of low and medium-temperature geothermal projects. (Enables efficient use of Earth's heat for heating and cooling, not just electricity generation).
- Strict Environmental Regulation and Water Quality Control. (Proper monitoring and management prevent groundwater contamination).

2. Metodology

2.1. Technical indicators

2.1.1. Capacity factor (%)

The capacity factor measures how consistently a power plant operates relative to its maximum potential. It is defined as the ratio between the actual electricity produced over a certain period (typically a year) and the electricity the plant would have produced if it had operated at full capacity during that time. A high capacity factor indicates stable, continuous operation, which is typical for baseload power sources like nuclear and geothermal energy.

2.1.2. Plant lifespan (years)

This indicator refers to the expected duration of the plant's operational phase before major refurbishment or decommissioning is required. The plant lifespan affects long-term economic performance, waste management, and decommissioning planning.

2.1.3. Construction time (years)

Construction time represents the period required to build, test, and connect the plant to the grid, from the initial ground phase to commercial operation. It includes site preparation, equipment installation, and commissioning phases. Longer construction times can increase financial risk and project costs, especially for capital-intensive technologies like nuclear power.

2.1.4. Power output (MW)

This is the net electric power the plant can deliver to the grid under normal operating conditions. It represents the usable capacity available for electricity supply after accounting for internal consumption and auxiliary systems.

2.2. Economic indicators

2.2.1. Capital Expenditure (CapEx)

CAPEX is a parameter that represents the initial investment required for the construction and installation of a power plant.

This investment includes design and engineering costs, the purchase of the necessary equipment (such as turbines and generators), civil works and assembly, associated infrastructures (electrical connections, access, etc.) and financial costs during construction (insurance, interest, etc.).

It is expressed per installed kilowatt (€/kW or USD/kW). High CAPEX is typical of technologies that require significant infrastructure, such as nuclear or deep geothermal plants.

In addition, in this project, the CAPEX values used for each nuclear power plant also include the costs of decommissioning and waste management, in accordance with the methodology followed in the main international reports.

In geothermal projects, CAPEX also includes a significant portion of underground exploration and drilling, which can represent more than 40% of the total cost. This includes geological studies, drilling of production and injection wells, well stimulation (in EGS systems), and reservoir characterization. Decommissioning costs are also included, although in geothermal, these are typically lower than in nuclear.

2.2.2. Operational Expenditure (OpEx)

OPEX represents the operating and maintenance costs incurred on a recurring basis over the lifetime of the plant. This parameter includes all costs necessary to ensure the continuous and safe operation of the plant.

These expenses include routine maintenance of equipment, costs of personnel and labour, materials, technical inspections, insurance during operation, and fuel costs and waste storage.

In the case of nuclear power plants, a distinction is usually made between operation and maintenance costs (O&M) and fuel cycle costs (fuel costs).

Unlike nuclear energy, geothermal plants do not require external fuel (such as gas, or in the case of nuclear plants, uranium), so the value of this parameter is practically linked to the cost of technical maintenance and management of the geothermal resource. In the case of EGS systems, these may include costs related to reinjection or stimulation of wells, as well as the loss of reservoir performance over time.

2.2.3. Levelized Cost Of Electricity (LCOE)

The LCOE is a method used in the evaluation of energy projects that allows the calculation of a figure representing the average cost of generating each megawatt hour (MWh) over the entire lifetime of the plant. It is calculated by dividing the total cost of generating electricity over the lifetime of a plant by the total amount of energy generated over that time.

With this parameter it is possible to objectively compare different technologies as it takes into account different parameters such as initial costs, operation and maintenance costs, fuel, financial costs and decommissioning, independently of whether the plant is solar, wind, nuclear, geothermal, etc.

The LCOE is used to:

- Assess the economic viability of a plant. This indicator makes it possible to determine if a project is economically profitable or not.
- Comparison between different energy technologies.
- Determine the selling prices of electricity. With the LCOE, more competitive prices can be established.
- Energy policy. Because thanks to the LCOE, governments can decide which technologies to promote.

The lower the LCOE, the more competitive the plant will be, as it can offer electricity at a lower price without compromising profitability.

The equation to be followed in this analysis is the following:

$$LCOE = \frac{CAPEX \cdot CRF + OPEX}{Annual\ electricity\ production}$$

Being:

- CAPEX = Capital Expenditures (billion USD).
- OPEX = Operational Expenditures (billion USD).

- Annual Electricity Production = Amount of net electric power generated by the plant in a year (MWh/year)
- CRF = Capital Recovery Factor, which depends on the discount rate (r) and the years of lifetime of the central (n). It is calculated as:

$$CRF = \frac{r \cdot (1+r)^n}{(1+r)^n - 1}$$

To estimate the LCOE, this study applies the Capital Recovery Factor (CRF). This parameter is a financial ratio used to convert an initial capital investment (CAPEX) into an equivalent annualized payment over the life of a project, taking into account the time value of money meaning that money spent today is worth more than the same amount spent or earned in the future.

Therefore, the CRF has two main objectives in the calculation of the LCOE:

- It spreads the cost of capital over the useful life of the asset.
- It applies interest to reflect that future payments have less value than present payments.

For example, if a plant costs a lot to build (high CAPEX) but lasts a long time (like a nuclear or geothermal plant), the yearly cost will look lower if the discount rate is low. This is because we value those future years more. Conversely, if the discount rate is high, those future years matter less, making the initial cost (CAPEX) seem more expensive each year.

The CRF increases with higher discount rates, because investors expect higher returns, which makes annualized capital recovery more expensive.

The discount rate shows the opportunity cost of investing the money somewhere else. It includes parameters like inflation, how risky the project is, and what's happening in the market. Basically, it tells us how much less future costs and income are worth compared to today.

Higher discount rates indicate greater financial risk or uncertainty and increase the weight of upfront CAPEX in the LCOE. This makes technologies with high initial costs (like nuclear or geothermal) seem more expensive. Conversely, lower discount rates reflect stable, low-risk environments and reduce the relative impact of CAPEX in the final LCOE figure.

2.3. Environmental indicators

2.3.1. CO_2 emissions (g CO_2/kWh)

This indicator quantifies the direct carbon dioxide emissions produced per kilowatt-hour of electricity generated. Both nuclear and geothermal plants have very low operational CO_2 emissions compared to fossil-fuel power plants, making them attractive for low-carbon energy strategies.

2.3.2. Other emissions

This refers to the release of gases other than CO_2 during plant operation. In geothermal plants, small amounts of non-condensable gases such as hydrogen sulfide (H_2S) and methane (CH_4) may be emitted, depending on the resource. Nuclear plants have no such emissions during normal operation.

2.3.3. Land requirement (m^2/MW or km^2/MWh)

Land requirement indicates the physical footprint of the plant and associated infrastructure relative to its installed capacity. It provides insight into land-use efficiency and potential environmental or societal impacts, such as habitat disruption.

2.3.4. Water consumption

Water consumption represents the volume of water used for cooling, steam generation, or reinjection (in geothermal systems) per unit of electricity produced. This is an important factor in regions with water scarcity or environmental constraints.

2.3.5. Waste generation

This indicator measures the type and amount of waste produced during operation. Nuclear plants produce radioactive waste that requires long-term management and secure disposal. Geothermal plants can produce mineral precipitates, such as silica or salts, which need appropriate handling to avoid environmental contamination.

3. Case Studies

3.1. Nuclear Projects

3.1.1. Hinkley Point C (United Kingdom)

The Hinkley Point C (HPC) nuclear power station, located in the south-west of England in Somerset.

It has been chosen to study in the present project because is currently the largest nuclear power project under construction in Europe, with a total installed capacity of 3,260 MW from two EPR units. It represents a strategic milestone for the UK nuclear revival as it is the only new plant in the UK since the 1990s.

There is also other Hinkley Point A and B power stations.

On the one hand, Hinkley Point A was one of the first nuclear power stations in the UK. It consisted of two Magnox type reactors, a first generation technology, developed in the 1950s and 1960s. The capacity of each reactor was 235MW (2 x 235MW in total). It started operating in 1965 and after 35 years of operation, it closed in 2000 due to the end of the reactors' lifetime. In addition to the end of their useful life, they became inefficient compared to more modern technologies.

In contrast, Hinkley Point B used more modern AGR (Advanced Gas-cooled Reactor) reactors which, by operating at higher temperatures, improved thermal efficiency. It consisted of two reactors of 660MW each (2 x 660MW in total). The plant began operations in 1976 and after 46 years in operation, it was closed in 2022 due to the deterioration of the graphite moderator, which affects the safety of the reactor structure. Similarly, maintenance costs increased at the same time as safety assessments by the Office for Nuclear Regulation became more stringent.

Both plants used carbon dioxide as a coolant and graphite as a moderator and are currently undergoing decommissioning, which involves the safe disposal of radioactive materials and the restoration of the site for other uses.

On the other hand, a more detailed explanation will be given on the Hinkley Point C nuclear power plant. It uses third-generation EPR (European Pressurised Reactor) reactors. It consists of two bigger generators of 1.63GW (giving a total installed capacity of 3.26GW). The technology of these reactors is PWR.

The energy it has expected to create should be enough to power around 6 million homes in the UK.

Cooling is carried out by an open-circuit seawater cooling system. The seawater cools the steam passing through the turbines before returning to the sea.

More specifically. It consists of taking water from the sea through two underwater tunnels of 3.3 km each. The water passes through the turbine condensers, cooling the steam that the turbines have moved and turning it back into liquid water. After having absorbed the heat, the water is returned to the sea through other tunnels. This water will be returned to the sea at a higher temperature, but always respecting the regulated environmental limits.

In this way, and thanks to its coastal location (as can be seen in the Figure 8), this plant does not need to use cooling towers. This provides high efficiency as well as a lower visual impact.

Figure 8. Location of Hinkley Point C.

Figure 9. Hinkley Point C in construction

This is one of the most complex projects in Europe. It has a large network of suppliers helping it out. These include EDF (France), who is the main operator and developer, CGN (China General Nuclear), who is a financial partner, Framatome (France), who is providing the main nuclear system and the EPR reactor design, and GE Steam Power (USA/France), who is supplying the Arabelle steam turbine system.

3.1.2. Flamanville 3 (France)

Flamanville 3 nuclear power plant is located in Flamanville, a municipality in northern France, in the Lower Normandy region.

This plant is a PWR type plant and was the first to use EPR type reactors, making it one of the most important projects in Europe.

Preceding this installation are the Flamanville 1 and 2 plants, also of PWR technology, but their reactor model is P4 REP 1300, which predates the EPR. Flamanville 1 began construction in 1979 and 2 in 1980, just one year later, just as both were connected to the electricity grid 6 years later, in 1985 and 1986, respectively.

Both plants generate a net power of 1,330MW. They are scheduled to operate for 51 years with Flamanville 1 scheduled to close in 2036 and Flamanville 2 in 2037.

Figure 10. Flamanville 1, 2 and 3.

Focusing on Flamanville 3, which is the most current, as mentioned above, it is PWR, it has implemented the first reactor of the EPR model, with a net power of 1.65GW. It has the capacity to supply around 1.6 million homes in France.

The technology of these EPR reactors is third generation and aims to improve reliability and reduce the risk of incidents compared to previous generation reactors.

3.1.3. Vogtle Units 3 & 4 (United States of America)

Vogtle nuclear power plant consist of Units 1, 2, 3 and 4.

It is located in the state of Georgia (USA) and is one of the most important nuclear power plants in the country.

Units 1 and 2 have been in operation since the 1980s, while Units 3 and 4 are newly constructed.

The first two units have Westinghouse 4-loop reactors. They are second-generation PWR technologies. Each unit has a 1.215 MW reactor, giving a total of 2.430 MW.

Unit 1 started operation in 1987, while Unit 2 started two years later, in 1989. Both had a 40-year operating licence, but as both plants were in favourable compliance with the established technical and safety requirements, in addition to regular equipment upgrades, and continued to be of high strategic and economic value, the US Nuclear Regulatory Commission (NRC) granted both plants an additional 20 years of operating licence. The lifetime of Unit 1 is therefore expected to be until 2047 and Unit 2 until 2049.

All four units share a common security infrastructure. In addition, as can be seen in the Figure 11, all four also have a cooling tower cooling system, although those in Units 3 and 4 are more efficient. They use water from the Savannah River to cool the system.

Figure 11. Vogtle Units 1, 2, 3 and 4.

Tower cooling involves taking water from the river using pumps and pipes.

The reactor heats the pressurised water that circulates inside the closed circuit. In turn, the water circulating in the secondary circuit is heated in the steam generator until it evaporates. This steam is driven by the turbines to generate electricity. The steam is then condensed by heat exchangers using cold water from the circulation system. The resulting hot water is then cooled in the cooling towers by heat exchange with the rising air. Once the water has cooled, it is collected at the base of the tower for recirculation and repetition of the process. However, as the hot water is in contact with the air in the cooling towers, some of this water is evaporated, forming visible clouds on the towers. This loss is compensated by new water extracted from the river.

Current Units 1 and 2 have already been discussed. However, it is important to study in more depth the recent Units 3 and 4.

Each of these Units uses a Westinghouse AP1000 type Generation III+ reactor. Each of these reactors generates approximately 1,117 MW (between the two reactors, they generate 2,234 MW). These facilities were the first to implement this reactor model in the United States.

Although these reactors are also pressurised water reactors, they are not as technologically advanced as EPRs. EPR reactors also have a higher electrical generating capacity and more advanced safety. However, they are much more expensive and suffered significant delays compared to AP1000 reactors, although these have also had cost overruns.

3.1.4. Taishan Units 1 & 2 (China)

Taishan nuclear power plant is located in southern China, in the city of Taishan in Guangdong province.

This is the first EPR plant to operate commercially in the world (in 2018).

This plant is also a PWR plant with two EPR reactors (Taishan 1 and 2). Each has a net capacity of 1.660 MW, giving a total of 3.320 MW. With this capacity, it is able to supply approximately 5 million Chinese homes.

Taishan 1 and 2 are a rare example of fully operational EPR reactors. Their successful deployment in China contrasts with the delays in European projects and provides valuable benchmarks for estimating actual capacity factors and operational performance.

In this case and as can be seen in the Figure 12 thanks to the coastal location, the plant is cooled by open-circuit seawater, so it does not need cooling towers either.

Figure 12. Taishan 1 and 2.

3.2. Geothermal projects

Historically, geothermal energy has been limited to regions with large natural heat flows, permeable rock formations and existing reservoirs of geothermal fluids. However, as the demand for low-carbon and dispatchable energy grows, new technological solutions are emerging to overcome these geological constraints. This section begins with a detailed description of enhanced geothermal systems (EGS), a promising solution to unlock geothermal potential in previously inaccessible regions. Subsequently, key experimental and conceptual projects-such as Project Red, FORGE, and Quaise Energy-are presented to illustrate the technological frontier of geothermal development.

EGS (Enhanced Geothermal Systems)

EGS is an evolution of traditional geothermal energy, developed as a solution to the problem of the lack of geothermal fluids and natural fractures in many promising but technically inaccessible geothermal regions. Its objective is to take advantage of the large volumes of dry and compact hot rock available in the subsoil, especially in areas without natural geothermal aquifers.

In order to implement this technology, the first step is to find the right location. For this, hot rocks must exist at depths between 3 and 10 km with temperatures above 150°C and geological conditions that allow fracturing of the rocks. Once the site has been identified using tools such as seismic images, geophysical surveys and 3D geological models, the drilling of boreholes proceeds.

Two main wells will be required, one injection well and one production well.

After drilling the injection well and casing it with steel pipes and cement to prevent leaks, hydraulic fracturing (also called 'fracking') begins, which consists of injecting a fluid composed of 90-95% water, 5-9% sand or particles that keep open the fractures created in the rocks and around 1% of chemical additives designed to reduce friction, prevent corrosion, and improve stimulation efficiency. The pressure exerted by this fluid is high enough to overcome the resistance of the rocks, creating small fractures within them. These fractures allow the cold injected water to flow through the hot rocks, absorbing their heat. The injection is then stopped and some of the fluid is allowed to return to the surface (flowback fluid).

The return is carried out by the production borehole, also cased with pipes. The flowback fluid, which will contain water and/or steam, dissolved minerals from the rocks and traces of the chemical additives, will rise naturally due to the pressure generated in the subsurface, although in certain cases additional pumps are also used to facilitate the flow. Once it has reached the surface, the hot water or steam will be treated to improve system efficiency, ensure sustainability, comply with regulations, protect equipment and prevent long-term problems.

Once we have the treated fluid, it is directed to the geothermal plant where the energy will be produced.

If the treated fluid is hot water, it will be directed to a plant whose power generation system is flash, double flash or binary cycle. However, if it is steam, it will go directly to the turbines of the geothermal plant.

Finally, once the electricity has been generated, the fluid is cooled to cold water that will be recirculated through the injection well to restart the process and thus form a closed-loop system that ensures sustainability and long-term resource efficiency, significantly reducing the need for freshwater withdrawals and minimizing environmental impact.

This technology has certain associated risks that must be carefully managed.

- Induced seismicity.

Hydraulic stimulation can generate microseisms (small earthquakes) due to the fracturing of rocks in the subsurface. In extreme cases, they can be felt at the surface or cause structural damage if not properly controlled.

Although the probability ranges from moderate to high, the impact is low to moderate and would only be high if it occurred near urban areas or critical infrastructure.

It is one of the most studied and debated risks as it generates public concern and opposition to the project.

This risk can be reduced or avoided through real-time seismic monitoring, pressure controls, good site selection, and establishing rapid response protocols in case of significant seismic events.

- Aquifer contamination.

If the well casing fails, the injected fluid can leak into subway aquifers, contaminating drinking water sources.

If the wells are well designed, the probability of this risk is low, although with a high impact.

This is a critical risk that can have serious consequences on public health and the environment, as well as legal problems and damage the reputation of the project.

It can be reduced or avoided through good well casing, regular monitoring of water quality and good management and treatment of fluids.

- Water consumption.

To carry out fracking and continuous operation, large quantities of water are required.

This could become a high probability risk in arid or water-scarce areas. Its impact would be moderate since it may generate conflicts with other water uses, such as agriculture or human consumption.

This risk is important in terms of sustainability and social acceptance of the project.

To reduce this risk, water is reused thanks to treatment prior to recirculation, non-potable water is also used, as well as systems that optimize the amount of water required for the operation.

- Corrosion and clogging of equipment.

The geothermal fluid may contain dissolved minerals and corrosive gases (such as carbon dioxide or hydrogen sulfide) that damage plant piping and equipment.

The likelihood is moderate, but the impact ranges from moderate to high, as it can increase maintenance costs and reduce equipment life.

It is a risk that directly affects the economic viability of the project.

The treatment of the fluid, the use of resistant materials and preventive maintenance can reduce this risk.

- Environmental and social impact.

EGS projects can generate environmental impacts (such as landscape alterations) and social impacts (such as opposition from local communities).

Depending on the location and design of the project, the probability will be moderate, generating a moderate to high impact, as it may delay or even stop the project due to social conflicts or environmental regulations.

It is a key risk for the acceptance and success of the project.

To reduce it, transparency and involvement of local communities is needed from the early stages of the project, environmental impact studies can identify and mitigate potential impacts, and good sustainable design will also minimize the environmental footprint of the project through sustainable practices.

The first version of EGS technology, called Hot Dry Rock, emerged in the 1970s and continued to be developed through various pilot projects. However, it was not until 2021 that a project capable of achieving viable commercial production with EGS technology emerged.

One of the first real-world applications to demonstrate the commercial potential of EGS technology is Project Red, part of a partnership between Fervo Energy and Google.

Project Red, Fervo Energy and Google

Project Red is a 3.5 MW geothermal power pilot project. It is located in the United States, in northern Nevada.

Fervo Energy is the company responsible for the technical development of the project. It has been in charge of carrying out the design, drilling and operation, achieving a breakthrough in EGS technology that has led to clearly satisfactory results in the production of continuous geothermal energy.

Fervo delivers clean energy directly to Google, a client and co-supplier, which has a Power Purchase Agreement (PPA) with Fervo. They provide partial financing for the pilot project and technical support. Google purchases the 100% carbon-free electricity generated to power its data centres in Nevada. In this way it promotes its goal of being 100% carbon-free 24/7 by 2030 and publicly supports geothermal as a good climate solution.

As for the financial aspects, they have not been publicly disclosed.

This project has been very important as it is the first commercial EGS project to show economic and technical feasibility. In addition, the initial investment and demand secured by Google is critical for modern geothermal to accelerate.

Following the success of this pilot project, Fervo is determined to continue with the development of the 400 MW geothermal Cape Station project in the United States.

Although Project Red demonstrates that commercial EGS is within reach, further research and controlled experiments are essential to refine subsurface modelling, well stimulation and reservoir management. In this context, the US Department of Energy has created the FORGE project, a specific test bed to advance EGS research.

FORGE (Frontier Observatory for Research in Geothermal Energy) (USA)

The FORGE project is a pioneering initiative in the development of EGS.

It is located in Milford, Utah, in the United States. It is managed by the Energy and Geoscience Institute at the University of Utah and is funded by the US Department Of Energy (DOE).

In 2014, DOE announces its intention to establish a dedicated EGS laboratory, but it is not until 2018 that the site (Milford) is chosen and has funding of $140 million. Between 2020 and 2023, drilling and well stimulation takes place. In 2024, the DOE grants an extra $80 million to extend the project until 2028.

FORGE aims to establish a replicable model for large-scale EGS deployment to be able to meet up to 8.5% of US electricity demand with geothermal energy by 2050.

While EGS projects attempt to create artificial reservoirs at depths of up to 5 km, other disruptive technologies aim to reach even deeper, beyond 10 or even 20 km, to reach areas of superheated rock where geothermal efficiency could rival or exceed that of fossil fuels. One of the most promising innovations in this field is being developed by Quaise Energy.

Quaise Energy's millimetre wave drilling technology

Quaise Energy is an energy technology start-up. It was founded in 2018 as a spin-off from the Massachusetts Institute of Technology (MIT) and is headquartered in Cambridge, Massachusetts. It aims to bring about the geothermal energy revolution by developing innovative drilling technology that accesses the Earth's deep heat sources at depths of between 3 and 20 km, where temperatures reach ‘superhot’ levels of over 400°C.

They use millimetre wave drilling technology. This is achieved using a device called a gyrotron, which emits high-power millimetre waves at frequencies ranging from 30 to 300 GHz. These vaporise the rock instead of mechanically drilling into it.

The gyrotron was already used in nuclear power to heat plasma to extremely high temperatures and control its stability by injecting directed waves. What Quaise Energy has done is to adapt this technology to reach rock depths of up to 20 km where the temperature can exceed 400°C, which will make it possible to generate electricity with very high thermal efficiency.

Quaise Energy has several flagship projects to demonstrate the commercial viability of its technology. Among them is the conversion of the TS Power Plant fossil power plant in Nevada, which it is carrying out in collaboration with Nevada Gold Mines. This project aims to replace the use of fossil fuels with deep geothermal steam, taking advantage of the plant's existing infrastructure.

Gyrotron drilling tests began in 2021 at Oak Ridge National Laboratory, but it is in 2024 that the first but still controlled field drilling of approximately 1 km begins, and in 2025 the first actual field drilling has taken place, formally starting the pilot project.

Further testing of the power generation pilot project is planned, for which Google has signed an agreement with Quaise Energy to test its technology in some of its data centres. If the current pilot project (from 2024 - 2025) works, deep geothermal energy could be used as a clean and constant source of energy.

Although still in the pilot phase, this technology could radically transform geothermal potential worldwide by enabling access to superhot rock almost anywhere on the planet, thereby offering a scalable, carbon-free baseload alternative to fossil fuels

This would bring many advantages:

- Access to deep geothermal energy would be possible anywhere in the world (not only in regions with volcanic activity).
- Clean and permanent baseload would be achieved (no need for storage or fossil back-up).
- Drastic CAPEX reduction in the medium term, as drilling beyond 5km is currently slow, expensive and risky.
- Acceleration of global decarbonization.

3.2.1. Hellisheiði (Iceland)

The Hellisheidi geothermal power plant is located in the Hengill region of southwest Iceland, near Reykjavíc.

The technology used is a double flash steam system combined with binary cycle, which allows for greater efficiency in the extraction and utilization of energy from the geothermal fluid.

What does the double flash steam system consist of?

Starting from the beginning, depending on where the power plant will be located, there will be natural geothermal aquifers where there is hot water or high pressure steam in a liquid and/or gaseous state, or there may not be. The first is the case here in Iceland. However, as in places like France or Germany, these aquifers do not exist, so hot water cannot be extracted directly from the centre of the Earth, which is why EGS (Enhanced Geothermal System) technology has been developed, which consists of injecting cold water from the surface at high pressure to keep it in a liquid state and thus heat it with the heat of the Earth's interior.

As there are natural geothermal aquifers in Iceland, the process begins with the extraction of geothermal fluid (a mixture of hot water and steam) from these permeable and naturally pressurized underground reservoirs. This water can be between 200°C and 300°C and is usually 2 to 3 km deep, so it is at a sufficiently high pressure to remain liquid, although a two-phase mix of water and vapour is the most common. This geothermal fluid is extracted by wells up to 2.5 or 3km. As it rises, the fluid gradually loses pressure, but the pressure is not allowed to drop completely on the way up. This fluid is led to a pressure separator where a first controlled depressurisation takes place. This separator will be the high pressure separator, which causes a sudden drop in pressure. What causes this drop is that part of the liquid water evaporates all at once, which is called the ‘first flash’. This resulting dry steam is fed to the high-pressure turbine to produce electricity, and the remaining liquid water (still very hot) is directed to the second separator. In the low-pressure separator, the same process is repeated, but at a lower pressure. The result is dry steam at lower pressure in the ‘second flash’, which is fed to the low-pressure turbine. This also generates electricity.

After both turbines, the vapour is condensed by heat exchangers and this liquid is re-joined with the excess fluid from the second separator which has not evaporated.

In this case, where the thermal heat is also used, what happens next is as follows: the resulting fluid, which is still hot, is fed to heat exchangers in which only thermal energy is transferred. It is then possible to use the heated water for domestic use (radiators, baths, etc.).

The fluid, having lowered its temperature a little further with this last heat exchange, is re-injected into the geothermal reservoir via injection wells, thus closing the geothermal cycle and maintaining the sustainability of the system. Re-injecting the fluid at a lower temperature helps to maintain thermal equilibrium and ensures that the aquifer remains sustainable in the long term.

The diagram of the cycle can be clearly seen in Figure 13 below. The only difference is that in this case, instead of a cooling tower to cool the fluid, there is a heat exchanger that allows the heat exchanged to be used as thermal energy.

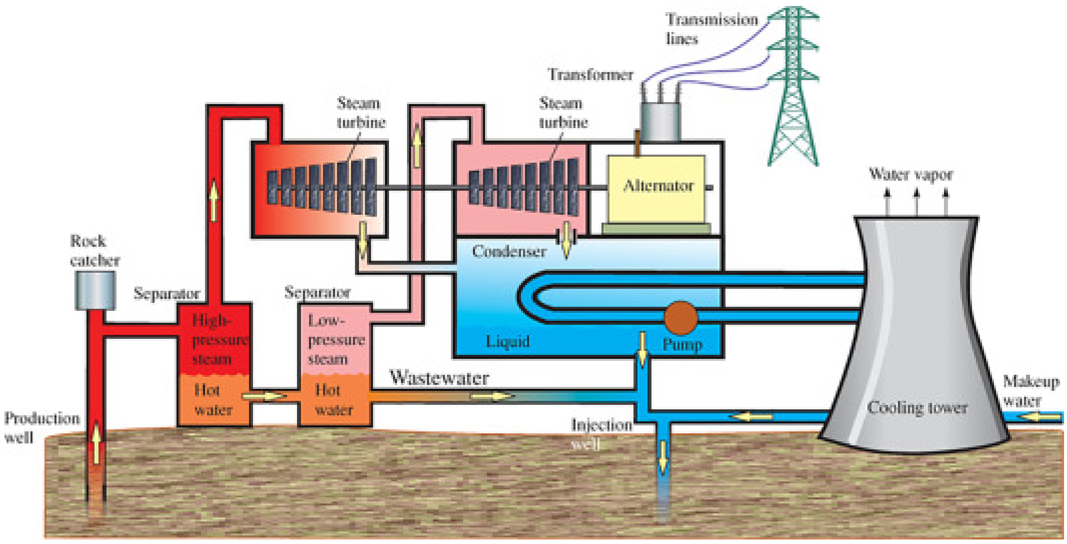

Figure 13. Scheme of double flash steam system.

It has an installed capacity of 303MW of electrical energy and 400MW of thermal energy for district heating, making it a geothermal CHP (Combined Heat and Power) plant.

The main components of the plant are several 45MW high-pressure turbines and a 33MW low-pressure turbine. In addition to 49 production wells, 17 injection wells and 6 groundwater wells.

To carry out cooling, 7 cooling towers are also required to condense the steam for re-injection.

The electricity generated is enough to supply around 90,000 households and also provides hot water for district heating in the capital region (Reykjavíc).

Figure 14. Hellisheidi.

3.2.2. Soultz-sous-Forêts (France)

The Soultz-sous-Forêts geothermal power plant is located in Alsace, northeast France, near the German border.

It is the first European EGS project, symbolizing the transition from early Hot Dry Rock (HDR) experiments to modern Enhanced Geothermal Systems, and is considered a technological milestone in the evolution of deep geothermal energy. It is therefore a reference for the development of EGS projects in Europe and even worldwide.

As just mentioned, the technology implemented by this project started as HDR, evolving to use EGS technology for the first time in Europe.

The drilling depth is about 5km and has one injection well and two production wells. The reservoir is at approximately 200 °C and electricity generation is carried out using an Organic Rankine Cycle (ORC), which is particularly suited for low- to medium-temperature geothermal resources like those found in Soultz.

There is 1.7 MW of gross installed electrical power and around 12 GWh is generated annually.

Figure 15. Soultz-sous-Forêts

3.2.3. The Geysers (USA)

This is the largest operating geothermal plant in the world. It is also one of the oldest and most mature geothermal fields globally, having been in continuous operation since the 1960s, which provides a valuable long-term benchmark for geothermal performance and reliability. The Geysers alone accounts for 20% of all geothermal electricity generated in the United States.

It is located in Sonoma and Lake counties in California.

It has 1,59 GW of installed electrical capacity and produces approximately 6,516 GWh each year. This electricity is enough to power about 725.000 homes.

The Geysers is also the first commercial (large-scale) dry steam plant.

Figure 16. The Geysers.

3.2.4. Larderello (Italy)

This plant is of particular historical significance, since, as has been mentioned before, Larderello is recognized as the first commercial geothermal power plant in the world thanks to Piero Ginori Conti. The technology used is dry steam.

This power plant is located in Larderello in Tuscany, Italy. It currently has more than 200 active wells with a depth of between 700 and 3,000m.

In this study, the Larderello refers not to a single geothermal power plant, but to the broader Larderello geothermal district located in Tuscany, Italy. This district encompasses around 34 interconnected geothermal plants with with 37 generating units. It is operated by Enel Green Power, with a combined installed capacity of approximately 800 MW. The system is managed as an integrated network, sharing geothermal wells, steam pipelines, and operational infrastructure. Among its components, the Valle Secolo plant stands out as one of the most modern and powerful units within the complex, commissioned in the early 1990s. The choice to analyze the district as a whole aligns with the methodological approach of comparing large-scale, base-load power generation systems.

The installed electrical capacity of this power plant is approximately 800 MW producing around 6 TWh annually, which represents around 5% of Italy's renewable energy. Its longevity and scale make it a key case study for assessing the economic and environmental performance of conventional geothermal energy over long operational periods. It is capable of supplying electricity to more than one million Italian households.

Figure 17. Larderello.

4. Results

4.1. Technical results

4.1.1. Capacity factor (%)

4.1.1.1. Nuclear power plants

Nuclear power plants are designed to operate continuously, which would be a 100% capacity factor. However, this is not the case as they have scheduled outages for refuelling and maintenance.

These scheduled outages usually last between 20 and 40 days, depending on the reactor. They are usually used for refuelling (where only 1/3 of the fuel is replaced) and at the same time, in order to reduce the number of outages, they are used for maintenance work.

These outages are carried out every 12 or 24 months, depending on the reactor design and the plant's operating strategy.

In addition, unscheduled and unexpected outages may also occur due to technical failures, anomalies, regulatory or fuel quality problems, or even external events such as loss of grid connection or earthquakes.

The frequency of these outages is very low and they usually take only a few days to restart. It is not an immediate start-up, but a slow, gradual and regulated process due to the large amount of energy involved. In addition, fission must be increased progressively, raising reactivity in a controlled and stable manner, heat must be transferred slowly to avoid thermal shocks, and they have very detailed protocols.

According to data published by the American Nuclear Society (ANS), the average capacity factor of nuclear power plants in the United States has remained close to 90 % since the early 2000s, as a result of more than a decade of operational improvements.

As the ANS points out: “Capacity factors of U.S. reactors have remained near 90 percent since the turn of the century, but it took more than a decade of improvements to reach that steady state. The payoff for nuclear investments is long-term and reliable” (American Nuclear Society, 2023).

On the other hand, the other three plants have the same type of reactors and according to the World Nuclear Association (n.d.), the EPR design (such as Hinkley Point C, Flamanville 3 and Taishan 1 and 2) has an expected lifetime availability of 92%. This high availability is aligned with the objectives of long-term continuous operation with minimal outages. As mentioned in the Areva NP (formerly Framatome ANP) report: “Availability is expected to be 92% over a 60-year service life.” (World Nuclear Association, n.d.).

According to EDF Energy (2016), Hinkley Point C will have an installed capacity of 3,260 MW and is expected to operate with a load factor of at least 90%. This implies a production of more than 25 TWh per year, which makes it possible to assume this value as representative in the LCOE calculation for this facility. As stated literally in the report: ‘Hinkley Point C would have a capacity of 3260 MW, with at least a 90% load factor. Over 25 TWh per annum would therefore be produced’. (EDF Energy, 2016, p. 6).

However, these values correspond to optimized operational trajectories, which are not representative of new facilities that are not yet operational and will face technical, regulatory and financial challenges in their start-up.

Nevertheless, these values correspond to ideal, optimized conditions that may not reflect the initial operating phases of new facilities. During start-up years, nuclear plants can experience lower availability due to commissioning delays, regulatory testing, or grid integration constraints.

On a global level, the International Atomic Energy Agency (IAEA) reports that “in 2023, the global median capacity factor was 88.0%. Boiling water reactors (BWR) and pressurized water reactors (PWR) have been the best performing reactors since 2013, with median capacity factors of 89.3% and 82.7% respectively” (IAEA, 2024, p. 10). These values confirm the high operational reliability of mature nuclear fleets under optimized conditions.

However, these high capacity factors are typically achieved in reactors that have been in operation for years, with established maintenance protocols and performance tuning. New nuclear projects, designs that are the first of their kind, or those in complex regulatory situations may not be as available at first. This is because of challenges in getting them going, unexpected technical problems, and getting them connected to the power grid.

For this reason, and in line with methodological prudence, a conservative capacity factor of **80%** is adopted for all nuclear units evaluated in this study. This value is a bit lower than the global median but within the observed range for pressurized water reactors, as reported by the IAEA. It allows for a realistic estimation of performance that reflects potential start-up inefficiencies while remaining consistent with long-term operational expectations. This assumption also aligns with the objective of applying uniform criteria across technologies for comparative economic analysis.

4.1.1.2. Geothermal power plants

In the case of high-enthalpy geothermal power, the capacity factor is also a key indicator for estimating actual generation. Unlike intermittent technologies such as solar or wind, geothermal power plants can operate steadily and stably, which makes them also a valid option for baseload generation.

Several well-established commercial plants such as Hellisheiði in Iceland, The Geysers in the United States, and Larderello in Italy have demonstrated capacity factors over 85 %, supported by high resource temperature, reservoir pressure stability, and optimized power plant design. For example, Hellisheiði reports availability values consistently above 90 % in recent records.

However, many of the emerging geothermal technologies considered in this study (particularly Enhanced Geothermal Systems (EGS) such as Soultz-sous-Forêts and Red Project, as well as conceptual ultra-deep drilling platforms like Quaise Energy) don't have much data on how they work over time. These technologies are still in demonstration or pilot phases, and are subject to uncertainties related to how long flow rates can last, how well reservoirs can be stimulated, and the risk of earthquakes.

Nevertheless, to maintain methodological consistency across technologies and avoid penalizing promising geothermal innovations due to lack of historical data, a standard capacity factor of **85 %** is applied to all geothermal plants analyzed. This value reflects the high technical potential of geothermal power in ideal resource contexts and is supported by international literature. For instance, the National Renewable Energy

Laboratory (NREL) indicates that modern geothermal power plants operating under optimized conditions can achieve capacity factors ranging between 80% and 90%, depending on resource quality and system design (NREL, 2021). This range reflects the high reliability and availability of geothermal systems used for baseload electricity generation, especially in geologically favourable areas with high-enthalpy resources

4.1.2. Plant lifetime (n) (years)

4.1.2.1. Nuclear power plants

The lifetime of a power plant refers to the period during which the facility is designed, licensed and expected to operate, generate electricity and recover the capital investment under defined technical and regulatory conditions.

In the case of nuclear reactors, modern designs (especially Generation III and III+, such as the EPR or AP1000) are technically designed to operate for up to 60 years. For example, Flamanville 3 in France was initially licensed for 40 years, with the option to apply for a 20-year extension, while Vogtle Units 3 and 4 in the United States were licensed for 60 years, potentially extendable to 80 years by the U.S. Nuclear Regulatory Commission. Therefore, the estimated technical life of the nuclear power plants analyzed in this project is considered to be 60 years.

However, in the context of economic and financial evaluations, such as the calculation of the LCOE, a shorter time horizon is often used. Most international financial planning models adopt an evaluation of period as the standard reference for amortization and payback. This is because extending the economic life beyond 30 years introduces increasing uncertainty related to major refurbishment needs, increased operating and maintenance costs, changes in regulatory frameworks or changing market conditions and electricity prices.

This approach is supported by international institutions. According to the International Atomic Energy Agency (IAEA, 2018), the original design life of nuclear reactors in countries such as Finland, Russia, Hungary and Korea was typically 30 years, based on the durability of reactor core components such as steam generators, reactor coolant pumps and pressurizers. The OECD Nuclear Energy Agency (2019) also confirms that most economic evaluations of nuclear projects apply a 30-year timeframe for cost-benefit analysis, even when technical lives are longer.

Therefore, in this study, and following both international best practices, a conservative and standardized economic **lifetime of 30 years is adopted for all nuclear units evaluated**. This decision ensures methodological consistency, facilitates comparability with other technologies and avoids speculative assumptions about revenues or costs beyond the practical horizon of the financial analysis.

4.1.2.2. Geothermal power plants

As for geothermal plants, their technical lifetime can also extend beyond two decades, especially when the resources are well managed and the facilities are well maintained. For example, Larderello has shown stable operation for more than 30 years, confirming the long-term technical viability of these facilities.

However, in the context of advanced technologies, EGS are newer, and there are questions about how well they will work over time, maintenance costs, and the stability of resources at extreme depths. Recent studies, such as Hackstein and Madlener (2021) "The lifetime of the presented case amounts to 23.8 years, which is a typical value for an EGS.", indicate that the economic and operational lifetime for a typical EGS case is about 23.8 years, with an estimated resource regeneration time of about 7,000 years, but economic operation cannot be guaranteed without subsidies or guaranteed feed-in tariffs.

In addition, the specialized Wikipedia article (2025) on geothermal power reports that EGS plants are expected to have an economic operating lifetime of 20 to 30 years.

For these reasons, and to maintain consistency with the economic criteria applied in the evaluation of nuclear power plants, this paper adopts a standard **lifetime of 20 years for all geothermal plants evaluated**. This approach allows a consistent comparison between technologies, reflecting a realistic expectation of sustained operation without assuming excessively long periods that could require partial rebuilds or additional costs not accounted for in the economic evaluation.

4.1.3. Construction time (years)

Construction time is a critical parameter in evaluating the feasibility and financial risk of power generation projects. It directly affects capital recovery, financing costs, and the speed at which a plant can contribute to the energy system. Nuclear and geothermal technologies show considerable differences in this regard due to their complexity, regulatory frameworks, and site-specific challenges.

4.1.3.1. Nuclear power plants

Large-scale nuclear power plants, especially Generation III+ projects, typically require long construction timelines. This is due to strict safety regulations, the complexity of reactor systems, and extensive civil infrastructure.

Hinkley Point C (UK)

A summary of the construction timeline for the HPC project is presented in Figure 18 below. The figure highlights key milestones and delays that have affected the overall schedule since construction began in 2016. These delays are attributed to a combination of factors, including the impact of the COVID-19 pandemic, global supply chain disruptions, and the inherent technical complexity of the EPR design. The case of HPC is representative of the challenges often encountered in large-scale nuclear power projects, particularly those involving next generation reactor technologies.

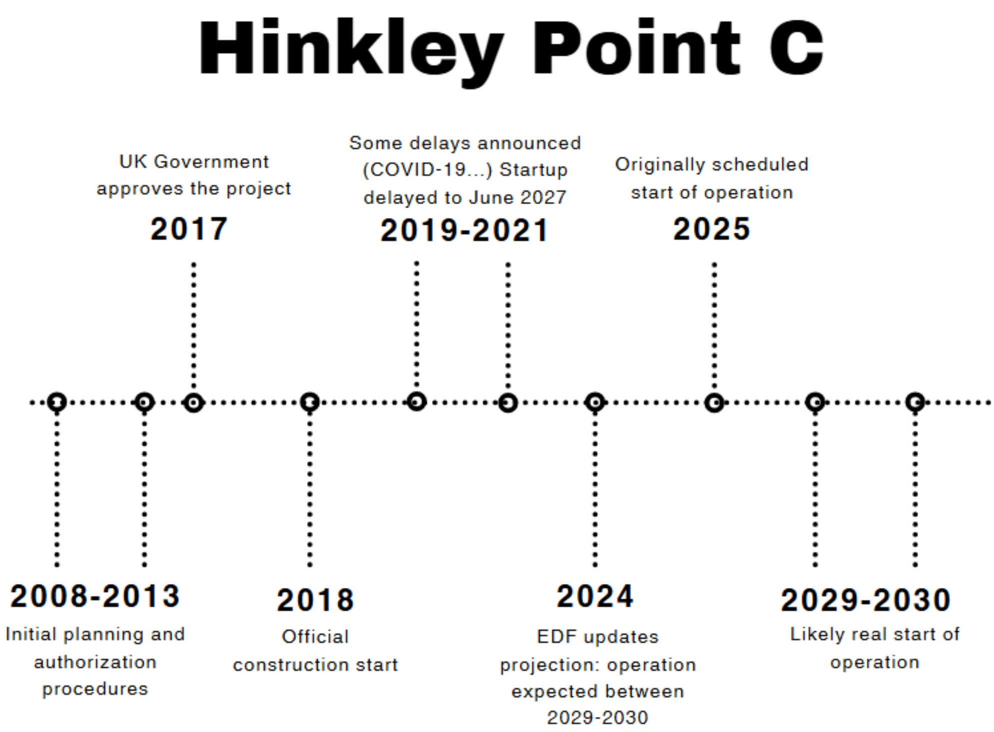

Figure 18. Timetable Hinkley Point C.

For the Hinkley Point C project, the official start of construction was marked by the pouring of first nuclear concrete in December 2018. The latest estimates from EDF (January 2024) say the first reactor should be up and running in 2030. That means it'll take about **12 years** to build, which is normal for other Generation III+ reactors in Western Europe.

Flamanville 3

A detailed chronology of the construction stages for the Flamanville 3 project is presented in Figure 19 below. The figure highlights key milestones and delays that have significantly affected the original schedule since the project was approved in 2007. These delays are mainly due to technical, quality and supplier problems with certain components. There were also problems detected in the composition of the steel of the reactor vessel (it did not have sufficient strength). In addition, multiple additional inspections and quality tests had to be carried out. The long development period also led to increasing material prices and changing safety regulations. This led to multiple delays and cost overruns.

Flamanville 3 illustrates the complexity and risks associated with the development of next generation (Gen III+) nuclear reactors in countries with limited recent nuclear construction experience.

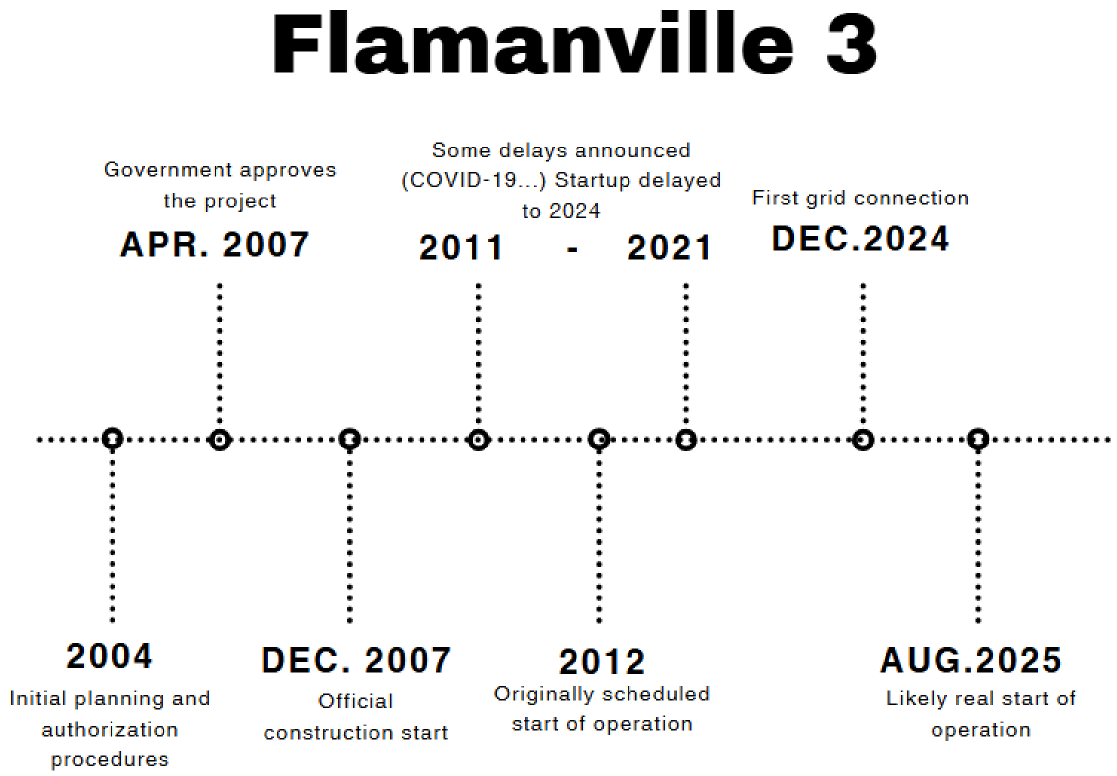

Figure 19. Timetable Flamanville.

For the Flamanville 3 project, the official start of construction was marked by the pouring of first nuclear concrete in December 2007. Originally expected to enter commercial operation by 2012, the project has faced multiple delays. According to the latest update, first grid connection is planned for late 2024, with full power testing continuing into 2025. This results in an estimated construction time of **17–18 years**, making it one of the most delayed Generation III+ projects in Europe.

Vogtle Units 3 & 4

Figure 20 presents a detailed overview of the construction timeline for Vogtle Units 3 and 4, which represent the first new nuclear reactors built in the United States in more than three decades. The project formally began in 2006, and its evolution over time reflects both the complexity and the risks associated with large-scale nuclear deployment. Several factors have contributed to significant delays and cost increases, including post-

Fukushima regulatory adjustments, the 2017 bankruptcy of Westinghouse (the reactor designer), increased labour and material costs, and the transition of construction management to Bechtel Corporation. The project is primarily financed by Southern Company, with additional support from U.S. federal loan guarantees, highlighting the role of public-private partnerships in delivering next-generation nuclear infrastructure.

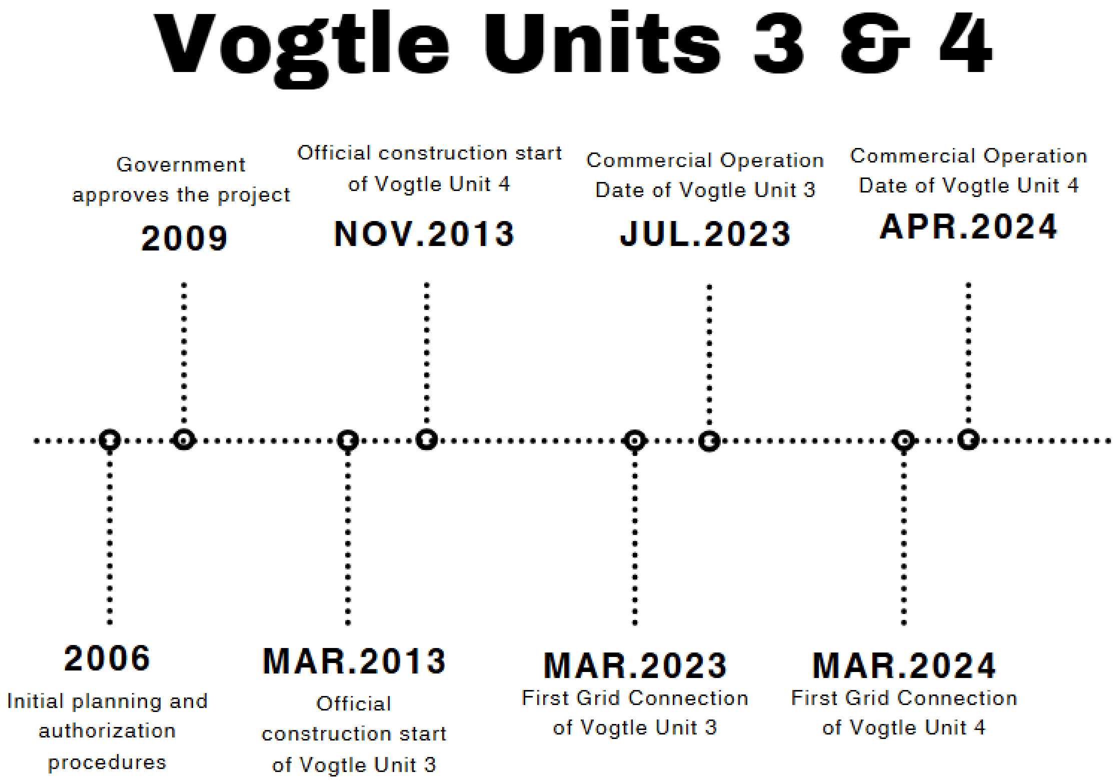

Figure 20. Timeline Vogtle Units 3 & 4

The official construction of Vogtle Unit 3 began in March 2013, followed by Unit 4 in November 2013, although the overall project development dates back to 2006. Initially scheduled to enter commercial operation between 2016 and 2017, both units experienced substantial delays. Unit 3 was connected to the grid in July 2023, and Unit 4 achieved commercial operation in April 2024. This results in an actual construction time of approximately **10–11 years per unit**. Vogtle thus exemplifies the challenges of deploying advanced nuclear reactor technologies such as the AP1000 in complex regulatory and financial environments.

Taishan 1 & 2

Figure 21 presents the full construction timeline for the Taishan nuclear power plant in China, which includes Units 1 and 2, both based on the European Pressurized Reactor (EPR) design. In contrast to the EPR projects in Europe, Taishan was able to adhere closely to its initial budget and construction schedule. The project is co-owned by China General Nuclear (CGN, 70%) and Électricité de France (EDF, 30%), and involves major suppliers such as Framatome (reactor design and components), GE Steam Power (turbine systems), and CGN Engineering (civil and plant infrastructure).

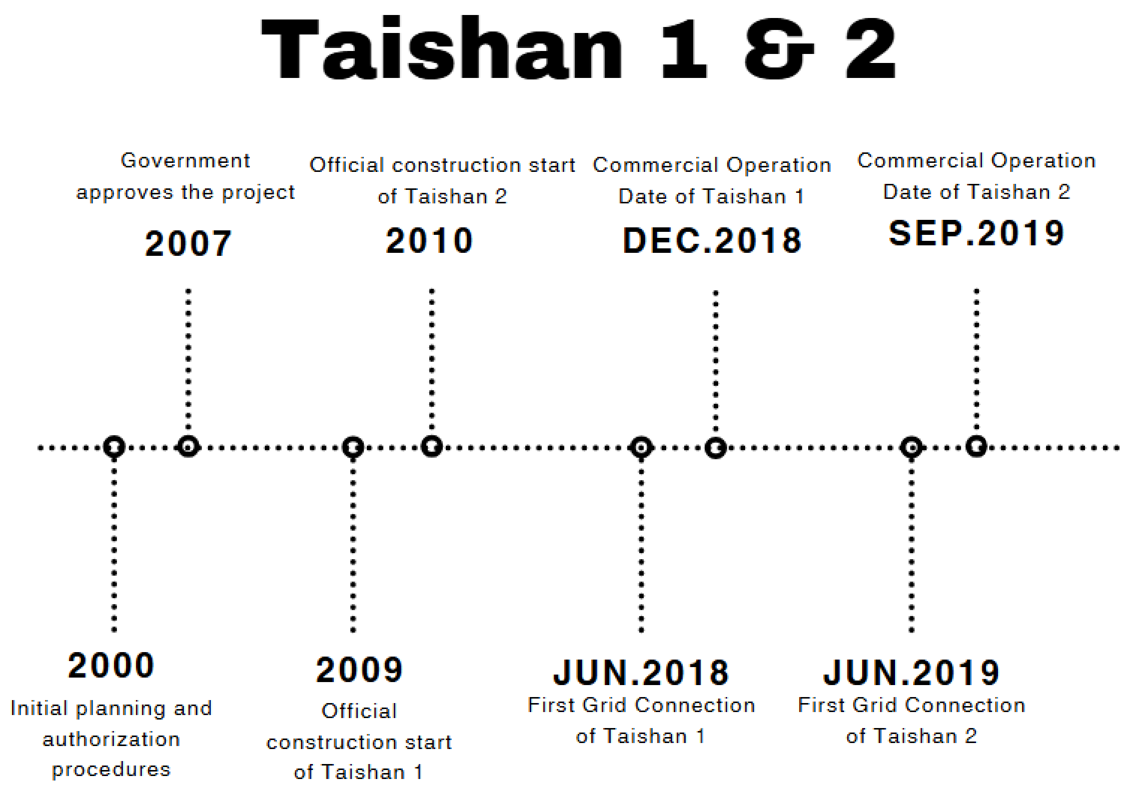

Figure 21. Timeline Taishan 1 and 2.

Construction of Taishan Unit 1 started in October 2009, and Unit 2 started in April 2010. Both were supposed to be running by 2013–2014. They were delayed by about five years, mostly because of safety reviews after Fukushima and problems with getting parts certified. But Taishan Unit 1 started running in December 2018, and Unit 2 in September 2019. It took **about 9 years** to build each unit, from the first concrete to commercial operation. Taishan was the first successful commercial project using EPR tech. The building time for Taishan 1 and 2 was way shorter than similar EPR projects in Europe.

This shows that China can build complex nuclear tech more easily because of its setup, rules, and industry. Taishan is a good example for future EPR projects and shows how important the national context is for nuclear projects. Taishan was more on time and on budget. This was because of things like lower labor costs, a strong local supply chain, simple regulations, and lots of experience building nuclear plants.

4.1.3.2. Geothermal power plants

Hellisheiði (Iceland)

Figure 22 illustrates the staged development timeline of the Hellisheiði geothermal power plant, one of the world's largest high-enthalpy geothermal facilities. Construction began after the 2001 resource assessment, with initial permit and infrastructure work starting in 2002. Unlike large nuclear projects, Hellisheiði followed a modular, phase-based strategy that allowed rapid deployment with minimal regulatory delays, reflecting Iceland's streamlined framework and geothermal expertise.

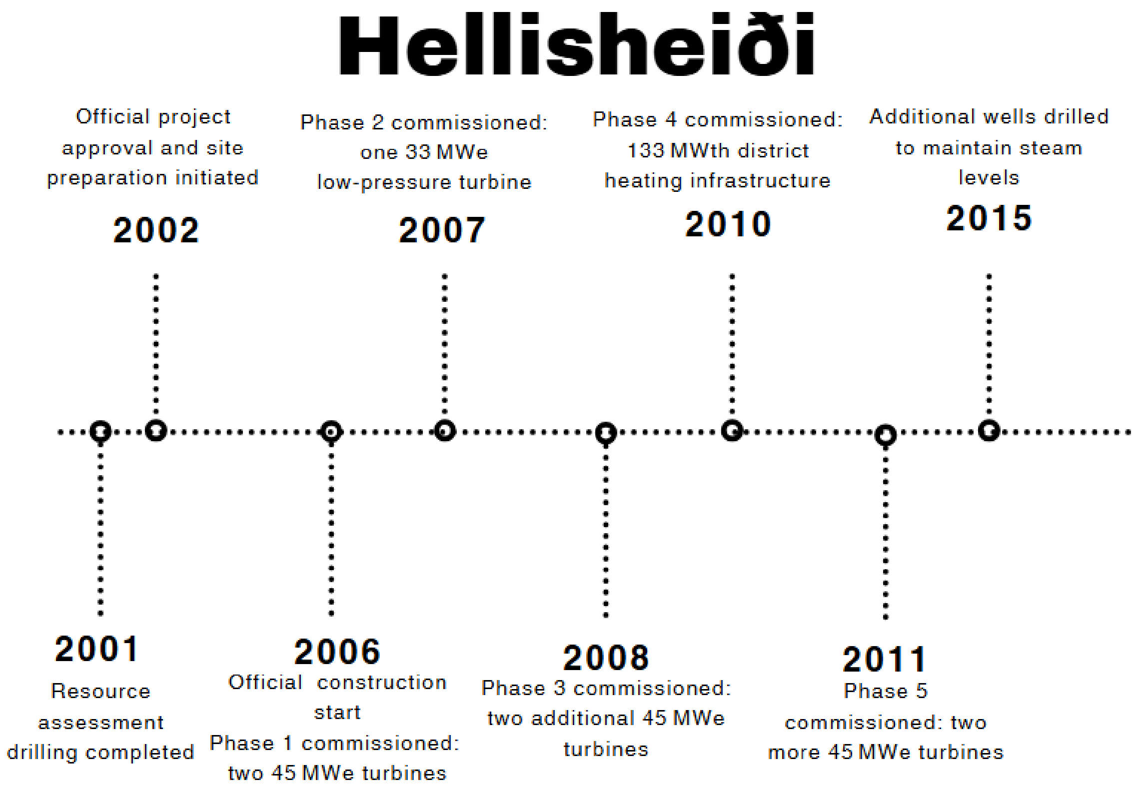

Figure 22. Timeline Hellisheidi.

The staged commissioning approach enabled Hellisheiði to reach full electrical capacity of ~303 MWe between 2006 and 2011, just **5 years** from first turbine commission to final turbine installation. This rapid, phased delivery contrasts sharply with the multi-decade schedules common to Gen III+ nuclear projects and underscores Iceland's effective modular deployment model.

Soultz-sous-Forêts (France)

Figure 23 shows the timeline of the Soultz-sous-Forêts a pioneering European EGS pilot. Starting as geological exploration in the mid-1980s, the project progressed through experimental drilling and reservoir stimulation, culminating in the commissioning of a small ORC power plant. Soultz served as a testbed for developing deep geothermal technologies and reservoir management methods

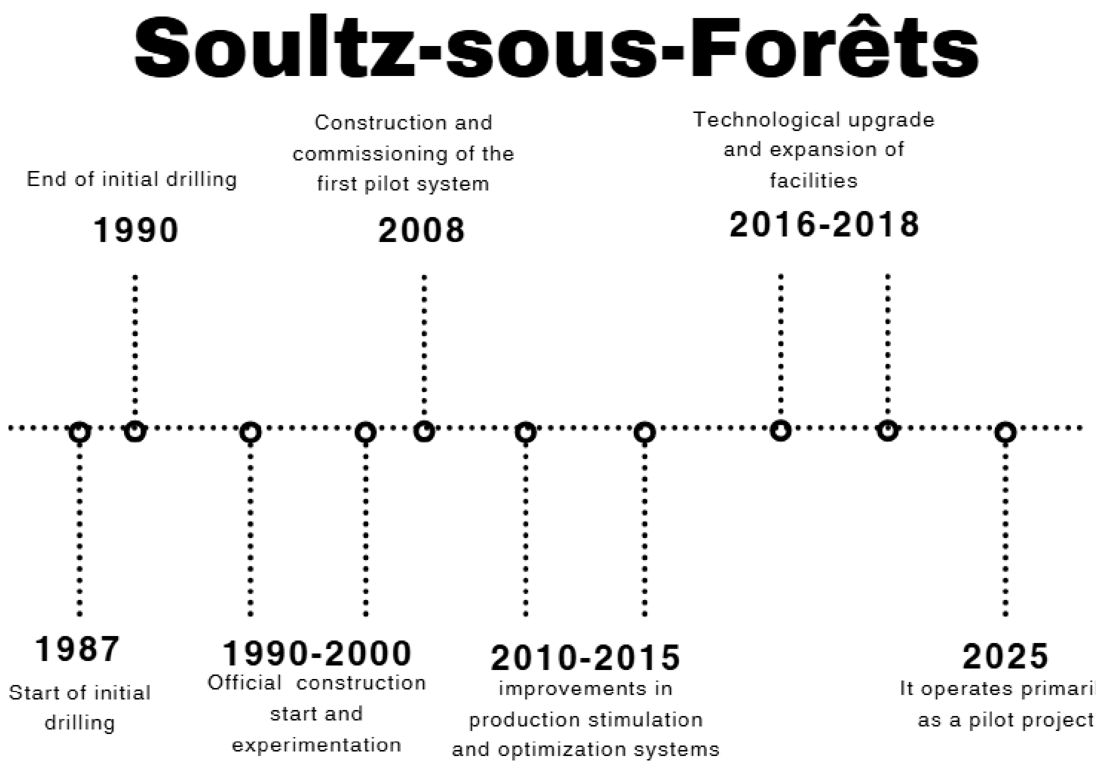

Figure 23. Timeline Soultz-sous-Forêts.

As it is a pilot project, it took approximately 11 years from the official construction start in 2005 to commercial operation in 2016. It reflects the complexity and long development cycles required for deep EGS technologies, with multiple testing and stimulation phases before achieving power generation.

Larderello (Italy)

The development timeline of the Larderello geothermal complex is illustrated in Figure 24, showcasing more than a century of gradual expansion at one of the world's oldest and most iconic geothermal sites. Instead of having one long construction project, Larderello has grown through continuous updates and adding more capacity. The newest phases, especially those led by Enel Green Power, show how good infrastructure and experience can help make geothermal energy scalable.

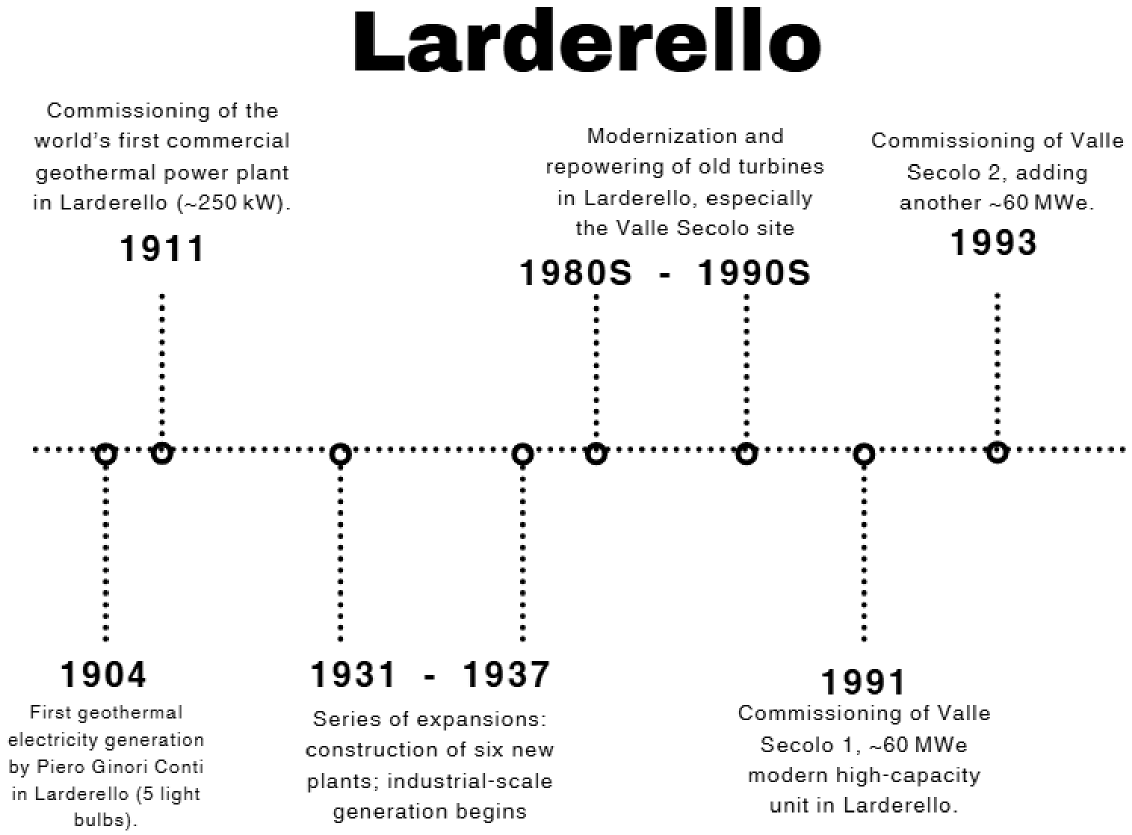

Figure 24. Timeline Larderello.

The Larderello geothermal district began commercial operation in 1911 and has undergone continuous expansion ever since. Its most significant modern development phase occurred in the early 1990s, when high-capacity plants such as Valle Secolo were commissioned. These additions brought the district's installed capacity close to its current level of 800 MW. Unlike nuclear projects, which are typically built in single, large-scale blocks, Larderello's infrastructure has been deployed incrementally over time, allowing for lower capital risk, flexible scaling, and faster commissioning of individual units.

The Geysers (USA)

Figure 25 outlines the development of The Geysers, the world's largest geothermal field. Initially tapped for therapeutic steam in 1921, its commercial phase began with modern drilling in the 1950s. Over time, the field has grown into a mature industrial operation featuring dozens of wells and multiple power plants, incorporating steam reinjection to sustain production.

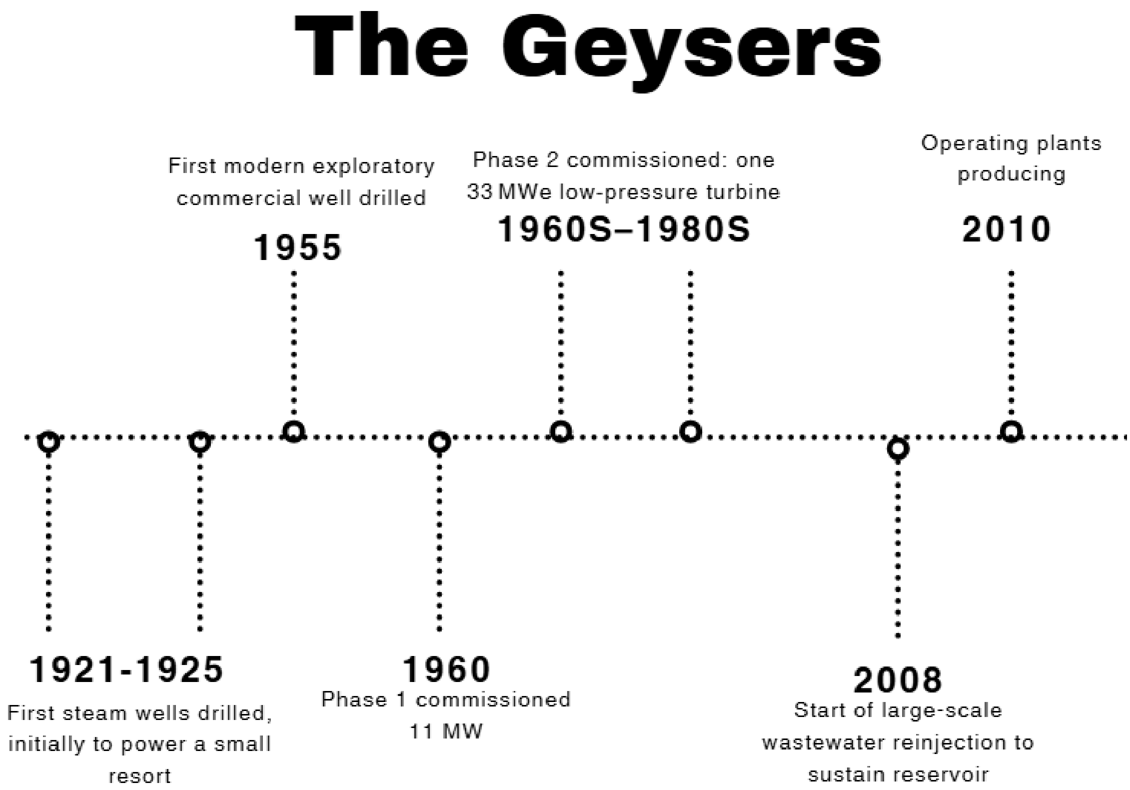

Figure 25. Timeline The Geysers.

Construction of The Geysers began around 1955, and in 1960 it was connected to the grid as a pilot project, during a construction period of 4 years. However, it had reached approximately 725 MWe of installed capacity in 1972 approximately. The complete process took about 14 years, following a phased development model.

4.1.4. Power output (MW)

4.1.4.1. Nuclear power plants

In this section, the installed capacity and the estimated annual electricity generation of the selected nuclear power plants are presented in the Table 2. These values re needed to measure how much each plant adds to the power system and to compare the costs and how well they operate. The installed capacity is shown in megawatts-electric (MWe), and the electricity production is shown in terawatt-hours per year (TWh/y), using real data or estimates.

The annual electricity production (E) is the amount of net electrical energy generated by the plant in a year. It is calculated as the net capacity of the plant (MW) multiplied by its capacity factor and by the total number of hours per year

(which is $24\ \frac{h}{day} \cdot 365\frac{days}{year} = 8760\frac{h}{year}$).

$$E\left(\frac{MWh}{year}\right) = Total\ Power\ Capacity\ (MW) \cdot \frac{CapacityFactor\ (\%)}{100} \cdot 8760(\frac{h}{year})$$

Nuclear Power Plant	Net capacity per reactor (MW)	Number of reactors	Total power capacity (MW)	Capacity factor (%)	Hours per year (h)	Net annual production (TWh)
Hinkley Point C	1630	2	3260	80%	8760	22,85
Flamanville 3	1650	1	1650	80%	8760	11,56
Vogtle Units 3 and 4	1117	2	2234	80%	8760	15,66
Thaisan 1 and 2	1660	2	3320	80%	8760	23,27

Table 2.Total power capacity and Net annual production Nuclear

4.1.4.2. Geothermal power plants

In the following Table 3 presents the installed electrical capacity and the corresponding annual electricity generation for each of the geothermal power plants analyzed. This information is key for figuring out how much energy the tech can make including hydrothermal and EGS. Installed capacity is in megawatts-electric (MWe), and electricity production is in gigawatt-hours per year (GWh/y), using reported figures or estimates based on the plant.

Geothermal Power Plant	Total power capacity (MW)	Capacity factor (%)	Hours per year (h)	Net annual production (TWh)
Hellishedi	303	85%	8760	2,256
Soultz-sous-Forêts	1,7	85%	8760	0,013
Larderello	800	85%	8760	5,957
The Geysers	725	85%	8760	4,367

Table 3. Total power capacity and Net annual production. Geothermal

4.2. Economic results

In order to ensure the comparability of economical values across different geothermal and nuclear power plants included in this study, all cost data have been standardized and expressed in constant 2023 US dollars (USD2023). This adjustment was necessary because the original capital expenditure values were reported in different years and currencies, depending on the source, the country of the project, and the publication date of the data. Without this, comparing costs would be wrong because of inflation and exchange rates.

4.2.1. Capital Expenditure (CapEx)

4.2.1.1. Nuclear power plants

This section examines the upfront capital costs required for constructing the power plants under study. The CAPEX is expressed as cost per installed megawatt-electric (MWe), which is a key metric for comparing projects of different scales and technologies.

The main source for CAPEX data, *"The Path to a New Era for Nuclear Energy"* (IEA, 2025), already reports its most recent figures in 2023 USD, as shown in detailed cost-benefit assessments of major reactor projects: "**The Vogtle Units 3 and 4** … initial capital cost estimate of about USD (2023) 5 600 per kW … rose to **USD (2023) 14 700/kW**", "**Hinkley Point C** … initially estimated at about USD (2023) 8 700/kW, the budget has risen to almost **USD (2023) 16 000/kW**" , "**The Flamanville 3**… with initial estimates of USD (2023, MER) 3 200/kW rising to **USD (2023, MER) 11 000/kW**".

Using 2023 as the reference year avoids the need to project economic data into the future (e.g., USD2025), which would require speculative inflation estimates and introduce unnecessary uncertainty. It also aligns with the reporting convention of leading institutions like the IEA, ensuring direct compatibility and transparency.

However, the original CAPEX value for the **Taishan 1 and 2** nuclear power units, was retrieved from the OECD/NEA report "Projected Costs of Generating Electricity – 2020 Edition" (NEA, 2020). This value is 3 222 USD2018/kW, is expressed in constant 2018 US dollars. For this reason, this value needs to be adjusted to account for inflation up to the year 2023.

To carry out the economic adjustment has required the use of the U.S. Bureau of Labor Statistics (BLS), the most reliable resource for this type of adjustments. It publishes the official Consumer Price Index (CPI) and it also contains the CPI Inflation Calculator, based on BLS data that helps to calculate the inflation factor. Using the calculator from January 2018 to February 2023, the resultant value of the CAPEX is approximately **3911 USD2023/kW**.

This calculation has also been done with U.S Inflation Calculator that provides the cumulative inflation rate from 2018 to 2023. The value is 21.38% inflation over the 5-year period.

$$\text{In}Inflation\ Factor = 1 + \frac{21.38}{100} = 1.2138$$

$$CAPEX_{2023} = 3222 \frac{USD2018}{kW} \times 1.2138 = 3910.86 \sim \mathbf{3911}\ \boldsymbol{USD2023/kW}$$

The result is the same with the two ways of adjustment.

However, the CAPEX reported for the Taishan 1 and 2 is notably lower than the capital costs observed for comparable nuclear projects in Western countries. When adjusted to 2023 dollars, this value remains significantly below the CAPEX figures reported for projects such as Hinkley Point C in the UK, Flamanville 3 in France, or Vogtle Units 3 and 4 in the United States, all of which exceed 10 000 USD/kWe in most recent assessments.

This discrepancy raises important questions regarding the comparability of the reported costs. A key consideration is that the Taishan cost estimate likely reflects only the initial construction budget and may not include ex cost overruns, interest during construction, or other indirect expenses that were in fact included in more recent analyses of Western projects. This hypothesis is strongly supported by the absence of officially documented cost escalations for Taishan 1 and 2.

A summary of the CAPEX used in this study for nuclear plants can be found in Table 4.

Nuclear Power Plant	CAPEX (USD/kW)	CAPEX (billion USD)
Hinkley Point C	16000	52,16
Flamanville 3	11000	18,15
Vogtle Units 3 and 4	14700	32,84
Thaisan 1 and 2	3911	12,98

Table 4. CAPEX. Nuclear

4.2.1.2. Geothermal power plants

In the search for CAPEX for geothermal power plants, a major challenge has been faced. Unambiguous, project-specific cost data are rarely present in open sources, usually due to proprietary agreements or unreliable reporting.

Faced with this obstacle, a rigorous methodological approach has been adopted based on consultation with the main authorities in order to obtain data that is as realistic and transparent as possible. These include the International Renewable Energy Agency (IRENA), the International Energy Agency (IEA), the U.S. Department of Energy (DOE) and the National Renewable Energy Laboratory (NREL). First, after consulting the most representative and current reports of these entities, have been estimated a set of CAPEX costs. Secondly, have been selected the values most similar in size to the scale, maturity and technological profile of each plant, always placing our choice in the lower or middle point of the ranges in order to remain conservative but not unrealistic. Finally, all costs have been converted to a common reference year (USD2023) by adjusting them to US CPI inflation, thus ensuring both consistency between plants and robustness over time.

In the case of **Hellisheiði**, the prevailing industry cost range is USD 2,000-6,000/kW (IRENA 2023). Taking into account the maturity of the power plant, the robustness of the infrastructure and the quality of the geothermal resource, a midpoint CAPEX of 4,500 USD/kW in 2022 dollars has been taken. With the official US CPI inflation rate of 2% from 2022 to 2023, this results in a CAPEX of **4,590 USD2023/kW** (4,500 × 1.02 = 4,590). This choice is within the reported ranges and is fully supported by comparative global data.

Soultz-sous-Forêts, a pilot enhanced geothermal system (EGS) in France, has inherently higher costs due to its test phase and lower output (about 1.7 MW). Industry reports (IEA 2010; IRENA 2023) put capital costs for EGS/binary plants at between $3,000 and $6,250/kW, with demonstration projects trending toward the higher end. $6,000/kW has been used for Soultz in 2022, a figure that represents and is below the observed peak. Inflation from the 2023 CPI yields a result of **6,120 USD2023/kW** (6,000 × 1.02 = 6,120), which we feel is adequately conservative and justified.

Larderello, a mature steam-dominated field in Italy with an extensive operating history and large capacity, is more accurately described using global averages for giant-scale flash plants rather than project-specific cost statements. From IRENA, EIA and ESMAP data of an average CAPEX of USD 3,729/kW in 2018 for comparable systems, this figure has been applied, adding a cumulative inflation factor of 21.38% to produce a cost in 2023 of **4,603 USD2023/kW** (3,729 × 1.2138 = 4,603). This method takes into account both Larderello's scale and the long-term operating efficiency gains of its facilities.

The Geysers, the largest steam-dominated geothermal field in the world, has decades of infrastructure optimization and resource management. DOE's Geothermal Technologies Office puts its CAPEX at about USD 3,500/kW in 2020. Rolling this forward to 2023 with a 18% inflation factor yields a CAPEX of **USD 4,130 USD2023/kW** (3,500 × 1.18 = 4,130). This is an estimate within the acceptable range in the market and demonstrates the maturity and economic soundness of the plant.

In summary, through extensive research and consistent application of conservative approximations, the 2023 CAPEX figures for these facilities have been determined to be as found in Table 5 below.

Geothermal Power Plant	CAPEX (USD/kW)	CAPEX (billion USD)
Hellishedi	4590	1,391
Soultz-sous-Forêts	6120	0,010
Larderello	4603	3,682
The Geysers	4130	2,994

Table 5. CAPEX. Geothermal

4.2.2. Operational Expenditure (OpEx)

4.2.2.1. Nuclear power plants

For this analysis, the OPEX values have been cautiously estimated from reputed international reference documents, relying principally on the report "Projected Costs of Generating Electricity, 2020 Edition" prepared by the International Energy Agency (IEA) and the Nuclear Energy Agency (NEA). This report offers detailed breakdowns of the average Operation and Maintenance (O&M) and fuel costs per kilowatt of installed capacity for a wide range of nuclear projects worldwide. According to this source, the fuel cost for nuclear power plants is estimated at 9.33 USD2019/kW for most facilities, with a slightly higher value of 10 USD2019/kW assigned to Chinese reactors such as Taishan, due to regional cost differences and supply chain considerations.

To align all financial values with current standards and ensure cross-comparability, these values have been converted to USD 2023.

Using the cumulative rate inflation from 2019 to 2023 is approximately 19.2%.

Then is known that the fuel cost for Taishan 1 and 2 is **11.92 USD2023/kW** (10 × 1.192 = 11.92) and for the rest of the power plants under study is **11.12 USD2023/kW** (9.33 × 1.192 = 11.12).

O&M costs for some individual plants have also been obtained from the same IEA/NEA report, and similarly adjusted to 2023 values.

For the Flamanville plant, the O&M value is **17,00 USD2023/kW** (14.26 × 1.192 = 17.00).

Vogtle Units 3 and 4 have a O&M figure of **13.83 USD2023/kW** (11.6 USD2019/kW × 1.192 = 13.83).

And the value of Taishan 1 and 2 is **31.49 USD2023/kW** (26.42 USD2019/kW × 1.192 = 31.49).

However, for Hinkley Point C, the O&M was no explicitly provided by the IEA/NEA 2020 report, thus a different approach was required. The plant is subject to a long-term Contract for Difference (CfD) with a strike price of 92.5 GBP2012/MWh, which serves as a proxy for total lifetime generation cost. Although the strike price includes CAPEX, OPEX, and profit margins, for this study we extract OPEX independently. According to the breakdown of typical nuclear power plant costs in the UK, prepared by the UK government from Wikipedia, O&M represents approximately 21% of the LCOE. Thus, assuming that the strike price (converted to 2023 USD) represents the LCOE, can be estimated the O&M cost of HPC.

First of all, to convert GBP2012 to USD2023, is necessary to use a cumulative inflation rate from 2012 to 2023, that is approximately 30.6% (UK CPI), and a 2023 exchange rate of 1GBP = 1.27USD.

Strike price (USD2023/MWh) = 92.5 × 1.306 × 1.27 = 153.33 USD2023/MWh

OPEX = 153.33 × 0.21 = **32.20 USD2023/MWh** (which includes the fuel costs).

OPEX costs were calculated as the sum of fuel and O&M expenses. The Table 6 below summarizes these harmonized OPEX figures.

Nuclear Power Plant	O&M (USD/MWh)	Fuel costs (USD/MWh)	OPEX (USD/MWh)	OPEX (billion USD)
Hinkley Point C	21,08	11,12	30,41	0,69
Flamanville 3	17,00	11,12	25,38	0,29
Vogtle Units 3 and 4	13,83	11,12	22,72	0,36
Thaisan 1 and 2	31,49	11,92	38,34	0,89

Table 6. OPEX. Nuclear

4.2.2.2. Geothermal power plants

After reviewing reports from major international energy organizations, a practical operating cost for geothermal power plants was determined. The average operation and maintenance costs (O&M) for standard geothermal plants are between 0.01 and 0.03 USD/kWh (as in the IRENA 2017 "Geothermal Power" article or in the American Investment Institute's (2024) "Geothermal Energy Brief").

According to this agreement and to ensure methodological consistency, a representative average value of **0.02 USD/kWh** is used for commercial scale confirmed geothermal plants such as Hellisheiði, Larderello or The Geysers. This is a midpoint between the reported minimum and maximum values and does not underestimate or overestimate O&M costs.

For pilot or demonstration plants based on enhanced geothermal systems (EGS), e.g. Soultz-sous-Forêts, a higher estimate is appropriate due to higher technical complexity, operational challenges and less familiarity with long-term maintenance. Soultz has therefore been assigned a conservative figure of **0.03 USD/kWh**.

One key aspect of geothermal power is that it doesn't need outside fuel. Unlike nuclear, coal, or gas plants, which need uranium, coal, or gas, geothermal plants get heat straight from the Earth as hot water or steam. This supply renews itself and doesn't need to be processed or bought, so geothermal systems don't have normal fuel costs. The fuel is just hot water that flows through rocks underground. This water is either put back or naturally replaced, making its cost close to nothing.

Given this, the fuel cost for geothermal energy is seen as zero when calculating the levelized cost of electricity (LCOE). This justifies the methodological decision adopted in this study to treat the operating expenditures (OPEX) of geothermal plants as equivalent to their operation and maintenance (O&M) costs. This approach is consistent with international literature and recognized methodology for geothermal cost modelling, such as the *Projected Costs of Generating Electricity 2020 Edition* by the IEA and NEA (2020).

Table 7 is the summary of the costs that compose the OPEX for geothermal plants is shown below.

Geothermal Power Plant	O&M (USD/MWh)	Fuel costs (USD/MWh)	OPEX (USD/MWh)	OPEX (billion USD)
Hellishedi	20	0	20	0,04512
Soultz-sous-Forêts	30	0	30	0,00038
Larderello	20	0	20	0,11914
The Geysers	20	0	20	0,08734

Table 7. OPEX. Geothermal.

4.2.3. Levelized Cost Of Electricity (LCOE)

The LCOE is calculated by dividing the total discounted costs of a project by the total electricity produced over its lifespan. This gives the minimum price needed to sell electricity to break even, covering all expenses without extra gains or losses. It includes factors like the project's lifespan, how much electricity it makes each year, and the discount rate.

The discount rate is a fundamental parameter in the economic evaluation of energy projects because it changes future costs and revenues into today's value. This idea known as the time value of money, means that money is worth more now than later because of conditions like inflation, financial risk, and the cost of missing out on other investments

In this study, three discount rates are considered 3%, 7%, and 10% to reflect varying financial conditions:

3%: For publicly funded or state-guaranteed and low-risk projects.

7%: For mixed financing schemes with moderate risk.

10%: For competitive-market projects with private capital with high-risk.

By applying the CRF at each discount rate, we convert the total CAPEX into an annualized cost. This, combined with the OPEX and fuel costs, enables the final LCOE to be calculated under different financial scenarios, facilitating a fair comparison between technologies and locations.

4.2.3.1. Nuclear power plants

Each nuclear plant under study has been assigned a specific discount rate based on its ownership model, financial structure, and risk profile.

Flamanville 3 has a state-owned and highly regulated project. It is fully financed by EDF (a public utility under French government control) the risk is low, and revenues are backed by a regulated framework. A **3% discount rate** is applied

Taishan Units 1 & 2 is also public, owned and financing by CGN and CNNC, both state-owned corporations, the project operates in a centrally planned energy market with low financing risks. A **3% discount rate** is also considered.

Hinkley Point C has a mixed financing, it has a privately owned, but EDF has a CfD (Contract for Difference) guaranteed by the government so the risk is partially mitigated. What the CfD guarantees is a fixed price per MWh of electricity generated for 35 years, adjusted for inflation. If the market price is lower than this fixed price, the government pays the difference. However, if the market price is higher, EDF pays the difference back to the government. A **7% discount rate** reflects the intermediate risk level.

Vogtle Units 3 & 4 also are developed under mixed financing with federal loan guarantees, but have experienced significant delays and cost overruns. The market exposure and elevated financial risks justify applying a **7% discount rate**.

A detailed summary of the LCOE results for all case studies, applying the three discount rates, is presented in the Table 8 below.

Nuclear Power Plant	Net annual production (TWh)	CAPEX (billion USD)	OPEX (billion USD)	CRF			LCOE (USD/MWh)		
				r = 3%	r = 7%	r = 10%	r = 3%	r = 7%	r = 10%
Hinkley Point C	22,85	52,16	0,69	0,0510	0,0806	0,1061	146,89	214,40	272,60
Flamanville 3	11,56	18,15	0,29	0,0510	0,0806	0,1061	105,46	151,87	191,89
Vogtle Units 3 and 4	15,66	32,84	0,36	0,0510	0,0806	0,1061	129,74	191,76	245,23
Thaisan 1 and 2	23,27	12,98	0,89	0,0510	0,0806	0,1061	66,81	83,31	97,54

Table 8. LCOE. Nuclear

4.2.3.2. Geothermal power plants

Geothermal projects also present varying degrees of financial risk depending on the market structure, public or private ownership, and technological maturity

Hellisheiði is owned and operated by ON Power, a subsidiary of Reykjavik Energy (a public utility), in a stable and regulated environment. Given the strong public backing, a **3% discount rate** is appropriate.

Soultz-sous-Forêts, although it is an R&D demonstration project with EU and public funding, it has faced significant technical challenges and uncertainties, placing it in a mid-risk profile. A **7% discount rate** is applied.

Larderello is operated by ENEL Green Power, part of the publicly controlled ENEL group. Given its maturity and regulatory context, the project is considered low-risk, and a **3% discount rate** is used.

The Geysers operates in a deregulated electricity market and is privately owned, subject to market pricing volatility. Therefore, a **10% discount rate** reflects the higher financial risk.

FORGE & Red Project are still pre-commercial or pilot-scale Enhanced Geothermal Systems (EGS) with substantial technological and financial uncertainties. A **10% discount rate** is used to reflect high risk and private financing structures.

Quaise Energy (USA - proposed deep-EGS): As an emerging project still in development with high technological risk and fully private investment, it falls under speculative ventures. A **10% discount rate** is also assigned here.

The Table 9 below presents a consolidated overview of the LCOE values calculated for all geothermal case studies, using three different discount rates.

Geothermal Power Plant	Net annual production (TWh)	CAPEX (billion USD)	OPEX (billion USD)	CRF			LCOE (USD/MWh)		
				r = 3%	r = 7%	r = 10%	r = 3%	r = 7%	r = 10%
Hellishedi	2,256	1,391	0,04512	0,0672	0,0944	0,1175	61,43	78,19	92,41
Soultz-sous-Forêts	0,013	0,010	0,00038	0,0672	0,0944	0,1175	85,25	107,58	126,54
Larderello	5,957	3,682	0,11914	0,0672	0,0944	0,1175	61,55	78,35	92,61
The Geysers	4,367	2,994	0,08734	0,0672	0,0944	0,1175	66,08	84,72	100,53

Table 9. LCOE. Geothermal

4.3. Environmental results

The environmental impact analysis presented in this document is mainly based on peer-reviewed and consolidated scientific literature. To ensure consistency and transparency, the majority of quantitative values and qualitative assessments are drawn from this key sources: the review article *Environmental Impact of Electricity Generation Technologies: A Comparison between Conventional, Nuclear, and Renewable Technologies* by Guidi, Violante, and De Iuliis (2023); the European Commission's Joint Research Centre (JRC) technical report *Technical Assessment of Nuclear Energy* (2021); and the subject review *Environmental Impact of Geothermal Power Plants* by Bošnjaković, Stojkov, and Jurjević (2019).

By basing the analysis on these three sources, all of which follow rigorous methodologies recognized in the scientific community, the following sections aim to provide a consistent, reliable and updated comparison between nuclear and geothermal electricity generation technologies from an environmental perspective.

4.3.1. CO_2 emissions (g CO_2/kWh)

4.3.1.1. Nuclear power plants

Lifecycle Assessments (LCAs) demonstrate that nuclear power emits very low Greenhouse Gases (GHG), typically between 5–12 $g\ CO_2-eq/kWh$. A comprehensive review (JRC 2021) reveals that light water reactors (LWRs) emit on average 5.1 $g\ CO_2-eq/kWh$, pressurized water reactors (PWR) average 8 $g\ CO_2-eq/kWh$, and boiling water reactors (BWR) around 18.4 $g\ CO_2 - eq/kWh$. Generation III EPR reactors emit around 5 $g\ CO_2 - eq/kWh$ if it is an opened cycle or 4.6 $g\ CO_2 - eq/kWh$ if it is a partially closed cycle.

4.3.1.2. Geothermal power plants

Emissions vary by plant type. If it is binary (closed-loop) systems have near-zero carbon output, while flash systems emit between 15 and 24 $g\ CO_2 - eq/kWh$ depending on configuration. If them are single-flash at 18 $g\ CO_2 - eq/kWh$ and double-flash at 15 $g\ CO_2 - eq/kWh$ average. Consequently, binary geothermal systems are as clean as nuclear, and flash systems are still much better than fossil fuels. EGS systems requires a bigger amount of energy and materials in the construction phase and for this reason, they show broader ranges from 7.3 to 37 $g\ CO_2 - eq/kWh$, though averages vary widely.

4.3.2. Other emissions

4.3.2.1. Nuclear power plants

During operation, nuclear plants do not produce sulfur oxides (SO_x), nitrogen oxides (NO_x), or particle pollution. Small emissions are related to non-essential support operations, such as on-site transportation but it's not much compared to fossil fuel plants.

4.3.2.2. Geothermal power plants

Flash plants emit trace gases such as H_2S, CH_4, NH_3, boron, and mercury, but estimates show these are under 5% of coal plant levels. Binary plants eliminate these emissions entirely due to closed-loop configurations.

However, modern plants deploy emission-control and reinjection systems to mitigate these, making environmental releases typically negligible

4.3.3. Land requirement (m^2/MW or m^2/MWh)

4.3.3.1. Nuclear power plants

Nuclear power requires relatively small land area per unit of electricity generated. For instance, the land footprint for most reactors, including necessary safety and exclusion zones, is approximately 0.13 m^2/MWh. According to the JRC 2021, the average land requirement for nuclear electricity is approximately from 0.1 to 0.4 m^2/MWh, among the lowest of all electricity generation technologies.

It has a high power density, that supports efficient land use in energy production.

4.3.3.2. Geothermal power plants

A geothermal power plant includes the power units, pads, and reinjection areas. It also has a big network of wells, piping, separators, heat exchangers, buildings, and roads, which stretches over large areas.

Although compact in terms of visible facilities, the total land occupation can vary considerably depending on the number and distribution of wells and the type of terrain. For example, Bošnjaković et al. (2019) note that while surface facilities may occupy only a few hectares, the entire geothermal field, including drilling infrastructure and pipelines, may cover several square kilometers. In terms of land use per electricity produced, Guidi et al. (2023) report an average of 0.1 to 1.5 m^2/MWh, depending on field configuration and plant technology.

The distribution of wells over large distances and the need for extensive piping systems to transport geothermal fluids often increase the effective land area involved, even if not fully constructed. However, geothermal projects can often share land and coexist with agricultural or forest land, which helps lower the visual and environmental impact.

4.3.4. Water consumption

4.3.4.1. Nuclear power plants

Nuclear power plants require a high water consumption. These plants are among the highest consumers of water per unit of electricity generated among low-carbon technologies. Water is primarily used for cooling purposes in systems such as once-through, closed-loop (wet cooling towers), or dry cooling, depending on plant design and location.

According to the JRC 2021, typical water consumption values for nuclear power plants range from 1.8 to 3.3 m^3/MWh.

In wet cooling systems, water is lost through evaporation, which increases total consumption. Closed-loop systems consume less water, but evaporation losses are higher.

4.3.4.2. Geothermal power plants

Geothermal plants use different amounts of water, but it depends on the technology and whether they use a reinjection system. In dry steam or flash steam plants, the water extracted with geothermal fluids is usually reinjected back into the reservoir, which minimizes net losses. However, in binary cycle power plants (which use an ORC), and especially in EGS, water can be used not only to extract heat, but also to fracture rock formations, maintain pressure, and occasionally for cooling. According to Bošnjaković et al. (2019) and Guidi et al. (2023), the average geothermal water consumption can range from 0.1 to 1.0 m^3/MWh., depending on plant configuration, fluid properties, and reinjection efficiency. In systems with efficient reinjection, net water consumption can be extremely low or almost negligible.

4.3.5. Waste generation

4.3.5.1. Nuclear power plants

Nuclear power creates all types of radioactive waste that need special handling and disposal. Most of this waste, between 90% and 97% of it is low and medium-level waste (LLW and ILW), like clothing, filters, and items from maintenance. They contain only 1% to 2% of the total radioactivity and are usually disposed of at surface sites (World Nuclear Association, 2023).

In contrast, high level waste (HLW) is much more dangerous. It is generated mainly from spent nuclear fuel, which is either directly deposited or reprocessed. A standard 1 GW nuclear power plant generates approximately 25-30 tons of spent fuel per year, which is reduced to about 3 m^3 of vitrified high-level waste after reprocessing (Wikipedia, 2023). The spent fuel is initially stored in pools of water for a few years to facilitate thermal and radiological decay. It is then shipped to dry cask storages, huge steel and concrete vessels that can hold waste for decades without the need for active cooling (IAEA 2022; NEA, 2021).

Long-term solutions for HLW are deep geological repositories, such as the Onkalo plant in Finland. However, interim storage is still the case in most countries, as there are no permanent repositories in operation. In the United States, for example, there are more than 90,000 tons of spent fuel stored in various interim storage facilities.

Although the total worldwide amount of HLW is relatively low, approximately 29,000m^3, it needs to be stored for thousands of years due to its long-lived radioactivity. To ensure safe disposal, nuclear operators are required by law to cover the entire cost of waste storage and disposal. This cost is usually internalized through a surcharge on the electricity produced by nuclear power of 0.1-0.14 eurocents per kWh, which represents about 5% of its total cost (World Nuclear Association, 2023).

Although the dangers of radioactive waste are well known, the amount of nuclear waste is relatively small compared to other energy sources. Nuclear power has a very high energy density, so a small amount of fuel will generate enormous amounts of electricity. Therefore, the total volume of high-level waste remains limited. According to the U.S. Department of Energy (DOE), all the used fuel made by U.S. reactors since the 1950s (about 90,000 metric tons) could fit on a standard soccer field stacked about 10 meters high (U.S. DOE, 2020). This shows how concentrated nuclear waste is, compared to ash and CO_2 from fossil fuels over similar time periods.

The problems of handling radioactive waste should not be ignored, but nuclear waste is often easier to manage than people think.

4.3.5.2. Geothermal power plants

Geothermal energy produces minimal amounts of waste compared to nuclear energy, and does not contain radioactive material. Drilling activities are the main cause of solid waste, which also includes mineral fouling and sludge from power plant operations.

In addition to solids, huge volumes of brine and condensed steam are handled in geothermal power plants. These fluids are usually reinjected back into the geothermal reservoir to maintain pressure and avoid surface contamination. However, due to the presence of trace elements such as arsenic, boron or lithium, treatment may be required prior to reinjection or disposal. In addition, about 15% of the dried sludge is toxic due to heavy metal composition and must be processed in controlled facilities.

5. Discussion on Economic Analysis results

5.1. Overview and consistency of results

Net annual electricity production is a fundamental metric when assessing the economic feasibility of power generation technologies.

Among the nuclear power plants analyzed, Taishan 1 and 2 report the highest net annual production at 23.27 TWh, closely followed by Hinkley Point C with 22.85 TWh. This reflects their large unit sizes and continuous base-load operation profiles. Notably, Flamanville 3, a single-unit EPR plant, generates 11.56 TWh, while Vogtle Units 3 and 4 deliver 15.66 TWh, aligning with the dual-reactor setup of Vogtle compared to the single EPR at Flamanville.

In contrast, geothermal plants exhibit much lower electricity output on an annual basis. The Hellisheiði plant, one of the largest in Europe, produces 2.256 TWh/year, which is already an exceptional figure for a geothermal facility. The Larderello complex in Italy, with its multiple interconnected units and long operational history, produces 5.957 TWh/year, the highest among geothermal entries. The Geysers, a mature field in California, produces 4.367 TWh/year, also showcasing high output due to decades of optimized operation.

However, Soultz-sous-Forêts, an EGS pilot plant in France, only produces 0.013 TWh/year, highlighting the technical and geological challenges of EGS in low-permeability environments. While such pilot plants are invaluable for R&D, their current production volumes are economically non-competitive.

CAPEX is one of the most critical economic indicators, especially for capital-intensive technologies such as geothermal and nuclear, where capital is a key determinant of viability.

Among the nuclear plants analyzed, Hinkley Point C is the most expensive, with a CAPEX of 52.16 billion USD, due to its capacity, the high cost of EPR technology, UK regulatory issues and the long construction lead time. This figure is almost three times that of Vogtle units 3 and 4 (32.84 billion USD), despite the cost overruns. Flamanville 3, an isolated reactor, has cost 18.15 billion USD due to construction delays, design modifications and French safety regulations. Taishan 1 and 2, built in China, have a much lower CAPEX of 12.98 billion USD, thanks to reduced labor costs, more standardized construction and fewer regulatory hurdles. This wide range highlights the influence of local conditions, supply chain maturity and governance structure on nuclear CAPEX.

In terms of capital investment, geothermal projects require much lower absolute investment compared to nuclear plants, although normalized costs may vary relative to production. Larderello hosts the largest CAPEX among geothermal plants, at 3,682 billion USD, reflecting its size and level of infrastructure over the years, spread across multiple units. Geysers, another similar complex, has an estimated CAPEX of 2,994 billion USD, in line with its extensive development.

Hellisheiði had a cost of 1.391 billion USD, relatively low given its high annual production and the new binary cycle power plant design, which improves efficiency and reservoir life. Soultz-sous-Forêts, despite its low production, had a cost of 0.010 billion USD, relatively expensive when considered per MWh generated. This demonstrates the exploratory and technological risk inherent in EGS development, of which deep drilling, hydraulic stimulation and unusual well design are part.

Therefore, geothermal CAPEX is usually moderate, but is highly site-dependent. While conventional geothermal fields offer a good investment-return ratio, high-geothermal and frontier geothermal projects struggle to justify high upfront costs in exchange for modest returns, in the absence of R&D funding or political support.

OPEX includes the recurrent yearly cost of running, managing, and maintaining a power plant. Some of these are staffing, maintenance, refueling (for nuclear), insurance, and administrative overheads. OPEX is critical in assessing long-term viability and competitiveness of energy sources.

Nuclear power plants have relatively high OPEX due to high safety protocols, advanced maintenance, and the cost of fuel cycle. Taishan 1 and 2, which are low CAPEX, have the maximum OPEX at 0.89 billion USD/year, which may be due to higher fuel costs and operating complexity despite being a recent plant. Hinkley Point C and Vogtle Units 3 and 4 record OPEX values of 0.69 and 0.36 billion USD/year, respectively, while Flamanville 3 records the lowest for the nuclear group at 0.29 billion USD/year.

On the other hand, the most favorable economic attribute of geothermal power is its extremely low OPEX. These plants, once built, have extremely low ongoing costs to operate, taking into account the absence of fuel cost and the closed-loop stability of the systems. Hellisheiði, despite its massive size, has an OPEX of only 0.04512 billion USD per year, with turbine maintenance, reinjection system maintenance, and environmental monitoring included.

Larderello and The Geysers also have relatively low O&M costs, 0.11914 and 0.08734 billion USD/year respectively, a small figure compared to their output.

Soultz-sous-Forêts, as a small research plant, has an OPEX of only 0.00038 billion USD (380,000 USD) per year, though even this is high relative to its very small energy output.

These values confirm that the OPEX is an advantage of geothermal in the operational phase. Once the reservoir is properly managed and the plant is optimized, the system has the potential to produce reliable power for decades at minimal cost, an ideal profile for energy systems with long-term cost stability objectives and minimal exposure to fuel price volatility.

Analyzing the capital recovery factor for the of 3%, 7% and 10% discount rates, the results for the nuclear plants are:

- 3% → 0.0510
- 7% → 0.0806
- 10% → 0.1061

And the results for the geothermal plants are:

- 3% → 0.0672
- 7% → 0.0944
- 10% → 0.1175

This implies that, under the same financing conditions, nuclear projects have longer payback period, making them more stable when capital costs increase. Geothermal projects need quicker cost recovery, which can be hard if energy production is low or initial drilling risks are high. Therefore, while geothermal may cost less up front, its financial success is more dependent on discount rates and how certain production levels are.

Nuclear power plants can generate a large-scale of low-carbon electricity, so they have important economic competition questions. The LCOE of nuclear plants is greatly affected by their high initial capital costs, long construction times, and how they are finance.

For our purposes, Flamanville 3 and Taishan 1 and 2 have relatively moderate LCOEs of about 105 and 67 USD/MWh respectively, based on a 3% discount rate. This implies that when nuclear power investments are backed by strong government guarantees, high interest rates or national strategic imperatives, they can be economically viable even if they have high CAPEX.

However, things get more complicated for projects that carry more financial risk. Hinkley Point C and Vogtle units 3 and 4, with a discount rate of 7% to reflect their public-private partnership structures and higher market exposure, show total ownership costs well above their own, about 214 and 192 USD/MWh, respectively. The cost competitiveness of nuclear power in deregulated electricity markets without strong subsidy provisions is daunting. Long lead times for nuclear projects increase total investment costs due to inflation and interest, and expose projects to political and regulatory pressures.

In comparison, the LCOE of geothermal power plants shows a persistent trend towards economic viability, especially when the cost of financing is low. Hellisheiði and Larderello, both with 3% discounting, yield very competitive LCOEs of about 61 USD/MWh. These experiences underline the virtues of low capital cost and high resource quality, conditions that are often found in geologically active regions. Their profitability is further enhanced by extremely low OPEX levels and consistently high capacity factors, resulting in a steady supply of electricity at low operating costs. These attributes make geothermal power not only grid stable, but also immune to volatile fuel prices and carbon compliance costs.

Even in the most technically challenging cases, such as Soultz-sous-Forêts and The Geysers, geothermal power remains profitable. Soultz, although small and built on the basis of experimental protocols, is approaching an LCOE of about 108 USD/MWh at a

7% discount rate, demonstrating that even pilot plant-scale enhanced geothermal systems (EGS) can approach economic viability with the right support programs. The Geysers, the world's largest geothermal field, shows a strong performance at a 10% discount rate and an LCOE of about 101 USD/MWh, demonstrating that geothermal can remain competitive even when capital costs are already amortized over more commercial terms.

5.2. Comparative interpretation: Nuclear vs Geothermal

When comparing nuclear and geothermal power plants, the first and the most obvious difference is the capital costs (CAPEX) of both technologies. Nuclear power plants involve extremely high initial investment costs, ranging from 12.98 billion USD (Taishan 1 and 2) to over 52 billion USD (Hinkley Point C). These figures consider the complexity of the plant and long building periods, as well as the high safety, regulatory, and environmental standards for nuclear power. In comparison, geothermal power plants require much less CAPEX, even for relatively large facilities. Hellisheiði and Larderello, for example, require 1.39 billion USD and 3.68 billion USD respectively, much less than any nuclear project. This contrast highlights one of the economic advantages of geothermal technology: its modularity, lower construction risk and shorter lead times, all of which serve to reduce cost and improve bankability.

Operating costs (OPEX) also play a role in this differennce. Nuclear power plants, due to their complex infrastructures and large operating equipment, have OPEX costs ranging from 0.29 billion USD to 0.89 billion USD per year. These high costs are a function of fuel handling, waste removal, constant safety inspections and ongoing personnel requirements. In the case of geothermal power, OPEX is always low, often a fraction of what is needed for nuclear operations. As an example, Hellisheiði OPEX is just 0.045 billion USD per year, while that of Larderello is somewhat higher at 0.119 billion USD per year. If the highest OPEX of the geothermal plants studied is compared with the lowest of the nuclear's one, there is still a difference of 0.17 billion USD per year.

These costs reflect the simplicity of geothermal operation, which, once established, is based primarily on passive heat extraction with minimal mechanical or chemical handling.

A more helpful comparison comes from looking at the Levelized Cost of Electricity (LCOE). This measure includes both capital expenditures and operating expenses, spread out over the plant's lifespan and energy production. By using different discount rates that reflect real-world economic situations (like 3% for government-funded projects such as Flamanville or low-risk locations such as Larderello, and 7-10% for riskier, market-driven investments), the resulting LCOE values provide important insights.

Nuclear LCOEs range from 66.81 USD/MWh (Taishan, r = 3%) to 214.40 USD/MWh (HPC, r = 7%), indicating a high sensitivity to the financial interest rate and investment cost. Although Taishan is competitive, it is an outlier due to reduced CAPEX and favorable financial conditions.

In contrast, geothermal LCOEs are much lower and stable, with values such as 61.55 USD/MWh for Larderello (r = 3%) and even The Geysers, with a rate of 10%, is still below 101 USD/MWh. This stability is a clear indicator of geothermal's resilience to financial stress, driven by its low OPEX and moderate CAPEX.

In conclusion, nuclear power can produce a lot of electricity in one place, but its affordability depends on keeping building costs down, getting cheap loans, and having stable government policies for a long time. If building is delayed or costs more than planned, which often happens with big nuclear projects, it can really mess up the LCOE and how the project makes economic sense. But geothermal energy, which usually has smaller production sizes, is attractive because it’s cost-saving, easy to run, and has stable economic performance over time. Its lower LCOE at different discount rates, along with less money and tech risk, make it a fit for a varied, spread out, and eco-friendly energy strategy.

5.3. Role of emerging projects and technological innovation

Technological innovation and future projects will play a key role in remaking the economic and technical profile of nuclear and geothermal energy.

In the nuclear sector, innovations are focused on standardization, modularization and safety optimization. Between these innovations there are the Small Modular Reactors (SMRs) and advancements in reactor safety and modularity in build are being described as game-changers. These technologies are designed to reduce drastically the construction time and cost (CAPEX), increase scalability, and extend the utility of nuclear to small or distant energy markets. For instance, SMRs envision savings on capital costs through facilitation of factory-based assembly and standard designs, which may lower the economic barrier to entry that has long plagued conventional large-scale nuclear projects. Furthermore, improvements in fuel cycles and passive safety technologies are expected to raise operation efficiency and social acceptability, which are two of the nuclear industry's historical issues. However, most of these technologies are still in the early stages of development or blocked by regulation and funding barriers. Their impact on LCOE will materialize only with the support of clear-cut political commitment, R&D spending, and market confidence in long-term nuclear projects.

In the geothermal industry, major progress could come from programs like the Red Project, FORGE (Frontier Observatory for Research in Geothermal Energy), and Quaise Energy. These initiatives concentrate on improving geothermal technologies and changing how and where geothermal energy is produced.

Red Project, under construction in Utah, serves as an EGS technology example. It shows that stimulation processes can create reservoirs in hot dry rock, allowing energy production even in less favorable geological conditions. With a concentrated capacity of 3.5 MW and high well productivity, Red could prove that EGS can compete with fossil fuels economically. If successful, it could become a model for commercial EGS plants globally, expanding geothermal energy's reach and lowering LCOE by producing more energy per well.

Utah's FORGE, funded by the U.S. Department of Energy, is perhaps the most advanced public R&D facility dedicated to geothermal technology. Instead of using already found reservoirs, FORGE aims to develop the needed tools, technology, and practices to re-engineer reservoirs to an industrial scale. This includes testing new drilling methods, downhole instruments, and heat extraction strategies that can work at depths of 3-5 km in hard rock. Its purpose is key: if FORGE proves that these technologies are economically and technically sound, it could enable gigawatt-scale deployment of EGS globally with a small environmental footprint and good CAPEX and OPEX profiles.

Quaise Energy is pushing the limits of current capabilities. It uses a new drilling method utilizing millimeter wave beams (gyroscopes) to heat and vaporize rock to depths of 20 km or more. At these depths, supercritical water could be accessed, offering much higher heat densities than current geothermal systems, enough to power turbines as efficiently as fossil fuel-based power plants. If feasible, this would remove geothermal energy's geographic limits, allowing energy facilities to tap into the Earth's internal heat anywhere. The possibilities are great, as it would provide baseload power with no fuel, a small surface footprint, no emissions, and possibly one of the lowest LCOEs of all energy technologies. But, of course, it is subject to tests of technical feasibility, scalability and cost reduction, all of which remain to be demonstrated on a large scale.

6. Discussion on Environmental Analysis results

The environmental record of electricity generation technologies becomes ever more important in influencing long-term energy policy. This section presents a detailed comparative analysis of the environmental effects of nuclear and geothermal power plants. The comparison is based on facts and data from three basic scientific sources: the comprehensive review of Guidi et al. (2023), the Joint Research Centre of the European Commission (JRC, 2021), and the in-depth geothermal study by Bošnjaković et al. (2019). For each environmental indicator, a consideration is made to determine the technology that has lower environmental impact and superior sustainability performance.

Greenhouse gas emissions ($\boldsymbol{g\ CO_2 - eq/kWh}$)

Nuclear electricity has some of the lowest lifecycle greenhouse gas emissions of any baseload power source. Based on fuel cycle and reactor type, the emissions range from 4.6 to 18.4 g $g\ CO_2 - eq/kWh$. The latest designs, i.e., Generation III EPR reactors, are the best—reaching as low as 4.6 g $g\ CO_2 - eq/kWh$ figures in part-closed cycles. Binary geothermal stations, due to their closed-loop configurations, also exhibit near-zero emissions. Flash plants emit somewhat more, averaging 15–24 g $g\ CO_2 - eq/kWh$, and Enhanced Geothermal Systems (EGS) have broader ranges (7.3–37 $g\ CO_2 - eq/kWh$) due to their drilling- and stimulation-intensive nature. So, both technologies are superior to fossil fuels, but overall, nuclear plants have better consistency in having low emissions at all locations and sizes.

Other emissions

Nuclear plants don't release much sulfur oxides (SO_x), nitrogen oxides (NO_x), or air pollutants when running. When emissions do happen, it's usually from extra parts that aren't part of the main process. Flash geothermal systems release small amounts of gases like hydrogen sulfide (H_2S), ammonia (NH_3), methane (CH_4), boron, and mercury. These are much lower than what fossil fuel plants release (often less than 5% of coal), but binary geothermal systems are better because they don't release these emissions at all. Current technology that puts fluids back into the ground and controls emissions reduces pollutants from flash plants, but there's still some effect on the environment. Nuclear power has almost no emissions into the air.

Land use efficiency (m^2/MWh)

Land use is one of the most important environmental integration indicators. Nuclear power, due to its compactness and high energy density, has one of the lowest land requirements, typically, between 0.1 and 0.4 m^2/MWh. Even after accounting for safety buffers and exclusion zones, this footprint is modest. Geothermal facilities, while generally appearing compact, require extensive surface and subsurface infrastructure. The need for distributed production and injection wells, lengthy above-ground pipelines and facilities, increases the overall land footprint. Estimates range from 0.1 to 1.5 m^2/MWh, depending on plant configuration and terrain. While geothermal locations can occasionally be shared with agriculture or forests (reducing ecological disturbance) the land actually used is nonetheless much higher in most configurations.

Water consumption (m^3/MWh)

Water use constitutes one of the greatest environmental differences between both technologies. Nuclear facilities, particularly those using wet cooling systems, are among the largest water users per unit of electricity generated, with consumptions ranging from 1.8 to 3.3 m^3/MWh. This is due to the cooling requirements inherent in thermal generation. Although closed-loop or dry cooling systems reduce overall water withdrawals, they still create evaporative losses. Geothermal plants, by comparison, have lower water usage, especially when reinjection systems are utilized effectively. Flash and binary plants typically range between 0.1 and 1.0 m^3/MWh, depending on site-specific reinjection and cooling practices. In this measure, geothermal has clear benefits, particularly where water is scarce.

Waste generation and management

Nuclear and geothermal energy make different kinds of waste. Nuclear power makes high-level radioactive waste (HLW), which is quite dangerous but not a lot of it. It has to be stored safely for a long time. The waste generated isn't much compared to the amount of energy made, but finding a long-term solution for storing it is a major environmental challenge.

On the other hand, geothermal power, on the other hand, doesn't make radioactive waste. It makes drilling waste, mineral buildup, and sometimes dangerous brines. About 15% of the waste needs special treatment because it has heavy metals. Usually, the fluids are pumped back underground to keep pollution off the surface. Even so, safely getting rid of toxic brines can sometimes be an issue for geothermal systems.

A summary of the environmental impact study carried out to facilitate subsequent conclusions can be found in Table 10 below.

Environmental Parameter	Nuclear Power	Geothermal Power	Best Performer
CO_2 emissions ($g\ CO_2 - eq/kWh$)	4.6 – 18.4	0 – 37 (Binary: ~0; Flash: 15–24; EGS: 7.3–37)	Nuclear or Binary geothermal
Other emissions	Negligible	Negligible in binary; low (H_2S, NH_3, CH_4, boron, and mercury) in flash systems	Nuclear or Binary geothermal
Land use (m^2/MWh)	0.1 – 0.4	0.1 – 1.5	Nuclear
Water consumption (m^3/MWh)	1.8 – 3.3	0.1 – 1.0	Geothermal
Waste hazard level	High-level radioactive, long-lived	Non-radioactive, minimal but sometimes toxic	Geothermal
Waste volume	Very low due to high energy density	Moderate from drilling and operations	Nuclear
Emission control systems	Mostly unnecessary due to lack of emissions	Necessary in flash plants	Nuclear or Binary geothermal

Table 10. Environmental analysis. Nuclear vs Geothermal.

From an environmental standpoint, both geothermal and nuclear are sustainable, low-carbon sources of electricity that have enormous advantages over their fossil fuel counterparts. Nuclear is more efficient in land use, has a low consistency of greenhouse gas emissions and very few atmospheric pollutants. Its environmental disadvantages are high water consumption and long-term radioactive waste disposal problems.

Geothermal energy, especially when set up in binary systems, almost produces no emissions, while flash and EGS setups release slightly more. Geothermal energy creates large amounts of water, but the waste is generally not toxic. Also, using the land for more than one thing can help reduce the amount of land needed. Yet, changes in output, mostly at EGS plants, and complicated handling of spread-out setups and salty waste pose some difficulties.

Finally, the best technology from an environmental point of view depends on the situation. When water is scarce, geothermal is clearly preferable. When the area is densely populated or land is scarce, the minimal footprint of nuclear power is critical. In terms of absolute emissions and pollutant production, the two technologies are nearly ideal, but nuclear has even better consistency.

Thus, instead of picking one as superior, it makes sense to see how they can work together. Nuclear energy can be a reliable, powerful source for basic energy needs. Geothermal energy serves as a versatile, low-impact choice, suited for areas with geothermal activity or deserts.

7. Integrated conclusions and scenarios

This section takes the detailed comparison of nuclear power and high-enthalpy geothermal energy and applies it to actual situations. We will look at the technical, economic, and environmental factors to form conclusions.

With this study is going to be possible to choose which energy source fits better in a special territory, considering its energy needs, resources, economy, and environmental goals.

7.1. Scenario 1: Large, centralized systems with strong investment capacity.

This scenario involves countries where the central government plans, finances, and operates the power supply. These governments (or government-supported utilities) can obtain large, long-term loans at reasonable interest rates, and their electricity grids are designed for a few large power plants. These systems usually have a few large generating units feeding a national transmission network, instead of many spread-out sources. France, China, and the United Arab Emirates fit this description. Each of these countries already has at least one large nuclear power program and has the organizational strength (engineering supply chains, long-range planning groups, and nuclear regulators) to manage projects that take ten years before they produce any energy.

In these situations, choices about investing are based not just on how much money is needed right away, but on the ability to have predictable output for years. Nuclear plants need a lot of money up front, which might stop them from being used in systems with less money. But this price is worth it because they last a while and work well. With lifespans of about 30 years and working more than 80% of the time, nuclear plants produce a lot of electricity and are usually available. Their constant output means there is less need to invest in energy storage, backup generation, or stronger transmission lines, which would be needed if there were mostly variable renewables.

On the other hand, geothermal energy, especially EGS, has some built-in limits in this situation. Geothermal plants can technically provide low-carbon electricity that can be turned on when needed, but they are much smaller and depend a lot on local geology. To get the same output as one nuclear unit, many geothermal plants would be needed. Each one would need its own site development, drilling, and exploration, which is risky. This raises the overall cost and makes it harder to deploy the project and connect it to the grid.

Also, EGS technologies are still new, with high costs and uncertainty about how they will perform in the long run. In areas with limited resources, like much of continental France, there are not many good places for high-enthalpy geothermal plants, which limits how much this solution can be used. Even in countries with good geothermal potential, the scattered nature of the resource requires a lot of infrastructure and makes it hard to have centralized systems.

Both technologies greatly reduce carbon emissions over their lifecycles. But in this scenario, geothermal energy can cause local problems, like induced seismicity and gas emissions (such as hydrogen sulfide), which need to be managed carefully. Nuclear energy, however, has the issue of radioactive waste, but countries like France already have plans and facilities for handling it long term.

In conclusion, in countries with strong financial markets, experienced nuclear organizations, and a grid system designed for large, consistent baseload power, nuclear energy is still the most financially sensible choice. Its higher capital cost is balanced by its large unit size, long life, grid-stability services, and lack of extra costs. High-enthalpy geothermal is helpful where resources are plentiful, but its limited scale and geographic restrictions stop it from replacing large nuclear power programs in centralized power systems.

7.2. Scenario 2: Regional systems with limited investment but geothermal resources

In regions where budget limits or political instability make big, centralized investments hard, but geothermal resources are available and well-studied, geothermal energy becomes a suitable solution. These areas often use local energy systems and invest in smaller, adaptable options instead of large-scale plants, which are designed for local energy needs.

Some examples are Kenya, Indonesia, the Philippines, and some parts of Latin America, like northern Chile and southern Mexico. These places usually have active volcanic areas or tectonically active crust, which are good for geothermal use. However, their budgets or credit scores often don't let them start big nuclear projects. Nuclear energy needs billions of euros upfront, as well as strong rules and long-term political stability.

Kenya offers a clear example. Over 45% of its electricity comes from geothermal power, mostly from the Olkaria geothermal field. The country built this by adding geothermal units slowly as money and knowledge increased. This gradual way is different from nuclear energy projects, which usually take ten years or more to plan and build before making any power.

In this setting, geothermal energy has some main advantages like smaller unit sizes and flexibility make it easier to match investments with available funds, shorter build times lower the risks from inflation, currency changes, and political shifts and local jobs in drilling, plant work, and maintenance help regional growth.

On the other hand, nuclear power faces some big difficulties in these regions like that the high initial costs are hard to pay for without government support or outside help, the complex permission processes, international safety rules, and nuclear regulatory groups are often not well-developed or don't exist, connecting to the grid is more difficult because many regional networks aren't made for big, centralized units and may have weak power lines.

Also, nuclear plants usually need a lot of water for cooling, which may not be available in dry or remote volcanic areas. They also need a constant skilled workforce, spare parts, and international safety checks, which make them less fitting in remote or local systems.

From a purely money view, geothermal development is often more feasible and less risky in these regions. There are still drilling risks and some geological unknowns, the power to grow projects slowly, but the international support from some groups makes it a reachable and lasting solution.

In short, in systems with little money but good geothermal potential, geothermal energy is the better choice. It fits the region’s technical, money, and environmental situations.

This idea also covers a different kind of country: those with high income and good energy systems, which could pay for nuclear, but have chosen geothermal for reasons about strategy and the environment. Some examples are Iceland, Italy (Tuscany), and New Zealand.

Iceland is a world leader for geothermal development. Italy, mainly the Tuscany region, is home to Larderello, the world's first geothermal power plant. New Zealand also has a lot of geothermal creation.

In all these cases, geothermal is chosen not just because of cost, but because it better fits the land, social structure, environment, and energy system features of the country. These countries either don't have public approval for nuclear or don't need the size and problem of such infrastructure.

In countries with few money but strong geothermal potential, like Kenya, Indonesia, or the Philippines, geothermal power is the better choice because it costs less to start, makes local jobs, and takes less time to grow. Nuclear, in contrast, is not possible under current money and system limits.

In more grown countries with both the money and the choice to pick, like Iceland, Italy, and New Zealand, geothermal has still been liked, often because it fits better with the national grid design, has lower risk in mind, has public support, and has a wish to grow domestic renewable resources as much as possible.

In conclusion, in regional systems with low or moderate investment power but strong geothermal resources, geothermal energy is the more practical, cost-saving, and environmentally right choice.

7.3. Scenario 3: Countries with urgent electrification needs

This analysis focuses on nations where a large segment of the population lacks dependable electricity. Expanding the grid and raising living standards are key national goals in these places. The main aim is to put energy infrastructure in place quickly, affordably, and reliably, often when institutional abilities, public funds, and grid systems are not strong. For example, Ethiopia, Tanzania, Papua New Guinea, and Honduras.

In these situations, nuclear energy is usually not a good fit. Starting a nuclear program takes a long time (at least 10–15 years), needs very high capital investment, and also needs a strong regulatory and safety system, plans for long-term waste control, and specialized employee instruction. Countries dealing with poverty, not enough basic infrastructure, and unstable governments usually cannot meet these needs.

Nuclear power plants also make a lot of power at once, which is often too much for the small and spread-out grids in many low-income nations. This can overload the system or waste power if there is not enough demand. atomic plants do not bend easily and must run all the time, so they need stable grids, which are not always present in these places.

On the other hand, geothermal energy has key benefits for quick electrification, assuming there is geothermal potential. Countries in the East African Rift or volcanic belts of Central America and Southeast Asia can gain a lot from this choice.

In all of these countries, the main thing is speed and saving money. Both are in favor of geothermal over nuclear. Though geothermal growth has risk when searching and costs money up front to dig, the project size, growth speed, and easy-to-control issues make it work better with the energy plans of these nations. The smaller size of geothermal plants lets them fit local demand and get placed closer to where people need power, avoiding big upgrades to how power moves.

Looking at the environment, both options are low-carbon, but geothermal has less risk to the system. Nuclear accidents, although rare, cause significant damage and generate political tension, especially in areas with weak governance and difficult emergency response. Waste disposal is another concern for nuclear energy, especially in countries without long-term storage plans. Geothermal projects may have small local impacts (such as land subsidence or gas releases), but these can be more easily monitored and addressed with good regulations and best practices.

In short, in countries where there is need to get energy fast, where there are small funds, and basic setup is not strong, nuclear power is not helpful. The long waits, high costs, and system needs make it not right for the fast goals of getting power to people and ending poverty.

Geothermal energy is better suited to achieving short- and long-term goals, especially in countries with geothermal sources and dispersed needs. It can grow, is built in parts, and uses local setup so it can get used faster and easier, with less money and worry to people.

In these cases, geothermal energy is not only a good option from a capacity perspective, but also more economically and regulatoryly. It cannot replace large baseload nuclear power generation in highly developed countries, but in areas with basic energy challenges, geothermal energy appears to be the most viable option, both in terms of its impact on costs and growth.

7.4. Scenario 4: Industrial countries seeking decarbonization without loss of power

This scenario is seen in countries with well-established electricity systems now working toward big carbon emission cuts (often targeting net-zero emissions by mid-century) while keeping their energy reliable and their industries and economies strong. These countries need dependable, low-carbon electricity that can be sent out when needed to take the place of fossil fuels, specifically natural gas and coal, in important areas like heavy industry, data centers, city heating, and electric transportation.

Some countries in this group are Germany, Japan, South Korea, the United Kingdom, Canada, and the United States. They each have a difficult issue to solve: how to stop using fossil fuels but still keep or increase the amount of electricity available, without making the grid less stable or depending too much on unreliable renewable sources like wind and solar.

Nuclear energy is becoming a very appealing choice for these developed countries, especially newer types of reactors that have a good mix of strong points like high power output, constant carbon-free energy production, and long lifespans. These are exactly the traits needed for big carbon emission cuts.

South Korea, for example, is keeping and growing its nuclear power plants to meet future energy needs while keeping emissions low. In Ontario, Canada, nuclear energy already provides over half of the province’s electricity and is key to getting rid of natural gas. The UK's Hinkley Point C and Sizewell C projects are specifically designed to replace fossil fuel energy on a large scale.

Nuclear power is very helpful in cold areas or countries with many industries close together where constant energy is very important. It also helps with hydrogen production, district heating, and clean water desalination, making it a helpful infrastructure investment.

The key limits are still high initial costs, long project times, and worries from the public. This is especially true in countries like Germany and Japan, where past nuclear accidents have caused political problems. But building plants in pieces, better ways to pay for them, and a history of good long-term work are helping to lower these problems.

Geothermal energy also has a part in this situation, but it is more specific to certain areas and a supplementary role. It makes a big impact on cutting carbon emissions and provides stable electricity that can be sent out when needed in countries with a lot of geothermal resources. But, in countries that can't easily get to high-temperature geothermal reservoirs, there are limits to how much geothermal can be used. EGS technologies could eventually allow for wider use, but they are still in the early stages of testing or commercialization. They come with high risks and costs for drilling. Developed countries like Germany and the UK have tried geothermal pilot plants, but problems with technology and the ground have slowed progress.

Also, geothermal can't yet produce as much power, heat for industries, or grid-stabilizing capacity as nuclear. It can help with carbon emission cuts in specific areas, especially in district heating and mid-sized power generation. However, it doesn't have the wide-ranging impact that nuclear can have in busy, industrial economies.

In conclusion, nuclear power is the only well-developed, scalable, and dependable option that can replace fossil fuels at the center of their power systems for advanced industrial economies aiming to cut carbon emissions completely without harming the economy. Geothermal is a helpful solution for certain areas or regions, but nuclear is the most important.

7.5. Scenario 5: Isolated or island systems

This scenario involves regions and countries whose power grids are not connected to larger continental grids. Think of islands or remote areas. These places often rely on costly, polluting imported fuels like diesel. Their small size makes it difficult to justify big, centralized power plants. Electricity demand is generally moderate but crucial, especially for tourism, basic industries, and homes. Countries such as Iceland, certain islands in the Philippines, Papua New Guinea, and small island nations in the Caribbean and Pacific fit this description.

Geothermal energy is a good fit in these places, mainly where resources are available. It offers stable, dispatchable electricity with low emissions and good availability. Iceland is a prime example. Thanks to geothermal and hydro resources, it has gotten rid of fossil fuels for electricity. It also provides cheap power with little to no carbon emissions. Also, island groups in the Philippines use geothermal where they can to cut down on diesel imports. In Papua New Guinea, geothermal opportunities near volcanoes could lead to cleaner energy, even in isolated grids, and avoid the high cost of transporting fuel.

Nuclear energy, though, faces major challenges in these systems. Standard reactors are too big and complex for these situations. They need lots of infrastructure, skilled labor, and strong grid support. The costs and risks of building, running, and regulating nuclear power aren't workable in small, spread-out systems. Small modular reactors (SMRs), a newer idea, seem good but are not proven in business. These systems still need high investment, long development times, and complex oversight. For isolated or island nations with limited technical skills and funding, using SMRs isn't doable right now.

From an economic point, geothermal gives a faster return on investment with lower initial costs. Development banks or climate funds can assist here. Maintenance is easier and can often be done locally through training. Nuclear systems, unlike geothermal, need international supply chains and long-term regulatory promises. Both approaches lead to low emissions, but geothermal has less waste to manage. Also, it avoids public worries about nuclear energy, which is important in small communities or tourist areas.

Overall, geothermal energy is the better and more realistic choice for isolated or island systems. It fits the size, technical skills, and financial limits of these places. Also, it delivers clean, reliable power. Nuclear energy, even in smaller forms, isn't ready due to its complexity, cost, and infrastructure needs. Geothermal offers immediate and long-term benefits for small, disconnected grids.

7.6. Scenario 6: Countries seeking to lead technological development

Some nations aim to meet their energy needs and become leaders in clean energy. They see energy policy as a way to boost their industries, increase exports, and gain influence. They invest in research, support partnerships, and adopt new technologies early, even if they are expensive or risky. The United States, Japan, South Korea, Germany, and China are examples.

Nuclear and geothermal technologies can both play important roles, depending on a country's strategy and resources.

Some countries are creating or backing new reactor designs, like Small Modular Reactors (SMRs) and Generation IV reactors, to improve safety, lower costs, and create new uses, like hydrogen production. For instance:

- In the United States, companies like NuScale and TerraPower are working on SMRs with support from the Department of Energy.
- South Korea sold its APR1400 design to the UAE and is investing in SMRs.
- China has connected advanced reactors to its grid to showcase its technology leadership.

Geothermal energy, especially EGS, is also gaining attention from countries that want to lead in new technologies. The U.S. Department of Energy's FORGE program is a major investment in EGS research. Germany is funding geothermal projects in Bavaria, and Japan is using its geology and drilling skills to test high-temperature systems.

New companies like Quaise Energy are trying to use millimeter-wave drilling to get geothermal energy from deep rock layers. This could greatly expand geothermal potential. These projects are risky but could be transformative, and leading countries aim to profit from patents and exportable technologies.

Economically, nuclear supports heavy industry and large-scale exports but faces financial and regulatory issues. Geothermal offers innovation, works well with oil and gas drilling, and is more publicly accepted if EGS becomes viable.

Both technologies support decarbonization, but geothermal has a smaller waste and safety impact. However, nuclear has higher energy density and reliability, especially in industrial settings.

In conclusion, nuclear and geothermal are both ways to achieve technological leadership, depending on a nation's strengths and goals. Countries like the U.S. or Japan might pursue both: nuclear for industry and exports, geothermal for innovation. The choice depends on strategy: nuclear for centralized leadership, geothermal for innovation and wide use. A combined approach is often best.

7.7. Scenario 7: Electrical systems with large peak demand constant energy needs.

This scenario looks at regions or countries where electricity demand changes a lot, with usage rising and falling quickly, while a steady power supply is still important. Places that have big factories mixed with homes and stores, or countries where cities are growing and people are changing their habits, are included here. These power grids must deal with both the highest needs and normal power levels without stopping.

Countries such as South Korea, Germany, and some parts of the United States face these kinds of problems. In South Korea, factories cause power needs to rise fast during work hours, while home use changes during the day. Germany uses a lot of solar and wind power that changes often, so it needs reliable power sources to keep the grid balanced when these renewables are producing little electricity. Also, many U.S. states with different energy sources see how their power usage can change fast.

Nuclear energy is a good choice for these situations since it gives a lot of steady power that runs without stopping for a long time. Nuclear plants help keep the grid stable by giving a dependable supply of power that does not change with the weather or time of day. This trust cuts down on the need to improve the grid or store lots of energy, which would be needed to deal with power peaks and lows.

However, geothermal energy, mainly the standard kind, is not good for meeting sudden, large power needs because it usually makes the same amount of power, but local resources limit that amount. Geothermal plants work better as steady, medium-level power sources instead of quick-response units.

In order to deal with peak needs, systems with geothermal energy usually need other power sources that can change, such as natural gas plants, batteries, or ways to control demand, which makes things complicated and expensive. Nuclear power helps lower these extra costs by giving a large, expected base amount of power.

Looking at money matters, nuclear power costs a lot to start, but it costs less to run and lasts a long time, which makes it appealing for systems that need a lot of constant power. Geothermal energy usually costs less per unit installed, but it may not be able to fully do what nuclear does for these grids because it is smaller and less flexible.

In conclusion, nuclear energy is the better choice for power systems with big demand peaks that need constant and reliable power. This is because nuclear has high capacity, runs steadily, and can support the grid without needing many backup resources. Geothermal energy can add to nuclear but cannot replace it in these situations.

7.8. Global conclusions

Whether to use geothermal or nuclear energy, based on the seven scenarios studied, depends on money, resources, how the power grid is set up, and what the main goals are.

Geothermal energy works better when:

- There are plenty of geothermal resources, but not much money or infrastructure (Scenarios 2 and 5).
- A country needs electricity quickly and affordably, with projects that can grow over time (Scenario 3).
- The focus is on new tech and small, eco-friendly power options (Scenario 6).
- Areas want power spread out and have environmental worries that keep large power plants away.

Geothermal is attractive because it costs less up front, gets built faster, makes less waste, and the public likes it more. It’s a good match when being adaptable, offering local gains, and spreading out investments cuts down on risks.

Nuclear energy is the best option when:

- There's a need for big, central systems with solid financial backing that can deliver a steady, strong stream of power (Scenario 1).
- Places with big industries or high demand want power that’s reliable and keeps the grid running smoothly (Scenarios 4 and 7).
- A country is after energy security for the long haul, with reliable, large-scale power, despite the high initial price tag.

Nuclear stands out in how much energy it can make from a small amount of fuel, its steady output, and how it helps the power grid. But it needs strong support from organizations, a lot of funding, and careful planning that looks far into the future.

To sum it up, geothermal shines in areas that are spread out, rich in resources, need flexibility, and don't have a lot of cash. Nuclear takes the lead in systems that are central, costly, need to meet high power demands, and must keep the grid stable.

Often, the smartest plan is to mix both, using what each does best to meet the specific needs of a country or area.

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