The Costs of Decarbonisation:

System Costs with High Shares of Nuclear and Renewables

Executive Summary

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Nuclear Technology Development and Economics

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ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

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The mission of the NEA is:

– to assist its member countries in maintaining and further developing, through international co-operation, the scientific, technological and legal bases required for a safe, environmentally sound and economical use of nuclear energy for peaceful purposes;

– to provide authoritative assessments and to forge common understandings on key issues as input to government decisions on nuclear energy policy and to broader OECD analyses in areas such as energy and the sustainable development of low-carbon economies.

Specific areas of competence of the NEA include the safety and regulation of nuclear activities, radioactive waste management, radiological protection, nuclear science, economic and technical analyses of the nuclear fuel cycle, nuclear law and liability, and public information. The NEA Data Bank provides nuclear data and computer program services for participating countries.

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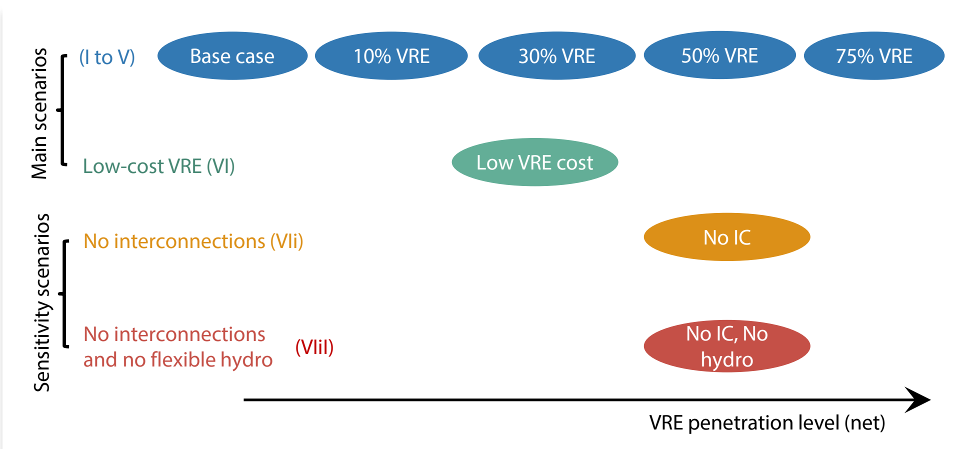
Executive summary

This study sets out to assess the costs of alternative low-carbon electricity systems capable of achieving strict carbon emission reductions consistent with the aims of the Paris Agreement. It thus compares the total costs of six different scenarios of the electric power sector of a representative OECD country, all of which are consistent with a low-carbon constraint of only 50 gCO_2 per kW, but which contain different shares of nuclear energy and renewable energies, in particular wind and solar photovoltaic (PV). These shares vary between 0% and 75% of total electricity consumption. A low variable renewable energy (VRE) investment cost scenario completes this analysis by assuming significant future cost reductions for VRE. Two sensitivity analyses built around different levels of available flexibility resources (availability of interconnection or flexible hydroelectric resources) complete a suite of altogether eight scenarios allowing a good understanding of the principal drivers of the costs of decarbonisation (see Figure ES1 below). In particular, the study highlights the impacts the variability of wind and solar PV production have on electricity system costs, which appears as costly adjustments to the residual system.

Figure ES1. **Eight scenarios to study the cost of low-carbon electricity systems with 50 gCO_2 per kWh**



The present study not only highlights the costs of achieving ambitious carbon targets but also sets out a policy framework for achieving them in a least-cost manner. The five principal pillars of this framework are 1) setting a robust price for carbon emissions, 2) short-term markets for efficient dispatch and revealing the system value of electricity, 3) regulation for the adequate provision of capacity, flexibility and infrastructures for transmission and distribution, 4) mechanisms to enable long-term investment in low-carbon technologies, including the reform of existing mechanisms and 5) the internalisation of system costs wherever practical and necessary. Achieving radical carbon emission reductions does not come for free. However this study shows that defining the right overall mix of the shares of nuclear energy and renewables as well as setting the right policy framework will allow the achievement of radical climate targets while respecting high standards of the security of electricity supply and overall reasonable costs to electricity consumers.

The context

Under the Paris Agreement, which was concluded in December 2015 and entered into force in November 2016, many OECD countries agreed to aim for a reduction of their greenhouse gas emissions sufficient to hold the increase in the global average temperature to well below 2°C above pre-industrial levels. This implies a major effort to decarbonise their electric power sectors. Holding the increase of global temperatures to 2°C requires limiting greenhouse gas concentrations in the earth's atmosphere to roughly 450 ppm of CO_2-equivalent emissions. This requires a massive effort to decarbonise electricity generation, as the electricity sector is expected to bear the brunt of the effort to reduce emissions during the next three decades. Projections indicate that in order to achieve reductions commensurate with the 2° objective, CO_2 emission from the electric power sectors of OECD countries would need to be reduced by almost 90% by mid-century. The average carbon intensity of the electricity produced in OECD countries of 430 gCO_2 per kWh today would need to be reduced to roughly 50 gCO_2 per kWh by 2050.

This decarbonisation will require a radical restructuring of the electric power sectors of each OECD countries and a truly massive deployment of low-carbon technologies, in particular nuclear energy and renewable energies such as wind and solar PV. Other generation options, including hydropower, are limited in a window of only 25-35 years, which is short given the intrinsic inertia of electricity systems, where power plants and transmission infrastructure frequently have lifetimes of 60 years and more.

Renewable energies have enjoyed in recent years both popular and political support. While average costs per MWh of wind and solar PV are still somewhat higher than those of nuclear energy, the cost gap at the level of plant-level generation costs (as calculated with the levelised cost of electricity (LCOE) methodology as set out in the 2015 OECD study on the *Projected Costs of Generating Electricity)* no longer seems insurmountable. However, as spelled out in the first OECD Nuclear Energy Agency (NEA) study on system costs, *Nuclear Energy and Renewables: System Costs in Decarbonising Electricity Systems* (2012), VRE technologies such as wind and solar PV cause a number of additional costs to the system, which are referred to as system costs.

The most important categories of the system costs of VREs are increased outlays for distribution and transmission due to their small unit size and distance from load centres, balancing costs to prepare for unpredictable changes in wind speed and solar radiation and, perhaps, most importantly, the costs for organising reliable supplies through the residual system during the hours when wind and sun are not fully available or not available at all. Variability also induces significant changes in the composition of the remainder of dispatchable technologies that ensure round-the-clock security of supply in the power system. When deploying VREs, one observes, in particular, a shift from technologies with high fixed cost, such as nuclear power to more flexible technologies with low fixed cost such as gas-fired power generation. While the latter will be able to better absorb the loss of operating hours due to VRE infeed, the overall costs of the residual system will increase, an effect known as "profile costs". In addition, deploying VREs does not automatically translate into carbon emission reductions. For instance, when nuclear power is substituted by a mix of VREs and gas-fired generation that produces electricity when VREs are not available, overall carbon emissions will increase.

All technologies have system costs. Nuclear, for instance, requires particularly strong network connections and access to reliable cooling sources. However, these costs turn out to be an order of magnitude lower than those imposed by the variability of renewable energies. The key advantage of nuclear power in the economic competition with wind and solar PV is the fact that nuclear power plants are dispatchable, i.e. they can produce large amounts of carbon free baseload power in a reliable and predictable fashion. In the context of the decarbonisation of electricity systems, this poses three important questions:

- What is the optimal mix of nuclear baseload and variable renewables from an economic point of view and what is the added cost of reaching a CO_2 emission target with exogenously imposed shares of renewable generation?
- Are electricity systems that are trying to reach these objectives primarily with large shares of variable renewables technically and, in particular, economically viable?

- What are the key policy instruments for creating frameworks that enable the level of investment in low-carbon generation technologies required to ensure a transition towards deeply decarbonised electricity systems?

The precise answers to these questions depend on a number of qualifying conditions, for instance the amount of flexibility resources available in an electricity system that are spelled out throughout the study using a "greenfield approach", where the system is optimised and costs are minimised without making any assumptions about the existing power generation mix other than the availability of hydroelectric resources. This improves the transparency and readability of the modelling results, and thus their pertinence for policy making in a time frame that spans all the way to 2050.

The defining features of this study and the nature of system costs

Today, system costs are no longer part of an unfamiliar concept but a universally accepted part of electricity system analysis. The first NEA study on system costs, published in 2012, was part of an early wave of studies that were instrumental in introducing and conceptualising the notion of system costs. While the initially developed concepts, as well as the basic methodology of working with residual load curves to assess profile cost, have proven robust, much has changed during the past five years. Among the changes that need to be accounted for are:

- the significant decline in the LCOE costs of renewable energies, in particular for solar PV, as documented in the changes in investment costs reported in the IEA/NEA reports on the *Projected Costs of Generating Electricity* for 2010 and 2015;
- the emergence of a broad and lively literature on the system costs of electricity systems, which includes the emergence of a widely shared methodological framework for assessing profile costs;
- a greater awareness and better understanding by policy makers of the importance of system costs
- a clearer idea of the policy-relevant questions that can be usefully asked and answered by the available conceptual and modelling tools given the present state of knowledge.

From the outset, it was clear that any new study should not simply provide an update of the well-regarded 2012 study. In the present study, great care has been expended to construct a representation of the electricity sector in a manner as complete as possible. In this process, the NEA worked with a team of experienced power system modellers at the Massachusetts Institute of Technology (MIT). NEA modelling of the eight scenarios is thus built on the Optimal Electricity Generation Expansion (GenX) model developed at MIT, which provides the detailed, comprehensive and flexible representation of an integrated electricity system that was required.

The electricity sector model that underlies this study thus includes not only hourly dispatch but also ramping constraints and reserve requirements that preserve both system stability and economic equilibrium. In addition, a carefully selected set of credible flexibility options has been added to the model. They include interconnections with neighbouring countries, a relatively high share of flexible hydroelectric resources, demand-side management (DSM) and several storage options. Both technological and flexibility options are important drivers of total system costs. This holds, in particular, if electricity generation includes a large share of wind and solar PV, since their variability challenges the workings of the system by increasing ramp costs and reserve requirements, and it also increases the demand for different flexibility options.

The defining feature of this modelling effort is the fact that all scenarios include the same stringent carbon constraint of 50 gCO_2 per kWh, which is consistent with a level that the electricity systems of OECD countries must achieve to contribute their share to limit the increase in global mean temperatures to 2°C. In order to allow for economic results that are as general, relevant and transparent as possible (and thus independent of the power generation mix of a particular country), this study has taken a "greenfield approach". This means that starting with a clean slate the electricity system evolves only as a function of electricity demand throughout the year and the specific costs of different technologies in an optimal fashion as if all plants were built from scratch on a green field. This approach is limited only by the exogenously imposed constraints, i.e. carbon emissions of 50 gCO_2 per kWh and different shares of VRE generation that are specified *ex ante*. Only the share of hydroelectric resources has been set exogenously.

The alternative – using a brownfield approach – would have yielded different results. In function of the existing mix, the results in this volume might help individual countries to better assess the cost of their transitions. However, the results of brownfield modelling would not allow drawing comparable general conclusions about the respective costs of electricity systems with different shares of nuclear and renewables. In particular, for variable renewables such as wind and solar PV, the total system costs are highly dependent on local conditions and the structure of the residual system.

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

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

The concept of system effects, which are heavily driven by these six attributes of VRE, has been conceptualised and explored extensively by the NEA and the IEA, and has benefitted from a significant amount of new research from academia, industry and governments. System effects are often divided into the following four broadly defined categories of profile costs (also referred to as utilisation costs or backup costs by some researchers), balancing costs, grid costs and connection costs.

Profile costs (or utilisation costs) refer to the increase in the generation cost of the overall electricity system in response to the variability of VRE output. They are thus at the heart of the notion of system effects. They capture, in particular, the fact that in most of the cases it is more expensive to provide the residual load in a system with VRE than in an equivalent system where VRE are replaced by dispatchable plants. A different way of looking at the profile costs of VRE is to consider that the electricity generation of wind or solar PV is concentrated during a limited number of hours with favourable meteorological conditions. This decreases value for the system of each additional VRE unit and corresponds to an equivalent increase in profile costs. In addition, the presence of VRE generation generally increases the variability of the residual load, which exhibits steeper and more frequent ramps. This causes an additional burden, also called the flexibility effect, to other dispatchable plants in terms of more start-ups and shutdowns, more frequent cycling and steeper ramping requirements, leading to lower levels of efficiency, an increase in the wear and tear of equipment and higher generation costs.

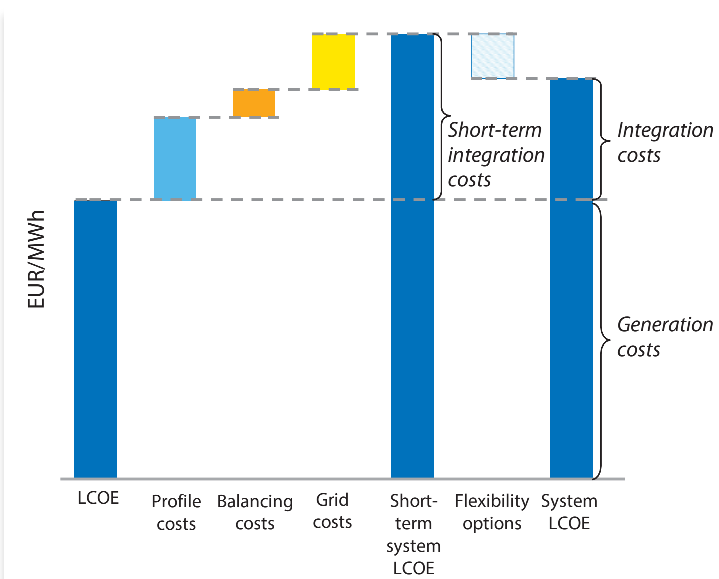
Balancing costs refer to the increasing requirements for ensuring the system stability due to the uncertainty in the power generation (unforeseen plant outages or forecasting errors of generation). In the case of dispatchable plants, the amount and thus the cost of operating reserves are generally given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

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

Connection costs consist of the costs of connecting a power plant to the nearest connecting point of the transmission grid. They can be significant especially if distant resources (or resources with a low load factor) have to be connected, as can be the case for offshore wind, or if the technology has more stringent connection requirements as is the case for nuclear power. Connection costs are sometimes integrated within system costs (see NEA, 2012), but are sometimes also included in the LCOE plant-level costs. This reflects commercial realities as different legislative regimes require connection costs either to be borne by plant developers or by the transmission grid operator. In the former case, they are part of the plant-level costs and thus fully internalised, while in the latter case they are externalities to be accounted for in the system costs.

The above list of four cost categories of system costs is not fully exhaustive. The provision of physical inertia, which is implicitly provided by dispatchable plants but not by VRE, is thus emerging as a topic of research. Together, the four categories nonetheless make up the bulk of system costs. Figure ES2 below summarises them.

Figure ES2. **Illustration of system cost**



Source: OECD, 2015.

Modelling results from the NEA system cost study

The NEA study shows that combining explicit targets for VRE technologies and a stringent limit on carbon emissions has important impacts on the composition of the generation mix and its cost. In particular, total generation capacity increases significantly with the deployment of VRE resources. Since the load factor and the capacity credit of VRE is significantly lower than that of conventional thermal power plants, a significantly higher capacity is needed to produce the same amount of electricity. While about 98 GW are installed in the base case scenario without VRE, the deployment of VRE up to penetration levels of 10% and 30% increases the total capacity of the system to 118 and 167 GW, respectively. The total installed capacity would more than double to 220 GW if a VRE penetration level of 50% must be reached. More than 325 GW, i.e. more than three times the peak demand, are needed if VRE generate 75% of the total electricity demand. In other words, as the VRE penetration increases vast excess capacity, thus investment, is needed to meet the same demand. The capacity mix of different generation technologies in the five main scenarios is illustrated in Figure ES3, while their respective electricity generation share is shown in Figure ES4 below.

Figure ES3. **The capacity mix with different shares of VRE**

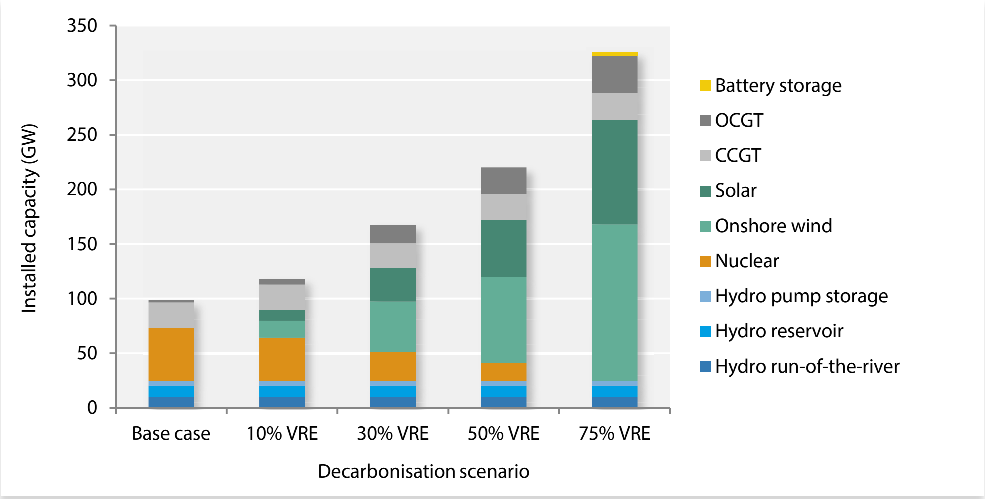
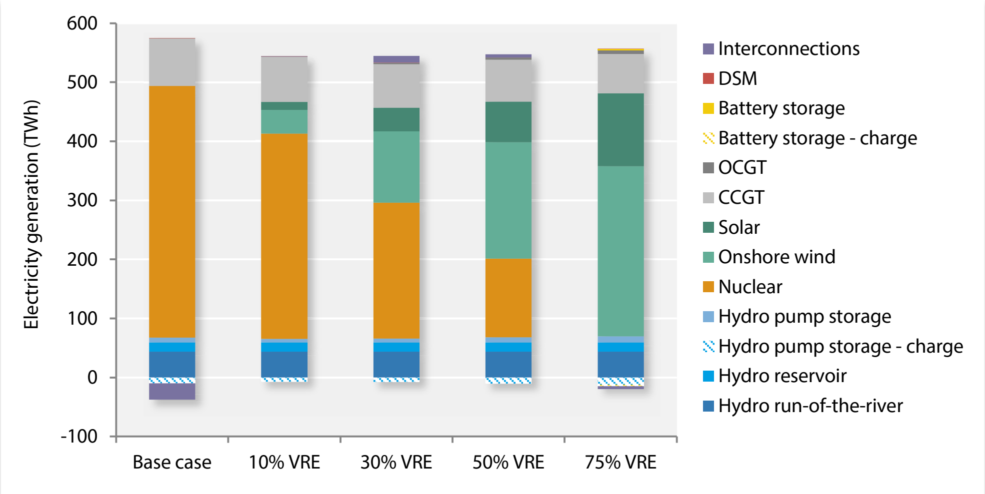


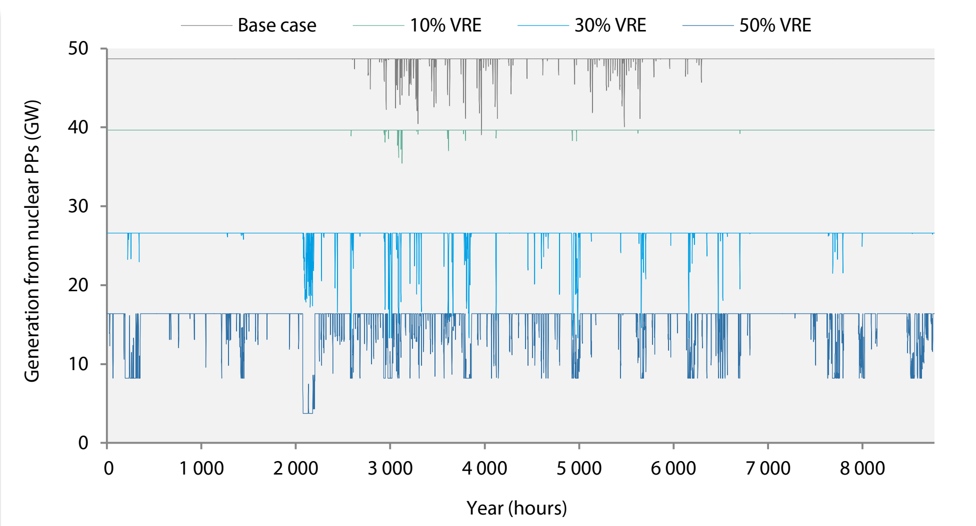
Figure ES4. **Electricity generation share in the main region (main scenarios)**



The integration of VRE changes the long-term structure of the thermal generation mix. The share of fossil-fuelled generation (open cycle gas turbine [OCGT] and combined cycle gas turbines [CCGT]) remains almost constant in all scenarios, as it is limited by the carbon cap. However, the structure of the capacity installed of gas plants and the relative share of generation from OCGT and CCGT changes significantly with the presence of VRE. While the capacity of CCGT power plants is almost constant in all scenarios considered, they are operated at lower load factor in the scenarios with more variable generation. Another important finding is that, under the stringent carbon constraint adopted for this study, coal is never deployed in any of the scenarios considered, despite being cheaper than the other technologies on a pure LCOE basis. In terms of generation, VRE displaces nuclear power almost on a one-to-one basis, which results from the fixed carbon constraint in combination with a fixed amount of hydroelectric resources.

The way in which thermal plants operate also changes significantly, with a reduction of the average load factors and an increase of ramping and load-following requirements. Figure ES5 shows the projected hourly generation pattern of the nuclear fleet for four of the five main scenarios considered (there is no nuclear generation under the 75% VRE). This allows a visualisation of the increased flexibility requirements from nuclear plants, as well as the reduction in nuclear capacity associated with VRE deployment.

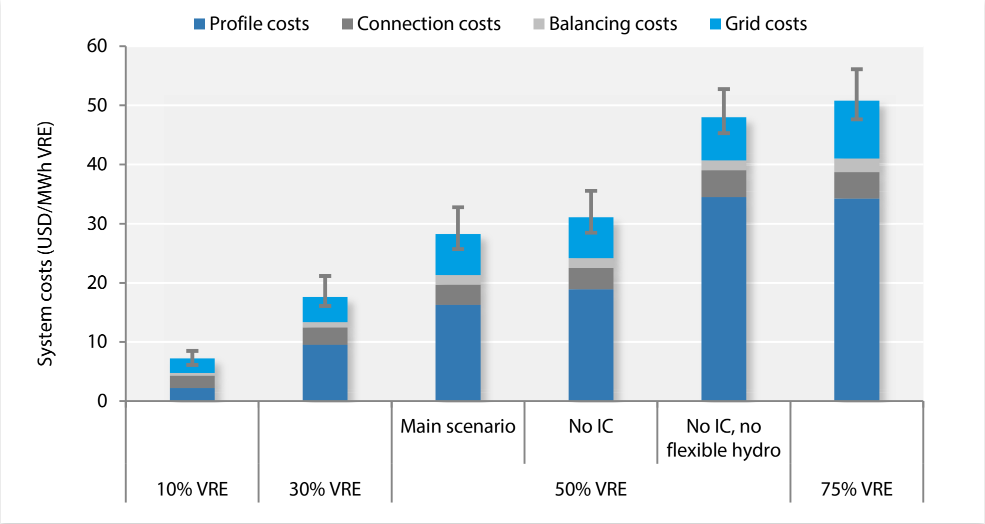
Figure ES5. **Projected generation pattern from nuclear power plants**



Nuclear capacity progressively decreases with the share of renewables. In the base case scenario with the lowest cost and no VRE, nuclear power is the major source of low-carbon electricity and produces about 75% of the total electricity demand with minimal demand on flexibility. At higher rates of VRE, the demand for nuclear flexibility increases progressively. In the 50% VRE case, nuclear units must ramp up and down by a maximal 30-35% of their installed capacity in one hour.

The changes in the capacity mix, the generation mix and load factors of the different technologies can be captured in the system costs of the different scenarios. Additional grid costs, balancing and connection costs are thus added to the profile costs already implicitly calculated in the different optimised scenarios. As already mentioned, profile costs result from the de-optimisation of the residual system due to the variability of VRE. Total system costs, expressed in USD per unit of net electricity delivered by VRE to the grid are shown in Figure ES6 for the four scenarios of 10%, 30%, 50% and 75% VRE as well as for the two sensitivity scenarios. These system costs must be understood as the increase of the total costs to provide the same service of electricity supply above the costs of the least-cost scenario without any VRE. System costs in the reference system are zero since the issue of variability does not arise because all the electricity is generated by dispatchable technologies. The figure also provides a breakdown of the total system costs into the four main components. Also, an error bar provides an indication of the uncertainty range deriving from a range of possible assumptions on grid, connection and balancing costs.

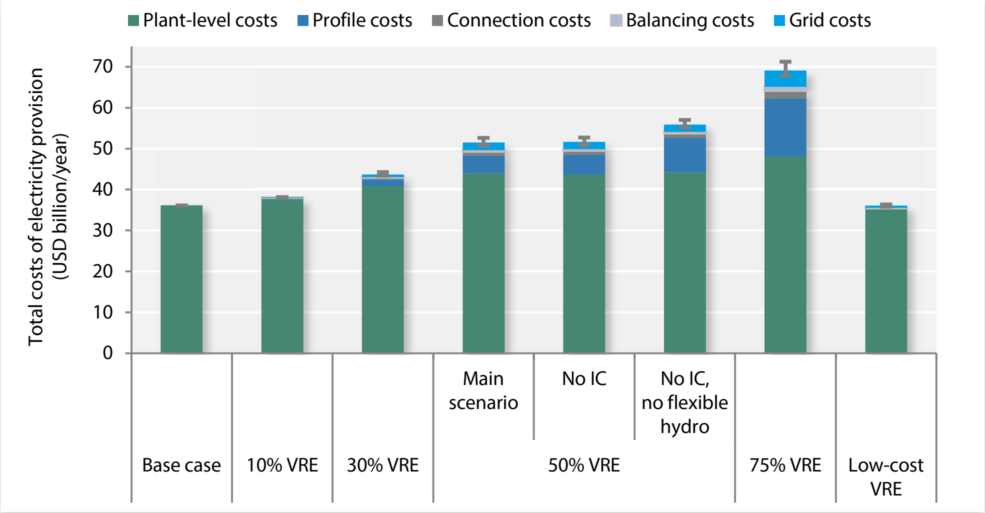
Figure ES6. **System costs per MWh of VRE**



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

Figure ES7. **Total cost of electricity provision including all system costs**

(USD billion per year)

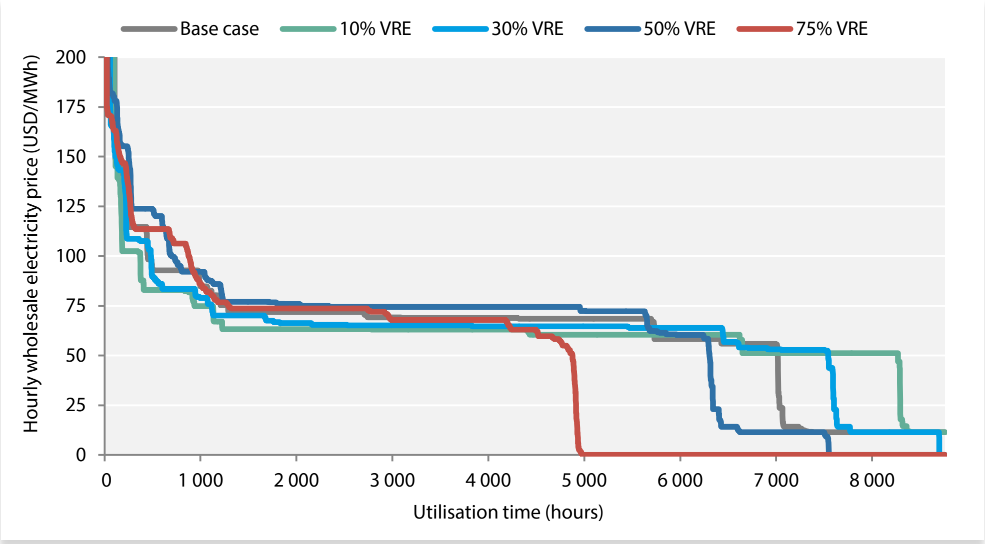


These values need to be compared to the plant-level generation costs of VRE, which range, depending on the scenario, from USD 60 per MWh for onshore wind to up to USD 130 per MWh for solar PV. It should also be noted that the system costs are largely unaffected by any declines in plant-level costs as long as the share of VRE remains exogenously imposed. Indeed, all four components of system costs (balancing, profile, connection and grid costs) increase with the deployment of VRE resources, but at different rates. By adding system costs to the costs of plant-level generation as assessed in LCOE calculations, one can calculate the total system costs of electricity provision for the eight scenarios analysed in this study (see Figure ES7 above).

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

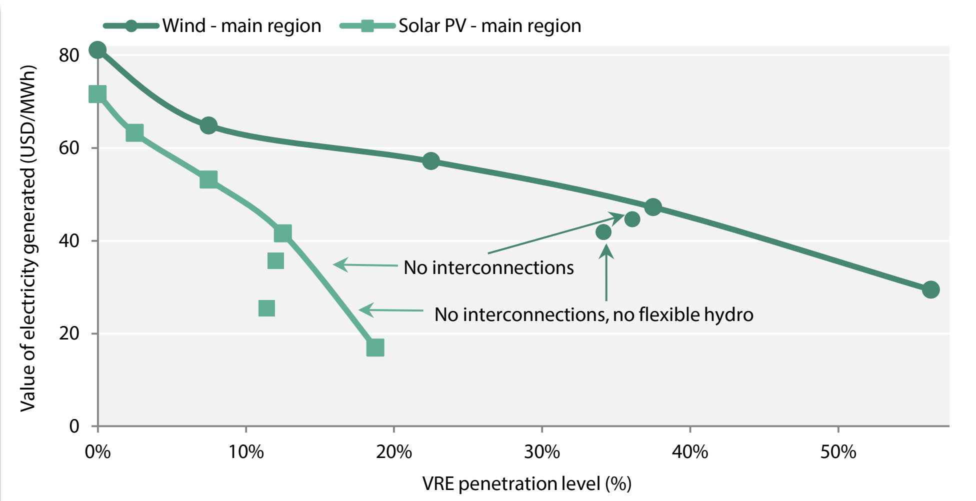
A striking effect of the deployment of low marginal cost variable resources on the electricity market is the appearance of hours with zero prices, a substantial increase in the volatility of electricity prices and the commensurate increase in capital cost (not modelled here). Such zero prices are not observed in the two scenarios with no or low VRE deployment but start appearing for 60 hours per year when VRE reach a penetration level of 30%. The number of occurrences increases dramatically with the VRE penetration level; at 50%, more than 1 200 hours in a year feature zero-price levels, i.e. about 14% of the time. When VREs produce 75% of the demand, zero prices occur during 3 750 hours, i.e. more than 43% of the time (see Figure ES8). Since the model works under a financing constraint, the higher frequency of hours with zero prices is compensated by an increase in the number of hours with high electricity prices, which increases volatility. At 75% VRE penetration, the number of hours with prices above USD 100 per MWh is more than double that at zero or low VRE penetration rate.

Figure ES8. **Price duration curves of wholesale electricity prices in the five main scenarios**



Last but not least, the generation by VRE as a function of the availability of natural resources such as wind speed or solar radiation, is not only more variable than that from dispatchable plants but also more concentrated during a limited number of hours. Periods with high generation are followed by periods with lower or zero output. Because they all respond to the same meteorological conditions, wind turbines and solar PV plants tend to auto-correlate, i.e. produce disproportionally more electricity when other plants of the same type are generating and to produce less when other wind and solar PV plants are also running at lower utilisation rates. In combination with the zero short-run marginal costs of VRE resources, this causes a decrease in the average price received by the electricity generated by VRE as their penetration level increases, a phenomenon often referred to as self-cannibalisation. Figure 48 summarises this effect by showing the average market price received by wind and solar PV generators in the wholesale electricity markets as a function of their share in the electricity mix.

Figure ES9. **The market remuneration received by wind and solar PV as a function of their share in the electricity mix**



The average price received by solar PV and wind resources in the electricity market declines significantly and non-linearly as their penetration level increases, and this price decrease is much steeper for solar PV than for wind as its auto-correlation is higher. The value of the solar PV generation is almost halved even when a penetration rate of only 12.5% is reached. Further deployment of solar PV capacity to a penetration level of 17.5% would further halve its market value to below USD 20 per MWh. Thus, even if the generation costs of solar PV were divided by five, its optimal penetration level would not exceed 17.5%. A similar trend, although less pronounced, is observed for onshore wind, which has a higher load factor than solar PV and whose generation spans over a larger time period. At a penetration level of 22.5%, the value of a megawatt-hour of wind is reduced by 25%. For penetration levels above 30%, the market value of wind electricity is below USD 50 per MWh compared to an average price of all electricity of USD 80 per MWh. Offshore wind with its even higher load factor might show less pronounced declines but was not included in the study as its overall LCOEs were significantly higher than those of competing low-carbon technologies including nuclear.

Last but not least, achieving more ambitious renewable targets also implies that VRE must be curtailed more frequently. Curtailment of VRE generation thus appears at 30% penetration level and increases sharply with their share. At 50% generation share, the curtailment rate of the marginal VRE unit deployed is above 10%. In the scenario featuring a 75% share of VRE generation, about 18% of the total VRE generation must be curtailed, and the curtailment rate of the last unit deployed is above 36%. Curtailment can be understood as an indicator that the system value of VRE is lower than its system costs, i.e. that reducing VRE output during certain hours constitutes the least-cost flexibility option.

Effective policy options to decarbonise the electricity sector

Decarbonising the energy system to achieve the climate goals set by the Paris Agreement represents an enormous challenge for OECD countries. To reduce the carbon intensity of the electric power sector to 50 gCO_2 per kWh, an eighth of the current levels, requires a rapid and radical transformation of the power system with the deployment of low-carbon emitting technologies such as nuclear, hydroelectricity and variable renewables (VRE). In the absence of mechanisms to capture and store the CO_2, this will mean phasing out coal and strictly limiting the use of gas-fired power generation. Given the massive investments that the realisation of this transformation requires, it is of paramount importance to create long-term frameworks that provide stability and confidence for investors in all power generation technologies. This has important implications beyond the electricity sector. Decarbonising the energy sectors and the economies of OECD countries will require an important effort of electrification (see also the IEA *World Energy Outlook 2018*). This concerns, quite obviously, the transportation sector, but also industry and housing. Effective action to reduce carbon emissions and to limit climate change depends on the creation of a robust low-carbon electricity sector.

If OECD policy makers want to achieve such a deeply decarbonised electricity mix they must foster vigorous investment in low-carbon technologies such as nuclear energy, VRE and hydroelectric power. Where hydroelectric power is constrained by natural resource endowments, nuclear and VRE remain the principal options. This is why the modelling in Chapter 3 took a brownfield approach to hydroelectricity, i.e. fixed the amount of available resources *ex ante*, independent of market conditions or VRE deployment. This is a useful starting assumption at the level of generality of this study. It should, however, be mentioned that the generating capacity of existing installations might also be increased under the right economic conditions. The generating capacity of hydroelectric resources might thus be increased, for instance, through the repowering of dams that are currently only used for irrigation (see Tester et al., 2012: p. 623). While the technical potential exists, there are, at the current costs of alternatives, questions about the economic potential (ibid.: 637). The economic costs of leveraging such additional existing hydroelectric resources are highly site-dependent and inversely related to the size of the plant. In particular, small-scale hydro-projects would thus need to be approached in a full cost-perspective that takes all local, regional and global costs and benefits into account.

Whatever their share of hydroelectric resources, all electricity systems of OECD countries relying on deregulated wholesale markets to ensure adequate investments are currently experiencing great stress in advancing towards the twin objectives of rapid decarbonisation and adequate investment in low-carbon technologies. The reasons are, in particular, the relative disadvantages experienced by technologies with high fixed costs in a deregulated market with volatile prices, the lack of robust and reliable carbon prices, and the out-of-market financing of large amounts of variable renewables with little thought on the impacts on the remainder of the electricity system. These shortcomings have made progressive re-regulation a distinct option for the future evolution of the electricity sector of OECD countries.

The risk is that such a return to regulated systems would do more harm than good by losing the efficiency gains brought by liberalisation without a clear roadmap for the road ahead. The alternative is to move towards specific market designs for low-carbon generation based on five distinct pillars: 1) the continuing working of short-term markets for efficient dispatch and the revelation of the true system value of the electricity produced; 2) carbon pricing; 3) frameworks for the adequate provision of capacity, flexibility and infrastructures for transmission and distribution; 4) appropriate mechanisms to foster long-term investment in low-carbon technologies, including the reform of existing support mechanisms; and 5) the internalisation of system costs wherever practical and necessary. While details of electricity market reform will require substantive expert discussion, it is important that policy makers understand the importance of these five pillars, which are required to maintain the appropriate equilibrium between short-term competitive pressures and long-term investment incentives for low-carbon generation.

First, maintain current short-term electricity markets for efficient dispatch. The deregulation of electricity markets did not get everything wrong. Even if there is widespread agreement that deregulated electricity markets have not provided on their own sufficient incentives for investment in low-carbon technologies, there is also recognition that they have been good at using existing assets efficiently. Marginal cost pricing based on short-term variable costs is not ideal to incentivise the construction of technologies with high capital costs. It is, however, the appropriate mechanism to ensure the optimal utilisation of existing resources, i.e. to produce a MWh of electricity at the lowest possible costs at any given moment and to expose generators to the discipline of market prices. Recognising this dichotomy implies combining markets for short-term dispatch with explicit mechanisms to foster investment in low-carbon technologies.

Second, whatever the institutional hurdles and lobbying efforts to prevent it, the most important immediate measure is the introduction of carbon pricing, which would raise electricity prices, reduce greenhouse gases and enhance the competitiveness of low-carbon technologies such as nuclear and VRE. A meaningful level for a carbon price in an emission trading system would mean a price high enough to ensure the following outcomes:

a) make gas competitive against coal and, where pertinent, lignite in the markets of all OECD countries;

b) improve the competitiveness of nuclear power plants against gas-fired plants where construction costs are sufficiently low without any out-of-market support;

c) improve renewable competitiveness against gas-fired generation where meteorological conditions are sufficiently favourable without any out-of-market support;

d) provide the dynamic incentive to invest in the development of new even more cost-effective low-carbon technologies.

The precise level of carbon prices to achieve such outcomes would vary on the relative costs of different technologies in different countries. As an order of magnitude, a carbon price of USD 50 per tonne of CO_2 can be considered sufficient to fulfil the criteria mentioned above. The leverage of fossil fuel-based generators and their stakeholders over political decision making has made effective carbon pricing the exception rather than the rule in OECD countries. Where introduced, however, in countries such as Sweden or the United Kingdom, it has been highly effective in driving decarbonisation. Independent of detailed efficiency considerations, a credible carbon price is a powerful signal in order to shape the expectations of producers, consumers and other stakeholders such as suppliers concerning the long-term evolution of the electricity system. Carbon pricing will produce an overall gain for society. However, it will also produce losses for some stakeholders, in particular, fossil fuel producers and their customers. Appropriate compensation will thus need to be part of any politically sustainable package.

Third, develop long-term frameworks for the adequate provision of capacity, flexibility and infrastructures for transmission and distribution: generation is at the heart of any electricity system, but it is ultimately only a part of it. Any electricity system requires frameworks for the provision of capacity, flexibility, system services and adequate physical infrastructures. While this was always the case, the variability of VREs and new technological developments make these complementary services increasingly important. The importance of flexibility provision is also underlined in the latest edition of the IEA's *World Energy Outlook 2018*. Technological and behavioural changes such as the digitalisation of network management, batteries and demand side management (DSM), as well as, in some cases, decentralising generation and consumption makes for an ever more complex equation to be solved. Short-term markets for flexibility provision, balancing, increased interconnections with neighbouring countries and capacity remuneration mechanisms are all part of this. It is also important to recognise the positive contribution to system stability and inertia of large centralised units such as nuclear power plants or hydroelectric dams and to value them appropriately.

Fourth, create appropriate mechanisms for fostering long-term investment in low-carbon technologies. In creating sustainable low-carbon electricity systems, all low-carbon technologies will need to play a part. However, their high capital intensity requires specific financing solutions as they will not be deployed solely on the basis of marginal cost pricing in competitive markets. This holds for all low-carbon technologies, but particularly for VREs, which themselves suffer most heavily from the lower prices they induce. Due to different lifetimes, risk profiles and financing structures, individual technologies will also continue to require dedicated, individually designed instruments, even though they all are based on the same principle that investment in high fixed cost technologies requires high levels of price and revenue stability.

On their own, neither carbon pricing nor capacity remuneration for dispatchable low-carbon providers will suffice, although they constitute, in principle, the appropriate instruments for internalising the external effects relating to the public goods of climate protection and security of supply. Capacity remuneration mechanisms (CRMs) designed to provide electricity during the rare hours of extreme peak demand will favour technologies with low fixed capacity costs, usually OCGTs, since they are the only ones willing to invest when expected operating hours are in the double digits. This is why policy makers have to make tough calls on striking the appropriate balance between out-of-market support and exposure to wholesale market prices for low-carbon technologies with high fixed costs such as nuclear and VRE. One the one hand, feed-in tariffs (FITs), long-term power purchase agreements (PPAs), contracts for difference (CFDs), regulated electricity tariffs, feed-in premiums (FIPs) or even direct capital subsidies through, for instance, loan guarantees, are all appropriate instruments to achieve long-term security of supply with low-carbon technologies. FIPs or direct capital subsidies even maintain a link with wholesale market prices, which is important for efficient dispatch and value discovery. Even employing FITs and other instruments that share the central characteristic of a long-term contract guaranteeing a price corresponding to average cost need not mean abandoning competition altogether. Competitive auctions can substitute competition *in* the market with competition *for* the market.

Fifth, internalise system costs, where the previous four pillars have not already done so. Carbon pricing will recognise the environmental attributes of low-carbon generation, while capacity remuneration will recognise dispatchability. In principle, exposure to electricity prices would internalise profile costs, and remunerate each unit of electricity generated at its true value for the system. This theoretically sound principle, however, finds its limitation in the need for long-term price guarantees for low-carbon technologies mentioned above. The important thing is not to add implicit subsidisation to explicit subsidisation.

Together, these five pillars form the basic structure of a design for low-carbon electricity markets allowing for the optimised co-existence between VRE, hydroelectricity and nuclear energy within an effective integrated electricity system that will yield deeply decarbonised electricity systems at least cost and high levels of security of supply, independent of individual cost assumptions or country-specific endowments. Even more importantly, these five pillars allow for the construction of market designs that will be sustainable in the sense that they enable the investments that are necessary for the large-scale deployment of low-carbon technologies required for the rapid and radical transformation of the power system.

It should be emphasised that this framework does not depend on country preference for nuclear, hydro or VRE. All low-carbon technologies have a role to play. Based on the cost assumptions used in the main scenarios, this study shows that a mix relying primarily on nuclear energy is the most cost-effective option to achieve the decarbonisation target of 50 gCO_2 per kWh. In addition, costs rise over-proportionally with the share of VRE forced upon the system. However, these results reflect current best estimates. In particular, a further decline in the costs of VRE generation technologies would lead to integrated systems with sizeable shares of both nuclear and VRE. This is the spirit of Scenario VI, “Cost minimisation with low-cost renewables”. With overnight costs for wind and solar PV that are between one third and two thirds lower than in the base case scenarios, it supports the vision of a future electricity mix that is realistic for a broad range of OECD countries. Such a mix integrating both VRE and dispatchable technologies would be composed of four main pillars:

i. a share of 30-40% wind and solar PV;

ii. a larger share of 40%-60% provided by dispatchable low-carbon technologies such as nuclear or, perhaps one day, fossil-fuelled plants with carbon capture, utilisation and storage (CCUS);

iii. the maximum possible amount of low-carbon flexibility resources, including hydro, demand response and grid interconnection;

iv. a progressively decreasing share of highly flexible unabated fossil-fuelled technologies ensuring the availability of residual flexibility.

Between now and 2050, the implicit time horizon of this study, research and development efforts are also likely to reduce the overall cost of power generation. Technologies are likely to be both cheaper and more flexible. Further cost reductions for low-carbon technologies such as nuclear, possibly in the form of small modular reactors (SMRs), VREs and batteries are likely. Largely for intrinsic physical reasons CCUS, for instance, is less likely to be a competitive option, even by 2050, but a decisive breakthrough cannot be excluded. The electricity sector is also likely to be more closely intertwined with other economic sectors due to cogeneration, power-to-gas and the convergence with information and communication technologies.

This study does not claim that the options modelled, their technical performances and their costs will be those eventually realised in 2050 and does not make any predictions about future technology developments. Its objective is to inform policy makers and the wider public about the intrinsic difficulties of achieving ambitious carbon emission reduction objectives with variable generation technologies alone. In practice, the choice of electricity market design generation mix and, in particular, the generation mix is a matter of political choices at the national level. While there is a global effort under way to reduce greenhouse gas emissions and prevent dangerous climate change, specific outcomes will be the result of a broader mix of social and political criteria. Local and regional pollution, system costs, technical reliability and the long-term security of supply will all play into the decision-making process.

A particular role in this process will be played by nuclear power. While it reliably provides large amounts of dispatchable, low-carbon power, it faces questions of social acceptability in a number of OECD countries. Nevertheless, this study shows how nuclear power still remains the economically optimal choice to satisfy stringent carbon constraints despite the economic challenges for nuclear during the changeover between different reactor generations. The reason for nuclear power's cost advantage is not in its plant-level costs. Instead, it resides in its overall costs to the electricity system. Variable renewables have reduced quite impressively their plant-level costs, but their overall costs to the system are not accounted for as their output is clustered during a limited number of high-level hours. All of these factors will come to play in the ultimate choices of each country.

Independent of their individual choices regarding the structure of their electricity mixes, OECD countries should move together to implement the five pillars for the design of low-carbon electricity systems. Technologies and consumer behaviour will continue to change rapidly in coming years. There is, however, a high likelihood that the orientations provided by the five pillars developed above – competitive markets for short-term dispatch, carbon pricing, centralised mechanisms for infrastructure provision, long-term stability for investors in low-carbon capacity and the internalisation of system costs – will remain the appropriate reference for the design of low-carbon electricity systems in the decades to come.

The Costs of Decarbonisation:

System Costs with High Shares of Nuclear and Renewables

Under the Paris Agreement, OECD countries agreed to aim for a reduction of their greenhouse gas emissions sufficient to hold the increase in the global average temperature to well below 2°C above pre industrial levels. This commitment requires a massive effort to decarbonise energy and electricity generation, a radical restructuring of the electric power sector and the rapid deployment of large amounts of low-carbon generation technologies, in particular nuclear energy and renewable energies such as wind and solar PV.

This study assesses the costs of alternative low-carbon electricity systems capable of achieving strict carbon emission reductions consistent with the aims of the Paris Agreement. It analyses several deep decarbonisation scenarios to reach the same stringent carbon emission target but characterised by different shares of variable renewable technologies, hydroelectric power and nuclear energy.

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