FINAL REPORT

ENCO-FR-(20)-13

POSSIBLE ROLE OF NUCLEAR IN THE DUTCH ENERGY MIX IN THE FUTURE

1st September 2020

TABLE OF CONTENTS

FIGURES

TABLES

ABBREVIATIONS

APR	Advanced pressurized water reactor
BBC	Borssele Benchmark Committee
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCUS	Carbon capture, usage, and storage
CfD	Contract for difference
CFT	Cold functional test
CGN	China General Nuclear
CL	Construction licence
COD	Commercial operation date
COL	Combined construction and operating licence
EDF	Électricité de France
EIA	Environmental impact Assessment
EPC	Energy performance certificate
EPR	European pressurized reactor
ETS	EU Emissions Trading System
EV	Electric Vehicles
FCL	First core load
FID	Final Investment Decision
FOAK	First of a kind
FSAR	Final Safety analysis report
Generation I	First prototype reactors during fifties and sixties.
Generation II	Reactors constructed according well developed safety guidelines during (1970-now))
Generation III	Very safe new generation reactors like EPR, AP1000, Hualong One, WWER-1200) (>2010)
Generation IV	Future very safe and sustainable reactors that are under R&D now (>2040)
GHG	Greenhouse gasses
HFT	Hot functional test

HPC	Hinkley Point C
HTGR	High Temperature Gas Reactors
H2-P2P	
IAEA	International Atomic Energy Agency
KNHP	Korea Hydro & Nuclear Power
LCOE	Levelized cost of electricity
LCOE*	LCOE plus costs of system effects
LCOS	Levelized Cost of Storage
LFR	Liquid-metal cooled fast reactors
LWR	Light water reactor
MSR	Molten Salt Reactors
NOAK	N^{th} of a kind
NPP	Nuclear power Plant
NRC	Nuclear Regulatory Commission
OCC	Overnight construction costs
OCGT	Open cycle gas turbine
OL	Operating licence
O&M	Operations and maintenance
PBMR	Pebble bed modular reactor
PHWR	Pressurised heavy water reactor
PSR	Periodic safety review
PSAR	Preliminary Safety analysis report
RAB	Regulated asset-based
RHP	Regulatory hold point
RPV	Reactor pressure vessel
SMR	Small Modular Reactors
STUK	Finland’s nuclear safety and radiation protection regulator
TMI	Three mile Island
TRL	Technology readiness level
UAMPS	Utah associated municipal power systems
VRE	Variable Renewable Energy Sources
WACC	Weighted-average cost of capital
WWS	Wind, water, solar

1 INTRODUCTION

This report is commissioned by Ministry of Economic Affairs and Climate Policy of the Netherlands in response to motion Yeşilgöz-Zegerius/Mulder (2018/2019 35167NR15) of the House of Representatives, to explore the possible role of nuclear energy in the future energy-mix in the Netherlands and to identify the costs and conditions related to the construction of new nuclear power plants in other countries.

The EU is embarking on the European “Green Deal”, with the target to be “climate neutral” by 2050. With 75% of EU greenhouse gas emissions coming from production and use of energy, and system challenges when the Variable Renewable Energy (VRE) contribution passes certain thresholds (both in system control and assurance of availability of power on 24/7 basis), all possible energy sources warrant a new look. Facing the need for a drastic reduction of CO2 emissions, the potential role of nuclear energy for the Netherlands in 2050 has been raised by the Dutch parliament. The interest is mainly in a possible role of nuclear energy in the Dutch energy mix. The Dutch parliament is particularly interested in the current position regarding nuclear energy amongst international organisations and the meaning behind; “ever increasing costs and schedules for construction of nuclear plants“.

This report is intended to give an overview of the various aspects of nuclear energy and the possible role in the Dutch energy mix in 2050. A series of questions covering specific aspects has been identified, answers to those is meant to establish a broad picture and help in understanding the issues. The Study’s scope was not to carry out new research, neither on the international nor on the Dutch-specific circumstances, but rather to critically assess and compile information from numerous studies and reports, and to put those in the specific Dutch perspective. The Study considered the position of various bodies dealing with nuclear power, but also took note of various other elements such as national plans and arguments as well as of roles of other technologies, in particular VREs. The Study is based on a range of sources of information, in particular those compiled by reputable international organisations.

To achieve its aims, the Study addresses issues and questions relevant for understanding the context and specific matters of relevance. In addition to a literature review of recent information on nuclear energy, specifically for the Netherlands, the Study also examines the costs of electricity from nuclear power plants and other low-carbon electricity sources. The report provides insight into the costs associated with system challenges as a result of a high proportion of VRE.

2 INTERNATIONALLY EXPECTED DEVELOPMENTS

2.1 CURRENT STATUS OF NUCLEAR POWER

A nuclear reactor was first used for the generation of electricity on September 3, 1948, at the X-10 Graphite Reactor, in Oak Ridge, Tennessee USA. On June 27, 1954, the world's first nuclear power plant for the generation of electricity to supply a power grid, started operations at the Soviet city of Obninsk. The world's first full scale power station, Calder Hall in England opened on October 17, 1956.

Through the 1960s and 70s, many nuclear reactors were constructed and put into operation for the purpose of generating electricity. Those were mainly similar in design to reactors utilised to power nuclear submarines, which are efficient and produce low cost emission-free electricity. They also have a very small mining and transportation footprint. At that time, a nuclear powered future was envisioned by many.

In 1974, France decided to make a major push for nuclear energy, resulting in 75% of their electricity coming from nuclear reactors. The US built 104 reactors, supplying around 20% the country's electricity demand. Eventually, labour shortages and construction delays resulted in an increase in the overall cost of nuclear reactors with a slowdown in market growth. Following on various operational incidents, including the nuclear accidents that occurred at TMI in 1979, Chernobyl 1986 and Fukushima in 2011 (in which, except for Chernobyl nobody ever died from radiation), the industry has seen further increased costs due to strengthened safety regulations. As a consequence between 1970 and mid-2019, a total of 94 of new nuclear plant projects were suspended.

Over the past 50 years, the use of nuclear power had directly resulted in a reduction in CO_2 emissions by more than 60 gigatonnes, which is equivalent to nearly two years' worth of global energy-related emissions. In another metric, nuclear power avoided the equivalent of five years' worth of CO_2 emissions from the electricity sector.

As of May 2020, 441 nuclear reactors are operating in 31 countries, with 389994 MWe total installed capacity as in the Figure 1. Further 54 nuclear power reactors are under construction, with a total of 57444 MWe total net installed capacity as in the Figure 2 [1]. Developing nations with increasing energy needs and those heavily relying on coal (e.g. China and India) are leading the way and incorporating own and foreign technology. Per IAEA, about 19 countries are starting or planning construction, and even countries that have never employed nuclear as an energy source, are reviewing their position (e.g. Australian parliament's report) [2].

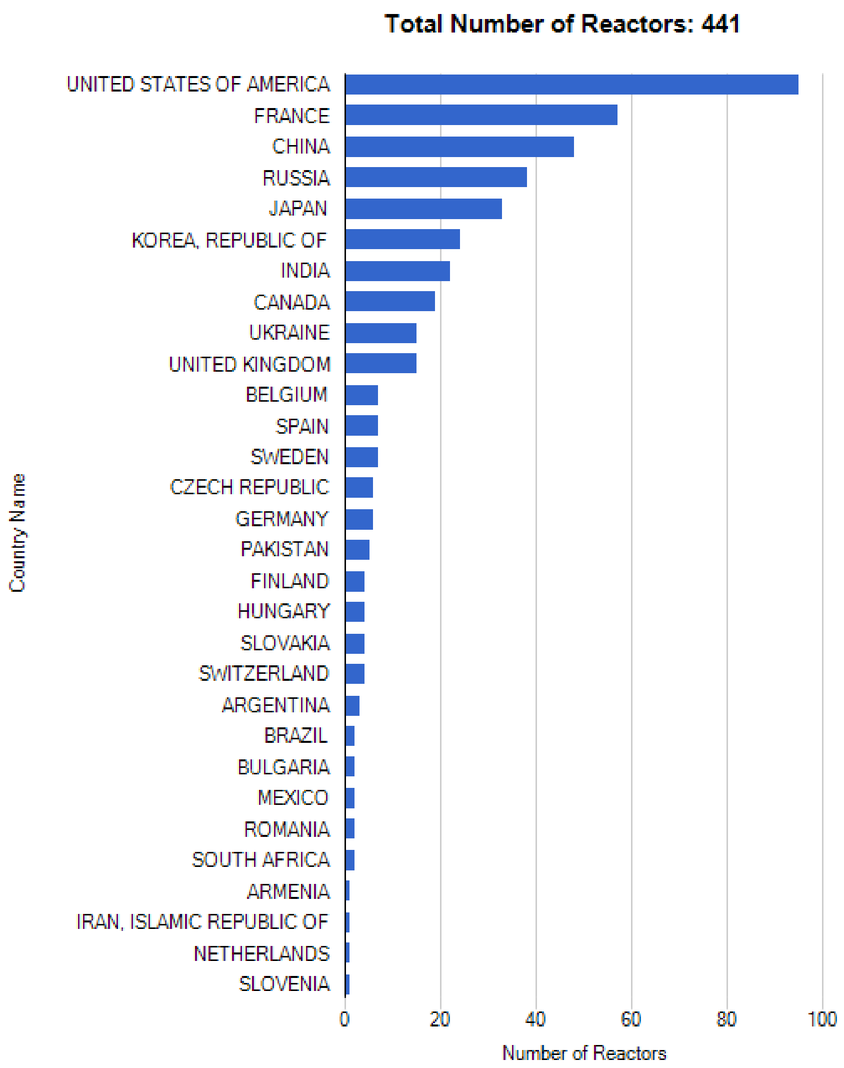


Figure 1 Total number reactors in the world in 2020

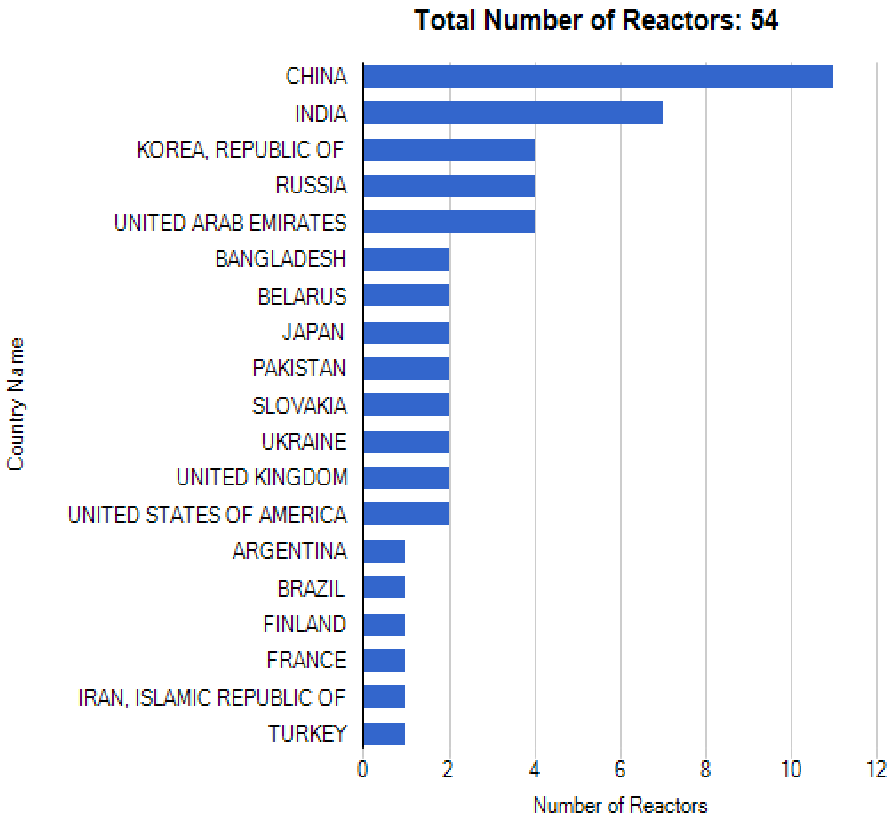


Figure 2 Reactors under construction in 2020

The world nuclear fleet generated 2,563 terawatt-hours (TWh) of electricity in 2018, a 2.4 percent increase over the previous year, which was essentially due to China's nuclear output increasing by 44 TWh (+19%), but still 4 percent below the historic peak of 2006.

During 2018, nine new nuclear power reactors with a total capacity of 10 358 MW(e) were connected to the grid, and seven reactors with a total capacity of 5424 MW(e) were retired. In 2018, construction began on five new units that are expected to add a total capacity of 6339 MW(e).

2.2 NUCLEAR IN EUROPE

At the end of 2019, nuclear electricity constituted about 26% of the EU's electricity generation, and 14 Member States are operating a total 126 nuclear power plants with 6 plants under construction and more in the preparation. Nuclear energy supports around 1.12 million jobs in Europe [3] . Currently there are 126 nuclear units in operation in the European Union, providing 118,119 MW nett electrical power

About half of the European Union Member States have gone through three nuclear construction waves - two small ones in the 1960s and the 1970s and a larger one in the 1980s (mainly in France).

The total number of permanently closed units remains at 94 in the European Union, and, as of 1 July 2019, the EU countries operated 126 reactors, about one-third of the world total, though 49 less than the historic maximum of 175 units in 1988.

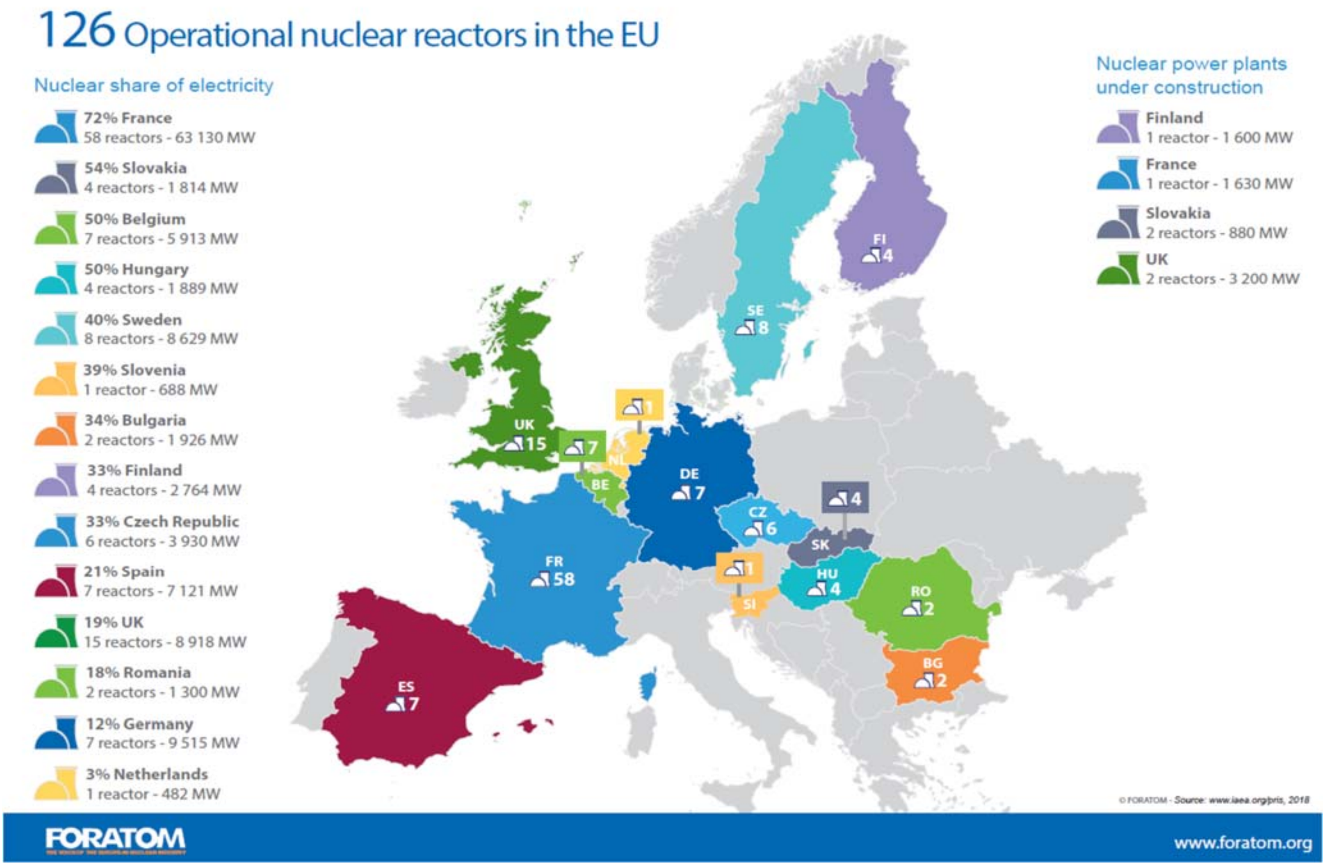


Figure 3: Operational nuclear reactors in the EU in 2018 Foratom [4]

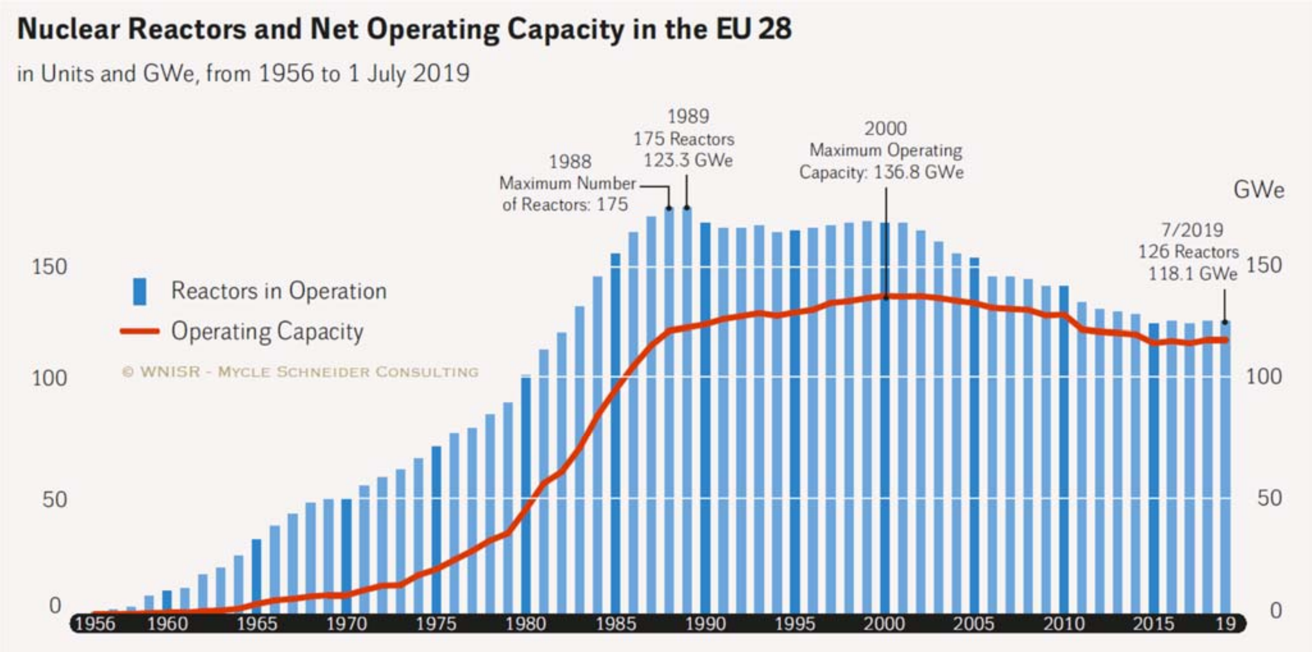


Figure 4: Nuclear Reactors and Net Operating Capacity in the EU 28 from 1956 until 2019 [5]

2.2.1 WESTERN EUROPE

The European reactors are aging, and there is too little new construction at present to replace those reactors that will eventually be permanently shut down. Nevertheless, with the decarbonisation commitment, several European countries are considering nuclear, amongst others, as a source of clean energy.

The **United Kingdom's** ageing fleet of 15 nuclear units supplies about 17% of the country's electricity. Remaining Gen I reactors are scheduled to be permanently shut down by 2023. The British branch of EDF continues to build two Gen III EPRs at Hinkley Point C (HPC) in Somerset, that are to supply about 7% of total UK demand. For the HPC, a 'Contract for difference' investment protection scheme was established, similar to those used for larger VRE projects in the UK. Two more EPR units are planned at the Sizewell site, and potentially, the Chinese CGN could be leading the way for the construction of two further units at Bradwell in Essex.

Although the prospect of new nuclear energy is attractive in the UK, financing still poses major hurdles. The main problem being the major capital outlay required for construction and the significantly long-term payback period and unclear economic returns, which cause uncertainty amongst potential investors. EDF-UK hired Rothschild as financial adviser for the Sizewell C project in order to find a solution, so that construction may start in 2022.

The UK government is looking into the option of a new financing model (typically used for funding UK monopoly infrastructure) called the "Regulated asset-based" (RAB) model [6]. Utilizing the RAB model will reduce the cost of capital and maximise value for money for consumers and taxpayers, whilst being able to provide acceptable returns to investors and reduce the cost of raising private finance. If the UK government were to utilise this model, it would potentially revive prospects for the construction of new units at Moorside, Wylfa, Newydd, and the Oldbury on Severn nuclear projects, all of which have stalled due to difficulties in financing.

France's nuclear fleet (> 60 GW) is on average younger than the UK's, giving it more time for deciding on the replacement. France currently receives 70% of its electricity from nuclear, with plans to reduce to 50%, making up the difference with VREs. In 2018, France announced its new energy strategy which aims for carbon neutrality by 2050. This strategy is three pronged, first extending the life of existing reactors while spreading the closing of oldest reactors; second, nuclear to remain the backbone of French energy strategy with 50% of the power mix; third, renewable energy sources to generate 50% by 2050.

The plan for reduction of nuclear generation started with the permanent shutdown of two Fessenheim units in February and June 2020. Another 4 to 6 reactors will be closed by 2028, leading to 14 units of 900 MW closed by 2035.

In 2019 the French government requested EDF to prepare a proposal for the construction of six new 'next-generation' EPR 2 units. It is expected that this proposal will be ready by mid-2021 and that an informed decision will be taken by the Government in 2022.

The key element of the new construction is the cost optimisation of the EPR design. While keeping its exceptional safety features and its rated capacity (up to 1650 MWe net electric output, depending on the site), the next-generation EPR would be significantly easier to be build. This is due to improvements in constructability (containment, reactor vessel manufacturing processes, etc.), together with the digital optimisation of the design process. Such optimisation would assure about 30% reduction in construction costs, to an estimated of 7.5 to 7.7 billion Euros per reactor (overnight cost) with 1650 MWe, on the basis of a 6 EPR units program. This amount is said to be inclusive of the cost of decommissioning. This estimated cost also encompasses a 500 million euros contingencies margin. The LCOE for the 6 next generation EPR units, as estimated by EDF is €70/MWh, which is competitive against other sources of dispatchable electricity.

On March 7th 2020 **Finland**'s long-delayed Olkiluoto 3, an EPR reactor, was granted the operating licence, allowing the plant to start-up. This will end the construction on the project that started in 2005 and saw a significant cost increase. The EPR is approved to the most modern safety standards of Finland and will supply about 15% of the Finland's' electricity.

In June 2007, Fennovoima Oyi a consortium of 67 electricity consumers took a decision to construct a new NPP at the Hanhikivi site in Finland. In October 2014 Rosatom signed the contract to construct the plant. Due to the delay in licencing caused by incomplete safety documentation being provided to the Finland's regulator STUK, the start of the construction is now projected for 2021 and first power in 2028.

In January 2020 STUK said it is preparing for the licensing of SMRs "due to the national and international interest in them." STUK notes that a working group set up by the Ministry of Economic Affairs and Employment is currently investigating the need to develop the country's laws on atomic energy. One of the areas being discussed is how suitable the current licensing system for nuclear facilities is with regards to licensing SMRs. A recent news report indicated a pending decision for a small reactor exclusively for heating purpose to be built in Finland.

Several Western European countries decided to phase out nuclear energy. **Germany** is to shut down its remaining nuclear units by 2022 (8.5 GW). **Belgium** was to shut down units by 2025 (5.7GW). After several changes in the law, it is now not fully clear whether any of 7 operating units would be shut down and when. **Spain**'s 7 rectors are to shut down gradually by 2035 (7.1 GW). **Switzerland**'s 4 reactors (3 GW) are to remain operational for as long as those are safe to operate and no new units are foreseen. Concerns are being raised in all four countries on the consequences of losing the baseload/dispatchable generation.

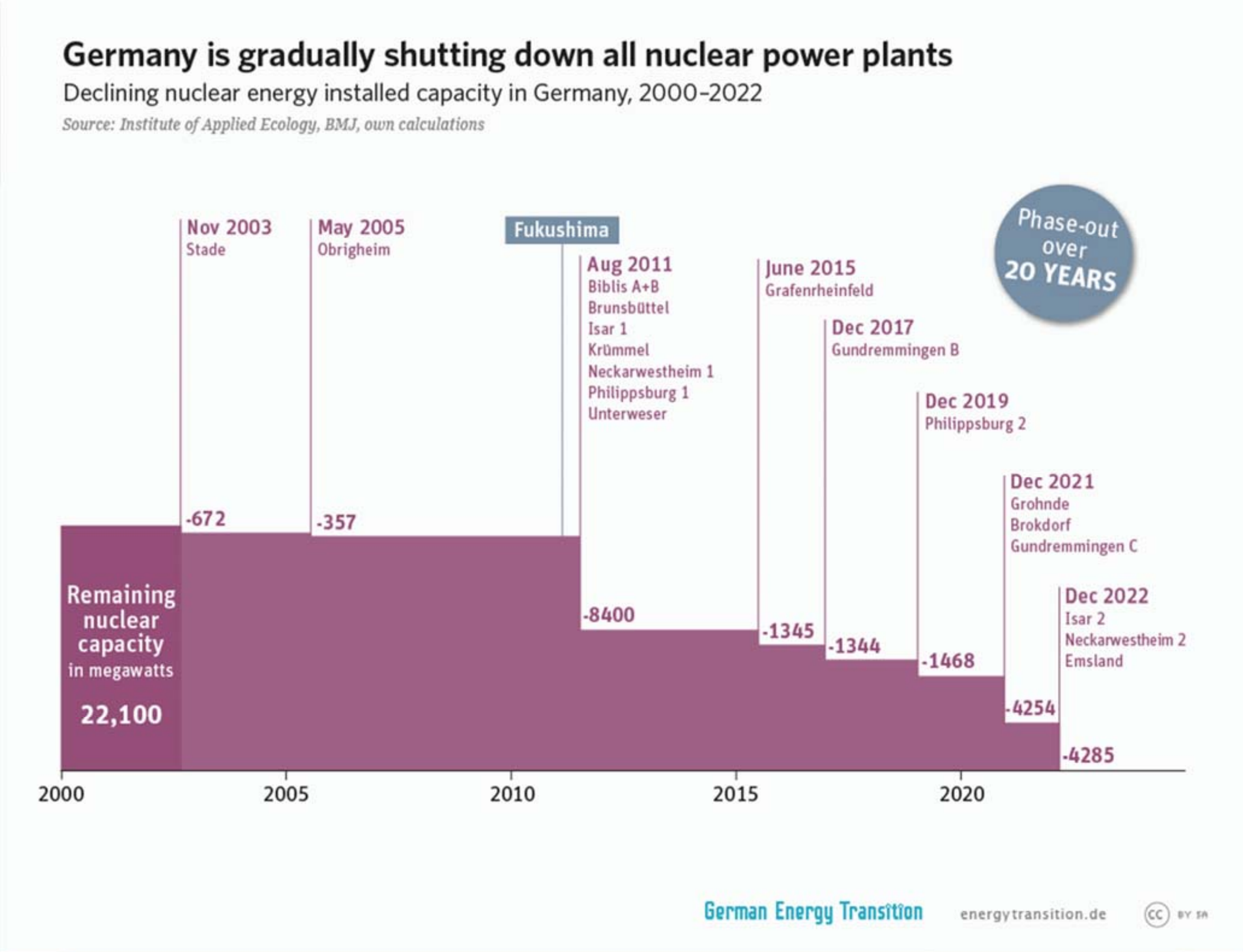


Figure 5: German nuclear phase out [7]

2.2.2 OTHER EU COUNTRIES

In Eastern Europe, the Czech Republic, Romania, Poland, Slovakia, Hungary and Bulgaria have all announced plans to build new nuclear power plants.

In the **Czech Republic**, current energy strategy calls for one unit to be built at Dukovany, followed by possibly three more, either at Dukovany or Temelín. Discussions have been held between the Czech government and the utility ČEZ (70% government owned), on how to expand nuclear power to replace the aging fleet of reactors that are scheduled for permanent shut down decades ahead. A supplier for the first unit is to be selected by end of 2022. According to market estimates, the expected costs are to be about 5 to 6 bn Euro. According to media outlets, five firms have expressed interest in the project; China's CGN, Russia's Rosatom, South Korea's KHNP, France's EDF, and the Atmea (MHI/EDF).

In May 2019 an agreement was signed with China General Nuclear for the completion of two Candu-6 type at Cernavoda site in **Romania**. Further Romania's objective is to refurbish Cernavoda-1 (about 30 years old), and by 2030 have another new unit on the same site. Furthermore, beyond 2030 Romania is considering new Generation IV reactors.

Poland has a long established goal for introducing nuclear power, with a National policy in 2014 envisaging 6 GW of capacity by 2035. Succeeding administrations has been delaying the final decision, mainly due to financing issues. In 2019 the government announced that it would establish a special-purpose company in which it will own a 51% stake, with the remaining 49% to be held by one or more foreign partners. According to the draft energy policy, the first unit could be in commercial operation by 2033. The policy outlines ambitious plans for six reactors providing 6-9 GW of nuclear capacity by 2043. This would account for about 10% of Poland's electricity generation.

In **Bulgaria**, significant progress has been made with the government shortlisted companies including Rosatom, CNNC, Korea Hydro, Framatome, and possibly General Electric to participate in the revived two-unit Belene nuclear power project. Rosatom, CNNC, and KHNP are invited to bid as investors in the project, while Framatome and GE would be offered the opportunity to supply equipment for the project.

In **Slovakia** there are four existing units at Bohunice (2x440 MW, 2x505 MW) and Mochovce 2x440 MW). Currently two 440-MW Russia-supplied WWER units at Mochovce (2x471 MW) are in the commissioning phase, with Unit 3 is expected to be connected to the grid in 2020.

Hungary's new build plans are expected to progress into 2020, with documentation for licence to be submitted and the construction licence to be issued for 2 new units (2x1000 MW) at the existing Paks NPP site. The Paks nuclear site currently has four units in operation. (4 x 473 MW).

In terms of the discussion above Europe is experiencing somewhat of a nuclear renaissance, with the exception of the four countries opting for phaseout. If all plans go through, and financing is achieved (which is one of the main hurdles) Europe could be looking at roughly 30 new units by 2050.

2.2.3 CHINA AND USA

As of 2019, **China** had 46 nuclear plants with 43 GW capacity in operation, with 11 under construction, with operating capacity reaching 58 GW in 2020. Additional nucleal plants of a total capacity of 36 GW are firmly planned.

National projections from 2018 indicated that China's nuclear generating capacity must increase to 554 GWe by 2050, if the country is its to achieve its climate change goals. The investment needed for such an expansion is estimated to be around 1.1 trillion Euros.

The construction cost in China are published to be lower than elsewhere, with Gen II could be about 1600 euro per kW, and the Gen III costs between 2500 and 4500 euros per kW. This is consistent with reported costs of 2 EPR reactors that are now in operation at Taishan site in China being 8.6 billion Euros (for 3500 MWe).

Assuming the total cost of Gen III, nuclear power plants will be 2800 Euro/kW, the National Development and Reform Commission (NDRC) set a wholesale power price of CNY 0.43 per kWh (or 60 €/MWh) for all new nuclear power projects, to promote the healthy development of nuclear power and guide investment into the sector.

In the **USA** there still more than 90 operating reactors, with initial 2 (of expected 20) units licenced to operate for up to 80 years design life. Two new reactors are under construction at Vogtle site in US state of Georgia, the first of the GEN III design. After significant delays and an increase of costs (which lead to the bankruptcy of the supplier Westinghouse), the first unit is now expecting an earlier start-up (in May 2021) rather than currently scheduled late 2021. The second unit is expected to start up about a year later. The other GEN III NPP in construction, VC Summer in South Carolina, was terminated in 2017 due to raising costs of the construction uncertainties caused by the bankruptcy of the supplier Westinghouse.

In the US, nuclear plants are under significant cost pressure mainly from cheap and abundant gas. While gas fired plants are mostly replacing coal which has much higher emissions, nuclear plants in deregulated markets are also closing down due to cost pressure. In some of US states (e.g. Ohio, Pennsylvania), changes in the law to offer "clean energy credits" to zero emission power producers such as nuclear plants, did lead to the cancelation of the 2018 deactivation notices for Beaver Valley, Davis-Besse and Perry nuclear power plants. Those are licenced to operate into late 2030s and 2040s and expected to stay on line. Various US studies have shown that without new nuclear, a large-scale decarbonisation is not possible.

2.2.4 REST OF THE WORLD

Table 1: Summary of plans for the utilisation of nuclear power in selected countries

Country	Operating NPP	In construction /planned	Highlights
Russia	36	4/xx	Russia plans many more reactors, and sees nuclear power as the backbone of its electricity production in the future. A barge with 2 SMR (each having 38 MWe gross capacity) was connected and started producing power in late 2019
Canada	18	0	SMRs are of high interest. Regulators issued the siting criteria for SMRs relevant for 2 pre-selected sites and committed to undertake licencing review for the SMR designs
UAE	1	3	4 Korean units constructed. Unit 1 started up in August 2020, others to follow
Saudi Arabia	0	17	National infrastructure prepared, a vendor for first two units to be selected soon
India	22	7/17	Mostly domestic technology deployed, with 2 Russian designed WWER in operation, 4 more under construction. 6 EPRs and several AP 1000 planned
Ukraine	15	0/2	2 units are planned for completion, subject to available funding. The operator (Energoatom) is working with Holtec of USA on the licencing of their SMR 160
Turkey	0	1/3	WWER under construction at Akuyu, 3 more to follow. 2 more sites prepared
Bangladesh	0	2	2 WWER under construction
Pakistan	5	2	Two units of Chinese-ingenious GEN III design, Hualong One, in construction

2.3 SMALL MODULAR REACTORS

As a possible contributor to the carbon-neutral future, small modular reactors (SMR) are receiving increased attention. This is due to the technological capability of nuclear to deliver on-demand electricity, coupled with a promise for great simplification and related cost reduction while applying industrial manufacturing and construction technologies at factory rather than on site. The SMRs are expected to resolve the biggest obstacle for large nuclear power plants: long construction periods causing high prices for the installed capacity.

The SMR concept is not new; small reactors have been around for a considerable time, used for special purpose, such as nuclear propulsion on boats and district heating, which is currently used in China and planned for Finland. The idea in putting together multiple modular reactors to achieve 'economy of scale' as large NPPs while keeping the costs in increments, was a German/South African development called PBMR, a helium cooled graphite-ball-fuelled 120 MWe reactor in the mid-nineties. Due to various reasons, mainly financial, but also the low level of interest in nuclear during the late nineties, the project never materialised. China is currently building a similar concept-reactor, allegedly reflecting some of the South African blueprints.

The SMRs of newer generation are designed to generate electric power up to 300 MW. Modular reactors would allow for a “type approval”, leading to simplified licensing, reduced on-site construction activity, thus shorter construction periods, earlier return on investment, increased containment efficiency, and greater security of nuclear materials. SMRs could fulfil the need of flexible power generation for a wide range of users and applications, including replacing aging fossil power plants, providing cogeneration as well as for energy systems that combine nuclear and alternative sources, including renewables. SMRs are being promoted as a possible backup for VREs, though the cost of such arrangements might limit the extent of their deployment.

Currently there are more than 50 SMR designs at various stages of development for different applications. SMR designs are being worked on, with technologies ranging from traditional light water moderated reactors to “exotic” molten salt and molten-metal-cooled cores. In terms of the EU definition of the Technology readiness level [8] it is possible that only one SMR (e.g. Chinese Pebble bed reactor) might be at the TRL (EU) 7, few might be at the TRL(EU) 6, while other concepts are below that.

Many of the proposed SMR designs are intended to be inherently-safe light water reactors. Others are offered as the Generation IV, including molten salt (Thorium), breeders (Thorium or Uranium) or other concept, still subject to extensive R&D. GEN IV concepts are still in relatively early stages of pre-commercial development. None of the companies have a completed detailed design and are only preparing for the reactor licensing.

For SMRs, “small” is seen in comparison to a conventional nuclear power plant (typically between 1000 and 1600 MW), “modular” means that the major components would be built in a factory and assembled on-site. The major components of SMRs will be small enough to be transported from the factory to the construction site by boat, truck, or rail.

Although SMRs are projected to have higher unit capital costs (i.e. per installed MW) than large NPPs, they would benefit from modular design, manufacturing and only assembly on site. Serial manufacturing of reactor modules is expected to substantially increase productivity and enable SMR construction schedules to be reduced and thus result in significant cost reduction. Recent studies by University of Cambridge showed that for the best case and a 250 MWe SMR, the combined effects of the standardisation of design (16% cost reduction), modularisation (-25%) and construction schedule (-16%). Taken together, the effects of those may lead to cost of construction of SMRs below that of a large reactor. Costs would fall further resulting from production learning (17%) across the larger number of units.

Furthermore, the UK assessment of nuclear sites shown that complying with the current nuclear siting rules, many more sites would be available for SMRs, because of their smaller space and lower cooling requirements, as well as (much) smaller emergency planning zones (EPZs). In theory, a pre-approved site would be ready to receive an SMR with licensed design, and would be subject to few, if any, contract variations. Construction time for the SMR could be reduced to as little as three years.

In particular in the USA and Canada there is a high interest in constructing SMRs. Several models at the various stages of approval by the US nuclear regulator, NRC. Furthermore, several site applications have been submitted for various SMR designs.

One of the more promising SMRs is the NuScale’s NuScale Power Module with the unit size is 60 MWe. The plan is that a plant will have twelve units and a total capacity of 720 MWe. A preliminary design approval for the NuScale power module has been applied for in the US and Canada. Nuscale turned in a Design Certification Application at the US-NRC in 2017. The final Safety Evaluation Review (SER) is expected to be achieved by the end of 2020). That is the first step in the “type approval” licensing process in those countries.

The first commercial customer for new NuScale power module is expected to be UAMPS, a consortium with 46 members. This includes the local utilities (electricity distributors) in California, Idaho, Nevada, New Mexico, Utah and Wyoming. In 2016, the U.S. Department of Energy issued a Site Use Permit to UAMPS, to identify and characterize potential locations. A site has been selected at Idaho National Laboratory, a nuclear research centre in the US, who would use the outputs of an initial 2 modules, with the rest being made available to the grid. The Consortium is expected to take a decision on Construction, sometime in 2023. The SMR plant would then be operational in 2026.

There is also international interest in the NuScale. Ukraine signed a Memorandum of Understanding with NuScale in February 2020 to jointly assess the extent to which the design complies with national safety and licensing requirements and whether the construction of a plant would be feasible. Four other countries, Canada, Jordan, Romania and the Czech Republic, also signed a Memorandum of Understanding with NuScale.

British engineering firm Rolls-Royce announced in January 2020 its plans for commissioning SMRs, based on proven LWR technology, but reduced in size and designed for industrial production by 2029.

While the most advanced (in terms of current level of completeness of design) SMR uses proven nuclear technologies and material, one could still expect a pretty lengthy design review and licencing process. SMR vendors are projecting lower costs than conventional large nuclear plants, these costs will remain inherently uncertain until FOAK (and perhaps several additional plants) are delivered. During that period the concepts like industrial production, site assembly etc. will be tested for both the cost of implementation as well as duration of construction. It shall be noted that in respect to cost of operation related to large nuclear plants, in particular the cost of staffing, further cost reduction remains feasible. However, the advantage might disappear when considering the significantly reduced time schedule and cost of construction for an SMR.

It is important to note that costs referenced in Figure 6 below for the advanced reactor concepts, are projected estimations based on the estimates for NOAK plants. These estimates assume a relatively standardised design reflecting on lessons learned from previous builds. Providing NOAK estimates is useful in understanding whether these concepts are likely to be cost competitive. However, today, most of these reactor designs are not licensed and no commercial demonstration plant exists. It is important to distinguish between these forecast costs and actual costs obtained from completed and operational plant.

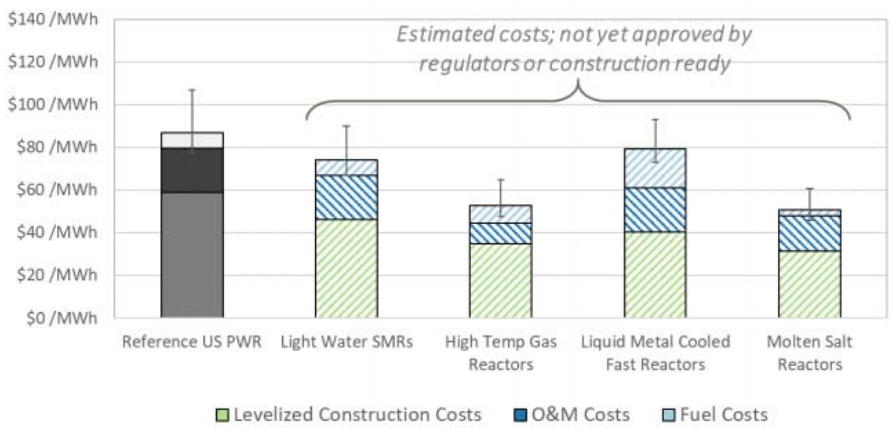


Figure 6: Estimated costs of SMRs and advanced nuclear reactors [ETI, 9]

3 THE OPINION OF INTERNATIONAL ORGANIZATIONS ON THE POSSIBLE ROLE OF NUCLEAR ENERGY IN THE ENERGY MIX

The Paris Agreement on climate of December 2015 marked a pivotal impact on world's energy strategy, as 174 countries and the European Union agreed to reduce greenhouse gas emissions to limit temperature increases to below 2 (1.5) degree Celsius. As electricity generation is responsible for roughly 40% of the world's CO2 emissions, it is at the centre of the CO2 emission reduction efforts.

The International Energy Agency states: "Recent increases in global greenhouse gas emissions from the energy sector stabilize at 33 GtCO2, due to higher nuclear output, increased generation from renewables and switching from coal to gas in advanced economies" [10].

This illustrates practically the universal position of all major international bodies that are addressing climate change and suggesting measures to be taken: nuclear is to remain a part of the energy mix. Without a strong increase of nuclear power, the decarbonization goals cannot not be achieved. Nuclear still generates about 10 % of the world's electricity, which is less than for example 20 years ago; nuclear energy's share of electricity production has declined from its 1993 peak of 17 %.

The general consensus of almost all international organisations is that without the security in electricity supply posed by nuclear (and hydro), VREs could not achieve the full decarbonisation. It is increasingly obvious that without nuclear, reaching the 1.5 Celsius temperate increase limit will not be possible. Another major concern recognised by some organisations, is that the current reactor fleet is ageing, and would need to be replaced. Otherwise the major contribution nuclear is providing in avoidance of CO2 emissions (per IEA, increase in global nuclear generation in 2019 resulted in avoiding an additional 50 MtCO2 emissions) would disappear [13].

The OECD found that the carbon intensity of the electric power sector would need to be reduced by a factor of ten, in order to lead to an effective reduction of emissions needed to meet climate goals. According to the OECD, governments need to execute effective policies, in order to achieve the carbon reduction targets in an effective manner, deploying all sources of electricity that are not releasing carbon into the atmosphere: VREs backed by nuclear capacity would ensure low carbon continuous power [11].

The International Energy Agency stresses that nuclear is ideally placed to work with other forms for low carbon energies, in particular VREs. In such a way, a continuous and stable electricity supply would be achieved, while meeting ambitious climate change goals [12].

The European Parliament adopted a resolution on COP25 – within the United Nations Framework Convention on Climate Change – which states that all technologies, including nuclear, are needed to combat climate change. The European Parliament "believes that nuclear energy can play a role in meeting the climate objectives as it does not emit greenhouse gases, and can also ensure a significant share of electricity production in Europe".

Furthermore, the European Green deal proposed in 2019 marks a significant turn towards an emission free Europe in 2050. Although not included in the support schemes that are envisaged for the decarbonisation, nuclear has been included in the technologies that are to be used to achieve decarbonisation.

The above shows a general international consensus; in order to reach the climate change goals, in addition to VREs, a major addition to existing nuclear capacity would be needed. Nevertheless, the main hurdle with adding nuclear capacity remains its social acceptance, even more long construction periods and, above all, high costs. The OECD/NEA study [13] found that nuclear is in fact the most economical low carbon option when taking into account the long operational life and the amount of electricity produced as a result. Nonetheless, the economics of nuclear need to improve, and the OECD believes that it is to the nuclear industry to resolve those issues.

Intergovernmental Panel on Climate Change

The IPCC [14] analysis identifies that the fossil fuelled electricity generation is, in the terms of GHG emission, the largest single contributor among uses of energy. With increased uses of electricity, this becomes even more important in the future. With a variety of mitigation options, the electricity sector plays a major role in the reduction of CO2 emissions. The decarbonization of the electricity sector may be achieved at a much higher pace than in the rest of the energy usage.

In the majority of stringent mitigation scenarios (430 – 480 ppm and 480 – 530 ppm total CO2 concentration in the atmosphere), the share of low-carbon energy (which includes renewable and nuclear) increases from presently about 30 % to more than 80 % by 2050. The IPCC stresses that achieving substantial reductions in emissions from electricity production requires more intensive use of all of the low GHG technologies such as renewable energy, nuclear energy, and CCS. The IPCC analysis projects that the low-emission investments in electricity generation allocations over the period 2016–2050 might be in a range of solar (0.08–0.9 trillion Euro/yr), wind (0.09–0.32 trillion Euro/yr.), and nuclear (0.09–0.23 trillion Euro/yr.) [14].

The IPCC concludes that nuclear energy could make an increasing contribution to low-carbon energy supply, but a variety of barriers and risks exist. Those include operational, financial and regulatory risks, unresolved waste management issues, nuclear weapon proliferation concerns, and adverse public opinion. New fuel cycles and reactor technologies expected to address some of these issues are under development and progress has been made on safety and waste disposal. However, the IPCC concludes that the implementation of climate change mitigation policies, i.e. pricing the CO2 emissions, would increase the competitiveness of nuclear technologies. A stable policy environment comprising of regulatory and institutional framework that addresses safety and management of nuclear waste as well as long-term commitments to the use of nuclear energy are required to minimize investment risks for new nuclear power plants.

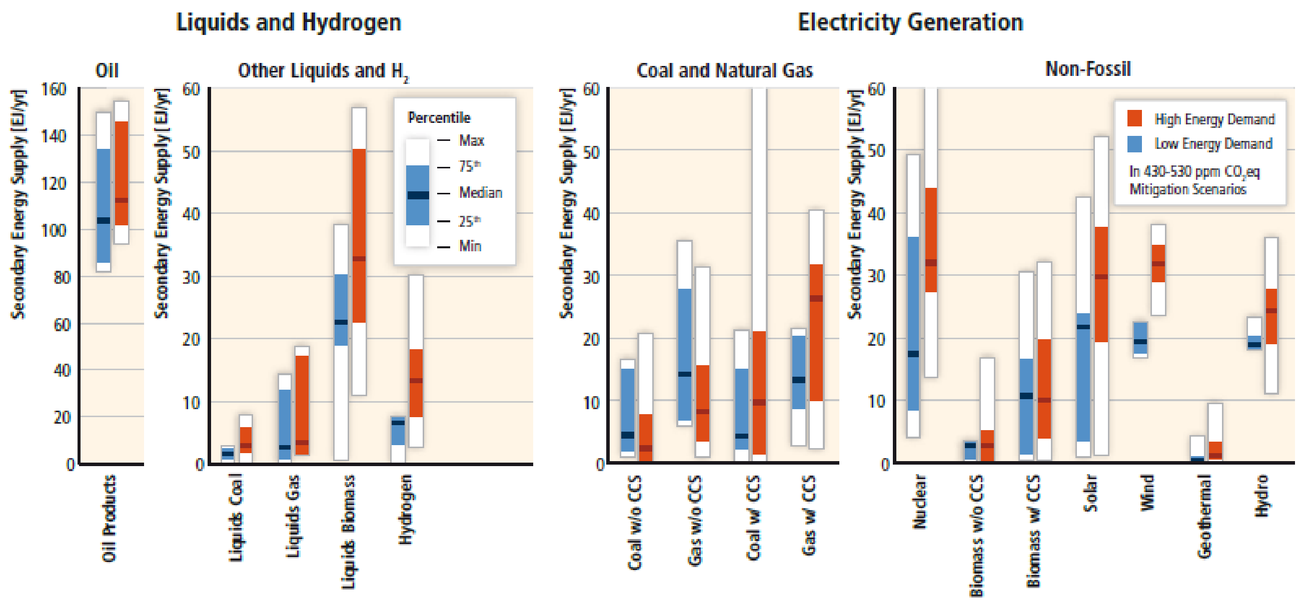
IPCC stresses that stabilizing CO2 concentration requires fundamental changes to the global energy supply systems, by adoption measures from the reduction of energy demand and enhanced efficiency over fuel switching (e. g. from coal to gas) to the introduction of low-carbon supply options such as renewables, nuclear or CCS. IPCC's analysis summarizes the effect of nuclear plants replacing coal, with pros and cons related with the economic, social and environmental impact.

Mitigation measures	Effect on additional objectives/concerns							
		Economic		Social (including health)		Environmental		Other
Nuclear replacing coal power	↑	Energy security (reduced exposure to fuel price volatility)	↓	Air pollution and coal-mining accidents	↓	Air pollution and coal-mining		Proliferation risk
	↑	Local employment impact (but uncertain net effect)	↑	Nuclear accidents and waste treatment, uranium mining and milling	↑	Nuclear accidents		
	↑	Legacy cost of waste and abandoned reactors	↑	Safety and waste concerns				

Figure 7: IPCC Analysis of Nuclear Replacing Coal [IPCC, 14]

The IPCC undertook a thorough analysis of possible energy system transformation pathways that would lead to limiting the CO2 concentration in the atmosphere to about 480 ppm CO2 by 2100. The scenarios from the three models are broadly representative of different strategies for how to transform the energy system. In each scenario, limiting concentrations to low levels requires the rapid replacement of fossil fuels. Nuclear power increases its share in most 1.5°C pathways, though in some the share of power from nuclear generators decreases. Some 1.5°C pathways even see no role for nuclear by the end of the century, while others project about 95 EJ/yr of nuclear power in 2100.

In many mitigation scenarios with low energy demand, nuclear energy supply is projected to increase in 2050 by about a factor of two compared to today, and even a factor of 3 or more in case of relatively high energy demand (see Figure 8 below). For nuclear - and this is not the case for some other low carbon energy alternatives - the availability of resources are not expected to be the main constraints, rather issues related the social issues i.e. safety and waste management. The utilisation scenarios rely on a combination of existing nuclear technologies and new options including small reactors as well as nuclear cogeneration.



1	2	3	4
High energy demand scenarios show higher levels of oil supply.	In high energy demand scenarios, alternative liquid and hydrogen technologies are scaled up more rapidly.	High energy demand scenarios show a more rapid up-scaling of CCS technologies but a more rapid phase-out of unabated fossil fuel conversion technologies.	In high energy demand scenarios non-fossil electricity generation technologies are scaled up more rapidly.

Figure 8: Influence of energy demand to deployment of technologies [IPCC, 14]

US Energy Information Administration [15]

The US EIA in its "International energy outlook 2019 (with projections to 2050)" stated that for advanced economies, nuclear has been the biggest low-carbon source of electricity and played an important role in the security of energy supply. Nevertheless, nuclear faces an uncertain future as ageing plants begin to shut down with only a few new nuclear plants being constructed in some advanced economies. In the clean energy transitions in which renewables are expected to continue to lead, nuclear power can also play an important part. Many countries envisaging a future role for nuclear account in this respect.

To achieve a trajectory consistent with sustainability targets, given the international climate goals, the expansion of clean electricity would need to be three times faster than at present. It would require 85% of global electricity to come from emission free sources by 2040, compared with just 36% today. The EIA concludes that along with massive investments in efficiency and renewable energy, the trajectory would need about 80% increase in global nuclear power production by 2040.

In terms of the electricity demand (see Figure 9), worldwide renewable energy contribution increases by about 3% per year between 2018-2050. Natural gas increases by 1.1 % per year. Coal is assumed to decline after the 2030s as it is replaced with natural gas and renewables. In the 2040s coal use increases anew as a result of increased industrialisation usages and rising use in electric power generation in the non-OECD Asia. In the reference case most growth in electricity generation is fuelled by renewables and natural gas; their combined share of total generation rises to 70% by 2050. In the reference case nuclear generation grows by 1% a year.

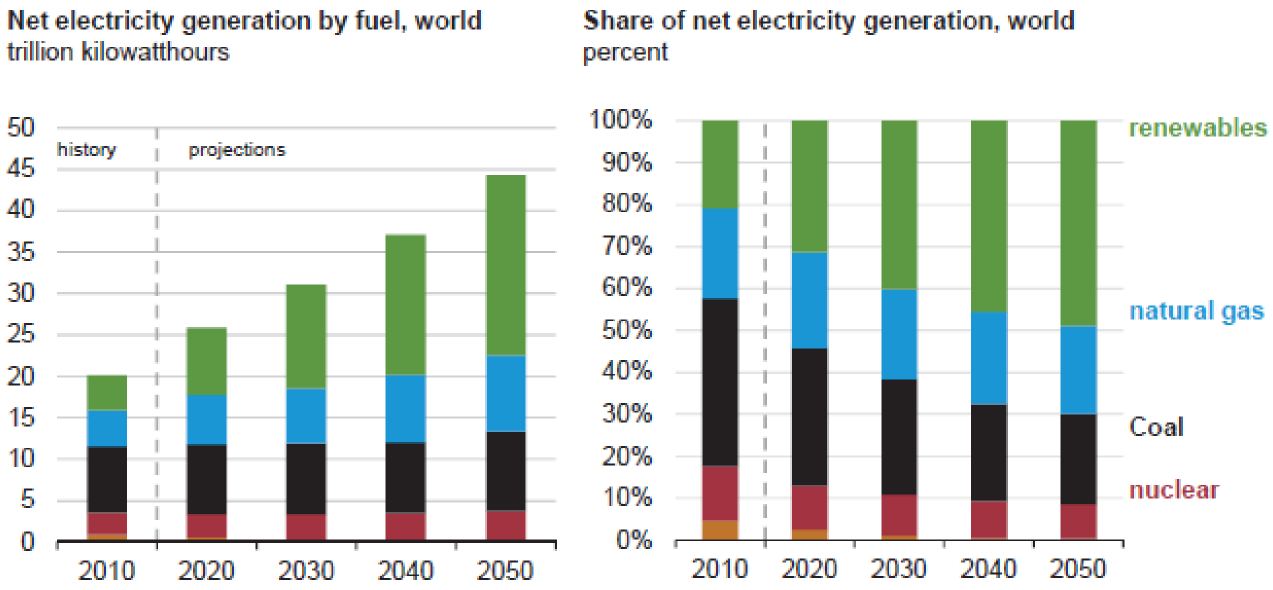


Figure 9: Net electricity generation by fuel and share of net electricity generation [IEA, 12]

International Energy Agency [12]

The IEA identified the need for using the nuclear power plants in each of its energy scenarios. The main factors for its choice were reliability and security of supply, with no CO2 emission. Solar and wind cannot accommodate the supply capacity needed. Furthermore, they do not provide continuous electricity supply as the nuclear option does. The reliability and safety of electricity supply from nuclear is one of the major factors which ensures its place in virtually all clean energy mix scenarios.

The latest projections in the "New Policies Scenario" of the IEA's World Energy Outlook, which takes account of current and planned policies including nationally determined commitments under the Paris Agreement on climate change, showed nuclear power continuing to play an important role in meeting the world's energy needs. The projected output from nuclear generation foresees a growth of 1.5% per year, though its share in total power generation falls slightly, from 10% to 9%. In the "Sustainable Development Scenario", which sets out an energy trajectory that addresses air pollution concerns, provides universal energy access and is consistent with the Paris Agreement's goals, the role of nuclear power is much more important: output grows by 2.8% per year to 2040 and its share in the generation mix reaches 13% worldwide. For advanced economies in total the growth between 2018 – 2040 will be about 10 % (see Figure 10).

The IEA investigated another situation called "Nuclear Fade Case", where nuclear is not supported nor appreciated as a technology to decarbonise. In this scenario, existing nuclear plants in advanced economies are being retired and few new plants are being built. When the "Nuclear Fade Case" is considered within the "New Policies Scenario", global nuclear power capacity declines steadily to around 370 GW in 2040 (about 50 GW down on the 2018 level), as the rapid decline in advanced economies more than offsets continued expansion in the developing economies. As a consequence, in the advanced economies the electricity has to be generated by other VRE's, with related system costs and a challenge in reliability of supply or generated by fossil fuels, leading to increased emissions.

In the New Policies Scenario (i.e. without "nuclear fade"), global capacity rises by about one-quarter, with strong growth in China, India and Russia (China becomes the leading nuclear power producer in 2030). Capacity falls slowly in advanced economies, levelling off at around 240 GW in 2040 (about 25% lower than in 2018 compared with 70% lower in the Nuclear Fade Case).

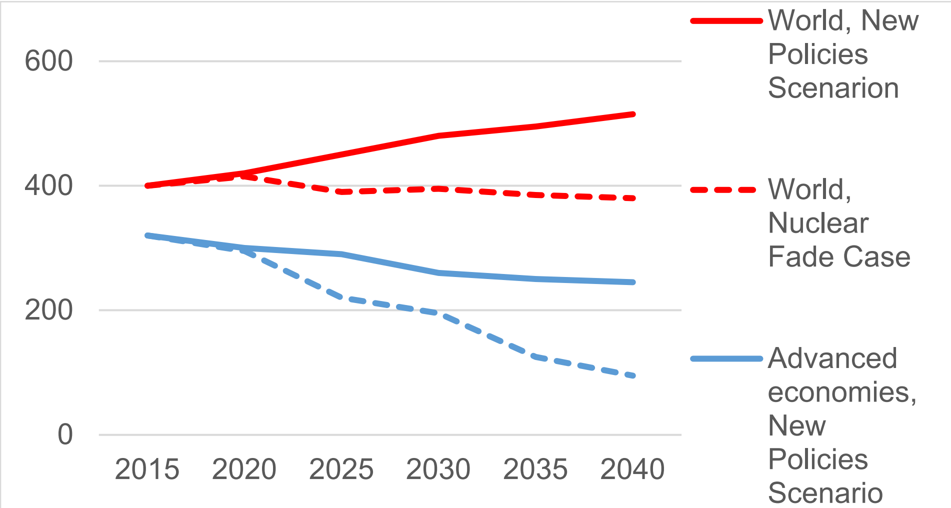


Figure 10: Nuclear power capacity in the New Policies Scenario and the Nuclear fade Case [IEA, 12]

Nuclear power makes an important contribution to the quicker expansion of low-carbon electricity supply in the "Sustainable Development Scenario". Global nuclear production is projected to reach 4960 TWh in 2040, i.e. 33% higher than in the New Policies Scenario and 90% higher than in 2018. Capacity reaches 678 GW by 2040, compared with 519 GW in the New Policies Scenario and 422 GW as of May 2019. The largest components of the increase are in China and, to a lesser extent, India, where coal represents most of power generation both now and in the future. Nuclear capacity in the two countries combined jumps from 53 GW in 2018 to almost 250 GW in 2040, compared with about 190 GW in the New Policies Scenario. Nuclear capacity additions In China and India largely to replace baseload coal in this scenario, yielding large emissions reductions without requiring major changes in the electricity system operation.

In advanced economies, nuclear power production increases by around 10% between 2018 and 2040 in the Sustainable Development Scenario, largely due to the restoration of nuclear production in Japan, as well as a combination of more lifetime extensions of existing reactors and some new construction in all regions. This compares with a fall of around 12% in the "New Policies Scenario". Nonetheless, the retirement of some plants and legally binding phase-out policies leads to a decline in output between 2018 and 2040 in several countries with a significant decline of nuclear capacity, notably the United States. In the Sustainable Development scenario nuclear production also falls slightly in the European Union. Yet the share of nuclear in the generation mix declines much less than in the "New Policies Scenario", alleviating the challenge of boosting renewables-based generation and integrating the VREs into the electricity system. In Japan, nuclear production recovers almost to the level it was before the Fukushima Daiichi accident. This would require a major effort to achieve social acceptance, as well as large investments to secure lifetime extensions of much of the idle fleet.

When comparing the IEA Sustainable Development Scenario with the IPCC pathway scenarios, in the majority of low carbon scenarios (consistent with limiting the global warming to 1.4 or 2 degrees C) IPCC's nuclear power contribution is higher than the IEA projections. This means that in its scenario, the IEA probably considers the lowest levels of nuclear generation necessary.

International Atomic Energy Agency [16]

The IAEA generates various projections related with the future utilisation of nuclear energy, and stresses its essential role in a clean energy transmission functioning as a backup for variable renewables. The IAEA established two base cases, one high utilisation and the other of low utilisation of nuclear energy. In the high case scenario, nuclear electricity production increases by 50% from the 2018 to 2030, with a further increase of 50% expected to occur by 2050, altogether a 2.2-fold increase. In terms of the contribution to the electricity production in the high case scenario the share of nuclear increases to 11.5% in 2030 and to 11.7% in 2050. In the low case scenario, nuclear electricity production increases only by about 11% by 2030 and about 16% by 2050. In the low case scenario, the projected share of nuclear generation of electricity is reduced to 8.5% in 2030 and to 6.1% in 2050.

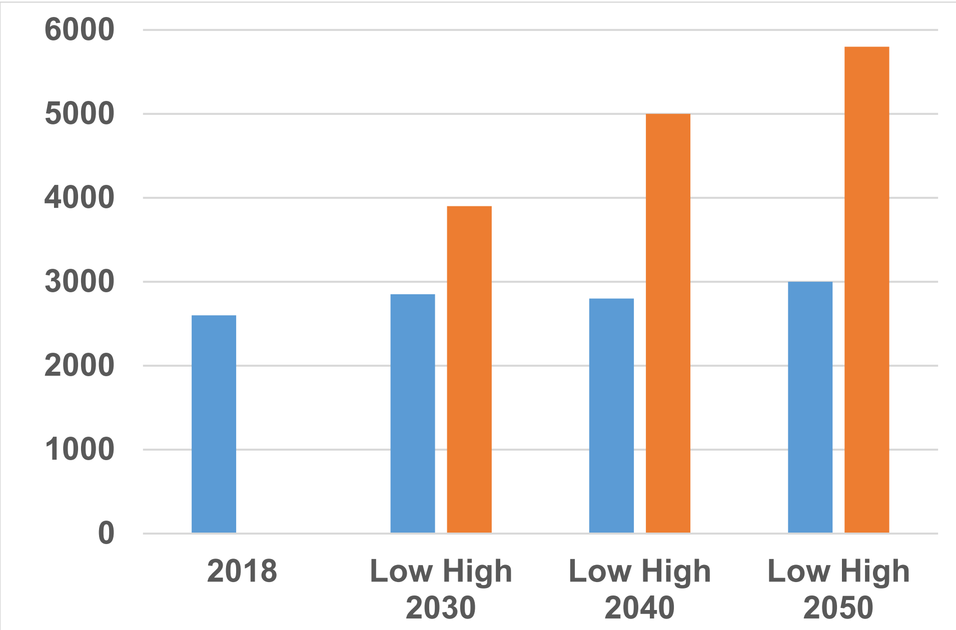


Figure 11: World Nuclear Electricity Production [IAEA, 16]

OECD Nuclear Energy Agency [11,13]

The NEA [13] published several reports highlighting the role of nuclear power on a global scale, as a source of clean energy, important for decarbonisation and providing stability to the grid [11]. The analyses conducted by the NEA address an important aspect of wind power generation economics, namely the costs that must be borne by the grid (as system costs) in order to ensure a stable and reliable electricity generation [17] providing a financial argument for a nuclear option.

In its thorough analysis on the "Cost of decarbonisation", which unlike some other studies do include the system costs, the conclusion is that ALL available low carbon generation options (including nuclear energy, VRE and possibly also fossil fuels with carbon capture) would need to be deployed to meet environmental goals in a cost-efficient manner. NEA concludes that while recognizing great strides that VRE achieved in recent past, those sources are not yet fully cost competitive with nuclear power. However, intrinsic variability and unpredictability of VRE imply that more capacity needs to be installed, that the investments are bigger and, that the grid needs to accommodate the peaks in generation. Therefore, the costs of the overall system will continue to rise over and above the sum of the plant level cost. This is exactly the opposite then for nuclear power with its reliable and predictable power supply. The NEA stresses that for the right decisions to be made, these factors (e.g. greater capacity needs, grid requirements, etc.), must be understood and properly taken into account.

The NEA concludes that with high likelihood, a cost-effective low carbon system would consist of a sizeable share of VRE, and at least an equally sizeable share of dispatchable zero carbon technologies such as nuclear energy and hydro, together with a residual amount of gas-fired capacity to provide added flexibility. The NEA nevertheless stresses that nuclear must evolve, in particular related to its construction time, costs and social acceptance.

Key points to consider are that the two countries with the fastest growth in energy demand are China and India, both start with relatively coal intensive fuel mixes. China is the world's largest source of growth in the energy supplies over the outlook, driven by rapid growth in renewables and nuclear power. Europe and the USA have similar trajectories of declining shares in coal and oil and increasing use of renewables.

Nuclear continues to grow, although less than the overall power generation, and as a result its overall share declines. In the OECD nuclear declines materially over the outlook as a result of ageing reactors and limited investment in new capacity, while in contrast in China it increases strongly to 1000 TWh over the outlook (Figure 12).

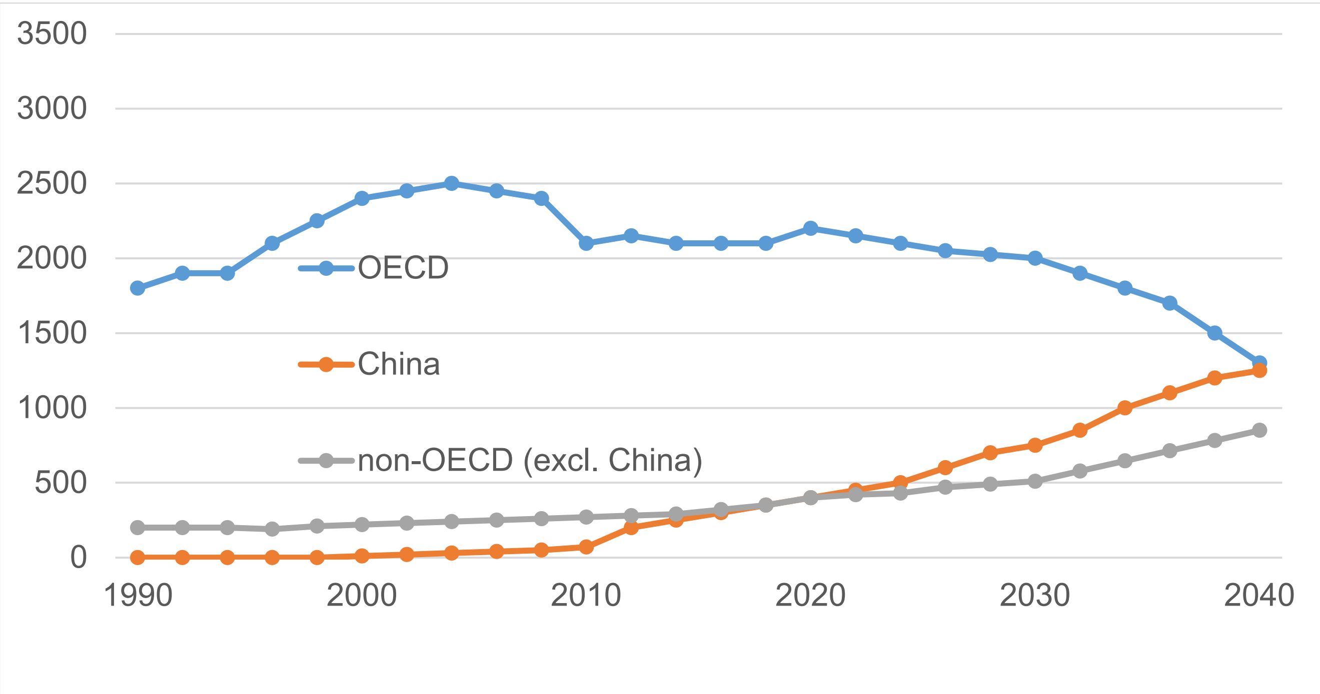


Figure 12: Nuclear capacity TWh to 2040 [OECD/NEA, 13]

McKinsey Global energy perspective [18]

According to Mckinsey's analysis, in the reference case the global primary energy demand will plateau around 2030. In 2019 renewables accounted for roughly 25% of power generation, raising to 50% by 2035 and close to 75% by 2050. Coal and oil generation are to rapidly decrease, partially substituted by renewables and partially by gas-based alternatives (with lower costs and lower carbon emissions). Gas generation will likely act as a stable baseload and dispatchable capacity provider. Nuclear remains a part of the energy mix and maintains more or less steady contribution (Figure 13).

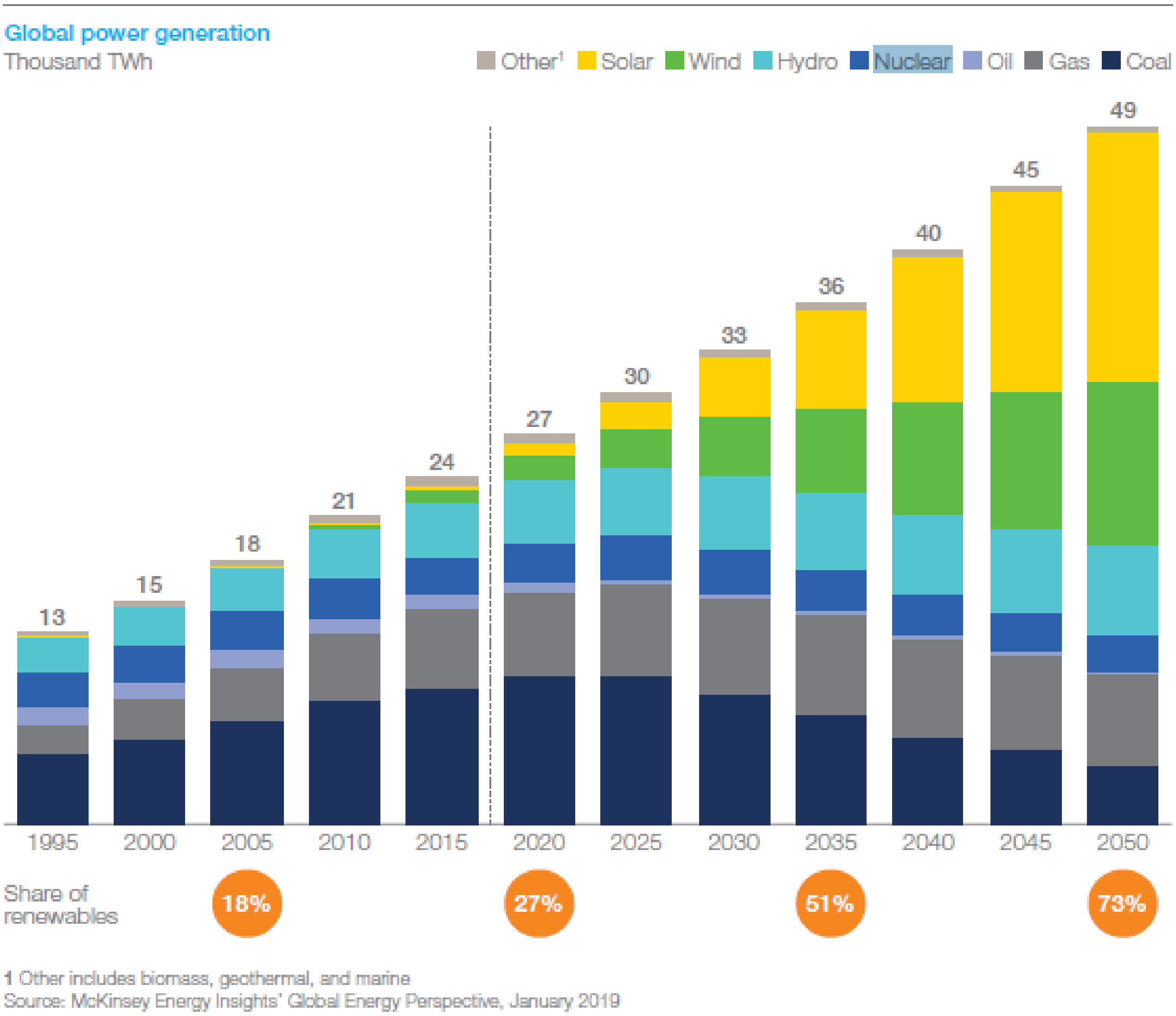


Figure 13: Global Power Generation (Thousand TWh) Mckinsey [15]

World Nuclear Association [19]

In the September 2019 report "The Nuclear Fuel Report: Global Scenarios for Demand and Supply Availability 2019-2040", the World Nuclear Association's projections for nuclear generating capacity growth have been revised upwards for the first time in eight years, following the introduction of more favourable policies in a number of countries.

In France, the country's energy policy has been modified, delaying the planned reduction of nuclear power in the share of its electricity mix and allowing operating lifetime extensions of existing reactors beyond 40 years. In the USA, state legislatures are starting to pass measures that support the continued operation of nuclear reactors, recognizing their valuable role in providing low-carbon electricity. At the same time, the process of granting a second operating licence extension for US nuclear reactors has begun, allowing reactors to operate for 80 years.

Both China and India have extensive nuclear expansion programmes and the prospects for new reactors in many countries have improved with several newcomer countries such as Turkey, Bangladesh and Egypt launching construction projects and several more, including Uzbekistan, Kazakhstan and Poland, demonstrating a clear interest in developing nuclear programmes.

The Upper and Reference Scenarios show global nuclear power capacities growing over the period to 2040 at a faster rate than at any time since 1990, increasing mainly due to extensive reactor building programmes in China, India and other countries in Asia. While projected growth in the Reference Scenario is moderate, with capacity growing to 569 GWe by 2040, in the Upper Scenario the present level of nuclear capacity is expected to almost double to 776 GWe. For the Lower Scenario, nuclear capacity essentially maintains its current level over the forecast period at 402 GWe.

World Energy Council [20]

In its flagship publication in “World energy issues monitor 2020”, the WEC recognises an increasing mix of clean heat, clean power and clean fuel solutions as a response to shifting demand in regionally diverse energy systems. The combination of financial and technology innovation continues to accelerate the pace of energy transition. There is growing interest in systems integration and flexible storage solutions to meet the challenges of variable generation.

New nuclear interest is evident in Europe, China, Africa and the Middle East. Coal-fired power is peaking in the USA and growing fast in India. Nuclear power remains important in Europe, though the opinion remains polarised in many European countries. Nevertheless, nuclear power is increasingly recognised as a carbon-free energy source and potentially an integral part of the future energy mix. There is qualified support among energy leaders to include nuclear energy to help create a carbon neutral continent and enable a just energy transition. In its scenarios to 2040, WEC recognised sizable contribution of nuclear to the electricity production.

Conclusion

Most international organisations are in favour of nuclear in order to cope with climate change. Many of those clearly indicate that there is little chance of full decarbonisation without significantly increased contribution of nuclear power.

However, drawbacks needs to be mentioned as well. The IPCC give some (see figure 7). In relation to the Taxonomy document, a debate is on-going in the European Union regarding the sustainability of nuclear energy. It goes beyond this document to discuss strengths and weaknesses of nuclear energy including e.g. non-proliferation issues, final disposal of radioactive waste including spent nuclear fuel in the deep underground and/or impact of accidents of the current generation of nuclear power plants. All of those issues have been extensively discussed elsewhere.

4 DURATION OF NPP CONSTRUCTION, CONDITIONS AND PROJECT CYCLE FOR NEW BUILT

A nuclear power plant must be managed in a safe and efficient manner throughout its entire life cycle, from design through to decommissioning, with the overall goal of providing reliable and affordable electricity. The following life cycle phases can be distinguished:

Table 2: Life cycle phases of a nuclear power plant

	Phase		Activity	Outcome
1	Project preparation	1.1	Project development	
		1.2	Licensing	License granted
		1.3	Site preparation	Final Investment Decision (FID), 1st concrete
2	Construction	2.1	Construction and installation	
		2.2	Commissioning testing	Operation license
		2.3	Start of commercial operation	Commercial Operation Date (COD)
3	Periodic Evaluations	3.1	Topical safety Evaluations	10 yearly Periodic safety review (PSR)
		3.2	Safety improvements and modernisation	
4	Decommissioning	4.1	Final shutdown	
		4.2	Post operation	Reactor core unloaded
		4.3	Decommissioning	End of nuclear license
		4.4	Dismantling	Brown or green field
		4.5	Storage of radioactive materials	

In terms of activities, the most important phase of nuclear plant is the construction phase. This is the phase where a majority of the costs of a plant originates. Normally, the costs during the project preparation phase are relatively low. Consequently, the delays during the preparation phase have a relatively limited impact on the cost of a nuclear plant project as the whole. On the contrary, the delays during the construction phase have an enormous impact, because of the capital costs for the already delivered equipment and services.

For that reason, the duration of the construction phase is a good indicator of the total project costs. Normally, the construction period is measured between the date of first pour of concrete and the " commercial operation date" (COD). Sometimes this is reported as the time between "first concrete" and the "first grid connection".

A global trend could be observed towards increasing construction times. National building programs were faster in the early years of nuclear power. As illustrated in Figure 14, the construction duration for the nuclear plants completed in the 1970s and 1980s were quite homogenous, while in the past two decades they have varied widely.

The longer-term perspective confirms that short construction times remain the exceptions. Nine countries completed 63 reactors over the past decade - of which 37 in China alone - after an average construction time of 9.8 years, a slight improvement over the decade 2008–mid-2018 with 10.1 years. Nevertheless, there are some notable short construction times, mostly with plants that were constructed in a series, where accumulated experience helped in shortening the schedule.

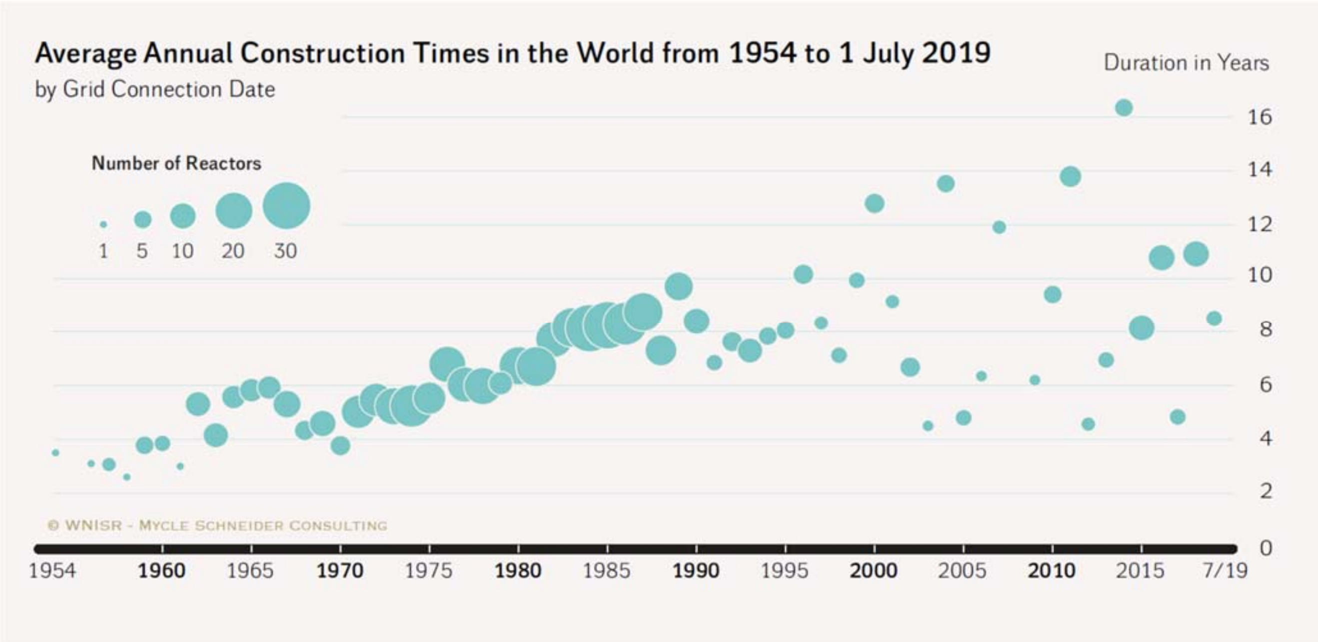


Figure 14: Average annual nuclear plant construction times in the world from 1954 to 2019 [21]

4.1 PRE PROJECT PREPARATION

Although the preparation/constructing time for NPPs is (very) long, nevertheless it should be noted that the lifetime of the NPP is much longer than that of other energy sources. NPPs of GEN II were designed for 40 years operating life, and they typically obtain an extension of operating license to 60 years and nowadays even more, up to 80 years. The GEN III reactors are designed from the beginning to operate for 60 years and it is planned to have them running for at least 80 years. This means that they will deliver electricity for up to 4 generations.

It is nevertheless important to distinguish between the time required to advance the project from a decision in principle (or other similar strategic decision-typically by the government) to the issuance of a construction permit. Although the pre-project planning is not a strong factor in terms of NPP costs, it does play a major role in terms of planning resources and overall budgeting, which depending on circumstances (e.g. new site or an existing nuclear site, etc.) may take 3 or even 5 years.

In the notable case of Hanhikivi project, although the Finnish Government granted a decision-in-principle for construction of a 1,800MW nuclear plant in May 2010, site selection was completed in 2011 and the plant supplier was contracted in 2013, the construction is still to begin. The design and safety-related documentation is being finalised and the company now expects to receive construction approval in 2021.

In the UK, the process of design review and construction approval for new NPPs was planned for 4 years. In the case of the HPC, it lasted 5 years.

In the USA, the application for the design certification of the Korean designed APR1400 design was submitted in 2013 and a revised version in March 2015. The USA nuclear regulator's NRC review confirmed appropriateness of the design in September 2018. The design certification was approved in May 2019 and formally awarded in August 2019, allowing any plant with such a design to be constructed at any pre-approved site in the USA.

4.2 CONSTRUCTION TIMES FOR GEN III

The design of new nuclear plants have changed substantially from the GEN II to GEN III. Technological advances and deployment of the modern technologies lead to increased robustness and safety, minimising or removing a possibility of off-site effects, but also maximize efficiency, the lifetime and reducing the generation of radioactive waste. The level of complexity between the GEN II and GEN III increased tremendously. Construction of those plants came at a high cost to countries which commissioned the deployment of GEN III early on and constructed the 'first of a kind' plants. From original estimates of about 5-6 years, FOAK Gen III are taking close to a decade to be completed.

Few GEN III reactors were launched after a long period without NPP construction, particularly in the US and Western Europe, often on a design that was not developed to a full level of details as well as with specifications that might not have been fully developed either. Responsible nuclear safety regulators, main vendors but also construction/erection companies lacked (lost) experience in complex nuclear projects. As expected, those projects were affected by delays and cost increases, often making dramatic headlines around the world. It is worth noting that the early examples of GEN II plants were subject to similar challenges, which were gradually overcome as the experience accumulated.

Part of the lengthy "construction" periods observed in some countries (notably Watts Bar in the US or Olkilouto 3 in Finland) might be associated to changes in regulatory requirements and time period necessary for obtaining all necessary licences. A central theme in NPP design, construction and then operation is assuring its safety. After an event or an accident, licensing, regulations and designs are affected in order to incorporate lessons learned, thereby directly improving safety, at the expense of time (delays). This was the case of NPP construction in the USA after the TMI accident in the late 1970s, and also all over the world after the Fukushima accident in 2011. In the European Union, all operating and proposed NPPs were reviewed within the "Stress tests" program to apply lessons learned from Fukushima, and in the USA a similar action was conducted by NRC.

The EPR reactors under construction in Olkiluoto 3 (Finland) and Flamanville 3 (France) were confronted with major delays and cost overruns. The Flamanville 3 was the reference plant for the construction of 2 EPRs at Taishan in China. While initially in the project the feedback from Flamanville 3 construction (and details for the design) were transferred to Taishan, the experience in construction of NPPs in China has led to the fact that Taishan, although also having some delay from its original schedule, was completed well before Flamanville 3. For other models of a GEN III NPP, e.g. Russian WWER 1200 but also AP 1000 in China, recent construction periods were in the order of 100 months, still longer that originally envisaged but shorter than EU and US examples. The erection of the first unit of the standard Chinese GEN III, Hualong One, seems to be on track to complete the construction within 5 years.

Table 3: Construction time at Taishan

Unit	Technology	Construction duration
Taishan 1	EPR	103 months
Taishan 2	EPR	109 months

The construction of EPRs in Taishan was notable for successfully testing new construction techniques. Large gains on the critical path have been achieved on e.g. the installation of the Containment liner, the Containment dome lifting and the welding of the primary circuit. Building two units on the same site has also allowed to optimize the construction resources, both workers and equipment. The site organisation allowed switching from one reactor to the other, to cope with construction bottlenecks. The lessons learned during the commissioning of unit 1 resulted in significantly shorter commissioning period on Unit 2 (Table 4). Just reducing the duration of the commissioning could reduce the construction period for significant time (the Unit 2 had much larger delay during the construction, due to focus of the resources on the Unit 1).

Similar schedule reductions were observed at AP 1000 plants in China. This give a raise to the consideration that a long construction schedule of initial GEN III plants would not to be expected when more units are constructed. The confirmation (or negation) of this trend would be confirmed with experience at HPC in the UK.

Table 4: The duration of different phases of the commissioning at Taishan

	Taishan 1	Taishan 2
Cold functional test -> Hot functional test	14.1 months	5.2 months
Hot functional test -> Fuel loading	13.2 months	4 months
Fuel loading -> Grid connection	2.6 months	2.4 months
Grid connection -> Commercial operation	5.5 months	2.5 months
Total length of the commissioning	35.4 months	14.1 months

According to the information from reactor vendors compiled by US EIA at the end of 2018, the duration construction of an NOAK nuclear plant is expected to be in the order of 6 years. The time periods needed for constructing a FOAK GEN III plants are typically much longer (about 10 years). However, observing lesson learnt from the construction, the time duration could be reduced substantially by means of optimization by building of several reactors (at least two on the same site), modularization and other methods.

According to data compiled by the IAEA on the 61 new power reactors connected to the grid over the last decade, units in the Far East were built almost twice as fast as those in Europe, taking on average 66 months versus 110 months [22].

4.3 COST FOR NEW BUILT

The construction costs, which are closely linked to the duration of construction, are a major concern for new nuclear plants. The costs are in billons euros and the investment goes on for extended period of time (up to 5 years pre construction and then 6-10 years construction) before the plant would start generating revenues. Nevertheless, the construction cost is only one of the elements that needs to be considered when assessing and comparing the cost of electricity. Typically, the cost needs to consider the four main elements, which would then enable pertinent cost comparison across the range of different sources of electricity. Those are:

- Capital costs, which include the cost of site preparation, construction, manufacture, commissioning and, as appropriate, financing of a nuclear power plant. To compare different power generation technologies, the capital costs must be expressed in terms of the installed generating capacity of the plant (for example as Euros per MW). Capital costs may be calculated with the financing costs included or excluded. If financing costs are included, then the capital costs change materially in relation to construction time of the plant and with the interest rate and/or mode of financing employed;

- Plant operating costs, which include the costs of fuel, operation and maintenance (O&M), insurances, taxes and a provision for funding the costs of decommissioning the plant and treating and disposing of wastes. Operating costs may be divided into 'fixed costs' that are incurred whether or not the plant is generating electricity and 'variable costs', which vary in relation to the output. Normally these costs are expressed relative to a unit of electricity (for example, cents per kWh), to allow a consistent comparison with other energy technologies;
- System costs, defined as the total costs accrued beyond the perimeter of a power plant to supply electricity at a given load and at a given level of security of supply. System effects measure the impact that the integration of a power generation source has on the whole electricity system. System effects of existing dispatchable technologies (nuclear power, coal and gas) are small and therefore have not needed to be taken into account by electricity grid operators. However, the technical and economic system effects of variable renewable technologies (offshore wind, onshore wind and solar) are mostly unaccounted for and are significant. Presently, these costs are borne by existing dispatchable technologies, grid operators and the general public through taxes or electricity tariffs;
- External costs, which are not covered by the electricity producer nor by the grid operator, but consist of health and environmental damages due to power generation including the whole power production cycle. In some countries the costs of environmental damage caused by CO2 emissions are passed on with the ETS system. The environmental costs that are covered by electricity producers are by definition not to be considered the external costs, as long as those are completely covered by the compensation.

In this Chapter, only the costs of the NPP construction are discussed. The latter three, the operating costs, the system costs and the external costs, are addressed in the Chapter 5.

It is important to realise that the end-of-life (decommissioning) costs are not included in the overnight capital costs of a nuclear plant, though those should always be included in the LCOE estimates. Normally, the costs of decommissioning and waste management are part of the operational costs of the plant (polluter pays principle) and should not be calculated twice. It should be considered that nuclear is the only source of electricity where the decommissioning and waste disposal funds are systematically accumulated as a plant is producing power. To enable a levelized companion, end-of life and decommissioning/waste and recycling costs needs to be considered on the similar basis for the VREs as well, which is often not the case.

The 2016 edition of the World Nuclear Association's The World Nuclear Supply Chain: Outlook 2035 tabulated the breakdowns in capital costs, by activity and in terms of labour, goods and materials.

Table 5: Breakdown of capital cost for a NPP [23]

Activity/area	percentage
Design, architecture, engineering and licensing	5%
Project engineering, procurement and construction management	7%
Construction and installation works:	
• Nuclear island	28%
• Conventional island	15%
• Balance of plant	18%
Site development and civil works	20%
Transportation	2%
Commissioning and first fuel loading	5%
Total	100%
Equipment	
• Nuclear steam supply system	12%
• Electrical and generating equipment	12%
• Mechanical equipment	16%
• Instrumentation and control system (including software)	8%
Construction materials	12%
Labour onsite	25%
Project management services	10%
Other services	2%
First fuel load	3%
Total	100%

In terms of costs related to new builds, there are two main elements influencing the cost. One is the financing costs, which are high for nuclear, because of a typically long construction period and related cost of financing and in some countries because of a political risk. The other important driver of the costs is the level of design completeness at the time of the initiation of construction.

When considering the costs of nuclear plants, it is often overlooked that the financing costs, due a long planning and construction periods, are the major contributor to the cost of nuclear power. Unlike VREs (and also some other plants, like highly standardised gas plants) that could be built in relatively short time and added in increments, and would begin generating income soon after the initial investment, nuclear plants are exactly the opposite: long investment periods, but then very long unitisation periods, up to 60 for many currently operating plants but also predicted to be extended to 80 years (e.g. the request for the extension of the operating licences for Peach Bottom 2&3 and Turkey Point 3&4 NPPs in USA are currently being processed by US NRC; when approved, as expected, those would be first plants to be licenced to operate for a duration of 80 years. Several other plants are expected to follow suit), as compared with 20 to 25 for most VREs, making them extremely sensitive to the cost of capital. This might be best illustrated in the Figure 15 below: more than 2/3 of the capital costs for the Hinkley Point C (HPC) under the construction in UK is due to the interest charges. As shown in Figure 16, the cost of capital could easily double the cost of a NPP, depending under which conditions the financing is provided.

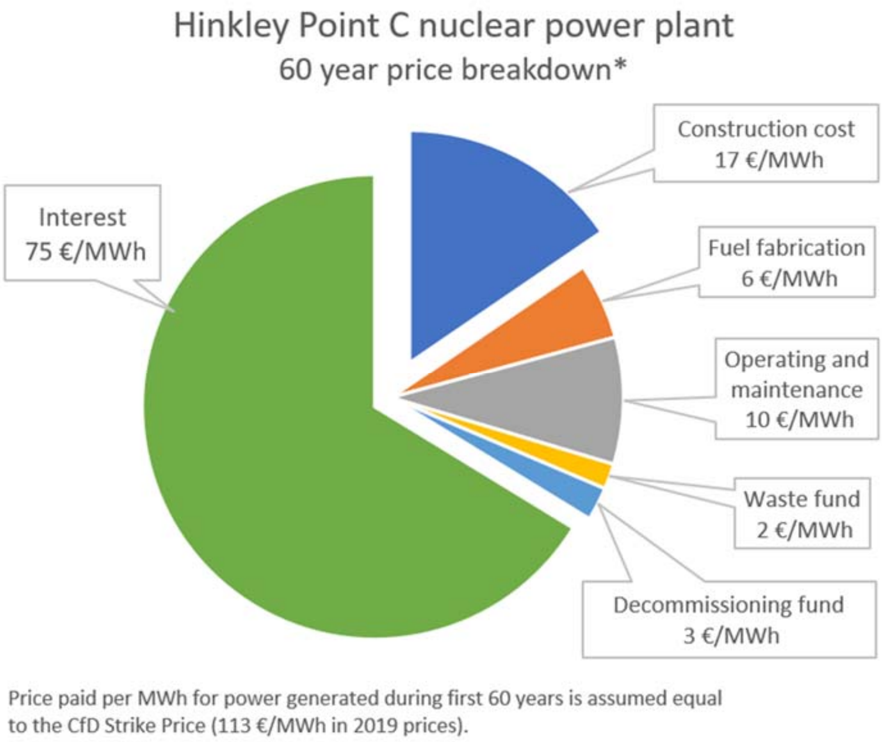


Figure 15: Distribution of lifetime cost for HPC [24]

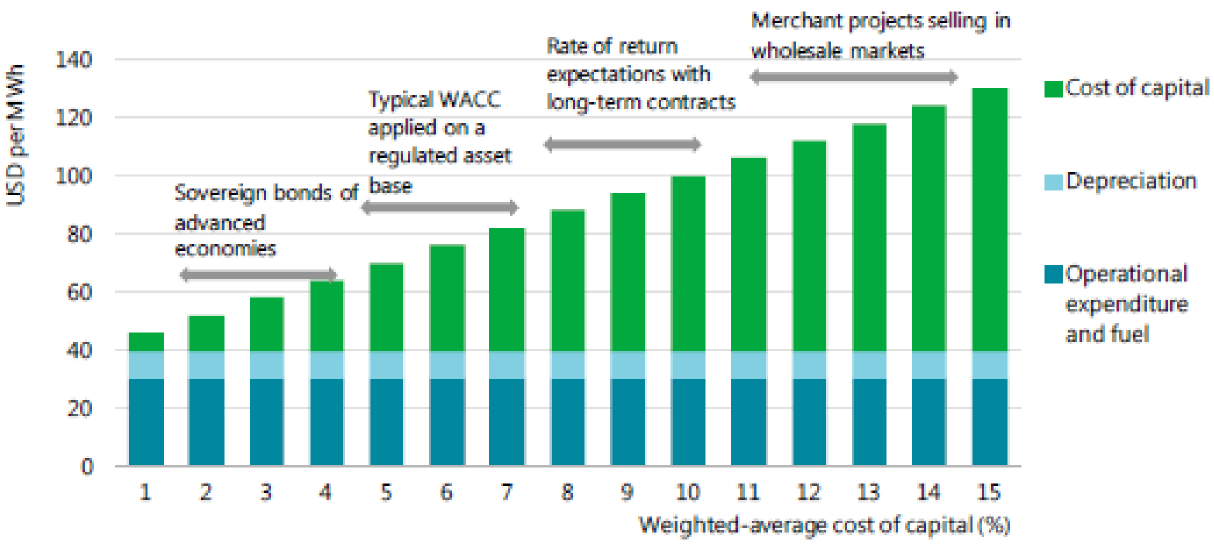


Figure 16: Impact on the nuclear LCOE in relation with the cost of capital [12]

According to ETI study [9], the degree of the completeness of the plant's design when construction began was one of the most important drivers of the total capital cost. In several cases, the plant design reviewed and approved by the nuclear regulator lacked many details necessary for the actual construction. A strong pattern emerged showing that high-cost projects had started with incomplete designs, while low-cost projects had started after a vendor finalised the full plant design and planned the construction project in detail.

In the Figure 17 below, each unit is a dot showing design completion and total capital cost, with a tight correlation across the dataset.

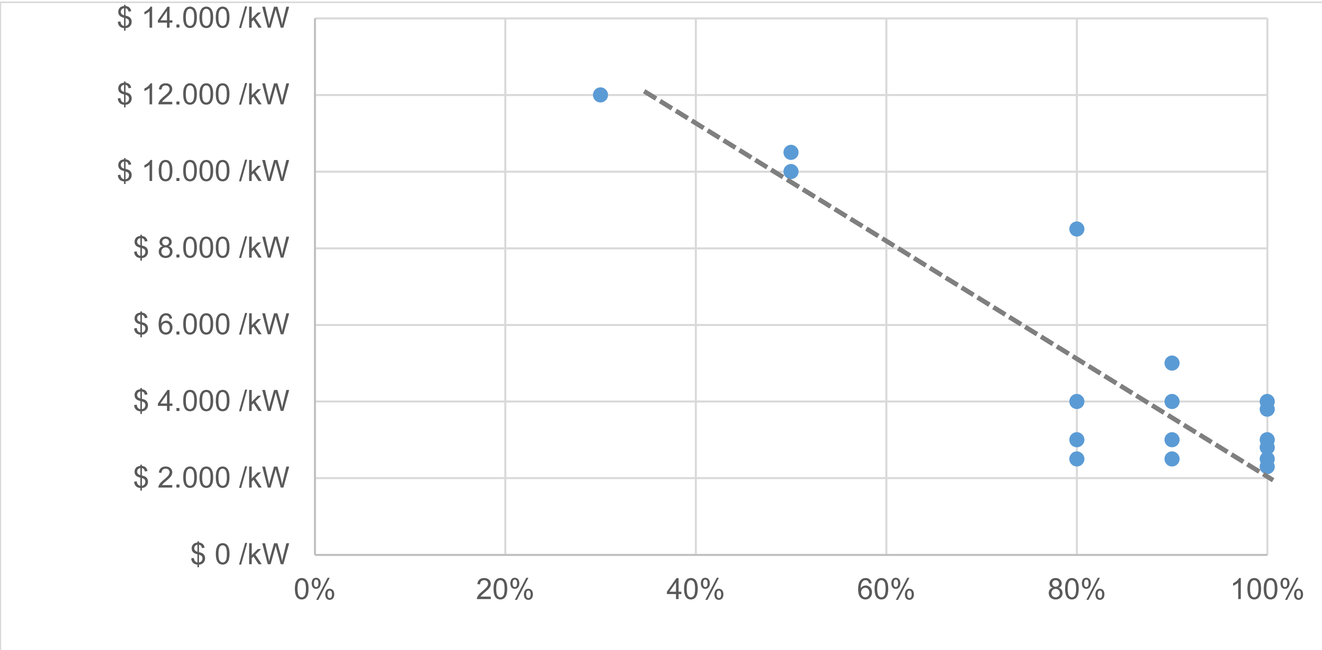


Figure 17: NPP Capital cost versus design completion at construction start, ETI [9]

From historic data (Figure 18) it might be concluded the because of the learning rate between FOAK and NOAK the costs of the fifth or sixth one are about half of the FOAK.

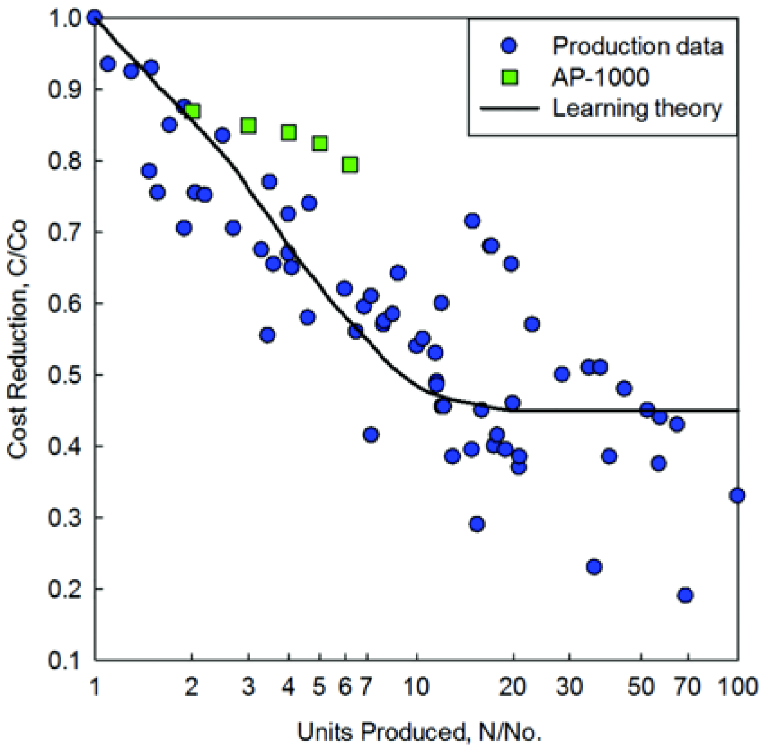


Figure 18: Composite technological "learning curve" with a Gen III example (AP 1000) [25]

The information on the actual costs of NPPs being built as summarised in the Table 6, and the conclusions from implementation of the GEN II projects indicate that the cost of new built NOAK reactor in Europe might be expected be in the range of 4000 to 8000 euro/kWe.

For a specific project in Central Europe, where a new nuclear plant is to be built on an existing site, the range of potential reactor designs falls between 3950 euro/kWe to 4800 euro/kWe. The Table 6 encompasses both completed projects (total costs = real costs), and ongoing or yet to start ones (total costs = projected costs).

Therefore, the costs are not fully comparable. Moreover, various vendors and owners have different structures when reporting the costs.

Table 6: Construction period and published cost data for NPPs [26-32]

NPP	Country	Units	Construction period	Reactor type	Total cost	Cost per kW	Vendor
Plants in operation (or about to start): Real costs							
Taishan	China	2 x 1660	2008 - 2018	EPR	8.6 bn Euro	2.590 euro/kW	AREVA
Sanmen	China	2 x 1080	2008-2018	AP1000	5.88 bn euro	2720 euro/kW	Westinghouse
Novovoronezh	Russia	2x 1200	2008-2017	WWER1200	Not published	-	
Barakah 1-4	UAE	4 x 1400	2013-2018	APR1400	22 bn euro	4824 euro/kW	KHNP
Olkiluoto 3	Finland	1650	2005-2020	EPR	> 8.5 bn euro	>5150 euro/kW	AREVA
Plants under construction or in planning : Projected costs							
Flamanville3	France	1600	2007-2023	EPR	12,4 bn euro	7500 euro/kW	EDF
Vogtle 3, 4	USA	2 x 1080	2013 –2021	AP 1000	22.5 bn euro	10416 euro/kW	Westinghouse
Hinkley Point C	UK	2 x 1600	2017-2025	EPR	29.5 bn euro	9120 euro/kW	EDF
Hanhikivi	Finland	1200	2021 - 2028	WWER1200	7 bn euro	5800 euro/kW	Rosatom
Akkuyu	Turkey	4 x 1200	2018 - 2024	WWER1200	18 bn euro	4160	Rosatom
EDF plan	France	6 x 1600	2023- 2048	EPR-2	46 bn euro	5200 euro/kW	EDF
Paks 2	Hungary	2 x 1200	2022-2028	WWER1200	12 bn	5000 euro/kW	Rosatom

Costs recalculated assuming 1 USD = 0.9 euro, 1 GBP = 1.18 euro, 1 CPY = 0.01626 euro

An interesting comparison of various factor influencing the construction costs of nuclear plants could be made. As expected, the FOAK and NOAK are the main driver including the associated level of development of the design and similar. Important cost reducers are the regulatory stability, experienced supply chain as well as strong oversight by the owner/operator. As expected, high or low cost of labour (a big advantage for China) as well as litigations (e.g. multiple litigation among many participants at Olkilouto 3) are very important cost drivers.

In 2017 the European Commission steered its Nuclear Illustrative Programme (PINC) to focus on improving cooperation between regulators when licensing new reactors and on encouraging industry to standardize nuclear reactor designs.

Table 8: Characteristics of low cost and high cost plants

Low cost plants	High cost plants
• Design complete prior to construction • NOAK design • High degree of design reuse • Experienced construction management • Low cost and highly productive labour • Experienced EPC consortium • Experienced supply chain • Detailed construction planning prior to starting construction • Multiple units at a single site	• FOAK design • Lack of completed design before construction started • Major regulatory interventions during construction • Significant rework required due to insufficient or lacking supply chain • Long construction schedule • Relatively higher labour rates and low productivity • Insufficient oversight by owner • Litigation between project participants

Comment: The above data concerns only the cost of construction and financing of a NPP.

4.4 CONDITIONS FOR NEW BUILD IN OTHER COUNTRIES

In order to build and operate a nuclear plant, a country needs to have a national infrastructure in place. The IAEA Safety Requirements and Safety Guides documents identified numerous infrastructural elements, from national legislation and regulations, over functioning and independent regulatory organisation to the specific technical infrastructure. In particular the licencing and permitting process, while in many cases being based on similar technical elements, would be significantly influenced by the administrative arrangements of specific countries. Some countries would need a “decision in principle”, that is a process where the state highest authority (parliament) agrees that the proponent would be allowed to construct and operate a plant in the first place. Only after that, the licencing process, which reviews safety, environmental impact and other conditions might be initiated. In other countries such a decision is not required, leaving in the permitting process in the hands of the national nuclear safety regulator, and possibly other regulators, depending on specific circumstances).

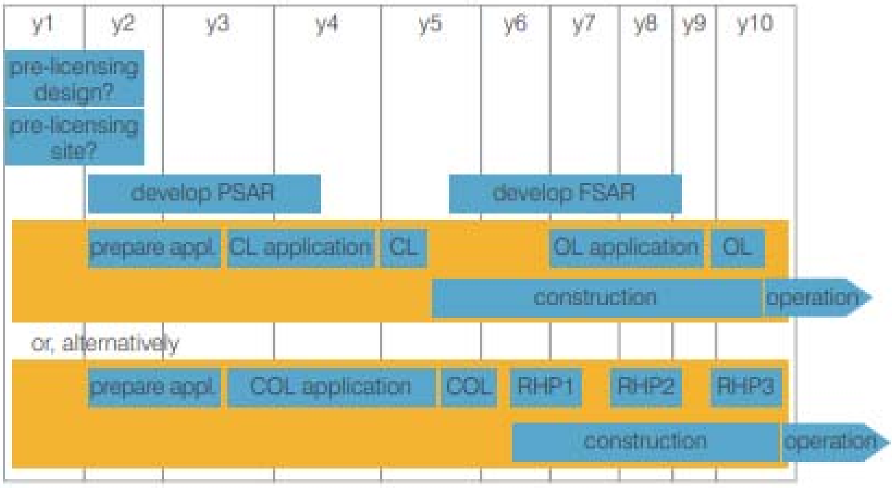


Figure 19: Major licencing steps for nuclear power plants [33]

The nuclear safety approval process, while fundamentally having similar objective and requirements, still differ between countries both in the processes and in the criteria. This, in some cases lead to the regulatory reviews required for a design that has already been reviewed and approved elsewhere. The World Nuclear Associations investigated the matter and published a document entitled 'Licensing and Project Development of New Nuclear Plants' which gives a thorough overview of the structure and processes related with licencing for new nuclear internationally.

Recognising that the regulation and the licensing process is an impediment to the development of nuclear, various initiatives has been put in place harmonise the approaches and enable utilisation of the safety reviews done elsewhere in the process. Notable initiatives in this respect exist in the EU through the European commission's initiatives including "Nuclear forum", but also in the WNA's Cooperation in Reactor Design Evaluation and Licensing (CORDEL). The IAEA series of standards are being increasingly adopted or being referred to by IAEA member states, supporting such a harmonisation. Other international initiatives like mutual recognition of regulatory approvals are ongoing.

Table 7: Pre licencing and licencing steps in selected countries [33]

	Pre-licensing	Licensing steps
France	ASN (Autorité de sûreté nucléaire) opinion on safety options (review of safety options)	1. Authorization decree for the creation of a basic nuclear installation 2. Licence for the commissioning of the installation
Germany	'Pre-statement' on project aspects (*e.g.* design) in the Nuclear Energy Act but never used	1. Construction licence in several steps (the first one being a type of design approval) 2. Operating licence in several steps
Canada	(Licence to prepare site) Pre-Licensing Vendor Design Review: an optional service provided by the CNSC (Canadian Nuclear Safety Commission) when requested by a vendor	1. Licence to prepare site 2. Licence to construct 3. Licence to operate

UK	GDA (Generic Design Assessment)	Nuclear site licence. Establishes hold points/consent points, typically: • First nuclear concrete • First nuclear island construction • First fuel brought to site • Start of active commissioning
US	Design certification Early site permit	10 CFR part 52: COL (combined construction and operating licence) 10 CFR part 50: 1. Construction licence 2. Operating licence

In relation with EPR reactors, notable initiative is the cooperation among national nuclear regulators of France, Finland, UK as well as China. While basically a similar EPR was still being approved in each country separately, there was extensive exchange on critical issues that lead to a common position on all national regulators in countries constructing the EPR reactors.

For the Netherlands in addition specific conditions for new build have been given in the letter to the Parliament 32645 nr.1 from 2011, "Randvoorwaarden voor de bouw van nieuwe kerncentrales". In this letter it is indicated that the reactor designs from all over the world could be licensed in the Netherlands. Nevertheless, an important conclusion might be that if a design has not been licenced or accepted in the EU Member States, the USA or in Canada, then the full licencing process in the Netherlands is due, which might be expected to take additional several years.

5 ESTIMATE OF THE COSTS FOR NEW NUCLEAR UNITS

5.1 COSTS SPECIFICALLY CAUSED BY NUCLEAR SAFETY REQUIREMENTS

Unlike other forms of electricity generation, the absolute primary requirement for the utilisation of nuclear generation is safety. The reason being that the resulting effects from a nuclear accident might be wider reaching and might have longer lasting consequences on public safety and environmental impact, than other generating technology. Consequently, while having the same objective as other "thermal" plants (to produce electricity), nuclear plants are equipped with a myriad of systems that are designed to make the operation of nuclear reactors "safe". As many of those systems have dual functionality, i.e. supporting the generation of electricity and being a part of a NPP safety concept, it is not easy to estimate the percentage of costs devoted to safety requirements at a nuclear plant. Nevertheless, it is generally estimated that the provision for safety could be 50% or even more of the costs of an NPP. This would include costs related to safety for the original plant design as well as subsequent safety improvements. It has to be noted that typically the cost of modernisation including safety improvements will be included in the LCOE for nuclear plants, especially when those costs are levelized over 60 or 80 years of projected lifetime.

It is important to distinguish between different safety costs, indirect and direct. Safety requirements are integrated in practically all systems, structures and components of the so called "nuclear island" but also there are safety provisions assigned to the conventional "turbine island", where the energy conversion is taking place.

The three primary objectives of nuclear plant's safety systems are to control reactivity (to control the chain reaction), to cool the reactor and to contain radioactivity (maintain the reactor in a shutdown condition and prevent the release of radioactive material). International standards (e.g. IAEA Fundamental Safety Principles -SF-1) and various engineering concepts are deployed to assure safety of the plant in all operating modes and in all conditions (including e.g. external events such as seismic activity, floods or human induced incidents, such as an aircraft crash). Those principles include redundancy and diversity of safety systems and components, physical separation, mutual independence as well as the requirement for high reliability of all equipment and adequately designed man-machine interface. Requirements such as regular surveillance testing but also rigorous training of staff and specially developed procedures to minimise the potential for operator errors leading to unsafe conditions are integral part of the safety concept of a NPP. It is clear that these requirements result in a significant increase to the costs of a nuclear plant.

It is interesting to observe the genesis of the development of safety concepts since the introduction of commercial nuclear plants. The first functioning nuclear reactor, designed by Enrico Fermi in the 1940s had, as a reactor shutdown system, a rope holding the shutdown rod, and a man with an axe to break it - to shut down the reactor (this is not made up, it is a true story: a fast reactor shutdown typically called "reactor SCRAM" is said to be originating from "safety control rod axe man"). The GEN I commercial reactors had rudimentary safety systems, aimed to shut down the reactor and injecting water if the coolant is lost. The GEN I reactors have nowadays been shut down all around the world (though some consider early UK ARGs as being the GEN I, and there are 3 of those still in operation, to be shut down in 2023 [34].

The GEN II reactors introduced redundant and sometimes diverse safety systems, but were generally poor on separation between systems, leaving plants vulnerable to hazards affecting several systems such as fire or a seismic event. Many of the GEN II plants are still in operation. Depending on the identified deficiencies of the original design, many of those plants (and all of such plants in the EU) have been subjected to multiple safety upgrades. Borssele NPP, being a GEN II NPP, has seen the addition (to the original design) of multiple safety systems located in a seismic and flood-proof bunker. Following the Fukushima accident, another round of safety improvements took place, further increasing the safety levels. With safety improvements implemented, it could be considered (e.g. the Outcome of the EU Post Fukushima stress test [35]) that some of the GEN II plants (in some cases those are termed GEN 2.5) may be approaching the safety level that is specified for the GEN III plants, though not in all areas (e.g. lack of core catcher, resistance to a crash of large aircraft, etc.). Nevertheless, unlike the GEN III plants, which as the design basis have the preclusion of off-site impact, the GEN II plans carry societal concern-resolutions that were needed to reduce the anxiety caused by large nuclear accidents like Chernobyl or Fukushima. While importance of these concerns are not easy to quantify, nevertheless, those remains present and are best recognised in the level of acceptance of (new) nuclear among the population.

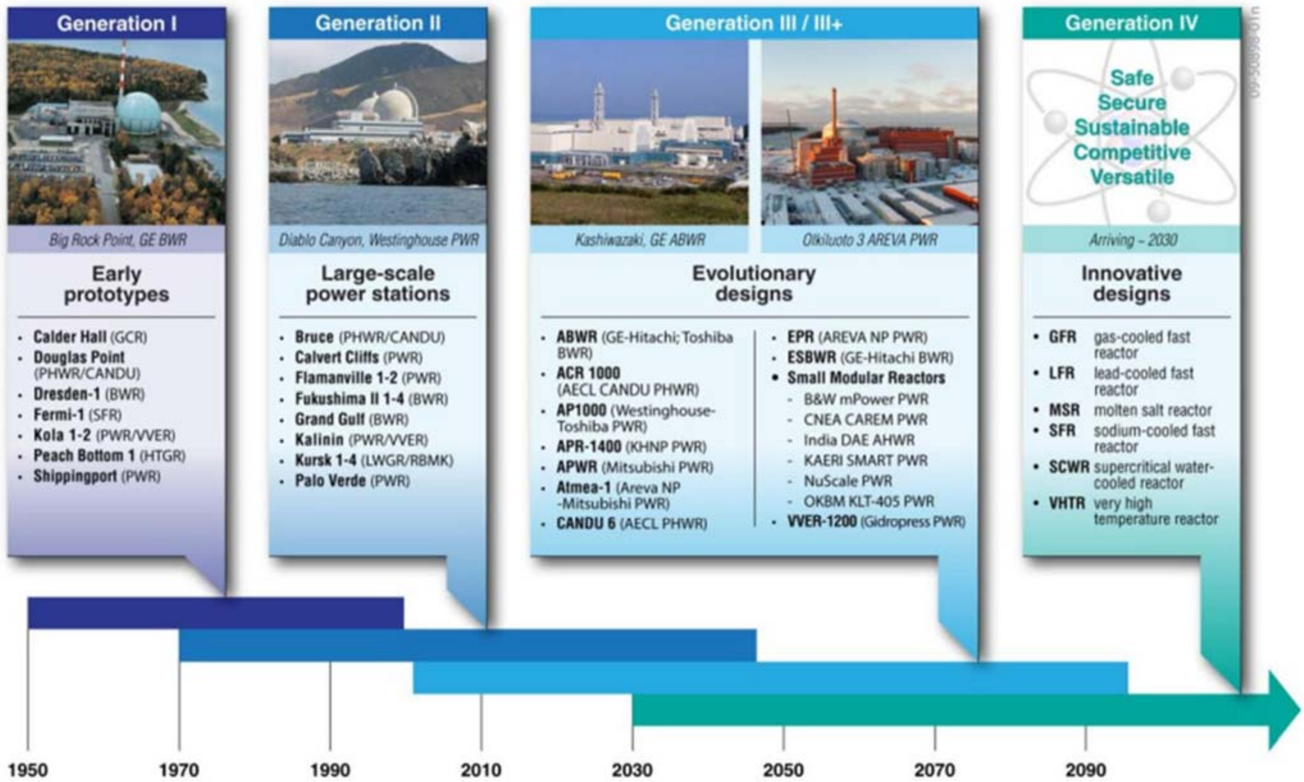


Figure 20: Nuclear reactors by generation, American Nuclear Society [36]

The GEN III NPPs, which are currently under construction (and few in operation), have the most stringent safety requirements as one of the cornerstones of their initial design. The European Power Reactor (EPR), jointly developed by Framatome and Siemens, is for example built around the design requirements that there shall be no long-term impact beyond 800 meters distance from the reactor in case of any accident. Such a design requirement allows for construction of EPRs in densely populated areas of Europe. This requirement is fulfilled for the broadest spectrum of disturbances to plant operation, that ranges from a devastating earthquake to a direct impact of a fully loaded (with fuel) large civilian aircraft. It has to be noted that while the safety requirement for a plant withstanding the aircraft crash is present in most of the EU countries, it is less so (limit on aircraft size and impact) in the US and in Asia. As a consequence, the EPR design, while being fundamentally similar had somewhat different specifications (mainly the strengths of the buildings; e.g. containment). when offered to the market in the EU, US or Asia. While the conditions, including prices offered by the Vendor are not publicly known, it is estimated by the author of this report that the impact of the higher safety standards in Western Europe might add 10 to even 20% on the costs of a new nuclear plant.

When comparing safety levels of various generations and designs of NPPs, the original GEN II had the probability of melting the reactor core and causing an offsite release of radioactivity in the order of 1E-3/year (some GEN II plants- e.g. small Russian designed WWER did not have a reactor containment, which would lead to any damage of the core directly becoming an external release of radioactivity). With the initial safety improvements (e.g. Borssele bunker, or safety pumps and a bunker for the Beznau NPP in Switzerland, currently the oldest operating reactor in the world) the probability of core melt went to 1E-4/year or a little lower, and the probability of external releases of radioactivity to 1E-5/year. Subsequent safety improvements, some of those being introduced post-Fukushima (the Beznau plant is investing around 600 million Euros to further increase safety, including 2 new separated Diesel generators; Krsko NPP in Slovenia is investing 250 million Euros in an aircraft crash and seismically-resistant new bunkered safety system) the resulting probability of an offsite release is falling below the 1E-5/year, and it might even reach closer to 1E-6/yr.

At Borssele NPP, thanks to major safety improvements in 1990s and 2000s when hundreds of millions of euros were invested, the requirements for safety improvements as the result of the Post Fukushima Stress test were (significantly) less than for some other EU plants. Nevertheless, the Post Fukushima Stress test improvement measures together with the results of the 3rd Periodic safety review, completed in 2013, identified about 100 recommendations, of which 11 were major ones requiring a licencing process. Those included specific measures to further enhance the safety level like external cooling of the reactor vessel, primary system make up or the spent fuel cooling, etc. The total volume of investment was several dozen million Euros.

Differently from the EU GEN II plants, the Fukushima reactors saw very few safety upgrades over their lifetimes, making them much more vulnerable in particular to external events. Many safety features, both hardware and operating procedures that were implemented at Western reactors of similar type (there were about 20 operating reactors of the Fukushima type in operation worldwide at the time of the event), were not present at Fukushima. As a result, 3 reactors at Fukushima sire melted the core, released radioactivity in the environment, causing damage that is estimated in excess of 200 billion Euros (including clean-up). If those reactors would have had e.g. a Borssele type bunker protecting safety systems from floodwaters, costs of which was less than 100 million Euros, the accident could have been prevented.

For the GEN III NPPs, in particular the EU version of the EPR, the design target is the probability of core damage below 1E-6 and the release of radioactivity below 1E-7/yr, when considering all technological, natural and man- induced events. Other designs including Westinghouse AP 1000, and Chinese Halong 1, or the Russian TOI might be somewhat above those values, mainly because of a weaker containment making plants more vulnerable to e.g. an aircraft crash.

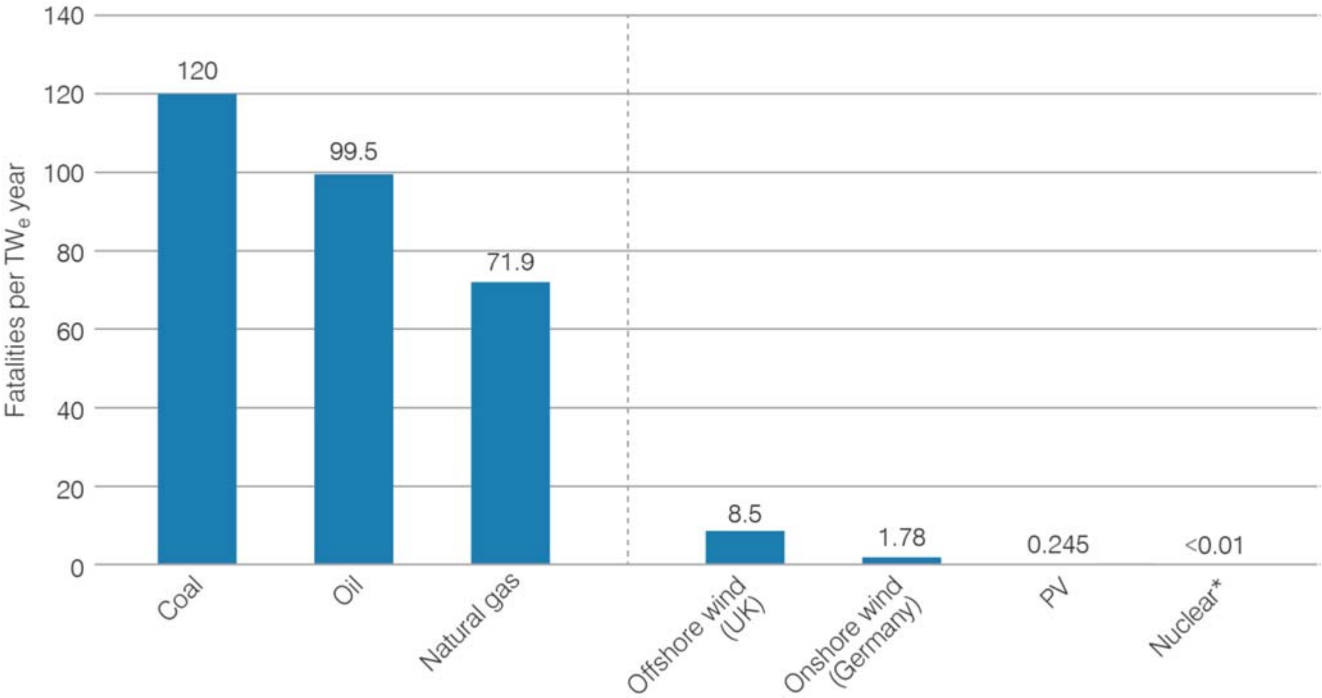
While the “safety” of nuclear power plants comes with a high cost, safety cannot be compromised. Although some might feel these costs to be excessive and possibly not required to such an extent, risk avoidance culture and the general social position towards nuclear have made it one of the most regulated and safest industries on the planet [37].

While safety costs cannot be avoided, the costs of safety could be optimized. With technological developments, costs could be reduced while not compromising safety. Even during the GEN III design, the cost reduction was in focus to reduce the number of safety components, to use passive rather than active means of implementing safety functions, as well as modularisation. An example of this is the US designed AP 1000 reactor, that achieved a visible reduction of safety costs by using fewer components and partially at least, passive systems.

One of the driving forces for the future SMRs is in simplification, modularisation and industrial production, while using proven safety concepts. The GE-Hitachi BWRX 300 being a scaled down ESBWR, is to achieve a 60% cost reduction from an ESBRW on installed MW basis. The Rolls Royce 400 MW SMR is promising at least 40% cost reduction per MWe installed capacity. Nevertheless, only a fraction of those savings might be due to optimisation of safety systems, much originates in the concept of modular, industrial production and reduced site activities compared to the traditional NPP.

Extended use of passive systems may lead to a reduction of costs of related to safety. The same applies to the GEN IV reactors, where innovative and/or revolutionary concepts might be expected to lead to a further cost reduction.

To conclude, the cost of safety requirements cannot be clearly separated from the overall costs of a nuclear plant. With nuclear reactors, safety is the fundamental principle that is observed during design, construction and operation. With much higher safety standards in place than any other technology today and with increased safety requirements, the nuclear power industry is the safest power generation available that is known to mankind today.



* Gen II PWR, Swiss
Source: Paul-Scherrer Institut. Data for nuclear accidents modified to reflect UNSCEAR findings/recommendations 2012 and NRC SOARCA study 2015

Figure 21: Energy related fatalities for OECD countries per TWh produced per year [37]

Nuclear plants are not just extremely safe places to work for their employees, the impact to the population even when accidents and releases are taken into account are much lower than any other currently used source of energy. The above figure was developed on the basis of realistic and a widely agreed scientific estimate on the impact of various pollutants, including particle releases for e.g. coal and radioactive doses and including accidents for nuclear. Contrary to the often quoted "assessments", the death toll of Chernobyl accident as confirmed by various UN/UNSCEAR investigations was in several dozen with up to some hundreds additional deaths caused by cancers. There were no fatalities from radioactive release in the Fukushima accident and possibly a few dozens of fatal cancers might be expected over the several decades. An interesting feature of the Figure 21 is that it considers the impact of GEN II nuclear plants, meaning that considering the GEN III, the resulting impact would be even lower.

Other studies, including the MIT study [38] and the WHO confirmed the findings of Paul Scherer institute, as above.

Table 8: Mortality rate per PWh (Peta hours) of electricity generated, WNA, [39]

Technology	Deaths
Coal – China	90.000
Coal – USA	15.000
Oil	36.000
Biofuel	12.000
Gas	4.000

Technology	Deaths
Hydro	100
Hydro - including disasters	1.400
Solar– Rooftop	440
Wind	150
Nuclear-Including Fukushima and Chernobyl	90

The public opinion that the nuclear is expensive because of the safety requirements is principally correct. Nevertheless, nuclear power cannot exist without stringent safety requirements in place, so reducing costs of "safety" with nuclear power would undermine the possibility to use nuclear power in the first place. With increased risk aversion of modern societies, safety requirements were steadily increased over the generations of nuclear plants. The GEN III plants are now clearly the safest source of power, taking into account both occupational and societal impact. This however, comes at a price. To remain a viable source of electricity for the next generation(s), nuclear has to maintain an exemplary safety record while, where possible, optimising and reducing the costs. The current GEN III is achieving the first (exemplary safety record), while the second part (significant cost reduction) remains in the focus with SMRs and further with the GEN IV reactors.

5.2 LEVELIZED COSTS OF ELECTRICITY FOR NEW BUILD

The costs of a NPP new build depend on a variety of factors. Not one size fits all, and there is no such a thing as "one nuclear plant". The country where a new NPP project is undertaken (whether already having a nuclear plant operator and experienced regulator or not), the site conditions, the selection of technology, FOAK or NOAK, how many units are to be built and many more elements have a direct effect the cost of the project. Nonetheless, there are some metrics which can be employed to shed light on the types of costs and price per kW installed power as well as per kWh of generated energy.

The overnight capital cost is a standard power industry metric for quoting the cost of an electric generating plant alternatives. This is the cost of building the plant as if it could be built instantly, that is using current prices and without the addition of finance charges related to the time required for construction. Another metric is the investment cost, which includes the effect of inflation, the duration of construction, and finance charges up to project completion.

The 'levelized cost of electricity' (LCOE, see annex 1) is a unit cost metric, which allocates the capital cost to electricity output over the life of the plant. It further encompass the operating and maintenance costs, including the cost of fuel as well as the management of the waste and the decommissioning. However, the LCOE does not include grid costs or other external costs.

The LCOE is the most common metric for comparing the competitiveness of power generation technologies, but does not take into account the value that each technology may provide to the overall electricity system in ensuring flexibility, security of supply and reliability, A more complete picture of competitiveness requires these values to be considered.

The IEA published the LCOE comparison of different electricity generation sources [12] shown in Figure 22.

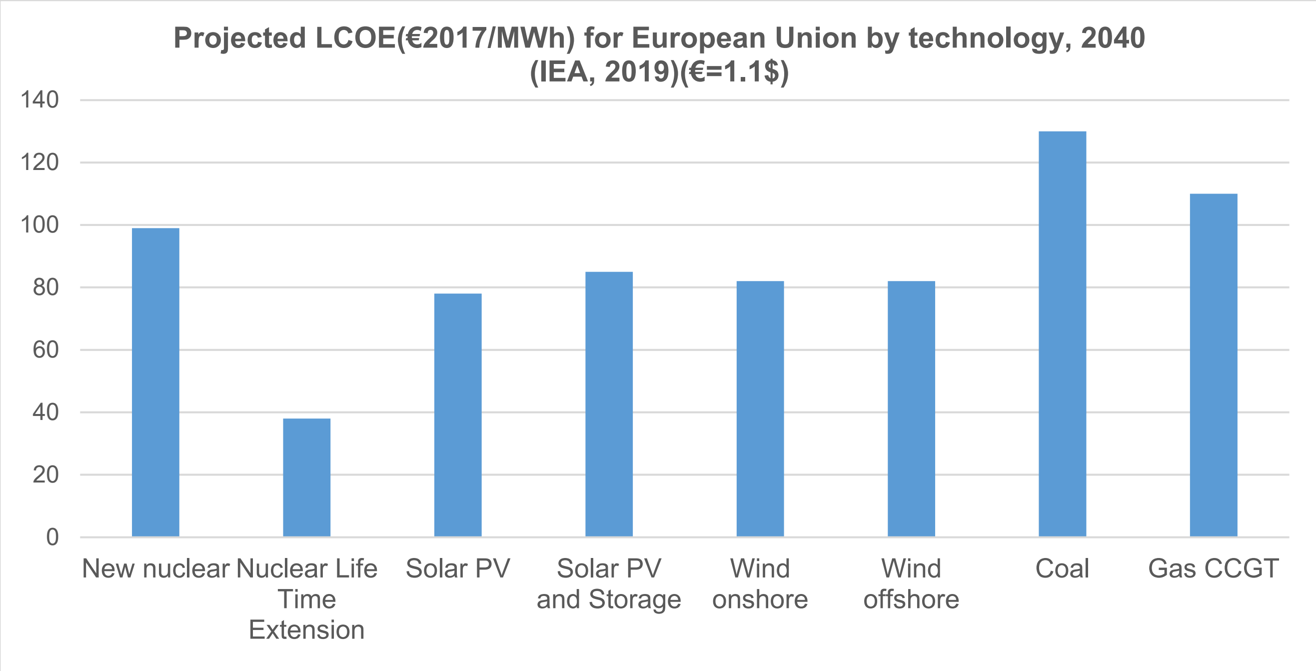


Figure 22: Projected LCOE for EU without system costs, IEA [12]

The Figure 22 shows the projected LCOE for the year 2040. It is apparent that existing nuclear power plants, with regulator-approved lifetime extension, would very well compete with intermittent renewable electricity sources, without taking into account the system costs (grid and intermittency). Nuclear lifetime extensions is the most cost-effective ways of providing low-carbon electricity. The LCOE associated with a nuclear lifetime extension generally falls in the range € 40-60 per MWh, based on an investment of € 500 million to € 1 billion and an extension of 10-20 years. For example, a 20-year extension of a 1500 MW NPP costing € 1 billion would result in an LCOE of around € 45 per MWh assuming an 8% weighted-average cost of capital (WACC).

For comparison, the average LCOE of new solar photovoltaics (PV) or wind projects even for the best meteorological conditions are projected to remain above 45 per MWh in the European Union and United States, under the same financing conditions.

According the IEA, this is despite a projected continuing decline (though levelling) in cost of solar and wind power. Solar PV costs fell by 65% between 2012 and 2017, and are projected to fall by a further 50% by 2040; onshore wind costs fell by 15% over the same period and are projected to fall by another 10-20% to 2040.

System costs

IEA noted that because of the omission of grid costs, but also not taking into account any penalty for intermittency in delivery of electricity, lead to a too optimistic picture of the costs of wind and solar power (See also 5.4).

Another finding of the IEA study, visible from the Figure 22 above, is that the LCOE of new nuclear is higher than the LCOE of the wind and solar VREs, when system effects are not taken into account. However, these system costs must be paid one way or the other, often only depending on a political decision. The applicable system costs would include costs for reserve capacity, for storage of electrical energy (batteries, hydrogen or hydro power) and costs for the unavailability of units, but exclude external costs.

The Figure 23 shows an indicative estimate of the system costs per MWh at a high penetration rate of VRE. These costs should be added to the LCOEs of the VRE in the figure above, based on the published study of NEA [17]. This study is performed for a “typical” western country, meaning that a certain proportion of the hydro energy sources is available (see Annex 2 for more details).

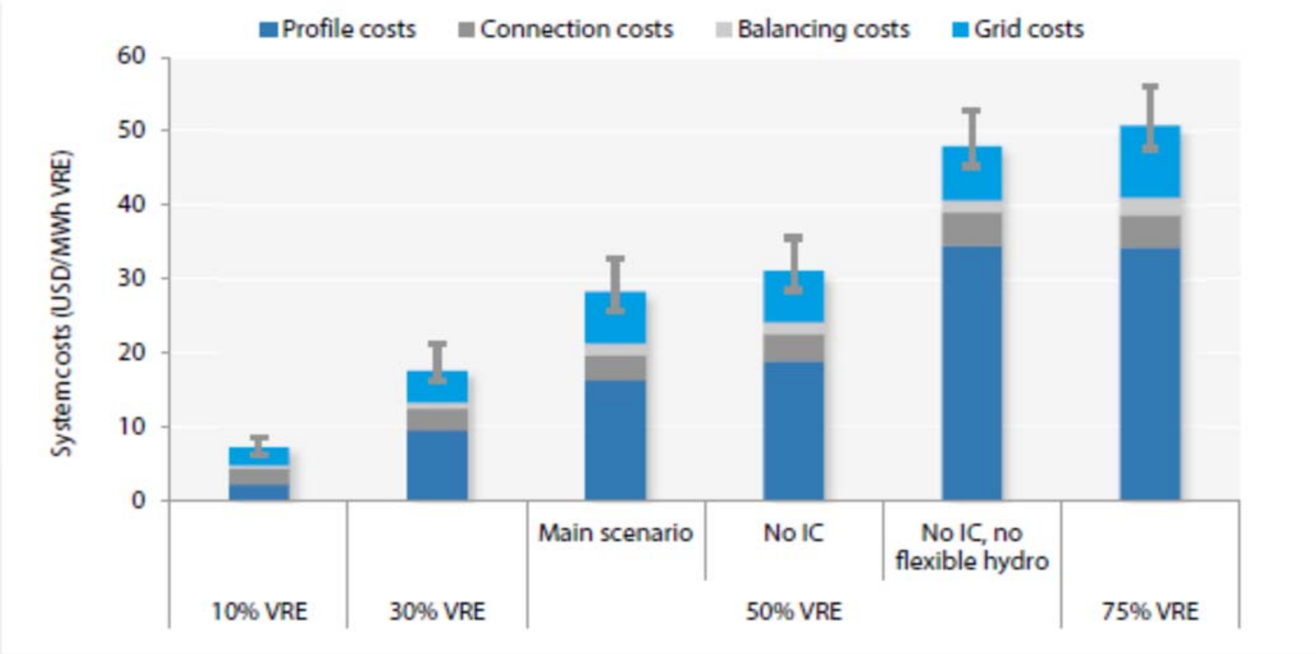


Figure 23: System costs per MWh of VRE, OECD/NEA [17]

The OECD NEA analysis estimates that for a "typical" country, the system costs are in the order of 30 €/MWh) at a 50% VRE penetration rate and in the order of (at least) 42 €/MWh at 75% penetration. It is obvious that the system costs are increasing with a higher percentage of VRE. To our opinion the system costs would be even higher in a country with no hydro power potential to balance the system, such as the Netherlands, because more expensive measures than hydro (see Figure 24) have to be taken.

Effects of subsidies

Apart from the aforementioned system costs, there are other costs to be included in the total costs of an energy source, e.g. energy specific taxes, industry levies but also subsidies and external costs. Nuclear-specific taxes are/were levied in several EU countries, including in Belgium, Germany (removed by Country's highest court) and Sweden (abolished in 2019). The UK imposes the Climate Change Levy. It is a downstream tax on energy delivered to non-domestic users in the UK introduced in 2001, and expected to be abolished in 2023. Initially levied against fossil fuels and nuclear, the government removed the renewables' exemption in its July 2015 Budget. In 2011 the UK government also introduced a carbon floor price – a mechanism that has long been seen as fundamental to the economics of new UK nuclear power. The government set a minimum CO_2 levy of £16 per tonne CO_2 from 2013, rising steadily to £30 per tonne in 2020, and £70 per tonne in 2030.

The Hinkley Point C CfD provides the strike price for the developer of £92.50/MWh (2012 prices) for a 35 year term from the date of commissioning. This would be reduced to £89.50/MWh in a case EDF take a FID on the proposed Sizewell C project. This means that for each MWh of electricity generated at HPC, the developer will be paid the difference between the strike price and the market reference price (a composite of wholesale price indices) for electricity sold into the market for the duration of the contract. The generator will pay back the difference should the market reference price rise above the strike price.

For comparison purposes between energy sources, normally the energy specific taxes and subsidies or industry levies are not included in the LCOE estimates. This is because those are reflecting on political decisions that might change at any time. Their inclusion in the LCOE would distort the comparisons that is supposed to be " neutral" in a sense that only technologies, their utilisation and impact are to be compared.

All Member states of the European Union including the Netherlands, are part of the EU Emissions Trading System (EU ETS) a market created to trade greenhouse gas emission allowances. The aim of the market is to add the cost to industries and energy generators who are emitting CO_2. Most/all European countries have specific sustainable/renewable energy subsidies, to promote these sources of energy. Further, in the UK and the Netherlands (SDE+) so called "contracts for difference" (CfD) are used. These subsidies level the difference between the production costs (including capital costs) and the market price of electricity.

5.3 COSTS COMPARISON OF NUCLEAR WITH OTHER SOURCES

One of the main concerns with new nuclear power plants is the cost outlay and long pay-back period and the investors see a return on their investment. As a result, other alternative sources of energy may seem more attractive, at least initially. Conventional forms of energy such as fossil fuels are slowly less and less viable (coal already becoming non-viable in practice), while countries are adjusting to the global climate targets. To ascertain the costs of nuclear weighted against other 'clean energy sources' some key parameters needs to be considered.

In Figure 24, the estimated LCOE of many (USA) electricity generation sources for the year 2023 are presented, based on a study of the US-EIA in 2019 [15].

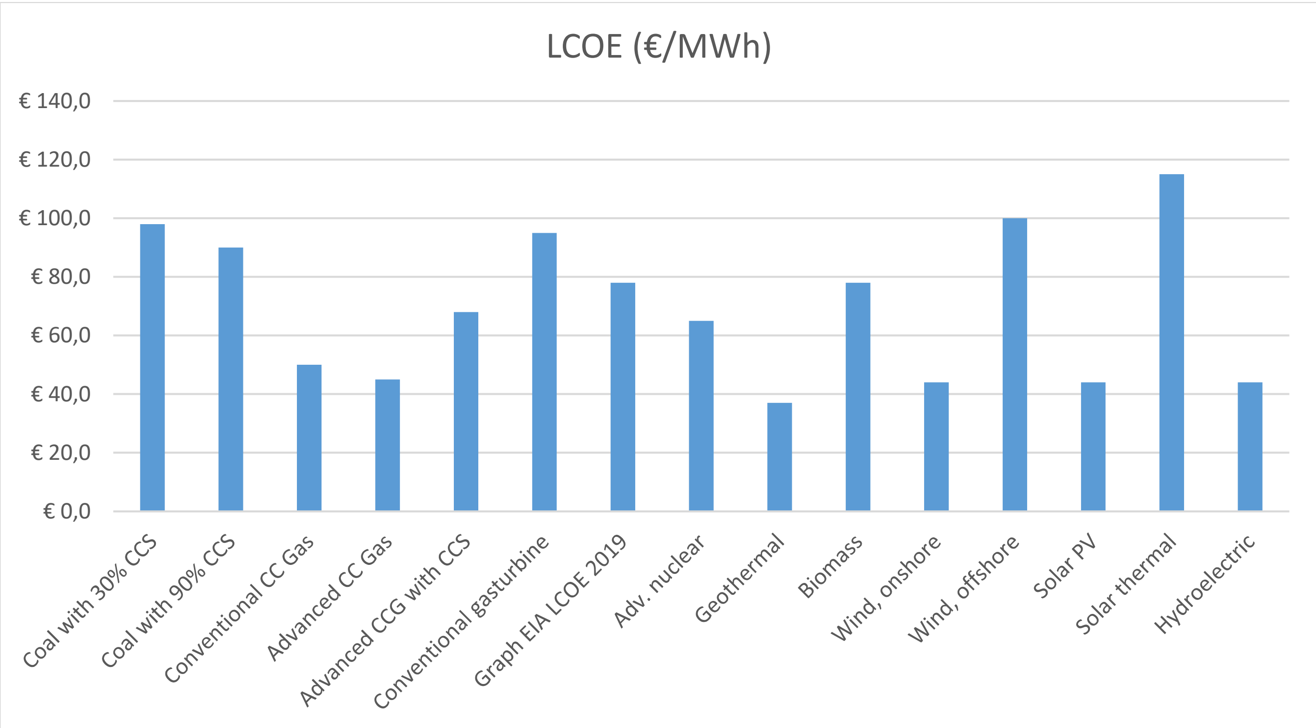


Figure 24: Estimated levelized cost of electricity (capacity-weighted average) for new generation resources entering service in 2023, without system cost US EIA 2019 [15]

The above figure could be compared with Figure 22, where the results reflect the IEA's assessment of the European situation in 2040. The LCOE estimates for the year 2040 for the VRE sources are similar for the US-EIA and IEA study. Wind onshore LCOE is 47 €/MWh (US-EIA) and 48 €/MWh (IEA), Wind off-shore 98 €/MWh and 81 €/MWh, solar-PV 44 €/MWh and 48 €/MWh, respectively.

However, there are some interesting differences between the two studies, especially for Advanced Combined Cycle Gas and New Nuclear. Most likely the CC-Gas difference (45 resp. 96 €/MWh) is due to the very strict emission requirements that were recently introduced in the EU for new gas units.

All figures regarding costs except figure 21 do not include the effect of the aforementioned system costs, external costs, nor the impact of energy source specific taxes and subsidies. Cost figures of VRE's (as presented in the media) often include the impact of subsidies without mentioning it explicitly.

The EIA calculated the levelized costs for non-dispatchable technologies based on the capacity factors for these technologies as 37% to 46% for onshore wind, 41%–50% for offshore wind, 22%–34% for solar PV, 21%–26% for solar thermal, 76% for hydroelectric, 90% for advanced nuclear [15]. Those are true for wind speeds 7-8,5 m/s and for solar panels providing yearly 15-20% of nominal power.

The present practice in Netherlands shows lower wind speeds and sun-hours. The current capacity factor for on-shore wind in Netherlands is 24%, for off shore wind 43% [40] and for solar panels is 10% (slightly lower than in southern Germany 11.4%). If other parameters are the same as in the study [25], the consequence is that the investment cost of wind turbines and solar panels, and thus the LCOEs will be correspondingly higher than the LCOEs presented in the above Figures.

For a more appropriate and accurate comparison between external cost of various energy technologies, the CO2 emissions of complete life-cycle of production needs to be estimated, including construction, operation and dismantling/recycling phases.

The construction of a wind or solar unit, relative to output and energy production, requires many more materials than the construction of a nuclear plant [41, 42, 43]. This is the effect of very low density of solar irradiation at the ground level in Europe and low power density of wind, while the power density of a nuclear energy is very high. Counted per unit of energy produced over lifetime, the amount of required concrete is 10 times more for onshore wind than for nuclear, while the amount of metal, steel and aluminium, is about 15 times more for off-shore wind turbines and 10 times more for solar PV than for nuclear power plants.

This results in a higher CO2 emissions for wind and solar than for nuclear. In the case of wind the ratio is about 15, and in the case of solar panels using aluminium, which has a high CO2 footprint about a factor of 40.

In 2009 OECD-NEA published a report 'Nuclear energy and addressing climate change' [44] that shows also the total figures of CO2 emissions in kg of CO2/MWh, calculated for the entire lifecycle from cradle to grave, including emissions due to nuclear fuel mining, enrichment, fuel production and final disposal.

The major contribution to lifecycle emissions in nuclear fuel cycle is the enrichment, for which Figure 25 shows two numbers: high for the diffusion enrichment process and low for centrifuge enrichment, as used at the enrichment facility in Almelo (NL). Nowadays, the latter dominates and in a few years will be the only technology used. As a result the CO2 footprint of nuclear fuel cycle will be the smallest of all technologies.

A more recent study [2] confirmed that when considering the life cycle carbon emissions, nuclear remains the lowest contributor.

Table 9: Lifecycle greenhouse gas emissions in CO2-equivalents per kWh [2]

Technology	Minimum	Median	Maximum
		gCO2-e/KWh	
Nuclear (PWR and BWR)	3.7	12	110
Wind (Onshore)	7	11	56
Solar PV (Utility scale)	18	48	180
Concentrated solar thermal	8.8	27	63
Coal (with capture and storage)	190	220	250
Combined cycle gas (with carbon capture and storage)	94	170	340

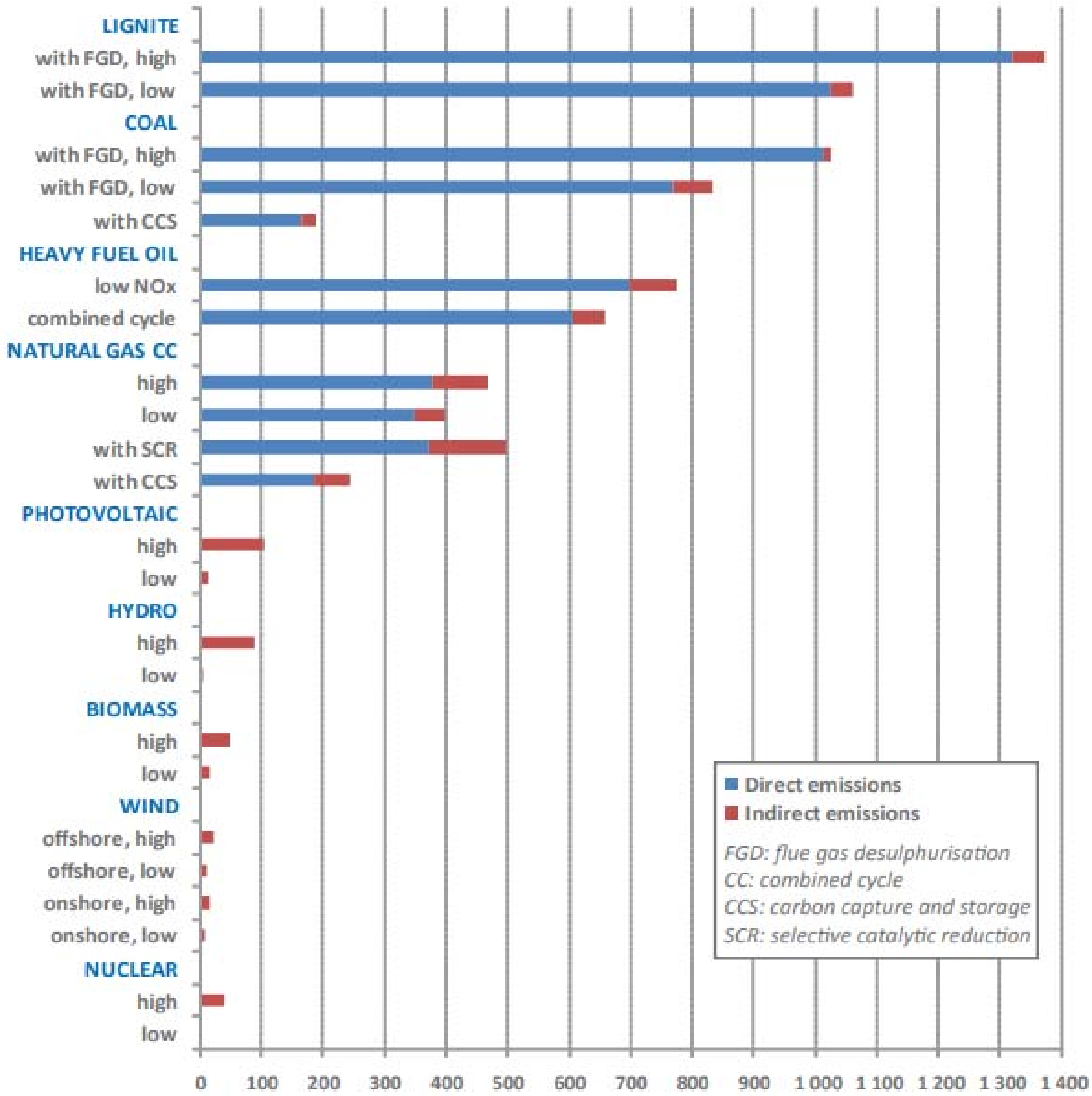


Figure 25: Direct and indirect CO2 emissions for various technologies in kg/MWh (CCS- carbon capture and storage, NGCC – natural gas combined cycle, SCR – selective catalytic reduction), NEA [17]

5.4 EXTERNAL COSTS

External costs for electricity are those that are not reflected in its price, but which society as a whole must bear. For example, damage to human health caused by emissions. External costs are the sum of three components: climate change damage costs associated with emissions of CO2; damage costs (such as impacts on health and crops) associated with other air pollutants and other non-environmental social costs.

Some 'external' costs are already reflected in the electricity price. For example the licencing conditions for a nuclear power plant typically require the plant operator to make a provision for decommissioning and for disposing of any waste, thus these costs are 'internalised' as part of operating costs (i.e are not external). Insurance premiums for nuclear accidents have also been internalized.

Electricity generation from fossil fuels is not regulated in the same way, and therefore the operators of such thermal power plants do not, yet, internalise the costs of greenhouse gas emission or of other gases and particulates released in the atmosphere. In some countries the external effects are paid for in the CO2 pricing. For wind and solar the method for waste handling and therefore the costs for decommissioning and waste management are not even known or under development. These unknown external costs are not included in most calculations of the LCOE of wind and solar. Including these external costs in the calculation for alternatives improves the economic competitiveness of new nuclear plants.

Several institutions, like the ExternE project of the EC, performed exercises to quantify the impact of external costs. The methodology used considers emissions, dispersion and ultimate impact. With nuclear energy, the risk of accidents is factored in along with high estimates of radiological impacts from mine tailings (waste management and decommissioning being already within the cost to the consumer).

For nuclear energy, the external costs were estimated to be in the range of c€ 0.4/kWh, much the same as hydro; coal is over c€ 4.0/kWh (4.1-7.3), gas ranges c€ 1.3-2.3 kWh and wind shows c€ 0.1-0.2/kWh average. If these costs were in included, the EU price of electricity from coal would double and that from gas would increase 30%. These are without attempting to include the external costs of global warming.

A further study commissioned by the European Commission in 2014 [45] estimated the external costs for nuclear as €18-22/MWh, including about €5/MWh for health impacts, €4/MWh for accidents and €12/MWh for so-called 'resource depletion', relating to the "costs to society of consumption of finite fuel resources now, rather than in the future". Although authors acknowledges that the resource depletion cost is difficult to calculate since the scarcity of a finite natural resource is already reflected in its market price, and could therefore just as well be zero, a high estimate was asserted using a questionable methodology and without taking account of the potential for recycling nuclear fuel.

External costs to society from the operation of nuclear power are usually assumed to be zero. Nevertheless, those could include the costs of dealing with a serious accident that are beyond the insurance limit and in practice might need to be covered by the government.

In many available studies the external costs, that might be associated with global warming, are omitted. If those would be included, this would further add to the cost of electricity generated from fossil fuels, but also, depending on what is included in the emission calculation, from some non-CO2 emitting generators, as in the Table 9 in the previous section.

Externalities of energy are not limited to environmental and health related impacts, but may result also from macro-economic, policy or strategic factors not reflected in market prices, such as security of supply, cost stability and broad economic impacts on employment and balance of trade. Although those externalities generally have not been subjected to quantitative evaluation, they have been analysed qualitatively in some studies and the results indicate that they are not a major cause of market price distortion.

One further aspect for consideration is in relation to the social impact is the land utilisation. For this aspect, the extremely high energy density of nuclear is a great benefit compared to VRE. Due to low energy density, the VRE require lots of space. This is particularly relevant for solar PV, where the installations are competing with land available for agriculture and/or encroaching the preserved nature, as well as for on shore wind, where increased opposition due to noise (on shorter distance), drop shadow, and intrusions into natural settings are raised.

Especially in the densely populated Netherlands, the enormous needs for space for some of the technologies to produce electricity is becoming increasingly challenging. Further to this, the disturbance of the landscape as well as 'not in my back yard' feelings are clearly on the raise. However, the external costs related with the land use and "NIMBY" phenomena are difficult to quantify in euros. Those external factors are relevant to all other generators of electricity, e.g. fossil or nuclear, where the population is opposing the construction close to their homes. However, due to a much higher energy density of nuclear plants (up to about a 1000 times), the number of people affected is only a fraction of those affected by the low energy density VREs.

5.5 SYSTEM COSTS

Besides the direct costs of investment, fuel, operation and maintenance as well as environmental costs, various technologies also have costs related to the integration of the generated electricity into the energy system. This is especially true for technologies with variable output, like wind power and solar PV. On the other side, dispatchable technologies like thermal and nuclear might be credited with a system benefit.

The system costs can be divided into the following elements, as defined by the IEA:

- Balancing costs: This covers the cost of handling deviations from the planned production and the possible extra cost for investments in reserves for handling outages of electricity generators or transmission facilities;
- Profile costs (utilisation costs): The value of the electricity generated to the electricity system or electricity market. The value is compared to a common benchmark, such as the average electricity market price. If the technology earns less than the average electricity market price, the difference can be considered a profile cost (and if the technology earns more than the average electricity price we consider this a profile benefit);
- Grid costs: Extra costs for expanding and adjusting the electricity infrastructure in order to feed in the electricity production from the technology in question.

System costs are highly dependent on the configuration of the electrical system (energy mix). It should be noted that nuclear power is a reliably dispatchable energy source, while solar PV and wind are on a day-to-day basis less reliable and non-dispatchable. The point of attention is the electric potential (in installed MW) that is needed to guarantee the supply of electricity (in dispatched MWh).

This issue might be explained by comparing solar and nuclear. Because of the capacity factor of 10 % for solar and 90 % for nuclear, one has to assure the installed capacity for solar is about 9 times larger. The LCOE 'levelized' this effect as it takes into account the expected production of electricity from different sources. Nevertheless, resulting grid costs and in particular the system costs, to assure reliable supply of electricity, are (much) higher for VRE like solar PV. Therefore, the grid-value of an electricity source must be taken into account. This is possible when grid costs are added to the producer cost of electricity generation-LCOE. These costs are also dependant on the share of VREs in the system (See Annex 2 for further details).

Since nuclear power is a reliable dispatchable energy source, while solar PV and wind are less reliable and non-dispatchable, system costs must be taken into account for any meaningful comparison. These costs depend on the share of VRE's in the system.

The system costs of VREs are large, typically at least one order of magnitude higher than those of dispatchable technologies. Those depend strongly on the country (e.g. geography, whether large hydro is available), the technology and the penetration level of VREs. Typical studies addressing the system costs always take into the account a certain proportion of hydraulic plants. Because the potentials for hydro-power in the Netherlands is limited, the system-cost corrected LCOE for wind and solar will be higher. Furthermore, the system costs increase disproportionately as the share of renewables increases in the generation mix.

A very important consideration is that the deployment of a large share of variable-electricity generating sources with nearly zero marginal cost, has a profound impact on the functioning of electricity markets and on the structure and operation of generating capacity. In the short term, reduced load factors (the compression effect) and lower prices affect the economics of all existing dispatchable generators. Due to its low variable costs, nuclear will fare relatively better than coal or gas. In the long term, reduced load factors will make it more difficult to finance dispatchable capacity to provide short-term flexibility and long-term adequacy to the electricity system.

The decarbonizing electricity systems of the future will require contributions from all low-carbon technologies. However, it should be noted that system costs rise disproportionately with the higher share of VRE renewables. This will increasingly require accompanying measures to ensure the security of electricity supply. In planning for future electricity systems, it is important to note that nuclear power is the only major dispatchable low-carbon source of electricity (other than hydropower, which has limited potential in the Netherlands).

With this correction for system costs new nuclear can compete with VRE's, and can be used as a complementary electricity source, next to solar PV and wind, to maintain a stable and reliable grid.

Also, it should be highlighted that some nuclear plants are now being approved to operate for 80 years, while the wind generators and solar panels have projected lifetime up to a maximum of 25 years (with discernible degradation over the lifetime for solar). Typically, after about 25 years, the investment in a nuclear plant is already paid off. For VRE, this is exactly the time when the new investment cycle is needed.

5.6 LCOE IN THE NETHERLANDS FOR THE YEAR 2040

5.6.1 INTRODUCTION

The Ministry of Economic Affairs and Climate Policy of the Netherlands specifically requested that the LCOE for several electricity generation technologies for the year 2040 is estimated, on a comparable basis, for the Netherlands. The following sources were selected:

- NOAK large nuclear GEN-III plant
- NOAK nuclear SMR
- Off-shore wind
- On-shore wind
- Large solar PV
- Hydrogen Power

To make this comparison meaningful, an adjusted LCOE*[1] was re-calculated, based on reliable references and data sources. Compared to the standard LCOE definition, this re-calculated LCOE* includes system effects, based on an energy-mix with 50% VRE's. Furthermore, in the base case, it is assuming a full utilisation of power-plants. Full utilisation means that the power-station is allowed to deliver to the grid when it is capable to deliver, independent of electricity-exchange-market or other prioritization mechanisms. In this respect, the terms capacity factor (CF), utilisation factor (UF) and the total capacity factor (TCF) are used, where the TCF equals the product of the capacity factor and the utilisation factor. The capacity factor depends on local conditions, like the design of the unit, the O&M practice and local weather. The CF is the average power that technically can be delivered during a certain year, divided by the rated peak power. The UF is the electrical energy that an installation is allowed to deliver to the grid, divided by the energy that technically can be delivered during that year. The CF is of internal nature (the plant) and the UF is of external nature (the market). This distinction between the CF and the UF is important, because power plants are being paid for the energy delivered. The UF for a certain technology is dependent on the energy-mix and mostly political determined marker-rules. It should be clear that the LCOE of every technology becomes extremely high, when only a UF of 1% is allowed.

To enable the stability of the electrical grid it is be expected that at higher VRE penetration rates, VRE units must shutdown or throttled at certain moments, like now is the case with fossil plants. This will result in UF lesser than 100%.

It is outside the scope of this study to estimate the UF's of the different generation technologies in the year 2020 or 2040.

Table 10 below provides a summary of the general assumptions made to calculate the LCOE* for the

[1] LCOE* = LCOE plus costs of system effects

selected electrical generation technologies. A detailed assumption list can be found in Annex 3.

Table 10 Summary of general assumptions used

General assumptions LCOE assessment	Nuclear	VRE	Hydrogen P2P
WACC	7%	4,3%	4,3%
Technical Lifetime (years)	60	25	20, electrolysers limiting
Depreciation period	technical lifetime	technical lifetime	technical lifetime
Utilisation factor	100%	100%	50%
Decommissioning costs	15% of capital costs, discounted at 3%	5% of capital costs, discounted at 3%	5% of capital costs, discounted at 3%
Waste costs	Spent fuel disposal and storage, decomm. waste included in decomm. costs and operational waste in O&M costs	Decommissioning waste included in decomm. costs and operational waste in O&M costs	Decommissioning. waste included in decomm. costs and operational waste in O&M costs
Construction time (years)	7	0,5 – 1,5	3, CCGT limiting

The system costs used in the estimation of the LCOE* are adopted from the NEA-2015 [46]. The hypothetical region NEA used in its models is similar to the Western European countries and in this case assumes lack/limited availability of hydropower.

Table 11: System costs €/MWh (NEA/IEA 2015) [46]

VRE penetration level	10% VRE	30% VRE	50% VRE Extrapolated
Nuclear	2	2	2
Onshore wind	13	24	35
Off shore wind	24	39	45
Commercial PV	24	38	52,5

The actual system effects are strongly country-specific and their different components are strongly interrelated. This limits the appropriateness of adding together elements generated in different models. Therefore the estimates provided are not supposed to be an exact prediction for the Dutch situation in the future, rather a visualisation/indication of their value for different technologies.

Of the three categories of the system costs, the utilisation costs (profile costs) are most difficult to predict. They capture the fact that in a system with VREs, it is generally more expensive to provide the residual load than in a system with a technology that is dispatchable but otherwise equivalent in terms of LCOE.

The residual load is an indicator in a power system. It shows how much capacity is left for the conventional (dispatchable) power plants to operate. The conventional power plants would vary their power output in accordance with the demand load curve. It is assumed that when the residual load becomes negative, VRE must be disconnected of the grid.

Another way of looking at the utilisation costs of VRE is to consider that the electricity production of all wind or all solar PV (or both) is concentrated during a limited number of hours, when the meteorological conditions are favourable. This auto-correlation reduces the average value of each MWh of VRE output. Especially at high penetration levels, any single VRE plant is more likely to generate when other VRE plants are also generating, which reduces the market value of the electricity produced as well as its contribution to the system.

The base case LCOE* calculations reflect a positive vision for all technologies, taking into account future developments and related cost reduction, when supported by sufficient evidence for such. The data used in the calculations were only those originating in official reports from respected national and international institutes.

The LCOE* costs estimated in this study are for the year 2040, and are considering current costs, reflecting historical progress with critical assessment of the future, and on possible future developments. It is important to understand that the electricity generation capacity available in the year 2040 would not be all constructed in 2040. Most of the capacity would be old(er), with relevant LCOE* reflecting the time of the construction, rather than that exact year 2040. Some generating capacity dates from 2020, some from 2040. With a lifetime of about 25 years for most VRE, a fair estimate of the average age in 2040 would be 10 years. The year 2030 is therefore used as the construction date for the calculations, to reflect the LCOE* of the generators in 2040.

5.6.2 LCOE* OF CO2 FREE SOURCES FOR 2040

Both LCOE* and LCOE are very dependent on the utilisation factor. The utilisation factor is an external factor (market factor) that has no relation with the technologies itself. For comparison reasons the LCOE* assessments presented assume full utilisation (UF=100%) in all cases.

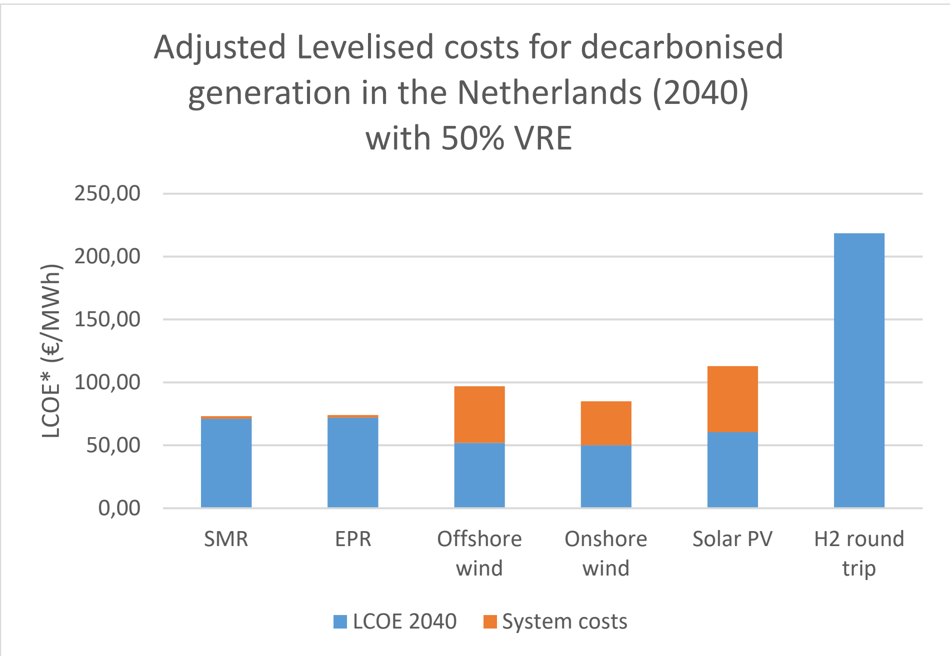


Figure 26: LCOE* for 2040 for CO2 free electricity, 50 % VRE penetration, assume full utilisation (2018 Euro)

With a higher percentage VRE than 50 % the system costs will be higher, as are the LCOE*. With a lower percentage VRE than 50%, it will be the other way around.

The 'Hydrogen Round Trip' depicted in the Figure 26 is using hydrogen as the buffer for the electricity generation. The Hydrogen electrolysers are used to generate hydrogen for storage, in periods when there is a surplus of available electricity on the market. When there is a lack of electricity in the system, hydrogen powered gas turbines will generate it. By the nature of the process, the efficiency of the process, where the hydrogen is generated first in electrolysers and then stored and finally used to generate electricity in the gas turbine when required, will be significantly less than 100%. For the base case estimate to enable comparison, we assume a full utilisation of the electrolysers and 50% utilisation of the gas turbine. The calculation assumes the use of PEM electrolysers, because of their higher load follow capabilities, as well as the use of salt caverns for the storage of the hydrogen. The electricity generation is assumed to take place in a CCGT gas turbine

From the Figure 26, it is obvious that the Hydrogen Round trip is very costly. The explanation is in the low efficiency, between 25% (OCGT) and 39% (CCGT), meaning that 60% to 75% of the energy is consumed in the process. The hydrogen storage in salt-caverns is the only possible storage of large quantities. When storage in high pressure casks is selected, the LCOE* for this option could be 5-10 times higher.

For better differentiation of the carbon free sources, Figure 27 provides a zoomed-in presentation without the Hydrogen round trip.

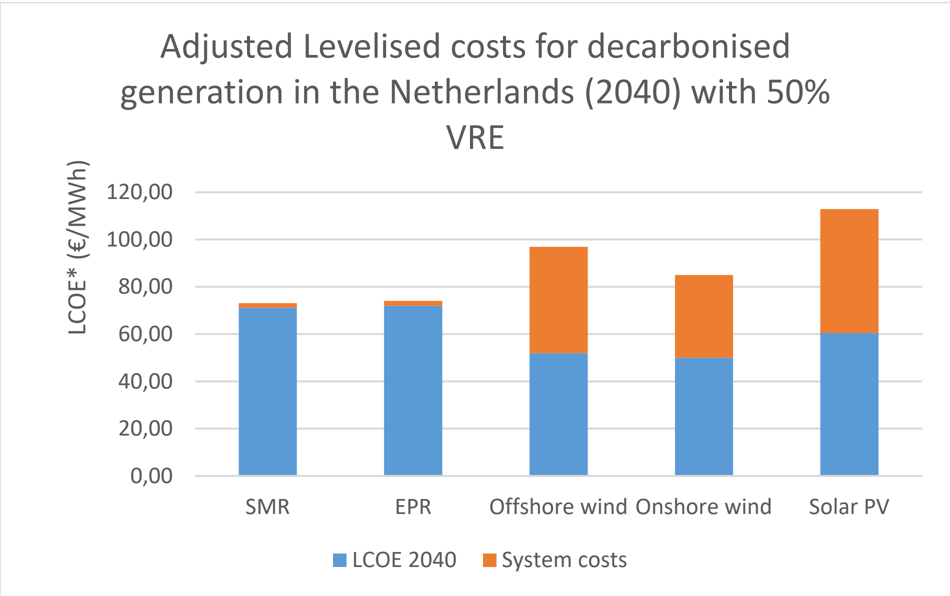


Figure 27: LCOE* for 2040 with 50% VRE – Zoomed in without Hydrogen Round trip

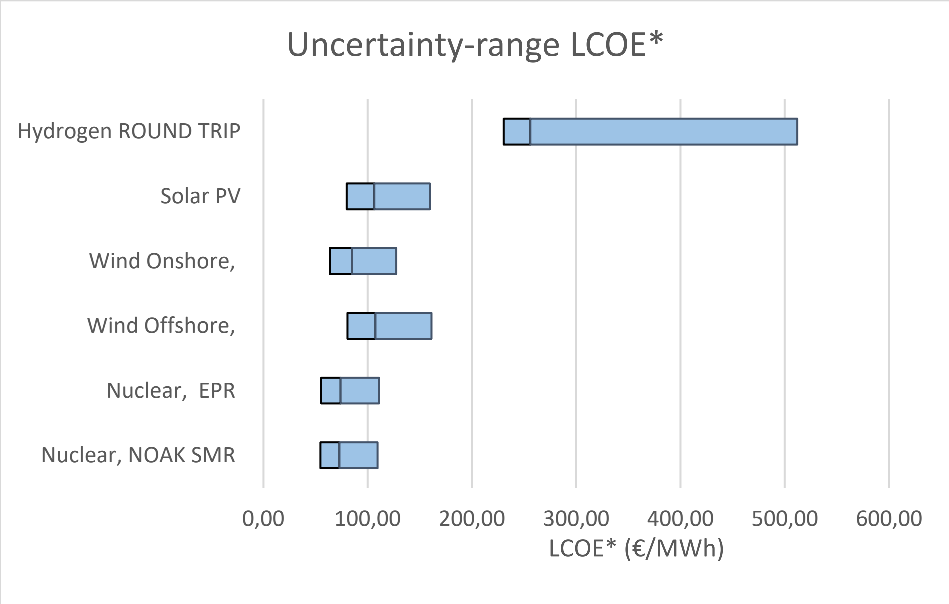


Figure 28: LCOE* for 2040, with uncertainty ranges, at UF=100%

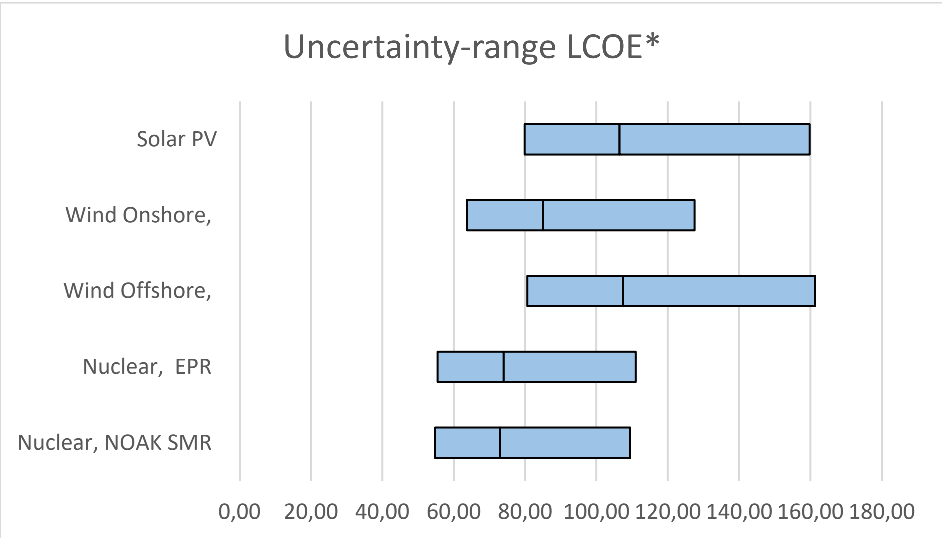


Figure 29: LCOE* for 2040, with uncertainty ranges, Zoomed in without Hydrogen Round trip

Compared with the offshore wind, onshore wind and solar PV, two nuclear options are cheaper, because in the LCOE* the system costs are included. In the Figure 27, the effect of the system costs can be observed.

We expect that in 10 or 20 years the costs of SMR's will be in the same LCOE* range as the NOAK of large nuclear reactors. The large units have the advantage of economies of scale, but the SMR's have the advantage of shorter construction times, by that an earlier generation of earnings, and the "industrial" production. The lower overnight capital costs per kW in case of the large nuclear units are compensated by the lower costs for capital in case of the SMR's, because of (expected) shorter construction time. Because of the lower capital costs per SMR unit, the WACC most likely will be lower. Nevertheless, in our assessment it is assumed to be same, e.g. 7%.

5.6.3 SENSITIVITY STUDIES

In the previous chapter we estimated the LCOE* for various sources of electricity for the Netherland for 2040. All such estimations, and in particular those that are addressing more distant future, could only be made on the basis of a set of assumptions, covering wide range of issues, from the technology development to the cost of financing and learning curves. While the projections of the LCOE* are considered the best estimate, it is highly interesting to assess how those estimates are influenced by changes in the assumptions and/or relevant parameters.

In order to obtain insights into impact of those changes, we conducted a series of sensitivity analysis, covering the following areas:

Learning effects consideration

- Construction times (duration)
- Impact of the lifetime of a plant
- Utilisation rates of a plant
- Interest-rate (WACC) sensitivity
- System costs sensitivity
- Sensitivity cases for hydrogen utilisation

The details of the sensitivity analysis, including the visualisation of impact is provided in the Annex 4. The insights obtained are summarised below:

- When system costs are included in the cost comparison, two nuclear options are cheaper than offshore wind, onshore wind and solar PV;
- The positive vision to include future developments is effecting the technologies offshore wind and nuclear SMR the most;
- In the near future, nuclear SMR technology could be able to compete with traditional nuclear large units, because of the claimed short constructions times, resulting in lower capital costs;
- While significant saving could be obtained by reducing the duration of construction, it is uncertain whether nuclear industry would currently be able to erect a NPP in Europe in less than 7 years, as in Asia seems to be the case now, and what was normal practice in some countries 25 years ago;
- When the design lifetime of nuclear power plant is being extended from 60 to 80 years, the impact of this change on LCOE* appears low. This is because of the devaluation of money, the impact of the last 20 years on the LCOE* for the full lifetime is not that significant (constant value calculation);
- The LCOE* of all selected electricity generation sources is driven by capital costs. All sources have roughly the same dependence on the utilisation, as all need to operate to generate income. The impact from 100% to 60% is moderate. Below 60%, the LCOE* increases fast.
- Reduction of the WACC for a nuclear power plant from 7% to 4,3% will reduce the LCOE* with around 25%. A government can support this by implementing risk-sharing instruments;
- The LCOE* of Hydrogen Round trip units is extremely high, especially because of a lower utilisation factor of the electrolysers. At a UF of 20%, a typical utilisation factor of a “Peaker” unit, the LCOE* will increase to above 700 €/MWh;
- Our assessment shows that an electrolyser is best combined with a CCGT instead of a OCGT.

6 CONCLUSION

From the information collected for this report and the analysis undertaken, several relevant conclusions could be made. Nuclear is a safe, secure and emission free energy with a low carbon footprint, which is able to supply a continuous and secure flow of electricity for generations to come. The main hurdle nowadays remains the economics of new nuclear power. For several decades nuclear energy was also one of the cheapest sources of electricity and for the running units this situation holds. As shown by numerous international studies, the life extension of operating nuclear plants reduces the CO2 emissions at the lowest cost of any of the available alternatives.

After the accidents at the TMI in US in 1979 and in Chernobyl USSR in 1986, no new nuclear power plants were ordered in the USA and Western Europe. After 20 years without new build activities, new build projects were started in Finland (2005), France (2007) and the USA (2013). Because of FOAK-related problems and loss of construction and regulatory experience, these projects were confronted with major construction delays and cost-overruns.

Lessons learned from the European and USA experience were adopted for construction in China or South Korea. The experiences in China show us that those construction problems are solvable, resulting in plants built on time and without (or smaller) costs overruns. When countries as the Netherlands select a NOAK plant from an experienced vendor, it might now be expected that the potential for major construction delays and cost overruns would be limited. The important element remains the project preparation, i.e. is that sufficient time is spent on project development, detailed engineering and licensing, so that no surprizes emerge during the construction phase.

Another economic hurdle related with the utilisation of nuclear power is the cost of financing, as vividly depicted in Figure 15 and Figure 16. Long periods between project initiation to plant operation, coupled with the conditions of a deregulated market and uncertain future electricity price, is leading to a higher cost of capital than for units with lower investment volume. New approaches are being employed by governments to reduce potential financial risk, by utilizing different mechanisms i.e. the RAB model or setting up (partially) state-owned special vehicles that are to lock in on extremely low borrowing costs available to the governments. While similar support mechanisms would also be adapted for VRE sources, such approaches make much more significant differences for nuclear, because the contribution of the financing costs to LCOE are much higher.

A LCOE for a NOAK nuclear plant in the Netherlands (in 2040) might be expected to be 72 €/MWh (see Chapter 5). This LCOE is 40% higher than the LCOE for e.g. off-shore wind. An important qualification is that in this figure the system costs are not taken in consideration. Because nuclear power is a dispatchable electricity source and wind and solar are not, the system costs for nuclear power are lower than for the other two. With this system cost correction, the LCOE* for new nuclear is 74 €/MWh (uncertainty range 56-111 €/MWh) compared to offshore wind 85€/MWh (uncertainty range 64-128 €/MWh).

Furthermore, it must be stressed that the LCOE (and LCOE*) calculation assume a different WACC for nuclear compared to the VRE: 7% for nuclear and 4,3 for the VRE. With new approaches, where the cost of financing of nuclear would be significantly reduced, (i.e. level playing field) the cost advantage of nuclear is even greater. As shown in the sensitivity analysis, while assuming a WACC of 7% for both nuclear and VRE, the LCOE for nuclear even without accounting for system costs, is on the same level as offshore wind.

Corrected for system costs, nuclear can more than compete with VRE's, and could be successfully deployed to maintain a stable and reliable grid.

For all high investment electricity sources (nuclear, wind, solar PV, coal, etc.), it is important that a generating unit is operational for a sufficient number of hours, to generate the earnings to pay-off the investment. For that reason, (future) nuclear power plants would be best (economically) deployed while operating at 75% capacity in a base load mode, making the rest of the capacity available to support medium and long term grid needs and/or to produce green hydrogen.

Increasing difficulties in financing the construction of large GEN III reactors, coupled with the need for more low-carbon dispatchable generation, are driving policy and investor interest in SMRs. This type of nuclear reactor could be more easily financed and maybe provide the additional push for nuclear fission technology. SMRs are much smaller (up to 400 MW) than existing reactor designs and are intended to be built in a modular fashion. Even if the average investment cost per unit of capacity (installed MWe) is comparable (or higher) to that of conventional large reactors, the smaller project size and shorter lead-times of SMRs promise to make financing easier. Modular design and factory construction mitigate project management risk, which is the single most-important obstacle to financing GEN III nuclear projects. Several SMR designs have inherent advantages in safety, which could ease licensing and improve social acceptance. In contrast to the hesitating private investment appetite for large GEN III reactors under the current financial conditions, SMRs are attracting considerable private venture capital for R&D. Nevertheless, none of the SMR designs have yet reached commercial maturity.

Small and medium-sized reactors allow a more incremental investment, provide a better match to grid requirements and are more easily adapted to a broad range of industrial settings and applications including district heating, industrial heat or hydrogen production.

Nuclear power emits virtually no greenhouse gases. The complete nuclear power chain, from uranium mining to waste disposal, and including reactor and facility construction, emits only 2–6 grams of CO2 per kilowatt-hour. This is even less that wind and solar, and up to two orders of magnitude below coal, oil and natural gas.

GEN III large nuclear plants as well as (some) of the SMRs concepts are “inherently safe”, meaning minimisation of accidents and exclusion of any off-site consequences even in cases when hypothetical accident is to occur. Deployment of such reactors would enable the construction also in highly populated countries, without significant concerns regarding safety by the population located in the vicinity. Important advances have been achieved in the management of long-lived high-level radioactive waste. Disposal in special canisters in geologically stable layers in the deep underground is internationally regarded as a safe solution. Successful examples of such already exist in Nordic countries. The non-proliferation is internationally controlled by the IAEA and in the EU, by the Union’s own safeguards. It is up to a country to balance drawbacks and benefits.

Nuclear should not be viewed as being in competition with "renewable" sources of energy, such as wind or solar. Nevertheless, as the reduction of carbon emissions becoming a top political and public opinion priority, both nuclear and renewable sources could have much larger roles to play. The problem is that no "renewable" source has been demonstrated to have the capacity to provide the "baseload" electricity at all times of power needed to replace large fossil fuel plants.

Given the discussion above and within the limitations of this study, a possible role of nuclear in the energy mix for the Netherlands beyond 2030 is discussed below.

Possible role of nuclear in the future Dutch energy mix

Nuclear is a high investment/low fuel costs generation technology. For economic and not technical reasons, nuclear power plants are not to be used as “Peaker” units, EDF’s experience shows that NPPs can be used in load following mode. Nevertheless, in its pathway to a decarbonised energy system nuclear could have an important complementary role to play, supplementing VRE sources like solar PV, onshore and offshore wind, in the following utilisation scenarios:

Always full-load: in this option nuclear power plants will deliver a major chunk of the required base load production. As nuclear can provide the needed power in a stable way (independent of weather conditions), it is a cost effective and reliable power source. Another advantage is that the land-use for nuclear power plants is negligible. Nuclear is by far the most concentrated way of generating electricity.

Partial full-load/partial load-following: Nuclear is a dispatchable source and is technically able to balance power in the electricity grid. It is important that because of the dispatching function, the utilisation-factor of nuclear units is not undermined. It has to be realised that in an electricity system mix containing only VRE and green “peaker” units, the utilisation of the VREs will be significantly less than 100%. It is expected that in the VRE-dominated electricity system, nuclear plants would operate economically, when running between 75 and 100%, resulting in an effective capacity factor of 75% to 95%. From the economic perspective, such an operation might be more beneficial than the first one, depending on the decisions on how to maintain the grid stability in a high VRE energy mix. The land-use advantage is similar to the first option.

<u>Partial full-load/partial green hydrogen production for chemical and transport sector:</u> In the electricity sector, some decarbonisation has been achieved, and it is rapidly continuing. It is important that the transport sector follows. The electrification of the commercial/heavy transport sector might be expected to be difficult. P2G might be expected to be the best solution to achieve major decarbonisation in the transport sector. The green hydrogen could be produced by VRE’s and by nuclear power. However, for nuclear the costs will be reduced because of the higher utilisation rates of electrolysers. As shown in the sensitivity analysis, the utilisation rate of the electrolysers is key for the economics of the P2G solution. The utilisation-factor would be significantly higher when connected to a nuclear power plant compared to VRE’s, because a nuclear power plant can deliver the power continuously. Advantages of this solution might be a cheaper green hydrogen production because of the higher UF of the electrolyzer. The hydrogen might be used to stabilize the grid, resulting in a lower need for expensive Peaker units.

On the question, asked by the Ministry of Economy of The Netherlands, as to whether nuclear could play an important role in the future energy mix of the Netherlands, the answer is affirmative. Nuclear energy, both large units and SMRs, when compared to VRE by using the same metrics, are cheaper, able to deliver dispatchable electricity to the grid (and stabilise the grid when needed) in a reliable fashion independent of weather conditions, while having the orders of magnitude smaller land- footprint than any other source of electricity, in particular, VREs.

Thirty years ago, the adage of the government with respect to the electricity was diversity of technologies. In the current energy transition era, this remains as important as ever.

7 REFERENCES

[1] PRIS Database IAEA, 2020

[2] ”Not without your approval: a way forward for nuclear technology in Australia” House of Representatives Standing Committee on the Environment and Energy, December 2019

[3] Deloitte for FORATOM: Economic and Social Impact Report, 25 April 2019

[4] A. Goicea. Nuclear Energy’s State of Play –European Perspective, FORATOM 29 October 2018

[5] https://www.worldnuclearreport.org/IMG/pdf/wnisr2019-v2-lr.pdf

[6] RAB model https://www.nsenergybusiness.com/features/regulated-asset-base-model-nuclear/#:~:text=What%20is%20a%20regulated%20asset%20base%20funding%20model%3F,the%20assets%20and%20operating%20costs

[7] BMJ Institute of Applied Ecology, “German nuclear phase out”, 2015

[8] TRL https://ec.europa.eu/research/participants/data/ref/h2020/wp/2014_2015/annexes/h2020-wp1415-annex-g-trl_en.pdf

[9] The ETI Nuclear Cost Drivers Project: Summary Report, Energy Technologies Institute LLP 2018

[10] IEA: Global CO2 emissions in 2019, Data Release, 11 February 2020

[11] NEA No. 7298, “The Full Costs of Electricity Provision”, OECD 2018

[12] Nuclear Power in a Clean Energy System, International Energy Agency (IEA), May 2019

[13] NEA No. 7299 “The Costs of Decarbonization: System Costs with High Shares of Nuclear and Renewables”, OECD 2019

[14] Multiple Authors. Energy Systems. Chapter 7. IPCC - Intergovernmental Panel on Climate Change 2018

[15] International Energy Outlook 2019 with projections to 2050. U.S. Energy Information Administration (US IEA), Office of Energy Analysis U.S. Department of Energy. September 2019

[16] Energy, Electricity and Nuclear Power Estimates for the Period up to 2050. IAEA - Reference Data Series No. 1, 2019 Edition

[17] NEA No. 7056, Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems OECD 2012

[18] Global energy perspective 2019: A Reference Case. Energy Insights by McKinsey 2019

[19] The Nuclear Fuel Report: Global Scenarios for Demand and Supply Availability 2019-2040, WNA, September 2019

[20] World Energy Council “World Energy Issues Monitor 2020-Decoding new signals of change”. London 2020

[21] The World Nuclear Industry Status Report 2019, A Mycle Schneider Consulting Project, Paris, Budapest, September 2019

[22] IAEA: https://www.iaea.org/newscenter/news/iaea-climate-conference-ends-with-call-for-major-nuclear-role, 2019

[23] World Nuclear Association's The World Nuclear Supply Chain: Outlook 2035

[24] J.V.Dorp. The Hinkley Point C case: is nuclear energy expensive? Generation atomic. December 2019. Author, Joris van Dorp, MSc.

[25] Current Status and Future Developments in Nuclear-Power Industry of the World in Journal of Nuclear Engineering and Radiation Science 2019 Vol 5.

[26] EDF: The second EPR reactor at China’s Taishan nuclear power plant about to enter into commercial operation, EDF September 2019

[27] H. Erdoğan. Westinghouse grid connects China's Sanmen nuclear plant - Sanmen 1's turbine generator connects to electrical grid and begins generating electricity, AA Energy March 2018

[28] A. Teivainen. Start-up of Olkiluoto 3 delayed by six more months until July 2020. Helskini Times. Uusi Suomi, July 2019

[29] H.Vella. Does the European Pressurised Reactor have a future?. Power technology, December 2019

[30] Basemat of Turkey's Akkuyu 1 completed. World Nuclear News, March 2019

[31] N. Wakim. Nucléaire : comment le gouvernement travaille en catimini à la construction de six nouveaux EPR. Le Monde, October 2019

[32] M. Dunai. Exclusive: Hungary makes EU bid to soften nuclear licensing rules to ease Paks expansion, November 2019

[33] World Nuclear Association "Licensing and Project Development of New Nuclear Plants", August 2015

[33] NucNet 16. January 2020; Nuclear in Europe/What Lies in Store In 2020

[35] ENSREG Stress tests performed on European nuclear power plants, Brussles April 2012

[36] E. Kelly. Generation IV international efforts. American Nuclear Society, Washington D.C section. December 17 2013

[37] Exploring Innovation Pathways to 2040 - In Collaboration with Accenture Strategy and the Paul Scherer Institute. Council World Energy Scenarios 2019, World Energy Council

[38] Multiple authors, The Future of Nuclear Energy in a Carbon-Constrained World, MIT Energy Initiative, 2018

[39] K. Lee. The Essential Role of Nuclear Power in Mitigating Climate Change: How can the nuclear community deliver. World Nuclear Association, INPRO Dialog forum June 2017

[40] https://www.cbs.nl

[41] C. J. Cleveland, C.G. Morris. Handbook of Energy Volume I: Diagrams, Charts, and Tables. Elsevier 2013

[42] C. Mone, M. Hand, M. Bolinger, J.R. Lawrence, D. Heimiller, J. Ho. 2015 Cost of Wind Energy Review. National Renewable Energy Laboratory 2017

[43] J. M. Bödeker, M. Bauer, M. Pehnt. Aluminium and Renewable Energy Systems – Prospects for the Sustainable Generation of Electricity and Heat, IFEU - Institut für Energieund Umweltforschung Heidelberg 2010

[44] Nuclear energy in perspective: "Nuclear energy and addressing climate change", NEA 2009

[45] https://www.world-nuclear.org/information-library/economic-aspects/economics-of-nuclear-power.aspx

[46] NEA No. 7057 'Projected costs of generating electricity'; NEA/IEA 2015

[47] SFEN-2018 'Les couts de production du nouveau nucleaire francais'; SFEN;March 2018

[48] Holttinen, H. e.: Design and Operation of Power Systems with Large Amounts of Wind. IEA Wind Task 25, 2013

References used for the input data and parameters for the "LCOE* calculations" (Section 5.6: LCOE in the Netherlands for the year 2040)

[13] NEA No. 7299, 'The costs of decarbonisation: system costs with high shares of nuclear and renewables'; OECD-NEA; 2019

[46] NEA No. 7057, 'Projected costs of generating electricity'; NEA/IEA; 2015

[49] SFEN-2018 'Les couts de production du nouveau nucleaire francais'; SFEN;March 2018

[50] WNA-2019 'Economics of Nuclear Power'; WNA website; Updated September 2019

[51] Rolls Royce-2017, 'UK SMR: A National Endeavour2017';Rolls Royce; 2017

[52] EFWG-2018, 'SMR ROADMAP'; ECONOMIC AND FINANCE WORKING GROUP CANADA; 2018

[53] Agora-2017'The Future Cost of Electricity Based Synthetic Fuels'; Agora Energiewende; 2017

[54] Berenschot-2020 'Systeemeffecten van nucleaire installaties in Klimaatneutrale energiescenario's 2050', Kalavista Berenschot

[55] Frauenhofer-2018,'Stromgestehungskosten enneuerbare energien', March 2018, Frauenhofer ISE

[56] Irena-2018(H2), 'Hydrogen from renewable power', Irena 2018

[57] Irena-2019(wind, 'Future of wind', Irena October 2019

[58] Irena-2019(solar),'Future of solar photovoltaic', Irena November 2019

[59] Alg.Rekenk-2018,'Focus op Kosten windenergie op zee', Algemene Rekenkamer September 2018

ANNEX 1: LEVELIZED COST OF ELECTRICITY

A common way to compare the costs of different electricity generation sources is the Levelized cost of electricity (LCOE). LCOE represents the average revenue per unit of electricity generated that would be required to recover the costs of building and operating a generating plant during an assumed financial life and duty cycle as relevant for each sources (e.g. 15-25 years for VREs, 60 and up to 80 years for nuclear).

LCOE is often cited as a convenient summary measure of the overall competitiveness of different generating technologies. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, the cost of the decommissioning and waste management, and an assumed utilization rate for each plant type. One has to be careful when the LCOEs are taken for comparison purposes from different studies. tThe parameters used (e.g. life time) to calculate the LCOE could be different, but also the assumptions on what is and what is not to be included in the LCOE differ (e.g. decommissioning, waste management, insurances, etc.). The exact parameters and assumptions are sometimes hard to find in the studies or not even mentioned.

The importance of each of these factors varies across the technologies. For technologies with no fuel costs and relatively small variable O&M costs, such as solar and wind, LCOE changes nearly in proportion to the estimated capital cost of the technology. For technologies with significant fuel cost, both fuel cost and capital cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax, can also affect the calculation of LCOE. As with any projection, these factors are uncertain because their values can vary regionally and temporally as technologies evolve and as fuel prices change.

Actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve many other factors not reflected in LCOE values. One such factor is the projected utilization rate of the technology, which depends on the varying amount of electricity required over life time and the existing resource mix in an area where additional capacity is needed. For example, a wind resource that would primarily displace existing natural gas-fired generation will usually have a different economic value than one that would displace existing coal-fired generation. A related factor is the capacity value, which depends on both the existing capacity mix and load characteristics in a region.

Because the electrical load to the grid must be continuously balanced, generating units with the capability to vary output to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (non-dispatchable technologies) such as those using intermittent resources to operate.

Limitations of LCOE to compare technologies

LCOE does not capture all of the factors and all costs that contribute to actual investment or policy decisions, making the direct comparison of LCOE across technologies problematic and misleading as a method to assess the economic competitiveness of various generation alternatives. Comparing two different technologies using LCOE alone evaluates only the cost to build and operate a plant and not the value of the plant's output to the grid. During the last decennia several methods were developed to bring this grid-value aspect into the equation like Levelized Avoided Cost of Electricity (LACE) (US EIA) and System effects (OECD NEA).

Methodology to determine LCOE*

LCOE* Formula

For this Study, a generally used LCOE approximation formula is applied. In this formula system costs are included to make it the LCOE*:

LCOE* (€/MWh) = 1/(8766*CF)*(CRF*OCC/POW+OM/POW) + FCC + PROV + SYS (1)

CFR = (r(1+r)N/((1+r)N-1) (2)

Where:

Capital Recovery factor (CRF)

Capacity Factor of the unit, annual availability (CF)

Overnight capital costs of the unit in € (OCC), including Interest During Construction (IDC)

Name plate power capacity of the unit in MW (POW)

Annual operation and maintenance costs in €/y (OM)

Fuel Cycle Costs in €/MWh (FCC)

Annual provisions for decommissioning and other (PROV)

Annual system costs in €/MWh (SYS)

The discount rate of the project (r=WACC) is a mix of debt and equity

Interest During Construction (IDC) is depending on WACC, Construction time and expected construction progress (assumed linear).

The input-data for the calculations are collected from recent reports of respected institutes including Irena, NEA. IEA, MIT, as listed in the Annex 3 " Assumptions".

Decommissioning costs

Decommissioning costs become relatively small when discounting over 60 years lifetime of a nuclear plant is assumed. In actual practice, the owner-operator makes annual contributions to a fund (e.g. a financially segregated "decommissioning trust fund" for financial security) during operations. In this way, the funds needed for the decommissioning and dismantlement (D&D), including waste management costs are accumulated. This fund usually earns a rate of return over the plant's lifetime, and hence is growing until D&D expenditures are due. Because of the long lifetime and the return on the fund, the annual contribution is a small part of a nuclear power plant's LCOE. NEA [11] estimates that that the decommissioning of a nuclear power plant would be about 15% of the original overnight construction costs, at an euro value of the year of construction start. Here an annuity savings calculation is in place. For our calculation we assume that the provision will be collected from the start of operation till the end of the life time.

TN = (1/i)*((1+r)n-1)*(1+r)*J = F(r,n)*J (3)

Where:

r = real interest-ratio = interest- and investment rate (%) minus inflation-rate (%) divided by 100

N = number of payment periods (here LT)

J = Fixed periodic payment = instalment and interest

TN is the needed provision total in the future (Year N) calculated current currency value

At a real interest-rate of 3% and a plant life time of 60 years, I = 0,03 and n = 60, in case of overnight construction costs of 5000 k$€_{2018}$/MWe, the estimated decommissioning costs are 750 k$€_{2018}$/MWe. F(i,n) = F(0,03, 60) = 33,33*4,892*1,03 = 167,945. So, when T60 = 750 k$€_{2018}$/MWe, than the annual period is only 4,47 k$€_{2018}$/MWe. NEA [11] indicates that Belgium, France and the UK do set aside annual 3,1 k€/MW, 2,7 k€/MW and 3,6 k€/MW respectively at an real interest-rate of 3%. Normally these costs are included in the fixed annual O&M costs. In our study these costs are calculated separately.

Estimation of technology progress in the future

For statistical extrapolation to the future of technology development, several theoretical models do exist, like the S-curve model and the combined S-curve model. In the real world these models cannot be used because of the lack of data to support the models. For the extrapolation from the present to the future in this study linear learning ratios (LR) are used. The LR's are calculated (in % improvement per decade) based on historical evidence, to predict the development for the future. One must always be careful that no plateau at the end of the learning is reached. So there must be sufficient evidence (science, R&D, market) that continued improvement will continue, to assume that historical performance will proceed in the future.

For the estimates of the VRE we follow the practice of Irena and other sustainable energy institutes, that the progress that is observed over the last 10 years will continue over the next 2 decades. Some warning is in place for solar PV where over the last 3 historical years a start of a plateau can be observed in the European countries. For solar PV, our calculation of the LCOE* might be optimistic.

For the off-shore wind we accepted the results of the recent auctions in the Netherlands as a starting point of the extrapolation. Here a warning must be in place, because these projects are not realised yet. The Borssele Windfarm was still under contract-for-difference regime and at this moment is connected to the grid. The wind-farm Hollandse Kust is not subsidised, except for the license and the grid connection, and is under construction.

The wind farm operators are beginning to realize that in the future, the utilisation will not always be 100% and thus the LCOE* might be higher than calculated.

For a large nuclear power plant we used the SFEN [47] for the estimate for the overnight capital costs for an EPR, where important lessons learned from all EPR projects in the world were incorporated. Major design measures are incorporated in a new design, resulting in lower construction costs and risks. For example, in a new EPR, no complex double containment will be used, but a single concrete containment, like the traditional French units, maintaining the same level of safety performance.

The SFEN cost analysis is used instead of other estimates, because the lessons in the report are very concrete and straight forward. The two Hinkley Point C units will still be of the current design, but it is expected that all newer units will be of the new series. We expect that a first Dutch unit would be number 3 or 4 of this series. Because of the NOAK effect, we assume a further 20% cost reduction of the overnight capital costs, being in the flattening side of the rapid learning phase.

ANNEX 2: SYSTEM EFFECTS

In recent international scientific discussions, it is noted that due to uncertain and variable electricity generation (i.e. by VRE), the total costs are more than the sum of plant-level costs as calculated with the levelized cost of electricity (LCOE). In 2012 OECD-NEA published a study [13], where the idea of 'system costs' was introduced. In the meantime, mainly due to the addition of significant amounts of variable renewables that have profoundly changed the behaviour and the economics of electricity markets, many others have joined in. In 2019 this study was deepened and enlarged in cooperation with the International Energy Agency (IEA) [12].

The principle of systems effects is based on the notion that in the electricity systems of the future, all available low carbon generation options, nuclear energy, wind, solar, hydroelectricity and, perhaps one day, fossil fuels with CCUS will need to work together in order to enable countries to meet their environmental goals in a cost-efficient manner. Plant-level costs do remain, and their importance is recognised by the great strides that VRE achieved in this area in the recent past.

However, their intrinsic variability and, to a lesser degree, their unpredictability, imply that the costs of the overall system will continue to rise over and above the sum of plant level costs. What nuclear energy and hydroelectricity, as the primary dispatchable low carbon generation options, bring to the equation is the ability to produce at will large amounts of low carbon power predictably according to the requirements of consumers. For the right decisions to be made in the future by governments and industry, the factors determining the system costs must be understood and addressed.

VREs share specific characteristics that make their integration into the electricity system particularly challenging. The IEA has identified six technical and economic characteristics that are specific to VREs and are a key element to explain and understand the system costs associated with their integration. The output of VRE is thus:

- Variable: the power output fluctuates with the availability of the resource (wind and solar) and not in function of demand or system needs.
- Uncertain: the amount of power produced cannot be predicted with precision. However, the accuracy of generation forecast increases with approaching the time of delivery.
- Location-constrained: the available renewable resources are not equally good in all locations and cannot be transported. Favourable sites are often far away from load centres.
- Non-synchronous: VRE plants must be connected to the grid via power electronics and are not directly synchronised with the grid.
- Modular: the scale of an individual VRE unit is much smaller than other conventional generators.
- With low variable costs: once built, VRE generate power at little operational cost. The short-run marginal costs of wind and solar PV units are zero.

The concept of system effects, which are heavily driven by these six attributes of VRE, has been conceptualised and explored extensively by the NEA and the IEA, and has benefitted from a significant amount of new research from academia, industry and governments.

System costs are defined as the total costs accrued beyond the perimeter of a power plant to supply electricity at a given load and at a given level of security of supply. System effects measure the impact that the integration of a power generation source has on the whole electricity system.

System effects of existing dispatchable technologies (nuclear power, coal and gas) are small and therefore do not need to be taken into account by electricity grid operators. However, the technical and economic system effects of variable renewable technologies (offshore wind, onshore wind and solar) are mostly unaccounted for and are significant. Presently, these costs are borne by existing dispatchable technologies, grid operators and the general public through taxes or electricity tariffs. Failure to recognize and internalize system costs does not provide a true picture of the total cost of electricity supply and may lead to unintended consequences on longer-term security of such supply.

System effects or system costs are often divided into the following four broadly defined categories:

- profile costs (also referred to as utilisation costs or backup costs by some researchers),
- balancing costs,
- grid costs and
- connection costs.

Profile costs (or utilisation costs) refer to the increase in the generation cost of the overall electricity system in response to the variability of VRE output. They are thus at the heart of the notion of system effects. They capture, in particular, the fact that in most of the cases it is more expensive to provide the residual load in a system with VRE than in an equivalent system where VRE are replaced by dispatchable plants.

A different way of looking at the profile costs of VRE is to consider that the electricity generation of wind or solar PV is concentrated during a limited number of hours with favourable meteorological conditions. This decreases value for the system of each additional VRE unit and corresponds to an equivalent increase in profile costs. In addition, the presence of VRE generation generally increases the variability of the residual load, which exhibits steeper and more frequent ramps. This causes an additional burden, also called the flexibility effect, to other dispatchable plants in terms of more start-ups and shutdowns, more frequent cycling and steeper ramping requirements, leading to lower levels of efficiency, an increase in the wear and tear of equipment and higher generation costs.

At high VRE penetration rates, the VRE will be required under certain grid-conditions to be disconnected from the grid or requested to reduce power. If disconnection takes place, it will result in lower utilisation factors and a resulting increased LCOE. The increase is an example of the profile costs.

The profile costs are used to express the relative value of generation to the electricity system or the electricity market. Basically, this is a question of timing: plants which are able to adjust their production according to the system demand have a higher value, whereas intermittent technologies such as wind power would usually have a lower value.

The value of the electricity generation in the electricity market is compared to a common benchmark, such as the average electricity market price. If the technology earns less than the average electricity market price, the difference can be considered a profile cost. If the technology earns more than the average electricity price, this can be considered a profile benefit.

As the share of wind and solar power increases, the value of the generated electricity from these technologies will fall. The first installed capacity may replace expensive generation (e.g. oil-fired) and in some countries, the first MW's yield electricity prices above the average market price, because for instance solar generation coincides well with the electricity peak load. With additionally increased wind and solar generation, cheaper generation is thereafter replaced.

In Denmark, wind power has generated electricity 5-15% below average electricity market price (2002-2014). Strong interconnectors and close location to the large hydro capacities in Sweden and Norway are a major reason for the relatively low-profile cost (price gap).

Balancing costs refer to the increasing requirements for ensuring the system stability due to the uncertainty in the power generation (unforeseen plant outages or forecasting errors of generation). In the case of dispatchable plants, the amount and thus the cost of operating reserves are generally given by the largest contingency in terms of the largest unit (or the two largest units) connected to the grid. In case of VRE, balancing costs are essentially related to the uncertainty of their output, which may become important when aggregated over a large capacity. Forecasting errors may require carrying on a higher amount of spinning reserves in the system.

In most electricity markets, electricity production is planned one day ahead in the spot market. If deviations from the planned operation occur during the day of operation, purchase or sale of electricity in the electricity market is necessary and will generate balancing costs. For this reason, balancing costs are particularly relevant for wind and solar power, but might also be applicable for other technologies. Compared to a coal-fired power plant, gas turbines have good regulating capacities.

Balancing costs encompass both the costs of holding sufficient reserves to deal with the deviations, and the costs of activating these reserves.

The cost of balancing is highly dependent on the flexibility of the surrounding electricity system, for example the availability of technologies with good regulation abilities such as hydro power with storage capacity and gas engines. The regulatory framework and the market setup may also have a significant impact on the balancing costs. Balancing markets, which have a high level of competition and allow all types of electricity generators and flexible consumers to participate, are likely to yield low balancing costs.

A survey by Holttinen [48] has shown that at 20 % wind power penetration balancing costs amount to approx. EUR 2 to 4 per MWh in thermal-based power systems and less than EUR 1 per MWh in power systems dominated by hydro power.

Grid costs reflect the increase in the costs for transmission and distribution due to the distributed nature and locational constraint of VRE generation plants. However, nuclear plants also impose grid costs due to siting requirements for cooling and transmission. Grid costs include the building of new infrastructures (grid extension) as well as increasing the capacity of existing infrastructure (grid reinforcement). In addition, transmission losses tend to increase when electricity is moved over long distances. Distributed solar PV resources may, in particular, require investing in distribution networks to cope with more frequent reverse power flows occurring when local demand is insufficient to consume the electricity generated, or to cope with very high maximum output of VREs during the day.

Grid-related costs are very site-specific as they depend highly on the location of the energy sources compared to the existing grid and the load centres. The IEA's publication [46] includes a review of wind integration costs in the US and the EU. Usually grid costs of solar and PV projects lie in the range of 2-10 USD per MWh. In some cases, grid costs may even be negative if the location of new generation close to consumers may contribute to deferring investments. This is particularly the case in networks where upgrades are required due to anticipated load growth.

Solar PV is often placed at or near the point of power consumption. At low penetration levels this can also reduce losses in the distribution and transmission networks.

Connection costs consist of the costs of connecting a power plant to the nearest connecting point of the transmission grid. They can be significant especially if distant resources (or resources with a low load factor) have to be connected, as can be the case for offshore wind, or if the technology has more stringent connection requirements as is the case for nuclear power. Connection costs are sometimes integrated within system costs, but are sometimes also included in the LCOE plant-level costs. This reflects commercial realities as different legislative regimes require connection costs either to be borne by plant developers or by the transmission grid operator. In the former case, they are part of the plant-level costs and thus fully internalised, while in the latter case they are externalities to be accounted for in the system costs.

.

Modelling system effects: results from the OECD NEA system cost study [12] for an hypothetical situation

For a hypothetical case, the NEA model study shows that combining explicit targets for VRE technologies and a stringent limit on carbon emissions has important impacts on the composition of the generation mix and its costs. In particular, total generation capacity increases significantly with the deployment of VRE resources. Since the load factor and the capacity credit of VRE are significantly lower than that of conventional power plants (thermal and nuclear), a significantly higher capacity is needed to produce the same amount of electricity. While about 98 GW are installed in the base case scenario without VRE, the deployment of VRE up to penetration levels of 10% and 30% increases the total capacity of the system to 118 and 167 GW, respectively. The total installed capacity would more than double to 220 GW if a VRE penetration level of 50% must be reached. More than 325 GW, i.e. more than three times the peak demand, are needed if VRE generate 75% of the total electricity demand. In other words, as the VRE penetration increases vast excess capacity, thus investment, is needed to meet the same demand. The installed capacity mix of different generation technologies in the five main scenarios is illustrated in Figure A1, while their respective electricity generation share is shown in Figure A2 below.

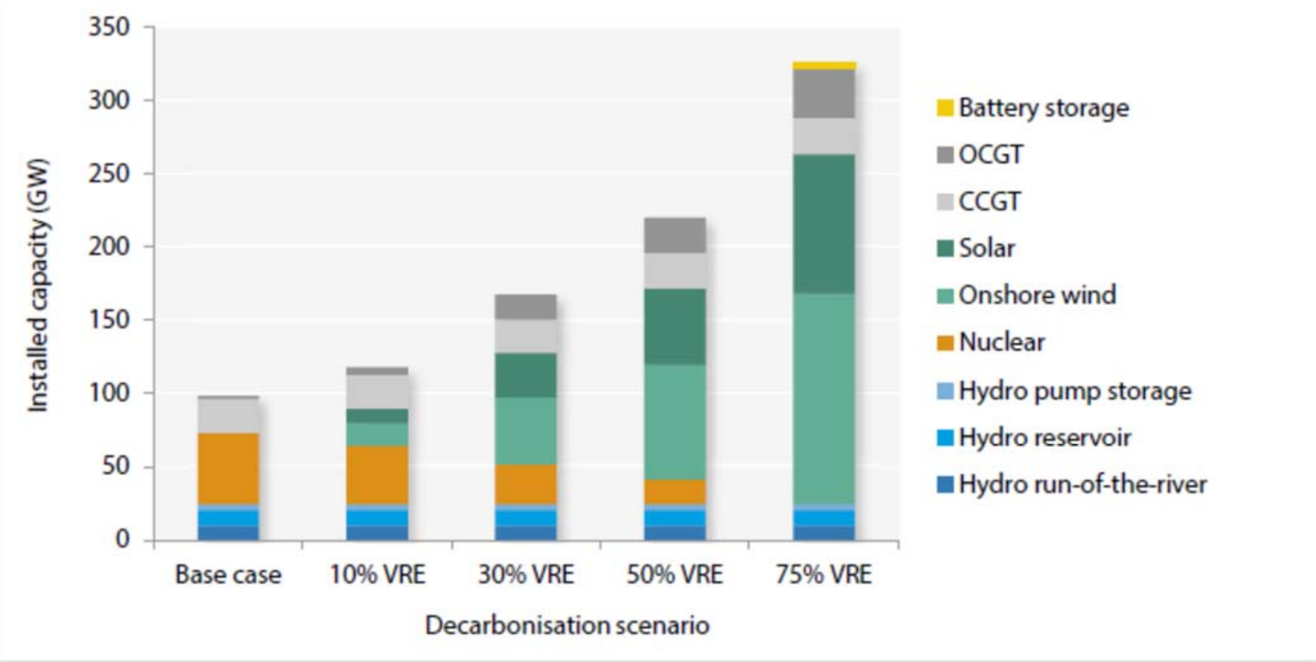


Figure A1. Total installed capacity mix with different shares of VRE needed to generate the same amount of GWh

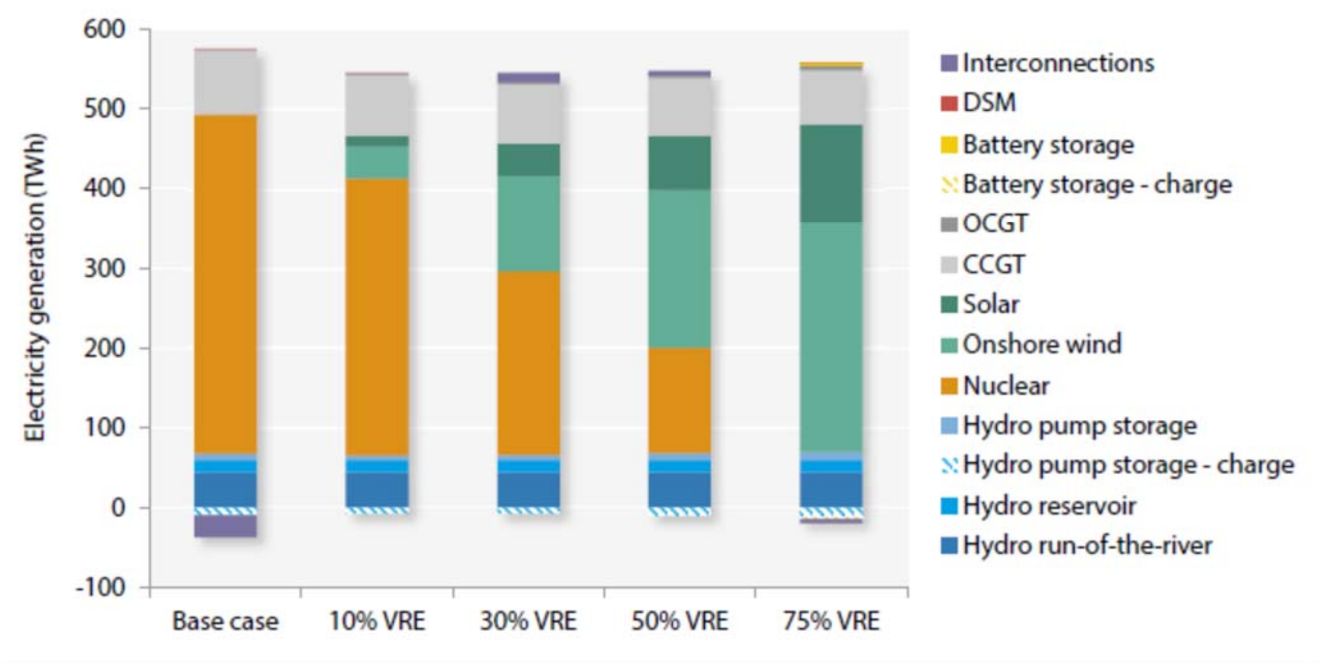


Figure A2. Electricity generation share in case of a the hypothetical situation

The NEA study shows that combining explicit targets for VRE technologies and a stringent limit on carbon emissions has important impacts on the composition of the generation mix and its costs. All scenarios include the same stringent carbon constraint of 50 gCO_2 per kWh, which is consistent with a level that the electricity systems of OECD countries must achieve to contribute their share to limit the increase in global mean temperatures to 2°C.

The electricity production goal for the Netherlands for 2030 is to have 70% VRE and the rest gas-powered, resulting in an average limit of 105 gCO_2 per kWh. The 2050 goal is an average zero gCO_2 per kWh, to balance the higher CO_2 demand of the other sectors (e.g. transport, industry, construction, etc.).

According to the 2019 Climate plan, the Dutch government wants to reduce CO_2 emissions by 49% in 2030 compared to 1990 emissions, and wants to reduce CO_2 emissions to zero by 2050. That means that by 2030 the contribution from sustainable sources must already be 70%. The hypothetical situation of the NEA study [12] is not fully applicable, because the Dutch long term goal is stricter, the hydro power possibilities are very limited and the present share of nuclear is 3% only. Nevertheless, the results of this model study illustrates the effects of the so called system costs in Figure A3 and A4. For the Dutch situation the projected system costs are expected to be higher, because of the lack of dispatchable hydro power.

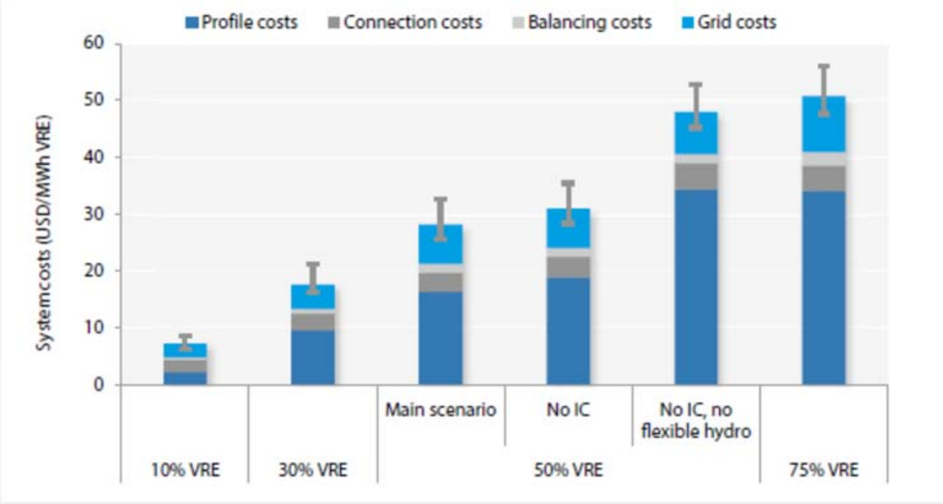


Figure A3. System costs per MWh of VRE (IC = interconnections to neighbouring region)

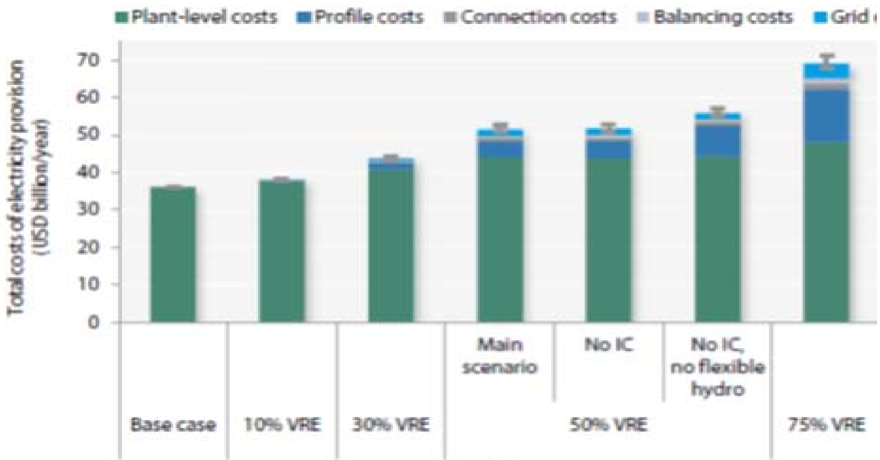


Figure A4. Total cost of electricity provision including all system costs

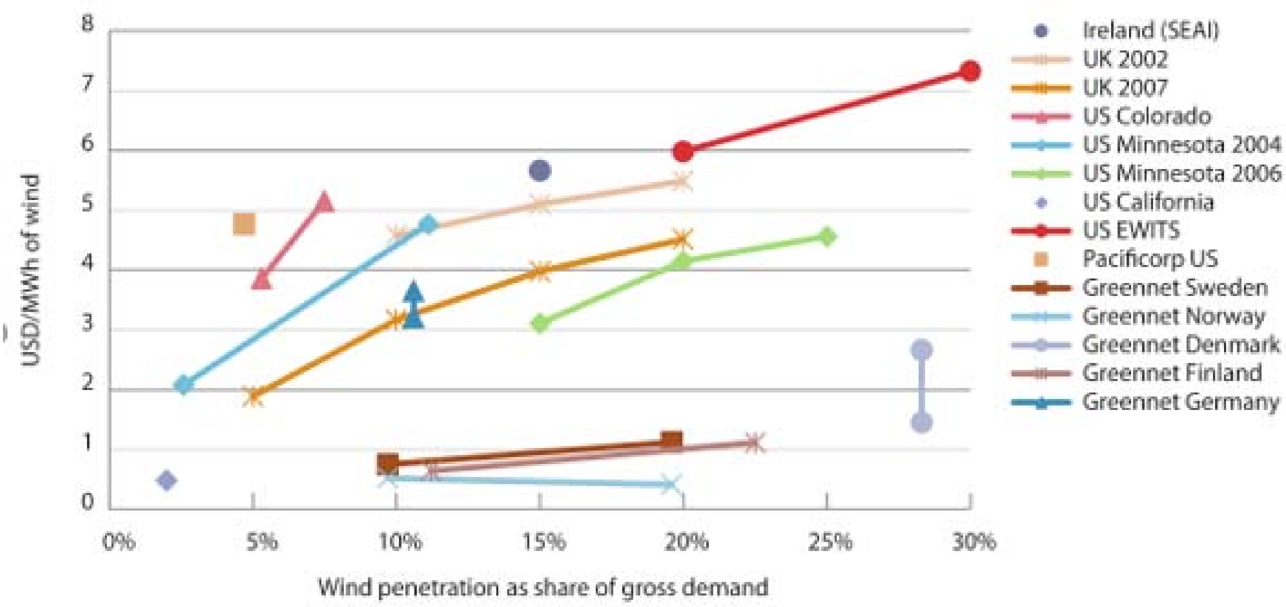


Figure A5: comparison of system modelling cost from different integration studies [46]

The system costs vary between less than USD 10 per MWh of VRE for a share of 10% of wind and solar to more than USD 50 per MWh of VRE for a share of 75% of wind and solar PV. Almost as important is the increase of USD 28 per MWh of VRE to almost USD 50 per MWh of VRE, both at a share of 50% of wind and solar, as a function of the availability of flexibility in the system in the form of interconnections with neighbouring countries and flexible hydroelectric resources. While such estimates come with some degree of uncertainty, the order of magnitude provides clear indications for policy choices.

These values need to be compared to the plant-level generation costs of VRE (the LCOE), which range, depending on the scenario, from USD 60 per MWh for onshore wind to up to USD 130 per MWh for solar. It should also be noted that the system costs are largely unaffected by any declines in plant-level costs as long as the share of VRE remains exogenously imposed. Indeed, all four components of system costs (balancing, profile, connection and grid costs) increase with the deployment of VRE resources, but at different rates. By adding system costs to the costs of plant-level generation, as assessed in LCOE calculations, one can calculate the total system costs of electricity provision for the eight scenarios analysed in this study (see Figure A4 above).

With 10% of VRE in the electricity mix, total costs increase only about 5% above the costs of a reference system with only conventional dispatchable generators, which in a mid-sized system such as the one modelled corresponds to additional costs of about USD 2 billion per year. At 30% VRE penetration, costs increase by about USD 8 billion per year, i.e. by 21% with respect to the base case. Reaching more ambitious VRE targets leads to considerably higher costs. Total costs increase by more than USD 15 billion per year if 50% of electric energy generation is provided by variable renewable resources, which corresponds to an additional 42% of costs compared to the base case. Reaching a 75% VRE target finally implies almost doubling the costs for electricity provision to almost USD 70 billion per year, representing more than USD 33 billion above the base case. For lower percentages VRE up to 30 % data from several studies are collected in figure A5. These studies were used as basis in the NEA study.

ANNEX 3: LCOE CALCULATIONAL ASSUMPTIONS

Table A1: Assumptions for the LCOE calculation: Nuclear EPR

Nuclear EPR		Base case	Mid case	Zero learning case
Overnight capital costs	€/kW	SFEN-2018:4500, Incorporating the impact of concrete design and construction learnings. Page 48 5067$/kW=4500€/kW	SFEN-2018:4673 page 26 Flamenville 3 6563 $/kW = 5841 €/kW, assuming 20% NOAK improvement	5100 €/kW, extrapolation of base and mid case
Fixed O&M costs	k€/MW/y	NEA 2019 (decarb) p95: 89 k€/MW/y	NEA 2019 (decarb) p95: 89 k€/MW/y	NEA 2019 (decarb) p95: 89 k€/MW/y
Variable O&M costs	€/MWh	NEA 2019 (decarb) p95: 1,34 €/MWh	NEA 2019 (decarb) p95: 1,34 €/MWh/y	NEA 2019 (decarb) p95: 1,34 €/MWh/y
Fuel cost	€/MWh	WNA 2019: 6,27 €/MWh final storage not included	WNA 2019: 6,27 €/MWh final storage not included	WNA 2019: 6,27 €/MWh final storage not included
Costs of waste	€/MWh	NEA-2015: 2,07 p33 2,33 $/MWh (spent fuel removal, disposal and storage)	NEA-2015: 2,07 p33 2,33 $/MWh (spent fuel removal, disposal and storage)	NEA-2015: 2,07 p33 2,33 $/MWh (spent fuel removal, disposal and storage)
Decommissioning costs	k€/MW/y	4,02 k€/MW, NEA-2015: 15% of overnight capital costs, discounted of life time using 3%/y	4,17 k€/MW, NEA-2015: 15% of overnight capital costs, discounted of life time using 3%/y	4,56 k€/MW, NEA-2015: 15% of overnight capital costs, discounted of life time using 3%/y
WACC	%/y	7%, NEA-2019 (decarb)	7%, NEA-2019 (decarb)	7%, NEA-2019 (decarb)
Technical lifetime	y	60 y. Is current lifetime Gen2 reactors. Gen3 EPR is designed for 80 y.	60 y. Is current lifetime Gen2 reactors. Gen3 EPR is designed for 80 y.	60 y. Is current lifetime Gen2 reactors. Gen3 EPR is designed for 80 y.
Construction time	y	7 y, CT of Taishan 1 minus 2 years Fukushima delay	8 y.	9y. Construction time of Taishan 1.
Capacity factor	ratio	95%, lifetime average CF of German Konvoi units, with the same online maintenance features as EPR	92,5%	90%, average of best PWR's in the world.
Name plate capacity	MWe	1630 MWe, design capacity is between 1600 and 1660, depending on the heat sink	1630 MWe, design capacity is between 1600 and 1660, depending on the heat sink	1630 MWe, design capacity is between 1600 and 1660, depending on the heat sink

Table A2: Assumptions for the LCOE calculation: Nuclear SMR

Nuclear SMR		Base case	Mid case	Zero learning case
Overnight capital costs	€/kW	5000 €/kW, NOAK, Rolls Royce 2017 and EFWG 2018	6000 €/kW	7000 €/kW, FOAK, EFWG 2018
Fixed O&M costs	k€/MW/y	94 k€/MW/y. EFWG 2018	94 k€/MW/y. EFWG 2018	94 k€/MW/y. EFWG 2018
Variable O&M costs	€/MWh	Included in fixed O&M, EFGW 2018	Included in fixed O&M, EFGW 2018	Included in fixed O&M, EFGW 2018
Fuel cost	€/MWh	WNA 2019: 6,9 €/MWh final storage not included, SMR 10% more costly (neutron leakage, higher manufacturing costs per kg)	WNA 2019: 6,9 €/MWh final storage not included, SMR 10% more costly (neutron leakage, higher manufacturing costs per kg)	WNA 2019: 6,9 €/MWh final storage not included, SMR 10% more costly (neutron leakage, higher manufacturing costs per kg)
Costs of waste	€/MWh	NEA-2015: 2,07, p33: 2,33 $/MWh (spent fuel removal, disposal and storage)	NEA-2015: 2,07, p33: 2,33 $/MWh (spent fuel removal, disposal and storage)	NEA-2015: 2,07, p33: 2,33 $/MWh (spent fuel removal, disposal and storage)
Decommissioning costs	k€/MW/y	4,47 k€/MW, NEA-2015: 15% of overnight capital costs, discounted of life time using 3%/y	5,36 k€/MW, NEA-2015: 15% of overnight capital costs, discounted of life time using 3%/y	6,25 k€/MW, NEA-2015: 15% of overnight capital costs, discounted of life time using 3%/y
WACC	%/y	7%, NEA-2019 (decarb)	7%, NEA-2019 (decarb)	7%, NEA-2019 (decarb)
Technical lifetime	y	60 y. Is current lifetime Gen2 reactors. Gen3 EPR is designed for 80 y.	60 y. Is current lifetime Gen2 reactors. Gen3 EPR is designed for 80 y.	60 y. Is current lifetime Gen2 reactors. Gen3 EPR is designed for 80 y.
Construction time	y	3 y per module, EFWG 2018	5 y.	7 y.
Capacity factor	ratio	90%, average of best current large PWR's in the world.	87,5%	85%, average of best of large PWR's around 2000. Needs experience to reach 90%.
Name plate capacity	MWe	200 MWe, SMR's will be between 50 and 200.	200 MWe, SMR's will be between 50 and 200.	200 MWe, SMR's will be between 50 and 200.

Table A3: Assumptions for the LCOE calculation: On shore wind

Onshore wind		Base case	Mid case	Zero learning case
Overnight capital costs	€/kW	1480 €/kW, Irena-2019 (wind) p34 for EU 1900$/kW=1700€/kW minus 13%/decade(irena)	1590 €/kW	1700 €/kW, Irena-2019 (wind) p34 for EU 1900$/kW=1700€/kW
Fixed O&M costs	k€/MW/y	37 k€/MW/y. Agora 2017 p56, 2,5% of capital costs per year	40 k€/MW/y. Agora 2017 p56, 2,5% of capital costs per year	43 k€/MW/y. Agora 2017 p56, 2,5% of capital costs per year
Variable O&M costs	€/MWh	Included in fixed O&M, Agora 2017	Included in fixed O&M, Agora 2017	Included in fixed O&M, Agora 2017
Fuel cost	€/MWh	zero	zero	zero
Costs of waste	€/MWh	Waste included in decommissioning costs	Waste included in decommissioning costs	Waste included in decommissioning costs
Decommissioning costs	k€/MW/y	1,97 k€/MW; NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y	2,12 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y	2,26 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y
WACC	%/y	Berenschot 2020: 4,3%	Berenschot 2020: 4,3%	Berenschot 2020: 4,3%
Technical lifetime	y	25 y, Berenschot 2020, Frauenhofer 2018	25 y, Berenschot 2020, Frauenhofer 2018	25 y, Berenschot 2020, Frauenhofer 2018
Construction time	y	1 y, Berenschot 2020	1 y, Berenschot 2020	1 y, Berenschot 2020
Capacity factor	ratio	32%, LR according Irena 2019W p35 14%/dec. Current CF 26%(NL)	29%	26%, current average CF in Netherlands
Name plate capacity	MWe	3 MWe	3 MWe	3 MWe

Table A4: Assumptions for the LCOE calculation: Off shore wind

Offhore wind		Base case	Mid case	Zero learning case
Overnight capital costs	€/kW	1710 €/kW, Alg.Rekenk.-2018 p17 AVG 1800 minus 6%/dec(Irena)	1800 €/kW Alg.Rekenk.-2018 p17 AVG 1800 estimate 2018	2250 €/kW, Alg.Rekenk.-2018 p17 AVG 2250 estimate 2017
Fixed O&M costs	k€/MW/y	54,7 k€/MW/y. Agora 2017 p56, 3,2% of capital costs per year	57,6 k€/MW/y. Agora 2017 p56, 3,2% of capital costs per year	72k€/MW/y. Agora 2017 p56, 3,2% of capital costs per year
Variable O&M costs	€/MWh	Included in fixed O&M, Agora 2017	Included in fixed O&M, Agora 2017	Included in fixed O&M, Agora 2017
Fuel cost	€/MWh	zero	zero	zero
Costs of waste	€/MWh	Waste included in decommissioning costs	Waste included in decommissioning costs	Waste included in decommissioning costs
Decommissioning costs	k€/MW/y	2,28 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y	2,40 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y	3,00 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y
WACC	%/y	Berenschot 2020: 4,3%	Berenschot 2020: 4,3%	Berenschot 2020: 4,3%
Technical lifetime	y	25 y, Berenschot 2020, Frauenhofer 2018	25 y, Berenschot 2020, Frauenhofer 2018	25 y, Berenschot 2020, Frauenhofer 2018
Construction time	y	1,5 y, Berenschot 2020	2 y	3 y
Capacity factor	ratio	51,3%, current best performance on the North sea	46%	40%, current average performance on the Dutch North sea
Name plate capacity	MWe	3 MWe	3 MWe	3 MWe

Table A5: Assumptions for the LCOE calculation: Solar PV

Solar PV		Base case	Mid case	Zero learning case
Overnight capital costs	€/kW	595 €/kW, Frauenhofer 2018 p10 PV frei, minus 15%/dec p24(Irena)	650 €/kW	700 €/kW, Frauenhofer 2018, p10 PV frei
Fixed O&M costs	k€/MW/y	11,9 k€/MW/y. Agora 2017 p56, 2% of capital costs per year	9,8 k€/MW/y. Agora 2017 p56, 2% of capital costs per year	10,5 k€/MW/y. Agora 2017 p56, 2% of capital costs per year
Variable O&M costs	€/MWh	Included in fixed O&M, Agora 2017	Included in fixed O&M, Agora 2017	Included in fixed O&M, Agora 2017
Fuel cost	€/MWh	zero	zero	zero
Costs of waste	€/MWh	Waste included in decommissioning costs	Waste included in decommissioning costs	Waste included in decommissioning costs
Decommissioning costs	k€/MW/y	0,79 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y	0,87 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y	0,93 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y
WACC	%/y	Berenschot 2020: 4,3%	Berenschot 2020: 4,3%	Berenschot 2020: 4,3%
Technical lifetime	y	25 y, Berenschot 2020, Frauenhofer 2018	25 y, Berenschot 2020, Frauenhofer 2018	25 y, Berenschot 2020, Frauenhofer 2018
Construction time	y	0,5 y, Berenschot 2020	0,5 y, Berenschot 2020	0,5 y, Berenschot 2020
Capacity factor	ratio	10%, No improvement expected, improvement indicated in Irena-2019 caused by PV fleet extension in in sunny areas	10%	10%, current average CF in Netherlands
Name plate capacity	MWe	20 MWe	20 MWe	20 MWe

Table A6: Assumptions for the LCOE calculation: Hydrogen electrolysis

H2 PEM electrolyser		Base case	Mid case	Zero learning case
Overnight capital costs	€/kW	700 €/kW, Irena-2018 (H2) p20	950 €/kW	1200 €/kW, Irena-2018 (H2) p20
Energy efficiency	ratio	0,64, Irena-2018 (H2) p20	0,6	0,57, Irena-2018 (H2) p20
Fixed O&M costs	k€/MW/y	14 k€/MW/y, Irena-2018 (H2) p20, 2% of capital costs per year	19 k€/MW/y, Irena-2018 (H2) p20, 2% of capital costs per year	24 k€/MW/y, Irena-2018 (H2) p20, 2% of capital costs per year
Variable O&M costs	€/MWh	4,44 €/MWh, Irena-2018(H2) p20, new stack 210 €/kW every 6y	7,1 €/MWh	10 €/MWh, Irena-2018(H2) p20, new stack 420 €/kW every 5y
Fuel cost	€/MWh	variable	Variable	variable
Costs of waste	€/MWh	Waste included in decommissioning costs	Waste included in decommissioning costs	Waste included in decommissioning costs
Decommissioning costs	k€/MW/y	0,93 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y	1,26 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y	1,60 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y
WACC	%/y	7%, because of large market risk	7%, because of large market risk	7%, because of large market risk
Technical lifetime	y	20 y, Irena-2018(H2) p20	20 y, Irena-2018(H2) p20	20 y, Irena-2018(H2) p20
Construction time	y	1y	1y	1y
Capacity factor	ratio	0,9, including stack replacement once every 5-6 years	0,9, including stack replacement once every 5-6 years	0,9, including stack replacement once every 5-6 years
Name plate capacity	MWe	100 MWe	100 MWe	100 MWe

Table A7: Assumptions for the LCOE calculation: Hydrogen blending

H2 CCGT/Blending		Base case	Mid case	Zero learning case
Overnight capital costs	€/kW	1260 €/kW, NEA-2019 (decarb) p95, added 20% for blending equipment	1260 €/kW, mature market	1260 €/kW. Mature market
Energy efficiency	ratio	0,64, expected efficiency CCGT in 2030	0,64, expected efficiency CCGT in 2030	0,64, expected efficiency CCGT in 2030
Fixed O&M costs	k€/MW/y	23.14 k€/MW/y, NEA-2019 (decarb) p95	23.14 k€/MW/y, NEA-2019 (decarb) p95	23.14 k€/MW/y, NEA-2019 (decarb) p95
Variable O&M costs	€/MWh	3,12 €/MWh, NEA-2019 (decarb) p95	3,12 €/MWh, NEA-2019 (decarb) p95	3,12 €/MWh, NEA-2019 (decarb) p95
Fuel cost	€/MWh	variable	variable	variable
Costs of waste	€/MWh	Waste included in decommissioning costs	Waste included in decommissioning costs	Waste included in decommissioning costs
Decommissioning costs	k€/MW/y	1,68 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y	1,68 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y	1,68 k€/MW, NEA-2015: 5% of overnight capital costs, discounted of life time using 3%/y
WACC	%/y	4,3%	4,3%	4,3%
Technical lifetime	y	25 y	25 y	25 y
Construction time	y	3 y	3 y	3 y
Capacity factor	ratio	0,99	0,99	0,99
Name plate capacity	MWe	80 MWe	80 MWe	80 MWe

Table A8: Assumptions for the LCOE calculation: Hydrogen storage & transport

H2 Storage/transport		Base case	Reference
Input capacity (MW-H2 LHV)	64 MW(H2)	In line with 100MW PEM electrolyser with 64% efficiency	100 MW electrolyser
Output capacity (MW-H2 LHV)	80 MW(H2)	In line with a 50MW CCGT having 64% efficiency	50 MW CCGT
Storage capacity (MWh(H2 LHV)	250.000 MWh(H2)	In line with a buffer of 0,5 year full electrolyser capacity.	0,5 y storage capacity
Transport distance	200 km	Back and forth from electrolyser to storage salt cavern	
Conversion kg H2	0,0333	1 kg H2 = 0,0333 MWh (H2 LHV), LHV is the enthalpy without water evaporation energy	Irena-2018(H2)
Estimate LCOH	€/MWh(H2)	Annual costs 250.000 MWh facility(20MPa)	
Annual Capital costs, incl. O&M	60 M€	8€/kg / 0,0333 MWh/kg * 250000 MWh	NREL-1998 'costs of ….hydrogen' Underground storage in salt
Annual transport costs	4,5 M€	1,3 €/kg * 500.000 MWh / 0,0333 MWh/kg at full electrolyser capacity	NREL-1998 'costs of ….hydrogen'
Annual total costs	64,5 M€	Neglecting capital costs for H2 in storage	NREL-1998 'costs of ….hydrogen'
LCOH (€/MWh LHV)	129 €/MWh(H2)	64,5 M€ / 500.000 MWh	At full electrolyser capacity and capital-interest on stored H2 neglected
LCOH (€/MWh LHV)	3,4 €/MWh(H2)	In the reference there is no indication of buffer capacity in full-load-hours and other assumptions that support this figure.	Berenschot (2017). 'CO2-vrije waterstofproductie uit gas' Underground storage in salt, using abandoned cavern.
ENCO Estimate LCOH	25 €/MWh(H2)	Re-using abandoned caverns and pipelines, but leading to doubling of transport distance to 400 km (Back and forth)	

ANNEX 4: SENSITIVITY ANALYSIS

Learning effects consideration

With a rapid development of technologies, while on the other hand recognising that certain technologies are reaching their material or utilisations limits, it is hard to predict what the future, even 20 years from now, would bring. Therefore we performed a series of sensitivity studies, varying specific parameters and observing the impact on the LCOE*. Our "Base case" reflects a positive vision for all technologies, considering continuous improvement, but observing some "natural" limits (e.g. sun will not shine longer during the day). To observe the impact of possible variations in the future, while taking into the account the development visions, we considered 3 learning cases:

- Base case: positive vision for all technologies, supported by sufficient reliable information
- Mid case: half way between the Base case and the Zero learning case
- Zero learning case: data from the current situation in the Netherlands, based on realised performance where data available.

As can be observed in the Figure A6, Nuclear SMR and Offshore wind are most effected by the learning vision assumptions.

Table A9 : Summary of parameters used in sensitivity analyses

Capacity factor	Nuclear EPR	Nuclear SMR	Onshore wind	Offshore wind	Solar PV
CF Base case	95,0%	90,0%	32,0%	51,3%	10,0%
CF Mid learning	92,5%	87,5%	29,0%	46,0%	10,0%
CF Zero learning	90,0%	85,0%	26,0%	40,0%	10,0%
Capital costs per KW	**Nuclear EPR**	**Nuclear SMR**	**Onshore wind**	**Offshore wind**	**Solar PV**
OCC Base case	4500	5000	1480	1710	595
OCC Mid learning	4673	6000	1590	1800	650
OCC Zero learning	5100	7000	1700	2250	700
Construction time (year)	**Nuclear EPR**	**Nuclear SMR**	**Onshore wind**	**Offshore wind**	**Solar PV**
CT Base case	7	3	1	1,5	0,5
CT Mid learning	8	4	1	2	0,5
CT Zero learning	9	5	1	3	0,5

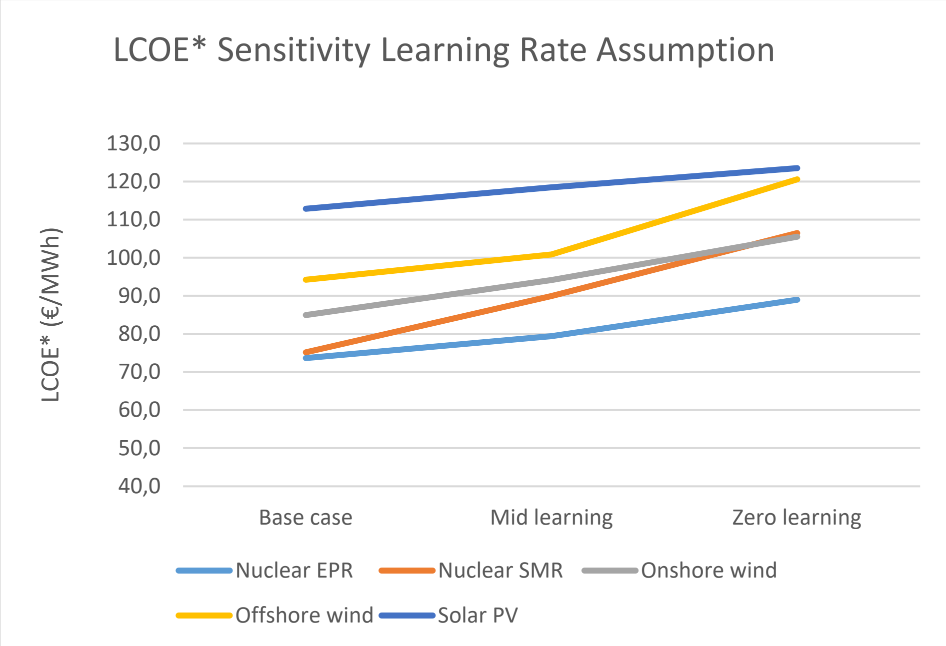


Figure A6: Sensitivity of the learning vision on LCOE*

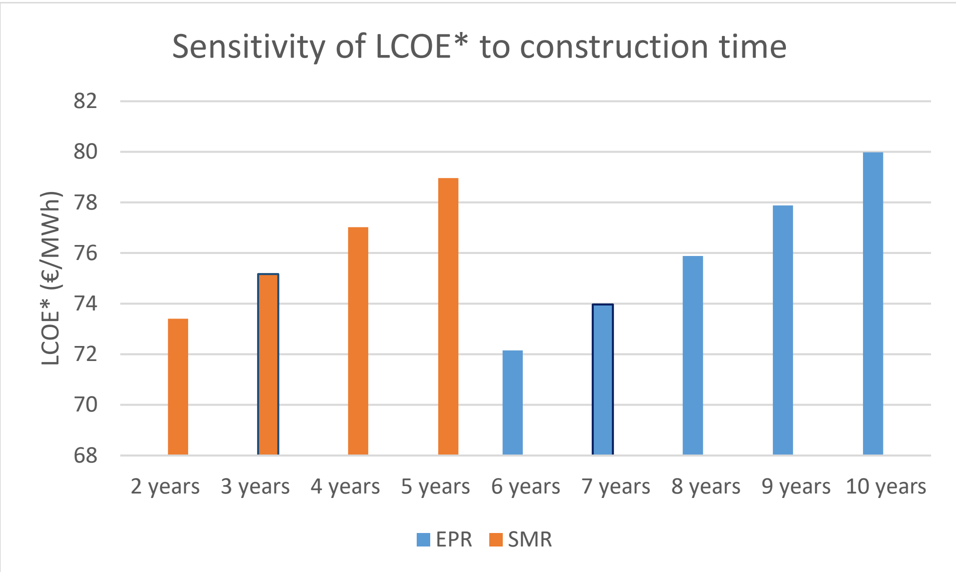


Figure A7: Construction time sensitivity at a WACC of 7%

Construction time sensitivity

For all electricity generators, during the construction period, there are no earnings and no instalments, resulting in a growing increase of the capital costs which is largely proportional to the duration of the construction. The impact on nuclear power plants, having a longer construction time, which is much more severe as compared to VRE's with (very) short construction time. The results presented in the Figure A 7 are considering a WACC of 7%. In the Base case, 3 years construction time is assumed for a SMR-module and 7 years for an EPR.

Twenty-five years ago, large nuclear power plants having capacity of a modern EPR were constructed in 4 to 6 years (Japan, Germany). In case of a NOAK EPR 6 years construction should be possible. A SMR could be a good solution to tackle the current long construction times and to reduce the capital costs risk.

Nevertheless, if or when the construction delays are avoided, there is certainly a market for large units. This is why China is continuing the development of large nuclear units and puts all its efforts in controlling the construction time.

Lifetime sensitivity

In former times, the design lifetime of nuclear power plants was 40 years. The reason for limiting the lifetime to 40 years was initially due to the (unknown) consequences of the neutron flux impacting the reactor pressure vessel (RPV), causing aging of its material. Already in the 1980s and 1990s, most of the NPP operators changed the nuclear fuel loading pattern of reactor fuel, resulting in a large decrease of the neutron flux impacting the RPV. This allowed lifetime extensions from 40 to 60 and to 80 years. Most running nuclear power plants nowadays have a licensed lifetime of 60 years and some already have an extension to 80 years. The EPR is designed for a lifetime of 80 years, but most likely the first license will allow for 60 years. In the base case calculations we assumed a lifetime of 60 years. The effect of different lifetimes on the LCOE* is shown in the Figure A8.

It has to be noted that a relatively small difference in price has more to do with the way the LCOE* was calculated, i.e. the depreciation time being equal to the lifetime. Consequently, the LCOE* estimated for the 80 years lifetime is dominated by financing costs and impact of the constant value calculation.

The reason for choosing such a calculation method is to assure the comparability of the results with other sources of electricity. This contradicts some methodologies of determining the LCOE*, where the realistic depreciation period (e.g. 25 years) is taken into the account, rather than the full operating lifetime, resulting in the “ cheapest” production years being excluded from the calculation. Nevertheless, it has to be noted that such a method is “penalising” for the plants with long lifetimes.

The reduction in the LCOE* for a nuclear plant, whose original lifetime was e.g. 60 years (meaning that the depreciation, financing costs but also reserves for the decommissioning have all been paid within 60 years) and its lifetime was extended to 80 years would be much more visible. This is because the total electricity production for the last 20 years of lifetime would be due to O&M costs only, which for a nuclear plant are in the range of 15% of the LCOE*. This explains why the “ life extension” of a nuclear plant is (by far) the cheapest source of the CO2- free electricity.

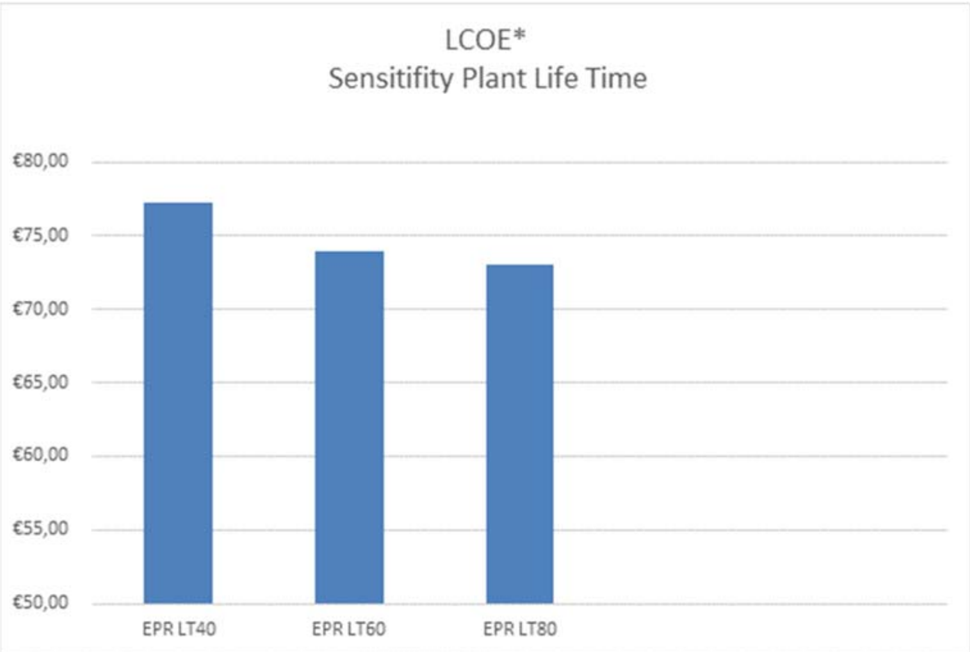


Figure A8: Sensitivity Plant lifetime on LCOE*

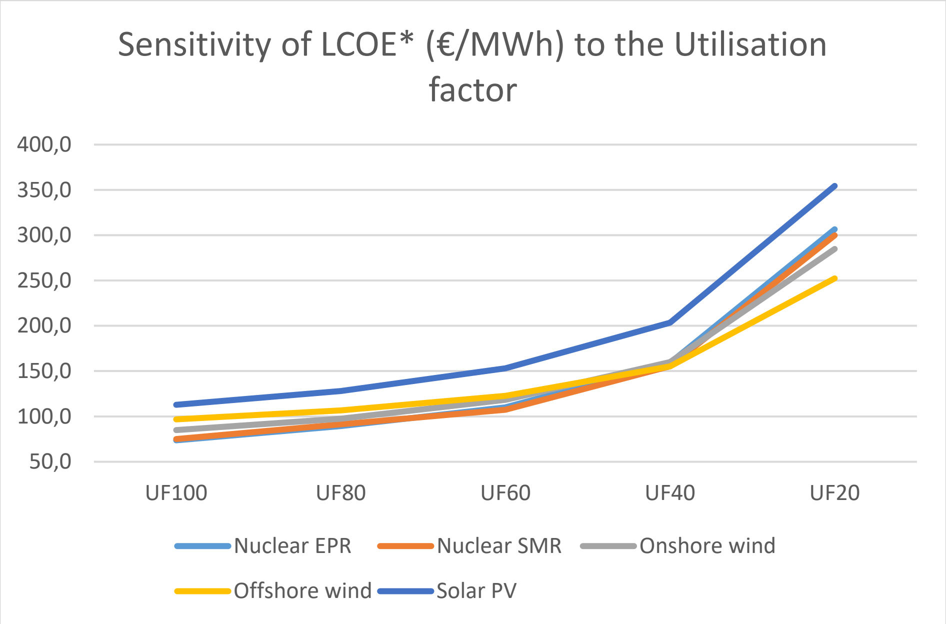


Figure A9: Sensitivity of the utilisation factor UF(%)

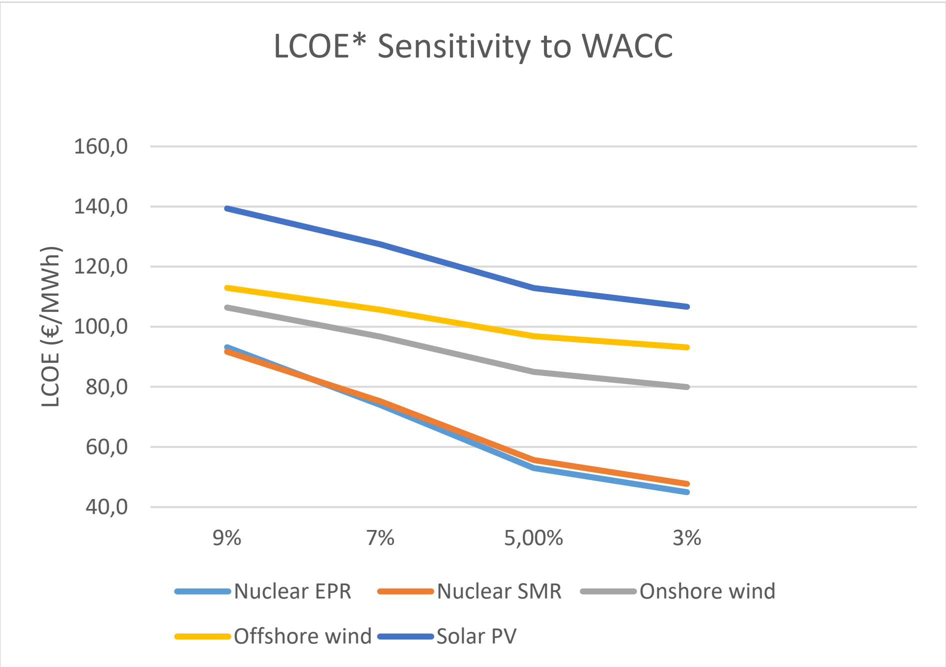


Figure A10: Sensitivity of the LCOE* on assumed WACC

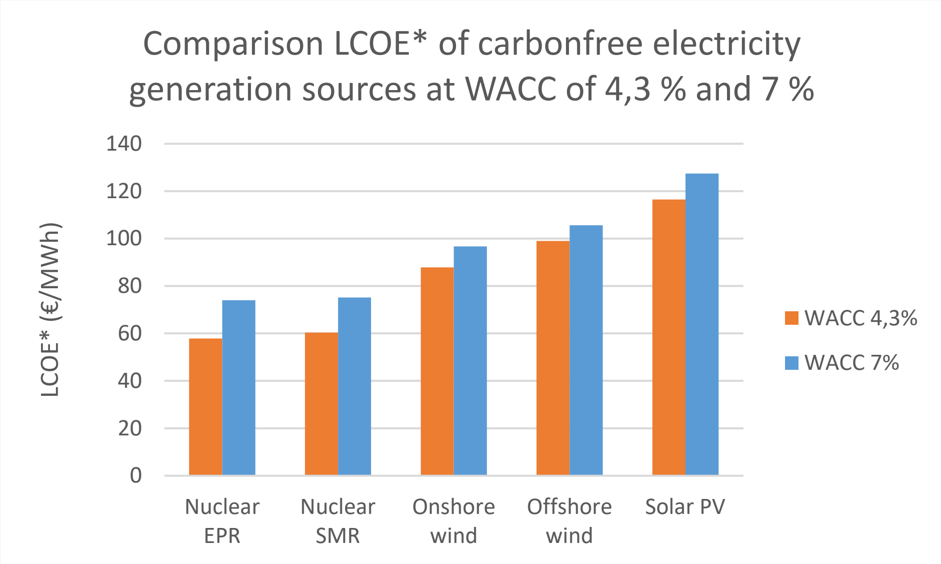


Figure A11: WACC sensitivity on LCOE* at 4,3% and 7% for EPR, SMR and VRE

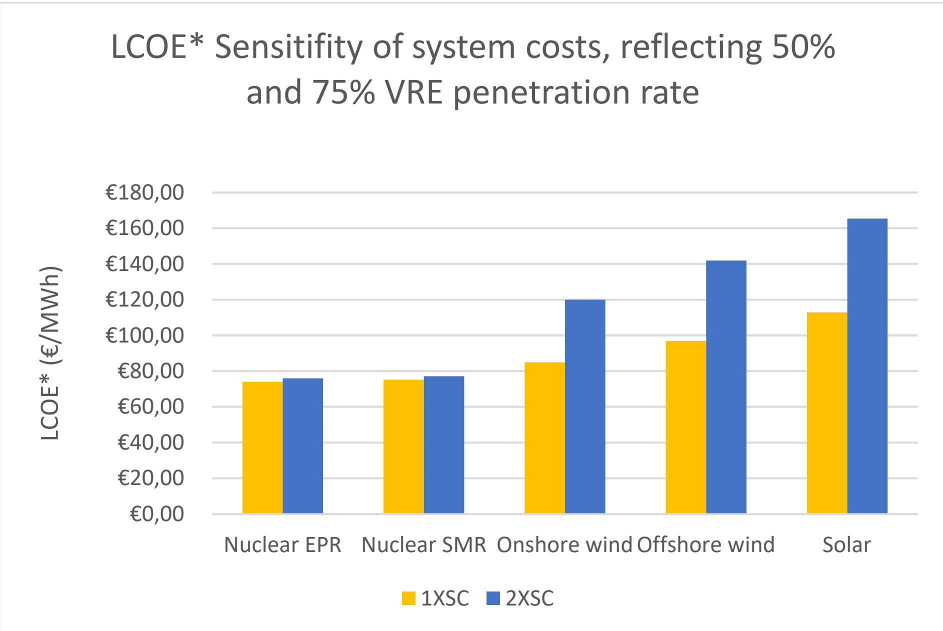


Figure A12: LCOE* Sensitivity of the system costs, reflecting the VRE penetration rate

Utilisation rate sensitivity

The LCOE* of all selected electricity generation sources is driven by capital costs. All show roughly the same dependence on the utilisation. They have to run to make money. The impact from 100% to 60% is moderate. All technologies require an environment that allows to be utilised above 60%, Figure A9. Below 60% the LCOE* increase fast.

Interest-rate (WACC) sensitivity

In the base case the WACC of 4,3% is selected for the VRE and 7% for nuclear. These two figures are compliant with typical industry practices. The WACC represents a combination of debt and equity. Equity is normally cheaper than debt, but is not always available in sufficient amounts In every company.

A high WACC creates a highly negative environment for nuclear new built developments, due to a long construction time and high investment costs, increasing the risk for investors. Governmental risk-sharing options could enable the use of a lower WACC, Figure A 10 and A 11.

Doubling of system costs

In this sensitivity study, the system costs for every technology are doubled (2XSC). Doubling reflects roughly the situation of 75% VRE penetration. This assessment can only give an impression of the direction of the development of the LCOE*, Figure A 12.

Hydrogen sensitivity cases

For the economics of a Hydrogen round trip power plant (H2-P2P), a high utilisation of the electrolyser is most important due to high investment costs (Figure A13). Nevertheless, 100% utilisation of the electrolyser and the corresponding gas turbine makes no sense. In that case, it would be better to directly use the electricity instead of destroying 60 to 75% of the electricity, at very high processing costs.

For the effective use of a H2-P2P plant both the electrolyser and the gas turbine are combined to balance the grid (short and long term). To achieve this, both the electrolyser and the turbine best run at a lower utilisation rate. To find an optimum is not in the scope of this study. For illustration purposes we performed some UF sensitivity studies, that give insight in the economics of a H2-P2P plant (Figure A13-A15).

To understand the economics of a H2-P2P, the multiplication effect needs to be considered. In case of a PEM/CCGT combination, the total efficiency is 39% and in case of PEM/OCGT 24%. The facility's revenues come from the output and not the input. When we assume that the costs of the input electricity is 60 €/MWh, the electricity purchase costs seen from the output is 60/0,39 = 154 €/MWh. This effects is the reason why the electrolyser and electricity purchasing costs (Figure A14 and A15) are of more importance than the storage and gas turbine costs. This is also the reason why a CCGT in all cases is cheaper than the OCGT, because of the higher efficiency of a CCGT that is determining this multiplication effect.

Table A10: Parameters for the hydrogen round trip sensitivity studies

Component PEM/CCGT	Capacity	Efficiency	Case UF100	Case UF50	Case UF20
Electrolyser PEM	100MW	64%	100%	50%	20%
Transport/Storage H2	100MW	95%	100%	50%	20%
Gas turbine (CCGT)	80MW	64%	50%	25%	10%
Component PEM/OCGT	**Capacity**	**Efficiency**	**Case UF100**	**Case UF50**	**Case UF20**
Electrolyser PEM	100MW	64%	100%	50%	20%
Transport/Storage H2	100MW	95%	100%	50%	20%
Gas turbine (OCGT)	50MW	40%	50%	25%	10%

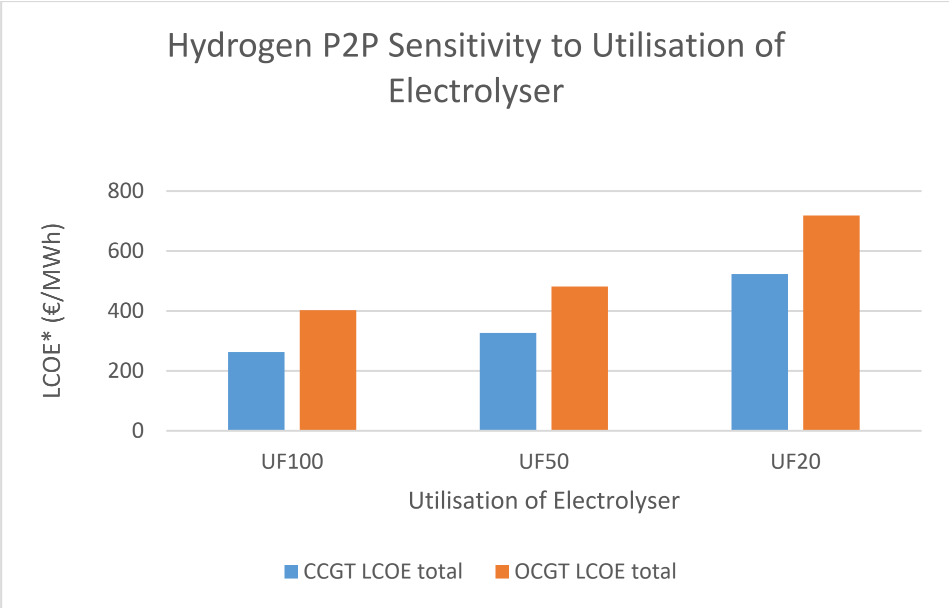


Figure A13: Sensitivity LCOE* of utilisation electrolyser PEM

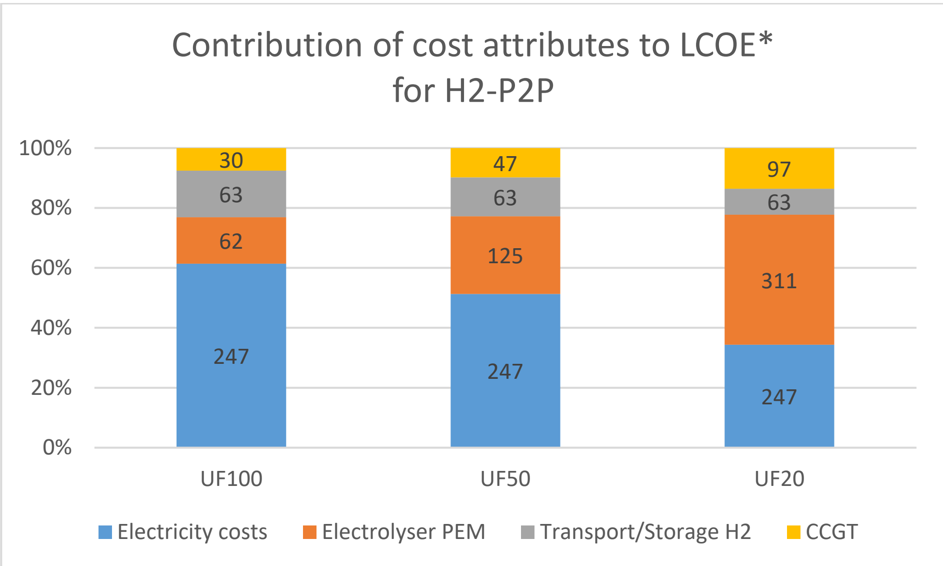


Figure A14: Contribution of the cost components as a percentage of the total

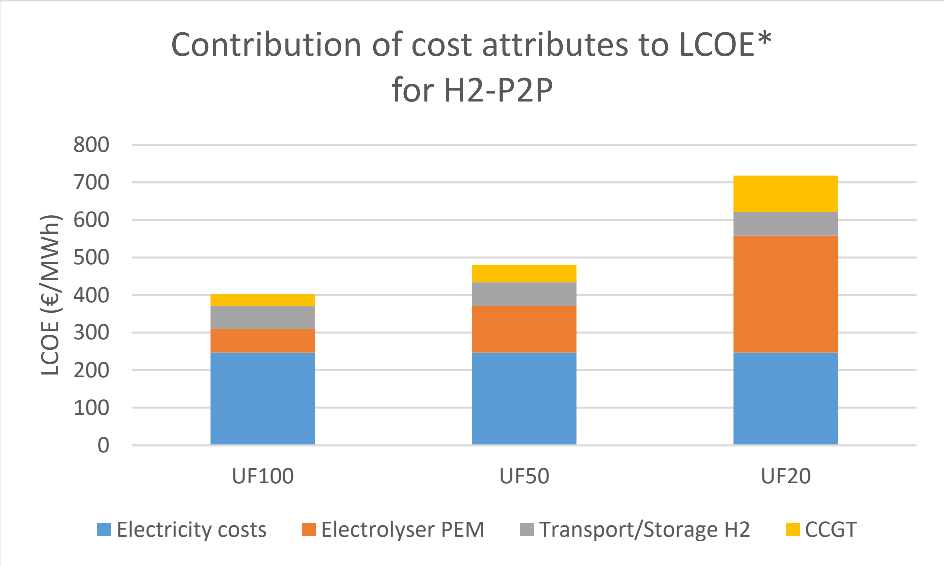


Figure A15: Contribution of cost components