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The Economic Issues Surrounding Support for Renewable Electricity

Jules Grimont and Jacques de Saint Pierre

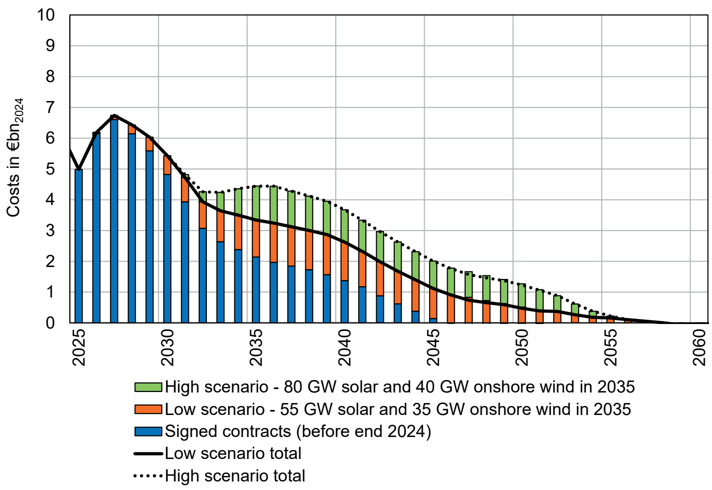
- Renewable electricity, when used to supplement nuclear energy, contributes to achieving the goals of the energy transition. This requires the widespread electrification of uses in transport, construction and industry. Renewables also enable us to reduce our dependence on fossil fuels, which are mostly imported, and thus strengthen our energy sovereignty.

- The competitiveness of renewable energy development projects depends on the sector (solar, onshore wind, offshore wind, etc.) and the ratio between their cost and the market price of electricity. In 2025, market prices in France were lower than in most neighbouring countries. While the cost of renewable electricity has fallen sharply in recent years, it has not yet reached the average level of current market prices in France. Hence, the development of these sectors still requires government support.

- Support for renewable energy aims to improve the return on investment. Its cost increases when electricity market prices fall, and vice versa. The increase in the volume of renewable electricity receiving support will automatically lead to greater exposure of public finances to market price fluctuations. As a result, support for renewables has had to change, in particular by transferring more of the risks borne by government to producers.

- Until 2035, the annual cost of supporting renewable electricity will continue to be dominated by the cost of contracts signed before the end of 2024 (see Chart). As a result of lower generation costs for renewable technologies, the unit support cost for new facilities will be lower than for existing ones. So, for solar and wind power, the average full generation cost for supported facilities should be approximately €80_{2024}/MWh in 2035, compared with €120_{2024}/MWh today, resulting in an automatic reduction in the cost of government support per MWh generated.

Estimated annual cost of support for for renewable electricity (solar, wind, etc.)



Sources: DG Trésor calculations, Energy Regulation Commission (CRE) data.

How to read this Chart: These estimates correspond to a median price scenario, with a stable market price of €70_{2024}.

In 2035, in a median price scenario, the annual cost of supporting renewable electricity is expected to be €$2.1bn_{2024}$ for contracts signed before the end of 2024, and €$1.2bn_{2024}$ to €$2.3bn_{2024}$ for contracts relating to planning scenarios (solar, onshore wind, etc.).

1. Support for the development of renewable electricity is necessary to achieve France's energy and climate objectives, and reduce dependence on imported fossil fuels

1.1 Renewables are playing a central role in achieving climate and energy sovereignty objectives

France[1] and the European Union[2] have made bold commitments to reduce their greenhouse gas emissions with a view to achieving net zero by 2050. In 2023, energy combustion – for various uses such as transport, industry, heating and electricity generation – accounted for 60%[3] of greenhouse gas emissions in France. In addition, nearly 60% of final energy consumption in France comes from imported fossil fuels. Phasing out fossil fuels will reduce the French economy's dependence on these imports. They represented a trade deficit of €63bn in 2024 after peaking at over €130bn in 2022.[4]

To achieve these objectives, France's strategy is based in particular on the widespread electrification of uses in key sectors: transport, construction and industry. Electrification has the dual advantage of decarbonising[5] and reducing French energy consumption due to the efficiency gains it brings. For example, an electric motor is more energy efficient than an internal combustion engine and thus consumes less energy to deliver the same amount of motion. Electrification will result in higher electricity consumption in the medium to long term.[6] French electricity generation, already low in carbon, will therefore have to increase to enable the decarbonisation of other sectors through electrification, especially given that part of the current generation capacity will need to be renewed by 2050.[7]

The revival of civil nuclear power is a priority in French energy policy,[8] focused on maintaining a low-carbon and dispatchable electricity generation capacity. The new reactors planned as part of the Nouveau Nucléaire Français programme, with a maximum of 14 reactors by 2050, representing the most ambitious proposal that the French nuclear industry can deliver at present,[9] will provide significant dispatchable electricity capacity to the French electricity grid. However, they are not expected to be commissioned before 2038.[10], [11]

The increase in low-carbon electricity generation capacity will necessarily have to rely on the complementary nature of renewables and nuclear power (see Box 1). The shorter development lead times for renewable electricity (three to seven years),[12] compared with more than ten years for nuclear power, will make it possible to meet the expected increase in electricity demand over the next ten years. Furthermore, there is significant uncertainty (of around 20% for 2035 projections) surrounding electricity demand (depending on the pace of electrification of heating systems, vehicles and industry, as well as the expansion of hydrogen production by electrolysis).[13] The pace of renewable energy development can then be adjusted to match demand, due to the shorter lead time.

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(1) Energy and Climate Act no. 2019-1147 of 8 November 2019.
(2) Regulation (EU) 2021/1119 of the European Parliament and of the Council of 30 June 2021.
(3) Ministry for the Ecological Transition (2024), "Key Figures on Climate - 2024 Edition".
(4) Ministry for the Ecological Transition (2024), "Key Figures on Energy - 2024 Edition".
(5) French electricity generation is largely decarbonised, with low-carbon generation accounting for 95% of the total in 2024. See *Réseau de Transport d'Électricité* (2025), "Annual Electricity Review 2024".
(6) *DG Trésor* (2025), "The economic challenges of the transition to carbon neutrality"; *Réseau de Transport d'Électricité* (2024), "Bilan Prévisionnel 2023-2035" (in French only); International Energy Agency (2025), "Electricity 2025".
(7) *Réseau de Transport d'Électricité* (2021), "Energy Pathways to 2050".
(8) President Macron's speech in Belfort (2022) and the Act to fast-track new nuclear facilities (2023), followed by meetings of the Nuclear Policy Council (CPN) in 2023 and 2025.
(9) *Réseau de Transport d'Électricité* (2021), op. cit.
(10) Nuclear Policy Council (2025), "Compte-rendu de la 4ème réunion" (in French only).
(11) The revival of nuclear power in France is also based on the development of small modular reactors (SMRs), which should be able to supply electricity or heat to French consumers as from the 2030s.
(12) Or even less for solar systems on buildings, from a few months to two years.
(13) I.e. 110 TWh, *Réseau de Transport d'Électricité* (2024), "Bilan Prévisionnel 2023-2035" (in French only).

Box 1: Complementary nature of nuclear power and renewables

Renewable electricity is playing an increasingly important role in the electricity mix, accounting for 152 TWh in 2024 (27% of total electricity generation), compared with 94 TWh in 2014[a] (17% of total electricity generation). Over the past two decades, the development of renewable electricity has partially offset the decline in nuclear power generation.[b] The interaction between renewable energies and nuclear power – the primary source of electricity in France since the 1990s – offers complementary benefits.

According to the Transmission System Operator (RTE), a French electricity mix comprising both nuclear and renewable energies is a guarantee of economic performance by 2050. Renewables and nuclear power offer different and complementary generation profiles, flexibility measures, investment trends and industrial risks. For example, although renewable energies, particularly wind power,[c] have low unit generation costs, an electricity mix composed mainly of renewables results in higher costs for the electricity system: development of the flexibility needed to maintain the supply-demand balance (e.g. batteries to absorb surplus generation, peaker thermal power stations in the event of a production deficit) and adaptation of the grid.

The use of a diversified mix of renewables and nuclear thus makes it possible to optimise grid costs and the cost of balancing supply and demand. Developing them in tandem offers greater resilience to uncertainties regarding the shift in demand and the respective costs of the technologies.[d]

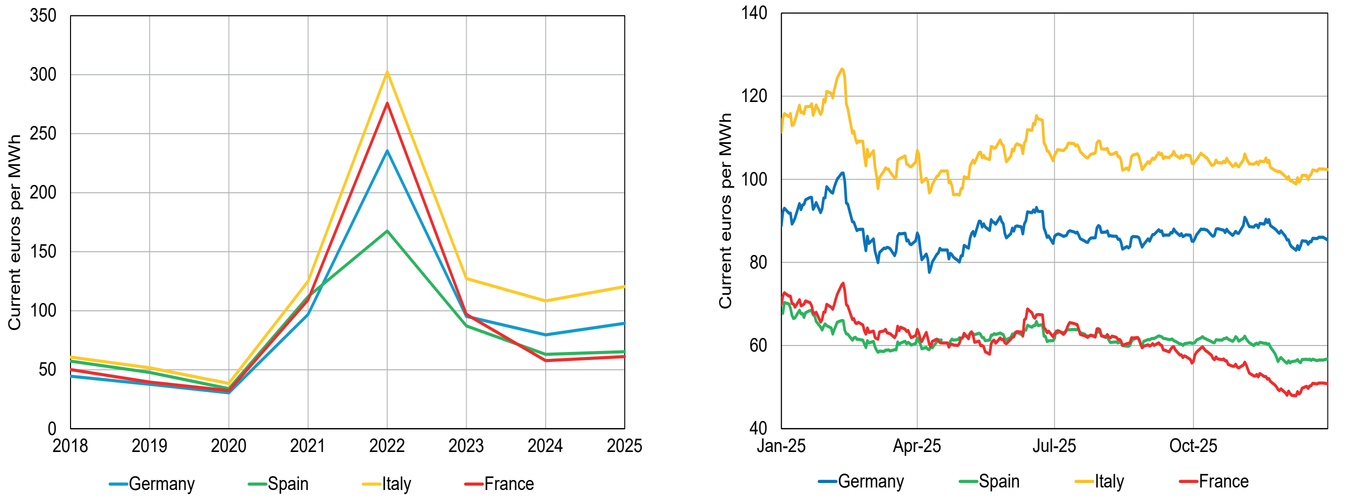
a. Ministry for the Ecological Transition (2025), "Chiffres clefs des énergies renouvelables - 2025 Edition" (in French only).
b. A fall of 90 TWh (i.e. a 20% drop between the 2010s and 2020-2023), due to stricter safety requirements following the Fukushima disaster, work to extend the lifespan of reactors, the impact of the COVID-19 pandemic on maintenance schedules, and the discovery of stress corrosion cracking.
c. According to RTE, renewable electricity capacity consisting mainly of wind power rather than solar would be economically optimal in 2050, given that solar generation, which is abundant in summer and at midday, occurs at times of low consumption and is therefore less valuable than wind power, which generates more in winter than in summer.
d. *DG Trésor* (2025), "The economic challenges of the transition to carbon neutrality".

1.2 France currently enjoys lower electricity prices than most neighbouring countries

Since the end of the energy crisis, wholesale electricity prices[14] in France have reverted to a level comparable to that observed before the crisis, i.e. lower than in most neighbouring countries (see Chart 1). This difference is linked to a return to high electricity generation in France from the existing nuclear capacity and relatively low demand. From a more cyclical perspective, significant renewable generation combined with low consumption has led to wholesale prices in France being significantly lower than in neighbouring countries, 32% below Germany and 49% below Italy in 2025.[15] This phenomenon is also reflected in forward prices,[16] with France having lower futures[17] contract prices than any of its neighbours, including Spain, at the end of September 2025. Lastly, these trends are reflected in the final prices for households and businesses: in the first half of 2025, electricity prices for French households were lower than in Germany, Italy or Spain.[18]

(14) Prices of electricity delivery contracts (financial or physical) traded on stock exchanges.
(15) Data corresponding to daily (spot) prices in 2025, LSEG data.
(16) Prices at which electricity delivery contracts are traded for maturities beyond the next day (e.g. week, weekend, month, quarter, year).
(17) Standardised futures contracts listed continuously on stock exchanges and subject to regular margin calls.
(18) Eurostat (2025), Household electricity prices in 1st half of 2025.

Chart 1: Average annual spot price (left) and calendar price for 2026 (right) in France and the main neighbouring countries



Sources: DG Trésor calculations, LSEG data.

How to read this Chart: In 2025, the average spot price[19] in France was approximately €61/MWh, compared with €89/MWh in Germany. At the end of December 2025, the 2026 calendar futures prices[20] stood at €51/MWh in France, compared with €57/MWh in Spain and €85/MWh in Germany.

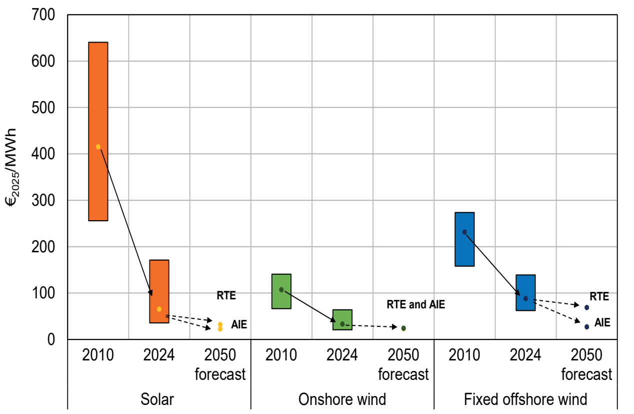
1.3 The full generation costs for renewable electricity have fallen sharply in recent years, without reaching the low market prices in France

Over the past decade, renewable electricity has seen significant cost reductions, particularly solar and wind power, where the cost per MWh fell by 85% and 70% respectively between 2010 and 2024 (see Chart 2). The reduction in generation costs is linked to the structure of the sector, with significant economies of scale, and to gains brought about by technological progress,[21] but also to government support, which has facilitated the financing of these technologies by reducing the cost of capital.[22]

However, it remains uncertain how generation costs will change in the future. While further cost reductions are expected in line with past trends, several external factors may slow them down. The recent rise in interest rates has increased project costs, which are highly sensitive to the cost of capital, despite government support. In addition, pressure on the supply chain is leading to short- and medium-term increases in component prices, adversely affecting the economic performance of projects.[23] Furthermore, although significant efficiency gains have been made in the past, wind and solar power may be approaching their maximum energy conversion limits.[24] Lastly, the most favourable sites are already being exploited,[25] leaving future projects with locations offering less potential in terms of resources.[26]

(19) Also known as the day-ahead price, this is the price at which a MWh of electricity is traded for delivery at a given time on the following day.
(20) The price at which a MWh of electricity is traded for delivery throughout a specified year.
(21) *DG Trésor* (2025), "The economic challenges of the transition to carbon neutrality".
(22) Reducing the cost of capital is brought about by minimising price uncertainties. IRENA (2025), "Renewable Power Generation Costs in 2024".
(23) For example, pressure on supply chains is linked to their geographical concentration against a background of rising demand (IEA, 2025, World Energy Investment 2025 and Special Report on Solar PV Global Supply Chains).
(24) Solar and wind technologies have maximum theoretical efficiencies limited by the physical principles of converting solar and kinetic energy into electrical energy.
(25) The regulatory framework may restrict project development: e.g. aviation and military constraints for onshore wind power.
(26) J. Devezeaux de Lavergne (2025), "Électricité bas carbone : éléments de prise en compte économique des impacts sociaux et environnementaux" (in French only).

Chart 2: Trends in the full costs of solar and wind power generation



Sources: DG Trésor calculations based on data from the International Renewable Energy Agency (IRENA), Réseau de Transport d'Électricité (RTE), International Energy Agency (IEA).

How to read this Chart: The lower and upper bounds represent the 5th and 95th percentiles, worldwide. For solar and onshore wind, the central point represents the cost of generation in France, whereas for fixed offshore wind it corresponds to Europe. Between 2010 and 2024, according to IRENA, the levelized cost of electricity (LCOE), representing the average discounted cost of generating 1 MWh of electricity over the lifetime of a project, fell by 85% for solar power in France, from €415_{2025} in 2010 to €65_{2025} in 2024.

How to read this Chart (2): In some countries, grid operators may pay the costs of connecting offshore wind farms, as is the case in France. Hence, their cost cannot be directly compared with solar and onshore wind.

The potential for renewable energy generation is diversified in France, combining large regions with high levels of sunshine and several areas with favourable wind patterns.[27, 28] However, the levelized cost of electricity (LCOE – see Box 2), is higher than in some neighbouring countries, Spain in particular. This difference can be explained in particular by lower installation costs in these countries, which may be associated with (i) lower labour costs, (ii) easier access to land, or (iii) more flexible authorisation procedures.[29] This situation in France, combined with relatively low market prices, reinforces the need to support renewable electricity,[30] as the generation costs of renewable energies are still higher than market prices, and the volatility of these prices discourages investment.

Box 2: The levelized cost of electricity (LCOE) is an indicator of the cost of generating energy from an asset over its lifetime, and should be used conservatively

The levelized cost of electricity (LCOE) is the average cost of generating one unit of electricity (in €/MWh) over the entire lifetime of a facility. It is calculated by dividing the discounted sum of all costs (e.g. initial investment, maintenance, fuel where applicable, decommissioning) by the discounted sum (at a rate reflecting the cost of capital) of the total quantities of electricity generated. This calculation method allows for like-for-like comparison of the pure generation cost at the power plant for each technology (renewable energy, nuclear, fossil fuel).

This indicator, which is relevant for an immediate comparison of the competitiveness of two similar projects, does have several limitations, however. It is heavily influenced by financial parameters (financial leverage, cost of equity, interest rates) and does not take into account the costs or benefits generated by the asset in question for the electricity grid. In particular, due to their fluctuating generation capacity and diffuse geographical distribution, renewable electricity may involve higher system costs than nuclear power, as a result of additional requirements in terms of grid access (infrastructure construction) and the development of flexibility (e.g. batteries, load shedding).

Consideration of system costs may also be supplemented by additional factors when determining the optimal electricity mix for society. In particular, each technology generates several externalities (e.g. impact on greenhouse gas emissions or on the landscape), some of which are difficult to express in monetary terms.[a] The OECD has put forward a method for including as many of these externalities as possible in order to establish the full social cost of a technology.[b]

a. IRENA (2025), op. cit.
b. OECD & Nuclear Energy Agency (2024), "NEA system cost analysis for integrated low carbon electricity systems".

(27) European Commission (2025), "Photovoltaic geographical information system"
(28) European Commission, Joint Research Centre (2018), "Wind potentials for EU and neighbouring countries".
(29) IRENA (2025), "Renewable power generation costs in 2024".
(30) R.W. Hahn et al. (2025), "A Welfare analysis of Policies impacting Climate Change", NBER, *Working Paper* 32728.

2. Support mechanisms for renewable electricity have changed in line with their growth

2.1 Support for renewable electricity, historically based on an obligatory purchase model, has shifted towards a feed-in tariff model providing greater exposure to the electricity market

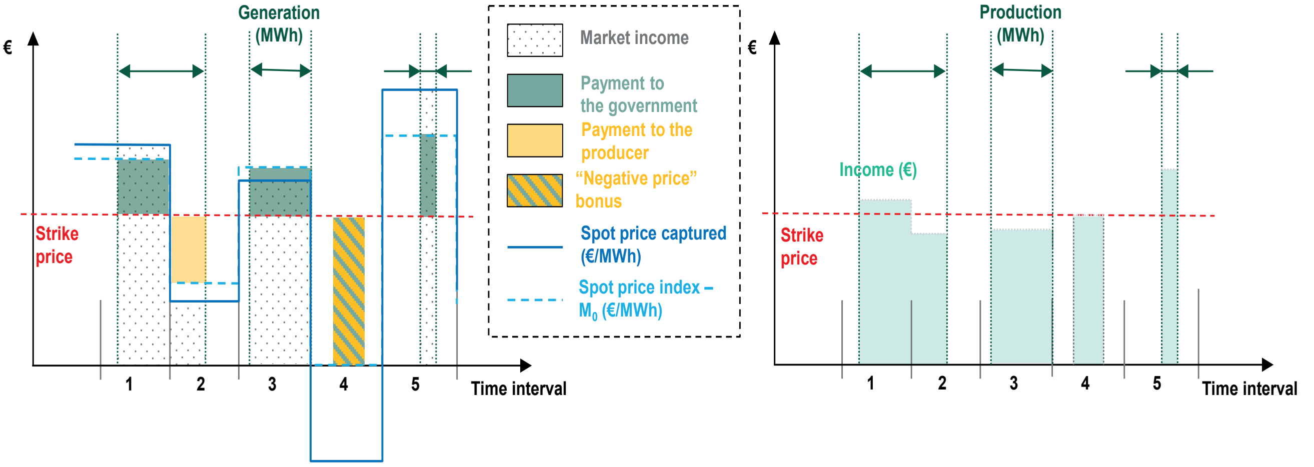
The cost structure of renewable energy projects is dominated by fixed costs (components, construction, connection, etc.), to which financial costs must be added. Together, they account for 85% of the full cost for solar and 70% for wind.[31] Uncertainty surrounding electricity market prices, and the income from these projects, constitutes a significant financial risk, which could have an impact on financing costs and the expected return on investment. Ensuring stable sale prices over the lifetime of the project makes it possible to reduce overall costs and improve the competitiveness of the technology, in exchange for transferring the risk to the entity that guarantees stability.

Box 3: How the feed-in tariff works

The feed-in tariff system is based on the principle of a bonus and takes the form of a Contract for Difference (CfD).[a] The facility sells its electricity on the market and receives a top-up payment, based on the difference between a (fixed) strike price and an average market price index. At each time interval (e.g. 15 minutes since 1 October 2025), if the observed market price is lower than the contract strike price, the government makes a top-up payment to the producer. If the opposite is true, the producer pays the difference to the government, and the contract is then referred to as a two-way Contract for Difference.

The market price reference used (M_0) is generally defined as the monthly average of day-ahead market prices capturedb by facilities in the sector (solar, wind or small hydropower). As a result, if the price captured[b] by the facility is above M_0, it will earn more than it would if it sold its output at the strike price. If the opposite is true, it will earn less. In other words, each supported solar or wind power facility has an incentive to capture higher prices than the average for similar facilities. This can be achieved by maximising the availability of the facility during peak hours, for example, thereby better meeting the requirements of the electricity grid. The Chart below shows the producer's final income over a few hours, once the feed-in payment has been made.

Chart 3: Financial flows between the producer and the government under the feed-in tariff system (left) and the final income for the generator (right)



Sources: DG Trésor, and I. Schlecht, C. Maurer and L. Hirth, ZBW (2023), Financial Contracts for Differences.

How to read this Chart: For the second hour represented, the spot price is below the strike price, and the spot reference price (M_0) is higher than the price captured by the facility. The facility receives the feed-in tariff but incurs a loss corresponding to the difference between its capture price and the average capture price for similar facilities (M_0). For the fourth hour shown, a "negative price" bonus is paid to the facility, which did not generate during that hour, which is preferable for the electricity system.

a. J. Hansen, A. Janssens and J. Percebois (2019), "Énergie: Économie et politiques" (3rd edition) (in French only).
b. The price captured by a facility corresponds to the average market price weighted by its hourly generation, reflecting the actual value of the electricity it feeds into the grid.

(31) IEA & Nuclear Energy Agency (2020), "Projected Costs of Generating Electricity".

Historically, the determination to promote the renewable energy sector and the lack of liquidity in the French electricity market have led to government support based on an obligatory purchase system, which currently accounts for 71% of the volumes supported. This system guarantees that the electricity generated will be purchased by the government at a predetermined fixed price, usually over 20 years.

Support contracts have gradually shifted from obligatory purchase to a feed-in tariff model, to encourage the participation of renewable energies in electricity markets and the development of aggregators.[32] The feed-in tariff system is a Contract for Difference (CfD) whereby producers sell their electricity at the market price and receive an additional premium based on the difference between a fixed reference tariff (strike price) and an average market price (see Box 3). This differs from obligatory purchase in that it introduces an incentive for producers to generate when market prices are higher, i.e. when it is most useful for the electricity grid.

2.2 CfDs facilitate the participation of renewable electricity in electricity markets

Contracts for Difference such as those used in France are comprehensive instruments that reduce the private cost of financing projects, ensure the implementation of projects necessary for the energy transition, and encourage producers to play an effective role in the market. In particular, when negative prices apply, the feed-in tariff is not paid and is replaced by a bonus conditional on the effective shutdown of the facility, which limits the contribution of renewable generation to the occurrence of negative prices (see Box 4). These features led the European Commission to encourage this type of support in the Electricity Market Design Regulation that was adopted in 2024.[33]

As such, this feed-in tariff model is the arrangement favoured by France to support new renewable electricity facilities. It accounted for 70% of contracts concluded for the period 2023-2024.[34] The remainder, under the obligatory purchase model, are mainly small facilities (e.g. rooftop solar panels on small buildings) that are not able to participate directly in the electricity market.

In 2025, Contracts for Difference should represent a total of 24 TWh, or 31% of renewable generation supported in France, with planned government expenditure of €654m,[35] or about 11% of the projected €6.2bn government support for renewable electricity. Divided by energy produced, the cost of government support provided through top-up payments is €27/MWh, more than four times less than support through the obligatory purchase model.

This difference is due to the fact that (i) obligatory purchase contracts are generally older and were concluded at higher prices, at a time when generation costs were higher, thus enabling the sector to get off the ground and (ii) the volumes supported via obligatory purchase come from proportionately smaller facilities, such as rooftop solar, where the purchase prices are higher than for large facilities, notably due to lower economies of scale.[36]

(32) An aggregator is a company that contracts with electricity producers to manage various transactions on the electricity markets: sales, balancing, flexibility.
(33) Regulation (EU) 2024/1747 amending Regulations (EU) 2019/942 and (EU) 2019/943, adopted in May 2024, known as the Electricity Market Design or EMD regulation.
(34) Energy Regulation Commission (CRE) (2025), "Bilan du dispositif de complément de rémunération" (in French only).
(35) Energy Regulation Commission (CRE) (2025), "Délibération relative à l'évaluation des CSPE" (in French only).
(36) Energy Regulation Commission (CRE) (2025), "Bilan du dispositif de complément de rémunération" (in French only).

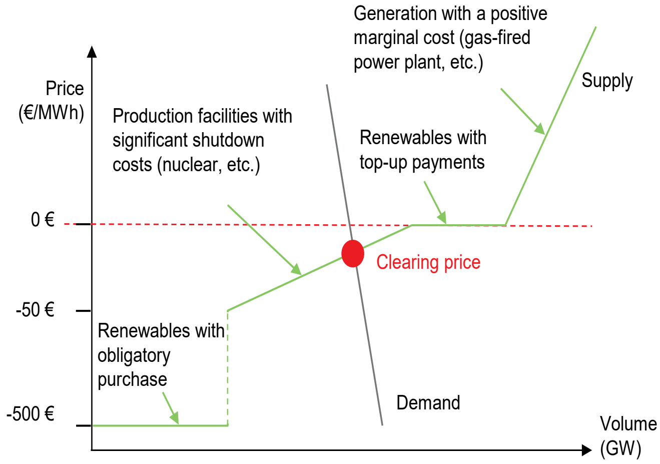
Box 4: Occurrence of negative prices on the wholesale market

The electricity grid is based on a permanent balance between supply and demand. On the day-ahead wholesale market, the price is determined by the intersection of the demand curve – which aggregates suppliers' buy orders – and the supply curve – which aggregates producers' sell orders. In theory, this supply curve is formed by stacking producers' sell orders, each setting its price according to its marginal cost of generation. Renewable energies, with zero marginal cost, should appear among the first, followed by conventional energies in ascending order (nuclear, hydropower, gas, coal, etc.). The price thus determined, known as the clearing price, corresponds to the marginal cost of the last production facility needed to satisfy the demand. All selected producers are remunerated at this price, according to the pay-as-clear mechanism (see Chart 4).

Facilities under the obligatory purchase system receive their remuneration at the guaranteed rate, regardless of the market signal. They therefore have an incentive to generate, regardless of the market price, as the support mechanism guarantees that they are paid at a fixed price whatever the circumstances.[a] Hence, there is no correlation between the corresponding bids and their marginal cost and they are set at –€500/MWh, the minimum possible on the spot market, ensuring that they are selected by the clearing mechanism. Facilities receiving top-up payments, on the other hand, have an incentive to stop generating in the event of negative prices, as government support is conditional on this, and they set their sell bid at around €0/MWh.

During periods combining low demand with high renewable generation (such as midday on a sunny weekend), the marginal generation facility selected may be a power plant (e.g. nuclear), which has to keep operating at a minimum level and is ready to pay, for a few hours, to generate rather than not generate. In this case, its marginal generation cost is negative, and the clearing price becomes negative (see Chart 4).

Chart 4: Schematic representation of negative prices in the electricity system[b]



Source: Energy Regulation Commission (CRE).

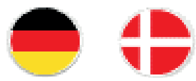
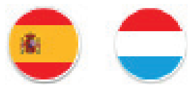
How to read this Chart: On the supply curve, renewables under the obligatory purchase system are represented with a bid of –€500/MWh, the minimum possible, in order to guarantee sales in all circumstances. In contrast, renewables receiving top-up payments have an incentive to stop generating if the price is negative: they are represented with a bid of €0/MWh.

a. *Office Franco-Allemand pour la Transition Énergétique* (2025), "Prix négatifs aux bourses de l'électricité: rôle et implications du photovoltaïque et de l'éolien" (in French only).
b. Energy Regulation Commission (CRE) (2025), "Analyse de la CRE sur le phénomène de prix de l'électricité négatifs" (in French only).

2.3 In European countries, support policies differ depending on the trade-offs made between economic efficiency and exposure of public finances

To achieve their renewable energy targets, European countries have adopted various support strategies. Some countries have chosen to base their overall support framework on market principles, while others, such as France, have focused their strategy on planning principles. Table 1 analyses national support strategies according to three economic objectives (i) reducing risks for project leaders and rolling out facilities at a lower cost, (ii) limiting the exposure of public finances to the cost of support and (iii) the capacity of the support system to achieve an optimal electricity mix for society. Some schemes have additional goals, such as supporting technological innovation, but these are not discussed here.

Table 1: Comparison of renewable energy support strategies, and their ability to achieve certain objectives

Overall support framework	Support strategy	Examples of countries where implemented	Objectives sought		
			Reduced risks for project leaders and lower generation costs	Reduced exposure of public finances to market price	Ability to achieve optimal mix for the community
Guided by planning principles	Government support through calls for tenders or on-tap mechanisms, and awarding of Contracts for Difference		+++	+	+++
Guided by market principles	Full exposure to the market (possibly with calls for tenders or on-tap mechanisms)		+	+++	++
	Green certificates, voluntary or with mandatory mechanisms		++	+++	+
	Development of Power Purchase Agreements (PPAs)		++	+++	+

Sources: DG Trésor (2024), "Étude Comparative Internationale" and Energy Regulation Commission (CRE) (June 2025), "Bilan du dispositif de complément de rémunération en France" (in French only).

How to read this Table: "Green certificate" schemes have been implemented in Denmark and Belgium. They moderately reduce the risks for project leaders and do not guarantee an optimal electricity mix, but they do eliminate the exposure of public finances to market prices.

Some European countries, such as Spain, rely heavily on long-term bilateral contracts (Power Purchase Agreements or PPAs),[37] which allow the risk of projects to be transferred to the private sector, thus neutralising the impact on public finances. These contracts are in the minority in France: they account for 5% to 10% of total annual wind and solar generation,[38] and their momentum slowed in 2024, coinciding with the fall in wholesale electricity prices.[39] This proportion is expected to remain low in the medium term because, firstly, the full cost of renewable generation is likely to remain above market prices,[40] and secondly, few buyers are able to commit to long-term consumption.[41] Furthermore, in countries where electricity generation is highly carbon-intensive, the supply of green electricity associated with PPAs can be a decisive factor in signing this type of contract. Thirdly, the incentive is reduced in France, due to the fact that the vast majority of its electricity generation is carbon-free.

Mechanisms such as guarantees of origin and green certificates make it possible to trace the renewable origin of energy, promoting green electricity to consumers and on markets.[42] Being more regulatory in nature, they do not directly affect the government budget, but they do not ensure the development of an optimal electricity mix for society. In theory, these mechanisms can – either spontaneously when the mix is carbon-intensive, or through mandatory requirements – enable the development of renewable energy according to market principles. Although they represent virtually no cost to public finances as they are funded by consumers, they have several limitations. Firstly, they do not guarantee the same level of predictability for stakeholders as top-up payments, as the price of certificates may vary according to market conditions (e.g. adjustment of the mandatory requirements by the public authorities). Secondly, they do not automatically guarantee investment in new capacity, unless the public authorities set a mandatory volume. Lastly, this type of mechanism limits the government's ability to decide which sectors to develop by favouring the cheapest generation capacity, without taking into account externalities for the electricity system (e.g. grid development costs, social acceptability).

(37) PPAs are long-term contracts whereby the producer undertakes to sell to a buyer, who in turn undertakes to pay a predetermined price over a predetermined period.
(38) Contracts signed since 2019 represent a total of about 5.4 TWh/year, compared with annual wind and solar generation of 70 TWh in 2024. Capgemini Invent (2025), "Baromètre des achats d'énergie verte en France" and SDES (2025), "Chiffres-clés de l'Énergie" (in French only).
(39) Energy Regulation Commission (CRE) (2025), "Observatoire de la CRE relatif aux PPA" (in French only).
(40) Baringa (2022), "Commercial Power Purchase Agreements".
(41) S. Mili and E. Côté (2025), "Green on demand? Offtaker preferences for corporate power purchase agreements", *Energy Policy*.
(42) A price is then set, depending on market conditions, for each green certificate issued.

3. The expected unit support cost for renewable energy should be lower than in existing contracts

3.1 Measures have been implemented to improve the effectiveness of support and reduce its cost to public finances

In the short term, the electricity grid is characterised by surplus generation, following a period of under-capacity during the 2022–2023 crisis.[43] This surplus contributes to lower wholesale prices in France, bolsters competitiveness for French consumers (see Chart 1) and is exported to neighbouring countries. This constitutes a favourable price signal for electrification by reducing the price ratio between electricity and fossil fuel alternatives, thereby improving the return on low-carbon investments by households: heat pumps, electric vehicles, etc.[44] For example, a decrease in the regulated sales tariff (TRV) of a similar magnitude to that observed in February 2025 (a 15% drop, or €43/MWh including VAT) reduces the total cost of acquisition of a heat pump by approximately 6%, or €1,800, all other things being equal.[45]

However, low market prices translate into a significant cost to public finances in supporting renewable energy. The cost of this support depends on the difference between strike prices and market prices. This cost changes in inverse correlation to market prices: i.e. the cost of support increases when electricity market prices fall, and vice versa.

The reduction in financing costs made possible by public support contracts (obligatory purchase or top-up payment) is effective at microeconomic level. From a macroeconomic perspective, these mechanisms transfer the price risk from investors to society.

To limit the exposure of public finances and expand the participation of renewables in electricity markets, various changes have recently been implemented to control costs. For example, part of the on-tap solar support mechanism, for which volumes exceeded planning targets, has been converted into calls for tenders with volumes set by the government.[46] Measures have also been introduced to limit the contribution of renewable energies under the obligatory purchase system to the intensity of negative price episodes,[47] thus limiting the fiscal cost of support. Furthermore, discussions are in progress to enhance the effectiveness of support mechanisms for renewable electricity generation (obligatory purchase and top-up payment).[48]

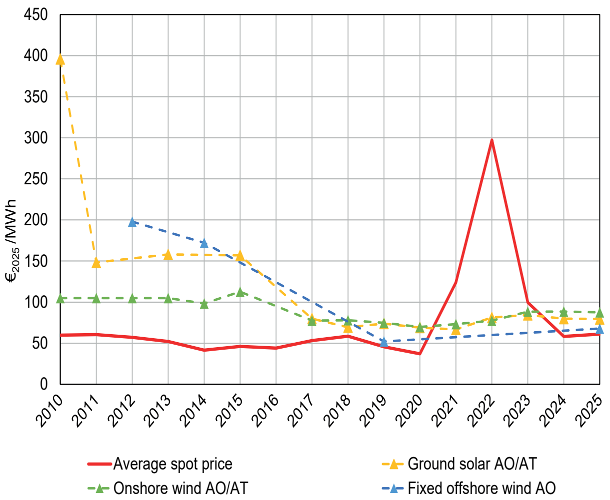
3.2 Installed renewable electricity is less costly today: until 2035, the annual cost of support will continue to be dominated by the cost of contracts signed before 2024

While saturation of the best sites or rising component costs[49] may push up generation costs, intrinsic cost reductions linked to technological improvements should prevail and enable the real cost of generation to continue to fall. For ground-mounted solar and wind power, the average price selected for calls for tenders or for the most competitive tariff orders, which is representative of the actual cost of the facilities,[50] has fallen sharply since 2010, approaching the average spot price (excluding the 2021-2023 crisis period, see Chart 5).

(43) Low-carbon electricity generation showed a downward trend during the energy crisis (380 TWh in 2022) due to (i) the shutdown of nuclear power plants due to stress corrosion cracking and (ii) a prolonged drought that reduced hydropower generation to its lowest level since 1976. In 2024, nuclear generation completed its recovery after the crisis of 2022/2023, and renewable hydropower generation reached an all-time high (70 TWh), according to the 2024 Annual Electricity Review from RTE.
(44) *DG Trésor* (2025), “The economic challenges of the transition to carbon neutrality”.
(45) Calculation assumptions: purchase cost of €15,000, total cost of acquisition over 20 years discounted at 7%.
(46) Order of 26 March 2025 amending the order of 6 October 2021 setting the conditions for purchasing electricity generated by solar facilities on buildings with a capacity of less than 500 kW – Légifrance.
(47) Amendment No. II-4003 of 12/11/2024 to the 2025 Budget Bill, adopted in the final version (Article 175).
(48) Energy Regulation Commission (CRE) (2025), “Bilan de la CRE sur le complément de rémunération et recommandations pour l’avenir” (in French only).
(49) T. Gerarden, M. Reguant and D. Yi Xu (2025), “The Role of Industrial Policy in the renewables sector”, *NBER.*
(50) The results of the calls for tenders or tariff orders shown represent a lower limit (some technologies, such as rooftop solar, have higher intrinsic costs).

In 2025, more than half the cost of support corresponds to facilities commissioned before 2015, even though they account for only a quarter of the generation receiving support. Some old contracts led to excessive remuneration for producers. The 2026 Budget Bill provides for their retrospective revision in order to restore a reasonable profit level.[51]

Chart 5: Comparison of historical daily spot prices and average tariffs guaranteed by the support mechanisms



Sources: DG Trésor calculations, Energy Regulation Commission (CRE) and LSEG data. For offshore wind, data from M. Jansen (2022), "Policy choices and outcomes for offshore wind auctions globally".

How to read this Chart: In 2011, the average price offered by the government for a ground-mounted solar facility was €1502025/MWh. The price shown for offshore wind tenders does not include connection costs.

Note: The abbreviations AO/AT indicate that the price indices used correspond to on-tap tariff orders (AT) before 2017 and to calls for tenders (AO) after 2017.

In the coming years, the annual cost of support will continue to be dominated by the cost of past commitments (see Chart on the cover page).

Economic assessments associated with the projected commissioning of renewable energy facilities by 2035 show that, in a median price scenario,[52] future facilities will have a lower unit support cost than facilities supported in the past.[53] These costs are highly sensitive to price scenarios, as changes in the cost of support depend mainly on changes in wholesale prices. In the case of offshore wind, the unit cost[54] of support is expected to fall significantly, from €37/MWh for existing contracts to –€4/MWh for new contracts, for a given price scenario. This negative value means that the expected costs should be lower than average market prices, and that the sector should therefore generate revenue for the government. The sector's willingness to accept this situation can be explained by the stability of income provided by top-up payments, which act as a form of insurance against price volatility and, as such, have intrinsic value for investors. However, these trends will still need to be confirmed, particularly in light of changes in the full generation costs of the facilities.

(51) Government (2025), "2026 Budget Bill". Article 69, adopted by a vote of both assemblies (outside the 49.3 procedure).
(52) $€70_{2024}$/MWh. Assumptions of the Electricity Public Service Charge Management Committee (CGCSPE).
(53) CGCSPE (2024), "Avis du CGCSPE sur l'étude d'impact de la PPE3" (in French only).
(54) The unit cost of support corresponds to the average amount paid by the government for the generation of 1 MWh from this sector, according to observed or expected price trends.

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Publication manager:

Dorothée Rouzet

tresor-eco@dgtresor.gouv.fr

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