Nuclear Power in a Clean Energy System

Under embargo until 1:00 a.m. Paris time on Tuesday, May 28.

May
2019

Abstract

Nuclear power and hydropower form the backbone of low-carbon electricity generation. Together, they provide three-quarters of global low-carbon generation. Over the past 50 years, the use of nuclear power has reduced carbon dioxide (CO_2) emissions by over 60 gigatonnes – nearly two years' worth of global energy-related emissions. However, in advanced economies, nuclear power has begun to fade, with plants closing and little new investment made, just when the world requires more low-carbon electricity. This report, *Nuclear Power in a Clean Energy System*, focuses on the role of nuclear power in advanced economies and the factors that put nuclear power at risk of future decline. It is shown that without action, nuclear power in advanced economies could fall by two-thirds by 2040. The implications of such a "Nuclear Fade Case" for costs, emissions and electricity security using two *World Energy Outlook* scenarios – the New Policies Scenario and the Sustainable Development Scenario are examined.

Achieving the pace of CO_2 emissions reductions in line with the Paris Agreement is already a huge challenge, as shown in the Sustainable Development Scenario. It requires large increases in efficiency and renewables investment, as well as an increase in nuclear power. This report identifies the even greater challenges of attempting to follow this path with much less nuclear power. It recommends several possible government actions that aim to: ensure existing nuclear power plants can operate as long as they are safe, support new nuclear construction and encourage new nuclear technologies to be developed.

Message from Executive Director

As the leading energy organisation covering all fuels and all technologies, the International Energy Agency (IEA) cannot ignore the role of nuclear power. That is why we are releasing our first report on the subject in nearly two decades in the hope of bringing it back into the global energy debate.

We are highlighting the issue at a critical time. The failure to expand low-carbon electricity generation is the single most important reason the world is falling short on key sustainable energy goals, including international climate targets, as we have highlighted repeatedly this year. The question is what nuclear power's role should be in this transition. Put another way: Can we achieve a clean energy transition without nuclear power?

For advanced economies, nuclear has been the biggest low-carbon source of electricity for more than 30 years, and it has played an important role in the security of energy supplies in several countries. But it now faces an uncertain future as ageing plants begin to shut down in advanced economies, partly because of policies to phase them out but also under pressure from market conditions and regulatory barriers.

Our report, Nuclear Power in a Clean Energy System, assesses its current role and considers its mid- and long-term outlook, especially in competitive electricity systems.

This report is part of an expanding view the IEA is taking of the global energy system. In June, we will be releasing another analysis on the future of hydrogen, at the request of the Japanese presidency of the G20 this year. We are also holding various high-level meetings to underscore the critical elements needed for a successful transition – including a high-level ministerial conference in Dublin next month on energy efficiency and another ministerial meeting on systems integration of renewables in Berlin in September 2019.

Government policies have so far failed to value the low-carbon and energy security attributes of nuclear power, making even the continued operation of existing plants challenging. New projects have been plagued by cost overruns and delays.

These trends mean nuclear power could soon be on the decline worldwide. If governments don't change their current policies, advanced economies will be on track to lose two-thirds of their current nuclear fleet, risking a huge increase in CO_2 emissions.

Without action to provide more support for nuclear power, global efforts to transition to a cleaner energy system will become drastically harder and more costly. Wind and solar energy need to play a much greater role in order for countries to meet sustainability goals, but it is extremely difficult to envisage them doing so without help from nuclear power.

Some countries have decided to refrain from using nuclear power, and their choice is well respected. However, those that aim to continue using it represent the majority of global energy use and CO_2 emissions. As governments seek to achieve a diversified mix in their energy transitions, the IEA remains ready to provide support with data, analysis and real-world solutions.

Dr Fatih Birol
Executive Director
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Executive summary

Nuclear power can play an important role in clean energy transitions

Nuclear power today makes a significant contribution to electricity generation, providing 10% of global electricity supply in 2018. In advanced economies,[1] nuclear power accounts for 18% of generation and is the largest low-carbon source of electricity. However, its share of global electricity supply has been declining in recent years. That has been driven by advanced economies, where nuclear fleets are ageing, additions of new capacity have dwindled to a trickle, and some plants built in the 1970s and 1980s have been retired. This has slowed the transition towards a clean electricity system. Despite the impressive growth of solar and wind power, the overall share of clean energy sources in total electricity supply in 2018, at 36%, was the same as it was 20 years earlier because of the decline in nuclear. Halting that slide will be vital to stepping up the pace of the decarbonisation of electricity supply.

A range of technologies, including nuclear power, will be needed for clean energy transitions around the world. Global energy is increasingly based around electricity. That means the key to making energy systems clean is to turn the electricity sector from the largest producer of CO_2 emissions into a low-carbon source that reduces fossil fuel emissions in areas like transport, heating and industry. While renewables are expected to continue to lead, nuclear power can also play an important part along with fossil fuels using carbon capture, utilisation and storage. Countries envisaging a future role for nuclear account for the bulk of global energy demand and CO_2 emissions. But to achieve a trajectory consistent with sustainability targets – including 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 clean sources by 2040, compared with just 36% today. Along with massive investments in efficiency and renewables, the trajectory would need an 80% increase in global nuclear power production by 2040.

Nuclear power plants contribute to electricity security in multiple ways. Nuclear plants help to keep power grids stable. To a certain extent, they can adjust their operations to follow demand and supply shifts. As the share of variable renewables like wind and solar photovoltaics (PV) rises, the need for such services will increase. Nuclear plants can help to limit the impacts from seasonal fluctuations in output from renewables and bolster energy security by reducing dependence on imported fuels.

Lifetime extensions of nuclear power plants are crucial to getting the energy transition back on track

Policy and regulatory decisions remain critical to the fate of ageing reactors in advanced economies. The average age of their nuclear fleets is 35 years. The European Union and the United States have the largest active nuclear fleets (over 100 gigawatts each), and they are also among the oldest: the average reactor is 35 years old in the European Union and 39 years old in the United States. The original design lifetime for operations was 40 years in most cases. Around one-quarter of the current nuclear capacity in advanced economies is set to be shut down by 2025 – mainly because of policies to reduce nuclear's role. The fate of the remaining capacity depends on decisions about lifetime extensions in the coming years. In the United States, for example, some 90 reactors have 60-year operating licenses, yet several have

[1] Advanced economies consist of Australia, Canada, Chile, the 28 members of the European Union, Iceland, Israel, Japan, Korea, Mexico, New Zealand, Norway, Switzerland, Turkey and the United States.

already been retired early and many more are at risk. In Europe, Japan and other advanced economies, extensions of plants' lifetimes also face uncertain prospects.

Economic factors are also at play. Lifetime extensions are considerably cheaper than new construction and are generally cost-competitive with other electricity generation technologies, including new wind and solar projects. However, they still need significant investment to replace and refurbish key components that enable plants to continue operating safely. Low wholesale electricity and carbon prices, together with new regulations on the use of water for cooling reactors, are making some plants in the United States financially unviable. In addition, markets and regulatory systems often penalise nuclear power by not pricing in its value as a clean energy source and its contribution to electricity security. As a result, most nuclear power plants in advanced economies are at risk of closing prematurely.

The hurdles to investment in new nuclear projects in advanced economies are daunting

What happens with plans to build new nuclear plants will significantly affect the chances of achieving clean energy transitions. Preventing premature decommissioning and enabling longer extensions would reduce the need to ramp up renewables. But without new construction, nuclear power can only provide temporary support for the shift to cleaner energy systems.

The biggest barrier to new nuclear construction is mobilising investment. Plans to build new nuclear plants face concerns about competitiveness with other power generation technologies and the very large size of nuclear projects that require billions of dollars in upfront investment. Those doubts are especially strong in countries that have introduced competitive wholesale markets.

A number of challenges specific to the nature of nuclear power technology may prevent investment from going ahead. The main obstacles relate to the sheer scale of investment and long lead times; the risk of construction problems, delays and cost overruns; and the possibility of future changes in policy or the electricity system itself. There have been long delays in completing advanced reactors that are still being built in Finland, France and the United States. They have turned out to cost far more than originally expected and dampened investor interest in new projects. For example, Korea has a much better record of completing construction of new projects on time and on budget, although the country plans to reduce its reliance on nuclear power.

Without nuclear investment, achieving a sustainable energy system will be much harder

A collapse in investment in existing and new nuclear plants in advanced economies would have implications for emissions, costs and energy security. In the case where no further investments are made in advanced economies to extend the operating lifetime of existing nuclear power plants or to develop new projects, nuclear power capacity in those countries would decline by around two-thirds by 2040. Under the current policy ambitions of governments, while renewable investment would continue to grow, gas and, to a lesser extent, coal would play significant roles in replacing nuclear. This would further increase the importance of gas for countries' electricity security. Cumulative CO_2 emissions would rise by 4 billion tonnes by 2040, adding to the already considerable difficulties of reaching emissions targets. Investment needs would increase by almost USD 340 billion as new power generation capacity and supporting grid infrastructure is built to offset retiring nuclear plants.

Achieving the clean energy transition with less nuclear power is possible but would require an extraordinary effort. Policy makers and regulators would have to find ways to create the conditions to spur the necessary investment in other clean energy technologies. Advanced economies would face a sizeable shortfall of low-carbon electricity. Wind and solar PV would be the main sources called upon to replace nuclear, and their pace of growth would need to accelerate at an unprecedented rate. Over the past 20 years, wind and solar PV capacity has increased by about 580 GW in advanced economies. But in the next 20 years, nearly five times that much would need to be built to offset nuclear's decline. For wind and solar PV to achieve that growth, various non-market barriers would need to be overcome such as public and social acceptance of the projects themselves and the associated expansion in network infrastructure. Nuclear power, meanwhile, can contribute to easing the technical difficulties of integrating renewables and lowering the cost of transforming the electricity system.

With nuclear power fading away, electricity systems become less flexible. Options to offset this include new gas-fired power plants, increased storage (such as pumped storage, batteries or chemical technologies like hydrogen) and demand-side actions (in which consumers are encouraged to shift or lower their consumption in real time in response to price signals). Increasing interconnection with neighbouring systems would also provide additional flexibility, but its effectiveness diminishes when all systems in a region have very high shares of wind and solar PV.

Offsetting less nuclear power with more renewables would cost more

Taking nuclear out of the equation results in higher electricity prices for consumers. A sharp decline in nuclear in advanced economies would mean a substantial increase in investment needs for other forms of power generation and the electricity network. Around USD 1.6 trillion in additional investment would be required in the electricity sector in advanced economies from 2018 to 2040. Despite recent declines in wind and solar costs, adding new renewable capacity requires considerably more capital investment than extending the lifetimes of existing nuclear reactors. The need to extend the transmission grid to connect new plants and upgrade existing lines to handle the extra power output also increases costs. The additional investment required in advanced economies would not be offset by savings in operational costs, as fuel costs for nuclear power are low, and operation and maintenance make up a minor portion of total electricity supply costs. Without widespread lifetime extensions or new projects, electricity supply costs would be close to USD 80 billion higher per year on average for advanced economies as a whole.

Strong policy support is needed to secure investment in existing and new nuclear plants

Countries that have kept the option of using nuclear power need to reform their policies to ensure competition on a level playing field. They also need to address barriers to investment in lifetime extensions and new capacity. The focus should be on designing electricity markets in a way that values the clean energy and energy security attributes of low-carbon technologies, including nuclear power.

Securing investment in new nuclear plants would require more intrusive policy intervention given the very high cost of projects and unfavourable recent experiences in some countries. Investment policies need to overcome financing barriers through a combination of long-term contracts, price guarantees and direct state investment.

Interest is rising in advanced nuclear technologies that suit private investment such as small modular reactors (SMRs). This technology is still at the development stage. There is a case for governments to promote it through funding for research and development, public-private partnerships for venture capital and early deployment grants. Standardisation of reactor designs would be crucial to benefit from economies of scale in the manufacturing of SMRs.

Continued activity in the operation and development of nuclear technology is required to maintain skills and expertise. The relatively slow pace of nuclear deployment in advanced economies in recent years means there is a risk of losing human capital and technical know-how. Maintaining human skills and industrial expertise should be a priority for countries that aim to continue relying on nuclear power.

Policy recommendations

The following recommendations are directed at countries that intend to retain the option of nuclear power. The IEA makes no recommendations to countries that have chosen not to use nuclear power in their clean energy transition and respects their choice to do so.

- **Keep the option open:** Authorise lifetime extensions of existing nuclear plants for as long as safely possible.

- **Value dispatchability:** Design the electricity market in a way that properly values the system services needed to maintain electricity security, including capacity availability and frequency control services. Make sure that the providers of these services, including nuclear power plants, are compensated in a competitive and non-discriminatory manner.

- **Value non-market benefits:** Establish a level playing field for nuclear power with other low-carbon energy sources in recognition of its environmental and energy security benefits and remunerate it accordingly.

- **Update safety regulations:** Where necessary, update safety regulations in order to ensure the continued safe operation of nuclear plants. Where technically possible, this should include allowing flexible operation of nuclear power plants to supply ancillary services.

- **Create an attractive financing framework:** Set up risk management and financing frameworks that can help mobilise capital for new and existing plants at an acceptable cost, taking the risk profile and long time horizons of nuclear projects into consideration.

- **Support new construction:** Ensure that licensing processes do not lead to project delays and cost increases that are not justified by safety requirements. Support standardisation and enable learning-by-doing across the industry.

- **Support innovative new reactor designs:** Accelerate innovation in new reactor designs, such as small modular reactors (SMRs), with lower capital costs and shorter lead times and technologies that improve the operating flexibility of nuclear power plants to facilitate the integration of growing wind and solar capacity into the electricity system.

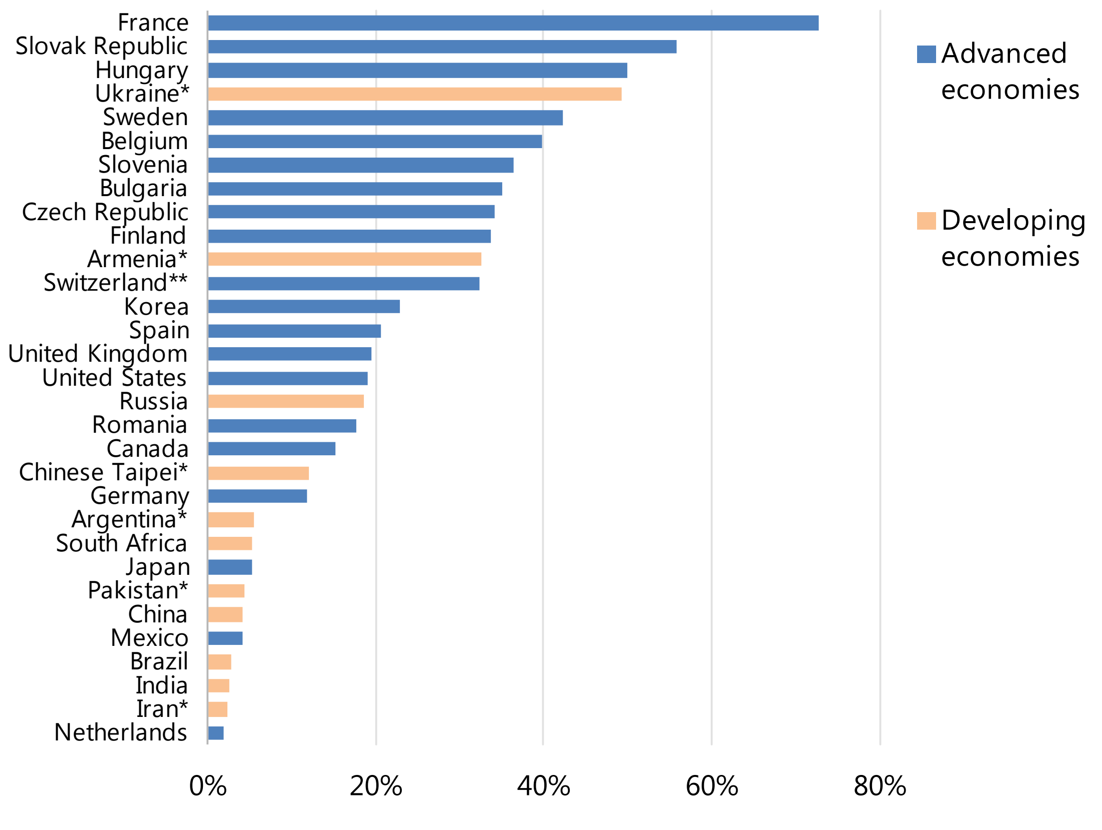
- **Maintain human capital:** Protect and develop the human capital and project management capabilities in nuclear engineering.

1. Nuclear power today

Role of nuclear power in global electricity supply

Nuclear power makes a significant contribution to global electricity generation, providing 10% of global electricity supply in 2018. As of May 2019, there were 452 nuclear power reactors in operation in 31 countries around the world, with a combined capacity of about 400 gigawatts (GW). Nuclear power plays a much bigger role in advanced economies, where it makes up 18% of total generation. In 2018, it provided over one-half of the power in France, the Slovak Republic and Hungary (Figure 1). The European Union obtained 25% of its electricity supply from nuclear reactors. Korea and the United States similarly relied on nuclear power for about one-fifth of their electricity. In Japan, nuclear power made up about 5% of electricity generation in 2018. Before the accident at Fukushima Daiichi in 2011, it had been on an equal footing with coal and gas as the largest sources of electricity in Japan at around 30%.

Figure 1. Share of nuclear power in total electricity generation by country, 2018

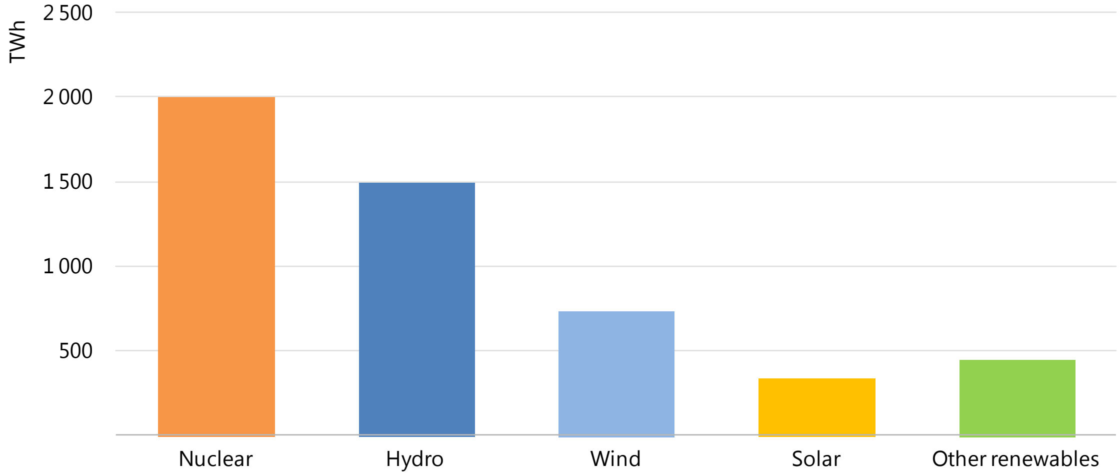


*2016 data; **2017 data.

Nuclear power is an important low-carbon source of electricity in many advanced economies.

In advanced economies as a group, nuclear power is the largest low-carbon source of electricity, providing 40% of all low-carbon generation (Figure 2). Nuclear generation totalled just over 2 000 terawatt hours (TWh) in 2018, outstripping hydropower by one-third, and representing nearly double the combined output of solar and wind projects. Nuclear power is the largest low-carbon source of electricity in 13 individual advanced economies: Belgium, Bulgaria, the Czech Republic, Finland, France, Hungary, Korea, the Slovak Republic, Slovenia, Spain, Sweden, the United Kingdom and the United States.

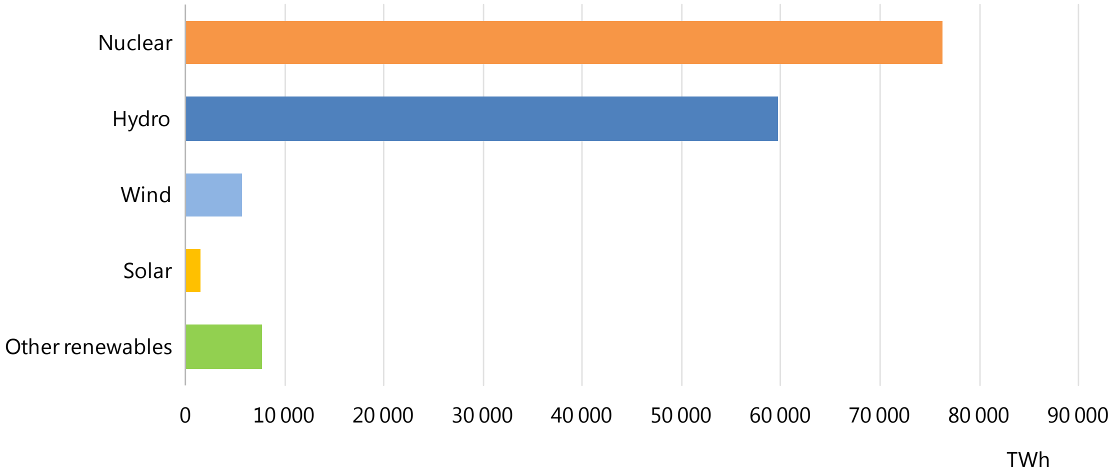
Figure 2. Low-carbon electricity generation in advanced economies by source, 2018



Nuclear power is the leading low-carbon source of electricity in advanced economies today.

Over the past 50 years or so, nuclear power has provided around one-half of all low-carbon electricity in advanced economies. During the period from 1971 to 2018, nuclear power provided some 76 000 TWh of zero-emissions electricity – more than ten times the total output of wind and solar combined (Figure 3).

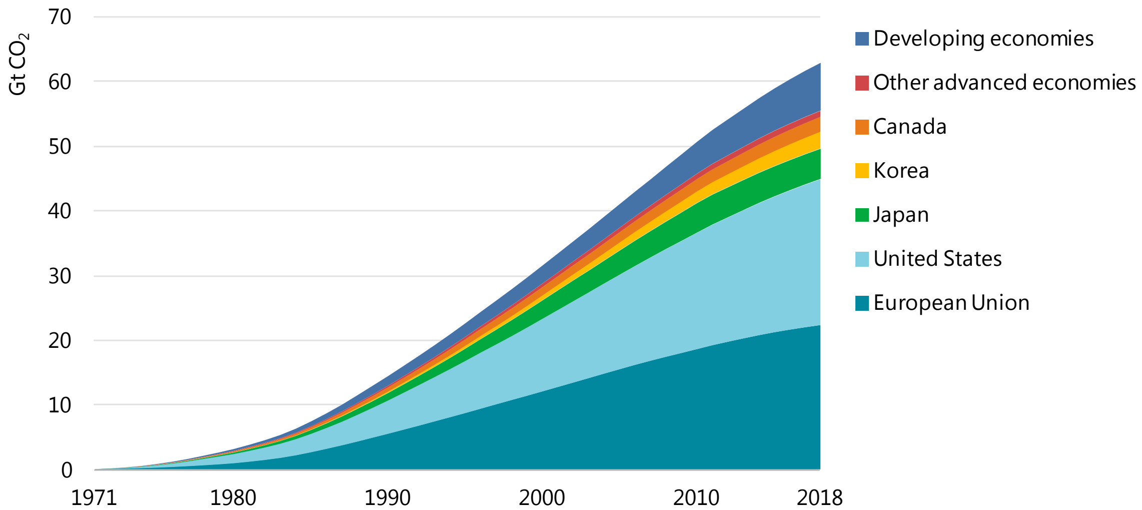
Figure 3. Cumulative low-carbon electricity generation in advanced economies by source, 1971-2018



Nuclear power and hydropower account for 90% of low-carbon electricity since the 1970s.

Nuclear power has helped to slow the long-term increase in emissions of carbon dioxide (CO_2) over the last half-century, particularly in advanced economies. Globally, nuclear power output avoided 63 gigatonnes of carbon dioxide ($GtCO_2$) from 1971 to 2018 (Figure 4). Without nuclear power, emissions from electricity generation would have been almost 20% higher, and total energy-related emissions 6% higher, over that period. Nearly 90% of the avoided emissions were in advanced economies. The European Union and United States each avoided about 22 $GtCO_2$ – equal to more than 40% of total power sector emissions in the European Union and one-quarter in the United States. Without nuclear power, emissions from electricity generation would have been 25% higher in Japan, 45% higher in Korea and over 50% higher in Canada over the period 1971-2018.

Figure 4. Cumulative CO_2 emissions avoided by global nuclear power to date

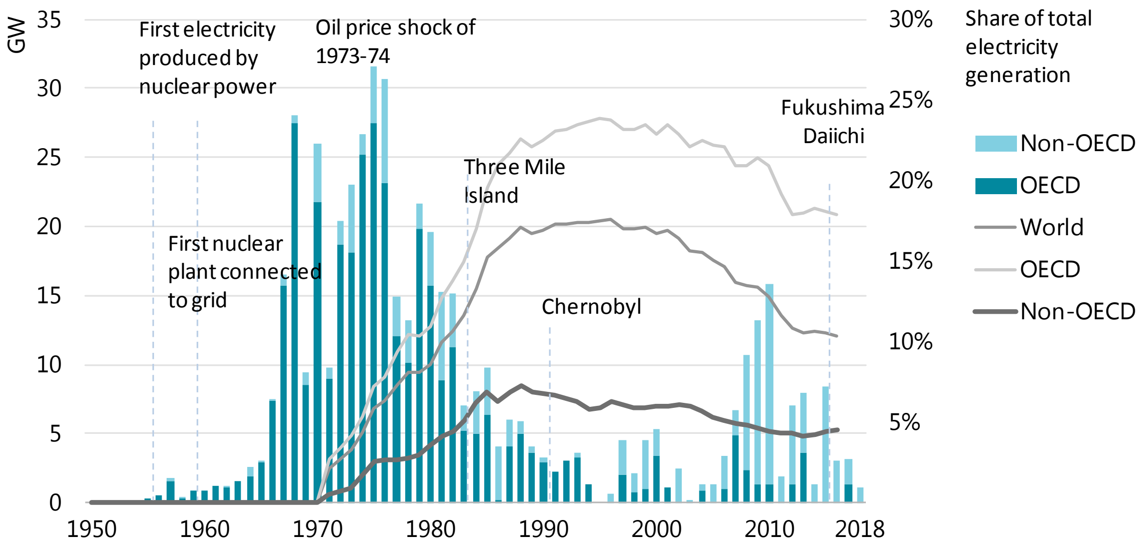


Without nuclear power, global CO_2 emissions from electricity generation would have been almost 20% higher over the last half-century.

Nuclear reactors in advanced economies are ageing

With a sharp slow-down in the rate of commissioning of nuclear reactors in advanced economies in recent years, the average age of the world's fleet of reactors has been rising, despite increased capacity in the developing economies. Most of the nuclear power plants now in operation in advanced economies were built in the 1970s and 1980s. In the early 1970s, nearly 80% of electricity generation came from coal, oil and gas, with hydropower making up most of the rest. The construction of nuclear reactors world wide surged in the 1960s and 1970s (Figure 5). In the peak years of 1974-75, over 30 GW per year was added – equivalent to nearly 3.5% of total global electricity demand at the time and about twice the share that electricity generated from renewable sources of energy (renewable electricity) is adding today. Most of this capacity was built in advanced economies. This wave of construction resulted in a rapid increase in the share of nuclear power in the overall electricity generation mix. By the mid-1990s, the share reached 18% world wide and 23% in advanced economies.

Figure 5. Reactor construction starts and share of nuclear power in total electricity generation



Note: OECD = Organisation for Economic Co-operation and Development.

Sources: IAEA (2019), Power Reactor Information System (PRIS) (database); IEA (2018a), Electricity Information 2018 (database).

Most of the nuclear reactors in operation today in advanced economies were built before 1990.

The number of construction starts for new nuclear power plants slowed dramatically in the 1980s, particularly in advanced economies outside Japan and Korea, and had slowed to a trickle by the late 1990s. Construction has picked up since then, with most new projects being located in developing economies, led by the People's Republic of China ("China") and India. There are now 54 reactors under construction (Table 1), of which 40 are in the developing economies, led by China, with 11 units, India (7), the Russian Federation ("Russia") (6) and the United Arab Emirates (4). In advanced economies, Korea has the most units under construction (4), followed by Japan (2), the Slovak Republic (2), the United States (2), and Finland, France, Turkey and the United Kingdom (1 each). The recent wave of construction starts in the developing countries is on a smaller scale than that in advanced economies four decades earlier, so the share of nuclear power in the generation fuel mix in the developing economies has grown more modestly, reaching 6% in 2018.

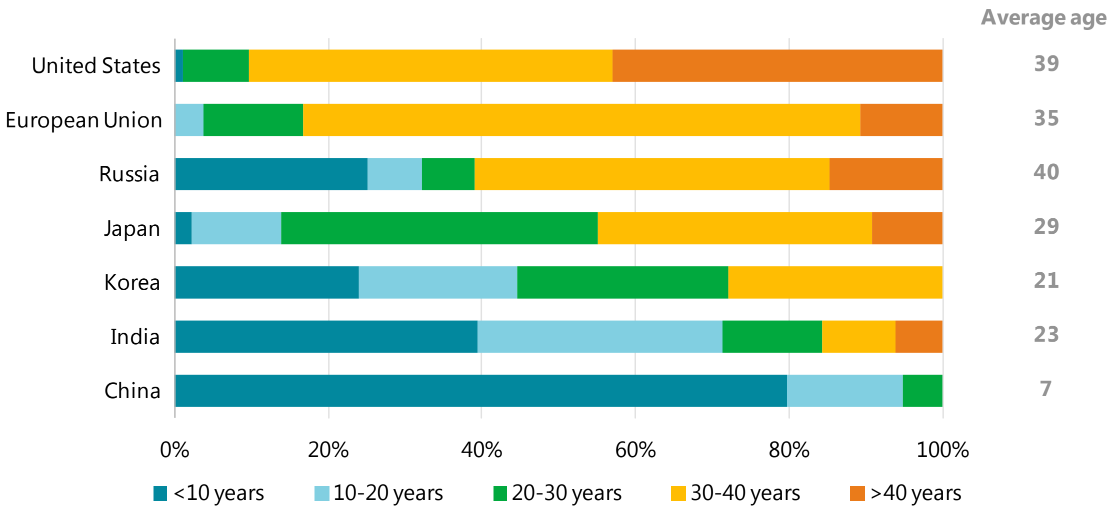
Table 1. Nuclear power generating gross capacity by country, May 2019

Country	Existing gross capacity (GW)	Gross capacity under construction (GW)
Advanced economies	**312**	**18**
Belgium	6	0
Bulgaria	2	0
Canada	14	0
Czech Republic	4	0
Finland	3	2
France	66	2
Germany	10	0
Hungary	2	0
Japan	39	3
Korea	25	6
Mexico	2	0
Netherlands	1	0
Romania	1	0
Slovak Republic	2	1
Slovenia	1	0
Spain	7	0
Sweden	9	0
Switzerland	3.5	0
Turkey	0	1
United Kingdom	10	2
United States	105	2.5
Developing economies	**110**	**41**
China	46	12
India	7	5
Russia	30	5
Other developing economies	27	19
World	**422**	**59**

Source: IAEA (2019), Power Reactor Information System (PRIS) (database).

The world's nuclear fleet is ageing due to the large construction wave in the 1970s and 1980s and the more modest rate of construction in recent years. Globally, the average age of nuclear capacity stands at 32 years. In advanced economies, it is 35 years. Outside Japan and Korea, nearly 90% of the nuclear reactors in advanced economies are more than 30 years old. By contrast, the average age in developing economies is just 25 years. Excluding Russia, most reactors in those developing economies are less than 20 years old. China, which accounts for most of the nuclear power plants built during the past two decades, has a particularly young fleet (Figure 6).

Figure 6. Age profile of nuclear power capacity in selected countries/regions



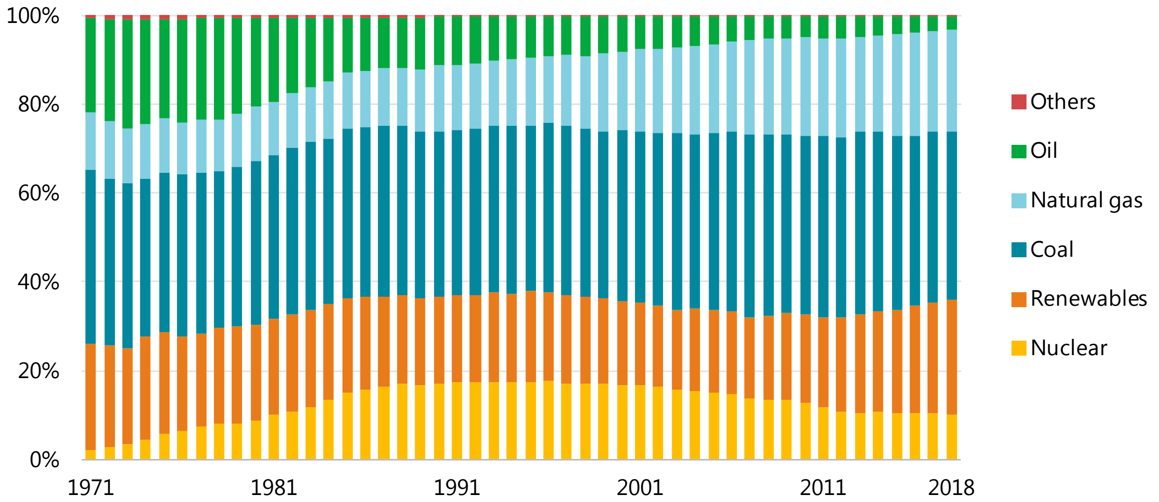
Source: IAEA (2019), Power Reactor Information System (PRIS) (database).

Most nuclear power plants in the European Union and the United States are more than 30 years old, while plants in developing countries – notably China – are much younger.

The operators of many older nuclear plants have been investing in improvements in their operational performance and extending their operating lifetimes. In some cases, this has involved increasing capacity. The lifetimes of several plants have already been extended well beyond those originally planned, and many others will soon face extension decisions. Most nuclear power plants have a nominal design lifetime of 40 years, but engineering assessments have established that many can operate safely for longer. In most cases, such extensions (typically to 50 or 60 years) require significant investment in the replacement and refurbishment of key components to allow units to continue to operate safely.

In the United States, where 90 of the 98 reactors in operation have already had their operating licences renewed from 40 to 60 years, the Nuclear Regulatory Commission (NRC) and the industry are focusing on "subsequent license renewals", which would authorise plants to operate for up to 80 years. The NRC has developed guidance for staff and licensees specifically for the subsequent renewal period. In Europe, several plants have recently obtained licence extensions or are on the verge of obtaining them. For example, plants recently obtained 20 year extensions in the Czech Republic, Finland and Hungary, while three reactors in Belgium have had their operations extended by ten years. In France, licences have so far been renewed for ten years on a rolling basis where they meet safety requirements. France's nuclear safety authority plans to issue a generic ruling on lifetime extensions for the 900 megawatt (MW) series of plants operated by state-controlled Électricité de France (EDF) by the end of 2020, given that final approvals would be further issued on a reactor-by-reactor basis. In Sweden, decisions have recently been taken to extend the operational lives of five reactors. In Canada, operators are pursuing lifetime extensions for most of the country's nuclear fleet.

Figure 7. Share of energy sources in global electricity generation



The decline in nuclear power's share in electricity generation has entirely offset the growth in the share of renewables since the late 1990s.

The share of nuclear power in the world's electricity generating fuel mix has fallen steadily in recent years, from a peak of around 18% in the mid-1990s to 10% in 2018 (Figure 7). This has slowed the transition towards a low-carbon electricity system. Despite the impressive growth of solar and wind power output in recent years, the overall share of low-carbon energy sources in total electricity supply in 2018, at 36%, was the same as it was 20 years earlier. In other words, the eight percentage point fall in the contribution of nuclear power over the past two decades entirely offset the increase in the share of renewables.

Nuclear power helps to bolster energy security

Nuclear power can contribute to energy security in three main ways. First, nuclear power provides diversity in electricity supply and in primary energy supply. For countries lacking their own domestic energy resources, reliance on nuclear power can reduce import dependence and enhance supply security. For example, in Japan, which must import all its fuels for non-renewable power generation, it is estimated that fuel imports over the period 1965-2010 were reduced by at least 14.5 trillion yen (USD 132 billion [United States dollars]) due to the development of nuclear power. Several countries in Central and Eastern Europe see nuclear power as an important means of enhancing their energy security (Box 1). Second, the relatively low fuel cost of nuclear power means that the operating costs of plants are less subject to fuel price volatility than fossil fuel plants, which are the other conventional source of power (a 50% rise in the fuel cost results in a mere 5% increase in the overall cost of generating electricity with nuclear power). Third, nuclear power plants provide reliability services as a dispatchable form of generation, i.e. output can be dispatched to the system as and when required.

Box 1. Nuclear power and energy security in Central and Eastern Europe

Several countries in Central and Eastern Europe have robust policies to support nuclear power. The share of nuclear power in electricity generation is above 30% in the Slovak Republic, and over 50% in the Czech Republic and Hungary – among the highest shares in the world. The policy stance is also supportive in Bulgaria and Romania. Nuclear power does not yet play a role in Poland, but there are plans to build the country's first reactor. There are some common factors that make nuclear power an attractive option across the region.

Coal-fired generation is expected to decline. Six countries (the Czech Republic, Hungary, Poland, Romania, the Slovak Republic and Slovenia) make up just 13% of total European Union (EU) electricity demand but over one-third of coal-fired generation. Their coal-fired plants are covered by EU climate policy, notably a carbon penalty under the European Union Emissions Trading System (EU-ETS), which raises questions about plant long-term viability, especially as most are old and inefficient. Given EU climate goals, there is no realistic prospect of any major investment in new coal-fired plants, so the region is set to lose a substantial amount of dispatchable coal capacity over the next two decades.

Gas supply security concerns. The region remains highly dependent on imports of gas from Russia. Apart from in Romania, there is little prospect of new domestic production. Disruptions in the supply of Russian gas through Ukraine in 2006 and 2009 highlighted the region's energy insecurity. While major progress has been made since then in building new gas interconnectors, reverse flow capability and increasing access to liquefied natural gas (LNG), governments in the region still regard their gas import dependency as an energy security risk. This limits the policy appetite for gas-fired power generation. Phasing out nuclear power and replacing it with gas would increase gas consumption by 37%, all of which would need to be imported.

Limited renewable energy resources. Prospects for the expansion of renewables are less encouraging than in the rest of Europe. There has been significant investment in wind power on the Black Sea coast of Romania, and the Czech Republic experienced one of the earliest booms in solar investment in 2010/11. But large parts of the region, including the Czech Republic, Hungary and the Slovak Republic, have a weak wind potential. Northern Poland has better resources, but there are considerable barriers related to land use and social acceptance. While the share of renewables in electricity generation will undoubtedly grow, official energy strategies in the region tend to regard 100% renewables as unrealistic and envisage nuclear power making a sizeable contribution to decarbonisation.

Social acceptance. Public opinion remains broadly supportive of nuclear power across the region; in most countries, there is a cross-party pronuclear stance. This makes it more feasible to implement nuclear projects that span several political cycles.

Domestic nuclear capabilities. In the Czech Republic, Hungary and the Slovak Republic, nuclear power plants have operated for many years. Consequently, there is a skilled workforce and well-developed expertise on nuclear engineering and operations. In particular, the Czech Republic has long-standing capabilities in manufacturing and supplying components for nuclear power plants. In contrast, there is virtually no manufacturing of renewable equipment anywhere in Central or Eastern Europe; nearly all the wind turbines and solar panels in use are imported. The existence of human capital and an industrial base makes it more attractive for governments in the region to retain nuclear in their energy mix.

The dispatchability of nuclear power makes it valuable to the electricity system. Dispatchable capacity contributes to system reliability and adequacy (the power system's ability to meet demand in the long term, ensuring there will be enough supply to meet demand with a high degree of certainty at all times). In practice, the relatively low fuel costs of nuclear power plants compared with plants that run on fossil fuels mean that, in many markets, they are better suited for baseload generation, providing power at full output in a continuous fashion throughout the year (except during maintenance shut-downs) rather than modulating their production according to the demand for electricity. However, nuclear power plants can be operated in a flexible manner, although this may require minor changes in plant design. In France, the cost-competitiveness of nuclear generation led to it attaining a high share in the overall generation fuel mix (around 75% since the 1980s) and has thus encouraged the incorporation of flexibility into reactor designs to allow some plants to ramp up and down their output quickly at short notice. German nuclear power plants also have these capabilities, allowing them to accommodate increasing shares of variable renewable energy (VRE). Such capabilities will become increasingly important as the overall share of VRE continues to grow (see below).

Prospects for existing plants in advanced economies

Policy decisions remain critical to the fate of ageing reactors

The rate at which the existing nuclear fleet of nuclear reactors in advanced economies is retired relies on policy and regulatory decisions, as well as economic factors (see the next chapter). As of May 2019, there were 318 reactors operating in those countries with a total capacity of 315 GW. This capacity is set to decline as retirements gather pace with ageing of the fleet: around one-quarter of capacity is set to be shut down by 2025. Phase-out policies are responsible for most of the recent retirements and those scheduled for the next few years. Over 15 GW of nuclear capacity is in the process of being phased out due to political decisions in Belgium and Germany. Switzerland has also decided to phase out nuclear power, although no dates have been set yet. Korea has set limits on the lifetime of existing plants that would see 12.5 GW retire by 2040. An agreement among Spanish utilities would see all the country's nuclear power plants close between 2028 and 2035 (Box 2). France, which has the largest nuclear power capacity in Europe, envisages a continuing long-term role for nuclear power, but it is seeking to reduce its share in the generation fuel mix to 50% by 2035.

Box 2. Agreement to close nuclear power plants in Spain

Spain has seven reactors with a total capacity of 7.4 GW (see the table below). Most of the reactors are co-owned by Spanish utilities, mainly Endesa and Iberdrola, which together hold 90% of the nuclear capacity. Following lengthy discussion about the future of existing reactors in Spain, an agreement was reached in March 2019 that all nuclear power plants would close between 2027 and 2035 – effectively limiting lifetimes of all the plants to 44-47 years. The deadline for deciding on an extension for the Almaraz I plant was March 2019, which led the utilities to seek a decision on extensions for all the plants. The agreement has a clause whereby the plants could shut down early should the Nuclear Safety Body impose onerous conditions on the investments needed. In addition, the new government that took office in May 2018 appears less favourable to nuclear power. Unless something unexpected occurs, this calendar will be respected by all stakeholders.

Agreed closures of nuclear power plants in Spain

Unit	Gross capacity (MW)	Year commissioned	Year scheduled for closure
Almaraz I	1 049	1983	2027
Almaraz II	1 044	1984	2028
Ascó I	1 032	1984	2030
Cofrentes	1 092	1985	2030
Ascó II	1 027	1986	2032
Vandellós II	1 087	1988	2035
Trillo	1 066	1988	2035

The decision to seek limited lifetime extensions was motivated partly by economic factors. In December 2012, in the middle of discussions about lifetime extensions, the Spanish Parliament approved new taxes on the production and storage of spent nuclear fuel and radioactive waste. These taxes came on top of existing levies aimed at funding the management of nuclear waste and the decommissioning of nuclear facilities. Due to the increased tax burden and low wholesale electricity prices, the economic case for investing in the plants to obtain lifetime extensions has been called into question. Despite this, an analysis prepared by the Massachusetts Institute of Technology suggests that it would bring economic and environment benefits.

Regulatory decisions about approvals required to extend operations at plants from the central regulatory bodies and local authorities will affect the rate of closures. Some 40 GW of nuclear power capacity in advanced economies is vulnerable to regulatory risks in the near term (Table 2). In the case of France, of the country's 58 reactors, which have a combined capacity of 66 GW, one-third must pass their fourth ten-year safety inspections before 2025 to continue operating and two-thirds must do so before 2030. In addition, concerns about the safety of old plants could lead to longer outages, as has occurred in recent years at plants in Belgium, France, Korea and the United Kingdom.

Table 2. Near-term regulatory decisions for existing nuclear reactors by country

Country	Decision type	Comment	Capacity (GW)
United States	Extension of operating licence	Operating reactors yet to receive initial 20 year extension: three more applications are expected	4.9
France	Extension of operating licence	Eighteen reactors must pass inspection before 2025 to	17

		continue operations	
Japan	Pending decisions to restart reactors	Ten reactors are under review to restart operations	9.4
Mexico	Extension of operating licence	Application submitted in 2015 pending for Laguna Verde	1.5
Spain	Extension of operating licence	Operating licences for all eight reactors expire by 2025	7.4

In the United States, the length of time that operations at ageing nuclear power plants can be extended is a major uncertainty. There are 98 reactors in operation with a total capacity of 105 GW and an average age of nearly 40 years. By 2030, 24 GW (nearly one-quarter) of this capacity will need to obtain extensions to operating licences or shut down; another 62 GW will reach the end of its operating licences by 2040. Eight reactors have not yet received an initial 20 year operational lifetime extension: one decision is pending and three further applications are expected soon. As of May 2019, six reactors had submitted applications to extend operations beyond the end of their current second licences that expire in the early 2030s, which would allow operations until 80 years.

In Japan, the central question on the future of existing nuclear power plants is how many of the 55 nuclear reactors that were taken off line shortly after the accident at Fukushima Daiichi in 2011 will ever be allowed to restart. Nine reactors have already been brought back into operation having received Nuclear Regulation Authority approval; another six have obtained the approval but have not yet been restarted. Two others are under construction. If no other reactors are brought back on line, the share of nuclear in electricity supply in Japan is expected to rise from 3% in 2017 to about 10% in 2030. In this case, achieving the target of a 44% share of zero-emissions energy sources in power generation in the same year under the Fifth Strategic Energy Plan (updated in 2018) will be difficult. Of the 44% share, 20-22% is expected to come from nuclear power. Another ten reactors with a combined capacity of 12.2 GW that are under regulatory review could provide an additional 80-90 TWh of electricity per year (7-8% of the total supply), making the zero-emissions target much more achievable. This level of output still falls well below the historical contribution of nuclear power: in the decade before the accident in 2011, nuclear power provided 26-31% of electricity supply each year. Even if all this capacity were brought back on line, without further operational lifetime extensions, nuclear power would provide just 2% of the electricity supply in 2040, as more than one-half of the nuclear fleet was built before 1990. An additional nine reactors with a combined capacity of 8.8 GW have not yet applied for licences to restart.

Owing to longer outages, Japanese nuclear power plants have had relatively short operating hours than those of the same age in other countries. Considering the long period that they were required to be off line after the Fukushima Daiichi accident, Japanese nuclear power plants would end up with much shorter operating periods than those in other countries if required to retire at 40 years. From a technical point of view, the ageing of the reactor vessel is primarily determined by the period when chain reactions are taking place in it; an idle reactor ages slower than one that is operated continuously.

Market pressures may lead to early retirements

Economic factors (notably electricity market conditions) are affecting the continued operation of existing nuclear power plants, particularly in the United States. Economic pressures on power generators in advanced economies have increased in recent years with the introduction of competitive wholesale electricity markets. Nuclear plants, like other conventional power plants in these markets, are now exposed to market conditions. Many plants were built and brought into operation at a time when the price of wholesale power was regulated, usually on the basis of cost, which protected them from the risk of unexpectedly low prices and short-falls in revenue.

Across advanced economies, weak electricity demand, rapid growth in renewables-based power supply and low natural gas prices in the United States are putting pressure on the financial performance of existing conventional power generators, including nuclear plants. Although the operating costs of nuclear plants are relatively low compared to other types of power plants, significant ongoing investments are often required (especially to obtain an extension to an operating licence), which operators may not be able to recover if wholesale prices are too low. In the United States, two nuclear units have been retired over the past three years and as many as nine more units could be retired in the next three years, largely for economic reasons. In some cases, the introduction of carbon pricing and rising carbon prices has provided some respite to nuclear power generators. The impact of competition in electricity markets on nuclear plants is explored in more detail in the next chapter.

Barriers to investment in new nuclear power plants

The prospects for new nuclear power projects remain highly uncertain. Some countries have decided to prohibit investment in new projects and phase out existing capacity in a progressive manner, though the timing of the closure of plants remains unclear in some cases. Others envisage a long-term role for nuclear power in their energy system. The countries that fall into the second category account for most of the global electricity demand and the CO_2 emissions, suggesting considerable potential for nuclear power to contribute to the transition to a clean energy system.

The prospects for building new nuclear capacity are of considerable importance to achieving the transition. Even if most existing reactors had long operational lifetime extensions, the share of nuclear power in electricity generation will eventually fall to zero if no new plants are built. A slow-down in nuclear phase-out programmes and longer extensions would reduce the need to ramp up the use of renewable power. However, without new construction, nuclear power can only ever be a bridging fuel.

There are major hurdles to investment in nuclear power, even in those countries that have retained the option to develop new capacity. Overcoming these hurdles represents a major challenge for policy makers and the nuclear power industry. The greatest barrier concerns the ability of nuclear power to compete with other generating technologies on cost, especially in countries that have introduced competitive wholesale markets (discussed in detail in the next chapter). This is exacerbated in power sectors where nuclear's low-carbon nature is not recognised, either through policies such as carbon pricing or wholesale market designs and mechanisms supporting investments in low-carbon technologies in general. However, even where investors are confident that future electricity and carbon prices will be high enough to cover the cost of new nuclear projects, some risks specific to the nature of the technology may prevent investment from going ahead. The main obstacles relate to the sheer scale of investment and related time horizons, the risk of construction problems, delays and cost overruns (project management risk), and the possibility of future changes in policy (policy risk) or in the electricity system itself (disruption risk). In terms of project lead-times, economic lifetimes and complexity of stakeholder management issues, the current nuclear projects are closer to major infrastructure projects than most other power generation technologies.

Huge capital needs and long time horizons increase project risk

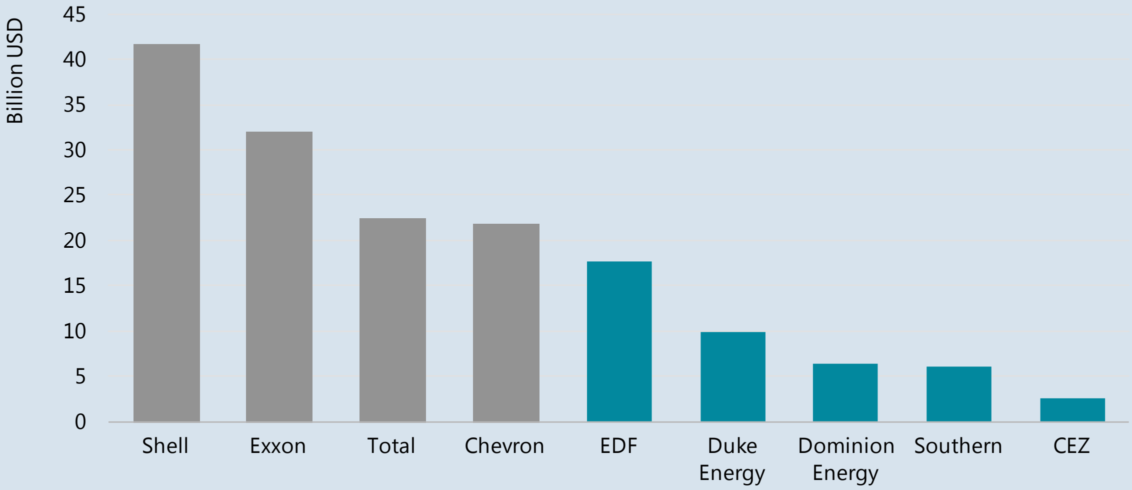
The construction of new nuclear power plants using current technology calls for huge amounts of capital for large-scale projects. Projects launched in the past decade in Europe and the United States involve advanced (or Generation III) pressurised water designs: the AP1000, developed and sold by Westinghouse Electric Company in the United States, and the European Pressurised Reactor (EPR), developed by France's EDF and Framatome (formerly Areva and now an EDF subsidiary) and Germany's Siemens. Both designs are intended for large-scale units with capacity exceeding 1 GW and require investment of several billion USD over a few years. For example, the cost of the 1.63 GW EPR being built by EDF in Flamanville in France has ballooned to over USD 12 billion. These projects are among the biggest energy projects in the world. The nuclear projects under way in developing economies, which primarily use Chinese and Russian designs, are also on a large scale. Globally, the average size of new construction starts in recent years has been above 1 GW.

Given the sheer size of investment needed in a nuclear power plant, financing can be difficult. In general, the liberalisation of wholesale electricity markets has increased investment risk for power generation projects and turned investment preferences towards less capital-intensive technologies such as gas turbines. The large individual project size of a nuclear plant reinforces the effect of market risk. Few private electricity utilities have the financial capabilities to support such an investment on their own. Investment in LNG projects can be on a similar scale to that in nuclear power projects, but there are important differences that make financing of LNG projects much easier in practice (Box 3).

Box 3. Size matters – investing in nuclear power is different to investing in LNG

The capital needs of a third-generation nuclear power plant are comparable to that of a large LNG facility. Both are susceptible to delays and cost overruns. However, there are important differences that affect the nature of the investment and the ease of financing. LNG projects are typically developed by large international oil companies, which have significantly larger financial strength than even the largest electric utilities of advanced economies (see the figure below). In addition, project risk is normally spread, with finance coming from several companies; the project developer often has a minority share only. For example, the largest LNG project in history, Gorgon in Australia, cost over USD 50 billion, but represented less than 20% of the capital spending of Chevron – the project developer – during its construction. As a result, despite cost overruns exceeding USD 17 billion, Chevron was able to maintain attractive returns on its entire corporate portfolio.

Financial performance* of selected major oil companies and large utilities involved in nuclear power, 2017



* Earnings before interest, taxes, depreciation and amortisation.

In theory, this approach to diversifying risk is possible in the case of nuclear power plants. However, in practice, it is hard to put in place due to a scarcity of potential investors and difficulties in allocating the complex risks of a nuclear power project. A new nuclear project would absorb nearly all the entire capital budget of most large utilities, so the stakes are higher for the company to bet on a single project. Developing a new fleet of nuclear power plants, which would enable the owner to take advantage of learning by doing to decrease unit costs, would be even more daunting.

Because of the sheer scale of the investment required, all but 7 of the 54 nuclear power plants under construction globally are owned by state-owned companies and all but one of the projects in private hands (all of which are in advanced economies) are subject to price regulation, which reduces risks to investors (Table 3). This is unlikely to change soon. In the current policy and market environment, it is difficult to see any privately owned utility embarking on a Generation III project in Europe or in North America without strong government support to minimise financial risks to investors. In developing countries, state-owned companies are responsible for all new nuclear investment.

Table 3. Nuclear power plants under construction by ownership and region

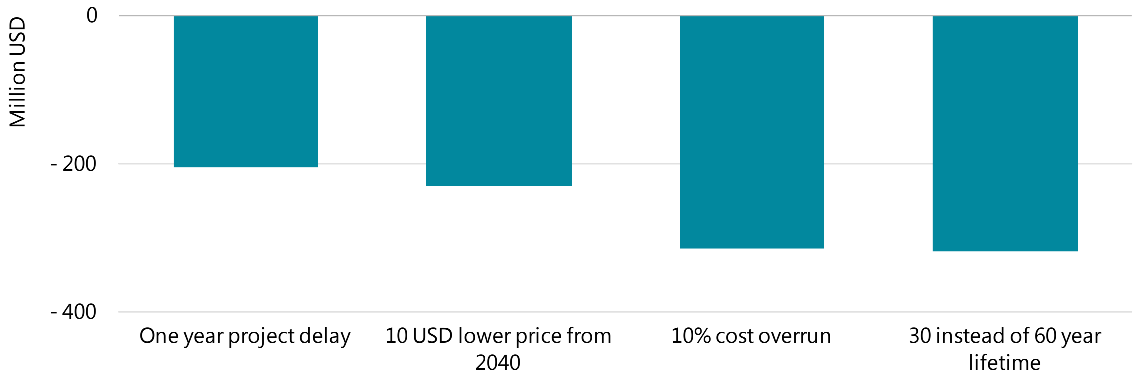
Economy type	Number of plants	State-owned operator	Private operator – regulated environment*	Private operator – wholesale market
Advanced economies	14	7	6	1
Developing economies	40	40	0	0
World	**54**	**47**	**6**	**1**

* Includes plants where construction began before the opening of wholesale markets.

Sources: IAEA (2019), Power Reactor Information System (PRIS) (database); Platt's Nucleonics Week Statistics Monthly (database).

The project development lead-time of a modern nuclear project designed for a 60 year lifetime is several years at a minimum and often exceeds a decade – even without project delays. This is well beyond the usual time horizon of normal business planning or even policy analysis. This increases the uncertainty about whether the plant, once commissioned, will be able to generate an acceptable return on investment, as revenues cannot be forecast with a high level of certainty. For example, cutting the average electricity price assumption by USD 10 per megawatt hour (MWh), in 2040 lowers the net present value (NPV) of a nuclear project launched today by over USD 200 million (Figure 8).

Figure 8. Impact of various risks on net present value of a 1 GW nuclear power project with guaranteed revenues to 2040



Note: All the sensitivities are compared with a "best-case" nuclear project, which assumes an investment cost of USD 4.5 billion per GW, a six year project construction time frame, a 60 year lifetime and a 7% cost of capital.

Economic viability of a large-scale nuclear power plant is highly sensitive to project delays, future electricity prices, cost overruns and plant lifetime.

In principle, the price risk associated with long lead-times can be reduced through long-term contracts with electricity buyers. Such contracts do exist in electricity markets among private players, but usually run for no more than 10 to 20 years, which is insufficient for nuclear power projects.

Another approach is to share the risk with electricity consumers. Public utilities in the regulated markets of North America can recover their costs associated with generation, networks and supply through regulated tariffs from end users. Even in liberalised retail markets, given the inertia of small consumers and their reluctance to switch suppliers, building a sizeable retail portfolio can be seen as a form of "virtual vertical integration". The sustainability of such an approach is questionable, as new digital solutions and the spread of decentralised solar generation make even retail revenues less predictable than before and carry the risk that government policy may require changes in market structure in the future. As a result, the impact of vertical integration as a means of reducing market risk is lessened. Contracting with or direct equity participation by energy-intensive consumers – an approach that Finland has pioneered – can also help manage price risk, but it is unclear to what extent this can be replicated in other jurisdictions.

In some cases, direct government intervention has been used to support private sector investment in nuclear power in electricity markets. The United Kingdom has been innovative in this regard. It has provided a contract for differences at a rate of GBP 92.50 (pound sterling) per MWh for 35 years for the Hinkley Point C plant. Following an extensive negotiation, the United Kingdom was not successful in obtaining new nuclear investment at the Wylfa site, despite its offer to provide one-third equity participation, the provision of debt financing required for the project and a contract price of up to GBP 75 per MWh. The United Kingdom is considering a Regulated Asset Base model, whereby the generator receives payments during the construction phase and during operations. This approach allows investors to see a return before the plant starts generating electricity. This has two effects on the financing cost of the project: first, it begins paying off the investment earlier, thus reducing the impact of compound interest, and second, it reduces the risk that investors see no return on investment so they may be willing to invest at a lower financing rate.

Disruption and policy risks are growing

Having been a technologically stable industry for many years, the electricity sector – from power generation, through transmission and distribution (T&D), wholesale and retail supply, to consumption – is now undergoing a profound technological transformation. This is having far-reaching effects on the way the sector operates and business is done. The rapid growth in wind and solar power is just one aspect of this transformation. Major changes are also occurring in the way the network is managed and operated, as well as in the way end users are consuming electricity, due to technological advances specific to electricity and the spread of digital technologies.

Future technological changes and associated changes in market structure could undermine the ability of investors in existing and emerging generating technologies to recover their investments. This "disruption risk" is growing because the future evolution of the electricity system and market structure is increasingly uncertain. One factor that is expected to undergo profound change is the provision of electricity system flexibility – modifying generation or consumption patterns to meet demand at any given moment. Up to now, flexibility has largely been provided through supply-side solutions, i.e. adjusting supply to meet a given level of demand by ramping up or down output at power stations. If deployed on a large scale, batteries and other forms of energy storage would have a major impact on price formation and thus on the returns of a nuclear power investment or other conventional technologies. Similarly, growth in the use of digitalised demand-side response, whereby consumers adjust their electricity consumption in real time in response to price incentives, or the use of electric vehicles (EVs) as storage to meet demand at peak, could have major implications for the way the industry operates and provides revenues to nuclear power and other conventional generators.

Emerging power generation and flexibility technologies generally have much shorter project lead-times and involve smaller projects than Generation III nuclear units. This makes them far more attractive to private investors, as the initial capital needs are smaller and investment strategies can be fine-tuned. Even the largest offshore wind farms[2] are far smaller than nuclear power plants; they use modular technology and are developed in stages.

A rational response from energy companies to increasing uncertainty over the future technology mix and business model is to focus on smaller, modular and short lead-time projects that benefit from learning by doing and enable a flexible rearrangement of the company's asset portfolio. Recent IEA research has documented the parallel decline of average project size and project lead-times in the oil and electricity sectors. Small modular reactors (SMRs), should they become technologically mature, would fit this overall investment approach far better than the Generation III units (see the last chapter).

Nuclear power plants are also subject to considerable policy risk, i.e. the risk that government policy on nuclear power will change at some point in the future. Such a change can include a decision to phase out the use of the technology entirely. Given long construction times, the introduction of a nuclear phase-out policy even 30 years after the original investment decision would still wipe out a substantial proportion of the anticipated revenue of the project (see Figure 8). This is the time frame between the strong pronuclear policies of the early 1980s and the decisions taken after the Fukushima Daiichi accident that have led to early decommissioning and phase-out policies in some countries. Licensing risk is a major concern for new nuclear technologies, and can have a significant impact on projects that are under construction or even in operation if nuclear regulators change the rules. In Japan, the uncertainty related to the timing of restart of idle nuclear power plants is perhaps the biggest uncertainty facing the electricity market.

Policy risks can also take other forms. The main attraction of nuclear power from a policy perspective is its ability to produce large volumes of low-carbon dispatchable power. Climate policies would therefore be expected to favour nuclear power. However, the future ambition and the design of climate policies are uncertain. Even an ambitious climate policy can be detrimental to the economic viability of nuclear power if it includes even stronger incentives for other emissions abatement options. For example, direct support for specific types of renewable energy sources, as opposed to an emissions target, has the tendency to depress wholesale prices and carbon prices, undermining the financial viability of nuclear power plants. Policy risk in advanced economies is discussed in more detail below.

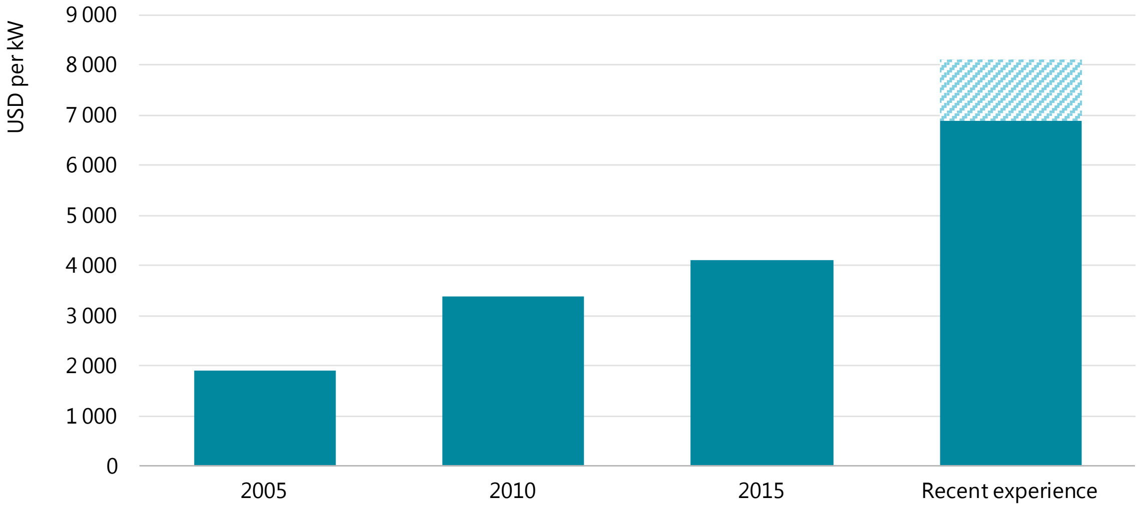
Construction problems, project delays and cost overruns are scaring off investors

The most important reason for the collapse of investor appetite for new nuclear projects in Europe and the United States is the project management track record of the last decade. The two EPR projects in Europe (Finland and France) and the two AP1000 projects in the

[2] Investment of around USD 2 billion is needed for a 0.5 GW project, with a typical lead-time of four to five years.

United States were supposed to herald a renaissance in nuclear power. Instead, they have all encountered major delays, and large cost overruns. In 2017, the construction of two 1.1 GW AP1000 reactors at the Virgil C. Summer plant in South Carolina was cancelled, and USD 9 billion of investment written off because of cost overruns. Work on the other three is continuing, with an average cost overrun of more than 300% compared with assessments made at the time of the investment decision and an average project delay of over five years. It is unlikely that any of these projects will ever generate an attractive return on investment for their owners. The construction cost of these Generation III projects is generally now estimated at around USD 7 000 to 8 000 per kilowatt (kW) – roughly four times the cost estimated in 2005 (Figure 9). Experience in Korea has been better, but even so, recent projects have taken longer to complete than planned.

Figure 9. Projected overnight construction cost of nuclear power capacity and recent United States and Western European experience



Source: IEA analysis based on IEA/NEA (2005, 2010 and 2015 editions), Projected Costs of Generating Electricity.

Construction costs of new nuclear power plants in the United States and Western Europe have turned out to be much higher than projected.

Soaring construction costs in recent years have affected technology suppliers. The EPR consortium in Europe provided guarantees on the construction costs of the new facilities being built in Finland, and Westinghouse did the same in the United States. The guarantees proved damaging to these companies. In 2017, Westinghouse filed for bankruptcy because of the liabilities associated with the AP1000s, and Areva had to be bailed out by the French government.[3]

A comparison between the unfavourable European and North American experiences and the much more successful Korean programme, as well as the historical lessons from the wave of construction in the 1970s, suggests that a sustained and consistent programme of nuclear reactor construction might be able to overcome some of the problems that led to the cost overruns and delays:

[3] Areva, which is majority owned by the French state, is responsible only for the liabilities related to the Olkiluoto 3 EPR project in Finland. The rest of its nuclear reactor construction business was sold to EDF in 2017.

The repeated construction of a standardised design, especially multiple reactors on the same site, can lead to gains in efficiency through learning by doing and economies of scale.

- While the AP1000 and the EPR were marketed as fully mature commercial designs suitable for a fixed price contract, they inevitably had some "first-of-a-kind" characteristics. In the case of all four projects, major design modifications (which are often a source of project management problems) occurred during construction. A complete detailed engineering design before construction starts typically reduces project risks substantially.
- Accumulation of industrial experience and know-how is a main contributor to the more successful new construction programmes outside Europe and North America. Lack of recent experience, a depleting industrial ecosystem and an ageing workforce have been major problems in building the AP1000s and EPRs. There had been no new nuclear construction activity for more than a decade in either Western Europe or the United States before construction of these plants got under way.

However, under existing policies, the chances of the wave of nuclear construction of the 1970s being repeated in Europe and North America appear slim. Given the lack of private sector appetite for investing in nuclear power, the first few projects would need to be underwritten by governments, representing a massive financial commitment. And the capacity additions involved would probably exceed actual needs. Given the large individual project sizes, the capacity built during this learning-by-doing phase would represent a substantial proportion of the electricity demand of a medium-sized system. For these reasons, SMRs, by the nature of their technology, may eventually prove a more attractive option, depending on technological progress.

2. Economics of nuclear power in advanced economies

Impact of competition in electricity supply

The establishment of competitive wholesale electricity markets – a central pillar of the wave of restructuring of the electricity supply industry that has been under way around the world since the late 20th century – is having a major impact on the nuclear power sector. That process, which has transformed the way the electricity sector functions, began in Chile and the United Kingdom in the 1980s, and has since spread to most advanced economies and many developing ones. Today, 53% of the world's electricity production is sold on competitive short-term markets that optimise operations among multiple participants whereby a single spot price is set according to bids from retailers and end users and offers from competing generators for the supply of energy over a specific time period (typically half-hourly or hourly blocks), before being supplied to end users via the grid. In many cases, short-term markets in energy are complemented with other instruments, such as capacity markets, to encourage investment. Competitive mechanisms have also been put in place for ancillary services needed to maintain reliable operations of the interconnected transmission system, including reserves (short-term back-up capacity in case of need), as well as markets for transmission congestion and financial derivatives such as electricity futures and options. Some countries have extended competition to the retail market, allowing all end users (including households in some cases) to choose their supplier.

Those reforms have generally proven successful in improving the efficiency of operations and investment decisions in the countries and subnational jurisdictions where they were implemented. Key to this success is the ability of competitive markets to exert constant downward pressure on the costs of operating, maintaining and developing the electricity system to meet the needs of consumers. Competition for the various services involved in electricity supply has encouraged innovation by market participants, responding to financial incentives to find the cheapest way to supply them, through new ways to operate the plants, by refurbishing them or by investment in new assets.

Although most of the nuclear power plants now operating in advanced economies were designed and built before competition was introduced, that development did not require any major changes to the way nuclear assets were operated. Nevertheless, it has boosted incentives to operate plants in a more efficient manner. Between 1992 and 1998 in the United States, nuclear plants in restructured markets experienced an additional 9.1% improvement in nuclear capacity factors compared to those in markets that did not restructure. Applications for uprates – an authorisation from the regulator for a nuclear plant to increase its output, usually by modifying or replacing certain components – have also been more common in restructured markets.

In countries that have restructured their electricity sector, nuclear power plants (existing and potential new ones) have to compete directly with other types of generators, including renewables and thermal fossil fuel plants. Recent market and policy developments have had a profound impact on the competitive position of nuclear power. This chapter assesses the factors affecting nuclear power's competitive position generally, reviews how nuclear power is faring in Europe and the United States, and assesses how various government support mechanisms are helping nuclear power to compete.

Costs of lifetime extensions and new plants

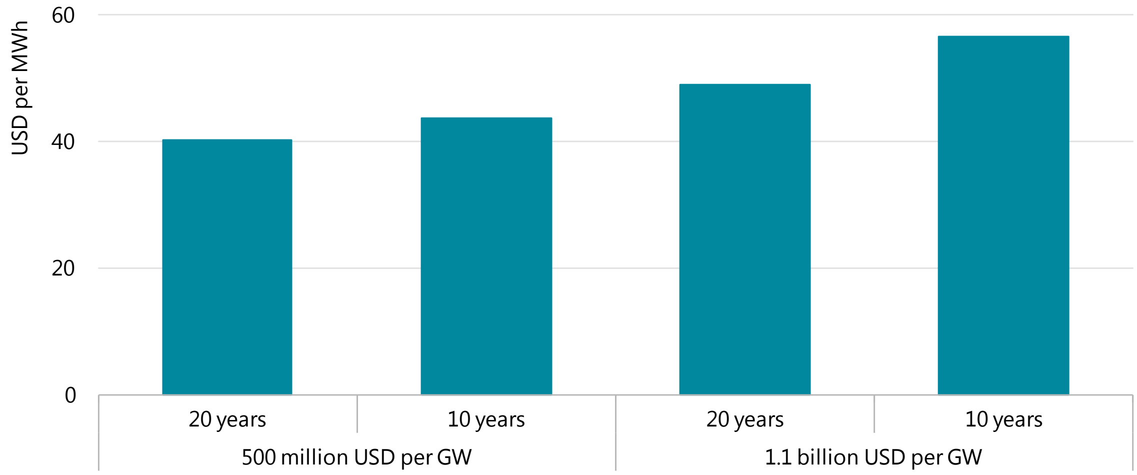
Lifetime extensions are cost-competitive source of electricity

In many cases, carrying out the investment required to obtain authorisation from the regulatory authorities to extend the operating lifetime of a nuclear reactor is an economically and financially attractive option compared with building other low-carbon technologies. The amount of investment varies considerably according to the type of reactor, the length of the extension and the location. In the case of light water reactors, that investment – though often substantial in absolute terms – has often proved less onerous than might have been expected, making it economic, especially where those investment have involved capacity uprates.

The capital cost of extending the operational lifetime of light water nuclear power plants generally ranges from USD 500 million per GW to USD 1.1 billion per GW (Figure 10). Process systems, including safety upgrades to meet regulatory requirements and other non-safety and conventional system upgrades, make up a large share of the total. This category includes work on the reactor itself, shut-down systems, turbo-generators, emergency systems, water circulation, instruments and controls, and cooling and electrical systems. Risk assessment activities and reviews of the operation and maintenance (O&M) procedures can cost more than USD 100 million per GW. Other costs, which cover activities related to aspects of the plant including the original design, operating conditions and maintenance practices since the start of operations, vary widely by plant; they can be as little as USD 50 million or as much as USD 500 million. The duration of lifetime extensions is most often between 10 and 20 years. Regular safety inspections, commonly performed every 10 years, are essential to ensure the continued safe operation of nuclear reactors.

Recent estimates for nuclear lifetime extension costs in France and the United States – the two largest markets for lifetime extensions – fall within the range described above. An OECD Nuclear Energy Agency analysis published in 2012 estimated that the cost of refurbishment of a 1 GW plant was lowest in Korea, at around USD 500 million, and highest in France, at USD 1.1 billion. A later survey of EU nuclear operators estimated the average cost at around USD 650-700 million for a plant of the same size. In the United States, 88 reactors have already started their extended period of operation or will do so within the next decade. A recent report estimated that the associated investment needs for these plants average USD 70 million per year per GW, or USD 700 million per GW over ten years. In France, it was estimated that the Grand Carénage programme of plant retrofits covering the country's entire fleet of reactors will require an annual investment of around EUR 4 billion (euros) over the 2014-25 period to extend the operational life of 64 GW of capacity beyond 40 years.

Figure 10. Indicative levelised cost of electricity (LCOE) for nuclear lifetime extensions



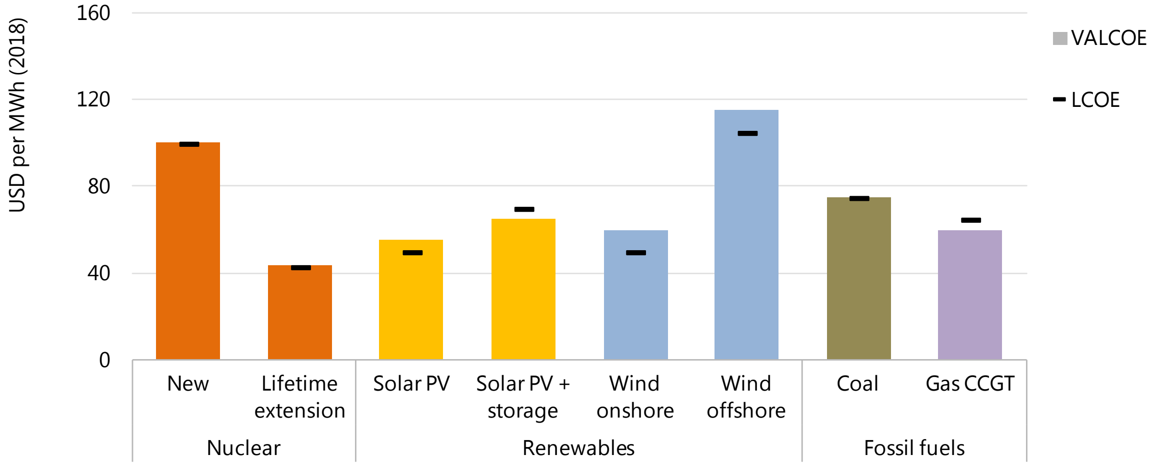
Note: LCOE is based on an 8% weighted-average cost of capital (WACC), 85% annual capacity factor, two year refurbishment period and USD 170 per kW annual O&M costs. LCOE is the average total cost to build and operate a power plant over its lifetime divided by the total energy output of the plant over the same period.

A refurbished nuclear plant will have a levelised cost in the range USD 40-55 per MWh.

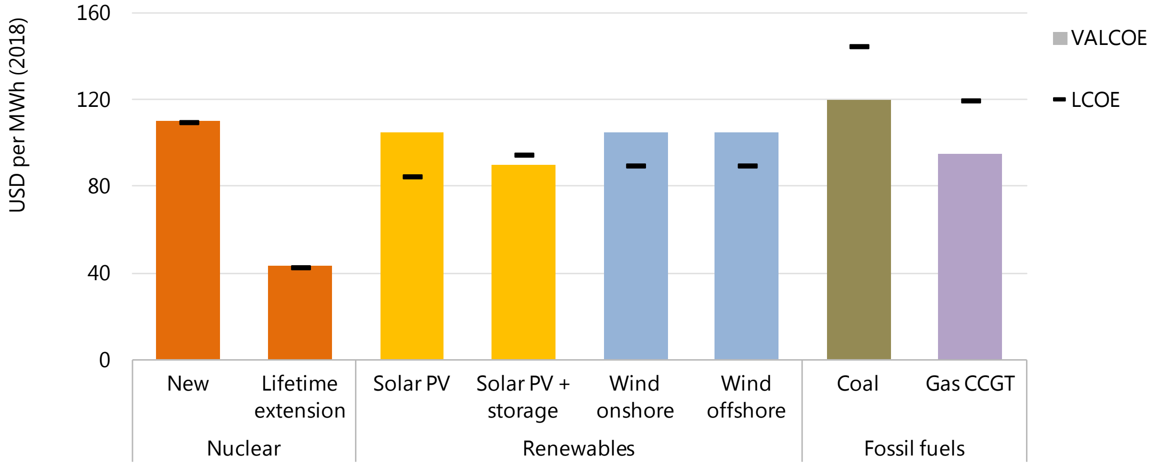
Nuclear lifetime extensions are one of the most cost-effective ways of providing low-carbon sources of electricity through to 2040. The levelised cost of electricity (LCOE) associated with a nuclear lifetime extension generally falls in the range USD 40-60 per MWh, based on an investment of USD 500 million to USD 1.1 billion and an extension of 10-20 years (Figure 11). For example, a 20-year extension costing USD 1.1 billion would result in an LCOE of around USD 50 per MWh assuming an 8% weighted-average cost of capital (WACC). For comparison, the average LCOE of new solar photovoltaics (PV) or wind projects are projected to remain above USD 50 per MWh in the European Union and United States under the same financing conditions. This is despite a projected continuing decline in solar and wind power costs. 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.

Figure 11. Projected LCOE and value-adjusted LCOE by technology, 2040

a) United States



b) European Union



Notes: PV = photovoltaics; coal = coal supercritical; CCGT = combined-cycle gas turbine. Nuclear lifetime extension LCOE is based on USD 1.1 billion investment to extend operations for 20 years. The cost of waste management is included in our assessment of the cost of generation. Decommissioning costs typically represent less than two percent of generating costs. Storage paired with solar PV is scaled to 20% of the solar capacity and four hours duration. LCOE is calculated based on an 8% WACC for all technologies. Other cost assumptions are from the World Energy Outlook 2018 (IEA, 2018b) and are available at www.iea.org/weo/weomodel/.

Nuclear lifetime extension is competitive with any generation of new build in the United States, and more so in the European Union.

Lowering the cost of capital is an effective means of reducing the LCOE of capital-intensive technologies, including many renewable energy technologies, nuclear power and, to a lesser extent, coal-fired power plants. For example, reducing the WACC from 8% to 4% decreases the presented LCOE of solar PV and wind projects by about 30% and the LCOE of nuclear lifetime extensions by 5-10%. One way of reducing the cost of financing is to reduce the risk related to the project. Long-term power purchase agreements at a specified price, which reduce revenue risk, are a common approach. Competitive auction schemes are an increasingly popular way of driving down the price of electricity supply, having resulted in low prices for solar PV and wind in a growing number of markets. Loan guarantees are another instrument available to policy makers to lower financing costs.

The competitiveness of nuclear plant extensions is even more favourable when the full value of nuclear power as a dispatchable low-carbon source of electricity is taken into account. The LCOE is the most common metric for comparing the competitiveness of power generation technologies, but considers only the costs of generation and does not take into account the value that each technology may provide to the overall electricity system in ensuring flexibility and reliability. A more complete picture of competitiveness requires these values to be considered. The value-adjusted LCOE (VALCOE), a new metric presented for the first time in the *World Energy Outlook 2018* (IEA, 2018b), combines a technology's costs with estimates of these values. Using this measure, nuclear lifetime extensions outperform solar PV and wind power by a wider margin than by simply using LCOE, mainly due to the rising energy costs of solar PV and wind and the increasing costs associated with enhancing system reliability and flexibility as the share of variable renewables in total generation increases.

The economics of new nuclear are difficult today, but could improve in the future

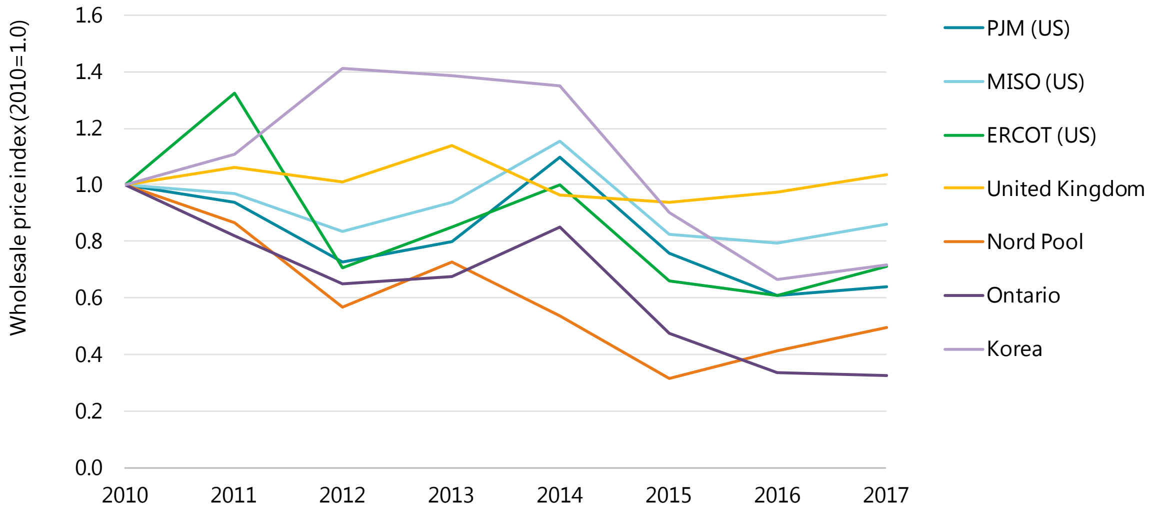
The competitiveness of constructing new nuclear power plants is much less favourable than for lifetime extensions at existing units. In practice, costs vary across countries, sites and type of technology, so projections of the cost of new plants should be considered as indicative of the average. Today, the high capital cost of nuclear makes it significantly more costly on a levelised cost basis than wind power or gas-fired generation in both the European Union and United States. By 2040, in the United States, the LCOE for nuclear power is projected to be around USD 100 per MWh, double that of solar PV and wind. In the European Union, the gap is smaller as nuclear's LCOE averages about USD 110 per MWh compared with wind and solar PV in range of USD 85-90 per MWh.

Using the VALCOE metric reduces this gap in the United States but does not change the picture. It is a different story in Europe, where the VALCOE metric suggests that nuclear power, provided capital costs decrease by one-third from today's levels, would be broadly competitive with solar PV and wind (onshore and offshore). The metric suggests that by 2040, solar PV with four hours of storage will be the most competitive generating technology in Europe (given the generation mix, fuel and CO_2 prices in the New Policies Scenario).

Factors affecting wholesale energy revenues of nuclear power plants

Market conditions in the electricity sector, especially in advanced economies, have changed significantly in recent years, largely because of a slow-down in the growth of electricity demand and the rapid expansion in generating capacity based on VRE. In some markets, notably the United States, a fall in the price of natural gas has also played a role. The net impact of these three factors has been a fall in the wholesale electricity price in all advanced economy markets with nuclear power plants, with the notable exception of the United Kingdom (Figure 12). This section discusses the factors behind the decline in wholesale prices, trends in other sources of electricity revenue for nuclear power plants, implications for existing nuclear power plants in North America and in Europe, and recent policy measures that aim to support nuclear power plants.

Figure 12. Wholesale electricity prices in selected advanced economy markets



Notes: PJM, MISO and ERCOT are independent system operators in the United States.

Source: IEA (2018b), World Energy Outlook 2018.

Electricity prices in almost all markets have fallen significantly since 2010.

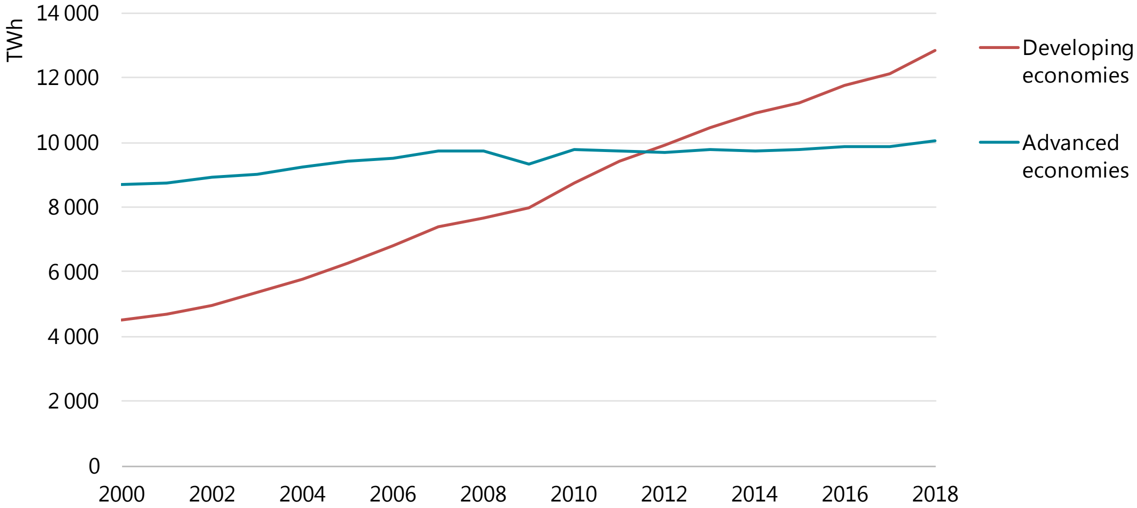
The shift in market conditions is generally affecting the prospects for new construction far more than the operations of existing plants. This is because capital costs represent a large share of the overall cost of nuclear power generation. The variable cost of nuclear power generation is low compared with other types of thermal plants as fuel costs are relatively low. Therefore, existing plants are usually still able to cover their operating costs most of the time, ensuring that nuclear plant is dispatched ahead of all but those renewable energy technologies that have zero variable costs (wind, solar and hydro power). Nonetheless, some existing nuclear plants are struggling to cover their operating costs, notably in the United States (see below).

Demand for electricity is slowing

Electricity consumption has remained about the same or even fallen in most advanced economies in recent years (Figure 13). Between 2010 and 2017, demand grew by 0.3% per year on average – less than one-third of the rate of the previous decade. During this period, electricity demand fell in 18 of the 30 IEA member countries. By contrast, electricity demand has continued to expand rapidly in developing economies as a group.

Several factors have slowed growth in electricity demand in advanced economies, the most important of which is gains in energy efficiency. Efficiency improvements have outpaced new sources of electricity demand growth such as digitalisation, particularly in industry (which accounted for 40% of overall efficiency improvements between 2010 and 2017), lighting and household appliances. Changes in economic structure, involving a stagnation in energy-intensive heavy manufacturing, have also been important. Strong economic growth, rapid industrialisation and a shift in energy use towards electricity has continued to drive electricity consumption in the developing economies ever higher, despite energy efficiency gains.

Figure 13. Electricity consumption in advanced and developing economies



Electricity demand is flat-lining in advanced economies, largely due to gains in energy efficiency.

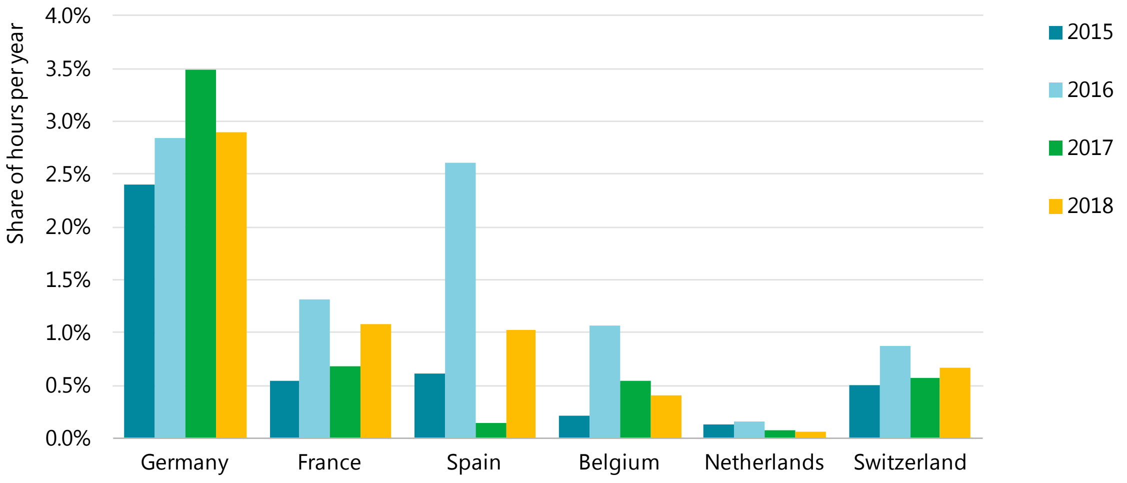
Rapid renewables growth is shrinking the market and depressing wholesale prices

Despite slow electricity demand growth, investment in electricity generation in advanced economies has been growing in recent years. This is primarily due to the growth in investment in renewable electricity generation, particularly wind power and solar power, both of which are types of VRE. Strong government support has been key to this growth, raising the share of the two energy sources in total generation in advanced economies from less than 1% in 2005 to 10% in 2018. Because their variable operating costs are close to zero, nearly all this additional wind and solar production is dispatched ahead of conventional generating plant (including nuclear power) in the merit order, thereby shrinking the market for conventional generation plants.

While the levels of investment in renewables have stabilised in recent years, prospects for continued growth in renewables capacity and production remain good. Continued cost reductions and policy support are set to continue to drive the deployment of wind and solar power world wide. Policy support remains strong, with higher targets for renewables recently adopted in the European Union, Japan, Korea and some US states. According to *Renewables 2018* (IEA, 2018c), renewables-based electricity production in advanced economies is projected to rise from 2 870 TWh in 2018 to 3 550 TWh in 2023, an increase of 680 TWh – more than twice the projected growth in electricity demand. Generation from other sources will need to fall to compensate.

The increasing shares of wind and solar power are having an indirect and, increasingly, a direct impact on wholesale electricity prices. The *indirect* impact arises from the displacement of output from conventional resources with higher fuel costs, thus lowering the market price at any time when new resources are available. The effect on prices can be magnified: wind resources and solar resources are often highly correlated within individual markets, i.e. when the wind blows strongly or the sun shines brightly, all generating units produce at or close to full capacity. This means that even in an electricity system where the share of VRE in total generation is low over the course of a year, in any given hour, the share of VRE can be large and can occur during periods of low demand. At these times, the wholesale market price can fall below the marginal fuel price of nuclear power, such that the use of VRE *directly* lowers the prices. Nonetheless, such events are still rare for now. For example, in Europe, where the share of VRE in total production is high, wholesale prices have been below the estimated variable (fuel) cost of nuclear power less than 1% of the time in most countries over the last four years (Figure 14).

Figure 14. Share of hours in each year when wholesale prices are lower than the estimated variable cost of nuclear power in selected European countries



Note: Average variable cost of nuclear power generation is estimated at EUR 8 per MWh.

Source: European Network of Transmission System Operators for Electricity (ENTSO-E) (2019), ENTSO-E transparency platform (database), and Nuclear Energy Institute (2019) NEI Statistics.

While low prices are a feature of markets with an increasing share of VRE, wholesale prices are still above the average variable fuel cost of nuclear power plants most of the time.

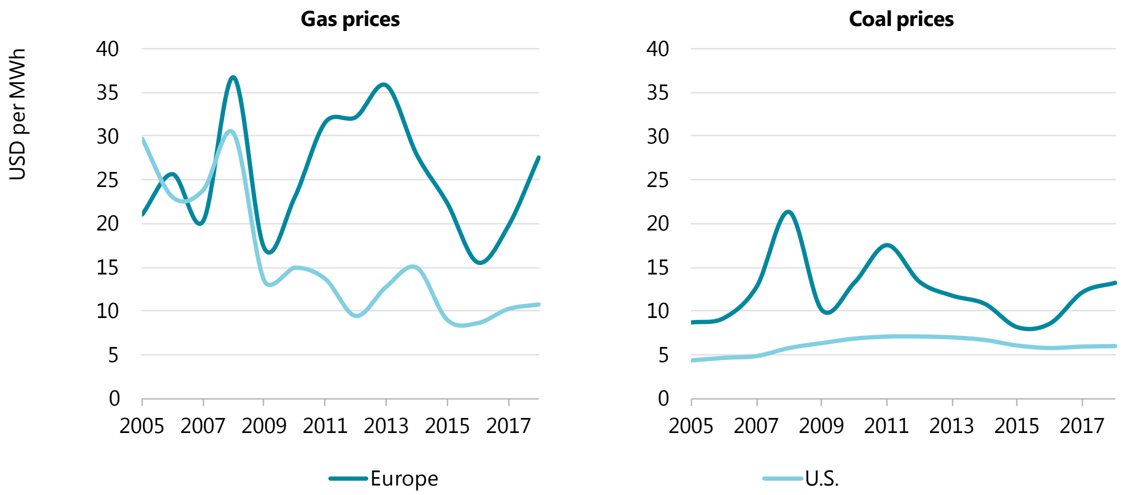
The shift in the position of nuclear power in the merit order in the wholesale electricity market due to the increasing share of VRE also applies to services other than the supply of pure energy. In particular, the prices of ancillary services have also changed due to changes in the merit order. The cost of providing ancillary services, especially operating reserves,[4] is mainly the opportunity cost or lost profit of generating energy at a market price. It thus differs for each plant and type of technology, i.e. the lower the variable cost, the larger the differential between the market price and the variable costs, and the more expensive it is for the system to reduce generation to have enough reserves. This is the main reason why nuclear power plants (with the notable exception of those in France), which have low variable costs, are generally not used to provide many of these services and are typically at the end of the merit order for ancillary services.

4 Operating reserve is the generating capacity available to the system operator at short notice to meet demand in case a generator suddenly goes off line. The operating reserve is made up of the spinning reserve – the extra capacity that is available by increasing the power output of generators that are already connected to the power system – and the non-spinning or supplemental reserve – the extra capacity that is not currently connected to the system but can be brought on line after a short delay.

Low natural gas prices are reducing wholesale electricity prices in North America

In North American and some other markets, the decline in natural gas prices over the last decade has had a significant impact on electricity market conditions, driving down average wholesale prices. This came about largely due to the boom in US shale gas production. As a result, gas has become much more competitive with coal in existing plants and with all other types of thermal generation for new construction, reshaping electricity markets across the continent. The situation in Europe is more complex, as natural gas prices increased earlier in the decade with higher oil prices (oil indexation in long-term gas supply contracts is still widespread) before falling back as oil prices fell and nascent US gas exports helped to decrease international LNG prices (Figure 15). Gas prices in Europe have since picked up. In both markets, the price differential between gas and coal has trended lower since the mid-2000s. Lower gas prices have helped to decrease wholesale electricity prices, as gas-fired power plants are often marginal sources of generation.

Figure 15. Average natural gas and coal prices in Europe and the United States



Note: Gas Henry Hub and Title Transfer Facility (TTF) prices, Coal API2 and IEA estimates.

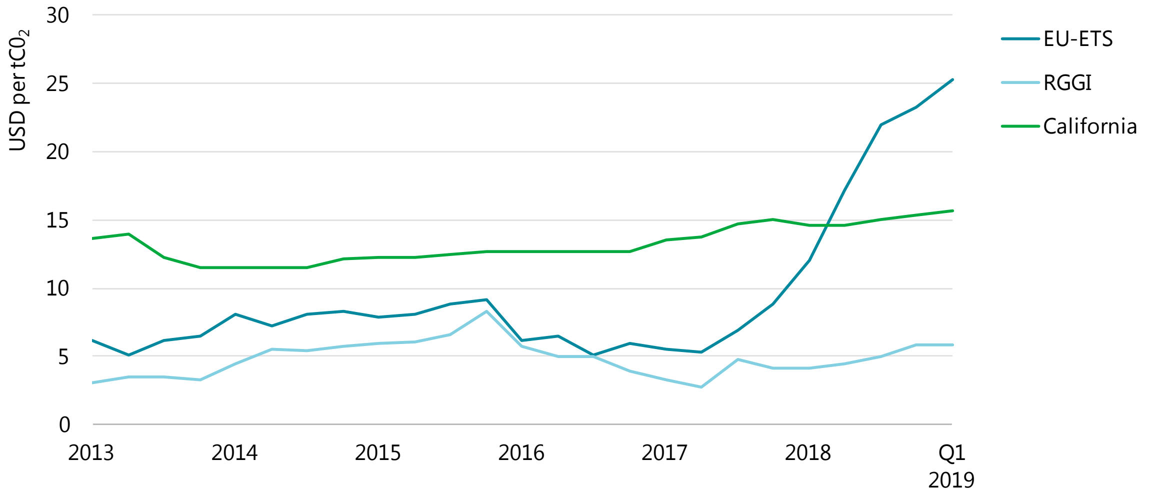
Sources: US Energy Information Administration (2019), Natural Gas Prices; Gasunie Transport Services B.V.(2019), Gas price reconciliation

Due to the shale revolution, the fall in US natural gas prices has reshaped the US electricity market.

Carbon prices are still too low to boost the economics of nuclear power

While the above factors put all types of existing generating plant under financial pressure, fossil fuel generators face greater cost pressures in those jurisdictions where there is carbon pricing, which favours nuclear power and renewables. Globally, nearly 20% of greenhouse gas emissions are already covered by carbon pricing systems such as emissions trading and carbon taxes. Carbon emissions trading systems have been implemented in several electricity markets, including in the EU-ETS and systems in a group of north-eastern US states and California. Power generation is included in all three systems. However, until recently, carbon prices in these systems have been low, meaning that they have had a modest impact on wholesale electricity prices (Figure 16). Prices have risen steadily in Europe since 2017, largely in anticipation of the effects of reforms eventually agreed in early 2018 for the period 2021-30, which limit the future availability of carbon allowances.

Figure 16. CO_2 prices in emissions trading systems in Europe, northeast United States and California



Note: Q1 = quarter 1; RGGI = Regional Greenhouse Gas Initiative.

Sources: European Energy Exchange, EU-ETS (2019), Spot Market Price, The Regional Greenhouse Gas Initiative (RGGI) (2019), Auction Results, California Air Resources Board (2019), Summary of Auction Settlement Prices and Results.

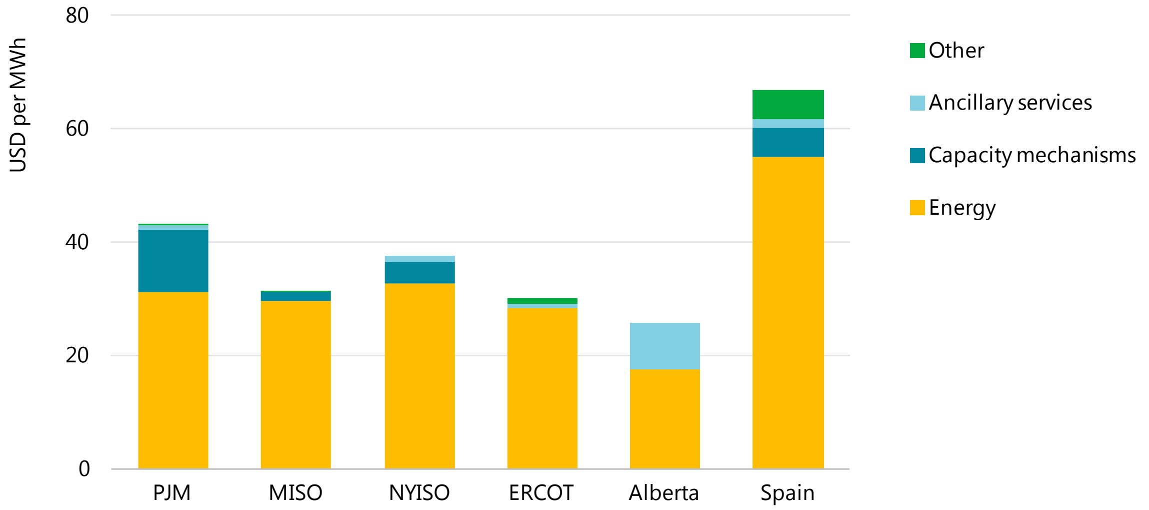
Carbon prices have remained relatively low, except for the recent surge in Europe.

Other market sources of revenue for generators

Revenues from capacity markets and ancillary services generally remain small

While sales of energy only on the wholesale market remain the main source of revenue for nuclear and other power generators in advanced economies, there are other electricity market services with potential to provide additional revenues. One such source of revenue is capacity mechanisms, which have been adopted in several markets as a way of attracting investment in new capacity. Capacity mechanisms remunerate generators for making available capacity from existing and future plants. They are common in US markets and have been introduced in some European countries, including Spain and the United Kingdom. However, revenues from capacity mechanisms make up a small portion of total revenues in most cases (Figure 17).

Figure 17. Sources of revenue for power generators in selected markets, 2017



Note: ERCOT = Electric Reliability Council of Texas; MISO = Midcontinent Independent System Operator (United States); NYISO = New York Independent System Operator; PJM = Pennsylvania, Jersey and Maryland Interconnection (regional transmission operator in north-east United States).

Source: IEA (2018b).

Energy provides most of the revenue earned by generators, even in systems with capacity markets.

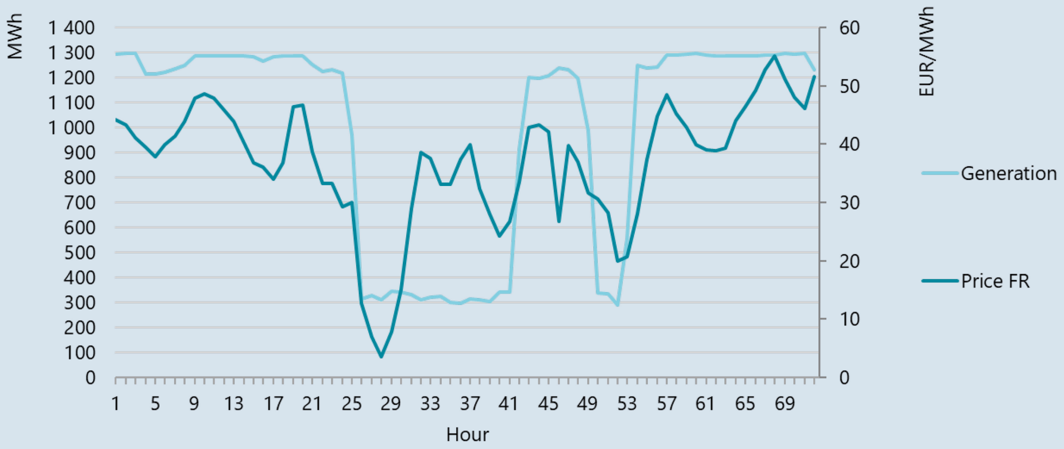
The other source of revenue for generation is ancillary services (e.g. the provision of load following, reserve capacity and similar services). Flexible resources are needed to provide these services. Most of today's nuclear power plants were built before competitive electricity markets were established. Nuclear power's low variable costs mostly ensured it was dispatched as part of the baseload fleet of generating plant. The large fleet of nuclear reactors in France, which requires some nuclear power plants to operate flexibly, is the main exception to this (Box 4).

It is technically feasible to operate most types of nuclear reactor in a flexible manner, though some technical modifications may be required. Flexible nuclear power plants can typically increase or decrease power by 10% within a few seconds or minutes to control the flow of alternating current (AC) power from multiple generators through the network (frequency control) and by 20-80% within a few hours to meet load variation. Ramp rates for this type of plant are typically of the order of 2% of the total rated thermal power capacity per minute. While in percentage terms, the flexibility offered by a nuclear power plant is smaller than that of a fossil fuel generating plant, the large size of a nuclear plant means this represents a large source of flexibility in absolute terms. Flexible nuclear operation can complement VRE within a low-carbon energy system, as it is generally possible to forecast renewables output a few days or hours in advance with a reasonable degree of accuracy.

Box 4. France's flexible nuclear fleet

The nuclear reactors in service in France are designed primarily to provide baseload capacity, but have a considerable amount of built-in flexibility, facilitating the accommodation of intermittent generation sources such as VRE. Of the country's fleet of 58 nuclear reactors with a combined net capacity of 63 GW, all of which are operated by EDF, up to 21 GW can be ramped up and down within 30 minutes. One example of a flexible plant is Belleville in central France (see the figure below). Flexibility is also provided on a yearly basis thanks to smart management of periodic refuelling outages. Flexibility was built into the plants in the design phase by various players in the country's nuclear industry – designers, suppliers and operators – as it was anticipated at an early stage that nuclear power would account for most of the country's generating capacity.

Production at Belleville 1 nuclear reactor, 2-4 April 2019



Source: European Network of Transmission System Operators for Electricity (ENTSO-E) (2019), ENTSO-E transparency platform (database).

French reactors are designed to be able to reduce output to 20% of rated capacity twice a day in under 30 minutes, i.e. a gradient of 30-40 MW per minute, depending on the type of reactor. Electrical output is varied using special control rods composed of materials that absorb less neutrons than the usual ones, making it possible to modulate the chain reactions more precisely. Control room operators receive specific training in this mode of operation on full-scope simulators, which are exact physical replicas of control room equipment. Dedicated operating specifications, validated by the Nuclear Safety Authority, are applied to this function.

In addition to near-term flexibility, the French nuclear fleet can also modulate output on an annual timescale, thanks to the size of the fleet and optimisation of the scheduling of planned reactor outages for refuelling and maintenance. The number of refuelling outages scheduled simultaneously thus fluctuates greatly over the year, with more than 15 reactors out of the 58 shut down for refuelling at the same time during the summer when load is lowest.

EDF is looking at the possibility of varying the composition of fuel reloads. When a reactor is shut down for refuelling, normally just one-third of fuel is replaced; therefore, each fuel element goes through three generation cycles. Adapting the number of fresh fuel elements for a new generation cycle would make it possible to extend or shorten the natural length of the cycle by as much as

50 equivalent full power days, thus enhancing flexibility.

Value of future nuclear flexibility will depend on the costs of other options

The need for flexibility is increasing with the growth of VRE. This represents a potential opportunity for existing nuclear power plants, alongside other potential low-carbon sources of flexibility including interconnections with neighbouring electricity grids, demand-side management (utility programmes to encourage the consumer to use less energy, especially during periods of peak load), storage (e.g. batteries or increased hydro storage) and flexible use of VRE.[5]

By operating flexibly, a nuclear plant may be able to reduce the times when it produces below its variable cost. In addition, flexible operation can generate revenue from ancillary service markets. In addition to France, such operations are already taking place to a more limited extent in the United States in response to the growth of wind power. The revenue from ancillary services must be weighed against the lost revenues from reduced energy sales in baseload operation. For example, in the case of France, the amount of energy that is not produced due to the use of reactors to provide frequency control and load following (ramping up and down briskly to meet daily changes in load) is, at this stage, around 3% of the maximal electrical output possible for the whole fleet. Furthermore, there is a cost involved in making the technical modifications to the existing plant, including the costs of obtaining the necessary safety approvals, to be able to operate flexibly.

The future role of nuclear power in providing flexibility will depend on the demand for flexible operations, the supply of other flexible resources and the way the market is designed with respect to how flexibility services are remunerated. Some studies suggest that there could be net benefits to the owners of nuclear power plants in operating flexibly in competitive markets. A study on the effects of flexible nuclear operation in the south-west of the United States shows that flexible operations can increase a nuclear plant's gross operating margin by two to five percentage points compared with baseload operations, despite reducing total output by 5-6%, while reducing curtailment of wind and solar resources – their forced disconnection due to network constraints – by 2-4% for wind and 11-14% for solar power. In practice, the scope for using nuclear capacity profitably to provide flexibility is likely to be limited for as long as the combined share of VRE does not exceed 40%, given expected falls in the cost of batteries, the growing use of cost-effective demand-side response (utility measures to encourage consumers to adjust their consumption in real time to reduce peak load and system costs) and the often large amount of existing available generating capacity based on fossil fuels. The presence of these other flexibility resources may instead reduce the requirement to curtail nuclear power operations.

The efficient operation and coexistence of nuclear capacity, other thermal generating plants and large shares of VRE will require markets to evolve to provide flexibility in a cost-effective manner through ancillary services and ramping capabilities. Many markets are moving in that direction. For instance, many system operators are increasingly developing mechanisms to take

[5] The potential of such resources is being examined in more depth in the IEA Power System Transformation series, addressing the flexibility of the VRE resources themselves.

advantage of the capabilities of VRE, splitting traditional ramping services into two different categories: ramping up and ramping down, where ramping down can readily be provided by VRE. This allows VRE resources to reduce their generation, avoiding expensive operations requiring inflexible thermal plants to stop and restart in a few hours. The development of efficient markets that accurately reflect scarcity of these services will be a crucial step in the transition to a low-carbon energy system, as a lot of this flexibility requires investments that yield benefits seen only in the longer term.

Support mechanisms for nuclear power plants

In recognition that the environmental and system benefits are not fully reflected in the remuneration obtained by low-carbon generators, some jurisdictions have introduced alternative mechanisms to increase their revenues. Most of those jurisdictions are not covered by economy-wide emissions trading systems or explicit carbon taxes. Some US states have adopted such support measures, notably Connecticut, Illinois, New Jersey and New York, together with Ontario province in Canada, and also Japan and Mexico.

The New York Public Service Commission adopted a Clean Energy Standard in 2016. It is designed to enable the state to meet the environmental goals set out in the New York State Energy Plan, which includes a 40% reduction in greenhouse gas emissions from 1990 levels by 2030. Nuclear power plants are supported by zero-emission credit (ZEC) payments from the New York State Energy Research and Development Authority (NYSERDA) based on the amount of electricity generated by each plant (in MWh).

The price of the New York ZEC is set for two years at a time and calculated according to a formula set out in the policy. It is based on the social cost of carbon, estimated by the federal government in 2015 at USD 42 per tonne (t), and the avoided carbon emissions that the nuclear power plants' generation enables, which is calculated as 15 million tonnes (Mt) per year. The ZEC price is USD 17.48 per MWh. The amount of ZECs each load serving entity (LSE) has to purchase is determined by the actual load from 1 April through to 31 March of the previous year. LSEs must purchase ZECs from NYSERDA in an amount that equals the given LSE share of the total state-wide load multiplied by the total number of ZECs purchased by NYSERDA in the compliance period. The ZEC purchase obligation is separate from any other obligation under the state's Renewable Energy Standard – a requirement that utilities obtain a specified percentage of the electricity they sell from renewable resources. As the load calculation is based on the previous year, after calculating the actual load served in the compliance period, the price of any unneeded ZECs is refunded by NYSERDA.

The policy has allowed Exelon – the owner of two nuclear power plants (Ginna and Nine Mile Point) that were due to be retired for economic reasons – to continue operating them. Exelon was also able to buy the FitzPatrick nuclear plant from Entergy and keep it in business (Entergy had planned to close the facility in early 2017.) New York State plans to implement the ZEC policy for 12 years.

New Jersey also adopted a ZEC programme in May 2018. Plants must be licensed to operate until at least 2030. As a result, the Oyster Creek nuclear plant does not qualify for this financial aid. The two other nuclear power plants in the state, Hope Creek and Salem, will receive about USD 253 million per year in revenue from ZEC sales to public utilities, according to government estimates, based on an average price of around USD 11 per MWh. The costs will be recovered through a fixed tariff of USD 0.004 per kilowatt hour (kWh) that will be added to retail prices.

In Illinois, ZECs for all types of low-carbon generation were introduced under the 2016 Future Energy Jobs Act. Illinois has six nuclear power plants with 11 reactors, which produce 50% of the state's electricity. The ZEC amount to be bought by the utilities is 16% of their output in the previous year. The support is provided on the basis of ten year contracts, requiring the power plants to keep operating during that period, to prevent plant early retirement. As a result, Exelon is expected to be able to keep its Clinton and Quad Cities nuclear power plants open due to USD 235 million in subsidy over ten years. The act sets the value of a ZEC at USD 16.50 per MWh based on the "Social Cost of Carbon" . This rate will increase by USD 1 per MWh in 2023 and each subsequent year.

The state of Connecticut has developed a power purchase agreement approach for zero-carbon resources, for which existing nuclear power plants are eligible. The two nuclear power plants supplying the state (one located in neighbouring New Hampshire) have signed power purchase agreements of up to ten years. Solar and offshore wind projects have also signed agreements.

In 2014, Mexico adopted a definition of "clean energy" that includes renewables, nuclear power, carbon capture, utilisation and storage (CCUS) and energy savings from efficient co-generation.[6] Under a Clean Energy Standard project launched in 2018, retailers are obliged to purchase an amount of energy from clean technologies. Under this system, only new facilities are awarded certificates. The country's only nuclear plant at Laguna Verde, where investment was needed to obtain an uprate, was awarded certificates in 2018.

In May 2018, Japan launched a zero-emissions trading system, which will cover nuclear power and renewables-based generators. It is the biggest certificate system in the country. Non-Fossil Value Certificates for electricity not covered by feed-in tariffs will be introduced during 2019. Retailers will need to obtain certificates to meet their obligation of procuring 44% of their electricity supply from sources that are not fossil fuels. The certificates are traded on a new market called the Japan Electric Power Exchange. As of 2019, when tracking systems for the certificates were introduced, large consumers are able to use the certificates to comply with the goals of RE100 – a global initiative bringing together influential businesses that are committed to buying 100% renewable electricity. The tracking ensures that the consumers are able to prove which plant produced the zero-carbon energy.

The Canadian province of Ontario uses a contract for differences methodology to support lifetime extensions at the Bruce nuclear station, which comprises eight units with a total capacity of around 6 GW. The price of the electricity output from the fleet of units is adjusted according to the expected cost of refurbishment each time a unit requires a lifetime extension. Once the cost has been agreed, any cost overruns are the responsibility of the generator. The government of Ontario is entitled to decline to fund the refurbishment if the planned costs are too high and can also terminate the agreement at specified points, if market conditions change so that the plants to be refurbished are no longer required.

For the most part, these support measures are intended to replace more market-oriented approaches, including explicit carbon pricing systems or capacity mechanisms. Of these two approaches, analysis suggests that implementing a moderate carbon price will have a greater impact on the competitiveness of nuclear power (and other zero-carbon) generation than a capacity mechanism (Box 5).

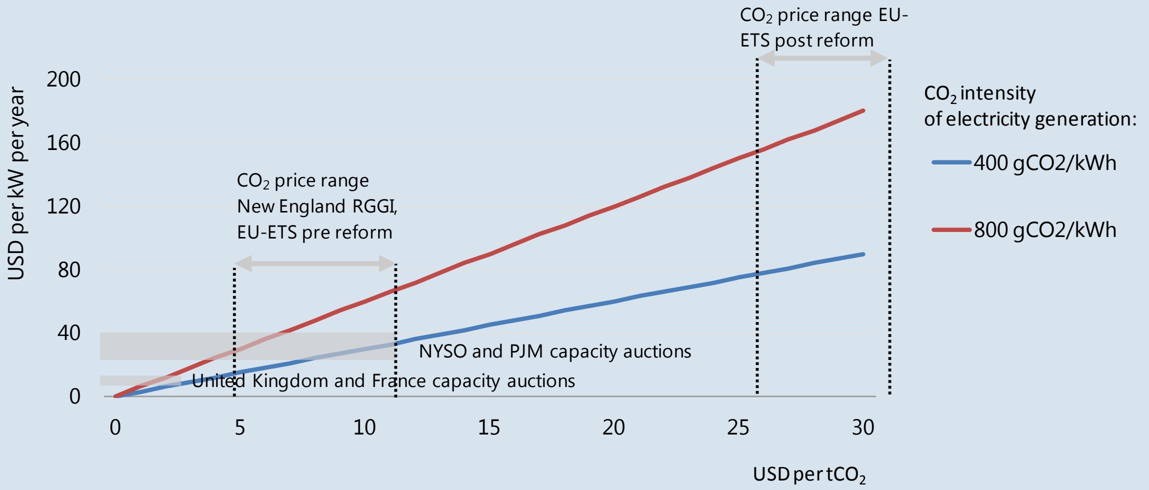
[6] *Co-generation* refers to the combined production of heat and power.

Box 5. Impact of carbon pricing on competitiveness of nuclear power

Nuclear power does not benefit from the same level of support as renewables in most countries and subnational jurisdictions, despite it being a low-carbon energy source. This reflects policy-maker recognition that VRE technologies, when these incentives were introduced, were not yet mature and that support systems would lead to cost reductions through scale or learning by doing. By contrast, nuclear technology is mature and the low variable costs of existing plants are expected to allow them to earn enough revenue to make continued operations profitable. However, this means that the low-carbon and other benefits of nuclear power are not specifically remunerated.

Carbon pricing is the simplest means of rectifying this imbalance. An explicit penalty on CO_2 emissions would ensure that nuclear power – for existing plants and for future capacity needs – competes on a level playing field with other energy sources and that the generating fuel mix yields the lowest prices for consumers. Only a few markets have adopted an explicit carbon pricing system, either in the form of emissions trading or carbon taxes. With falling wholesale electricity and low capacity prices, the lack of a carbon price and low prices in those markets that have carbon pricing have a significant impact on the competitiveness of nuclear power – much more so than the capacity value or flexibility value that nuclear power is able to provide. In practice, revenues from recent capacity auctions have the same impact on nuclear plant revenues as a modest carbon price – a few USD per t in the case of France and the United Kingdom and USD 4-12 per t in US markets (see the figure below). Following revisions to the EU-ETS in 2018, carbon prices have risen to over EUR 26 per t in anticipation of an EU-wide reduction of carbon allowances in 2019-23. At this price level, revenues to nuclear power producers would rise by USD 70-150 per kW per year – 10 to 20 times more than those from recent European capacity auctions and two to four times more than those in the United States.

Revenues of power generators from CO_2 pricing and capacity payments in electricity systems with moderate and high carbon intensity



Prospects for nuclear power in key markets

Existing conventional generators are losing market share

Existing conventional power generators (including nuclear power plants) in the electricity markets of advanced economies are being squeezed by lower wholesale prices and dwindling market share. Most new renewables-based generators with power purchase agreements or similar mechanisms have not been badly affected by the fall in wholesale electricity or (where they exist) capacity prices in recent years, as other revenue sources entirely or partially offset the impact of low prices. Most existing conventional generators have no such arrangements. With demand set to continue to stagnate and new renewables-based capacity likely to continue expanding in the medium term, it is expected that low prices will persist as the share of low marginal cost renewables increases. In effect, existing generators are facing a game of musical chairs, as an increasing amount of dispatchable capacity is displaced with each round of renewable additions.

This is raising concerns that some nuclear capacity may be decommissioned, reducing back-up capacity, which could undermine electricity security. Nuclear power is normally dispatched after renewables and ahead of other thermal generation plants, as nuclear fuels are of relatively low cost. However, being dispatched does not guarantee financial viability: revenues need to be high enough to pay the fuel costs and the costs of operations, and also to finance ongoing capital expenditures. The ability of nuclear power plants to prosper depends upon particular market circumstances. The rest of this chapter focuses on developments in Europe and the United States.

Low energy and CO_2 prices are making some existing US nuclear plants uneconomic

Electricity market conditions and the viability of existing nuclear power stations in the United States are different to those in Europe. Nuclear plants in the United States are given an operating licence for 40 years, and can obtain a licence extension of 20 years. All but 2 of the 98 nuclear units in operation are over 30 years old, 90 of which have already received the 20 year licence renewal. Each renewal requires significant amounts of capital spending. Fuel and other operating costs have been broadly stable, while ongoing capital investments have declined in recent years as most life extension investments and safety and security upgrades after the Fukushima Daiichi accident have been completed.

The US nuclear fleet is about to experience a wave of retirements. Nine units are due to be retired within the next three years (Table 4). This compares with only two closures in the past three years. In addition, the owner of the last two units operating in California has announced that it will not seek extensions for them and will close them upon expiry of their current licences in 2024 and 2025. In most cases, market conditions have been cited as the main reason for closure.

Table 4. Retirements of nuclear reactors in the United States, 2016-21

Reactor unit	Net capacity (MW)	Closure year	Licence expiry date	Licensed lifetime (years)	Age at closure (years)	Stated reason for retirement		
						Capital expenditure	Market conditions	State policy
Actual 2016-18								
Oyster Creek	619	2018	2029	60	48	O		
Fort Calhoun 1	482	2016	2033	60	43		O	
Planned 2019-21								
Pilgrim 1	677	2019	2031	60	46		O	
Three Mile Island 1	819	2019	2034	60	44		O	
Indian Point 2	1 020	2020	2024	60	45			O
Davis Besse	894	2020	2037	60	43		O	
Duane Arnold	601	2020	2034	60	46		O	
Perry	1 256	2021	2027	40	35		O	
Indian Point 3	1 040	2021	2025	60	44			O
Beaver Valley 1	921	2021	2036	60	45		O	
Beaver Valley 2	905	2021	2027	60	34		O	

Sources: US NRC; IAEA (2019), Power Reactor Information System (PRIS) (database); US Department of Energy (2017), Staff Report to the Secretary on Electricity Markets and Reliability.

There are two main factors undermining the viability of maintaining operations at existing US nuclear power plants. First, revenues from electricity markets appear insufficient to cover costs, including those associated with obtaining operational lifetime extensions, mainly due to the low price of natural gas. According to annual nuclear power cost data published by the US Nuclear Energy Institute, covering capital, fuel and non-fuel operating costs reported by all the operating nuclear units in the United States, average operating costs in 2017 were USD 33.50 per MWh.[7] Given that this is close to the marginal cost of gas plants that set prices in most US power markets, most nuclear power plants are barely able to cover their operating costs let alone the capital costs associated with obtaining operational lifetime extensions. Second, the need for environmental upgrades related to the use of water for cooling, the cost of which has been attributed as a factor in plant closures in California, New Jersey and New York, has added to the cost burden of existing plants. Nuclear power plants are significant users of water for cooling. New regulations require existing plants to upgrade their cooling water systems, which involve a need to invest hundreds of millions of USD. Carbon pricing is not able to compensate for these factors, as a pricing mechanism is not in place in all markets. In addition, where one exists, CO_2 prices are too low to benefit greatly nuclear power (see below).

Nuclear power plants that operate in competitive markets, which make up 64 GW of the total US nuclear capacity of 98 GW, must rely on market revenues unless they have a power purchase agreement. Power plants in those markets have three possible streams of revenue from those markets: revenue from selling energy, revenue from making capacity available (if this is offered by the market) and revenue from ancillary services, which is insignificant for US nuclear power plants. Wholesale electricity prices on competitive markets have been falling in recent years. In

[7] Costs are generally much lower for plants with two or more reactors. The 36 multiunit plants in the survey have an average generating cost of USD 30.89 per MWh compared with USD 42.67 per MWh at the other 62 single-unit plants.

the PJM market in the north-east, the average price from 2007 to 2017 fell by nearly one-half, from USD 61.66 to 30.99 per MWh. The main reason for the decline is a fall in the price of natural gas delivered to power generators, from USD 7.31 per million British thermal units (MBtu) in 2007 to USD 3.52 per MBtu in 2017 – a similar percentage decline as for electricity prices. Revenues from capacity markets, where these exist, can be a significant source of revenue for nuclear and other existing generators. They are important in PJM and Independent System Operator New England (ISO NE) markets, but they either do not exist or are not significant elsewhere.

Table 5. Nuclear power in US organised electricity markets, 2017

Market	Net capacity (MW)	Average energy price (USD/MWh)	Capacity price (USD/MWh)
PJM	33 163	30.99	11.23
MISO	12 420	29.46	-
ISO NE	4 010	35.23	19.00
NYISO	4 820	25.24	2.00
ERCOT	4 960	28.25	N/A
SPP	2 061	23.43	N/A
CAISO	2 894	37.59	N/A

Notes: CAISO = California Independent System Operator; N/A = not available; SPP = Southwest Power Pool. NYISO prices are for the Central Zone, where two nuclear power plants are located.

Source: ISO 2017 Market Monitor Reports.

The independent electricity market monitors in some of these markets have identified the competitiveness of existing nuclear power as a major concern. In the case of PJM (the north-eastern regional transmission system), the market monitor concluded that 9 of 19 plants would have lost money in 2017. This was an improvement over the previous year when 16 out of 19 plants would have done so, but still far higher than in previous years. Similarly, an analysis by the NYISO market monitor found that the market and capacity revenues for the upstate nuclear power plants have fallen significantly in recent years, in part because the plants are located in a zone where supply is plentiful. By contrast, the plant near New York City would appear profitable as it benefits from higher electricity and capacity market prices. In the ERCOT system, the market monitor noted that the average revenue received by nuclear generators, at USD 24.73 per MWh, was well below the average wholesale price, as nuclear power plants run in baseload mode. While it found that nuclear power provides a hedge against a rise in gas prices, such a rise is unlikely to occur in Texas in the short term. The findings of the market monitors – that some plants are competitive even under these market conditions, but others are in difficulty – are consistent with other analyses.

The same underlying pressures on nuclear power producers – falling natural gas prices, stagnant demand and growth of renewable generation – are also apparent in regulated systems. The principal difference is that in organised markets, these factors affect the bottom line of the asset owner, who can then decide to continue operating the plant or to close it. For vertically integrated monopoly utilities, regulators act as a substitute for market signals. Regulators can put pressure on utilities that have excess generation capacity to close the least economically viable plants to reduce the burden on power consumers.

Carbon pricing is offering little respite to US nuclear producers. Not all systems have carbon pricing; where they do, CO_2 prices remain low. There are two regional systems in operation: one in California and a second, the RGGI, covering nine states in the north-east, affecting generators in New England, New York and part of the PJM market. Prices in the California market are highest: the latest auction cleared at USD 15.62 per t, adding about USD 6 per MWh to the cost of gas-fired electricity in California. The latest auction prices in the RGGI, at an average of USD 5.27 per short ton (USD 5.81 per metric t), are roughly one-third of this, implying a cost increase for natural gas generation of just over USD 2 per MWh. While the CO_2 price may have some impact on the competitiveness of nuclear producers in California (e.g. a USD 6 per MWh price rise translates into an extra USD 100 million per year in revenue to the owners of the Diablo Canyon plant), it has not changed the decision to close the plants in the mid-2020s. In contrast, the low CO_2 prices in the RGGI have had little impact on electricity prices in the New England, New York and PJM markets.

Prospects for building new nuclear reactors in the United States remain bleak

If existing nuclear power plants are struggling to cover their costs, the prospects of new nuclear power plants being able to make a profit under current market conditions are even less promising. With recent advances in technology, falling costs and favourable policies, most power generation investment is now going to wind and solar power. Compared with a decade ago, when there was optimism about a nuclear renaissance, a more conservative demand outlook and more bullish prospects for renewables have reduced the expected need for conventional and nuclear generation in 2030 by 1 300 TWh under current and planned policies. This is equivalent to the production of over 170 GW of baseload capacity.[8] Most of this reduction is expected to be met by decommissioning of coal capacity, but the projected call on nuclear power has also been trimmed.

The last application for a new construction licence in the United States was made a decade ago. Eight licences were issued in 2007-09, of which only one (the Vogtle project) is under construction. Three of the remaining seven have been terminated, and it is doubtful that any of the four pending projects will go ahead. These applications were made at a time when US gas production was expected to decline, and LNG imports would stabilise North American gas prices at a permanently high level. As the shale gas revolution was unfolding, gas price expectations for 2030 were revised down from USD 11.3 to 3.8 per MBtu. The difference this has made to the marginal cost of gas-fired generation has effectively cut the NPV of a 1 GW nuclear reactor by USD 5 billion. It would take a CO_2 price of USD 120 per t to compensate for this. The shift in market conditions was cited as the primary reason for cancelling the licence in all three cases. Even without the cost inflation and difficulties in managing the ongoing project, the change in market conditions would have raised questions about the economic viability of new nuclear projects.

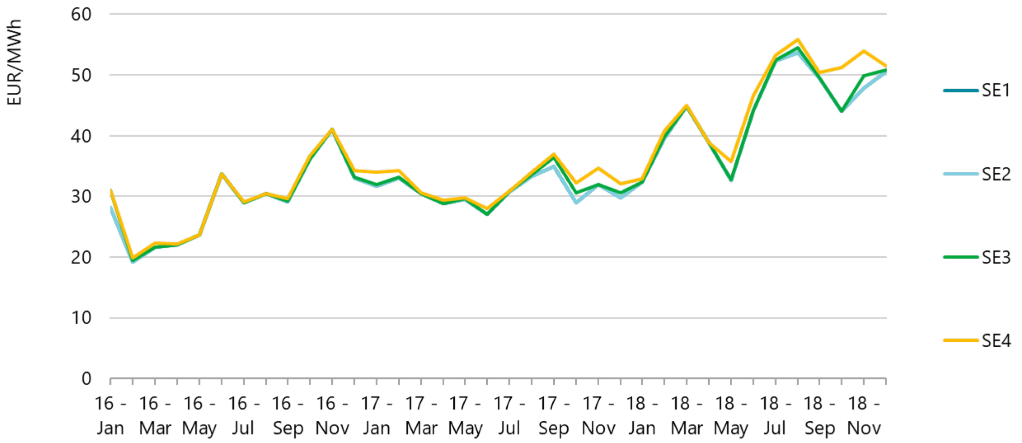
Higher fuel and CO_2 prices are helping existing nuclear plants in Europe to compete…

The competitiveness of existing nuclear power plants on continental European markets has improved recently due to natural gas prices that are structurally higher than in North America, as well as due to explicit pricing of CO_2. EU-ETS CO_2 prices, which had been trading as low as

[8] Projections of the World Energy Outlook 2009 compared with those of the 2018 edition (IEA, 2018b) for 2030 in the central New Policies Scenario.

EUR 5 per tonne as recently as 2017, have since rebounded to over EUR 26 per tonne in anticipation of the implementation of reforms to the system that are due to come into effect in 2021. Higher CO_2 prices have increased the marginal cost of generation for a gas-fired CCGT plant by EUR 8 per MWh, and that of a coal-fired plant by nearly EUR 20 per MWh since 2017. The introduction of a carbon price floor in the United Kingdom in 2015 provided support to wholesale prices in that market. Reliable data on the variable costs of nuclear power in Europe are not available, but at current levels, wholesale market prices are undoubtedly high enough to cover those costs in all cases. Market reforms as part of the EU Clean Energy Package are also expected to level the playing field between nuclear power and renewables.

Figure 18. Average monthly wholesale electricity prices in Sweden by bidding zone



Source: ENTSO-E.

Wholesale electricity prices in Sweden have risen substantially since 2016, in part because of EU-ETS reforms and because of the reduced availability of hydropower due to low rainfall.

The situation is different in the Nordic bidding zones within the European electricity market, where wholesale power prices are generally lower due to the large proportion of hydro and wind power, which have almost zero variable costs. For example, prices in Sweden have risen since 2016, in line with the trend in the rest of continental Europe. However, they remain low, jeopardising the viability of existing nuclear power plants (Figure 18). As a result, a decision was made recently to phase out a tax on nuclear capacity that the plant owners claimed would force them to retire their plants early (Box 6).

Box 6. Abolished nuclear power production tax in Sweden

In 2016, the Swedish government decided to phase out a tax on nuclear power production, introduced in 1984, over a two year period from 2017 to 2019, to discourage the operators of existing plants from retiring them early. The decision formed part of a political agreement that set a goal of producing all electricity from renewables by 2040. In 2017, the tax amounted to around EUR 8 per MWh of electricity produced. Vattenfall, Fortum and Uniper (the principal owners of the nuclear production capacity in Sweden) had previously warned that nuclear power was no longer economic and had threatened to close four reactors by 2020, when additional investment to meet safety requirements will be necessary. Nonetheless, the move to phase out the tax will most likely not improve the profitability of existing plants sufficiently to keep all the plants running, despite higher prices since 2016 due to lower levels of rainfall (which have restricted the availability of hydropower) and higher prices in continental Europe (where the Nordic region exports a lot of power). It is expected that only 6 out of the original 12 reactors in Sweden will continue to run after 2020.* Investment in new power plants remains difficult, as government policy stipulates that they cannot be subsidised either directly or indirectly.

* Of the original 12 nuclear power plants, 2 were closed due to political decisions in 1999 and 2005, and 2 were closed due to financial reasons in 2015 and 2017. Another 2 are expected to close due to financial reasons and will not get the security upgrades allowing them to continue operation after 2020.

… but new nuclear power plants in Europe are not viable for now

Higher carbon and natural gas import prices are making the economics of potential new nuclear power plants more favourable, but financing new construction is extremely difficult in countries that continue to support a role for nuclear power. Due to a combination of the Eurozone crisis and the market impact of rapid growth in renewables, the financial position of the major utilities in Europe is considerably more fragile than that of utilities in the United States. The degree of competition in Europe is also greater: the US projects that have proceeded to new construction – as well as the cancelled ones that survived longest – are all in states that have not deregulated electricity markets.

Competitive wholesale markets effectively make financing of new nuclear projects in Europe unfeasible if they have to rely on market prices. Long-term contracts can be designed for new construction, but they usually apply to actual future production that is several years from the project start. Therefore, during construction, specific financing solutions are needed. Moreover, the risks associated with project management and cost overruns are too high for most electricity off-takers. A significant proportion of the utility industry is "ownership unbundled", i.e. the generating assets are not owned by the companies that own the network assets, so generators do not benefit from the stable and predictable cash flow of the network assets. Even in the case of legal unbundling, where the network assets remain in the same corporate holding, there are strict regulatory restrictions on cross-financing. As a result, the ability of the utilities to undertake large and capital-intensive projects is considerably weaker than in a vertically integrated regulated business model. For unbundled utilities operating in competitive electricity markets, the overarching strategic priority usually is an asset-light business model of retail, energy services and trading activities, coupled with less capital-intensive generation technologies such as gas and wind. Generation III nuclear units are the exact opposite of this business model. As a result, despite higher gas and explicit carbon prices, the new construction outlook in Europe is as pessimistic as in North America, with several prospective projects cancelled or indefinitely delayed – most recently in the United Kingdom.

The prospects for nuclear power remain clouded even in France, which represents nearly one-half of Europe's total nuclear production. The new French long-term energy strategy launched in late 2018 envisages a reduction in the share of nuclear power in the total generation, but leaves the possibility of new construction open as a strategic option. No binding decisions have been made on site selection, pricing or a financing model for any possible new project. This will require a substantial amount of investment by EDF, particularly considering the company's commitments to the construction of Hinkley Point C nuclear plant in the United Kingdom.

European countries with a legally binding phase-out policy – Belgium, Germany and Switzerland – represent only 17% of European nuclear production. However, a further 19% is in countries that have no active policy for new construction and where current operators have no plans to invest in new reactors because of market conditions, financing and cost barriers. Countries where policies support the development of new nuclear capacity, including the Czech Republic, Finland, Hungary, the Slovak Republic and the United Kingdom, account for around one-fifth of European nuclear production. Poland is a special case as a country that does not use nuclear power, but which is planning to authorise the construction of new nuclear plants. No decision has been taken on any particular project in Poland, with the choice of technology and financing still being open questions.

3. Impact of less nuclear investment

Outlook for nuclear power

Electricity market conditions for nuclear power in advanced economies remain difficult. This is because the underlying drivers of low wholesale electricity prices – low demand growth, rising wind and solar power capacity, and low natural gas prices – look set to continue for the foreseeable future. In addition, public concerns about the safety of continued operations at ageing nuclear reactors could lead to a shift in public policy and more stringent regulation, which could render operational lifetime extensions and new construction economically unviable or even impossible. To maintain public confidence, comprehensive safety reviews by independent regulators must be successfully completed before providing lifetime extensions for existing nuclear power plants. Technology and project management risks, highlighted by the ongoing problems being encountered by project developers in Europe and elsewhere, are adding to the uncertainties surrounding prospects for the nuclear power sector.

These uncertainties have never been greater, yet the need for low-carbon sources of electricity has never been more urgent. With the continuing electrification of the world's energy system, decarbonisation of power generation is central to the transition to clean energy. In principle, nuclear power could play a major role. If it does not, reliance on other forms of clean energy, essentially renewables, will have to increase even further to compensate. This could have far-reaching consequences for the way the electricity system operates, for the cost of supplying electricity and for providing the flexibility that will be needed to make the system work reliably and efficiently. This could also, ultimately, impact the likelihood that such an outcome can be achieved.

The latest projections in the New Policies Scenario of the *World Energy Outlook* (IEA, 2018b), which take 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 (Box 7). Output of nuclear power grows by 1.5% per year between 2018 and 2040, though its share in total power generation falls slightly, from 10% to 9%. In a 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 goal of holding the increase in the global average temperature to well below 2°C, 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%.

Neither outcome is assured. It is far from certain that even the policies that have already been agreed will be fully implemented, such that nuclear power production could fall short of the levels projected, notably because of barriers to investment in advanced economies. It is even less certain that the ambitious targets in the Sustainable Development Scenario will be achieved, as they require a significant increase in policy support. What would the consequences be for the rest of the energy system if nuclear output fails to rise as projected? To try to answer that question, we have a devised the *Nuclear Fade Case*, in which it is assumed that no new investment in nuclear lifetime extensions or new projects in advanced economies. This case is applied to the New Policies Scenario and the Sustainable Development Scenario. The underlying assumptions in each case are the same, though the outcomes are markedly different, largely because nuclear power plays a much bigger role in advanced economies in the

Sustainable Development Scenario. For both scenarios, we investigate the implications for the generating mix and the provision of flexibility services, with emphasis on the Sustainable Development Scenario, which encapsulates the stated environmental and social goals of the international community.

Box 7. The New Policies Scenario and Sustainable Development Scenario

The Nuclear Fade Case set out in this report is applied to two of the main scenarios – the New Policies Scenario and the Sustainable Development Scenario – analysed in the IEA *World Energy Outlook.* The **New Policies Scenario** provides a quantitative assessment of where today's policy frameworks and ambitions, together with the continued evolution of known technologies, might take the energy sector in the coming decades. The policy ambitions include those that have been announced and incorporate the commitments made in the Nationally Determined Contributions under the Paris Agreement, but does not assume any evolution of these positions. Where commitments are aspirational, the measures under development are considered as an indicator of the likelihood of those commitments being met in full.

The **Sustainable Development Scenario** starts from selected key outcomes and then works back to the present to see how they might be achieved. The outcomes in question are the main energy-related components of the United Nations Sustainable Development Goals, agreed by 193 member states in 2015, namely:

- Delivering on the Paris Agreement – the Sustainable Development Scenario is fully aligned with the Paris Agreement's goal of holding the increase in the global average temperature to well below 2°C.
- Achieving universal access to modern energy services by 2030.
- Reducing dramatically the premature deaths due to energy-related air pollution.

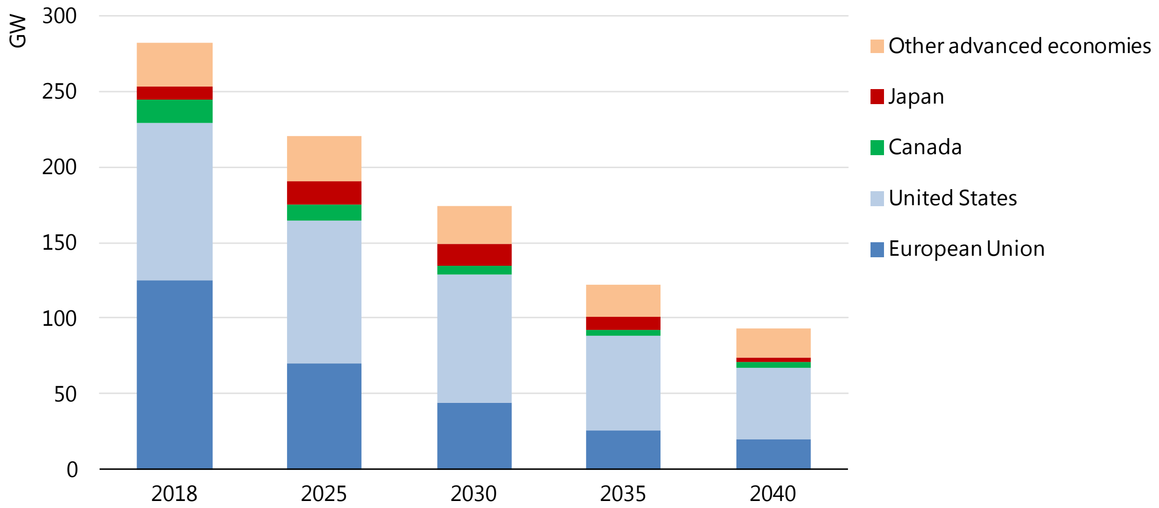
Source: IEA (2018b), World Energy Outlook 2018.

The Nuclear Fade Case

The basic assumption of the Nuclear Fade Case is that no new nuclear power capacity is built beyond those projects already under construction, no further lifetime extensions to existing nuclear reactors are granted and no new investment in existing plants occurs in advanced economies. No change is made to the assumptions about nuclear power development in developing economies on the grounds that the market pressures and uncertainties surrounding the nuclear power sector in those countries are generally less acute (partly because those economies are considering a variety of sources to meet growing electricity demand). In other words, the failure to extend the lifetimes of nuclear power plants in advanced economies is assumed to have no impact on either the extension of the lifetimes of nuclear power plants or on the expansion of the fleet in the developing economies. This is supported because the primary growth markets for nuclear power – China and Russia – will increasingly rely on their own domestic nuclear technology and engineering capabilities (or already do so). However, other developing economies are more likely to rely on international co-operation for technology and project management, which could prove harder if the nuclear industry is in decline in advanced economies. In that way, less nuclear investment in advanced economies could have a negative effect on the expansion of nuclear power in other markets. However, this was not explored in the Nuclear Fade Case.

In the Nuclear Fade Case, the total nuclear capacity in advanced economies declines by around two-thirds to 2040, from 282 GW in 2018 to just over 90 GW (Figure 19). The following 13 countries were considered: Bulgaria, Canada, the Czech Republic, Finland, France, Hungary, Japan, Korea, Mexico, the Slovak Republic, Turkey, the United Kingdom and the United States.

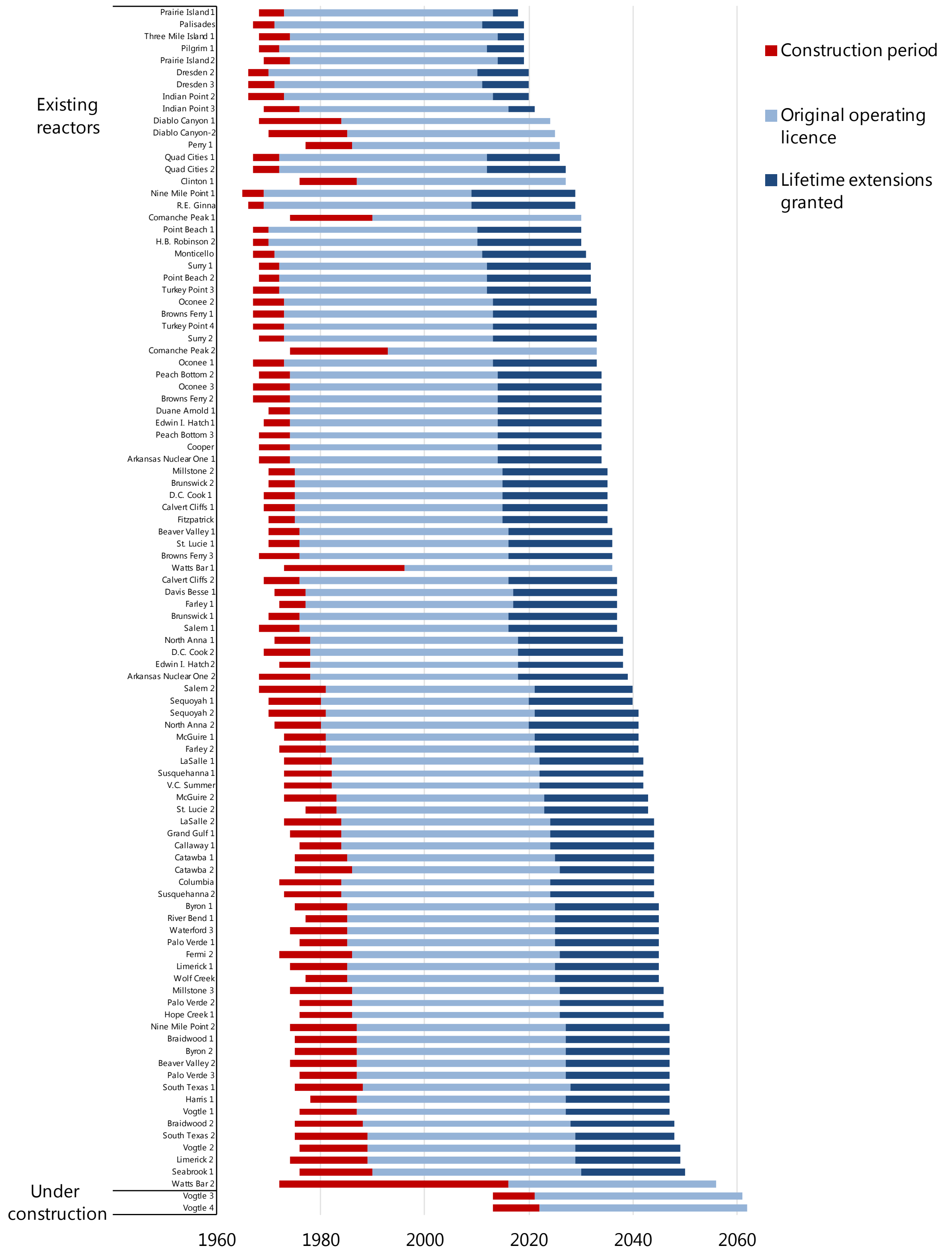
Figure 19. Operational nuclear power capacity in advanced economies in the Nuclear Fade Case



Without new investment in nuclear power, nuclear capacity in advanced economies would decline by two-thirds by 2040.

The European Union sees the largest decline in capacity in absolute terms, at over 100 GW, in the Nuclear Fade Case. Of the 126 reactors in operation, 89 are set to be decommissioned by 2030 without further extensions. By 2040, just 15 of the existing reactors are still in operation, complemented by four reactors that are under construction (Olkiluoto in Finland, Flamanville in France, and Mochovce 3 and 4 in the Slovak Republic). The decline in nuclear capacity in the United States is less severe than in the European Union, because nearly all of the existing fleet has already received initial 20-year lifetime extensions (Figure 20). Even still, nuclear power capacity in the United States declines by about half to 2040.

Figure 20. Current decommissioning dates for nuclear reactors in the United States



Note: Last updated on 20 May, 2019.

Sources: U.S. NRC (2019) ; IAEA (2019), Power Reactor Information System (PRIS).

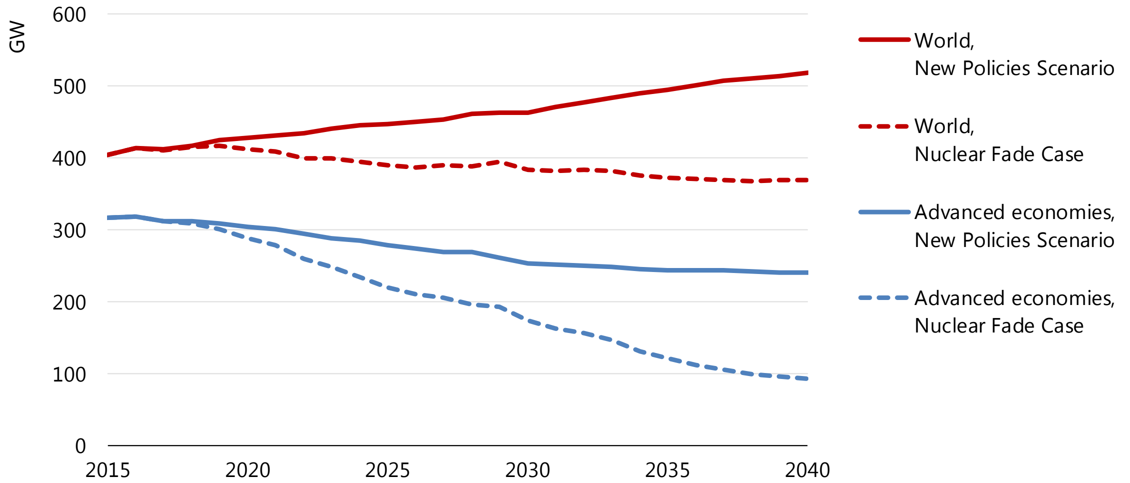
Without further lifetime extensions, 6 out of 10 nuclear reactors in the US would be decommissioned by 2040, even though nearly all have already received 20-year lifetime extensions.

In Japan, restarting reactors that are in temporary shut-down boosts operating capacity over the next few years, before the ageing fleet is rapidly retired. Capacity drops from a peak of around 17 GW in the early 2020s to almost nothing by 2040 when just two reactors (Shimane-3 and Ohma, which are under construction) are still in operation. Korea sees a one-third decline in nuclear capacity over the same period.

Implications of the Nuclear Fade Case in the New Policies Scenario

When the Nuclear Fade Case applied to the New Policies Scenario, global nuclear power capacity declines steadily over the projections period to around 370 GW in 2040 (about 40 GW down on the 2018 level) as the rapid decline in advanced economies more than offsets continued expansion in the developing economies (Figure 21). In the New Policies Scenario, global capacity rises by more than one-quarter, with strong growth in China, India and Russia (China becomes the leading nuclear power producer in 2030, overtaking the United States). 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 21. Nuclear power capacity in the New Policies Scenario and the Nuclear Fade Case



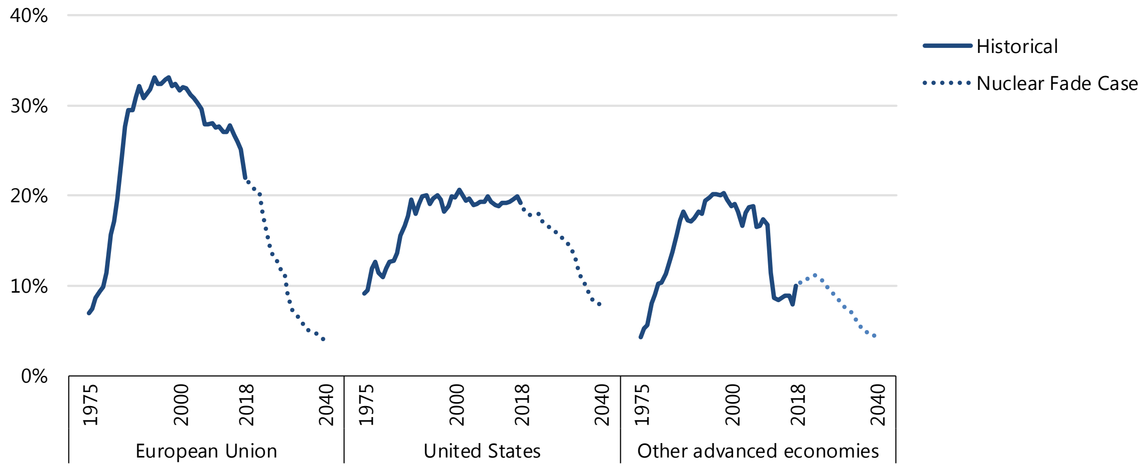
The steep decline of nuclear power in advanced economies in the Nuclear Fade Case outweighs growth in developing economies, driving down global nuclear power capacity to 2040.

Nuclear power will decline rapidly without lifetime extensions

In advanced economies, the share of nuclear power in total generation drops from 18% in 2018 to 5.5% in 2040 in the Nuclear Fade Case of the New Policies Scenario, returning to levels not seen since the early 1970s. This compares with a share of 14% by 2040 in the central New Policies Scenario – the result of an estimated USD 18 billion of cumulative investment in existing and new reactors. Total nuclear generation is about 1 000 TWh lower in 2040 than in the central New Policies Scenario in advanced economies as a whole.

The largest reductions in nuclear output in the Nuclear Fade Case occur in the European Union, where the share of nuclear power in electricity supply falls from 25% in 2018 to less than 5% in 2040– the lowest level since the 1970s (Figure 22). This results in nuclear power falling behind wind power, hydropower, gas, solar photovoltaic (PV), bioenergy and coal to become the seventh-largest source of electricity in Europe; it is the leading source today. In the United States, the share of nuclear drops from 19% to just 8% of total generation in 2040 – the lowest level since before 1975. In other advanced economies, nuclear power's share falls by more than half. Canada sees its share of nuclear power slump by three-quarters to just 4% of electricity supply in 2040; Mexico stops producing nuclear power altogether. In Japan, nuclear power's contribution drop to just 2%. In Korea, with a relatively young fleet and five reactors under construction, the role of nuclear is more stable, its share of total electricity supply remaining close to 20% through to 2040. As a result of these declines in advanced economies, China emerges as the new global leader for nuclear power well before 2030, surpassing both the European Union and United States.

Figure 22. Share of nuclear power in electricity supply in advanced economies in the Nuclear Fade Case of the New Policies Scenario

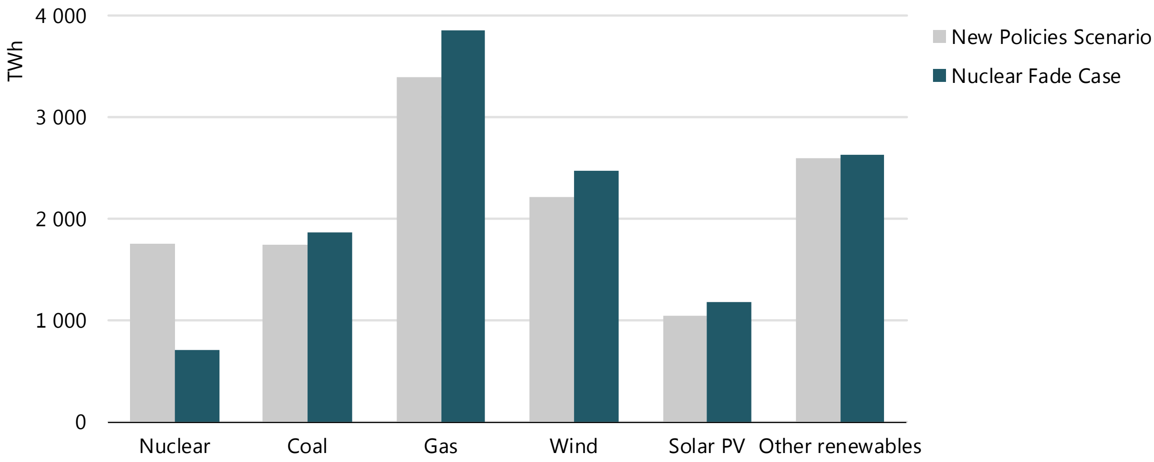


Without further investment, nuclear power will lose its position as the leading source of electricity in advanced economies, providing 6% of electricity supply in 2040 compared with 18% today.

Fossil fuels and renewables offset nuclear power reductions

The rapid decline of nuclear power output in advanced economies in the Nuclear Fade Case must be compensated by other sources, as the total electricity supply remains the same as in the central New Policies Scenario – rising from 11 200 TWh in 2018 to around 12 800 TWh by 2040. Nuclear output falls by 1 250 TWh – slightly more than the fall in coal-fired generation – between 2018 and 2040 in advanced economies. The two sources combined fall from 45% of electricity supply today to 21% in 2040. Most of the loss of nuclear production in the Nuclear Fade Case compared with the central New Policies Scenario is met by increased output from expanded generation from gas-fired and renewables-based power plants; coal-fired generation is only marginally higher (Figure 23). Fossil fuels – mainly gas – provide almost 60% of the increase in output needed to compensate for lower nuclear output; wind and solar power account for most of the rest. Natural gas becomes the single largest source of electricity in advanced economies in the Nuclear Fade Case, reaching 30% of the mix in 2040. The additional gas use in power generation increases overall gas consumption by 4% in advanced economies in 2040, which would put limited upward pressure on domestic and import gas prices. The share of renewables in total generation reaches nearly 50% in 2040, compared with 46% in the New Policies Scenario.

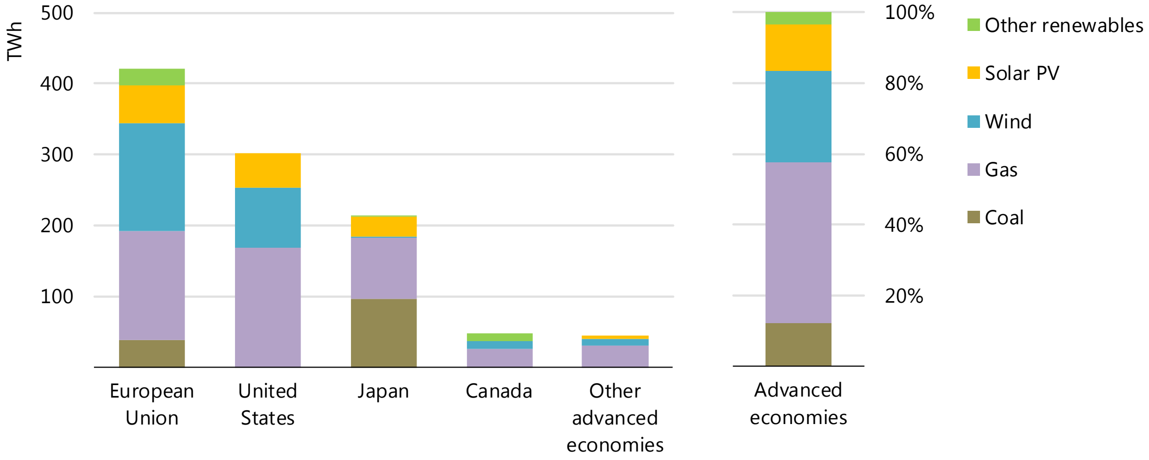
Figure 23. Electricity generation by source in advanced economies in the New Policies Scenario and Nuclear Fade Case, 2040



Natural gas contributes the biggest increase in electricity generation to compensate for less nuclear in the Nuclear Fade Case, with renewables – notably wind and solar PV – adding most of the rest.

The impact of lower nuclear output on other fuels varies by region, according to the policy environment, resource availability and local cost factors. In the United States, cheap gas resources mean it is the primary replacement for reductions in nuclear power (Figure 24). Policy support at the state level for wind and solar PV, along with their improving competitiveness, mean they are next in line to add to the mix. In the European Union, close to one-half of member states have formal coal phase-out plans, so there is limited scope to increase output from coal, making wind power the marginal source of electricity in those countries where nuclear output declines. Gas-fired generation also increases notably in the medium to long term in Europe. In Japan, coal and gas replace lower output from nuclear power in nearly equal measure, with existing capacity running more often and more new capacity being built (24 GW of gas-fired capacity and 12 GW of coal-fired capacity are added by 2040) alongside some additional growth in solar PV. In Canada, where nuclear generation falls by almost 50 TWh, natural gas offsets more than one-half of this amount, complemented by wind and solar PV.

Figure 24. Electricity supply by source in the Nuclear Fade Case relative to the New Policies Scenario, 2040



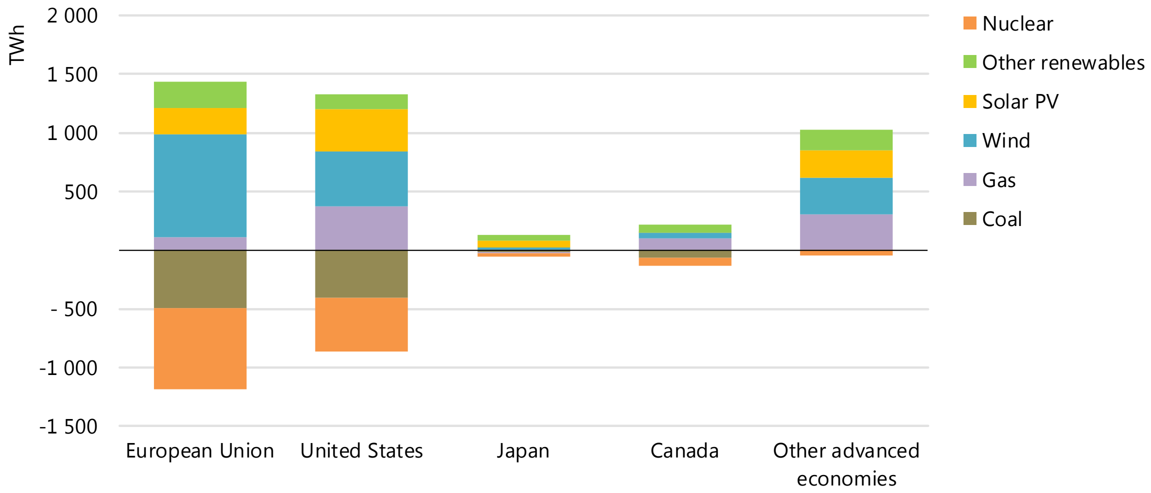
Fossil fuels account for the bulk of the increase in output needed to offset the decline in nuclear power compared with current trends.

Lower nuclear output reinforces the call on renewables

The sharp fall in nuclear output through the projection period in the Nuclear Fade Case means that renewables – especially wind and solar power – grow even more rapidly. Globally, wind power output more than triples between 2018 and 2040, increasing by 1 700 TWh – the biggest increase of any source in absolute terms. This growth comes from new wind farms, with around 720 GW of new wind power capacity added in advanced economies between 2018 and 2040. Of the total capacity additions, over 400 GW is in the European Union and about 175 GW is in the United States; Korea adds 32 GW, Canada 25 GW, Mexico over 20 GW and Australia about 20 GW. New solar PV projects account for around 950 TWh of additional electricity supply, with about 800 GW of capacity added – 300 GW in the European Union, 270 GW in the United States and more than 90 GW in Japan. Other renewables, including hydropower, bioenergy, geothermal and marine power, add to the growth in renewables capacity.

Despite the increase in the use of gas for power across advanced economies, the amount of generation provided by dispatchable sources falls dramatically in the Nuclear Fade Case of the New Policies Scenario (Figure 25). This changes the nature of the power supply in advanced economies and increases the need for flexibility (see the next chapter). In the European Union, the fall in nuclear and coal-fired power output totals more than 1 100 TWh between 2018 and 2040, equal to 30% of all electricity supply. Wind power accounts for the lion's share of the compensatory increase in output from other sources and surpasses gas as the largest source of electricity by 2030. The development of offshore sites contributes some 40% of the growth in wind power, concentrated in Belgium, Denmark, Germany, the Netherlands and the United Kingdom. Gas-fired generation also increases in the European Union, but mainly to meet the need for flexibility rather than baseload supply. Solar PV and other renewables expand to 2040 in the region, helping to lift the share of renewables overall from 14% in 2018 to 42% by 2040. With these developments, the CO_2 emissions intensity of electricity supply in the European Union falls by nearly one-half, to 136 grammes of carbon dioxide (gCO_2) per kWh – compared with a 60% reduction in the central New Policies Scenario.

Figure 25. Change in electricity supply by source over time in advanced economies in the Nuclear Fade Case of the New Policies Scenario by region/country, 2018 to 2040



Declines in nuclear and coal-fired generation are mainly compensated by growth in renewables and gas-fired generation.

In the United States, nuclear power generation in the Nuclear Fade Case falls by nearly 400 TWh between 2018 and 2040, similar to the decline in coal-fired output. Gas-fired generation compensates for one-half of these reductions, and wind, solar PV and other renewables for the rest. These sources also meet the additional 300 TWh of electricity demand projected to 2040. Despite the loss of low-carbon nuclear production, the expansion of renewables and the greater role for natural gas result in the emissions intensity of electricity in the United States declining by one-quarter to 2040. Even so, it remains above 300 gCO_2 per kWh – close to triple that of the European Union in 2040.

In the other advanced economies, nuclear power production drops by 170 TWh between 2018 and 2040 in the Nuclear Fade Case, with coal-fired power output also falling slightly. Renewables play the lead role in offsetting lower nuclear output and meeting growing demand, led by wind and solar PV. Gas also plays a significant role, particularly in Canada and Korea.

System adequacy relies more heavily on gas

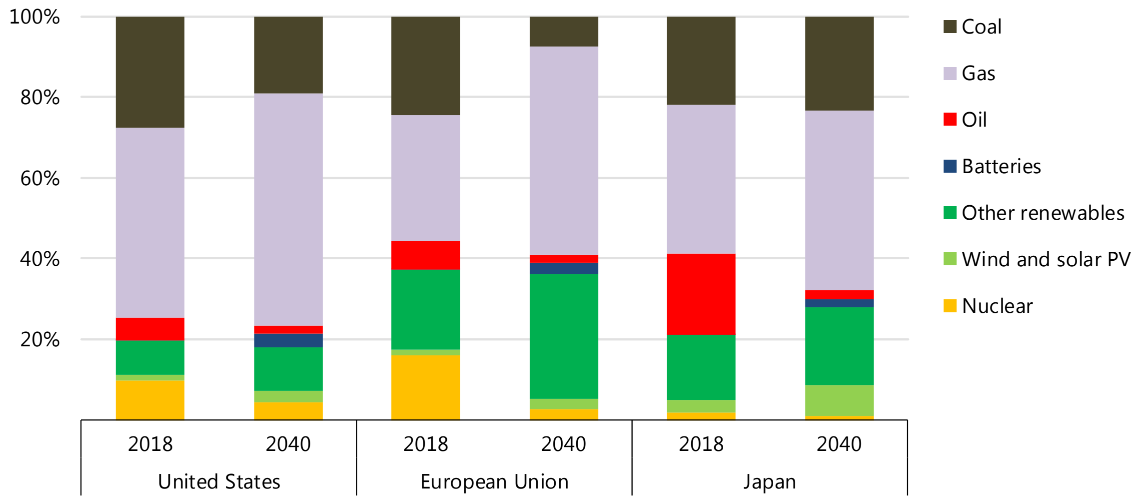
The decline in nuclear power in advanced economies in the Nuclear Fade Case accelerates the shift away from dispatchable capacity. This type of capacity, which includes power plants fuelled by coal, gas, oil and bioenergy, as well as hydropower and solar thermal technologies, accounts for over 80% of installed capacity today. By 2040, the amount of dispatchable capacity remains close to current levels, but its share of the total drops to just over 60%. This occurs in parallel with an increasing need for flexibility in power systems, as variable renewables in the form of wind power and solar PV make up a rising share of capacity. Flexibility, which historically has been provided primarily by dispatchable capacity, would need to come increasingly from energy storage, demand-side response and network interconnections (see the next chapter).

Less nuclear capacity accentuates the decline in dispatchable coal-fired capacity, which also contracts in advanced economies, from 590 GW in 2018 to under 400 GW by 2040 in the Nuclear

Fade Case. Policies have recently been established to phase out coal-fired power in 11 countries in Europe, including Germany, Italy and the United Kingdom, and also in Canada. Several other advanced economies are looking to limit the use of coal-fired generation as a way of reducing CO_2 and pollutant emissions. Difficult market conditions are putting financial pressure on the ageing fleet of coal plants. For example, in the United States, competition with gas-fired power plants has accelerated the retirement of old coal-fired stations.

With less nuclear capacity, the reliance on gas-fired power capacity to maintain sufficient flexibility in power generation to maintain the security of electricity becomes more pronounced in advanced economies in the Nuclear Fade Case. Gas is already the primary source of system adequacy in all regions, and this becomes even more the case over the projection period. Variable renewables are less able to provide system adequacy as their capacity is not always available, so other types of capacity are needed to ensure demand can be met at all times. The role of batteries is also projected to grow, though their contribution remains small. Of the capacity added to the system by 2040, gas-fired power makes the greatest contribution to adequacy, as well as flexibility in balancing the system (Figure 26). In the United States, where gas supply is abundant, gas-fired capacity expands by 220 GW to help meet the growing need for capacity, providing 55% of system adequacy in 2040. In the European Union, gas is no longer the main source of power supply in 2040, but nonetheless, its installed capacity grows by some 100 GW compared with current levels, meeting more than one-half of system adequacy needs by 2040. This is a substantial increase on today's levels and even higher than in the central New Policies Scenario. Difficult market conditions and limited prospects for high utilisation rates raise doubts about how this additional gas-fired capacity would be procured in Europe. Japan adds around 60 GW of gas-fired capacity and Mexico about 50 GW between 2018 and 2040. Aside from nuclear power, other low-carbon technologies also contribute to the adequacy of the system, including dispatchable renewables, notably bioenergy-fired plants, and fossil-fuelled power plants fitted with CCUS.

Figure 26. Contribution to system adequacy in the Nuclear Fade Case of the New Policies Scenario by source and region/country

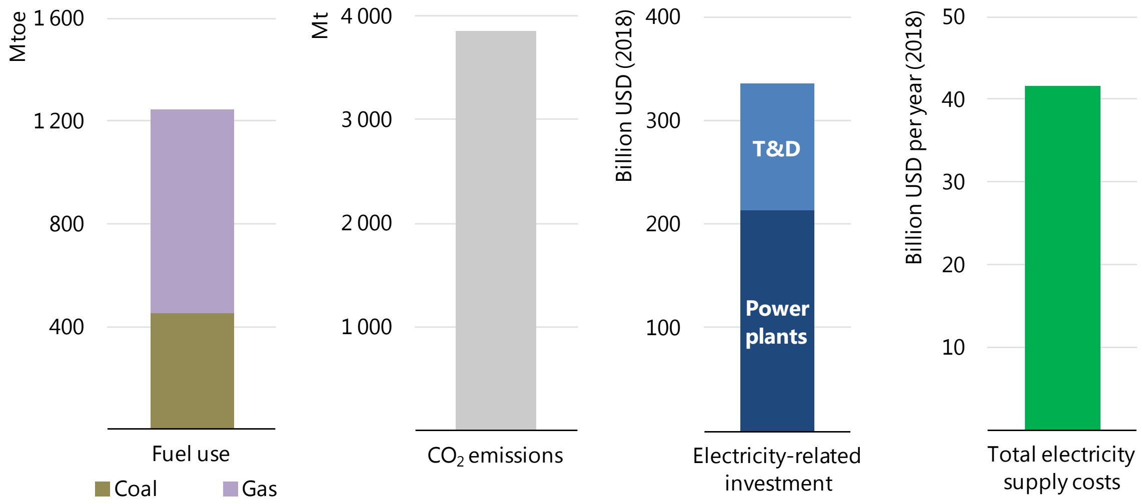


To compensate for the loss of nuclear power, more capacity from other sources – primarily gas-fired plants – is needed to ensure that the total capacity is always adequate to meet peak load.

Lower nuclear output results in higher costs to consumers

The sharp reduction in nuclear power output in advanced economies in the Nuclear Fade Case has wide-ranging implications for the energy system. The amount of coal and gas consumed in advanced economies increases due to higher coal- and gas-fired electricity generation relative to the central New Policies Scenario. Over the period 2018-40, cumulative coal use for power is 4% higher and gas use 8% higher (Figure 27). Most of the increase in coal use occurs in Japan and, to a lesser extent, in the European Union, where coal-fired plants operate at higher capacity factors. The European Union accounts for nearly one-half of the increase in natural gas use.

Figure 27. Change in key indicators in advanced economies in the Nuclear Fade Case relative to the New Policies Scenario, 2018-40



Note: Mtoe = million tonne of oil equivalent.

Lower nuclear would raise fossil fuel use and associated CO_2 emissions, increase power sector investment needs and add an average of 3% to consumer electricity bills.

The increased use of fossil fuels, notably coal in Europe and Japan, drives up CO_2 emissions in the Nuclear Fade Case. Cumulative emissions increase by almost 3 900 Mt, or 5.2%, to 2040 compared with the central New Policies Scenario. This is equivalent to more than twice China's CO_2 emissions from the power sector in 2018. The European Union accounts for more than 45% of the increase, followed by Japan with close to 40%.

Investment costs also increase because of the need to build additional greenfield power plants and refurbish existing non-nuclear plants, as well as to expand or upgrade T&D networks to tap into additional renewable resources. Extending the lifetime of nuclear power plants is generally a cost-effective means of supplying electricity over the projection period. In the New Policies Scenario, some USD 170 billion (in real 2018 dollars) is spent to extend the lifetime or increase the rated capacity of existing nuclear power plants in advanced economies. In the Nuclear Fade Case, lower nuclear investment leads to higher overall power sector investment; over the period to 2040, additional investment is close to USD 340 billion, or 5%, higher compared with the New Policies Scenario. Just under two-thirds of the increase in non-nuclear investment, or around

USD 210 billion, is spent on power plants. The remainder, over USD 120 billion, is invested in networks, with more projects requiring new connections to the grid and many renewables at lower voltages.

The combination of increased use of fossil fuels and higher investment costs results in an increase in the overall cost of electricity supply and higher prices to consumers in advanced economies in the Nuclear Fade Case. The cumulative cost of supply is around USD 750 billion higher than in the New Policies Scenario over 2019-40. As a result, consumers pay an average of USD 35 billion, or 3%, per year more than in the New Policies Scenario over that period. The burden of these additional costs is not equal across advanced economies. The increase in costs is larger in countries with the largest reductions of nuclear power and where imported fuels are needed to compensate for reduced nuclear output.

Implications of the Nuclear Fade Case in the Sustainable Development Scenario

Sustainable development calls for more low-carbon energy

The Sustainable Development Scenario depicts an energy pathway that simultaneously achieves three major United Nations (UN) policy objectives: a trajectory of energy-related CO_2 emissions consistent with achieving the Paris Agreement's goal of holding the increase in the global average temperature to well below 2 °C, a measurable improvement in local air quality and the achievement of universal energy access. Due to the scale of these challenges, the policies and measures that are necessary to meet these objectives go well beyond the policies in place or planned, especially with respect to energy efficiency and ramping up low-carbon energy supply.

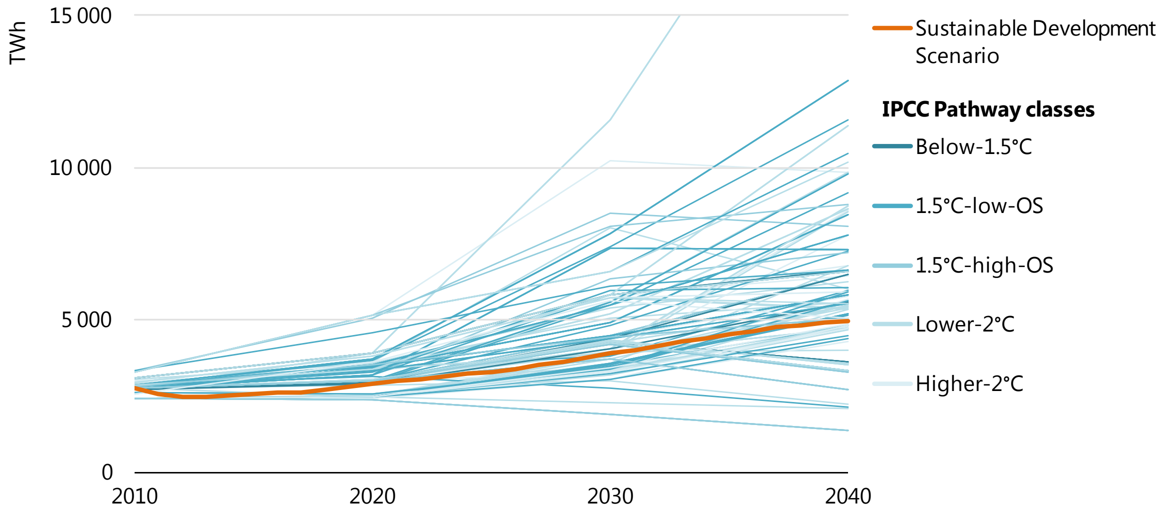
Electrification and the decarbonisation of power generation together play an important role in achieving the multiple UN Sustainable Development Goals, reflecting that the low-carbon sources that are seeing the fastest technological improvements and that can be scaled up most easily are all power generation technologies. Moreover, the use of electricity does not give rise to any pollution at the point of use. While the share of electricity in total energy consumption worldwide has been growing for many years, the rate of increase in that share doubles in the Sustainable Development Scenario, compared with only slightly faster in the New Policies Scenario. The output of low-carbon electricity also increases far more quickly in the Sustainable Development Scenario, tripling by 2040, compared with a 60% increase in the New Policies Scenario. As a result, the global average carbon intensity of electricity, which has fallen by just one-quarter over the past two decades, declines by more than 80% between 2018 and 2040 (compared with 40% in the New Policies Scenario). Wind and solar power, which already account for the bulk incremental generation in the Sustainable Development Scenario, grow much faster, with their combined output expanding by a factor of almost ten between 2018 and 2040.

Nuclear power makes an important contribution to the quicker expansion of low-carbon electricity supply in the Sustainable Development Scenario. As it does not generate any pollution, nuclear power also makes an important contribution to the air quality targets in that scenario. Its impact on energy poverty is much less significant, as most of the world's nuclear fleet will still be in countries where access to modern energy is already universal, or close to being so. Nevertheless, nuclear power plants under construction in countries such as

Bangladesh and India will help provide universal access in those countries. Global nuclear production is projected to reach 4 960 TWh in 2040 – 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 412 GW today. The largest components of the increase are in China and, to a lesser extent, India, where coal represents most of power generation. 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 there largely replace baseload coal, 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 amount of nuclear capacity, notably the United States. 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 it into the electricity system. In Japan, nuclear production recovers almost to the level it was at 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.

Figure 28. Global nuclear power production in the Sustainable Development Scenario compared with IPCC scenarios consistent with 2°C warming



Note: All IPCC scenarios included for 4 pathway classes: Below-1.5°C, 1.5°C-low-OS, 1.5°C-high-OS and Lower-2°C and Higher-2°C.

Source: Huppmann et al. (2018), release 1.1.

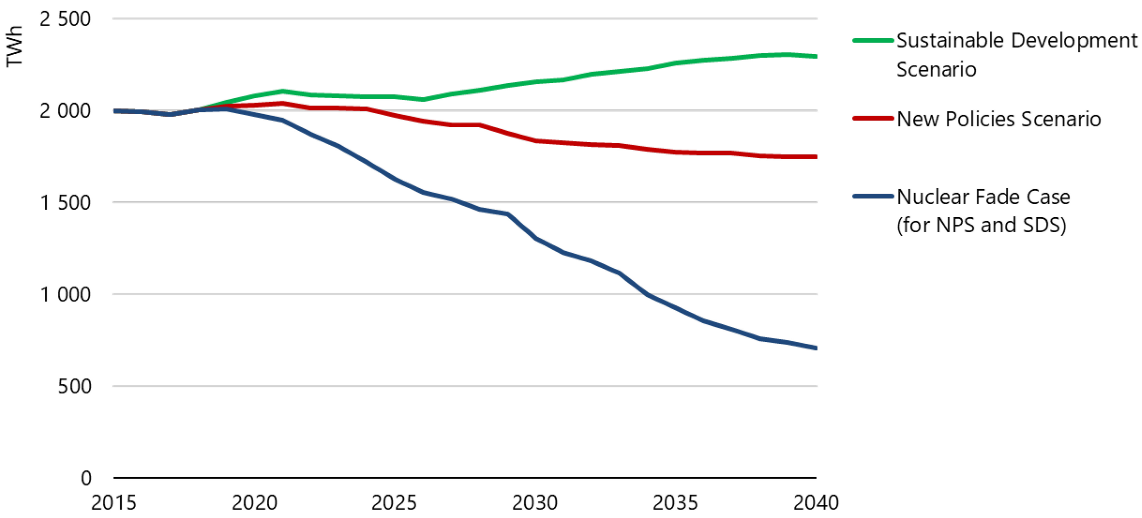
Nuclear power production in most low-carbon scenarios is higher than in the IEA Sustainable Development Scenario.

Nuclear power's potential role in decarbonisation is well established. Among the pathways consistent with 1.5°C to 2 °C – scenarios that limit peak warming to below 2 °C during the entire

21st century with 50% likelihood or higher – reviewed by the Intergovernmental Panel on Climate Change (IPCC) in its latest Special Report on Global Warming of 1.5°C (SR15) (Rogelj, Shindell, & Jiang, 2018), nuclear power production makes a major contribution to decarbonisation. Indeed, the IEA Sustainable Development Scenario is among the more cautious in terms of nuclear expansion (Figure 28).

Applying the Nuclear Fade Case to the Sustainable Development Scenario results in a significant short-fall in nuclear output in advanced economies. By 2040, output falls to a level that is 70% below that in the central Sustainable Development Scenario, compared with 25% lower in the New Policies Scenario (Figure 29). The output gap in 2040 amounts to 1 600 TWh, equal to 8% of total power generation in the Sustainable Development Scenario. To achieve the same pace of emissions reductions, this shortfall must be made up with increased output from other low-carbon energy sources in the Nuclear Fade Case.

Figure 29. Nuclear power production in advanced economies by scenario

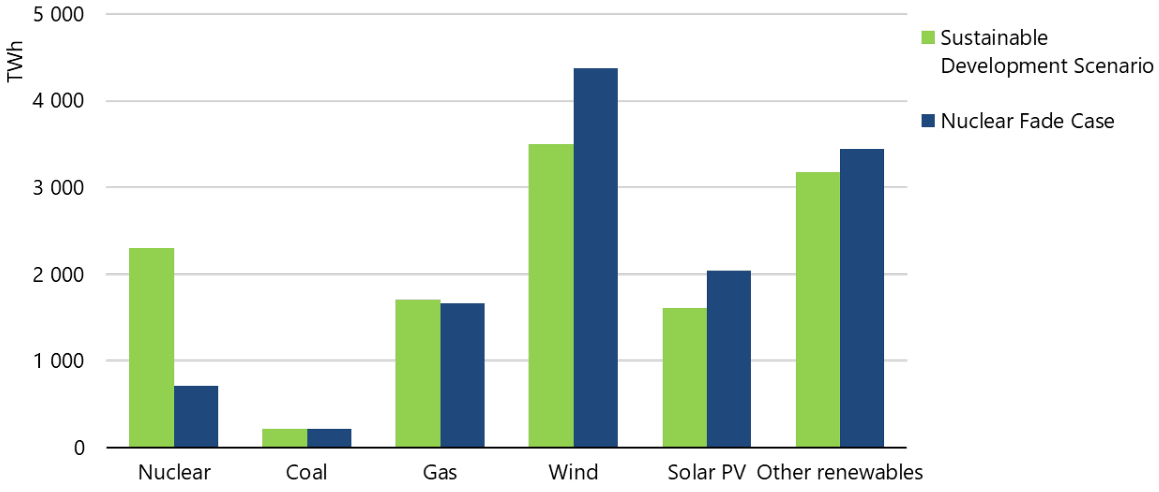


A large shortfall in low-carbon electricity would emerge without nuclear lifetime extensions or new projects, calling on other low-carbon sources to fill the gap to keep to a sustainable energy path.

Wind and solar are best positioned to fill the gap left by lower nuclear output

It is possible to achieve the emissions pathway described in the Sustainable Development Scenario in advanced economies with no new investment in nuclear power, though it is significantly more difficult. Indeed, some countries and jurisdictions have ambitious decarbonisation objectives coupled with a legally binding ban on nuclear construction, or plan to phase it out, and are designing policies to achieve those objectives. In view of the constraints on other technologies, wind power and solar PV plug most of the gap left by reduced nuclear output in advanced economies in the Nuclear Fade Case compared with the central Sustainable Development Scenario (Figure 30). Increases from other renewables – including hydro, bioenergy, CSP and geothermal – help fill the gap from lower nuclear power production.

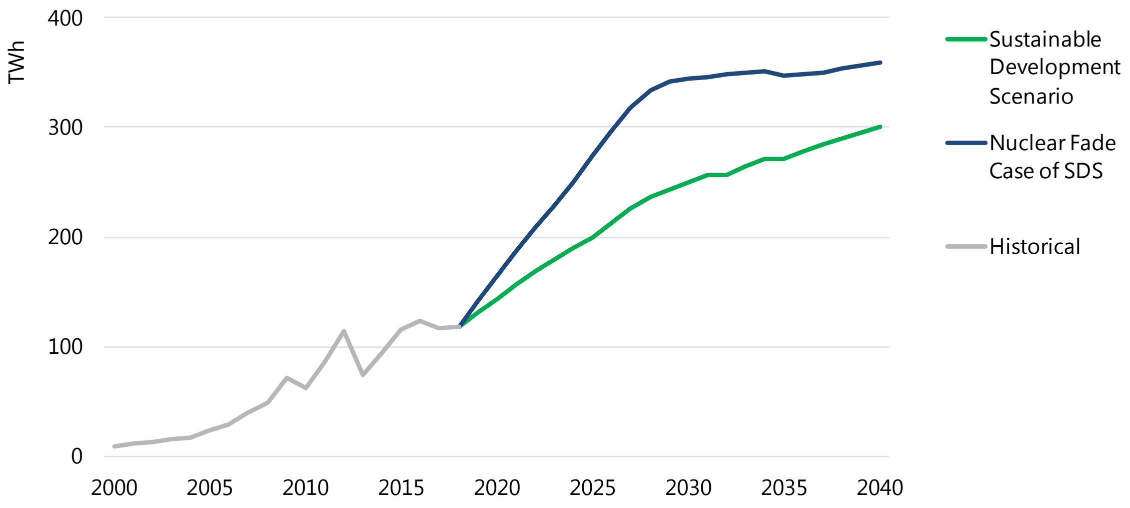
Figure 30. Electricity generation by source in advanced economies in the Sustainable Development Scenario and Nuclear Fade Case, 2040



A combination of wind power, solar PV and other renewables is needed to make up the shortfall in nuclear output in meeting sustainable development goals.

In the Nuclear Fade Case, the rate of increase in wind and solar PV power output in advanced economies to 2040 is roughly one-third higher than in the main Sustainable Development Scenario and three times higher than that of the past decade (Figure 31). This means that power production from wind and solar PV rises six-fold from 2018 to 2040 (instead of five-fold in the Sustainable Development Scenario). Wind and solar PV account for over half of total electricity generation in advanced economies in 2040 in the Nuclear Fade Case, compared with about 40% in the central Sustainable Development Scenario and 8% in 2018.

Figure 31. Combined wind and solar power production growth in advanced economies in the Sustainable Development Scenario and the Nuclear Fade Case



To achieve sustainable energy development, output from wind and solar power would need to expand twice as fast as in the past, and three times as fast in the absence of new nuclear investment.

The increase in wind and solar PV capacities in the Nuclear Fade Case is much greater than the loss of nuclear capacity, because their load factors are far lower. Additions of wind and solar capacities in 2017 in advanced economies amounted to 55 GW, which would be expected to produce around 240 TWh per year under normal weather conditions. This is the same order of magnitude as power generated by the 34 GW of nuclear capacity added at its historical peak in 1977, which was capable of producing around 250 TWh per year. However, while wind and solar PV capacity additions have continued to increase over the last four years, the energy output from that additional capacity has fallen, as investment has shifted to solar PV, which typically has a lower load factor than wind turbines. The much faster rate of growth in VRE also has important implications for the provision of flexibility (see the next chapter).

There are sufficient geographical resources to accelerate the rate of capacity additions of wind and solar PV in advanced economies to that required in the Nuclear Fade Case of the Sustainable Development Scenario. Both technologies are mature; there is some slack in turbine and PV panel manufacturing capacity globally, and which could be increased sufficiently with enough investment. Learning by doing and economics of scale have been successful in reducing costs to such a degree that, in some regions, the LCOE is often lower than that of either conventional thermal generation or nuclear generation (see the previous chapter). Wind and solar PV are modular technologies that are well suited to high-volume modern manufacturing, offering further opportunities to reduce costs. Potential sites are much more widely available than for geothermal power plants, and there is no feedstock requirement like for bioenergy power plants. While the scale of manufacturing and project management capabilities would need to increase hugely in the Nuclear Fade Case of the Sustainable Development Scenario, the barriers to achieving that are far easier to overcome than those facing the nuclear industry.

Stronger policy support for wind and solar PV would be necessary to scale up deployment to the degree needed. Policies drive nearly all renewables investment. Under long-term capacity auctions, which have emerged as the favoured regulatory mechanism for securing such investment, the amount of capacity added is determined by policy makers, while the auctions determine how much is paid to the investors. Other investment channels that do not involve government support, such as voluntary corporate purchases of renewable energy and wholesale market-based renewables investment, which have been seen in Europe and some regions of North America, have become more important in recent years, but investment levels remain small. For stronger policy support for wind and solar PV to be effective, various non-market barriers would need to be overcome, including public and social acceptance of the projects and the associated expansion in network infrastructure (see the next chapter).

CCUS or dispatchable non-hydro renewables could help fill the gap

There are several alternatives to wind and solar power that could, in theory at least, plug the gap in low-carbon production left by the loss of nuclear power in the Nuclear Fade Case. However, none of them appear to be in a position to expand rapidly soon. The main options are CCUS and dispatchable non-hydro renewables.

In principle, the loss of nuclear output in the Nuclear Fade Case could be offset by the much faster deployment of CCUS at conventional coal- and gas-fired power stations, yielding a similar CO_2 emissions trajectory to that in the Sustainable Development Scenario. This would enable one dispatchable type of generating capacity to be effectively replaced by another, with minimal implications for system flexibility. Retrofitting existing plants could also minimise modifications to network infrastructure as they are already connected. However, deployment of CCUS at an even faster rate than envisaged in the Sustainable Development Scenario would be difficult to achieve. As an emerging technology, there are enormous uncertainties surrounding the technical and economic viability of deploying CCUS on a large scale. The rate of deployment of CCUS is presently running at just 0.15% of that required in the Sustainable Development Scenario by 2040. Recent high-profile projects have suffered similar cost overruns and project management problems as new nuclear projects, and new CCUS projects are facing similar investment barriers. Achieving the rate of CCUS deployment in the Sustainable Development Scenario would already be a major achievement; expecting an even faster rate to compensate for lower nuclear production is probably unrealistic.

There are also limits on how much dispatchable non-hydro renewables capacity – essentially bioenergy (biomass) and geothermal power – could be expanded beyond the rate of increase already projected in the Sustainable Development Scenario. In both cases, electricity is produced by a steam turbine and is able to provide the same capacity adequacy and system services as conventional thermal or nuclear generation. Geothermal plants normally run as baseload capacity, while biomass-fired plants can take advantage of the easy storability of the fuel to ramp flexibly. Nevertheless, there are constraints on the availability of sustainable biomass feedstock. The rate of expansion of bioenergy-based generation already pushes up against ecological constraints in the Sustainable Development Scenario – the projected increase in this type of generation to 2040 is equivalent to 1 billion tonnes of wood per year being burned. That scenario also incorporates a large expansion of biomass heat and liquid biofuels, which compete for the same sustainable ecological potential. Using even more bioenergy to compensate for low nuclear power would put further pressure on feedstock supply.

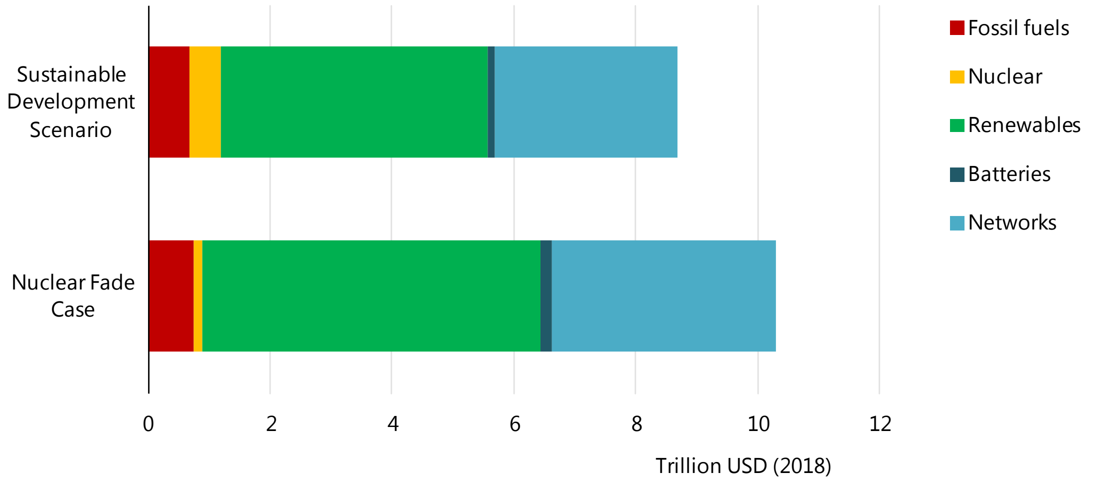
The scope for expanding geothermal power using current technologies is also limited. The potential varies by country and region, but is significant only in active zones such as some countries in Southeast Asia, Iceland and Kenya. Second-generation geothermal technologies based on hydraulic fracturing (fracking) of hot dry rock may allow production to be scaled up considerably, as it could be deployed in many more areas. But it is still at the experimental stage, and costs would probably be high initially. According to the IEA *Geothermal Technology Roadmap*, it might be possible for output to reach a level equal to about 40% of current global nuclear power by mid-century, but only under optimistic assumptions about the rate of technological progress (IEA, 2011).

Achieving sustainability with lower nuclear power production raises investment needs and the cost of the energy transition

Investment needs in power plants and the network in advanced economies increase substantially in the Nuclear Fade Case compared with the central Sustainable Development Scenario. Despite recent declines in wind and solar capital costs, building new renewable capacity requires considerably more capital investment than extending the lifetimes of existing nuclear reactors. Part of the higher cost is due to the need to extend the transmission grid to connect new plants, which are often located in areas where transmission lines are either non-existent or inadequate to handle the extra generating capacity. Lifetime extensions at existing plants require no additional investment in the grid. The much bigger additions of VRE capacity in the Nuclear Fade Case would inevitably mean exploiting less accessible sites.

Over the next two decades, around USD 1.6 trillion more investment would be needed in net terms in the electricity sector in advanced economies in the Nuclear Fade Case than in the central Sustainable Development Scenario (Figure 32). Although investment in nuclear power would be close to USD 400 billion lower, roughly USD 1.2 trillion more investment would be needed in renewables-based generating capacity and around USD 700 billion in network upgrades to integrate the larger renewables fleet. A smaller amount of additional investment in gas-fired capacity (mainly for system adequacy purposes) and in battery storage, totalling around USD 100 billion, would also be needed.

Figure 32. Cumulative electricity sector investment in advanced economies in the Sustainable Development Scenario and Nuclear Fade Case, 2019-40



An additional USD 2 trillion of investment in renewables and in networks would be required to achieve sustainability, far exceeding the USD 400 billion reduction in nuclear investment.

The European Union accounts for the largest share of the increase in power sector investment in the Nuclear Fade Case, calling for an additional USD 560 billion from 2019 to 2040. Renewables account for the bulk of the incremental investment (USD 470 billion) in the Nuclear Fade Case of the Sustainable Development Scenario followed by transmission and distribution networks (USD 240 billion), more than outweighing the USD 210 billion fall in nuclear spending. Average annual wind and solar deployment would need to double the recent pace and be one-third higher compared with the central Sustainable Development Scenario.

Achieving the clean energy transition in Japan without further nuclear investment raises investment needs by USD 540 billion from 2019 to 2040. This is because the restoration of existing nuclear capacity and new plants play a major role in the Sustainable Development Scenario. With the decline in coal-fired power, additional investment in renewables, mostly solar PV, and distribution networks is close to USD 600 billion, more than ten times the fall in nuclear investment (USD 55 billion). Japan is a special case as it recently experienced a wave of investment in solar PV, which proved to be unsustainable. For example, in 2015, generous solar feed-in tariffs stimulated deployment of almost 11 GW, over 20% of global solar PV deployment in the year (Japan represents less than 5% of global electricity demand). This upswing and strong solar PV deployment in other recent years created a significant financial burden on consumers and considerable technical difficulties in integrating the new capacity into the electricity system. This led to regulatory changes to bring solar investment down to more manageable levels. The Nuclear Fade Case of the Sustainable Development Scenario would require a renewed surge in spending on solar and wind power to facilitate a doubling of the rate of deployment. Given the limited prospects for wind power in the near term, the deployment of solar PV would need to be significantly above the 2015 peak.

In the United States, cumulative power sector investment is about USD 370 billion more in the Nuclear Fade Case compared with the central Sustainable Development Scenario. Most of the additional investment is directed towards renewables, where investment rises by over USD 300 billion. Investment also increases in distribution networks (USD 80 billion) and to a lesser extent in batteries (over USD 30 billion) and in transmission (close to USD 20 billion). The fall in nuclear investment is USD 100 billion. The rate of deployment of wind and solar PV in the Nuclear Fade Case is double that observed in recent years. But the need for more renewables is likely to be even greater beyond 2040, when the remaining nuclear plants would shut down. The contribution of nuclear power is still significant in 2040 even in the Nuclear Fade Case, as many plants commissioned in the 1980s with licences to operate until 60 years of age would still be operating. However, by 2040, most of these surviving plants would be within five years of closure.

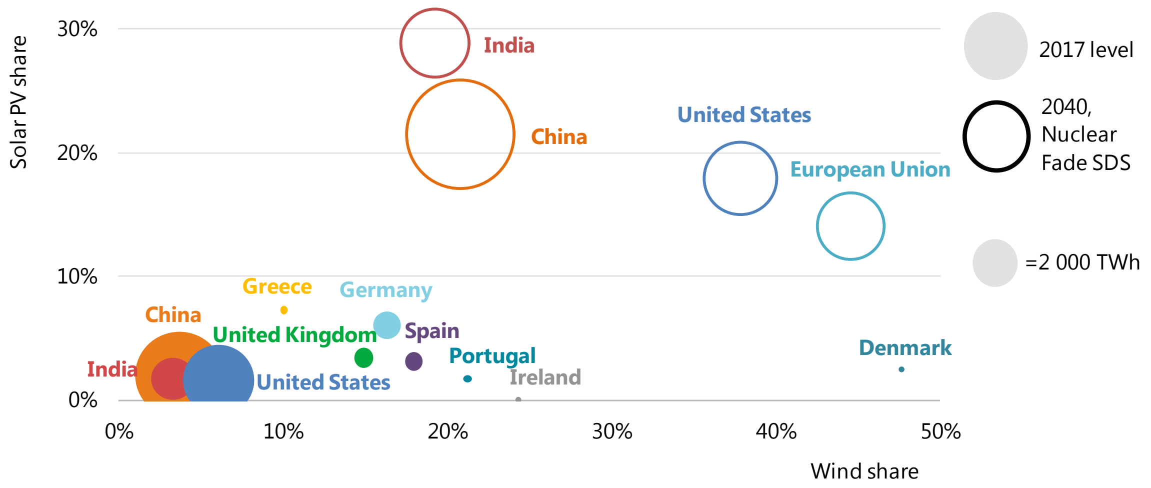
The total costs of electricity supply from 2019 to 2040 are 5% higher in advanced economies in the Nuclear Fade Case of the Sustainable Development Scenario than with nuclear investment. The additional investment required is not offset by savings in operational costs, as fuel costs for nuclear power are low, and operation and maintenance is a minor portion of total electricity supply costs. Electricity supply costs are close to USD 80 billion higher per year on average for advanced economies as a whole. The burden is largest where nuclear power has the potential to play the largest role in the clean energy transition due to modest renewable energy resources, and where fuels are imported. For example, the additional cost of the clean energy transition would be 10% higher in Japan, compared with 6% higher in the European Union and 3% higher in the United States.[9]

[9] Electricity supply cost estimates may not fully capture the network-related system integration costs for the rising shares of wind and solar PV. Detailed grid integration studies would be required in order to accurately estimate the network-related integration costs for the described generation mix.

4. Achieving sustainability with less nuclear power

Boosting renewables-based power generating capacity in advanced economies to fully compensate for the short-fall in low-carbon electricity in the Nuclear Fade Case as applied to the Sustainable Development Scenario is achievable in principle. It would nonetheless require an extraordinary effort by policy makers and regulators to create the conditions needed to bring forth the required investment. However, the challenge concerns other issues in addition to the amount of generating capacity needed. Wind and solar PV are not perfect substitutes for nuclear power in two important respects. First, wind and solar power plants occupy much larger amounts of land than nuclear power stations, which can give rise to constraints on siting. Second, wind and solar power are types of VRE with much lower load factors than nuclear power; this augments the need for flexibility in the electricity system as the share of wind and solar power in the total generating capacity rises. The transition to a clean energy system hinges on overcoming these hurdles. Large electricity systems would have to move to high shares of variable renewables (Figure 33), which is unprecedented historically.

Figure 33. Share of wind and solar in selected electricity systems today and in 2040



Note: Circles are proportional to the system size.

In the Sustainable Development Scenario, especially in the Nuclear Fade Case, large systems would need to overcome land use, infrastructure and flexibility barriers of a high renewable share.

Land use and permitting

Gaining public acceptance of even more renewable energy projects will be hard

Siting is potentially a greater constraint on wind and solar power than on nuclear power. Nuclear power plants are extremely efficient in using land owing to the energy density of nuclear fission. A nuclear facility capable of producing an average of 2 GW at full capacity normally occupies only a couple of hundred hectares (ha) of land, including all the supporting functions. This is far less than the land needed for an equivalent amount of wind or solar power capacity. A 100 MW solar farm located close to the Equator typically requires 100 ha and would operate at best one-quarter of the load factor of the nuclear reactor, resulting in land needs at least 40 times greater for the same annual production.[10] In temperate climates, where most nuclear power plants are located, the land required can be as much as 100 times more. Onshore wind farms require much more space, but unlike solar farms, most of the land can be used for its original purpose once construction has been completed. In the case of solar PV, there is a large potential for using the rooftops of residential and commercial buildings. But, in densely populated areas, such as most Western European countries, Japan and the coastal regions of North America, social and community acceptance of wind and solar power is already emerging as a significant hurdle to siting new projects in many locations. Local and wider populations often object to such projects on the grounds of visual impact, particularly in areas of natural beauty, and in the case of wind, noise and the possible impact on bird populations.

The scale of deployment of renewables in the central Sustainable Development Scenario already implies the need for stringent efforts on the part of policy makers to gain public acceptance. For example, around 150 000 wind turbines are installed across the United States and a similar number in Europe through to 2040. Given that the annual production of a 1 GW nuclear reactor is equal to that of about 2 000 wind turbines, the Nuclear Fade Case implies the need to build 400 000 more turbines across all advanced economies. It is far from certain that social and community objections to this scale of deployment could be overcome with the required speed.

One possible strategy to get around this problem is to concentrate the location of new projects in less densely populated areas, preferably with attractive natural wind or solar resources. In the case of wind, this is already happening in North America: most of the deployment is taking place in the "wind corridor" from North Dakota to Texas, which has a low population density, making access to land much easier and reducing problems of public acceptance. The average load factor of turbines in this wind corridor is close to double the global average. Transmission investment within the region has also been robust. But a rapid scaling up of deployment in this region is likely to encounter problems: the share of wind in total generation in some states in the wind corridor is already around four times the national average of 8%, ranging from 32% to 37% in Oklahoma, Kansas and Iowa. Further increases in capacity would soon result in output frequently exceeding local demand, necessitating large investments in transmission infrastructure to export the surplus electricity to consumption centres outside the region. Obtaining permits for new long-distance transmissions lines can be extremely time consuming, with no guarantee of success (Box 8).

[10] Bioenergy is even more demanding: the biomass needed to fuel a power station to produce the same amount of electricity as a nuclear power plant requires around 10 000 times more land.

Box 8. The Plain and Eastern ultra high voltage direct current transmission project

The proposed Plain and Eastern long-distance transmission project aims to connect the best wind sites in Oklahoma with demand centres in the much less windy south-east United States, which relies heavily on nuclear power, and illustrates the difficulties of replacing nuclear power with renewables. The project is based on ultra high voltage direct current (UHVDC) technology – a maturing technology well suited for point-to-point one-directional flows over distances of more than 500 kilometres (km). UHVDC has been deployed mainly in China up to now, but there is growing interest in North America and Europe. The prospects of the Plain and Eastern line ever being built are still uncertain nine years after the permitting process started. Even if it clears all the remaining legal hurdles and is finally built, it will transport the equivalent of the production of a two-reactor 2 GW nuclear plant, supplying less than 3% of the electricity demand of the south-east region.

Resistance to siting wind and, to a lesser extent, solar farms is a major obstacle to scaling up renewables capacity in many parts of Europe. There is no equivalent of the US wind corridor in Europe. The best onshore wind sites are at or near the coast, where population density tends to be high and tourism is a major economic activity. Public opposition to new wind farms is affecting deployment in some locations such as Brittany in France or the Midlands in the United Kingdom.

Siting wind farms offshore is one solution, but there are cost and infrastructure barriers

With increasing public opposition to wind farms, the focus of investor interest in Europe is shifting to offshore sites, primarily in the North Sea and, to a lesser degree, the Baltic Sea. Recent progress in developing offshore wind projects has certainly been impressive. Due to a combination of successful transition to a new generation of larger turbines, accumulated experience in managing offshore projects and increased investor confidence, costs have fallen sharply, exceeding most investors' expectations. While offshore projects can have an impact on offshore activities like fishing and shipping, gaining public acceptance and permitting are often easier than for onshore projects. In addition, offshore wind output is usually more stable and more predictable, which makes it easier to integrate capacity into the system and reduces the need for modifications to the network. While Europe pioneered the technology, it is also emerging in the north-east United States as a strategic response to barriers to local onshore wind farms and long-distance transmission lines.

However, the large increase in offshore wind capacity called for in the Nuclear Fade Case of the Sustainable Development Scenario raises complex questions about the need for supporting infrastructure. Most offshore wind farms have a point-to-point connection to an onshore grid. If offshore wind power is deployed on a much larger scale, it would be more efficient to build an interconnected offshore grid. This would probably make use of direct current (DC) transmission technology, which is more efficient than AC lines over long distances. Nonetheless, some technological, policy and grid co-ordination obstacles would need to be addressed. While point-to-point DC transmission is mature, interconnected DC grids are still at an early stage of deployment and some technical problems need to be overcome. The capacity of undersea DC cables is far easier to scale up than that of an existing onshore network that uses AC technology. In some cases, the landfall points for new offshore projects are located near to a major load centre, like London, but in others, they are located close to an existing network bottleneck, such as in northern Germany.

Technological advances (e.g. floating wind power) might help resolve some of these problems. There are some promising pilot floating wind projects under development, and innovation is progressing. It could be an important option in regions where onshore wind is limited by land-use constraints and water depth rules out the development of conventional offshore projects. Japan and California fall into this category. The prospects for floating wind power are still uncertain and it therefore plays a minor role only in the Sustainable Development Scenario.

Scaling up solar power massively would call for more transmission capacity

Investment in solar PV faces fewer land-use and public acceptance barriers, although it may prove difficult to expand T&D networks to accommodate the extra capacity for large solar projects and decentralised solar output. There is a considerable potential for decentralised production on top of buildings in advanced economies, though it would not be sufficient to provide all the solar capacity needed in the Nuclear Fade Case of the Sustainable Development Scenario. Installing solar PV panels on top of every single-family house in the United States would generate only around one-half of current nuclear production and meet only 11% of total low-carbon generation needs in 2040.[11] But for ground-based projects, there is a lot of other space that could be used. There are promising initiatives under development world wide for ground-based utility-scale projects using degraded land, such as former industrial and mining sites, where permitting is likely to be much easier.

The key constraint on expanding solar power capacity that might necessitate building more long-distance transmission capacity is the extent to which solar can satisfy winter demand in a given region. The United States is in an advantageous position of having some of the world's best solar potential in close proximity to major load centres like Los Angeles and Las Vegas, where summer peak demand is driven mainly by air conditioning. However, in some northern regions of the United States and large parts of Canada and Europe, electricity demand peaks in winter because of its widespread use for space and water heating. The trend towards electrification of heating in buildings is set to greatly increase the winter-summer discrepancy between solar output and winter load in these regions. In the United States, a substantial proportion of the US nuclear fleet and some of those plants most at risk of premature decommissioning are located in the north-east and the midwest, where the need for renewables production to replace nuclear capacity in the Nuclear Fade Case is greatest. Proposals to build long-distance transmission line to link sunny regions in the south with distant load centres face similar legal and public acceptance barriers as projects to transmit power from the wind corridor.

The imbalance between solar output and winter power demand is pronounced in Europe. At present, around one-half of European solar capacity is in Germany and the United Kingdom, where solar output in the winter is minimal. Even in the Mediterranean region, which has much better solar resources than northern Europe, solar potential is less than in the US Southwest. Improving interconnections within the European Union to address these regional imbalances is

[11] With 56 million single family homes, 5 kW of panels in each home and an average load factor of 17%, total output would be 420 TWh per year, compared with nuclear production of around 807 TWh in 2018.

a policy priority, but progress in linking the Mediterranean with Northern Europe has been slow. In some cases, geographical barriers and competition from other land uses, primarily tourism, has forced project developers to opt for capital-intensive solutions, such as routing cables in tunnels under the Alps from Italy to France and Austria, and laying cables under the Bay of Biscay from Spain to France. The capacity of the north-south interconnection projects that are being held up by permitting problems is an order of magnitude lower than that necessary for Mediterranean solar power to play a meaningful role in meeting winter demand in Northern Europe.

In Japan, improving the limited regional interconnections is a key policy priority. The geography of the country is conducive to undersea DC transmission technology. Better interconnectivity could unlock wind resources in Hokkaido in the north and solar resources in Kyushu in the south, both of which are underexploited because of network bottlenecks. However, given the geography and population density of the country, land use will surely remain a major barrier to the rapid expansion of wind and solar capacity.

Difficulties in permitting new transmission lines could limit the role of renewables

The need for long-distance transmission lines will inevitably grow as the deployment of new renewables capacity rises and the focus of development of renewables moves to more remote locations. It is not possible to predict whether these difficulties would make it impossible to achieve the increase in low-carbon electricity production required in the Sustainable Development Scenario, let alone the Nuclear Fade Case. However, there is a clear risk that legal and public acceptance hurdles could prove insurmountable. While the overall additional investment in networks is less than that in renewables, the infrastructure required is still substantial. Experiences in North America and Europe suggest that even network expansion projects with secured financing often struggle to move ahead due to licensing and permitting issues. There are currently 34 million km of T&D lines in advanced economies, which would need to grow to as much as 48 million km by 2040 in the Sustainable Development Scenario. The scale of investment in lines is uneven across regions. In OECD Europe, 5.5 million km of new lines are needed, of which more than 90% are distribution lines. The United States has 11 million km of network lines, which need to increase to around 14 million km by 2040. However, Japan only needs to add 200 000 km to its current network of 1.55 million km over the same period.

Making the Sustainable Development Scenario a reality, especially in the Nuclear Fade Case, will call for policy measures to address barriers related to land use and permitting. However, the experience in most densely populated democracies is that such measures are highly controversial and politically difficult. Given that the Sustainable Development Scenario would already require potentially controversial measures like high carbon prices, any further increase in the social acceptance bar may prove a step too far politically for many advanced economies. Of course, nuclear power also needs to be accepted by the public if it is to play a role in meeting the need for low-carbon energy. This can be a major obstacle to a greenfield development, and in the case of Japan, to authorising the restart of an existing unit. But public resistance is generally less pronounced in the case of lifetime extensions to allow the continuous safe operation of existing plants. In fact, local communities are often in favour of lifetime extensions because of the employment and economic benefits that nuclear power plants bring. The new nuclear power plants that are built in advanced economies in the Sustainable Development Scenario are predominantly on existing sites that benefit from existing transmission interconnections and where social acceptance is stronger.

System integration of renewables and flexibility

Flexibility of the power system will need to be enhanced

Integrating new VRE capacity – essentially wind and solar power – into the overall electricity system will be critical in making the Sustainable Development Scenario a reality, even more so in the absence of new investment in nuclear power in advanced economies. As the share of VRE grows, the need for flexibility also increases, because VRE is not dispatchable, i.e. it is not always available when needed. An electricity system needs to balance supply and demand at all times. Demand patterns change hourly, daily, weekly and with the seasons; system operators need to follow that by controlling supply, and where available, activating demand-side response. Demand for and supply of electricity are subject to random variability, as they are driven by weather and economic fluctuations as well as unplanned technical outages. Flexibility is needed for the system to be capable of maintaining a constant balance of electricity supply and demand in the face of uncertainty and variability in supply and demand. This is not a new phenomenon; even conventional power systems without variable renewables need flexibility from various sources. These include thermal generation and hydropower capacity, which can be ramped up and down at short notice, together with a combination of pumped storage hydropower, interconnections with other networks that allow electricity to be imported when needed, and demand-side response from large industrial and commercial consumers. These traditional sources of flexibility provide around 375 GW of flexibility world wide (IEA, 2018b).

This paradigm is changing with the growth in non-dispatchable VRE resources. At low shares of these resources in the total generation mix, variability of the wind and sunshine is absorbed into the overall volatility caused by weather affecting demand and conventional production. At higher shares, VRE becomes a major source of power system variation. VRE can provide an element of flexibility beyond simply curtailing output; for example, technology such as "smart inverters", which use digital technologies to control output, can be deployed with solar PV systems to provide a degree of flexibility. And wind farms can also provide a limited range of flexibility services, including spinning reserves by operating a fraction below the capacity that wind conditions would allow and thus maintaining an ability to ramp up quickly. Nonetheless, the projected increase in VRE in the scenarios presented here, especially in the Nuclear Fade Case of the Sustainable Development Scenario, would increase substantially the need for short-term flexibility (reacting to changes within minutes or hours) and for remaining thermal power plants to follow steeper and less-predictable changes in load over longer periods.

The need for flexibility is increasing at different rates across electricity systems according to the rate of penetration of VRE and the degree to which the demand profile matches supply-side characteristics and the size of the system. For example, where VRE output matches demand closely, such as in hot regions where cooling needs and solar PV output largely coincide, and where systems are large, the rate of growth in the need for flexibility tends to be slower (IEA, 2018). Flexibility requirements are also driven by the evolution of electricity demand. In some cases, growing end uses such as EVs, heating or even cooling are accentuating the seasonal peaks in demand, which may not match the availability of VRE. A substantial proportion of demand growth in advanced economies will be applications such as electric cars or digital equipment, which can potentially provide demand-side response if the appropriate regulations and incentives are put in place. There are six distinct phases in the process of integrating renewables into the electricity system (Box 9).

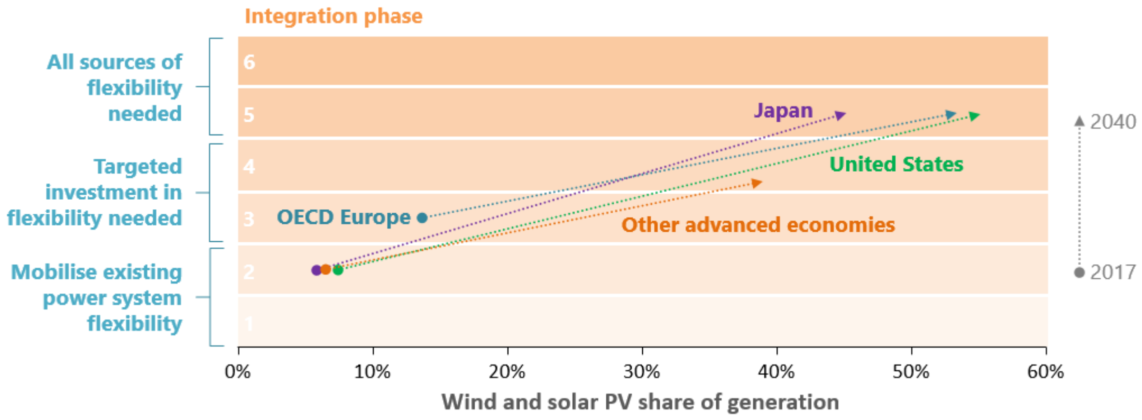
Box 9. Six phases of renewables integration into the electricity system

VRE, such as wind and solar PV, demonstrates a variety of properties that differentiate it from other sources of electricity. The most salient of these is that VRE output fluctuates over time, driven by the changing availability of wind and sunlight. There are six distinct phases of VRE deployment (IEA, 2018b):

- When the capacity of the wind or solar PV plants that are installed represents a small proportion of the total capacity of the system, such that their output and inherent variability have no noticeable impact on the system.
- When the impact of VRE becomes noticeable as capacity grows, but by upgrading some operational practices, VRE capacity can be integrated easily. A reliable forecasting system may need to be established to support efficient balancing.
- When the impact of VRE variability is felt in terms of overall system operation and by other power plants. At this point, power system flexibility becomes important.
- When VRE provides most of the electricity generation during certain periods. This generally requires advanced technical options to ensure system stability, causing changes in operational and regulatory approaches.
- When VRE output frequently exceeds power demand (for days or weeks) and, if left unchecked, these surpluses would result in large-scale curtailment of VRE output, thereby capping further expansion. Enhancing flexibility by means of the electrification of other end-use sectors such as transport and heating with flexible charging and heat storage can mitigate this concern.
- When the structural energy imbalance lasts for long periods, typically due to seasonal imbalances between VRE supply and electricity demand. This creates a need for seasonal storage and use of electricity, such as the production of synthetic fuels or hydrogen, which can be converted back into electricity, or another chemical form that can be stored cost-effectively

The pathway to a truly sustainable energy system inevitably involves a step change in the need to find ways of providing flexibility to integrate VRE into the electricity system. In the Nuclear Fade Case of the Sustainable Development Scenario, the rate of expansion in VRE output is such that Japan, OECD Europe and the United States quickly move into much higher phases of integration (Figure 34). The requirements of managing the system at this level of variable renewables will drive a growing portion of investment needs.

Figure 34. Phases of VRE integration in the Nuclear Fade Case of the Sustainable Development Scenario in selected advanced economy regions/countries



Rising VRE output needs to be accompanied by increased investment in various sources of flexibility, such as batteries, interconnections, electrolysis for hydrogen storage and demand-side management.

Sources of flexibility

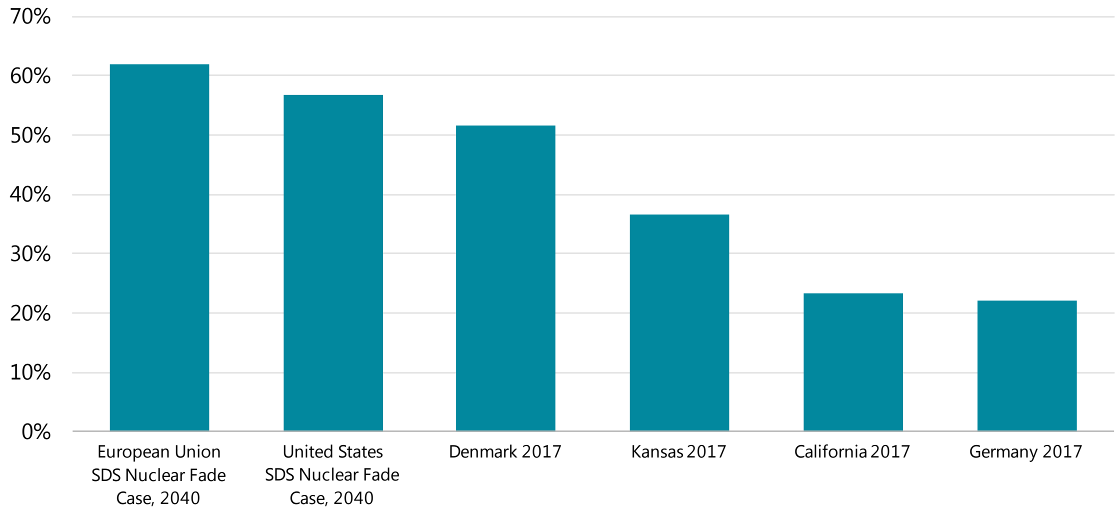
There are several potential sources of flexibility for an electricity system. The appropriate mix of options for a given system depends on local factors and costs. In most cases, dispatchable power plants will remain the primary source. The huge projected increases in wind and solar PV output in advanced economies in the Nuclear Fade Case of the Sustainable Development Scenario would increase the variability of residual demand (demand net of wind and solar production). Dispatchable power plants, including gas-fired ones, could play a central role in dealing with this variability given their ability to adjust output flexibly, particularly in relation to the minimum level at which output remains stable (minimum turn-down), the rate of change of generation output (ramp rate), and the length of time to start or shut-down. The flexibility of existing power plants can be improved by retrofitting equipment or replacing with new more flexible plants (IEA, 2018).

Network infrastructure can contribute to flexibility by balancing the load among different areas, reducing the amount of ramping that needs to be provided by generating plant and by pooling sources of flexibility from neighbouring areas. Exploiting flexibility on the demand side, particularly through demand-side response, is another option, potentially transforming the increased electrification of end uses from a system burden into a system benefit. The potential of demand-side response is projected to increase from around 4 000 TWh today to nearly 9 300 TWh in 2040 in advanced economies in the Sustainable Development Scenario. Baseload nuclear production also benefits from demand response, primarily from shifting consumption from the afternoon peaks to night-time. Some of the largest demand-response programmes in France and Central Europe were historically used to help the system cope with a high share of baseload nuclear production by controlling hot-water boilers. However, a high renewable share will require a different, more dynamic demand response than that historically developed for off-peak nuclear power.

Battery storage is another potentially important source of flexibility. Total battery capacity in advanced economies reaches 400 GW in 2040 in the Sustainable Development Scenario, up from just 4 GW in 2017. This increase is capacity would need to be supported by an appropriate market design to reward such assets for providing flexibility services. Many utility-scale battery installations are likely to be paired with solar PV and wind power to increase their ability to dispatch, to earn revenues from energy arbitrage and to offer ancillary services to the grid. In addition, pumped storage hydropower, which accounts for 97% of global storage capacity, is also projected to continue to expand, but at a slower rate than battery storage, which is expected to become more competitive as costs fall with technological advances. To the extent that geography and social acceptance allow the expansion of pumped storage hydro, it could also play a useful role in expanding flexibility in the Nuclear Fade Case. One of the overlooked consequences of more deployment of storage technologies is a higher overall utilisation of power generation capacity, translating into a lower risk of overcapacity and higher average revenues for generators.

Existing electricity systems that get nearest to the share of variable renewables that would be needed in the Nuclear Fade Case of the Sustainable Development Scenario tend to be small, with a high degree of interconnection across the systems and which benefit from high-quality wind resources. This factor is important: the predictability and high load factor of such resources in places like Denmark or the Great Plains of the United States contribute substantially to lowering the need for flexibility. Strong interconnectivity means that most of the flexibility is provided from outside the system. This is the case in Denmark, which relies heavily on dispatchable hydropower capacity in other parts of the Nordpool system. But this model is not applicable at a continental scale. In the Nuclear Fade Case of the Sustainable Development Scenario, the share of variable renewables in 2040 reaches 55% in the United States and over 60% in Europe, compared with little more than 20% in 2017 in those countries or states that apply rigorous renewables and climate policies on large electricity systems (Figure 35).

Figure 35. Combined share of wind and solar power in total generation in 2040 in the Nuclear Fade Case of the Sustainable Development Scenario and in 2017 in selected countries/regions



Rising wind and solar shares of generation in large geographic regions mean that interconnections may not provide much additional flexibility in the Nuclear Fade Case.

There is a limit to how much flexibility system interconnections can provide

The potential for enhancing connections among electricity systems – a valuable means of providing flexibility – is likely to be limited by geographical factors. Europe and North America are essentially closed electricity systems, so relying on flexibility sources from external systems is not an option in reality. Similarly, an undersea cable from Japan to Korea or the Russian Far East is technically feasible, but even if such a project were built one day, it is unlikely that it would ever play a significant role in balancing the Japanese system. Overland interconnections can also encounter public resistance, as discussed above.

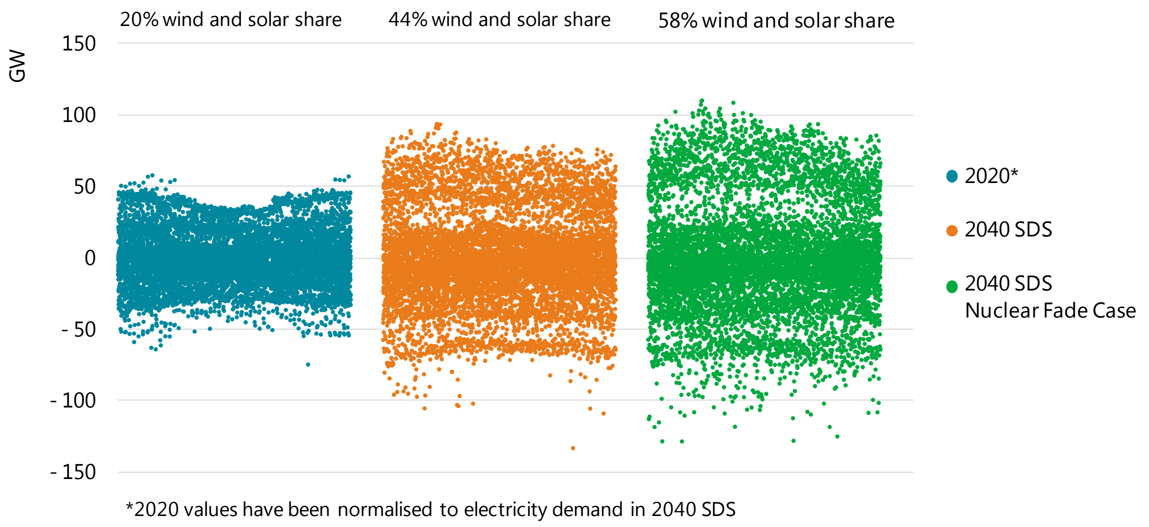
When the share of VRE reaches a high level across an entire region, the scope for interconnections to provide flexibility by tapping into the flexibility resources of neighbouring systems will be reduced. One reason is that all systems will need more flexibility. Another is that the availability of flexibility from an adjacent system may be lowest when the need for flexibility is highest because weather conditions may coincide, even over a large territory.

Continental-scale systems can have the advantage of a fleet of renewables plants spread over different climatic and weather zones. This provides a degree of self-balancing to the extent the output from different generators is uncorrelated. But the degree of correlation for VRE can be high within and across those systems. In the case of solar power, the intensity of sunshine at any given moment can be similar over areas covering several thousand . So, if there is an urgent need to fill the shortfall in output from solar capacity in one system, there is likely to be a similar need in an adjacent system, such that an interconnection between the two would be of limited value to the former. This can also be true for wind power. For example, the North Sea can be affected by weather systems that result in simultaneously high or low levels of production across the whole of northern Europe, from the United Kingdom to northern Germany. Even across countries as far apart and climatically different as Germany and Spain, there is roughly a one-third probability that the hours of low renewables share coincide. This tends to occur during evening peak hours when solar availability is guaranteed to be zero while wind might or might not be available.

The challenges in integrating VRE will be big, even with continuing nuclear investment

The ability of the power systems to deal with output variability as the share of renewables rises has been improving generally across advanced economies. This has resulted from technological innovation, mainly through the widespread digitalisation of grid management. This innovation has been encouraged by changes to regulatory frameworks and market designs. Further improvements, representing nothing less than a profound transformation of the way electricity systems operate, will be necessary make the Sustainable Development Scenario a reality in advanced economies. Without any new nuclear investment, that transformation would need to go even further. Such an outcome is technically feasible. But the difficulties in achieving it should not be underestimated. In the European Union, the flexibility needs to respond to the short-term variability of renewables production more than double. This will necessitate a volatile operation of existing flexibility assets such as gas turbines and investment in new flexibility sources such as battery storage (Figure 36).

Figure 36. Hour to hour ramps needed to fully integrate wind and solar power in the European Union



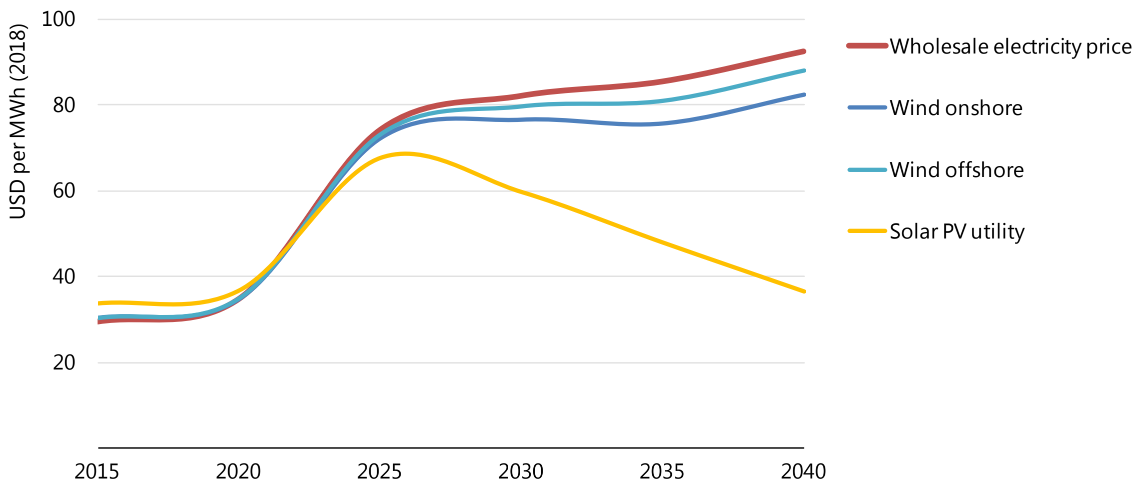
Increased short-term volatility will put an increasing strain on the existing flexibility assets of the system, necessitating new investment and regulatory reforms for additional flexibility.

The principal challenges that are likely to be encountered during the system integration of a wind and solar fleet consistent with the Nuclear Fade Case of the Sustainable Development Scenario include the following:

- *Steeper ramp rates and hourly volatility*. As the renewable capacity increases from an already high share, the output from new wind turbines and solar panels will be increasingly correlated with the existing ones. Their production will tend to increase and decrease simultaneously, so flexible assets will have to operate ramping up and down more and more steeply. Natural gas would continue to play a major role in providing flexibility, but the business model for gas-fired plants would be transformed: their average load factor drops to little more than 10% (i.e. they would run for only around 1 000 hours per year, as and when needed for balancing) by 2040 in the Sustainable Development Scenario. The even greater penetration of renewables in the Nuclear Fade Case would depress this factor further. The regulatory framework would need to ensure that these plants are able to make a profit. In addition, demand-side response would need to be exploited to the full, including the potential for using the storage capability of EVs and other appliances. This would need to be coupled with investment in stationary batteries, which have high ramp rates and are well suited to providing frequency control services.
- *Declining system value of renewables*. Even aggregated across a large geographical area, an increase in the average annual share of wind and solar power in total generation to over 40-45% by 2040 in the Nuclear Fade Case of the Sustainable Development Scenario implies a share of up to 70% during the windiest and sunniest hours. The wholesale electricity price could be low at these times, depending on the marginal cost of the next-highest generating plant in the merit order. As the penetration of renewables increases, the average wholesale price they earn is likely to fall, unless the output profile is markedly different to that of existing plants. In fact, every new solar panel or new wind turbine that is installed will tend to cut the market value of all the solar panels and turbines that have already been installed. This effect varies by technology and region (Figure 37).

- *Need for seasonal storage*. While the cost and performance of batteries have been improving, they still represent an expensive means of providing storage, especially for long periods. The average storage time of utility-scale batteries is only around two hours. A natural consequence of the rising share of wind and solar output in the Nuclear Fade Case of the Sustainable Development Scenario is that a substantial proportion of the additional production occurs during times of the year when total production is close to or over 100% of demand. That surplus power would need to be stored. The need for longer-term storage in each system would be highly dependent on demand and renewable production profiles, but when the share of renewables in annual power generation exceeds two-thirds, the need for storage would almost certainly exceed the technical limitations of batteries. In this case, storage would need to be provided by other technologies, including chemical technologies such as using hydrogen (involving electrolysis and reconversion to power using a fuel cell) or power to gas technologies.

Figure 37. Average energy price received by technology in the European Union in the Nuclear Fade Case of the Sustainable Development Scenario



As the deployment of solar PV rises, the average revenue earned by solar producers falls, despite higher wholesale prices.

In principle, the challenge of integrating the much larger amount of wind and solar capacity in the Nuclear Fade Case of the Sustainable Development Scenario can be overcome. Handling ramp rates and hourly volatility is perhaps the aspect of system integration where the technological prospects are most promising, given the recent declines in the cost of batteries and the projected rapid spread of EVs. Several countries, including those that have renounced nuclear power, are increasing research and development (R&D) into hydrogen and power to gas technologies. Scaling up longer-term storage would help to overcome the loss of the renewables market value that will occur as their market share rises.

However, achieving the goal of a clean energy system could come at a much higher economic cost without continuing reliance on nuclear power in those countries that have retained that option. Nuclear power can play a major role in easing the technical difficulties and lowering the cost of transforming the electricity system. The speed with which that transformation needs to take place, involving a massive increase in production of low-carbon energy over the next two decades, adds to the economic value of maintaining existing nuclear power and building new capacity. In the longer term, some advanced nuclear technologies, notably SMRs, specifically designed for flexible operation might be able to play a role in supporting the required growth in renewable production. The smaller size and negligible land needs of such reactors compared with renewables would allow them to be sited in a way that avoids the need to expand the transmission networks. As a result, their contribution to a clean energy system could be disproportionately greater than their share in the generation mix.

In addition to the physical rigidities that hinder the pace of transformation, there are also institutional rigidities. Implementing a reform of electricity market design or the structure of network tariffs can often take several years, given the complexity of the regulatory process and the diversity of stakeholders involved. A good example is the flexibility that could be provided by EVs: the digital technology for exploiting that potential already exists, but overcoming legal, regulatory and market barriers could take years. This makes a well-designed long-term national strategy for the energy transition all the more important.

Perhaps the biggest uncertainty concerns the prospects for long-term storage of energy, such as hydrogen and power to gas technologies. Most scenarios depicting a low-carbon/low-nuclear future (including the Nuclear Fade Case of the Sustainable Development Scenario in this report) involve the rapid and large-scale deployment of long-term storage. Interest on the part of policy makers and investors is certainly growing, but investment barriers remain daunting. Without nuclear power, long-term storage could make or break the vision of a clean energy system.

5. Policies to promote investment in nuclear power

Policy and regulatory framework

Nuclear power is the largest source of low-carbon electricity in advanced economies as a whole. It makes an important contribution to energy security in all those countries around the world that have nuclear power plants. The declining share of nuclear power in the global energy mix in recent years is one of the main reasons why the rapid expansion of renewables has failed to stop the increase in CO_2 emissions. Several countries have made a decision not to use nuclear energy, and the IEA naturally respects that choice. In others, nuclear power could play a major role in the clean energy transition. However, nuclear power is not on track to fulfil its potential, even where there are strong pronuclear policies. This is partly due to policy imperfections, which can be corrected.

The existing fleet of nuclear power plants in advanced economies is coming under increasing financial pressure, especially where they operate in competitive wholesale markets. This is due to excess capacity, poor market design and a failure to value the environmental and energy security advantages of nuclear power. It is normally technically possible to extend operations at a nuclear plant in a safe manner to at least 60 years. Such a lifetime extension is usually economically attractive and can provide a valuable bridge to a low-carbon energy system that, depending on policy decisions, may contain a new generation of nuclear plants. But it is far from certain that such extensions will always occur in the absence of a supportive policy framework that adequately remunerates plant operators for the incremental investments normally required. Two-thirds of nuclear capacity in advanced economies is at risk of early closure in the next two decades. If this happens, putting advanced economies onto a sustainable development path, involving an extremely rapid growth in renewables, would be difficult.

It is vital that countries which have kept open the option of using nuclear power reform their policies to ensure that nuclear power is able to compete on a level playing field and address barriers to investment in lifetime extensions and new capacity. The most important focus of policies should be on designing electricity markets in a way that values the clean energy and energy security attributes of nuclear power. With regard to the clean energy component, this can be achieved by explicit carbon pricing, clean energy credits and contractual arrangements that reward nuclear and other low-carbon sources of electricity. With regard to the energy security component, the dispatchability and reliability of nuclear power should be rewarded through mechanisms that adequately remunerate plants for flexibility services in a technology-neutral fashion.

These measures would ensure that extending the lifetimes of almost all existing reactors to at least 60 years would be financially viable. Securing investment in new nuclear plants would require more intrusive policy intervention given the high cost of projects and the unfavourable recent experience with construction of Generation III plants. Investment policies aimed at the current Generation III technology need to overcome financing barriers by a combination of long-term contracts, price guarantees and direct state investment. A successful nuclear investment policy should also support learning by doing and accumulation of industrial know-how. It is particularly important to avoid design changes during the construction phase, unless there is a strong safety reason to do so, in view of the impact this tends to have on costs.

The difficulties faced in building large nuclear plants and the evolving needs of the power system have generated interest in advanced nuclear technologies that are amenable to smaller plants, including SMRs. This technology is still at the development stage. There is a case for governments to promote it through funding for R&D, public-private partnerships for venture capital and early deployment grants. While the nature of the SMR technology holds the promise of substantially lower costs through learning by doing, initial costs could be high, deterring its early deployment. As a result, policy makers should consider supportive investment policies such as long-term contracts and price guarantees. Such support should be transitional, with the objective being to compete with other electricity technologies.

Lifetime extensions for existing reactors

Most countries that already have nuclear power have kept open the option of extending the lifetimes of those reactors that are still in operation, including some countries that have ruled out the construction of new reactors. Even where a country's energy policy envisages an eventual transition to 100% renewables, nuclear lifetime extensions can provide a cost-effective means of supporting the transition, allowing more time to put in place policies that accelerate the deployment of renewables and associated infrastructure deployment and transforming system operation. Given the flexibility that nuclear power plants can provide and the often relatively low cost of investing in refurbishment needed to obtain the necessary authorisation, lifetime extensions can also lower the economic cost of the clean energy transition.

In Europe and North America, light regulatory intervention appears to be sufficient for most lifetime extensions, given the limited modifications that are typically required. In general, the investment necessary is likely to be justified by the value of the continued output of the plant, taking into full account the low-carbon and electricity security advantages of nuclear power. In practice, these benefits may be reflected in explicit carbon pricing, ZECs, clean energy contracts or similar measures. In most cases, the shadow price of carbon (an estimate of the value of those benefits over and above the market prices received for the power) incorporated into support schemes for new renewables capacity is considerably higher than the one that would make nuclear lifetime extensions viable. A 20 year nuclear lifetime extension is comparable to the operating lifetime of new renewable assets, so each extension effectively replaces the need for an entire generation of renewables capacity. In Japan, the economic case for lifetime extensions is even more powerful due to high import LNG prices, though social acceptance barriers will need to be overcome and the licensing regime will need to support secure lifetime extensions.

There are legitimate concerns about the ability of electricity market designs to support adequate investment in assets to provide flexibility services. A high share of renewables in the generation mix would require flexibility for the electricity system to operate securely. The appropriate policy approach is to target the flexibility needs of maintaining electricity security rather than the contribution of nuclear capacity on its own. Market reforms will need to be designed in a broad technology-neutral fashion to allow nuclear plant extensions to compete fairly with other options for providing flexibility. In practice, this could make the difference between a lifetime extension and a shut-down.

Supporting new nuclear construction

It has become increasingly clear that the construction of a new wave of large-scale Generation III reactors in all European or North American electricity markets is inconceivable without strong government intervention in view of the policy, technology and project management risks, as well as market and financing barriers. There are some ways in which governments can help to alleviate these risks, at least during the initial and most expensive phases of deployment. The most important measures that should be considered are as follows:

- *Long-term price guarantees*. This measure aims to eliminate the unpredictability of cash flows inherent in the wholesale electricity market. It can take the form of a conventional power purchase agreement. This was the approach used in the case of the Akkuyu plant being built in Turkey. Another option is a contract for difference, essentially a swap between an agreed fixed price and the wholesale market. This is the way future revenues are guaranteed for the Hinkley Point C reactor being built in the United Kingdom. In both cases, the wholesale market risk is transferred to a government entity. The financial liability of the off-taker is potentially large. If Hinkley Point C had already been operational in 2018, the contract for difference would have paid out a short-fall in revenues from the wholesale market of more than GBP 800 million (USD 1 billion) that year. Given the size of the financial risk, the contracting party usually needs to be either a government or a government-mandated entity backed by a sovereign guarantee.
- *Appropriate valuation of low-carbon production.* Carbon pricing is subject to similar problems of volatility and time horizons as wholesale electricity prices. As a result, it is doubtful whether even an ambitious and well-designed carbon pricing regime would be sufficient to stimulate investment in new nuclear capacity. Nevertheless, it can complement well a mechanism that guarantees the price received by the owner of a nuclear plant. Theoretically, once the off-take price is guaranteed, it does not matter whether wholesale prices reflect environmental externalities. However, in practice, by raising the value of clean energy production, payouts can be reduced under contracts for differences, which can improve the social acceptance and reduce the policy risks associated with price guarantees.
- *Sovereign guarantees on borrowing.* Long-term contracts and price guarantees can greatly improve the creditworthiness of a new nuclear project. By doing so, they have traditionally been seen as a precondition of project financing. Unfortunately, in the case of large nuclear projects, technology and project-specific risks may still be considered excessive, even with a price guarantee, primarily due to the risk of cost overruns. As a result, a direct sovereign guarantee on the borrowing for the project can be applied to enable it to tap into cheaper debt finance from banks or bond markets. The Hinkley Point C project has received a guarantee from the British government, though the project company has not yet issued guaranteed bonds. An alternative structure is that adopted in Hungary, where the government borrowed the money directly for a new reactor being built at the Paks power plant, which will be reallocated to the state-owned company that develops the project.
- *Inclusion in the Regulated Asset Base.* Most nuclear power plants operating in advanced economies were built by vertically integrated utilities, a model that is still common in the United States. A regulatory decision to include new nuclear assets in a utility's rate base – the value of all the assets on which a public utility is permitted to earn a rate of return, including network infrastructure, set by the regulator – is an effective way of mitigating project risk by ensuring that it is possible to make a return regardless of market conditions. Often in the United States, the impact on the rate base takes effect from the moment the project is approved, so cash flow is boosted straight away. The downside is that this

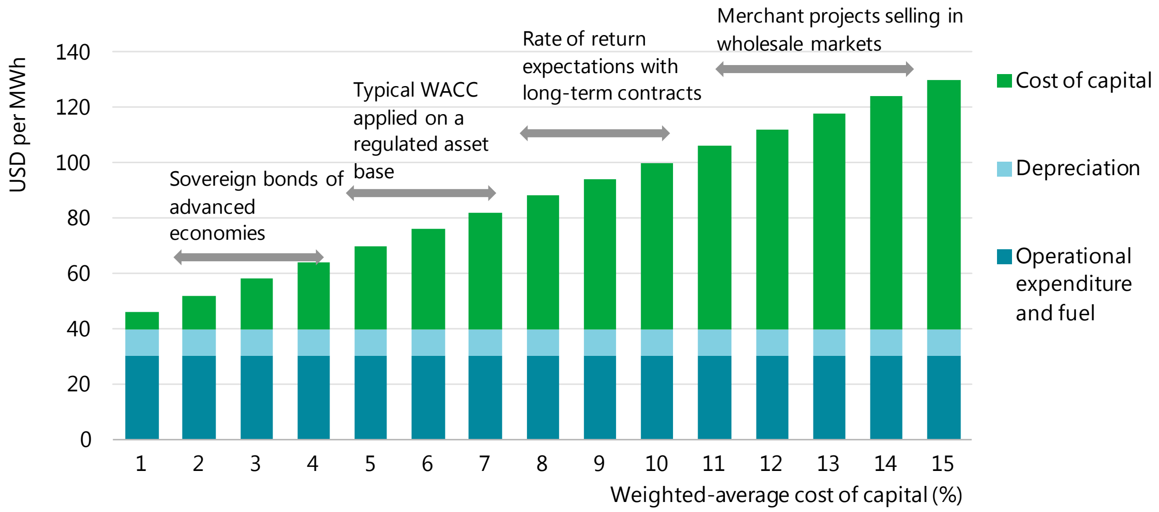
practice, which effectively transfers risk to consumers, can lead to political problems if the project encounters difficulties at a later stage. For example, the Virgil C. Summer project in South Carolina that was cancelled in 2017 resulted in households paying, on average, USD 1 500 for a nuclear power plant that will never come into operation. This has generated a considerable reluctance among regulators elsewhere to adopt similar financing structures. In the European Union, it is unclear whether such a model could be applied without significant changes in energy and competition law.

- *Involvement of the technology provider in equity joint ventures.* This approach would reduce difficulties in raising equity through vertical integration, which mitigates project management risk and provides a powerful incentive for efficient construction. The Akkuyu plant in Turkey applies this structure, and the recently cancelled Wylfa project in the United Kingdom intended to do so as well.
- *Direct investment by state-owned companies.* This is by far the most widespread model of nuclear power plant construction world wide. Even in advanced economies, most of the projects under construction and most of the planned projects that are most likely to proceed are either being led by 100% state-owned project companies, like Paks-2 in Hungary, or majority state-owned corporations, like EDF in France, Polska Grupa Energetyczna in Poland and CEZ in the Czech Republic. In the case of a majority state owned stock market listed corporation, management has a fiduciary responsibility to protect shareholder value under corporate law, so even state-owned companies have to ensure the new plant is financially viable. Most other state-owned companies have profitable existing assets that can support the investment needs associated with a new nuclear power project. As a majority owner, the government can determine the dividend policy and enable the company to recapitalise itself from retained earnings so that new nuclear investment can be financed directly from the balance sheet.

Government measures are crucial in enabling the financing of new nuclear investment at viable interest rates. The cost of capital has a pronounced impact on the competitiveness of nuclear power, because of its high capital intensity. This is generally true for all low-carbon technologies, including wind and solar PV. In the case of renewables, measures to reduce or even eliminate market risk such as feed-in tariffs and long-term fixed price power purchase agreements have played a critically important role in mobilising investment and enabling learning by doing. A fall in the cost of capital, aided by loose monetary policy, is the main reason for the radical decline of renewables auction prices in recent years. In effect, cheaper financing has reinforced the impact of technological innovation and learning by doing. Large hydropower plants are mainly developed by state-owned utilities in the developing economies, most often financed by state-owned or international development banks.

The cost of capital has a pronounced impact on the economics of new nuclear power projects because of the size of the required investment and long project lead-times (comparable to the largest hydropower projects). Investment involving several billion USD needs to be financed during construction for many years before the project can generate electricity and earn revenues. For example, for a new 1 GW plant costing USD 4.5 billion, the LCOE would increase by around USD 5 per MWh for each percentage point increase in the cost of capital. It would double with an increase in the cost of capital from 3% (the typical return on sovereign bonds today) to 13% (the rate that merchant plants selling directly into wholesale markets would normally have to borrow at) (Figure 38).

Figure 38. Illustrative LCOE of a new nuclear power plant project according to the cost of capital



Note: Based on a 1 GW plant with an investment cost of USD 4.5 billion.

Access to cheap capital makes a huge difference to the cost of producing electricity for a new nuclear power project.

The environmental and security benefits of nuclear power provide justification for a more active role for governments in financing new plants, where the technology remains an option. But this may not be sufficient in view of the hurdles facing new projects, especially in advanced economies. The recent cost and project management difficulties faced by projects in several countries have come at a time when the cost of other low-carbon technologies, primarily wind and solar PV, have fallen dramatically. Changes in electricity business models with the spread of competition in wholesale markets has complicated the financing of new large-scale nuclear investments. In addition, the ability and cost of integrating variable renewables into the power system has improved significantly, reducing the comparative advantages of nuclear power in providing flexibility. In fact, wind and solar investment have been moving towards a more competitive, more market-based model. While policy incentives are still essential for renewables in most cases, there has been a move towards so-called market premium models, which expose projects to wholesale market shorter duration off-take contracts. Non-energy companies have also emerged as major buyers of wind and solar power; projects underwritten by such corporate buyers now represent a non-negligible proportion of renewable deployment.

Encouraging investment in small modular reactors

Increasing difficulties in financing the construction of large Generation III reactors, coupled with the need for more low-carbon dispatchable generation, is driving policy and investor interest in small modular reactors (SMRs). This type of nuclear reactor could prove much easier to finance and may be the way forward for nuclear fission technology. SMRs are much smaller than existing reactor designs, have a shorter lifetime and are intended to be built in a modular fashion in factories. Even if the average investment cost per unit of capacity is comparable to the "list price" of conventional large reactors, the smaller project size and shorter lead-times of SMRs promise to make financing easier. Modular design and factory construction mitigates project management risk, which is the single most-important obstacle to financing Generation III nuclear projects. Several SMR designs have inherent advantages in safety and waste management, which could ease licensing and improve social acceptance. In contrast to the collapsing investment appetite by the private sector for large Generation III reactors, SMRs are attracting considerable private venture capital for R&D. Nevertheless, none of the SMR designs under development have yet reached commercial maturity.

SMRs are defined as nuclear reactors with an electrical capacity of less than 300 MW per module. They are usually designed to be built in a factory to take advantage of economies of series and then transported to the site where they are to be installed. They exploit inherent safety features, such as passive safety systems and simplified designs, involving fewer and simpler systems and components. It is expected that they will be deployed in series, using a global supply chain to lower costs. SMRs could be installed as single modules distributed throughout the grid, which may be attractive in countries or regions with less developed networks, in remote regions or as dedicated sources of electricity for industrial complexes, as well as in more traditional large-scale plants by grouping together several modules. In principle, SMRs could be suitable to meet the needs for flexibility in power generation demanded by the electricity systems of the future that combine baseload with increased shares of variable generation. This could be utilised by a wide range of users and for different applications, including energy storage, co-generation and non-electric applications.

SMR designs may use any type of fuel and coolant, and can be coupled with various power conversion systems (steam or gas turbines) or used to produce fresh water, hydrogen and district or industrial heat. Several different types of SMRs are under development (Table 6), a few of them in the United States. Light-water-cooled SMR designs have achieved the highest technology and licensing readiness levels, with several concepts under construction or advanced in the licensing process. The development of liquid-metal-cooled SMRs, molten-salt-cooled and gas-cooled SMR designs (also called Generation IV SMRs) is generally less advanced, but may prove to be more successful as they have the potential to reach higher temperatures to optimise co-generation and non-electric applications, as well as providing fuel cycle services such as multirecycling. This could make them suitable for providing flexibility at Phase 6 of the process of integrating VRE into electricity systems (see Box 9).

A micro modular reactor (MMR) – a new type of SMR – has recently been proposed. MMRs are defined as units with a capacity of less than 10 MW with a rugged design, capable of semiautonomous operation and easy to transport. They could be coupled to ultracompact power conversion systems, such as Stirling engines, supercritical CO_2 cycles or direct conversion devices. They are intended to be used to serve remote communities, seasonal industrial complexes, mining sites, offshore platforms, military bases or expeditionary forces (MIT, 2019).

Table 6. SMRs under development

Design	Net output per module (MW)	Type	Designer	Country	Status
Light-water cooled					
KLT-40S	70	Floating PWR	OKBM Afrikantov	Russia	Pre-commissioning testing
CAREM	30	PWR	CNEA	Argentina	Under construction
SMART	100	PWR	KAERI	Korea	Certified design, feasibility study to construct in Saudi Arabia (desalination)
NuScale	50 (× 12)	PWR	NuScale Power	United States	Licensing process, two projects planned in the United States (Idaho and Tennessee)
SMR-160	160	PWR	Holtec International	United States	Preliminary design
BWRX-300	300	BWR	GE Hitachi	United States	Conceptual design
(no name)	220	PWR	Rolls Royce	United Kingdom	Conceptual design
(no name)	170	PWR	CEA/EDF/Naval Group/ TechnicAtome	France	Conceptual design
Generation IV (non-light-water cooled)					
HTR-PM	210	HTGR	Tsinghua University	China	Under construction
ACP100	100	PWR	CNNC	China	Start of construction planned for end of 2019
SC-HTGR	272	HTGR	Framatome	United States	Conceptual design
Xe-100	35	HTGR	X-energy LLC	United States	Conceptual design
4S	10	LMFR	Toshiba	Japan	Detailed design
EM2	265	GMFR	General Atomics	United States	Conceptual design
IMSR	190	MSR	Terrestrial Energy	Canada	Basic design
ThorCon	250	MSR	Martingale Inc	United States	Basic design

Notes: BWR = boiling water reactor; CEA = Alternative Energies and Atomic Energy Commission; CNEA = Comisión Nacional de Energía Atómica (Argentina); CNNC = China National Nuclear Corporation; GMFR = gas-cooled modular fast reactor; HTGR = high-temperature gas-cooled reactor; KAERI = Korea Atomic Energy Research Institute; LMFR = liquid metal fast reactor; MSR = molten salt reactor; PWR = pressurised water reactor.

Sources: OECD NEA and IAEA.

Box 10. Status of SMR research, development and deployment

In Russia, fuel loading at the two units of the Akademik Lomonosov floating plant (KLT-40S) was completed in October 2018. Start-up of the first unit took place in November 2018 in Murmansk, and the second reactor is expected to follow shortly. The vessel is expected to be towed to its permanent base at Pevek in Russia's Chukotka region in the summer of 2019.

In China, a demonstration plant with two HTR-PM units is on track to be connected to the grid and start electricity generation in 2019. China Huaneng is the lead organisation in the consortium building the demonstration units, together with CNNC subsidiary China Nuclear Engineering Corporation and Tsinghua University's Institute of Nuclear and New Energy Technology, which is the nuclear R&D leader. The reactors will drive a single 210 MW steam turbine, using helium gas as the primary coolant and reaching temperatures as high as 750°C.

In November 2018, the Canadian government released a roadmap (NRCan, 2018) that outlines potential applications for SMRs for the country. It identifies clear roles for SMRs as a clean alternative to coal-fired power stations and as a source of clean heat and electricity to industry, as well as for providing energy to remote communities. In parallel, Canadian National Laboratories (CNL) launched an invitation to proponents of SMR projects to build and operate an SMR demonstration unit at a CNL-managed site. Applicants include Global First Power (GFP), StarCore Nuclear and Terrestrial Energy. In April 2019, the Canadian Nuclear Safety Commission received the first licence application for a type of SMR from GFP, with support from Ontario Power Generation and Ultra Safe Nuclear Corporation. The project involves building an MMR at Chalk River in Ontario. The high-temperature gas reactor would have a power output capacity of 5 MW and heat output of 15 MW.

In the United States, NuScale's SMR technology is undergoing design certification review by the NRC, while Utah Associated Municipal Power Systems is planning the development of a 12 module plant using that technology at a site at the Idaho National Laboratory, to be completed in the mid-2020s. NuScale has also signed memoranda of understanding to explore the deployment of its SMR technology in Canada, Jordan and Romania. In April 2019, the NRC issued an early site permit for the Tennessee Valley Authority to build two or more SMRs at a site in Clinch River.

Owing to their smaller size, SMRs may be deployed in countries or regions with small electricity grids that could not handle large GW-sized reactors or on sites with limited water supply for cooling. SMRs also offer the advantage of scalability of capacity additions. In other words, utilities will be able to add capacity to the grid in smaller increments, allowing them to more easily adapt capacity to changes in electricity demand. Construction lead-times are also expected to be much shorter, thanks to their factory manufacturing and the use of advanced modular construction techniques. The decoupling of civil construction and reactor manufacture processes should also allow plant owners to shift and reallocate financial risk through the plant construction period, due to reduced capital outlays and shorter time to generate a positive cash flow much earlier in the plant life cycle.

As they have smaller cores and, for most SMRs, inherent passive safety features, SMRs may be licensed with smaller emergency planning zones and simplified emergency preparedness procedures. This may facilitate the siting of SMRs, including close to population centres. This attribute could favour the rapid deployment of SMRs in the increasingly distributed electricity grids of the future, including on the sites of existing coal-fired power plants of similar capacity.

SMRs have been designed with load-following capabilities, making them capable of operating effectively in electricity grids with increasing shares of VRE. While this flexibility is highly desirable from a grid stability and reliability point of view, it does not necessarily result in an economically attractive business case for a technology that is optimally designed to operate at full power as baseload like large-scale reactors. However, given their potential use for co-generation and non-electric applications, SMRs may be able to generate sufficient revenue from the production of heat, fresh water, hydrogen or energy (heat) storage, in addition to the revenue from electricity generation, to recover their costs.

Estimates indicate that the LCOE of SMRs could be competitive with larger nuclear units and with other dispatchable generating technologies (NEA, 2016). This will hinge on the development of a global market to establish a robust supply chain and sustainable construction know-how to lower construction costs.[12] In the meantime, prototype and demonstration units are likely to be expensive. O&M costs for SMRs could be lower than for larger nuclear units if the regulators allow SMR licences to take advantage of some of their intrinsic features. For example, several prospective SMR vendors propose to use advanced digital instrumentation and control technologies and advanced digitalisation and automatisation to manage and operate the units. This would allow the plants to be operated with fewer staff in a way that optimises the use of fuel and power output (NEA, 2016).

The flexibility in the size, timing and siting of SMRs may make them a more attractive option than larger nuclear power plants for private investors. First, the total size of the investment would be significantly smaller, making SMRs much more affordable, though not necessarily cheaper on a per MW basis. Financing is expected to be easier because of their lower total cost, shorter period of construction and overall lower construction risk due to factory manufacturing. The ability to add increments of SMR capacity would also facilitate the management of financial risk (Maize, 2010). SMRs may be attractive to countries with no experience of nuclear power, especially those with smaller and less robust electricity grids, due to the overall lower total cost and their simplicity of operation. In many cases, due to grid stability and reliability concerns, SMRs may be the only technically feasible nuclear technology option available to fit the grid (MIT, 2018).

Reform in the licensing process may be necessary to fully take advantage of the inherent advantages of these reactors and lower costs. Exploiting economies of series to the full would require harmonisation of licensing processes for SMRs across countries and regions, though licensing would still require compliance with country and local regulatory requirements (e.g. environmental impact assessments or public consultative processes). This would facilitate the establishment of a global supply chain and a global SMR market.

A clear goal to establish standardised designs is important. While the array of existing SMR designs being developed is a healthy development that will promote innovation at this early stage, this vitality could be dissipated unless focused into a smaller number of promising designs. A fast technological convergence of the various existing conceptual designs, prototypes and first-of-a-kind models into reasonably standardised designs would allow for the value chains to develop, and for the promise of economies of scale and learning by doing to be fulfilled.

[12] www.energycentral.com/c/ec/ge-hitachi-offer-300-mw-smr.

Although the true economics of SMRs are not fully known, there is a large potential for these technologies to represent a complementary way forward for nuclear power development. SMR market development will strongly depend on the successful deployment of prototypes and first-of-a-kind plants. SMRs will become economically viable only in the presence of well-defined and predictable licensing processes. SMR vendors and potential customers will need to work closely with nuclear regulators to quickly resolve various hurdles in deployment of the technology, including validation of innovative safety features and solutions, and factory assembly (NEA, 2016).

The investment policy for SMRs will need to combine the general principles of low-carbon electricity market design with innovation policy to facilitate early deployment. For the first pilot projects, special investment measures, including capital grants, guarantees and tailor-made long-term contracts, could be justified. If the technology matures, policies will need to evolve to incorporate a more market-based approach, whereby generators are adequately remunerated for the value of the low-carbon energy and system services they provide.

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General annex

Abbreviations and acronyms

AC	alternating current
BWR	boiling water reactor
CAISO	California Independent System Operator
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilisation and storage
CEA	Alternative Energies and Atomic Energy Commission
CNEA	Comisión Nacional de Energía Atómica (Argentina)
CNL	Canadian National Laboratories
CNNC	China National Nuclear Corporation
CO_2	carbon dioxide
DC	direct current
EDF	Électricité de France
ENTSO-E	European Network of Transmission System Operators for Electricity
EPR	European Pressurised Reactor
ERCOT	Electricity Reliability Council of Texas
EU	European Union
EU-ETS	European Union Emissions Trading System
EV	electric vehicle
GFP	Global First Power
GMFR	gas modular fast reactor
HTGR	high-temperature gas-cooled reactor
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
ISO NE	Independent State Operator New England
KAERI	Korea Atomic Energy Research Institute

LCOE	levelised cost of energy
LMFR	liquid metal fast reactor
LNG	liquefied natural gas
LSE	load serving entity
MISO	Midcontinent Independent System Operator
MMR	micro modular reactor
MSR	molten salt reactor
N/A	not available
NPV	net present value
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
OECD	Organisation for Economic Co-operation and Development
O&M	operation and maintenance
PJM	Pennsylvania, Jersey and Maryland
PV	photovoltaics
PWR	pressurised water reactor
Q1	quarter 1
R&D	research and development
RGGI	Regional Greenhouse Gas Initiative
SMR	small modular reactor
SPP	Southwest Power Pool
T&D	transmission and distribution
UHVDC	ultra high voltage direct current
US	United States
VALCOE	value-adjusted levelised cost of energy
VRE	variable renewable energy
WACC	weighted-average cost of capital
ZEC	zero-emission credit

Currency codes

EUR	euro
GBP	pound sterling
USD	United States dollar

Units of measure

gCO_2	gramme of carbon dioxide
$GtCO_2$	gigatonne of carbon dioxide
GW	gigawatt
ha	hectare
km	kilometre
kW	kilowatt
kWh	kilowatt hour
MBtu	million British thermal unit
Mt	million tonne
Mtoe	million tonne of oil equivalent
MW	megawatt
MWh	megawatt hour
t	tonne
TWh	terawatt hour

Acknowledgements, contributors and credits

The study was designed and directed by Laszlo Varro, International Energy Agency (IEA) Chief Economist, and Keisuke Sadamori, IEA Director of Energy Markets and Security.

The main authors of this report were Laszlo Varro, Brent Wanner, César Alejandro Hernández Alva, Antoine Herzog and Peter Fraser. Other principal contributors were Kieran McNamara, Yasmine Arsalane, Claudia Pavarini, Stefan Lorenczik, Randi Kristiansen, Carlos Fernández Alvarez, Matthew Wittenstein and Sunah Kim. Special thanks to Sama Bilbao y León, Head of the Division of Nuclear Technology Development and Economics at the Organisation for Economic Co-operation and Development Nuclear Energy Agency, who contributed the section on small modular reactors.

Valuable comments and feedback were provided by senior management and numerous other colleagues in the IEA, in particular, Paul Simons, Paolo Frankl, Heymi Bahar, Cédric Philibert and Nick Johnstone.

Thanks go to the IEA Communications and Digital Office for help in producing the final report and website material, particularly Jad Mouawad, Therese Walsh, Jethro Mullen, Astrid Dumond and Christopher Gully. Diana Browne provided essential support to the peer review process.

Trevor Morgan (principal editor) and Caren Brown (copy-editor) are thanked for their editorial support.

On 25 February 2019, the IEA held a workshop on Nuclear Power in a Clean Energy System in Paris. The participants of this workshop are thanked for their valuable contributions.

In addition, the following external reviewers are acknowledged:

Emil Bédi	Ministry of Economy of the Slovak Republic
Michel Berthélemy	Commissariat à l'Energie Atomique
Sama Bilbao y León	Nuclear Energy Agency
Giulia Bisconti	US Department of Energy
Jean-Paul Bouttes	Independent expert
Chrissy Borskey	General Electric
Tuğrul Çağrı Cinkara	Ministry of Energy and Natural Resources, Turkey
Russell Conklin	US Department of Energy
Matt Crozat	Nuclear Energy Institute
François Dassa	Électricité de France
Marc Deffrennes	Nuclear Energy Agency
William D'haeseleer	Katholieke Universiteit Leuven
Christopher W. Evans	Natural Resources Canada

Kirsty Gogan	Energy for Humanity
Alasdair Harper	Department for Business, Energy & Industrial Strategy, United Kingdom
Liisa Heikinheimo	Ministry of Economic Affairs and Employment, Finland
Shin Hosaka	Ministry of Economy, Trade and Industry, Japan
Attila Hugyecz	Paks II Nuclear Power Plant Ltd
Richard Ivens	Retired FORATOM Director of Institutional Affairs
Yiota Kokkinos	Natural Resources Canada
Ken Koyama	Institute of Energy Economics, Japan
Kelly Lefler	US Department of Energy
Philippe Mercel	Électricité de France
Marco Migliorelli	European Commission
Mark Muldowney	BNP Paribas
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John Paffenbarger	Exelon Corporation
Henri Paillère	Nuclear Energy Agency
Lara Pierpoint	Exelon Corporation
Assaad Saab	Independent expert
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Krzysztof Szymański	Ministry of Energy, Poland
Aidan Tuohy	Electric Power Research Institute
Billy Valderrama	US Department of Energy
Antonio Vayá Soler	Nuclear Energy Agency
Aditi Verma	Nuclear Energy Agency
Yoichi Wada	GE Hitachi
Tim Yeo	The New Nuclear Watch Institute
Bronislava Žemberová	Ministry of Economy of the Slovak Republic

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Typeset in France by IEA - May 2019
Cover design: IEA
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