Conditions and Requirements for the Technical Feasibility of a Power System with a High Share of Renewables in France Towards 2050

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Abstract

This report, commissioned by France's Ministry for the Ecological Transition and written jointly by the International Energy Agency and RTE, the French Transmission System Operator, examines the conditions and requirements needed to assess the technical feasibility of scenarios with very high shares of variable renewable energy in France's power system. The report looks into trends for energy demand and renewable resource availability in the 2020 National Low-Carbon Strategy (Stratégie nationale bas-carbone, or SNBC). Several scenarios of high shares of renewables are examined: mainly based on onshore wind, mainly based on offshore wind expansion and mainly based on distributed PV. Building on these scenarios, the report looks at changes in the system's flexibility needs and how the range from short-term to long-term flexibility can be satisfied by new technologies such as flexible charging of electrified transport, battery storage, demand-side flexibility and sector coupling. The report then looks to essential questions on electricity security, i.e. addressing the issue of keeping system stability in the context of decreasing system inertia, ensuring adequacy of the system and the sizing available reserves under a scenario of large shares of variable renewables. Finally, the report evaluates the VRE integration capacity of the existing French transmission network, as well as necessary modifications and expansion beyond 2035. The recommendations and findings of this report form the basis for further detailed technical and economic assessments that are to be carried out by RTE in 2021.

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Executive summary

France is one of several countries which have pledged to achieve net zero carbon emissions by 2050 to meet its climate change mitigation commitments under the Paris Agreement. To help it reach this goal, the French government recently published a new energy and climate law and the *National Low-Carbon Strategy* (*Stratégie nationale bas-carbone, or* SNBC). This comprehensive strategy for achieving carbon neutrality relies largely on energy efficiency, systematic use of biomass and greater use of electricity.

France already enjoys extremely low-carbon electricity, owing largely to its nuclear generation fleet built in the 1980s and the 1990s. The operating life of these nuclear generators is assumed so far to be 60 years, so by 2050 most will have been decommissioned. To keep emissions in the power sector to a minimum, two options are thus on the table: replacing retiring reactors with new ones and renewables or replacing them with renewables only to eventually reach a power system with 100% renewable energy sources. Both options rely on significantly scaling up variable renewables: wind and solar photovoltaic (PV) power.

The French Ministry for the Ecological Transition commissioned the International Energy Agency (IEA) and France's transmission system operator, RTE, to jointly carry out a framework study identifying the conditions and requirements to assess the technical feasibility of scenarios in which the power system would be based on very high shares of renewables. This report presents their findings.

The main conclusions focus on **four sets of strict conditions that would need to be met towards a technically secure integration of very high shares of renewables** in a large power system such as that of France:

1. Even if they still need to be proven at large scale, there is a general scientific consensus that technological solutions to maintain **power system strength** – and hence system stability – without conventional generation exist in several cases. Specific difficulties are expected in the case of a system with a significant share of distributed solar PV. Further assessment of the impacts of distributed PV on the distribution network is needed as well as their implications for electricity security.
2. **System adequacy** – i.e. the ability of a power system to cope with load at all times – can be ensured even in a system mainly based on variable renewables such as wind and solar PV, when substantial sources of flexibility are available, including demand-response, large-scale storage, peak generation units, and well

developed transmission networks and interconnections. The maturity, availability and cost of these flexibility sources need to be considered.

3. The sizing of **operational reserves** and the regulatory framework for balancing responsibilities and procurements would need to be substantially revised, and forecasting methods for variable renewables continually improved.
4. Substantial **grid development** efforts would be necessary beyond 2030 at both transmission and distribution levels. This requires strong pro-active steps and public engagement in long-term planning, assessing costs and working with citizens on social acceptance. These efforts can nonetheless be partly integrated in renewals of ageing network assets.

Assessing the costs of these conditions is beyond the scope of this report. However, the study underlines that costs may be substantial and that meeting these conditions has deeper technical and social implications. **Further socio-economic studies are necessary**, building on the conclusions of this report, to assess the different options to reach carbon neutrality by 2050 in France. As a next step, in 2021 RTE will publish a full assessment of different electricity scenarios to reach carbon neutrality.

Context

The SNBC relies on three pillars: energy efficiency (reducing final consumption by almost half, from 1 600 TWh to 900 TWh), a stronger use of biomass (from 200 TWh to 430 TWh by 2050), and a more significant role for (decarbonised) electricity as a final fuel, which must go from 25% to 50% of final energy needs by 2050. The increase in electrification of end uses is in line with most European scenarios that aim for carbon neutrality.

The SNBC does not specify which kind of decarbonised electricity should be used, but it does not foresee the use of fossil fuels associated with carbon capture, utilisation and storage (CCUS) nor the massive use of biomass or biogas for electricity generation. This leaves renewables and nuclear power as the two possible options.

France's civil nuclear programme, implemented in the aftermath of the oil shocks in the 1970s, led to the building of 58 nuclear reactors in 25 years, amounting to up to 400 TWh per year of decarbonised electricity generation – around 75% of the French total electricity generation. As a result, 93% of electricity generated is carbon-free. In 2019, the average emission factor of electricity generation was 35 g CO_2/kWh – 11 times less than Germany and 13 times less than the Unites States in the same period. While hydropower has also contributed to France's low average emission factor, it amounts to only 11% of electricity production, and the potential for further expansion is limited as full potential was already exploited in the 1970s.

Nevertheless, questions over the future of France's nuclear fleet have started to emerge over the last ten years. First, the desire to rebalance the electricity mix, seen as too dependent on one technology and one generation of reactors, has emerged at the social and political levels, in particular after the accident at the Fukushima-Daiichi nuclear power plant in Japan in 2011. The development of renewables in France (mainly wind power and solar PV) which started in the late 2000s, sped up recently with the adoption of the Multi-Annual Energy Plan (*Programmation pluriannuelle de l'énergie,* or PPE). The PPE envisages a significant increase in annual renewable generation from 109 TWh to 300 TWh in ten years. At the same time, a target to reduce the share of nuclear in electricity generation to 50% by 2035 has been signed into law.

Second, it is now paramount to develop an industrial strategy for replacing existing nuclear generators when they reach the end of their lifetimes. The reactors currently in operation were built over a short period: the fleet is 35 years old on average, with 27 out of 58 reactors scheduled to reach the 40-year threshold over the next five years. A major industrial programme has been launched to extend the lifetime of these reactors past 40 years, subject to case-by-case assessment and approval by the independent Nuclear Safety Agency. As of today, there is a broad consensus that current generators may not be operated for more than 60 years and that the vast majority will be decommissioned between 2030 and 2050.

France will therefore be confronted with the task of managing the retirement of some of its nuclear reactors, while at the same time expanding its decarbonised electricity supply, to reach climate change mitigation targets. This, regardless of the political discussion of recent years about the "rebalancing" of the electricity generation mix between nuclear and renewables. In other words, what is at stake is a strategy to replace the capacity for generating 400 TWh of decarbonised electricity in France over the next 30 years. Two options are on the table:

1. Replacing some decommissioned reactors with new ones – i.e. launching a new nuclear programme – and complementing this with higher shares of renewables to obtain a full decarbonised electricity mix by 2050.
2. Replacing decommissioned reactors with renewables only. If this option is chosen, the share of renewables would reach about 85-90% by 2050 and 100% by 2060.

High shares of renewables and the role of this report

While both options would significantly increase the share of variable renewable generation, the second option, 100% renewables, departs so considerably from the current situation that numerous questions arise about its technical feasibility.

Apart from small systems mainly based on dispatchable hydroelectric units, there is no experience of operating such systems. Advocates for 100% renewables claim – with reason – that past alarmist predictions of operational problems from increasing renewables in the power sector have been proven wrong. However, given that there is no proof of concept regarding the integration of high shares of variable renewables –such as wind and solar PV- in large power systems, technical challenges are bound to come up. This uncertainty has raised scepticism about large shares of renewables as an option to combat climate change, particularly in comparison with other low-carbon solutions. In France this debate has been lively, given that the current generation mix combines exceptionally low CO_2 emissions with a high reliance on nuclear power.

While no consensus has been reached in the French debate about the overall possibility of a future power system based only on renewables – notably with high shares of variables sources like wind or solar PV – the first step is to assess whether and under what conditions and requirements such a system could be technically feasible, which is the aim of this report. It is the first milestone established in the framework of the PPE, which states that the different options to ensure the power supply-demand balance in the long run need to be reviewed in mid-2021.

The report identifies and discusses conditions and requirements for the technical feasibility of scenarios with high shares of variable renewables. Results on this topic are a necessary precondition for further studies, including the next stages of the general modelling started by RTE for 2021. Technical feasibility has been considered in a broad sense, encompassing key technical system-wide challenges associated with such scenarios.

The report does not address whether those scenarios are socially desirable or appealing, or how much they cost and whether they are financially sustainable. Those questions will be addressed at a later stage on the basis of simulation work conducted by RTE with stakeholders. Even if one or more scenarios may appear technically feasible, any conclusions on their socio-economic desirability would thus require further analysis. Moreover, the report does not compare high renewables scenarios with others, either technically or economically.

This report has been commissioned by the French Ministry for the Ecological Transition. To answer the questions asked by the Ministry, the IEA and RTE have joined forces. In October 2020, the IEA published its latest *World Energy Outlook*, which includes two scenarios to reach global net-zero emissions. The Sustainable Development Scenario (SDS) puts the energy system on track to achieve sustainable energy objectives in full, including the Paris Agreement, energy access and air quality goals. The SDS assumes that relevant carbon-neutrality targets of countries and companies as announced so far are achieved, helping to put global emissions on track for net zero by 2070. For the first time, the IEA has expanded the SDS with a Net-Zero Emissions by 2050 case, which details the necessary steps in the next ten years to put global emissions on track for net zero by 2050. In addition, *Energy Technology Perspectives 2020* offers a complementary tool for policy makers to understand the necessary steps in terms of technology maturity requirements. Notably, the ETP 2020 highlights that half of the cumulative emissions reductions needed for reaching net-zero emissions by 2050 stem from technologies that are not commercially available today.

RTE publishes a yearly report (*Bilan prévisionnel*) which serves as the reference report on the electricity sector in France, both for the adequacy assessment and for perspectives for the power sector.

The current report combines the international experience of the IEA with the modelling expertise of RTE to identify what precisely is at stake in opting for large shares of renewables and to provide strategic insights for policy making. It provides high-level conclusions on some points, and identifies questions requiring additional work and new analyses regarding other points.

RTE will follow up on those questions in its ongoing work to establish new reference scenarios for the public in France, based on a wide-ranging consultation with all stakeholders. This work, expected to conclude in 2021, will be published in the next edition of *Bilan prévisionnel*, dedicated to long-term scenarios aiming at reaching net zero by 2050.

Box 1.1 International decarbonisation targets

The debate in France over the future of the power sector is taking place as many governments, international organisations and stakeholders are engaged in discussions over the best policies to implement the Paris Agreement on climate change. Several countries and jurisdictions have introduced net-zero carbon targets, and more than 50 countries have already pledged to achieve 100% renewables. Denmark, Sweden and the United Kingdom have legally binding net-zero emission ambitions by 2050 or earlier, based on a wide range of measures. Chile and Ireland have started processes to enact climate action laws by mid-2020, and they have published indicative plans to integrate renewable energy, electrify transport, improve energy efficiency in buildings and implement market reforms. In the United States there are more than 100 commitments at state and city level to 100% renewable energy, including net-zero emissions from the power sector. California has committed to net-zero economy-wide emissions by 2045 and the state of New York by 2050, relying heavily on solar and wind power. Since September 2020, three major Asian countries announced carbon neutrality targets: Japan and South Korea by 2050 and China by 2060.

While the emission targets and timelines are similar for many of these countries, paths for implementation depend significantly on the endemic resource availability, industrial mix and legacy policy and institutional framework. Chile, Denmark and Ireland favour increased variable renewables and interconnectivity. The United Kingdom is looking at extensive electrification, particularly of transport and heating, and expanding both renewable and nuclear generation while offsetting remaining emissions with carbon capture and storage. Sweden is aiming at negative emissions while anticipating a decommissioning of its nuclear fleet by market forces.

The IEA SDS assumes that all relevant net-zero emission targets announced before summer 2020 will be achieved. In the SDS, all low-carbon technologies – including renewables, nuclear and CCUS – play an important role in decarbonisation pathways consistent with the Paris Agreement. Beyond a balanced portfolio of low-carbon generation options, the SDS highlights the importance of electricity networks as well as demand-side measures, end-use electrification and energy efficiency. In the SDS, variable renewables are set to exceed 50% of electricity generation in the world by 2050. This implies that for many countries there will be an increasing amount of hours where variable renewables will make up for most or all of the generation. Investment in power system flexibility will therefore become increasingly important to ensure system stability and cost-efficiency while a country transitions to much higher levels of variable renewables.

Key findings on technical feasibility

From a technical point of view, four main issues would prove challenging in transitioning to very high shares of variable renewable energy sources in a large electricity system like France's.

1. System strength, with a focus on reduction of inertia

Nowadays the stability of large, interconnected power systems is based on the alternator rotors of conventional power plants rotating together at the same frequency, set nominally at 50 Hertz in Europe as well as in most of Asia and Africa.

These rotating machines stabilise the system by contributing to inertia and short-circuit power. This contribution is called "system strength". When the system faces a disturbance, these machines automatically help to stabilise frequency by releasing some of the kinetic energy stored in their rotating rotor before other reserves take over. In addition, they are able to generate their own voltage waveform and to synchronise independently from other electricity sources: they are naturally "grid-forming". Rotating machines are a historical cornerstone of power system stability.

With higher shares of non-synchronous generation sources like wind and solar PV, rotating machines would become less available. As opposed to conventional generators, wind farms and PV panels are connected to the network through power converters. Present conventional converter technologies do not provide full system strength. They do not contribute to system inertia, as they are not able to generate their own voltage waveform and are dependent on the frequency signal given by other sources, such as conventional generation, to run properly: they are "grid-following". Future power systems will host many more converter-based connections via electric-vehicle charging, grid-scale battery storage, HVDC connections and others.

This report finds that while several technical solutions exist to overcome the difficulty of inertia reduction, they are at different stages of maturity. While some are already deployed in field operations, others are in the research and development stage and will need to be tested in real-life settings before being deployed at scale.

To achieve a high share of renewables, the first step is to develop a new way for converters to operate when they start dominating the system. New services are needed to cope with the reduction of inertia. These services, known as *fast frequency response* or *synthetic/virtual inertia*, can be provided by specific converters that allow renewable generation to adjust very rapidly to a deviation of the frequency signal, e.g. by temporarily increasing power output, thereby helping to re-establish system frequency. Such services have already been implemented in Ireland and Quebec.

However, these solutions do not have the same effect as the inertia of rotating machines and cannot guarantee secure operation of the system if the instantaneous share of PV and wind becomes very high, for example, above 60-80%, in the synchronous area. It is therefore necessary to go beyond such solutions in systems based on wind and solar PV and significantly revamp the way the power system is operated.

To go further, one solution would be to deploy synchronous condensers. They operate similarly to synchronous generators: their motors provide inertia and short-circuit power and, therefore, system strength, but they rotate freely, without producing electrical power. Synchronous condensers are a well-known and proven technology, historically used to maintain voltage in specific areas, including in France. More recently, this solution has been used in Denmark and South Australia and has proven effective to ensure system stability. While this solution has been proven in specific situations, a generalised roll out in the context of large-scale system strength has yet to be evaluated. The associated costs of deployment are low on an individual basis, but they must be taken into account with other system costs in a thorough economic evaluation of scenarios with high shares of renewable production.

Another possibility would be to develop grid-forming controls for converters that give wind and solar power plants the ability to generate their own voltage wave. This solution has been successfully tested in the laboratory (for example, in the European project MIGRATE) and on microgrids, but not yet at the scale of a large power system, where other complications could arise. Full-scale experiments are needed in the coming years to validate this concept.

The issues at stake are not just technical. The regulatory instruments chosen to deploy these technologies and the institutional allocation of responsibility for providing these services need to be considered as well in light of the current French and European institutional frameworks. Policy makers need to keep oversight on this topic taking into account the cost impacts on end consumers, manufacturers, developers and system operators. For example, specific grid-forming capabilities could be required through technical standards levied on original equipment manufacturers, impacting technology costs. Alternatively, transmission operators could directly own or contract synchronous condensers owned by third parties or create competitive parameter-based services, leaving the technology choice and successful deployment to market participants. All three options come with specific cost and system security trade-offs, which will need to be evaluated in follow-up analyses and eventually decided on by policy makers.

Finally, the technical challenges related to system strength differ depending on the mix of renewables. Moving towards grid-forming controls would be much more challenging for a power system relying largely on distributed solar PV generation, as it would have a strong impact on the operation of distribution grids. The challenge would be smaller if the system were mainly based on large wind farms, onshore or offshore, compared to many solar PV installations connected to low-voltage networks. In any case, a system with a significant share of distributed PV would need a further detailed assessment of the impacts on the distribution network and their implications for electricity security.

To sum up:

1. There is now a broad scientific consensus on the theoretical stability of a power system without conventional generation.
2. However, the necessary technical solutions in power electronics are not yet commercially available at the scale of large meshed systems like those in France. Thus, innovation and large-scale testing would need to accelerate.
3. It will be necessary to continue R&D projects. This will include launching demonstration and pilot-projects, learning from operational experience of the considered solutions, and understanding and testing system stability in large-scale applications.

2. Adequacy and flexibility resources to cope with the variability of wind and solar PV

Coping with the variability of energy produced from wind and solar PV is the main challenge for integrating renewables in power systems. Yet, power systems with high shares of renewables in France will be based mainly on wind and solar PV. Hydropower has already been developed to nearly its full potential, so it can only cover part of future needs, and the potential of bioenergy for electricity generation is limited.

On average, wind and solar PV have different and complementary seasonal generation patterns, with more wind power on winter and more PV generation in summer. But their monthly, weekly, daily and hourly variability create challenges for keeping a continuous system balance. Thus, maintaining system adequacy – the ability of a power system to cope with load at all times –requires developing additional tools to cope with this fundamental variability in generation.

RTE adequacy analyses have repeatedly concluded that the development of wind and PV scheduled in the next ten years in France under the PPE can be accommodated by existing and planned generation units (in France and neighbouring countries) as well as demand-side flexibility at a reasonable level. Beyond 2035, however, it is no longer possible to accommodate higher shares of renewables without significantly developing flexibility.

Targeting a system based overwhelmingly on variable renewable electricity generation therefore requires the development of four types of flexibility, in different proportions depending on the considered scenarios.

1. New dispatchable peaking units. These currently use fossil fuels – albeit in very small proportions – but they could use other fuels, such as hydrogen or biogas.
2. Large-scale, dedicated storage facilities, such as batteries to address daily fluctuations; new or revamped pumped-hydroelectric generation units to address weekly variations; or synthetic fuels production (power-to-hydrogen or power-to-gas) and storage to address inter-seasonal and inter-annual variability.
3. A considerable amount of demand-side flexibility. Installations in buildings and factories would need to be able to respond automatically to market triggers or explicit requests from grid operators.
4. Strengthened power grids, enabling large-scale geographical power system integration to mitigate local variations and facilitate access to a maximum of flexibility sources. Regional and international interconnection of networks will indeed play a major role in integrating higher shares of renewables to the power system.

The development of new uses for electricity provides opportunities to develop flexibility sources on the demand side, such as electric vehicles, hydrogen production and its multiple uses, and heating in new buildings, where advanced smart management demand can be implemented. Extensive use of the batteries of electric vehicles with smart charging systems could be a key element to ensure adequacy. Batteries will already be there for the purpose of fuelling vehicles, so the main challenge would be to define the right interfaces with the power system. Mobilising the necessary flexibility resources will require both physical investment in assets like storage as well as regulatory and market frameworks than can unlock smart, distributed flexibility solutions.

In addition to adapting the power system to integrate variable renewables, it is possible to optimise the deployment and operation of variable renewables through best combinations of PV and wind capacity. This will require optimal siting targeting high capacity factors and, possibly, minimising the size of grid connections. Such measures would be complemented by the participation of variable renewables in markets and accurate forecasting of infeed.

Complementing variable renewables with peakers, storage, extensive demand-side management and grid to ensure system adequacy has important cost implications. Cost analysis, which is not in the scope of this report, will be carried out at a later stage of the process in RTE's future 2050 scenarios. Any future evaluation should focus, however, on overall system costs rather than on metrics like levelised cost of electricity because these fail to account for costs associated with technical requirements (security of supply and others). Both the IEA and RTE believe that any cost estimation should take into account all the costs associated with a high share of renewables, including the costs of storage, demand-side flexibility and grid development. This report shows that those costs might be substantial in France after 2035. It sets the stage for the future cost-evaluation on metrics shared at international level.

This kind of scenario has implications in terms of industrial feasibility, which should be studied in conjunction with RTE's future 2050 scenarios. Since the capability to reach a very high share of renewables in the mix will rely on batteries, digital technologies for smart load management, or synthetic fuel production (power-to-hydrogen or power-to-gas) and storage, it is important to assess the maturity of these technologies and the ability to efficiently roll them out at scale. Future analyses should not only focus on projected cost but also encompass a purely industrial dimension and consider the challenges of increasing the rate of deployment for technologies at various levels of technological readiness. This implies thinking about the conditions for developing the necessary industrial environment.

Finally, the environmental footprint of deploying these flexibility resources – on land use and critical materials – must be considered. This applies to their social acceptance – in particular, to generalised demand-side response uptake in the residential sector or for the deployment of infrastructure such as electrolysers or interconnectors. This environmental and societal analysis must consider the whole energy system, integrating all flexibility resources.

To sum up:

1. Attaining ~50% share of renewable energy generation in France by 2035 under the PPE scenario would be possible with existing non-renewable generation capacity and some additional demand-side flexibility or distributed storage. But, reaching higher shares afterwards would require additional peak generation units, large-scale storage and/or intensive demand-side management at some point.
2. Rather than using metrics like LCOE, future assessments of the cost of different options for high shares of wind and PV should focus on system costs, including flexibility resources, balancing and grid assets.

3. Significant steps have to be made in coming years to take some flexibility resources to industrial-scale deployment, for example large-scale flexibility from electric vehicles or synthetic fuels production (power-to-hydrogen or power-to-gas) and storage.

3. Operational reserves

In a liberalised power system, market parties are responsible for keeping their portfolio in balance. However, operational reserves are procured and used by the TSO to balance the system in real time wherever markets do not deliver or in case of unforeseen outages. Reserves are sized to cover uncertainties and contingencies in generation, consumption and grid capacity. The shift towards a greater share of variable renewables, along with changes in electricity consumption foreseen in the SNBC, mean that the type and amount of those reserves will also change.

Although the dimensioning of operational reserves and balancing responsibilities is a well understood issue in current debates about market design, the issue has not attracted a lot of attention in relation to long-term scenarios at policy level. Moreover, the impact of wind and solar PV on operational reserves is generally not considered in academic publications on large-scale deployment of renewables.

For the time being, France does not need to procure large volumes of operational reserves compared to other countries, and its balancing system is competitive, resulting is low costs for the consumer compared to other European countries. The generation fleet in largely dispatchable and market regulations provide for resource pooling and proactive balancing systems that help to minimise costs.

In the future, increasing variable renewables will require revising current practices for the sizing of operational reserves and the allocation of balancing responsibilities. Today, the uncertainties taken into consideration to determine these reserves are mainly related to risks of sudden disconnections of major generation units and of unexpected deviations in consumption patterns. However, the practices for procuring and using operational reserves should evolve to account for rising shares of wind and solar PV. This is because wind and solar PV are difficult to forecast accurately, even within one day before real time, because of the local characteristics of the weather patterns and the small size of these units. This difficulty is particularly pronounced for distributed solar PV systems because a large proportion of their production cannot be monitored in real time – i.e. they do not necessarily have a metering device that measures generation in real time and transmits to grid operators.

As a result, high shares of wind and solar PV could lead to important uncertainties about future production, even a few hours from real time. Efforts are therefore needed to improve the real-time monitoring of wind and, especially, solar PV to enable better predictability or a direct and accurate estimation of net load (i.e. load minus distributed generation). Short-term forecasting, sizing and operations of reserves could also be improved. Current methodology for sizing operational reserves will need to be updated to take into account the increase in uncertainty due to a large share of variable renewables.

In the extreme situation, when current conditions of predictability and real-time monitoring for renewables were applied up to 2050, the need for operational reserves increases dramatically. By contrast, this increase could be largely mitigated if full monitoring were implemented. This difference underscores the need for improved visibility of new renewable generation, forecasting techniques and balancing obligations.

To keep the need for new operational reserves to a reasonable level, efforts to improve predictability and real-time monitoring of variable renewables are being made. Using new technologies to collect, transmit and analyse data from distributed generation like PV panels is one path taken to meet this objective. Another way of balancing the system in the future would be to use renewables as balancing units that respond to more stringent obligations, like those currently placed on traditional units. Wind and PV units have been installed in recent years as marginal units and thus have not been subject to the traditional regulations applied to bigger generation units. This practice, perfectly sound for the early stages of developing renewables, is not suited to scenarios in which renewables may comprise nearly all generation by 2050. This issue is increasingly being addressed in recent grid codes around the world, albeit only for new generation units.

Lastly, future areas for improvement also include the use of new sources of power system flexibility – storage, peaking units, demand-side flexibility and especially the charging of electric vehicles – for balancing the system in real time. They could indeed provide additional power reserves that can be activated very quickly. There remain operational challenges to overcome in the field, and stepping up efforts to demonstrate successful large-scale participation of distributed units to provide significant volumes of operational reserves – for example, with electric car charging – could be an industrial priority in the coming years.

To sum up:

1. Integrating large volumes of wind and solar PV requires dedicated action to cope with uncertainties and the decentralised nature of variable renewables. This will also affect how operational reserves are sized and used.
2. Forecasting methods need to be improved while work is already under way to optimise balancing processes at the international level.

3. Over the next ten years, regulatory improvements are necessary to take into account the changing nature of the power mix. These should make it possible to use the flexibility of wind farms, PV panels and electric vehicles, and establish conditions for new units and refurbished ones in order to ensure that the power system has sufficient reserve capability.

4. Grid development

To reach high shares of renewables in the power mix, electricity grids will need to be developed and modified in important ways.

A power system with a higher share of renewables is indeed much less geographically concentrated than a system with nuclear power or large thermal fossil fuel plants. More grid reinforcement and expansion are necessary to connect generation facilities and match demand patterns, geographically and in time. By contrast, if the grid is correctly developed, such a system would be more resilient to the loss of single large components such as network line or a generation unit.

Key grid developments are already planned for the next ten years both at the national level and as part of the wider regional European power system. In France, RTE has recently published its reference Ten-Year Network Development Plan (*Schéma décennal de développement de réseau*, or SDDR) up to 2035. At the European level, the European Network of Transmission System Operators (ENTSO-E) publishes a Ten-Year Network Development Plan (TYNDP) every two years, which already accounts for the implications of planned grid development within and between countries. To accommodate the integration of renewables, these plans envision not only grid adaptations but also a push in grid optimisation through the generalisation of real-time use of flexibility from renewables (mainly wind farms). In the medium term, these changes are enough to keep the need for new grids in France lower than, for example, Germany today or France in the 1980s, while still attaining ambitious targets for renewables.

Beyond 2030, however, grid expansion, reinforcement and restructuring would be needed to increase the share of renewables in the power mix. The report explains the key actions needed to shape this grid refurbishment and expansion.

By 2050, the very high-voltage grid used for interregional and international exchanges (400 kV and most of 225 kV) will still be in place. Built mostly between the 1970s and the 1990s to make the nuclear programme possible, it was planned to allow large transfers of energy across France. As such, this backbone is well adapted to integrating renewables. Apart from a few well-identified weak zones, this very high-voltage backbone can cope with the variability of renewables until 2030 under the assumptions of the PPE scenario. Greater ambitions for 2050 will require more substantial reinforcements, however. The emergence of new transmission technologies – such as superconductivity, gas-insulated assets, and AC to HVDC switching – should make it possible to gradually adapt the existing system to an even larger share of renewables.

Offshore grids and cross-border interconnections would also need to be developed in addition to the reinforcements to the national transmission network. On the one hand, this would allow integrating offshore energy to its full economic potential. Wind turbines far from shore require planning for a co-ordinated offshore transmission grid, possibly connected to sites of decommissioned nuclear plants. On the other hand, grid expansion should also significantly increase exchange capacity across Europe by adding more cross-border interconnections (west-east and north-south).

By 2050, the high-voltage grid (63-90 kV – which is part of the transmission grid in France), traditionally used to supply electricity to consumers, will need to be redesigned in any case, as it has been built mainly between the end of the Second World War and the 1970s. Preparing for this renewal is an important part of the network plan RTE published in September 2019. This grid will need to be significantly adapted to take into account the higher targeted share of variable renewables. This represents an opportunity to keep costs on track by combining refurbishment and expansion.

Social acceptance and costs will be crucial factors in implementing structural changes in the grid. A power system with very high shares of renewables would mean a bigger footprint for grids (as well as generation units), and local resistance to grid reinforcement is sometimes already high – even when shares of wind integration are low and grid reinforcements much smaller than required to meet the energy transition goals. Lastly, while costs do not currently seem to be the most substantial point of discussion when it comes to grid development, they should be considered in future studies when looking at the context of power system development towards 2050.

To sum up:

1. In France, the current transmission grid provides a good platform to build upon. It is not poised to become a limiting factor for the integration of renewables in coming years if targeted reinforcements are implemented. To further increase the share of renewables, adjustments to the grid structure are necessary but remain limited compared with the pace of grid development in the 20th century.
2. Beyond 2030, fundamental grid expansion, reinforcement and restructuring will be needed to reach high shares of renewables. Given the time required to consult

stakeholders and obtain permits, these developments must be planned soon and decided in the coming years.

3. Gaining social acceptance for grid adaptation is a key factor in facilitating the development of wind and PV. Solutions such as forward spatial planning of grid adaptations (for example, to connect offshore grids) and using flexibility sources in addition to new grids could play a significant role in enabling this transformation.
4. Public authorities and regulators need to establish an effective system to enable industries to attract enough investment for network development and overcome social acceptance hurdles.

Next steps

The findings and methodological propositions of this report will be used to follow work undertaken at French level, particularly for the next issue of RTE long-term scenarios (*Bilan prévisionnel)*, which will study the means to achieve net-zero emissions by 2050.

This work, initiated in 2019, has been held in consultation with stakeholders. It is currently at the end of its framing phase, before simulations are conducted and discussed collectively. This integrates (1) a complete description of possible scenarios (including differences in lifestyles and individual behaviours) with and without new nuclear reactors; (2) a quantitative technical analysis of supply-demand balance and grid requirements, taking into account the effect of climate change according to different IPCC scenarios; (3) an extensive modelling of the European power sector; (4) a detailed modelling of interactions between the power sector and other energy carriers; (5) a full system cost-analysis; and (6) an assessment of environmental effects, including not only greenhouse gas emissions and footprint but also items such as the need for critical minerals and the impact on land use. Those new scenarios are scheduled to be completed in 2021.

Chapter 1. Introduction

Electricity is becoming increasingly vital for our economies and societies. Industry and citizens expect maximum levels of reliability, and even short disruptions can have widespread economic impact. At the same time, efforts to meet long-term climate targets are leading to decarbonisation of the power sector through new technologies such as renewable energy, far beyond what has already been deployed, together with other low-carbon solutions such as nuclear power and CCUS depending on the country. As a result, new challenges are emerging in power systems across the globe, which are intensified in areas with very high shares of variable renewables. These challenges require dedicated attention from policy makers in co-ordination with system operators, industry and researchers.

Within the framework of international climate action, the French government has built a national low-carbon strategy for reducing greenhouse gas emissions and reaching carbon neutrality in 2050. Electricity would then supply half of the energy France needs, compared with one-quarter today. Renewable energy sources would have a higher share in the electricity mix than today while the strategy keeps the role of nuclear energy open.

To contribute to the debate, the French Ministry for Ecological Transition asked the International Energy Agency (IEA) and the French transmission system operator RTE to carry out a framework study of the conditions and requirements needed to assess the technical feasibility of a system with high shares of renewables by 2050, possibly heading towards 100% eventually. The report focuses on four technical dimensions:

- the management of system stability, focusing on reduction of inertia from rotating machines and their contribution to system strength, to be addressed by fast frequency response devices, synchronous condensers and further development of grid-forming converters;
- security of supply, ensuring adequacy and flexibility resources so that the power system can supply consumers also in a mix dominated by variable generation from solar PV and wind;
- required evolution of operational reserves and margin needs and supplies;
- network adaptation to integrate renewable energy sources and supply it to consumers, matching relevant geographical and time demand patterns.

Chapter 2. Renewable energy scenarios in France's National Low-Carbon Strategy

Key messages

- The National Low-Carbon Strategy (*Stratégie nationale bas-carbone*, or SNBC) provides a roadmap for France to reach its objective of achieving a carbon-neutral energy mix, protected by law.
- The SNBC seeks to strongly reduce energy consumption and use almost exclusively domestic forms of decarbonised energy, such as biomass and low-carbon electricity. It plans for an increase in the use of electricity, both as a final energy consumption and as a means to decarbonise other energy carriers such as hydrogen.
- Like the European Union and the IEA, the SNBC recognises that increased electrification is necessary to achieve carbon neutrality. The electrification in transports, buildings and industry provided for by SNBC is consistent with the scenarios of the European Commission and those from the IEA aiming for carbon neutrality.
- There are two main options for the future electricity mix in France: a scenario combining renewables with new nuclear reactors and a scenario leading to the exclusive use of renewable electricity. Both options require high shares of variable renewables.
- The second option would rely primarily on wind power (onshore and offshore) and solar PV. This is because of limits on other options: hydro power is already exploited close to its full potential; carbon capture, utilisation and storage (CCUS) is considered a last resort option; and imports of biomass or decarbonised gas are also supposed to be minimal. The sources of biomass in France would be dedicated primarily to heat or biogas production and not to electricity generation. By 2050, the electricity generation mix in France would thus rely mainly on variable power sources such as wind and solar PV and power electronics to connect them to the grid.
- The operation of the power system depends not only on the evolution of the mix in France, but also on the mix in all the interconnected countries. Modelling work carried out by RTE takes into account the whole European power system for analyses on security of supply, inertia and stability.

The low-carbon strategy relies on massive integration of decarbonised energy sources and reduction of energy consumption

France has pledged to achieve net zero carbon emissions by 2050 and passed this commitment into law. It also designed a comprehensive scenario to achieve carbon neutrality, the National Low-Carbon Strategy (SNBC), and defined new objectives for the energy sector in the Multi-Annual Energy Plan – *Programmation pluriannuelle de l'énergie* or PPE.

This comprehensive strategy is supported by two pillars:

- **Almost exclusive use of domestic decarbonised forms of energy** – namely decarbonised electricity and biomass to a limited extent – as sources of production for final energy uses. To achieve this, the shares of the different energy carriers will change profoundly. Any residual emissions are expected to be offset by carbon sinks, such as forests.
- **Reducing energy consumption**. Compared with 2015 levels, the SNBC energy consumption is halved to reach about 900 TWh/year in 2050, with big drops in the transport and buildings sectors (see Figure 2.2). This reduction derives from energy efficiency and behavioural change. Energy efficiency gains are mostly based on already mature technologies and on changes in final energy use, such as greater use of electricity in transport. Behavioural changes are needed – as well as changes in lifestyle and collective organisation, an approach known as energy sufficiency – because the decrease in final consumption cannot be achieved only through energy efficiency.

In this strategy, CCUS is a limited, last-resort option that does not allow for the use of fossil fuels. It would compensate irreducible emissions from some industrial processes, limited to 15 $MtCO_2$ by 2050, which leaves no space for abating further emissions from fossil fuels (DGEC, 2020). In the same spirit and contrary to what is contemplated by some other countries in Europe, there is no plan to use CCUS in the production of low-carbon hydrogen.

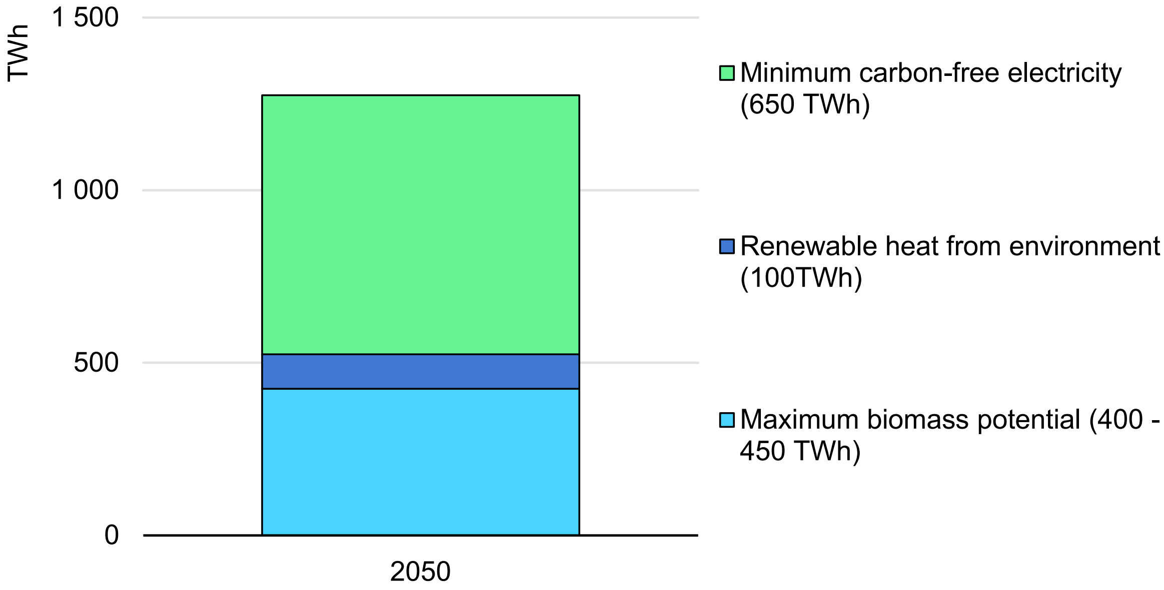
One of the structuring hypotheses of the SNBC is energy independence, which appears explicitly among the objectives of the energy-climate policy. It would depart significantly from the current situation, where approximately 50% of the energy used in France is imported. It also means that the SNBC has been built around the potential for decarbonised energy production in France. The main choices of SNBC depend on this initial framing:

- energy independence can only be achieved if total demand decreases significantly by 2050 from today's level of 1 800 TWh/year;
- biomass being scarce, it should be allocated to the most efficient energy uses, and the share of gaseous and liquid fuels is limited;
- direct and indirect uses of electricity should increase.

Taking all decarbonised energy sources into account, the French potential is estimated at least around 1 200 TWh per year, before conversion and distribution (Figure 2.2). This is made up of:

- at least 650 TWh/year of carbon-free electricity (nuclear and renewable, not differentiated)
- 400 TWh to 450 TWh/year of biomass
- 100 TWh/year of renewable heat from the environment, including heat pumps and geothermal energy.

Figure 2.1 Estimated potential for decarbonised energy sources considered in SNBC



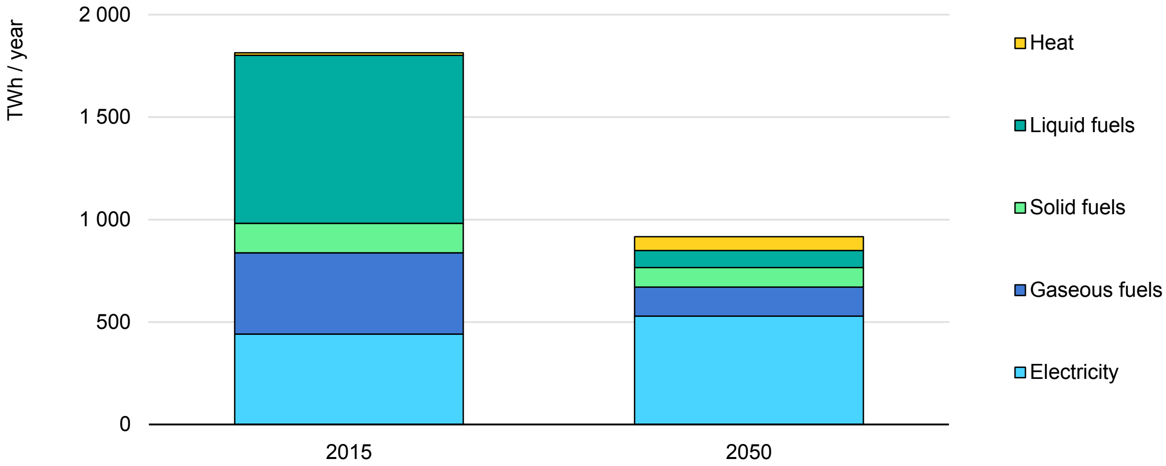
Note: Figures stand for estimated resources before conversion and distribution.
Source: RTE analysis based on DGEC (2020) and PPE 2020.

By 2050, the use of biomass for energy would be about 2.5 times higher than today – a striking feature of the strategy. Biomass would then, directly or indirectly, supply a much larger part of final energy needs, though different carriers: gas, solid fuels (firewood) and liquid fuels (biofuels). Heat would become a significant energy carrier, rising from 12 TWh currently to around 70 TWh by 2050 through increased use of heat networks in industry, electrified heat and renewable heat. The limited amount of biomass requires it to be used as efficiently as possible, as a way to store CO_2, as lumber, for heat or biogas production or in co-generation. This leads to limited use in the electricity sector (see Chapter 3).

Electricity generation would also increase compared to the current situation, but by comparatively lower factor, 30% respective of today's volume, taking into account electricity needed for indirect uses such synthetic gas and fuel production).

The distribution of final consumption over the different energy carriers would radically change by 2050 (Figure 2.2). This transition is largely based on the decarbonised nature of electricity, which is projected to supply 58% of final energy consumption in 2050, up from 25% in 2015.

Figure 2.2 Final energy consumption by energy vector, 2015 and 2050



Note: 2050 levels are projections in the National Low-Carbon Strategy.
Source: RTE analysis based on Direction Générale de l'Energie et du Climat (2020) and PPE 2020.

The French Low-Carbon Strategy assumes an increase in electricity consumption

Beyond the big picture, electricity demand depends on many factors, such as GDP growth or the overall level of industrial activity, collective and individual choices about energy consumption, and actual fuel switching.

The SNBC assumes sustained GDP growth in France, with the annual growth rate assumed to reach between +1.3% and +1.7% up until 2050. This hypothesis is based on the recommendations of the European Commission in its EU Reference Scenario (before the coronavirus crisis).

Second, the SNBC is based on a significant improvement of energy efficiency, but also, to some degree, on energy sufficiency. Those are two different notions: energy efficiency refers to the possibility to use less energy for the same degree of service, whereas energy sufficiency refers to the will to reduce energy consumption through changes in behaviour, lifestyle and collective organisation (such as less car use, more local and better quality food, reduction of heating temperature).

The SNBC, envisages a significant increase in energy efficiency, for example in industry, with 20 to 40% improvements by 2050, buildings or in electric appliances. Improvements in energy sufficiency are also assumed, based on a heightened concern for environmental issues at a societal level. For example, the strategy assumes both a reduction in vehicle ownership per household along with a 1 °C reduction of average temperature in buildings.

The pace of fuel switching to electricity also plays a key role, particularly in transport, building and industry, as well as the volume of electricity considered for transformation in other vectors, in particular power-to-gas and power-to-heat. In addition, industrial, services and residential demand-side response are important, benefiting from the flexibility of uses of electricity, including electric vehicle charging and "white" appliances such as dishwashers and washing machines.

The SNBC provides a detailed scenario for the evolution of electricity consumption between now and 2050 in terms of annual energy. It is thus based on assumptions about evolution of energy efficiency levels, transfers from fossil energies to electricity, coupling between electricity and other energy vectors, and efforts of consumers to reduce consumption (Table 2.1).

Table 2.1 Assumptions on energy efficiency, energy sufficiency and fuel switching as defined in the French National Low-Carbon Strategy and Multi-Annual Energy Plan

Parameters		Assumptions
Energy efficiency		<u>Buildings</u> • 100% of residential and services buildings (newly built, rebuilt and refurbished) respect low-energy standards • Specific electricity: unit consumption gains between 15% and 60% depending on the appliances between today and 2050 <u>Industry:</u> energy efficiency improvements of 20% to 40% between 2015 and 2050 depending on the industry sectors
Environmentally conscious behavioural change and rationalisation of uses		• 1°C temperature decrease in buildings • Change in consumption modes including decrease in comfort
Use transfer	Power-to-gas	50 TWh of electricity per year
	Industry electrification	• Electrification rate of 74% (vs. 38% in 2015)

	Transport electrification	• Personal cars
		  ○ Almost 100% electric in 2040
		  ○ 12.5 kWh/100 km in 2050: 30% lower than today
		• Light-duty vehicles
		  ○ 80% market share in 2050
		  ○ 16.9 kWh/100 km in 2050: 30% lower than today
		• Heavy goods vehicles
		  ○ 30% market share in 2050
		  ○ 118 kWh/100 km: 40% lower than today

	Heat electrification	• 45% market share in the residential sector • 60% market share in the commercial sector[1]

Note: Assumptions written in the baseline scenarios but which may subject to sensitivities in later studies.
Source: RTE analysis based on DGEC (2020).

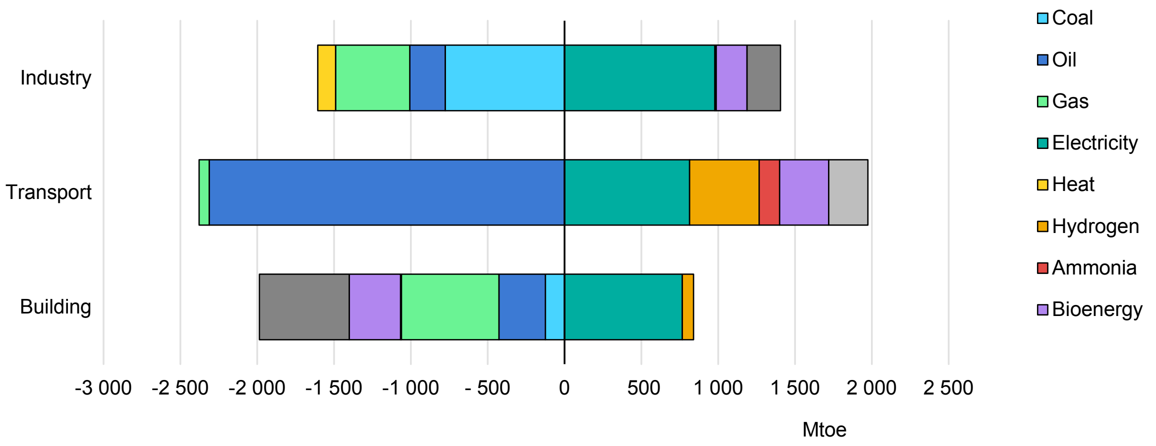
While France's demand for electricity is currently close to 500 TWh, totalling final electricity consumption plus energy losses and consumption from the energy sector, it is projected to reach almost 600 TWh by 2050. Additional electricity generation would be needed for power-to-gas, which would amount to 50 TWh by 2050. This means that total generation would need to reach 650 TWh per year (Figure 2.3).

When analysed in the light of other scenarios aiming for carbon neutrality, the SNBC does appear similar to the many global scenarios as regards electrification. In

[1] Meaning 47 TWh/y and 13 TWh/y of electricity in the residential and service sectors, completed by heat extracted by heat pumps from environment.

particular, it assumes structural changes in final energy demand, with important fuel transfers towards electricity in three main sectors: industry, transport, and buildings.

Figure 2.3 Change in global final energy demand by fuel and sector in the Sustainable Development Scenario, 2019-70



Source: IEA, ETP 2020.

In the residential sector and the services (or tertiary) sector, electrified heating and energy efficiency are expected to drive the evolution of electricity demand. Electrified heating is expected to increase through the development of heat pumps, from around 15% in the residential and 25% in the services sector to 45% and 60% by 2050 (including heat from the environment provided by heat pumps). Energy efficiency is also expected to increase sharply: by 2050, all residential and services buildings should respect low-energy standards, whether they are newly built, rebuilt or refurbished. Progress in energy efficiency will also reduce the load from specific uses of electricity.

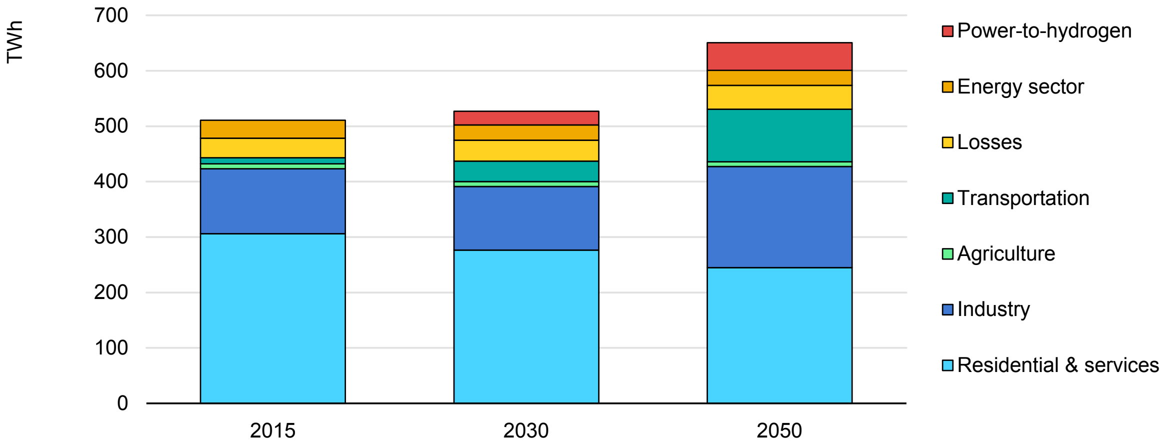
Electricity demand from the industry sector should also increase by 40% despite an increase in energy efficiency. This implies massive electrification of processes beyond 2030.

At the same time, electricity demand for transport should also increase significantly. Light-duty transport would be almost fully electrified, including all individual cars and 80% of other light-duty vehicles. As for heavy-duty vehicles, electricity is expected to power 30% of them by 2050.

The strategy also provides guidance on sector coupling between gas and electricity, in particular on the volumes of electricity required to produce synthetic gas. These volumes are significant but remain lower than in some other European scenarios. Decarbonised gas is mainly derived from biomass (through methanisation or pyrogasification), while the development of power-to-gas (for hydrogen production by electrolysis and to a lesser extent for methane production) is assumed to be more limited. Imports of decarbonised gas from other European countries are also projected to be low – in that sense, the strategy of France is clearly different from that adopted in some other countries in Europe like Germany.

Overall, the SNBC's path to net-zero emissions includes a projection that electricity demand will increase, especially between 2030 and 2050, along with strong efforts in energy efficiency. Reaching net-zero emissions would therefore require significant conversion of uses to electricity in the building, industry and transport sectors. This is why the share of electricity in final energy consumption is expected to increase sharply, from 25% today to 58% in 2050.

Figure 2.4 Evolution of annual electricity demand in the National Low-Carbon Strategy (including French overseas departments)



Note: Comparison between 2015 and the projections of the National Low-Carbon Strategy towards 2050.
Source: RTE analysis based on DGEC (2020).

Such an increase in the share of electricity can also be found in the vast majority of global and European energy scenarios aiming at carbon neutrality. For instance, the European Commission's 2050 energy strategy sets out eight pathways, with electrification level in final energy demand in 2050 ranging high too, between 41% and 53%. The increase of electricity share is also found in recent scenarios from the IEA ETP 2020 (see section 2.5), which concludes that spreading the use of electricity into more parts of the economy is the single largest contributor to reaching net-zero emissions.

Even in scenarios that depend on synthetic fuels produced in France to cover final energy demand, the electricity system will play a significant role. **Indirect electrification through production of synthetic gases and fuels (power-to-gas) and production of heat (power-to-heat) is expected to be further developed and will therefore represent significant additional amounts of electricity generation.**

From energy projections to a detailed analysis including hour-by-hour assessment of security of supply

The SNBC provides a general scenario for reaching net zero, but it does not contain specific modelling of the power sector. It thus does not address the issue of power demand profile or, more specifically, the balance between power supply and demand at particular times. In this regard, while the SNBC envisages a broad role for the use of demand-side flexibility, the strategy is unclear about how such flexibility can help to balance supply and demand on an hourly and even sub-hourly basis.

The present report investigates the technical challenges arising from achieving scenarios aiming at carbon neutrality by 2050 such as the SNBC while having a power system mostly or only based on renewables (that is to say, for France, a situation where existing nuclear reactors would not be replaced by new ones when decommissioned). To assess the technical feasibility of this kind of power system, the first necessary step is to define hourly profiles of electricity demand, which requires going into more detail than what the main scenarios for climate neutrality usually do.

Such detailed simulations of long term scenarios for the power sector are ongoing: RTE is in the process of running simulations with widely varying sets of assumptions, ranging from a continuation of current patterns to very different paradigms. Stakeholder engagement is key to ensure that simulations use appropriate parameters. This work is part of the detailed long-term scenarios that RTE will publish in 2021. This RTE-IEA report uses only one set of assumptions, which match the SNBC's hypotheses on energy efficiency and societal changes (including the development of energy sufficiency).

This assessment has been made through Europe-wide modelling with the Antares software used for the forecast assessment published by RTE in its 2017 Adequacy Report (*Bilan prévisionnel* 2017). This report does not integrate all the modelling evolutions that will be incorporated in future adequacy assessments, notably for the long-term forecast to 2050-60. For example, future scenarios will integrate new climate models according to the RCP 4.5 and RCP 8.5 scenarios developed by the Intergovernmental Panel on Climate Change (IPCC).

As mentioned earlier, the SNBC supposes a large effort in energy efficiency and even some development in energy sufficiency. Those assumptions are of crucial importance for the technical assessment of power sector scenarios. In particular, they are supposed to be enough to mitigate the increase in peak load[2]. This is due to two reasons:

[2] The increase in peak load is estimated based on a one-in-ten peak load.

- a general increase in energy efficiency, which is expected to reduce the impact of appliances on peak loads. For example, by replacing electric heaters in poorly insulated housing.
- the broad adoption of smart uses of electricity, including smart charging of electric vehicles (EV) and smart electricity at home (RTE 2020)[3].

Future hourly profiles are nevertheless extremely sensitive to a variety of parameters. Beyond such traditional key indicators as the rate of direct electrification and the spread of electric appliances, new factors such as the development of social habits regarding smart charging or the impact of climate change -during cold waves and heat waves- will need to be taken into account. Thus, these parameters should be carefully considered both in future scenario-building in France, and in the upcoming long-term scenarios prepared by RTE.

In this report, peak demand has thus been considered broadly stable or moderately increasing.

Scenarios with high shares of renewables will rely mainly on wind and solar PV

The SNBC leaves open the question of the electricity mix by 2050, and this report is about only one group of possible scenarios for the power sector. However, even within the category of scenarios heading towards 100% of renewables, a large variety of possibilities exist, allowing for different levels of development for the following energy sources[4]:

- onshore and offshore wind power
- solar PV power
- hydropower
- electricity from biomass, biogas, or low-carbon methane or hydrogen,
- cogeneration (based on biomass, biogas or gas-to-power).

Technical potential is promising for some of these technologies but far less so for others.

For some renewable electricity sources, prospects are limited in France. Beyond marginal development in new sites and upgrading of existing facilities, hydropower

[3] With the same modelling of EV and hot water as in the 2017 adequacy report (hot water consumption mainly at night and EV charging: 40% natural load + 60% tariff-based and smart charging).

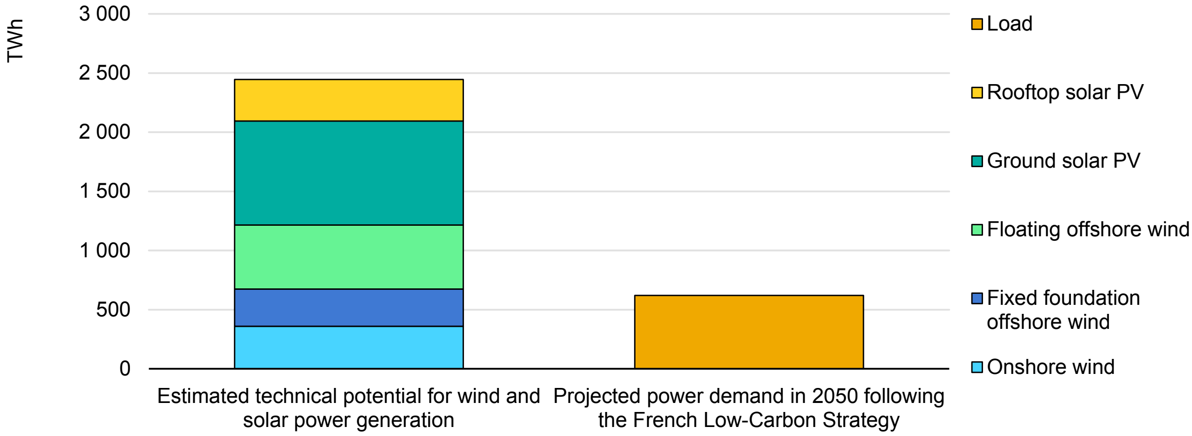
[4] Geothermal and marine energy sources other than offshore wind are not expected to make up a significant share of the renewable energy mix.

capacity would be difficult to develop further as almost all suitable sites are already equipped. Use of biomass and biogas for electricity generation is not given priority as there is limited potential for biomass and its use should be directed to other sectors (i.e. direct heat production, production of biogas for the industry, or biofuel production for heavy transport, such as planes and ships).

For other energy sources, the Multi-Annual Energy Plan (MTES, 2020) mentions substantial technical potential in France: more than 770 GW of ground-based solar PV power plants (CEREMA, 2017), around 350 GW of rooftop solar PV, 290 GW of onshore wind power and around 245 GW of offshore wind (ADEME, 2015).

Together, wind and solar offer vast technical potential for low-carbon energy that far exceeds the power demand projected by the SNBC in 2050 (Figure 2.4). Nevertheless, these numbers are technical, and do not take into account social acceptance, cost, industrial capability and environmental impacts, such as raw material consumption and land use. These important issues are not addressed in the present report but will be thoroughly examined in RTE's next long-term forecast assessment.

Figure 2.5 Technical potential for wind and solar power generation in France compared with estimated load level by 2050



Note: Social acceptance, costs, industrial capability and environmental impacts have not been taken into account.
Source: RTE estimations based on the Multi-Annual Energy Plan 2020 and National Low-Carbon Strategy.

Given the limitations on increasing hydroelectricity potential and the clear directions provided by the SNBC regarding the use of biomass, high shares of renewables – and possibly eventually 100% – could only be attained through considerable development of wind energy (onshore and offshore) and solar energy.

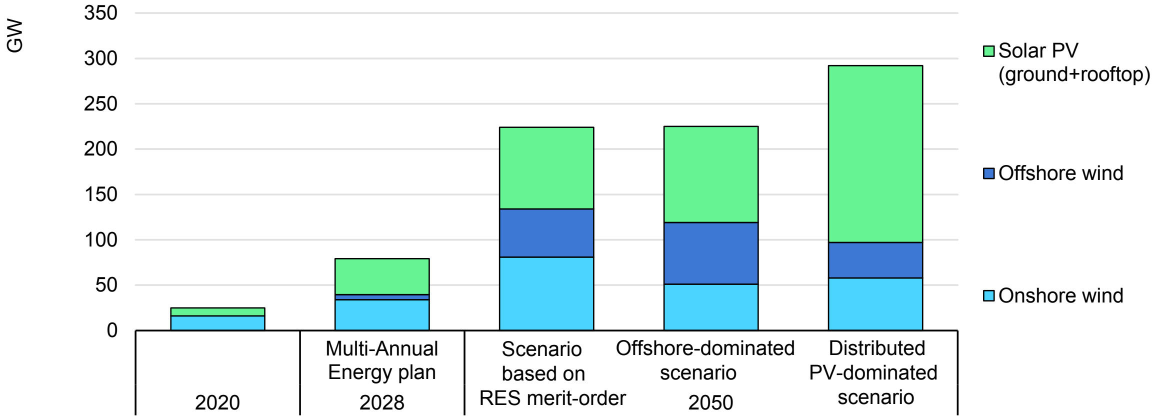
For France, reaching the minimum capacities necessary to replace existing nuclear reactors when they are decommissioned, while following the SNBC's projections for electricity generation, would mean a significant departure from the present situation for onshore wind, offshore wind and solar PV. By 2050, no scenario heading towards 100% renewables can work with less than 50 GW of onshore wind, 30 GW of offshore wind and 100 GW of solar PV (equivalent to more than 11 times the level of today). For onshore wind and solar PV this represents, respectively 3 and 11 times the current installed capacity. As for offshore wind, this would require 60 windfarms of 500 MW each, while none have been developed so far and only 7 are planned in the next years. Such a development would lead only to 60-65% of renewable energy in the electricity mix by 2050. This means that in order to have at least 85% of renewables by 2050, a precondition to reach 100% by 2060, it is necessary to go beyond these levels for onshore wind, offshore wind or solar PV.

Considering this framework, ongoing studies on the electricity generation mix in France by RTE for the long-term forecast assessment consider three broad types of scenarios, all of which use hydroelectricity at its maximum level (Figure 2.5):

- A scenario where renewables would be developed according to a purely economic merit order, favouring large units (onshore and offshore wind and mainly ground solar PV). In this option, onshore wind would need to be developed to a greater extent than offshore wind and solar PV.
- A scenario mostly based on offshore wind, that would develop close to its maximum potential in order to reduce the onshore footprint of renewables in mainland France.
- A scenario, specifically aimed at developing distributed renewable generation, in particular rooftop solar PV.

In all those scenarios, other technologies could complete the mix, such as storage, demand-side response but also gas turbines, since the SNBC allows for 20 TWh of hydrogen and 25 TWh of decarbonised gas (before conversion into electricity) available for electricity generation by 2050 (see next chapter).

Figure 2.6 Variable renewable generation scenarios compared with today's capacity



Note: Figures concerning the Multi-Annual Energy plan correspond to mean values between lower and higher objectives for 2028.
Source: RTE (2020) based on the Multi-Annual Energy Plan 2020.

Some technical characteristics are common to those 3 types of scenarios with very large shares of renewables. In particular, all three are largely based on converter-based resources. This dramatically changes the way the inertia stability of the power system can be ensured (see Chapter 4).

Conversely, 100% renewable power mixes would behave differently in terms of security of supply, requirements for operational reserves, and power flows and network constraints, depending on the capacities of onshore, offshore wind and solar PV. These variations arise because of different production characteristics, such as seasonal load factor, weekly and daily variability, and production uncertainty. This will influence the amount of operational reserves necessary to cope with unexpected variations (see Chapter 6). Last, the location of generation also differs depending on whether renewable generation is distributed or centralised, onshore or offshore, wind-powered or solar PV-powered (see Chapter 7).

Some power systems already experience the challenges of dealing with such variations. Analysis of the operation of these systems would help France to overcome the challenges involved in developing a power system with a high share of renewable energy sources.

The National Low-Carbon Strategy is largely consistent with IEA low-carbon scenarios

The French National Low-Carbon Strategy takes place in a galaxy of low-carbon policies from around the world that are being explored thoroughly in IEA analyses.

The IEA uses two main scenarios to explore technology pathways over the period to 2070, which are characterised by their assumptions regarding governments' policy choices:

- The Stated Policies Scenario (STEPS): This scenario serves as a benchmark for projections used in the Sustainable Development Scenario. It assesses the evolution of the energy sector based on policies and commitments that have already been adopted or announced; these include commitments in countries' Nationally Determined Contributions under the Paris Agreement. Globally, this scenario would lead to a slight increase in annual emissions, from 33 $GtCO_2$ today to 35 $GtCO_2$ in 2050. According to the 2019 UNEP Gap Report, implementing the Nationally Determined Contributions would lead to an average global temperature rise of 3.0°C to 3.5°C in 2100. Taking into account the recent net-zero emissions targets announced by the European Union and about 65 countries, in addition to the policies considered in the Stated Policies Scenario, would reduce annual emissions only modestly, by 2050 compared to current levels.
- The Sustainable Development Scenario (SDS): This scenario lies at the heart of the IEA *Energy Technology Perspectives 2020* (ETP 2020), which sets out a pathway to achieve global net-zero emissions by 2070. It broadly describes the necessary evolution of the energy sector to reach the energy-related UN Sustainable Development Goals (SDG7, SDG 3.9 and SDG 13) and assesses what is needed to meet these, including the Paris Agreement commitments, in a realistic and cost-effective way.

The two main IEA scenarios do not include specific trajectories about energy and CO_2 emissions at country level, only at European level, which makes it difficult to compare them precisely with the French National Low-Carbon Strategy. Furthermore, while the standard SDS only focuses on net-zero emissions by 2070, this is not incompatible with particular countries achieving this target by 2050. Additionally, *ETP 2020* does include a Faster Innovation case, which brings global net-zero forward to 2050. While this is not designed to be an ideal pathway for accelerated decarbonisation, it illustrates the importance of accelerating technology deployment at a pace not seen before and leaving no room for delay in deployment.

While not being completely comparable, IEA scenarios share many common directions with the French Low Carbon Strategy. More specifically, the ambitions contained in the French low-carbon strategy are highly consistent with sustainability measures considered in both IEA scenarios for the EU and advanced economies at large, in particular regarding decarbonizing power generation through renewables, electrification of energy uses and reduction of energy consumption. Carbon capture use and storage (CCUS) is also assumed to play a role.

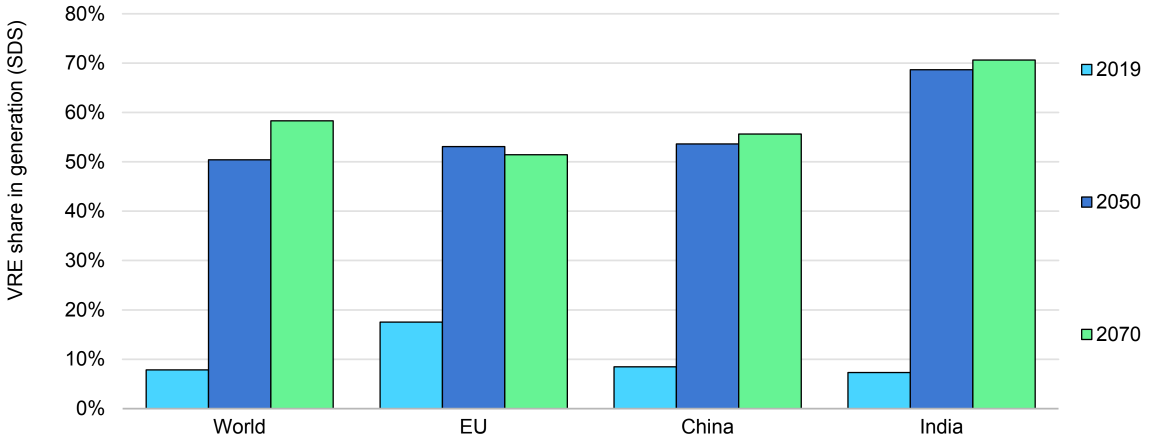
Three key developments in the SDS, also found in the SNBC, underpin the transformation of energy systems around the world: electricity's increasing share in final energy demand, increasing variables renewables as a share of electricity generation and the importance of upcoming and emerging technologies. Such considerations are equally relevant for many of the technology assumptions underpinning the present study, alongside assumptions about behavioural change in energy consumption and ambitious progress in bridging the gap between research and mass-scale technology deployment.

The first key development relates to the shift in energy consumption patterns envisaged in different scenarios and policies. As a whole, according to the SDS, electrification rate is expected to grow from 19% today to 47% of final energy demand in 2070. This shift is driven not only by reductions in energy intensity of end-uses but also by fuel-switching. In the SDS, the share of electricity in final energy demand in Europe could reach almost 40% in 2050, with France, Germany, Italy and the United Kingdom reaching overall electrification levels over 43% - bearing in mind that those levels are not sufficient to reach carbon neutrality by 2050 in the SDS. In the French National Low-Carbon Strategy, electrification also increases massively, as the share of electricity in final energy consumption goes from about 25% to more than 50% in 2050. All scenarios are thus based on an important increase in the rate of electrification, which can vary between countries according to local resources, the development of synthetic fuels and indirect electrification and the desire for energy autonomy

The second shift in the world's generation mix is towards power systems with majority shares of variable renewable generation. Overall, electricity generation is expected to triple by 2070, with 70% of this growth driven by rising electricity demand, and 30% owing to the production of low-carbon fuels such as hydrogen (Figure 2.6). To meet rising electricity demand while staying on track to meet net-zero goals, substantial investments will be necessary.

The European power mix in the Stated Policies Scenario is based on guidance from the EU Clean Energy for all Europeans package. Taking into account country-level targets in addition to the Clean Energy Package, the Stated Policies Scenario projects that the share of renewables will exceed 50% of electricity generation by 2030, with wind power becoming the European Union's leading source of electricity around 2025, and 80% of coal power phased out by 2030. As expected, the SDS has a higher level of renewable power generation than the Stated Policies Scenario, mostly through increased wind capacities.

Figure 2.7 Electricity generation from variable renewables by region in the Sustainable Development Scenario



Source: IEA (2020b), *Energy Technology Perspectives 2020*.

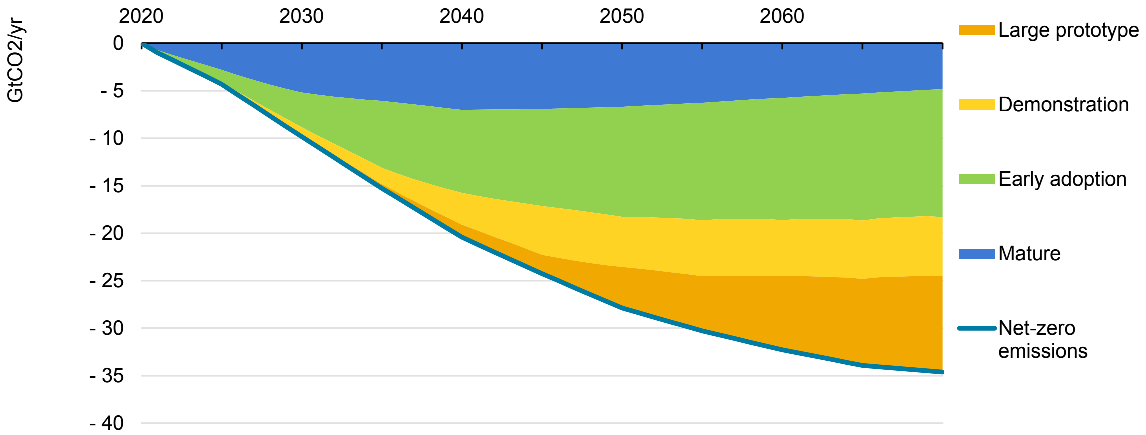
In the Sustainable Development Scenario, wind and solar supply more than half of total electricity in advanced economies by 2050, with renewables reaching 80% of total generation in the EU, while the share of nuclear energy decreases but remains significant. Given the age of the nuclear fleet in advanced economies today, such a share of nuclear electricity in 2050 would imply building new nuclear capacities.

The French energy and climate strategy plans to close the last coal-fired power plants by 2022, consistent with European policies and trends. It prevents any addition of fossil-fueled capacity as from 2022, ensuring one of Europe's lowest-emitting electricity mixes.

The third key trend is the importance of upcoming and emerging technologies – and their relative market maturity – in ensuring a cost-effective and resilient power system (Figure 2.8).

In *ETP 2020*, the projections from the SDS show not only the variety of technologies necessary to achieve net-zero emissions by 2070, but also the combination of necessary technologies based on their technological maturity. The power sector is particularly important in achieving these goals as it currently contributes 41% of energy-related emissions. In terms of industrial policy, *ETP 2020* estimates that of the cumulative emissions reductions needed for achieving net-zero by 2070, just under 15% will be contributed by currently mature technologies, with the bulk of emissions reductions coming from technologies currently at early adoption stage. In the decades following 2040, demonstration-stage technologies and large prototypes will become increasingly significant. These findings are consistent with long-term scenarios for power systems with high shares of variable renewables. The SNBC also provides guidance so that Research and development (R&D) efforts intensify in order to scale up technologies that could be mature soon (such as electric vehicles) or are currently at the testing phase (such as power-to-hydrogen or -gas).

Figure 2.8 Energy-related CO_2 emissions and reductions by maturity of source in the Sustainable Development Scenario



Source: IEA (2020b), *Energy Technology Perspectives 2020*.

Overall, the French National Low-Carbon Strategy is consistent with international scenarios, as well as the Paris Agreement and the associated Nationally Determined Contributions, but is more ambitious with its path to reach net-zero emissions by 2050. Its narrative fits with the SDS in that it bridges the gap between previously announced policies and the long-term climate target. In this regard, **the French National Low-Carbon Strategy could also be read in conjunction with the SDS Faster Innovation case in the *ETP Special Report on Clean Energy Innovation*** (IEA, 2020).

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Chapter 3. Resources for power system flexibility: International experiences and the French context

Key messages

- Changes in the generation mix and consumption patterns influence the flexibility requirements of the system. These range from very short-term flexibility needs to very long-term interannual flexibility requirements.
- Currently, most of the flexibility in France's power system dispatchable power plants (hydro, thermal or nuclear). This will no longer be the case by 2050, with the closure of the last coal-fired units, the ban on constructing new units using fossil fuels, and the scheduled decommissioning of nuclear generators. This will significantly reduce the available capacity from current flexible resources and prompts the need for finding new flexibility sources.
- Integrating high shares of renewables requires making the best possible use of all flexibility resources: generators (thermal and renewables), demand-side flexibility, storage, sector coupling and grids.
- Around the world, countries with higher shares of variable renewables are already deploying advanced renewables for flexibility either through new capability requirements included in grid codes or through new market products.
- Demand response can also substantially contribute to balancing the French power system. France's experience with historical load management measures and regulatory readiness offer great potential as flexibility requirements increase.
- Battery storage can also help to satisfy French flexibility needs, but business models that enable revenue stacking need to be developed and the regulatory framework needs to be clarified.
- Sector coupling through the flexible deployment of electrified mobility, according to RTE analyses, shows significant potential to balance the French power system. However, it is still unclear how different charging technologies and behavioural patterns will influence the availability of this source of flexibility.

- Sector coupling through power-to-gas technologies is expected to add 50 TWh of electricity demand and provide 40 TWh of hydrogen production that can help to meet long-term flexibility requirements. Deploying this solution effectively will depend on the cost of production as well as linkage to gas storage infrastructure.
- Cross-border interconnections with neighbouring systems will be a key flexibility provider for a system with high shares of renewables. The way European countries coordinate matters, and choices made by other countries can make the task of reaching a very high level of variable renewable energy in France more or less difficult.

The need to balance supply and demand is a strong constraint on the operation of the power system. To maintain this balance, several resources can be used to provide flexibility, whether on the production side (most current resources), the demand side (load shaping) or the storage side (batteries and hydro storage). The balance and use of these flexibility sources are largely determined at the European level, taking into account interconnection capacities between countries.

Flexibility needs depend on several factors, including the level and types of load (new power uses, thermal sensitivity), the generation mix, and in particular the share of non-dispatchable energies (run-of-river hydropower, wind and solar PV production). They also depend on the country's load profile and geo-spatial spread of load and generation.

Challenges of integrating large shares of renewables

System planners, academics, and policy makers worldwide have carried out many studies to better understand the technical feasibility, adequacy impacts and cost-effectiveness of integrating high shares of renewables in power systems, with a particular focus on wind and solar PV. Such studies vary widely in scope, considering parameters including time-resolution, geographical aspects and network topology, and deterministic as well as stochastic scenarios.

Integrating large shares of renewables could require increasingly decentralised power systems with greater flexibility needs and a shift from synchronous to converter-based technologies; it is particularly important to study the implications of this shift. Given the complexity of accounting for all these factors, integration studies often focus on one or a subset of them. Most studies take a development perspective and focus on system costs and overall system adequacy. Each has its own assumptions, model limitations, strengths and weaknesses.

Heard et al. (2017) used four criteria to assess the findings of 24 variable renewables integration studies: consistency with mainstream forecasts, time-resolution of reliability constraints, transmission and distribution constraints, and maintaining provision of ancillary services. They concluded that more information is necessary to evaluate the feasibility of power systems dominated by variable renewables. However, Brown (2018) established that the shortcomings identified by Heard et al. (2017) have been addressed and that feasibility of integration can be extrapolated from countries and regions with high shares of renewable generation. This includes Brazil, Canada, Costa Rica and Iceland and the region of Schleswig-Holstein in Germany, New Zealand's South Island and the Orkney Islands, which to varying extents rely on combinations of flexibility resources such as hydropower, geothermal, biomass and strong interconnections with neighbouring power systems. Both papers combined provide valuable insights into the key criteria needed to assess the feasibility of high renewables scenarios (Table 3.1, next page).

However, compared to the academic studies mentioned before, there is a difference when studies looking at high shares of renewable energy come from system planners or organizations with a legal mandate to inform on the security or cost-effectiveness of such scenarios. A particular example is that of the Australian Energy Market Operator (AEMO) which recently published its Renewable Integration Study. The study looks at the medium-term challenges of maintaining system security while operating with high instantaneous penetrations of variable renewable generation (AEMO, 2020). The report recommends actions grouped around system operability, distributed PV integration, frequency management, voltage stability and resource adequacy, and proposes a set of operational and market measures in each group. If these measure were implemented, AEMO expects that instantaneous penetration levels of up to 75% would be possible, whereas operational constraints would limit instantaneous penetration to between 50% and 60% if no additional measures were implemented.

Table 3.1 Methodology criteria to assess the techno-economic feasibility of high renewable energy scenarios, compared with the ambition of the 2021 *Bilan prévisionnel*

Methodology criterion	Description	Ambition of the 2021 *Bilan prévisionnel*
Demand projections	Is a plausible level of demand growth, electrification, conversion efficiencies and energy efficiency measures included? How does this match with technically available renewable energy resources?	✓
Time resolution	Does the time resolution of the analysis (e.g. hourly or every five minutes) provide a picture of all relevant flexibility challenges such as system ramps and technical capabilities of resources? Is further granularity needed?	✓
Extreme events	Does the analysis show robustness for extreme weather events? Are longer-term climate change related trends included in robustness analyses?	✓
Network topology	Are transmission constraints taken into account or is the power system modelled as single copper plate? To what extent are distribution network constraints considered?	✓
Degree of interconnection and development of neighbouring countries	What level of flexibility and availability is expected from neighbouring power systems? To what extent can imports be relied on to ensure adequacy in stressed conditions?	✓
Provision of ancillary services	Are changes in ancillary service requirements considered? Are these requirements successfully met?	✓
Technology cost assumptions	What are the expected investment costs for new and existing technologies? What are the assumptions for fuel and other variable costs?	✓
Consideration of wider sustainability impacts	Are assumptions of large hydropower capacity expansion realistic? Have social acceptability and carbon impact of biomass been considered?	✓
Geospatial and resource analysis	Is deployment of renewables coherent with resource availability and other land use requirements?	✓
Technology efficiency	What are the assumptions for thermal efficiency in conventional generation? What capacity factor improvements are assumed for new technologies?	✓

While the French context differs significantly from Australia, such analyses offer a first indication of sensible next steps for the French power system. The methodology explained in Chapter 2, which will be applied in the long-term scenarios in the next *Bilan prévisionnel* in 2021, considers several elements in Table 3.1. This includes the use of multiple climatic years, coverage of long-term climatic changes, high time resolution to account for variability of renewables, ancillary service provision and sensitivity analysis of technology costs such as electrolysers. In addition, a number of scenarios for cross-border interconnection and the generation mix in neighbouring countries have been considered. Several aspects still need further consideration to strengthen the methodology to assess adequacy and flexibility in a future system with very high shares of renewable energy.

Flexibility resources

The flexibility of a power system refers to its ability to modify or buffer electricity production or consumption in response to variability, expected or otherwise. Flexibility can refer to the system's capacity to change power supply and demand as a whole or within a particular unit. In the energy sector, resources that can provide power system flexibility include generation, transmission, storage assets, demand-side management and sector coupling (Table 3.2). Flexibility sources compete to offer similar services, which can affect their economic viability.

In practice there are many more technical needs in a power system than pure supply/demand balance that can require flexibility from connected assets. In most analyses, and in this report, flexibility is the ability of the system to cope with variability of supply and demand and remain in balance at all times, from the hourly or even infra-hourly to the inter-annual time scale. Other more technical challenges related to system stability are addressed in Chapter 4.

Table 3.2 Flexibility solutions at different time scales

Flexibility timescale → Flexibility resource ↓	Ultra-short term (subseconds to seconds)	Very short term (seconds to minutes)	Short term (minutes to hours)	Medium term (hours to days)	Long term (days to months)	Very long term (months to years)
State-of-the-art variable renewables	Controller to enable synthetic inertia; very fast frequency response	Synthetic inertial response; AGC	Downward/ upward reserves; AGC; ED of plants including VRE	ED tools; UC tools; VRE forecasting systems	UC tools; VRE forecasting systems	VRE forecasting systems; power system planning tools
Demand-side resources	Power electronics to enable demand response	Demand-side options including electric water heaters, electric vehicle	Air conditioners with cold storage and heat pumps; most equipment listed under	Smart meters for time-dependent retail pricing	Demand forecasting equipment	Demand forecasting equipment; power-to-gas
Storage	Supercapacitor; flywheels; battery storage; PSH modern variable speed units	Battery storage	Battery storage; CAES; PSH	PSH	PSH	PSH; hydrogen production; ammonia or other power-to-gas/liquid
Conventional plants	Mechanical inertia; generation shedding schemes	Mechanical inertia; generation shedding schemes	Cycling; ramping; AGC	Cycling; quick-start; medium-start	Changes in power plant operation criteria	Retrofit plants; flexible power plants; keeping existing generators as reserve
Grid infrastructure	Synchronous condensers and other FACTS devices	SPS; network protection relays	Intraregional power transfers; cross-border transmission lines	Internodal power transfers; cross-border transmission lines	Control and communication systems to enable dynamic transmission line ratings; WAM; HV components such as SVC	Transmission lines or transmission reinforcement

Note: Notes: AGC = automatic generation control; CAES = compressed air energy storage; ED = economic dispatch; FACTS = flexible alternative current transmission system; HV = high voltage; PSH = pumped storage hydro; SPS = special protection schemes; Speed droop control = relates to the sensitivity of governor response to frequency changes; SVC = static var compensator; UC = unit commitment; VRE = variable renewable energy; WAM = wide area monitoring system.

Source: IEA (2018), Status of Power System Transformation.

Flexibility from generators

Conventional power plants are currently the predominant source of flexibility in most power systems. Flexible power plant operation can take many forms, from rapidly changing plant output, to starting and stopping more quickly, to reducing their output to minimum levels if required. Strategies that can make existing conventional power plants more flexible can be categorised into two areas (IEA, 2019):

- **Changes to operational practices for existing plants.** Significant new capital investments are not necessarily required to operate power plants more flexibly. Changes to certain plant operational practices – often enabled by improved data collection and real-time monitoring – can be used to unlock latent flexibility.
- **Flexibility retrofit investments for existing plants.** A range of retrofit options are available to improve the various flexibility parameters of power plants. For instance, connecting battery energy storage to existing plants is increasingly becoming a viable means of boosting flexibility, both in technical and economic terms.

Flexibility of France's thermal fleet according to the French Multi-Annual Plan and National Low-Carbon Strategy

The last four coal-fired generation units in France will be decommissioned by 2022, ending a process of gradual closure of large- and medium scale generation units since a dozen of years. By that time, the fleet of generation units using fossil fuels in France will be modest, consisting of:

- 6.7 GW[5] of mid-merit units (combined-cycle gas turbines, or CCGTs), mostly built in the 2010s and currently competitive on European electricity markets;
- 2 GW of peaking units (open-cycle gas turbines, or OCGTs), mostly commissioned from the 1980s to 1990s (some date from 2010)
- 6.5 GW of gas engine combined heat and power (CHP or cogeneration) plants and decentralised thermal generation, most of it ageing and not competitive on the electricity market without support schemes.

[5] Including the plant planned to be commissioned in Brittany in 2021.

The French Multi-Year Energy Plan prohibits new capacity for the exclusive production of electricity from fossil fuels. The capacity of fossil-fired power plants is thus bound to decrease, except potentially new cogeneration plants.

By 2050, for technical (age), environmental and economic reasons, most remaining thermal plants are supposed to be decommissioned, retrofitted and/or switched to a decarbonised fuel such as low-carbon hydrogen or synthetic methane.

The fate of thermal plants raises an important question for scenario modelling and for policy-making. In power systems with high shares of renewables, flexibility needs are going to increase considerably (see Chapter 5) and can be fulfilled in part by generation units. Assessing the economics of fuel conversion for existing units is therefore an option to consider and to compare with other possibilities, including storage, demand-response, CCUS and nuclear. Recently, attention has focused on the possibility of developing power-to-gas-to-power (by using hydrogen as an interim fuel or adding an additional step of methanation to use synthetic methane) or of importing decarbonised synthetic gases from outside Europe. These options could rely on existing thermal power plants, if it is proven that fuel switching can be implemented in a cost-effective way.

Scenarios aiming at net zero emissions by 2050 with high shares of renewables tend to rely on those technologies. For example, the SNBC projects that hydrogen and decarbonised gas (before conversion into electricity) would be available for electricity generation by 2050 to a limited extent. Nevertheless, generating some dozens of terawatt hours of electricity from synthetic gas, only as back-up solutions when wind or solar availability is low, would still require significant installed capacities[6]. In France, this option could require at least a few dozens of OCGTs and CCGTs running as back-up units with synthetic or decarbonised fuels[7], i.e. significantly more than the existing fleet of such units.

[6] Considering the efficiency rate of a new OCGT or CCGT, (42% to 60%).

7 For instance, tens of gigagwatts of hydrogen-to-power capacity and of methane-to-power capacity could run with a low load factor (around 10%). Nowadays, OCGTs are assumed to be able to run from a cold start-up to half load in 30 minutes reliably or to full load if they were planned to do so (not at the last minute) or in 15 minutes with more risk of failure. CCGTs can run from a cold start to minimal power (40% of maximum capacity) in 3 to 4 hours. OCGTs can ramp upward or downward by 65% and CCGTs by 200% of their maximum capacity by hour.

Some fossil-fired power plants could still be in operation in 2050, particularly 6.7 GW[8] of CCGTs that were mainly commissioned by 2010, although these could be at the end of their life by then. OCGTs were commissioned in the early 1980s, early and late 1990s and around 2010. Their capacity (2 GW) is therefore expected to decline gradually between now and 2050, unless new investments are made. The capacity of cogeneration plants (5.3 GW) and decentralised thermal generation plants (1.2 GW), which are ageing and not competitive enough, could also be reduced.

In addition, the capacity of fossil-fired power plants would only be likely to increase with new cogeneration plants because the French Multi-Year Energy Plan prohibits new thermal capacity otherwise.

Precise calculations, such as those that will be performed in the next long-term scenarios in the Bilan prévisionnel 2021, will be necessary to assess the number of power plants needed, and the economics of this option. Existing data are nevertheless sufficient to show that this option should not be ruled out and should be studied further.

Opportunities to increase generator flexibility

Improved flexibility of thermal plants through retrofits

The increasing market share of renewable energy and higher fuel prices in Europe have changed the operational profile of CCGT power plants, which are faced with fewer operating hours than expected in their original business plans. In Germany, where the penetration of wind has already modified the operating hours and ramping requirements of conventional generation, several thermal plants have been retrofitted to maintain profitability, such as the Mainz Wiesbaden CCGT (Box 3.1).

The IEA report Status of Power System Transformation 2018 includes a series of best practices to increase flexibility in thermal generation.

[8] Including the plant planned to be commissioned in Brittany in 2021.

Box 3.1 Mainz Wiesbaden quickstart CCGT

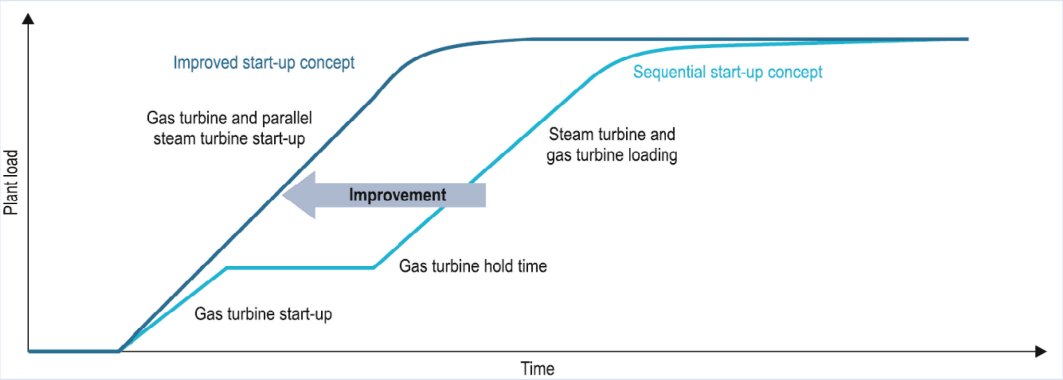
The Mainz Wiesbaden CCGT in Germany is an example of a plant which was originally built in 2000 for baseload operation and that has been successfully retrofitted to operate in a more flexible cycling mode (IEA, 2018).

The plant is now equipped with a gas turbine in a multi-shaft configuration. This feeds three pressure stage drum boilers, which supply steam to a steam turbine with steam extraction to supply district heating and process steam. The owner, Kraftwerke Mainz Wiesbaden AG (KMW AG), has upgraded the plant several times. In August 2014 the plant was upgraded with the Hot Start on the Fly (HoF) procedure.

The HoF procedure uses an improved start-up concept that allows the parallel start-up of both gas turbine and steam turbine in hot start conditions (below figure). The HoF process has proven to be an extremely fast and efficient start-up method with only moderate reduction in plant lifetime. Since its implementation, the HoF procedure has been used frequently for hot starts on weekdays, demonstrating consistent availability and reliability with great accuracy in start-up times. The successful implementation of the HoF procedure has reduced the start-up time from 67 to 27 minutes.

During the commissioning of the HoF procedure, KMW AG and Siemens successfully tested concepts for an even more advanced HoF procedure, known as HoF+. It was found that an evacuated high-pressure turbine at the beginning of the steam turbine start-up process could further reduce hot start-up time by 4 minutes. The shutdown time was shortened by 6 minutes, allowing plant shutdown from base to no load in just 20 minutes.

The HoF start-up concept



Source: Siemens (2018), published in IEA Status of Power System Transformation 2018.

As France's share of variable renewables increases, it will be important to improve the flexibility of existing thermal assets, and to ensure that new assets can meet the power system's changing flexibility needs. The speed and precision of response of thermal assets will be particularly important in meeting the country's energy transition goals, depending on the need for operational reserves.

Ensuring the deployment of flexible variable renewable generation

In their infancy, variable renewable technologies were integrated under a fit-and-forget process. Modern technologies, in particular the biggest plants, are now capable of participating in the wholesale and to some extent reserve markets (depending on market rules), which enables them to support the operational balance between supply and demand.

Variable renewables can either run at full output and dispatch downward when needed ("downward dispatch"), or run at reduced output and use this "headroom" to dispatch upward or downward when needed ("full flexibility"). These types of operation have been tested and studied in several jurisdictions, including California (CAISO, 2017), Chile and Puerto Rico (Gevorgian, V. B. O'Neil, 2016). Various European systems also allow for such operation. It has been proven that flexible operation of solar PV resources provides greater operational cost savings as annual solar PV penetration increases on the grid and that cost savings are more significant when solar PV power plants are operated in "full flexibility" mode. Keeping such operation economically viable will require rethinking how energy and ancillary services are procured.

In the context of France's energy strategy, ensuring the deployment of flexible and system-friendly variable renewables will be vital to reduce the overall cost of the energy transition. For both solar PV and wind, this can be achieved through several measures, including market-based remuneration of variable renewables, participation in enhanced ancillary services (as in Ireland) and, at a more technical level, modifying grid-codes to ensure that variable renewables contribute to system resilience.

Bioenergy-based generation could provide more flexibility running as peakers

Three types of bioenergy-based electricity production – waste fuel, biomass and biogas – currently operate in France, with a load factor of around 50%. With the same volume of energy, it should be possible to envisage an increase in their production capacity without using more resources. Given that biomass and biogas are not prioritised in the SNBC for producing electricity, if the same amount of these resources could be dedicated to electricity in a mix with a high share of variable wind and solar PV generation – meaning the same amount of energy could be provided to the power system – bioenergy-based electricity generation could thus operate more at peak times. It would hence contribute more to security of supply and complement traditional peakers. For instance, concentrating their production during 10% of the year for the same amount of energy would multiply their capacity by five. Under this rationale, they could represent more than 10 GW[9].

There are three conditions for improving flexibility of bioenergy, however. First, it is only possible for bioenergy capacity that is not constrained by the co-generation process and relevant heat demand. Second, it may also require investment in tanks of adequate capacity to store the resources instead of burning it in a lean stream. Third, current support schemes provide incentives to use bioenergy for running baseload. These should be revised to encourage use of bioenergy for running peak load.

The economic, environmental and social conditions for dedicating the same amount of energy as today for bioenergy-based electricity production but using it more for peak-load running will be analysed in the next long term scenarios.

Flexibility sources beyond generators

Flexibility can be secured not only through existing generators and system-friendly variables renewables, but also on the demand side, through a whole array of technologies including demand response, distributed battery storage and distributed generation.

The SNBC identifies the need to smooth the demand curve by mitigating load peaks in order to balance supply and demand. Electricity-intensive consumers can use demand-side response, while individual consumers can reduce and control their load pattern by using smart devices or postponing their load outside the peak period.

Some countries are already more advanced in deploying variable renewables and/or integrating more flexibility. Analysis of their experiences is instructive and can shed some light on the case of France.

International experience and opportunities for demand flexibility

Demand-side flexibility is usually categorized into implicit and explicit demand response. With implicit demand response, consumers adjust their electricity consumption in response to dynamic price signals. Explicit demand response is

[9] Bio-energy with CCUS is more likely to supply baseload power because of fixed cost of CCUS installations.

offered through mechanisms such as balancing markets, or capacity mechanisms where a system operator can call on distributed energy resources to be dispatched.[10] To unlock both implicit and explicit demand-side flexibility, the right intervention mechanism needs to be in place that can enable distributed energy resources to serve as flexibility assets.

As of 2018, the IEA estimated that 40 GW of flexible load was in use globally, or 0.5% of global electricity generation capacity. This flexibility is obtained mainly through traditional arrangements such as interrupting service at critical times.

The United States, alone has 33 GW, 28 of which are activated through a combination of reliability and frequency response programmes, whereas 5 GW comes from retail programmes. France ranks second with slightly over 3 GW, followed by Japan and the United Kingdom with 1 GW each. Australia, Ireland and Italy are next with around 0.5 GW each. The untapped potential is much higher.

The ways in which demand response resources are activated vary greatly from country to country. In the United Kingdom, they include the capacity market, peak demand reduction and increasingly some local flexibility markets deployed by distribution network operators. In Ireland the auctions for 2019-20 capacity cleared 426 MW for demand-side flexibility. In Italy, 350 MW has been activated through virtual power plants. Australia has activated around 600 MW through demand response programmes for emergency reserve through retailers and distributors, with plans to open up demand response aggregation for third parties.

Time-of-use pricing in California

California has already started experimenting with large-scale direct demand response. Time-of-use (TOU) rates, which have been available for 20 years, became the default setting for the 22.5 million customers of the state's three investor-owned utilities in 2020. Although customers are allowed to opt out to their old rate, in earlier test projects 90% to 99% of customers chose to stay on the TOU rate. The utilities have demonstrated that for every 10% increase in the TOU rates, peak demand falls by 6.5% to 11%. The highest decrease was obtained for customers with automatic control systems, such as smart thermostats that optimise heating based on TOU rates. Switching 22.5 million consumers to TOU rates was technically possible because 84% of residents have automated meters (EIA, 2019).

[10] Historically, demand-side flexibility has consisted mainly of load shaping, or demand-side management. The increasing trend towards co-ordinated deployment of adjustable loads and behind-the-meter generation and storage has shifted the focus to distributed energy resources.

PJM's demand response solution

PJM is a regional transmission organization that co-ordinates the movement of wholesale electricity in all or parts of 13 US states and the District of Columbia. Its interconnection wholesale markets have enabled demand response through several services over the last ten years (PJM, 2017). In this market, curtailment service providers enable the participation of demand response, which usually amounts to 5% of annual capacity. Additionally, the capacity performance mechanism enables demand response resources to reduce load throughout the year, as well as aggregating multiple assets to improve the match with availability requirements.

French potential for demand-side response

Demand-side response in France was pioneered in the 1970s with ToU tariffs, which are still in place. These have shown that implicit price signals can shift load to night-time hours and balance the system. While most clients on ToU tariffs only see two price schedules, the wide-scale deployment of smart meters with enhanced time-granularity offers significant potential. The success of implicit demand-side flexibility will depend, however, on retailers' ability to offer a wide-enough array of flexible tariffs. In France, the regulator has recently opened a consultation that should enable the emergence of dynamic retail tariffs.

Regarding participation in explicit demand-side flexibility programmes, France is also one of the most advanced countries in terms of reducing entry barriers to its capacity markets scheme and to frequency regulation services, while ensuring a level-playing field for aggregated loads. Ambitious policies to favour demand-side management from third-party operators were implemented in the 2010s. The potential for market-based demand response (i.e. triggered by a specific economic signal) is around 3 GW in France. This does not include so-called "citizen participation" in case of emergency.[11]

The French Multi-Year Energy Plan projects demand-response capacity overall to increase to 4.5 GW in 2023 and 6.5 GW in 2028. The target in the Multi-Year Energy Plan is ambitious and requires that a large part of the maximum technical potential (around 10 GW based on the most recent evaluation – RTE, 2020) is engaged in demand response schemes.

Transformations scheduled in the broader economy to achieve net zero emissions also have the potential to provide opportunities for demand-side management.

[11] Controlled load of domestic hot water also accounts for 1 GW of additional flexibility today.

For instance, heating could become more flexible with the deployment of hybrid heat pumps in new buildings with hot water loops, or refurbishing buildings with gas boilers. Solutions like hybrid heat pumps would provide both negative thermal sensitivity and flexibility to manage stress situations even if they are not related to cold spells. District heating can also provide flexibility, through the combination of different heat sources or through thermal storage. The next long term scenarios will include those options, based on the recent RTE-ADEME on buildings (RTE-ADEME, 2020).

Experiences and opportunities for flexibility from battery storage

In recent years, technological development and declining prices have strengthened battery storage's potential as a flexibility source, particularly for short-term flexibility (BNEF, 2019). One advantage of battery storage is its ability to serve several applications. These include providing energy and ancillary services to the bulk power system, alleviating congestion at the distribution and transmission levels, contributing to reserve requirements and helping to manage energy usage for individual customers. For this reason, storage is often regarded as having the ability to "stack value" – to provide services and derive revenue from several applications. Enabling such stacking requires careful consideration of how different market segments interact and how essential services such as frequency response can be guaranteed by the provider. Policy, market and regulatory frameworks often do not allow technically capable resources to provide several services simultaneously. The full economic value of storage will only be realised if these frameworks are modified with a focus on cost-effectiveness and reliability.

Hornsdale Power Reserve

Several policy or regulatory changes in different parts of the world are enabling benefit-stacking for battery storage. The Hornsdale Power Reserve in Australia – one of the world's largest lithium-ion batteries – participates in regulation, contingency reserve and energy markets in the Australian National Electricity Market. Built with support from the state government of South Australia to improve power system security, the battery has several value streams, which are made possible through a combination of overlapping contracts attached to particular capacity blocks of the battery. The state government has reserved 70 MW for improved system security, including frequency control and other services. The remaining 30 MW are contracted by Neoen, a French company that developed the battery with Tesla, for arbitrage in the energy market and participation in the eight frequency control ancillary services (FCAS) markets. This comprehensive combination of revenue streams was enabled through active co-ordination between the state government, Neoen and AEMO, but the underlying market rules would still allow future battery storage projects to simultaneously participate in the energy and ancillary services markets. The battery's deployment has contributed to reducing the prices for regulation services. It has also helped to drive down FCAS prices, due to increased competition in the FCAS market during periods where FCAS services had to be provided locally.

Deploying new storage technologies requires overcoming challenges relating to the definition of storage within the power system's legal framework, as well as prequalification requirements and steps to enable participation in multiple system services. In Australia this has been done through a combination of avenues, with AEMO for FCAS, with state governments and through arbitrage in energy markets. In other countries, similar steps have been taken, particularly when participation in multiple system services concerns various stakeholders. For example in Great Britain's power system barriers were removed by reforming National Grid's exclusivity clauses for ancillary services. In the United States, states like New York and California have taken different steps to enable participation in multiple markets. In New York, following the Federal Energy Regulatory Commission's ratification of Order 841 (FERC, 2020), battery storage aggregators are able to participate at the same time in ancillary services run by distribution and transmission system operators, but need to include distribution service obligations in their day-ahead bids, to ensure consistency across both levels. The California Independent System Operator has determined 11 rules to harmonise participation across multiple services and introduced criteria that prioritise reliability over non-reliability services.

Potential for storage in France

In France, enabling the participation of battery storage in multiple system services will also be vital to enable cost-efficient battery deployment that contributes to power system flexibility. Enabling value-stacking is also consistent with the direction set by the latest EU Electricity Directive.

Large storage batteries as well as smaller behind-the-meter batteries could hence play a role in the French system flexibility. The 2017 RTE adequacy report estimated that the battery capacity of residential self-consumers (consumers who generate their own energy) could amount to 10 GW by 2035 (with a 1-hour duration capacity), depending on the level of deployment, economic factors and social willingness.

While batteries have already significant potential for providing short-term flexibility services, there is still a need to also ensure longer-term flexibility. Options such as pumped storage hydro and "power-to-X" technologies (e.g. electrolytic hydrogen production) may be able to meet longer-term flexibility needs, such as covering daily and even seasonal or interannual imbalances in production of variable renewables. These options will become more important with increasing shares of renewables. Hydropower technologies, although technically reliable and well established, are limited to suitable sites. Other longer-term storage options are still not cost-effective but will be considered in future work on long-term scenarios.

Using electrified transport to boost flexibility

Electrified transport presents an additional emerging resource for flexibility. Depending on the charging methodology – managed unidirectional charging or bidirectional charging (V2G) – electric vehicles (EVs) can contribute system flexibility in a manner similar to demand response or stationary battery storage. Effective use of EV fleets to boost system flexibility will depend on both technical and policy conditions. Technical conditions include deployment of the necessary monitoring and control infrastructure and availability of widespread and appropriate private infrastructure. Policies are needed that enable aggregation and create a better link between incentives to end-consumers and operational constraints in the power system.

Figure 3.1 Technical and policy requirements for using EVs for flexibility

	Technical requirements	Policy requirements
1.- Unmanaged charging	Investments in generation and network capacity	
2.- Smart charging (V1G)	IT systems to monitor and manage speed of charging	Introduction of Time-of-use tariffs
3.- Aggregated smart charging	Interoperability of platforms and charging protocols	Aggregation and access to multiple markets
4.- Large-scale bidirectional (V2G) and smart charging	Wide-spread availability of V2G-enabled charging	Reviewing taxes and levies to avoid double taxation

Source: IEA (2020b), Next Steps for Systems Integration Webinar.

As with other distributed energy resources, deploying electric mobility fleets for flexibility, in France or worldwide, will require substantial policy action to open up revenue streams and ensure cost-effective deployment. At the same time, given the limited size of current frequency regulation services, the value derived from EV flexibility will eventually become low due to market saturation. This raises the question of what other value streams may emerge as power systems evolve in order to make EV smart charging viable at a larger scale, enabling values for consumers beyond frequency regulation.

Most of EV flexibility nowadays comes from managed unidirectional charging deployed in ancillary services for frequency regulation. V2G may offer greater potential to balance the system but has greater costs than smart charging, so it is still difficult to assess how much greater its contribution to system value might be.

Depending on the assumed income sources in integration studies, V2G could contribute 3 to 13 times more value than smart charging, depending on how efficiency losses are accounted for (Coignard et al., 2018; Thingvad et al., 2016; RTE, 2019 with the contribution of AVERE-France). However, this potential is unlikely to be realised without policy support that reduces the cost of V2G. Given that the technology required to enable V2G can be integrated either in the charging station or in the cars themselves, reaching economies of scale through mass deployment will require either co-ordination with car manufacturers or a strategic approach to rolling out charging infrastructure.

DC V2G in Denmark

One of the first large-scale, commercial V2G projects was the Parker project in Denmark. The EV charger manufacturer ENEL partnered with the software developer Nuvve to aggregate 50 DC V2G-capable EVs to offer frequency containment reserves to the Danish transmission operator Energinet. Response rates ranged from five to six seconds through the aggregator to only a few seconds when the charger and cars were controlled directly via local frequency measurements. The EVs provided power up to 30 minutes and the average revenue was about EUR 1 860 per year per vehicle. Identified barriers were unstandardized connection pre-qualification for the various assets (different vehicles and charging connectors), high costs for settlement meters, high energy taxes that included double counting, charging and discharging losses, and battery degradation.

V2G in UK

Larger DC projects are now being realised in the United Kingdom, such as the rollout of 1 500 smart and V2G chargers for business consumers by EDF and Nuvve, capable of delivering 15 MW of power to the grid. Another large UK rollout is being realised by Kaluza, which is installing 1 000 DC V2G home chargers. Home charger installation as well as the electricity supply come at no cost to the consumer, with the service provider making revenue from V2G services.

Opportunities for flexibility from electric vehicles in France

Electric vehicles could also provide an important contribution to demand-side response flexibility in France (RTE, 2019, with the contribution of AVERE-France). Flexibility associated with EV charging can be particularly significant when the share of smart charging is high and connecting vehicles to the grid becomes economically viable.

In particular, EV smart charging (uni- and bidirectional) could help substantially to modulate the national French load curve and adapt it to renewable energy production, while continuing to meet the mobility needs of EV users. This could significantly reduce daily and weekly variations in residual demand (total national electricity consumption minus non-dispatchable renewable power production), which otherwise have to be balanced with dispatchable generation (nuclear, fossil fuel and hydropower plants).

Use of the generation fleet could therefore be optimised, by considerably reducing the periods when renewable energy production needs to be curtailed, peaks in generator profiles, and ramping and start up events. Such optimisation would lower operational costs and emissions, the need for power generated by fossil fuel plants, and even the need for back-up capacity to ensure security of supply.

In contrast with other countries, France can accommodate increasing transport electrification easily, because of the spare capacity of distribution networks built to accommodate electrical heating and the favourable regulatory framework for demand-side flexibility. However, using transport electrification to meet the power system's flexibility needs may require further refining the price signals facing consumers and making appropriate charging infrastructure widely available. This is of particular importance as some scenarios to 2050 require a substantial share of bidirectional flexibility from V2G (this point will be explored in the upcoming RTE analysis of long-term scenarios). Without targeted steps to accelerate V2G, it will be necessary to procure short-term flexibility from dedicated stationary storage or back-up assets, at a potentially higher cost.

Potential flexibility from power-to-gas

Integration between electricity and heat or "power-to-X" provide further avenues for mid-term and longer-term power system flexibility. Power-to-X, which refers to several conversion pathways, offers the potential for balancing longer-term flexibility. However, its cost-effectiveness depends on a country's existing infrastructure. In Northern European countries with widespread gas networks, electrolysis and methanation may offer better potential for long-term storage.

Different models may develop for power-to-gas: using renewable production excess only, running when electricity prices become low enough to offset the high fixed cost of electrolysers, or even partially "off-grid". In any case, this means that the associated electricity consumption is flexible and will adjust to production availability. Depending on the gas network infrastructure and on-site storage, power-to-gas can be used for seasonal balancing if it is associated with gas turbines, albeit with a low yield. The whole amount of installed power-to-gas capacity could then be considered flexible if technical conditions are gathered for gas storage.

A specific case of power-to-gas is the use of solid oxide electrolyser cells (SOEC) in fuel cell mode. On top of a salt cavern, such an installation can provide flexibility on any time horizon.

French potential for sector coupling in the SNBC

Coupling electricity with others sectors could provide flexibility on short time horizons (close to real time) and on long time horizons (considering the seasonal or interannual variability of the power system). Close to real time, the ability of electrolysers to vary their level of electricity consumption in a few seconds means it is technically possible for them to provide services to the electrical system, for supply-demand balance and for network operation. On longer time horizons, to cope with seasonal and inter-annual variability, power-to-gas could also be a solution in France, storing the synthetic gas from one season or one year to the next.

Ongoing work by RTE on long-term scenarios is devoted to model precisely different scenarios of hydrogen production from electricity. Considered cases range from a small increase to a "hydrogen revolution" ("hydrogen+" variant), with SNBC serving as the baseline scenario. The use of hydrogen and synthetic gas as a flexibility for balancing the power system and ensuring security of supply will be a result of the simulations – and not an *ex ante* hypothesis. In scenarios with very high shares of renewables, power-to-gas-to-power appears an option to consider (see Chapter 5).

Interconnections, electricity consumption and mix at the European level

The European Internal Energy Market is a reality of today, leading to intensive trade between market players at the European scale on integrated markets and largely interconnected grids. France is a traditional exporter of electricity, thanks to the characteristics of its generating fleet; mostly nuclear and renewables with low marginal costs. It also imports in situation of peakload, using flexibilities located in neighbouring countries. This large and increasing integration between countries is important for prospective studies on power mix, especially at long term horizons like 2050.

It is difficult to project what could be power flows between European countries in 2050, as these will result from many decisions yet to be taken on national basis regarding each country's energy mix. Like many national strategies, the SNBC makes an implicit assumption that the French electricity system will be in balance in terms of annual exports and imports by 2050. However, in 2050 the French electricity system will continue to depend on the balancing of the whole European electricity system. Unless the French system is physically disconnected, France's import/export situation will depend on the European electricity system (generation, transmission, flexibility and demand) and its market design. This is the reason why the next long term scenarios prepared by RTE in the next *Bilan prévisionnel* are based on modelling a Europe-wide power system.

The European Union is supposed to reach carbon neutrality in 2050, as stated in the European Green Deal. Nevertheless, national strategies may take widely differing directions. The main key parameters of national strategies are the share of renewables, the degree of autonomy versus the reliance on global energy markets, and policies to speed up the switch towards low-carbon energy sources. These key parameters are largely decided at Member State level, even if common strategies and goals are defined at EU level. The degree of alignment of these national strategies will also have a strong impact on the European electricity system.

This question is of importance for assessing the conditions and requirements for the technical feasibility of a power system with high shares of renewables in France towards 2050.

Notably, a large availability of dispatchable low-carbon power sources in a well interconnected European power system – including from hydropower, sustainable bioenergy, nuclear, fossil fuel power plants with CCUS or imported synthetic gas – would make technical conditions for achieving high penetration of variable renewables in France less severe, albeit still significant. Conversely, a European decarbonisation scenario primarily based on domestic renewables – with no or little low-carbon dispatchable power sources beyond hydro power – could be more stringent, as all European countries would face the same kind of technical challenges at the same time.

In this report as well as in ongoing long-term scenarios (*Bilan prévisionnel* 2021), a European-wide model is used, and the technical feasibility of power system with high shares of renewables is assessed on the most challenging hypothesis, that is to say a major push in Europe to ensure net zero emissions by 2050 by relying almost entirely on domestic renewables.

If some countries opt for CCUS or the import of synthetic gases to a large extent, the power system in Europe would face fewer technical challenges, relaxing some of the preconditions described in this report.

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Chapter 4. Ensuring grid stability in systems with high shares of variable renewables

Key messages:

- Scenarios with high shares of renewables in France imply a massive development of wind and solar PV. Such units are currently "grid-following" rather than "grid-forming": they do not provide the inertia needed to stabilise the power system.
- Beyond certain thresholds (60% to 80% of grid-following wind and solar PV instantaneous penetration – over total generation), system stability can be at risk because of this lack of grid-forming capability.
- The qualification of such situations in terms of generation mix requires simulations of the overall supply-demand balance, such as those in the long-term scenarios studied by RTE in its next Adequacy Report (*Bilan prévisionnel 2021*), with the full set of adequate assumptions, including generation and flexibility mix, load profile in France and abroad, and interconnection capacity.
- Four options are proposed to ensure stability in a power system relying massively on converter-based technologies such as wind and solar:
  - Maintaining a minimum of conventional generation operating instantaneously in the power system (20% to 40% of generation, depending on operational conditions), possibly at the expense of renewable production.
  - Implementing new fast frequency response services on variable renewables, batteries, EV chargers, high-voltage direct current (HVDC) systems and others.

    These two first options allow the share of renewable capacity to be increased but cannot directly replace synchronous inertia provided by conventional generating units because of their fundamentally different response to high rate of change of frequency events. Two other types of solutions would be necessary to go to very high shares of variable RES :
  - Using synchronous condensers, historically developed in areas missing generators.

  - Using innovative converters in renewable generation assets to provide grid-forming services.
- A major challenge in deploying grid-forming converters is the adaptation of protection against fault, combining three possible solutions : 1) increase the rating of the converters, 2) use more differential protection in the grid, 3) use the fact that most converter-based renewable generation is almost never producing at maximum power.
- A clear roadmap for grid-forming converters can be defined for the next decade to ensure system stability in coherence with the national energy policy and taking into account the impact on all system actors. It is built on three complementary pillars:
- **Demonstrators** to progressively increase the confidence of converter manufacturers and transmission system operators in the reliability and reasonable cost of converter-based grid-forming solutions.
- **Consultations with stakeholders in the regulatory process** to prepare a harmonised European definition of system requirements and performance measures for grid-forming solutions.
- **International collaboration** to allow for a large enough market for manufacturers of grid-forming solutions.

The stability of power systems is currently ensured by the inertia provided by conventional synchronous generators (thermal, nuclear and hydro). Conventional generators also participate in system stability by generating a stiff voltage wave, altogether synchronised, as well as providing high fault current used for fault detection and resolution. Stability requires this three-fold contribution, provided historically by conventional generators.

In scenarios with very high shares of variable renewables such as the ones studied in this report, by contrast, stability would need to be ensured by the power electronics of wind and PV generators, which is currently not possible. The very feasibility of scenarios predominantly based on wind and PV has therefore been questioned in public debates and discussed in scientific literature.

This report argues that system strength can be ensured under different conditions. It proposes a list of actions, including research, demonstration and policy-making, which would need to be taken if the option of a power system based only on converter-based renewables was to be chosen as a priority.

The historical role of the inertia of synchronous rotating machines for electrical systems

Historically, the rotating inertia of thermal generation was relied on to stabilise power systems. In conventional generation – coal, gas, oil, nuclear, bioenergy and hydro – the rotating parts used for power generation spin at the same electrical speed across an interconnected power system, with all generators keeping one another in balance. This can be compared to cyclists on a tandem bike working together. The common speed of synchronous generators defines the power system frequency, which needs to be maintained at the same level (Box 4.1).

Box 4.1 The role of system frequency

The existing electrical system works with alternating current (AC) and voltage. These alternating signals are generated by synchronous machines (in coal, gas, nuclear, biomass and hydro power plants) which contain magnets (or electromagnets) that rotate. The rotation speed of the magnet is directly related to the frequency of oscillation of the voltage.

One of the important features of an interconnected power system is that the frequency is the same all over the grid, to allow for energy exchange, for many different reasons:

- Customers' appliances require the frequency to be in a narrow band around nominal.
- Big generators are designed to operate at a nominal frequency, so any deviation from this leads to loss of efficiency and/or vibration and lower life expectancy.
- Some components of the transmission grid have also been designed for a frequency close to nominal value, such as transformers; when the frequency deviates from nominal, the losses increase.

Source: own analysis carried out by RTE.

Synchronous generators can easily make up for lost output in the case of a generator outage. Provided that the disturbance is not significant relative to the remaining synchronous generation, the stored kinetic energy of the rotating parts will be partially transferred into electrical energy and fed into the system. In classic power systems dominated by synchronous generation, it is easier to maintain the frequency following a disturbance, as each individual generator will have to transfer limited kinetic energy to compensate for a disturbance. To use the tandem bike analogy, if one cyclist fails, the others will be able to take over with a loss of speed that will be all the smaller the more numerous the cyclists are on the bike.

- Conventional generators can behave like this because they are voltage sources. They thus share four technical properties:
- They can **generate their own voltage wave at a given reference frequency and amplitude**. As a result, they are not very influenced by variations of current on the network, particularly from consumers. They are able to "hold" voltage regardless of other components connecting or disconnecting from the network.
- They can **synchronise altogether autonomously**, operating together without altering one another's operation and without needing to communicate with one another or to know how the other generators operate. Common technical requirements, implemented locally in each generation units, are enforced and they all follow the same basic rules.
- They can **operate in a separate system,** to run in an island[12] mode or even in an interconnected system. Provided that the supply-demand balance can be reached on the new perimeter of the separate system, a conventional generation unit must be capable of keeping the new system under voltage within acceptable ranges, whether or not it is the only one operating there.
- They can **give high output current surges** during a system transient while remaining in stable operation. Such output current surges support the stability of the system as well.

In the past, the inertia of the power system was inherent to power generation, given the main technologies used, providing alternating current using rotating machines.

Historically, other installations with the properties of voltage sources have been used in some areas of the French power grid, particularly in the Western region of Brittany: **synchronous condensers**. A synchronous condenser has some similarities with a conventional generator: it consists of a rotating mass, but once started, it is no longer connected to a thermal engine supplying energy. Most important, synchronous condensers have the ability to run idle. As a result, they do not produce any useful power to consumers, known as active power. Synchronous condensers have mainly been used to provide a voltage reference in areas lacking generators. At the same time, they provide the system with a frequency reference. From the point of view of

[12] Islanding is the ability of a generator that disconnects from the network to keep running while only supplying its auxiliary loads.

inertia, it therefore has the same role as a conventional generator. The combined effect of providing inertia and stable voltage is called system strength. Synchronous condensers can either be new devices in areas lacking sufficient system strength, or retrofits of thermal generators that were to be decommissioned.

Conventional generators and synchronous condensers are said to have the ability to be grid-forming. In other words, they are able to start up, and stabilise a network because they supply a voltage insensitive to current, synchronise autonomously and can operate as a separate network or even in island mode.

Variable renewables connected to the grid by power converters behave differently

Unlike synchronous generation, which directly injects AC power into the grid, variable wind and PV generators are connected to the power system through power electronics called converters.[13] These are essentially very fast digital switches that modulate DC or AC output produced by variable renewables into AC to match the power system's frequency.

Today's wind and PV generators are operated as "grid following" units. They only "read" the frequency set by the alternating current signal in the AC power system, they do not impose a voltage and frequency reference to the network as do conventional generators. As the power system's share of variable renewables increases, the robustness of the frequency signal is bound to decrease if variable renewables continue to operate in 'grid-following mode', jeopardising system stability.

The main challenge is two-fold.[14] First, inertia decreases due to the decreasing share of rotating machines in conventional generation units. In an incident such as the loss of a large production facility, the frequency will vary more because there will be fewer other conventional means of production to absorb this shock.[15] With a lower inertia, the frequency will therefore vary both more rapidly and more widely. Some fear that the adjustments of the remaining conventional generation unit will no longer be fast enough to respond correctly, and thus ensure the stability of the system. The key

[13] Hydropower as well as geothermal, biomass-, biogas- or waste-fuelled power generators are rotating machines directly connected to the AC network and thus contributing to the power system inertia.
[14] Note that various technical challenges, often interrelated, emerge from high shares of converters. For sake of brevity this note refers to the most often referred aspect of low inertia. For more complete overviews of challenges and solutions, see the selected documents given as references.
[15] To continue with the example of the tandem bike, with fewer cyclists on the tandem bike.

questions here are at which level of variable renewables will problems occur, and what solutions exist to these problems.

Second, the decrease in the share of rotating conventional generation facilities weakens the voltage reference signals. As a result, the voltage wave used as a reference by the converter in wind and PV installations is significantly disturbed by variations in the load and injection of the converter itself. The voltage is then not "strong" enough, which makes it difficult to convert direct current into alternating current.

These disturbances can be aggravated by the presence of multiple converters. For example, when a producer has fine-tuned the converter (grid-following) of a wind or solar PV farm, for specific conditions, and a second grid-following converter-based installation is connected nearby, the performance of the first tends to deteriorate. In some cases, instabilities can even lead to the untimely disconnection of one of the generating facilities, endangering the balance between supply and demand.

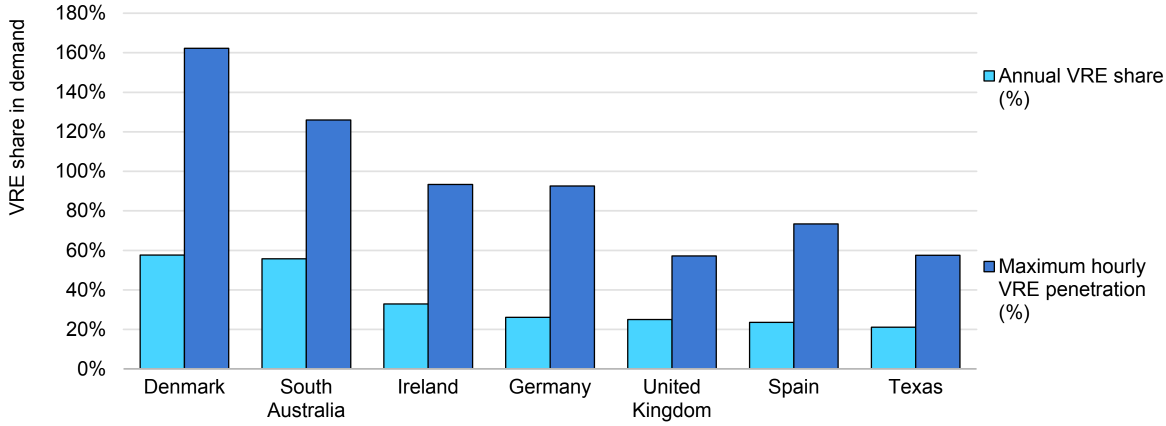
This issue related to converters is not new, as such interactions already happen in the power system between, for example, HVDC terminals and nearby industries, and should be assessed by transmission system operators. It is now recognised that replacing voltage sources with grid-following converters increases the risk of this type of phenomenon.

The specific level of variable renewables for which declining inertia and stability become problematic varies depending on network topology, other infeed, operating point of generating units and specific network locations. Based on a reduced model of the British and Irish transmission grid, the EU-funded MIGRATE project estimated that stability problems can be expected when instantaneous penetration of grid-following variable renewables reaches 60% to 80%. (MIGRATE, 2020).

The stability of a system then mainly depends on the size of the synchronous units (or more generally grid-forming ones – see Chapter 3) connected to the system, whether traditional generation or synchronous condensers, and not on their active power output. Similarly, stability depends mainly on the number of grid-following converters connected to the grid and not on their output. The more the variable renewable power produced, the more conventional generators are displaced out of the supply-demand balance and are likely to be disconnected from the grid (synchronous generators cannot operate below their technical minimum). However, keeping the renewable infeed identical but installing many synchronous condensers would boost stability while keeping the share of power electronics output constant in the generation mix.

Even if the 60% to 80% threshold of variable renewables seems high, such shares of hourly or instantaneous penetration can be reached also with much lower annual shares of variable renewable generation. Already in 2019, several countries with an annual share of around 30% of wind and solar on total electricity generation, have reached or surpassed 100% of demand supplied by variable renewables in certain hours of the year (see Figure 4.1). As their annual average share increases, the number of hours with very high instantaneous penetration of variable renewables will significantly increase as well. Many of these countries have therefore already begun to develop specific solutions to ensure system strength (see below).

Figure 4.1 Annual solar PV and wind levels and maximum hourly levels in selected countries in 2019



Source: IEA Analysis based on 2019 Renewable Energy Market Report

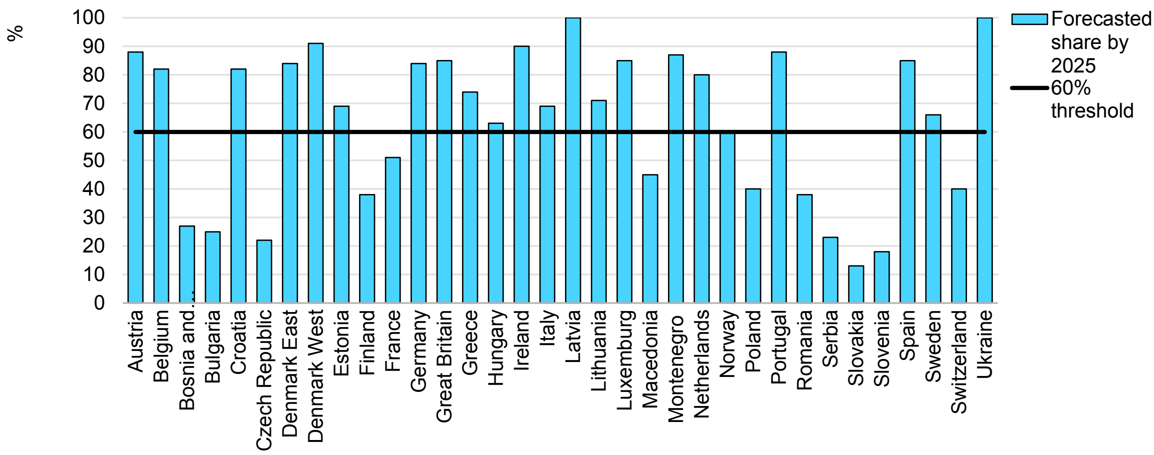
In an interconnected country like France, the precise qualification of such situations in terms of the share of renewables in the generation mix will require realising the whole process of quantitative analysis of 2050 scenarios, in particular simulations of the overall supply-demand balance. A full set of adequate assumptions are needed, including generation and flexibility mix, load profile in France and abroad, and interconnection capacity, and will be established based on the National Low-Carbon Strategy and stakeholder feedback.

In France, such situations are expected to be infrequent in the coming 15 years. Nuclear power is expected to remain the dominant form of electricity generation until at least 2035, when its share of the total generation mix is expected to decrease to 50% from around 70% today. Moreover, hydropower production accounts nowadays for 10 to 15% of total generation in France and should still account around 10% of generation on average in 2035. In Ireland, by contrast, instantaneous wind infeed has already reached 65% as a share of generation, with wind making up 27% of generation in 2018.

In the scenarios studied for this report, wind and PV form a dominant share of France's generation mix from 2040, so stability issues will need to be addressed in a timely manner.

Many regions in Europe will soon have to accommodate a substantially increasing share of variable renewables. The Ten-Year Network Development Plan of the European Network of Transmission System Operators (ENTSO-E) projects that by 2025 in eight European countries up to 100% of instantaneous demand will be covered by converter-based renewable generation and 22 countries will reach at least 50% for the most challenging hour. To be able to operate parts of the European electricity system when levels of converter-based wind and solar generation are very high, all stakeholders will have to collaborate on new monitoring and power system controls, as well as innovative technological solutions such as grid-forming converters.

Figure 4.2 Expected highest hourly penetration levels of renewable energy sources in Europe by 2025 in % of generation



Note: Forecast for the 2025 national trends scenario.
Source: ENTSO-E (2020), Ten-Year Network Development Plan.

The occurrence of situations with 100% converter-based infeed may not increase progressively. A large system split can already lead to part of the system being dominated by wind or PV. Despite balanced generation and load, continuity of supply would be compromised as wind turbines are grid-following.

These considerations show that system stability with a high proportion of renewables is a challenge not just for France but more broadly for continental Europe, where decarbonisation will be massively supported by the development of converter-based wind and solar PV production.

Some European countries at the forefront of wind and solar PV development already experience or will soon experience the effect of massive integration of converter-based generation. Smaller synchronous areas such as Ireland or Great Britain are expected to experience issues earlier. Although stability issues will not concern France as a whole in coming years, they may appear locally because of the uneven distribution of traditional generators. Particular attention therefore needs to be paid to regions with no hydropower capacity where nuclear generators will be decommissioned early.

Technical challenges beyond inertia: system strength and stability

System-wide inertia has received widespread attention in recent decades, for two main reasons. Inertia is easy for non-experts to understand, and the frequency stability it provides is a key operational need. However, the technical challenges that need to be overcome in converter-dominated systems go beyond inertial stability, to include lower voltage stiffness and lower fault current levels. The combined impact is often referred to as system strength (ENTSO-E, 2020).[16]

In addition, inertia should not be seen as a simple system-wide phenomenon (Box 4.2). The EU-funded MIGRATE project showed that a large interconnected system is made up of several centres of inertia. In the case of disturbances, the system can no longer be expected to respond as a rigid body represented by a single total inertia.

Box 4.2 Monitoring inertia and system stability in Texas

Wind generation in Texas more than doubled between 2013 and 2019 as coal-fired plants were retired and CCGT plants were commissioned as a result of low gas prices. As a response to this shift in the generation mix, ERCOT, the independent system operator for the Texas Interconnection, started monitoring an expected decrease of inertia in real-time.

Contrary to expectations, ERCOT found a lower decline than expected, partly because of:

- variable renewables curtailment due to more pressing network constraints,
- higher minimum loads,

[16] Presently the 3 levels (inertia fault current and voltage stiffness) are linked by synchronous machines, but in the future with specific behaviour of converters, these might be discoupled.

- switching from coal to gas units (which provide more inertia), and
- the substantial inertia contribution of synchronous generation in private use networks.

ERCOT developed a set of tools to monitor and forecast frequency and inertial response requirements, allowing for enough lead time to ensure availability of thermal generation (Matevosyan, 2018). For inertia monitoring, ERCOT is able to forecast 168 hours ahead on a rolling basis. Wherever needed, ERCOT is able to procure fast frequency containment reserve through an ancillary service called Responsive Reserve Service (RR).

ERCOT is looking into technologies that will enable it to reduce its inertia requirements from 100 gigawatt-seconds (GWs) to 90 GWs[17]. Future measures include addressing issues related to weak grids, synchronous condenser deployment, improving modelling of converter-based resources and real-time transient stability analysis.

Source: Matevosyan (2020), Presentation held at IEA Webinar "Technical secure integration of large shares of converter based power sources".

Compensating for the decrease in inertia as the share of conventional generation decreases

Several complementary solutions can ensure the stability of the power system while conventional generation decreases and variable renewable generation increases. These solutions range from the most conventional to the most innovative:

- maintaining a minimum of conventional generation operating instantaneously in the power system (thermal, nuclear or hydro power), with some levels of variable renewables occasionally curtailed;
- developing new frequency services (fast frequency response, or services mimicking an inertial response, sometimes labelled "synthetic inertia" or "digital inertia");

[17] Power system engineers typically describe the inertia of a generator in terms of stored rotational kinetic energy (in the rotating part of generator), so inertia has the same units of energy (power delivered over a period of time). However, because inertia typically only responds for a short amount of time (seconds), inertia is often measured with units of MWseconds (MWs) or GWseconds (GWs). So, a generator with 1 GWs of inertia can deliver 1 GW of power for 1 second from energy stored in its rotor. https://www.nrel.gov/docs/fy20osti/73856.pdf.

- installing synchronous condensers, rotating machines that run “at no load” and do not supply active power;
- developing renewable generation facilities connected to the grid by grid-forming converters that can “hold” voltage, establish a frequency signal, synchronise with other grid-forming facilities and allow for islanding.

These solutions have different prerequisites, consequences, advantages and drawbacks. They can become relevant at different times and can complement one another.

Maintaining a minimum of conventional generation operating instantaneously in the power system

Even though converter-connected renewable generation is growing, one way to maintain the inertia of the electrical system is to establish a minimum volume of conventional generation (thermal combustion, nuclear or hydro) that must be constantly operating.

This conventional generation mix could be provided by renewable generation if sufficient hydro, biomass and other synthetic fuel-based generation exists in the power system. It could also be provided to some extent by carbon-free nuclear generation. A last option is to run fossil-fuel generators, possibly combined with CCUS, for specific periods of time.

These generators can then be operated at their minimum production level because the inertia they provide to the system is independent of their level of production. It depends approximately only on the mass of their rotor. The minimum production level must take into account contingencies that could disturb those generators.

In an AC interconnected system, maintaining (or “imposing”) a minimum share of conventional generation in one area to maintain inertia does not necessarily imply reducing converter-based wind and solar PV. If interconnection capacity is high enough, imposing a minimum level of conventional generation in country A can be compensated by a decrease in conventional generation in country B, if the operating constraints and exchange capacities allow it.

Imposing a minimum level of conventional generation nevertheless ends up constraining the maximum instantaneous level of converter-based wind and PV generation. In the long run, other things being equal, maintaining a minimum level of conventional generation thus slows the growth of the share of renewable generation in the electricity mix.

Several other solutions have already been implemented around the world to increase the instantaneous share of converter-based renewable generation while ensuring stable operation and are detailed below.

Developing new fast frequency response services

Some countries are managing the challenge of integrating an increasing share of generation via converters by updating their network codes. Ireland and the Canadian province of Québec are steadily requiring new wind power generation facilities to provide a **fast frequency response (FFR**) service. This comes closer than normal frequency response services to the speed of inertial response and partly reproduces effect of inertia from synchronous generation.

When the system frequency decreases, a FFR supply is obtained by temporarily increasing the power produced by the wind turbine beyond the power actually supplied by wind instantaneously, using new control systems that make this possible. After the FFR supply, the turbine of the wind turbine will have to recover this energy to return to its optimal rotation speed. Pilot projects, practical implementations and analyses of major events on these systems (such as the accidental disconnection of large conventional installations) have shown that FFR has a response speed and effect similar to that of the inertia of the rotating machines. Implementing this capability in wind turbines comes at a cost as some components need to be over-dimensioned.

The example of FFR from variable speed wind turbines in Québec

While hydropower is the predominant source of electricity generation in Québec, wind generation has increased substantially in recent years, from 0.7% in 2006 to 3.6% in 2016, or 7 360 GWh. Despite the low share of wind generation, Hydro-Québec was the first utility to require wind generators to provide FFR. A grid integration study found that integrating the 2 000 MW wind generation sought through tenders in 2005 would lead to instantaneous penetration levels of up to 25% at low demand levels. Without FFR, frequency could deteriorate by up to 0.2 Hz within 10 seconds of a large disturbance (AECOM, 2017).

The first wind turbines to provide FFR were connected in 2010 following a grid code amendment in 2006 that applied to generators above 10 MW (Hydro-Québec, 2018). Hydro-Québec's grid code requires new wind generators to be able to respond within 1.5 seconds (including detection) to major disturbances and to be capable of maintaining a 6% power boost for 9 seconds. Hydro-Québec's approach – a grid code requirement specifically for all wind turbines – differs from more market-based approaches, such as the Irish one (see below) where FFR provision is defined as a commercial flexibility service with specific parameters and plant operators can decide if and how to participate.

As of 2019, more than two-thirds of the 3 000 MW of installed capacity in Québec was able to deliver FFR. The operation of these new wind turbines was further evaluated during a transformer failure in 2015 when 1 600 MW of power generation went offline, resulting in frequency drop from 60 Hz to 59.1 Hz. In this incident 126 MW of FFR was immediately provided by the wind turbines, which reduced the frequency deviation by an estimated 0.1 Hz to 0.2 Hz. Hydro Québec estimated that this was equivalent to the inertial effect that conventional power plants would have offered.

Although the immediate FFR response was sufficient to remain within frequency emergency margins, the wind turbines took a longer time to recover to their nominal production level than conventional power plants. Under different circumstances, recovery from the 2015 event could have resulted in another drop of frequency, potentially causing a blackout. As a result, Hydro-Québec revised its standard for wind turbines to limit power reduction during FFR response. The slower recovery rate following dispatch of wind turbines for inertial response was also observed in other jurisdictions. Wind turbine manufacturers are now designing turbines with limited power reduction that adhere to the new standards.

Preparing Ireland's power system for higher shares of converter-based infeed

The yearly average share of renewable generation and imports via HVDC interconnectors that does not contribute to inertia exceeded 30% in Ireland in 2018. Trends indicate that inertia will decline even further as penetration of non-synchronous renewable generation increases. The present aim is to enable 70% instantaneous penetration of non-synchronous supply, expressed through a Simultaneous Non-Synchronous Penetration (SNSP) target. In response, EirGrid and SONI, the Irish transmission system operators, have taken several measures, through their Delivering a Secure Sustainable Electricity System programme (DS3), to reduce the impact of lower inertia on the system and enable larger instantaneous wind infeed levels in a reliable and cost-effective manner (EirGrid, 2020). The DS3 programme is based on two main approaches. The first focuses on adapting power system equipment, grid codes and protection to cope with higher rates of change of frequency and larger frequency swings (Rezkalla and Marinelli, 2018). The second approach tries to accommodate more converter-connected generation by providing different forms of inertia services or incentives for more flexible plants or plants with a higher synchronous inertia.

In Ireland, provision of FFRs by wind turbines is one of the measures that has already increased the level of maximum instantaneous grid penetration of non-synchronous generation to 65%, with the original objective of reaching 75% in 2020.

Before wind generation began to provide FFR service at the end of 2018, a trial was undertaken with a 36 MW wind plant comprised of 16 wind turbines. Through novel systems which control the kinetic energy in the rotating mass of the turbines, the wind turbines can respond to a reduction in system frequency by temporarily increasing power output beyond that enabled by present wind conditions. This therefore allows for FFR, after which the wind turbine will need to recover this energy and restore its optimal rotational speed. A successful six-month pilot project demonstrated the technical capability of wind power plants to provide both energy and very short-term frequency response in multiple timeframes. As a result, EirGrid contracted the first wind power plants for frequency response at the end of 2018. Additional wind power plants are expected to be contracted once other technical issues are resolved related to legacy distribution-connected rate of change of frequency relays, the main factor limiting the instantaneous amount of non-synchronous generation

FFR services can also be complemented by other fast services, which come even closer to an inherent inertia-like response due to specific faster control mechanisms. EirGrid and SONI hence introduced a Synchronous Inertial Response service in addition to the FFR service. Synchronous Inertial Response includes more precise specification of available kinetic energy and the power levels at which it can be supplied.

EirGrid's commitment to these and expected future additional services is reflected in the rapid acceleration of spending on ancillary services, expected to reach 30% of total electricity costs by 2030, up from 5% a few years ago. It is no longer just must-run production assets but also market-driven units providing stability support.

In October 2019, EirGrid started working on a strategy to increase its penetration capability from 70% to 95%, which is deemed necessary to allow a three-fold increase in wind capacity and some level of PV.

Limitations of FFR

However, synthetic inertia cannot directly replace synchronous inertia provided by conventional generating units, because synthetic and synchronous inertia respond in fundamentally different ways to high rate of change of frequency events. In Great Britain, National Grid studied the effect of synthetic inertia on Great Britain's power system and found limitations to its usefulness. Due to inherent control delays, synthetic inertia simply is not fast enough to limit frequency deviations when real inertia levels are very low. Moreover, the effectiveness of the additional FFR is dependent on the size of the system and how much FFR is already available. At some point, the additional FFR begins to provide less support for arresting the initial rate of change of frequency and re-stabilising the power system (NERC 2020) FFR therefore helps to enable some higher levels of variable renewable infeed, but postpones the real issue and does not offer an ultimate solution.

In order to reach very high shares of variables RES, other options such as the two mentioned below need to be implemented.

Installing synchronous condensers, a well-known and robust solution for ensuring the inertia of a power system

Historically, synchronous condensers were deployed to provide a voltage reference (voltage support and fault currents) to an area without enough conventional generation. Now they are also deployed to provide inertia in areas lacking rotating machines. To address shortfalls in inertia and low fault current levels, synchronous condensers could be placed at relevant points in the network. This solution is proven and can be implemented quickly, as recently illustrated in Brazil, California, Denmark, Germany, New Zealand and Norway (Igbinovia and Fandi, 2018).

For example, the South Australian grid operator decided in 2019 to install the equivalent of 4 400 MW of inertia in its area to ensure safe operation, without having to force conventional generation to remain in operation. Similarly, synchronous condensers were installed in 2018 in the windiest area of Texas, the Panhandle, which has significant wind generation capacity but few synchronous generators. In Denmark, seven synchronous compensators were installed. Some were installed as early as the 1960s. In the United States the National Renewable Energy Laboratory (NREL) has highlighted synchronous condensers as one option for improving stability during severe faults at high levels of variable renewable infeed in the US Western Interconnection system (Miller et al. 2014). NREL noted that this is possible “using good, established planning and engineering practice and commercially available technologies”.

Existing generators can be retrofitted as synchronous condensers. Some references indicate that synchronous condensers retrofitted from existing generation units or those about to be decommissioned can be one-third cheaper than off-the-shelf units.[18] Others claim that they are more expensive and complex to operate (Stein, 2014).

[18] Some solutions implemented in Tasmania for existing hydro plants were relatively low cost.

Synchronous condensers in Denmark to cope with low thermal infeed

A favourable policy framework and industrial development have made Denmark one of the countries with the highest penetration of variable renewables and one of the most advanced countries for renewable integration. In 2019, variable renewables accounted for close to half of the country's power consumption. In September 2019, wind generation exceeded the country's electricity demand. To integrate such high levels of variable renewables, Denmark has relied on several measures, including extensive interconnectivity to neighbouring power systems, wholesale market design improvement, system-friendly remuneration mechanisms for variable renewable generation and improving the flexibility of its thermal fleet.

As with other systems with high levels of variable renewables, however, frequency stability and fault current levels are becoming increasingly important (ENTSO-E, 2020), and require local technical solutions. In response, Denmark has deployed seven synchronous condensers, amounting to 1.82 GWs, to address short-circuit contribution, voltage management and robustness constraints, particularly at times with reduced operation of synchronous generation (Yang, 2015).

In addition, Denmark requires new power plants above 1.5 MW to be able to cope with rates of change of frequency above 2.5 Hz/s. Denmark's updated regulations also require smaller solar and wind plants down to 11 kW to withstand such changes for at least 200 milliseconds to avoid mass tripping during system events. This requirement goes beyond specifications in many other jurisdictions and gives an indication of how other systems (even large interconnected ones) could evolve when variable renewables increase.

Figure 4.3 Locations of synchronous condensers in Denmark

Source: DTU (2015), Studies on low inertia systems and application of synchronous condensers.

Synchronous condensers as a solution for system strength issues in South Australia

Variable renewable generation in Australia amounted to 9% in 2019. Some states, such as South Australia, have significantly higher levels, driven by a combination of federal and state-wide policies. Policies to meet the target were shaped around two schemes. The Large-Scale Renewable Energy Target required large producers to procure a fixed proportion of their electricity from renewable sources. The Small-Scale Renewable Energy Scheme focused on small rooftop PV, solar water heaters and heat pumps. With 2.1 million installations, Australia had the world's highest penetration of residential rooftop PV mid-2019.

South Australia is at the forefront of variable renewable integration, not only due to its high level of penetration, 49%, but also due to its limited interconnection to neighbouring power systems and specific transmission grid topology. Following a blackout in 2016 and the resulting Finkel Review, AEMO introduced a series of market and operational reforms to ensure the secure integration of growing shares of renewables (Hartmann, Vokony and Taczi, 2019). Additional measures following the Finkel Review include the establishment of an independent Electricity Security Board and AEMO's mandate to develop Integrated Resource Plans. These plans evaluate energy scenarios to ascertain adequacy, grid development and flexibility requirements.

Following the 2019 National Transmission Network Development Plan, AEMO identified a 6 000 MW.s inertial shortfall in South Australia during islanding events (AEMO, 2018; ElectraNet, 2019), for example following interconnector trips. ElectraNet, the transmission network company, was instructed to address this by 31 May 2020 to avoid keeping synchronous generation online for system strength purposes. To comply with this requirement, ElectraNet procured four high-inertia synchronous condensers, each with 575 MVA nominal, 275 kV fault capacity and 1 100 MW.s inertia contribution, to meet the power system's minimum threshold level of inertia. This solution is expected to deliver on average EUR 1.8 to EUR 3 (AUD 3 to AUD 5[19]) in yearly savings on typical consumer bills compared with conventional generator solutions. The remaining shortfall, adding up to the 6 000 MWs of inertia needed for secure operation, could be met by options such as generation contracting, batteries and other equipment capable of providing inertia support (ElectraNet, 2019).

Limitations of synchronous condensers

Deployment of synchronous condensers has already shown that they can ensure the stability of regionally sized power zones in the absence of synchronous conventional generators. This solution still requires redundancy and regional spread of the synchronous condensers, however, to ensure system stability if one of them is lost. Black start capabilities must also be well understood and specified as the system moves from centralised black start processes to the use of distributed assets.[20] Otherwise, the accidental loss of a synchronous condenser could lead to the loss of converter-based renewable generation, as it would no longer have a voltage and frequency reference signal.

[19] EUR 0.6 for AUD 1.

[20] Black start is the ability to start up (here the synchronous condenser) on its own, without any energy supplied by the power network, thanks to an on-site energy supply (for instance, a small generator supplied by a tank of diesel).

As synchronous condensers are a well-known technology, costs are not a major issue. For Great Britain or France, it can be assessed around or less than EUR 1 / MWh for end consumers, even considering the most expensive synchronous condensers (Brown, Bischof-Niemz and Blok, 2018). This value is small compared with the costs of deploying variable renewables or even of grid development. Consequently, it is not a major economic issue, in particular given the scale of the other technical challenges, such as flexibility needs.

While synchronous condenser technology solutions have been proven in specific situations, a generalised roll out in the context of large-scale system strength has yet to be evaluated. In particular, because synchronous condensers are assets with relatively long lifetimes requiring longer term contracts and the system needs may evolve dynamically, their roll-out as the preferred strategy to deal with concerns of system inertia, still needs to be compared to other technical solutions that may be more flexible in terms of their implementation or more cost-effective once they reach market maturity.

Grid-forming converters: using renewable generators or batteries to set system frequency

A more innovative and far-reaching approach is to enable variable generators or batteries to become part of the solution themselves, by utilizing grid-forming power converters to connect them to the grid.

Converters for renewable installations or batteries can have grid-forming capabilities, mainly under two conditions:

- using voltage source control, a technology present today in all the converters of wind and solar PV installations or batteries;
- ensuring a minimum amount of energy is available – from a battery or a supercapacitor – to cover the transient needs of the grid.

Experience with grid-forming capabilities

Grid-forming controls are deployed in several applications already, but not yet at large scale in an interconnected power system where the number of infeed sources changes dynamically. Experiences include:

- **Microgrids**: Grid-forming controls have operated small islanded power systems for hours or even days. A key difference from a large interconnected power system is that there is no meshed topology and there is upfront certainty on size and location of all other generation sources.

- **Offshore wind**: HVDC links for offshore wind include an electrical substation with grid-forming capabilities.
- **HVDC interconnectors** such as the one between France and Spain can operate in black start mode, which is similar to grid-forming control.
- **Uninterruptible power supply**: Critical infrastructure such as hospitals and data centres often have local units to ensure continuity of supply. These are small and do not operate in a large meshed network.

Grid-forming converters are now being installed in various countries. A 69 MVA existing wind farm has been upgraded for testing grid-forming capabilities by Siemens Gamesa on the Scottish Power network. A 7.4 MW battery with grid-forming capability was successfully tested in Louisiana by Entergy in February 2020. And other grid-forming installations are also ongoing on the TEPCO network in Japan and the Dalrymple BESSin Australia.

Grid-forming controls can contribute to stabilise synchronous generation

In power systems with with predominant converter-based infeed, grid-forming controls help stabilise remaining synchronous generation, for example by reducing the normalised stress they experience after a load step event (Tayyebi et al., 2019).

The EU-funded MIGRATE project also showed that in its specific power system model it was necessary to switch some power electronics control to grid-forming control when the share of instantaneous variable renewables approaches 80% (Markovic et al., 2019). Having grid-forming converters in the energy mix can therefore improve stability of the overall system.

To achieve very high levels of converter-based sources, some controls of synchronous generators will need to be retuned, especially their power system stabiliser loops. Historically these loops were added to avoid oscillations between synchronous machines. These need to be updated to better reflect the interaction with power electronics across the system.

Grid-forming services provided 100% by converters appear theoretically viable

Recent research, in particular the MIGRATE project, shows that 100% converter-based systems without any conventional generation could be operated by defining grid-forming controls of converters (Prevost and Denis, 2019). These facilities would thus be able to behave as closely as possible to an ideal voltage source, as do conventional generators. They would also be able to generate their own voltage wave at a reference frequency and amplitude. As a result, the voltage provided would be almost insensitive to current variations on the network. Such converters would also be able to synchronise with other voltage sources, such as conventional generators, or with other facilities with grid-forming capability. They would also be able to operate in a separate grid if an event were to cause fragmentation of the interconnected grid.

To show that it is possible to operate a system with different grid-forming controls, the MIGRATE project successfully tested three types of interoperable grid-forming controls. In a lab setting these controls have proven their robustness in their ability to filter through frequency drops as well as reproduce the behaviour of mechanical oscillators and synchronous machines (Colas et al., 2020). Additional controls have been developed commercially by manufacturers and developers. The feasibility of these in large interconnected power systems still needs to be tested, however.

Challenges for the widespread use of grid-forming converters

Several risks associated with grid-forming controls need to be addressed before a 100% converter-based large-scale, meshed power system is possible.

Beyond grid-forming converters, increased deployment of IT and digital controls requires greater digital resilience

Digitalisation of power system management fundamentally changes the rules when it comes to **system security**. Making a power system fully digital exposes it to involuntary programming errors, or worse, hacking, for example during updates or when operational settings are being defined. This risk is of particular importance when transitioning to a system with more converters, as grid-forming converters set the voltage wave and frequency that are fundamental features for operating the power system.

In any case, it is necessary to consider new system vulnerabilities, whether through grid-forming converters or more generally on other digital assets, depending on potential access to IT systems and the resilience of the chosen control algorithms. This impact of the various choices for digital controls can be seen in the following discussion of high current protection scheme designs.

Protection against faults will need to be adapted

Today, short circuits on the power network create high fault current thanks to the reaction of conventional synchronous generators. The high level of fault current is then used to detect, locate, act and relieve fault.

The overcurrent capability of converters is much more limited than that of synchronous machines. This limits fault current, modifying management of short circuits. To ensure the stability of the power system, three options are possible. In practice, options 2 and 3 are not exclusive and could be combined, but it is important to understand the trade-offs of each:

Option 1: Increase the rating of the converters: Since the switches in the converters are sensitive to higher temperatures, they have very little overloading capability. Consequently, requiring a short-term overcurrent could be as costly as requiring steady state overcurrent. Introducing converters with a higher rating has been proposed by the British transmission system operator National Grid. This solution would deal with the issue that while synchronous machines can cope with around five times their nominal current for about 100 milliseconds, converters cannot go past 1.4 their nominal rating and for less than 20 milliseconds.

Option 2: Use more differential protection in the grid: Power systems use distance protection and differential protection. The first is a plug-and-forget type of device that measures the presence of a fault based on pre-established settings.[21] By contrast, differential protection requires telecommunications to compare system conditions and identify faults in real time with 100% selectivity of faults. Its main drawback is the requirement of real-time telecommunications[22], which are not typically available in lower voltage networks but could be enabled through devices with IP (Internet Protocol) and 5G connectivity.

While Option 2 would require updating and replacing existing protection schemes, which are currently based on high currents, it could be cheaper than Option 1 because it uses smaller circuit breakers.

Because the average lifespan of protection systems is around 20 years, by 2040 it could be possible to replace existing protection schemes with differential protection schemes. This would require the installation of the necessary telecommunications infrastructure, however, as well as prioritisation of areas with higher concentrations

[21] It detects fault comparing the ratio of voltage and current to a target value: if the ratio is smaller than the target value for the transmission element under scrutiny (its impedance), a fault is present.
[22] That is why the warning about the sensitivity of power system with a high share of converter-based generation also applies to protection scheme.

of converter-based generation. Moreover, protection schemes for single-phase or two-phase faults still need to be developed.

Option 3: Use the fact that most converter-based renewable generation is almost never producing at maximum power. Using the headroom in most converter-based generation would allow for greater current during fault compared to pre-fault conditions. However it is still necessary to understand whether this headroom would be enough to activate distance protection relays, effectively selecting faults, while avoiding negative interactions between converters.

In any case, deployment of such solutions requires a proactive approach as there is a risk that systems will not be ready when instantaneous variable renewable infeed becomes very high.

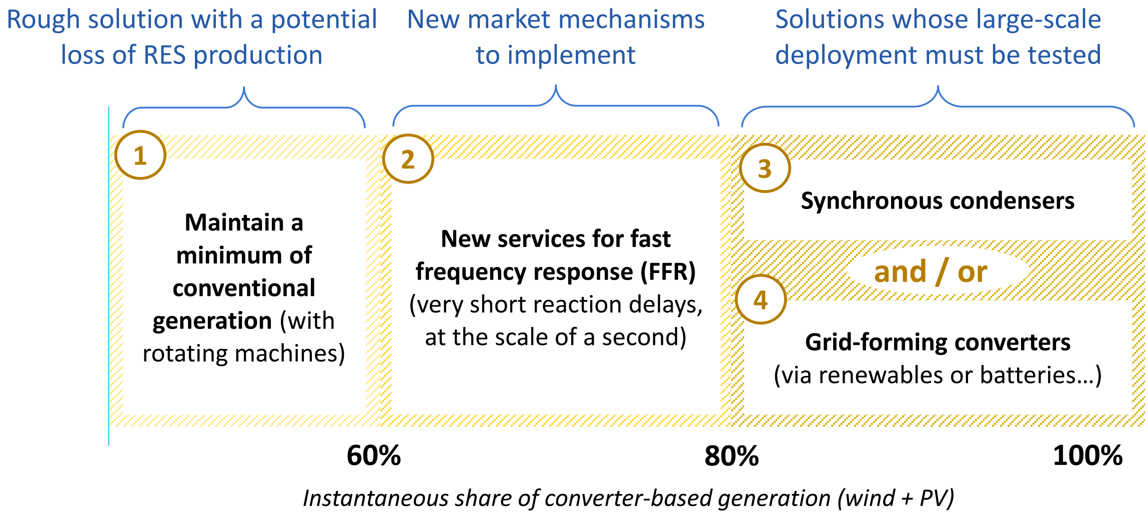
In Germany and Great Britain, transmission system operators have already started to add a requirement for some sort of grid-forming control in their grid codes. In such cases, manufacturers have started preparing for grid-forming solutions. These solutions remain tailor made, however. Off-the-shelf solutions can only be expected when increasing numbers of countries see the need for grid-forming solutions. To scale up the use of grid-forming converters in a timely manner, there needs to be clarity about grid-code design and about how the additional costs of these technologies will be recognised, without impacting variable renewables projects or market competitiveness.

Way forward

Operating a network with only converter-based devices such as wind and PV while ensuring power system stability can be technically feasible in principle, but needs further testing and demonstration at large scale. Synchronous condensers and FFR can already be deployed and the technological maturity of grid-forming solutions has improved rapidly over the last ten years. This technology will be tested in real conditions in 2022 on the European continental system, in France. Grid-forming converters are now being installed in various power systems. Demonstrators on a real power system are now essential to show that grid-forming is feasible, that issues have been resolved and that this technology is steadily progressing towards full maturity and system-wide deployment.

To ensure that the right technologies, financial incentives and regulatory frameworks will be in place when necessary, actions must be taken well before stability issues materialise. A clear roadmap can be defined, depending on the level of variable renewable penetration (Figure 4.3).

Figure 4.4 Stability solutions, depending on share of converter-based generation



Source: own analysis carried out by RTE.

A sequence of steps can be followed to securely integrate high shares of inverter-based generation such as solar PV and wind:

- Assess stability limits of maximum instantaneous non-synchronous grid-following generation early in the planning process, and monitor it closely in real-time, to ensure that it remains below 60% to 80% of total generation.
- Initially, if a system is not prepared, a high infeed of PV and wind may need to be curtailed and covered by conventional generation, often based on fossil fuels. This is not cost-effective in the long term and makes it more difficult to achieve low-carbon targets.
- Synchronous condensers may be a viable option when system strength becomes an issue.
- New fast frequency services ("synthetic inertia") can help go the extra mile and limit curtailment of variable renewables, in combination with real-time assessments. These services could be procured from a variety of assets, including variable renewables, batteries and EV chargers.

These solutions, however, are only enough to enable instantaneous penetration of 60% to 80% variable renewables, because a number of issues, including voltage control issues emerge at higher shares. To go higher, a further set of options may be possible:

- Grid-forming solutions can be applied to push the level of instantaneous variable renewable infeed higher. This will require further innovation and demonstration projects to increase technology readiness levels for large-scale implementation. A roadmap is essential to go from demonstration projects to the widespread deployment of grid-forming controls. Pilot regions can be considered that are already at the forefront of the development of renewable energy sources.

- Grid-forming solutions require planning now to ensure technical specifications are clear, harmonised, checked for interoperability, and enforced in appropriate regulatory procedures.
- Grid-forming generators should be of sufficient size and preferentially connected to the transmission system, for two main reasons:
  - It is easier for the "strength" provided by the grid-forming assets to flow through the grid when impedance is low between the node of interconnection and other grid nodes. Thus, having grid-forming units connected to the transmission grid usually shortens the electrical distance and reduces the impedance compared to connection at the distribution level by reducing the number of intermediate transformers and other assets between the nodes.
  - The islanding capacities expected from grid-forming installations may pose problems of compatibility with distribution network protections, especially in low voltage networks, where the need to control unit costs leads today to very simplified technical solutions (no communicating protections, sometimes simple fuses). This is to be studied in new research projects.

Planning and cost allocation are essential. While grid-forming converters may be necessary, they may not be necessary throughout the system. Research in the United Kingdom power system (Urdal, Ierna and Roscoe, 2018) and in the Irish power system in the framework of the MIGRATE project (Flynn et al., 2019) shows that 20% to 30% penetration of grid-forming converters connected at the transmission level would be enough to maintain stability.

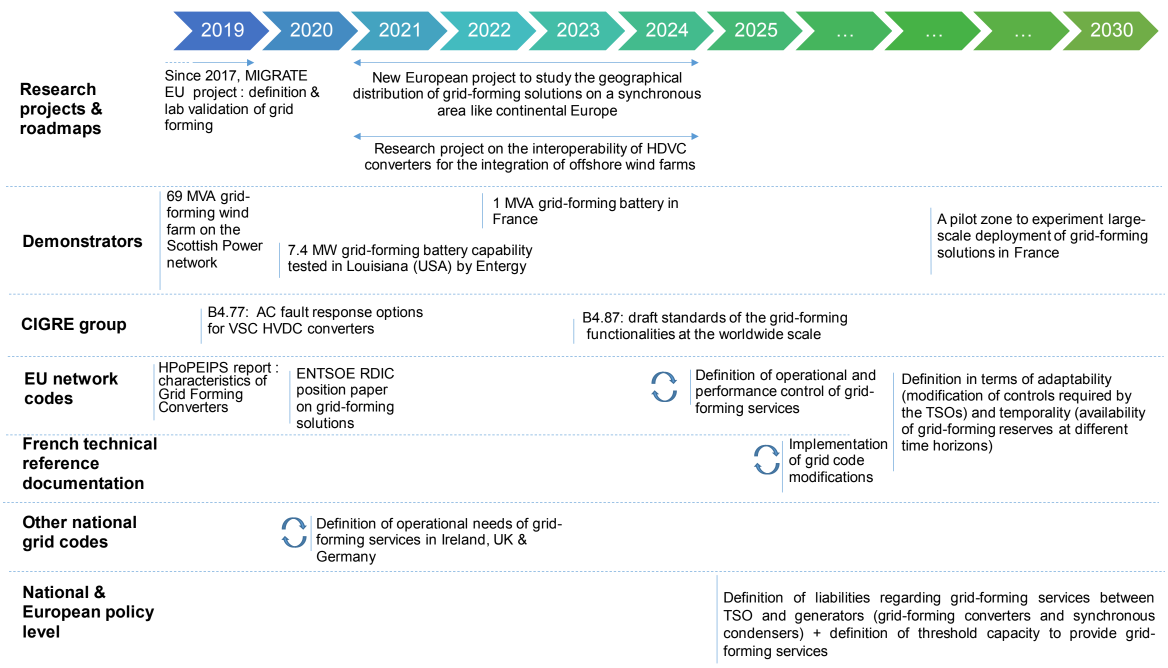
Policy makers considering cost should bear in mind the many options – fast frequency products, synchronous condensers and grid-forming converters. Assessing the significance and stability contributions of different technology mixes will help to put the additional costs into perspective.

As the power system integrates more converter-based connections – from variable renewables, loads, DC interconnections and battery storage – it will be linked to many fast-acting and highly controllable devices. At the same time, power systems are becoming more complex to control and model, and stability challenges more vital to address. Regions such as Ireland, South Australia and Québec have already experienced a higher share of converter-interfaced power sources, leading to modifications in their market rules, operational practices and connection requirements. Each case was specific and required a clear understanding of the context to identify the options that were most appropriate.

With new needs emerging as shares of PV and wind continue to increase, additional solutions may be needed. This will require further upscaling of technology readiness levels, understanding of wide system impact, and upscaling of industry to supply these solutions. Security considerations and economic incentives will arise, which makes an open stakeholder debate and clear regulatory processes essential.

Demonstration projects can progressively increase the confidence of converter manufacturers and transmission operators in the reliability and reasonable cost level of grid-forming solutions based on converters. Consultations with stakeholders in regulatory debates can prepare a harmonised European definition of system needs, adequate requirements and performance measures for solutions. Grid-forming can be part of this process. International collaboration allows for a large enough market for manufacturers of grid-forming solutions.[23] Regulatory processes can structure the sector in the long run, in coherence with national energy policies and taking into account the impacts on all system participants (Figure 4.6).

Figure 4.5 Expected steps of grid-forming qualification in practice and in regulatory processes



Source: own analysis carried out by RTE.

Beyond the demonstration projects already listed, discussions at the regulatory level, in which RTE participates, are ongoing at ENTSO-E to define and integrate grid-

[23] Note that this is also a stake for all the interconnected power system targeting a large share of variable renewable generation in their power mix (as already illustrated in North America with Texas or Québec, as well as Australia, …)

forming capability into European grid codes for connection for generators (RfG – requirements for generators) and HVDC links. This process is steered by the EU Agency for the Cooperation of Energy Regulators and any grid code update will need to be validated in a legislative process involving EU institutions and member states. In a fast scenario, the operational need should be defined in the grid codes in 2021 and performance control in 2024, when the codes will be updated.

These European requirements will then have to be reflected in national grid codes.[24] Germany has already defined a significant part of these requirements in its grid code and the United Kingdom is in the process of doing so.

For system operation, methods must be defined to optimise the deployment costs:

- A pilot zone could test industrial deployment of grid-forming solutions in France in the next decade. RTE is discussing this possibility with some manufacturers.
- A new European project whose definition is ongoing and that should be carried out approximately between 2022 and 2025 will also build a methodology to study the geographical distribution of grid-forming solutions on a synchronous area such as the continental European system. It will consider the question of locating grid-forming solutions on onshore or offshore grids, at the regional scale, and its impact on the distribution grids.
- ENTSO-E has defined a roadmap for a four-year research project on the interoperability of HDVC converters, notably aiming at solving technical and technology challenges for the integration of offshore wind farms. Several questions are being considered: interoperability of HVDC converters from different manufacturers while standardising controls, interactions between AC and DC grids while taking into account grid-forming capabilities, and third party DC connections.
- By the end of the decade, one could expect grid-forming requirements to be defined in terms of adaptability (modification of controls required by transmission operators) and temporality (availability of grid-forming reserves at different time horizons) as is the case for balancing reserves nowadays.

[24] The technical reference documentation in France (*documentation technique de référence*).

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Chapter 5. Security of supply

Key messages

Increasing the share of electricity generation that comes from wind power and solar PV beyond 35% as from 2035 in France will require several major changes to the power system both, on the power system's flexibility needs and flexibility resource deployment.

Changes to power system's flexibility needs

- Residual load (net of wind and PV) will be more variable whatever the time horizon (daily, weekly and inter-annually, except seasonally). Daily variability will increase as the share of solar PV production rises. Inter-annual and weekly variation will increase as the share of wind production grows.
- Managing the balance between supply and demand will be less regular than today. In particular, variations in wind generation will be much more significant than variations between working and non-working days or between seasons.
- Management of day-night alternation will be modified by the development of solar PV production. Residual load will be lower in the middle of the day than at night, with two significant peaks in the morning and the evening.
- Inadequacy risks will evolve in nature: cold spells will be less of a problem, but periods of low wind and heat waves will prove more challenging than today.

Changes to flexibility resource deployment

- A different mix of flexibility resources will be needed: peak generation units, large-scale storage and/or intensive demand-side management (several gigawatts or tens of gigawatts as a whole), as well as the development of interconnections.
- Bidirectional couplings with other energy carriers will develop. The renewable generation mix should be dimensioned not only for the needs of the power system but also to satisfy its couplings such as synthetic gas production. Conversely, couplings should be dimensioned both to meet the needs of other sectors and to increase the flexibility of the power system.
- Significant steps have to be made in coming years to take some flexibility resources from demonstration to industrial deployment.
- The costs of flexibility sources must be taken into account in future assessments of the different options, as they could form a significant share of total costs. Using levelised cost of electricity (LCOE) does not provide a good proxy for this analysis.

Over the last 15 years, France's security of supply has gone from a situation of "overcapacity" – with supply capacity greater than peak needs – to a situation of strict compliance with the public criterion of security of supply, an average annual 3-hour risk of inadequacy. This has been reflected in the latest RTE's Adequacy Report (*Bilan prévisionnel* 2019), where different indicators relative to security of supply in France have been published (RTE, 2019).

Historically, the variability of electricity load and hence of dispatchable generation modulation results from the alternation of day and night, working and non-working days, and seasonal alternation, as well as interannual variations of temperature. On average, load in France is higher during the day than at night, on working days than on days off, in winter than in summer, and in cold winters than in warmer ones. Concerns about security of supply have hence focused on winter working days at the morning and evening peaks, around 8.00 am and 7.00 pm, specifically during cold spells. The 2003 heat wave also exceptionally raised concerns about security of supply.

The massive development of variable renewable energies (wind and solar PV) is leading to new challenges for ensuring security of supply and managing the supply-demand balance. In particular, situations may become more frequent in which production facilities are unable to produce or conversely adapt demand to excessive production. Variable renewable generation thus requires flexibility solutions that can ensure the balance between supply and demand at all times. Its combination with the variability of load may reshuffle the rhythms of dispatchable generation modulation.

Public discussion about the appropriate flexibility mix for achieving high shares of variable renewable energy in France can be broadly categorised into two opposite camps.

Some observers consider that a "redundant dispatchable system" is necessary to compensate for the variability of renewable generation and cover demand when renewable capacities do not produce – possibly several days in a row for wind power. In reality, this approach underestimates the effect of pooling renewable generation on a national and European scale. To ensure that the security of supply criterion is met, it is not necessary to add one megawatt of controllable generation for every megawatt of installed renewable generation. Many such misconceptions about integrating renewables have been clarified by IEA work, such as *Getting Wind and Solar onto the Grid* and the *Status of Power System Transformation* reports (IEA, 2017, 2018, 2019).

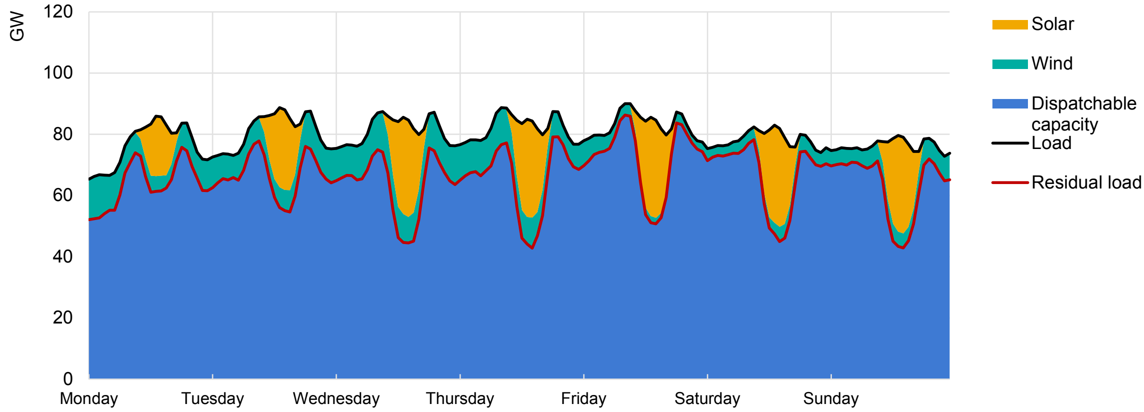
Other stakeholders tend to emphasise the prospect of mobilising significant new demand flexibility capacities to balance load and variable renewable generation, in particular intraday or day-ahead. But this view underestimates the current role of nuclear units in providing flexibility to the power system, a source of flexibility that would need to be replaced in scenarios heading towards very high shares of renewables. For instance, in spring 2020, variations of around 10 GW in several hours were recorded in nuclear output in France, highlighting how reactors production adapts in real time to match changing load and wind generation. Also, it does not always take into account the implications of such a need for flexibility, including costs, acceptability and industrial capabilities.

In order to estimate flexibility needs, it is first essential to assess the variability experienced by the supply-demand balance when the share of variable generation tends towards 100% of load. The question is then whether different flexibility mixes are adequate to ensure security of supply in the power system. For further in-depth analyses in the elaboration of the scenarios up to 2050, it is crucial to explicitly communicate the overall implications of flexibility mixes in terms of system costs, social acceptability, environmental impact and industrial deployment capability. Overall, long term analyses of supply-demand balance prompt questions about how to measure security of supply and reflect consumers' preferences.

High shares of renewables will profoundly change the management of system adequacy

Power system operation requires maintaining the balance between generation and demand at all times. Because of the natural variability of load and of some forms of generation (such as wind, solar PV or small hydro), it is necessary to adapt the operation of other power system components. Such modulation is made possible by dispatchable capacities (from generators, flexible load, storage. These assets can be located both in France or elsewhere in Europe and accessed through interconnectors. Moreover these assets are able to follow residual load, which is the system load, minus output from wind and solar generation, before any activation of demand response (see Figure 5.1).

Figure 5.1 Definition of residual load – example of a typical week in winter, 2035 horizon



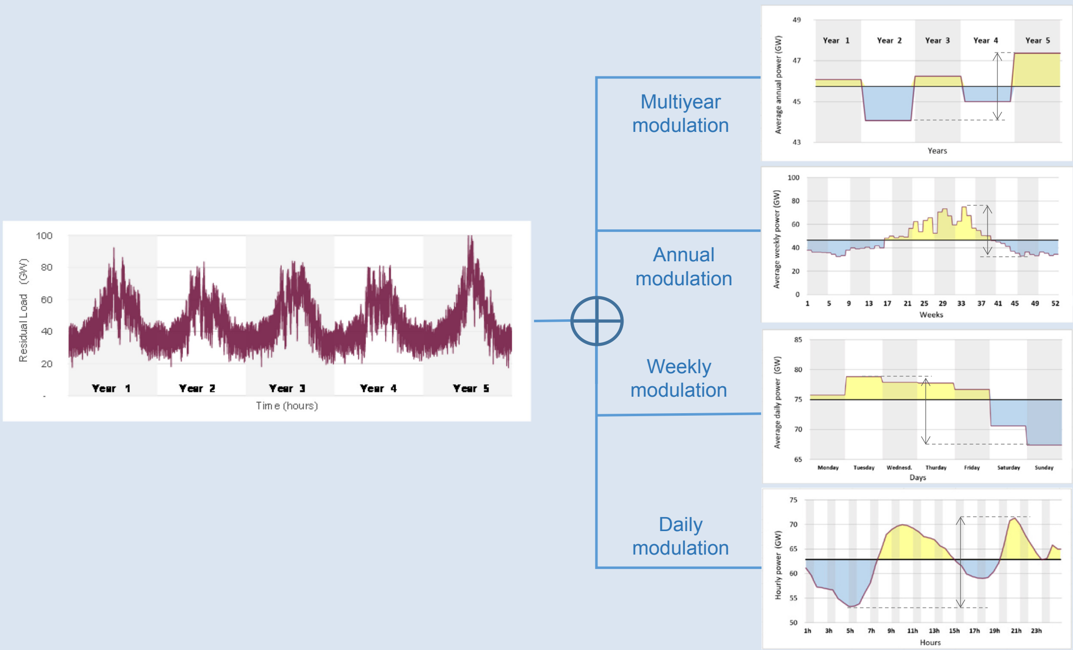
Source: adapted from RTE (2015), Adequacy Report.

Overall, modulation requirements appear complex and very variable (Figure 5.2). Nevertheless, cycles are present in both load and intermittent generation. Load, wind and solar PV production varies according to different cycles and to different extents: daily, weekly, seasonally and from one year to the next, depending in particular of meteorological conditions (even without considering climate change).

Box 5.1 Calculating inter-annual, seasonal, weekly and daily needs for modulation

The need for modulation to follow net load variations can be broken down into interannual, seasonal, weekly, and daily requirements.[25]

Components of residual load modulation requirements



Source: RTE (2020), adapted from RTE (2019), Groupe de travail « interfaces entre l'électricité et les autres vecteurs », Document de cadrage [Workgroup "Interfaces Between Electricity and Other Vectors", Framework Document].

The variability of residual load at each time horizon is assessed by comparing the average value of net load to variations on the given time horizon. The following formulas are applied:

[25] Fourrier analysis confirms that the main "frequency" components in the residual load are yearly, weekly and daily.

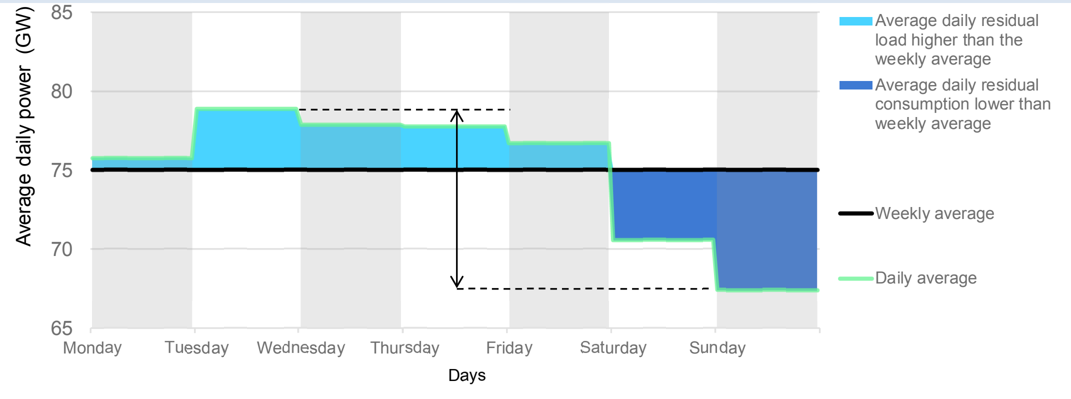
Type of variability and their factors

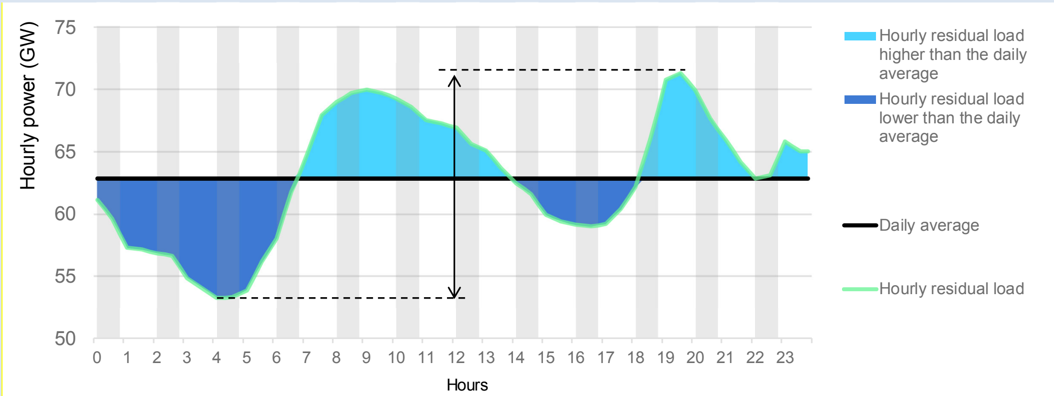
Type of variability	Factors
Inter-annual	Annual average residual load – average residual load over all years
Seasonal	Weekly average – annual average
Weekly	Daily average – weekly average
Daily	Hourly average – daily average

Source: own analysis carried out by RTE

The need for modulation is quantified by the "equivalent stock" that would be needed to smooth the load curve perfectly over time over a given time horizon. The energy size of the stock is therefore expressed in terms of energy to move to smooth the load curve on the one hand (shaded areas in Figure 5.3), and power need (difference between the minimum and maximum average power value) on the other (the arrow on Figure 5.3).

Calculation of the amount of energy to move to flatten residual load and the difference between the maximal and the minimal values of the residual load curve – illustrated on the weekly and daily variability



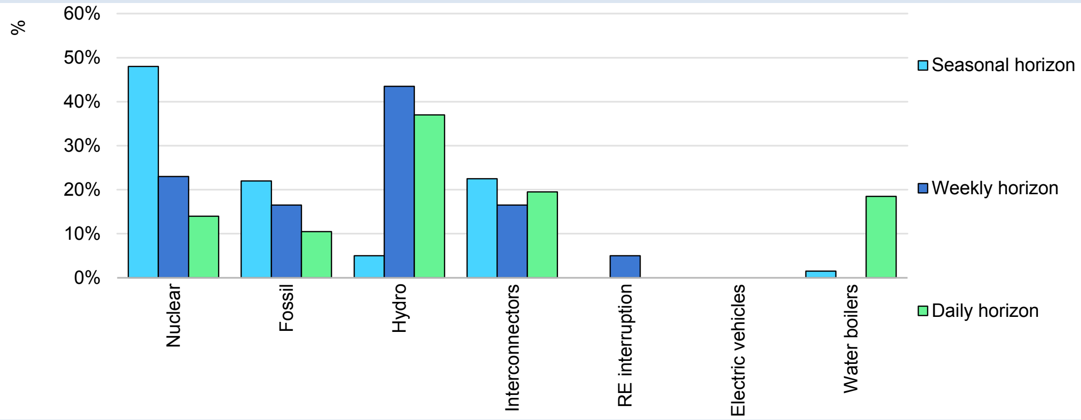


Source: RTE (2020), adapted from 2015 Adequacy Report (*Bilan prévisionnel* 2015).

These indicators vary from one day, week or year to the other. If the power system is sized only to their maximum value, it is likely to be oversized because only extreme situations are considered. Nevertheless, the power system should be sized to be able to cope with most variations. The 95th percentile has hence been chosen since it allows for a probability of only 5% that the residual load variations are above those values considering all hours of the years and possible meteorological conditions. Note that the 95th percentile flexibility needs identified for the different time horizons do not add up as the same flexible resource can provide flexibility for different time horizons, depending on its characteristics.

In practice, a complete technical and economic analysis is required to determine the required flexibility resources by comparing their costs and benefits. This will be carried out in the studies of long-term scenarios (*Bilan prévisionnel 2021*) once corresponding assumptions have been set after consultations with stakeholders. Such analysis is needed for two reasons. First, a given flexibility source is generally able to meet flexibility needs at different time horizons. Second, flexibility sources complement each other. For instance, interconnection can allow generation in France to be exported and hence meet flexibility needs abroad, or generation from neighbouring countries to be imported, meeting flexibility needs in France. Generation and storage capacity can complement each other when energy stored is released from storage.

Current flexibility sources in France



Source: RTE (2019), Groupe de travail « interfaces entre l'électricité et les autres vecteurs », Document de cadrage [Workgroup "Interfaces Between Electricity and Other Vectors", Framework Document]

Current flexibility needs are mainly interannual (around 120 TWh) and seasonal (around 60 TWh) (Figure 5.5). Load mainly varies at seasonal time horizons, as well as from one year to another. Power requirements are first focused at the seasonal time horizon, reaching around 50 GW, while 20 GW are needed to cope with power variations both at the weekly and daily timeframes. Interannual power variations only account for 6 GW.

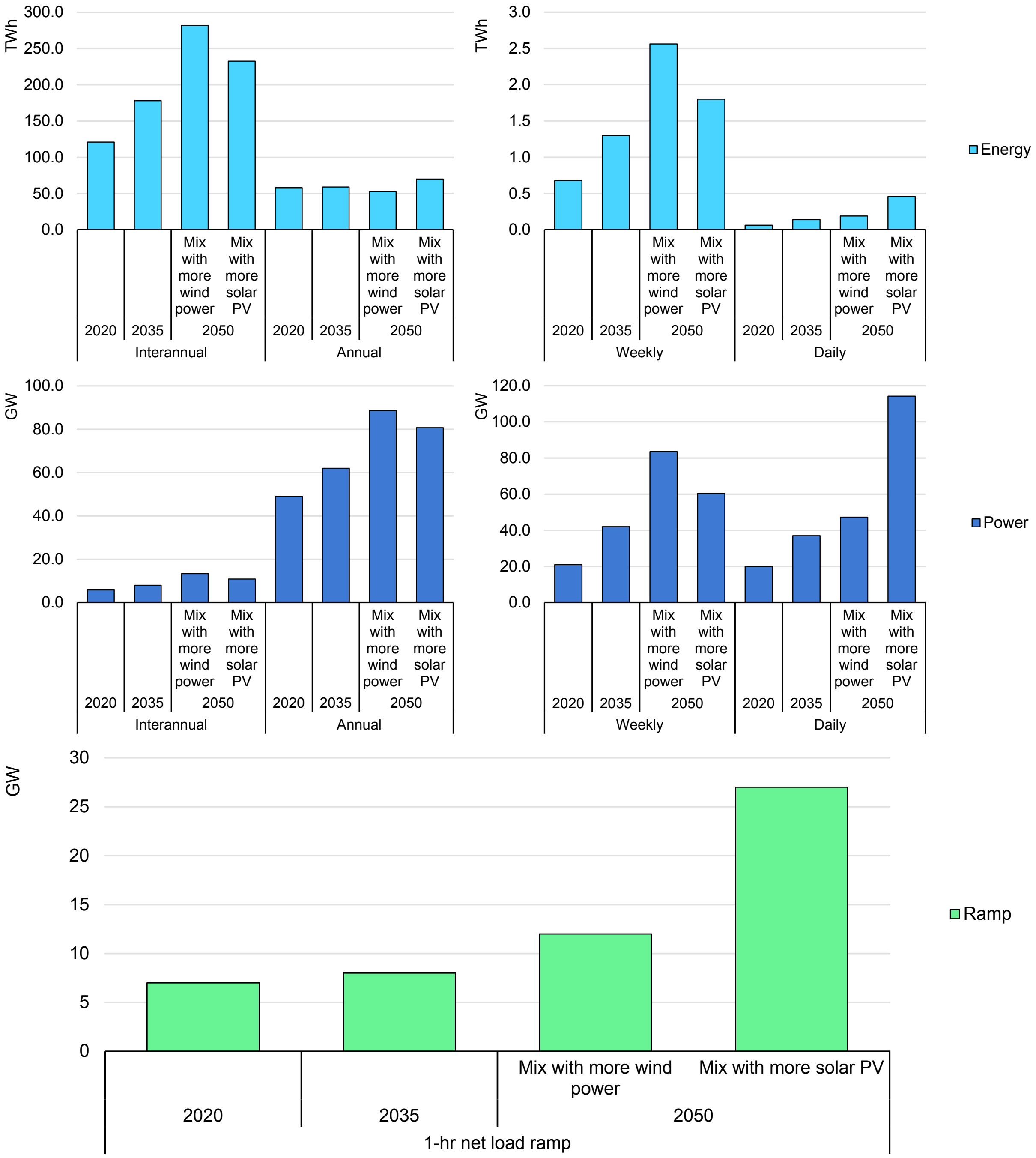
At the 2035 time horizon, the need for modulation significantly evolves for almost all the indicators. This is mainly explained by the development of variable renewable capacity in the continuation of the Multi-Annual Energy Plan (MTES, 2020). By 2035, 59 GW of wind capacity and 67 GW of solar PV capacity should be installed, up from 16 GW of wind and 9 GW of solar PV today, and electricity use will have evolved, for example with the development of electric vehicles. The evolution of these indicators ranges from a 50% increase of the inter-annual variability, reaching 180 TWh, to a more than 100% increase for weekly and daily power variations, reaching around 40 GW. This means that within a day or within a week, the difference between the maximum power level and the minimum power level can be twice as high as its current value. Such a power system is far more variable than today's, from one day to another or from one week to the other (seasonal energy variations of residual load are expected to remain roughly equal in 2035).

This increase of flexibility needs does not necessarily imply that a large number of new flexibility resources have to be developed. Indeed, some existing flexibility resources can partly cover this increase.

The power mix projected for 2035 in the scenario of the French Multi-Annual Energy Plan is close enough to the ones achieved in scenarios *Ampère* et *Volt* of RTE's 2017 *Bilan prévisionnel* (RTE, 2017), and the conclusions on the technical feasibility are consistent. They can read as follows: in France, increasing renewables' share of the generation mix to 50% (including hydroelectricity) while maintaining a significant nuclear capacity (~52 GW) and developing flexibilities such as demand-response to a reasonable level, is compatible with the public criterion on security of supply.

Beyond that threshold, under the assumptions considered for the evolution of load and renewable load factor, flexibility needs would keep increasing, except for seasonal energy variations. The biggest evolutions are expected for weekly and daily variations, which can be multiplied by a factor of four, six or seven. **By 2050, all the studied scenarios relying mostly on renewables are characterized by much greater variability, several orders of magnitude higher than today for most of the relevant indicators**. The precise scale of variability as well as the most affected time horizons depends on the renewable generation mix deployed.

Figure 5.2 Flexibility needs in energy and power of the French Multi-Annual Energy Plan to 2035 and National Low-Carbon Strategy to 2050 with different renewable mixes, compared with today's values over 200 meteorological conditions



Note: See Box 5.1 for the explanation of the indicators for energy and power variations and below for ramps. The mix with more wind power is the centralised RES scenario and the mix with more solar PV is the decentralised RES scenario.

Source: own analysis carried out by RTE.

Changes in generation profile pose challenges for security of supply and system balance

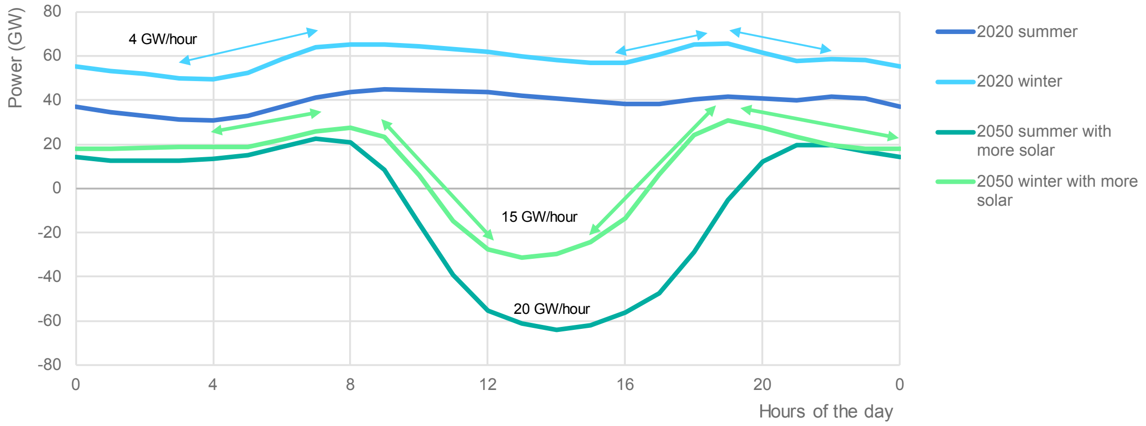
Wind and solar PV generation affect differently the variation in residual load because they experience variations themselves at specific time horizons.

Solar PV

Solar PV generation will mainly increase the daily variations of residual load and to a smaller extent seasonal variations. Indeed, solar PV production naturally increases each day from zero at dawn to a maximum in the beginning of the afternoon before decreasing until twilight. Daily output variations of this magnitude were previously unknown for most generators.

The daily variation of solar PV also affects ramps – the need for most rapid variation of flexibility. Today ramps occur mainly in the morning, of two to three hours, with 4 GW/hour variation and a less prominent evening ramp up, due to the daily variation of economic and residential activity. System ramp requirements could reach 12 GW/hour by 2035 with the power mix resulting from the Multi-Annual Energy Plan (with only 50 GW of solar PV capacity). They could rise even higher as the capacity of solar PV rises toward 2050. While todays' ramps could persist and remain of the same order of magnitude, new ones could appear and reach 20 GW/hour during four hours on average in morning and evening, strongly influenced by the development of PV. It can also be noted that solar eclipses can also imply significant system ramp requirements (see ENTSO-E, 2015 for the assessment of the effect of the 2015 solar eclipse). Dedicated assessments need to be carried out and complete the analysis of the 2050 scenarios for more precise estimations of flexibility needs and capacity available to cope with these specific events.

Figure 5.3 Average daily ramps in 2020 and 2050 with more or less wind and solar PV capacity



Source: own analysis carried out by RTE.

Solar PV production also obviously varies with season because days are longer and there is less cloud cover in summer. Development of solar PV will hence tend to increase the seasonal variation of residual load, since load is higher in winter than in summer contrary to PV generation.

At first glance, solar PV is not likely to contribute to security of supply in a country where peak-load occurs in the evening in winter. However, the *Bilan prévisionnel 2017* has shown that solar PV could still boost security of supply. In particular, midday solar production can be significant during cold spells, including in winter, and benefit the system more broadly, by allowing to store energy that can then be released during the evening peak.

Wind

Wind generation increases weekly and interannual variations of residual load but reduces its seasonal variations. In fact, wind generation has very different characteristics from those of solar PV generation. On average it is more abundant in winter than in summer. As a consequence, the average seasonal variation of wind generation (offshore or onshore) matches well the average seasonal variation of load, and therefore reduces residual load and the associated need for flexibility at this time horizon.[26]

[26] The load factor of wind generation depends on wind generation capacity. More wind generation capacity generally leads to install new wind farms in less windy areas, which reduces the national wind load factor. Consequently, the value presented here must be considered as an illustration dependent on the wind generation capacity installed and subject to some changes if this latter parameter is modified.

Wind generation is not restricted to the daytime, which means that load during evening peaks can be partly covered by wind power. Wind generation varies more from day to day and week to week than solar PV generation, however (Figure 5.7). In addition, periods of low wind production can last several days or even weeks. The French wind fleet has already experienced two weeks in a row with a load factor smaller than 10%. In order to assess security of supply in 2050 projections, RTE uses the database provided by Météo-France, the national meteorological service. This database contains periods with low wind, lasting up to one month, though only 1% of these last longer than 10 days.

Wind generation can also vary significantly from one year to the next. For instance, since 2012, the average recorded wind load factor has varied varying by 4 base points (between 25% and 29%). In the future, the maximum spread of interannual variations (between the minimum and maximum possible annual load factor) could increase to 16 base points. Interannual variations due to wind power would increase dramatically, up to more than 90 TWh between the lowest and highest possible wind power output for a given scenario. Thus will lead interannual variations to reach almost 250 TWh overall, twice today's level.

Table 5.2 sums up the qualitative impact of wind and solar PV generation on the flexibility need at the four time horizons.

Table 5.1 Qualitative effects of wind and solar PV generation on flexibility needs

Time horizon	Interannual		Seasonal		Weekly		Daily	
Modulation need	Energy	Power	Energy	Power	Energy	Power	Energy	Power
Wind generation	↑	↗	↘	↗	↑	↑	→	↗
Solar PV generation	↗	↗	↑	↑	↗	↗	↑	↑

Source: RTE (2020), adapted from RTE (2019), Groupe de travail « interfaces entre l'électricité et les autres vecteurs ». Document de cadrage, [Workgroup "Interfaces Between Electricity and Other Vectors", Framework Document]

As the share of variable renewables increases, whatever the time horizon, power system will need to adapt to more randomness.

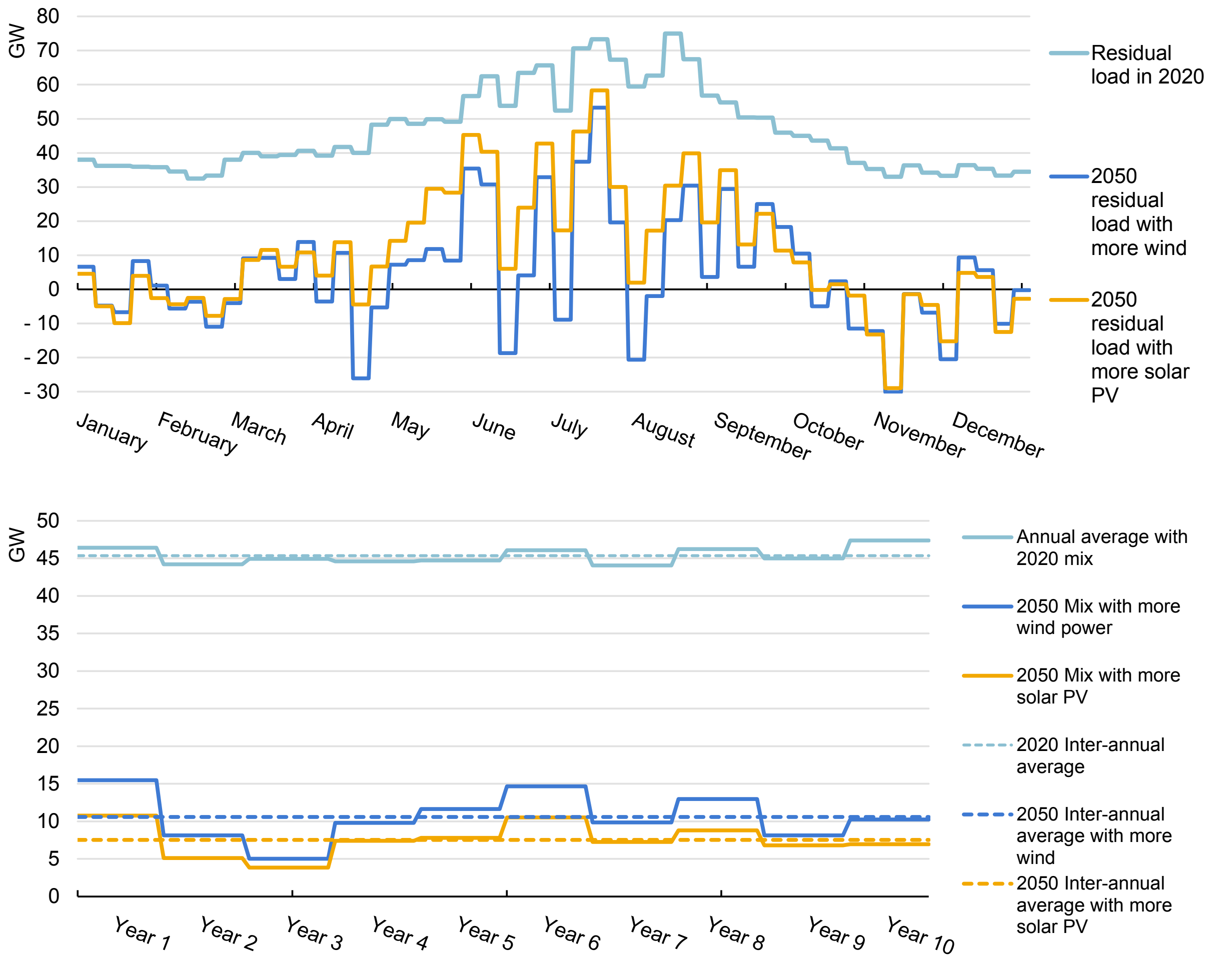
A key conclusion of the present report is that modulation needs would increase to a large extent at all time horizons. In the following, findings are presented from longer to shorter time horizons.

As wind capacity increases, the need for meeting interannual flexibility requirements (see Figure 5.7 down) appear to be an even bigger stake for security of supply than seasonal flexibility needs, which have taken centre stage in debates thus far.

Even at the seasonal time horizon, it is difficult to ascertain a specific value for the additional flexibility requirements. On average wind generation is well correlated with load, both being higher in winter. As a consequence, seasonal flexibility need in terms of energy tends to decrease with higher shares of wind power. However, wind also increases the variability of residual load which in turn increases the flexibility need in terms of power at this time horizon.

Balancing supply and demand is also expected to become less regular at the weekly time horizon. In particular, the variability of wind power will become much more significant than the variation in load between working and non-working days.

Figure 5.4 Illustrations of weekly (top) and interannual (down) variations of residual load – comparison between 2020 and expectation for 2050



Note: Weekly variations of residual load are illustrated using identical meteorological conditions for one year in 2020 and 2050. Interannual variations are illustrated using a set of ten years with identical meteorological conditions in 2020 and 2050. The 2050 scenario with more wind power is the centralised scenario and the 2050 scenario with more solar PV is the decentralised scenario (see chapter 2).

Source: own analysis carried out by RTE.

Last, management of day-night alternation will be modified by the development of solar PV production. Unlike today, residual load will be lower in the middle of the day than at night. High solar PV capacity combined with high wind capacity could lead to excess of overall variable renewable production compared with inflexible load during some periods. This would require reducing the output of dispatchable generation, such as nuclear, thermal and dispatchable hydropower, to their minimum stable output levels or even shutting them down and dispatching flexible load at specific times.

Managing the balance between supply and demand will depend on wind and solar generation profiles, as well as cyclical nature and uncertainty at different time horizons. Until today, nuclear, thermal and dispatchable hydropower generation have been used to manage variability. Time-of-use tariffs, load management and pumped hydropower storage have also contributed to a lesser extent. In future, changes in the variability in residual load, regardless of the time horizon, will raise questions about the appropriate flexibility mix and available capacities of each flexibility source The use of these flexibility sources between now and 2050 will also raise questions about their acceptability, cost, environmental impact and industrial readiness for mass deployment.

Massive integration of variable renewables requires rethinking power system management

By 2035, France's electricity generation mix is supposed to comprise 45% renewables (including hydropower), 50% nuclear, and less than 5% fossil fuels. Meeting both, this objective and the public criterion for security of supply is possible (RTE, 2017). This would rely mainly on existing flexibility sources, that is to say mainly nuclear generation (52 GW in 2035), hydro power and thermal generators, mainly in the rest of Europe and accessible through interconnectors. Demand-side response is also supposed to be developed to a reasonable level by then, as well as significantly improving energy efficiency in buildings and appliances.

In any case, the increase in flexibility needs by 2035 would still be accommodated mostly by existing generation assets, with no need for additional development of storage facilities.

This picture would change completely beyond 2035. With more decommissioning of dispatchable generation units such as nuclear units and a further increase in the share of renewables, running a power system with the same quality of service as today would imply a revolution in the use of flexibility sources to balance the power system.

In the different renewable generation mixes considered in this report, around 80% of yearly inflexible power load (i.e. excluding electric vehicles, power-to-gas and demand-side response) could be covered directly by variable renewable generation with sufficient instantaneous production levels. The remainder of inflexible power load (around 20%) must be covered by controllable production, demand-side response or storage (in addition to periods of surplus production to be managed – see below).[27] Direct renewable production will not be enough to cover (inflexible) power load for around half of the time. Periods with excess renewable production will have to be managed the other half of the time.

The flexibility needs identified above are so high that they imply significant modifications in the management of power system balance. This will have to be based on a global balance between different flexibility resources, which nonetheless do not operate on the same time horizons.

The different flexibility resources that have the technical potential to meet these new flexibility requirements can be classified into 4 different categories:

- dispatchable peaking units; these currently use fossil fuels – albeit in very small proportions – but could use other fuels such as hydrogen or biogas;
- large-scale, dedicated storage facilities, such as batteries to address daily fluctuations, new or revamped pumped-hydroelectric generation units to address weekly variations, or synthetic fuels production (power-to-hydrogen or power-to-gas) and storage to address inter-seasonal and inter-annual variability;
- demand-side flexibility: installations in buildings and factories would need to be able to respond automatically to market triggers or explicit requests from grid operators;
- increased power grid capacity, enabling large-scale geographical power system integration to mitigate local variations and facilitate access to a maximum of flexibility sources.

[27] Electric vehicles and power-to-gas will be supplied by renewable production too.

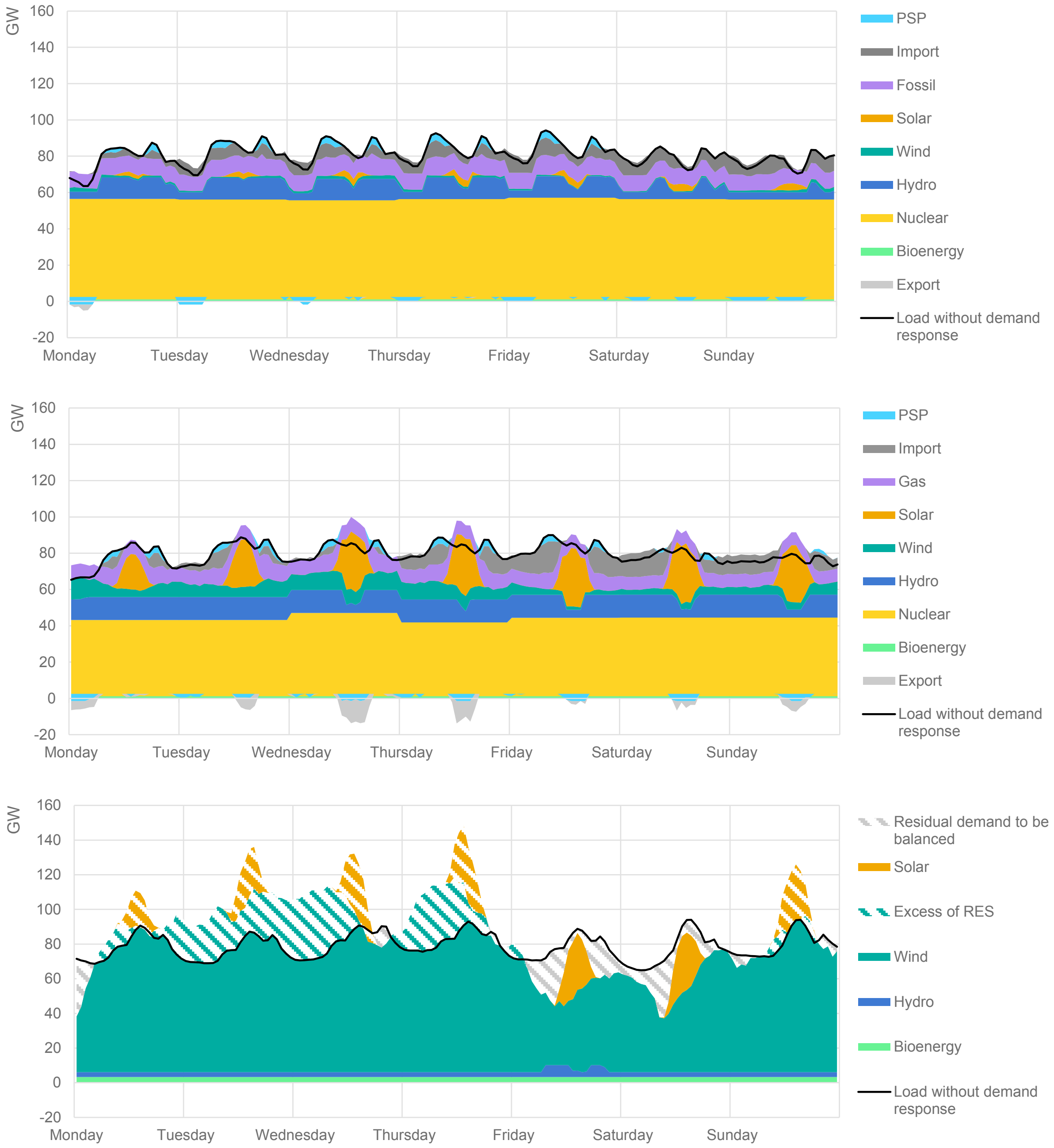
Table 5.2 Flexibility resources and their time horizon actions

Flexibility resources (Time horizon)		Inter-annual	Seasonal	Weekly	Daily
Generation	Renewable curtailment & further dispatchability	✓	✓	✔	✔
	Thermal power plants	✔	✔	✔	✔
Load flexibility	Demand-side response			✓	✔
	Smart charging of EVs			✓	✔
	Power-to-gas, power-to-heat	✔	✔	✓	✓
Storage	Batteries			✓	✔
	Hydropower dams		✔	✔	✔
	Pumped hydroelectric storage			✔	✔
Interconnections		✔	✔	✔	✔

Note: ✔ indicates an expected significant contribution of the resource to flexibility need at the considered time horizon while ✓ indicates an expected smaller contribution of the resource to flexibility needs. Unfilled cells suggests that contribution is expected to be insignificant at the considered time horizon.
Source: own analysis carried out by RTE.

The services provided by those flexibilities are of different nature. For example, dispatchable generation units, such as OCGTs or CCGTs fuelled by biofuels or synfuels, can run when renewable production is low, particularly at night and when wind is low. This production would rise (especially during winter) when production from renewables is not sufficient to cover load.

Figure 5.5 Generation and flexibility mix in the second week of January, today (first) and in 2035 (second) compared with flexibility need in 2050 (third)



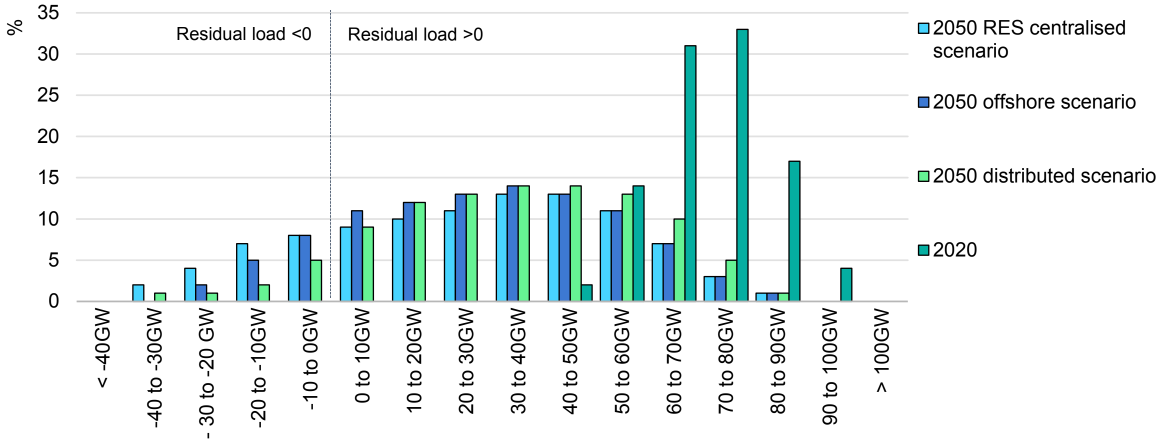
Note: Change of label from "Fossil" in 2019 to "Gas" in 2035 is due to decommissioning of coal.
Source: own analysis carried out by RTE.

If average wind production is well correlated with power load, its variability can sometimes keep residual load high.[28] Dispatchable capacities are therefore required, including dispatchable generators, demand-side response and storage capacities

[28] On average, there is more wind in winter when inflexible power load is higher, because of heating in particular.

injecting energy into the power grid. Significant negative values are also required, implying a need for evacuation or storage of the production surplus, or spillage on last resort.

Figure 5.6 Statistical distribution of hourly inflexible residual load in January for 200 meteorological conditions



Source: own analysis carried out by RTE.

This example shows that the dispatchable capacities in addition to renewables would make a major contribution to balancing supply and demand, but probably for short periods of time. The size of this contribution must be compared, however, with capacity of other flexibility resources (demand-side response, V2G, gas-to-power, pumped hydro, batteries) and dispatchable generation identified in chapter 2 and 3, which will be done in detail for the different long-term scenarios in future work. In particular, further studies will be needed to take into account interconnection capacities as well as available flexibility resources and dispatchable generation in neighbouring countries.

Another possibility is to **develop even more renewable capacity**. The amount of renewable production in excess of power load would be higher, but this would avoid having to resort to flexible thermal generation and downward demand-side response.

Conversely, other flexibility resources could help in managing periods with excess renewable wind and/or solar PV production. Flexible load, in particular smart charging or power-to-gas and power-to-heat, can also benefit from these periods. Renewable production can also be curtailed. In the case of an energy mix with a very significant share of solar PV, numerous flexibility sources (in particular stationary batteries or V2G) could be used to store electricity during the afternoon for release in the evening or the morning to balance the power system.

Since the supply-demand balance of the power system is set at the European scale, the required mix of flexibility resources at the national scale will have to take into account interaction at the interconnected scale. Interconnection of the French power system with the rest of Europe allows the need for national flexibility to be reduced by 20 to 30%, based on 2020 and the 2035 scenario. Flexibility accessed via interconnected systems can help balance the system during sunrise and sunset ramps. However, decarbonisation at the European scale needs to be considered.

Massive integration of variable renewables requires deeper sector coupling

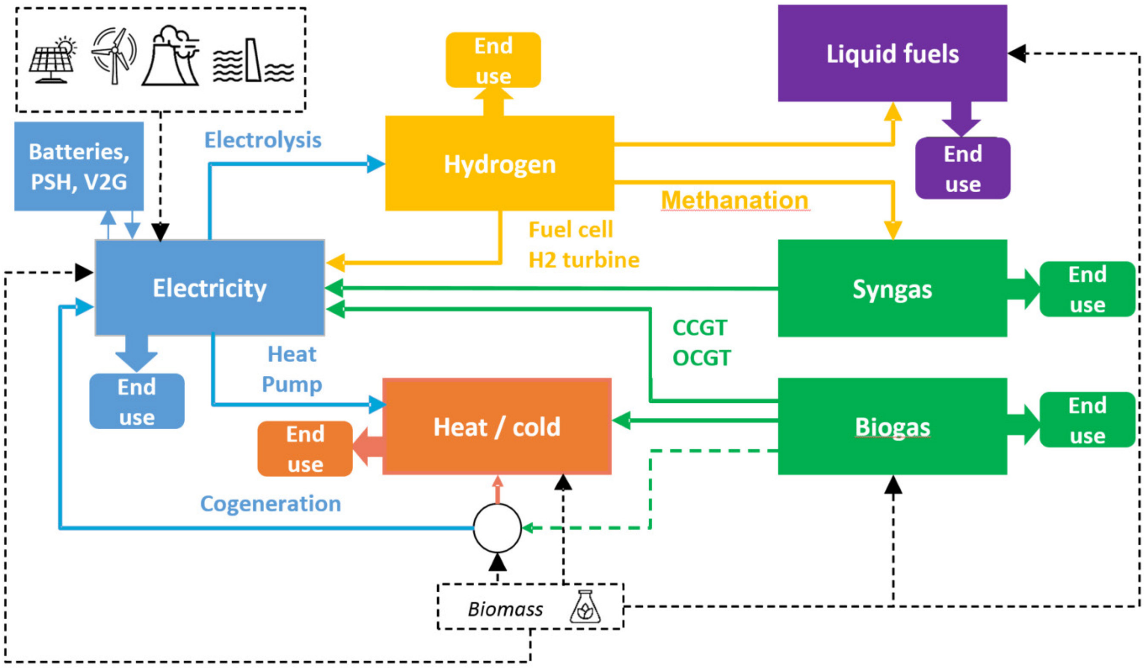
Several studies have already indicated that developing sector coupling was a prerequisite to integrate very high shares of renewables. This broad perspective encompasses a large variety of interactions: gas-to-power (which already exists with gas-fired generation units), power-to-gas (which is to developed through electrolysis and, possibly, methanation), power-to-heat (through heat pumps or storage of large volume of hot water underground), etc. Those forms of sector coupling refer to different purposes that are too often not well identified and distinguished in the public debate, especially when hydrogen is discussed (RTE, 2020).

On the one hand, sector coupling is a means to decarbonize energy carriers such as gas and liquid where direct electrification is not possible or too expensive. By 2050, it is assumed that this will have to be developed regardless of the choice on the electricity mix. In order to have low-carbon hydrogen, synthetic methane or synfuel, low-carbon electricity needs to be generated in sufficient quantities, and nuclear units, thermal units with CCUS and renewables are candidates to do so. In the kind of scenarios studied in this report, that means that renewable generation mix should be large enough to not only cover the the needs of the (inflexible) power system but also to provide inputs for gaseous or liquid low-carbon energy.

On the other hand, sector coupling can be a means to provide flexibility to the power system. In this perspective, low carbon electricity would be transformed into decarbonised energy carriers that might be easier to store (such as gas and heat), and then possibly retransformed into electricity when needed. Yet this conversion performs poorly in terms of round-trip efficiency as it is currently understood that around 70% of the energy is lost in the process. Thus, this kind of flexibility only appears necessary in scenarios with very high shares of wind and solar PV.

For France, simulations conducted for the present report show that "power-to-gas-to power" could develop when renewables are significantly higher than 50% of generation. For example, in a power system with very high penetration of renewables - more than 80% of direct production from wind, solar PV and hydro- , periods of low wind and solar production could be compensated by using CCGTs and OCGTs, running with synthetic methane or hydrogen, that would have been first produced using electricity and stored.

Figure 5.7 Couplings of the power system with other energy carriers



Source: RTE (2019), Groupe de travail « interfaces entre l'électricité et les autres vecteurs ». Document de cadrage, [Work Group "Interfaces between electricity and other vectors", Framework Document].

These flexibility resources could also be necessary to ensure short-term balancing of the power system and absorption of imbalances between supply and demand linked to contingencies or uncertainties in forecasts (see chapter 6).

Security of supply can be technically ensured in a power system with a high share of variable renewables and different mixes of flexibility resources

Traditional methods of optimization, which are used to develop an "optimal" electricity mix based on fixed and marginal costs per technology, can also take flexibility sources into account. Studying the trade-offs between investing in peak generators (such as OCGTs) and demand-response is not new and has already been integrated into adequacy studies in the 1980s. Yet determining an "optimal mix" of flexibility resources associated with a given power mix made of renewables brings new questions and leads to new methodological issues.

In 2017, RTE has proposed a methodology to assess the technical potential and the economics of a "flexibility mix". This new method aimed at shifting from individual and separate assessments of flexibility potential for marginal development, which is generally the kind of study carried out to assess smart grid demonstrators, to a comprehensive study of a combined large-scale roll-out of different flexibility resources, such as demand-response, storage by batteries, and renewable generation shedding (RTE, 2017). This report also pointed out the sensibility of such an "optimal mix" to the economics of different flexibility resource combinations but also to societal hypotheses, leading to multiple equilibriums that could differ largely based on social preferences.

At long term horizons such as 2050, it is even more difficult to compute an "optimal" flexibility mix. Considering the ongoing work on the long term scenarios for the next *Bilan prévisionnel*, several flexibility mixes appear technically fit to ensure security of supply. The following examples show that while there are solutions to meet public reliability criteria at very high shares of renewables, it is impossible to choose one solution that would be clearly preferable over its alternatives. Examples are provided in the following, leading to large ranges of uncertainty: this means that there are solutions to meet public reliability standards even with very high shares of renewables, but that there is no definitive preferred solution that would emerge.

Initial analyses show that several tens of gigawatts of flexibility resources would be needed to ensure security of supply in long-term scenarios with high shares of renewables. These needs could be covered by various combinations of flexibility resources. Despite the various combinations possible, some flexibility resources appear to be common to all studied scenarios with high shares of VRE.

Box 5.2 Example of a "flexibility mix"

- Flexible demand for new uses of electricity such as EV charging and hydrogen production, ensuring that they support the power system, for example, charging when renewable generation is high and not during supply-critical situations,
- Wider deployment of demand-side response (several GW), including the residential, tertiary and industrial sectors. Around 3 GW have been deployed today but the potential could be increased by a few additional gigawatts in the long term),
- Increase in pumped storage installed capacity today from around 5GW to at least 6 GW, according to the Multiannual Energy Plan,

- Utility-scale batteries and V2G capabilities from the electric vehicle fleet (several GW),
- A few dozen of GW thermal units, based on current capacity, plus any additional units, all of which may be able to run on synthetic gases, biomass, biofuels or fuel cells supplied with hydrogen. The current fleet of thermal plants where conversion may become an option include CCGTs, OCGTs, CHP and other small peaking units.
- At least twice the interconnection capacity available today when considering the network development plan from 2019 (See Chapter 7). This would allow access to flexible resources in neighbouring countries, potentially adding up to hundreds of GW. In this respect, some flexible units could be developed either in France either in neighbouring countries and provide equivalent service.

In all cases, some flexibilities appear to be common to all scenarios with a large development of renewables. V2G and utility-scale batteries will be needed in particular to cover for daily variations but it is likely that they will not be sufficient to ensure security of supply in all cases (for example during several days with low wind) as they generally have a storage capacity limited to a few hours of energy. Peaking units would therefore be required in addition, in substantially high proportions. If these units are running on synthetic fuels, specific production and storage infrastructures might also be needed.

Further analyses conducted by RTE in its work on 2050 scenarios will provide more precise assessment on flexibility mixes required in each scenario. Along with costs and social acceptance – to which analysis shows high sensitivity – factors that determine the optimal flexibility mix include:

- renewable mix and load
- flexibility capacity and mixes in European countries (demand-side response, sector coupling, amount of indigenous or imported green gas or CCUS), as well as interconnection capacities
- detailed modelling of some flexibility capacity, in particular demand-side response, electric vehicles, power-to-gas or storage
- impact of climate change on performance of the above power system components.

Additional flexibility capacity may also be needed to provide required reserves (see chapter 6).

Even if changes to the assumptions used modify individual values for flexibility capacity, the main point is that a mix of flexibility sources can make scenarios of close to 100% renewable generation technically feasible, under the right set of policy conditions.

From technical feasibility to broader policy questions

A power system with a very high share of wind and solar PV relies on a massive deployment of flexibilities; this raises policy questions about costs as well as industrial, social and environmental constraints.

The significant volume of additional flexibility sources prompts the need to assess system costs in future analyses

The costs of technologies are often compared using the levelised cost of electricity (LCOE), but this metric does not take into account all the associated costs, such as the need for other flexibility sources for security of supply or balancing, grid and the additional costs of managing stability. The need to complement variable renewables with peakers, storage, extensive demand-side management and grid to ensure system adequacy has important implications for costs, which will be evaluated at a later stage of the process of the 2021 *Bilan prévisionnel*.

The question is hence whether the full cost of a system comprising variable renewables, storage, demand-side response and peaking generation units (Chapter 6 on balancing and reserves too) plus network (see Chapter 7) plus grid-forming solutions (see Chapter 5) is higher or lower than alternative scenarios with nuclear power. This is why RTE does not consider LCOE a relevant tool to compare technologies: cost estimations by RTE in the last *Bilan prévisionnels* and the 2019 transmission network development plan (RTE, 2019) compare the full system costs of the power system for a specific scenario (Houvenagel et al., 2020). Similarly, the IEA has preferred to use value-adjusted levelised cost of electricity (valCOE) to consider associated values of a specific technology to the system for energy costs, flexibility and capacity. In short, both the IEA and RTE believe that the total system cost estimation used to evaluate shifts in the generation mix should take into account all associated costs, including the cost of storage and demand-side flexibility. The above first assessment of flexibility needs shows that those costs might be substantial in a country like France past 2035.

In addition to adapting the power system to variable renewables, deployment and operation of renewables need to be optimised themselves, by seeking the best combinations of PV and wind capacity considering their respective impact on residual load, by looking for siting that minimizes overall costs including grid and improves capacity factors, by managing participation of renewables in markets and by accurately forecasting infeed.

Significant steps are needed to take flexibility resources from demonstration to deployment

Pace of deployment

The required development of flexibility sources implies a significant effort to change the power system.

There is a significant gap between the situation today and the mix of flexibility sources required in a power system that would rely mostly on wind and solar PV. Today, most of the flexibility of the power system is provided by nuclear units and hydropower. Taken as a whole, the nuclear fleet can adjust its production by more than 10 GW in a few hours. Hydropower alone can change output by up to 10GW in just a few hours. Thermal generator capacity is around 14 GW, with 6 GW of CCGTs on 11 sites, 2 GW of OCGTs on six sites, and 6 GW of smaller thermal generators (including cogeneration) dispersed on around 1 000 sites. There are currently around 100 MW of batteries connected to the French grid and between 300 and 400 MW are planned for the end of 2021 or beginning of 2022. No fuel cells are connected to the power network, electrolysers or V2G are running only in demonstration and demand-response represents less than 3 GW.

To develop a “flexibility mix” substantial enough to cope with very high shares of renewables, the different kind of flexibilities would need to develop rapidly, especially after 2035. Over this period, average annual development rates of hundreds of megawatts per year would be necessary for batteries and / or thermal generators and fuel cells (depending on assumptions about decommissioning of existing peaking generation units). In a power system heading towards very high share of renewables, technical feasibility depends on adequate development of those flexibility sources in time. Decision deadlines will need to be made explicit to reach the required industrial maturity of these technologies and hence implement such a power system confidently.

In comparison, between 2016 and 2019 around 100 MW of utility-scale batteries and 160 MW of home storage power batteries were added on average in Germany (Reuters, 2018 and 2020). In France, between 2005 and 2016 one to two CCGTs were built per year on average, or 560 MW per year. Yearly installed capacity was even higher between 2009 and 2013, reaching more than 1 700 MW of CCGTs in 2010.

Similarly, between 2007 and 2010 six new OCGTs were added to the French power system for 1 GW, or around 300 MW per year.

Industrial maturity

The expected mix of flexibility required in the prospect of a power system with a very high percentage of variable renewables is based mainly on three technological building blocks: (1) batteries; (2) digital technology for smart load management; (3) power-to-gas-to-power conversion to store large volumes of energy.

The industrial maturity of these different building-blocks is crucial. Beyond questions of costs, an industrial effort is needed to deploy the required capacities. Manufacturers must structure in order to deliver the required amount of those technologies not only at the scale of France but more generally at the scale of Europe and even worldwide to provide carbon-free solutions. There are also questions about environmental impact (including land use and critical material) and social acceptance, not only of demand-response but also of other flexibility sources and their infrastructures – generators, batteries, electrolysers or interconnectors.

Building block 1. Batteries are already technically mature, even if their performance is expected to keep improving. The main challenges associated with the prospect of using them widely is about their environmental footprint. There are indeed several environmental issues associated with the widespread use of batteries, including their carbon footprint from a full life-cycle perspective, the use of critical materials, the need for recycling and land use. These need to be concretely answered at the national scale and put into perspective in the framework of worldwide development.

Building block 2. Digital technology for smart load management encompasses different degrees of complexity with diverse technical and industrial levels of maturity. It ranges from more or less dynamic time-of-use retail tariffs (with adequate smart meters) to remote management of load such as smart heaters or even vehicle-to-grid.

While time-of-use tariffs rely on well-known technologies, the roll-out of smart meters offer new opportunities for more dynamic tariffs, which retailers and end-users could seize if they are interested. Several vehicle-to-grid projects have been piloted around the world, showing their technical feasibility. Wide deployment of smart-demand management in buildings and relying on electric vehicles for battery storage shift the challenge to the field of social acceptance. Car owners will have to accept that their vehicles can be remotely and smartly charged or have sufficient confidence that this remote control has no impact on transport service they expect, as is the case for hot domestic water today. People will need to get confidence that beyond-the-meter devices used for smart demand management respect their privacy and do not lead to undesirable transfers of data. The difficulty to roll out smart meters – much less intrusive than smart load management systems – in several European countries including France show that this question is not a small one and must be considered.

Building block 3. There is currently no full demonstrator of **power-to-gas-to-power** for peakers in a carbon-free power system. This technology can be implemented in two ways, which raise different technical questions. It can rely on the direct storage of hydrogen only or on the storage of synthetic methane. If hydrogen is preferred as the vector for power-to-gas-to-power, two solutions are possible. Either hydrogen is used in fuel cell – a set of known but confidential technologies that would then need to be generalised – or hydrogen turbines would need to be designed. Some gas turbines are already able to run today blending gas and hydrogen (see for instance GE 2019; Siemens 2019; Mitsubishi Power 2020). Gas turbine manufacturers are working to increase this share to 100% hydrogen. A 24 MW turbine using 60% hydrogen developed by Siemens is scheduled for completion in 2021 in São Paulo, Brazil, for Braskem, the largest petrochemical company in Latin America. Otherwise, methane can remain a vector for producing electricity with peakers, such as those running today. A methanation step is then needed to convert hydrogen to methane after electrolysis. Methanation is still in the demonstration phase. It must also be noted that methanation requires a source of CO_2, which needs to be either locally produced by methanation (as a co-product of biogas from bio waste) or transported through pipelines from a remote source (captured and stored by CCUS from industries, for instance).

Relying on synthetic hydrogen or methane raises social acceptance questions, too. Hydrogen raises concerns regarding security and CO_2 transportation raises environmental concerns. Fuel cells also raise environmental questions as they rely on critical material such as platinum.

In the 2021 *Bilan prévisionnel*, the long-term scenarios and variants will analyse questions about environmental impact, social acceptance and industrial deployment, and highlight when decision deadlines should be set to enable a confident commitment to a 100% renewable French power system.

In a power system relying mostly on renewables, the definition of security of supply itself could evolve

In France's power system – as in other unbundled European markets – the balancing of the system is mainly the responsibility of market participants. They are responsible of anticipating future loads, availability of renewables, fuel supply and other factors within France and in interconnected neighbouring systems. Balance responsible parties need to commit to a schedule and keep their portfolio in balance.

As a TSO, RTE is responsible for avoiding any residual market imbalance and therefore also anticipates stressed conditions.

In all power systems, the TSOs, in relations to public authorities, have nonetheless important responsibilities to forecast load and supply from the short to the long term, monitor the situation in real time, and act as a last resort. Adequacy reports have developed everywhere and are a key component of liberalised energy markets.

Power system adequacy is measured against one or several criteria. In France, as in many countries, the number of expected hours of scarcity evaluated in probabilistic adequacy studies, commonly referred to as the *Lost of Load Expectation* (LOLE), is the main indicator monitored. Other indicators exist, such as the Loss of Load Probability or the system resilience to given stress tests.

This means both, that security of supply is considered as a public good and that the question of whether or not it is ensured prompts response such as yes or no. The reality is somehow more nuanced, and the very notion of security of supply could evolve over time.

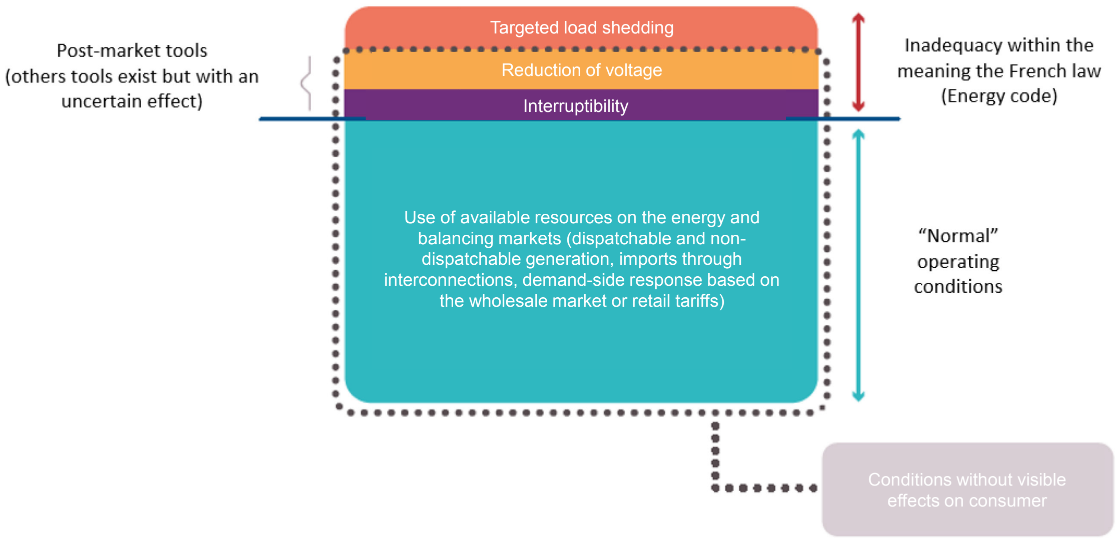
Current practices in security of supply

In France, generation and demand-side response capacities are sized in accordance with the reliability standards set in French law (the Energy Code).

Inadequacy between power supply and demand could mainly occur in extreme cold spells or simultaneous unavailability affecting the nuclear fleet. Situations of "weak wind" availability in larger areas can also lead to inadequacy when combined with a cold spell or low nuclear availability. In such situations, RTE activates post-market resources to avoid or limit the use of load shedding. The activation of these resources does not necessarily indicate a disruption of supply but rather compliance with reliability standards.

To ensure the adequacy of the power system (balance between supply and demand, frequency and voltage), RTE today uses "normal" operating tools (generation and demand-side response via the energy and balancing markets) as well as "post-market" tools, such as calls for action from citizens, requests from other European transmission operators within the framework of emergency contracts, reduction of balancing reserves, activation of interruptible capacities in large-scale industry, and reduction of voltage on the distribution networks.

Figure 5.8 Current available instruments to ensure supply demand adequacy and therefore avoid load shedding



Source: RTE (2019), Adequacy report.

Box 5.3 Security of supply in France: the three-hour criterion

In France, security of supply is assessed against a public criterion, provided for by law (Article D. 141-12-6 of the Energy Code). This criterion is expressed in the form of an inadequacy duration during which the balance between supply and demand cannot be satisfied, which must remain less than three hours per year, on average, considering different meteorological events or operating conditions that France could experience.

The Multi-Annual Energy Plan published in April 2020, refined the criterion. Some inadequacy situations may be short and limited, and covered by tools that are of no consequence for most citizens, such as interruption of industrial consumers with an interruptibility contract, or reduction of voltage on the distribution networks. Other situations may be particularly critical because of their duration or the number of consumers affected: these are the ones that should receive the most attention. The refined criterion:

- retains the limit of three hours per year of inadequacy while specifying the notion of inadequacy (a situation requiring the activation of post-market tools to ensure system balance);
- adds a second criterion, a loss of load limit of less than two hours per year.

Analysis of the impact of post-market tools makes it possible to show that these two criteria are globally equivalent in the current configuration of the French power system, in particular given the post-market tools now used.

Compliance with the criterion therefore does not mean no risk of load shedding.

The regulatory framework applied to security of supply is thus explicitly based on a collective trade-off between the benefits resulting from a high level of security of supply and the costs necessary to achieve it. This criterion can be interpreted as the result of the trade-off between a theoretical value of loss of consumers' load and the investment in a new peak load generator or demand-side response capacity that avoids this failure.

In France, RTE has the legal mission to carry out security of supply assessments for the coming years, which it publishes in the annual *Bilan prévisionnel*.

To carry out its analysis, RTE collects information from all the market players to build forecasts on the evolution of power load and production in France and Europe.

A "probabilistic" analysis is then carried out: this makes it possible to assess the risks of inadequacy by simulating the operation of the balance between supply and demand at hourly intervals over a whole year. These simulations then incorporate a very large number of meteorological configurations (cloud cover, wind, water conditions, temperature) and a wide range of possible operating conditions of the generation fleet (such as unavailability of generators). The results make it possible to assess the risk of inadequacy, including frequency and average duration, and to compare this level of risk with the public criterion of security of supply.

The diagnosis of security of supply also leads to the presentation of additional indicators to characterise the inadequacy risk and the statistical dispersion of the results, including probability of calls to post-market resources according to the configurations, "missing" capacity for each simulated inadequacy period, and continuous inadequacy duration. The average number of hours of inadequacy as targeted by the criterion for security of supply does not contain all the information necessary to perfectly reflect the representative nature of the configuration under study, such as the number of citizens or industrial sites disconnected.

A detailed analysis of power supply security in France – characterisation of inadequacy situations, duration, depth, distribution over the year and the day – makes it possible to rank the risks beyond the three-hour criterion.

Probabilistic analysis can be complemented by stress-tests on specific extreme events - low wind production during several days, cold spell, heat wave, unavailability of nuclear reactors during the winter, etc. - in order to have information on the maximum disruption of supply associated with such events. France's 2019 Adequacy Report includes this kind of analyses.

In the long term, the diversification of the power mix, the effects of climate change or changes in power uses could lead to new factors that affect security of supply. The analyses carried out up to 2050 in this report and the 2021 Adequacy Report therefore aim to shed light on the public debate on the characterisation of the new challenges related to this issue.

According to the conditions set earlier on, if new structures can be established that allow the power system to run with a very high share of wind and solar PV in a secure manner – taking into account load, variable renewable generation, dispatchable generation, flexibility resources and interconnection capacity – the nature of the adequacy risks will change and keep changing. The distribution of the different characteristics of inadequacy periods – yearly length, continuous duration, frequency, depth in energy and maximal shed load – are then likely to change.

The *Bilan prévisionnel 2017* highlighted that in all the scenarios studied (Ampere, Volt, Hertz, Watt), the inadequacy periods were more frequent but also shorter than today. As a consequence, the probability of having to call on post-market resources once a year was expected to increase from 25% today to 40% in all the scenarios by 2035. The report also showed that increasing solar PV production must gradually reduce or even eliminate inadequacy periods in the middle of the day. However, inadequacy periods are likely to arise during the night.

As the adequacy risk profile changes, so do the factors that affect inadequacy. Until recently, load has been the main factor influencing inadequacy. In future, several different factors are expected to be significant, such as low wind periods or zero solar PV production at night.

To determine adequacy risk in a power system with a high share of renewable energy sources in 2050, assumptions and variants need to be established for a new set of influencing factors:

- load trajectories,
- development trajectories of flexibility resources (notably V2G and P2G), which, with the experience gained from recent studies (e.g. the electromobility study – RTE 2019) are the subject of in-depth modelling,
- integration of new meteorological databases that consider climate change,
- the range of renewable energies integrated into the power system,
- the mix of the rest of European power system.

In 2050, with high shares of variable renewable production, the critical conditions for security of supply are likely to evolve. Cold spells would probably remain risky, although their frequency and magnitude could decrease with climate change.

Windless periods could also pose a risk for security of supply. The precise conditions for these critical situations remain to be characterised, not only in winter but also in summer if wind and solar PV production are too low (both in installed capacity and sunshine conditions), in France or in Europe. The mix of wind and solar PV might then affect the frequency and length of inadequacy periods. Extended heat waves and/or droughts (whose frequency increases in the climate scenarios studied) might have a strong impact on power load and production (both on dispatchable generators and renewable resources, especially hydropower). They could lead to the emergence of inadequacy periods in summer.

Looking ahead to 2050, the set of tools available to RTE for operating the system is more uncertain from today's point of view: some are likely to be adjusted (or even disappear) and others could appear. For instance, sector coupling could help switch some uses to other energy sources in case of stress on the power system, such as hybrid heat pumps. Alternatively, load shedding could be targeted to specific power uses depending on specific prioritisation schemes. The SOLENN project (SOLENN, 2020) has for instance shown that loss of load could be less costly if specific uses of electricity could be targeted.

Finally, in the context of an energy mix composed of generation technologies that are mostly different from today's, it will also be necessary to study whether a criterion based on expected loss of load duration implies that the indicators above will have the same properties in 2050 as today and whether it would still be socially acceptable. For instance, if the power system infrastructure is compliant with the 3-hour criterion but implies that a large number of consumers are cut off each year during windless periods, it might raise some concerns on whether this criterion is really acceptable. This issue is difficult to handle as it will depend on the evolution of consumer needs in the long term. Some consumers might require a high level of warranty against power interruptions while others might consent to reduce their electricity consumption during tense situations in order to help operate the system and integrate renewables to the grid.

In addition to the regulatory indicators, an approach aimed at assessing the resilience of the system to particularly constraining situations, through several stress tests, will therefore be carried out by RTE in its next long-term study.

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Chapter 6. Short-term balancing and frequency regulation: reserve requirements and provision

Key messages

- Balance between electricity supply and demand should be ensured at all times. Operational reserves are necessary to maintain this balance in the event of forecast errors or unforeseen events such as forced outages.
- Real-time monitoring of some renewable energy production assets, in particular small-scale solar PV, is not common in France today. This currently poses no difficulty for the operation of the power system, but could prove a challenge later: as installed capacity of solar PV increases, uncertainties on real-time production may significantly increase reserve requirements in order to maintain the quality of balancing and frequency regulation.
- Several complementary options are being discussed to limit the growth of reserve requirements:
  - improving the accuracy of wind and solar PV forecasting models;
  - directly or indirectly improving monitoring of solar PV production and therefore power load (with dedicated sensors or other real time measures, real time high resolution satellite pictures to estimate solar irradiance, etc.).
  - operational process automation, considering the amplitude of unexpected production gradients (several hundred MW/minutes).
- It is also necessary to implement market rules that give market players adequate incentives to balance their perimeters quickly enough, in energy and also in capacity.
- The use of new sources of power system flexibility - storage, peaking units, demand-side flexibility and especially the charging of electric vehicles – is an opportunity for improved real-time monitoring, both in terms of additional capacity and speed of response.
- Demonstrating adequate performance and securing sufficient volumes are two remaining challenges for the deployment of new distributed energy resources in operational reserves. Flexibility from electric vehicles is an example of a possible industrial priority in the coming years.

- Conditions and contracts for network access should encompass the provision of reserves remotely activated by the TSO, regardless of whether new flexibility resources are connected at the transmission or distribution grid.
- Changes in the operational and market management of reserves and grid constraints may be needed to ensure that reserve activation is not limited by grid constraints.

Efforts are needed on the monitoring and forecasting of wind and especially solar PV to enable a better predictability of these generations and improvements on sizing and operations of reserves. New solutions are hence being developed, with a lot of initiatives at the R&D stage. The current methodology for sizing and managing operational reserves will also need to be updated in order to recognise the increase in uncertainty due to VRE generation.

At the same time, new sources of flexibility, such as storage, peaking units and demand flexibility especially on the charging of electric vehicles, may emerge and would be able to provide power reserves that can be activated with short notice (a few minutes) and could help balance the system. Despite the development of these new flexibility resources, this situation would be difficult to handle at operational level and will require a shift of responsibility, making renewables balancing units as today’s conventional units.

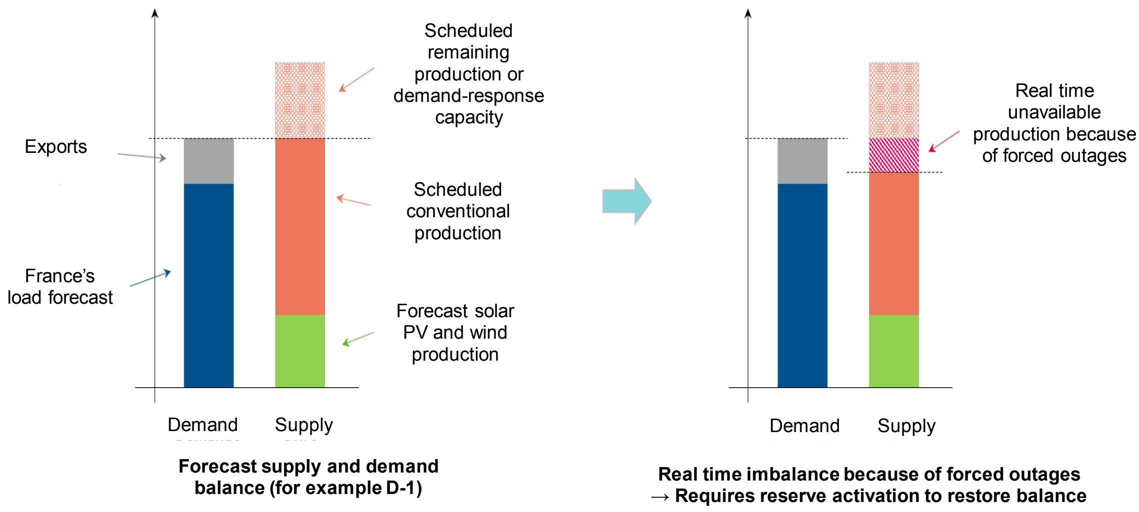
Operational reserves and real-time balancing are important features of the operation of a power system

The adequacy challenge, developing the right amount of generation facilities, storage, and demand-side response to meet the reliability standards expected from the society, is a key condition to address when assessing the technical feasibility of a power system with high shares of renewables. Yet it is not sufficient: real-time operation of the power system also poses specific challenges that need to be addressed.

Each transmission system operator has the legal obligation to balance supply and demand within their perimeter – mainland France for RTE – while taking into account electricity imports and exports.

The balance between supply and demand has to be anticipated, since generation and load cannot adapt instantly to each other. This relies heavily on forecasts of power load, wind, solar PV and parts of hydropower, and on production schedules elaborated by generators for both conventional and the largest hydro power plants, which are made and updated in accordance with forecasts.

Figure 6.1. Challenges of short-term balancing of supply and demand against contingencies



Source: adapted from RTE (2020).

Because it is not technically possible to perfectly equalize electricity production and load in real time, there generally remains a residual imbalance, which directly affects the frequency of the power system as a whole (see chapter 4 on stability). To ensure the secure operation of the power system and the proper functioning of its components, it is essential to keep this frequency close to its nominal value of 50 Hz.

To ensure the balance between electricity production and load in real time and deal with contingencies affecting the forecast balance, RTE (like any transmission system operator) must ensure the availability of flexible generators, demand-side response capacities or storage facilities that can dynamically and appropriately respond to contingencies, and therefore constitute reserves. The sizing of these reserves is mainly based on statistical evaluations of forecast errors which affect the balance between supply and demand, and on the main unexpected contingency that may occur, such as forced outages of the largest power plants.

Operational reserves are a crucial feature of power system design. This is the reason why this report sheds light on the dimensioning of operational reserves and balancing responsibilities under the framework of a power system with high shares of renewables. This aspect is well understood in present market designs but has received limited attention for longer term high VRE scenarios so far.

The issue appears of minimum importance in France today, partly because operational reserves are extremely low. This is mainly due to the fact that the large majority of generation is dispatchable, that market parties have clear balancing incentives and that present French balancing rules give RTE a lot of control over generation. So far, the issue has not attracted a lot of attention in long-term scenarios at policy level, nor at academic level in Europe, and the impact of wind and solar PV on operational reserves is not even considered in many publications on large-scale deployment of renewables.

The remainder of this chapter details how the operational reserves are sized today, how the development of VRE generation affect the need for reserves and which solutions are required to deal with this issue.

The supply-demand balance forecast encompasses many short term uncertainties that remain substantial today for some renewables

Operational reserves are sized to cover uncertainties and contingencies on generation, load and grid capacity. The amount of reserves required therefore depends on the quality of supply and demand forecasts, which varies with the nature of generation and the ability to monitor it effectively.

Wind and solar PV production forecasts are based on weather forecasts and available real time data

Wind and solar PV production forecasts, for a given moment and at a given time horizon, rely on specific tools and data that make it possible to update the forecast closer to real-time. In France, as in other countries, the TSO makes decisions based on both, the production schedules, which are used for firm production, and forecasts, which are the reference for variable generation and load.

- **A production forecast based on weather forecasts:** Wind and solar PV output is projected by using both weather forecasts (wind speeds, temperature and cloud cover) and wind and solar PV power plants' characteristics (geographical coordinates, installed capacity). The weather forecasts are updated using observations reported in real time by weather stations.

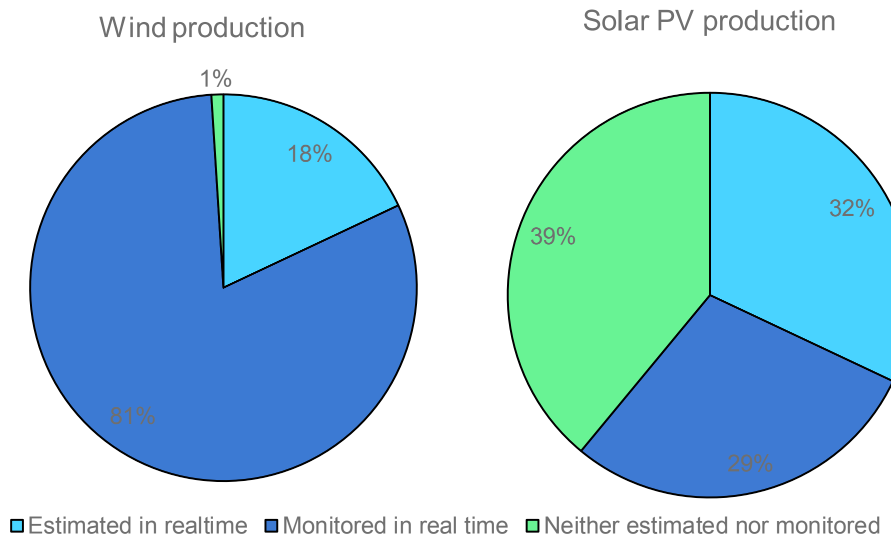
  By definition, forecasts are not always accurate and measured data can differ from what was projected by forecasts. In normal life operation, margins are integrated to cope with those deviations, and calculated based on stochastic approaches.

- **An estimation of wind and solar PV productions in real time:** Contrary to the situation for traditional generation units, the generation from small units (such as individual PV panels, the first generation of wind farms, or even some small hydro units) is not monitored in real time but collected afterwards. While, in theory it is possible to estimate the real-time output of all renewable generation units, some smaller or older units may not be equipped with the same metering and communications equipment due to cost considerations or technical requirements at the time of their construction. For wind and PV, three approaches can be taken:
  - **If it is possible to monitor the output of the plant in real time,** the value of its production in real time is measured by a specific sensor located on the plant site (or more generally at the substation to which the plant is connected).
  - **If, despite the absence of monitoring, it is possible to estimate the plant's output.** In cases where a significant correlation between the plant output and other monitored plants, located closely, has been identified, it is possible to estimate the real-time output of generators without measurement equipment. These estimations require accurate data on past production from the concerned plants.
  - **If it is neither possible to monitor or estimate a generator's output**, the real time production of the plant is considered to be the most recent forecast. This is the case for most small-scale distributed solar PV production.

In the case of wind generation, the predominance of directly measurable capacity, 81% today, means that even if there are inaccuracies in the real-time estimation of wind generation, short-term forecasts are largely based on a large amount of real-time monitoring and therefore very accurate (Figure 6.2).

By contrast, for solar PV, because of the reasons mentioned above, it is not possible today to measure or estimate real-time output for more than a third of installed capacity and only less than a third is directly monitored (Figure 6.2). Short-term forecasts of solar PV output are therefore much less accurate. However, the more frequent updates of the weather forecasts used for PV production (cloud cover data updated every hour) can be regularly integrated in production forecast models and make it possible to partially overcome this lack of real time monitoring.

Figure 6.2. Real time monitoring and forecast certainty distributions of wind and solar PV production in installed capacity



Source: adapted from RTE (2020).

The estimation of conventional power plant output is based on scheduling and leads to almost no uncertainty close to real-time

In contrast with variable renewables, the real-time estimation of conventional power plants is considered to be almost perfect since most of these plants are equipped with real-time accurate dedicated sensors.

Conventional power plants (thermal and hydropower) are requested to submit schedules to the TSO.[29] In France, scheduling is in theory mandatory for each generation unit above 1 MW[30], and not portfolio-based.

Forced outages

Power plants have a legal obligation to follow their schedules. However, unexpected technical constraints can prevent a power plant from respecting its schedule. This can result, for example, in the sudden disconnection of the unit (tripping) or in a significant power drop. These contigencies can occur at any time, but the risk is increased during the start-up (or coupling) of the generation units.

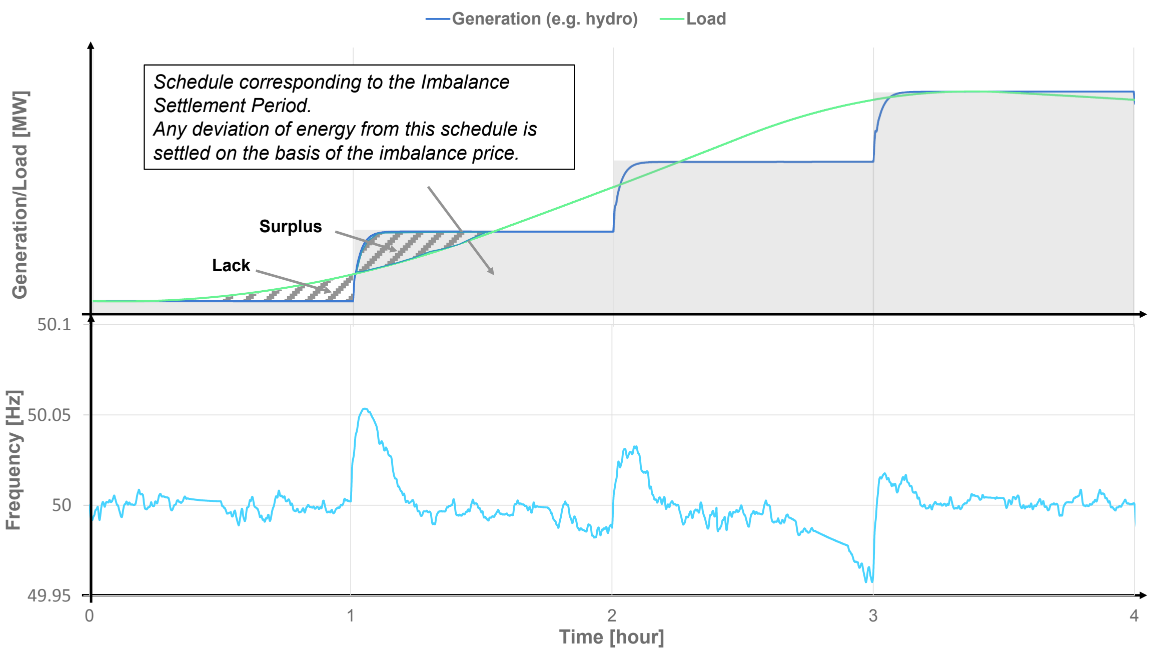
[29] There is a part of non-dispatchable hydro power production which sends programs that are concretely forecasts.
[30] Directly to the TSO for generators connected to the transmission grid or through the DSOs that send them to the TSO, aggregating them at the connection points with the transmission grid.

Setpoint changes at round hours

Because of the discrepancy between the given step duration of market products and scheduling (Imbalance Settlement Period or ISP – 30 minutes for generation in France, 15 minutes in other countries and one hour on interconnections) compared to the smoother variations of demand, significant short imbalances can happen at round hours or half-hours (and even every fifteen minutes in countries where scheduling is done with 15-minute steps).

These imbalances have a negligible effect on the forecast of the supply-demand balance, since it is performed every half hour, but they can instantaneously have significant effects on frequency. These are particularly important at round hours because of the hourly interval for interconnection schedules (Figure 6.3). This problem is expected to decrease with the reduction of the Imbalance Settlement Period to 15-minute steps according to grid codes

Figure 6.3. Impact of the set-point change on the supply-demand balance and frequency



Source: own analysis carried out by RTE.

Combining weather forecasts and real-time monitoring to forecast load

Forecasting short-term load (from day-ahead to real time) is based on the same principles as wind and solar PV production forecasts:

- **A load forecast model is based on weather forecasts.** A machine learning statistical model forecasts power load by using weather forecasts at different locations in mainland France. This forecast is adjusted by RTE's operators at the National Control Centre through comparison with similar past situations (position of the day in the week, period of the year, year, specific weather phenomena). Like the forecasts of wind and solar PV production, these forecasts are updated within the day according to the evolution of the weather forecasts.
- **An estimation of the electricity load in real time.** Like wind and solar PV production forecasts, load forecasts are updated with the most recent real-time estimation of power load, to better predict power load at short time horizons. Rather than trying to directly measure the power load of all consumers, the real-time power load is estimated as the sum of all power generation from all generation sources (wind, solar PV and conventional), corrected with imports and exports (which are accurately measured at the interconnections).

Grid does not encompass major uncertainty

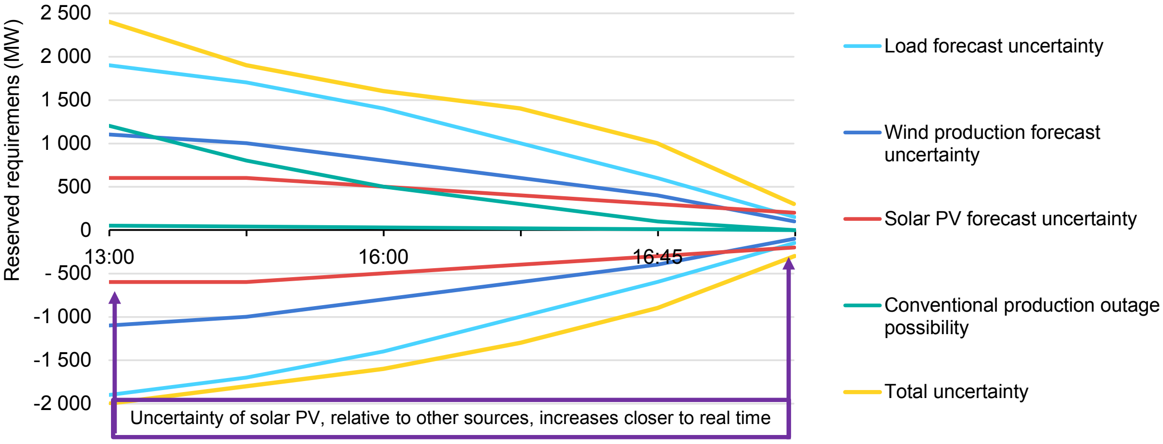
Beyond power production and load forecasts, other factors are taken into consideration by RTE to ensure the balance between supply and demand in France:

- **Grid availability.** Some facilities in the electricity grid operated by RTE may experience outages. These can be planned outages (for example, for maintenance or reinforcement work) or contingencies (short circuits, lightning, storms or other external events) and can affect some generation or load sites. The sizing of the grid infrastructure as designed by RTE makes it possible to compensate for most outages but some exceptional events can lead to specific operational actions (such as changing grid topology) or even disconnections of load or generation.
- **Schedules of imports and exports with neighbouring countries.** Uncertainty from imports and exports does not impact reserves sizing except for HVDC contingencies. Otherwise, imports and exports are considered to be perfectly known.

Uncertainties only decrease in the last hours before real time because of the effect of real-time estimations

Uncertainties only decrease in the last hours before real time because of the effect of real-time estimations. Therefore some uncertainties related to load, wind power and particularly to solar PV production still remain significant in real time because real time monitoring is partly lacking (see Figure 6.4). Relative to other components the relevance of solar PV uncertainty becomes more pronounced in real-time as opposed of hours ahead of real-time. This pattern could impact the sizing of reserves as the amount of solar PV grows.

Figure 6.4. Decrease in the 98% confidence interval affecting the supply-demand balance when getting close to the real-time delivery



Source: own analysis carried out by RTE.

Ensuring the supply-demand balance requires anticipating reserve needs

Because balancing supply and demand relies on imperfect forecasts and measurements, real-time power generation and load will vary from their scheduled or expected values. This deviation is greater the longer the time horizon of the underlying forecasts.

Since there is no guarantee that there will be enough system resources, such as dispatchable generation and demand-side response, market and operational measures in real-time are needed to compensate forecast errors, at all times and all time horizons.

To ensure the balance between supply and demand in real time, RTE must therefore ensure the availability of capacity that can respond quickly enough, sizing reserve requirements with different dynamics and contracting reserve capacities.

The different reserves and their interactions

Available reserve and reserve requirements must be clearly distinguished.

Reserve requirements are sized by the TSO in order to ensure sufficient capacity will be present at any time to cope with most severe imbalances. Reserve requirements are hence the reserve capacity targets that ensure the balance between supply and demand in real time. Details on sizing of the different kinds of reserves are explained in the following sections of this chapter.

Available reserves comprise the available capacity of generation, storage, demand-side response on hand to restore the balance between supply and demand when required. According to the considered technical constraints, different kinds of reserves can take different values. For instance, a generator running at maximal power can provide downward reserve but no upward reserve.

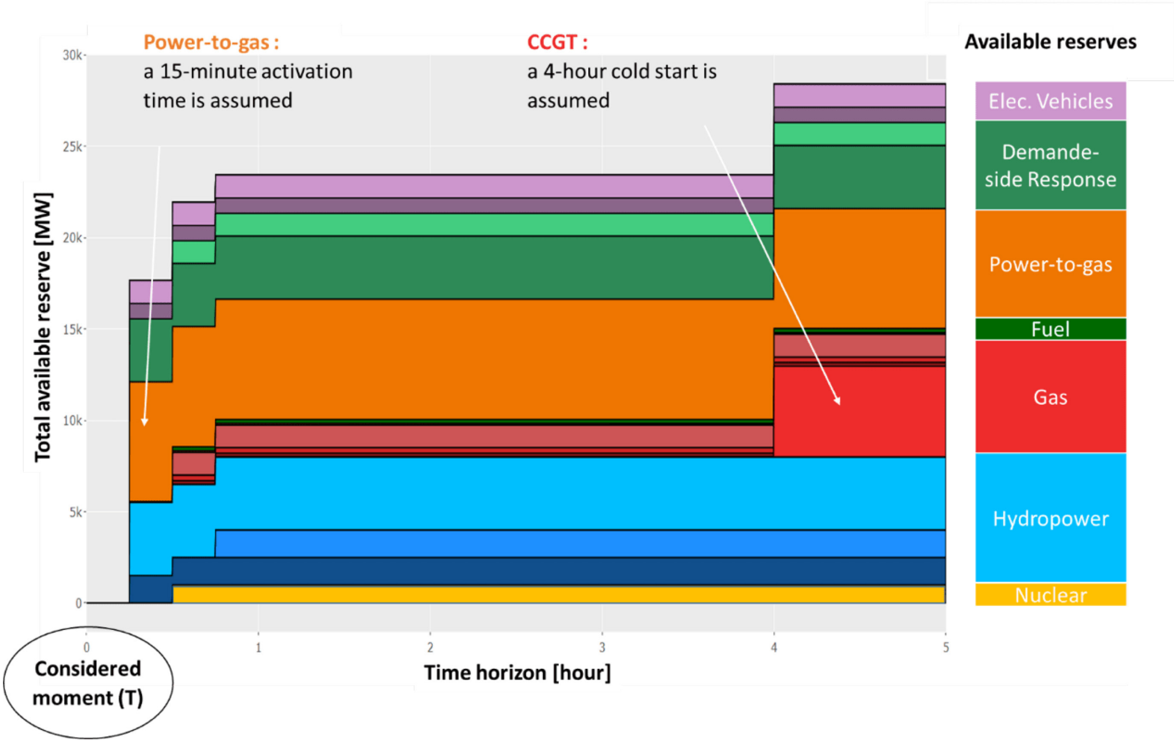
These available reserves may be "upward" in the case of a need for an increase in production or a decrease in load, or "downward" in the case of a need for a decrease in production or an increase in load to restore the balance between supply and demand.

The available reserves depend on:

- The moment that is considered: for example, fewer dispatchable power plants are available for upward reserves during peak load periods than in the middle of the night. Inversely, dispatchable power plants running at minimum in the middle of the night today may not be available for downward reserve.
- The time horizon that is considered: some resources may require fairly long activation times, such as the cold start of a CCGT plant, which can take up to four hours, whereas hydro or battery storage can be activated in a few minutes or seconds.

To ensure that enough reserves are available, TSOs contract part of them through reserve services. For services covering the shortest time horizons, reserves are activated automatically (and so systematically contracted), because it is not possible to make fast and dynamically relevant manual activations, while the manually activated reserves can be partly contracted.

Figure 6.5. Available reserves according to the considered time horizon for a typical moment in 2035



Note: This is an illustrative example.
Source: RTE (2020).

There is therefore a continuum of the different types of reserves, the proportion of which depends on the considered time horizon:

- At time horizons of a few tens of seconds, the balance between supply and demand is restored by the Frequency Containment Reserve (**FCR**). The total requirement for this is contracted in advance. Generators automatically provide the required FCR amount in real time with a local measure of frequency, without TSO intervention.
- At time horizons of a few minutes, the supply-demand balance is restored by the automatic Frequency Restoration Reserve (**aFRR**), also fully contracted. Generators provide the required aFRR amount with a signal computed by the TSO in real time.

These two reserve services are activated only after an imbalance when the frequency deviates from 50 Hz. The remaining reserves can be activated manually in anticipation of an imbalance and can be partially contracted by the system operator in advance or activated as the need arises:

- Manual Frequency Restoration Reserve (mFRR), with an activation time of 15 minutes
- The Replacement Reserve (RR), with an activation time of 30 minutes aims at guaranteeing that the available capacities of FCR and aFRR are always sufficient for achieving an efficient real-time, automatic, local control of the system frequency.

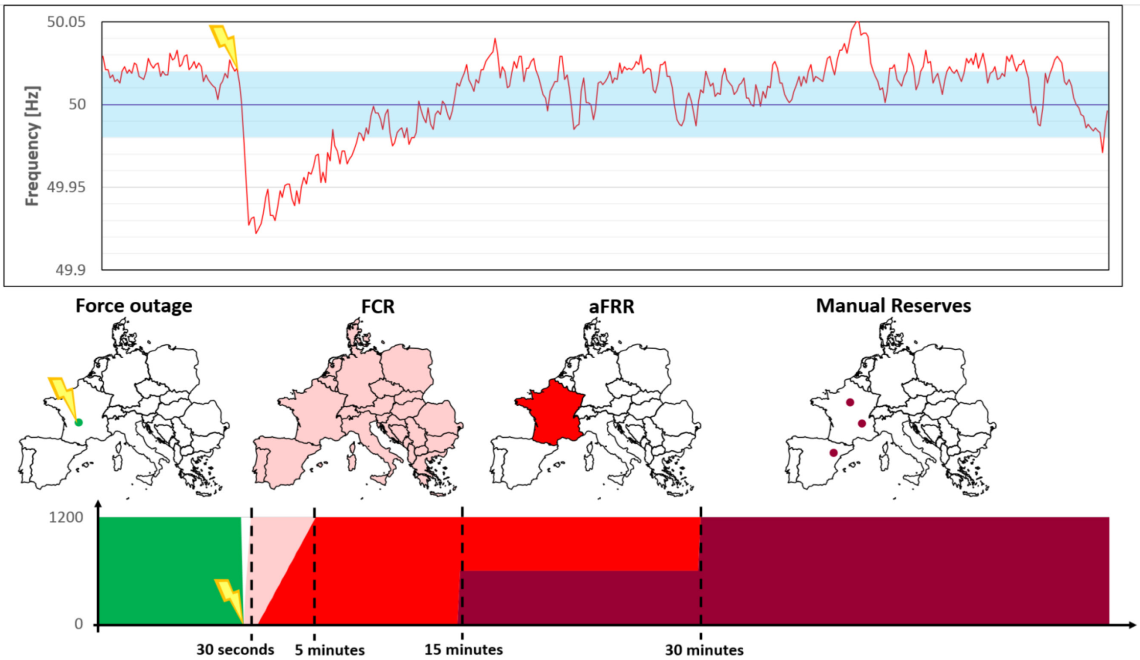
Sizing of automatic reserves

Currently, the FCR requirement is determined at the Continental European scale in order to be able to cope with a simultaneous outage in the two largest units connected to the grid, meaning 3 GW of instantaneous production loss.

The aFRR aims at freeing FCR and bringing back cross-border electricity flows to their scheduled values. It is sized at the scale of the perimeter of each transmission system operator, historically according to forecast power load. New statistical methods are being designed to better anticipate load.

In real time, the volume of automatic available reserves (FCR and aFRR) at a given time is likely to be fully used. The remaining manual reserves are used in particular to restore these automatic reserves, and to be able to cope with new imbalances latter on.

Figure 6.6. Activation sequence of reserves after the loss of a 1,200 MW power unit



Source: RTE (2020).

Sizing manually activated reserves

Reserve requirements are determined with statistical quantifications of forecast errors affecting the supply-demand balance. Frequency quality is no longer considered to be relevant for imbalances anticipated at time horizons above 15 minutes. RTE thus calculates the required reserves as the sum of forecast errors for power load, wind and solar PV generation, as well as the statistical quantification of forced outages of conventional power units. For the sake of simplicity, in the remainder of this section, the term contingency will be used rather than forecast error, with a qualifier to specify its origin (for example, wind contingency). The aggregation of all the contingencies affecting the supply-demand balance is called the total contingency.

The amounts of required reserves are established statistically so that the probability of resorting to exceptional measures and safeguard actions (such as interruptions, load shedding, emergency ramp-up to maximum production level) is kept to less than 1%.

Reserve requirements are estimated first by calculating a probability density for each type of contingency. These probability densities depend on the following parameters (Table 6.1)

Table 1.1 Parameters for forecast error calculation per type of contingency

Parameter	Type of contingency			
	Load	Conventional generation	Wind generation	Solar PV generation
Estimation method	Probability density based on quantile regression	Log-normal probability density	Gaussian probability density	Gaussian probability density
Updates closer to real time	Yes	Yes	Yes	Yes - to a small extent
Estimation of load/output	Load forecast	Generation schedule	Wind production forecast	Solar production forecast
Additional parameters	Correction for national holidays	Forced outage probability Average start-up delay	Time since last weather forecast	Cloud cover forecast

Source: own analysis carried out by RTE.

While all contingencies decrease closer to real-time, this decrease is less pronounced for solar PV. This is because of two factors: First, the limitations in monitoring and estimating solar PV production in real time are a barrier for the efficient update of forecasts. Second, too little real-time metering data is available for solar PV plants to efficiently calibrate forecast models that could better take into account the cloudiness observations every hour.

It is not expected that the ability to monitor solar PV in the French power system will improve in the coming years. This is due the fact that installations below 1MW, which are currently not equipped with real-time monitoring, currently represent more than 50% of installed solar PV capacity and this share is expected to increase with the development of residential and local direct uses of electricity. Given this, reducing the amount of solar PV contingency will mainly rely on improvement of monitoring and estimation techniques as well as better forecast models.

Finally, the global contingency, which is used as an input for sizing reserves, is obtained by aggregating all the contingencies mentioned before in Table 6.1 load, conventional generation, wind and solar PV, assuming their independence.

Challenges to short-term balancing at high shares of variable renewables

The quality of forecasts for wind and solar PV production will have an increasingly significant impact on the management of the supply-demand balance, in particular at short term horizons, as the share of renewables rises. Key technical issues will hence need to be addressed in the management of prospective energy mixes.

Assessing reserve requirements with high variable renewables

Wind and solar PV production differs from conventional production in several ways that can influence the supply-demand balance (Table 6.2).

Table 1.2 Demand-supply parameters influenced by wind and solar PV

	Wind or solar PV power plants	Conventional power plants
Output	Depends on weather conditions	Stock of fossil fuels (gas, coal, oil), uranium or water
Connection to the grid	Power electronics	Synchronous alternator
Average size of plant	Mostly small modular plants, but large farms comparable to GW-scale thermal plants	Large production units
Location	Distribution and transmission grid	Transmission grid
Contingencies	Uncertainties about production forecasts and forced outages	Forced outages

Source: RTE (2020).

Consequently, the massive development of renewable energies is likely to modify the reserve requirements. Assessing long-term needs requires detailed analyses that are still in progress, but initial intuitions can be highlighted (Ramasubramanian et al, 2018).

Expected changes in sizing of automatic reserves

Automatic reserve services are currently sized based on a Continental Europe reference contingency (around 3 GW). Consequently, their sizing is not expected to change much in prospective energy mixes, unless unlikely new features of the electrical system appear, such as:

- The development of generation units or HVDC power lines with a capacity over 1.5 GW, for example for offshore wind generation or international interconnections;
- The development of very geographically concentrated renewable generation: its production could be dramatically decreased by a local voltage drop;
- The increase of short-lasting imbalances at round hours combined with a higher sensitivity of frequency to these imbalances.

Nonetheless, even if any of these developments were to drive an increase in automatic reserve requirements, the relative country-by-country increase would be limited, as the overall requirement would be spread across all countries in the interconnected synchronous European power system.

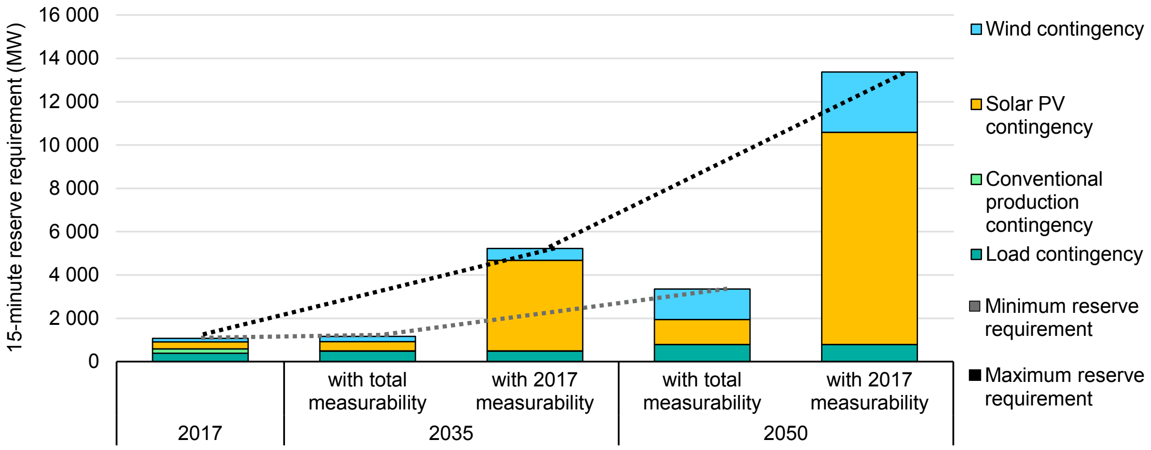
Managing a significant increase in upward reserve requirements

In the coming decades growth of wind and solar PV is expected to substantially increase reserve requirements if the current forecast and operating practices are kept. The interaction between variable renewables and conventional generation, added to changes in electricity uses are also expected to influence the calculation of manual reserve requirements. More importantly these changes will have an impact in how each type of reserve-relevant contingency is calculated dynamically throughout the day:

- **With current model and data, the solar PV contingency** would dramatically increase during sunshine hours (especially at sunrise, when forecasts are less accurate), in particular at short term horizons if generation forecasts are not improved. Even if several improvements lead to a reduction in the forecast error as a percentage of production, uncertainty would still increase in absolute terms (GW) because of the overall increase in installed capacity of solar PV. This uncertainty is further increased in the scenarios with very high shares of distributed solar PV production.
- **Wind contingency** is set to increase significantly during the course of the day because of the expected development in installed capacity. However, wind production is easier to measure so uncertainty is much lower than for PV production at short time horizons.
- **The conventional production contingency** applying to generators supplied by decarbonized fuels – nuclear, hydrogen, biogas, or complemented by CCUS assets – could decrease substantially to almost zero in the hours where wind or PV generation are high. However, it can occasionally reach higher values, especially at sunset, when conventional generation must gradually replace PV generation: more frequent coupling and decoupling represent the only real challenge regarding conventional production in scenarios with large shares of renewables.
- **Changes in the load contingency** will depend on the contingencies arising from upcoming electricity uses, such as electric vehicles and electrolysers, as well as the quality of the real-time estimation of power load, which today is highly dependent on the estimate of wind and above all of PV generation. But load controllability, and elasticity to prices may increase dramatically, hence becoming rather a lever than a hazard in the short-term.

This increase in reserve requirements would be more severe in the middle of the day when solar PV produces close to its maximum. Assuming the continuation of today's monitoring techniques, 15-minutes reserve requirements would increase significantly by 2050. Improving measurability of variable renewables thus appears as a priority as, for solar PV, it can mean the difference between about 1GW and 10GW of additional reserve requirements in 2050. At the same time, developing such quantities of PV without improvements in monitoring techniques and increase in storage capacity seems unlikely as such developments should help keep the increase in reserves requirements to a minimum (see below).

Figure 6.7. Typical expected 15-minute reserve requirements at midday in March 2020, 2035 and 2050



Source: own analysis carried out by RTE.

There are three paths to mitigating the growth of reserve requirements:

- **Improving the accuracy of wind and solar PV forecasts and associated forecast models.** These can be based on national forecast models rather than aggregated local models, mathematical and methodological improvements or more accurate data for example provided by Distribution System Operators (DSOs) and market participants.
- Several options are being discussed to improve the measurability of solar PV production, for example:
  - Combining a sample of dedicated sensors measuring power production in real time with the accurate locations of all installed capacity. In other words, better spread and more thorough metering of solar PV production, alongside high-quality information about solar PV power plants (or distributed panels).
  - Combining real-time satellite imagery to better estimate local solar irradiance and cloudiness with high-definition satellite imagery to more precisely locate and evaluate installed capacities. This solution is more economically efficient than the previous one since it does not require additional sensors or facilities and relies on already available data, but its accuracy and its complexity are yet to be determined.

- It could also be possible to directly and accurately estimate load minus distributed generation. However, it would be extremely difficult to forecast the evolution of this netted load since it would be affected by different types of phenomena, for instance changing load or solar PV generation, without data available to separate them while they follow different dynamics. More generally, it may be possible to use the real-time metering that is already available for alternative uses, which are currently being investigated. For example, it may be possible to use the aggregated real-time estimation error to reduce the need for fast balancing reserves.

The overall solution is likely to be a compromise between the cost of the provision of additional reserves and the costs and efficiency of the different ways of mitigating future reserve requirements.

A likely significant increase in downward reserve requirements

The shift in the generation mix will not only bring a size increase in reserve requirements, but also in the direction of these reserves. Historically upward reserves have been required to compensate for sudden outages or technical restrictions that limit or decrease the output of conventional generators. By contrast, situations where technical constraints force thermal generation to increase its output are rare[31]. Because of this, provision of reserve capacity has been mainly focused on upward reserves.

Variable renewable output, however, is just as likely to be higher or lower than expected. At high shares of variable renewables, the requirement of reserves becomes more symmetrical, requiring both upward and downward services. In general, downward reserve requirements are likely to become as significant as upward reserve requirements, even if they are also likely to be non-symmetrical at given moments.

[31] Pumped storage hydropower is a notable exception, particularly when technical constraints modify injections or withdrawals schedules.

Expected new dispatchable capacities to provide reserves

With the perspective of increasing amounts of wind and solar PV, a shift of responsibility will need to occur, making renewables balancing units of the system, with more stringent obligations as those currently placed on traditional units.

1. Integrating large volumes of wind and solar PV requires dedicated action to cope with uncertainties and the decentralized extent of it. This will mainly impact how operational reserves are dimensioned and used.

2. Improvements in forecasting and monitoring methods will be paramount, and work is already ongoing to optimize balancing processes at international level.

3. Over the next 10 years, further regulatory improvements are necessary to take into account the changing nature of the power mix and fully integrate the flexibility capacities of wind-farms, PV panels and electric vehicles in the system's balancing mechanisms.

4. It will be essential to establish new requirements for new units and refurbished ones to ensure sufficient reserve capability is in the system.

If the development of renewable production increases the reserve requirements, it is also likely that an increased volume of available reserves with short (upward and downward) activation times will be available for short-term balancing (Jouini, Markovic and Gross, 2020; Prevost and Denis, 2020). Most modern flexibility resources necessary to ensure security of supply in a power system with high renewables have short activation times:

- **Modern and refurbished hydropower** (dams and pumped storage hydropower) can adjust its production very quickly, generally within a few minutes.
- **EV charging** can be activated in minutes or even seconds if suitable devices are deployed (RTE, 2019). This flexibility capacity can be enhanced if vehicles and charging stations are suitable for two-way charging (vehicle-to-grid).
- **Batteries** are likely to develop further and could provide available reserves to the power system with very short activation times. However, reserves provided by batteries, as well as reserves provided by PSH and EVs, are subject to availability constraints that are yet to be studied.
- **Demand-side response,** some of which already provides available reserves at short time horizons, also represents a source of flexibility that could be developed, in particular for new power uses with adequate technological innovations.

- **Power-to-gas and gas-to-power facilities** (electrolysers, generators fuelled with hydrogen or synthetic gases such as fuel cells, and OCGTs), although not in operation today, are also expected to be able to quickly adjust their load or production at short time horizons.
- **Modulation of renewable production** could also represent a source of flexibility that can be triggered quickly, mostly downward through curtailment but even upward in some situations, such as cancellation of curtailment during periods with excess of renewable production and constant derating of renewable generators to make them able to provide reserves at any time. The possibility of curtailing renewable production (or cancelling curtailment) at short time horizons will be all the more important as it is correlated with situations of high uncertainty due to possible forecast errors.

Given that the procurement of reserves will substantially rely on new types of flexibility resources, it is essential to start planning specifications for their remote control and fast activation. This need for planning has two main implications for the coming years.

First, if these flexibility resources benefit from support schemes, for instance renewable production, such support schemes must be designed to allow for the provision of reserves, as feed-in premium contracts already allow to some extent. The challenge then stems from distributed renewable generation that may keep benefiting from feed-in contracts whose requirements should be adapted to allow for reserve provision. A possibility could be shifting from lifetime-based to output-based renewable generation support mechanisms.

Second, regardless of whether they are connected to the transmission or distribution network, all flexibility resources should be able to participate in reserve services operated by the transmission operator wherever this is cost-effective. For the part of system resources connected to the distribution network transmission and distribution system operators will have to develop coordination mechanisms to check that such activation is adequate for managing the distribution system. Conversely, if distribution network operators develop platforms or markets to manage local flexibility needs, their operation should not be detrimental to management of the system as a whole; particularly in regards to balancing and constraint management.

New operational challenges

Independently of the assumptions considered, the required and available reserves anticipated for 2035 and 2050 are much larger than those calculated in 2020. Current operational processes probably do not enable system operators to deal with such levels of uncertainty without major changes. This means that management of the ratio of automatic reserves to manually activated reserves may need to be reviewed before 2050.

At short time horizons, the difficulties of accurately forecasting wind and solar PV production level could lead to very significant unexpected production gradients over some periods (up to 200 MW/minute in 2035). Good levels of process automation to balance power supply and demand would therefore be required to guarantee the availability of sufficient capacities of fast flexibilities, in addition to measurability of solar PV production.

At longer time horizons, when the balance between supply and demand is the result of market players' actions, it is also necessary to implement market rules that give them sufficient levers and incentives to balance their perimeter quickly enough, in energy and in power, and with volumes potentially far higher than those of today. Imbalance settlement periods will become shorter, 15 minutes by the middle of the decade, instead of 30 minutes today. More cost-reflective allocation of reserve costs, along with marginal pricing, could also incentivize market players to balance their perimeter more quickly.

Aside from interconnection capacity reserved for sharing FCR reserves at the European level, there is currently little interaction in the operation of reserves and grids. In the future, massive integration of solar PV and wind generation would significantly increase local grid constraints, despite its likely adaptations and the use of local flexibilities. Consequently, it may no longer be possible to manage reserves and grid congestion separately, as it is done today, because grid constraints may prevent the activation of some reserves. Adequate changes in the operational and market management of reserves and grid constraints would therefore be needed to ensure reserve activation does not breach the safety limits in grids (Ruberg, 2020). It is indeed important to bear in mind that the actual system balance has to be dealt with at the European level.

The way forward for managing reserves at high shares of renewables

Liberalized markets worldwide are making progress in optimising the procurement and activation of operational reserves. Despite this progress, it is essential to keep other system trends in mind, in particular the future providers of reserves and more fundamentally the types of contingencies the system should be covered against.

In systems that relied on coal or gas plants for reserves, these providers may exit the system. Market reforms that favour more technology-neutral criteria and more timegranular ancillary products with shorter lead times have led to a substantial increase in reserves provided by demand, storage and aggregators. Variable renewables themselves should be able to provide specific operational reserves (mainly downward) though in practice this only happens in few power markets such as Quebec, Ireland and Spain.

A more substantial question for future electricity security is what kind of contingency the system should be designed to withstand. A typical design criterion in many systems is that of maximum loss of infeed. It puts a threshold on the maximum size of a single generator or interconnector to limit the maximum imbalance in case of a failure. However there are other criteria that will become increasingly relevant in more decentralised power systems with high renewable shares. For example a system split event, where one area of the grid splits operationally from the rest of the system may bring other limitations such as a lack of local inertia. In the future, as the power system faces new types of contingencies, it will be crucial to understand how referencing incidents can drive investments not only in grids, but also in reserves and the connection capabilities of grid users.

With the advent of new large DC corridors and offshore wind farms, some system plans include new electricity "hubs" in the grid with multi-GW interconnections. New technologies may result in a system that is inherently more intelligent and controllable. But they could also result in a system where a combination of different simultaneous failures can lead to larger contingencies and make the system more fragile.

As power systems evolve in different directions, there is no single formula to determine the best strategy for updating reserve requirements in systems with high shares of variable renewables. However, as well as taking the necessary steps to mitigating and satisfying additional reserve requirements, policy makers can follow logical steps for future system planning:

- matching potential future energy mixes with appropriate system design strategies
- updating and defining reliability targets based on an evolving set of reference contingencies
- redefining reserve requirements to cope with a new range of contingencies
- introducing new reserve products that recognise the characteristics of new resources in the system
- combining mandatory capabilities required from new system resources with new commercially procured reserve products.

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Chapter 7. Transmission grid

Key messages

- Very high levels of variable renewable generation will not be possible unless electricity grids fundamentally evolve to match the new locations of generation units and the changing patterns of power flows.
- France's transmission grid is a good platform to build upon. A first step of grid adaptation is already scheduled for the coming years and has been approved by the minister and regulator. It provides for a new cycle of grid development but not to the extent of that of the 1980s. If the grid adaptation targeted in the new 15-year network development plan is implemented, the grid will not be a limiting factor in the coming years.
- Beyond 2030, fundamental grid expansion, reinforcement and restructuring would be needed to reach high shares of renewables. Given the time needed for consulting and obtaining permits, those developments must be planned very soon and decided before 2025.
- By 2050, important changes in grids are necessary in all scenarios with high shares of renewables. Social acceptance appears to be the major constraint in managing this transformation. Grid costs at both transmission and distribution level should also be considered in system cost analysis.
- Connecting off-shore wind farms will also require major investments, which may be reduced by sharing connections between plants and/or with interconnectors.
- The need for new interconnections will depend on available flexibility resources in France and abroad.
- Regional high voltage networks are key to integrate renewables but will also need major renewals as they have been built for most part in the aftermath of World War II. This refurbishment provides an opportunity to revamp the network structure, deploy new technologies and mitigate the need for new assets.

France's electricity transmission network largely dates back to the second half of the 20th century. Its progressive construction has accompanied the major changes in the electricity system over the last century.

- The first electricity networks were built on a local basis early in the 20th century according to the needs of industry or public lighting. Their extension during the inter-war period through the first transmission networks made it possible to link consumption and the first hydropower generation centres.

- After the Second World War the electricity sector was nationalised, and the development of the transmission network accompanied the electrification of the country and the pooling of larger generation units. The development of large hydroelectric production facilities in the Alps coincided with the appearance of the 400 kV network, adapted to the transmission of electricity over long distances. At the same time, the first international interconnections were built to provide back-up and pool complementary power plants on a European scale.
- From the 1970s onwards, the growth of the French electricity transmission network was strongly influenced by the expansion programmes for thermal and mostly nuclear generation. New interconnections were also developed in the 1980s, notably the IFA 2000 submarine interconnection linking the French and British grids in 1986.
- Since the end of the nuclear power expansion programme, the French grid has not changed significantly. The French power sector, however, has since been liberalised.

The energy transition will bring a new wave of investments, in a context where social acceptability of infrastructure has changed. The 15-year network development plan[32] published in 2019 by RTE shows that while the need for investments until 2035 will be significant, it will remain lower than for the nuclear programme in the 1980s. Reaching a higher share of renewable electricity sources thereafter will bring new needs for investments.

Box 7.1 Voltage and transit constraints on transmission network management

To transmit power from generators to load centres, several electrical parameters need to be kept within limits imposed by features of the network facilities (and of generation and load devices), in particular current and voltage. Current and voltage constraints can be thought of as flow and pressure constraints, by analogy with a water network

These two kinds of constraints can thus be distinguished:

[32] *Schéma décennal de développement du réseau*, or *SDDR*.

Electrical current constraints

The current that can flow through power transmission system facilities is limited. When current passing through a line increases, the metal alloy conductors undergo heating due to the Joule effect and tend to dilate. In the case of overhead lines, dilatation or thermal expansion of conductors increases line sagging, decreasing the lines' distance from the ground. If transmission capacities are exceeded, the resulting electric arcs could endanger people or goods near the lines.

To comply with minimum regulatory safety distances, RTE acts at various levels. In the long term, it develops new infrastructures when the existing network is no longer sufficient. In the short term, RTE prevents risks of overloading. In particular, it complies with the N-1 rule: if there is an incident on a power line, the transfer of power flows to other lines does not lead to overloads or additional disconnections. To observe the N-1 rule, RTE can use various tools to reduce power flows. These include modification of the network topology (line switching) or of the generation plan (redispatching), or even, as a last resort, activation of interruptible contracts, reduction of voltage on distribution networks or rolling load shedding.

Voltage control

TSOs also have to control voltage so that it remains within the established limits of stability of supply.

Reactive power, an element of voltage stability, cannot be transferred over long distances, making it a local issue, unlike frequency. Several measures can be implemented to counter a lack of reactive power. Traditionally, voltage regulation was mainly managed with conventional power plants. Where voltage regulation by generators is not sufficient, transmission operators install complementary reactive power compensation devices. These are mostly switchable or non-switchable capacitors and reactors/electrical coils. The voltage level can also be regulated directly or indirectly with synchronous condensers (which also boost system stability by solving inertia and stability issues), tap-changing transformers and dynamic devices, known as flexible AC transmission systems (FACTS). Network operational solutions such as line switching can also be used to maintain steady voltages.

Source: own analysis carried out by RTE.

Radically transforming the electricity mix requires major new grid routes in France and Europe

A high share of variable renewables will have different effects on four distinct parts of the network:

- **Regional high-voltage networks**, operated by RTE in France[33], were historically built to supply most demand and adapted in recent years to interconnect small and medium solar PV and onshore wind generation. These networks, typically 63 kV, 90 kV and 225 kV, will be strongly affected by further development of variable renewables.
- **Very high voltage networks (400 kV backbone)** connect large-scale generators, interconnectors and major load centres, and help to balance variable renewable generation distributed across the national territory. The capacity of these very high-voltage (VHV) power lines is optimised for the present location of generators, load centres and interconnectors. The best potential locations for renewable generation, however, are seldom close to load centres, even if generation is distributed. Development of renewable generation (and decommissioning of conventional generation) can therefore be expected to increase transmission flows across the whole system and require the expansion of VHV infrastructure.
- **Interconnectors** allow the optimisation of the European mix of generation, demand and flexibility, while improving security of supply. They also help to balance variable renewable generation at the European scale. The need for interconnectors depends on the evolution of the different national generation, demand and flexibility mixes in Europe.
- **Offshore networks** are not only necessary to connect offshore facilities, which can play a key role in a generation mix with high variable renewables, but also to create interconnections, even between mainland countries if the social acceptability of onshore large overhead power lines is low.

Between 2020 and 2030, transmission investment is expected to increase and focus on regional and offshore networks, even if few weak corridors have been identified on the VHV network. Beyond 2030, as development of renewables continues, transmission investment needs would be even more structural and higher than

[33] In France, RTE operates the regional and transmission grids (above 45 kV) while DSOs operate distribution grids (below 45 kV).

estimated for the previous decade, possibly on the scale experienced when the nuclear fleet was developed from the 1970s to the 1990s. The investment needs in this period are expected to increase regardless of the kind of the network considered – regional, VHV, interconnectors or offshore. Between 2035 and 2050, VHV and offshore networks, as well as possibly interconnectors, should account for a larger share of investment than between 2020 and 2035.

Several factors can increase or reduce investment needs (Table 7.1). These include:

- The location of renewable generation: distributed generation requires more investment in regional networks, while offshore generation requires very high voltage connections to the shore;
- The development of flexibility on the demand side but also on generation in France or in Europe. Particularly the recent ten-year network development plan published by RTE proposed to generalize the use of automatic devices to adjust wind generation in real time and limit its infeed in some occasions (no more than 0.3% of annual wind production on average, saving 7 billion euros of investments in 15 years);
- The deployment of innovative equipment on the transmission network: HVDC, and low dilatation cables that reduce the need for reinforcements at higher voltage levels ,but possibly at higher costs;
- The nature and coherence of energy policy decisions adopted across Europe, which has an effect on the need for cross-border interconnections ;
- The effects of climate change and, notably, higher outdoor temperatures, which reduce the capacity of overhead lines and increase the need for investment, mostly on regional networks.

Table 7.1 Transmission investment between 2030-30 compared to investment tendencies between 2035-50 by impacting factor tendencies

Network	2020-30 average investment (M€/yr)	2035-2050					
		Investment tendency	Factors affecting needs for transmission investment				
			RES location	Innovative equipment	Flexibility mixes in France	Europe decarbonisation	Climate change
Regional (renewal)	660	++		-			
Regional (investment)	370	+	+		-		+
Very high voltage	140	++	+	-			
Interconnectors	130	0 to +++			--	++	
Off-shore	460	+++	+++	-		+	

Source: own analysis carried out by RTE.

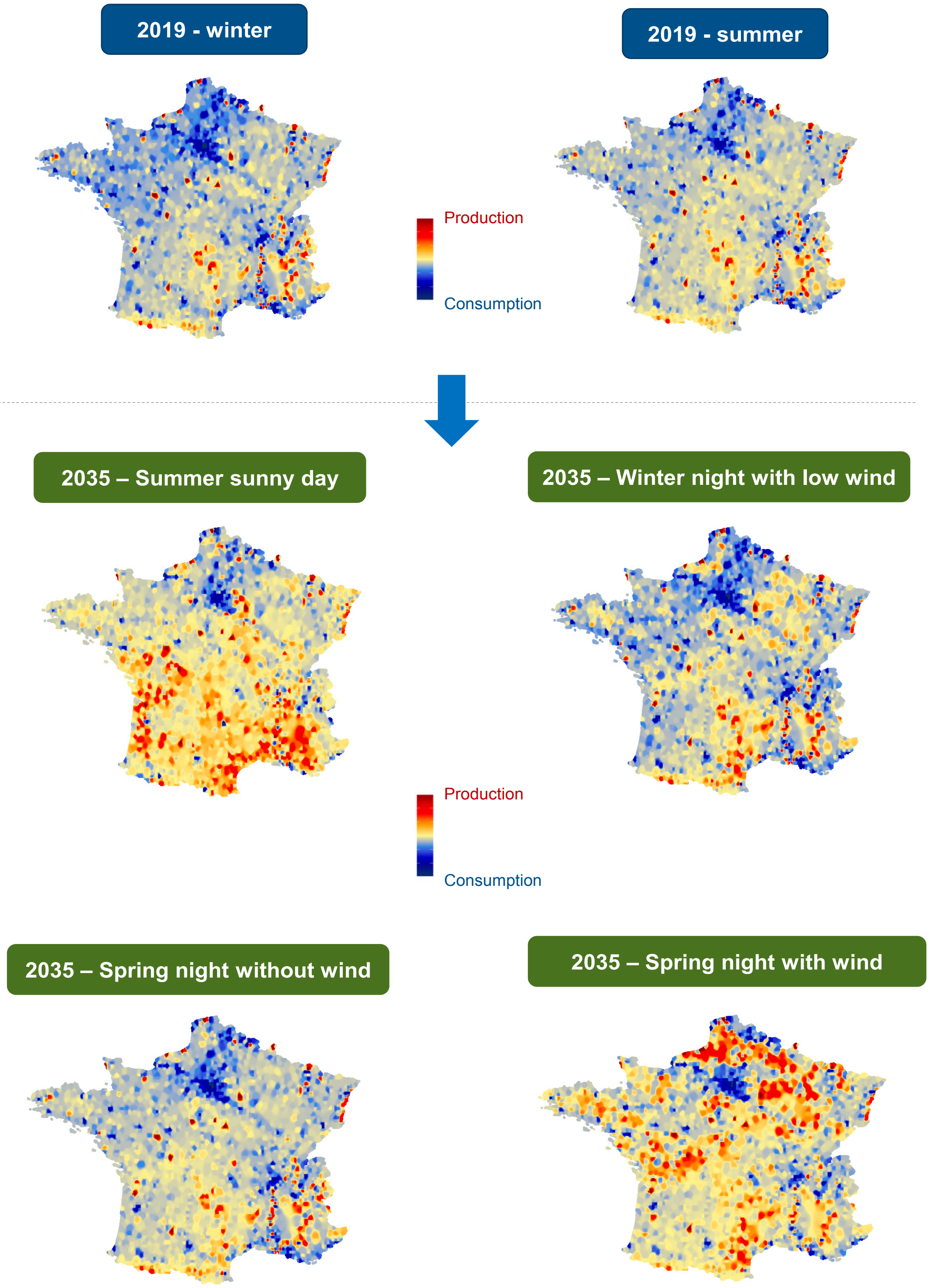
In 2050, the network will remain a large-scale pooling tool to enable a more distributed, more variable mix

The primary function of the transmission grid is to pool different sources of large-scale power generation and load centres. This pooling at the national and European levels allows load to be served with the least-cost resources.

This “hub” function of transmission networks will become even more important with the energy transition. In its 2019 network development plan, RTE has modelled the operation of the European power system with a more distributed and variable mix, according to different scenarios. This modelling revealed a twofold change in the mix, geographical and temporal (Figure 7.1):

- generation will become less concentrated geographically as nuclear reactors close and production increases in areas currently devoid of generation, reducing production potential on rivers and increasing its concentration on some coastlines;
- daily and seasonal production will vary more not only in volume but also in spatial distribution, with more episodes of high production in the south on sunny summer days and in the north on windy spring nights.

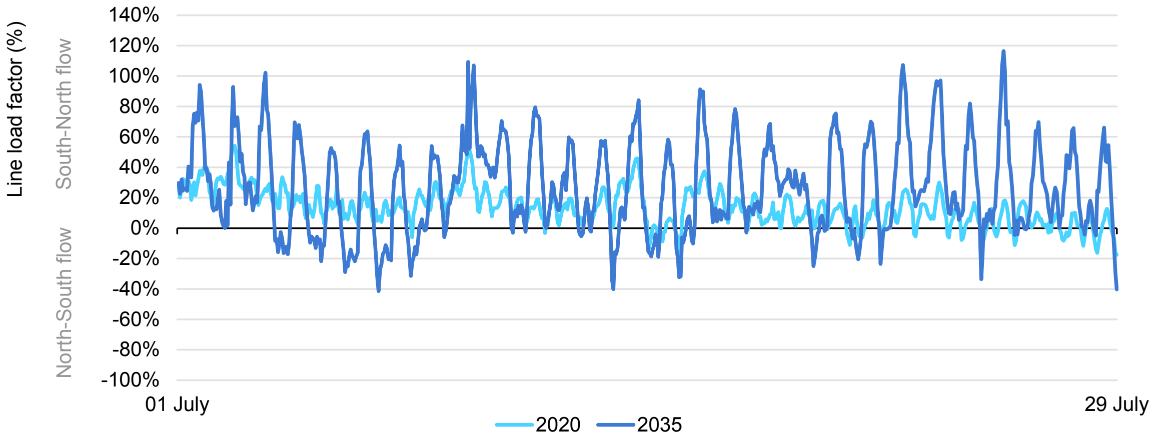
Figure 7.1. Typical distributions of electricity production and load, 2019 and 2035



Note: 2035 scenario based on the French Multi Annual Energy Plan.
Source: RTE (2019), French Transmission Network Development Plan.

High shares of renewables are only feasible if transmission networks provide a high degree of pooling of resources. Network developments therefore "naturally" follow those of production. The historical structure of the transmission grid, which links the territory through major vertical and transverse axes, is well suited to host wind and solar PV generation. The variability of flows on certain axes (particularly north-south) is expected to increase significantly over the next few years (Figure 7.2).

Figure 7.2. Expected evolution of flows on a north-south axis of the French transmission grid, today and 2035

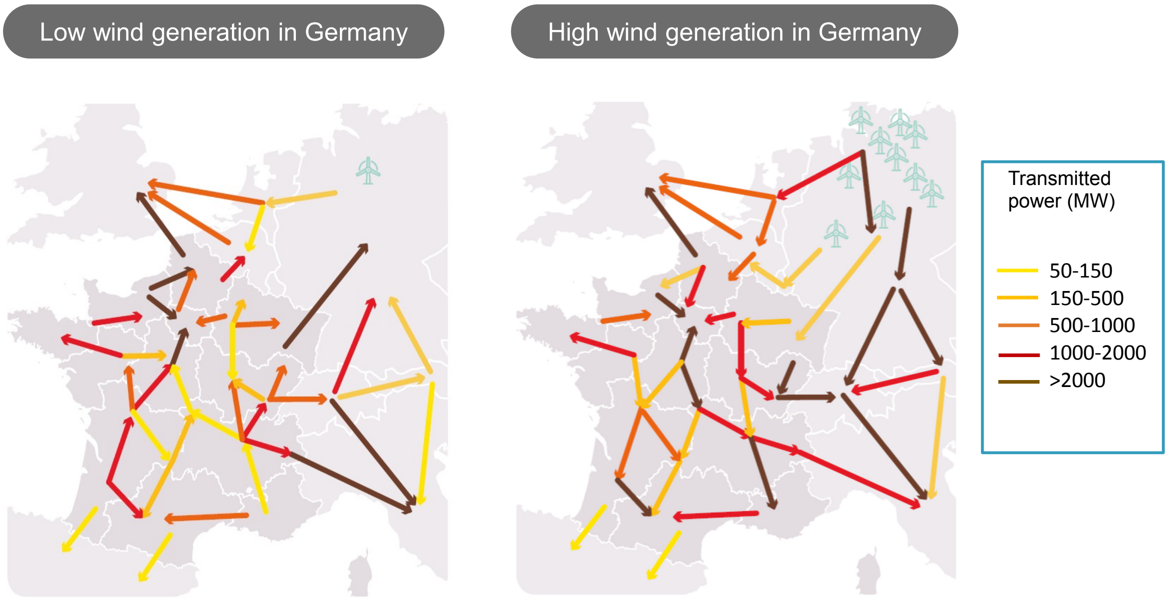


Source: RTE (2019), French Transmission Network Development Plan.

Network flows will undergo major changes, in line with the energy transition in France and abroad.

A fundamental change is under way in the power system as its organisational logic shifts from a national to a European scale. The growing interdependence of European countries in electricity supply is a result of increasing European integration in recent decades. Based on an ever-increasing physical interconnection between countries, the internal electricity market is the dominant logic for the organisation of flows in Europe. This means that instead of single countries actively deciding when to import or export, the market selects the most competitive generators regardless of their location. Electricity exchanges between countries flow mechanically as a result. The growing interconnection capacities between European countries make it possible to facilitate the integration of renewables at lower cost (Figure 7.3). For instance, the French power grids and interconnections make it possible today to cope with situations where wind production is high or low in the North of Germany.

Figure 7.3. Influence of wind generation in Germany on the French transmission grid



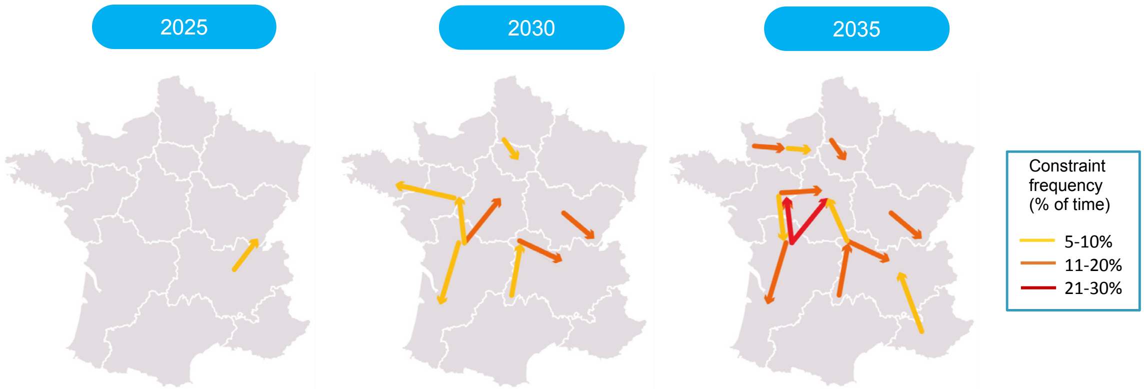
Source: RTE (2019), French Transmission Network Development Plan.

Changes in the location and nature of the electricity mix, on national and European scales, will therefore deeply modify the flows that transit on the French and European transmission grid, which will be greater than today on certain corridors.

Today's network is not adapted to transmit all the flows of an electricity mix with a significant share of variable renewables.

The French transmission grid is now well dimensioned and, in the vast majority of cases, fulfils its role as a "hub" by supplying French consumers with the cheapest electricity production at all times. As the electricity mix changes, however, if flows increased too significantly they could exceed the transmission lines' capacity (Figure 7.4).

Figure 7.4. Main constraints on the French transmission grid in the absence of network adaptation, 2025, 2030 and 2035



Note: scenario based on the French Multi Annual Energy Plan and baseline assumptions of the national network development plan
Source: RTE (2019), French Transmission Network Development Plan.

If development of variable renewables follows the French Multi-Year Energy Plan, transmission constraints could arise along several axes of the network if changes are not implemented (RTE, 2019; MTES, 2020). To prevent such constraints, specific or structural measures can be taken:

- **Redispatch**: After the network has been reconfigured to redirect flows, the cost-optimal generation schedule can be modified to account for transmission constraints. Generators behind the constraint can be replaced with generators in other locations, though these are often more expensive and emission-intensive. The pool resulting from this redispatch may not satisfy demand as cheaply but resolves transmission constraints. Such approaches should be considered as one-off measures; in the long run, the aggregate costs of redispatch may warrant implementation of structural measures.
- **Structural measures** consist in adapting the grid by creating new lines or reinforcing others.

The investments envisaged to resolve constraints should be compared with the overall benefits they bring, in particular by allowing more optimal use of renewables. For example, from 2035, in absence of grid adaptations, reliance on redispatch and other specific measures would increase production costs by around EUR 1 billion per year. This would lead to a situation similar to Germany's, where insufficient transmission capacity leads to constant redispatch that curtails variable renewable generation and replaces it with carbon-intensive thermal generation.

Adapting the grid to the energy transition is essential to reap the economic and environmental benefits of integrating renewable energies into the electricity mix. The costs and benefits of the necessary adaptations must be analysed to develop the grid in an optimal manner from a technical and economic point of view.

Structural changes in the transmission grid structure by 2050 will be necessary and are under study

Preliminary analyses of the transmission grid's adaptation needs have already been carried out, yielding scenarios with different levels of variable renewables and different time horizons.

RTE's 2019 network development plan has clarified the 2020-35 development needs of the French transmission grid. Its analysis shows that once a certain threshold for variable renewables has been reached, some structural reinforcements, albeit of limited magnitude, will be necessary on the transmission grid. This threshold would be around 50 GW of installed capacity for onshore wind and solar PV, double the present capacity. In practice, this assessment depends on the location of renewable installations and all other parameters, but the scale of the increase seems to be a relevant reference.

Beyond 2030, the continuation of energy transition policy would induce more structural changes in the transmission grid.

There is currently limited literature on the quantitative need for future electricity grids, but some projects have already described a tentative "high voltage backbone" to go with 100% renewables scenarios. Among them, *E-highway 2050* (ENTSO-E, 2015) aimed at identifying the needs of the transmission grid for Europe as a whole by 2050. The study was conducted from 2012 to 2015 by 28 partners, including academics, industrials and transmission system operators, among them RTE. Five highly contrasting scenarios were tested, ranging from a mix still largely centred on fossil and nuclear energy to a 100% renewables mix. Within these scenarios, different reinforcement possibilities were tested, starting from the 2030 grid (seen from 2012), and cost-benefit analyses were carried out.

Although the scenarios tested are very different, reinforcement needs have systematically emerged on major north-south corridors, in particular to make the best use of hydropower and wind power in the Scandinavian countries and to facilitate the integration of solar PV in the southern countries. Thus, **in the five scenarios studied, the need to reinforce the north-south transit capacities of the French network was identified**. This need varies between 3 GW and 17 GW of additional transit capacity depending on the scenarios. The methodology used in *E-highway 2050* leaves open the question of the location of these north-south network reinforcements.

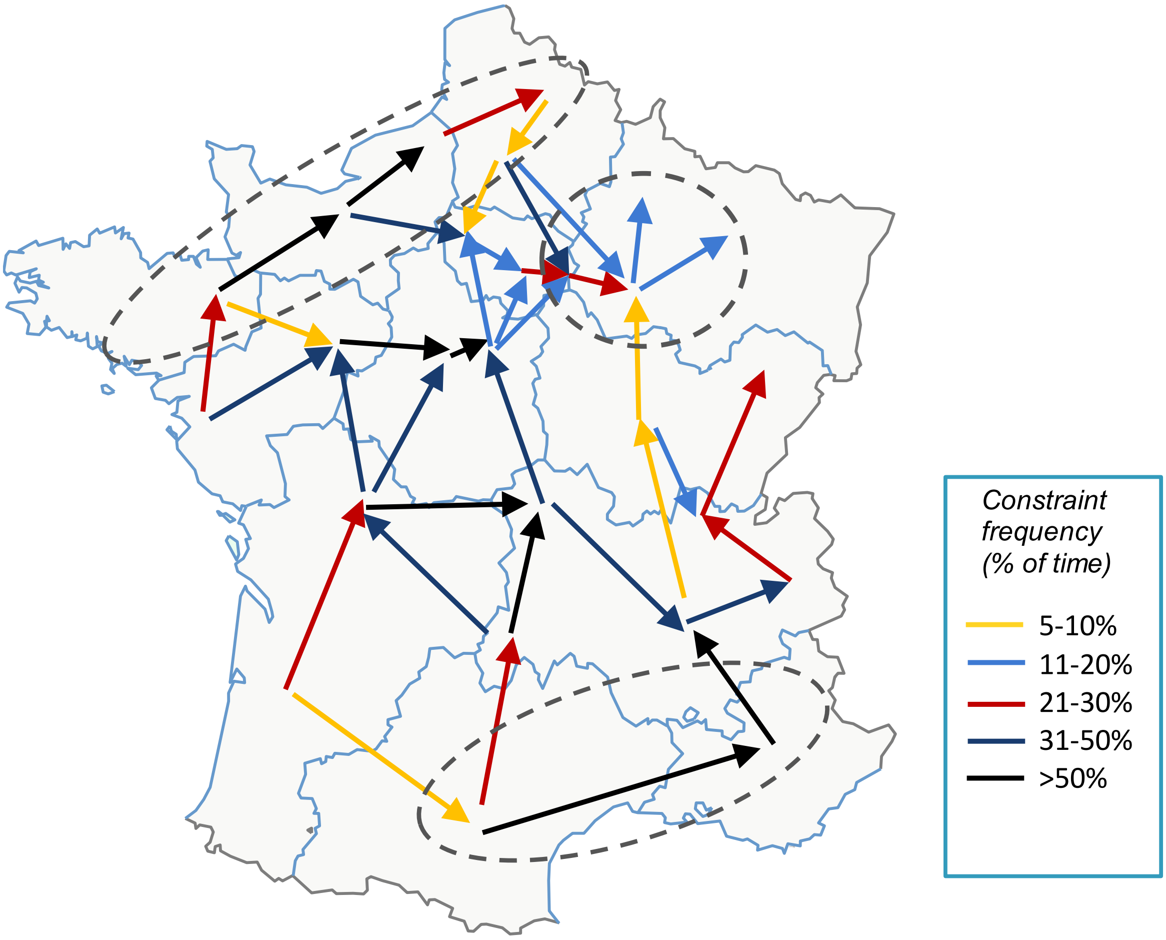
In the framework of the long-term scenarios studied for the 2021 *Bilan prévisionnel*, preliminary analysis has been also carried out on a generation mix targeting 100% renewables by 2050, with large shares of offshore wind capacity and solar PV combined with the use of flexibility resources such as power-to-gas, EVs, load management and storage. Comparing projections to 2035 with those to 2050 shows that **the reinforcements needed by 2050 include the adaptations described in the 2019 French network development plan**:

- north/south flows created by the daily inversion between northern wind and hydro and southern PV will increase the strain on the three north-south corridors to be reinforced
- west-east flows from offshore generation in the Atlantic and the English Channel will contribute to the need to upgrade the Normandy-Paris corridor and expand towards the north of France.

New needs for reinforcement could appear in two other areas:

- west-east flows from Brittany offshore generation to eastern France load centres will add to the expanded Normandy-Paris corridor.
- west-east flows from south-west France to the Riviera and Auvergne will arise with the development of offshore and PV in these areas.

Figure 7.5. Additional constraints on a 2035 target network under a high renewables scenario



Note: These results are illustrative only. Further analysis is needed of different renewable and flexibility scenarios, to be carried in the 2021 Adequacy Report (Bilan prévisionnel).
Source: own analysis carried out by RTE.

These results depend on the assumptions made about mixes of renewables and flexibility resources in France and abroad, as well as their location on the national territory. They will be refined by further analysis of the technology, capacity and location of generation, load and flexibility, in the framework of the 2021 *Bilan prévisionnel*.

Emergence of grid reinforcement needs by 2050

The studies in the RTE network development plan, covering the period 2020-2035, will be extended to more contrasted generation mixes to answer the following questions:

- Which grid adaptations and reinforcements are needed to accommodate different generation mixes incorporating a very high share of variable renewables?
- Are the reinforcement needs identified in the 2019 network development plan still necessary in every mix? Will they be sufficient in the long term?
- When do these investments need to be triggered, considering the long duration between investment decision and commissioning of lines?
- What are the impacts of connecting new generation or load (in particular power-to-gas) facilities to the network requirements (excluding specific connection costs)?
- Will network costs remain in the same order of magnitude as today's with a generation mix comprising a far higher share of wind and solar PV? How will costs be affected by the mix between onshore, offshore wind and solar PV?

To adapt and strengthen the grid, a first essential building block is to resolve questions about the necessary technologies and strategies, such as:

- Should massive use of very high voltage DC links built underground be considered, to ease social acceptance both of network and generation? What would the costs be, depending on the mobilisation of equipment manufacturers?
- In view of the growing number of third parties expected to provide local flexibility, how can their flexibility resources, such as power-to-gas, be used to resolve constraints on the transmission grid and target network reinforcements only when no other option is available?

High ambitions for offshore production require an offshore grid

Developing marine renewable energies, in particular offshore wind power, is one of the main thrusts of France's policy to diversify its electricity mix. With a metropolitan maritime area of 375 000 km^2 and favourable winds, France has significant potential to develop fixed-foundation or floating offshore wind turbines.

Some scenarios to 2050 thus envisage offshore wind capacity from 30 GW to more than 70 GW. This new power generation raises questions about connecting and integrating it into the global grid.

Optimising connection costs and associated costs is all the more important as these costs make up a significant share of the total cost of a project and could increase as offshore wind farms are developed further from the coast.

RTE therefore presented several optimisation levers in its 2019 network development plan published in 2019:

- developing hubs as shared and modular platforms to connect offshore wind farms at lower costs thanks to mutualised and easily evolving infrastructures
- adapting the size of farms and calls for tender to the standard capacity of equipment, such as cables or substations, to avoid threshold effects (for example, a 900 MW farm generally requires the deployment of three cables as opposed to at least four cables for a slightly higher capacity);
- standardising some infrastructure such as offshore HVDC conversion and transformer stations.

These levers are conditional, however, on long-term national planning of future facilities and on choices of location and timing, allowing the pooling of connection infrastructure. By 2050, planning will be even more important to accommodate massive volumes of offshore wind power and to optimise the joint development of generation, offshore grid and onshore grid. Studies should make it possible to examine the planning options.

Some European stakeholders are proposing to pool investments in interconnections and in the connection of offshore wind farms in favourable regions, particularly in the North Sea. Various technologies (AC or DC) and ways of connecting wind production at sea are planned (Figure 7.6):

(i). simple (radial) connection between an offshore farm and the onshore electricity grid (default strategy)

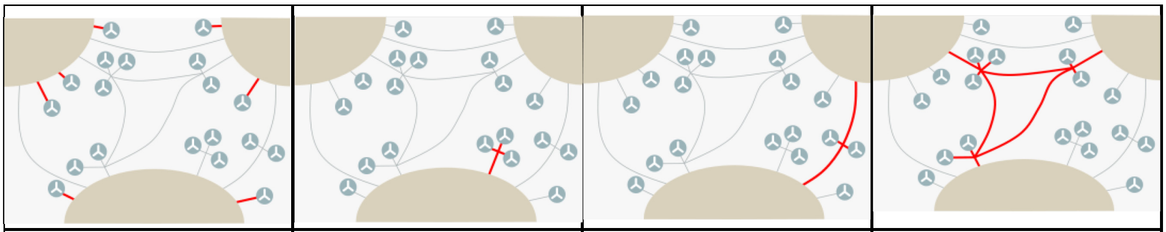
(ii). connection of several offshore farms to the onshore power grid via a hub (medium-term strategy proposed in 2019 RTE network development plan)

(iii). hybrid projects, with interconnection between two countries via one or more offshore farms

(iv). "offshore multi-terminal hubs" linking several offshore platforms and several countries.

Methods (ii) to (iv) could be coupled with other forms of energy, for example by including power-to-gas systems on offshore platforms. These strategies will have to be studied in detail, taking into account all the technical and economic implications.

Figure 7.6. Examples of connections of offshore wind farms



i) simple connection	ii) connection via hub	iii) hybrid project	iv) offshore multi-terminal hub

Source: adapted from ENTSO-E (2020), Position on Offshore Development. Market and Regulatory issues.

Changes in the French and European electricity mix raise questions about interconnections

Strengthening the interconnection of networks is a political priority for the European Union as it helps to achieve energy and climate objectives. This priority has been asserted at each stage of the construction of the single market in electricity. It has been reflected in European law and in practice by a permanent priority for construction of new interconnection lines and gradual coupling of electricity markets. At EU level, this priority has taken the form of a target set in 2014 for increasing the import capacities of member states to reach 10% of their installed capacities by 2020 and up to 15% by 2030 (European Commission, 2014) under the condition that the cost-benefit analysis yields a positive result.

Interconnections were developed to increase the security of supply of national electricity systems. They still help reduce the need for peaking generation units in Europe by 30% compared with isolated national power systems (Heggarty et al., 2018). Their role has since expanded, via the integration of European markets. **They now make it possible to 1) pool generation resources by using the cheapest resources, and 2) promote the integration of renewables by taking advantage of energy complementarities** between countries and the proliferation of variable energy sources.[34] Interconnections also strengthen countries' capacity to protect their power systems from extreme events (such as low temperatures or low availability of generating facilities) by promoting mutual assistance and thus enabling each country to avoid over-investing in very costly peak capacities.[35]

The size of interconnections and national generation capacities must therefore be managed jointly; this constitutes a global challenge for transforming the mix in the

[34] Several regions do not necessarily face extreme renewable production events (very high or very low production) at the same time.
[35] The contribution of interconnection capacity to the security of supply of France is estimated at around 7 GW.

long term. The level of development of interconnections is a flexibility parameter to be integrated in long-term scenarios in a consistent way with other possible sources of flexibility, such as batteries, power-to-gas and peak capacities.

Plans for future developments are under study and longer-term needs appear from 2040 onwards.

Reinforcement of European interconnection networks is based on the Ten-Year Network Development Plan (TYNDP), developed every two years by the European Network of Transmission System Operators (ENTSO-E) in application of European regulations. The TYNDP is a central tool for planning the electricity system and in particular the network infrastructure. The most recent TYNDP (ENTSO-E, 2018) lists 15 projects for France. Some are under construction while others are still at a preliminary stage.

To prioritise and sequence these new interconnection projects, RTE used a "multi-criteria" assessment to prepare the 2019 French Transmission Network Development Plan (RTE, 2019). The interconnection projects have been grouped into "packages" according to their technical, economic and contextual maturity:

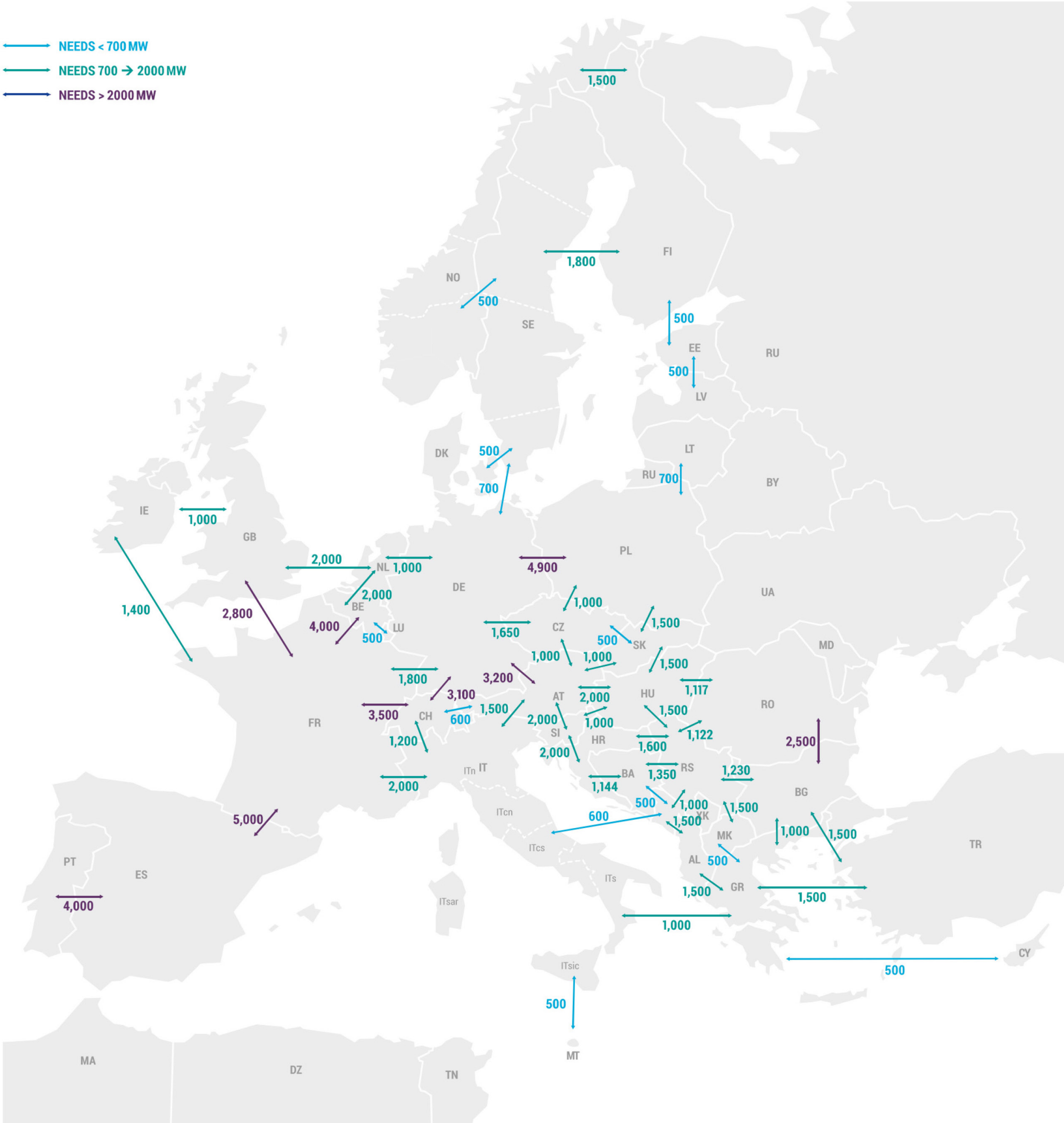
- a "certain" or "absolute priority package" grouping the interconnections under construction for commissioning over the next three years (IFA2 and ElecLink between France and the United Kingdom and Savoie-Piemont between France and Italy),
- a "no-regrets" or "priority 1 package" covering interconnections already committed or to be committed immediately because they are profitable in all situations and politically mature (reinforcement projects with Belgium and Germany representing approximately 3 GW of additional capacity and the Bay of Biscay project with Spain),
- a "conditional" or "priority 2 package" grouping interconnections in less certain contexts and to be committed over the next few years if a certain number of conditions are met (Celtic, between France and Ireland, for example).

Finally, for both economic and societal reasons, some projects do not seem ready to be decided and commissioned within the time frame of the network development plan, for example trans-Pyrenean projects.

However, the interest of projects that have been put aside until 2035 could be confirmed in some 2035-50 scenarios, depending on the changes in the electricity mix envisaged. New potential projects could also be added to the list at the start of the reflection on scenario development, particularly following the publication by ENTSO-E in 2020 of the Identification of System Needs (IoSN) (ENTSO-E, 2020). The

IoSN, which identifies possible new needs for reinforcement of European electricity interconnections, is projected up to 2040. While the scenario used in the IoSN features massive development of renewable generation, it also includes dispatchable fossil fuel-based generation in Europe and a limited amount of flexibility sources in France. It envisages less than 10 GW of additional exchange capacity. In these conditions, flexibility sources developed at the European scale play a key role in dimensioning the grid in France. In addition, developing interconnections beyond the 2035 packages identified in the 2019 French network development plan can reduce renewable curtailment and CO_2 emissions. Every package in the 2019 development plan is hence relevant.

Figure 7.7. New interconnection opportunities by 2040 compared with 2020



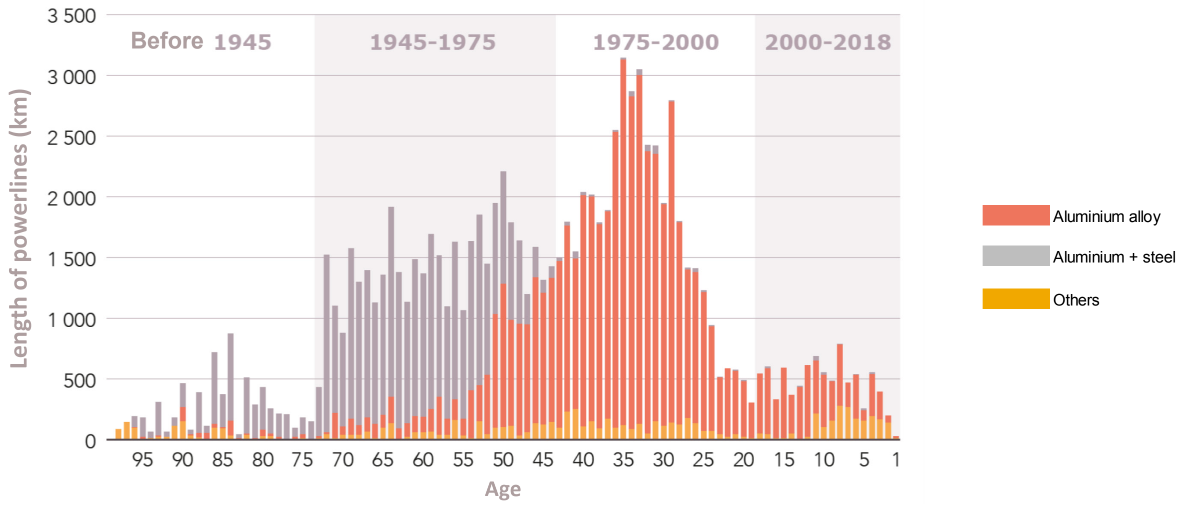
Source: ENTSO-E (2020), Ten-Year Network Development Plan 2020. Completing the map of power system needs in 2030 and 2040. Draft version prior to public consultation.

While the RTE and ENTSO-E studies both illustrate possible needs for new interconnection capacity, their results strongly depend on generation and flexibility mix, at not only the French but also the European scale. Further studies need to be carried out to give a more precise picture in various European and French scenarios with more renewables and different mixes of flexibility sources such as batteries, EVs and green gas imports.

Widespread ageing of regional networks will lead to massive restructuring needs

After the Second World War, the creation of a French national operator through the nationalisation of the majority of electricity companies in 1946, as well as the takeover of infrastructure planning by the state, made it possible to create the first overall network in the country with the 225 kV transmission grid. At the same time the grid was extended to rural areas with the 63 kV and 90 kV power grid, in a context of strong economic development and electrification. Many parts of the current regional networks were thus commissioned between 1945 and 1970 and will reach the end of their life by 2050. The 400 kV network, mainly developed between the 1970s and 2000s in connection with the nuclear power programme, will still be largely functional in 2050. Between 2000 and 2020 there has been more moderate development of overhead power lines, while resorting more frequently to underground cables along with the emergence of new power lines with low thermal expansion coefficients, which offer better transmission capacity (Figure 7.8).

Figure 7.8. Age pyramid of overhead power lines



Note: Aluminium alloy referred to as Almeléc
Source: RTE (2019), French Transmission Network Development Plan.

France's power transmission grid is about 50 years old on average, relatively older than elsewhere in Europe. RTE's maintenance policy has made it possible to operate the network over a longer lifespan and to significantly reduce the need for renewal compared with other European countries.

The life of the network cannot be extended indefinitely, however. Renewal of the network will therefore be a crucial issue in the years to come, particularly in the 2030s to 2050s as far as regional networks are concerned, as an increasing number of lines, built during reconstruction after the Second World War, will reach the age limit of 85 years.

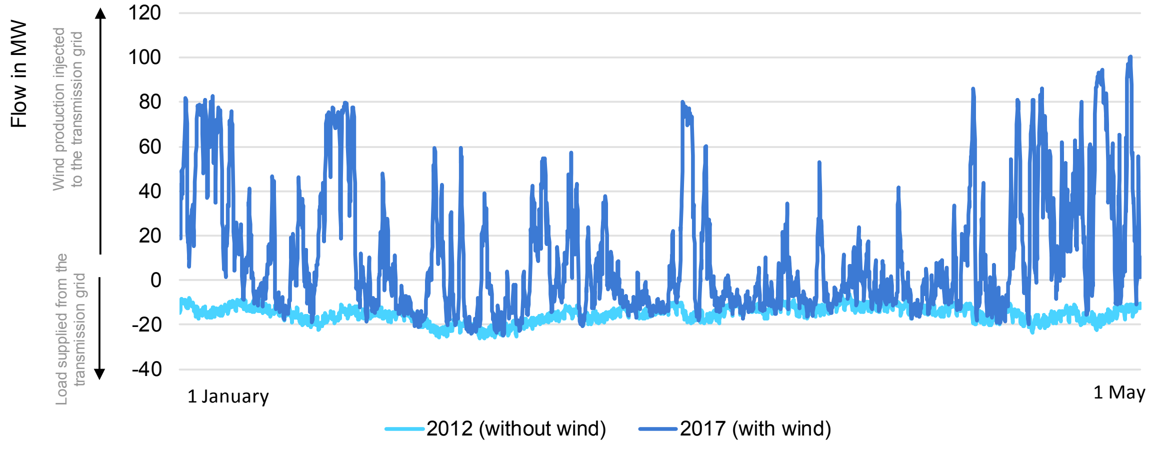
Identical network renewal is not the only way to guarantee high electricity quality

The energy transition is changing the role of regional networks.

As more wind and solar PV generators are connected to regional networks or distribution grids, energy flows on these networks are transformed. If instantaneous renewable production is consumed locally, regional networks deliver the renewable production to consumers within the territory concerned. If the instantaneous renewable production is not entirely consumed locally, regional networks send the renewable production to the very high-voltage grid so that it can be used to supply other regions.

As well as their historical function of serving load, regional networks therefore must now harvest and integrate renewable production into the power system. This new role has a major impact on electricity flows. Historically, electricity mostly flowed from the transmission grid to load centres. Transits were therefore stable and oriented in the same direction throughout the year. From now on, as soon as local renewable production is higher than load, transits are more likely to be reversed, with highly variable flows from the regional networks to the transmission grid that are potentially much higher (Figure 7.9).

Figure 7.9. Power flow through a regional line before and after installation of wind farms



Source: own analysis carried out by RTE.

Renewable generators will affect the relationship between transmission and distribution grids in different ways depending on their size. While large generators, such as offshore wind farms or very large solar PV plants, will have little or no impact on regional networks, smaller generators will need reinforced co-ordination between transmission and distribution operators. Intermediate-size plants (30 MW to 100 MW) will be connected either to the regional transmission grid or to medium-voltage distribution networks (as it is often the case today for plants with capacity of tens of megawatts). Smaller generators, down to individual self-consumers (consumers who generate their own electricity), will be connected to distribution networks and will deeply modify flow patterns at the HV/MV substations between the regional and distribution grids.

In all cases, beyond the obvious need for distribution network adaptions, transmission and distribution operators will need to reinforce their co-ordination to optimise the overall integration cost of renewable to the power grids, through choices of both HV/MV substations and voltage connections.

The need to renew regional networks can thus be shared with the need to adapt these networks to the arrival of renewable generators. Opportunities to reconfigure regional networks will appear as infrastructure renewal is planned. As the role of these networks evolves from energy supply to energy collection, the end of life of assets in an area could be used to question the overall structure of the network in that area. Several possibilities will be systematically studied:

- renewal of end-of-life assets identically;

- removal of some assets that have been made unnecessary by changes in generation and load in the area;
- restructuring to jointly integrate the needs for renewal and adaptation linked with the connection of renewable generators to the grid.

For regional networks, even more than for VHV transmission lines, a major need for renewal raises the question of technologies to be used. The current choice of voltage values may be questioned. A higher voltage level increases transmission capacity and reduces Joule losses. Costs of voltage upgrades may be reduced by making such changes in the context of a major renewal. At the same time, the use of underground cables may greatly expand.

Studies will also need to integrate the possibility of using flexible third parties to provide complementary solutions to network infrastructure development, for example by using distributed storage capacities such as EVs to solve network constraints. Renewal and development of infrastructure on regional networks will also need to take into account acceptability issues, which will often be associated with issues of acceptability of joint development of renewable production in the area.

Network flexibility as an option for power system transformation

In some specific situations, electricity networks and other flexibility sources can be considered as substitutes since local development of generation and load flexibility or storage reduces the need for transmission capacity – whatever the voltage level, from regional networks to interconnections. RTE's 2019 network development plan has shown that optimisation tools such as sensors (including dynamic line rating), renewable curtailment and adequate controllers decrease investment needs for network reinforcement by EUR 7 billion (over EUR 33 billion once all optimisation tools are considered).

At the same time, electricity networks enable system flexibility by allowing a broader set of flexible hardware resources to be shared across a wider area. For example allowing generators in neighbouring regions to meet increasing demand or through large energy storage facilities can store excess variable renewable generation from a power plant hundreds of kilometres away. Interconnections play an important role in providing flexibility as power systems integrate higher levels of variable renewables. Variable renewables typically have a smoother aggregate profile that is easier to integrate across a larger region.

Policies are crucial in supporting grid interconnectivity as it enables power system flexibility. A trade-off between grid and the other flexibility sources is needed, however, to optimise the size of the system.

There are different approaches to the improved flexibility that can be accessed from electricity networks. Operations of existing transmission lines can be improved to increase carrying capacity in real time, or localised assets can be deployed to handle specific constraints.

Dynamic line rating

Dynamic line rating is one way of improving the use of existing infrastructure according to real-time conditions. Various transmission operators increasingly apply dynamic line rating to improve overall transmission efficiency. Transmission line capacity is limited by the maximum conductor temperature and the maximum allowable sag that leaves sufficient clearance with the surroundings. Traditionally transmission operators use conventional ratings that are static and only vary with the seasons to determine the transmission capacity of the line. Dynamic line rating monitors and forecasts transmission line capacity based on weather conditions, such as ambient temperature and wind velocity. Generally, 10% to 20% of extra capacity is available 90% of the time and in some instances even twice the capacity. The technology is becoming used more widely by transmission operators worldwide, including RTE.

Battery storage for network congestion relief

EnspireME is a pilot project in northern Germany to test the viability of co-locating wind farms and battery storage to relieve network congestion. Congestion requires distribution operators to curtail variable renewables and hence compensate variable renewable generators. The main benefit of the project is in avoiding these redispatch costs. The project, developed by the Dutch energy company ENECO and Mitsubishi Corporation of Japan, stores wind energy at times of local generation surpluses and offers stored energy in the primary reserve market.

In this particular case, wind farm operators have an incentive to increase their profits by selling excess energy to the battery storage, while the network operators have an incentive to reduce the redispatch cost. Redispatch costs have gained political relevance in Germany as they have steadily increased and are passed through to end-consumers through network charges. Battery storage is an alternative in Germany because of its zonal market and the prevalent transmission constraints between the wind-rich north and load centres in the south. In France, three pilot projects of developing batteries to relieve congestions are also currently being developed in the transmission grid.

The examples above show alternative ways to maximise integration of variable renewables by improving use of transmission network hardware or developing local commercial alternatives to relieve congestion. Their generalization implies an adaptation of the regulatory framework pertaining to grid development, enabling TSOs to enter into long term commercial agreement with third-party flexibilities instead of investing in new assets. In the German case, the effective deployment of local alternatives depends on both the regulatory regime of local network operators and the remuneration scheme for generation of variable renewables. In France, similar issues of transmission and distribution constraints may arise given the assumptions on North Sea offshore wind as well as distributed solar PV. In France, an important step has been made in 2020 with the positive opinion given by the regulatory authority on the holistic approach proposed by RTE for adapting the grid the coming years. This comprises both structural adaptations of network infrastructure and optimising their use thanks to flexibilities such dynamic line rating or third party flexibility (storage, demand-side response) (CRE, 2020).

Voltage management with high share of decentralised renewable generation

Transmission network management can be affected not only by changes in current but also by voltage constraints, whether they come from voltage that is too low or too high.

Problems related to low voltage

In areas with mainly load and little generation capacity, power plants may not be able to maintain the network voltage, which may lead to cascading disconnections and outages over a large part of the network. This phenomenon is known as voltage collapse.

The risk of voltage collapse only occurs in areas with few power plants (typically "electrical peninsulas" or large urban areas) and during extreme local imbalances between generation and load, typically during unfavourable contingencies such as cold spells that lead to high load and unavailability of power plants.

The shutdown of power plants in areas already poorly equipped with generation facilities can magnify the risk of voltage collapse, other things being equal. In France today, the grid is well developed and conventional generation appears evenly distributed. Only the north-western quarter of France and Brittany may experience problems associated with low voltage. This risk is expected to diminish in a few years when several generators are commissioned.

Voltage control is one of the technical issue to monitor in a future electricity mix with a high share of wind and solar PV generation. Prospective studies therefore need to identify regions where production would be too low compared with load. However, technical solutions are already available, such as capacitance or static VAR compensators, and can be implemented without raising major economic or social issues.

Problems related to high voltage

High levels of voltage are linked to low transits on transmission network lines, for example in situations of low residual load (see Chapter 5). Such situations are occurring more and more frequently, for example in areas where local renewable generation can supply part of the load. Deployment of underground cables on regional high-voltage grids or on distribution network lines may also lead to high voltage. These two situations –installation of renewables and underground lines – as well as decommissioning of conventional power plants, are bound to increase in the coming years and may require investment in voltage management systems.

While conventional generators were mainly connected to the transmission network (225 kV and 400 kV), most onshore renewable generators are connected to distribution grids (below 45 kV) and sometimes regional grids (63 kV and 90 kV).[36] The high-voltage challenge therefore stems more from the location of connection (regional and distribution grids rather than transmission grids) than from the change to renewable generation.

To address this challenge, the converters from variable renewable generators can be used for local voltage regulation on regional and distribution networks. They can help transmission operators control voltage of regional networks and at the interface between regional and distribution grids. The converters of renewable generators can technically provide reactive power even when sun is not shining or the wind not blowing, provided that the regulatory framework allows it and that the service is demanded by the transmission operators.

Voltage on the 225 kV and 400 kV networks cannot be fully regulated, however, as reactive power from the generation connected to the regional and distribution grids does not travel well. At the same time, grid codes now require that not only onshore

[36] In France, RTE operates the regional and transmission grids while DSOs operate distribution grids.

and offshore renewable power plants connected to transmission grids but also other centralised resources – like HVDC and stationary batteries – be able to regulate voltage. These capabilities will replace voltage regulation by synchronous generators. In areas where centralised voltage regulation resources connected to the transmission grid are still lacking, reactive power compensation devices could be deployed, such as switchable or non-switchable capacitors and reactors or coils, FACTS and synchronous condensers.

Voltage concerns also arise from the French Network Development Plan's preference – for environmental and acceptability reasons – for underground cables rather than overhead lines when creating new corridors or renewing existing ones on regional networks, unless technically, environmentally or economically impossible. Maintaining voltage in underground cables within acceptable values has additional cost implications as it requires the deployment of additional electrical coils. Even with maximising assumptions, adequate investment to maintain voltage stability by replacing the voltage regulation capability provided by conventional power plants with reactive power compensation devices does not seem to be significant when compared to the overall costs of the power system.

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