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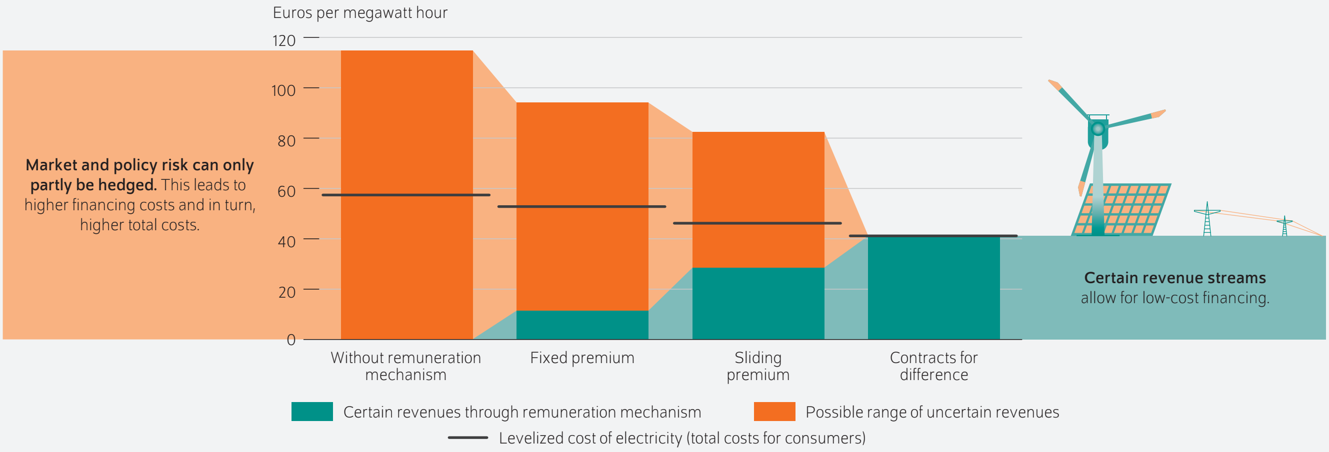
AT A GLANCE

Affordable electricity supply via contracts for difference for renewable energy

By Nils May, Karsten Neuhoff, and Jörn C. Richstein

- The extent to which electricity consumers can benefit from the falling cost of renewable energy technology depends on the remuneration mechanism
- A financing model shows that the current sliding premium is leading to increasing financing costs
- Contracts for difference can remedy the situation – unlike fixed premiums or abolishing remuneration mechanisms entirely
- Introducing contracts for difference facilitates more efficient and simpler incentives for system-friendly locational choices and plant designs

Contracts for difference hedge the revenues of renewable energy projects and thus also lower the total costs borne by consumers



Source: Authors' own depiction, based on exemplary calculations for large solar plants.

FROM THE AUTHORS

"Only contracts for difference allow electricity consumers to fully benefit from the falling cost of renewable energy technology."

— Karsten Neuhoff, study author —

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ABSTRACT

The cost of renewable energy technology has plunged in recent years. But the extent to which electricity consumers can benefit from the reduced costs depends on the design of renewable remuneration mechanisms. Calculations of a financing model show that the current sliding premium is leading to increasingly higher risks for investments and in turn, increasing equity requirements. As a result, financing costs increase, which counteracts the lower cost of technology. Furthermore, increased equity requirements could negatively affect the diversity of players investing in renewable energy and thus the level of competition as well as the rate of project realization in the sector. A change towards contracts for difference (CFDs) can remedy the situation. CFDs lead to low financing costs and therefore reduce overall costs of supplying renewable electricity, reducing expected annual costs for German consumers by approximately 0.8 billion euros per year by 2030. They also safeguard consumers against high payments for renewable electricity in case of high electricity prices. A transition to CFDs provides the opportunity to create more effective and simpler incentives for system-compatible site selection and plant design.

Plants for generating electricity from renewable energy sources have become significantly more affordable in recent years. For example, the cost of electricity from large photovoltaic (PV) plants has fallen by 85 percent since 2007.[1] This translates into a fundamental reduction in the costs of continuing to expand renewable energy. If the cost of electricity from renewable energy decreases to the extent that it approaches the prices obtainable in the wholesale electricity market, the result could be significant deviations in financing conditions that depend on remuneration mechanisms. Financing costs play a major role in capital-intensive wind power and solar energy.

The current remuneration mechanism for renewable energy in Germany raises the question of whether electricity consumers will be able to benefit fully from the rapid decline in technology costs. This report shows the consequences of technology cost decreases relative to obtainable market values for different renewable remuneration mechanisms. It shows that in the case of contracts for difference (CFDs), electricity consumers benefit from lower technology costs. For this remuneration mechanism, a discussion of various design options follows.[2]

Financing costs play key role in renewable energy

Wind power and solar plants have low variable costs but relatively high capital costs. This is why the costs of financing the investment are a key part of their overall cost. In turn, financing costs depend on the level of certainty involved in the future revenues from electricity generation. Uncertain revenues increase the cost of financing significantly compared to a market designs with renewable energy remuneration

1 See Nils May, Ingmar Jürgens, and Karsten Neuhoff, "Renewable Energy Policy: Risk Hedging Is Taking Center Stage," *DIW Economic Bulletin* no. 39/40 (2017): 389-396. (Available online, accessed June 28, 2018; this applies to all other online sources in this report unless stated otherwise).

2 The authors would like to thank Simon Hagedorn, Marian Klobasa, Mario Ragwitz, Bernhard Strohmayer, Stefan Thimm, and Silvana Tiedemann for their helpful comments and discussions, and the Federal Ministry for Economic Affairs and Energy for funding (*Bundesministerium für Wirtschaft und Energie*, BMWi), grant number 03MAP316 (SEEE). Key sections of the present report are based on a recent discussion paper: Karsten Neuhoff, Nils May, and Jörn Richstein, "Renewable energy remuneration mechanisms in the age of falling technology costs," *DIW Discussion Paper* no. 1746 (2018) (forthcoming).

mechanisms that reduce this uncertainty by avoiding policy risk and serving as hedge for market price uncertainties.

If the revenue from electricity production is ensured at the time of the investment decision, investors can use this certain revenue stream to raise risk averse but low-cost capital from bonds or debt to finance their investment. On the contrary, to the extent that revenues are uncertain at the time of the investment decision, investors require higher shares of risk-taking equity capital. This increases the overall cost of financing their investment.

In principle, investors can also conclude long-term power purchase agreements, for example with large energy suppliers, to reduce their revenue risk. However, this only "shifts" the risk. Rating agencies rate long-term contracts like these as additional liabilities, which reduce the energy supplier's creditworthiness and increase financing costs.[3] Thus, risk surcharges are incurred even in presence of long-term power-purchasing agreements with intermediaries. Only contracts with final consumers could eliminate the risk, and thus the surcharge. However, in the presence of retail competition it is too difficult to sign 20 year contracts with domestic consumers and few industrial and commercial electricity consumers are in a position to sign 20 year contracts.

A survey on the financing costs of wind power plants in Europe and a microeconomic assessment of the effects of long-term agreements show that the costs rise by around 30 percent if remuneration mechanisms do not provide long-term hedging for policy and price risk.[4]

Current renewable energy remuneration mechanism: sliding premium

The sliding premium as renewable remuneration mechanism for larger wind power and solar plants became mandatory in Germany in 2014. The aim was to drive renewable energy's market integration and at the same time, safeguard low financing costs for investors. Prior to the investment, project developers submit their strike price in an auction. The projects that submit the lowest strike prices win the auction and thus a guarantee for this price for 20 years. During operation, project operators then sell their electricity production in the market. On a monthly basis, the average revenue of all plants of a technology, e.g. PV, is calculated – the so called "market value of the electricity". If the market value is below the strike price specified by the project developer, the project receives the difference between the strike price and the market value – as so called "sliding premium" from the grid operator. Costs are then shared across all electricity consumers.

Previously, the strike price was significantly higher than the average monthly market value of renewable electricity. Therefore project developers always anticipated to obtain a positive sliding premium for all months of their operation and thus anticipated to receive total revenues corresponding to the strike price at all times. The stable framework this creates allows investors to finance investments at favorable conditions, and smaller market players with little equity capital can also invest in renewable energy. In this setting, changing expectations of the future market value in the period between bid submission and plant construction did not impact projects' profitability and supported high realization rates.

Box 1

Calculations of the financing costs of PV plants for various remuneration mechanisms

The basis for calculation of the financing cost differences among the remuneration mechanisms is a financing model for determining debt and equity shares under competitive determination of strike prices and uncertain electricity market revenue.[1] It is assumed that equity makes up at least 20 percent. Certain revenue from remuneration mechanisms is used to raise debt, while uncertain revenue from the electricity market must be covered by equity. Since investors are under competitive pressure during the auctions, they will take possible revenue from the electricity market into account in order to keep their bids as low as possible. This causes the competitively determined strike price to be lower than the cost of electricity.

The example calculations for large PV plants are presented under the assumption of continued decreasing technology costs. System investment costs of approx. 608 euros per kilowatt and 1,000 annual full load hours are assumed.[2] At a return on equity of seven percent and return on debt of seven percent, this equals a CFD payment of 41.24 euros per megawatt hour. This corresponds to the product of the average relative market value of PV electricity in Germany in 2017 (0.96) and the Phelix Base-Future 2019 as of June 28, 2018 (43 euros per megawatt hour).

A probability distribution is used to map the market values of uncertain electricity market revenue. The assumption is that the market values are equally distributed between zero and twice the value of the assumed CFD.

1 For more information on the calculation, see Neuhoff et al., "Renewable energy remuneration mechanisms".

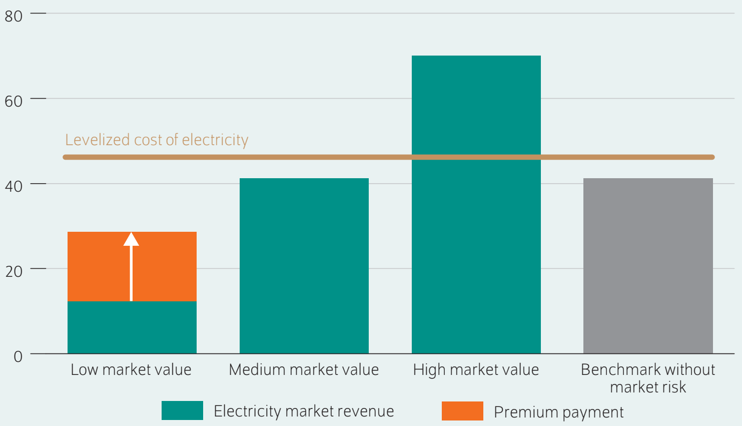
2 This is the currently expected level of photovoltaics costs for the period 2025 until 2030. Fraunhofer ISE, Stromgestehungskosten erneuerbare Energien (2018) (available online).

3 See Standard & Poor's, *Key Credit Factors For The Regulated Utilities Industry*; and Baringa, "Power purchase agreements for independent renewable generators – an assessment of existing and future market liquidity," 2013 (available online).

4 For detailed information, see Nils May et al., "Renewable Energy Policy" and Nils May and Karsten Neuhoff, "Financing Power: Impacts of Energy Policies in Changing Regulatory Environments," *DIW Discussion Paper* no. 1684 (2017) (available online). This level of additional cost is comparable to the estimates of other studies. See Aurora Energy Research, "Erneuerbaren-Markt ohne Subventionen bringt neue Risiken," *Tagesspiegel Background Standpunkt* (2018) (available online).

Figure 1

Revenues and levelized cost of electricity with a sliding premium
In euros per megawatt hour

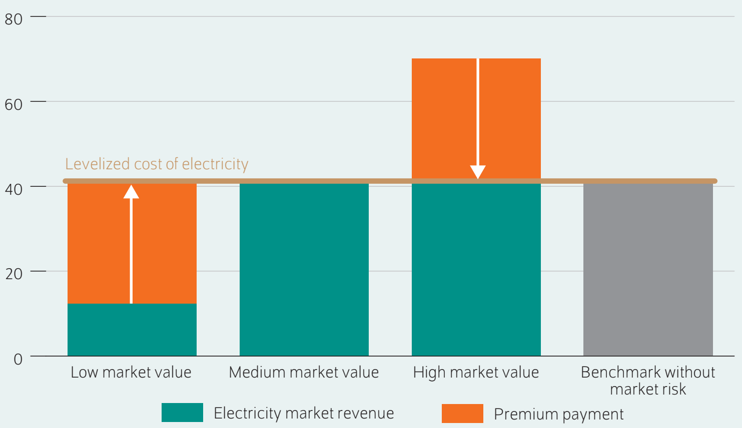


Source: Authors' own calculations.

As the strike price falls below the levelized cost of electricity, the premium applies only in case of low realized market values.

Figure 2

Revenues and levelized cost of electricity with contracts for difference
In euros per megawatt hour



Source: Authors' own calculations.

If high market values are realized, the premium is refunded.

With continued declines of the cost of renewable technologies as well as more likelihood attributed to scenarios of increasing electricity prices, triggered by increasing fuel and carbon prices, it is increasingly likely that the market value will exceed the "strike price" from the auctions.[5] As a result, the price of electricity above and beyond this strike price will contribute an increasing share to possible revenues. At the same time, the share of revenue that is secured with the strike price will fall. Since electricity market revenue above the minimum price is uncertain, this implies that an increasing share of equity is required for the investments, financing costs will rise and electricity consumers will no longer be able to benefit from falling technology costs to the fullest extent.

Four options for policy action

Under current circumstances, policy makers have four options for the design of the future renewable energy remuneration mechanism:

- Retaining the current sliding premium
- Developing them further as contracts for difference
- Implementing a fixed premium
- Abolishing all dedicated renewable energy remuneration mechanisms

We discuss their consequences in the following. For each of these four options, the German Institute for Economic Research (DIW Berlin) has simulated revenues and the electricity cost of future PV plants under different market value scenarios (see Box 1).

Sliding premium: rising financing costs counter cost reductions

Germany could keep the current premium scheme. However, this would reinforce the process by which uncertain electricity market revenue is increasingly included in bid calculations, ultimately resulting in rising financing costs.

In the case of lower realized market values, the strike price will effectively be the minimum price, because electricity market values are topped up with the sliding premium (see Figure 1, left column). Additional revenue from electricity market sales materialize if the realized market value is above the strike price. This is the case in the middle and high market value scenarios.[6] But unlike the strike price, this additional revenue is uncertain and thus cannot be used for financing with low-cost debt. For this reason, more equity is required for financing. Hence, higher financing costs offset part of the lower technology costs of renewable energies, and consumers do not fully benefit from the cost savings.

5 This relates to the obtainable plant-/technology-specific market values that are typically below the average electricity price .

6 However, it must be considered that in the middle case, the revenue is exactly equal to the cost of electricity under no-risk financing – the strike price is below this cost. In the case of lower market values, the required return on equity could not be paid out.

Contracts for difference: hedging for investors and protection for consumers

With only a few adjustments, the sliding premium could be structured as a contract for difference. Instead of only providing investors with a hedge against low market values, investors and the public could sign contracts for difference. The United Kingdom is already using this remuneration mechanism. Contracts for difference are long-term power purchase agreements at strike prices determined in auctions. As with the sliding premium currently used, operators receive additional revenues when the market value of the electricity they generate is below the agreed strike price. However, if the electricity price that plant operators obtain is above the strike, the operators must pay the difference to the grid operators (see Figure 2, third column). This lowers the renewable energy levy (in Germany: *EEG-Umlage*) and can even render it negative in the long run. This can increase acceptance of the energy transition, as electricity consumers, who have safeguarded renewable energy operators for many years against low electricity prices, are protected against high electricity prices in the future to the extent of existing contracts for difference.

CFDs ensure that project developers do not expect electricity market revenues in addition to the strike price. As a result, uncertain revenue no longer needs to be included in the financing calculation, which would increase financing costs to rise.

The model calculations show that when technology costs fall, the strike price under the sliding premium falls more strongly than the strike price of CFDs (see Figure 3). But in the sliding premium case, electricity consumers have additional costs for electricity consumption in case of high prices or when the market value of renewable energy is high. Falling technology costs are partially offset by rising financing costs in that case, and electricity customers will therefore benefit from only part of the technology cost reduction.

Fixed premiums not fit for low technology costs

In the case of fixed premiums, investors receive a payment per megawatt hour of generated electricity that is determined in auctions before the project begins – in addition to the electricity price revenue (see Figure 4). Similarly, if capacity-based remuneration was implemented, investors receive a fixed monthly payment per megawatt of installed capacity. In both cases, investors bear a high electricity price risk. This necessitates making investments with high equity shares, pushing up the total cost.

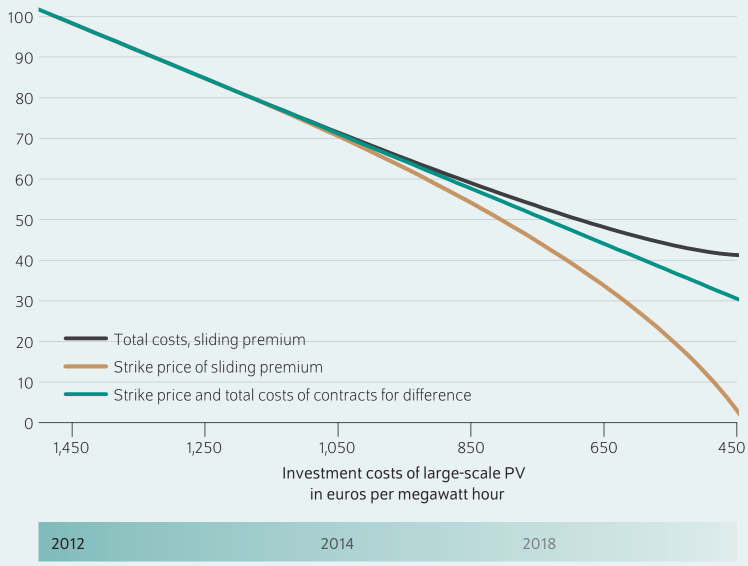
Abolishing premium mechanism continues to raise financing costs

A further policy option would be to abolish remuneration mechanisms altogether. In this case, incentives to invest would come from rising electricity prices due to a stronger carbon price signal, for example.

Figure 3

Strike prices and total costs for decreasing investment costs

In euros per megawatt hour



Note: Assuming 2017's market values.

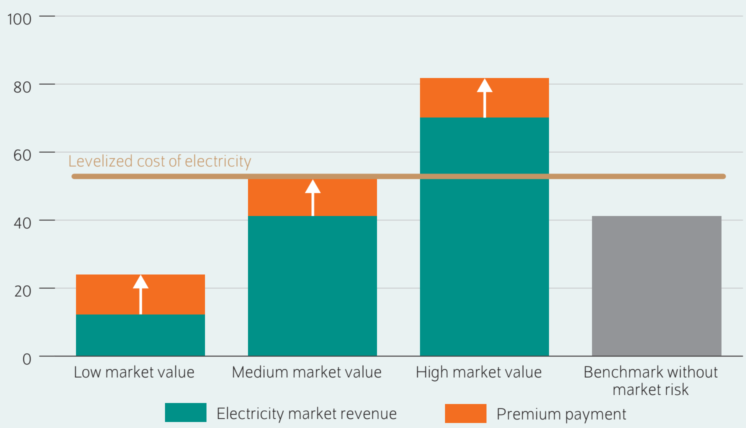
Sources: Authors' own calculations and data by Fraunhofer ISE.

The strike price of the sliding premium decreases more than the total costs.

Figure 4

Revenues and levelized cost of electricity with a fixed premium

In euros per megawatt hour

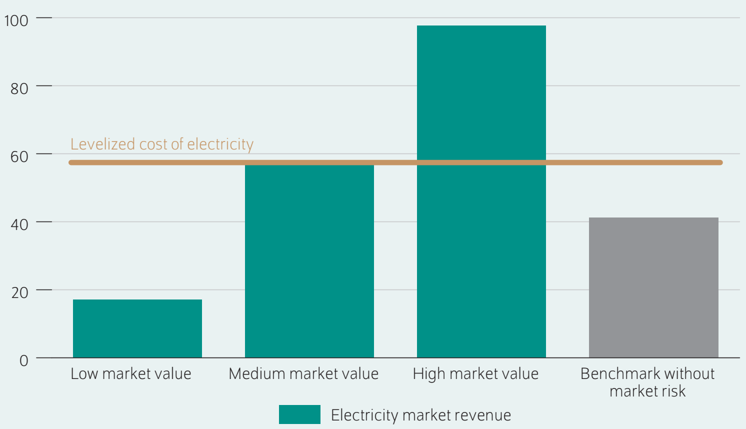


Source: Authors' own calculations.

The fixed premium is always the same, independent of the realized market values.

Figure 5

Revenues and levelized cost of electricity without a remuneration mechanism
In euros per megawatt hour

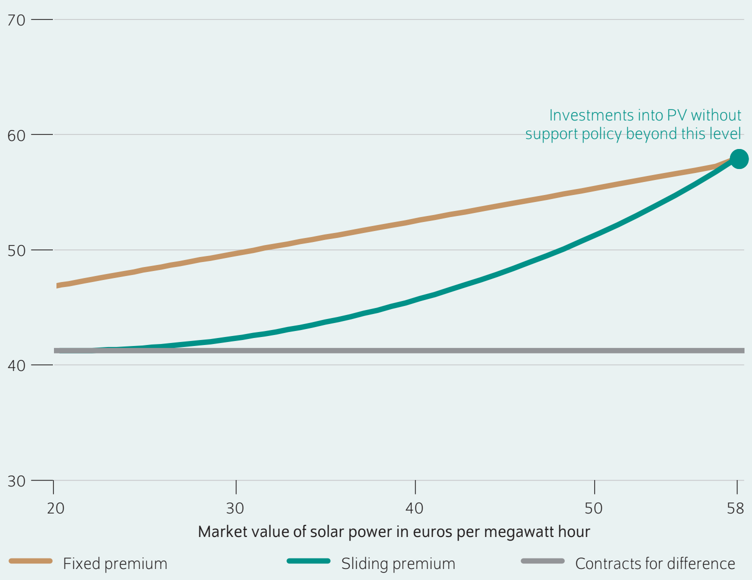


Source: Authors' own calculations.

Without a remuneration mechanism, electricity production costs are highest due to full equity financing.

Figure 6

Total costs under different remuneration mechanisms
In euros per megawatt hour



Source: Authors' own calculations.

Total costs are lowest under contracts for difference.

Without remuneration mechanisms, however, the revenue from electricity sales will not be hedged, which would result in the highest financing costs. If new renewable energy plants were built without a remuneration mechanism, the plants would be around one-third more expensive than plants built with risk hedged through CFDs. Project developers would only invest if the expected obtainable market values are more than one-third higher (e.g. due to higher carbon prices) than they are in comparable scenarios that include cost-effective remuneration mechanisms (see Figure 5).

Contracts for difference ensure the lowest total cost

For various expected market values of solar electricity and a range of policy options, we calculate the total cost that electricity consumers on average have to pay for new solar power plants. In the case of CFDs, the costs are independent of the expected market value, therefore remaining constant at the lowest possible value.

For a sliding premium, on the contrary, the total cost rises when the expected market value rises. When the market value is very low, a sliding premium functions like a CFD. It protects total revenue from electricity price uncertainty and leads to the same low costs. Yet, when market values are high, additional electricity market revenues exceeding the (falling) strike price of the sliding premium gain importance. This leads to higher financing costs and the total cost for electricity customers rises.

Due to the lack of protection against low market values and the resulting unfavorable financing conditions, fixed premiums always result in a higher total cost than the other remuneration mechanisms. This also applies to alternative implementations like capacity-based payments proportional to installed capacity.

If all remuneration mechanisms were abolished and market values are low, there would be little or no incentive to invest into new renewable energy plants. It would not be profitable to invest until the expected market value was around 30 percent higher than the price of a CFD.

This comparison of policy instruments shows that electricity consumers only fully benefit from falling technology costs in the case of CFDs. If the current sliding premium was retained, if a fixed premium was implemented, or if all remuneration mechanisms were abolished, this would not be the case, as the technology cost savings would be partially offset by increasing financing costs.

Germany's new coalition agreement stipulates that in 2030, a total of 65 percent of the electricity in the country will be generated from renewable sources.[7] Due to the more favora-

7 CDU, CSU, and SPD, Coalition agreement between the CDU, CSU, and SPD, 19th legislature period (available online).

ble financing conditions when implementing CFDs, by 2030, electricity consumers could realize annual savings of around 800 million euros in comparison to what they would pay if the current sliding premium was kept. This is the result of a back-of-the-envolope estimation (see Box 2). If the investments were made under a fixed premium, additional annual costs of just under 2.7 billion euros in comparison to the case with CFDs would be the result. And if remuneration mechanisms were simply abolished, the costs would be even higher at around 3.4 billion euros above the costs with CFDs.

Contracts for difference support actor variety and high realization rates

Only CFDs provide incentive for a wide range of actors to invest in renewable energy, enabling them to participate in the energy transition (see Table 1). Uncertain electricity market revenue must be taken into consideration when refinancing investment when the premium is sliding or fixed or in the absence of renewables remuneration mechanisms. It requires higher shares of equity for financing. This can be a detriment to actor variety, as small actors tend not to have large balance sheets of large energy suppliers that are in a better position to dedicate larger shares of equity to a project.[8] Reduced participation may result in a decline of support from local groups in the energy transition.

Reduced participation also reduces the competitiveness of the auctions. Although policy makers stipulated special rules for community energy companies as a means of compensating smaller actors for disadvantages in auctions, they ended up not meeting their goals[9] and have already been partially suspended in the medium term. Hence, a remuneration system that allows all actors to finance investments with low equity requirements is of particular relevance.

In the absence of CFDs, the investors with the most optimistic market expectations are increasingly winning the renewable energy auctions. The "winner's curse" could cause project realization rates to drop: Significant declines in expected longer-term power prices between the time of the renewable auction and final investment choice (closure) may trigger investors to revise their previous assumptions and abandon a project and pay the relevant penalties instead. This scenario would endanger Germany's expansion targets for renewable energy.

Changing electricity price or market value trends in the period between the auction and plant construction have no influence on operator revenue in a CFD system. This leads to higher realization rates.

8 Thorsten Helms, Sarah Salm, and Rolf Wüstenhagen, "Investor-Specific Cost of Capital and Renewable Energy Investment Decisions." In *Renewable Energy Finance – Powering the Future*, edited by Charles W. Donovan. Imperial College Press, 2015.

9 Bundesrat, Entwurf eines ... Gesetzes zur Änderung des Erneuerbare-Energien-Gesetzes (2018) (available online).

Box 2

Investment costs for reaching the 65-percent target by 2030

To calculate the relative additional cost of the remuneration mechanisms, we parameterize the financing model as follows. Electricity generation from renewable energy plants is assumed to increase from approximately 210 terawatt hours in 2017[1] to 505 terawatt hours.[2] We assume two-thirds of this growth to come from wind power (75 percent onshore and 25 percent offshore) and one-third from solar power (75 percent from ground-mounted systems and 25 percent from rooftop systems). We furthermore assume that eight gigawatts of old wind power plants will shut down or be replaced between 2020 and 2030. This is equal to half of the existing old plants, which will lose their claim to payment between 2020 and 2025.[3]

To estimate the implied investment volume between 2018 and 2030, we consider the costs of the least expensive plants (i.e., those that will win auctions) projected for 2025.[4]

Phelix-DE Base Futures for 2019 (43 euros per megawatt hour on June 28, 2018) serve as power price assumptions, which were multiplied with the current relative market values.[5] The result is a market value of 41.24 euros per megawatt hour for photovoltaics and 35.88 euros per megawatt hour for onshore wind power. Although the relative market values of renewable energy might fall until 2025, this will likely be offset by a rise in the absolute price of electricity.

1 Fraunhofer ISE, Energy Charts (2018) (available online).

2 Based on the average of the scenarios in the Deutsche Energie Agentur (dena) pilot study, which achieve emission reductions of 80–95 percent by 2050. See dena, dena-Leitstudie integrierte Energiewende, (2018) (available online).

3 See Deutsche WindGuard, Perspektiven für den Weiterbetrieb von Windenergieanlagen nach 2020 (2018) (available online).

4 Fraunhofer ISE, Stromgestehungskosten erneuerbare Energien (2018) (available online).

5 European Energy Exchange (EEX) Market Data (2018) (available online).

Table 1

Qualitative evaluation of remuneration mechanisms

	Sliding premium	Contracts for difference	Fixed premium	Without remuneration mechanism
Realization rates (avoiding Winner's Curse)	0	+	–	n.a.
Facilitating investments by a wide range of investors	0	+	–/0	–
Hedging of electricity consumers against high prices	0	+	–	–
Low renewable energy levy	+/0	0	+/–	+ (levy is zero)
Low financing costs and thus also low total costs	0	+	–	–

Source: Authors' own depiction.

All things considered, contracts for difference have the best performance.

CFDs also lead to symmetrical hedging of investors and electricity consumers. Investors obtain a hedge against low market values for renewable energy, and electricity consumers obtain a hedge against increasing wholesale power prices. The other three alternatives do not lead to long-term protection of electricity consumers.

Smooth transition to contracts for difference expected

The transition to CFDs can be implemented with only a few adjustments of the current remuneration mechanism. Its key feature, possible repayments to grid operators, can be achieved by simply adjusting the definition of the existing sliding premium. Currently, the premium is zero when the price of electricity is higher than the strike price. This would have to be changed such that in accordance with the difference between the strike price and the technology-specific market value of the electricity, the payment can also be negative.

If plant operators can exit CFDs in the months and years when electricity prices are high, then consumers would forego their part of the deal, the hedge against high power prices. This is why CFDs should not comprise exit options. Investors can decide, prior to project start, whether they prefer to invest within the remuneration mechanism and participate in auctions for CFDs or whether they rather invest without such a CFD.[10]

Four options for implementing contracts for difference

Various options for the implementation of CFDs are available. The options differ in two aspects. First, whether local incentives ("Where will the new plants be built?") are provided through the reference yield model, as currently in Germany the case for wind power, or whether they are provided through regionally differentiated auctions. The second aspect relates to the question how incentives for system-friendly design choices are created – either through opportunities for better marketing of the production in spot markets or through a market value factor. The design choices primarily influence the investment decision but can also impact operating decisions (see Table 2).

A system-friendly, regional distribution of plants across the system reduces costs for balancing the system and results in fewer grid bottlenecks. The variety of sites ultimately required to provide sufficient renewable energy for a decarbonized economy would thus be developed in parallel rather than starting from the sites offering for example the highest wind-speeds. A remuneration mechanism creating regionally differentiated incentives also limits excessive profits and rents on sites with more favorable resources.

In the case of wind power, the reference yield model has determined plant- and site-specific adjustment factors since 2000. They enable investment in sites with less wind and tap excess revenue at strong wind sites. The payment amount is adjusted to the expected yield: the wind turbines on sites at which fewer (but not too few) full load hours of electricity generation are expected receive a higher payment. The remuneration mechanism for photovoltaics does not entail such a locational element, but both options for locational incentives are in principle feasible.

Alternative plant designs such as system-friendly wind turbines with lower peak generation capacity compared to overall power production, or east-west orientation of solar plants, shift the electricity production from times with very high renewable power production, when renewable power is less valuable, to times with lower renewable power production when the power is more valuable for the system. Thus overall system costs and possibly grid requirements can be reduced.

10 The Bundesverband der Energie- und Wasserwirtschaft (BDEW) industry association examined the issue and recommends a multiple bottom line model by which project developers can select a payment form ex ante. Bundesverband der Energie- und Wasserwirtschaft, Marktkräfte beim Erneuerbaren-Ausbau stärken (2018) (available online).

Option 1: Reference yield model + electricity market revenue

CFDs could be implemented without changing the existing incentives for the locational diversification and system friendly design of wind power and solar plants. The reference yield model provides incentives for site selection. A site-adjustment-factor is applied to the remuneration level as function of the projected wind output at a site. In five year intervals the realized wind-output (excluding down-times of turbines) is then measured and the site-adjustment factor corrected in case of large deviations. This system in principle allows for the installation of wind-turbines across a range of sites. It provides some hedge for the expected revenues against deviations from the expected site quality, thus reducing risks and financing costs for investors and ultimately consumers. At the same time, it protects electricity consumers against payments that are too high on sites with better wind resources.

Incentives for system-friendly plant dimensioning is, in this design option, expected from spot market sales: A system-friendly plants produces a large share of the electricity in times of higher electricity prices and are therefore able to obtain a higher monthly average electricity price than the average of all plants. Defining the CFD with a monthly reference period based on production of all German plants (of a technology category like solar) thus creates an incentive for the choice of a system friendly plant. This incentive is however weak, since the possible added revenue generated across plant lifetimes is uncertain. Therefore, this additional revenue cannot be used to raise bonds or loans to cover the additional costs of system-friendly plants. Instead, the additional costs must be financed with equity. This leads to high revenue discounts and in turn, to low incentives to build system-friendly plants.

Option 2: Regional auctions + electricity market revenue

As an alternative to the reference yield model (Option 1), locational incentives could be created with regional elements in auctions for the CFDs. For on-shore wind auctions one such differentiation is already implemented. A constraint has been implemented on the volume of bids (in megawatts) from wind turbines in the northern German grid expansion area that will be awarded contracts in the auction. However, if smaller regions with fixed and binding constraints are implemented, this will reduce the level of competition of the auctions. Furthermore, prospects of success for auction participants are more difficult to predict if fixed and binding constraints reduce liquidity in the auctions. It could thus also reduce competition between regions, which in itself creates incentives for efficient planning processes. Instead, auction results would lead to higher payments in regions with higher regulatory barriers, and all German electricity consumers would have to pay for them in the form of the EEG levy. In any case, further research is needed on protecting investors and consumers against uncertain site assessments.

Table 2

Options for the design of contracts for difference

		Incentives for system-friendly design	
		Power market revenues	Market value factor
Locational diversification	Reference yield model	Option 1	Option 3
	Regional tenders	Option 2	Option 4

Note: Option 1 represents the status quo for wind power in Germany.

Source: Authors' own depiction.

Option 3: Reference yield model + market value factor

Differing from Option 1, a market value factor can be determined for each project that bids in an auction, which provides incentives for more system-friendly plant design. The market value factor would be calculated prior to the auction based on the projected hourly electricity production using wind data from a reference year and an hourly electricity price profile for this reference year. The higher market value of a system friendly turbine would be used to adjust the strike price for which project developers bid in the CFD auctions.

Therefore investors will include the expected additional revenue of a system-friendly turbine fully in their investment decisions. Exposure to electricity price developments during operation are no longer required. Accordingly, the reference period of the CFDs can be reduced from a month to an hour, as already is customary in the UK. This lowers both the revenue risk and financing costs, thus reducing the overall costs of expanding renewable energies.

Either historical hourly electricity prices (from the previous year, for example) or price time series from long-term forecasts can be used as the basis for the market value calculation. The relevant electricity price profile would be published by the regulatory agency. It would have to be updated on an ongoing basis and announced early enough to give investors stable framework conditions for project development.[11]

Option 4: Regional auctions + market value factor

Regional auctions, as introduced in option 2, can also be combined with a market value factor. The market value factor would be determined by the procedure described in Option 3.

11 The national regulatory board – in Germany, the Federal Network Agency (*Bundesnetzagentur*) – could model the electricity sector for a future period, and this could be used as an alternative basis in the long term. The regulatory board could use such modeling to publish an electricity price profile that could be a means of comparing the relative market values of the plants at a given site. In the process, other factors such as the system-friendliness of the plants could be included. For more information, see Nils May, "The Impact of Wind Power Support Schemes on Technology Choices," *Energy Economics* 65 (2017) 343–354; and in modified form, Karsten Neuhoff, Nils May, and Jörn Richstein, "Incentives for the Long-Term Integration of Renewable Energies: A Plea for a Market Value Model," *DIW Economic Bulletin* 46/47 (2017): 929-938 (available online).

Conclusion: Transition to contracts for difference should be initiated

Renewable energy technologies have seen large cost reductions in recent years and further reductions are expected for the future. The type of remuneration mechanism impacts to what extent electricity consumers can benefit from such cost reductions. The calculations presented here show that if the cost of electricity continues to fall relative to the market value of renewable electricity production, higher financing costs partially offset the cost reductions in the current remuneration mechanism (sliding premium). Therefore, electricity consumers do not fully benefit from falling technology costs. The increased risk exposure also requires higher shares of equity in project finance – and may thus increasingly preclude participation of some actors, resulting in reduced levels of competition and possibly causing the realization rate of projects to decrease.

If the current remuneration mechanism were replaced by contracts for difference, plant operators would be hedged against a low market value of their electricity. At the same time, electricity consumers would be protected against high payments for renewable electricity in case of high electricity prices. In contrast to the sliding premium, plant operators would not retain the additional income if future power prices turn out high. Contracts for difference ensure that additional revenues are returned to consumers through a lowered EEG levy, which can in the long-run even turn negative. Further, investors have a revenue hedge under the CFD system, which enables favorable financing costs and in turn, a lower total cost of renewable electricity. Compared to the sliding premium, contracts for difference are expected to save around 800 million euros annually by 2030 in investment costs.

Other possible options, such as a fixed premium or abolishing remuneration mechanisms entirely, would, however, lead to an increase in total costs by 2.7 and 3.4 billion euros annually compard to CFDs, respectively, and are, therefore, not considered viable alternatives.

There are a number of alternative ways to implement CFDs that provide an opportunity to create more effective and simple incentives for system-friendly site selection and plant design. The combination of a reference yield model and a market value factor appears to be a particularly effective means for the further development of the remuneration mechanism.

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