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Review of different national approaches to supporting renewable energy development

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1. EXECUTIVE SUMMARY

1.1 Introduction

To increase the share of RES-E, governments have designed and implemented promotional policies which provide direct and indirect financial aid to RES-E adapters and developers. These promotional policies include several instruments and support schemes. Different countries, and in some cases different governments in a country, use different combinations of these support schemes to promote different renewable technologies. In this work, we study support schemes that have been implemented since the late 1990s or early 2000s in five countries: the UK, Germany, Italy, Spain and Australia. We provide an overview of these schemes and their timelines for the following RES-E technologies: onshore wind, offshore wind, utility-scale solar PV, rooftop solar PV and solar thermal.[1] In addition, it is important to evaluate the effectiveness and efficiency of support schemes in promoting these RES-E technologies. We tackle these two values and provide specific discussions on each country, support scheme and technology. In what follows, we present a summary of our analytical approach and a summary of our findings.

1.2 The support schemes studied

The cost structure of RES-E technologies has been the most important factor hindering the development of electricity generation from RES. These technologies normally require high investment costs at the beginning, while their operating costs are much lower than those of conventional power plants. The issue of high RES-E investment cost was even more striking in the late 1990s and early 2000s, when an industry learning effect was not yet realised for these technologies. Therefore, governments have been offering different support schemes to investors to promote the deployment of renewable sources for electricity generation. Such support schemes can be classified as direct or indirect, regulatory or voluntary and price- or quantity-driven instruments (Haas et al., 2011). Table 1 shows this common classification of support schemes for RES-E as reported in the literature (Haas et al., 2004; Menanteau et al., 2004; Haas et al., 2008).[2]

Table 1. Promotional strategies for supporting RES-E taken from Haas et al. (2008).

		Direct		Indirect
		Price-driven	Quantity-driven	
Regulatory	Investment focused	Investment incentives Tax credits Low interest/soft loans	Tendering system for investment grant	Environmental taxes Simplification of authorisation procedures Connexion charges, balancing costs
	Generation based	(Fixed) Feed-in tariffs Fixed premium system	Tendering system for long term contracts Tradable green certificate system	
Voluntary	Investment focused	Shareholder programs Contribution programs		Voluntary agreements
	Generation based	Green tariffs		

Our focus in this work is on direct support schemes, which involve direct support payments to RES-E investors, and ones that are provided through regulatory approaches. The focus on regulatory approaches is because they are the main instruments that “differentiate the development pace and penetration of RES in different countries.” As Table 1 shows, these schemes involve either investment or generation and they can be price-driven or quantity-driven. The analysis in this work considers both price- and quantity-driven generation-based regulatory instruments to promote wind and solar technologies. These instruments include feed-in tariffs (FiTs), feed-in premiums (FiPs),

1 Note that not all these technologies are relevant to all the countries studied.

2 For a detailed explanation of the terminology in Table 1, refer to Haas et al. (2008).

tendering systems and tradeable green certificates (TGCs).[3] Table 2 provides a summary of instruments implemented to promote wind and solar technologies from the late 1990s in the five countries investigated.

Table 2. Historical overview of support schemes for electricity generation from wind and solar technologies. Own elaboration.

Country	Timeline	Scheme	Technology	Duration of support
United Kingdom	2002-2017	Renewable Obligation Certificate (ROC)	Onshore wind and solar PV	20 years
	2010-2019	FiTs	Onshore wind and solar PV	Onshore wind 20 years, solar PV 25 years
	2013-today	Two-sided FiPs through Contract for Difference (CfDs) (tenders)	Onshore wind and solar PV	15 years
Germany	2000-today	FiTs	Onshore wind and solar PV	20 years
	2012-today	FiPs	Onshore wind and solar PV	20 years
	2015-today	FiPs through tenders	Onshore wind and solar PV	20 years
Italy	2001-2012	Tradeable Green Certificates (TGCs)	Onshore wind and solar PV (until 2006) Onshore wind (2006-2012)	8 years 15 years
	2006-2013	FiTs	Solar PV	20 years
	2007-today	FiTs	Onshore wind	20 years
	2012-today	FiPs through tenders	Onshore wind (2012-2018) Onshore wind and solar PV (2019-today)	20 years 20 years
Spain	1998-2012	FiTs and FiPs	Onshore wind, solar PV and solar thermal	Onshore wind 20 years, solar PV 25 years
	2014-today	FiPs through tenders	Onshore wind, solar PV and solar thermal	Regulatory lifetime
Australia	2001-2010	Renewable Energy Certificates (RECs)	Onshore wind and solar PV	20 years
	2010-today	Large-scale Generation Certificates (LGCs)	Onshore wind and solar PV	20 years
	2010-today	Small-scale Technology Certificates (STCs)	Solar PV	20 years
	2008-today	State-level FiTs	Solar PV	20 years

For each of the countries investigated, we study the support schemes reported in Table 2 and changes in them until the present day. We analyse the schemes in terms of their effectiveness in attracting investments in RES-E generation technologies (wind and solar technologies in this study) and their efficiency. We follow Haas et al. (2008) by defining support policy effectiveness and economic efficiency as follows:

Effectiveness: The outcome of a support scheme in attracting deployment of RES-E technologies, i.e. the annual new and the cumulative installed capacity of a certain technology in the period that the scheme was implemented.

Efficiency: Based on the actual generation costs to society of each technology under a specific scheme and total generation by each technology under the specific scheme, changes in support levels over time are analysed.

1.3 Support schemes implemented and their outcomes in each case study

UK case study

We address four RES-E technologies in the UK: onshore wind, offshore wind, utility-scale solar and rooftop solar. The cumulative electricity generation by these technologies reached more than 89 GWh in 2020, with onshore and offshore wind corresponding to about 30 GWh each. Since the early

3 Called Renewable Obligation Certificates (ROCs) in the UK.

2000s, three different support schemes have been implemented in the UK[4] and contributed to the growth of the four technologies investigated.

Market-based Renewable Obligation Certificates (ROCs), introduced in 2002, was the first scheme to promote RES-E deployment in a competitive and technology-neutral manner.[5] The nature of ROCs was such that only large-scale generators could benefit from the scheme so it was not relevant to rooftop solar PV. With some changes along the way, ROCs continued to provide support for new installed capacity until 2017. In the early years of the ROC scheme, mainly onshore windfarms were accredited, while several years afterwards the introduction of banding for offshore wind and utility-scale PV kickstarted investments in these technologies too. During the period 2002-2017, 12.2 GW of onshore wind, 6.5 GW of offshore wind and 6 GW of utility-scale PV were accredited under the ROC scheme. These measures show that more than 75% of the existing onshore wind capacity and more than 60% of offshore wind and utility-scale PV capacities were created under this scheme, suggesting the effectiveness of the scheme. However, some criticisms have been made of the ROC scheme These include ineligibility of small-scale generators to benefit from it, a high risk of ending up in a zero price certificate market for generators and the high level of support which led to high total costs for consumers.[6] In fact, in terms of support payments, we estimate that ROCs remained the most important tool in the 2019/2020 fiscal year. Approximately 70% of the total payments supporting wind and solar technologies in the UK were made under the ROC scheme in this year. In terms of cost effectiveness, no decreasing trend has been seen for support payments per MWh generated under the ROCs scheme.

As already mentioned, the ROC scheme did not target small-scale generators such as rooftop PV. To fill this gap, administratively set feed-in tariffs (FiTs) were introduced in 2010 and were implemented until 2019, targeting RES-E generators with capacities below 5MW. The FiT scheme has been particularly important in stimulating the deployment of rooftop PV. 3.91 GW of rooftop PV, 0.97 GW of utility-scale PV and 0.74 GW of wind generation were installed under the FiT scheme. In terms of support costs, the share of FiT payments began to increase in 2011 when rooftop PV started to kick off by benefiting from the scheme. FiTs corresponded to about 10% of total support payments in 2019. Administratively set FiT levels, however, followed a decreasing trend for all the technologies but specifically for utility-scale and rooftop PV. The rationale behind the frequent reductions of FiT levels by the regulator was to limit windfall profits due to a gap between the FiT generation payments and continuing decreasing technology costs. This had a direct impact on average support payments per MWh of electricity generated under this scheme between 2010 and 2019. In this period, FiT payments decreased by approximately 45% for rooftop PV and 66% for utility-scale PV. Nevertheless, the level of FiT support is the highest compared to other schemes. This can be explained by the fact that significantly smaller generators, which benefit less from economies of scale in terms of investment costs, are supported by the scheme.

The newest and currently the main scheme supporting adoption of new RES-E capacity in the UK is the Contract for Differences (CfDs) scheme, which provides support for RES-E in the form of premiums. The CfD scheme started in 2013 with administratively set premiums but it adopted an auction-based mechanism to allocate premiums in 2014. So far, already about 12.9 GW of offshore wind, about 1 GW of onshore and remote island wind and 72 MW of utility-scale solar PV generation have been awarded CfD contracts in the UK. Not all this capacity has yet been built. This scheme, together with the ROC scheme, has led to the UK currently being the world leader in offshore wind deployment. The premiums for offshore wind projects that are to be delivered by 2023 and later are near zero. This means that ultimately these projects might cost the government (and the end consumer) almost nothing in subsidies. However, it is argued in the literature that adding some design elements (e.g. a delivery penalty) and some implementation measures (e.g. more frequent auctions)

4 In the chapter dedicated to the UK, we also briefly discuss PPAs and NFFO, two RES-E policies that were implemented in the period 1990-1998. However, we do not discuss them here as they date back to more than two decades ago and they did not have a significant impact on the deployment of the technologies investigated.

5 Technology-neutrality, which was the objective of the scheme at the beginning, changed later on as technology-specific bandings were introduced.

6 This has been pointed out by Haas et al. (2011), Mitchell et al. (2006) and Toke (2007).

could improve both the effectiveness and cost-efficiency of the scheme (Welisch and Poudineh, 2020). CfDs represented 20% of total support payments in 2019.

Germany case study

As in the case of the UK, we investigate onshore wind, offshore wind and utility-scale and rooftop PV technologies in Germany. Among these technologies, onshore wind is the main RES-E source in Germany with a significant 104TWh of generation in 2020. This is followed at a distance by utility-scale PV, offshore wind and rooftop PV, which collectively generated 75TWh of electricity in 2020. Growth in onshore wind generation is particularly attributable to implementation of a FiT scheme in 2000.

The FiT scheme in Germany dates back to 1991, yet it became effective in attracting RES-E investments in 2000. Since the start of the scheme in 1991 until 2019, approximately 25GW of onshore wind, 12GW of utility-scale PV and 23GW of rooftop PV capacities have been installed. Due to the large-scale nature of offshore wind plants, they are not relevant to this scheme. The majority of onshore wind capacity installations with FiTs took place in the early years of implementation of the scheme and before the introduction of caps on the size of plants benefiting from the scheme. The uptake of utility-scale and rooftop PV started in 2007 with FiTs but, like onshore wind, new capacity installations decreased for utility-scale PV after the introduction of size caps in 2014 and 2016. Since 2016, the scheme has only been relevant for small-scale installations and mostly rooftop PV. Besides the caps on eligible capacity sizes, a steep reduction in support levels also contributed to decreased investments in utility-scale PV. The same was true for rooftop PV. The rationale for this decrease in support levels for PV technologies under the FiT scheme was to keep up with the decrease in generation costs, and therefore limit generators making excessive profits. Indeed, Germany was one of the countries which cut or modified support levels according to technology cost reductions. Nevertheless, until 2017 support payments under the FiT scheme were the majority of total RES-E support payments, but they dropped to 45% in 2019.

In 2012, administratively set feed-in premiums (FiPs) with no capacity limits were introduced in Germany for all four technologies. However, as participation in the market was a compulsory requirement to benefit from the scheme, rooftop PV was excluded in practice. Obligatory participation in this scheme was introduced in 2014 for capacities above 500 kW and the scheme was modified to include capacities above 100 kW in 2016. These obligations were set to push direct participation by large-scale RES-E technologies in the electricity market. 16 GW of onshore wind, 2.3 GW of offshore wind and 9 GW of utility-scale PV have been added under this scheme from 2012 until 2019. The administratively set feed-in premiums contributed to kickstarting offshore wind technology in 2014 and 2015. However, an introduction of new capacity limits in 2017 made it impossible for offshore wind installations to benefit from the scheme.[7] In terms of support levels, utility-scale solar PV projects enjoyed a higher market premium payment than onshore and offshore wind projects from the start of the scheme.

Auctioning is currently the main mechanism in Germany for allocating financial support for renewable resources and for determining the level of support. FiPs have been allocated to RES-E technologies since 2015. 10 GW of onshore wind capacity, 3.1 GW of offshore wind capacity and 4.7 GW of utility-scale solar PV capacity have been awarded in 50 auction rounds until October 2020. The high frequency of auctions allows bidders to have more time to plan their projects and a higher chance of getting support, although the support level awarded might be lower in later tenders. The auction mechanism resulted in zero subsidy bids for offshore wind in auctions in 2017 and 2018 (the only auctions that were held for offshore wind). The resulting strike prices in auctions for onshore wind have been stable since 2017 but utility-scale PV strike prices decreased from their initial values in 2015 and have been stable since 2018.

7 In practice, with the 2017 capacity limits only medium-size installations (between 100 and 750 kW) can benefit from the scheme.

Italy case study

In this chapter we focus on three renewable technologies in Italy, namely onshore wind, utility-scale PV and rooftop PV. In terms of installed capacity, utility-scale PV is ahead of the other technologies with a total of 17 GW installed capacity in 2020. Support schemes in Italy have been differentiated for PV and non-PV technologies. In particular, utility-scale and rooftop PV have been supported with FiTs while Tradable Green Certificates, FiTs and FiPs have been used to promote onshore wind deployment.

Tradable Green Certificates (TGCs) were implemented from 2001 to 2012. They were similar to ROCs in the UK with the exception that they did not include PV technologies from 2006. Until 2006, TGCs did not induce any investments in PV technologies. As for onshore wind, not much interest was shown in deploying this technology in the first seven years of TGCs being implemented. Only 1.7 GW of onshore wind capacity was installed during this period. However, deployment of this technology boosted in 2008, when a reform of the scheme resulted in improving the dynamics in the certificate market. From 2008 to 2012, more than 6 GW of onshore wind capacity was installed under the TGC scheme, resulting in a 340% increase in electricity generation by this technology. Before the PV installation boom under the FiT scheme in 2011, TGCs had the highest share of RES-E support payments. This changed significantly in 2012. Support per MWh of generation (cost-efficiency), however, has remained stable since the start of the scheme.

Administratively set FiTs were another form of support for onshore wind. This started in 2008 and has continued until now. This was not a successful mechanism in Italy in terms of attracting investments in onshore wind technology. Until today, only about 250 MW of onshore wind capacity has been installed under the FiTs scheme. This is much lower than Germany's 25 GW. One important reason for this is that the FiT scheme in Italy included a cap on the size of onshore installations that were eligible to receive FiTs (200 kW until 2012, 1 MW between 2012 and 2016, 500 kW until 2019 and 250 kW after 2019). FiTs in Germany did not involve such limits on eligible onshore wind installations and allowed all installations with different capacities to benefit from the scheme.

Since 2012, FiPs have been allocated to new onshore wind installations through auctions. A total of 3.2 GW of onshore wind capacity was auctioned and awarded during the period 2013-2019. However, this volume is not very significant considering that the TGC mechanism led to investments in 6 GW of capacity (twice as much) in the six years before the start of the auctions. In addition, there are some criticisms regarding the inconsistency of auctions (no auctions were held in 2017 or 2018). However, auctions were relatively successful in decreasing the support level for onshore wind projects by 48% between 2013 and 2019.

Utility-scale PV and rooftop PV received support in the form of FiTs from 2006 to 2013. The policy under which FiTs were allocated to these technologies was called Conto Energia. 14 GW of utility-scale PV and 2.5 GW of rooftop PV were installed using FiTs by 2013. In particular, the technology boom happened in 2011 and continued to grow, although at a lower rate, until 2013, when the scheme was closed for new PV installations. Although FiTs were quite successful in kickstarting the technology, they came at quite a high cost. They have been accountable for 70% of RES-E support payments since 2011. Two reasons have been suggested in the literature for this outcome: a) the FiTs were too generous and b) the support levels were not adjusted to reflect the decreasing cost of technology. In an attempt to cut costs, support levels were decreased with reforms of the Conto Energia in 2011 and 2012 but these efforts were not timely enough to contain the increase in costs. After the end of FiTs for PV technologies in 2013 no specific scheme was introduced or implemented for these technologies until 2019, when they became eligible to participate in auctions and receive FiPs.

Spain case study

The three RES-E technologies in Spain which we focus on are onshore wind, solar PV and solar thermal. Onshore wind is the front-runner among these technologies in terms of both installed capacity and generation. In 2020, electricity generation by onshore wind reached 54 TWh, followed by

15 TWh of solar PV and 5 TWh of solar thermal. RES-E generation in Spain was supported with FiTs and FiPs through a *special regime* from 1998 to 2012. This support mechanism was retroactively abolished in 2013 and was finally replaced in 2014 with a new mechanism called *specific remuneration*. The new *specific remuneration* mechanism provides support for both new and existing RES-E installations in the form of FiPs.

Onshore wind was the technology which benefited more than the others from FiT and FiP schemes under the *special regime,* with cumulative capacity increasing from 1 GW in 1998 to 23 GW in 2012. During this period, the cumulative capacity of solar PV increased by 5 GW from zero, while the measure for solar thermal was only 2 GW. FiPs were more effective in attracting investments in onshore wind compared to FiTs. However, solar PV and solar thermal were almost entirely financed by FiTs. As expected, the level of FiTs was always set higher than that of FiPs, which contributed to their greater attractiveness. From 2007, solar PV installation could only receive FiTs. In the same year, FiTs for this technology were increased as since 1998 the mechanism had failed to attract investments in solar PV. The result was a boom in the sector in 2008, but it led to support costs soaring in successive years. Indeed, while until 2009 FiP payments had the highest share in total support costs (70%), after 2009 it was the FiTs scheme which had the majority of support costs.

The increasing cost of support led to abolishment of FiTs and FiPs under the *special regime* for all new and existing installations and the introduction of *specific remuneration* with FiPs as the only form of support in 2014. After the introduction of *specific remuneration*, average support payments per MWh for each technology decreased too, reflecting the reduced level of support awarded under this mechanism. Although *specific remuneration* was relatively successful in containing the increasing costs, some criticisms of this mechanism include heightened investor uncertainty regarding the stability of the policy, a lack of uncertainty regarding future revenue, a high level of complexity and lack of transparency in the support allocation procedure.

Australia case study

Onshore wind, utility-scale PV and rooftop PV are the RES-E technologies in Australia that we investigate. Like the majority of other cases in this work, onshore wind is the dominant technology in Australia. In 2020, 22.6 TWh of electricity was generated by this technology. When it comes to solar PV technologies, however, it is rooftop PV that has the higher generation value, with 15.7 TWh in 2020, compared to that of utility-scale PV equalling 8.1 TWh. The most relevant technology in terms of cumulative installed capacity by 2020 among the three examined is onshore wind, followed by rooftop PV and then utility-scale PV. Support schemes for RES-E in Australia can be classified as support for large-scale installations including onshore wind and utility-scale PV and support for small-scale installations including rooftop PV.

Support for large-scale installations has been provided through two national-level schemes: the first is national-level Renewable Energy Certificates (RECs) from 2001 to 2010 and the second is national-level Large-Scale Generation Certificates (LGCs) from 2010 onwards. The RECs were not really effective in attracting investments in either onshore wind or utility-scale PV. Only 1.5 GW of onshore wind was installed in 2001-2010. In contrast, LGCs have been more successful, with 9.5 GW of onshore wind and 7 GW of utility-scale solar having been installed since 2010. The support given to large-scale generators under these market schemes varied wildly and no certain trends can be seen. Additionally, the levels of payment under the second scheme were higher than under the first one, both in terms of average and maximum values. This explains the greater effectiveness of LGCs.

Support for rooftop PV can be divided into national-level (in the form of certificates) and state-level (in the form of FiTs). Two main national-level schemes have been implemented to support rooftop PV in Australia. The first was national-level Renewable Certificates, which started in 2006 and ended in 2010. The second, national-level Small-scale Technology Certificates (STCs), started in 2010 and continues until today. Like RECs, the first national-level scheme supporting rooftop PV was not successful and less than 100 MW of capacity was installed under it. Instead, the effectiveness of STCs was quite significant as the scheme led to a cumulative 7.1 GW of installed capacity by 2019. Like RECs and LGCs, these are market-based schemes and the levels of payment are volatile.

As for the state-level FiT schemes for rooftop PV, the collective installed capacity under these schemes was about 3 GW in 2019. The state-level FiT schemes, as can be seen from their name, are specific to each state and the FiT levels are set in each state independently from the others. Nevertheless, the state-level FiTs offered are considered to have been relatively generous in the initial years of potential accreditation. The level of support decreased in successive years in all the states that offer them.

1.4 How did RES-E support schemes perform?

In what follows, we discuss the different support schemes in terms of their effectiveness in promoting RES-E deployment and their economic efficiency.[8]

Feed-in Tariffs

Feed-in Tariff is a generation-based promotional scheme for RES-E. With FiTs a fixed regulated payment is allocated to RES-E generators as the financial support per kWh of their electricity generation regardless of the electricity price or generation cost. Under the FiT scheme, the financial support is paid to eligible generators by governments, utilities or suppliers. A corresponding governmental institution that decides upon RES-S support policies also sets the FiT levels.

FiTs can be successful in promoting less mature technologies[9] if investors are provided with a tariff level sufficient to meet their costs for a long time. This gives them assurance that they will have a revenue stream for a long time. In the cases investigated, FiTs have mostly been used to promote PV technologies rather than onshore wind. It has turned out to be an effective scheme to increase deployment of the technology in a short time. In Germany, Italy and Spain, PV sector booms happened shortly after the introduction of high FiTs.

The size of installations is another important factor in designing support schemes. Smaller technologies such as rooftop PV grow faster under FiT schemes. This is first because FiT levels are relatively high and provide an attractive investment opportunity for rooftop PV owners. Second, smaller installations do not have the potential to participate in certificate markets or to sell their generation on the electricity market and receive FiPs. In all the cases investigated, rooftop PV has been financed with FiTs. Large-scale technologies, on the other hand, can be promoted with different schemes, including FiTs. In this sense, stating that one support scheme is more effective than another is not straightforward, and it depends on how the policy is designed. For instance, FiTs were used to promote onshore wind in both Italy and Germany, with the difference that in Italy a capacity cap on eligible installations was in place (up to 200 kW) while in Germany no limits were set. The result was that onshore wind blossomed in Germany under FiTs while capacity additions in Italy under this scheme were marginal. Instead, the scheme under which onshore wind grew in Italy was Tradable Green Certificates.

The fast adoption of RES-E technologies under FiT schemes can result in the realisation of learning effects much faster than under other support schemes. This outcome will reduce the need for future high support levels and reduce overall support costs. However, due to the fact that FiTs are usually set at high levels and are awarded for long periods, they should be implemented with caution. In particular, future support levels for new installations under FiT schemes should be adjusted frequently to reflect technology cost reductions and to avoid putting an excessive cost burden on consumers. This approach can result in efficient implementation of the FiT scheme, albeit if done

8 We follow in Haas et al.'s (2008, 2011) footsteps by highlighting the performance parameters of different support schemes based on some of their corresponding design and implementation features. However, as they also note, there are other factors that can impact the effectiveness and efficiency of policy instruments. Resource endowment of RES and the dynamics of existing electricity systems in different countries are such factors. Analysis of these factors is beyond the scope of this work.

9 The maturity of RES-E technologies impacts investors' decisions to adopt them. Investors might not be keen to invest in less mature and riskier technologies. Therefore, promotion of different technologies needs to relate to their maturity levels to make the risk even for investors. Support schemes deal with this issue in different ways.

ex-ante, for new installations. On the other hand, ex-post adjustments to FiTs can result in increased uncertainty for investors regarding future revenue streams and thus discouraging them from investing in RES-E technologies (weakening the effectiveness of the scheme).

In the cases we investigate, Germany came out as quite successful in efficiently implementing FiTs. While the PV industry boomed in the country thanks to early generous FiTs, frequent, and steep, support level adjustments for new installations prevented significant support cost increases. As a result, the scheme still continues to exist for small-scale installations in Germany. This was not the case in Italy and Spain. Both countries provided generous FiTs for PV installations that were effective in promoting deployment of the technology. However, failure to adjust the tariffs to be more technology cost reflective for new installations in a timely manner led to excessive increases in the cost of the schemes and finally their abolishment in both countries.[10] In case of Spain, the scheme was abolished retroactively, for all existing and new installations. This led to sever financial difficulties for several existing installations and an increased sense of uncertainty among the investors.

Tradable Green Certificates/Renewable Green Certificates

Tradable Green Certificates (Renewable Obligation Certificates in the UK) are quota-based quantity-driven support schemes. Under these schemes, electricity generators/suppliers are obliged to produce/supply a certain percentage of their electricity from renewable sources. The said percentage or quota is decided upon by governments based on what they perceive to be the required level of RES penetration to reach their climate and energy targets. To demonstrate fulfilment of the obligation by generators/suppliers, they are required to provide a number of certificates that corresponds to the volume of electricity generated by RES. Generators/suppliers can obtain certificates by producing renewable electricity themselves or by buying it from other generators. The certificates are tradable in a specific market, thus, generators/suppliers have also this possibility to buy the certificates in the market without buying the electricity itself.

Among the five cases investigated, green certificate (quota-based) trading systems are only still in place in Australia, while their adoption for new installations has ended in both the UK and Italy. Nevertheless, quota-based trading systems have been quite successful in attracting investments in least-cost technologies with large-scale characteristics such as onshore wind. Deployment of onshore wind in the UK and Italy took place mainly through this scheme rather than FiTs. In the UK 75% of the existing onshore wind capacity has been financed through renewable certificates.

Green certificates have been used to promote both mature (such as biomass or hydroelectric) and less mature (such as onshore wind or utility-scale PV) technologies. Adoption of technology-specific weighting factors (such as bandings in the UK) allows promotion of novel and/or more expensive technologies. By allocating more than one certificate per MWh of generation to such technologies, they are compensated for their high generation costs.

However, some design elements can hinder the effectiveness (increasing deployment of RES-E technologies), and to some extent the cost-efficiency, of quota-based trading systems. In fact, both TGCs in Italy and ROCs in the UK were criticised for their poor performance and high support levels in the early 2000s (Haas et al., 2008, 2011; Mitchell et al., 2006). The most important criticism regarded the dynamics of the certificate market, which were affected by the administratively set buy-back prices. In addition, there were claims (see the chapter on the UK) that certificate markets can be gamed by generators so that zero price certificates were avoided. To address these issues, reforms were implemented in both countries that led to more effective schemes. In Italy, it was only after these reforms that deployment of onshore wind technology was enhanced. In terms of efficiency, no support cost reduction was seen in the countries investigated but as the cost of FiTs started to grow in the early 2010s less criticism was made of green certificate mechanisms as it turned out that their costs to society were much less than those of FiTs.

10 Note that in both countries complexities and mistakes during the implementation of announced policy reforms also contributed to augmenting FiT costs.

Tendering Mechanisms

The same as in the case of tradable green certificates, the tendering mechanism is a quantity driven strategy. Under this mechanism, auctions/tenders are held to allocate a pre-defined amount of capacity to eligible bidders. The auctioned capacity is decided upon by governments based on what they perceive to be the required level of RES penetration to reach their climate and energy targets. Auctions can be technology specific or multi-technology. The outcome of auctions is allocation of a RES technology capacity that is eligible to receive support for a specific duration, to the winning bidders. Allocated support under the tendering mechanism (auctions) is in the form of Feed-in Premiums.[11]

Compared to other schemes, tendering mechanisms are quite new instruments to promote RES-E generation. Their adoption was mainly due to the will of governments to move toward market-based approaches to allocating support and their will to encourage RES-E generators to participate in electricity markets. Except for Australia, all the countries investigated are currently using tenders as their main RES-E support scheme. In the UK, Germany, Italy and Spain participating in auctions is now obligatory for all new medium size and large installations to receive financial support and auctions are mostly technology specific. Not much can be said regarding the effectiveness of the tendering mechanism in terms of increasing RES-E capacities as the capacities auctioned are set by governments in advance and are based on required RES-E capacities to reach national/EU targets. However, the competition rate[12] can be considered a proxy for the effectiveness of these schemes, as it shows investors' willingness to invest in offered RES-E capacities. For instance, in Germany auctions can be perceived as effective in attracting investments in utility-scale PV, as in all previous auctions the capacities bid have always been more than those auctioned. The same has been true for onshore wind auctions in Italy.

For tendering mechanisms, in terms of cost-efficiency, heightened competition leads to lower allocated support levels, and therefore greater cost-efficiency. In fact, in Germany the resulting strike prices in utility-scale PV auctions decreased by 39% from 2015 to 2020. In the UK, strike prices for offshore wind installations decreased by 66% for projects to be delivered in 2025 compared to those which have been delivered in 2018. In Italy, the support level for new onshore wind installations decreased by 48% from 2013 to 2019.

Auctions can be considered quite successful in terms of attracting investments in mature and large-scale RES-E technologies with the least impact on consumers in terms of support costs. They can also be useful in promoting deployment of specific technologies (technology-specific auctions). However, there are some design and implementation issues that can threaten this success. A complex participation procedure, non-transparent auction rules, inconsistency of auction rounds and penalty levels set too low[13] are examples of such issues.[14]

The remainder of this report consists of five chapters, each corresponding to one of the country cases. They are presented in this order: the UK, Germany, Italy, Spain and Australia. In each chapter for each country we provide an overview of the support schemes implemented to promote wind and solar technologies and changes in them over time. We also discuss successful design features and implementation elements that resulted in certain schemes failing or being abolished.

11 Feed-in Premium (FiP), is a generation-based form of financial support under which a fixed amount is added to the electricity price per kWh of generation. It is different from FiT under which the whole payment (including the electricity price) to the generator is fixed. As the whole payment changes with the electricity price under FiP, it is considered to be more volatile comparing to FiT under which fixed payments are accredited to RES generators regardless of the electricity price.

12 The competition rate in an auction round is defined by AURESS II (2016) as the capacity bid over the capacity auctioned.

13 Setting too low delivery penalties or no penalties at all (as was seen in the UK) might increase the risk of non-delivery of the awarded capacities by winners.

14 These issues have been seen in investigated countries. Issue/country-specific discussions are provided in each corresponding chapter.

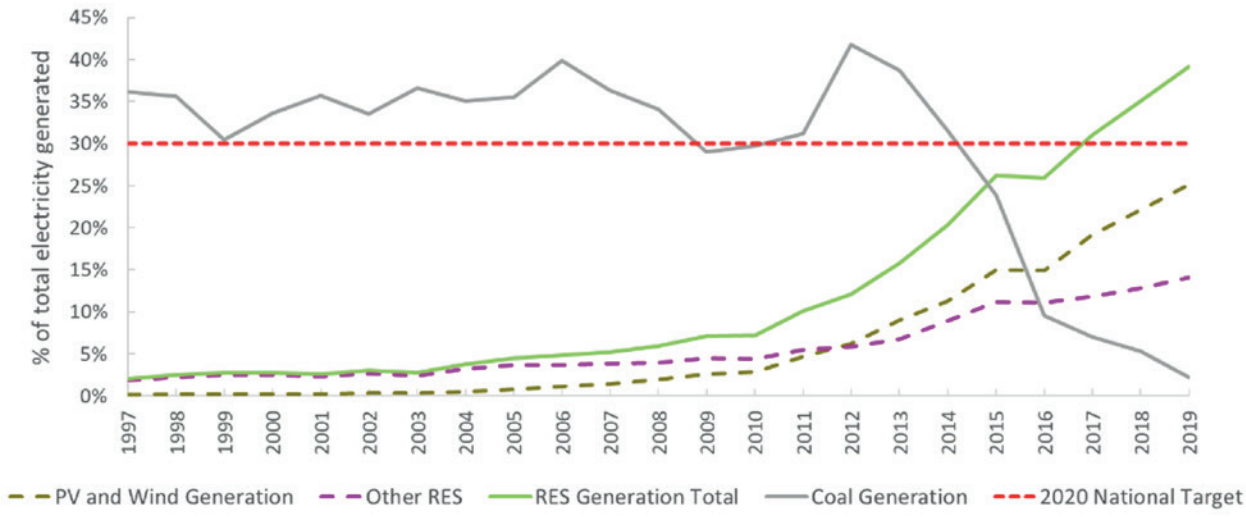
2. The United Kingdom (UK)

In this chapter we describe and analyse the main renewable support schemes that have been introduced in the United Kingdom (UK) to stimulate investment in onshore wind, offshore wind, utility-scale solar photovoltaic (PV) and rooftop solar PV. The chapter consists of five sections. First, we provide a general introduction. Second, we give an overview of the different support schemes that have been put in place and their effectiveness in terms of promoting the deployment of the renewable electricity generation technologies considered. We distinguish four schemes: auctioned power purchase agreements under the non-fossil fuel obligation (1990-1998), renewable obligation certificates (2002-2017), administratively set feed-in tariffs (2010-2019) and contracts for difference (2013-today). Third, we describe the annual costs of the different tools for each generation technology. Fourth, we discuss the cost-effectiveness of the support schemes, which we define as the annual expenditure of a support scheme per MWh of energy produced by all generators benefiting from the scheme. Last, we discuss the impact of the renewable support schemes on electricity bills.

2.1 General introduction

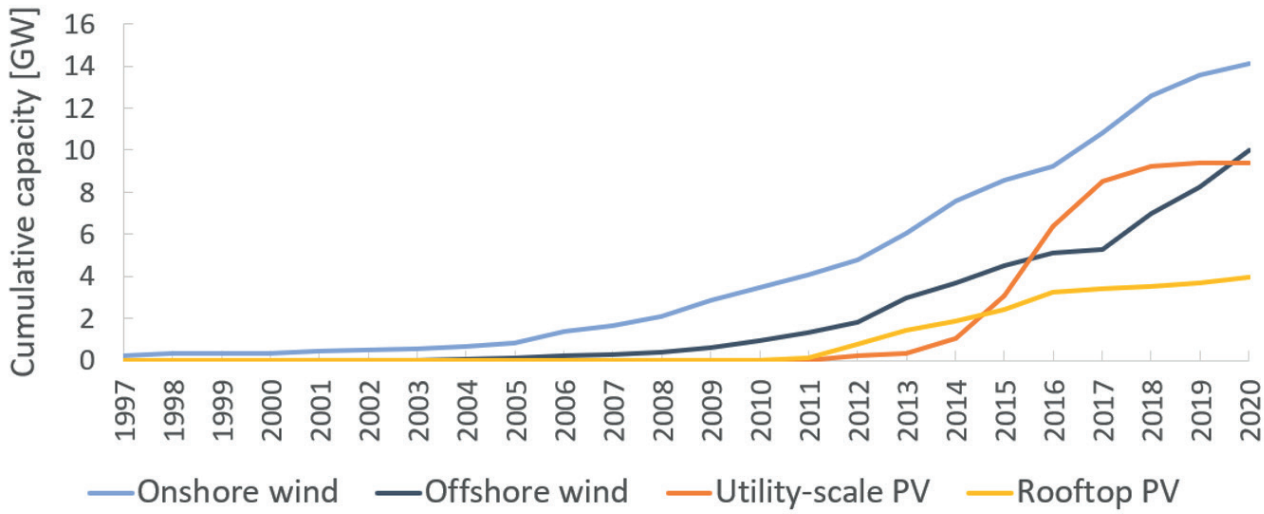
In recent decades governments have been promoting the uptake of renewable electricity technologies in many countries. These technologies are often deemed important elements in national strategies to reach climate goals. This is no different in the case of the United Kingdom (UK). An important milestone in this regard was the European 20-20-20 targets and the more recently adopted 2050 Net Zero target (European Commission, 2009; Piebalgs et al., 2020; UK Government, 2019a). Figure 1 shows the evolution of electricity generated from renewable electricity sources in the UK between 1997 and 2019. It can be seen that already in 2017 the UK reached its national target of 30% of electricity being generated from renewable sources by 2020 (UK Government, 2010). In 2019 almost 40% of electricity generated was produced from renewable energy sources, the majority of which were wind (21%), which was followed by biomass (12%) and solar PV (4%). 2019 was the first year in which renewables produced more electricity than fossil fuel generators (38%), and especially the decline in electricity production by coal power plants since 2014 has been significant. The remainder of electricity was produced by nuclear (19%).

Figure 1: Total RES generation versus coal and the 2020 renewable electricity target (1997-2019). Main source: BEIS (2020a)



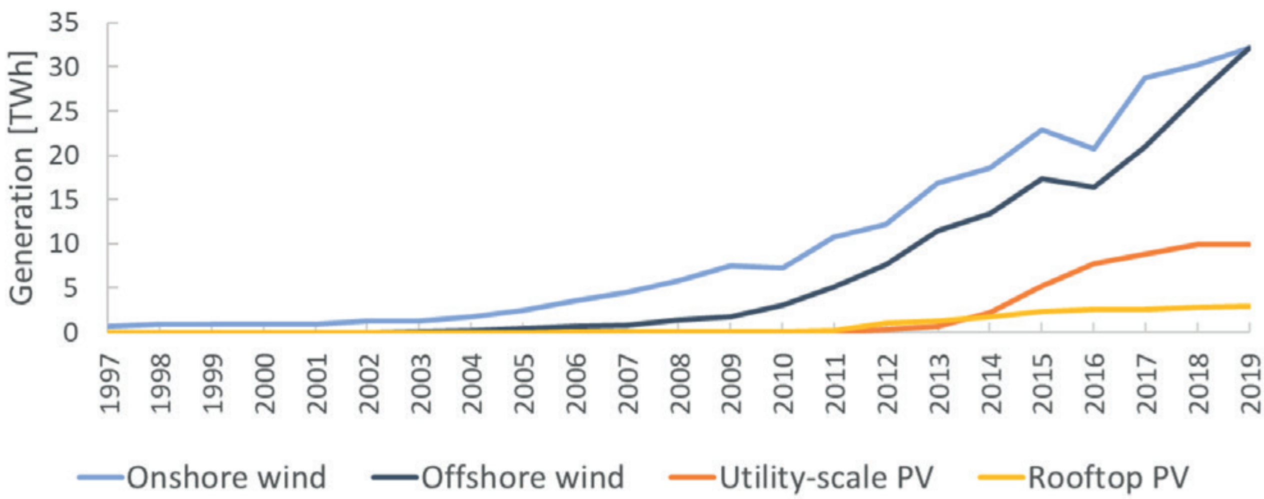
We focus on promotion via public financial support for four renewable electricity generation technologies: offshore wind, onshore wind, utility-scale photovoltaic (PV) and rooftop PV.[1] Figure 2 and Figure 3 show the evolution of the deployment of and the electricity generated by these four technologies in the UK.

Figure 2: Cumulative capacity installed in the UK (01/01/2007-01/01/2020). Solar PV with a capacity below 50 kW is considered rooftop. Main sources: BEIS (2020a, 2020b)



From Figure 3 it can be seen that in 2019 for the first time as much electricity was produced from onshore as from offshore wind generators. Each fulfilled about 10% of the electricity demand. A drop in terms of wind generation is noticeable in the year 2016, while the cumulative capacity installed increased year by year. This drop was the result of record wind speeds in 2015 followed by below average wind speeds in 2016 (UK Government, 2019b). Although below average wind speeds were repeated in 2019, the increase in capacity offset them and led to a record amount of electricity generated from both onshore and offshore wind.

Figure 3: Annual generation in UK (1996-2019). Main sources: BEIS (2020a, 2020b)



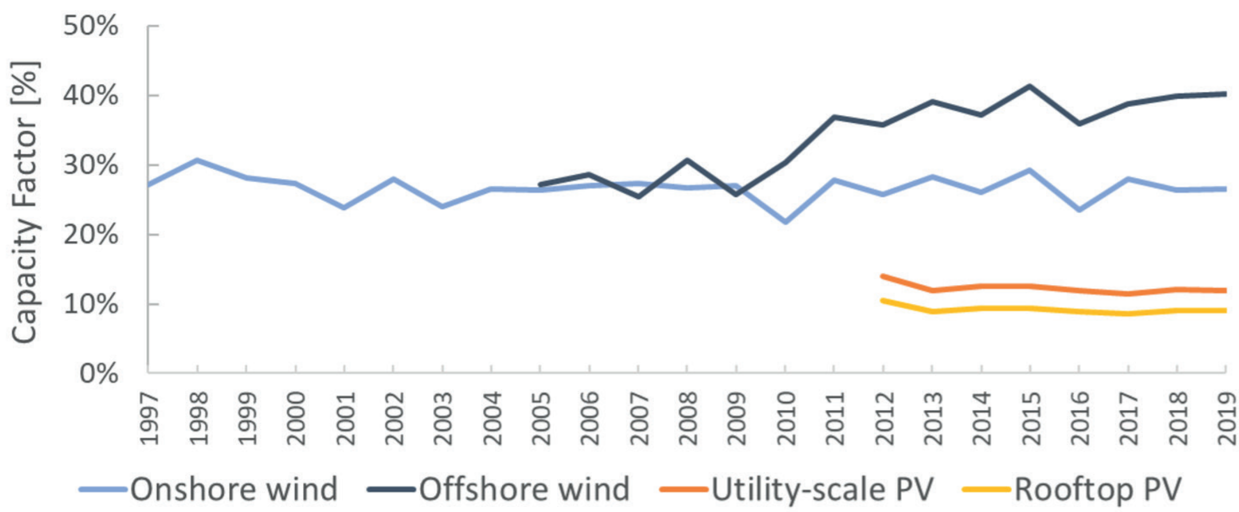
1 In this text, we consider all solar PV installations smaller than or equal to 50 kW to be rooftop PV and all solar PV installations bigger than 50kW to be utility-scale PV. We do not distinguish between solar PV attached to a building and ground-mounted. The majority of solar PV installations attached to buildings will be below this threshold and that of ground-mounted installations will be above it.

Finally, Figure 4 shows the capacity factors of the different generation technologies. These factors are calculated as follows:

$$Capacity\ factor = \frac{Generation_i}{8760*(0.5*Cumulative\ capacity\ _j + 0.5*Cumulative\ capacity\ _{j+1})}$$
$$with\ i\ year\ and\ j: snapshot\ on\ the\ 1st\ January\ of\ year\ i$$

The capacity factors of previously installed offshore wind turbines (2005-2009) were not very different to those of onshore wind turbines. This can be explained by the fact that initially offshore wind turbines were located quite close to the shore in shallow waters. Over the years, offshore turbines have been installed further out to sea to profit from higher average wind speeds, leading to higher capacity factors. Regarding solar PV, only the installed capacity of utility and solar PV and the total electricity generated from solar PV have been found. Assuming the capacity factor of rooftop PV to be 75% of that of utility-scale PV, annual solar PV generation has been divided between utility-scale and rooftop PV.

Figure 4: Capacity factors in the UK (1996-2019). Computation based on BEIS (2020a, 2020b)



In what follows, we describe in more depth the different support schemes that have driven the deployment of these four renewable electricity generation technologies in the UK.

2.2 Four different support schemes and their effectiveness

We identify four major renewable electricity support schemes that have been employed in the UK between 1990 and today. These support schemes were identified in a literature review (Haas et al., 2011; Li et al., 2020; Lockwood, 2016; Mitchell and Connor, 2004; Ragwitz and Steinhilber, 2014; Welisch and Poudineh, 2020) combined with public information available on the websites of Ofgem, the UK regulator, and the Department for Business, Energy and Industrial Strategy (BEIS). These four support schemes and their timelines are visualised in Figure 5. The different colours of the boxes represent information about different support schemes.

Figure 5: Overview of the different major renewable support schemes mapped onto capacity installed for each technology. Main sources: BEIS (2020a, 2020b) and Ofgem and BEIS websites.

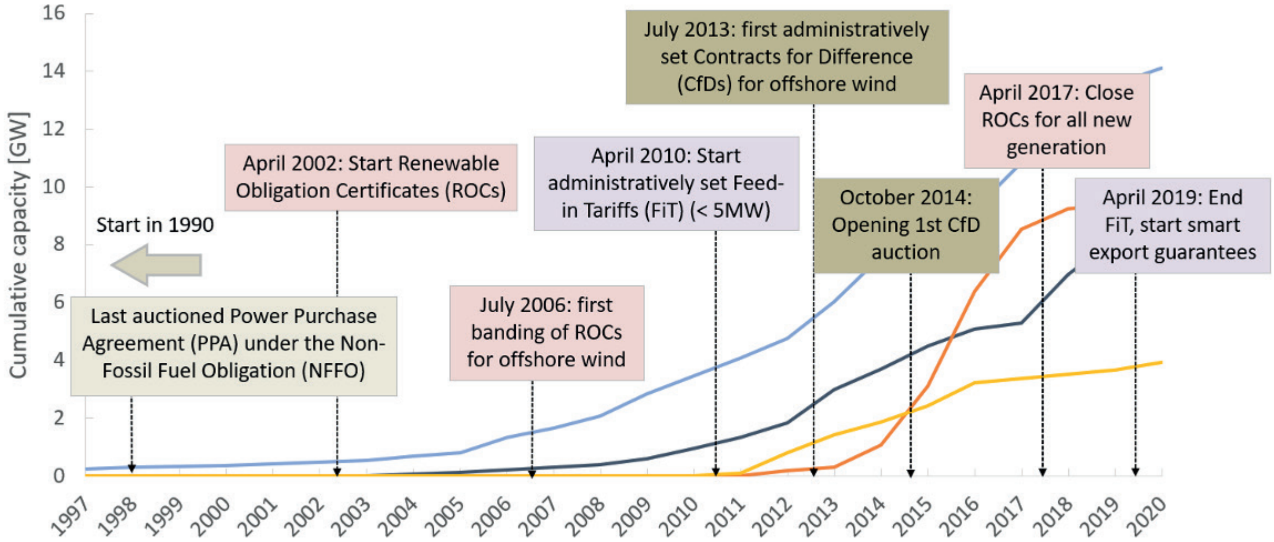


Table 1 gives an overview of the main characteristics of the support schemes. In the remainder of this section, we describe each scheme in more detail and provide data on its effectiveness in terms of capacity installed.

Table 1: Main characteristics of the four support schemes for renewable electricity in the UK

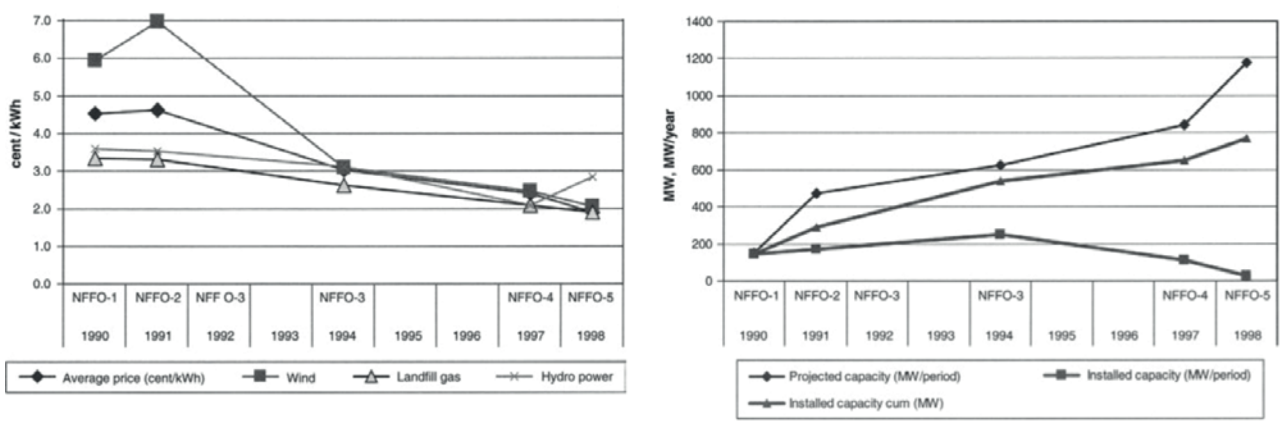
Timeline	*Instrument*	*Allocation*	*Price-level (£/ MWh)*	*Duration of support*	*Technologies*
1990-1998	Power purchase agreement (PPA)	Auction	Set in the auction	Max 15 years	Technology specific
2002-2017	Renewable Obligation Certificate (ROC)	Accreditation	Market-based	20 years	Technology neutral (until 2007)
					Technology specific (2007-2017)
2010-2019	Feed-in Tariff (FiT)	Accreditation	Administratively set	20 years, 25 years for solar PV	Technology specific
2013-to-day	2-sided Contract for Difference (CfDs)	Call for projects (2013)	Strike price administratively set	15 years	Per group of technology
		Auction (2014- to-day)	Strike price set in the auction		Per group of technology

2.2.1 1990-1998: Auctioned Power Purchase Agreements (PPAs) under the Non-Fossil Fuel Obligation (NFFO)

Mitchell and Connor (2004) explain that the 1990 Electricity Act enabled the adoption of a fossil fuel levy to pay for the Non-Fossil Fuel Obligation (NFFO). The same Act also specified which renewable energy technologies were included in the definition of eligible non-fossil fuel technologies.[2] Haas et al. (2008) state that the UK's NFFO was originally envisioned to deliver 1500 MW of installed capacity from renewable energy sources by 2000. In order to stimulate the deployment of this capacity, auctions were organised for each (renewable) technology group on a pre-set date. In each technology category the winning bids were selected by cost. Relatively long-term power purchase contracts (PPAs), up to 15 years, were signed with integrated distribution and supply companies providing a guaranteed (indexed) price per unit of output. The difference between the price established in the PPAs and the average monthly pool purchasing price was paid back to the integrated distribution and supply companies through the NFFO levy in consumer electricity bills.

Pollitt (2010) documents that in total five tendering rounds were conducted in England and Wales between 1990 and 1998 in which a total of 993 contracts were awarded representing 3639 MW. Mitchell and Connor (2004) provide more background on how the exact auction rules were slightly adapted from one auction to another. Figure 6 (left) shows the prices. It can be seen that, as expected, competitive bidding resulted in declining prices over time. After the first round in 1990, the average price of the PPAs awarded for wind decreased from 6-7p/kWh to about 2p/kWh. Even lower prices, less than 2p/kWh, were obtained in Scotland, lower than electricity from coal, oil, nuclear and some natural gas during that time. Revenues for generators began once plants were commissioned. Therefore, developers were heavily incentivised to commission the power plants as soon as possible. In addition, developers were incentivised to go to high wind speed sites. Haas et al. (2011, 2008) at a first glance, the historic development of renewable energy sources in the electricity (RES-E state that on the surface this appeared to be a successful scheme.

Figure 6: NFFO prices (left) and capacity projected and installed (right). From Haas et al. (2008).



From Figure 6 (right) it can be seen that not all the capacity awarded was finally installed. Pollitt (2010) states that in all the NFFO rounds of 933 contracts awarded 477 were built, representing 1202 MW out of 3639 MW. Mitchell and Connor (2004) state that deployment proved very slow due to permitting problems. Furthermore, these authors identify two major issues with the NFFO scheme: a total cost cap too low and a lack of a penalty for companies which did not take up their contract. Regarding the former, NFFO bids were often seen as 'best-situation' bids and were too low. They were therefore uneconomic and were not taken up. A higher cost cap would have reduced compe-

2 These authors and Pollitt (2010) add that initially the NFFO was set up to support nuclear power. In order to avoid this being seen as a discriminatory subsidy of the nuclear industry, it was recast as a way of supporting non-fossil fuel generation more generally and a small portion was allocated to support renewable energy.

tition and enabled higher bids which may have enabled development. Regarding the latter, the lack of a penalty allowed low bids, which at least provided the option of financial support for a renewable project, which did not have to be taken up if the project turned out to be uneconomic. Bidding very low prices and then not going through with the development of the project also had the benefit of ensuring that competitors did obtain contracts.

2.2.2 2002-2017: Market-based Renewable Obligation Certificates (ROCs)

While not at the bottom of the list of European countries in terms of deployment, in the early 2000s the UK was well behind high achieving European countries such as Germany and Spain. Mitchell and Connor (2004) explain that the 2000 Utilities Act, which was initially intended to alter the basis of utility regulation (gas, electricity and water) in the UK, led to three major implications for renewables and their deployment. First, the Act unbundled formerly integrated distribution and supply companies, thereby removing the legal basis of the NFFO scheme and requiring either the NFFO scheme to be transferred within the new legislation or a new mechanism to be put in place. Second, New Electricity Trading Arrangements (NETA) were implemented in April 2001. And third, Ofgem's role with respect to the environment was marginally increased by, for example, having to publish an annual Environmental Action Plan.

According to the same authors, the Government required the mechanism replacing the NFFO to counter its supposed defects. The most important of these were poor effectiveness in terms of deployment, priority access for supported renewable generators and 'picking winners' instead of being technology neutral. Mitchell et al. (2006) add that it was also important for the mechanism to remain market-based on the grounds that it would increase deployment while at the same time maintaining a competitive incentive to keep costs down. Expecting to fulfil these criteria, the Renewable Obligation (RO) scheme was introduced in April 2002 in England, Wales and Scotland and was followed by Northern Ireland in 2005. The RO scheme reversed the NFFO rules with an obligation on suppliers to purchase and supply a certain amount of renewable electricity and not to grant PPAs for specific renewable electricity projects.

A wide range of renewable electricity technologies were eligible for accreditation under the RO scheme such as onshore wind, offshore wind and solar PV, and also hydroelectric, biomass and geothermal plants. Once accredited, these generators received Renewable Obligation Certificates (ROCs) in proportion to their electricity generation for 20 years from the date of accreditation. Generators falling under the RO scheme were rather large-scale as the scheme only established a demand for renewable electricity from suppliers but it provided no other support such as, for example, exemption from balance responsibility. An explicit aim of the scheme was to force renewable generators to make electricity market decisions. Therefore, rooftop PV was not relevant in this context.

Suppliers need to fulfil a renewable obligation each fiscal year by presenting their ROCs to Ofgem. This obligation can be fulfilled by generating enough ROCs from their own generation portfolio or by purchasing ROCs directly from other eligible renewable energy generators or from other suppliers. Mitchell et al. (2006) add that up to 25% of a supplier's obligation can also be met with ROCs banked in the preceding year, while borrowing ROCs against generation in future years is not possible. In 2002-2003, 3% of the electricity supplied was required to be covered by ROCs and this requirement gradually rose to 48.4% in 2019-2020 for England, Wales and Scotland.[3] Northern Ireland has its own separate target. Suppliers missing the required amount of ROCs have to pay a penalty called the buy-out price. The buy-out was set at £30 per MWh in 2002-2003 and each year it is adjusted in line with the Retail Price Index (RPI). The presence of the buy-out price means that from the perspective of the supplier if its renewable obligation is not met it is in its economic interest to buy renewable electricity as long as it is cheaper than the conventional generation price plus the buy-out

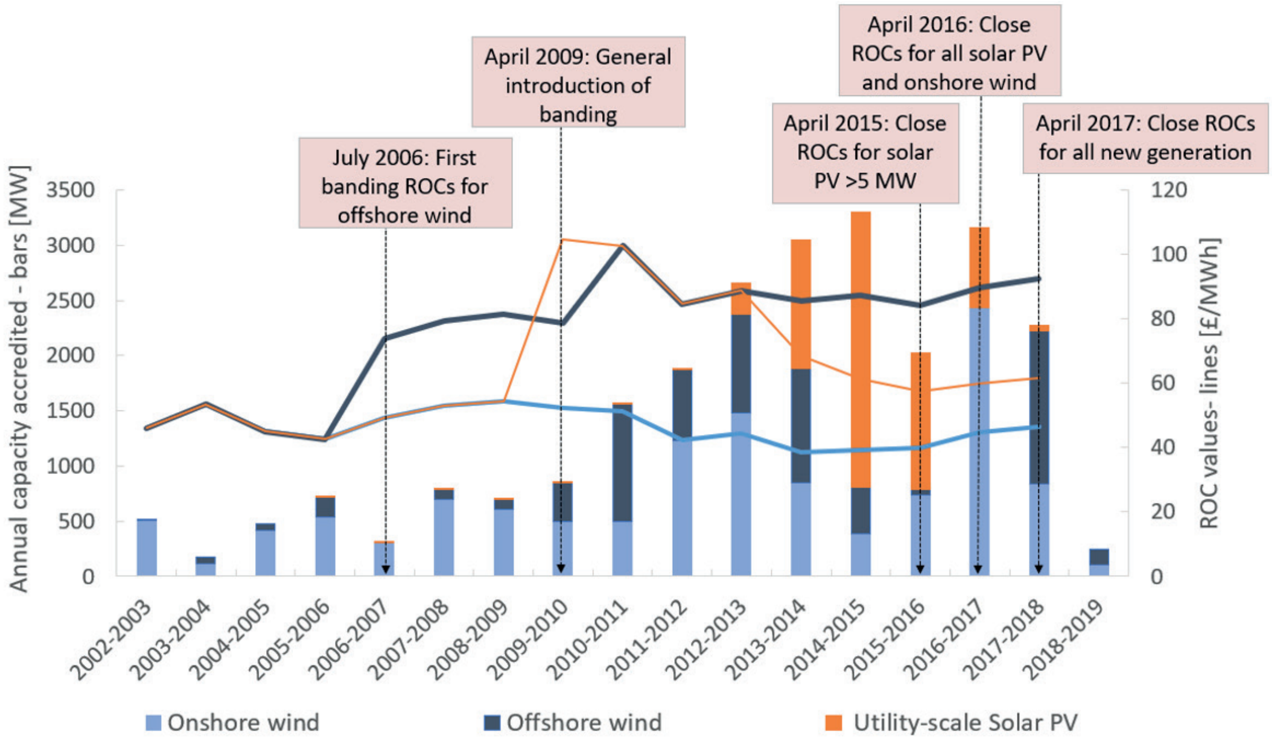
3 This increased requirement over the years not only reflects more stringent targets for the share of renewable electricity in the generation mix but it is also driven by the introduction of banding, i.e. generators receiving several ROCs per MWh produced instead of just one. The number of ROCs a project receives per MWh produced is dependent on the technology and year of accreditation. Ofgem (2019) documents that for the year 2009-2010 on average 1.04 of ROCs were issued per MWh of generation and that this number gradually increased to an average of 1.34 for 2018-2019. Banding is explained in more detail later in this text.

price. Importantly, this means that the buy-out price serves as a de facto price cap on expenditure of the renewable obligation each year which is passed through from the supplier to consumers.

A special feature of the UK RO scheme is the recycling mechanism. With this mechanism, penalties paid into the buy-out fund are redistributed to suppliers in proportion to the number of ROCs they have presented. Thus, the recycling mechanism increases the value of the ROCs for the years when the overall renewable obligation is not met. As Shao et al. (2021) explain, this means that, while the actual prices of ROCs are determined in bilateral trades and are unknown to the public, in theory the price of an ROC should reflect both the buy-out price and the recycle value. The first term is an administratively determined penalty reflecting the renewable obligation and the second term is the gain received from redistribution. This second term is driven by market dynamics. For example, in 2017-18 as the buyout price was £45.58 and the recycle value was £5.85 the suggested total value of an ROC was £51.43 (Ofgem, 2019a). It is important to add that this reasoning only holds in the case of an undersupply of ROCs awarded relative to the overall renewable obligation. In the case of an excess of renewable production beyond the supplier's obligation, the price of ROCs would fall below the buy-out price. In fact, the price of ROCs could approach zero if renewable and non-renewable generation costs became similar, as there would be little or no need for a subsidy of renewable generation. To limit this risk for generators, a so-called headroom mechanism was introduced into the scheme in 2009. This aims to ensure ROC undersupply by increasing the demand for ROCs beyond the expected number of ROCs issued (BEIS, 2021; European Commission, 2009).

Originally, the RO scheme was technology neutral. Each accredited generator, whether it was a solar PV plant or onshore or offshore wind, received one ROC per MWh generated. However, banding was later introduced to stimulate certain less mature technologies and limit windfall profits for more mature technologies. For example, offshore wind generators accredited after 12 July 2006 and before 1 April 2010 were awarded 1.5 ROCs per MWh. For offshore wind generators accredited after 1 April 2010, the banding was adjusted again. Solar PV accredited after 1 April 2009 and before 1 April 2013 received 2 ROCs per MWh. Similarly, the banding was adjusted again afterwards. Onshore wind generators accredited before 1 April 2013 received 1 ROC per MWh. Onshore wind generators accredited after that date until the ROC scheme was closed for new onshore wind generation received 0.9 ROCs per MWh. More details are shown in Figure 7. The figure shows the capacity of generators accredited under the RO scheme each year, the key dates the scheme was adjusted and the value of an ROC each fiscal year for one MWh generated by a certain technology that is accredited in the same fiscal year.

Figure 7: Yearly accredited capacity under the RO scheme for technologies and the ROC value per MWh produced in a fiscal year for a generator accredited in the same fiscal year. Main sources for accredited capacities: Ofgem (2021a, 2008, 2007, 2005, 2004). Main sources for value of ROCs and banding: Ofgem (2019a, 2014) and Renewable Energy Foundation (2021).



From Figure 7 we can see that in the early years of the RO scheme mainly onshore windfarms were accredited, while several years afterwards banding was introduced for offshore wind and utility-scale PV investments in these technologies were also kickstarted. According to the data displayed in Figure 7, 12.2 GW from onshore wind, 6.5 GW from offshore wind and 6 GW from utility-scale PV were accredited under the RO scheme. As Section 3 elaborates further, to date the ROC scheme has been the biggest among the different support schemes implemented in the UK in terms of deployment of renewable electricity generation and costs. What can also be seen from Figure 7 is that deployment of utility-scale PV suddenly started booming from 2012 but then declined rapidly again after 2017. Solely under the ROC scheme, during those 5 years more than 60% of the total current capacity of utility-scale PV was built. One of the reasons for this is that in these years the banding of utility-scale PV was adjusted downwards (from 2 ROCs per MWh before 2013 to 1.3 ROCs per MWh for ground mounted solar PV installed during fiscal year 2015-2016). In addition, from 1 April 2015 solar PV bigger than 5 MW was excluded from the scheme and a year later the RO scheme was closed for all solar plants. As is also discussed in Section 3, the main reason for this was to limit costs for consumers. On the downside, some media reported that this drastic decline in newly installed utility-scale PV capacity led to important job losses and bankruptcies (King, 2020). Finally, in April 2017 the ROC scheme was closed for all new generation capacity with the exception of projects that are eligible to apply for a grace period. However, the RO scheme will run in parallel with other schemes until 2037, allowing for revenue from ROC prices during the 20 years after the last new plant enters the certificate system. This means that the renewable obligation target will need to be adapted over the years to reflect the expected decreased participation in the scheme and to keep prices stable (Held et al., 2014).

Overall, the academic literature is quite critical of the RO scheme. Toke (2007) assesses its effectiveness and concludes that “there are problems with the British RO, and it certainly does not deliver renewable energy any more cheaply than a feed-in tariff." Haas et al. (2011)at a first glance, the historic development of renewable energy sources in the electricity (RES-E provide a historical review of renewable support schemes in the EU and find that countries that implemented a quota-based system, such as the UK, Italy and Belgium, were less effective while providing a relatively high level of support than more efficient countries like Austria, Germany, Portugal and Spain, which introduced feed-in tariffs. Mitchell et al. (2006) compare the German feed-in tariff system under the Renewable Energy Sources Act (EEG) with the RO scheme in the UK. They also argue that the German feed-in tariff is more effective at increasing the share of renewables than the RO scheme because it reduces risk for renewable generators more effectively. Furthermore, Li et al. (2020) identify possibilities to game the ROC recycle mechanism. Finally, Shao et al. (2021) argue that with both vertical integration and the recycling mechanism existing in an RO scheme, independent suppliers are disadvantaged in accessing ROCs given insufficient supply.

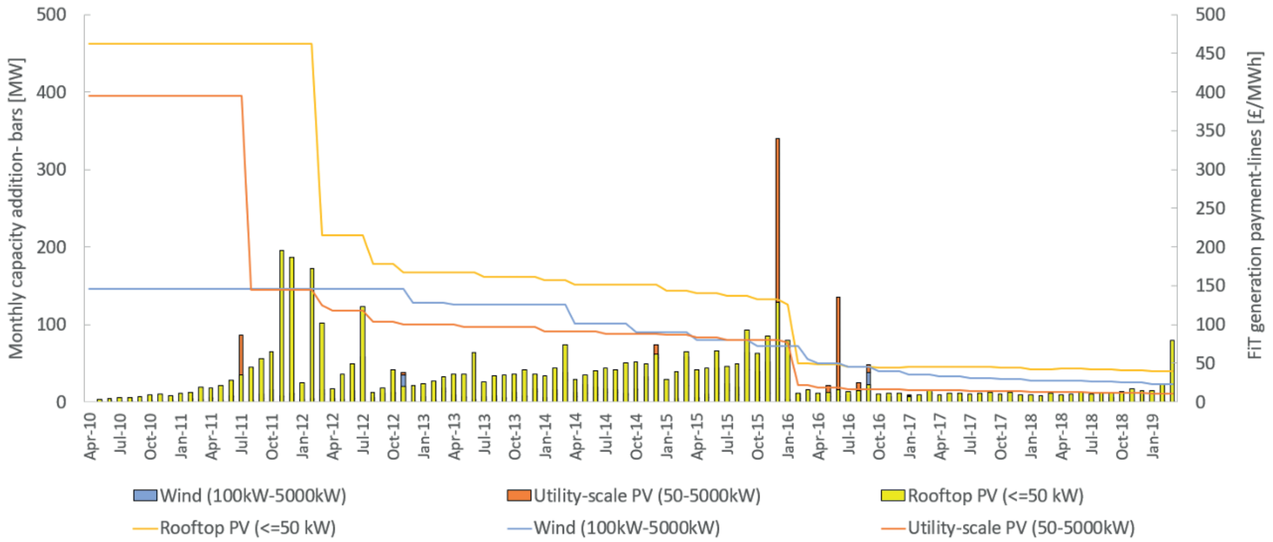
2.2.3 2010-2019: Administratively set feed-in tariffs (FiTs)

The Secretary of State for Energy and Climate Change used enabling powers contained in the 2008 Energy Act to introduce an administratively set feed-in tariff (FiT) scheme in Great Britain in April 2010 (Ofgem, 2011). The FiT scheme ran in parallel with the RO scheme but they targeted differently sized renewable electricity generation projects. The FiT was designed to incentivise the uptake of small-scale renewable and low carbon technologies with up to 5MW capacity. Generators accredited under the FiT scheme could be solar PV or wind plants and also hydro, anaerobic digestion or combined heat and power technologies.

The FiT scheme requires licensed electricity suppliers to make tariff payments on both the generation and export of renewable electricity from accredited generators for 25 years for solar PV and for 20 years for the other eligible technologies. The FiT generation payments are made to the accredited generators based on their metered generation. The exact FiT generation payment depends on the technology and time (FiT tariff period) of accreditation. Importantly, for each technology there is also a deployment cap, which represents a limit on the capacity that can receive a particular FIT tariff in each tariff period. The FiT generation payments are adjusted according to the RPI. The FiT export payment can be seen as a surplus payment that is received because an accredited generator is effectively exporting electricity to an energy supply company, which can then sell it to its customers. Depending on the type of installation the share of electricity generated onsite that is exported can be measured or a share can be assumed, as is further illustrated later in this section. The FiT export payment depends on the time of accreditation but is typically not technology specific, although there are some exceptions (Feed-in tariffs, 2021). The FiT export payments are also adjusted according to the RPI.

We focus on FiT generation payments which are one-two orders of magnitude larger than the value of FiT export payments, at least in the early years of the FiT tariff scheme, and can be seen as the true subsidy payment. Figure 8 shows the monthly capacity additions falling under the FiT scheme for wind, utility-scale PV (50-5000kW) and rooftop PV (<=50 kW). FiT generation payments are also shown. These are average values as payments can differ depending on the size of the generator.

Figure 8: Monthly capacity additions for each technology for generators subject to the FiT scheme and feed-in generation payments (average values as payments could differ depending on the exact size bracket to which a generator belonged). Main sources for capacity additions: BEIS (2020b, 2019a). Main source for feed-in generation payments: Ofgem (2021b).



From Figure 8 it can be seen that the FiT scheme has been mainly important to stimulate the deployment of rooftop PV. According to the data in Figure 8, 3.91 GW of rooftop PV, 0.97 GW of utility-scale PV and 0.74 GW of wind generation were installed under the FiT scheme. What can also be seen from the same figure is that the FiT generation payment is very frequently reduced. Ofgem (2018) explains that the reductions in tariff rates for new installations (so-called degression) are based on the deployment levels of each technology. The rationale behind these adjustments was to limit windfall profits due to a gap between the FiT generation payments and the continually decreasing technology costs. In general, two major price changes can be observed, first around the end of 2011 and then around the end of 2016. Interestingly, significant capacity additions just before these drops in payments and the end of the scheme can be observed. It was precisely these capacity additions that made the FiT rates go down as they led to reaching the deployment cap. This was possibly a self-fulfilling prophecy. More specifically, if many new projects are being built, developers can foresee that the deployment cap will be reached and FiT rates will decrease. Therefore, pressure is created to quickly get new projects accredited to still profit from the higher FiT rates. In turn, these significant capacity additions lead to what was predicted in the first place, hitting the deployment cap and producing significant reductions in the FiT rates.

A last point to add regards rooftop PV and the export FiT payment. This export FiT payment on top of the FiT generation payment is quite specific to the UK case. In many other countries a net-metering scheme is or was implemented on top of a FiT generation payment. Compared to net-metering, the UK export tariff lies far below the full retail tariff for buying electricity. Green and Staffell (2017) show that in December 2016 a small system in an energy-efficient home received 4.18p/kWh through the FiT scheme for every unit generated and an additional 4.91p/kWh for every kWh exported. However, at that point in time, the UK did not require owners of small systems to install export meters. Instead, it was assumed that 50% of the electricity produced by panels (which is metered) was exported. The amount of electricity actually exported was not recorded. This effectively means that consumers received 6.64p/kWh for all their generation but nothing extra for the units that were actually exported. Green and Staffell (2017) calculate (based on EdF Energy's tariff) that the electricity that is self-consumed is worth an additional saving of 13.93p/kWh because it reduces the amount of power passing through the import meter. Therefore, the arbitrage value of avoiding exports and storing electricity until it can offset consumption triples the value of the stored energy and provides a strong incentive for self-consumption, for example by installing a battery or by smart charging an EV.

Entries for new generation to the administratively-set FiT scheme were ended in April 2019 and replaced by Smart Export Guarantees (SEG), which came into force on 1 January 2020 (Ofgem, 2021c). Under the SEG, there are no generation payments but energy suppliers are legally obliged to pay an export payment to their customers for each unit of electricity exported (as long as the system is 5MW or below). Another difference to the FiT scheme is that these export payments are not set by the government on a national basis but instead each supplier determines the rate, contract length and other terms. The only requirement is that the export payment is set above zero.

2.2.4 From 2013: Administrative (2013) and auctioned (after 2014) Contracts for Difference (CfDs)

The Contracts for Difference (CfD) scheme is currently the UK government's main mechanism for supporting the deployment of renewable electricity generation. A 'two-way' CfD is implemented in the UK with a duration of 15 years. A two-way CfD provides for payments to be made to a generator when the market reference price for its electricity is below the strike price set in the contract. However, when the reference price is above the strike price, the generator pays back the difference. There are two market reference prices in the CfD contract: the baseload market reference price and a market reference price based on day-ahead prices (LCCC, 2021). For intermittent generation technologies such as wind and solar PV the latter market reference price is used.

The first CfD contracts were awarded in 2013. The strike prices of these CfDs were set administratively according to a certain methodology (BEIS, 2013). The European Commission (2014) explains that the UK organised a tender as a transitory measure while awaiting finalisation of the new scheme based on auctioned CfD. Eight advanced renewable projects including five offshore wind generators received CfD contracts. These CfD contracts with an administratively set strike price were sometimes also called Investment Contracts (ICs). From 2014 onwards, renewable generators located in the UK meeting the eligibility requirements could bid for a CfD contract by submitting a form of 'sealed bid.' There have been 3 auctions, or allocation rounds (ARs), to date and a fourth is planned for late 2021. Successful developers of renewable projects enter a private law contract with the Low Carbon Contracts Company (LCCC), a government-owned company. Table 2 provides more information about the three auctions that took place.

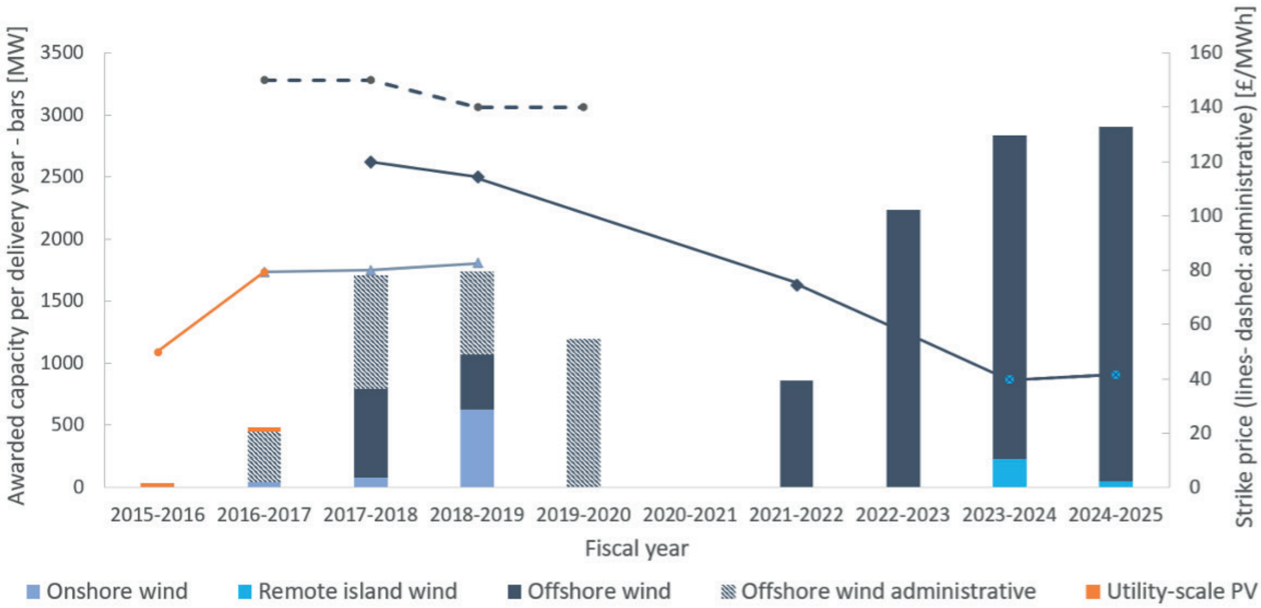
Table 2: Information about the UK auctions for CfDs. Source: BEIS (2019b, 2017a, 2014)

	Window for bids	Delivery years*	Budget**	Technologies
AR 1	10/2014-03/2015	2015/16, 2016/17, 2017/18 and 2018/19	B£ 1.47	Two technology groups
AR 2	03-09/2017	20/21 and 2021/22	M£ 580	Technology neutral (only one technology group)
AR 3	05-09/2019	2023/24 and 2024/25	M£ 65	Technology neutral (only one technology group)

*The delivery year indicates the first phase of construction for projects built in multiple phases
**2011-2012 prices

In the auction, project developers bid the lowest strike price they can accept for delivering a certain project in a certain year. The government caps the maximum amount a project can bid by setting an administrative strike price. All projects compete for each delivery year. The auction is administered by the National Grid and bids are ranked lowest to highest based on the requested strike price. The lowest bids are all accepted until the maximum budget has been reached. During the first auction, the auction system ran two independent tracks with dedicated budgets. 'Pot 1' auctions included established technologies such as onshore wind and solar PV, while 'pot 2' auctions included less established technologies such as offshore wind. In the subsequent auctions, only a budget for technologies from ‘pot 2’ was available. Figure 9 shows the strike prices and capacities awarded a CfD contract for each technology and delivery year.

Figure 9: Strike prices and capacities awarded a CfD contract for each technology and delivery year. Main sources: BEIS (2019c, 2017b, 2015), DECC (2014) and European Commission (2014).



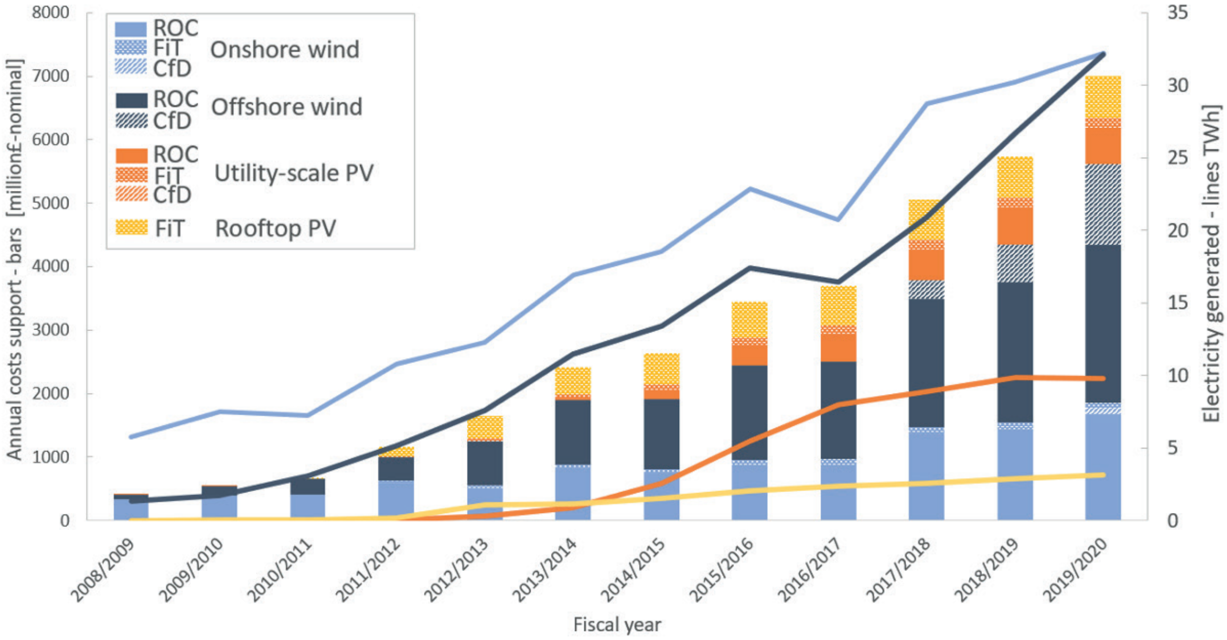
So far, already about 12.9 GW of offshore wind, about 1 GW of onshore and remote island wind and 72 MW of utility-scale solar PV generation have been awarded CfD contracts in the UK. Not all this capacity has been built yet. This scheme, together with the RO scheme, has led to the UK currently being the world leader in offshore wind deployment. Strongly decreasing strike prices have led many commentators to celebrate the success of the CfD auctions, especially for offshore wind (Parnell, 2019; Stoker, 2019). The strike prices for offshore wind projects that are to be delivered by 2023 and later are near the expected wholesale market prices. This means that ultimately these projects might cost the government (and the end consumer) almost nothing in subsidies.

Welisch and Poudineh (2020) study the auction design and are more sober in arguing that a possible explanation for the observed auction outcome is that a non-stringent penalty for failure to deliver the project, along with a long lead time, turns an awarded CfD auction into a kind of ‘real option’ for developers. Currently, if a developer is unable to fulfil its contract, it is subject to a non-delivery disincentive mechanism. This means that the developer will not be able to participate in the next CfD auction if it occurs in the following two years. The same authors argue that a more stringent non-delivery penalty to induce truth-telling can improve deployment rates without increasing support costs. They also add that by holding more regularly scheduled (annual, for example) auctions information on technology cost decreases can be better incorporated into the bids, which would lower investor uncertainty and therefore have a positive effect on the required support costs. EWB Staff (2019), Renews.biz (2017) and Tisheva (2016) report cancellations of energy-from-waste, biomass and solar PV projects which were awarded CfD contracts.

2.3 Total annual costs of the support schemes

In Figure 10, we show the total annual nominal cost of the support allocated via the ROC, FiT and CfD support schemes for each technology considered. We do not consider the NFFO scheme as the costs incurred were limited and incurred more than 2 decades ago. Mitchell and Connor (2004) report that M£ 848 was spent under the NFFO scheme between 1990 and 2002. Furthermore, the figure starts in fiscal year 2008-2009. Before that year, we calculate that M£ 376 was spent via the RO scheme between 2002 and 2008. We exclude the costs associated with the administration of the different support schemes as they are minor compared to the amount of money allocated to the renewable electricity generation projects. The total costs for the technologies considered and support schemes is estimated at B£ 6.9 in fiscal year 2018-2019, which is about £100 per capita.

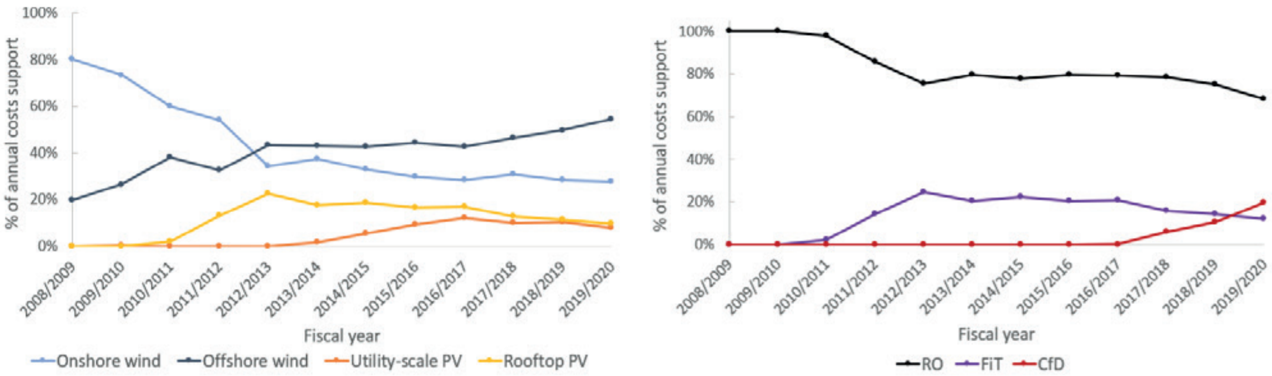
Figure 10: Left scale: estimated costs for the technologies considered via ROCs, FiTs and CfDs. Own calculations based on annual RO reports (Ofgem, 2021a), FiT price levels and deployment from BEIS (2019a) and Ofgem (2021b) and CfD cost data from the Low Carbon Contract Company (2021). Right scale: annual volume of electricity generated by each technology.



The annual costs of the support schemes and generation technologies are estimated as follows. First, for the RO scheme the costs that are obtained for each fiscal year are the number of annual certificates awarded for each technology multiplied by the sum of the buy-out price and the recycle payment for that year. These data are publicly available (Ofgem, 2021a; Renewable Energy Foundation, 2021). This calculation remains an approximation as the sum of the buy-out price and the recycling payment is an estimation of the price of an ROC of which the cost was finally passed through to consumers via suppliers. Second, for the FiT scheme, the annual cost is calculated as the FiT generation payment awarded to a certain accredited generator multiplied by the annual estimated generation. The average FiT generation payment levels and monthly capacities of accredited generators shown in Figure 8 are used. Furthermore, to estimate the electricity generated, a capacity factor of 22% for onshore wind, 10.5% for utility-scale PV and 8% for rooftop PV is used. The FiT generation payments are adjusted with a monthly inflation rate of 0.2%. Last, for the CfD scheme, annual costs for each generation technology can be found directly on the website of the Low Carbon Contract Company (2021).

Figure 11 (left) shows the allocation of the annual support cost for each technology. It can be seen that before 2012 onshore wind was the technology receiving most of the financial support and afterwards it was surpassed by offshore wind. In 2019-2020, 54% of all spending was allocated to offshore wind while 28% went to onshore wind. Rooftop PV reached its highest relative share (22%) of annual support costs in 2012-2013. Afterwards, wind capacity increased much faster and the FiT generation payment levels for solar were gradually reduced. In 2019-2020, 10% and 8% of the annual costs were attributed to support rooftop and utility-scale PV respectively. Figure 11 (right) shows the allocation of the annual support cost for each support scheme. The RO scheme has always been the most important support tool in terms of money spent. The relative cost of FiTs reached a maximum of 25% in 2012-2013 and remained relatively stable around 20% until it started decreasing again in 2017. Since the first generators came online under the CfD scheme in 2016-2017, the relative costs of this scheme have been increasing year by year. It is expected that they will increase significantly as more offshore generators will come online next year, while the RO scheme has been closed for new generation since April 2017. The CfD scheme might surpass the RO scheme in terms of money spent in the next few years. However, this will depend on many factors, among which the strike prices that are awarded in the next CfD auctions.

Figure 11: Left: Annual percentages of support costs for each technology. Right: Annual percentages of support costs for each support scheme. Own calculations based on cost data shown in Figure 10.



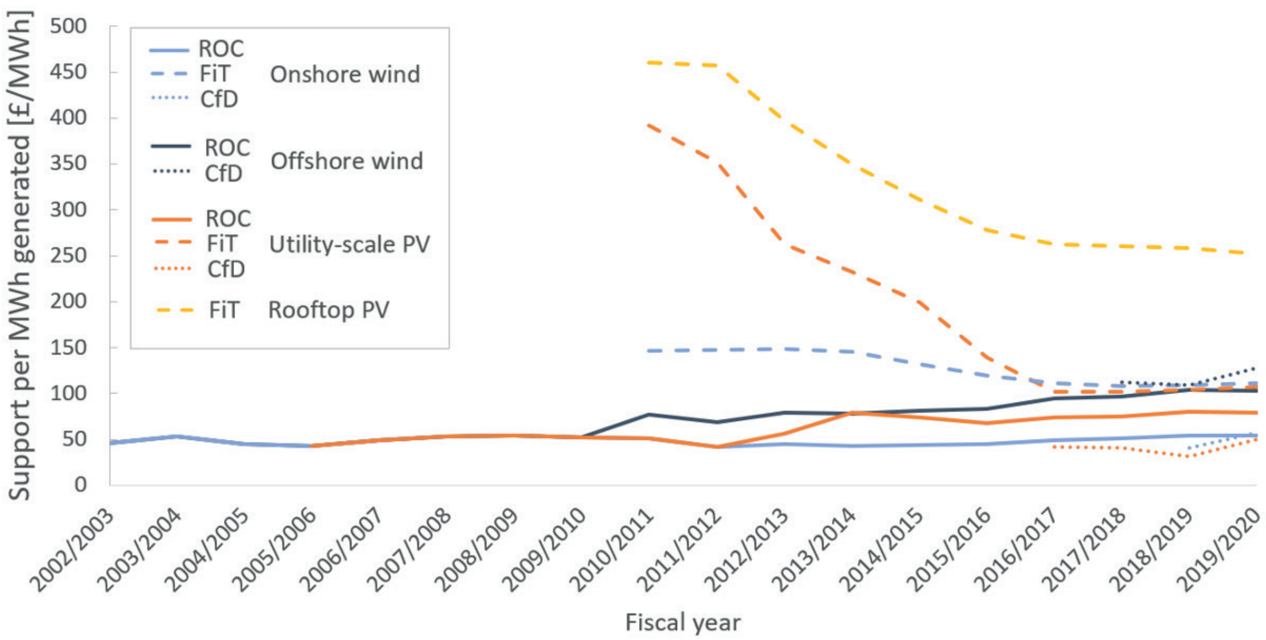
An important concept when discussing total support costs of renewable support schemes in the UK is the Levy Control Framework (LCF). Lockwood (2016) describes the history behind the LCF and its workings in depth. He explains that before 2010 there was no official limit on energy policy costs in the UK. However, following the general election in 2010, the new Conservative-Liberal Democrat coalition government introduced an overall cap on the costs passed through to consumers created by the Department of Energy and Climate Change (DECC) through energy policies. This cap was formalised as the LCF and included all renewable electricity policy costs but not the costs of other policies, such as the Capacity Market, the Warm Home Discount and the Energy Company Obligation for energy efficiency (HoC ECCC, 2016). In practical terms, spending reviews carried out by the Treasury set annual spending caps for a number of years ahead. Lockwood (2016) further states that the LCF puts a budgetary mechanism on top of existing price-based and quantity-based mechanisms for renewable electricity support. Importantly, with the introduction of the LCF support for renewable energy was reallocated from the spheres of energy and environment to that of budgetary control and therefore implied a shift of the locus of policy control from the DECC to the Treasury.

Lockwood (2016) explains that the LCF can be seen as an attempt to provide a solution to managing potential tensions between aims to expand renewable energy on the one hand and costs for energy consumers on the other. In addition, the LCF is deemed essential for investor confidence as uncontrolled costs can undermine public support for policy measures. Before 2015, the LCF did not attract much attention as spending remained below the cap. However, in that year overspending was anticipated in the coming years and changes to renewable support schemes were made to drive future spending down. Examples are a premature exclusion of entry for utility-scale PV (> 5MW) in the RO scheme in April 2015 and a year later the exclusion of all solar PV and onshore wind. Other examples are that decreases in generation FiT payment levels were announced in summer 2015 and announcements of new CfD auctions were delayed in the same year (Lockwood, 2016).

2.4 The cost-effectiveness of support schemes

Figure 12 shows the cost-effectiveness of each support tool for the technologies considered. We define cost-effectiveness of a support scheme as annual expenditure (for each generation technology) divided by the total annual volume of electricity generated by the generators that benefit from the scheme. For example, in Figure 10 we find that in fiscal year 2017-2018 B£ 2 were allocated to offshore wind generation under the RO scheme. In the same fiscal year, we find from Ofgem (2021d) that 39050 ROCs were awarded to offshore wind for 20661 MWh of electricity generated.[4] To calculate the level of support for offshore wind generation under the RO scheme in that fiscal year we divide B£ 2 by 20661 MWh, resulting in 97.2 £/MWh. In other words, in fiscal year 2017-2018 an average of £ 97.2/MWh of public support was allocated to offshore wind under the ROC scheme.

Figure 12: The cost-effectiveness of each support scheme and technology considered calculated by dividing the annual cost shown in Figure 10 by the electricity generated in the year supported by the support scheme for each technology. Data from the same sources as in Figure 10.



We see several interesting trends in Figure 12. Regarding the RO scheme, it can be seen that the level of support is fairly stable around 50 £/MWh until 2009-2010. Afterwards with banding in place, first more support per MWh generated was given to offshore wind and later to utility-scale PV. It would be expected that the level of support given per MWh generated would decrease over time because more and more generation came online for which the investment cost decreased due to innovation efforts. Therefore, a lower level of support would be needed. While this is clearly the case for the FiT scheme, it is not for the RO scheme, with the exception of utility-scale PV between 2013-2016 due to a lowering of the bands for this technology. Furthermore, regarding the FiT scheme, after a steep decline in support per MWh, the level stabilised for each technology after 2017 as little capacity was added due to strongly decreased FiT generation payments. Only when the initial (high) FiT generation payment contracts start to expire around 2035 will the level of support per MWh electricity generated decrease further. The FiT level of support is the highest among the schemes. This can be explained by the fact that significantly smaller generators which benefit less from economies of scale in terms of investment costs are supported by this scheme. Regarding the CfD scheme, it might be too early to detect trends as only limited capacity subject to CfD contracts was generated

4 This implies an 'average banding factor' of 1.89 for offshore wind in that fiscal year.

before 2020. The slight increase in the level of support for offshore wind in 2019-2020 can be explained by generators subject to relatively high administrative CfD prices coming online that year. Nevertheless, considering the strongly reducing strike prices for the coming delivery years shown in Figure 9, we can expect the level of support per MWh generated by offshore wind generators subject to this scheme to significantly decrease in the future.

2.5 Impact on electricity bills

In principle, funding for renewable policy costs can be paid by taxpayers if it comes from a public budget or general taxation. Alternatively the costs can be paid by consumers via a levy included in energy bills or passed through via suppliers. CEER (2018) reports that in 2016-2017, in the large majority of European countries the renewable energy policy costs were paid by electricity consumers.[5] To limit uncertainty and fiscal impacts, this is in line with guidance from the European Commission (2013) to keep the financing of support schemes off-budget. Also in the UK, the costs of the renewable schemes are paid by electricity consumers. This happens indirectly through levies or obligations on suppliers which are ultimately passed on to domestic and non-domestic electricity consumers' bills (BEIS, 2020c). In 2016-2017, only in France, Denmark, Finland, Malta and Denmark were the costs of renewable energy policies not fully levied from consumers. In these cases general taxation or the state budget also contributed part of renewable energy policy costs.

Also important in this regard is the fact that in many countries there are (partial or full) exemptions to financing contributions. Such exemptions may increase the financial burden on non-exempted consumers. CEER (2018) reports that the most important exemptions in place are for energy-intensive industries as a means of preserving their international competitiveness (12 countries out of 27 in 2016-2017) and for self-generated electricity from RES or conventional power plants consumed on site (9 out of 27 in 2016-2017). In the UK, the government has operated compensation schemes and exemption schemes from the costs of ROCs, FiT and CfDs for electricity-intensive industries since 2015 (Lockwood, 2016).[6] Certain eligibility criteria need to be met to profit from this exemption, as is documented by BEIS (2020c). For example, businesses need to show that their electricity costs amount to 20% or more of their Gross Value Added (GVA) over a reference period.[7] These schemes have been approved by the European Commission as compatible State aid and the exemption schemes have been implemented by secondary legislation approved by Parliament. It is estimated that in 2018 about 10 TWh of consumption would qualify for the exemption scheme (BEIS, 2018). The total electricity consumption by final users was about 300 TWh that year (BEIS, 2020d).

Figure 13 (left) shows electricity consumption in the UK between 2008 and 2019. It can be seen that total consumption slightly decreases over the years from 340 TWh in 2008 to 295 TWh in 2019. Besides total electricity consumption, it also shows consumption by sector.[8] The share of consumption by energy-intensive industries exempt from (part of) renewable energy policy costs from 2015 onwards is estimated to be 10 TWh for each relevant year. Figure 13 (right) shows the cost per MWh of consumption of energy policies supporting deployment of wind and solar generation.[9] There is a minimal difference between the costs per MWh when considering all final electricity consumption and all final electricity consumption which is not exempt from contribution to the cost.

5 Batlle (2011) argues that in the context of overall renewable energy targets, all energy consumers should pay the costs of renewable promotion programmes in proportion to their final energy consumption regardless of the origin of the renewable energy (such as biofuel, wind or solar energy). In practice, costs for supporting renewable electricity generation are allocated solely to electricity consumers.

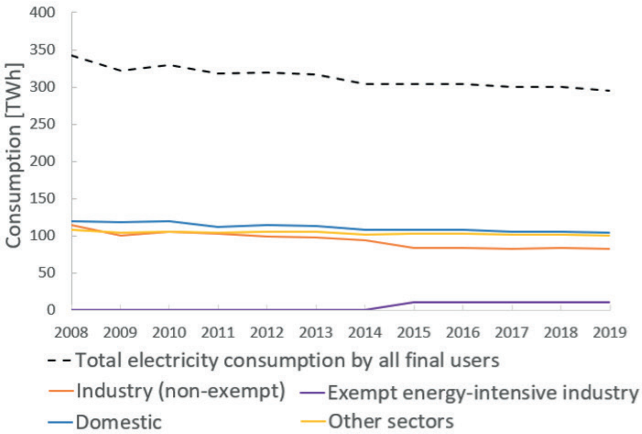
6 The CfD, RO and FiT exemption schemes do not apply to Northern Ireland. Companies based solely in Northern Ireland can currently apply for RO compensation (BEIS, 2020c).

7 GVA is defined as earnings before taxes, interest, depreciation and amortisation (EBITDA) excluding items which are extraordinary and all staff costs including employers' pension and national insurance contributions, director's salaries and bonuses, casual and agency staff costs and other arrangements where employees are paid indirectly.

8 "Other sectors" are public administration, transport, agricultural and commercial sectors.

9 One caveat is that we divided the consumption per calendar year by the policy costs per fiscal year (starting on the 1st of April). The same caveat applies to Figure 14.

Figure 13: Left: Electricity consumption in the UK (2008-2019). Source: BEIS (2020c). Estimates of consumption by energy-intensive industries exempt from (part of) policy costs from 2015 onwards based on BEIS (2018). Right: costs of renewable energy policies (only considering wind and solar, data from Figure 10) divided by total consumption with and without exemptions.



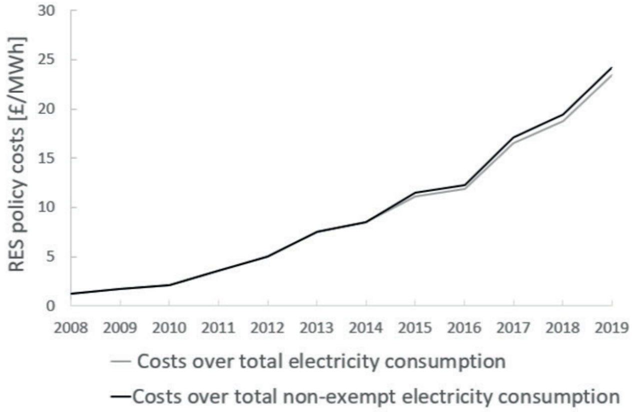
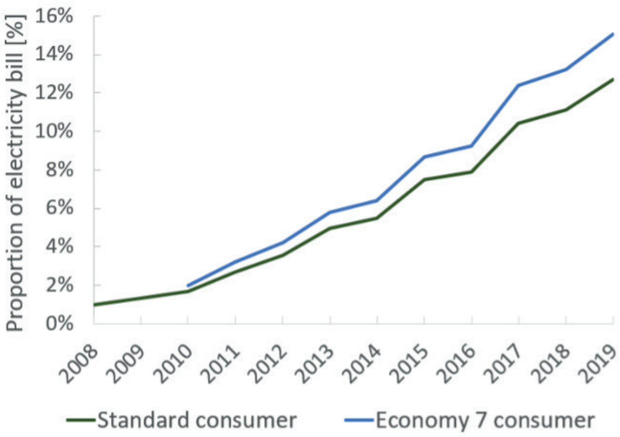
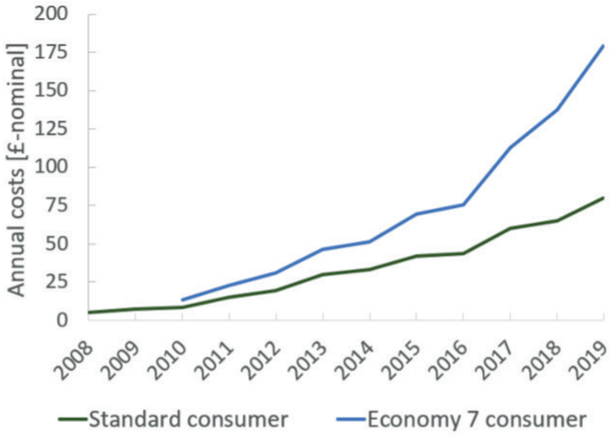


Figure 14 (left) shows the estimated (nominal) annual cost of policies in place to support wind and solar generation for average standard and economy 7 consumers (from 2010). The economy 7 tariff gives a cheaper electricity rate at night and a more expensive one in daytime. This type of tariff is typically selected by consumers with electrical heating. All the electricity consumption data come from documentation in BEIS (2020e). The proportion of consumers on standard tariffs was 81% in 2008 and 90% in 2019. Standard and economy 7 consumers in the UK consumed on average 3305 kWh and 7413 kWh in 2019 respectively. Standard consumers reduced their average consumption by 23% compared to 2008 (4297 kWh), while economy 7 consumers increased their average consumption by 16% compared to 2010 (6395 kWh). Figure 14 (right) shows the proportions of costs in electricity bills of the policies supporting wind and solar generation for average standard and economy 7 consumers. The average electricity bill for standard consumers was £630 in 2019, an increase of 16% compared to 2008 when not considering inflation (£546). Considering inflation, the average electricity bill for standard consumers actually decreased by 3% according to BEIS (2020e). The average economy 7 consumer had an electricity bill of £1191 in 2019. Not considering inflation this is an increase of 81% compared to 2010 (£658). Considering inflation, it increased by 55% according to BEIS (2020e). As expected, it can be seen in Figure 14 (right) that the proportion of policy costs in electricity bills is slightly higher for economy 7 consumers because average energy costs (excluding policy costs) are expected to be lower for these consumers.

Figure 14: Left: renewable policy costs (only considering wind and solar) as a percentage of typical consumer bills. Right: (nominal) annual renewable policy costs (only considering wind and solar) for standard consumers and economy 7 consumers. Renewable policy cost information comes from Figure 13. Consumption and consumer bill data are from BEIS (2020e).





When cross-checking against information provided by Ofgem (2021e), the data shown in Figure 14 seem to lie in the expected range. Ofgem (2021e) states that 23% of average electricity bills in the UK consisted of environmental and social obligation costs, while we find that for the same year 13% of electricity bills consisted of costs of policies for supporting wind and solar generation. Another important reference is the retail monitoring report by ACER and CEER (2020). ACER and CEER (2020) report that renewable levies for a standard household in London represent 21% of electricity bills. The 8 percentage point difference can be explained by the costs for supporting other renewable technologies (e.g. biomass, hydro, geothermal and others) and other environmental programmes such as the domestic Renewable Heat Initiative (RHI). In addition, we assume that large (non-exempt) grid users pay the same rate in £/MWh for the contribution to renewable energy policy costs as domestic consumers. This might not always be the case. In absolute value, Ofgem (2021e) reports that in 2019 £141 of the average electricity bill was paid to contribute to environmental and social obligation costs, while we find that in the average electricity bill for standard consumers £80 is for policies supporting wind and solar generation. This represents 57% of the environmental and social obligation costs. ACER and CEER (2020) report that renewable levies in electricity bills cost standard households in London around £148 a year.

Finally, it is important to note that we report the gross costs of renewable support policies. These policies also have positive impacts on the cost of electricity, e.g. by decreasing the average electricity wholesale price. More information about the net effect of policies on electricity bills can be found in the latest Ofgem State of the Energy Market reports (e.g. Ofgem (2019b)).

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3. Germany

In this chapter, we describe and analyse the main renewable support schemes that have been introduced in Germany to stimulate investment in onshore wind, offshore wind, utility-scale solar photovoltaic (PV) and rooftop solar PV (capacity below 100 kW). The chapter consists of five sections. First, we provide a general introduction. Second, we give an overview of the different support schemes that have been put in place and their effectiveness in promoting the deployment of the renewable electricity generation technologies we consider. We distinguish three schemes: a first come, first served administratively-set feed-in tariff scheme introduced in the Renewable Energy Sources Act (EEG) (2000-today); first come, first served administratively-set sliding feed-in premiums (2012-today); and auctioned one-sided sliding feed-in premiums (2015-today). Third, we describe the annual costs of the different support schemes for each generation technology. Fourth, we discuss the cost-effectiveness of the support schemes, defined as the annual expenditure by a support scheme per MWh of energy produced by all generators benefiting from the scheme. Last, we discuss the impact of the renewable support schemes on electricity bills.

3.1 General introduction

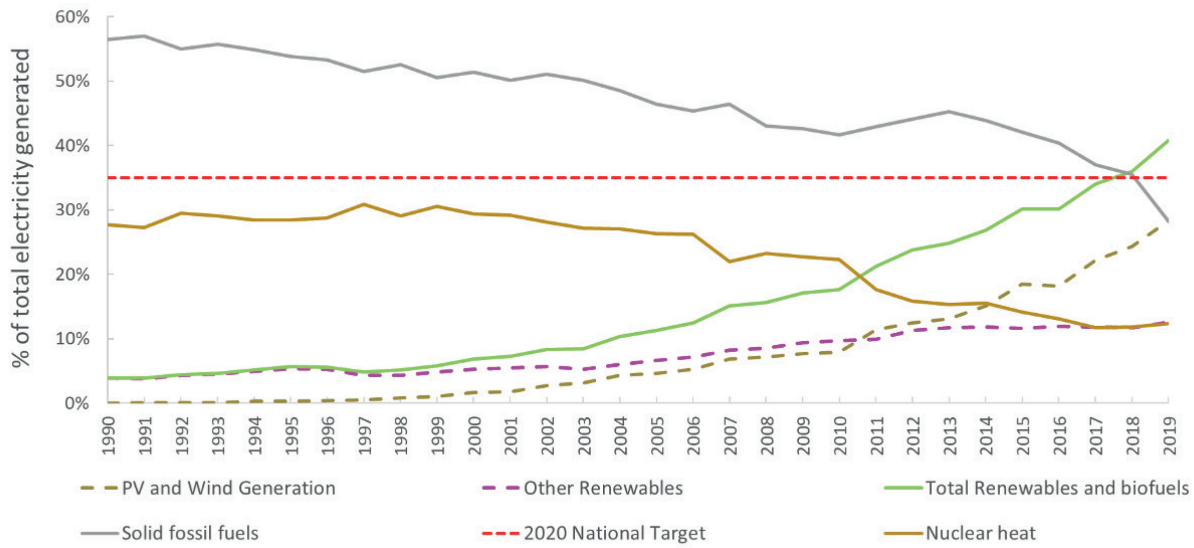
Germany's government, like that of the United Kingdom (UK), has been actively promoting the uptake of renewable electricity technologies to meet climate targets and other strategic metrics.[1] The German word 'Energiewende' – first coined in the title of a 1980 publication by the German Öko-Institut – has been used at the political level to designate this phase in German energy policy and also to frame key policy documents (Kuittinen & Velte, 2018).[2] Important milestones in this regard were the adoption of the Renewable Energy Act (EEG) in 2000 and successive amendments, of the European 20-20-20 targets in 2008, of the Energiekonzept long-term energy strategy in 2010; of the Klimaschutzprogramm 2030 and Climate Change Act in 2019 and of the German National Energy and Climate Plan (NECP) in 2020 (Bundesministerium fuer Wirtschaft und Energie – Germany, 2020; Bundesregierung, 2019; Federal Ministry for the Environment, 2007, 2019; Kuittinen & Velte, 2018; Ministry et al., 2016; Parliament & European Council, 2009; Piebalgs et al., 2020; Strunz et al., 2016a)with Morrison Hershfield (the Consultants.

Figure 1 below shows the evolution of electricity generated from renewable electricity sources in Germany between 1990 and 2019.

1 Renewable electricity technologies are not only supported by public policy with the aim of meeting climate targets. Other objectives also play a role such as reducing air pollution from traditional energy sources, industrial leadership and energy independence. For a discussion, see, for example, Morris et al. (2012); Schmidt et al. (2019); Strunz et al. (2016b).

2 For a more detailed treatment of the energy policy mix and relative aims of the German government, refer to the report 'Mission-oriented R&I policies: In-depth case studies – Case Study Report Energiewende' by Kuittinen and Velte (2018).

Figure 1. Total RES generation versus solid fossil fuels and nuclear and the 2020 renewable electricity target (1990-2020). Main source: Eurostat (2021a).



From Figure 1 it can be seen that already around 2018 Germany reached its national target of 35% of electricity being generated from renewable sources by 2020 (Federal Ministry for the Environment, 2007; Germany, 2021). In 2019, more than 35% of electricity generated was produced from renewable energy sources, the majority of which was from wind (17%), followed by biomass, other RES (12%) and solar PV (7%). 2019 was also the first year in which renewables produced more electricity than solid fossil fuel generators (35%). The decline in electricity production by coal power plants since 2014 has been significant, as in the UK case. The remainder of electricity produced in 2019 was from nuclear (12%).

In this chapter, we focus on promotion via public financial support of four renewable electricity generation technologies: offshore wind, onshore wind, utility-scale photovoltaic (PV) and rooftop PV.[3] Figures 2 and 3 below respectively show the evolution of the (cumulative) installed capacity and of the annual electricity generated by these four technologies in Germany. We also indicate the year of introduction of the three main policy support tools later examined (first come, first served administratively-set feed-in tariffs, first come, first served one-sided administratively-set sliding feed-in premiums and auctioned sliding feed-in premiums) and the six versions of the Renewable Energy Act (EEG 2000, EEG 2004,…) in this time period. These six versions of the Renewable Energy Act dictated the design of the three main support schemes.

3 In this text, we consider all solar PV installations smaller than or equal to 100 kW to be rooftop PV and all solar PV installations bigger than 100kW to be utility-scale PV. We do not distinguish between solar PV attached to a building and ground-mounted. Most solar PV attached to buildings is most likely to be smaller than this threshold and ground-mounted solar PV bigger. Annual generation from rooftop solar PV – in the absence of better and more coherent sources – is extrapolated from data relative to generic solar PV using the relative share of cumulative installed capacity. The latter is derived from a publicly available list of EEG-accredited power plants downloadable from the Netztransparent website (Netztransparenz.de, 2019).

Figure 2. Cumulative capacity installed in Germany (01/01/1997-01/01/2020). Solar PV with a capacity below 100 kW is considered rooftop. Main sources: BNetza, n.d.; Netztransparenz.de, n.d.

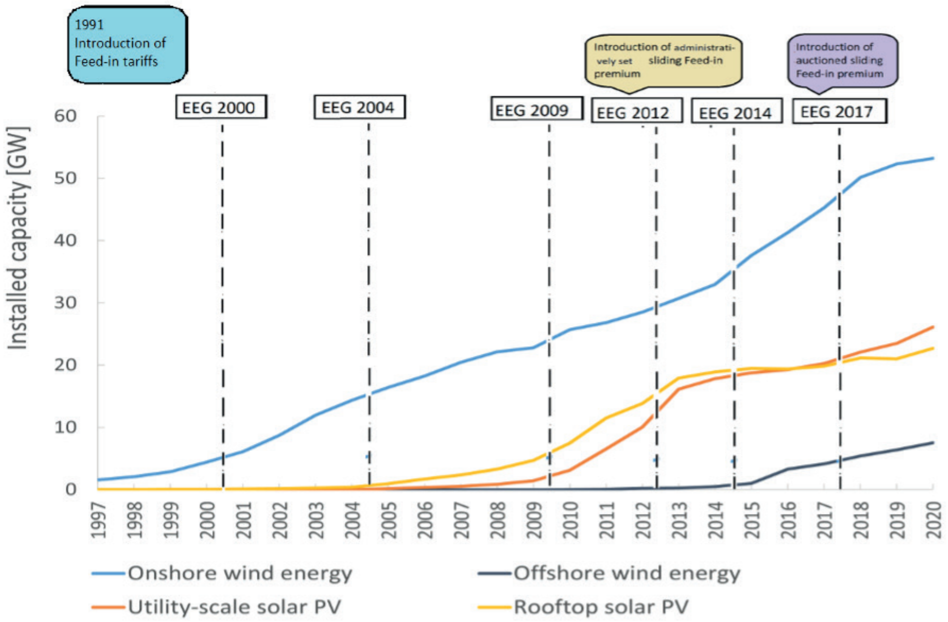
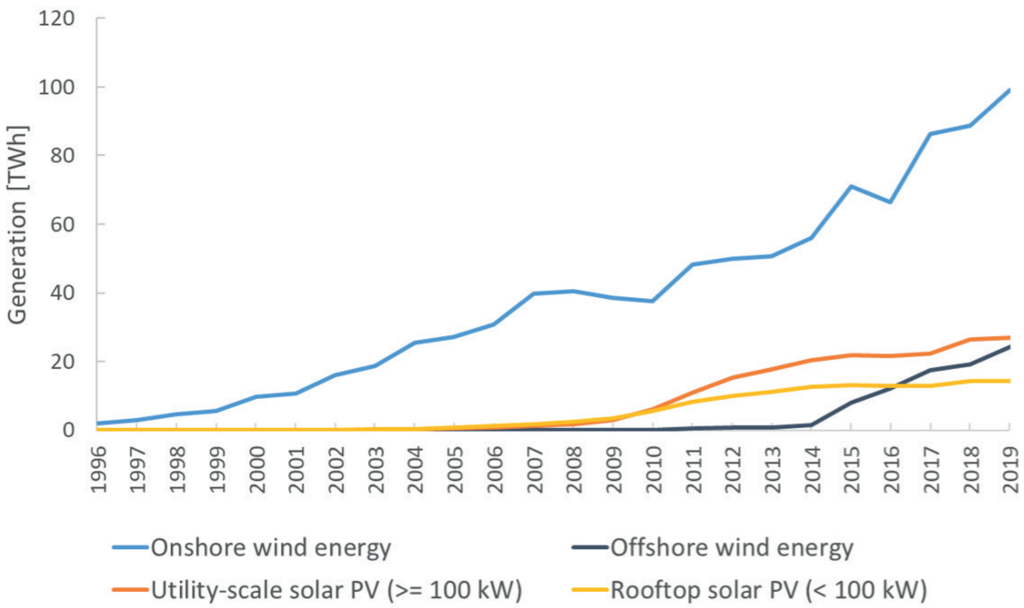


Figure 3. Annual generation in Germany (1996-2019). Main sources: BNetza, n.d.; Netztransparenz.de, n.d.

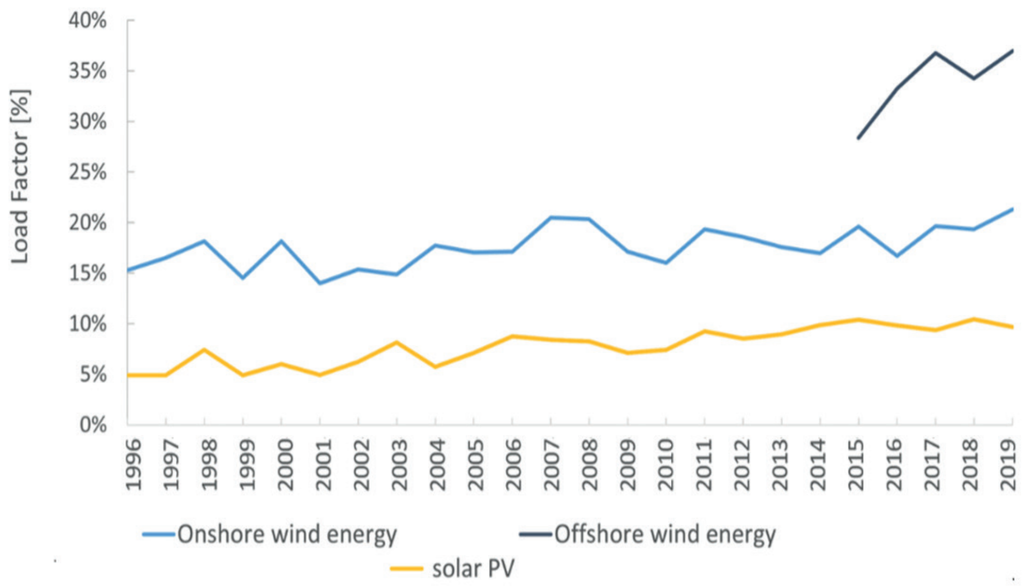


We observe that onshore wind generators saw the largest capacity deployment and also produced the most renewable electricity among the four technologies in the whole time period under study (1997-2020). By 2019 slightly more than 50 GW of onshore wind had been cumulatively installed, whereas only 20 GW each of utility-scale and rooftop solar PV were installed. In 2019-2020, whereas onshore wind was responsible for meeting 19% of electricity demand, the other three technologies each met about 4-5%. As in the UK case, in 2016-2017 a drop in terms of wind generation is noticeable although the cumulative capacity installed was increasing. Although no documentation supporting this has been found, the drop could be the result of 2015 record wind speeds followed by below average wind speeds in 2016, as is mentioned in the UK case study (UK Government, 2019b). Finally, both the cumulative installed capacity and annual generation from offshore wind only started to become comparable in order of magnitude to the other renewable electricity technologies considered from 2015 onwards. Whereas cumulative installed capacity for offshore wind in 2019 was around a third of that of utility-scale solar PV (and rooftop solar PV), the relative annual generation in 2019-2020 was slightly higher. This is clearly due to the higher capacity factors of offshore wind compared to solar PV. Figure 4 below shows the annual load factors, or capacity factors, of the different generation technologies according to our estimations. The annual load factors were estimated as follows:

$$Annual\ load\ factor = \frac{Generation_i}{8760 * \left(Cumulative\ capacity\ _j\right)}$$

$$where\ i{:}\ year\ and\ j{:}\ snapshot\ on\ 1\ January\ of\ year\ i$$

Figure 4. Estimated annual load factors for the technologies under study in Germany (1996-2019). Computation based on: BNetza, n.d.; Netztransparenz.de, n.d. See footnote 3 for more information on the derivation of the solar PV load factors.



From Figure 4 we highlight three points. First, the estimated annual load factors for solar PV slightly increased over the last decade from an average around 5-7% in 1996-2005 to circa 8-10% from 2015 onwards. Second, the estimated load factors for onshore wind show a profile with more significant variability due to the yearly variation in wind energy, ranging between 15% and 20%. Third, the estimated annual load factors for offshore wind turbines are visibly higher than those for onshore wind turbines installed in the same period, ranging between 30% and 40%. This indicates that offshore installations were by then located in waters further away from the shore and could exploit higher average wind speeds, leading to higher annual load factors.

Figure 5 reports the maximum and mean project size for each installation year and technology. More information about this chart can be found in Annex A.

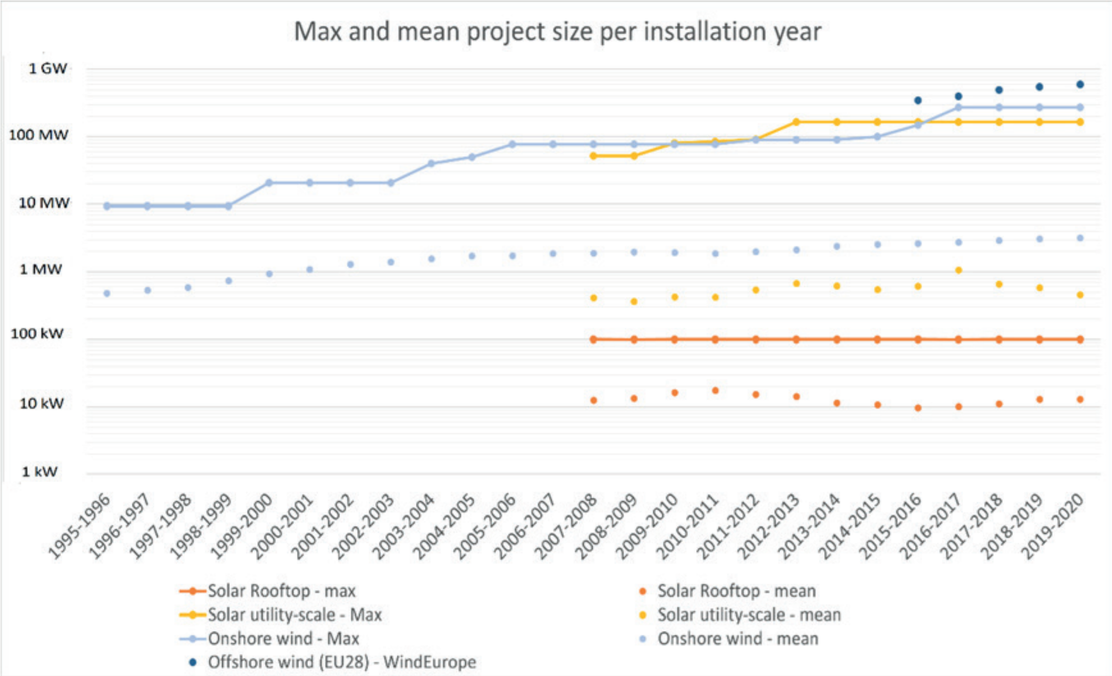


Figure 5. Maximum and mean project sizes for each installation year and technology in Germany (01/01/1995-01/01/2020) in logarithm scale. Computation based on: Amelang et al., 2020; Enkhardt & PV Magazine, 2020; Gupta & PV Magazine, 2021; Scully & PVTech, 2021; TheWindPower, 2021.

3.2 Three different support schemes and their effectiveness

As was previously mentioned, we identify three main renewable electricity support schemes that have been employed in Germany between 2000 and today. The first support scheme – 'first come, first served (administratively-set) feed-in tariffs' – was actually introduced with the 1991 'Feed-in Act.' Afterwards, it was modified with the 2000 EEG 'Erneuerbare-Energien-Gesetz' (Renewable Energy Sources) act. In the remainder of this chapter we focus on the design of this scheme from 2000 onwards, in line with literature which argues that this scheme was particularly effective from that point in time (Haas et al., 2011)at a first glance, the historic development of renewable energy sources in the electricity (RES-E. Successive versions of the EEG act – released in 2012 and 2017 – introduced the second scheme – 'first come, first served (administratively-set) one-sided sliding feed-in premiums' – and the third scheme – 'auctioned one-sided sliding feed-in premiums.'

These support schemes have been mainly identified through public information available in the texts of the various amendments to the EEG (Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2000, 2004, 2008, 2012, 2014a, 2017) and on the website of the BMWi Federal Ministry for Economic Affairs and Energy (Germany, 2021) combined with a literature review (Haas et al., 2011; Klobasa et al., 2013; Kuittinen & Velte, 2018; Mitchell et al., 2006; Purkus et al., 2015; Ragwitz & Steinhilber, 2014). [4]

The technologies of the projects which were mainly awarded financial support, the three policy

4 We do not study other support schemes which are less relevant from the capacity deployment perspective, such as the '100/250 MW Wind Program' (1989-1996), '1000-Daecher-Program' (1991-1993), 'TUV, Gruner Stromlabel e.V., Oko-Institut' (1998-present), '100 000 Daecher-Program' (1999-present), 'landlord-to-tenant

support schemes, and the relative time periods are visualised in Figure 6. As can be seen from the figure, except for rooftop PV there were overlaps between the different support schemes. Indeed, there were some periods when projects in the same technology set but belonging to the different ranges of installed capacity determined in the EEG acts were eligible for different schemes.

Figure 6. Overview of the different renewable support schemes studied mapped over the time period 1997-2020 for each technology. Main sources: BNetza, n.d.; Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2000, 2004, 2008, 2012, 2014b, 2017; Netztransparenz.de, n.d.[5]

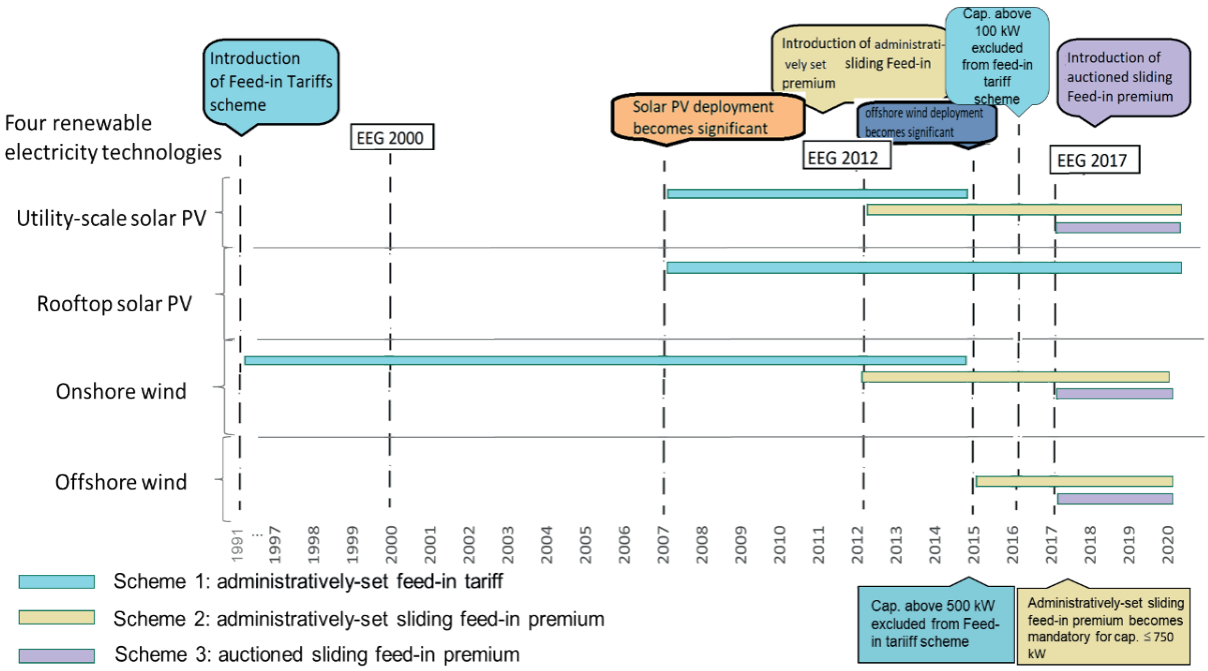


Table 1 gives an overview of the main characteristics of each support scheme. All three support schemes paid out support per MWh produced by renewable generators.

Table 1. Main characteristics of the three support schemes for renewable electricity in Germany

Time-line	*Scheme*	*Allocation mechanism*	*Price-level determination*	*Duration of support*	*Technologies*	*Recipient responsibility for electricity sales*
2000 - ongoing	Feed-in Tariff (FiT) under EEG	Accreditation according to eligibility conditions	Administratively-set (EUR/MWh)	20 years	Technology specific	No
2012 - ongoing	One-sided sliding feed-in premium (FiP)	Accreditation according to eligibility conditions	Strike price administratively-set (EUR/MWh)	20 years	Technology specific	Yes
2015 - ongoing	One-sided sliding feed-in premium (FiP)	Auctions	Strike price set in the auction (EUR/MWh)	20 years	Technology-specific & technology-neutral	Yes

5 Capacity awarded under the Landlord-to-tenant supply premium (valid from EEG 2017 onwards) was not significant enough to be included in this analysis.

In the remainder of this section, we describe each scheme in more detail and provide some quantitative data. In particular, we do so by answering the following questions for each scheme:

- What is the definition of the scheme?
- How was the allocation mechanism designed?
- How much installed capacity of the eligible technologies was supported in the time period under study?
- What were the price levels and payment durations under the scheme in the time period under study?

3.2.1 2000-today: the EEG First come, first served administratively-set feed-in tariff scheme

The feed-in tariff scheme rewards the renewable electricity generated and injected [EUR/MWh] by projects accredited under certain eligibility conditions. However, project operators are not expected to find a seller for their production in the market and are hedged against risks linked to power price signals. Indeed, the responsibility for selling the accredited renewable electricity on the spot market falls on the TSOs.[6] In Table 2 below we show the technologies that could mainly benefit from the support scheme in the time period under study.

Table 2. Conditions for renewable projects to be accredited in an EEG feed-in tariff scheme in Germany. Main sources: BNetza, n.d.; Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2000, 2004, 2008, 2012, 2014b, 2017.

Payment models	EEG 2000	EEG 2004	EEG 2009	EEG 2012	EEG 2014	EEG 2017
Utility-scale solar PV	Non-significant capacity deployment	Any installation commissioned			Only capacity ≤ 500 kW	Not eligible ≤ 100 kW limit *
Rooftop solar PV (≤ 100 kW)	= utility-scale solar PV	Non-significant capacity deployment	Any installation commissioned			
Onshore wind	Wind installations commissioned before or after 1. April 2000	Any installation commissioned			Only capacity ≤ 500 kW	Only small onshore wind (≤ 100 kW) & pilot project onshore wind up to 125 MW/yyear
Offshore wind	= Onshore wind		Non-significant capacity deployment		Not eligible Only capacity ≤ 500 kW	Not eligible ≤ 100 kW limit *

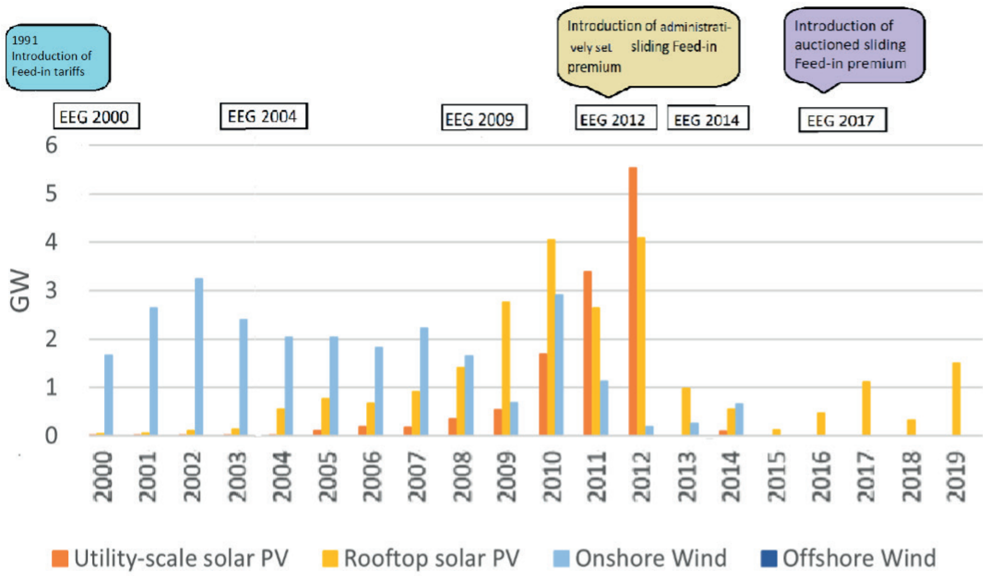
Note: a diagonal line background indicates that the renewable projects in the time period for the technology mostly could not benefit from renewable support schemes, whereas a blue background indicates the opposite. * An exception to the rule is that of renewable projects applying for 'shortfall remuneration.'

6 As Haas et al. (2011)at a first glance, the historic development of renewable energy sources in the electricity (RES-E state, the payment levels under the feed-in tariff scheme from 2000 onwards were uncoupled from electricity retail prices and based on estimated levelised generation costs. Additionally, specific technological characteristics (e.g. significant variability of onshore and offshore wind resources according to location) were also accounted for. Finally, a mechanism for changing the level of payments on a yearly basis according to the difference between a set capacity deployment target and actual installed capacity was also introduced. As Figure 3 shows, installed wind capacity significantly increased from 2000 onwards – coinciding with the introduction of the EEG.

Essentially, all the technologies considered except offshore wind have benefitted to a certain extent from the feed-in tariff scheme. However, from 2014 onwards only relatively small projects (below 500 kW between 2014 and 2016, and below 100 kW from 2016 onwards) could still be accredited to the scheme. The reason was that, apart from rooftop PV, projects became bigger (see Figure 5) and more total capacity was installed for each technology (see Figure 2). Finally, note that under the 2000 EEG onshore wind projects commissioned before the introduction of this act (1 April 2000) could also receive a payment worth the price level specified for newly-installed projects but applied for a shorter period of time. The time duration specified for these pre-existing projects was the larger of 20 years (standard duration for feed-in tariff payments) minus half the project's operational lifetime at the time of accreditation and 4 years.

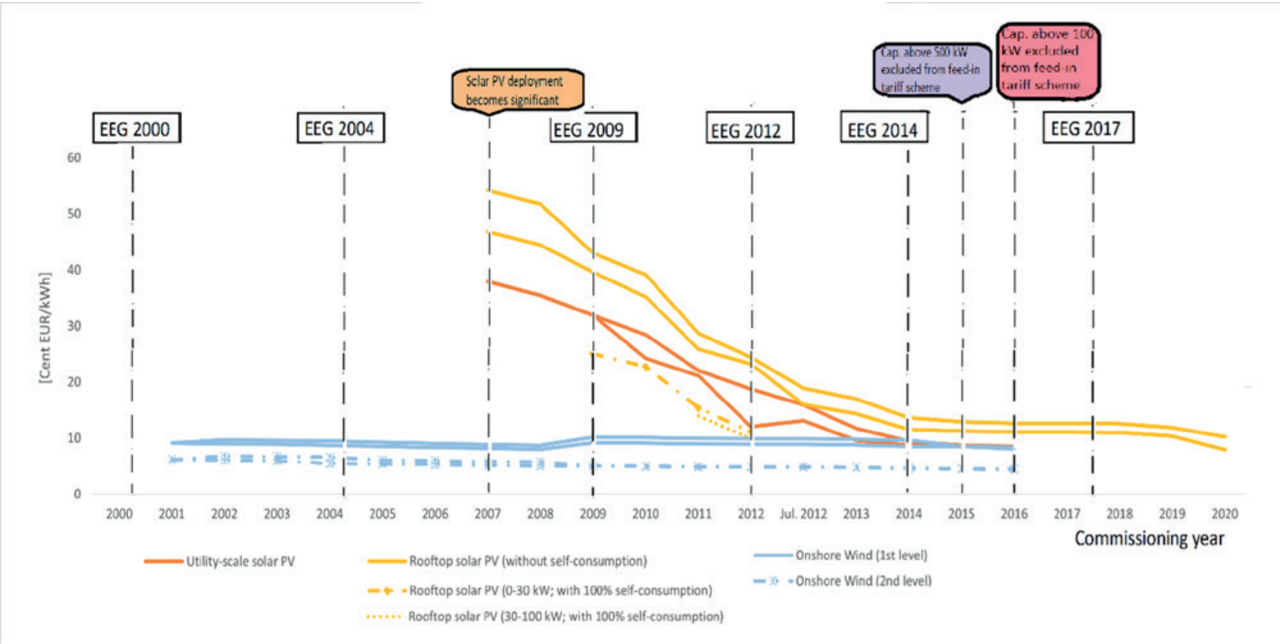
Figure 7 below gives further details on the estimated awarded capacity for each eligible technology under the EEG feed-in tariff scheme.

Figure 7. Estimated awarded capacity under the EEG Feed-in Tariff Scheme in Germany. Main sources: BNetza, n.d.; Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2000, 2004, 2008, 2012, 2014b, 2017.



As can be seen, the feed-in tariff scheme was responsible for a large share of capacity deployment of onshore wind, utility-scale solar PV and rooftop solar PV before 2013. From the implementation of the 2014 EEG onwards – limiting accreditation to the feed-in tariff scheme to projects below a certain size threshold of installed capacity – there was a significant drop in the capacities awarded for all the technologies. The capacity awarded for rooftop solar PV projects dropped from 3-4 GW/year before 2014 to around 1 GW/year or less of accredited capacity after 2014, most probably due to the significantly lower feed-in price levels. Figure 8 below shows the feed-in price levels for each eligible technology.

Figure 8. Levels of payments for projects accredited in the EEG feed-in tariff scheme. Main sources: BNetza, n.d.; Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2000, 2004, 2008, 2012, 2014b, 2017.



The price levels awarded for accredited utility-scale solar PV and rooftop solar PV projects were significantly high in 2007, ranging around 38-54 c€/kWh. From then onwards solar PV deployment also became significant (GWs). The price levels decreased significantly from 2007 to 2014, reaching 8.5-14 c€/kWh in 2014. The rationale for this decrease was to keep up with the decrease in generation costs, and therefore to limit excessive profits by generators. Payments were also foreseen in the 2009 EEG for electricity generated from rooftop solar PV and self-consumed, although they were phased out with the 2012 EEG.[7] However, it is unclear how the measurement or estimation of the amount of electricity self-consumed was done. It is important to highlight that the six EEG versions each identified different sub-categories of utility-scale solar PV and rooftop solar PV, which each received different levels of support. In contrast to solar PV, the feed-in price levels for accredited onshore wind projects remained stable at around 4-10 c€/kWh in the period under study. A bonus for onshore wind projects capable of "improving network integration and stability" was also available.

Finally, the price levels of feed-in tariffs reported in Figure 8 are paid for a finite number of years. The duration of 20 years is common to the three technologies which mostly benefitted from feed-in tariff schemes in the time period under study, and did not change with the different EEG acts. The duration of 20 years for onshore wind projects is split among two different time periods according to locational and technical characteristics, each with a different price level.[8] Additionally, onshore wind projects qualifying as 'repowering' can receive the initial higher price level for a longer time period or benefit from a bonus price level.

7 In Figure 8 above, this would correspond to the range between the two continuous yellow lines (rooftop solar PV (without self-consumption) for two different categories of installed project capacity) and the two dashed yellow lines (rooftop solar PV with 100% self-consumption for two different categories of installed project capacity).

8 In German the initial higher price level is called 'Anfangsverguetung.' The successive lower price level is called 'Endverguetung.'

Table 3. Duration of feed-in tariff payments. Main sources: BNetza, n.d.; Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2000, 2004, 2008, 2012, 2014b, 2017.

B. Duration value	Number of levels	EEG 2000	EEG 2004	EEG 2009	EEG 2012	EEG 2014	EEG 2017
Utility-scale solar PV	1 level				20 years		Not eligible
Rooftop solar PV	1 level					20 years	
Onshore wind	1° level				Min 5 years; f(% reference yield)		Only small onshore wind (< 100 kW)
	2° level				Difference between 20 years and duration of 1° level		Only small onshore wind (< 100 kW)
Offshore wind	1° level	= onshore wind				Min 12 years; f(water depth; distance from coastline)	Not eligible
	2° level	= onshore wind				Difference between 20 years and duration of 1° level	Not eligible
Offshore wind (Optional increased initial payment)	1° level		-			Min 8 years; f(water depth; distance from coastline)	Not eligible
	2° level		-			Difference between 20 years and duration of 1° level	Not eligible

Note: a diagonal line background indicates that the renewable projects installed in the time period and belonging to the technology mostly could not benefit from renewable support schemes, whereas a blue background indicates the opposite.

3.2.2 2012-today: the First come, first served administratively-set one-sided sliding Feed-in Premium (FiP) (direct marketing)

The German first come, first served administratively-set one-sided sliding feed-in premium scheme (also called a "direct marketing scheme" in the EEG) awards a payment for renewable electricity generated and injected (€/MWh) by projects accredited under certain eligibility conditions.[9] Eligible projects can either be newly-installed or older projects that were previously recipients of the feed-in tariff scheme and which opted to switch. A main change compared to the feed-in tariff is that in the FiP support scheme accredited generators are responsible for finding a seller for their production in the market. The generators are also balance responsible.

The market premium payment MP (€/MWh) under the one-sided sliding FiP is calculated according to the following formula: MP = EV – MW + PM, where EV is the pre-set strike price (anzulegende Wert), MW is the technology-specific retroactively calculated actual average monthly value of the hourly power contract for the EPEX spot exchange zone and PM is a management premium for unavoidable transaction costs and the associated risks related to the marketing procedure (i.e. the costs of balancing forecasting errors and of handling market transactions). Unlike the feed-in tariffs, the level of payment for the one-sided sliding feed-in premium is updated on a monthly basis and is a function of average hourly power exchange prices. The premium is one-sided in the sense that if the market premium (MP) is positive, accredited generators receive the MP, but when the MP is negative they do not have to pay the MP back. Instead, they do not receive support for that month (except for the management premium). The technology-specific, retroactive calculation of actual average monthly values is done using an online extrapolation tool published on an internet site by the transmission system operators. The reason for the 'technology-specific' attribute is that, whereas onshore wind technology generates more renewable electricity at times of low demand, solar PV tends to generate when demand is relatively higher (i.e. noon) (Gawel & Purkus, 2013). Note that due to direct marketing there was in increase in the importance of electricity trading companies, which have

9 In this chapter we do not study the 'green electricity privilege' or other alternative forms of direct marketing which were less effective in stimulating deployment. Most of these, including the 'green electricity privilege,' were phased out by the 2014 EEG.

the skills and infrastructure to sell electricity directly on the market on behalf of small/medium renewable electricity promotors. Finally, it is important to add that a mechanism was introduced in the 2014 EEG to reduce the payment entitlement of projects accredited in the sliding feed-in premium scheme whenever six consecutive hours of negative hourly power exchange prices are registered.

Table 4 below shows that, whereas under the 2012 EEG any installation was free to choose to be accredited to the feed-in tariff scheme or to the sliding feed-in premium scheme, from 2014 onwards the sliding feed-in premium scheme became compulsory for installations above a certain installed capacity threshold (500 kW in 2014 and 100 kW in 2016).

Table 4. Conditions for technological projects to be accredited in a sliding feed-in premium scheme in Germany. Main sources: BNetza, n.d.; Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2000, 2004, 2008, 2012, 2014b, 2017.

Payment models	EEG 2012	EEG 2014	For capacity commissioned from 1. Jan. 2016	EEG 2017
Utility-scale solar PV	Any installation, free to choose either «direct marketing» or «feed-in tariffs»	Obligations for Installations above 500 kW	Obligation for Installations above 100 kW	Obligation for capacity between 100 kW and 750 kW
Rooftop solar PV (≤ 100 kW)	Not able to participate (not economically feasible to participate in the market)	Not able to participate (not economically feasible to participate in the market)		
Onshore wind	Any installation, free to choose either «direct marketing» or «feed-in tariffs»	Obligations for Installations above 500 kW	Obligation for Installations above 100 kW	Obligation for capacity between 100 kW and 750 kW
Offshore wind	Any installation, free to choose either «direct marketing» or «feed-in tariffs»	Obligations for Installations above 500 kW	Obligation for Installations above 100 kW	Obligation for capacity between 100 kW and 750 kW

Note: a diagonal line background indicates that renewable projects installed in the time period and belonging to the technology mostly could not benefit from renewable support schemes, whereas a blue background indicates the opposite.

With the introduction of the 'auctioned sliding feed-in premium' in the 2017 EEG, the eligibility condition was narrowed to a range of installed capacities between 100 and 750 kW (basically excluding offshore wind projects and a significant proportion of utility-scale solar PV and onshore wind projects). Rooftop solar PV projects are not able to participate in this scheme, given that it would not be economically feasible for such small installations to directly participate in the market.

In Figure 9, we report the awarded capacity for each technology and year under the 'first come, first served sliding feed-in premium scheme.' Under the 2012 and 2014 EEGs the capacity awarded for onshore wind projects was significant and ranged between 2 and 4 GW. For utility-scale solar PV, awarded capacity ranged between 1 and 2 GW. With the 2017 EEG introducing the narrowing of the eligibility condition to a range of installed capacities between 100 and 750 kW, the capacities awarded for onshore wind projects and offshore wind projects dropped significantly. This is shown in Figure 5, which reports the mean project sizes for onshore wind projects of circa 2 MW and for offshore wind projects of 200-600 MW.

Figure 9. Estimated awarded capacities under the sliding Feed-in Premium Scheme in Germany. Main sources: BNetza, n.d.; Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2000, 2004, 2008, 2012, 2014b, 2017.

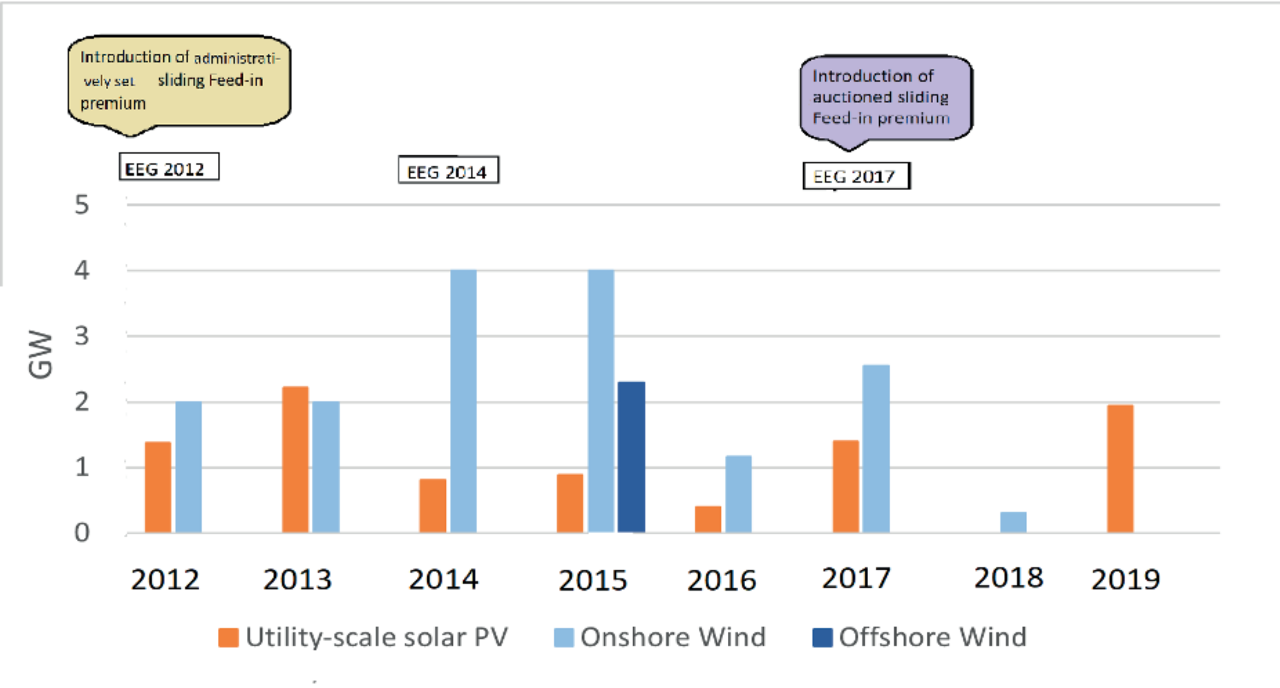
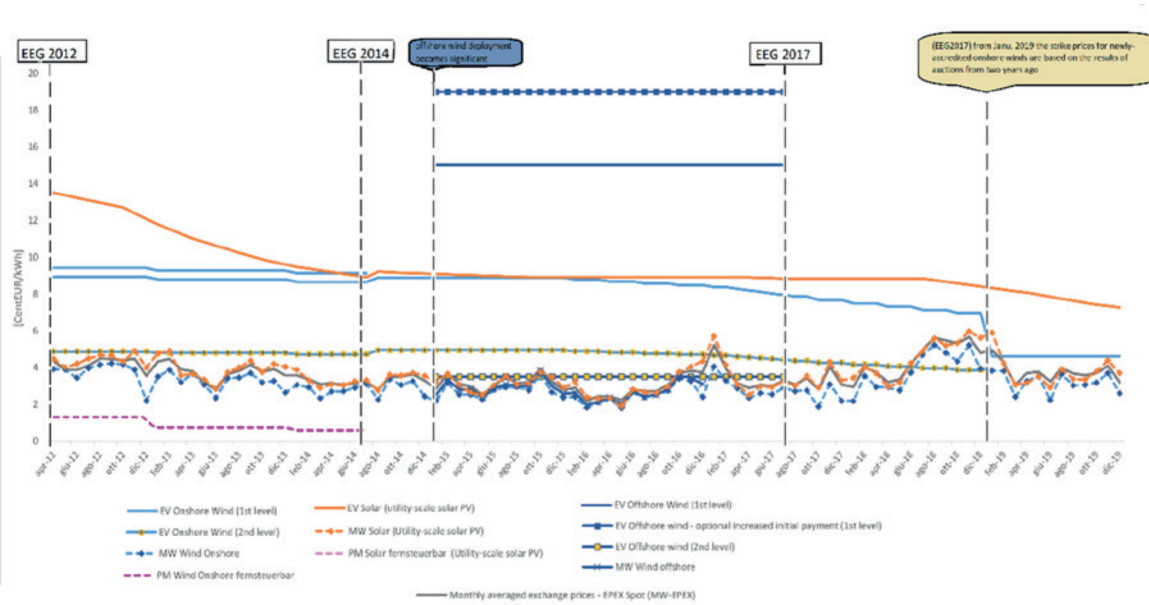


Figure 10 shows the expected market premium payments estimated as the levels of strike prices (EV), the calculated monthly average power prices (MW) and the premium for transaction costs (PM). It should be noted that in the period of validity of the 2012 EEG (2012-2014), the levels of strike prices coincided with the levels of feed-in tariffs. However, starting with the 2014 EEG the two started to differ and the levels of the strike prices were calculated by adding 0.4 c€/kWh to the levels for feed-in tariffs. Starting on 31 January 2019, the level of the strike price for newly-accredited onshore wind projects was replaced with a weighted average of bids in the auctions two years previously[10] under the auctions scheme (Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2017). The resulting drop in the levels of strike prices for newly-accredited onshore wind projects between the end of 2018 and early 2019 is quite visible (±2 c€/kWh). By connecting the outcome of the auctions with this administrative mechanism, price-levels no longer depended on the estimated generation costs of the technology.

10 The "average of the bid values of the highest bid still awarded funding from the bid deadlines for onshore wind energy installations in the year before the preceding year" (Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2017).

Figure 10. Levels of payment for projects accredited in the sliding feed-in premium scheme in Germany. Main sources: BNetza, n.d.; Bundesministeriums der Justiz und für Verbrauch-erschutz in Zusammenarbeit, 2000, 2004, 2008, 2012, 2014b, 2017. Note: the reported strike prices for solar PV refer to utility-scale solar PV projects[11]



Note: EV = administratively-set strike price, MW = monthly average market value, PM = administrative premium.

Whereas strike prices for onshore and offshore wind projects remained mostly constant in the time period examined except for from 2019 onwards for onshore wind, the strike prices for newly-accredited utility-scale solar PV projects fell significantly from 14 c€/kWh in 2012 to ± 9 c€/kWh in 2014. From 2014 onwards the strike price for utility-scale solar PV remained mostly constant.[12]

Regarding the management premium PM, under the 2012 EEG a bonus was offered for installations with remote control capabilities (see Figure 11 below). With the 2014 EEG, remote control capability and the availability of real-time data became a requirement for accredited projects (Purkus et al., 2015). The management premium became implicit in the EV levels of strike prices. In the 2017 EEG the management premium was phased out.

Figure 11. The management premium in the 2012 EEG and the Management Premium Ordinance 2012. Source: Gawel & Purkus, 2013

Year	Dispatchable RES	Wind/PV according to EEG 2012 (old)	Wind/PV according to MaPrV, 29.08.2012 (new)	
			Plants whose output can be remote controlled	Other plants
2012	0.30 ct/kWh	1.20 ct/kWh		
2013	0.275 ct/kWh	1.00 ct/kWh	0.75 ct/kWh	0.65 ct/kWh
2014	0.25 ct/kWh	0.85 ct/kWh	0.60 ct/kWh	0.45 ct/kWh
From 2015	0.225 ct/kWh	0.70 ct/kWh	0.50 ct/kWh	0.30 ct/kWh

Finally, Table 5 reports the durations of payments for projects accredited in the sliding feed-in premium scheme. For utility-scale solar PV and onshore wind there are no major differences between the durations in the sliding feed-in premium scheme and the previously discussed feed-in tariffs

11 It should be noted that the vertical scale in Figure 10 for strike price levels in the sliding feed-in premium scheme does not coincide with that for the price levels of the feed-in tariffs scheme (0-20 c€/kWh) in Figure 8 f (0-60 c€/kWh). This is partly due also to the different time periods under study (2000-2019 vs 2012-2019).

12 Similarly to the decreasing yearly levels of payments under the feed-in tariff scheme, this decrease can be explained as a mechanism to keep up with the decrease in generation costs and to avoid excessive profits by project promoters.

scheme (Table 4). Similarly, accredited offshore wind projects can choose between two payment models – each with a different initial price level and a different relative duration.[13]

Table 5. Durations of payment for projects accredited in the EEG Sliding Feed-in Premium scheme. Main sources: BNetza, n.d.; Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2000, 2004, 2008, 2012, 2014b, 2017.

D. Duration of payments	Number of levels	EEG 2012	EEG 2014	EEG 2017 For capacity commissioned from 1. Jan. 2019
Utility-scale solar PV	1 level	20 years		
Rooftop solar PV	1 level			20 years
Onshore wind	1° level	Min 5 years; f(% reference yield)		20 years
	2° level	Difference between duration of 1° level and 20 years		
Offshore wind	1° level		Min 12 years; f(water depth; distance from coastline)	
	2° level		Min 5 years; f(% reference yield)	
Offshore wind (Optional increased initial payment)	1° level		Min 8 years; f(water depth; distance from coastline)	
	2° level		Difference between duration of 1° level and 20 years	

Note: a diagonal line background indicates that the renewable projects in the time period and belonging to the technology mostly could not benefit from renewable support schemes, whereas a blue background indicates the opposite.

When we compare the expected payments across the three technologies, it can be seen that utility-scale solar PV projects clearly have a higher market premium payment than onshore wind projects, and probably a higher premium than offshore wind projects. More specifically, although the monthly average power prices calculated for utility-scale solar PV projects are slightly higher than those for onshore wind projects, strike price levels for utility-scale solar PV are significantly higher than those for onshore wind projects before 2014. Additionally, onshore wind projects do not benefit from the initial higher strike price level over all 20 years of accreditation. After a certain time period, they benefit from a lower strike price level. The situation is similar for offshore wind projects. Although their initial strike price level (16 c€/kWh or 20 c€/kWh) is at least one and a half the level of the strike price for solar PV (10 c€/kWh), the second lower strike price level (5 c€/kWh) is almost half.

3.2.3 2015-today: the Auctioned one-sided sliding Feed-in Premium (FiP)

Auctioning is currently the main mechanism in Germany for allocating financial support for renewable resources and for determining the level of support.[14] The introduction of auctions to allocate renewable support was planned for the first time in the 2014 EEG[15] and they finally started in April 2015 with the pilot auction round for ground-mounted solar PV projects. After the success of the pilot auctions in terms of attracting participants in 2015 and 2016 (explained in the following), the 2017

13 Starting with the2012 EEG newly-accredited offshore wind projects benefitting from the sliding feed-in premium scheme could choose between two groups of payment models. One group benefited from an even higher initial price level compared to the other one – as shown in Figure 10 – but over a shorter period (a minimum of 8 years rather than 12 years, as is shown in Table 5 below). No information has been found in the literature on how many offshore wind projects decided to adhere to the first group rather than the second one.

14 With the exception of capacities below 100kW for solar PV and onshore wind, which are still eligible to receive administratively-set feed-in tariffs, and solar PV and onshore wind capacities between 100 and 750kW, which will receive a feed-in premium based on the outcomes of auction rounds in previous years.

15 This coincided with the EU Commission modifying its renewables state-aid guidelines in 2014 and putting more emphasis on adoption of competitive approaches to support allocation (Leiren and Reimer, 2018).

EEG introduced regular annual auctions to determine support levels (strike prices that are used to calculate market premiums) substituting the administratively-set FiTs and FiPs. Importantly, as with the administratively-set FiP, new installed capacities that receive the FiP through auctions are balance responsible (CEER, 2018).

The Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railways (Bundesnetzagentur, BNetzA) is responsible for running the auctions (Bundesministeriums der Justiz und für Verbraucherschutz in Zusammenarbeit, 2017), while grid operators are responsible for signing contracts with the projects awarded and for paying them for the electricity generated. Table 6 below presents information on the proposed number of auction rounds per year for each of the technology-specific auctions and the annual capacity auctioned in each round as proposed in the 2017 EEG. Besides the technology-specific auctions which are presented in Table 6, since 2018 two rounds of multi-technology auctions a year with a capacity to be auctioned equal to 200 MW in each round have taken place jointly for onshore wind and solar PV projects.

Table 6. Information about auctions in Germany. Sources: EGG (2014, 2017) and Sach et al. (2019).

Auction	Eligible technologies	Total capacities to be auctioned (annually)	Rounds of auction per year	Realisation time limit	Penalties
Onshore wind auctions	Technology-specific, capacities >750 kW	2017, 2018: 2.8 GW 2020: 2.9 GW (Total installed capacity to reach 67-71 GW by 2030)	2017, 2018: 3-4 2019: 6-7 From 2020: 3	Penalty-free: 24 months Penalties phase in: 24-29 months Award decision and support payment suspends, the full penalty amount applies: 30 months (24 months for 2019 rounds).	10 €/kW: months 24-26 20 €/kW: months 27-28 30 €/kW: after month 28
Solar PV auctions	Technology-specific, capacities >750 kW	2017-2020: 2.5 GW (Total installed capacity to reach 98 GW by 2030)	2015-2018: 3 2019: 5 2020,2021: 7 From 2022: 3	Realization period without penalties: 18 months Realization period until support right is withdrawn: 24 months	0.3 c€/kWh deductions from the awarded value: months 18-24 Penalty if non-realized after 24 months: 50 €/kW
Offshore wind auctions	Technology-specific	Total installed capacity to reach 20 GW by 2030	2017, 2018: 1 2019, 2020: 0 From 2021: Number of tender rounds not specified	Planning approval phase: 12 months Connection to the grid: +24 months Realization: +18 months	Non-delivery at any of the milestones: withdrawal of the license Penalty: full or partial confiscation of 100 €/kW

In each auction round, participants compete for sliding market premiums (also known as asymmetric or one-sided contracts for difference) with a duration of 20 years by submitting the strike price they want for their project. For each auction round BNetzA sets a ceiling on strike prices which makes the bids above it unqualified.[16] The total generation capacity that is auctioned in each round is set in advance in the 2017 EEG.[17] The bidders with the lowest proposed strike prices are awarded support for their proposed installation capacity until the capacity cap for the auction round is met. The winning bids receive the strike price that they bid (pay-as-bid).[18] For qualification purposes, besides

16 'This ceiling is calculated as the average bid price of the last bids awarded in the last three auction rounds increased by 8 % (Sach et al.,2019).

17 These volumes are reviewed in the 2021 EEG for future auctions.

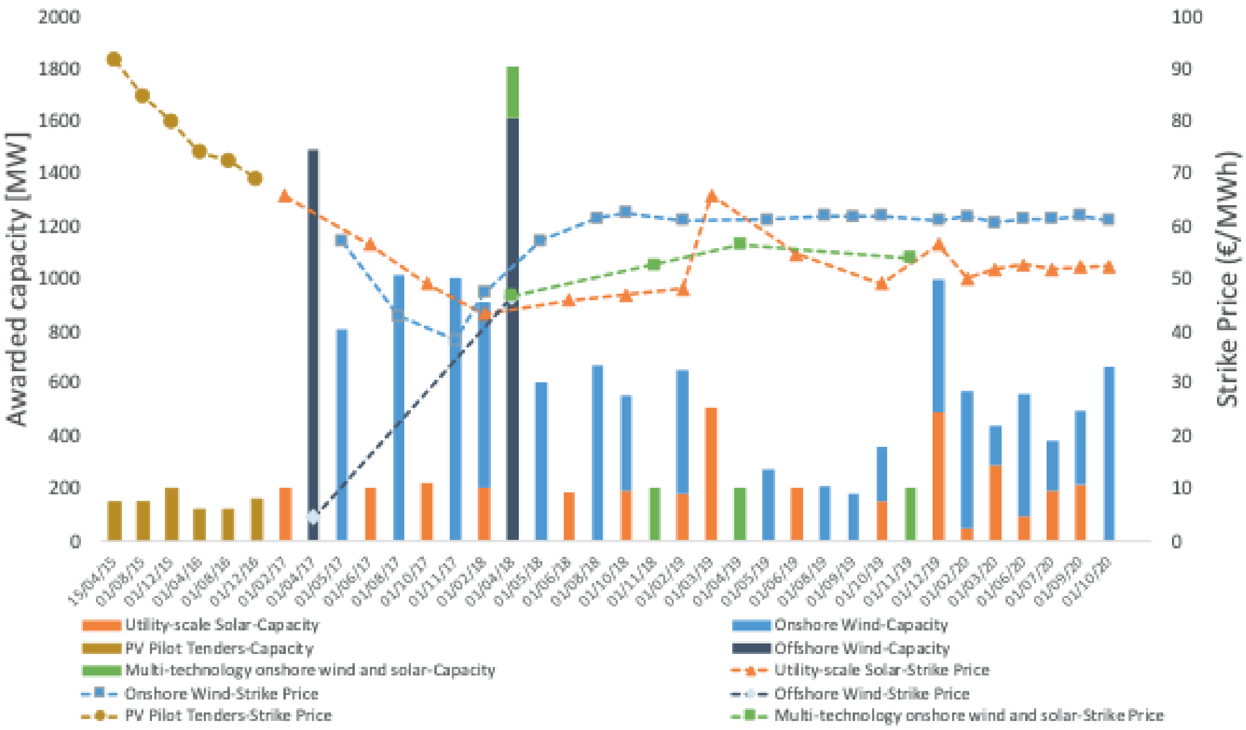
18 Citizen energy cooperatives benefited from significant competitive advantages including longer realisation periods and receiving the highest winning bid price, even if their bid was lower, unlike other bidders which should follow the pay-as-bid pricing rule (Leiren and Reimer, 2018; Lundberg, 2019).

their proposed strike prices and the size of their projects, bidders should also provide information on the location of the projects. This is especially important for onshore wind developments.[19] According to the technology that they are bidding for, they also need to provide some information regarding the project planning, acquisition of the permits required etc.[20]

The permitted realisation period and the penalty mechanism (in the case of delivery failure in each phase of the project) are unique to each of the technology-specific auctions. The technology specificity considers differences in the implementation and realisation of the different stages of a project. For instance, while the whole realisation period for a solar PV plant might be 18 months, for an offshore wind project it might take 12 months just to obtain the required planning approval. Table 6 provides a summary of the permitted realisation periods and the penalty conditions for each of the technology-specific auctions.

From the start of the auctioning mechanism in 2015 up to October 2020 there were 50 auction rounds in which support was allocated to 17.6 GW of wind and solar projects. More precisely, 10 GW of onshore wind capacity, 3.1 GW of offshore wind capacity and 4.7 GW of utility-scale solar PV capacity have been awarded so far. The high frequency of auctions allows bidders to have more time to plan their projects and a higher chance of getting support, although the support level awarded might be lower in later tenders. The capacities and support levels (strike prices) awarded in each round are shown in Figure 12.

Figure 12. Strike prices and capacities awarded for each technology. Source: Own calculations based on EEG in Zahlen (2019).



As Figure 12 illustrates, only two offshore wind auctions, one in 2017 and another in 2018, have taken place so far, allocating 1.5 GW and 1.6 GW respectively. A total of ten projects were awarded support in these auctions with a bid price for three projects in 2017 and two projects in 2018 equal

19 Based on the reference yield model (REM, Refererenzertragsmodell) and to take into account the quality of project locations in terms of wind resources, for onshore wind projects bid prices are adjusted against a 100% reference site before ranking them (Sach et al.,2019). This helps to have a geographically balanced distribution of wind plants and to avoid an accumulation of onshore wind capacities especially in northern parts of the country which have more wind sources (Haas et al., 2011).

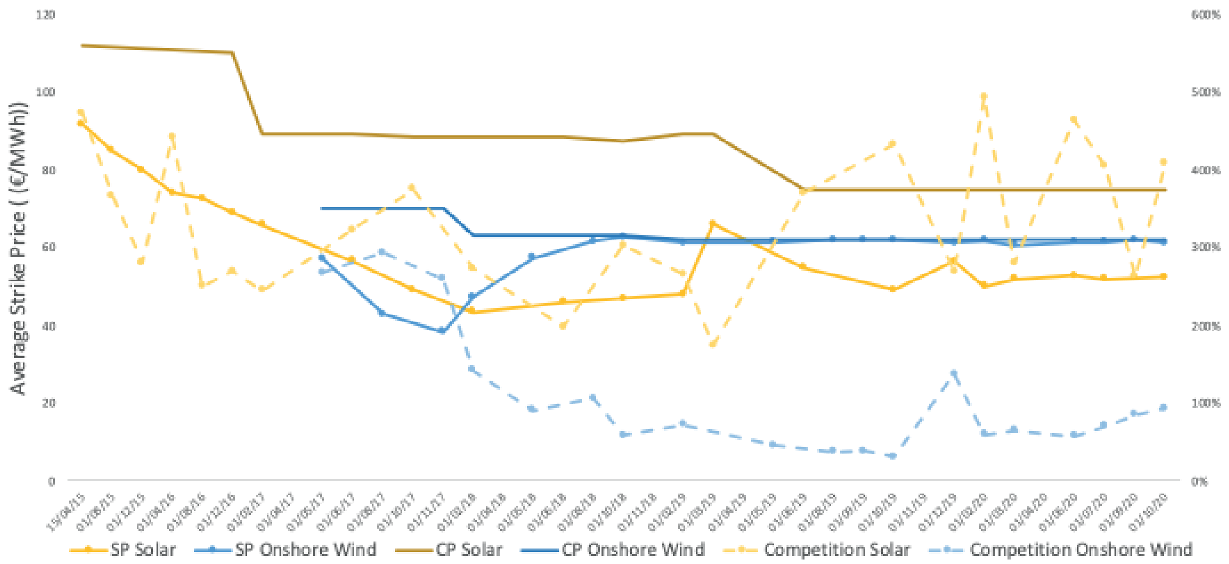
20 For instance, for onshore wind technology, only projects that are in the late stage of the project planning cycle can take part in the auction and they need to present the corresponding permits (Sach et al., 2019).

to zero, resulting in an average support level much lower than the ceiling in each round. Sach et al. (2019) state that these zero subsidy bids might be due to the fact that in general offshore wind installations come into operation years after they have been awarded the support and when they do, they might benefit from lower technological costs (higher technical efficiency).[21] However, when bid prices are very low, there is always the risk of projects not being able to cover future costs with their awarded bid. This is known as the 'winner's curse' in RES auctions (Lundberg, 2019; IRENA, 2017; Haufe et al., 2017; Kreiss et al., 2017).

The two offshore wind auctions were part of a transition period in which only existing projects that were already in their final development phase (and already had the permits necessary) could receive support and grid connection rights (Sach et al., 2019). After this transition period and as of 2021, annual auctions allocating 700-900 MW to new offshore wind power projects are held.

Figure 13 shows the evolution of ceiling prices, the resulting strike prices and competition levels in onshore wind and solar PV auctions. This figure helps us analyse the effectiveness and cost-effectiveness of the auction mechanism in supporting RES. Competition levels in this figure are calculated as the sum of the bid sizes (the sum of the capacities of the projects bidding) in each round that are over the auctioned capacity preannounced by BNetzaA. This measure indicates the attractiveness of the technology auctioned. If it is higher than 100% it means that competition for support is high and therefore the mechanism can be considered successful at attracting investments in RES.

Figure 13. Strike prices (SP), ceiling prices (CP) and competition levels in onshore wind and solar PV auctions. Source: Own calculations based on EEG in Zahlen (2019).



Looking at the yellow lines representing the strike prices, competition levels and ceiling prices for solar PV, we can conclude that the auctions have been effective in further developing utility-scale solar PV plants. [22] The competition levels for this technology have always been over 100%. In addition, the ceiling prices and resulting strike prices decreased respectively by 27% and 39% from 2015 to 2020. The resulting strike price in the first tender for ground-mounted solar PV in April 2015 was 91.7 €/MWh and it fell to 52.2 €/MWh in August 2020.

In contrast, regarding onshore wind it seems that the success of the early auctions did not continue in later auction rounds. Onshore wind auctions started in May 2017 with 70 €/MWh as the ceiling price and 57.1 €/MWh as the strike price (see the blue lines in Figure 13). These prices dropped in

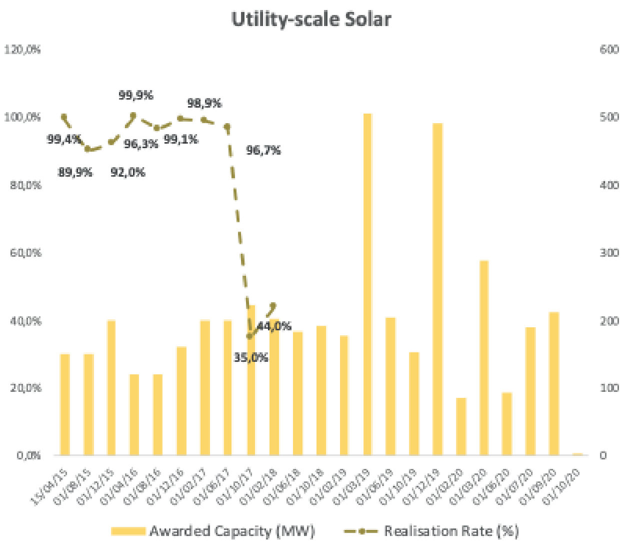
21 For a discussion on this topic, refer to Berkhout et al. (2018).

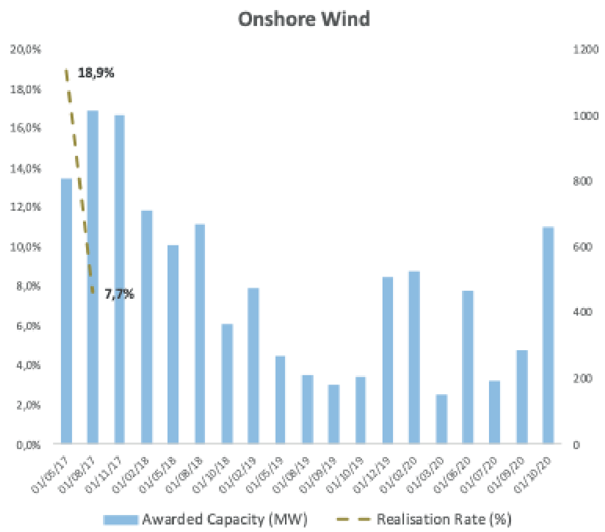
22 By development we do not mean full commissioning or realisation of the projects. This is another concept, which we will discuss later on. Here, we only mean willingness to develop RES projects.

the next three auction rounds, which also saw competition levels above 100%.[23] However, participation in onshore wind auctions decreased slightly from May 2018 with most of the tenders experiencing undersubscription. As a result, the strike prices increased and came closer to the ceiling prices. BNetzaA has not made significant changes to the ceiling prices since October 2018. Sach et al. (2019) report the reasons for this undersubscription to be "acceptance issues, delays in the land-use planning, emerging minimum distance rules at the state level, and the structural organisation of lawsuits against wind projects."

Finally, Figure 14 illustrates the realisation rates of utility-scale solar PV (left) and onshore wind (right) projects that have received support through the tendering mechanism. Almost all the ground-mounted solar PV projects that were awarded support in the pilot auctions in 2015 and 2016 became functional within their realisation limits. The realisation rate for projects the allowed realisation period (based on penalty schemes) of which ended by June 2017 was about 97%. The realisation rates for solar PV projects awarded after this date have not yet been published but for most of them the realisation period is still open. The same is true for onshore wind projects (right), considering that the realisation period for these projects is much longer than that for solar PV. Therefore, little can be said regarding the realisation rate for onshore wind projects. Sach et al. (2019) state that the high realisation rate for solar PV projects can be attributed to proportionate penalties and careful prequalification requirements.

Figure 14. Realisation rates for utility-scale solar PV (left) and onshore wind (right) projects awarded support in auctions. Source: Own calculations based on EEG in Zahlen (2019).



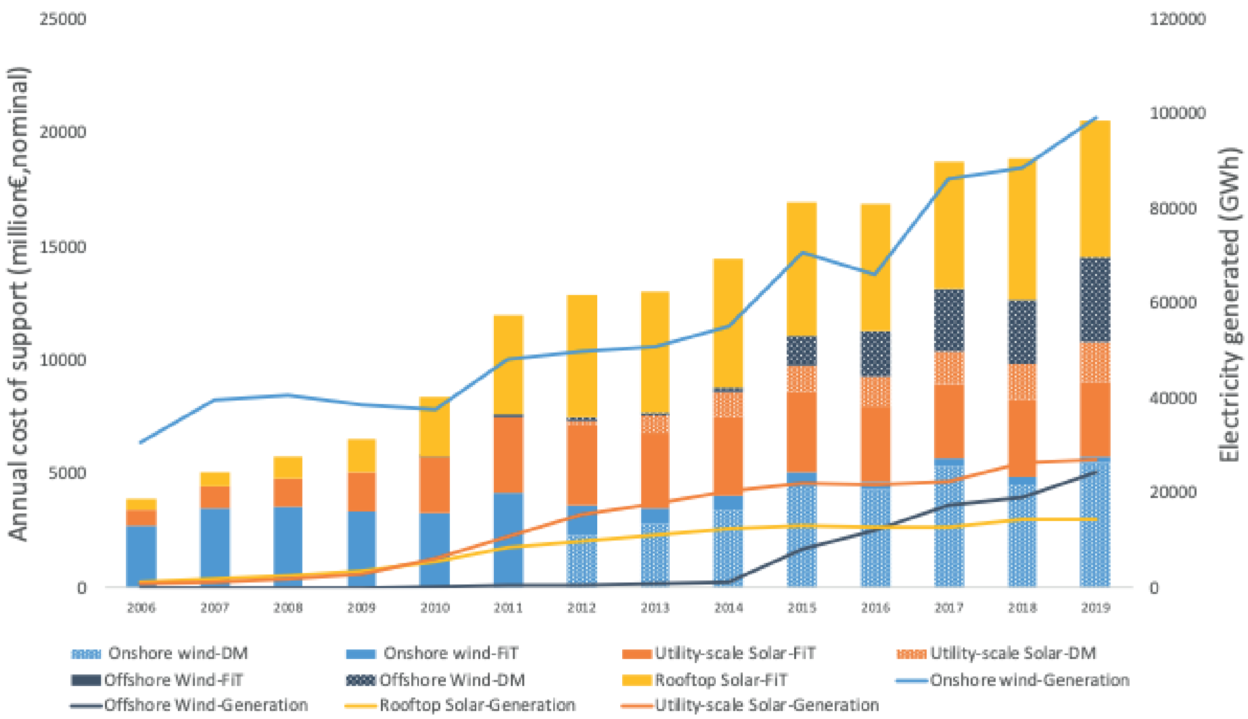


23 The high participation rate in these rounds can mostly be attributed to specific advantages allocated to citizen energy cooperatives, which resulted in them having a high participation rate. More than half the capacities auctioned in these rounds were allocated to citizen energy cooperatives (corresponding to 90% of the winning bids) (Lundberg, 2019).

3.3 The total annual costs of the support schemes

The total annual nominal costs of each support scheme (FiT, FiP and auctions) for each of the technologies considered are presented in Figure 15. The figure covers the period 2006-2019, during which several revisions of the EEG were implemented. As in the UK case, the administrative costs of the different support schemes have been excluded. While the total annual cost of schemes supporting wind and solar was less than €5bn at the end of 2006, the costs had more than quadrupled by 2019, amounting to about €20bn a year. The per capita cost of support increased from €61 to €240 during this period.

Figure 15. Left: annual nominal costs of each support scheme and technology. Own calculations based on annual EEG in Zahlen reports (2006-2019). Right: annual volume of electricity generated by each technology.

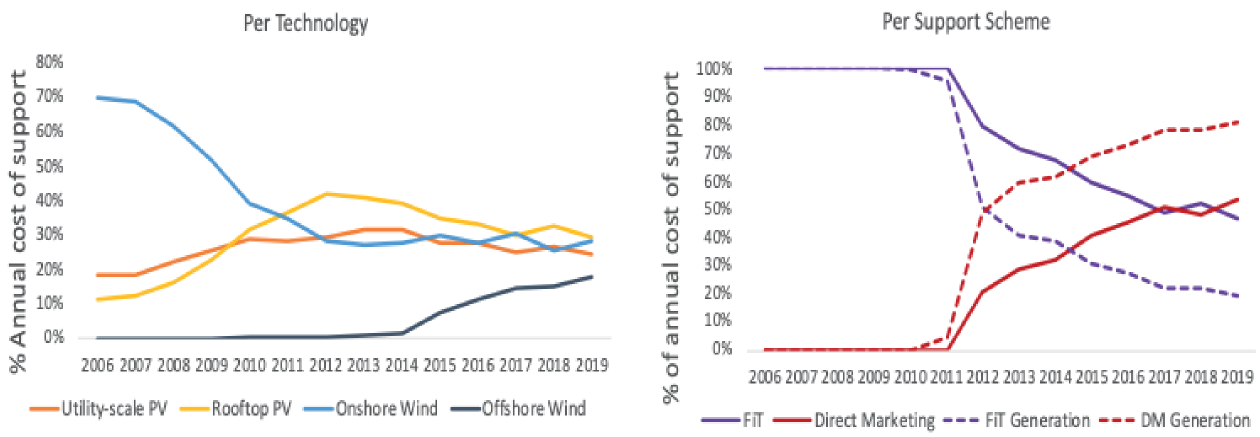


The annual costs reported in Figure 15 are estimated based on the data available in the annual EEG in Zahlen (EEG in Numbers) reports published by BNetzaA. These annual reports include measures related to implementation of the German EEG. In the EEG in Zahlen reports, payments by EEG are categorised in two types corresponding to the different supporting schemes: 1) payments under the FiT scheme and 2) direct marketing payments covering both the administratively-set and auctioned FiPs. Note that the cost calculations for 2006-2012 corresponding to utility-scale and rooftop PV remain approximations based on installed capacities and generation. The reason is that for this period the cost data (and the generation data) are only available in a combined generic measure and we have had to determine the share of each of the technologies. For 2013-2019 the cost and generation data are available individually for rooftop and utility-scale PV.

Two points to note regarding Figure 15 are the drop in costs in 2016 and the lack of increases in the annual support costs in 2013 and 2018 with respect to the previous years. The drop in support costs in 2016 is mainly due to a reduced wind load factor reducing wind generation. This also occurred in the UK. The reason for the support costs remaining stable in 2013 and 2018 with respect to the previous fiscal years is increases in the market value of the electricity generated. Under direct marketing the market premium is equal to the difference between the market value and the average strike price. In both 2013 and 2018 the average market value increased compared to the values in the previous years leading to lower market premium values being paid to RES generators[24] and making the costs of EEG financial support in these years remain similar to the values in the previous fiscal years.

As can be seen in Figure 16 (left), from 2006 to 2010 most of the financial support was allocated to onshore wind (70% in 2006 and 40% in 2010). The relative shares of both utility-scale and rooftop solar PV increased between 2006 and 2012. Due to the FiT scheme, the rooftop solar capacity awarded had significantly increased by 2011 and the share of rooftop solar receiving support surpassed that of onshore wind in the same year (41%). A similar trend is seen for utility-scale solar in 2012 (30%). After the introduction of direct marketing in 2012 and the gradual migration of large-scale RES generators (with capacities over 100 kW) to the newly-introduced support scheme, the relative share of onshore wind of support costs, which had been decreasing up to that point, stabilised at between 27 and 30%. Instead, payments to both rooftop and utility-scale solar have been gradually reducing since then. This trend slightly escalated in 2014 with the obligation for large-scale generators to directly market the electricity they generate. With direct marketing (which included administratively-set FiP until 2017 and auctioned FiP since then for large-scale renewable generators) technologies such as offshore wind began to receive a higher share of support payments. The relative share of offshore wind technology receiving support payments increased from almost zero in 2014 to around 19% in 2019.

Figure 16. Left: annual support costs divided by technology. Right: annual support costs divided by support scheme (2006-2019). Own calculations based on cost data as shown in Figure 15.



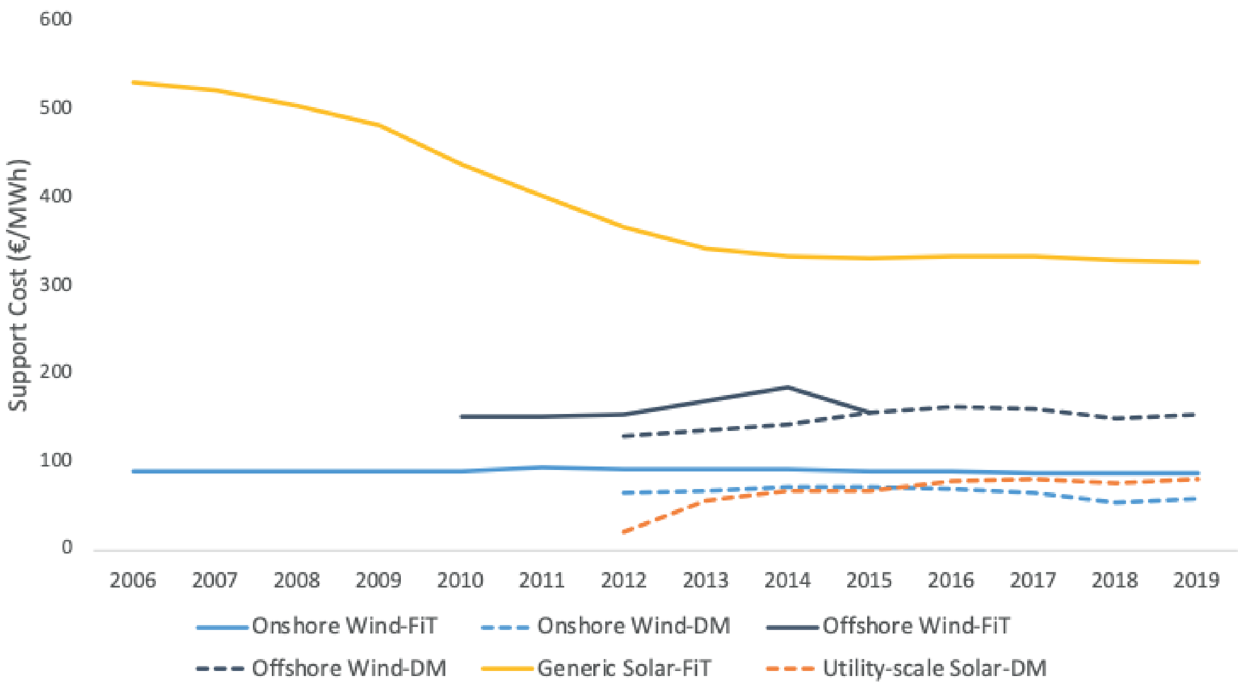
Regarding the relative costs of the different support schemes, the direct marketing share gradually increased from 20% in 2012 to 50% in 2017 and 2018. In 2019, the share of costs of direct marketing began to overtake that of FiTs. This is due to several rounds of auctions being held each year to allocate financial support for large-scale wind and solar technologies. Most of the recipient projects should become operational 24 months after being awarded support, meaning that an increasing amount of support payments under the direct marketing scheme will be allocated to these projects in the coming years. Another factor which is expected to contribute to a decreasing share of FiT in support costs is the termination of the 20-year support period for the capacities that started receiving relatively high feed-in tariffs in the early stages of the programme.

24 On average, the market value increased from 4.15 c€/kWh in 2012 to 4.4 c€/kWh in 2013 and from 3.5 c€/kWh in 2017 to 4.5 c€/kWh in 2018 (Netztransparenz.de, 2019).

3.4 The cost-effectiveness of the support schemes

In this section we analyse the cost-effectiveness of each support tool for each of the technologies considered. To calculate cost-effectiveness the same approach used in the UK case has been used for Germany. The cost-effectiveness of the support scheme for each of the technologies considered is defined as the annual payments divided by the total annual volume of electricity generated receiving payments under that specific support. Figure 17 shows how the cost-effectiveness of each support scheme for each technology considered evolved in the period 2006-2019.

Figure 17. The average cost of each support scheme for each technology considered, calculated by dividing the annual cost as shown in Figure 15 by the annual amount of electricity generated supported by each scheme for each technology. The data come from the same source as in Figure 15.



In Figure 17, generic solar-FiT is calculated as the weighted average level of support under the FiT scheme for utility-scale and rooftop solar.[25] This measure started as high as 530 €/MWh in 2006 and decreased continually until 2013. Afterwards it remained stable at around 330 €/MWh. This stability can be attributed to the roll-out of DM and lower capacities awarded a FiT together with the potential impact of technology improvements lowering investment costs and the need for high FiTs. Nonetheless, the weighted average FiT level of support for solar technologies remained the highest among the support levels attributed to other support schemes covering these technologies (DM for utility-scale solar). This can be explained by the fact that initially many small-scale solar generators (mostly rooftop PV with capacities below 100 kW) enjoyed high FiTs in the early stages of the support scheme between 2000 and 2006. While high amounts of payments were given to these generators, their generation remained low as they were using early PV technologies which had lower capacity factors. This is not true for onshore and offshore wind generators which received FiTs. In fact, the level of support for such generators has remained stable at around 90 €/MWh (from 2006 to 2019) and 180 €/MWh (from 2010 to 2015) respectively. However, it is expected that with the expiry of the

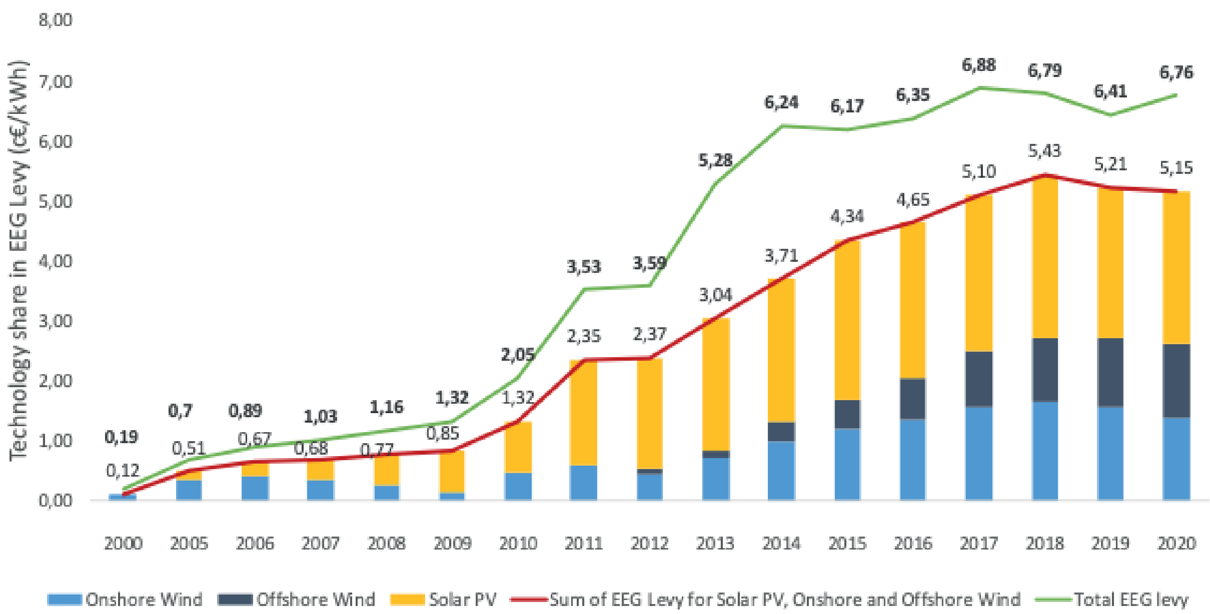
25 The reason is that we only had access to the generic solar cost and generation data under the FiT scheme instead of separate cost and generation data for utility-scale and rooftop solar under this scheme.

initial highly generous FiT contracts in the coming years, the cost of FiT scheme will decrease. Support per MWh generated under the DM mechanism followed a stable trend during the period 2012-2019 for all the technologies considered.

3.5 The impact on electricity bills

The renewable support schemes are funded via the EEG surcharge. The levy is paid by industrial (with partial exemptions for power-intensive industries), commercial and household consumers as part of their electricity bills.[26] The value of the surcharge for the following year is set each year on 15 October by Germany's four TSOs (namely 50 Hertz, Amprion, TenneT and TransnetBW). This value is estimated based on both historical and current data, the TSOs' forecasts of future renewable power feed-in, the wholesale market price and their expected expenses (remunerations to RES) (BMWi, 2021). In 2000, when FiT payments started, the EEG surcharge amounted to 0.19 c€/kWh. With increases in subsidised RES power feed-in in the following years, the EEG surcharge increased continually until 2017, when it was equal to 6.88 c€/kWh. Poser et al. (2014) argue that besides increasing RES generation, industry exemptions and wholesale market price reductions were the other two drivers resulting in an increasing trend in the EEG levy. The levy decreased for two consecutive years in 2018 and 2019 but saw an increase again in 2020, equalling 6.76 c€/kWh (still lower than the peak in 2017). Historically, solar PV has been the technology with the highest share in the EEG levy, followed by onshore wind and since 2014 offshore wind. Figure 18 illustrates these shares plus the evolution of the EEG surcharge since 2000.

Figure 18. The EEG surcharge since 2000 and shares of RES technologies. Source: BMWi (2021).



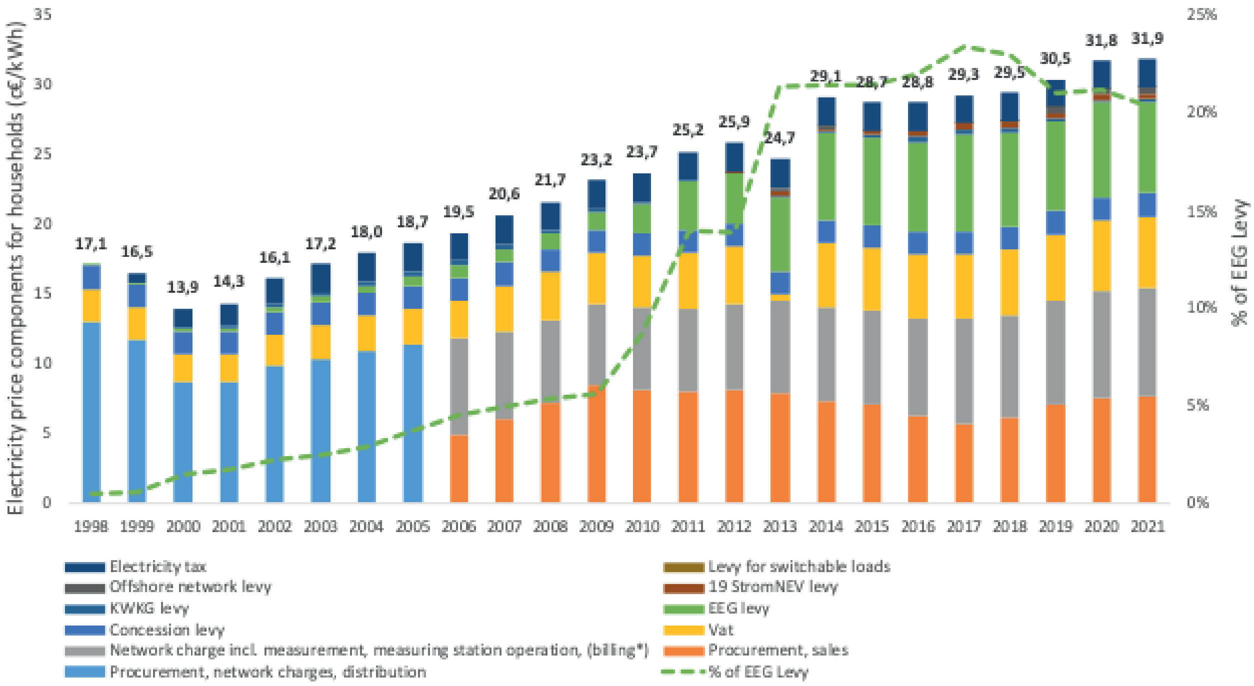
Using our cost calculations in Figure 15 and total electricity consumption in Germany (which is discussed below) we calculate the cost which has been paid to solar and wind technologies per kWh of electricity consumed and compare it to the measures reported by BMWi (2021) in Figure 18. It seems that our calculations are of the same magnitude as these measures and are robust enough.

26 Households and industrial consumers (with consumption between 160 MWh and 20 GWh) pay the full levy, while power-intensive industries (with consumption over 70 GWh) are totally exempt from paying the levy (BDEW, 2021). Industries with a consumption level between 20 and 70 GWh are partially charged. BMWi (2021) reports that about 2000 manufacturing companies benefit from partial exemptions every year. These partial and full exemptions are in place to maintain the competitiveness of German industries with respect to their international counterparts (CEER, 2018).

As an example, in 2019 the total support paid to solar, onshore and offshore wind projects was €20.5 billion while total consumption was 511 TWh. Therefore, based on our calculations, the support cost for solar and wind technologies per kWh of total electricity consumption in 2019 was equal to 4.2 c€/kWh.

Household electricity prices in Germany are some of the highest in the EU. While the EU-28's average price of electricity for households was 22.4 c€/kWh in 2018, in Germany this measure was 29.5 c€/kWh (Eurostat, 2021b).[27] The difference can be attributed to the high share of levies and taxes that are included in final electricity bills in Germany. German electricity bills consist of several components: the cost of power for suppliers (procurement and sales), grid charges, a concession fee, a levy for renewable energies (EEG), a levy for CHP (KWK-Aufschlag), a levy for grid charges to large users, an offshore wind levy, sales tax and a standard electricity tax (Pyrgou et al., 2016; BMWi, 2021). The share of the EEG surcharge has been increasing in both household and industrial final power bills since 2000. The share of the EEG surcharge is usually higher in (non-exempt) industrial power bills than those of households. The reason is that industries are exempted from some other bill components, such as value added tax, which leads to a generally lower price for electricity consumption and therefore a higher share of the EEG surcharge for non-exempted industries (BDEW, 2021).[28] As Figure 19 shows, the share of RES support in household electricity bills increased from 2.5% in 2000 to 21% in 2020. For non-exempted industries this increase is more severe, with a change from 2% in 2000 to almost 40% in 2020 (BDEW, 2021).

Figure 19. Household electricity prices and the share of RES support in household electricity bills. Source: BMWi (2021) and BDEW (2021).

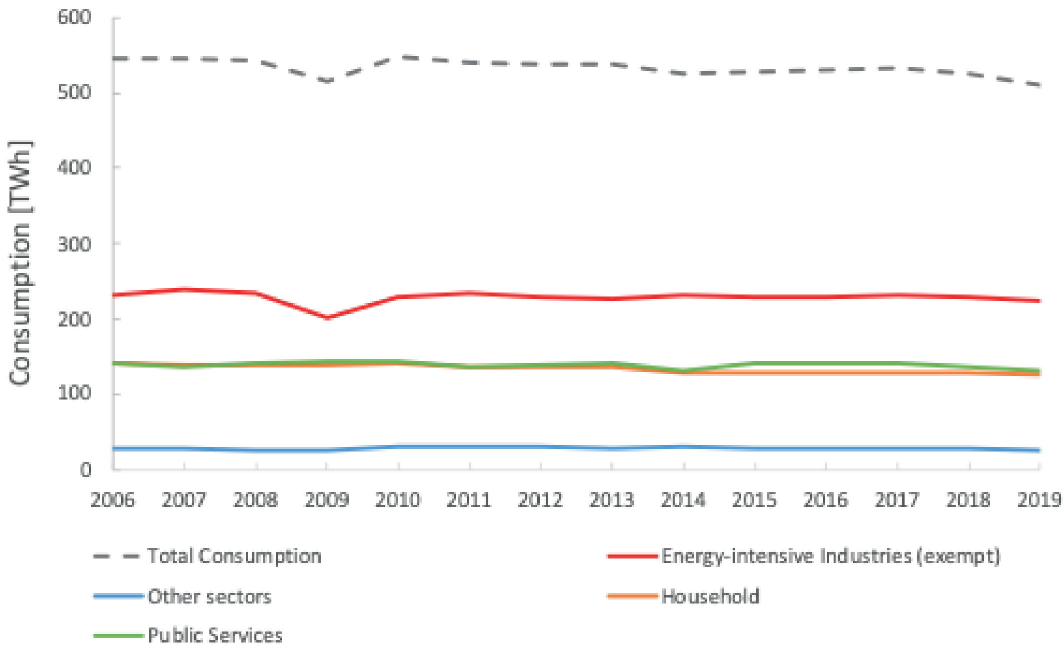


27 This is while electricity wholesale prices in Germany are among the lowest in the EU (Eurostat, 2021b).

28 The average price of electricity in 2020 was 31.8 c€/kWh for households (with an annual consumption of 3500 kWh per household) while it was 17.76 c€/kWh for non-exempted industries (BDEW, 2021).

Figure 20 shows both total and sector-specific electricity consumption in Germany from 2006 to 2019. Total consumption in Germany remained fairly stable during this period, with a slight reduction from 545 TWh in 2006 to 511 TWh in 2019. Regarding the share of consumption by each sector, around 24% of electricity is consumed by households, while the annual consumption by energy-intensive industries is 230 TWh on average, equalling around 45% of total consumption.

Figure 20. Germany's total electricity consumption and electricity consumption by sector. Source: Eurostat (2021c).



Considering that households pay the full EEG levy, in 2019 when the EEG levy was equal to 6.41 c€/kWh households paid €8.1 billion to support RES-E. The total renewable surcharge in 2019 was equal to 22.7 billion euros, which means that households paid 35% of the support costs allocated to renewables while their consumption was around a quarter of the total. This is compatible with BMWi (2021) stating that 50% of the contribution to the EEG surcharge comes from industry, trade, commerce, and services, almost 30% from households and 20% from public institutions. We can also consider consumption and the EEG contribution by households and the public sector together and compare this with that of industry. Households and the public sector together consumed 50% of total electricity (259 TWh) in 2019 but as they paid the full EEG surcharge equal to 6.41 c€/kWh they paid 73% of RES support (€16.6 billion). The exemption of power-intensive industries is raising some debates on the distributional effects of renewable support in Germany (especially feed-in tariffs) and the issue of low-income household electricity poverty (Frondel et al., 2015; Fischer et al., 2016). With the increasing trend in the share of the EEG surcharge in electricity bills, as is shown in Figure 19, these debates are attracting more attention (Winter and Schlesewsky, 2019).

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Annex A. More information about renewable project sizes in Germany

- The average project size for rooftop solar PV in Germany ranges between 10kW and 20kW according to an analysis based on Netztransparenz.de (2019), whereas the maximum size does not exceed 100kW in coherence with the definition chosen for this technology in this chapter.
- Average project sizes for utility scale solar PV in Germany are larger by definition, ranging between 350kW and 1MW according to an analysis based on Netztransparenz.de (2019). Maximum project sizes reached even 168MW (Brandenburg-Senftenberg Solarpark) in 2011-2012 (PVResources, 2016). Upcoming projects in the rest of 2021 promise scales beyond 100MW (Enkhardt & PV Magazine, 2020; Gupta & PV Magazine, 2021; Scully & PVTech, 2021).
- Average project sizes for onshore wind in Germany from 2000 onwards ranged between 1MW and 5MW according to analysis based on Netztransparenz.de (2019). These project sizes are comparable to an onshore wind farm with a few turbines of 0.5-3MW, according to the technological standards of a large German wind manufacturer as shown in Amelang et al. (2020). Maximum project sizes ranged between 100 and 300MW in the last decade (e.g. Windpark Holtriem-Dornum with a capacity of 275MW, including 138 turbines, Windfeld Uckermark at 243 MW with 112 turbines and Windpark Asseln at 129MW with 92 turbines) (TheWindPower, 2021).
- Offshore wind is the only technology for which comprehensive data on project sizes in Germany has not been found. However, we have found such data at the EU-27 regional level for projects built from 2015 onwards. In the EU-27 region, average project sizes for offshore wind technology were estimated to range between 200 and 600MW according to WindEurope. After checking the data for the few offshore wind projects in Germany installed in 2019, we can assume that the EU regional average estimates also apply for Germany. We provide the following three examples: the EnBW Hohe See project in Germany – built in 2019 – with 497MW of capacity connected and 71 turbines, the Deutsche Bucht project with 260.4 MW and 31 turbines and Trianel Windpark Borkum 2 with 101.3MW and 16 turbines (Wind Europe, 2020).

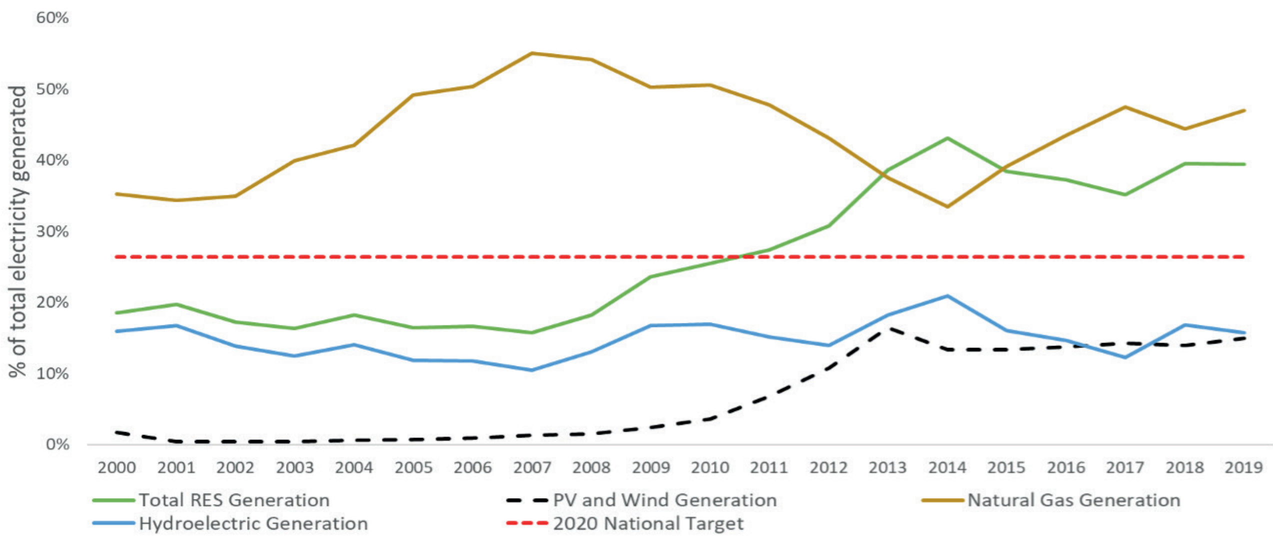
4. Italy

In this chapter, we describe and analyse the main renewable support schemes that have been introduced in Italy to stimulate investment in onshore wind, utility-scale solar photovoltaic (PV) and rooftop solar PV. The chapter consists of five sections. First, we provide a general introduction. Second, we give an overview of the different support schemes that have been put in place and their effectiveness in promoting the deployment of the renewable electricity generation technologies considered. We distinguish four schemes: Tradable Green Certificates (2001-2012), administratively set feed-in tariffs (2008-today), one-sided sliding feed-in premiums (2012-today) for onshore wind and feed-in tariffs through the special Conto Energia regime for photovoltaic systems (2006-2013). Third, we describe the annual costs of the different tools for each generation technology. Fourth, we discuss the cost-effectiveness of the support schemes, which is defined as the annual expenditure of a support scheme per MWh of energy produced by all generators benefiting from the scheme. Last, we discuss the impact of the renewable support schemes on electricity bills.

4.1 General introduction

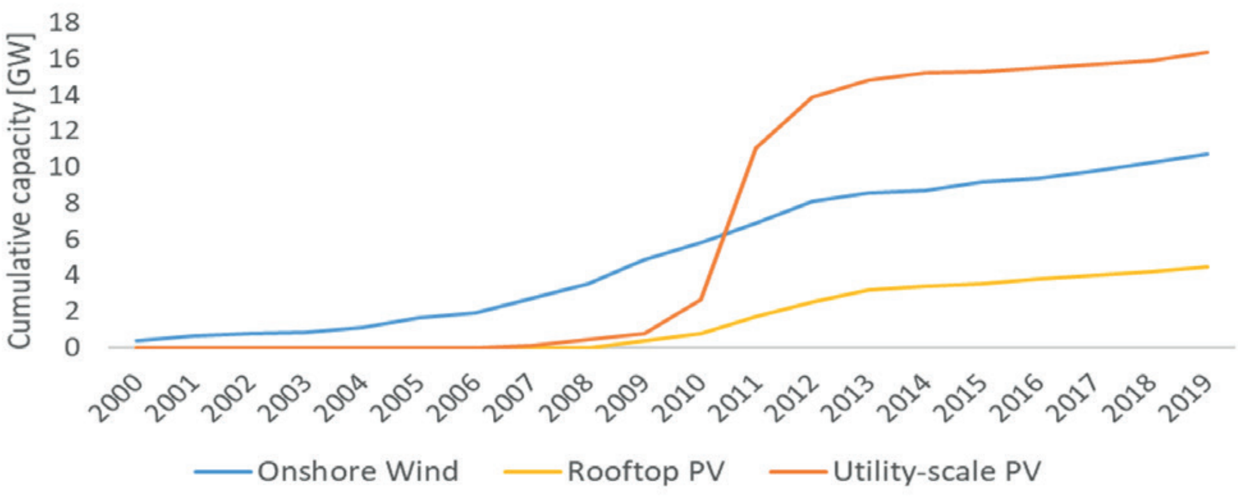
Like many member states in the EU and other nations around the world, Italy has been developing and implementing policies to promote electricity generation from renewable resources. Such actions started in Italy as early as 1992, with several climate and energy milestones being reached since then, including the European 20-20-20 targets and the more recently adopted 2050 net zero target (European Commission, 2009; Piebalgs et al., 2020). In this regard, Italy committed to a target of a 26.4% share of electricity generated from renewables in 2020. Figure 1 shows the evolution of electricity generated from renewable electricity sources in Italy between 2000 and 2019 (Terna, 2021). The Italian national target share of RES electricity generation was already met in 2011, when the share of renewables in the electricity mix reached a total of 27%. Although this measure increased to 39% in 2019 – with hydro constituting 16% and the sum of wind and PV constituting 15% – the majority of electricity in Italy is still generated from fossil fuels (61%), with natural gas being the main source (47%). The only time when the share of RES generation surpassed that of natural gas was 2014, when demand for generation from natural gas power plants fell to its lowest level in the aftermath of the 2008-2009 economic crisis. However, the supply of renewable generation was also at its highest in 2014, with this year being considered a high-water supply year (ARERA, 2020) and other RES generation continuing to grow due to generous support which had been provided in the previous years. With the demand for electricity increasing, natural gas once again became the number one energy source in Italy in 2015.

Figure 1: The 2020 renewable electricity target for Italy – Total RES generation versus natural gas and hydroelectric (2000-2019). Main source: Terna (2021)



We focus on promotion through public financial support for three renewable electricity generation technologies: onshore wind,[1] utility-scale photovoltaic (PV) and rooftop PV.[2] Figures 2 and 3 show the evolution of the deployment of these three technologies in Italy and the electricity they generate. As can be seen from Figure 2, since 2010 utility-scale PV has had the highest amount of accumulated installed capacity among the technologies considered, with rapid development between 2010 and 2012. This is unique compared to the other country cases analysed in this report, in which either onshore or offshore wind has the highest accumulated installed capacity. In fact, the growth in onshore wind plants in Italy followed a more linear path. In 2019, the overall accumulated installed capacity of these three technologies amounted to 32 GW, with the installed capacity of utility-scale solar equalling 17 GW, followed by 11 GW of onshore wind and 4 GW of rooftop PV.

Figure 2: Accumulative capacity installed in Italy (01/01/2000-31/12/2019). Solar PV with a capacity just under 20 kW is considered the rooftop. Main sources: GSE (2007-2021) GSE (2007-2021)

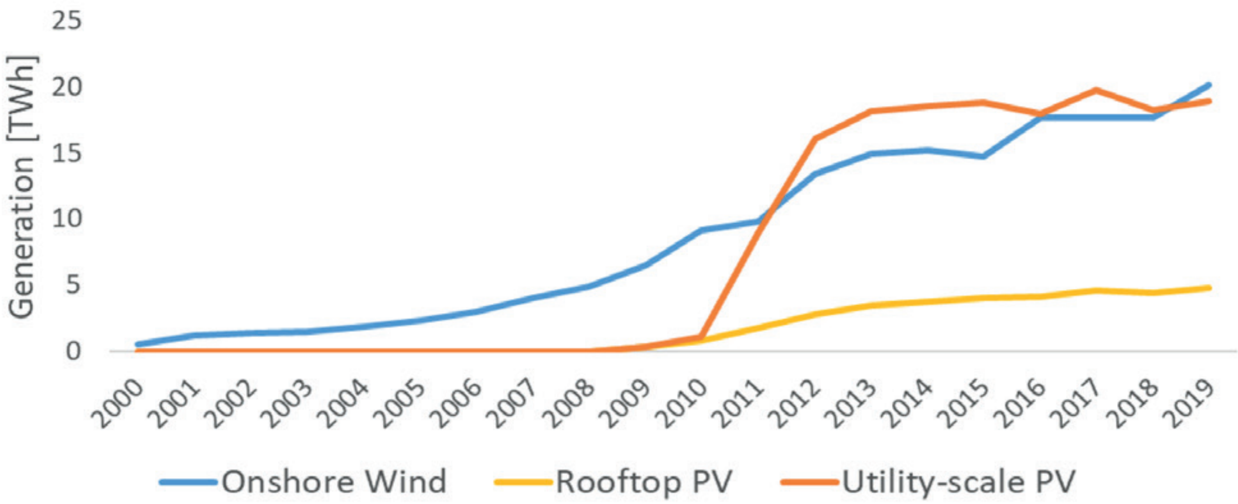


1 There are currently no active offshore wind installations in Italy.

2 In this analysis we consider all solar PV installations smaller than or equal to 20 kW to be rooftop PV and all solar PV installations above 20kW to be utility-scale PV. We do not distinguish between solar PV attached to a building and ground-mounted. The majority of solar PV attached to buildings will be below this threshold and that of ground-mounted solar PV will be above.

From Figure 3, it can be seen that from 2011 to 2018 generation from utility-scale PV was the greatest among the three technologies, ranging between approximately 18 and 19 TWh. However, since 2018 and although the accumulative installed capacity of utility-scale rooftop remained the highest, electricity generation from onshore wind once again (after 2011) surpassed that from utility-scale PV, equalling 20 TWh. This is due to the general higher capacity factor of wind installations compared to that of PV plants. Figure 4 shows the capacity factors of these generation technologies in Italy.

Figure 3: Annual generation in Italy (2000-2019). Main sources: GSE (2007-2021)

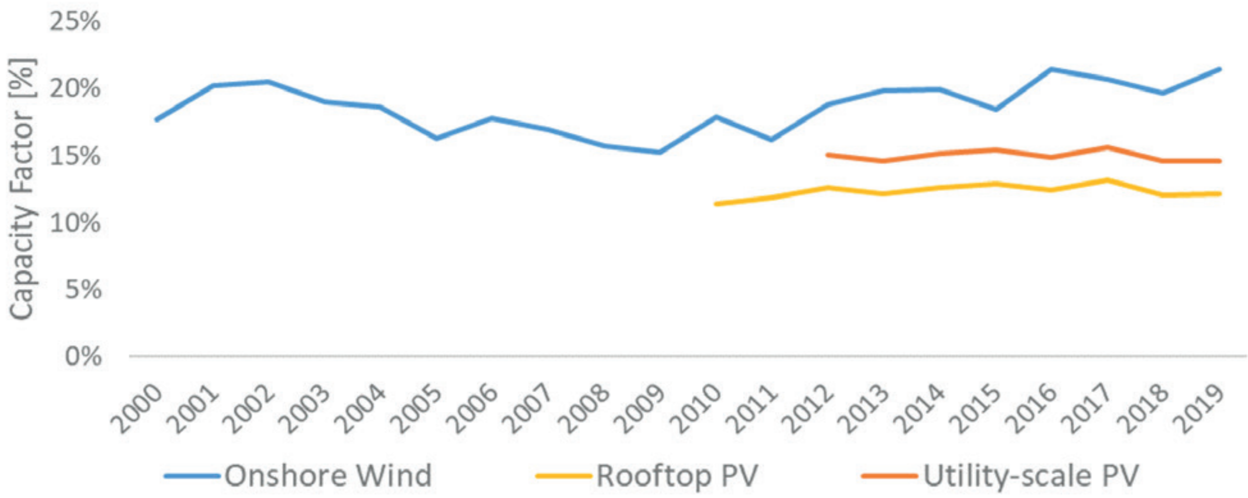


The capacity factor is calculated as follows:

$$Capacity\ factor = \frac{Generation_i}{8760 * \left(0.5 * Cumulative\ capacity\ _j + 0.5 * Cumulative\ capacity\ _{j+1}\right)}$$
$$where\ i = year\ and\ j = snapshot\ on\ 1\ January\ in\ year\ i$$

In the 2000-2019 period, the capacity factor for onshore wind installations fluctuated between 16% and 22%, mirroring the fluctuations in wind speed year by year as has also been seen in the other countries studied in this report. For solar PV, the capacity factor of utility-scale PV installations remained higher than that of rooftop PV in the 2000-2019 period, with a magnitude of 2-3%.

Figure 4: Capacity factors in Italy (2000-2019). Computation based on generation and installed capacity values from GSE (2007-2021)

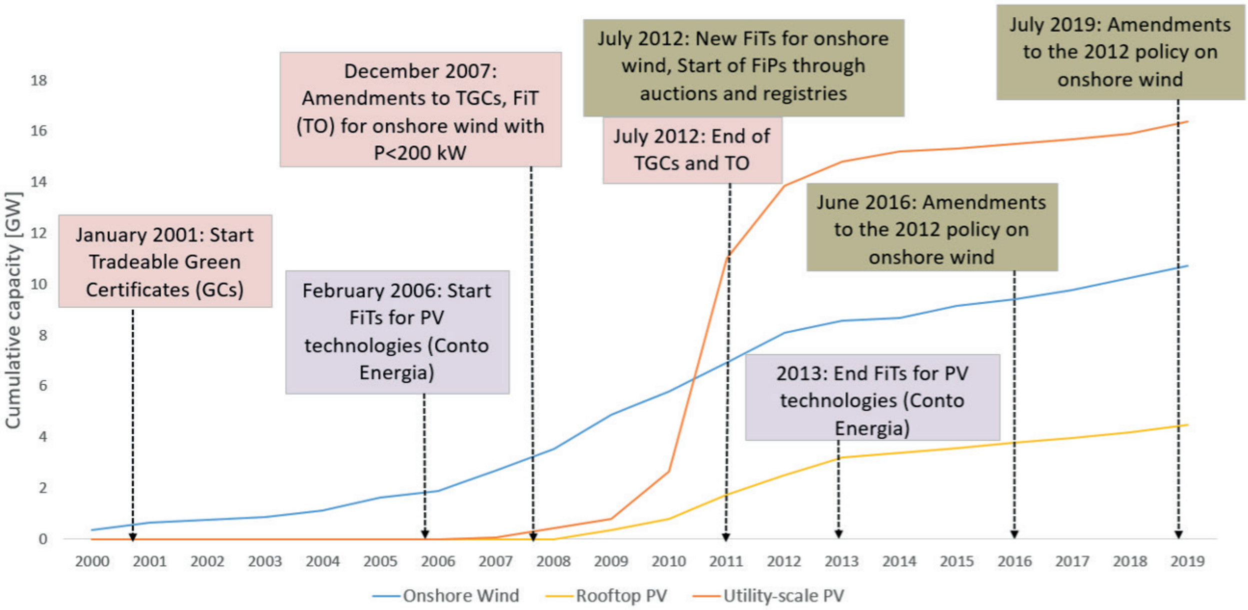


In what follows, we describe in more depth the different support schemes that have driven the deployment of these three renewable electricity generation technologies in Italy.

4.2 Three technologies, four support schemes

As previously mentioned, our focus in this work is on three renewable technologies in Italy, namely onshore wind, utility-scale PV and rooftop PV. By means of a literature review (Cai et al., 2017; this paper investigates to what extent the deployment of renewable energy sources (RES Marcantonini & Valero, 2017; Di Dio et al., 2015; Prontera, 2021; Haas et al., 2011; Mitchell and Connor, 2004; Ragwitz and Steinhilber, 2014) and through access to public information available on the websites of ARERA, the energy regulatory authority in Italy, GSE, the Italian energy services manager, and the Ministry for Economic Development we have identified the following mechanisms supporting these technologies in Italy: Tradable Green Certificates, feed-in tariffs (FiTs) and feed-in premiums (FiPs) for onshore wind and FiTs for utility-scale and rooftop PV. These support schemes and their timelines are visualised in Figure 5. The different colours of the boxes indicate different support schemes.

Figure 5: Overview of the different main onshore wind and solar PV support schemes mapped onto the capacity installed for each technology. Main sources: Cai et al., 2017; Marcantonini & Valero, 2017; Di Dio et al., 2015; Prontera, 2021 and the GSE and ARERA websites



4.2.1 Support schemes for onshore wind

Since 2001, onshore wind has been promoted through various support mechanisms in Italy including Tradable Green Certificates, all-inclusive tariffs (FiTs) and the most recent one-sided sliding premiums (FiPs), which are allocated through auctions and registries. This section discusses these mechanisms, their corresponding tariff levels and subsequent modifications.

2001-2012: Tradable Green Certificates

Tradable Green Certificates (TGCs)[3] were introduced for the first time in 1999 in Legislative Decree 79/1999 and they became operational in 2001 and replaced the CIP 6/92 in promoting electricity generation from renewable energy resources. In the 1999 Decree, annual quota obligations were (administratively)[4] set for producers and importers of more than 100 GWh of electricity generated from conventional resources. These obligations required the aforementioned suppliers to provide a minimum share from renewable resources in their total output in a fiscal year. In the following fiscal year the suppliers had to present the equivalent number of TGCs to Gestori Servizi Energetici (GSE), which is the government-owned entity responsible for managing energy services and renewable support schemes in Italy. The TGCs were tradable in a market operated by the Gestore dei Mercati Energetici (GME). Therefore, power plants could either produce the amount of energy corresponding to the quota obligation from renewable resources themselves or could buy the equivalent number of certificates on the TGC market. This allowed qualified renewable plants,[5] which automatically received TGCs in proportion to their electricity generation, to trade their TGCs on the market and gain revenue additional to that from selling the electricity they generated. Therefore, this extra revenue source became the main incentive to develop large-scale renewable projects. Like ROCs in

3 'Certificati Verdi (CV)'

4 The quota obligation was equal to 2% of the total supply in 2001 and it gradually increased to 7.55% in 2012 when structural modifications to the scheme were introduced. This gradual increase in the obligation was in response to national and EU targets to achieve certain shares of renewable electricity by 2020 (GSE, 2012).

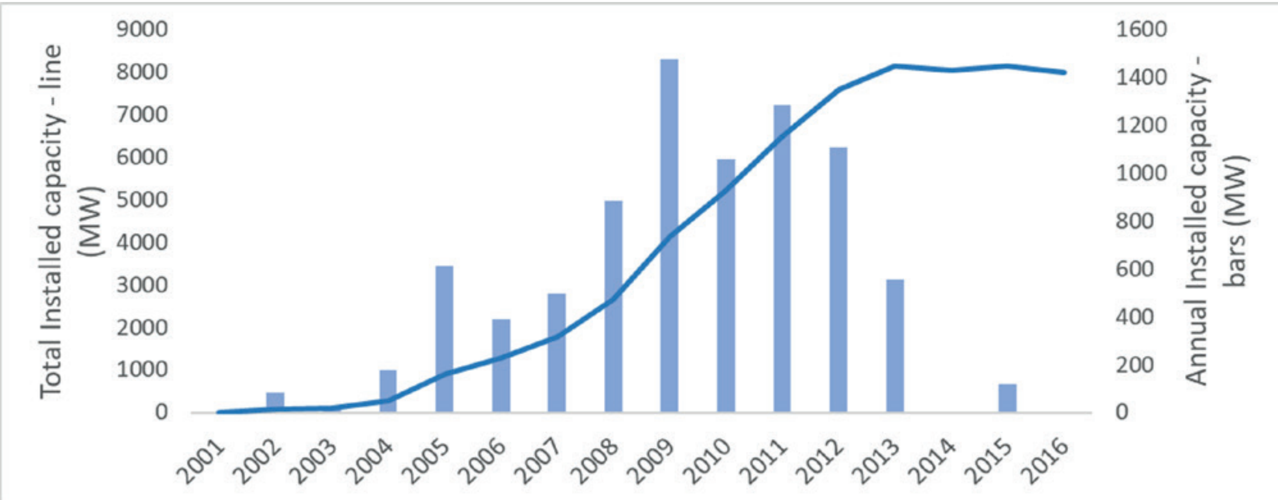
5 The GSE is responsible for identifying renewable plants qualified to receive incentives. This is done by reviewing technical requirements set in various legislative decrees (GSE, 2021).

the UK, although the Tradable Green Certificate mechanism targeted large-scale installations, it was technology-neutral and a wide range of renewable technologies such as onshore wind, solar PV,[6] biomass, hydroelectric, etc. could participate in the scheme. The scheme was only technology-specific in terms of the banding which was used to allocate the number of TGCs that suppliers would receive in proportion to their electricity generation. The banding for onshore wind was set at 1MWh of net electricity generation for one TGC. This banding did not change over the entire scheme period. Until 2007, TGCs were accredited to renewable plants for a period of 12 years but this changed to 15 years in 2008 when several amendments to the scheme were introduced.

The GSE was the entity responsible for issuing certificates to the eligible suppliers and renewable generators and to sell them at a price called 'prezzo di riferimento,' or reference price. The reference price was administratively set each year until 2008. Therefore, the TGC market was closely affected by the activities of the GSE (Marcantonini & Valero, 2017). In fact, as Marcantonini & Valero (2017) report, in the early years of the programme when the number of TGCs provided by renewable plants was significantly less than that provided by the GSE, the TGC market price was practically equal to the reference price offered by the GSE. Therefore, the market lacked a dynamic to incentivise RES plant development and participation.

This lack of interest in the first seven years that the TGC mechanism was implemented is observable in the case of onshore wind. The scheme was not successful at attracting investments in new onshore wind plants from 2001 to 2007. This can be seen in Figure 6, which shows the evolution of accumulated and annual installed onshore wind capacity under the TGC scheme. By 2007 only 1.7 GW of onshore wind capacity had been installed. In addition to insufficient market dynamics, Prontera (2021) states that in general the slow development of renewables in the first years that TGCs were implemented could be attributed to several exemptions which were available to conventional power plants and to delays in the processes to authorise the development of new RES plants.

Figure 6: Total and annual accredited onshore wind capacity under the TGC scheme. Main sources: GSE (2007-2021)



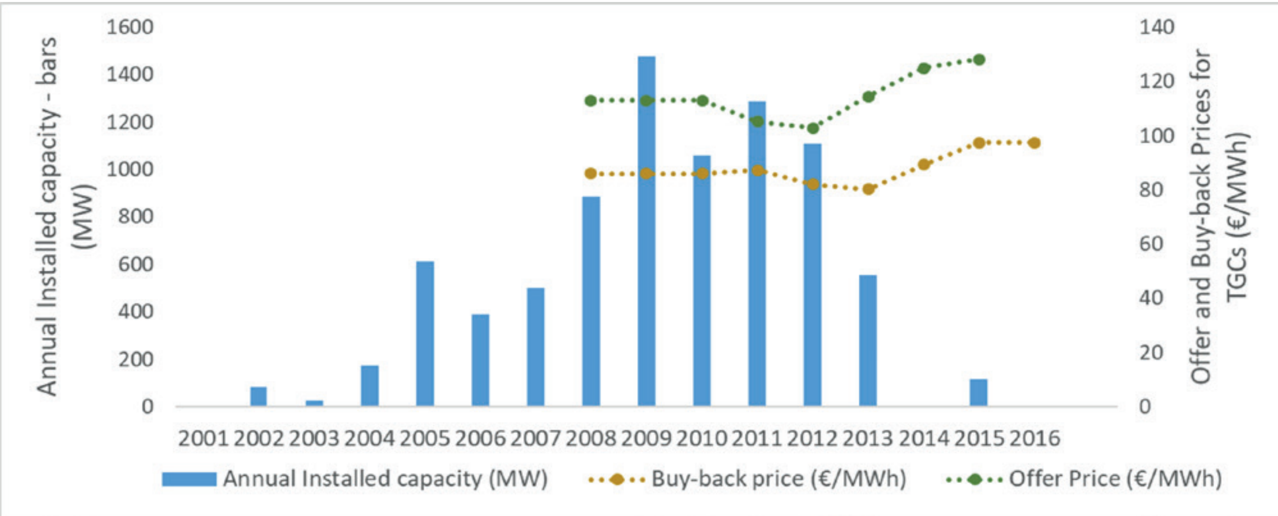
In an attempt to reverse this trend, a series of amendments to the TGC mechanism were introduced in 2008. These amendments included the previously mentioned extension of the eligibility period to 15 years, modification of how the reference price offered by the GSE was calculated and au-

6 As in the case of ROCs in the UK, TGCs were not relevant for rooftop PV due to the small scale of this technology. However, although utility-scale PV plants came under this mechanism with their large scales, available records show that almost no investment was made in solar PV using this mechanism. High technology costs, especially in the early 2000s when the PV technology was experiencing high initial investment and lower power output than other renewable technologies such as onshore wind, combined with long authorisation processes, could have contributed to this result. As will be discussed later in this work, to compensate for this lack of interest an exclusive mechanism was introduced in 2006 to support solar PV and from 2008 no solar technology could participate in the TGC scheme.

thorisation of the GSE to buy unsold certificates on the market at a buy-back price. The introduction of the buy-back price proved particularly successful as in the 2008-2011 period more than 5 GW of onshore wind capacity was installed under the TGC scheme (Figure 6), resulting in a 340% increase in electricity generation (from 3.5 TWh to 12.7 TWh) by onshore wind installations participating in the scheme. According to our analysis, in 2012 more than 92% of the total 8 GW installed capacity of onshore wind in Italy was supported by the TGC mechanism.

According to a Ministerial Decree of 18/12/2008, the reference price offered by the GSE was to be calculated as the difference between 180 €/MWh and the average annual price of electricity sold on the market in the previous year. In addition, the decree stated that for the period 2009-2011 the GSE would calculate the buy-back price as the average market price of electricity in the three years preceding the buy-back date. In July 2012 a Ministerial Decree was introduced which abolished the TGC mechanism for new renewable installations and replaced it with an auction mechanism. For existing renewable plants under the TGC mechanism and plants already under construction, a transition period from 2012 to 2015 was introduced, during which they would be eligible to sell at a new buy-back price equal to 78% of the reference price. From 2016 instead, these plants were eligible to receive a feed-in premium equal to the new buy-back price. Figure 7 shows these prices and the annual installed capacity of onshore wind under the TGC scheme from 2001 to 2016.

Figure 7: Yearly accredited onshore wind capacity under the TGC scheme and the administratively set GSE offer and buy-back prices. Main sources: GSE (2007-2021)

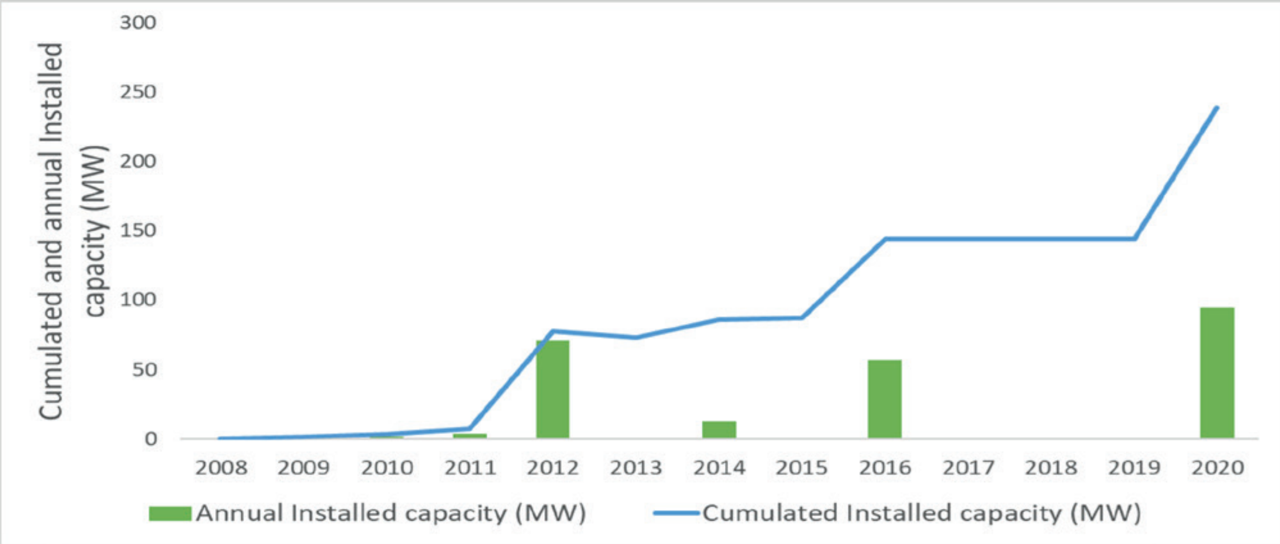


2008-now: administratively set feed-in tariffs

The adoption of feed-in tariffs for onshore wind in Italy started in 2008 with the tariffa omnicomprensiva (TO), or the all-inclusive tariff. This was later replaced with new FiTs in 2012. This section provides more details on these tariffs and their effectiveness.

The same December 2008 Ministerial Decree which introduced changes to the TGC mechanism also for the first time introduced an administratively set feed-in tariff (FiT) as an alternative to green certificates for non-PV small-scale renewable projects. For onshore wind installations the capacity limit was set at 200 kW. The tariff, which was called tariffa omnicomprensiva (TO), was all-inclusive, meaning that it included both the value of the electricity injected into the grid and the incentive. This constrained receiving projects from participating in the market. However, as an incentive, the tariff was fixed for the guaranteed support period, which was set at 15 years. For onshore wind installations the TO was set at 30 €/MWh from the start of the scheme in 2008 until its replacement with new FiTs in 2012. 30 €/MWh was higher than the market electricity price in 2009-2011 (Marcantonini & Valero, 2017), which compensated for the ban on market participation. The difference between the TO and the market price was passed on to consumers as a part of their electricity bills. The cap on capacities eligible to receive TO was too small for onshore wind installations as this technology mostly involves projects with magnitudes of 1-5 MW (for medium-scale projects) and above 5 MW (for large-scale projects). This resulted in small onshore wind capacities participating in the support scheme, as is demonstrated in Figure 8. The figure reports accumulated and annual installed onshore wind capacities under the FiT scheme from 2008 onwards.

Figure 8: Accumulated and annual installed onshore wind capacities under the FiT scheme from 2008 onwards. Main sources: GSE (2007-2021)



The TO was not successful in attracting many investments or an expansion of onshore wind due to the small size of its target group. From Figure 8 it can be seen that in the 2008-2011 period, when the TO mechanism was in place, only a total of 7 MW onshore wind capacity was added.

The same is true for the new FiT mechanism which was introduced in 2012. A 6 July 2012 Ministerial Decree introduced all-inclusive FiTs, which would be allocated to small-scale renewable sources other than solar PV through a direct access mechanism. Under this new FiT mechanism, renewable plants with capacities up to 1 MW received a fixed administratively set basic tariff, which was differentiated by size and by technology, for 20 years. Although no overall capacity cap was introduced in the 2012 decree, an annual budgetary cap was included to limit the cost of renewable incentives. This cap, which was €5.8 billion, corresponded to incentive payments to non-PV resources under different mechanisms, including FiTs allocated through the direct access mechanism and those allocated through the lowest bid auction and the registry mechanisms (these will be discussed in detail in the next section). Onshore wind plants with capacities below 1 MW would have the possibility of directly receiving FiTs as long as their eligibility was approved by the GSE and the budgetary cap on non-PV RES support costs was not reached.

The 2012 Decree was modified twice, in 2016 and 2019. A 23 June 2016 Decree reduced the capacity cap for projects eligible to receive FiTs from 1 MW to 500 kW and the 4 July 2019 Decree decreased it even further to 250 kW. This may be perceived as counterintuitive considering that the earlier TO mechanism, which also had a low capacity cap of 200 kW for onshore wind, had failed to bring installed onshore wind capacity expansion. In fact, from Figure 8 it can be seen that in 2012-2019 only 140 MW of wind capacity was added under the new FiTs and through the direct access mechanism. More than half this capacity was installed between 2012 and 2016 when the cap on the eligible project size was 1 MW.

2012-now: feed-in premiums through lowest bid auctions and registries

An introduction of one-sided sliding feed-in premiums for non-PV renewable projects was another new measure in the 2012 Ministerial Decree. The FiPs were to be allocated to renewable plants with capacities exceeding 1 MW and to those with capacities below 1 MW which opted out from receiving an all-inclusive FiT. For eligible onshore wind installations the incentive is paid for 20 years, corresponding to the average useful life of such plants. It is paid for the net electricity production fed into the grid and is calculated as the difference between the auction outcome and the hourly zonal price of electricity. More precisely, the incentive is calculated as:

$$I = Tb - Pz,$$

where (I) is the incentive (FiP) and Tb is the base tariff which is set administratively in the decree for each source, type of plant and power class and was reduced by 2% annually from 2013. In the case of registries, the Tb does not change and the incentive is equal to the difference between Tb and the hourly zonal electricity price. In the case of auctions (which are in the form of reverse auctions) Tb is used as the starting (maximum) tariff. Projects make their bids for the amount of the reduction of Tb and if they win the auction they receive a FiP equal to the difference between this reduced Tb (auction outcome) and the hourly zonal electricity price.

Pz is the hourly zonal price for the area in which the electricity produced by the system is fed into the grid. In the event that the value of the incentive is negative it is set at zero. Unlike recipients of the all-inclusive FiT, the energy produced and fed into the grid by plants receiving FiPs remains available for the producer to sell on the market or to the GSE.

Two types of mechanism were introduced in the 2012 Decree for accessing FiPs. These mechanisms are differentiated by project size and are as follows:

- Access through registries for medium size projects with capacities above 1 MW and below 5 MW;
- Access through lowest bid auctions for large-scale projects with capacities above 5 MW.

Capacity allocation under both mechanisms is a technology-specific process. The capacity volumes to be awarded for each technology are set and announced in different calls by the GSE, which acts as the counterparty. Besides the cap on accreditable capacities, the decree also put a cap on the annual accumulative cost of support given to new non-PV renewables. As was mentioned in the previous section, this cap is equal to €5.8 billion a year and includes the cost of FiPs and FiTs awarded through the registry, lowest bid auction and direct access mechanisms.

Registry mechanism

Medium size projects with capacities between 1 and 5 MW can apply to access the FiP by participating in the registry mechanism. As was mentioned above, the capacity volumes to be accredited are set and announced in calls issued by the GSE. Under this mechanism, projects are ranked and evaluated only based on qualitative criteria (AURES, 2016). Priority is given to plants based on their size (priority for smaller plants), date of authorisation (priority for early authorisation) and date of application (priority for early applications). The wining plants receive a uniform FiP equal to the difference between the administratively set Tb (which is technology- and size-specific) and the hourly zonal electricity price (i.e. I=Tb-Pz).

Focusing on onshore wind, accredited projects should become operational during the 16 months after the ranking is announced. For each month after this deadline, the FiP is reduced by 0.5% and it is fully withdrawn after 12 months.

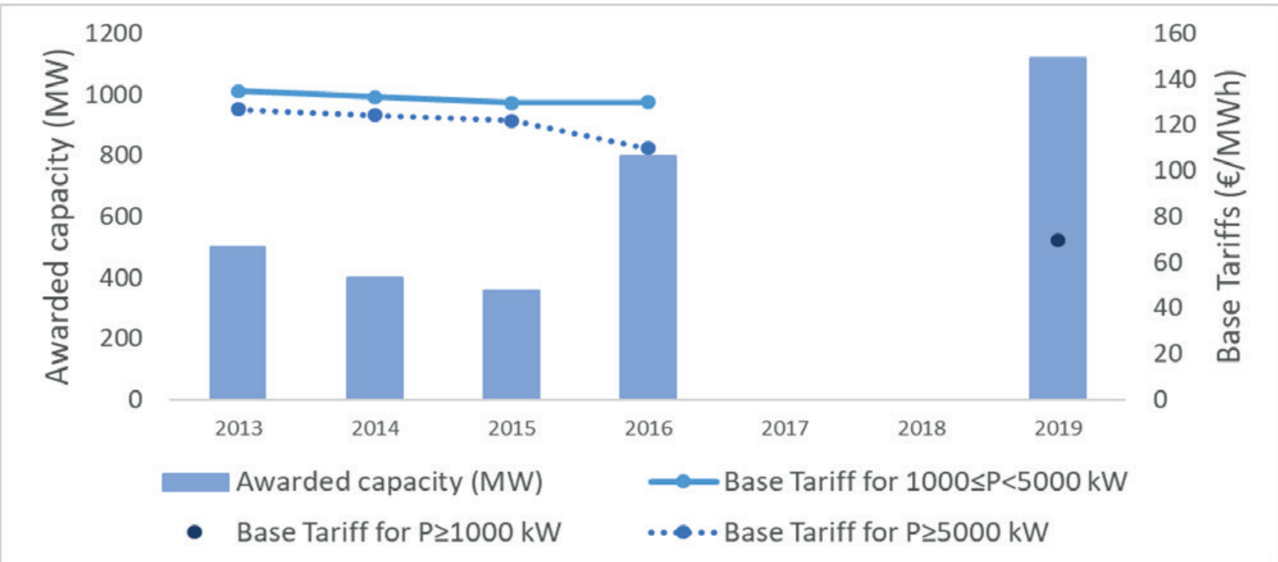
We do not report the outcome of the registry mechanism in this analysis due to the following limitation. Under this mechanism support is provided to a mixture of small- and medium-scale projects that are eligible to receive either FiTs (60 kW < P < 1 MW) or FiPs (1 MW < P < 5 MW). However, a clear set of data separately reporting the volumes receiving FiTs and the volumes receiving FiPs has not been found. We can only report that the accumulated awarded onshore wind capacity under the registry mechanism since 2012 is 330 MW. Due to the same constraint support levels cannot be reported either.

Lowest Bid Auctions

The 2012 Decree for the first time introduced auctions to allocate RES capacities and provide large-scale renewable resources other than PV with access to FiPs. Plants with capacities over 5 MW are required to participate in a lowest bid auction to receive FiPs for a period of 20 years. Like the registry mechanism, volumes to be auctioned are set and announced by the GSE in various tender calls. The pricing rule is pay-as-bid, auctions are technology-specific and they are in the form of reverse auctions. This means that a maximum base tariff is set administratively (Tb), plants offer how much they are willing to reduce the base tariff and they are ranked from the highest to the lowest reduction. In the 2012 Decree floor (2%) and ceiling (30%) reduction measures were set in order to avoid plants under- or over-bidding (AURES, 2016). The ceiling for the reduction percentage was increased to 40% in the 2016 Decree. Furthermore, bidders need to provide safety bonds equal to 5% of the administratively estimated investment cost. Winning projects should double the safety bonds to 10%. Successful onshore wind projects should be commissioned in the 28 months (increased to 21 months in the 2016 Decree) after the auction results are published. Failure to do so results in a 0.5% monthly reduction of the FiP awarded and the FiP is fully withdrawn 24 months after this deadline and the safety bonds are withheld by the GSE.

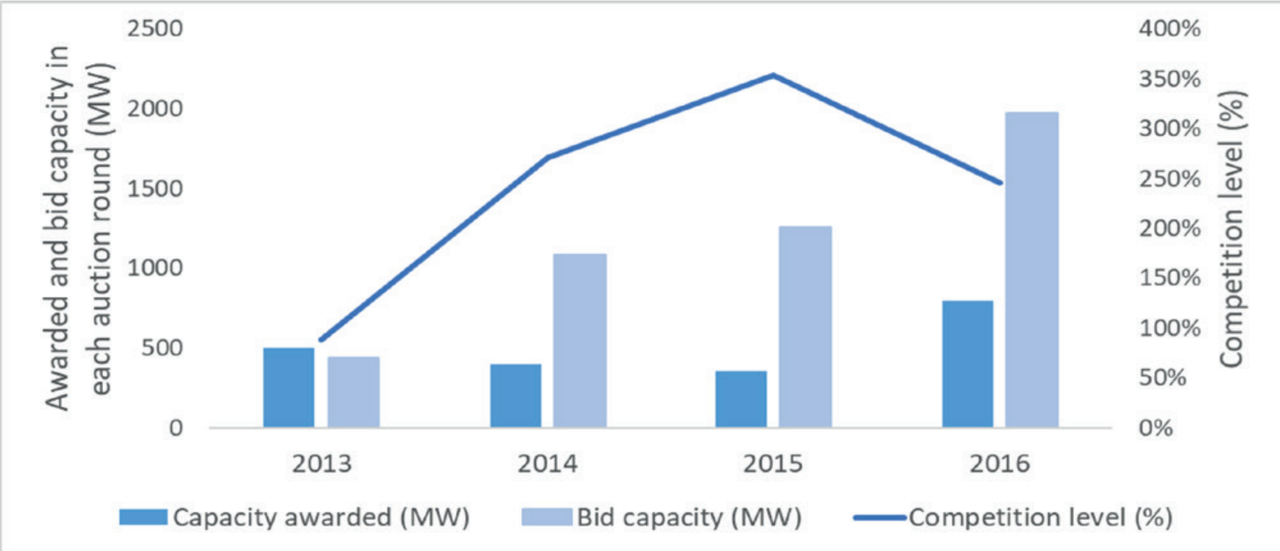
Technology-specific auction rounds were held from 2013 to 2016. After a two-year lag and in line with the 2019 Decree, six multi-technology auction rounds were held in 2019. A total of 3.2 GW of onshore wind capacity was auctioned and awarded during the period 2013-2019. Figure 9 shows the volumes of capacities awarded and the base tariff specific for onshore wind technology, which was set administratively in the calls for auctions.

Figure 9: Awarded onshore wind capacities and base tariffs in each auction round. Main sources: GSE (2007-2021)



As Figure 9 shows, the auctions were relatively successful in decreasing the support level for onshore wind projects from 127 €/MWh in 2013 to 66 €/MWh in 2019. This is a 48% decrease, which is quite significant. This is in line with the high competition levels for auctioned onshore wind capacity. Figure 10 shows the level of competition in each auction round, which can be considered a proxy for demand for onshore wind capacity by investors and is calculated as the bid capacity over the auctioned capacity. Apart from the first auction round,[7] the bidding capacity has always been higher than the capacity auctioned (high competition), which led to a reduction of support levels.

Figure 10: Competition level in each auction round. Own calculation based on data from GSE (2007-2021)



It is worth noting that the volume of capacity for onshore wind auctioned in six years (3.2 GW) is not very significant considering that the TGC mechanism led to investments in 6 GW of capacity (twice as much) in the six years before the start of the auctions. This could be traced back to the budgetary cap which was introduced in the 2012 Decree, which limited the financial support that could be given to non-PV renewable projects and so affected the capacities which could be auctioned. In addition, no auction was held in 2017 or 2018, putting in question the consistency of the mechanism.

The latest GSE report on the status of winning projects (GSE, 2021) states that all the plants which were awarded in the auction rounds from 2013 to 2016 had come into operation by 2019, although with repeated delays forcing some projects to pay penalties. Cai et al. (2017) identify grid connection problems and unreliable financial pre-qualification criteria as the main reasons for delays in project delivery.

4.2.2 Support schemes for solar photovoltaic systems (PVs)

The Energy Account, or Conto Energia (CE), was the main mechanism that the Italian government (the Ministry for Economic Development) established to support electricity generation by photovoltaic systems (PVs). The scheme became operational in 2006 and was ended in 2013. During this period, five versions of it were introduced providing photovoltaic systems with feed-in tariffs for their electricity generation for 20 years. Like the other RES-E support schemes in Italy, payment of FiTs from the Conto Energia is managed by the GSE. This section discusses the five versions of the CE and their design elements.

The first version of the Conto Energia, known as the ‘Primo Conto Energia’ (I CE), was introduced in and came into operation with Ministerial Decrees of 28 July 2005 and 6 February 2006 respective-

7 AURES (2016) suggests that this low participation measure in the first round of auctions could be attributed to the transitory agreement which allowed projects under construction to benefit from the TGC mechanism.

ly. In the first CE, grid-connected PV systems with capacities between 1 kW and 1 MW could receive FiTs differentiated by their size in these categories: 1 < P <= 20 kW, 20 < P <= 50 kW and 50 kW < P <= 1 MW. The First CE also introduced an annual cap on total installed PV system capacity of 500 MW.

Table 1 shows the average FiT announced for each capacity category under each of the five CE versions. For small-scale PVs (capacities below 20 kW) the average FiT was established at 445 €/MWh, while for capacities above 20 kW and below 1 MW it was 475 €/MWh. Although the FiTs established under the First Conto Energia were perceived as generous (Prontera, 2021; Di Dio et al., 2015) they were not successful in attracting investments in PV systems. Figure 11 shows the amount of total PV capacity installed under each version of the Conto Energia. By 2007, only 50 MW had been installed under the I CE (GSE, 2021). Prontera (2021) and Di Dio et al. (2015) argue that reasons for this lack of effectiveness could be time-consuming and difficult-to-follow procedures to obtain the FiTs established in the decrees and the 1 MW cap on eligible project capacity, which acted as a barrier against participation by utility-scale plants.

Table 1: Feed-in tariff levels for each capacity and installation type under the five versions of the Conto Energia. Source: Di Dio et al. (2015)

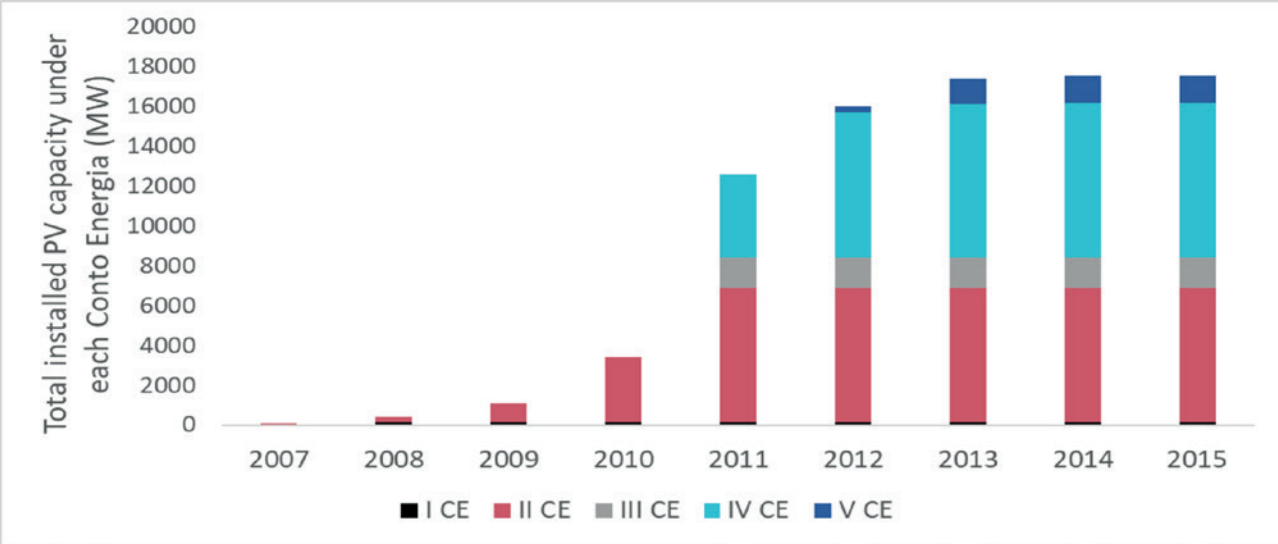
Rated power	I CE	II CE		III CE		IV CE		V CE	
1 kW ⩽ P ⩽ 3 kW	0.445	0.4	NIPV	0.362	OPV	0.344–0.221	OPV	0.320–0.178	OPV
		0.44	PIPV	0.402	IBPV	0.387–0.252	IBPV	0.334–0.184	IBPV
		0.49	BIPV	0.44	IBIPV	0.427–0.410	IBIPV	0.474–0.293	IBIPV
				0.37	CPV	0.359–0.345	CPV	0.416–0.254	CPV
		0.38	NIPV	0.339	OPV	0.319–0.202	OPV	0.296–0.166	OPV
3 kW ⩽ P ⩽ 20 kW	0.445	0.42	PIPV	0.377	IBPV	0.356–0.227	IBPV	0.310–0.174	IBPV
		0.46	BIPV	0.44	IBIPV	0.427–0.410	IBIPV	0.474–0.293	IBIPV
				0.37	CPV	0.359–0.345	CPV	0.416–0.254	CPV
		0.36	NIPV	0.321	OPV	0.306–0.189	OPV	0.254–0.154	OPV
20 kW < P ⩽ 200 kW	0	0.4	PIPV	0.358	IBPV	0.338–0.214	IBPV	0.268–0.162	IBPV
		0.44	BIPV	0.4	IBIPV	0.388–0.373	IBIPV	0.450–0.278	IBIPV
				0.37	CPV	0.359–0.345	CPV	0.416–0.254	CPV
		0.36	NIPV	0.314	OPV	0.291–0.155	OPV	0.188–0.122	OPV
200 kW < P ⩽ 1 MW	0	0.4	PIPV	0.355	IBPV	0.325–0.202	IBPV	0.202–0.130	IBPV
		0.44	BIPV	0.37	IBIPV	0.388–0.373	IBIPV	0.408–0.256	IBIPV
				0.32	CPV	0.310–0.298	CPV	0.374–0.233	CPV
		0.36	NIPV	0.313	OPV	0.277–0.140	OPV	0.158–0.112	OPV
1 MW < P ⩽ 5 MW	0	0.4	PIPV	0.351	IBPV	0.314–0.164	IBPV	0.160–0.118	IBPV
		0.44	BIPV	0.37	IBIPV	0.359–0.345	IBIPV	0.408–0.256	IBIPV
				0.28	CPV	0.272–0.261	CPV	0.308–0.194	CPV
		0.36	NIPV	0.297	OPV	0.264–0.133	OPV	0.144–0.102	OPV
P > 5 MW	0	0.4	PIPV	0.333	IBPV	0.299–0.154	IBPV	0.156–0.108	IBPV
		0.44	BIPV	0.37	IBIPV	0.359–0.345	IBIPV	0.408–0.256	IBIPV
				0.28	CPV	0.272–0.261	CPV	0.308–0.194	CPV

The Second Conto Energia (II CE) was announced on 19 February 2007 and introduced a number of changes and novelties compared to the First CE. Among these changes, the following were the most significant:

- Simplification of the procedures to obtain FiTs;
- The maximum annual installed capacity was increased to 1200 MW;
- The 1 MW upper capacity limit was removed;
- In addition to size, tariffs were also differentiated by type of installation.[8]

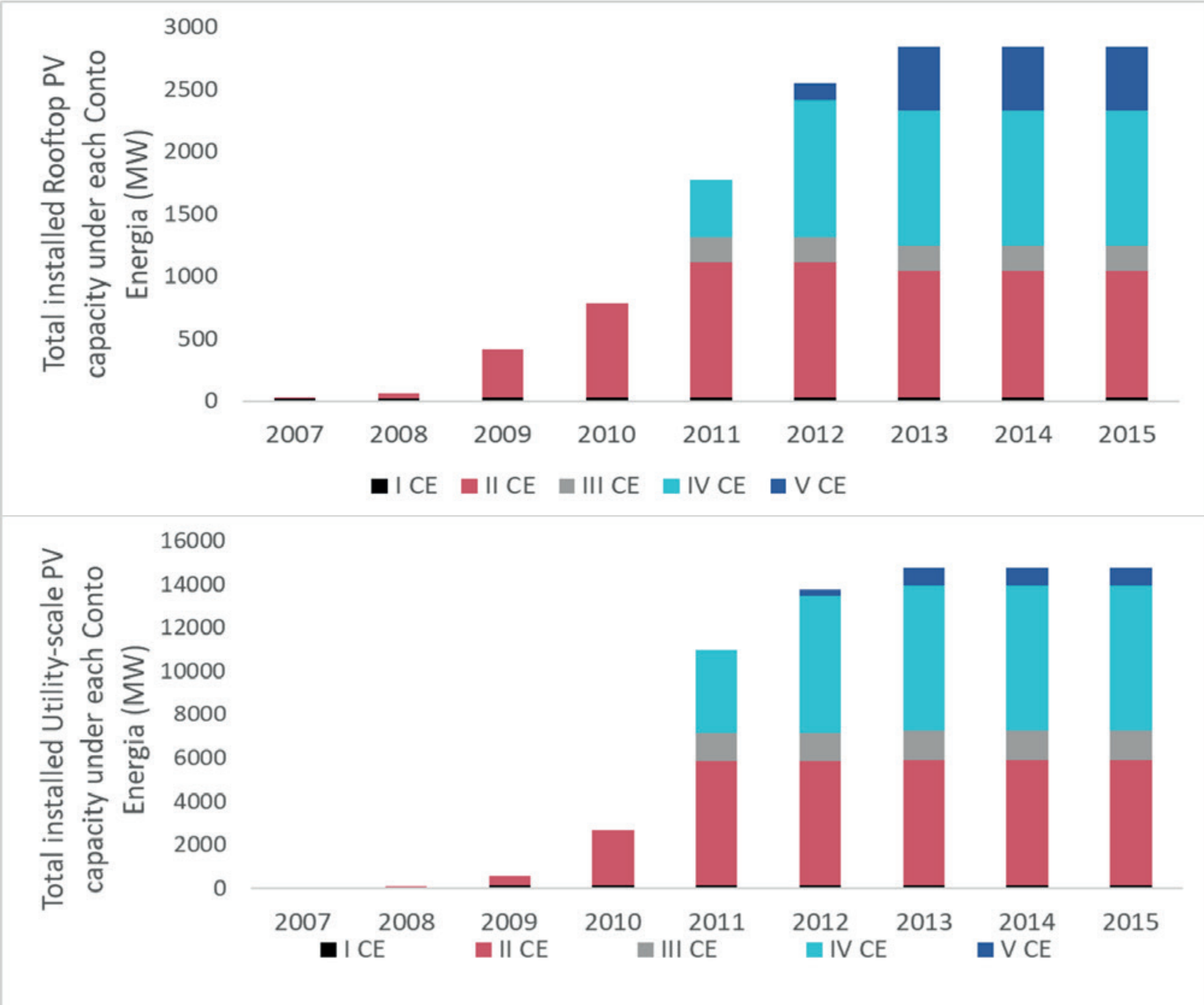
8 PV installations were categorised as Field-Installed PV (FIPV), Not-Integrated-in-building PV (NIPV), Partially-Integrated-in-building PV (PIPV) and Building-Integrated PV (BIPV). From the Second Conto Energia, FiTs were set specific to both size and type of installation. However, for ease of analysis we report average FiTs differentiated only by size of installation.

Figure 11: PV capacity installed under each of the five versions of the Conto Energia (CE). Main source: GSE (2007-2021)



These changes contributed to kicking-off the PV sector in Italy between 2007 and 2010. The total capacity installed under the Second CE increased from 50 MW in 2007 to 3.3 GW in 2010. In addition to the above-mentioned changes, generous FiTs under the Second CE also played an important role in attracting investments in PV systems. In 2007, the FiTs ranged between 430 €/MWh for rooftop PV (capacities below 20 kW) to 400 €/MWh for utility-scale PV (capacities over 20 kW). These tariffs were considered among the highest in the EU (alongside the FiTs in Spain) (Di Dio et al., 2015). The Second Conto Energia also introduced a digression mechanism which reduced the tariffs by 2% each year. However, this reduction in support levels was not compatible with the fast reduction in the cost of PV technologies (Marcantonini & Valero, 2017). While the PV construction cost was 6000-7500 €/kW in 2006-2007, it had decreased by almost 35% by 2009-2010 (Di Dio et al., 2015). The high incentive rates and the decreasing technology cost resulted in both small-scale and utility-scale PV installations becoming great investment opportunities. As Figure 12 (first panel) shows, the total installed rooftop PV capacity increased from 30 MW in 2007 to 800 MW in 2010. The total installed utility-scale PV capacity increased from 20 MW to 2.5 GW in the same period (Figure 12, second panel). This growth in installed capacity (and consequently in PV electricity generation) resulted in growth in the cost of the FiT mechanism.

Figure 12: Total installed rooftop and utility-scale PV capacity under the five versions of the Conto Energia. Main source: GSE (2007-2021)



Recognising the growing cost of the Conto Energia, the Ministry for Economic Development announced that the Second CE would be replaced with the Third Conto Energia (III CE) by the end of 2010. This decreased the FiTs and introduced new PV system classifications. However, a number of issues resulted in it being abolished in May 2011 after only five months.[9] First, the FiT reductions were not significant enough to slow down deployment of PV systems (Marcantonini & Valero, 2017). Second, a legal loophole allowed PV systems to be eligible for the higher FiTs in the Second CE until mid-2011 even though the Third CE was in place (Di Dio et al., 2015), making the latter dispensable. In the 'Salva-Alcoa' Decree, the Italian government allowed PV projects which were commissioned but not yet connected to the grid until 31 December 2010 to continue receiving the FiTs under the Second CE after this date. This resulted in a rush of project developers commissioning their plants before this deadline (Di Dio et al., 2015). In fact, in a matter of months, by mid-2011 the total installed PV capacity connected to the grid almost doubled, reaching 6.8 GW (1.1 GW of rooftop PV and 5.7 GW of utility-scale PV). The added capacity was eligible to receive the high FiTs under the Second CE and so contributed to the increasing cost of the CE mechanism. The cost of support associated with the Second CE increased from €636 million in 2010 to €2.9 billion in 2011.

9 Nonetheless, in its short implementation period, 1.5 GW of PV capacity (mostly utility-scale – 1.3 GW) was installed under the Third CE (Figure 11).

In June 2011 the Fourth Conto Energia (IV CE) was announced to replace the Third CE and end the application of the 'Salva-Alcoa' Decree. As Table 1 shows, the Fourth CE further decreased the FiTs with the aim of aligning the support levels with the technology costs and so reducing the support costs. It also introduced an annual cap on total incentive payments under the CE of €6 billion. Although the FiT reductions were sharper in the Fourth CE than in the Third CE, the CE still attracted PV investments. Until it ended in July 2012, 1.1 GW of rooftop PV and 6.6 GW of utility-scale PV capacity were connected to the grid with support under the Fourth CE. The high interest in the new CE combined with the outcome of the previous CEs, particularly the Second Conto Energia, resulted in the spending cap being reached in less than a year. Consequently, in July 2012 the government announced a Fifth Conto Energia, which came into force in August of the same year.

In the new Conto Energia, in addition to decreasing the FiTs, PV installations had the possibility of accessing a premium in the form of net-metering. In particular, PV plants with nominal power up to 1 MW were entitled to both a FiT for the net electricity produced and fed into the grid and a premium for electricity produced and consumed on site (net-metering). Instead, PV plants with nominal power greater than 1 MW received the net-metering premium plus a sliding FiP for the net electricity they produced and fed into the grid, which was calculated as the difference between the corresponding FiT and the hourly zonal electricity price. Thus, the Fifth CE favoured small-scale installations. Moreover, the Fifth Conto Energia again had an annual spending cap on PV support but it was slightly increased to €6.7 billion. This cap was reached in July 2013 and the Ministry of Economic Development decided to permanently close the Conto Energia mechanism for new installations. In addition to the high cost of the mechanism, Di Dio et al. (2015) report a great reduction in the cost of PV technologies together with a desire to promote other sectors which could more efficiently contribute to Italy's (national) and the EU's energy and climate plans as the main reasons why the Italian government decided to terminate the Conto Energia mechanism.

Overall, in the period 2006-2013 more than 18 GW of PV capacity was installed in Italy under the Conto Energia. Utility-scale PV was the number one beneficiary of the mechanism with an accumulated installed capacity of 15 GW. In comparison, 3 GW of rooftop PV was installed in the same period under the CE. With the support provided by the Conto Energia, the total electricity generated by PV systems increased from 41 GWh in 2007 to over 20 TWh in 2013. However, this success came at an increasing cost: from €19 million in 2007 to €6.7 billion in 2013. This was mainly due to the non-adaptability of the CE FiTs to the decreasing cost of PV technologies.

4.3 The total annual costs of the support schemes

Figure 13 shows the total annual nominal cost of support allocated through TGCs, FiTs and FiPs for onshore wind, utility-scale PV and rooftop PV.10 The figure starts with 2008, when the FiT scheme for onshore wind began and when the FiT scheme for PV systems (the Second CE) slowly started to flourish. Before that year, we calculate that €590 million was spent on onshore wind through the TGC scheme between 2001-2007 and about €12 million on solar PV under the Conto Energia in 2006 and 2007. Data on annual support payments for electricity generation from renewable resources under the different support schemes are publicly available on the GSE website and in its annual reports.

Figure 13: Total annual nominal cost of support allocated through TGCs, FiTs and FiPs for onshore wind, utility-scale PV and rooftop PV (CE stands for Conto Energia, CV stands for Certificati Verdi or TGCs). Main sources: GSE (2007-2021) and ARERA (2020).

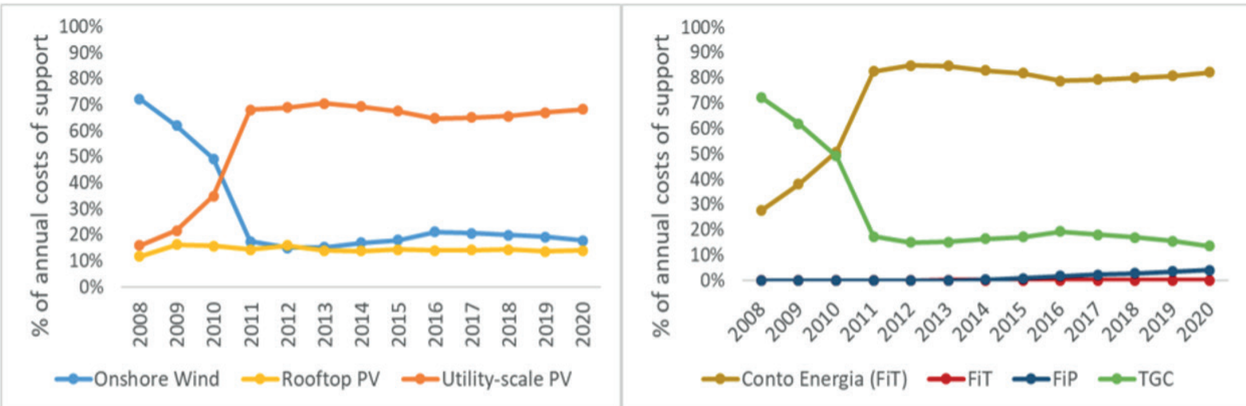
As can be seen, the total cost of the support schemes for the technologies considered was estimated to be €7.5 billion in 2020, which is approximately €126 per capita. The most dramatic change in the total cost of the wind and PV support schemes occurred from 2010 to 2011, when, as was discussed in the previous section, a sudden boom in the PV sector, in particular in utility-scale PV,

10 As in the other cases in this study, the costs associated with administration of the different support schemes are excluded as the amount is minor compared to the payments supporting electricity generation by renewable projects.

took place and quite generous FiTs were paid for this technology. While the total cost of supporting wind and solar technologies was €1.5 billion in 2010, it tripled in 2011, coming to about €4.6 billion. As more PV systems benefiting from the CE were connected to the grid, the cost continued to grow in 2012 and 2013, although at a more moderate rate. A total of €7.6 billion of support was allocated to wind and PV installations in 2013. The total cost remained more or less the same in the next years, until 2017 when the measure grew by 6% compared to 2016 and was equal to €8 billion. ARERA (2018) reports that this increase was a result of increased solar irradiation in Italy in 2017, which resulted in a 1.5 TWh increase in electricity generation by PV systems in 2017 compared to 2016.

Figure 14 (left) shows the allocation of the annual support cost to each technology. It can be seen that until 2010 onshore wind was the technology receiving most financial support (50% in 2010). Onshore wind was surpassed by utility-scale PV from 2011, when the capacity connected to the grid of the latter doubled and high FiTs were paid for electricity generation from utility-scale PV. In 2020, 68% of the spending was allocated to utility-scale PV while the shares of onshore wind and rooftop PV were respectively 18% and 14%. Figure 14 (right) shows the allocation of the annual support cost to each support scheme. Before the kick-off of the PV sector in 2010 with FiTs under the Conto Energia, the TGC scheme for onshore wind was the most important support tool in terms of money spent. Since 2011, the Conto Energia has had the majority share of total support payments (on average 82% of annual payments). It is expected that Conto Energia will continue to make the highest share of support payments at least until 2030, when the 20-year duration of support will end for about 6.7 GW of PV systems, which were funded with the high FiTs under the Second Conto Energia.

Figure 14 Left: Annual support costs divided by technology. Right: Annual support costs divided by support scheme. Own calculation based on the cost data shown in Figure 13.

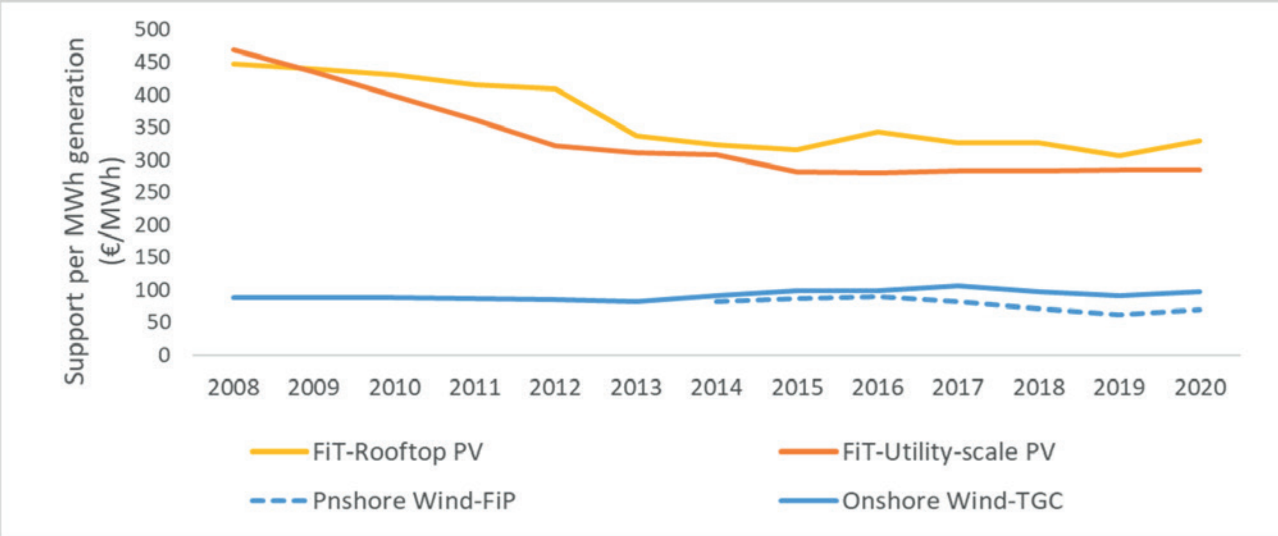


The TGC scheme's share started to decrease in 2017 as several onshore wind plants opted out of the scheme (ARERA, 2018). The decrease is projected to continue as the duration (12-15 years) of the support will end for several beneficiaries. FiT payments for onshore wind technology did not constitute a significant share and remained below 1% during the period analysed. The share of FiP payments to onshore wind projects has been growing steadily since 2016 as the first generators that were accredited in the first three rounds of auctions came online. This share grew to more than 4% in 2020 and is expected to grow further in the next years as more already accredited onshore wind projects will be connecting to the grid, increasing the relative cost of the scheme, and also as more auction rounds offering further capacity allocations are planned for the next years (ARERA, 2020).

4.4 The cost-effectiveness of the support schemes

Figure 15 shows the cost-effectiveness of each support tool for each technology considered. We define the cost-effectiveness of a support scheme as the annual expenditure (for each generation technology) divided by the total annual volume of electricity generated by the generators benefitting from the scheme. Data on the cost of the schemes and on the volumes of electricity generated by each technology under each support scheme are publicly available on the GSE website and in its annual reports.

Figure 15: The cost-effectiveness of each support scheme for each technology considered. This is calculated by dividing the annual cost shown in Figure 13 by the annual amount of electricity generated. The data come from the same sources as in Figure 13.



We see several interesting trends in Figure 15. Regarding the TGC scheme for onshore wind, it can be seen that the level of support was stable at around 85 €/MWh until 2013. From 2014 to 2016 the level increased as the GSE increased both the offer and buy-back prices of Green Certificates. Support for the TGC scheme reached its highest level in 2017, 106 €/MWh. Two factors contributed to this outcome that year: a) some onshore plants opted out of the TGC scheme resulting in a decrease in electricity generation under the scheme; b) in 2016 there was an increase in the GC buy-back price paid as a premium. Regarding support for both utility-scale and rooftop PV, a gradual decreasing trend is observed in the period 2007-2012. The support level then decreased at a steeper rate from 2012 to 2013 due to the cuts in the FiTs. This decreasing trend stabilised at about 285 €/MWh for utility-scale PV after 2014-2015 as support for new installations and already funded fully commissioned projects was closed. There was a sudden jump in support for rooftop PV in 2016. This may be due to low irradiation levels in 2016, which resulted in decreased electricity generation by PV systems (GSE, 2017 and 2016).[11] It is expected that support for both these technologies will start to significantly decrease in 2027, when the 20-year support duration ends for the installations receiving the high FiTs under the Second Conto Energia.

Regarding FiPs for onshore wind, with more awarded projects being realised thus increasing the generation, the support level gradually decreased from 85 €/MWh in 2014 to 69 €/MWh in 2020. Nevertheless, considering the strongly reduced auction outcomes (FiPs) for the coming delivery years, we expect the level of support per MWh generated by onshore wind generators subject to this scheme to significantly decrease in the future.

11 Note that generation from utility-scale PV was also reduced due to lower irradiation but the impact on support was limited, keeping it mostly the same in both 2015 and 2016. This was due to lower FiT levels allocated to utility-scale PV compared to the FiTs for rooftop PV.

4.5 The impact on electricity bills

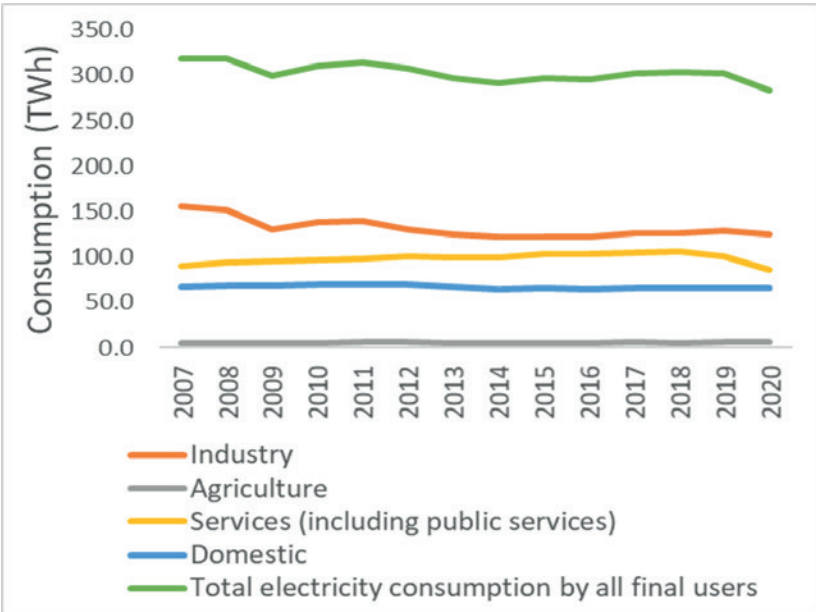
As in the majority of EU member states, funding for the cost of renewable policy in Italy comes from electricity consumers via a levy in their electricity bills (CEER, 2018). This surcharge, which was known as the 'A3' electricity bill component until 1 January 2018 and 'Asos' since,[12] collects revenue from all electricity consumers based on their consumption class to contribute to the development of renewable energy resources. In particular, support paid to renewable resources through different support schemes including TGCs, FiTs, FiPs for non-PV renewables and FiTs for PV systems under the Conto Energia is funded with the A3/Asos surcharge.

The A3/Asos payments go into an account that finances new renewable plants at the Energy and Environmental Services Fund (Cassa per i Servizi Energetici e Ambientali, CSEA). The CSEA and the GSE assess the finance required to be covered by the surcharge each year according to the cost of supporting renewable resources and they communicate it to ARERA. The annual values of A3/Asos can be found in the GSE annual reports. It is then the responsibility of ARERA to determine the amount of revenue to be collected via the surcharge to cover support for renewable resources. The resulting A3/Asos component is applied to consumers' electricity bills and is differentiated by consumer class.

Data on the annual values of the surcharge that each consumption class needs to pay is publicly available and can be found in the annual reports of the GSE and ARERA. In this analysis, we focus on the impact of support costs for wind and solar technologies on domestic consumers with a consumption of 2640 kWh/year.[13]

Figure 16, shows electricity consumption in Italy between 2007 and 2020. It can be seen that total consumption slightly decreased over the years, from 319 TWh in 2007 to 284 TWh in 2020. Besides total electricity consumption, the figure also shows consumption by sector. Electricity consumption by the domestic sector in Italy was stable over the years at around 65 TWh (approximately 22% of total consumption) while industrial electricity consumption decreased from 155 TWh in 2007 to 125 TWh in 2020.

Figure 16: Total and sector-specific electricity consumption in Italy between 2007 and 2020. Main source: Terna (2021)

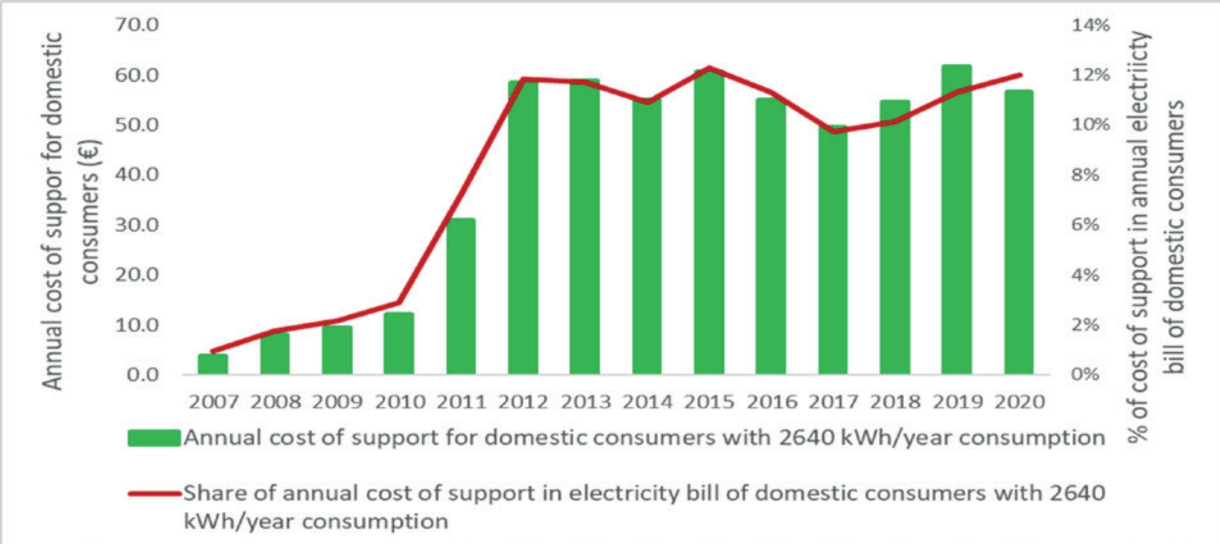


12 Starting from 2018 and following resolutions 922/2017/R/eel and 923/2017/R/com of December 27 2017, the Authority (ARERA) defined a new structure of the A3 component and changed the name to Asos. The structural change was minor involving only separation of a small part attributed to non-biodegradable waste as another component in electricity bills.

13 ARERA uses this category of domestic consumers when reporting electricity prices.

Figure 17 shows the estimated (nominal) annual cost of policies supporting wind and solar generation for domestic consumers with 2460 kWh annual consumption. In addition, it shows the proportion of this cost in the same consumers' electricity bills. These measures are estimated using the annual values of the A3/Asos component which are annually reported by the GSE and ARERA and our estimations of the cost of supporting wind and solar technologies as reported in Figure 13.

Figure 17: Estimated (nominal) annual cost of policies supporting wind and solar generation for domestic consumers with 2460 kWh annual consumption. Own calculation based on data from GSE (2007-2021) and ARERA (2020).



The annual cost of wind and solar support policies for a domestic consumer (bars) increased from €4 in 2007 to €56 in 2020. This was mainly due to the generous support given to PV systems and the technology boom in 2011-2012. Figure 17 also shows that the annual cost to domestic consumers of supporting wind and solar generation almost doubled from 2010 to 2011 and then again from 2011 to 2012. As was discussed in section 2.2 this increase in cost was the main reason for introducing the Fourth Conto Energia in 2011. After 2012, the cost for domestic consumers remained at about €58/year. The average electricity bill for a domestic consumer was €413 in 2007 and €472 in 2020 (ARERA, 2021). This is a 14% increase in nominal terms. The share of support costs for wind and solar in electricity bills (line) also increased from 1% in 2007 to 12% in 2020. This share is close to the 13% in the UK, considering that in the case of the UK offshore wind was the major contributor in terms of costs, installed capacities and generation, a technology which is lagging far behind in Italy.

Nevertheless, as in the other cases, it is important to note that we report the gross costs of renewable support policies. These policies have positive impacts on the cost of electricity, e.g. by decreasing the average electricity wholesale price. For this reason, a conclusion cannot be reached on whether the increase in wind and solar generation support costs caused the increase in electricity bills. This would require a more detailed analysis examining relevant environmental, technological and economic factors.

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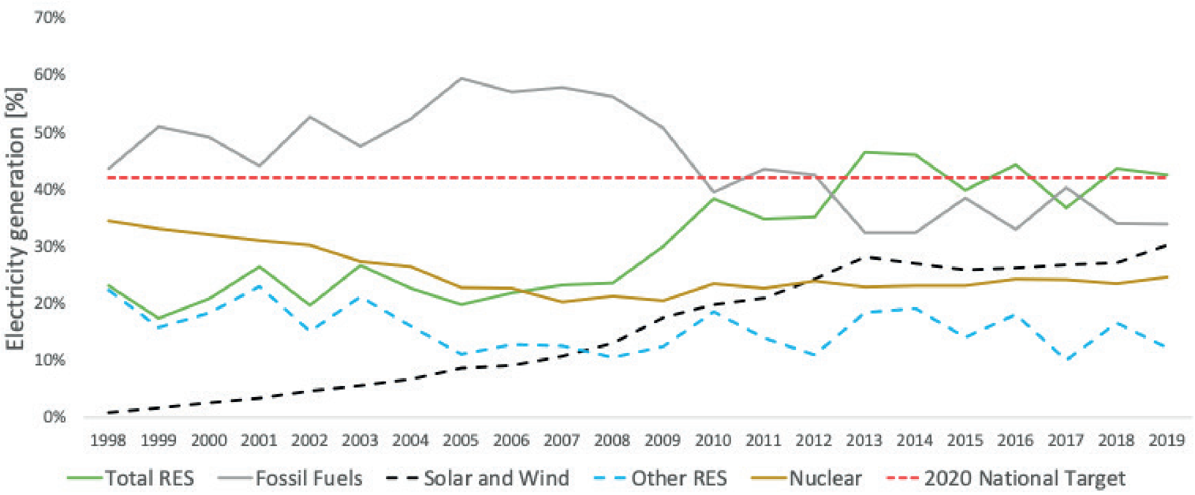
5. Spain

In this chapter, we describe and analyse the main renewable support schemes that have been introduced in Spain to stimulate investment in onshore wind, solar photovoltaic (PV) and solar thermal. The chapter consists of five sections. First, we provide a general introduction. Second, we give an overview of the different support schemes that have been put in place and their effectiveness in promoting the deployment of the renewable electricity generation technologies considered. We distinguish two mechanisms: the special regime (1998-2012) and the specific remuneration regime (2013-today). These mechanisms use feed-in tariffs and feed-in premiums to promote deployment of renewable energy sources. Third, we describe the annual costs of the different tools for each generation technology. Fourth, we discuss the cost-effectiveness of the support schemes, defined as the annual expenditure of a support scheme per MWh of energy produced by all generators benefiting from the scheme. Last, we discuss the impact of the renewable support schemes on electricity bills.

5.1 General introduction

Like many other Member States in the EU, renewable electricity technologies are considered an important element in Spain's national strategy to reach both national and EU level energy and climate goals. In this regard, several important milestones were set, including the European 20-20-20 targets and the more recently adopted 2050 Net Zero target (European Commission, 2009; Piebalgs et al., 2020). Figure 1 shows the evolution of electricity generated from renewable electricity sources in Spain between 1998 and 2019. Spain's 2020 national target for electricity generation from renewable sources was set at 42%, and was already met in 2013, when it hit 46%. 2013 was also the first year in which RES electricity generation surpassed that from fossil fuels (coal plus natural gas), as the proportion of the latter in the electricity generation mix decreased sharply to 32% (from 42% in 2012).[1] The proportion of RES-E decreased to below the national target in 2015 and 2017, which were low-water years and hydro electricity generation was lower than usual (REE, 2018). In 2019, 42% of electricity was generated from renewables. Wind was the main source of renewable electricity generation with 24%, followed by hydro (11%), solar PV and solar thermal (6%). The remainder of electricity was generated by nuclear (24%), coal and natural gas (34%).

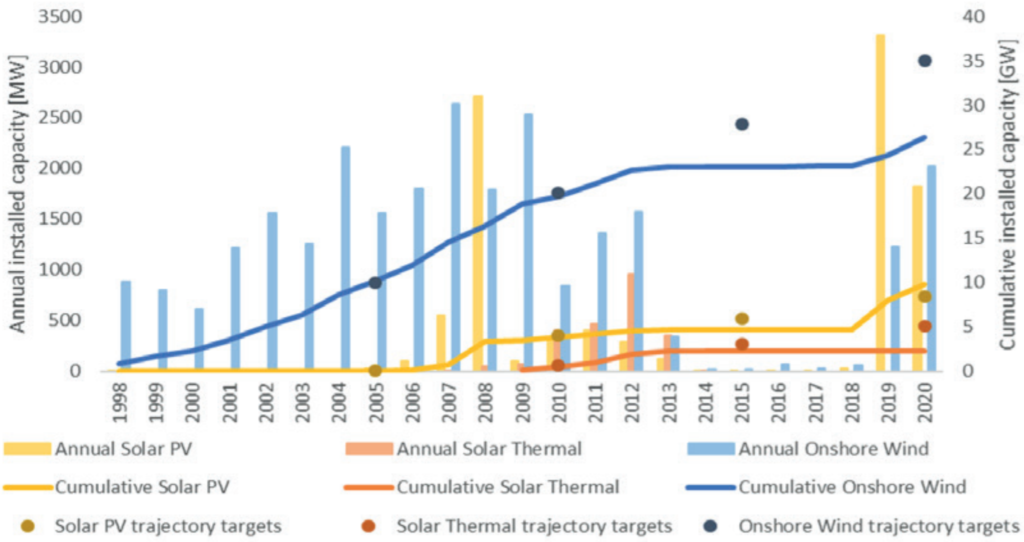
Figure 1: Total RES generation versus nuclear and fossil fuels and the 2020 renewable electricity target (1998-2019). Main source: REE (2021) and Eurostat (2021)



1 Spain's economy was one of the ones that was hit hard by the 2008-2009 financial crisis. As a result, energy consumption declined rapidly during the aftermath of the crisis. Consequently, burning coal and natural gas, which were the main energy sources in Spain before the crisis (see Figure 1), decreased by 24% from 2008 to 2013.

We focus on promotion through public financial support for three renewable electricity generation technologies: onshore wind,[2] solar photovoltaic (PV) and solar thermal.[3] Figures 2 and 3 show the evolution of the deployment of and the electricity generated by these three technologies respectively. Figure 2 also shows Spain's national installed capacity trajectory targets for each of the technologies.

Figure 2: Accumulative and annual capacity installed in Spain (1998-2020) and the national trajectory targets for each technology. Main sources: CNMC (2021), REE (2021) and Castro-Rodríguez & Miles-Touya (2016)

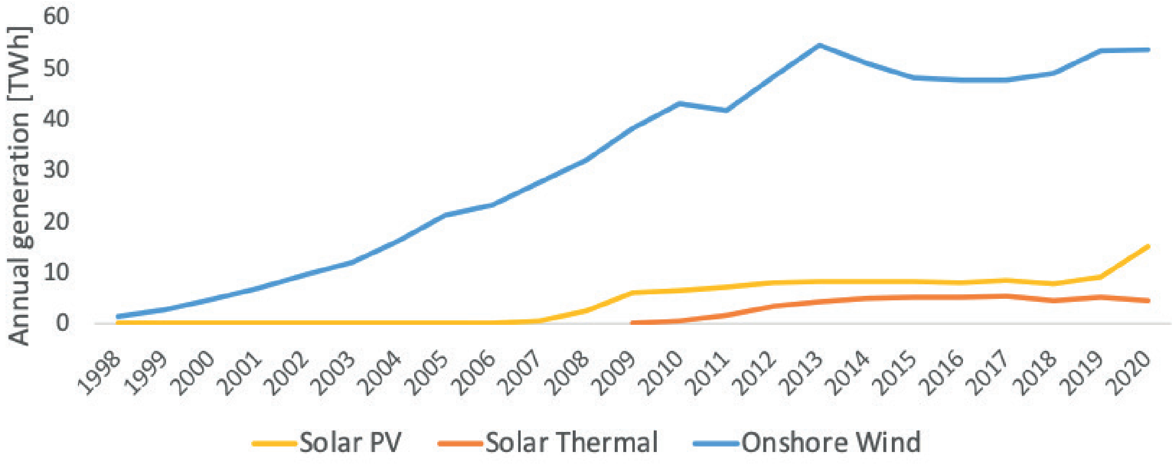


As Figure 3 demonstrates, onshore wind electricity generation was dominant with respect to other technologies in the 1998-2020 period. With 54 TWh of electricity generation in 2020, onshore wind generation was more than three times that of solar PV and solar thermal combined (14.1 TWh). Onshore wind generation followed an increasing trend between 1998 and 2013, when it reached its peak of 55 TWh, but it dropped in 2014 and 2015 following a retroactive decision to suspend support payments and decreasing productivity of older wind generation. In 2018-2019, as new support mechanisms for both new and existing plants were implemented, onshore wind generation started to grow once again. Electricity generation from solar PV stayed in the 7-8 TWh range between 2009 and 2018 but it grew to 9.2 TWh and 15 TWh in 2019 and 2020 respectively for the same reasons behind the increase in onshore wind electricity generation.

2 We do not consider offshore wind technology in this work as the accumulative installed capacity for this technology is not significant. By 2020 only 5 MW of offshore wind was deployed in Spain (Offshore wind in Europe, 2021).

3 The available data on deployment of solar PV in Spain does not allow us to differentiate rooftop and utility-scale technologies in terms of installed capacity, electricity generation and support payments. However, data on FiT and FiP support levels for different capacity classes of PV technology are publicly available in different Royal Decrees. We report these support levels in this work. In addition, to bring more diversification to this study, we present deployment of solar thermal technology in Spain, which is in fact quite significant (even in comparison to other EU member states).

Figure 3: Annual generation in Spain (1998-2020). Main sources: CNMC (2021), REE (2021)

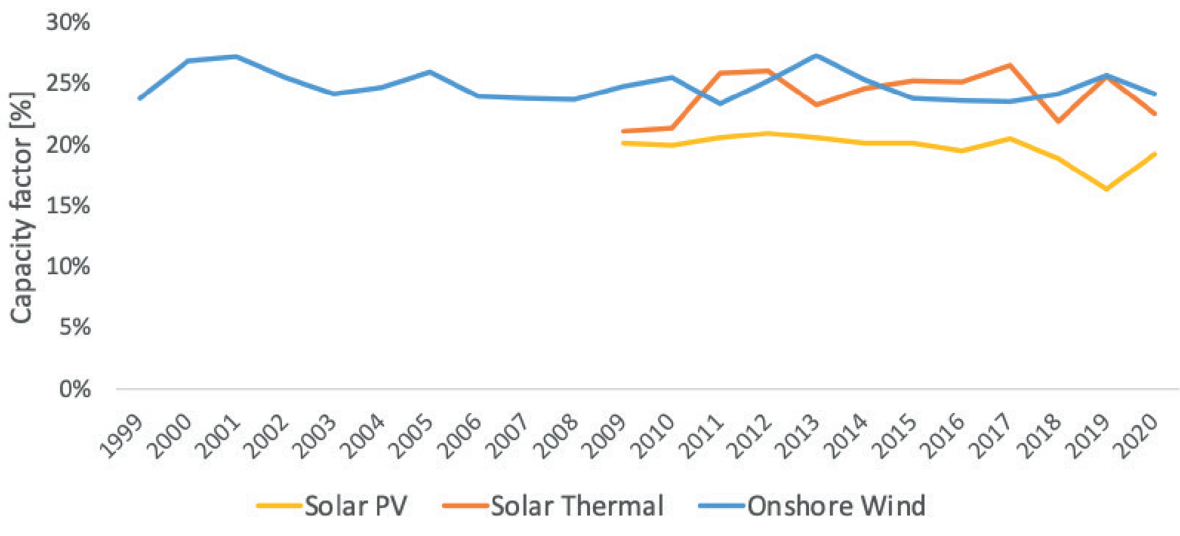


Finally, Figure 4 shows the capacity factors of the different generation technologies. The capacity factor is calculated as follows:

$$Capacity\ factor = \frac{Generation_i}{8760*(0.5*Cumulative\ capacity\ _j + 0.5*Cumulative\ capacity\ _{j+1})},$$
$$where\ i = year\ and\ j = snapshot\ on\ the\ 1st\ of\ January\ in\ year\ i$$

The capacity factor for onshore wind technology remained between 24% and 26% in the 1999-2020 period. The capacity factor for solar thermal was more or less in the same range with an average value of 24%. Solar PV, as expected, had the lowest capacity factor among the technologies studied, with an average value equal to 20%. It should be noted that the high value of the solar PV capacity factor in Spain compared to other cases in this study can be attributed to high solar irradiation in Spain, which makes the country one of the EU's Member States with the highest solar PV power potential (Global Solar Atlas, 2021). The sudden drop in the solar PV technology capacity factor in 2019 was due to capacity additions that year which were not yet fully operational but were registered as installed capacities.

Figure 4: Capacity factors in Spain (1999-2020). Computation based on CNMC (2021) and REE (2021)

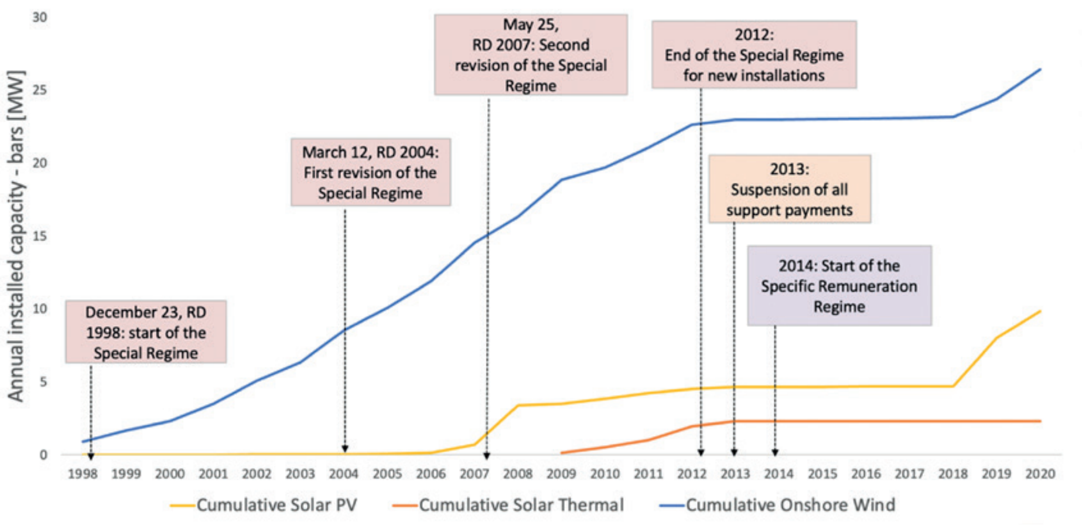


In what follows, we describe in more depth the different support schemes that have driven the deployment of these three renewable electricity generation technologies in Spain.

5.2 Two different support regimes and their effectiveness

We identify three main renewable electricity support schemes that have been employed in Spain under two regimes between 1998 and today. These support schemes were identified through a literature review (Haas et al., 2011; Li et al., 2020; Lockwood, 2016; Ragwitz and Steinhilber, 2014; Welisch and Poudineh, 2020) combined with public information available on the websites of the semi-state-owned electricity system operator (Red Eléctrica de España, REE), the State Agency Official Gazette (Agencia Estatal Boletín Oficial del Estado, BOE) and the Association of Renewable Energy Businesses (Asociación de Empresas de Energías Renovables, APPA). The two regimes which introduced the support schemes for renewable sources and their respective timelines are shown in Figure 5. The different colours of the boxes indicate information about the different support regimes.

Figure 5: Overview of the different main renewable support schemes mapped on the capacity installed for each technology. Main sources: Own elaboration based on BOE (Agencia Estatal Boletín Oficial del Estado) website, REE (2021) and data from CNMC (2021)



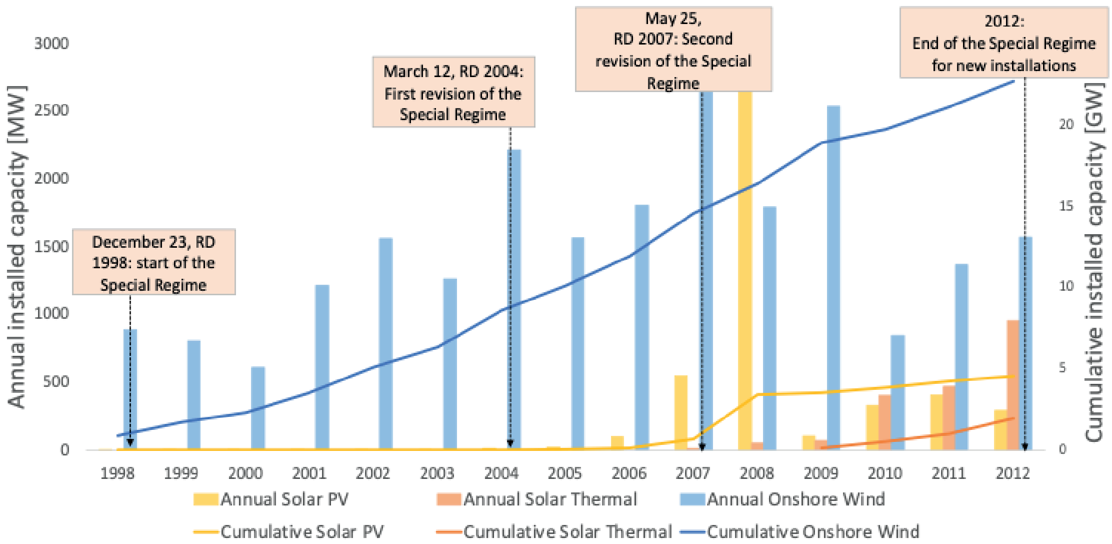
In the remainder of this section, we describe each scheme in more detail and provide data on its effectiveness in terms of the capacity installed.

5.2.1. 1998-2012: Feed-in Tariffs and Feed-in Premiums under the Special Regime (Régimen Especial)

Boosting electricity generation from renewable energy resources (RES) in Spain dates back to Law 82/1980, in which a "special regime for electricity production" was first introduced for (mostly hydraulic and co-generation) RES self-producers (Blanco-Díez et al., 2020). The special regime allowed the eligible self-producers to sell their surplus to the electricity supplier and to receive an administratively set price for it. The special regime was further consolidated with Royal Decree 2366/1994, which allowed renewable resources (again mostly hydraulic and co-generation at that time) to receive support in the form of feed-in tariffs (FiTs) (Blanco-Díez et al., 2020). Four years later, the Spanish government introduced Royal Decree 2818/1998, which established a remuneration mechanism with the aim of ensuring the viability and profitability of RES under the special regime. Later, in 2004 and 2007, structural reforms were introduced to the special regime and the 1998 Royal Decree on how the financial support should be allocated. Finally in 2012, following a retroactive law and in an attempt to reduce the growing tariff deficit, all the previous support mechanisms for RES were abolished. In 2013, a new support mechanism called specific remuneration (Régimen Retributivo Específico) was introduced for both existing and new RES facilities.

Figure 6 reports the evolution of accumulated installed capacity together with the annual installed capacity for onshore wind, solar PV and solar thermal technologies under the special regime from 1998 until it was abolished in 2012. As can be seen from this figure, onshore wind was the technology which benefited more than the others from FiT and FiP schemes under the special regime, with an increased accumulated capacity from 1 GW in 1998 to 23 GW in 2012. During this period, the accumulated solar PV capacity increased by 5 GW from zero, while the measure for solar thermal was only 2 GW.

Figure 6: Annual and accumulated installed capacity for each technology under the special regime, 1998-2012. Source: CNMC (2021)



Figures 7 and 8 report for each technology the evolution of FiT and FiP levels respectively together with the amount of technology-specific annual installed capacity that received FiTs/FiPs from 1999 to 2012. From these figures, it can be seen that while FiPs were more effective in attracting investments in onshore wind compared to FiTs, solar PV and solar thermal were almost entirely financed by FiTs. As expected, the level of FiTs was always set higher than that of FiPs, which contributed to their attractiveness for solar technologies. These technologies have a lower capacity factor compared to onshore wind and so require higher incentives to enable them to cover their investment costs and to assure them an acceptable source of revenue.

Figure 7: Evolution of FiT levels and annual installed capacity for each technology under the special regime, 1998-2012. Source: CNMC (2021)

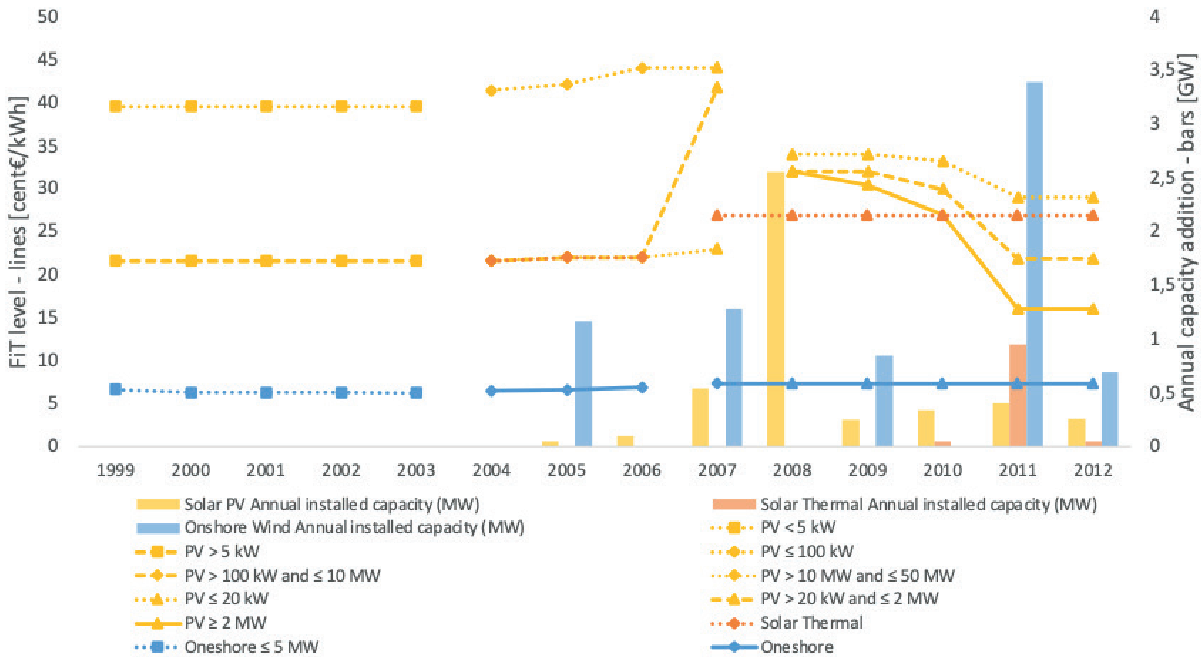
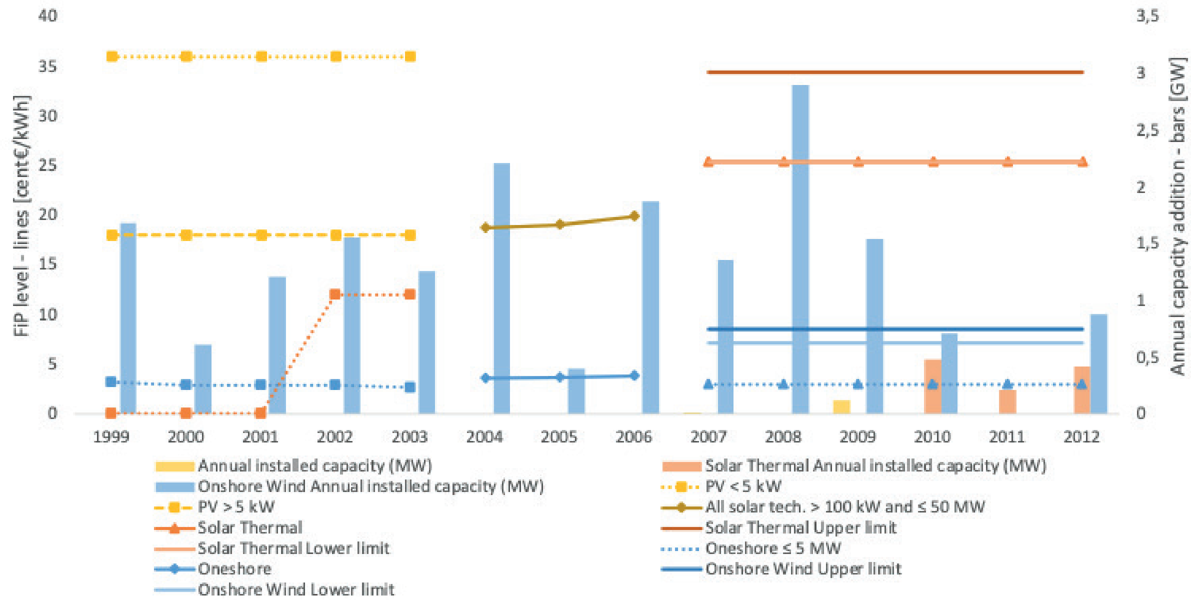


Figure 8: Evolution of FiP levels and annual installed capacity for each technology under the special regime, 1998-2012. Source: CNMC (2021)



In the rest of this section, we discuss the special regime and reforms of it, their design and their relative effectiveness in the period 1998-2012.

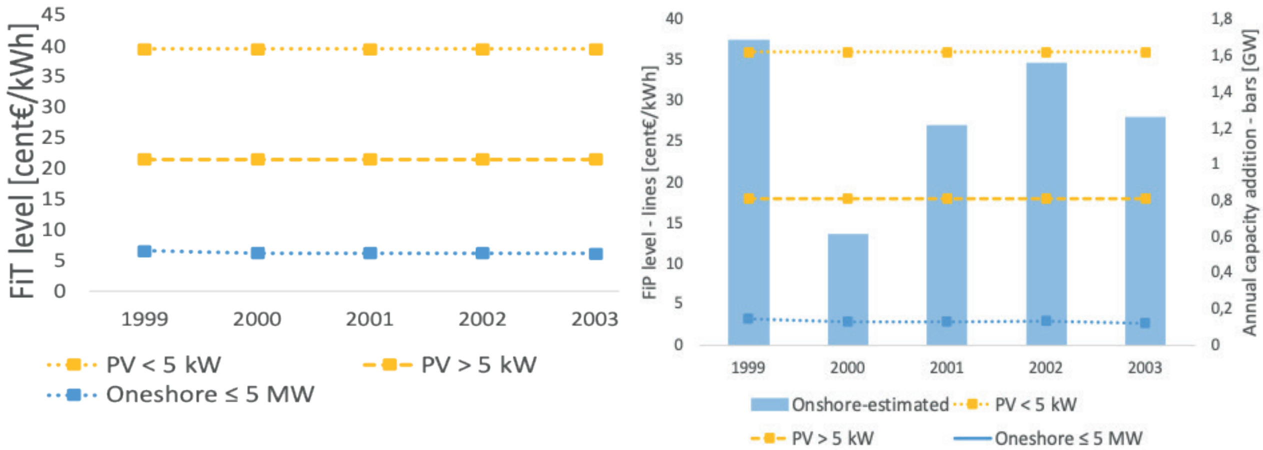
Royal Decree 2818/1998

The RES-E remuneration mechanism which was established in the 1998 Royal Decree enabled renewable electricity generators to choose between two options: a) receiving a fixed total price (FiT) or b) a fixed premium (FiP) on top of the electricity market price. del Río (2008) explains that the reason for providing these two options for RES-E was that the Spanish government aimed to promote a gradual participation of renewable resources in the electricity market but also to ensure a certain support level for them. The RES-E generators would supply their electricity to the distributors, which would also pay the tariffs to the suppliers. These payments were then passed on to the Comisión Nacional de la Energía (CNE), which would pass these costs to the end consumers (del Río and Gual, 2007).

Both the FiTs and FiPs were set to be adjusted annually and the eligible RES-E generators were to receive them for an indefinite time. The lack of a time limit for receiving incentives was stated in the 1998 Royal Decree to be necessary to ensure that costly RES-E technologies had the possibility of participating in the market and to satisfy the need to internalise their environmental benefits over time (Blanco-Díez et al., 2020). However, as del Río (2008) states, the no-time-limit policy had weak legal force with non-transparent conditions. As for the annual adjustment of tariffs, del Río (2008) argues that this was pushed by the Ministry of Economy, which aimed to maintain the financial burden on consumers through annual assessments of payments to RES-E and to avoid windfall profits for these technologies. This mechanism was considered to be helpful for the government to avoid payment of excessive support for a long time. However, del Río (2008) suggests that the annual tariff assessments created uncertainty for many RES-E generators about their future revenue and consequently they considered it to be a drawback of the 1998 Royal Decree.

The *special regime* under the 1998 Royal Decree lasted until 2004, when a reform was introduced. During this period, financial support was provided to installations with capacities under 50 MW in the form of FiTs and FiPs. The support levels were set administratively and were differentiated by installed capacity and technology. Of the three technologies analysed, onshore wind was the one which benefited most from the support payments, specifically FiPs. Figure 9 (left) shows the FiT levels and annual installed capacity for the three technologies from 1999 to 2003 (the first and last years of the 1998 Royal Decree). The same measures for FiPs are shown in Figure 9 (right).

Figure 9. Left: FiT levels and annual installed capacity for each technology from 1999 to 2003. Right: FiP levels and annual installed capacity of each technology from 1999 to 2003. Sources: 1998 Royal Decree and del Río (2008)



As can be seen, from 1999 to 2003 the FiT mechanism was not successful in promoting onshore wind, solar PV or solar thermal technologies (which is why no bars are shown in Figure 9 left).[4] The same was true for solar technologies with FiPs. They did not realise any capacity additions from 1999 to 2003 under the FiP mechanism. On the other hand, thanks to FiPs onshore wind technology started to flourish in this period. With an average FiP of 29 €/MWh, cumulative onshore wind capacity increased from below 1 GW before 1999 to more than 6 GW in 2003.

Royal Decree 436/2004

On 12 March 2004, the first revision of the special regime was announced.[5] This revision introduced changes to FiTs and FiPs,[6] to how the support was calculated and to how suppliers could sell their electricity. Under the 2004 reform, suppliers had the option of selling their electricity generation either to the distributor or directly on the market. This was to further encourage RES-E generator market participation.

Regarding tariffs, a new calculation method was introduced based on the average electricity price/tariff (AET). Plants had two options:

1. To receive a regulated tariff (FiT) calculated as a technology-specific percentage of the AET when selling to the distributor;

2. To receive the market price plus an incentive to participate in the market7 and a premium (FiP), which was calculated as a technology-specific percentage of the AET when directly participating in the market.

The AET was still decided on by the government on an annual basis,[8] but the resulting FiTs and FiPs were allocated for the lifetime of the accredited RES-E installations, thus abolishing the annual adjustments which were included in the 1998 Royal Decree.[9] This provided a more certain revenue stream for investors as it was a more transparent support allocation approach than in the 1998 Royal Decree. Although FiTs and FiPs were allocated for the lifetime of plants, they were set to decrease after a certain time (25 years for solar and 5 to 15 years for onshore wind technologies).

Realising the ineffectiveness of the 1998 Royal Decree in promoting deployment of solar technologies, more attention was given to these technologies in the 2004 revision of the special regime. In the calculation of FiTs, solar PV and solar thermal technologies were allocated a percentage of the AET equal to 575% and 300% respectively compared to the 90% for onshore wind technology. In addition, while under the 1998 Royal Decree FiTs were higher for solar PV installations with capacities below 5 kW, under the 2004 reform the capacity cap was raised to 100 kW, enabling a larger number of solar PV installations to receive high FiTs.

Figure 10 (left) shows the FiT levels and annual installed capacity of the three technologies from 2004 to 2006 (the first and last years of the 2004 Royal Decree). The same measures for the FiP are shown in Figure 10 (right).[10]

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4 It should be noted that no FiTs were introduced for solar thermal technology in the 1998 Royal Decree (1998-2003). Therefore, only FiTs for solar PV technology are shown in Figure 9 left.

5 Negotiations to revise the RES policy took place among three main stakeholders: the government represented by the Ministry of Industry, RES-E generators and the National Energy Commission (CNE).

6 FiTs and FiPs were differentiated according to both technology and the size of installations.

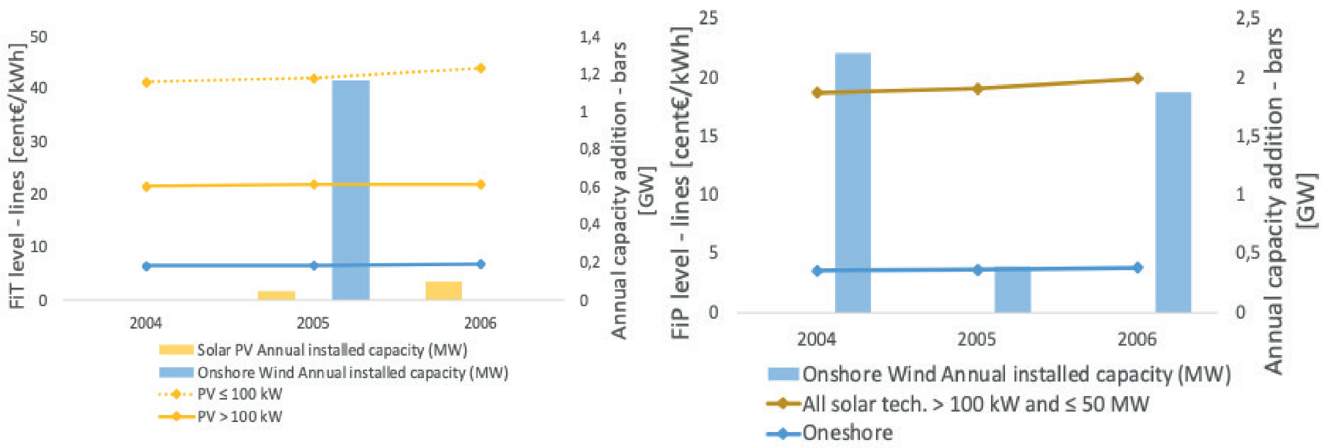
7 This was called a 'market incentive' and was equal to 10% of the AET. Accrediting the 'market incentive' was part of the government's plan to further encourage RES-E generators to participate in the market and to reduce the administrative intervention in setting electricity prices (del Río, 2008; Blanco-Díez et al., 2020).

8 The AET followed an increasing trend and was set as follows: 7.20 €c/kWh in 2004, 7.33 €c/kWh in 2005, 7.65 €c/kWh in 2006 and 7.65 €c/kWh in 2007 (del Río, 2008).

9 Instead, adjustments to support levels were to be made every four years and only for new plants.

10 Note that, although technology specific FiTs were introduced for solar thermal in this period, this technology was not yet being deployed by investors. Therefore, we do not report it in the figures.

Figure 10. Left: FiT levels and annual installed capacity of each technology from 2004 to 2006. Right: FiP levels and annual installed capacity of each technology from 2004 to 2006. Sources: 2004 Royal Decree and del Río (2008).



As can be seen from this figure, both FiTs and FiPs were set at slightly higher levels under the 2004 Royal Decree than under the 1998 Royal Decree. In addition, as the administratively set AET followed an increasing trend, the FiTs and FiPs also increased over time.

Onshore wind continued to grow under the 2004 Royal Decree, particularly as a result of receiving FiPs. The total onshore wind installed capacity almost doubled, from 6 GW in 2003 (the last year of the 1998 Royal Decree) to 11.5 GW in 2006 (the last year of the 2004 Royal Decree). Unlike onshore wind, solar PV technology benefited from FiTs instead of FiPs. This was in fact due to the small scale of solar PV installations, which made high FiTs a more attractive option for this technology than participating in the market and receiving lower FiPs for small volumes of electricity generation. The reformed FiT calculation method and the new capacity-specific FiTs which allowed installations below 100 kW to receive a higher FiT contributed to kick starting solar PV deployment in Spain. However, the growth rate of adoption was not significant. In the three years up to the end of 2006, only a total of 150 MW of solar PV capacity was installed in Spain.[11]

Royal Decree 661/2007

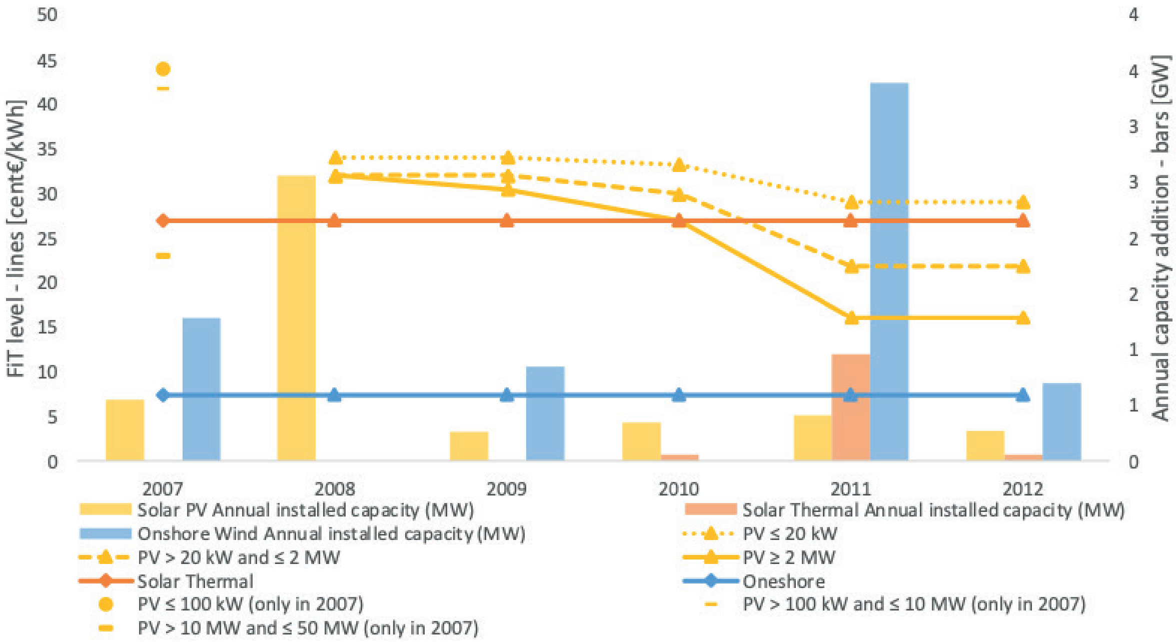
The second reform of the special regime was introduced on 25 May 2007. Like Royal Decree 436/2004, negotiations took place among the Ministry of Industry, RES-E generators and the CNE. Encouraging RES-E market participation and reducing system costs were the two important subjects in the negotiations. However, as del Río (2008) argues, some elements in the 2007 reform in fact discouraged further market participation. The first of these was elimination of the market participation incentive which was introduced under the 2004 Royal Decree as part of the FiP. The second was the introduction of a cap-and-floor system for FiPs (for suppliers that directly participated in the market). The cap-and-floor system meant that when the market price plus the premium was higher than the cap, RES-E suppliers would only receive the cap, and when this sum was lower than the floor they would be guaranteed the floor price. del Río (2008) states that the assignment of a floor price was welcomed by RES-E generators, while the government was in favour of the cap price to reduce system costs, which were paid by consumers. Another tariff design element which was changed in 2004 was a delinking of tariffs from the AET. Instead, they were tied to the consumer price index (CPI).

The rationale behind these changes was to reduce the burden of costs on consumers by decreas-

11 It should be noted that the 2004 Royal Decree for the first time introduced a 12% target for the share of RES in final energy consumption by 2010. It also set caps on installation capacity, which when they were reached the tariffs would be revised. These caps were 150 MW for solar PV, 200 MW for solar thermal and 13 GW for onshore wind (Royal Decree 436/2004). These caps were reached at the time of the second revision of the special regime in 2007.

ing the support payments, which were escalating due to the AET increasing and increasing spot market prices (del Río, 2008; Alonso-Llorente, 2006).[12] However, at the same time as the above elements were introduced with system cost reduction in mind, higher support levels than under the 2004 Royal Decree were offered to RES-E generators in the 2007 Royal Decree. This was inconsistent with the cost-reduction argument. Figures 11 and 12 show the evolution of FiTs and FiPs together with annual capacity additions for each technology in the 2007 Royal Decree and the 2008 Royal Decree for solar PV.[13]

Figure 11: Evolution of FiTs and annual capacity additions for each technology under the 2007 Royal Decree and under the 2008 Royal Decree for solar PV. Sources: 2007 Royal Decree and del Río (2008)



FiTs were allocated according to the technology and installation size. For solar PV installations, more size brackets were introduced in the 2007 Royal Decree.[14] Comparing the FiTs reported in Figure 11 and those in Figure 10 (left), we calculate that FiTs for solar PV installations between 20 kW and 2 MW were increased by approximately 20% under the reforms introduced in 2007. The FiTs for PV were increased to further accelerate deployment of this technology, as the existing capacity was far behind the 2005-2010 trajectory targets (Del Río & Mir-Artigues, 2012). This increase provided an attractive investment opportunity for RES investors and led to a turning point in solar PV deployment in Spain. The total installed solar PV capacity in Spain increased from 150 MW in 2006 to more than 4.5 GW in 2012 (a 96% increase). Only from April 2007 to August 2008 2.7, GW was installed.[15]

12 del Río (2008) explains that although market prices were following an increasing trend, no regulatory effort was made to adjust the premiums accordingly and to avoid windfall profits for suppliers which selected the market option. This in turn contributed to an increase in overall system costs. We discuss this further in the next sections.

13 FiTs and FiPs were allocated to eligible installations for their whole lifetimes but as before they were set to reduce after a certain time (solar 25 years, wind 20 years).

14 Solar PV installations were divided into below 100 kW, between 100 kW and 10 MW, and between 10 MW and 50 MW in the 2004 Royal Decree. The size classification was changed in the 2007 Royal Decree to below 20 kW, between 20 kW and 2 MW, and above 2 MW.

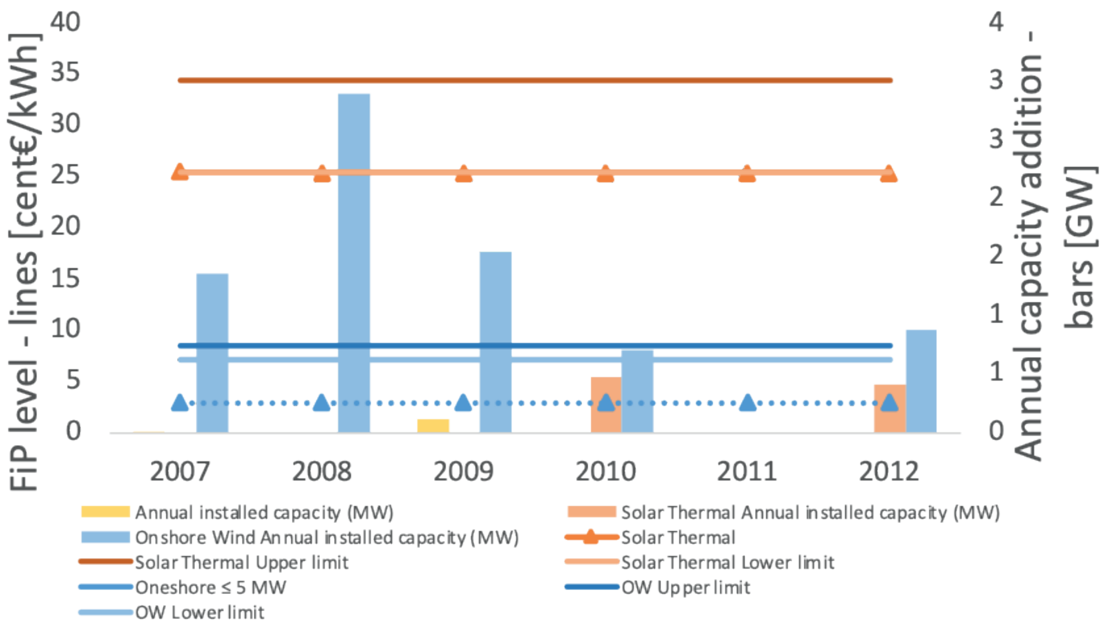
15 Several reasons are mentioned in the literature for this boom. It took a year from the start of negotiations on the reform to its announcement in May 2007. News of the new RES-E policy was well circulated during this time and RES-E investors and lobby groups were both pushing for higher levels of support for solar PV and were anticipating the start of the expected changes (del Río, 2008). In addition, a capacity cap was included in the 2007 Royal Decree (371 MW), which, if reached, required a new royal decree to be issued on solar PV in at most a year. The cap was reached in June 2007. Del Río & Mir-Artigues (2012) suggest that there was an expectation among investors that the FiTs would be reduced in the coming royal decree and therefore they rushed to submit proposals for the existing higher FiTs.

This was all under the FiT mechanism as in the 2007 Royal Decree solar PV installations were not allowed to participate in the market.

In September 2008, a new royal decree (Royal Decree 1578/2008) on solar PV was issued. This regulation contained two novelties: a) for the first time, solar PV installations were classified into 'rooftop, type I (less than 2 MW)', and 'ground, type II (more than 2 MW)', b) a capacity quota system was adopted for each classification (500 MW in total for the two types in 2009 and in 2010) (Blanco-Díez et al., 2020). In addition, capacity allocation was to be done on a first-come-first-served basis after the publication of calls (Del Río & Mir-Artigues, 2012). Capacity additions decreased significantly after the 2008 Royal Decree. Only 250 MW was added in 2009. Besides reasons such as a lack of proficiency in administering the new regulation, the economic crisis and difficult access to credit, the quota system also limited adoption of more solar PV capacity in 2009 (Del Río & Mir-Artigues, 2012). More precisely, while demand for type II installations was much higher than the relative quota (133 MW), this was not the case for type I installations (Del Río & Mir-Artigues, 2012).

The FiTs for onshore wind and solar thermal were also set at more generous levels in the 2007 Royal Decree (12% higher for onshore wind and 17% higher for solar thermal, according to del Río (2008). These two technologies also saw increases in their deployment between 2007 and 2012. Onshore wind under the FiT mechanism increased by about 6 GW in this period while solar thermal increased by 1.1 GW.

Figure 12: Evolution of FiPs and annual capacity additions for each technology under the 2007 Royal Decree. Sources: 2007 Royal Decree and del Río (2008)



Like FiTs, FiPs were allocated according to the technology and installation size. Solar PV installations were not allowed to participate in the market or receive premiums.[16] The lower and upper limits for solar thermal premium payments under the cap-and-floor system were 254 and 344 €/MWh respectively. This meant that solar thermal installations would receive at least 254 €/MWh. Subtracting an average market price of 50 €/MWh,[17] this meant that such installations would receive on average 204 €/MWh in the form of support, which was 14 €/MWh more than what was received, again on average, under the 2004 Royal Decree. This led to solar thermal installed capacity increasing by 1.1 GW in 2007-2012 under the FiP mechanism, albeit in a more costly manner.

16 In the 2004 Royal Decree only solar PV installations with capacities under 100 kW were banned from participating in the market.

17 The average spot market price in 2006 (Alonso-Llorente, 2006).

As with the 2004 Royal Decree, under the 2007 Royal Decree onshore wind was the biggest winner in terms of installed capacity, with nearly 7 GW capacity added between 2007 and 2012. The lower and upper limits for onshore wind premium payments under the cap-and-floor system were 71.2 and 84.9 €/MWh respectively. Again, subtracting an average market price of 50 €/MWh means that onshore wind installations were awarded at least 21.2 €/MWh in premiums, which is lower than the average premium that was set in the 2004 Royal Decree at 37 €/MWh. This decrease in premiums for onshore wind projects was a direct result of a government policy to reduce system costs. However, with more RES-E generation participating in the market, implementing a floor level also meant that if the market price decreased a larger amount of support would be paid to RES-E suppliers. This larger amount would eventually be passed on to consumers, increasing the cost to them of supporting renewables.

Cost-containment measures: Royal Decrees from 2009 to 2012

From 2000, the Spanish electricity system saw a rising trend in total system costs. However, the Spanish authorities did not adjust consumer tariffs accordingly. This was mainly a political choice by Spanish governments to maintain regulated tariffs at low levels (despite the increasing costs) from the early 2000s (Del Río & Mir-Artigues, 2012). As in the previously mentioned Royal Decrees on RES-E policy (2004 and 2007) the Spanish government's main concern was to decrease (or at least not increase) the burden of RES-E support costs on consumers. However, instead of regulating the market in a competitive way to keep electricity prices down, they did this artificially by avoiding adjusting consumer tariffs to reflect the cost of energy (Castro-Rodríguez & Miles-Touya, 2016which arose as a consequence of shortfalls in the previous subsidy regime. However, the new support mechanism inherent to the post-reform regime is already increasing investor uncertainty, and endangering Spain´s ability to meet EU renewable energy installed capacity and output targets. As part of an effort to comply with EU renewable energy targets, Spain has relied on various renewable energy support mechanisms over the last few decades. From 1998-2013, Spain essentially used various versions of the feed-in-tariff (FIT; Blanco-Díez et al., 2020). As Blanco-Díez et al. (2020) state, this trend over the years led to the "generation of a structural problem related to the economic sustainability of the Spanish electricity system." The result of this structural failure was the creation of an increasing tariff deficit from 2000, which threatened the stability of the whole Spanish electricity system (Castro-Rodríguez & Miles-Touya, 2016which arose as a consequence of shortfalls in the previous subsidy regime. However, the new support mechanism inherent to the post-reform regime is already increasing investor uncertainty, and endangering Spain´s ability to meet EU renewable energy installed capacity and output targets. As part of an effort to comply with EU renewable energy targets, Spain has relied on various renewable energy support mechanisms over the last few decades. From 1998-2013, Spain essentially used various versions of the feed-in-tariff (FIT). The accumulated tariff deficit, which was 250 million euros in 2000, increased to more than 21 billion euros in 2009. In an attempt to decrease this gap between the cost of the electricity system and revenue, a series of decrees containing corrective measures were introduced between 2009 and 2012. Among the measures introduced to decrease the tariff deficit were the introduction of a new pre-assignment of remuneration registry for new installations, a limit on the number of operating hours for which new installations were eligible to receive support, an access toll of 0.5 €/MWh for all electricity generators and suspension of support allocation for all new installations.[18] However, these measures failed to decrease the tariff deficit and it soared to more than 36 billion euros in 2012. On 27 December 2012 in Law 17/2012 on the General State Budget for 2013, it was decided that in 2013 only support payments to existing RES-E installations would come from the State Budget.[19] Finally, in 2013 the government announced a retroactive abolishment of all RES-E support mechanisms and introduced a new RES-E support policy called the specific remuneration regime. We discuss this new policy in the next section.

18 See Blanco-Díez et al. (2020) and Royal Decree Law 9/2013 for a detailed review of these measures.

19 Therefore, support payments in 2013 were administratively set and were in the form of FiTs rather than FiPs. We discuss this in Section 3.

5.2.2 2013-today: Specific Remuneration (Régimen Retributivo Específico)

On 12 July 2013, Spain's Ministry of Industry issued Royal Decree Law 9/2013, which introduced a new RES-E policy and a new support mechanism (the specific remuneration regime) for electricity generation from renewable sources. In its introduction, the 2013 Royal Decree states that the reform was necessary to reduce the growing tariff deficit which it claimed was mostly linked to RES-E support payments under the special regime.[20] The new mechanism was said to have been designed to ensure 'reasonable profitability' for RES-E generators during their regulatory lifetimes. This 'reasonable profitability' is in line with the rate of return on 10-year government bonds plus a spread (Royal Decree Law 9/2013 and Royal Decree 413/2014). The specific remuneration which is allocated to ensure this 'reasonable profitability' is composed of:

- A remuneration term for each unit of installed power called investment remuneration (Rinv), expressed in €/MW.
- A remuneration term for operating costs not covered by market prices, called operation remuneration (Ro), expressed in €/MWh. This was in essence a premium.

The components of the specific remuneration (Rinv and Ro) for a typical installation are calculated based on those for a 'standard' facility. More precisely, the various parameters for a standard facility and its corresponding Rinv and Ro were defined and set in advance.[21] Then, the Rinv and Ro for a typical installation were decided on by benchmarking its parameters against those of a 'standard' facility. These parameters include technology, installed power, age, location, hours of operation, initial investment cost, wholesale market income and operational costs during the facility's regulatory lifetime.

As was previously mentioned, the 2013 reform was retroactive and so also affected existing RES-E generators. The principles for calculating the specific remuneration are the same for new and existing installations, in the sense that for both types of installations remuneration includes Rinv and Ro components benchmarked against those for standard facilities. However, the procedures for allocating the specific remuneration are different. While existing RES-E installations were automatically eligible to receive support,[22] new installations have to go through a competitive procedure (auctions) to receive it. From the start of the specific remuneration regime in 2013, auctions became the main tool to promote adoption of RES-E in Spain.

Under Royal Decree Law 9/2013, tenders are only invited when there is a need to increase installed RES-E capacity to meet national and/or EU targets for energy generated from RES. The conditions, technologies, types of standard facilities and groups of specific installations able to participate in each auction round were defined in a royal decree (Royal Decree 413/2014) issued by the State Secretary for Energy. The CNMC (Comisión Nacional de los Mercados y la Competencia)[23] is the entity which runs and supervises the auction procedure and outcome. Auction participants bid for a given capacity in a price-only auction (by offering discounts on the initial investment in the corresponding standard facility). AURES (2016) explains that "the outcome of an auction is a discount on the standard value of the initial investment in the reference standard plant. From this value, plus the rest of retributive parameters, the remuneration for the investment of the standard plant will be obtained." At the end of the auction uniform pricing is applied, which means that all the winners receive the discount in the last bid accepted (AURES, 2016).

20 Royal Decree 9/2013 stated that while income from consumer tolls increased by 122% from 2004 to 2012, the regulated cost of the electricity system increased by 197%. It then claimed that premium payments under the special regime contributed to this increase in cost as they increased sixfold in the same period (Royal Decree Law 9/2013).

21 Royal Decree 2015 (on the 2016 auction) and Royal Decree 2017 (on the 2017 auctions) provide technology-specific lists of standard facilities, their corresponding parameters and their specific Rinv and Ro values.

22 Albeit with some considerations. Because the reasonable return is calculated over the lifetime of a facility, the income obtained in the past by existing facilities is taken into account to determine the value of future support. Therefore, considering the support received in the past and the expected market income until the end of their regulatory lifetimes, installations that will reach the guaranteed return soon will face a cut in future support.

23 Previously CNE (National Energy Commission).

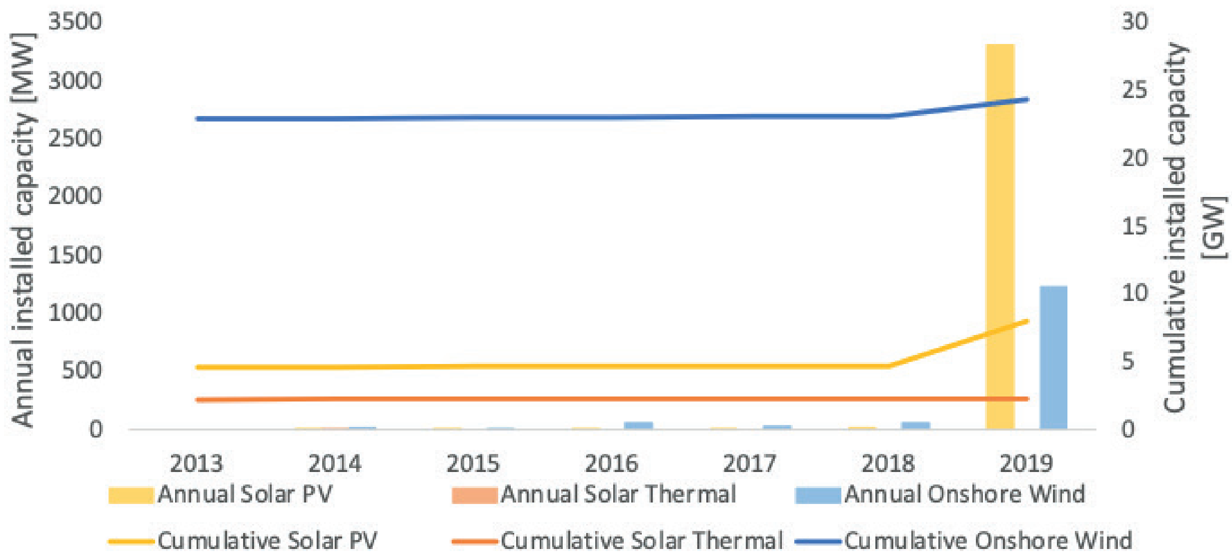
From 2013 to 2019 only three rounds of auctions took place in Spain, with the first one held in 2016 (no new installation was awarded support in the first three years). Of the total 8.5 GW RES capacity which was awarded in the auctions, 92% was allocated to onshore wind and solar PV technologies. Table 1 provides an overview of these auctions, including the auctioned and awarded capacities and other design elements such as penalties[24] and the realisation period allowed. Note that for the second auction round in 2017 it was announced that a conditional 3000 MW of capacity would be auctioned. 'Conditional' meant that more capacities would be awarded if and only if additional capacities could be developed with zero costs for the system (in other words if the auction outcome entailed zero support payments) (del Río, 2018). Indeed, in the second auction round more than 5000 MW of capacity was awarded instead of the 3000 MW auctioned.

Table 1: An overview of auction rounds from 2013 to 2019 with auctioned and awarded capacities and other auction design elements. Sources: 2015 Royal Decree, 2017 Royal Decree, AURES (2016) and del Río (2018)

Auction Round	Technology	Product auctioned	Auctioned capacity	Awarded capacity	Support duration	Penalty	Realisation Period
2016-January	Onshore wind	Capacity	500 MW	500 MW	20 years	20 €/kW	48 months
2017-May	Technology-neutral	Capacity	3000 MW (total)	Wind: 2980 Solar PV: 1 MW	25 years	60 €/kW	36 months
2017-July	Onshore wind-Solar PV	Capacity	3000 MW (conditional)	Wind: 1130 Solar PV: 3900 MW	25 years	60 €/kW	36 months

Figure 13 shows the evolution of annual added capacity and accumulated installed capacity between 2013 and 2019 under the specific remuneration regime.

Figure 13: Evolution of annual added capacity and accumulated installed capacity from 2013 to 2019 under the specific remuneration regime. Sources: CNMC (2021), 2015 Royal Decree, 2017 Royal Decree



24 Awarded projects are subject to paying the penalties established if they fail to become operational in the realisation period established. These penalties correspond to payments for each unit of awarded capacity that has not been delivered (€/kW).

Considering that new RES-E installations were only awarded support through auctions and that only three rounds of auctions were held between 2013 and 2019, a significant capacity addition in this period is not expected. In addition to the limited number of auctions held, it should be noted that the realisation period that was applicable to the projects awarded in these auction rounds was not yet over by 2019. For onshore wind, of the total 4.6 GW capacity which was awarded in auctions, only 1.2 GW was realised by 2019 (26%). This measure was much better for solar PV projects, of which 84% were realised. 3.3 GW of the 3.9 GW of capacity awarded was already connected to the grid by 2019. Of course, the high realisation rate of solar PV projects is attributable to the fact that construction of these projects is much faster than that of their onshore wind counterparts. In addition, the administrative processes (such as permit approval) are in general much faster for solar PV projects.

Overall, a number of criticisms of the specific remuneration regime have been made. Castro-Rodríguez & Miles-Touya (2016which arose as a consequence of shortfalls in the previous subsidy regime. However, the new support mechanism inherent to the post-reform regime is already increasing investor uncertainty, and endangering Spain´s ability to meet EU renewable energy installed capacity and output targets. As part of an effort to comply with EU renewable energy targets, Spain has relied on various renewable energy support mechanisms over the last few decades. From 1998-2013, Spain essentially used various versions of the feed-in-tariff (FIT) argue that although more financially sustainability of the electricity system could be foreseen with the new regime, uncertainty for investors was heightened. They argue that the arbitrary intervention leading to the retroactive abolishment of support policies negatively impacted the confidence of investors, who feared repetition of the same trend in the future (Blanco-Díez et al., 2020). Lack of certainty regarding future revenue also made it harder for investors to request credits from financial institutions.[25] This could jeopardise their achievement of RES targets. Another issue with the new regime is the high level of complexity and lack of transparency in the support allocation procedure (auction design) (del Río, 2018). del Río (2018) criticises the choice of investment-based support in the design of auctions and argues that it might negatively impact optimal functioning of installations. In addition, there was some uncertainty over how the auctions would be implemented, including the conditional capacity auctioned in the third round, which made it difficult for investors to decide whether to participate or not (del Río, 2018).

5.3 The total annual costs of the support schemes

Figure 14 shows the total annual nominal cost of the support allocated via the special (FiTs and FiPs) and specific remuneration (FiPs) support schemes for each technology considered from 2005, when deployment of onshore wind and solar technologies started to kick off, to 2019.[26] In 2019, a total of 5.2 B€ was paid in support of onshore wind and solar technologies, which was approximately €110 per capita.[27] We estimate that before 2005 less than 900 M€ was paid in the form of FiPs, all of this to onshore wind installations. As can be seen from the figure, in 2005 and 2006 most support payments still remained in the form of FiPs and for onshore wind projects, and the total cost of the support increased to 2.2 B€. This was due to a significant increase in the AET in 2006 (del Río, 2008), which eventually led to delinking the support levels from the AET and instead basing them on the CPI in the 2007 reforms.

As was discussed in Section 2.1, deployment of RES-E with FiTs, especially solar PV, was only triggered in 2007, when new reforms were introduced to the special regime. Accumulated solar PV capacity increased by 550 MW from 2006 to 2007. All this added capacity was supported by high FiTs, as under the 2007 Royal Decree solar PV installations could not participate in the market. The total FiT payments for solar PV installations increased from 46 M€ in 2006 to 215 M€ in 2007. However, this was only the beginning of an investment boom in the Spanish PV sector, and consequently

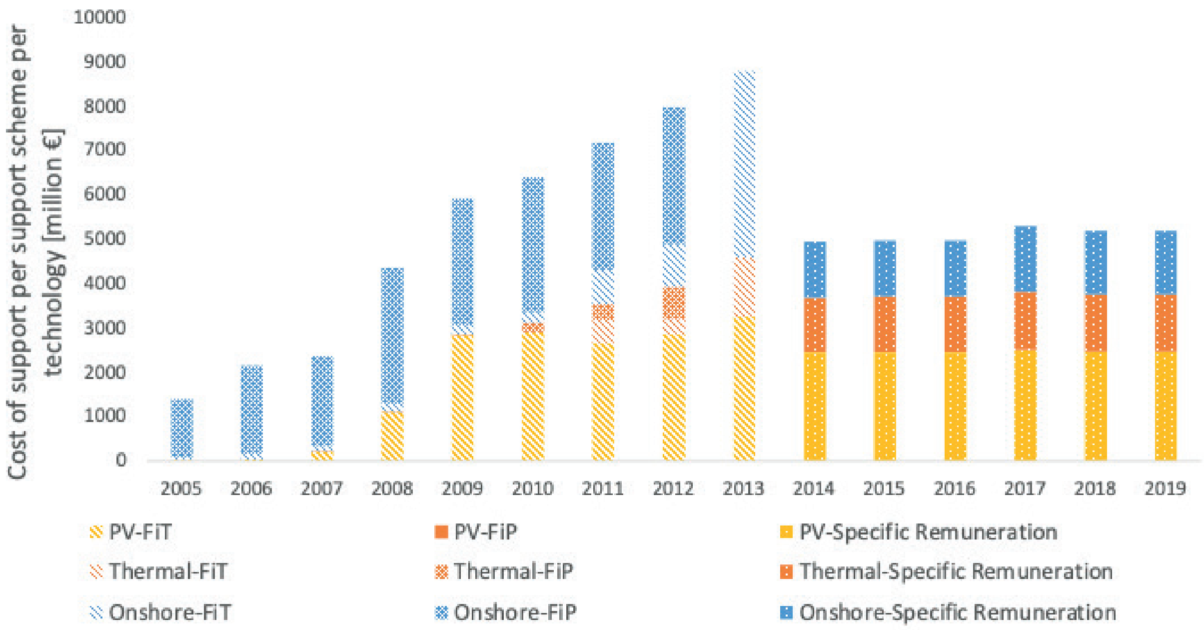
25 Castro-Rodríguez & Miles-Touya (2016) mention that this triggered a flood of lawsuits against the Spanish government from existing projects which were put in serious financial difficulties.

26 As in other cases in this study, we exclude the costs associated with administration of the different support schemes as these are minor compared to the amount of money allocated to renewable electricity generation projects.

27 Support paid to onshore wind and solar technologies in 2019 divided by Spain's population in 2019.

only the beginning of an increasing trend in total support costs. From May 2007 to September 2008 (when the 2008 Royal Decree on solar PV support was issued) the number of solar PV installations increased more than fourfold. Consequently, FiT payments for solar PV technology increased five-fold, from 215 M€ in 2007 to 1.1 B€ in 2008. The increase continued in 2009, when these payments more than doubled in a year to reach 2.8 B€. The impact of increased FiT payments on the total cost of support for onshore wind and solar technologies was such that the total cost also more than doubled from 2.4 B€ in 2007 to 6 B€ in 2009. The support cost for solar PV technology accounted for almost 50% of the total support cost in 2009, while this technology produced only 14% of the total subsidised electricity generated.

Figure 14: Total annual nominal cost of support allocated via FiTs, FiPs and premiums under the specific remuneration regime for onshore wind, solar PV and solar thermal. Source: CNMC (2021)



Following this increasing trend, several cost-containment measures were applied in 2009 (as was discussed in Section 2.1). However, the total support cost continued to grow until 2012, when it reached 8 B€. FiP payments for onshore wind and FiT payments for solar PV accounted for 80% of the cost. In 2012 a moratorium on RES-E support was introduced which suspended support for all new installations. In addition, a specific temporary measure only for 2013 was put in place allowing the RES-E support cost to be paid from the General State Budget through administratively set FiTs (suspending FiPs).[28]

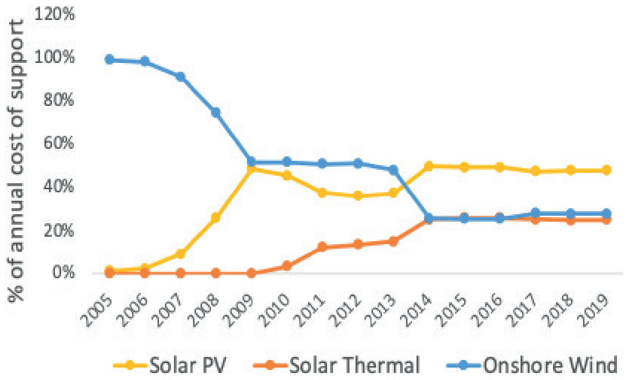
As the total support cost reached its peak of 8.8 B€ in 2013 and as the electricity system tariff deficit reached more than 40 B€, a retroactive decision on RES-E support policy was announced in 2013 abolishing the special regime and announcing that a new RES-E support policy would be introduced in 2014: the specific remuneration regime. As was discussed in Section 2.2, the specific remuneration regime was retroactive and affected support payments for existing installations and also established competitive procedures as the main tool for allocating support for new installations. Under the new scheme, the total support cost dropped by 44% in 2014 and remained at approximately the same level until 2019. The drop in total costs is attributed to the design of the new scheme, which limited the number of hours for which RES-E generators were eligible to receive support for their electricity production. However, the level of cost remained approximately the same (about 5 B€) as only three auctions allocating support for new installations were held until 2019. Moreover, the outcome of all these auctions were such that the wining projects were only remunerated at market prices without

28 This is why in Figure 14 we show only FiT costs for 2013.

an additional premium provided by the electricity system. However, if in future years the market price of electricity drops to a level that makes it hard for the facilities awarded to recover their initial investment they will receive support (Rinv) and the total support cost will increase (del Río, 2018).

Figure 15 (left) shows the allocation of annual support for each technology. It can be seen that in 2005 the proportion of support for solar PV started to increase. With the boom in the solar PV sector and the increase in support payments for this technology, its share equalled that of onshore wind in 2009. Between 2010 and 2013, the share of support going to onshore wind remained stable at around 51%. Solar thermal technology saw an increase in deployment in this period and consequently its share of the support increased from 3% in 2010 to 15% in 2013. This affected the share of support going to solar PV technology, which decreased from 45% to 37%. The introduction of the specific remuneration regime in 2014 heavily affected support payments for onshore wind as its share of the spending decreased by 25% in 2014 and equalled that of thermal solar. Under the specific remuneration regime, the share of support payments going to solar PV technology surpassed that of onshore wind in 2014 and followed the same trend (about 50% of support payments) until 2019.

Figure 15. Left: Annual support costs divided by technology. Right: Annual support costs divided by support scheme. Own calculation based on the cost data shown in Figure 14.



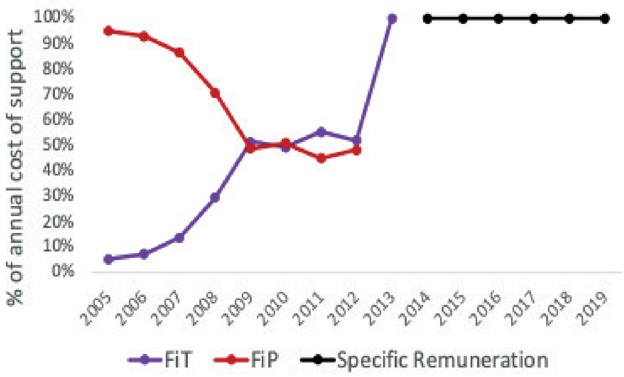
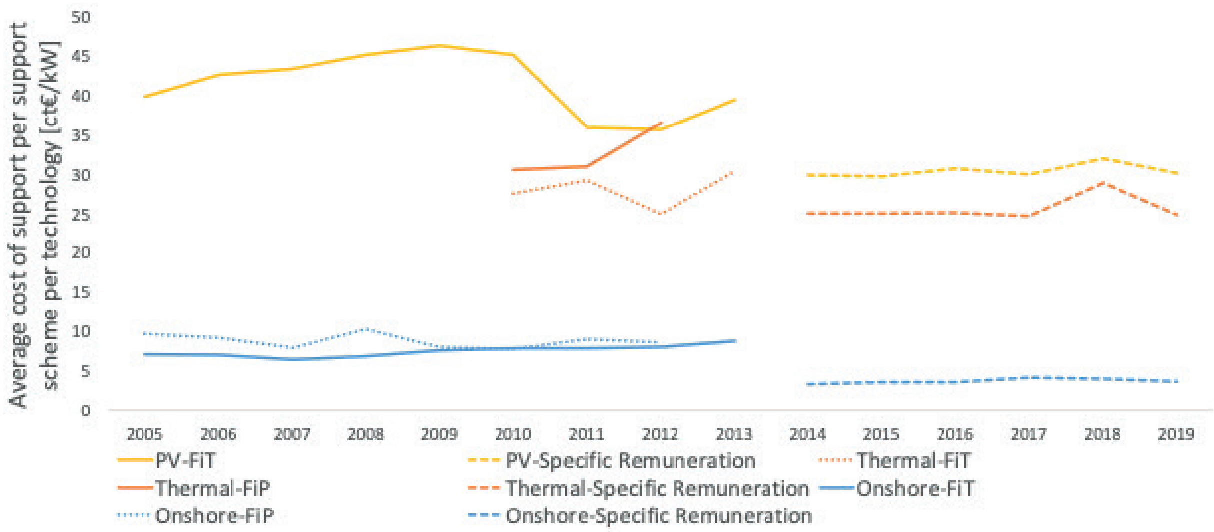


Figure 15 (right) shows the allocation of annual support under each support scheme. It can be seen from this figure that before the kick-off of solar PV technology in 2007 and 2008 with FiTs which were introduced in the 2007 reforms and the 2008 Royal Decree, the FiP for onshore wind was the most important support tool in terms of money spent. This changed in 2009 as solar PV generation, which was receiving generous FiTs, doubled. The dominance of FiTs as the tool providing the majority of support payments continued until 2012. Note that support payments were made in a special way in 2013 as spending was done following an administratively set procedure. Therefore, although the payments were in principle in the form of administratively set FiTs, they should not be regarded as part of a FiT mechanism. From 2014 premium payments under the specific remuneration regime were the only tool supporting RES-E generation and so constituted 100% of spending.

5.4 The cost-effectiveness of the support schemes

Figure 16 shows the cost-effectiveness of each support tool for each technology considered from 2005 to 2019. We define the cost-effectiveness of a support scheme as the annual expenditure (for each generation technology) divided by the total annual volume of electricity generated by generators benefitting from the scheme. Data on the cost of the schemes (as reported in Figure 14) on the volume of electricity generated by each technology under each support scheme are publicly available on the websites of REE, BOE and APPA. Note that we do not present the average cost of FiPs for solar PV installations in Figure 16 since this tool was abolished for this technology from 2007 until 2013 and before that, until 2005, it did not attract any investment in this technology.

Figure 16: The cost-effectiveness of each support scheme for each technology considered, calculated by dividing the annual cost as shown in Figure 14 by the annual amount of electricity generated. Data from the same sources as in Figure 14.



As can be seen in Figure 16, the average support cost for solar PV (FiTs) followed an increasing trend from 2005 and reached its peak (460 €/MWh) in 2009. As was discussed in Section 2.1, this high average cost of support was directly related to regulatory decisions made in the 2007 reforms. The support level significantly increased under the 2007 Royal Decree, which led to investors rushing to deploy solar PV with higher FiTs before the anticipated 2008 Royal Decree decreased them. The exponential increase in installed solar PV capacity by the end of 2008 resulted in a further increase in support payments in 2009. The average cost of support for solar PV technology increased to its peak in 2009. After the 2008 Royal Decree capacity additions and consequently support payments for solar PV installations dropped from 2009 to 2012. The average cost of FiTs for solar PV was 360 €/MWh in 2012.[29] The specific remuneration regime resulted in further cuts in the average cost of support for RES-E, including solar PV. These costs remained at about 300 €/MWh from 2014 to 2019 and are expected to remain the same in the following years as capacity additions through auctions resulted in zero support cost for the system.

Regarding onshore wind, the average cost of support under the specific regime and FiTs increased from 70 €/MWh in 2005 to 90 €/MWh in 2013, demonstrating that the reforms during this period failed to lower the cost of support. As for FiPs, except in 2008 the average cost of support under the specific regime remained stable at around 90 €/MWh between 2005 and 2013. It reached 100 €/MWh in 2008 as a result of higher electricity market prices that year, which led to an increase in FiP payments (Gelabert et al., 2011). The average cost of support for onshore wind installations

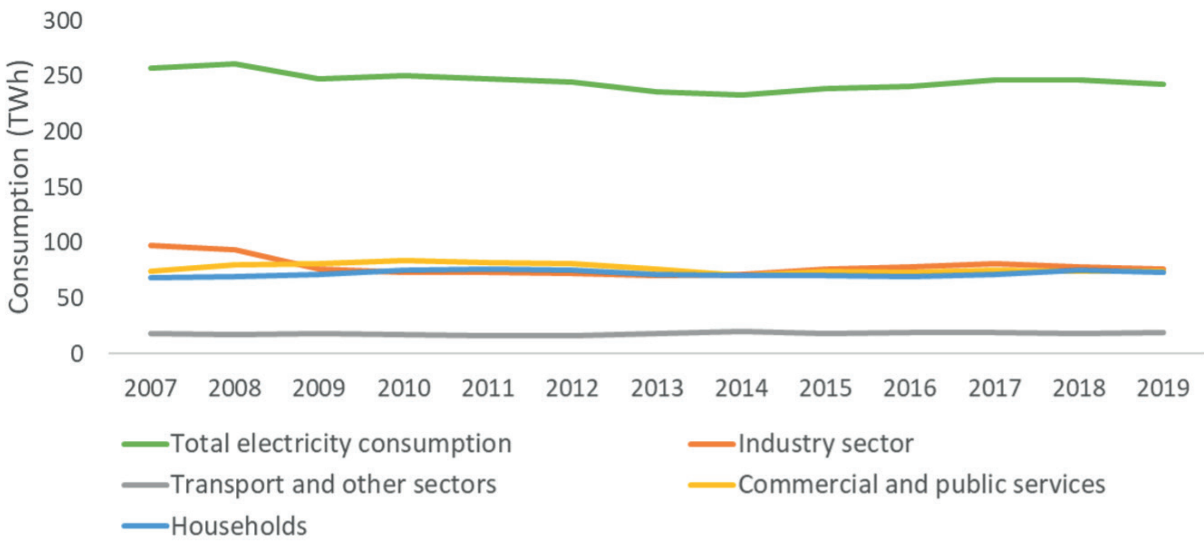
29 Note that 2013 was a special year so we do not consider FiT payments in this year as a part of the support mechanism.

dropped by 55% in 2014 under the specific remuneration regime. It remained stable at about 40 €/ MWh between 2014 and 2019. If in future years market prices remain at a level that allows onshore wind projects to recover their initial investments, it is expected that the support cost will remain more or less at the same level. Otherwise, if market prices drop heavily, remuneration should be paid to onshore wind installations, which will increase the average cost of specific remuneration payments for this technology.

5.5 The impact on electricity bills

Funding of renewable policy costs in Spain is paid by domestic and non-domestic electricity consumers via a levy included in their electricity bills (REE, 2021). Figure 17 shows electricity consumption in Spain between 2007 and 2019. It can be seen that total consumption slightly decreased over the years, from 258 TWh in 2007 to 243 TWh in 2019. Besides total electricity consumption the figure also shows consumption for each sector. In the 2007-2019 period, household electricity consumption in Spain was stable at around 72 TWh (approximately 30% of total consumption) while industrial electricity consumption decreased from 97 TWh in 2007 to 76 TWh in 2019. The annual consumption by commercial and public services was close to that of households in this period (approximately 31% of total consumption). Transportation and other sectors were responsible for 7% of total consumption in this period on average.

Figure 17: Total and sector specific electricity consumption in Spain between 2007 and 2019. Main source: REE (2021).



Electricity bills for households in Spain consist of three cost components:

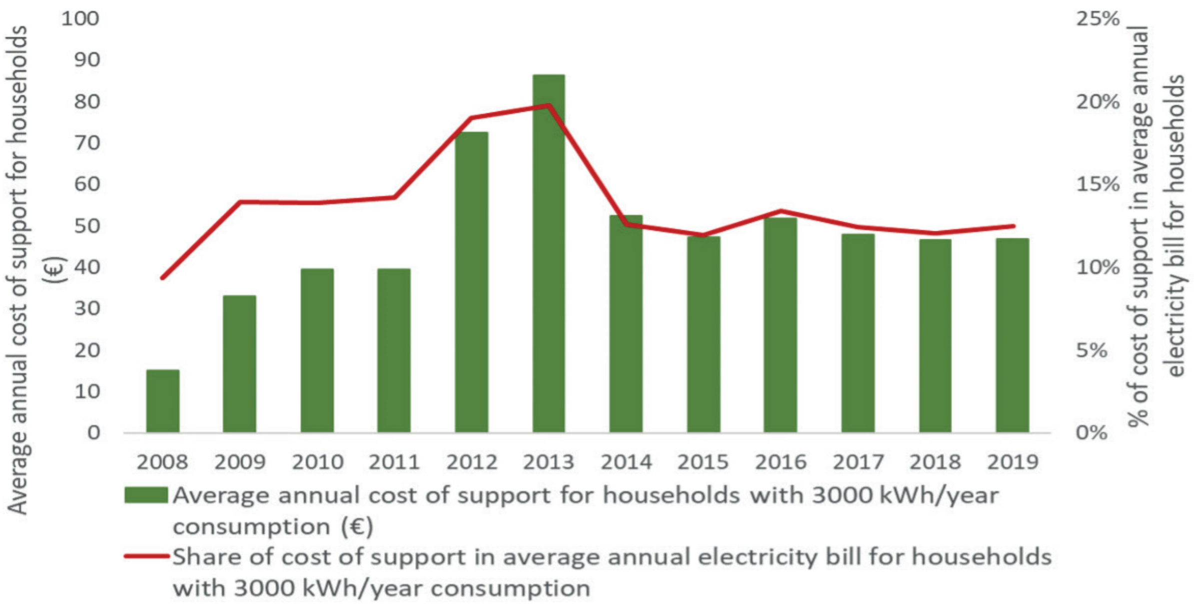
- An access fee. This includes the cost of operating the electricity system such as network costs (transmission and distribution costs) and policy costs (RES-E support costs). This is set by the Ministry of Industry.
- Taxes – duty on electricity and VAT.
- Electricity production costs.

Households[30] in Spain can choose between two different markets in which to buy their electricity: a regulated market and a free market.[31] Accordingly, depending on the market they choose, consumers are charged two different types of tariffs: the voluntary price for small consumers (PVPC)[32] in the regulated market and rates that are set by retailers in the free market. These two tariffs share two of the electricity bill cost components, namely the access fee and taxes. The difference is in how electricity production costs are calculated. Since our focus in this works is on the impact of renewable subsidy costs on electricity bills, we only focus on the access fee, which includes these costs, but not the other components or how/why the two tariffs differentiate.

Data on the value of the access fee and of its components, including RES-E support costs, are publicly available in the monthly Electrical Indicators Bulletin published by CNMC. In this analysis, we focus on the impact of support costs for wind and solar technologies on the electricity bills of domestic consumers with an average consumption of 3000 kWh/year.[33]

Figure 18 shows the estimated (nominal) annual cost of policies supporting wind and solar generation for domestic consumers with 3000 kWh of annual consumption between 2008 and 2019. In addition, it shows the proportion of these costs in the same consumers' electricity bills. We estimate these measures using data available from CNMC and our estimations of the cost of supporting wind and solar technologies reported in Figure 14.

Figure 18: Estimated (nominal) annual cost of policies supporting wind and solar generation for domestic consumers with 3000 kWh annual consumption. Own calculation based on data from CNMC (2021) and METDC (2009-2020).



The annual cost of wind and solar support policies for a domestic consumer (bars) increased from €15 in 2008 to €47 in 2019. This was mainly due to the generous support allocated to RES-E generators under the special regime, especially after the 2007 reforms. Following the boom in solar PV deployment in 2008/2009, the share of wind and solar support costs in households electricity bills doubled. It reached €33 in 2009 and continued to grow until 2012, when it reached €73. The reason

30 Households in Spain are defined as low voltage consumers with contracted power equal to or below 10 kW.

31 In 2019, approximately 56% of Spanish households had contracts in the free market and the remainder bought their electricity on the regulated market (Own elaboration of data from the Ministry for the Ecological Transition and the Demographic Challenge, METDC).

32 The PVPC has been implemented in Spain since 2014 for small low voltage consumers (P < 10 kW). Before that a tariff known as CESUR was used which was set through quarterly energy procurement auctions (For more information, see FSR Global (2020).

33 We decide on this value of average annual consumption per household on the basis of data on electricity consumption by household consumers available in two public sources: the Electrical Indicators Bulletin published by CNMC and the Statistics and Energy Balances datasets published by the Ministry for the Ecological Transition and the Demographic Challenge.

behind the sudden increase in the share of wind and solar support costs in 2012 can be traced back to a cost-containment measure which was introduced by the Spanish government in 2011-2012. Consequently, the share of wind and solar support costs in final electricity bills increased with respect to previous years. This confirms what has been argued in the literature regarding how RES-E support policies were designed and implemented in Spain. These arguments suggest that these policies were designed without considering the trade-off between generation outputs and support payments to technologies (Blanco-Díez et al., 2020; Castro-Rodríguez & Miles-Touya, 2016which arose as a consequence of shortfalls in the previous subsidy regime. However, the new support mechanism inherent to the post-reform regime is already increasing investor uncertainty, and endangering Spain´s ability to meet EU renewable energy installed capacity and output targets. As part of an effort to comply with EU renewable energy targets, Spain has relied on various renewable energy support mechanisms over the last few decades. From 1998-2013, Spain essentially used various versions of the feed-in-tariff (FIT). After the introduction of the specific remuneration regime in 2014, the share of wind and solar support costs in household electricity bills decreased by 40%, reaching €52/year. This can also be seen in Figure 14, where the annual support cost for wind and solar generation is shown to drop by 44% from 2013 to 2014. From 2015, the cost for households remained at about €49/year until 2019.

The share of support costs for wind and solar in the electricity bill (line) also increased, from 8% in 2007 to 12% in 2019. This share is the same as that in Italy. Both countries focused more on providing financial support for onshore wind and solar PV technologies. As in Italy, offshore wind technology has not significantly developed in Spain.

Nevertheless, as in other cases, it is important to note that we report the gross costs of renewable support policies. These policies also have positive impacts on the cost of electricity, e.g. by decreasing the average electricity wholesale price. For this reason, a more detailed analysis examining relevant environmental, technological and economic factors is required to grasp the exact impact of wind and solar generation support costs on electricity bills.

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6. Australia

In this chapter, we describe and analyse the main renewable support schemes that have been introduced in Australia to stimulate investments in onshore wind, large-scale solar photovoltaic (PV) systems, and small-scale solar PV (capacity below 100 kW) from 2000 onwards. The chapter consists of four sections. First, we provide a general introduction to the Australian renewable electricity landscape by examining renewable electricity generation, national yearly renewable electricity targets, cumulative installed capacity, yearly load factors and typical sizes of renewable electricity projects. In the second and third sections, we focus respectively on the effectiveness and cost-effectiveness of policy support schemes for large-scale renewable generators (i.e. onshore wind and large-scale solar PV) and for small-scale solar PV projects. We notice that whereas large-scale renewable generators have mainly benefitted from national-level policy support schemes for over two decades, the landscape for small-scale solar PV projects is divided into three main types based on accreditation in different support schemes. Indeed, some small-scale solar PV projects could only benefit from national-level support whereas others could benefit simultaneously from national-level support and one of two possible types of state-level support. In particular, the two possible types of state-level support we identify ('gross' and 'net') differ according to the types of electricity generation remunerated. In the fourth and final section, we discuss the cost-allocation of support for residential bills and related fairness issues.

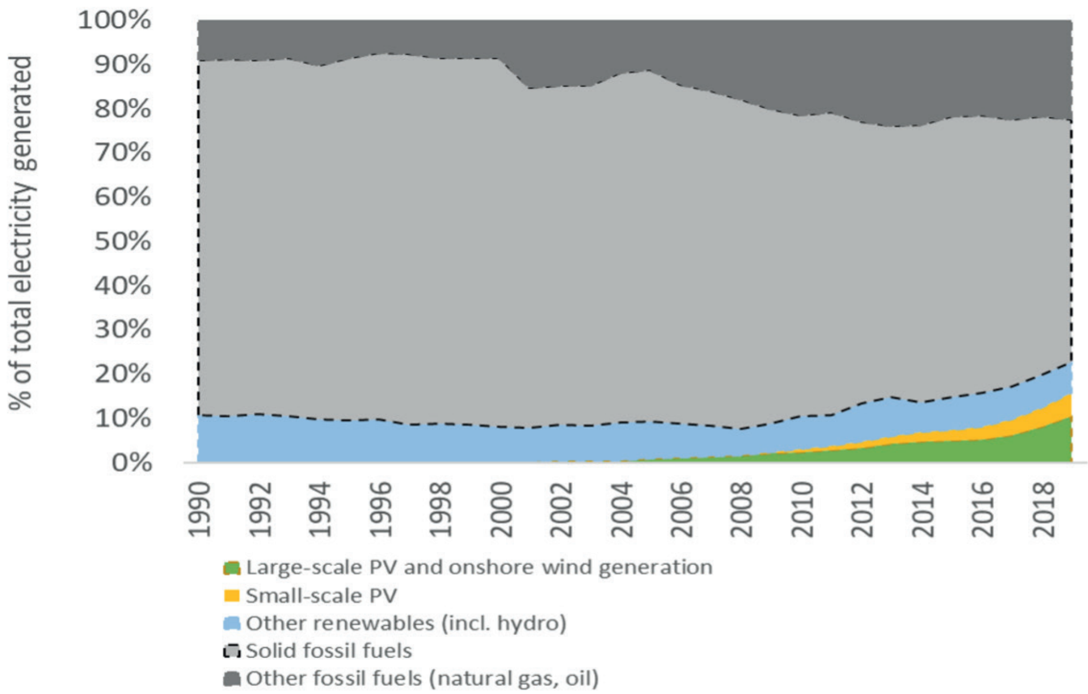
6.1 General introduction: Australia's renewable electricity landscape

Australia[1] represents an interesting case-study of how renewable energy has been supported. Although much of the Australian power mix is still based on fossil fuels (see Figure 1 on the next page), promoting renewable energies has also been a significant point in Australian energy policies since the early 2000s. Some important milestones were the Renewable Energy (Electricity) Act 2000, the Renewable Energy (Electricity) Regulations 2001, the signing of the Kyoto protocol by the Australian government in 2007, the Renewable Energy (Electricity) Amendment Bill 2009, the 2014 Renewable Energy Target Review, the Renewable Energy (Electricity) Amendment Bill 2015 and the confirmation by the Clean Energy Regulator that the 2020 Renewable Energy Target had been met [1]-[6]. As we will examine later, policy support schemes both at the national and at state levels have played a role. In particular, the main national-level policy support schemes identified for both large-scale generators and small-scale solar PV systems are, interestingly enough, market-driven schemes based on renewable electricity certificates and coupled with national yearly renewable electricity targets [7], [8]. Finally, Australian support for small-scale solar PV technology has to be analysed while considering that some systems mainly benefitted from national-level support schemes alone and others from a combination of national-level support and one of two possible types of state-level solar feed-in tariffs. Therefore, in this chapter we include a section on policy support schemes tailored for large-scale generators (large-scale solar PV and onshore wind) and a section on policy support schemes tailored for small-scale solar PV systems rather than focusing individually on these policy support schemes.

Figure 1 below shows the evolution of the power generation mix in Australia between 1990 and 2019.

1 Australia had a population of almost 25.7 million in March 2021 (compared to 83.9 million in Germany in July 2021), a total area of almost 7.7 million km2 (compared to 0.35 million km2 in Germany) and an estimated total final energy consumption of 1185 TWh in 2019 (compared to 2497 TWh in Germany in 2019), of which an estimated total final electricity consumption of 238 TWh in 2019 (compared to 510.5 TWh in Germany in 2019) [9], [51]-[56].

Figure 1: The power generation mix in Australia [9]



Until recently, the Australian power mix was prevalently dominated by solid fossil fuels (e.g. coal), although the relative share of total electricity generation has significantly decreased (from almost 80% in 1990 to circa 55% in 2019). Instead, the share of other fossil fuels (natural gas, oil) increased from 10% to almost 20% in the same time-period. Concerning renewable electricity generation, we can distinguish renewable electricity generation from large-scale PV and onshore wind, from small-scale PV and from other renewables (including hydro). Whereas the share of other renewables (including hydro) slightly decreased over time from circa 10-12% in 1990 to circa 5-7% in 2019, the share of other renewable electricity generation technologies (large-scale PV and onshore wind, and small-scale PV) increased significantly in 15 years from a negligeable value in 2005 to circa 10% in 2019. It is also important to note that there has not been recent significant offshore wind deployment in Australia.[2] Likewise, small-scale onshore wind (≤ 100 kW) has not been relevant in the Australian context [10].

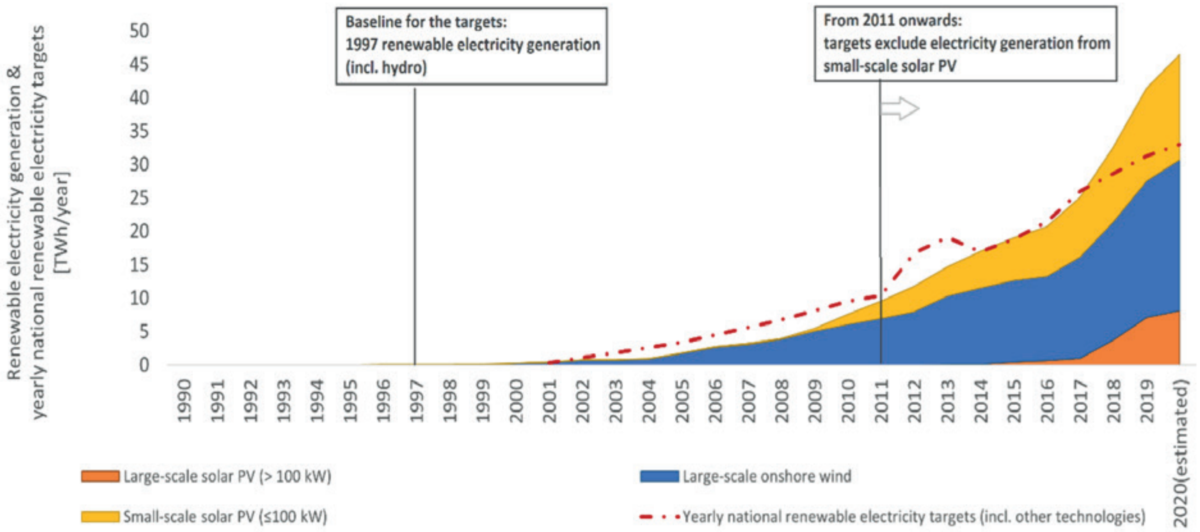
However, the Australian renewable electricity share of circa 15%[3] by 2019 is still significantly below European values. For example, the renewable electricity share in the EU27 in 2019 was 34.1% [11] and that in Germany in 2019 was 39.8% [12].

Figure 2 on the next page focuses on overall renewable electricity generation from large-scale PV, onshore wind and small-scale solar PV in the same time period.

2 Indeed, according to [13], "Australia has 14 offshore wind farm projects of which none currently operating, none where construction has progressed enough to connect the turbines and generate electricity, none are in the build phase, and none are either consented or have applied for consent."

3 Including large-scale PV and onshore wind, small-scale PV and other renewables (including hydro).

Figure 2: Renewable electricity generation in Australia from large-scale solar PV, onshore wind and small-scale solar PV (≤ 100kW) [9]



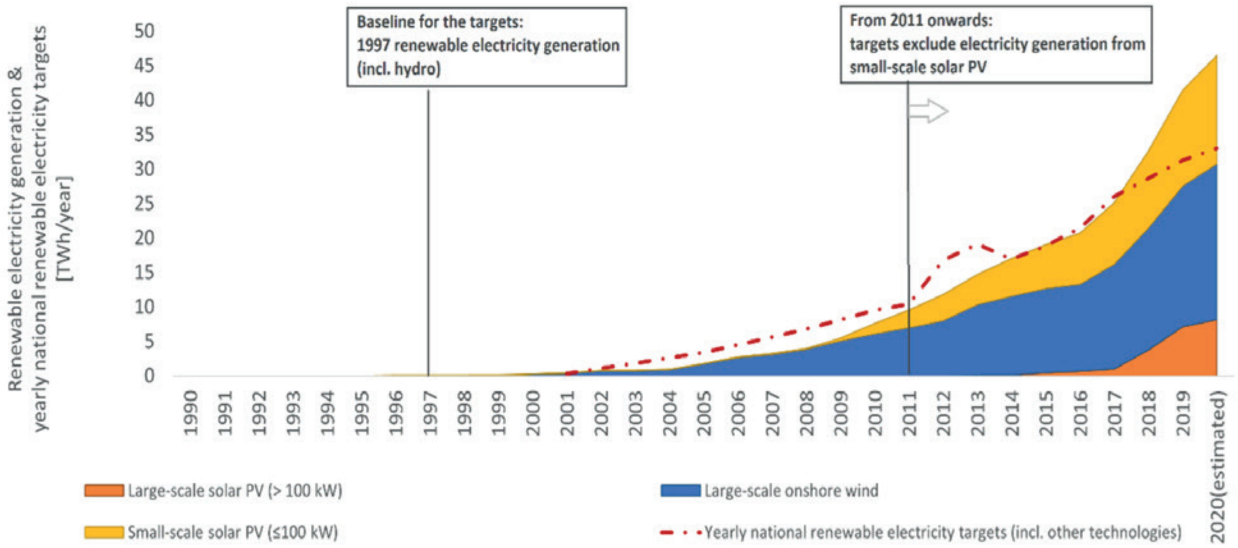
The aggregate renewable electricity generated from large-scale solar PV, onshore wind and small-scale solar PV increased from a negligeable value in 2001 to 47.8 TWh/yr in 2020 (estimated). This is slightly more than the increase in total electricity generation in Australia in this period (+40.4 TWh/yr), most probably due to a reduction in electricity generation from fossil fuels.

We notice the following for the three categories of renewable electricity generation technologies examined:

- Renewable electricity generation from onshore wind started to significantly increase in 2004, starting from a negligeable value and reaching 22.6 TWh/yr in 2020.
- Renewable electricity generation from large-scale solar PV saw significant growth from 2017 onwards, starting from a negligeable value and reaching 8.1 TWh/yr in 2020.
- Renewable electricity generation from small-scale solar PV started to significantly increase in 2009, starting from a negligeable value and reaching 15.7 TWh/yr in 2020.

In Figure 3 on the next page, we compare these previous values of renewable electricity generation with the yearly national renewable electricity targets set for 2001 onwards.

Figure 3: Renewable electricity generation in Australia from large-scale solar PV, onshore wind and small-scale solar PV (≤ 100kW) vis-à-vis yearly national renewable electricity targets [7], [9], [13], [14]



We find the following three points related to the yearly national renewable electricity targets interesting:

- *Technologies included in the targets*

  The yearly national renewable electricity targets are set for additional renewable electricity generation with respect to a baseline year (1997) and therefore also include other technologies besides large-scale solar PV, onshore wind and small-scale solar PV. The exception is 'other renewables (including hydro),' which already existed by 1997. Starting from 2011, these yearly targets also exclude renewable electricity generation from small-scale solar PV. Therefore, renewable electricity generation from large-scale onshore wind and large-scale solar PV was the main contribution to these targets during this period.

- *Achievement of the yearly targets set for 2010 and 2020*

  The target set for 2010 (+9.5 TWh/yr of additional renewable electricity generation with respect to 1997) was reached on time, whereas the target set for 2020 (+33.0 TWh/yr of additional renewable electricity generation with respect to 1997, excluding generation from small-scale solar PV) was reached a year later in 2021.

- *An odd pattern of yearly targets in 2011-2014*

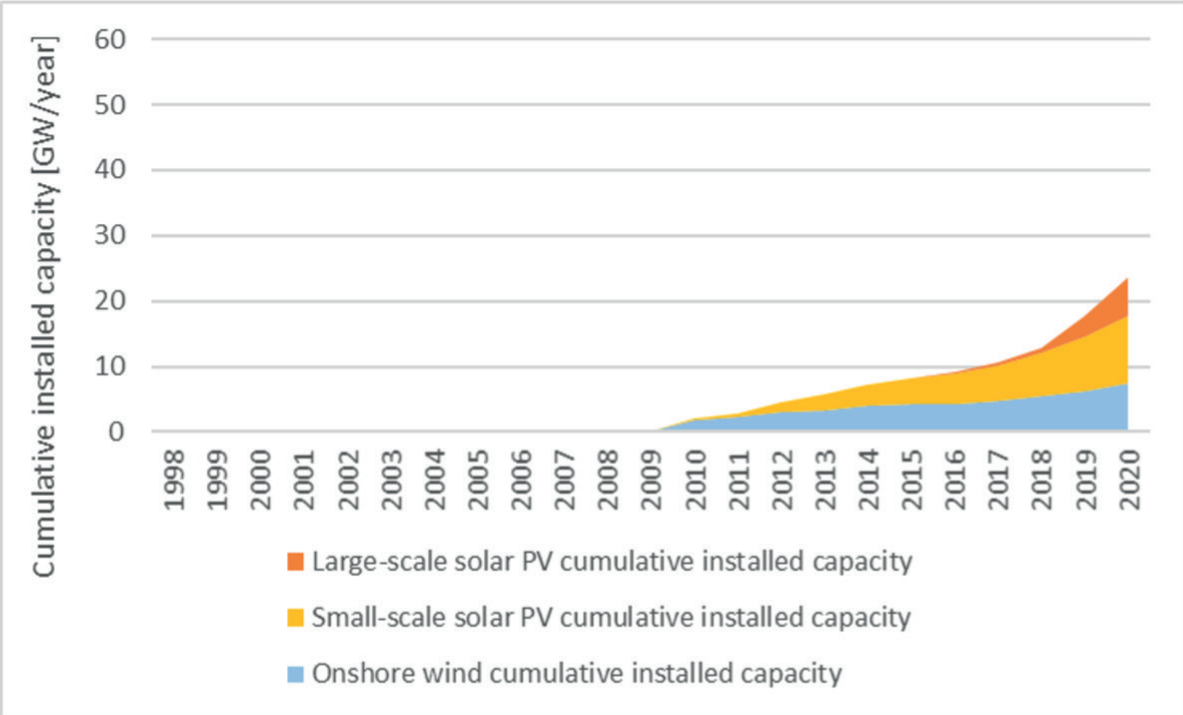
  These yearly targets rose more steeply and were followed by a slight drop in the period 2011-2014. This was mainly due to a political decision to adjust these targets, which were previously legislated in 2011. In particular, the yearly targets for 2012 and 2013 were adjusted upwards by circa 4.5 TWh/year and 4.9 TWh/year respectively.[4]

4 The justification reported for these adjustments is two-fold: 1) they account for the number of renewable energy certificates at the end of 2010 exceeding 34500 GWh (upwards adjustment in 2012-2013) and 2) they account for the introduction of coal mine waste gas projects as an eligible renewable energy source (upwards adjustment from 2012 onwards) [57].

These national yearly renewable electricity targets were also used by the Australian Clean Energy Regulator to define the demand for renewable electricity certificates under national-level support Schemes 1 and 2, as will be examined later. Therefore, these targets also – indirectly – influenced the relative levels of payment for large-scale generators (Schemes 1 and 2, 2001 – ongoing) and for small-scale solar PV systems (Scheme 1 only, 2006-2010/2011).

In Figure 4 below, we report the cumulative installed capacity for large-scale solar PV, small-scale solar PV and onshore wind.

Figure 4: Cumulative installed capacity of renewable electricity technologies at the beginning of the years reported [9], [15], [16]



The aggregate cumulative installed capacity of large-scale solar PV, small-scale solar PV and onshore wind increased from a negligeable value in 2009 to circa 23.6 GW in 2020 (estimated).

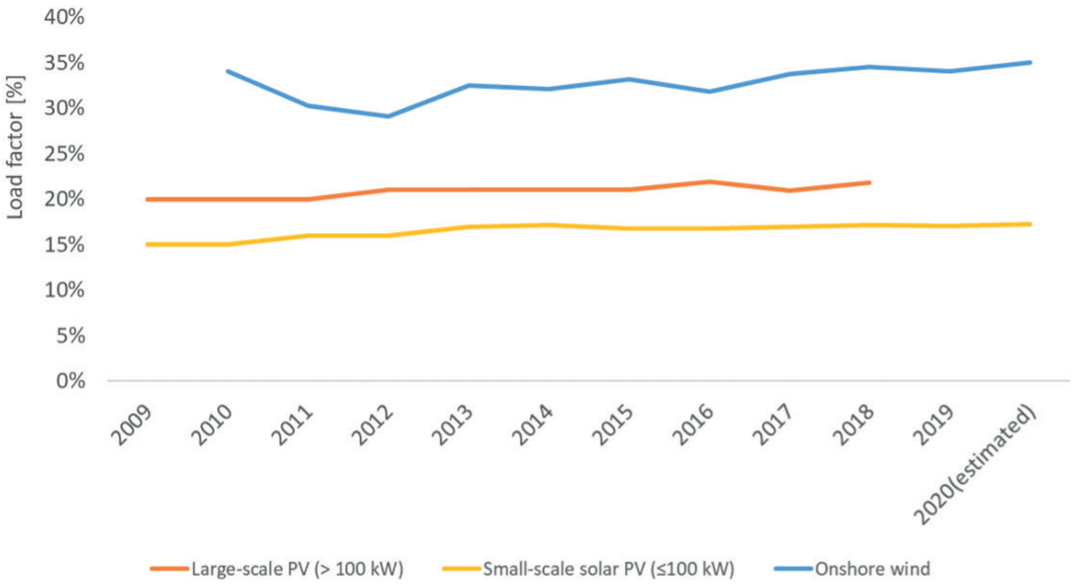
Whereas in Australia the aggregate cumulative installed capacity of these three renewable electricity technologies in 2020 was equal to circa 23.6 GW (29.4% of total generation capacity[5]), in Germany this value was equal to 128 GW (61% of total net generation capacity).

Similar observations for technology-specific trends in renewable electricity generation can also be made for cumulative installed capacity. The most relevant technology in terms of cumulative installed capacity in 2020 of the three examined is onshore wind, followed by small-scale solar PV and then large-scale solar PV. Likewise, the technologies for which a significant growth trend started to be observed earlier on are – in order – onshore wind, small-scale solar PV and large-scale solar PV.

In Figure 5 on the next page, we report the estimated technology-specific yearly load factor from 2009 onwards in Australia.

5 IRENA [58] estimated total electricity generation capacity in Australia at 80.2 GW in 2020.

Figure 5: Estimated technology-specific average yearly load factors in Australia from 2009 onwards[6]



We notice the following:

- *A slight increase in estimated load factors for small-scale solar PV and large-scale solar PV from 2009 onwards*

  The estimated load factors for small-scale solar PV and large-scale solar PV slightly increased in this time period. We can assume that technological learning does not have a large impact.

- *Significant yearly variability in estimated load factors for onshore wind*

  The estimated load factors for onshore wind are more variable year by year than those for large-scale solar PV and small-scale solar PV. We assume that this is mostly due to yearly resource variability.

- *The estimated load factors for onshore wind in Australia are on average higher than those in the EU27*

  The values reported above for average yearly load factors for onshore wind are higher than the average values estimated for most EU Member States – according to JRC NESPRESO's modelling covering all available surfaces [17]. The EU Member States with a comparable average load factor (in average wind conditions) to those shown above for Australia (30-34%) are Portugal (30%), the Netherlands (32%), Denmark (37%) and Ireland (45%). The average values estimated for Australia (30-34%) are also higher than those estimated for the EU territory in 2020 by IEA (i.e. 29%) [18].

- *The estimated load factors for large-scale solar PV and small-scale solar PV in Australia are on average significantly higher than those in the EU27*

  Similarly, the values reported above for average yearly load factors of large-scale solar PV and small-scale solar PV in Australia (19-21% and 15-16% respectively) are significantly higher than the average values estimated for most EU Member States – according to JRC NE-

6 The load factors for large-scale solar PV and small-scale solar PV before 2016 and 2013 respectively – for which estimates derived from renewable electricity generation and cumulative installed capacity were not robust enough – were estimated by the author on the basis of the following source: "Also, large- and small-scale solar PV will continue to have capacity factors of 21% and 15% respectively" [59]. Additionally, the following source confirms the values estimated for onshore wind: "Australia has excellent wind resources by world standards ... Australian wind farms produce on average capacity factors of 30-35%, making wind an attractive option"[60].

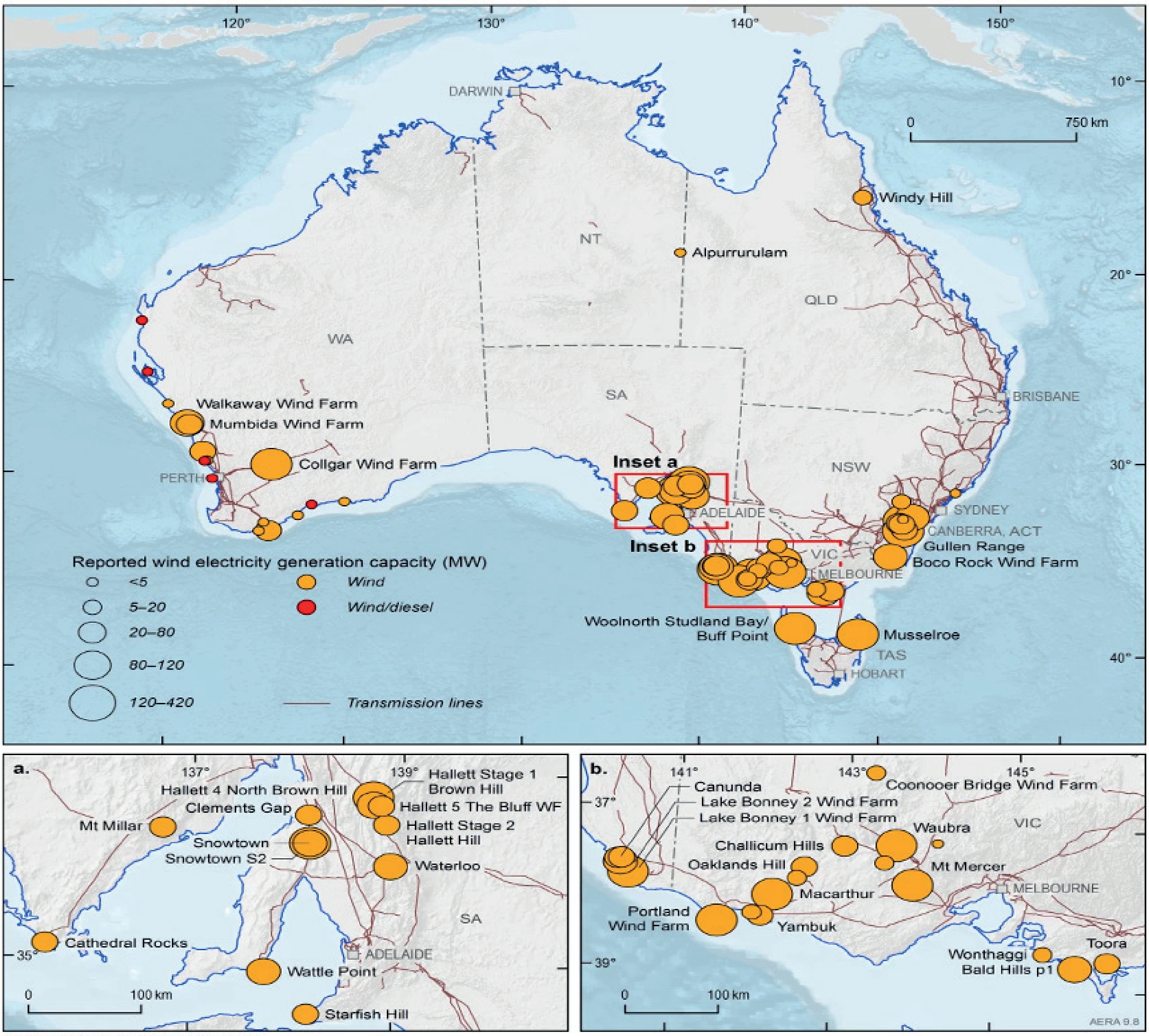
SPRESO's modelling[7] [17]. The EU Member States with comparable average load factors to those for Australia are Italy (14%), Spain (15%), Greece (16%), Cyprus (18%) and Malta (18%). The average values estimated for Australia are also higher than those estimated for the EU territory in 2020 according to IEA (i.e. 13% for generic solar PV) [18].

Finally, we report below the typical project sizes in Australia of renewable electricity projects using these three technologies as a potential indicator to understand the types of investors involved.

- *Typical project sizes of onshore wind in Australia*

  In December 2017 (Figure 6 below), the size of most onshore wind projects in Australia was above the 20 MW threshold and in the range of 80-420 MW. This hints at the presence of large investors with different, but nevertheless significant, capital availability.

Figure 6: Onshore wind projects installed in Australia – and relative project sizes on 31 Dec. 2017 [19]



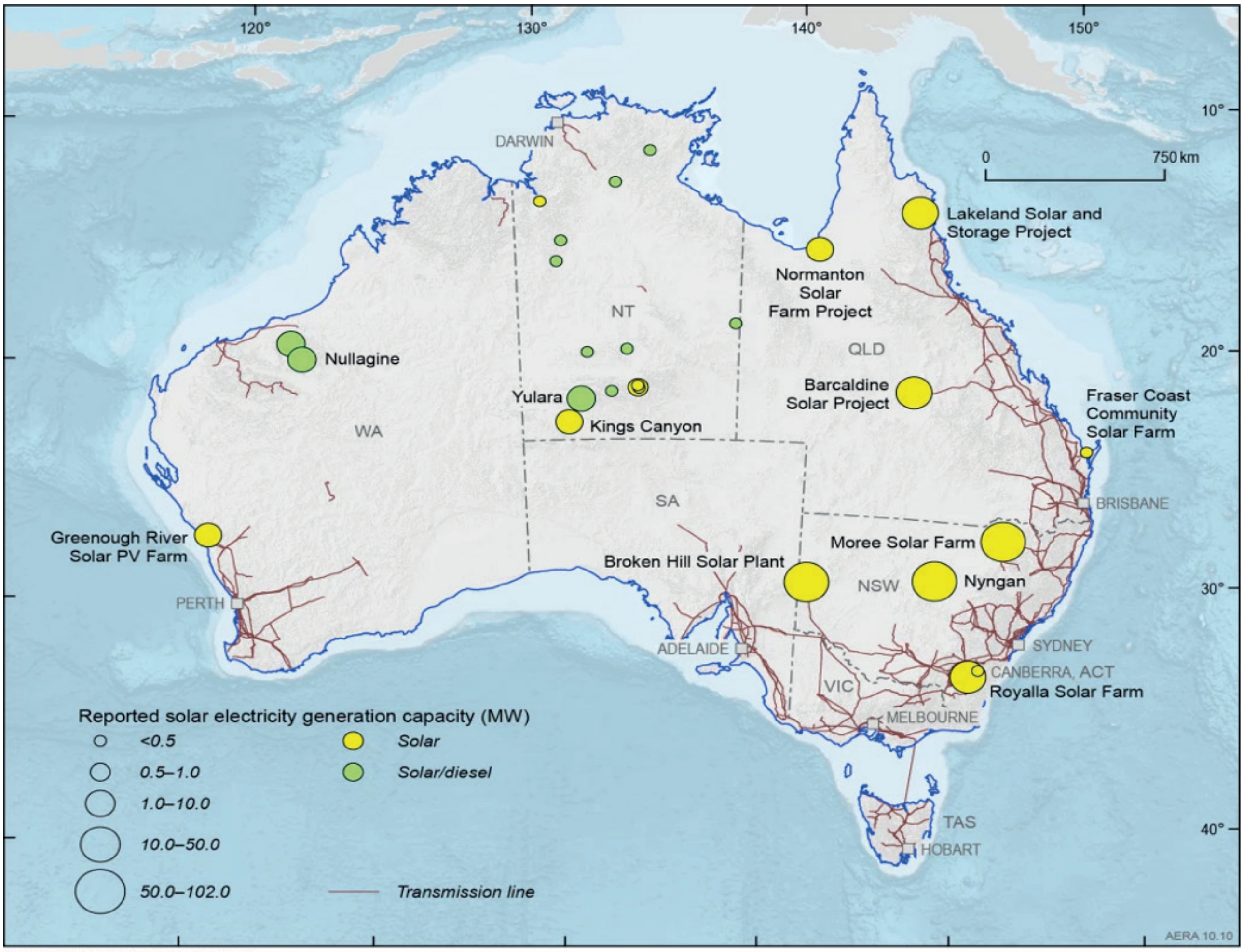
Source: compiled by Geoscience Australia, 2016

7 The model assumes a south orientation of 45% and a performance ratio of 0.75.

- *Typical project sizes of large-scale solar PV in Australia*

  In December 2017 (Figure 7 on the next page), many large-scale solar PV projects in Australia had a size above the 0.5 MW threshold, some in the range 1 MW-10 MW and others in the range 10-102 MW. This wide range of typical project sizes – slightly different from the range for onshore wind (i.e. 20 MW to 420 MW) – hints at the presence of investors of significantly different sizes.

Figure 7: Large-scale solar PV projects installed in Australia – and relative project sizes – on 31st Dec. 2017 [19]



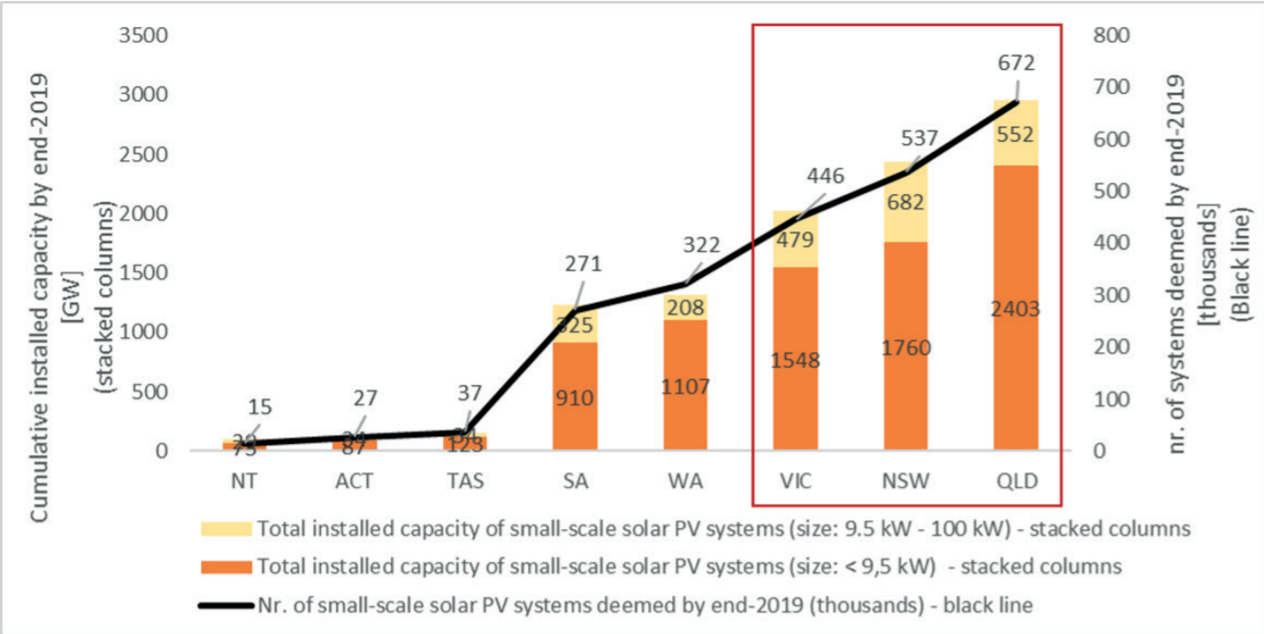
Source: Compiled by Geoscience Australia

- *Typical project sizes of small-scale solar PV in Australia*

  We can distinguish two cases of typical project sizes of small-scale solar PV from an analysis of the seven Australian states plus ACT (Figure 8 below):[8] residential size (< 9.5 kW) and commercial size (9.5 kW-100 kW). The large majority of the installed capacity and systems of small-scale solar PV at the end of 2019 belonged to the first case (residential size; < 9.5 kW). Additionally, state-level average sizes – derived by dividing overall cumulative installed capacity by the overall number of installed systems – range between 4.0 kW/system and 4.6 kW/system. Another interesting observation – which will be used later – is that the majority of the installed capacity and of the number of installations at the end of 2019 was concentrated in the top 3 states of Victoria (VIC), New South Wales (NSW) and Queensland (QLD).

8 In addition to the Australian capital territory (ACT), a total of seven administrative states compose the Australian territory: Western Australia (WA), South Australia (SA), Northern Territory (NT), Queensland (QLD), New South Wales (NSW), Victoria (VIC) and Tasmania (TA) [61].

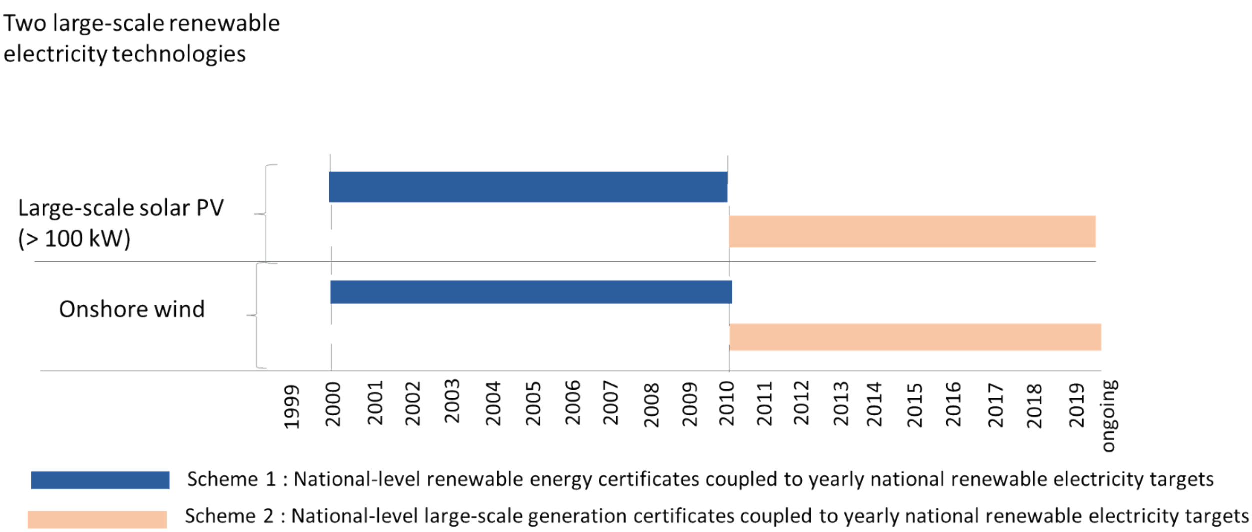
Figure 8: The number of installations and cumulative installed capacity in two size brackets in the seven Australian states plus ACT at the end of 2019 (< 9.5 kW & 9.5 kW – 100 kW).[9] Red boxes indicate the top three states [10], [15], [16]



6.2 Support for onshore wind and large-scale solar PV: two decades of relatively cheap and volatile national support

In this section, we analyse the main policy support schemes for (large-scale) onshore wind and large-scale solar PV. In particular, as we hinted earlier in the first section, this support was mainly given through two successive national-level schemes, each lasting approximately a decade. The two schemes are reported in Figure 9 below.

Figure 9: Two large-scale technologies, two decades, two national-level schemes



9 Data on the total installed capacity in these two size brackets separately for ACT and NSW is not available (only in aggregate form indicating the total installed capacity in both ACT and NSW). Therefore, we derive total installed capacity for small-scale solar PV in them by scaling the aggregated data for 2019 according to the number of systems reported in each region in 2019.

In Table 1 below we also report some relevant aspects of these two schemes, i.e. the period of potential accreditation, levels of payment and duration of payment.

Table 1: Some relevant aspects of the two national-level schemes supporting large-scale generators (large-scale solar PV and onshore wind)

	Period of potential accreditation	Levels of payment	Duration of payment
Scheme 1 National-level renewable energy certificates (RECs) coupled to yearly national renewable electricity targets	2001-2010	Market based, volatile	Dependent on the duration of the support scheme (2010) and on the lifetime of the accredited project
Scheme 2 National-level large-scale generation certificates (LGCs) coupled to yearly national renewable electricity targets	2010-ongoing	Market based, more volatile than scheme 1	Dependent on the duration of the support scheme (ongoing, expected to last until 2030) and on the lifetime of the accredited project

We make the following observations from Table 1:

- *i. Period of potential accreditation*

  We notice that Scheme 2 was phased-in when Scheme 1 was phased-out. Overall, the two schemes each lasted about a decade.

- *ii. Levels of payment*

  We notice that both schemes are market-based and that the levels of payment are volatile – as will later be supported by Figure 12.

  Indeed, these two renewable electricity certificate schemes are both based on a demand for certificates – imposed as an obligation on "liable entities"[10] to surrender certificates on a yearly basis and in a quantity set by the Australian Clean Energy Regulator – and on the supply of certificates – which is dependent on renewable electricity generation by accredited generators.[11]

- *iii. Duration of payment*

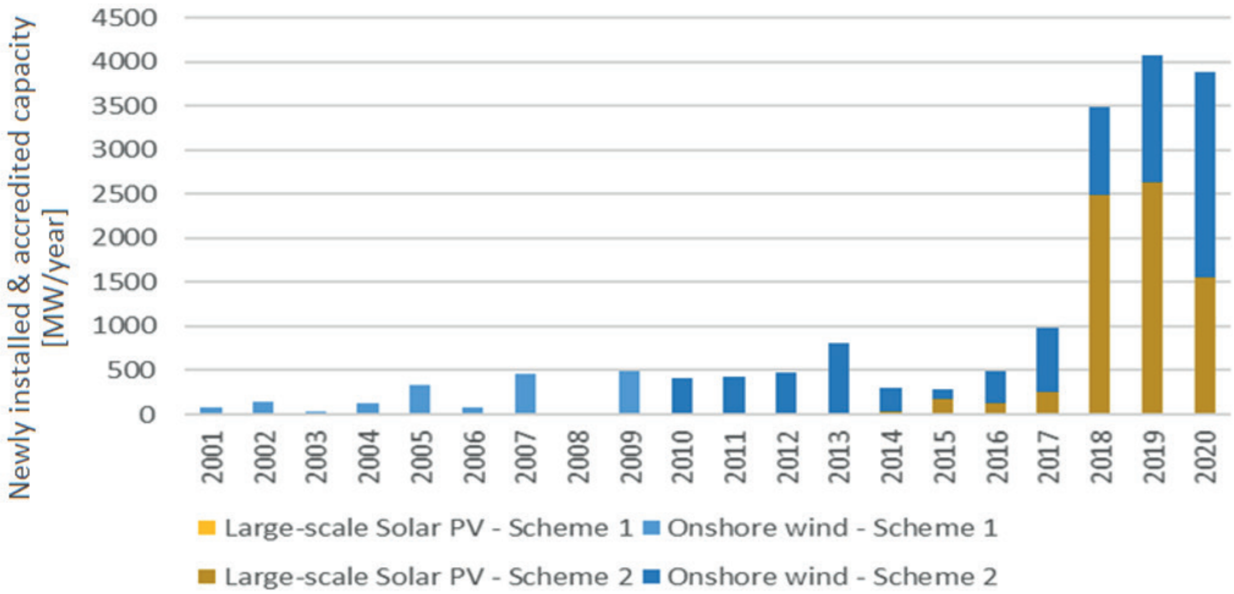
  We notice that the duration of the payments relative to both schemes depends on the duration of the schemes themselves and on the lifetime of the project. Whereas payments under Scheme 1 lasted for a maximum up to 2010, payments under Scheme 2 are still ongoing for some accredited projects and could last for a maximum until 2030.

10 These "liable entities" are mostly Australian electricity suppliers. Data on the number of liable parties before 2007 are not available. In 2007, 70 liable parties can be identified, in 2008 72,in 2009 76 and in February 2011 81. The obligation set on these entities is based on their "total electricity acquisitions" and on a "renewable power percentage (RPP)" set by the regulator ex-ante on the basis of the national renewable electricity targets. "Liable entities" which do not comply with this obligation are liable to a debt of certificates not surrendered – which will need to be paid financially. Under certain circumstances (e.g. delivering the previously non-surrendered certificates within the following three years – and without accumulating other debts). "Liable entities" which have had to pay financially for a debt of certificates can get a refund.

11 Most of the accredited generators under Scheme 1 and all the accredited generators under Scheme 2 are large-scale generators. Therefore, their renewable electricity generation – and the relative creation of certificates – are relatively easy to track.

In Figure 10 below, we report the newly installed and accredited capacity for these two large-scale technologies under these two schemes.

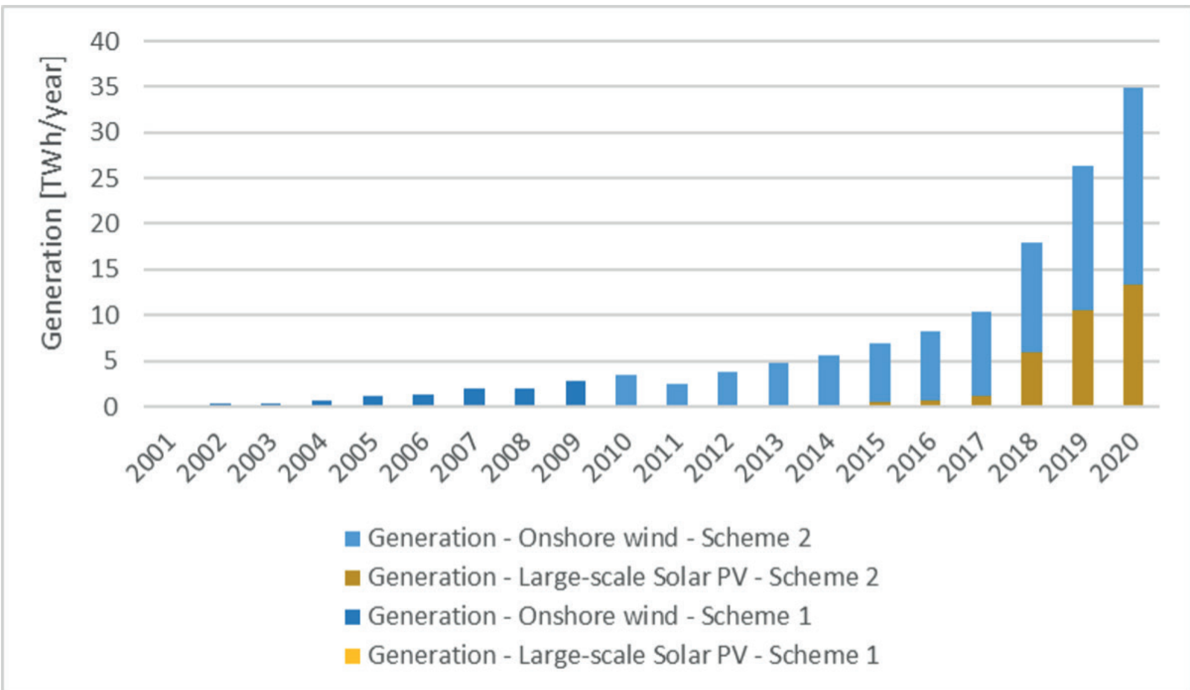
Figure 10: Onshore wind and large-scale solar PV capacity annually installed and accredited



We notice that whereas a certain capacity of (large-scale) onshore wind was installed early on and could be accredited to both schemes, almost all large-scale solar PV capacity was only accredited in the second scheme (national-level large-scale generation certificates (LGCs) coupled to yearly national renewable electricity targets). Additionally, much more capacity was newly installed and accredited under Scheme 2 (from 2011 to 2020) than under Scheme 1 (from 2001 to 2010).

In Figure 11 below, we report the annual generation from cumulatively accredited capacity under each scheme. These numbers are derived by multiplying the estimated average load factors previously presented in Figure 5 by the estimated cumulatively accredited capacity shown in Figure 10.

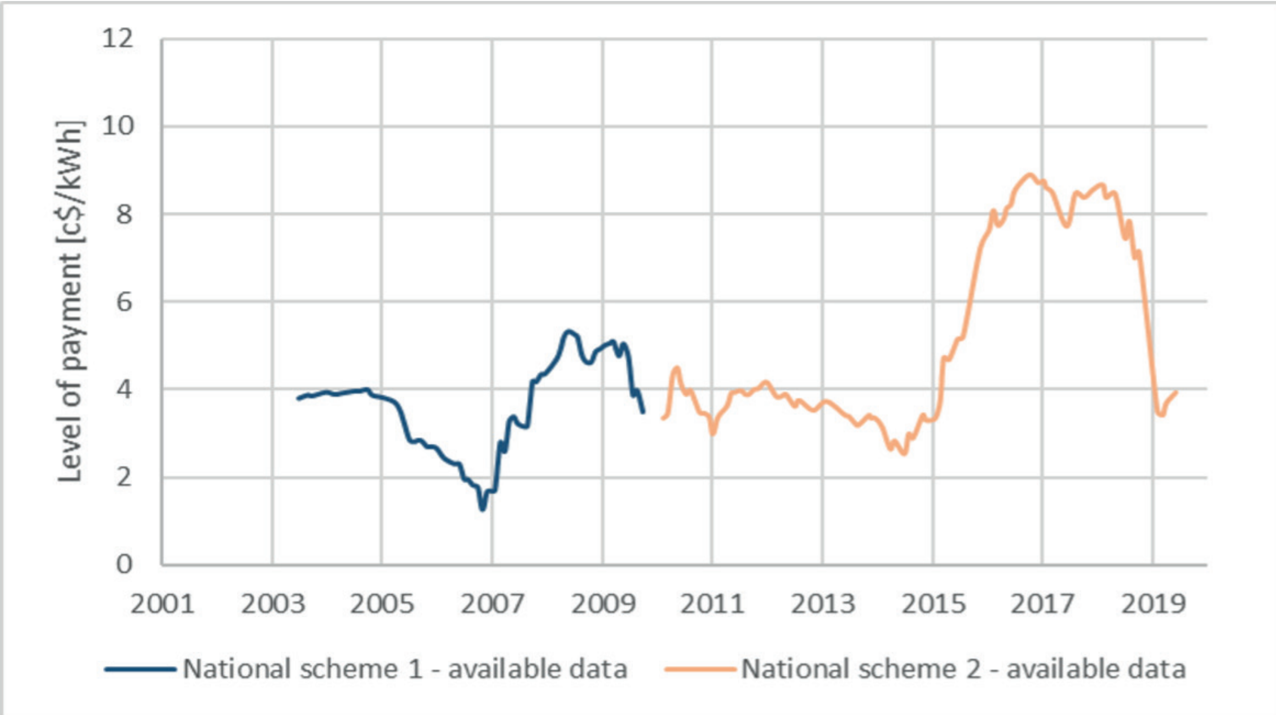
Figure 11: Annual generation from cumulative accredited capacity of onshore wind and large-scale solar PV



We come to similar conclusions to those previously made regarding the estimated newly-installed and accredited annual capacity of these two technologies under the two schemes (Figure 10):

- there is a larger share of generation by accredited onshore wind capacity than by accredited large-scale solar PV capacity over the period examined; and
- there is an overall larger share of generation under Scheme 2 than under Scheme 1.
- In Figure 12 on the next page we analyse the overall cost-effectiveness of renewable electricity generation under Schemes 1 and 2 , which we also call 'levels of payment' [c$/MWh].[12]

Figure 12: Levels of payment per unit of electricity generated by large-scale generator projects accredited to national-level schemes (Schemes 1 and 2) [20]-[22][13]



It is clear from the analysis underlying Figure 12 above that the support given to large-scale generators under these market-based schemes varied wildly. In particular, as was previously mentioned, the levels of payment under Scheme 2 (from 2011 to 2020) were more volatile[14] than those under Scheme 1 (from 2001 to 2010).

Additionally, the levels of payment under Scheme 2 were higher than those under Scheme 1 in terms of both average[15] and maximum values.[16] This also implies that the levels of payment were overall more relevant in the second decade (2011-2020, under Scheme 2) than in the first one.

Based on information available online [23]-[25], we assume that this volatile trend is mostly due to the rising annual demand for certificates,[17] to the unstable growth in quantities of certificates ef-

12 We note that the overall cost-effectiveness of these schemes in capacity deployment [$/MW] cannot be computed without making strong assumptions, mostly because of the highly volatile remuneration of generators under the schemes and the associated inability to predict future remuneration.

13 Data on the levels of payment under scheme 1 between 2001 and 2003 have not been found.

14 Levels of payment under Scheme 1 varied between circa 1.5 c$/kWh to 5 c$/kWh, compared to a variation between circa 2.5 c$/kWh and 9 c$/kWh under Scheme 2.

15 Circa 3-3.5 c$/kWh under Scheme 1 vs circa 5-6 c$/kWh under Scheme 2.

16 Circa 5 c$/kWh under Scheme 1 vs circa 9 c$/kWh under Scheme 2.

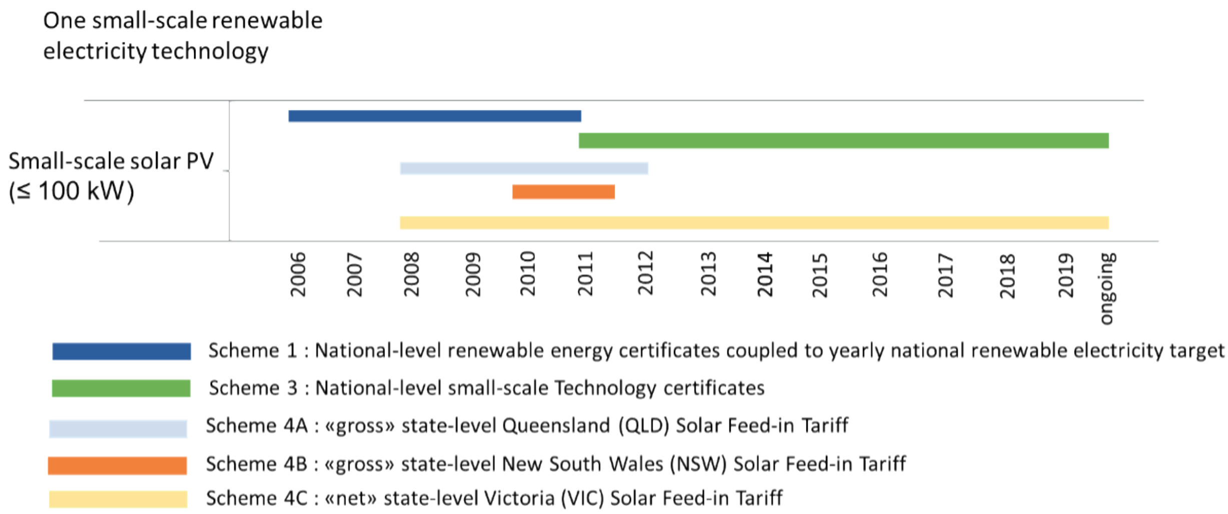
17 The rising trend in the annual demand for certificates – set ex-ante by the Australian Clean Energy Regulator – reflects the rising trend in the national yearly renewable electricity targets.

fectively generated,[18] to the penalties for non-surrendered certificates [19] and to temporary booms in quantities of certificates not surrendered in certain periods (e.g. 2016-2019[20]).

6.3 Support for small-scale solar PV: a heterogeneous landscape with three main types of projects accredited in different support schemes

In this section, we analyse the main policy support schemes for small-scale solar PV we have identified. These individual schemes are reported in Figure 13 below together with their accreditation periods.

Figure 13: One small-scale technology (small-scale solar PV) over circa 15 years. Different policy support schemes at both national and state levels[21]



Overall, we examine five main individual support schemes that we identify for small-scale solar PV systems, some of which are at the state level and some are at the national level.[22] This number is larger than the two relevant schemes identified for large-scale generators, which were both national-level schemes. Additionally, the periods for accreditation in the state-level schemes vary significantly but they all overlap with periods for accreditation in national-level schemes. Finally, we distinguish two possible types of state-level scheme depending on the type of electricity generation remunerated ('gross' or 'net,'[23] Schemes 4A and 4B, and Scheme 4C respectively).

18 The unstable growth in quantities of certificates effectively generated is due to unstable growth in annual renewable electricity generation by eligible investments, which also depends on newly-installed eligible investments. Political uncertainties – such as the 2014 Warburnt review and the speculation by the Abbott coalition on closure of the renewable electricity certification scheme – are thought to have had an impact on the amount of newly-installed eligible investments. Additionally, the fact that renewable electricity generation by small-scale solar PV projects also counted as eligible for the production of certificates from 2006 to 2010, and was promoted through a 'Solar credit multiplier' mechanism from June 2009 until 2010, is also thought to have had an impact [23]-[25].

19 In the period 2001-2010, relative to Scheme 1, the penalty – also called the 'shortfall charge' – was 57.14 USD/ non-surrendered certificate (including post-tax costs) or 40 USD/non-surrendered certificate (nominal, non-tax deductible). In the period 2011-2020, relative to Scheme 2, the penalty increased to 92.86 USD/non-surrendered certificate (including post-tax costs) or 65 USD/non-surrendered certificate (nominal, non-tax deductible).

20 This boom in quantities of non-surrendered certificates in 2016-2018 is suspected to have occurred because of the skyrocketing price of certificates above the penalty threshold and a mechanism enabling potential monetary reimbursement of penalties paid in specific circumstances [23]-[25].

21 Scheme 3 – national-level small-scale technology certificates (STCs) – is also referred to in the literature as the 'national solar rebate (subsidy)' scheme.

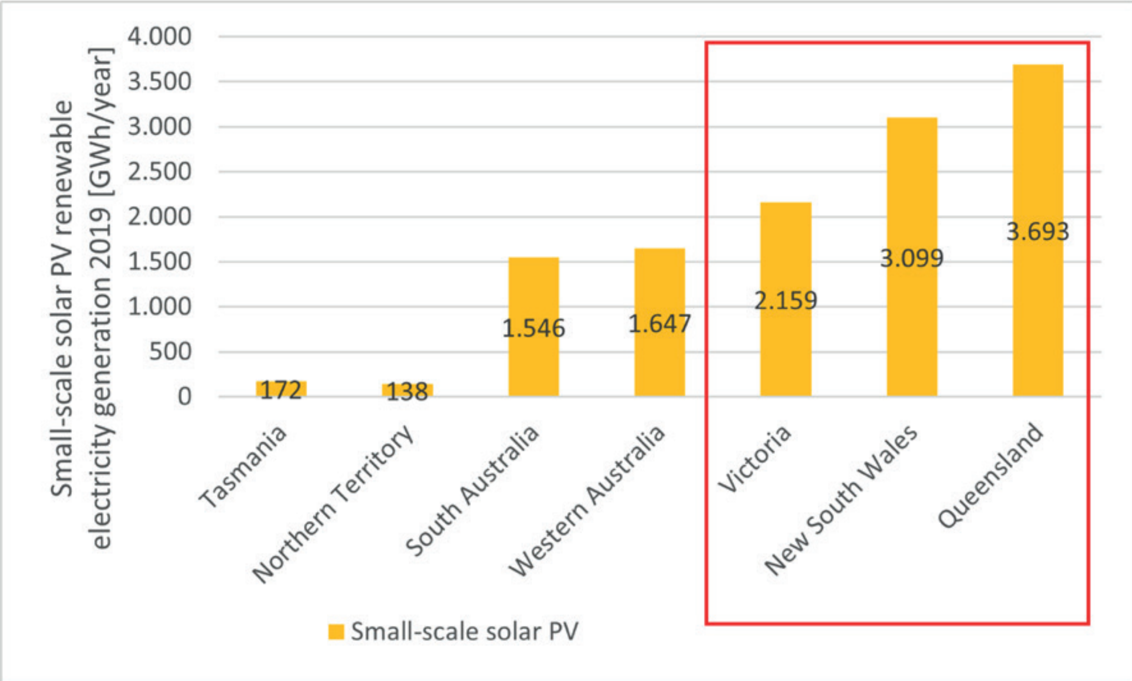
22 Note that the national-level Scheme 1 we refer to is the same as the national-level Scheme 1 referred to in the previous section – also supporting large-scale generators.

23 As will be mentioned later, 'gross' electricity generation refers to electricity generation for both self-consumption and injection into the grid. Instead, 'net' electricity generation only refers to electricity generation for injection into the grid.

We choose to examine three state-level solar feed-in tariff schemes adopted in Queensland (QLD), New South Wales (NSW) and Victoria (VIC). This simplification is based on the following three facts.[24]

i. These three Australian states have recently had the largest small-scale solar PV deployment (in terms of renewable electricity generation, number of installations and total installed capacity in 2019 – as is shown in Figure 14 and the previous Figure 8);[25]

Figure 14: Renewable electricity generation in 2019 in the seven Australian states (WA, SA, VIC, NSW, QLD, TAS, NT)[26] [9]



ii. These states are the most representative of the total Australian population[27] and also in terms of overall electricity demand;

iii. State-level solar feed-in tariffs are identified in the literature [21], [26]-[29] and by an expert[28] as having also been important in supporting the deployment of small-scale solar PV in Australia.

Figure 15 on the next page reports some relevant features of the two main national-level schemes and the three main state-level schemes identified: i. the period of potential accreditation, ii. the type of electricity generation remunerated, iii. payment levels and iv. duration of payment.[29]

24 Other state-level schemes may also have played a role, but they are not as effective in terms of small-scale solar PV deployment or as cost-effective in terms of levels of payment.

25 From the number of units installed by Sept. 2021 we estimate that almost 3 million residential dwellings out of a total of 10.5 million (slightly more than a quarter) had a small-scale solar PV system in Australia by March 2021 [10], [15], [52].

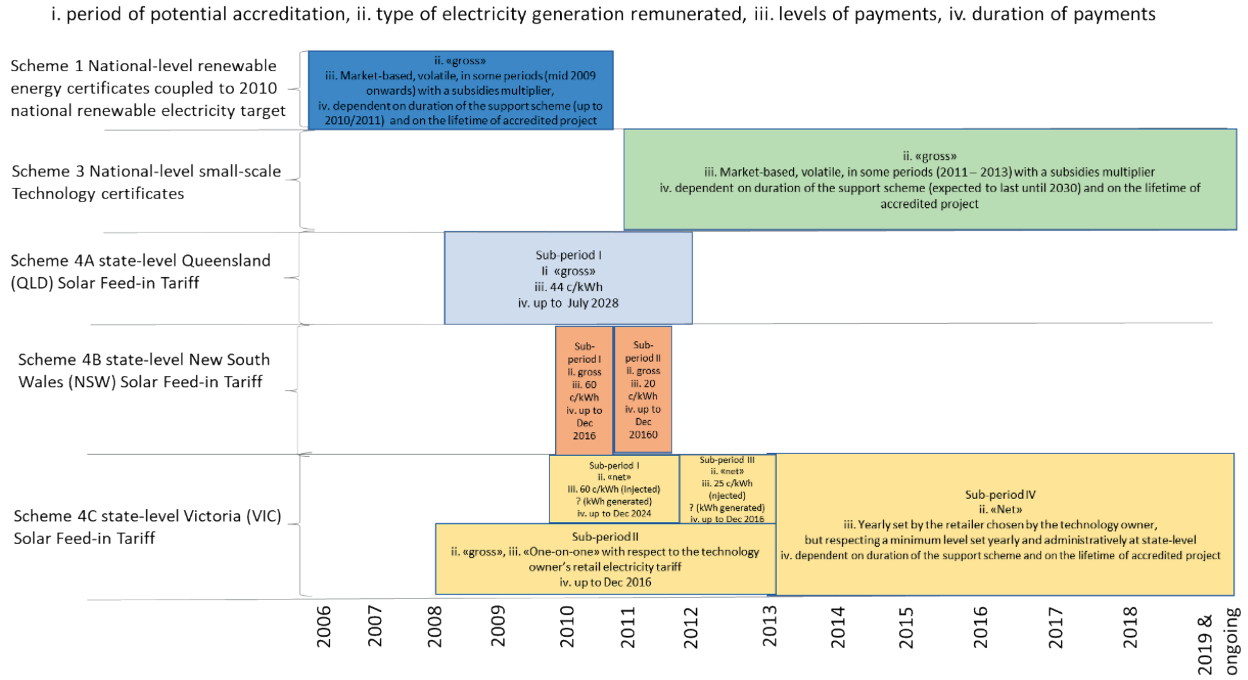
26 Note that the sum – 12,144 GWh/year – corresponds to 63% of small-scale solar PV electricity generation in Germany in 2019 (i.e. 19,262 GWh/year according to [62]).

27 Overall, circa 20 million out of 25.7 million in early 2021 [52].

28 Mr. Mike Swanston, the Customer Advocate. The author would like to thank him for his valuable inputs.

29 We also examined other features, such as eligibility requirements, allocation mechanisms and whether the recipient of payments is responsible for electricity sales, but we found them less relevant.

Figure 15: Some relevant features of the five main policy support schemes for small-scale solar PV identified[30]



A first observation we can make from Figure 15 is that we identify different sub-periods in two state-level support schemes (NSW Solar Feed-in Tariff and VIC Solar Feed-in Tariff) with the relevant features identified partly changing from one sub-period to another. Whereas for the NSW Solar Feed-in Tariff scheme we identify two different sub-periods, for the VIC Solar Feed-in Tariff scheme we identify four – some overlapping with others. These sub-periods evidence a large degree of experimentation and successive corrections to the design of these individual policy support schemes.

Additionally, we make the following observations regarding the different features examined:

- *i. The potential accreditation period*

  We notice that national-level Scheme 3 had phased-in while national-level Scheme 1 had phased-out. Additionally, the three state-level support schemes examined differ in terms of the overall potential accreditation period but overlap with the potential accreditation periods of national-level schemes. Whereas only one state-level support scheme is still open for new accreditations and has had a long potential accreditation period (Scheme 4C state-level Victoria Solar Feed-in Tariffs), the other two (Schemes 4A and 4B) had relatively short potential accreditation periods – lasting circa 4 years and circa 2 years. Finally, we identify some sub-periods in which the other features examined differ.

30 Regarding the Scheme 4C state-level Victoria (VIC) Solar Feed-in Tariff, we identify four different sub-periods as is shown in Figure 11. While we number each sub-period in this chapter, in online sources these sub-periods also have specific labels [35]–[38]:

- VIC Solar Feed-in Tariff 'sub-period I' corresponds to 'Victoria premium solar Feed-in Tariff'
- VIC Solar Feed-in Tariff 'sub-period II' corresponds to 'Victoria transitional solar Feed-in Tariff'
- VIC Solar Feed-in Tariff 'sub-period III' corresponds to 'Victoria standard solar Feed-in Tariff'
- VIC Solar Feed-in Tariff 'sub-period IV' corresponds to 'Victoria minimum solar Feed-in Tariff'

- *ii. The type of electricity generation remunerated*

  We notice that the state-level solar feed-in tariffs examined can be classified in two different categories: 'net' solar feed-in tariffs (which only remunerate electricity injected into the grid) and 'gross' solar feed-in tariffs (which remunerate both electricity injected into the grid and electricity deemed to have been self-consumed). Currently, the state-level Victoria (VIC) Solar Feed-in Tariff – which is the only state-level scheme still open for new accreditations – can be classified as net. Instead, the NSW and QLD state-level Solar Feed-in Tariffs and the two national-level support schemes examined can be classified as gross as there is no differentiation in remuneration between electricity injected into the grid and electricity deemed to have been self-consumed.

- *iii. Levels of payment*

  We notice that national-level Schemes 1 and 3 are market-based and the levels of payment are volatile, similarly to those supporting large-scale generators. Instead, the two 'gross' state-level Schemes 4A and 4B were mostly characterised by levels of payment which were relatively generous in the initial years of potential accreditation, ranging between 20 and 60 c$/kWh. Instead, 'net' state-level Scheme 4C is an exception as it is characterised by levels of payment [c$/kWh-generated] unknown to the authors, as will be examined later.

- *iv. Duration of payment*

  We notice that, whereas payments under national-level Scheme 1 lasted a maximum up to 2010/2011, payments under national-level Scheme 3 are still ongoing and could last a maximum until 2030. Instead, relative to the state-level schemes examined above, we notice that the duration of payment differs significantly between different schemes, and even between different sub-periods of the same scheme. Payments under Scheme 4A and Scheme 4C (specifically in sub-periods I and IV) can still be ongoing for accredited projects and still within their technical lifetime.

Having described some of the relevant features of each individual scheme (Figures 13 and 15), from now on we will refer to three main types of small-scale solar PV projects which differ in terms of accreditation and consequently in terms of cost-effectiveness. These three main types are the following:

- *Type 1*: small-scale solar PV projects which we assume to be only accredited[31] to national-level schemes (Schemes 1 and 3):
  - projects installed in a specific state for which the relative state-level scheme has been examined (QLD, NSW, VIC), but in a year outside the period of potential accreditation.[32]
  - projects installed in any year in states for which we have not examined the state-level scheme (WA, NT, SA, TA, ACT).[33]
- *Type 2*: small-scale solar PV projects which were accredited in a combination of a national-level scheme and a 'gross' state-level scheme (schemes 4A and 4B in QLD and NSW):
  - projects installed in a specific state for which a relative 'gross' state-level scheme has been examined (QLD, NSW) in a year overlapping periods of potential accreditation of state-level and national-level schemes (2008-2012 and 2010-late 2011 respectively).
- *Type 3*: small-scale solar PV projects which were accredited in a combination of a national-level scheme and a 'net' state-level scheme (scheme 4C, VIC):
  - projects installed in a specific state for which a relative 'net' state-level scheme has been examined (VIC) in a year overlapping periods of potential accreditation in state-level and national-level schemes (2008-2019 and probably ongoing).

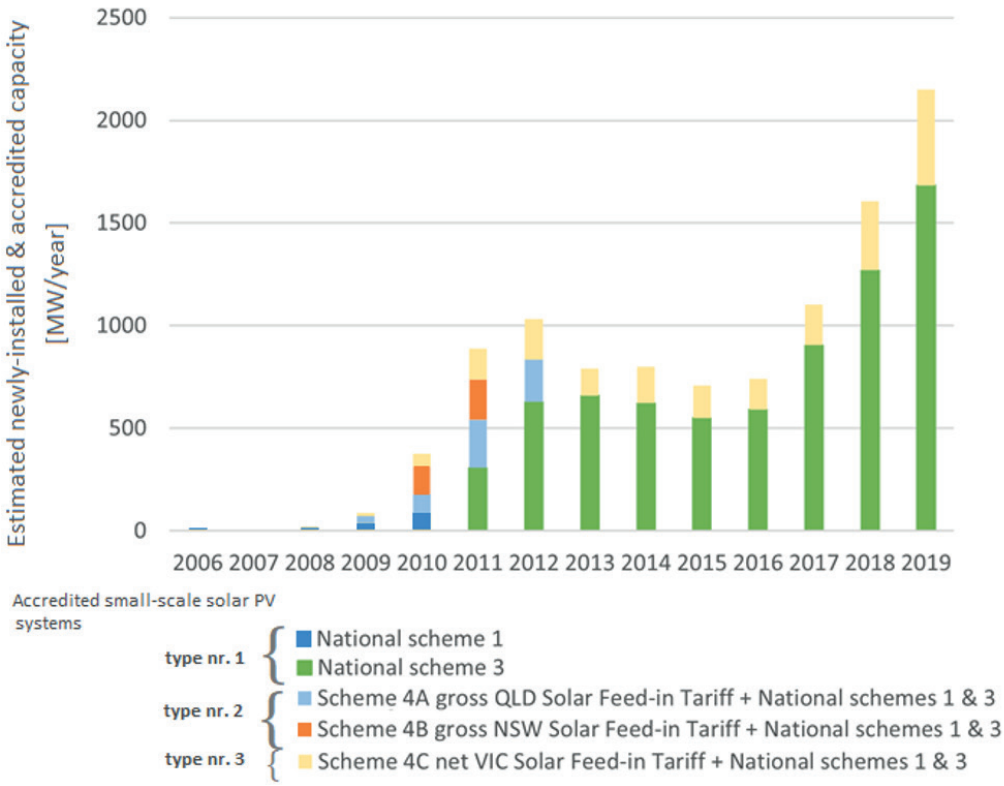
31 Accreditation in policy support schemes is assumed to occur in the same year as that of installation.

32 Before 2008 and after 2012 for QLD, before 2010 and after 2012 for NSW and before 2008 for VIC.

33 Western Australia (WA), Northern territory (NT), South Australia (SA), Tasmania (TA) and Australia Capital Territory (ACT).

Figure 16 below reports the estimated yearly capacities of newly installed and accredited small-scale solar PV projects belonging to the three main types identified. Additionally, we also specify the newly installed and accredited capacities of the schemes of these three main types, be they only national-level schemes or a combination of a national-level and one of two possible types of state-level schemes ('net' or 'gross').

Figure 16: Estimated yearly capacities of the three main types of small-scale solar PV projects identified



We notice that:

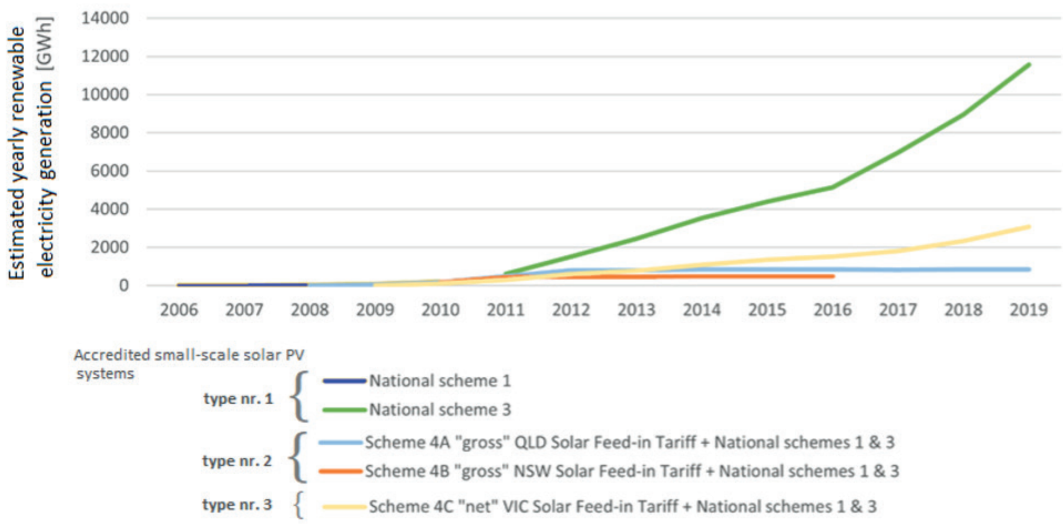
- until 2011 the overall amounts of newly installed and accredited capacities grew significantly. Most capacities are estimated to have been accredited in a combination of a national-level scheme and a state-level scheme (mostly 'gross').
- in 2012-2015 in the years immediately after some 'gross' state-level schemes had been phased out and the level of payment in a national-level scheme had significantly decreased (as will be examined later), there was a slight decrease in the overall amount of newly installed and accredited capacities. In this period the majority of the capacities installed were only accredited national-level schemes and a minority in a combination of national-level scheme 3 and the 'net' VIC Solar Feed-in Tariff (Scheme 4C).
- From 2016, the overall amounts of newly installed and accredited capacities grew significantly again. The majority of them were only accredited in national-level Scheme 3.

Finally, compared to Figure 10, which refers to schemes supporting large-scale generators, we notice two main differences:

- almost all newly installed and accredited capacities of small-scale solar PV were concentrated in the last decade, 2011-2020, whereas newly installed and accredited capacities of large-scale generators (in particular onshore wind) in the preceding decade, 2001-2010, were also relevant.
- In the last few years, newly installed and accredited small-scale solar PV capacity still remained smaller than that of large-scale generators. For example, whereas the overall amount of newly installed and accredited small-scale solar PV capacity was 2000 MW/year in 2019, the overall amount of newly installed and accredited large-scale generator capacity was 4000 MW/year in 2019.

Figure 17 below reports the estimated yearly renewable electricity generated from accredited cumulative capacity belonging to the three main types of small-scale solar PV projects identified. As in Figure 16, we notice that in the last decade the yearly renewable electricity generated by projects only accredited in a national-level scheme (in particular, scheme 3) was much more than the renewable electricity generated by projects accredited in a combination of a state-level scheme and a national-level scheme. Additionally, the estimated yearly renewable electricity generated in 2001-2010 was significantly less than in the decade 2010-2019.

Figure 17: Estimated yearly renewable electricity generated from accredited cumulative capacity belonging to the three main types of small-scale solar PV projects identified[34]

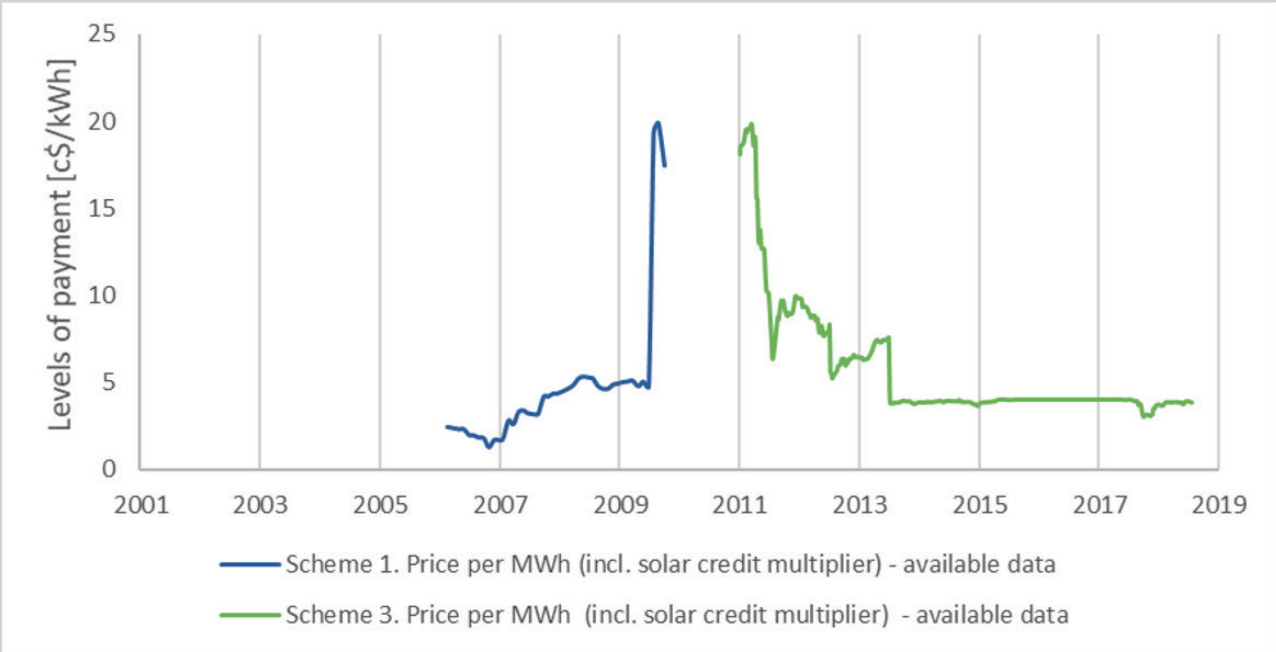


We now analyse the overall cost-effectiveness of renewable electricity generation [c$/MWh] for each of the three main types in the order presented above and highlight the underlying policy support schemes:

- *Type 1: Small-scale solar PV projects which we assume to be only accredited in national-level schemes (Schemes 1 & 3)*

34 These estimates of yearly renewable electricity generated are derived by multiplying the accredited cumulative capacity – in Figure 16 – by the load factor.

Figure 18: Levels of payment per unit of electricity generated by small-scale solar PV projects assumed to be only accredited in national-level schemes (Schemes 1 or 3) – type 1 [7], [20], [21], [30].[35]



We notice that support – in Figure 18 called 'levels of payment' – for small-scale solar PV projects belonging to this main type varied even more between 2006 and mid-2013 than support for large-scale generators between 2001 and 2019 (Figure 9). Indeed, the levels of payment in both Scheme 1 (from 2006 to 2010) and Scheme 3 (2011 onwards) varied from 1-4 c$/kWh to circa 20 c$/kWh. Overall, support in Scheme 3 (2011-ongoing) is more volatile than in Scheme 1 (2006-2010). Instead, from mid-2013 the support given in Scheme 3 remained relatively stable at circa 4 c$/kWh.

We guess that this significantly volatile trend between 2006 and mid-2013 is mostly due to the introduction – and successive gradual phase-out – of the 'Solar Credit Multiplier.' Indeed, starting from mid-2009 one kWh of renewable electricity generated by a small-scale solar PV project was awarded five times ('multiplier five') the 'spot' price of a certificate (3-4 c$/kWh). Successively, the reduction of the multiplier from five to three in mid-2011, from three to two in mid-2012 and from two to one in mid-2013 (phase-out) also led to sudden drops in the levels of payment [5], [7], [30]-[32].

Instead, the relatively stable trend from 2014 onwards (under Scheme 3) – with levels of payment at circa 4 c$/kWh – is largely due to three combined factors:

- the scarcity of the supply of certificates (created both by 'deemed' renewable electricity generation by accredited small-scale solar PV systems and by the 'STC auction house' in times of scarcity) compared to the market demand (an obligation set on the same 'liable entities' as those under the previous Scheme 1 or under the contemporary Scheme 2 and decided ex-ante by the Australian Clean Energy Regulator)
- a cap on certificate prices (set by the fixed price of 4 c$/certificate on certificates sold by the STC auction house[36])
- the phase-out of solar multiplier credits (therefore, 4 c$/certificate = 4 c$/kWh)

35 Data on the levels of payment under Schemes 1 and 3 are derived by multiplying the certificate prices [c$/kWh] by the Solar Credit Multiplier (5x from mid-2009 to mid-2011, 3x from mid-2011 to mid-2012, 2x from mid-2012 to mid-2013, 1x in the other years).

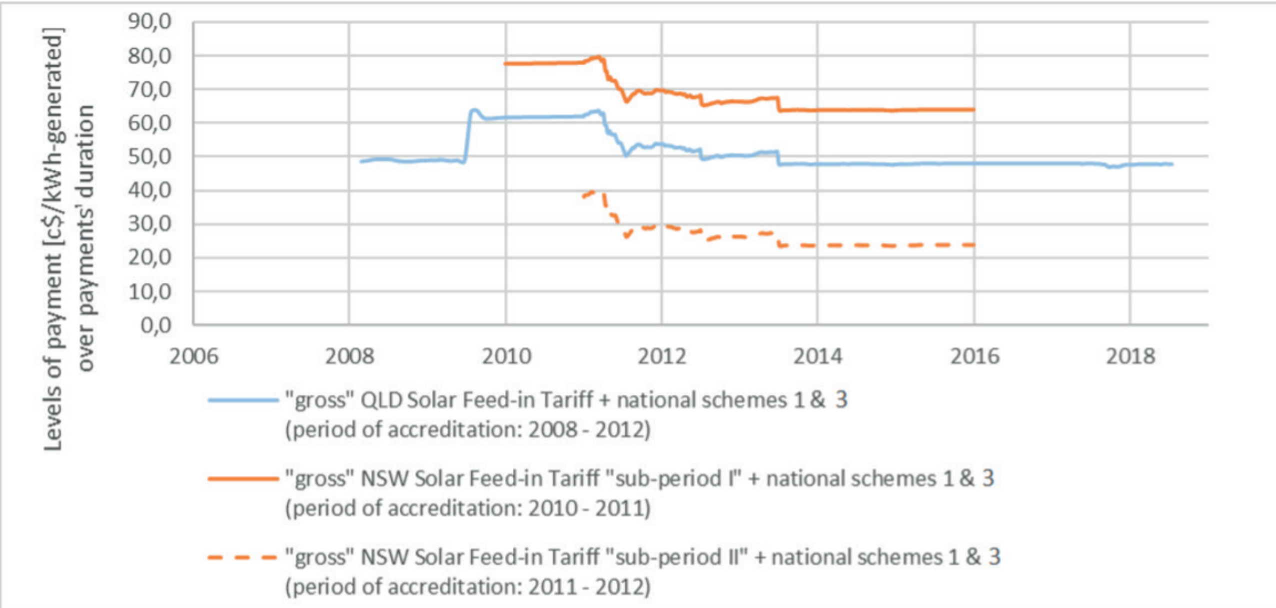
36 Indeed, the STC auction house can facilitate transactions and sell any quantity of certificates on the market – more on occasions of certificate scarcity – under the condition that the prices of certificates sold in this way are fixed at 4 c$/certificate (nominal, non tax-deductible). Therefore, in a situation of scarcity of supply of certificates the STC auction house would sell certificates to meet demand otherwise not supplied– setting the the certificates' spot market price at 4 c$/certificate.

This situation of scarcity of supply of certificates compared to the market demand is also intended by the Australian Clean Energy Regulator – responsible for setting ex-ante the demand for certificates – to keep the spot prices of certificates as close to the cap as possible, consequently ensuring sufficient remuneration for accredited systems.

Overall, there were no major differences in terms of maximum value[37] between the two schemes, whereas the average value for Scheme 3 can be assumed to have been slightly higher.[38] It is interesting to note that there has been a significant increase in estimated newly installed and accredited small-scale solar PV system capacity under Scheme 3 since 2015 (Figure 12), although the levels of payment were not significantly high. This is probably due to the decreasing cost of small-scale solar PV systems and to the rising electricity retail prices described in the literature [26]-[29].

- *Type 2: small-scale solar PV projects which were accredited in a combination of a national-level scheme and a 'gross' state-level scheme (Schemes 4A and 4B for Queensland and New South Wales respectively)*

Figure 19: Levels of payment per unit of electricity generated by small-scale solar PV projects accredited in a combination of a national-level scheme and a 'gross' state-level scheme – type 2 [7], [20], [21], [27], [30]–[34][39]



We notice from Figure 19 above that the levels of payment per unit of electricity generated for this type of small-scale solar PV project correspond to the sum of the levels of the national-level schemes (Figure 18) and the fixed-levels of the state-level 'gross' solar feed-in tariff schemes examined (QLD, NSW).[40] Indeed, the profiles are similar to those in Figure 18 with the main difference being the levels of payment and the durations of payment.

The levels of payment received by projects which managed to accredit in these schemes were quite significant, reaching circa 50-80 c$/kWh for some of them. Even in the case of projects accredited in 2011-2012 in the 'gross' NSW Solar Feed-in Tariff sub-period II and the national-level

37 Circa 20 c$/kWh under both schemes.

38 Somewhere between 3 c$/kWh and 6 c$/kWh under Scheme 1 vs somewhere between 4 c$/kWh and 8 c$/kWh under Scheme 4.

39 Missing data for national schemes 1 and 3 between mid-2009 and 2011 has been interpolated.

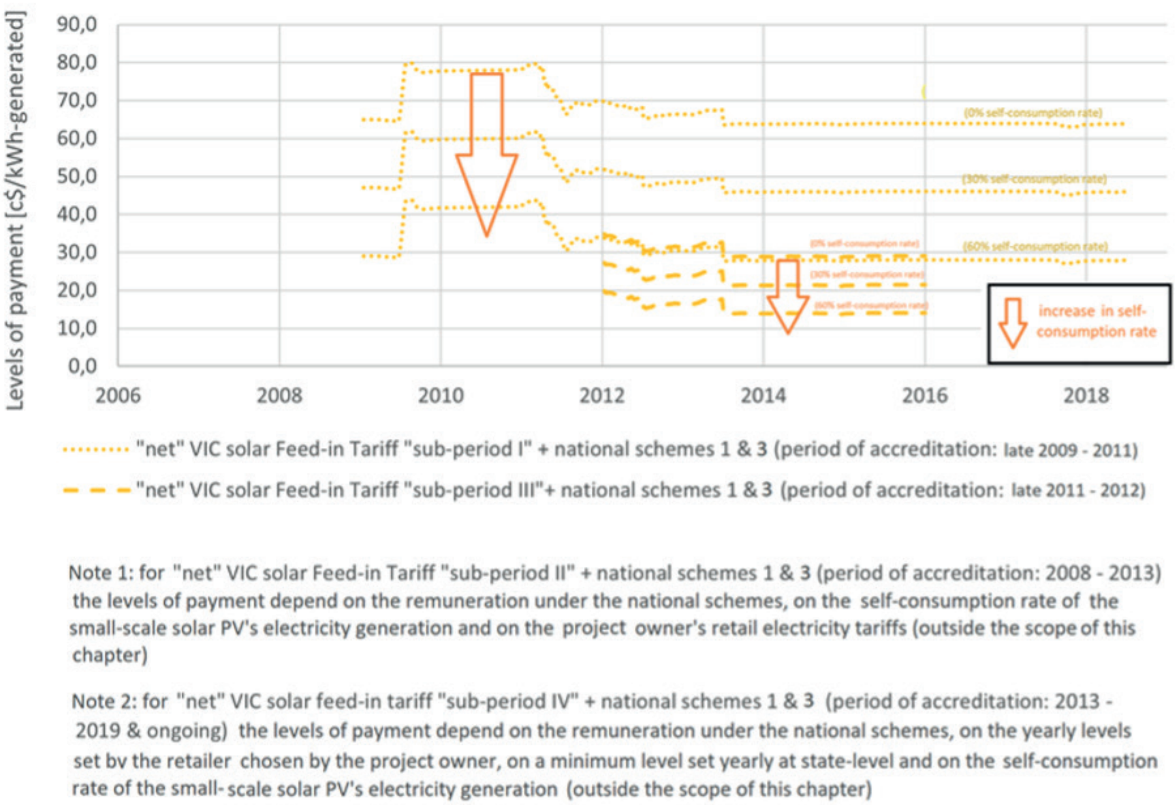
40 44 c$/kWh in the 'gross' QLD Solar Feed-in Tariff scheme to be paid until July 2028 (accreditation period 2008-2012), 60 c$/kWh in the 'gross' NSW Solar Feed-in Tariff scheme sub-period I paid until Dec. 2016 (accreditation period 2010-2011) and 20 c$/kWh in the 'gross' NSW Solar Feed-in Tariff scheme sub-period II paid until Dec. 2016 (accreditation period 2011-2012).

schemes 1 and 3 the payments were between 24 c$/kWh and 40 c$/kWh. These levels are much higher than those for small-scale solar PV projects only accredited in national-level schemes (Figure 18) and those for large-scale generators accredited in national-level schemes (Figure 12). However, the periods of accreditation were also significantly shorter. Therefore, as Figure 16 shows, not many systems ended up being accredited in this combination of national-level schemes and ‘gross’ state-level schemes.

While the duration of the payments under national-level schemes 1 and 3 mainly depends on the duration of the schemes themselves (the payments under one of the national-level schemes are still ongoing and could last a maximum until 2030), the duration of the payments in the ‘gross’ NSW Solar Feed-in Tariff scheme lasted until 2016 and that in the ‘gross’ QLD Solar Feed-in Tariff scheme will last until 2028.

- *Type 3: small-scale solar PV projects which were accredited to a combination of a national-level scheme and a ‘net’ state-level scheme (Scheme 4C, Victoria)*

Figure 20: Levels of payment per unit of electricity generated by small-scale solar PV projects accredited in a combination of a national-level scheme and a ‘gross’ state-level scheme – type 3 [20], [21], [27], [35]-[38][41]



Overall, the effective levels of payment remain unknown for this type of project. This is due to the fact that the levels of payment per unit of electricity generated for this type of small-scale solar PV project correspond to the sum of the levels of payment under the national-level schemes (Figure 18, known) and an additional remuneration (unknown). Across the different sub-periods of the ‘net’ VIC solar Feed-in Tariff, this additional remuneration is unknown and depends on various uncertain factors:

41 Missing data for national Schemes 1 and 3 between mid-2009 and 2011 has been interpolated.

- For sub-period I (period of accreditation: late 2009-2011) and sub-period III (period of accreditation: late 2011-2012) – illustratively reported in Figure 20 above – the unknown additional remuneration (c$/kWh of electricity generated) will depend on two factors:

  i. the (known) fixed level of the 'net' solar feed-in tariff of the state-level schemes examined (VIC)[42] (c$/kWh-injected into the grid) and

  ii. the (unknown) self-consumption rates of the electricity generated by small-scale solar PV systems. The higher the self-consumption rate, the less electricity is injected into the grid and the less remuneration the system will receive. Understanding the self-consumption rates of the different project owners of small-scale solar PV systems would require a detailed investigation into their load profiles and the electricity generation profiles of the different systems in Victoria accredited in these schemes in the years examined. Additionally, it would require identification of a methodology to estimate the relative self-consumption rates in the wide time-period examined and with adequate time-granularity so that the estimate is solid. A precise estimate of these self-consumption rates is beyond the scope of this chapter. Instead, in Figure 20 on the previous page we have reported an illustrative decreasing trend in levels of payment with an increasing self-consumption rate (represented by an arrow) and illustrative levels of payment with constant self-consumption rates of 0%, 30% and 60%.

- For sub-period II (period of accreditation: 2008-2013) reported in a note in Figure 20 on the previous page, the unknown additional remuneration will depend on two factors:

  i. the project owner's retail electricity tariffs and

  ii. the self-consumption rate of the electricity generated by small-scale solar PV systems.

  Analysing the different retail electricity tariffs for the owners of small-scale solar PV systems in Victoria in 2008-December 2016 and their interactions with the self-consumption rate is beyond the scope of this chapter.

- For sub-period IV (period of accreditation: 2013-ongoing) reported in a note in Figure 20 on the previous page the unknown additional remuneration will depend on four factors:

  i. the project owners' choice of retailers;

  ii. the yearly levels of payment set by the chosen retailers;

  iii. the self-consumption rate of the electricity generated by small-scale solar PV systems; and

  iv. the yearly minimum level set ex-ante at the state level.

  Analysing the project owners' choice of retailers, the different yearly levels of payment set by the chosen retailers and their interaction with the self-consumption rate is beyond the scope of this chapter.

42 60 c$/kWh in the 'net' VIC Solar Feed-in Tariff scheme sub-period I to be paid until December 2024 (accreditation period: 2010-late 2011) and 25 c$/kWh in the 'net' VIC Solar Feed-in Tariff scheme sub-period III paid until December 2016 (accreditation period: 2012-2013).

Instead, the duration of payments for the different sub-periods is clear (Figure 15):

- For sub-period I and sub-period III the expected durations of the payments are until December 2024 and December 2016 respectively.[43]
- For sub-period II the expected duration of the payments is until December 2016.
- For sub-period IV the expected duration of the payments depends on the duration of the support scheme (still ongoing) and on the lifetime of the accredited project.

There was a significant increase in the estimated yearly capacities of this type 3 of accredited small-scale solar PV system from 2016 onwards in sub-period IV. Unfortunately, the levels of payment in sub-period IV are unknown to us and we cannot draw conclusions linking them to the capacities.

6.4 Cost-allocation of support in residential bills with an increasing presence of prosumers [44]

In this section, we analyse how the costs of Australian support for renewable energy development previously examined have been allocated in residential bills. First, we consider the cost-allocation of national-level support for large-scale generators in the average national residential bill. Then, we consider the cost-allocation of support for small-scale solar PV systems in residential bills. In particular, in alignment with the previous section, we consider the cost-allocation of support for the three main types of small-scale solar PV system previously identified in the following residential bills (in which their costs were mostly or fully allocated):

Table 2: Summary of the three main types of accredited small-scale solar PV system and the residential bills in which these respective costs were mostly allocated

Type	Type of accredited small-scale solar PV system	Residential bills in which the costs were mostly or fully allocated
1	small-scale solar PV projects which were assumed to be only accredited in national-level schemes (Schemes 1 and 3)	Average national residential bill
2	small-scale solar PV projects which were accredited to a combination of a national-level scheme and a ‘gross’ state-level scheme (Schemes 4A and 4B for Queensland and New South Wales respectively)	Average Queensland and New South Wales residential bills (mostly)
3	small-scale solar PV projects which were accredited to a combination of a national-level scheme and a ‘net’ state-level scheme (scheme 4C, Victoria)	Average Victoria residential bill (mostly)

Finally, we describe some fairness issues we identify concerning the cost-allocation of support for these three main types of accredited small-scale solar PV system in residential bills with the increasing presence of prosumers.

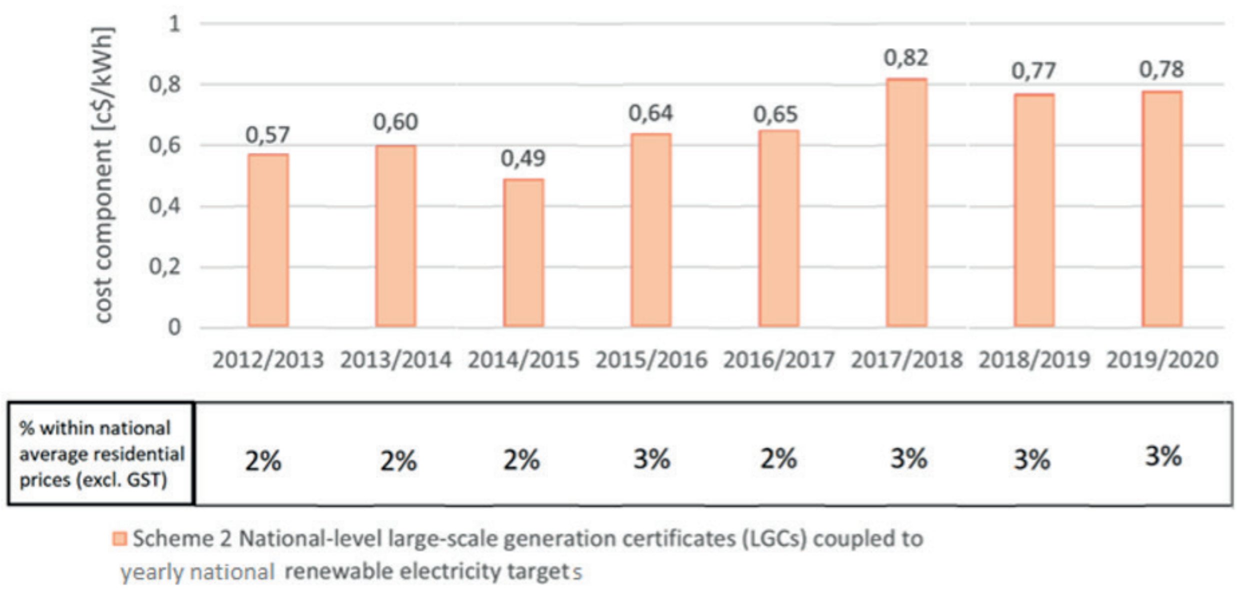
43 Unless the project owner breaches one of the accreditation conditions, such as changing electricity retailer, changing the address of main residence or upgrading the accredited small-scale solar PV system by increasing its size. More details can be found in [35].

44 In this chapter, ‘prosumers’ refers to investors in small-scale solar PV systems (residential scale or commercial scale).

Note that data on the cost components of average residential bills in Australia (national-level and state-level) has only been found for 2012/2013 onwards.

- *Full cost-allocation of national-level support for large-scale generators in the average national residential bill*

Figure 21: The cost component [c$/kWh] in national average residential prices (excl. GST) due to national-level support for large-scale generators (in particular, Scheme 2) [39]–[46]



We notice that the cost component due to national-level support for large-scale generators amounted to less than 1 c$/kWh in the period 2012-2020 and varied between 0.49 c$/kWh (2014/2015) and 0.82 c$/kWh (2017/2018). This increase by a factor of 2 could possibly be justified by a combination of the following factors:

» levels of payment increased circa twofold, from circa 3 c$/kWh in 2014/2015 to slightly above 8 c$/kWh in 2017/2018 – as is shown in Figure 12;

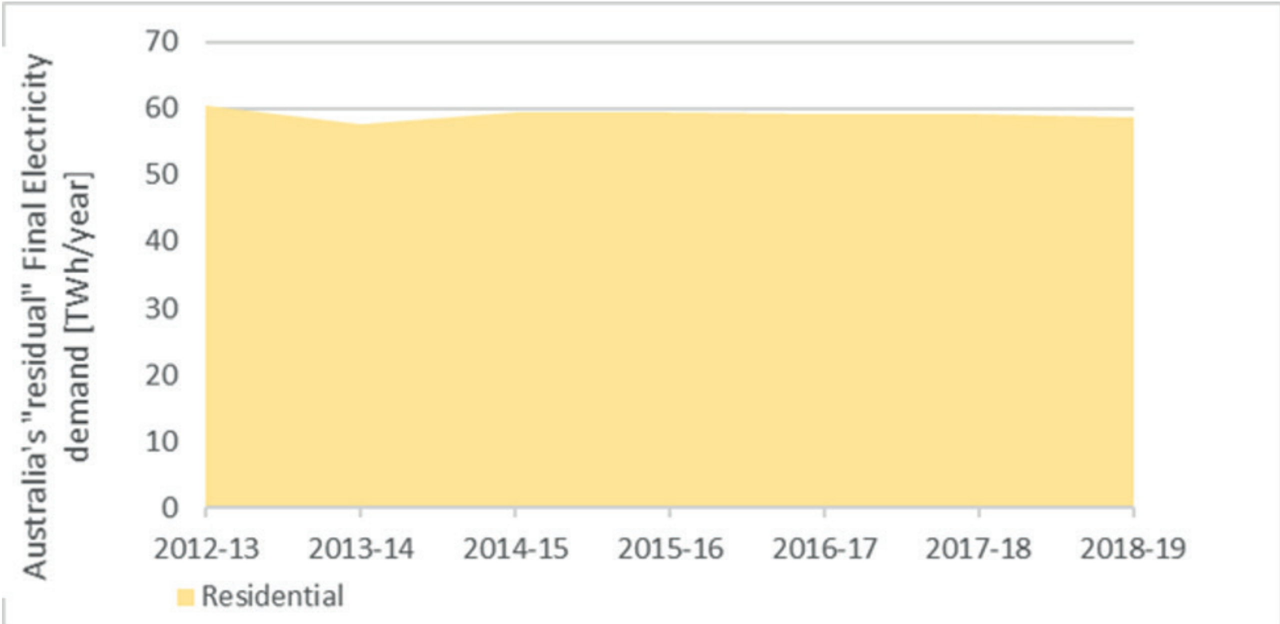
» levels of renewable electricity generation from cumulative accredited capacity almost doubled in this period – as is shown in Figure 11;

» 'residual' residential electricity demand at the national level underlying paid residential bills[45] remained relatively constant in this period – as is shown in Figure 22 on the next page;

» other factors which may have played a role but are not related to residential bills (e.g. non-residential electricity demand contributing to payment of the cost of this support).

45 These estimates exclude energy consumed or lost in conversion and distribution. Therefore, electricity generated by small-scale solar PV systems and self-consumed is not taken into account in these estimates.

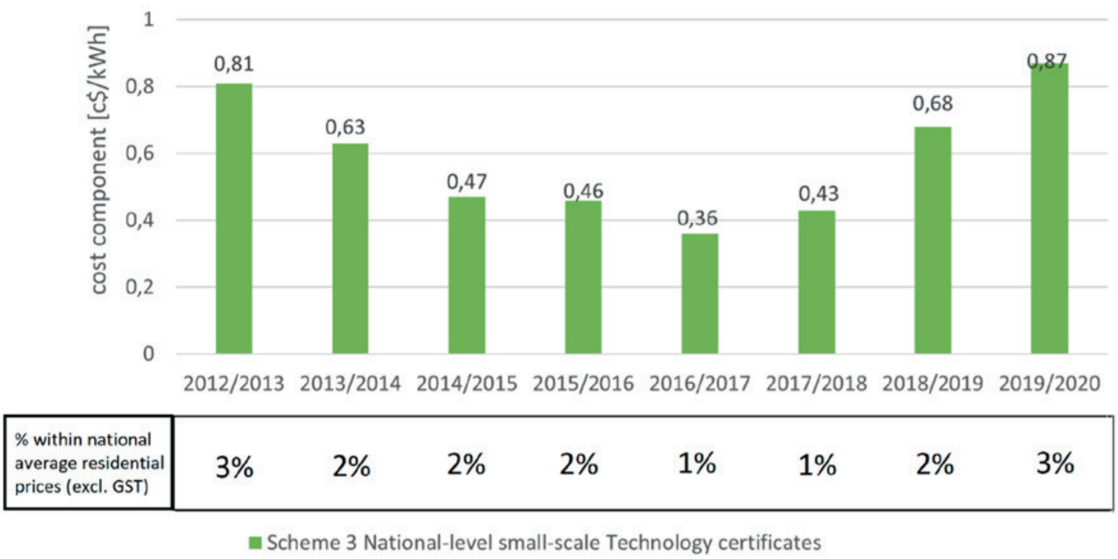
Figure 22: Australia's 'residual' residential electricity demand in the period from 2012/2013 to 2018/2019 [47][44]



Since no data were available before 2012/2013 it is not possible to comment on the cost component due to national-level support for large-scale generators before 2012/2013, in particular under Scheme 1.

- *Full cost-allocation of support for accredited small-scale solar PV systems of type 1 in the average national residential bill*

Figure 23: The approximate cost component [c$/kWh] of national average residential prices (excluding GST) due to national-level support for small-scale solar type 1 PV[46] (in particular, under Scheme 3) [39]-[46]



46 "Approximate" since the cost components reported in Figure 23 also include costs due to national-level support for small-scale solar PV of types nos. 2 and 3. However, the overestimation is not likely to be significant. Indeed, Figure 17 shows that the generation of type no. 1 supported is significantly larger than that of types nos. 2 & 3 in the period studied.

We notice that the cost component due to national-level support for small-scale type 1 solar PV systems amounted to less than 1 c$/kWh at the national level in the period 2012-2020 and varied between 0.81 c$/kWh (2012/2013) and 0.36 c$/kWh (2016/2017), and then up to 0.82 c$/kWh (2019/2020). This variability by a factor of 2.25 – first downwards and then upwards – is difficult to explain. In fact:

» levels of payment under national-level Scheme 3 remained mainly constant, from circa 5-6 c$/kWh in 2013/2014 to circa 4 c$/kWh from 2014 onwards – as is shown in Figure 18;

» the amount of renewable electricity generated from cumulative accredited capacity increased almost four-fold in this period – as is shown in Figure 17;

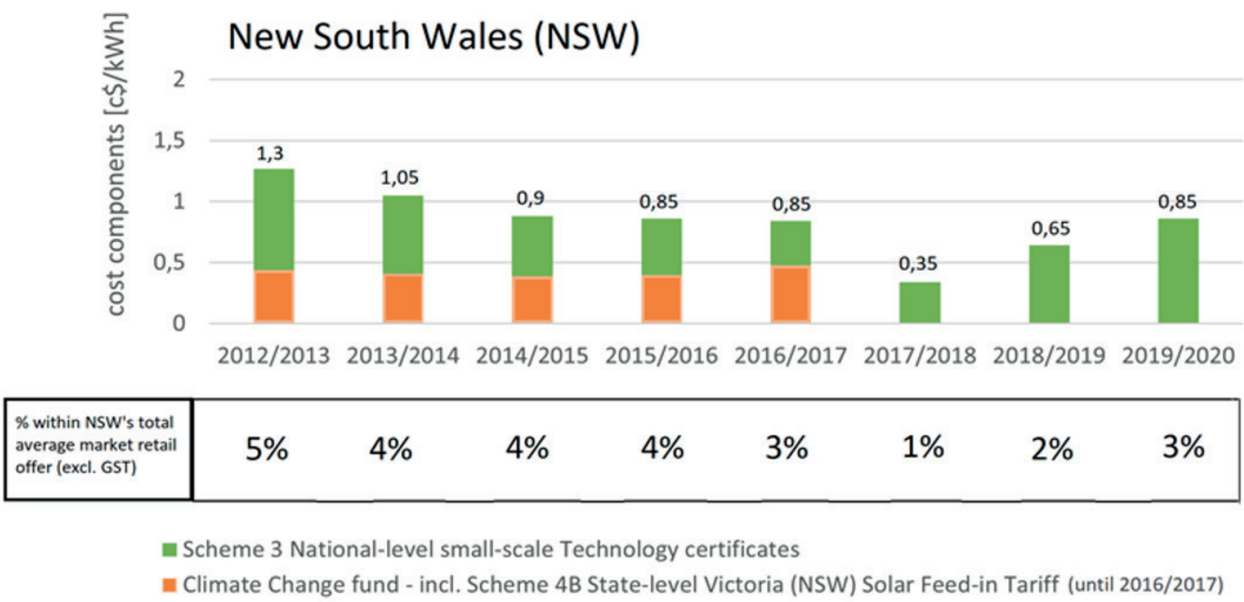
» the national 'residual' residential electricity demand underlying paid residential bills remained relatively constant in this period – as is shown in Figure 22 on the previous page;

» other factors not related to residential bills may have played a role (e.g. non-residential electricity demand contributing to payment of the cost of this support).

The sum of this cost component at the national level and that relative to national-level support for large-scale generators (Figure 23 on the previous page) overall amounted to a non-significant 3-6% of national average residential prices (excluding GST).

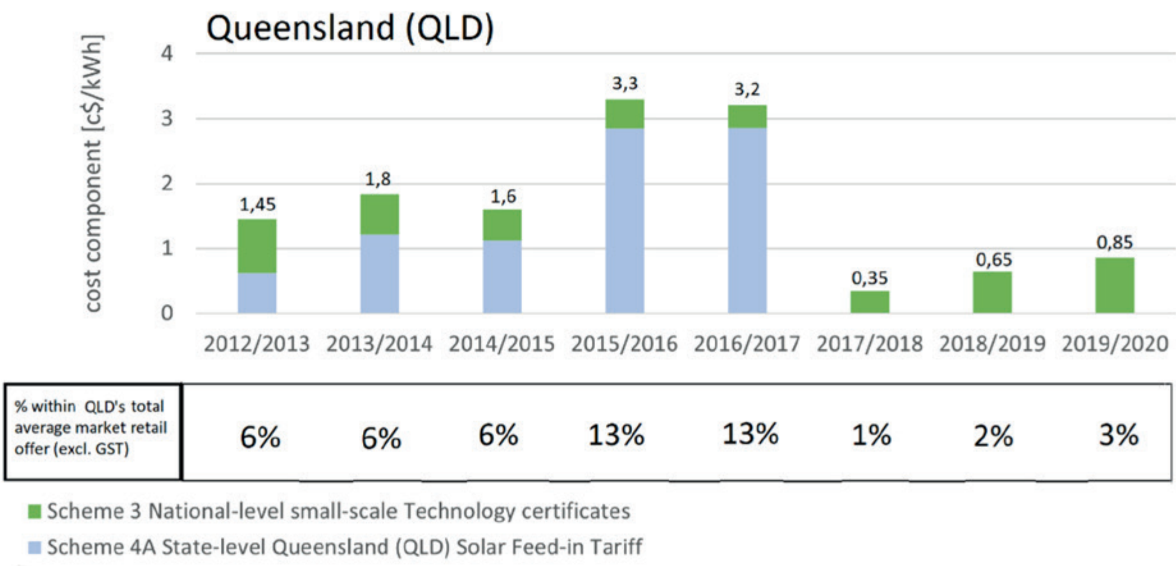
- *The cost-allocation of support for accredited small-scale solar PV systems of type 2 mostly in the average Queensland and New South Wales residential bill*

Figure 24: Cost-allocation of support for accredited small-scale solar PV systems of type 2 (located in NSW) in the average NSW residential bill [39]-[46][47]



47 Data for the cost component due to the Climate Change fund was not reported from 2016 onwards given that by then the NSW Solar Feed-in Tariffs had been phased-out and the relative costs were no longer included in the Climate Change fund.

Figure 25: Cost-allocation of support for accredited small-scale solar PV systems of type 2 (located in QLD) in the average QLD residential bill [39]-[46][48]



We notice from Figures 24 and 25 that the cost components due to national-level support plus state-level solar feed-in support for small-scale solar PV systems of type 2 in Queensland and New South Wales were significantly different in the period 2012-2017. Whereas the cost component in the NSW average market retail offer[49] decreased from 1.3 c$/kWh in 2012/2013 to 0.85 c$/kWh in 2016/2017 (-35%), that in the QLD average market retail offer increased from 1.45 c$/kWh in 2012/2013 to 3.2 c$/kWh in 2016/2017 (+120%). This is largely because of the different cost sub-components associated with the state-level solar feed-in tariffs, which were higher in QLD (0.5 c$/kWh) in 2016/2017 than in NSW (3.2 c$/kWh) in the same period.

We assume that the relatively constant trend of the cost sub-component for the NSW Solar Feed-in Tariff incorporated in the climate change fund is also linked to the short period of accreditation in the NSW Solar Feed-in Tariff scheme. Indeed, the period of accreditation did not exceed April 2011. From 2012/2013 onwards, no new systems could accredit in the NSW Solar Feed-in Tariff Scheme and the estimated yearly renewable electricity generated from accredited cumulative capacity remained relatively constant at 450-500 GWh.

Instead, it is difficult to understand the increasing trend in the cost sub-component of the QLD Solar Feed-in Tariff, in which other factors beyond the scope of this chapter may have played a role. On the one hand, the QLD Solar Feed-in Tariff had higher levels of payment (Figures 15 and 19) and a larger window for accreditation (2008-2012) than the NSW Solar Feed-in Tariff. However, on the other hand, from 2012/2013 onwards no new systems could accredit in the NSW Solar Feed-in Tariffs and the estimated yearly renewable electricity generated from accredited cumulative capacity remained relatively constant at 800-850 GWh.

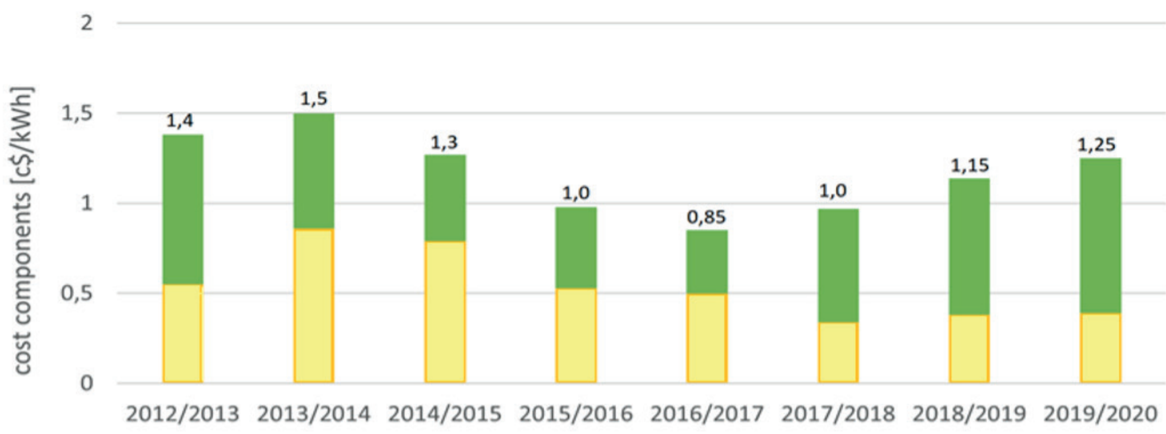
Finally, from 2017/2018 onwards the costs of sub-components due to the state-level solar feed-in tariffs are null or not reported. Payments of the NSW state-level solar feed-in tariffs ceased in December 2016 (Figures 15 and 19) whereas payments of the QLD state-level solar feed-in tariffs – which were still ongoing – were reported to be null or were not reported by AEMC.

- *Cost-allocation of support for accredited type 3 small-scale solar PV systems in the average Victoria residential bill*

48 Data for the whole Queensland region in 2013-2019 is not available. Therefore, we approximate it with the available data for South-east Queensland. Instead, data for 2012-2013 and 2019-2020 for the whole Queensland region was made available and is reported in the plot.

49 In this section, the average residential bill is proxied by the average market retail offer in the absence of data relative to the former.

Figure 26: Cost-allocation of support for accredited type 3 small-scale solar PV systems in the average Victoria residential bill [39]-[46]



% within Victoria's total average market retail offer (excl. GST)	5%	5%	4%	4%	3%	3%	4%	4%

■ Scheme 3 National-level small-scale Technology certificates
■ Scheme 4C State-level Victoria (VIC) Solar Feed-in Tariff

We notice that the cost component due to national-level support and state-level solar feed-in support for type 3 small-scale solar PV systems in Victoria amounted to a maximum of 1.5 c$/kWh in the period 2012-2020. Indeed, this cost component varied between 1.5 c$/kWh (2013/2014) and 0.85 c$/kWh (2016/2017), and then to 1.25 c$/kWh (2019/2020).

If we look into the trends in the underlying cost sub-components due to Scheme 3 and Scheme 4C we also notice a certain degree of variability, with the cost sub-component due to Scheme 4C slightly increasing over the years and then decreasing, and vice-versa for the other cost sub-component due to Scheme 3. This overall variability by a factor 1.75 to 1.5 – first downwards and then upwards – is difficult to explain. In fact:

» the levels of payment in this period are unknown due to uncertainty over the self-consumption rate, as was mentioned in the previous section (Figure 20);

» the levels of renewable electricity generated from cumulative accredited capacity increased almost five-fold in this period, as Figure 17 shows;

» the 'residual' residential electricity demand trend in Victoria underlying paid residential bills is unfortunately not known;[50]

» other factors not related to residential bills (e.g. non-residential electricity demand contributing to paying the costs of this support) may have played a role.

- *Fairness issues identified concerning the cost-allocation of support for these three main types of accredited small-scale solar PV system in residential bills*

We identify three main fairness issues concerning the cost-allocation of support for these three main types of small-scale solar PV system in residential bills, which we assume are all the more relevant because of the significant numbers of small-scale solar PV systems and accredited cumulative

50 However, the overall final electricity demand in Victoria remained relatively constant in this period [47].

capacity in Australia (Figures 16 and 17 respectively):

i. The underlying support for single accredited systems was ‘equally’ allocated – independently of the amount of support and of the residential bill paid by the system’s owner – in the residential bills of all the electricity consumers (with or without small-scale solar PV systems) in the same geographical area (national-level or state-level). Therefore, there could have been space for non-cooperative behaviour such as investing in a small-scale solar PV system – even of larger size – while being aware that the associated support would be shared among the residential bills of all the electricity consumers in the same area. This issue is present for all three main types of system identified above.

ii. Electricity generated by an accredited small-scale solar PV system and then self-consumed reduces the amount of electricity demand underlying the residential bill and therefore reduces the payments by the system’s owner supporting its own system and those of others. Ultimately, there could have been space for non-cooperative behaviour such as increasing the self-consumption rate of accredited small-scale solar PV systems in order to shift the costs of their own support onto other users. In this case, we can differentiate between small-scale solar PV systems of types 1 and 2 (according to the table above), which also receive support for self-consumed electricity and for which this issue is more relevant, and systems of type 3, which receive less support for higher self-consumption rates and for which this issue is less relevant.

iii. Likewise, electricity generated by an accredited small-scale solar PV system and then self-consumed reduces the payments by the system’s owner towards other cost components of the residential bill (e.g. wholesale and retail market, regulated distribution and transmission networks, other environmental policies, metering …). Therefore, there could have been space for non-cooperative behaviour such as increasing the self-consumption rate of accredited small-scale solar PV systems in order to shift the costs of these other cost components of the residential bill onto other users. This behaviour would be accentuated by the tariff design used and could also lead to “subsequent volumetric-losses” and inefficiencies [28], further increasing the costs allocated to other users.[51] [48]-[50] and [28] respectively look at tariff designs capable of recovering costs – in particular, sunk grid costs – and tariff designs capable of reducing “implicit subsidies” by non-solar PV owners of solar PV owners when there is a high penetration of small-scale solar PV systems. This issue is present for all three main types of system identified above.

51 This reasoning was also confirmed by:

- Mr. Mike Swanston in one of his presentations at FSR in February 2019 (“The growth in renewables (in particular, small-scale solar PV) is accelerating … Why? … continuing high retail prices, stubborn volumetric tariffs, a strong customer business case for self-consumption …”)
- [48] “By investing in PV and batteries, active consumers push the sunk costs towards passive consumers (equity issue). Ironically, the active consumers can even end up paying more (efficiency issue). To avoid being screwed by the others, active consumers could overinvest. They are in a non-cooperative equilibrium. We find that the outcome of this game between the DSO (and the regulator) trying to recover sunk costs and active consumers reacting to the distribution grid tariff depends heavily on the way the tariff is designed.”
- [28] “Three layers of compound network tariff increases and the funding of the Premium FiT thus created a new dimension to the problem – sharply rising cross-subsidies flowing from households without solar PV to households with solar PV. These ‘implicit subsidies’ are consistent with Severance’s (2011) “energy market death spiral” of increasing rates for households that do not, or cannot, adopt or afford solar PV.” … “The outcome of this conflation of drivers is that network tariffs have become unstable. A death spiral involving rising tariffs, demand response, further tariff rises, further demand response, has now resulted in network price increases of 112% in just five years in an ostensibly low inflation environment … non-solar households are paying more than they should, while solar households are paying too little.”
- [63]: “Retail electricity prices are important to the financial return on solar PV as every kWh of solar output that is consumed by the owner of the system avoids the variable component of the retail electricity price.” The “rising financial paybacks for solar PV systems (between 2017 and 2019 were) driven by higher retail electricity prices.”

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