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# From FIT to FIP: assessing the impact of feed-in policies on renewable development and spot market in Germany

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# From FIT to FIP: assessing the impact of feed-in policies on renewable development and spot market in Germany

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**Abstract**:

This study investigates the effectiveness of feed-in policies in Germany. By adopting the autoregressive distributed lag error correction model, we examine both the short- and long-term impacts of feed-in policies on renewable energy deployment in terms of power generation and approved installation capacity. The estimation results show that the feed-in premium scheme achieved its objective of encouraging the market integration of wind energy, but discouraged and retarded investment in solar power technologies. Additionally, our results confirm that the feed-in tariff mechanism creates greater investment security for solar power projects.

**Keywords**: Feed-in Premium, Feed-in Tariff, Renewable Energy, Market Integration, Autoregressive Distributed Lag

## 1. Introduction

Under the feed-in-tariff (FIT) framework, the tariff for RE electricity is set according to the actual power generation cost of each RE technology and maintained at the same level regardless of demand--supply balance or market price. An alternative emerged with the adoption of the feed-in premium (FIP), a market premium system announced by EEG[1] 2012, which sets incentives for demand-oriented RE feed-in and efficient marketing of RE electricity in Germany (Purkus et al., 2015). Previous German research has mainly focused on the effectiveness of the FIT policy (Dillig et al., 2016; Böhringer et al., 2017; Hitaj and L Löschel, 2019); however, our study compares the impact of the market premium FIP system with the fixed-tariff FIT approach, in order to illustrate the possible changes in the investment environment of RE caused by the policy transition from FIT to FIP. Since the optional sliding FIP was implemented in 2012, both onshore and offshore wind power investors have shown more willingness to participate in direct marketing than solar energy technology investors have. Along with the EEG amendment, the share of direct marketing of onshore wind power increased from 68.7% in 2012 to 96.1% in 2021. There has been a sharp decrease in the share of the FIT for solar energy since the enforcement of the optional FIP; meanwhile, 57.8% of solar power generation is still incentivized based on the FIT approach in 2021[2].

## 2. Empirical Model

To identify the short-run relationship between changes in tariff rates of feed-in policies and RE deployment, we utilize the cointegration techniques of the autoregressive distributed lag (ARDL). The unit root tests of augmented Dickey-Fuller and Kwiatkowski-Phillips-Schmidt-Shin confirm that all the variables' order of integration does not exceed the value of 1 (I(0) or I(1)); this suggests that the ARDL model is appropriate for this study. Long-term elasticity is further estimated, since the ARDL bound test suggested that all variables have a cointegration relationship. The ARDL in its unrestricted error correction model (ECM) form can be represented as follows:

$$\Delta\, lnY_t = \beta_0 + \beta_1 \sum_{i=1}^{p} \Delta\, lnY_{t-i} + \beta_2 \sum_{i=1}^{q} \Delta\, lnX_{t-i} + \alpha_1 lnY_{t-1} + \alpha_2 lnX_{t-1} + \lambda Trend + \epsilon_t,$$

where $\Delta$ denotes the first difference, the short run impacts are represented by $\beta_1$ and $\beta_2$, $\alpha_1$ measures the speed of adjustment back to long run equilibrium, and the estimations of $\alpha_2$ divided by $\alpha_1$ and multiplied by (-1) determine the long run impacts. The dependent variables $Y_t = (generation_t, approvedcapacity_t)'$ are used to represent power generation and the

[1] The Renewable Energy Sources Act (in English), Erneuerbare-Energien-Gesetz (in German).
[2] Authors' own calculation according to "EEG in figures: Remuneration, differential costs and EEG surcharge from 2000 to 2022".

newly approved installation capacity of RE[3] facilities in month t. These indicators are used to capture the market integration and investment intention for RE. The independent variables $X_t$ include FIP and FIT tariff rates for REs, installed capacity of RE facilities, natural gas-fired power generation, and electricity imports. Trend is the monthly time trend. Optimal lag values p and q are obtained under the Akaike information criterion.

The time-series data of this study cover the period from January 2015 to September 2018 for Germany's electricity spot market. Data for renewable power electricity generation are gathered from the ENTSO-E (European Network of Transmission System Operators for Electricity). Information on newly approved capacity of RE power plants is from the register data on renewable power plants released by the Federal Network Agency4. Approved capacity is the estimated capacity to be reached after the construction work of projects is completed and projects become fully operational. In this study, newly approved capacity of power plants in each month is used to capture the investment intention of power producers. Previous studies also use these indicators to measure renewable power deployment (Menz and Vachon, 2006; Hitaj and Löschel, 2019). As policy incentive variables, we use the monthly tariff rate of feed-in policies. The tariff rate of the $FIP$ is calculated every calendar month as the difference between the predetermined reference tariff ($r$) (legally defined for each technology under the sliding FIP scheme) and monthly market value of the electricity sold ($MW$): $FIP = r - MW, if\ r - MW \geq 0;\ FIP = 0$, otherwise. Calculation of the monthly market value for electricity from wind energy and solar energy is based on their own hourly electricity generation ($w_t$) and hourly market price ($p_t$) : $MW = \sum_t w_t p_t / \sum_t w_t$. For both wind and solar energy, the reference tariff rates under the FIP and the tariff rates of FIT decrease regularly. To simplify the calculation of incentives under the FIP, the reference tariff rate of the market premium for solar power is the weighted average of the tariff rate for different scales of a project. The reference tariff for wind power is the weighted average of the initial and basic values based on different definitions of the initial period based on the EEGs[5]. We hypothesize that a uniform reference tariff is offered at all wind project locations, as opposed to the wind potential-dependent incentive[6].

## 1. Estimation results and Discussion

Regarding the power generation models' results in Table 1, there is evidence of a positively and statistically significant impact of the FIP on encouraging power generation from both onshore and offshore wind energy in the short term. For instance, there is a 0.63% increase in onshore wind power

[3] In this study, RE sources include solar, onshore, and offshore wind power.
[4] EEG register data and reference values for payment, Bundesnetzagentur.
[5] The EEG 2014 states that power generators should receive the initial reference tariff for the first 5 years of operation, and the basic value for the remaining 15 years. The first 12 years after the installation are defined as the initial period in the EEG 2017.
[6] Hitaj and Löschel (2019) adopted a similar approach.

generation in response to a 1% positive shock in FIP tariff rate. Additionally, as shown in columns (3) and (5) in Table 1, a further increase in onshore and offshore wind power generation is observed under the maximum incentive level[7] in the short term. These results show the ability of wind power producers to react to market signals, through the RE aggregators, combined use of storage battery and heat storage systems (Sheikhahmadi and Bahramara, 2020), and demand-response resources. The negative and statistically significant coefficients of the ECM reveal that most short-run deviations of the variables can be returned to the long-run equilibrium within a short period.

[Table 1]

Columns (1)-(3) in Table 2 show the long-run elasticities of the power generation model[8]. The opposite sign of the coefficients of FIP and FIT reveal that onshore wind power production had a symmetrical response to the change in the FIP tariff level in the long-term equilibrium state; meanwhile, the FIT did not exert a similar market integration impact, since tariff levels under the FIT remain independent from the market price. Simultaneously, we find that receiving maximum incentive would not encourage wind power generation in the long term, which confirms the efficiency of the current incentive level under the FIP.

[Table 2]

Moreover, the incentives assigned to RE had different effects on newly approved capacity of power plants (Table 3). In the short run, we find that adopting a FIP has negatively affected investment intention for solar power by decreasing the scale of newly approved projects (column (1), Table 3). For solar energy investors, especially for producers of distributed solar power projects, FIP schemes entail additional elements of uncertainty, including transaction costs, costs for forecasting weather and demand, and imbalanced pricing, resulting in higher financing costs (Energypedia, n.d.). The FIP policy-induced reduction in newly approved capacity of solar power projects indicates that developers tend to invest in small-scale projects, as direct market exceptions are granted to small power plants with capacities below a certain threshold[9]. This exception gives investors an additional option to avoid potential financial risk under the FIP. Investors' willingness to invest in solar energy shifted to medium and small-sized[10] power generation facilities. Wehrmann (2020) expected much of the growth of solar power to be driven by

[7] In this case, we assume that wind power projects receive the maximum incentive, which is the initial reference tariff for the entire 20-year operation period.
[8] The long-run elasticities are calculated as the value of the long-run coefficient divided by the ECM value and multiplied by (-1). The long-run coefficients and ECM values are shown in Tables 1 and 3.
[9] Direct marketing obligation exceptions have been granted to RE plants with installed capacities below 500 kW since August 2014. The obligation targets were extended to power plants with installed capacities above 100 kW from January 2016.
[10] The Federal Network Agency defines small-sized power plants as power plants with installed capacities over 100 kW and up to 750 kW.

small projects whose capacities are below the 750-kW limit, which exempts them from auctions for RE support.

[Table 3]

By focusing on long-term elasticities of the approved installed capacity model (columns (4)-(6) in Table 2), we find that the promotion of solar power technologies can be positively affected by the FIT only in the long run. The FIT scheme for RE has promoted investment and encouraged new entrants into RE, as power producers enjoy the benefits of predictability of a return on investment (Kobayashi et al., 2020). The FIP mechanism did not show a similar statistically significant effect, since the remuneration of produced energy is now market dependent, unlike the price stability of the FIT scheme (Loukidis et al., 2018). As stated in Schallenberg-Rodriguez and Haas (2012), fixed tariff FIT creates greater investment security. The lower-risk environment can encourage the participation of smaller and more risk-averse investors.

## 2. Conclusions

This study confirmed that wind energy reacts to market signals in Germany. We find that the policy intervention of market premiums has had a sustainable market activation effect over the long term, by encouraging market integration of onshore wind power generated electricity. By contrast, our results confirm that the FIT has encouraged the promotion of solar energy projects, while FIP significantly decreasing the investment intention for solar projects. Solar power developers tend to invest in distributed projects excluded from the direct marketing obligation, to avoid potential financial risk under the FIP.

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Table 1. Estimation results on power generation
*(with diagnostics tests results)*

| | power generation | | | | |
|---|---|---|---|---|---|
| | lnsolar | lnonshore wind | | lnoffshore wind | |
| | (1) | (2) | (3) | (4) | (5) |
| Short term | | | | | |
| D.lnFIP_solar | -0.470 | | | | |
| | (0.474) | | | | |
| D.lnFIT_solar | 5.528 | | | | |
| | (8.017) | | | | |
| D.lnFIP_onshore wind | | 0.6303*** | | | |
| | | (0.1083) | | | |
| D.lnFIP_onshore wind_i | | | 2.4526*** | | |
| | | | (0.3198) | | |
| LD.lnFIP_onshore wind_i | | | 1.5419** | | |
| | | | (0.5508) | | |
| L2D.lnFIP_onshore wind_i | | | 0.8699* | | |
| | | | (0.4677) | | |
| L3D.lnFIP_onshore wind_i | | | 0.8165** | | |
| | | | (0.3582) | | |
| D.lnFIT_onshorewind | | -25.4469*** | -9.4659 | | |
| | | (3.9195) | (8.3250) | | |
| LD.lnFIT_onshorewind | | | 7.0294 | | |
| | | | (10.7354) | | |
| L2D.lnFIT_onshorewind | | | -18.0549 | | |
| | | | (12.7496) | | |
| D.lnFIP_offshore wind | | | | 1.6133*** | |
| | | | | (0.4827) | |
| LD.lnFIP_offshore wind | | | | 1.0267 | |
| | | | | (0.7188) | |
| L2D.lnFIP_offshore wind | | | | 1.0689* | |
| | | | | (0.5575) | |
| L3D.lnFIP_offshore wind | | | | 0.9624* | |
| | | | | (0.4827) | |
| D.lnFIP_offshore wind_i | | | | | 2.6952*** |
| | | | | | (0.8282) |
| LD.lnFIP_offshore wind_i | | | | | 1.6271 |
| | | | | | (1.2092) |
| L2D.lnFIP_offshore wind_i | | | | | 1.7458* |
| | | | | | (0.9407) |
| L3D.lnFIP_offshore wind_i | | | | | 1.6086* |
| | | | | | (0.8208) |
| Long term | | | | | |
| L.lnFIP_solar | -0.896 | | | | |
| | (0.915) | | | | |
| L.lnFIT_solar | -12.258 | | | | |
| | (10.421) | | | | |
| L.lnFIP_onshorewind | | 0.2884*** | | | |
| | | (0.0400) | | | |
| L.lnFIT_onshorewind | | -11.6426*** | -12.0724*** | | |
| | | (1.2362) | (1.3691) | | |
| L.lnFIP_onshorewind_i | | | 0.315 | | |
| | | | (0.2603) | | |
| L.lnFIP_offshorewind | | | | -0.4175 | |
| | | | | (0.4523) | |
| L.lnFIP_offshorewind_i | | | | | -0.6402 |
| | | | | | (0.7791) |
| ECM | -0.5246*** | -2.1857*** | -1.6857*** | -1.1576*** | -1.1453*** |
| | (0.115) | (0.2558) | (0.2632) | (0.1802) | (0.1806) |
| cons | 23.973 | 67.1138*** | 54.4428*** | 13.1413*** | 13.8984*** |
| | (17.068) | (9.0778) | (9.2039) | (2.7352) | (3.6491) |
| Controls | YES | YES | YES | YES | YES |
| Time trends | YES | YES | YES | YES | YES |
| Diagnostics Tests | | | | | |
| Adj.$R^2$ | 0.802 | 0.738 | 0.840 | 0.750 | 0.745 |
| Durbin-Watson | 2.314 | 2.345 | 2.283 | 2.248 | 2.231 |
| LM | 0.187 | 0.077 | 0.137 | 0.226 | 0.236 |
| White | 0.427 | 0.427 | 0.427 | 0.427 | 0.427 |
| Jarque-Bera | 0.168 | 0.239 | 0.213 | 0.764 | 0.770 |

Note: standard error in parentheses. The diagnostics tests are based on the F-statistics: LM refers to the Breusch-Godfrey test; ***, **, * mean significant at the 1%, 5%, and 10% levels, respectively.

Table 2. Elasticities

| | Power generation | | | Newly approved installation capacity | | |
|---|---|---|---|---|---|---|
| | lnsolar | lnonshore wind | | lncap_solar | lncap_onshore wind | |
| | (1) | (2) | (3) | (4) | (5) | (6) |
| L.lnFIP_solar | | | | -0.903*** | | |
| L.lnFIT_solar | | | | 9.620*** | | |
| L.lnFIP_onshorewind | | 0.132*** | | | | |
| L.lnFIP_onshorewind_i | | | | | | |
| L.lnFIT_onshorewind | | -5.327*** | -7.162*** | | | |

Notes: ***, **, and * mean significance at the 1%, 5%, and 10% levels, respectively.

Table 3. Estimation results on newly approved capacity of power plants
*(with diagnostics tests results)*

| | Newly approved capacity | | | | |
|---|---|---|---|---|---|
| | lncap_solar | lncap_onshore wind | | lncap_offshore wind | |
| | (1) | (2) | (3) | (4) | (5) |
| Short term | | | | | |
| D.lnFIP_solar | -3.4831*** | | | | |
| | (0.7125) | | | | |
| D.lnFIT_solar | 8.9779 | | | | |
| | (15.4326) | | | | |
| LD.lnFIT_solar | -14.5462 | | | | |
| | (12.7935) | | | | |
| D.lnFIP_onshorewind | | -0.1124 | | | |
| | | (0.2074) | | | |
| LD.lnFIP_onshorewind | | -0.0459 | | | |
| | | (0.6028) | | | |
| L2D.lnFIP_onshorewind | | 0.7689 | | | |
| | | (0.5499) | | | |
| L3D.lnFIP_onshorewind | | -0.4261 | | | |
| | | (0.3460) | | | |
| D.lnFIP_onshorewind_i | | | -0.5139 | | |
| | | | (0.7028) | | |
| LD.lnFIP_onshorewind_i | | | -0.522 | | |
| | | | (1.0341) | | |
| L2D.lnFIP_onshorewind_i | | | 1.5569 | | |
| | | | (0.9860) | | |
| L3D.lnFIP_onshorewind_i | | | -0.6903 | | |
| | | | (0.6631) | | |
| D.lnFIT_onshorewind | | -56.8122*** | -63.7556*** | | |
| | | (16.6885) | (15.5389) | | |
| LD.lnFIT_onshorewind | | 39.0671* | 45.5793** | | |
| | | (19.6509) | (20.2323) | | |
| L2D.lnFIT_onshorewind | | -52.1178** | -39.1831 | | |
| | | (23.8856) | (23.9355) | | |
| L3D.lnFIT_onshorewind | | -24.783 | | | |
| | | (24.1306) | | | |
| D.lnFIP_offshorewind | | | | -3.4163 | |
| | | | | (2.5816) | |
| D.lnFIP_offshorewind_i | | | | | -5.5272 |
| | | | | | (4.4809) |
| Long term | | | | | |
| L.lnFIP_solar | -1.7735*** | | | | |
| | (0.3619) | | | | |
| L.lnFIT_solar | 18.8944*** | | | | |
| | (4.4815) | | | | |
| L.lnFIP_onshorewind | | 0.1888 | | | |
| | | (0.3680) | | | |
| L.lnFIT_onshorewind | | -1.2927 | -0.5208 | | |
| | | (3.3303) | (3.8137) | | |
| L.lnFIP_onshorewind_i | | | 0.9521 | | |
| | | | (0.6527) | | |
| L.lnFIP_offshorewind | | | | -8.3351 | |
| | | | | (6.5414) | |
| L.lnFIP_offshorewind_i | | | | | -13.5053 |
| | | | | | (11.2512) |
| ECM | -1.9640*** | -1.4149*** | -1.2918*** | -0.4099*** | -0.4093*** |
| | (0.3681) | (0.3088) | (0.3222) | (0.1417) | (0.1423) |
| Cons | -88.3186*** | 3.2473 | 0.9652 | 32.1548 | 38.785 |
| | (27.8533) | (10.0100) | (10.1897) | (20.7048) | (24.6945) |
| Controls | YES | YES | YES | YES | YES |
| Time trends | YES | YES | YES | YES | YES |
| Diagnostics Tests | | | | | |
| Adj.$R^2$ | 0.645 | 0.930 | 0.929 | 0.127 | 0.122 |
| Durbin-Watson | 1.992 | 1.904 | 1.836 | 2.019 | 2.008 |
| LM | 0.976 | 0.641 | 0.371 | 0.851 | 0.889 |
| White | 0.247 | 0.427 | 0.427 | 0.240 | 0.224 |
| Jarque-Bera | 0.198 | 0.945 | 0.760 | 0.965 | 0.964 |

Note: standard error in parentheses. The diagnostics tests are based on the F-statistics: LM refers to the Breusch-Godfrey test; ***, **, * mean significant at the 1%, 5%, and 10% levels, respectively.

# Appendix

Table A1. Summary Statistics

| Variables | Abbreviations | | Mean | Std. Dev. | Min | Max |
|---|---|---|---|---|---|---|
| **Market Premium:** | | | | | | |
| Market Premium for solar | lnFIP_solar | % | 1.920 | 0.156 | 1.439 | 2.101 |
| Market Premium for onshore wind | lnFIP_onshore wind | % | 0.960 | 0.566 | -1.820 | 1.409 |
| Initial value of market Premium for onshore wind | lnFIP_onshore wind_i | % | 1.687 | 0.220 | 0.918 | 1.951 |
| Market Premium for offshore wind | lnFIP_offshore wind | % | 1.993 | 0.110 | 1.640 | 2.139 |
| Initial value of market Premium for offshore wind | lnFIP_offshore wind_i | % | 2.510 | 0.064 | 2.311 | 2.598 |
| **Feed-in Tariff:** | | | | | | |
| Tariff rates for solar PV | lnFIT_solar | % | 1.915 | 0.076 | 1.770 | 1.991 |
| Tariff rates for onshore wind | lnFIT_onshore wind | % | 2.394 | 0.023 | 2.357 | 2.442 |
| **Electricity generation:** | | | | | | |
| Solar power generation | lnsolar | % | 16.12 | 0.762 | 14.50 | 17.02 |
| Onshore wind power generation | lnonshore wind | % | 16.96 | 0.375 | 16.23 | 17.74 |
| Offshore wind power generation | lnoffshore wind | % | 15.20 | 0.507 | 13.86 | 16.00 |
| **Newly approved installation capacity:** | | | | | | |
| Newly approved installation capacity of solar | lncap_solar | % | 4.944 | 0.741 | 3.829 | 6.509 |
| Newly approved installation capacity of onshore wind | lncap_onshore wind | % | 5.634 | 0.735 | 3.879 | 7.205 |
| Newly approved installation capacity of offshore wind | lncap_offshore wind | % | 3.257 | 1.921 | 0.000 | 5.751 |
| **Controls:** | | | | | | |
| Electiricity import | import | % | 8.105 | 0.421 | 7.175 | 8.920 |
| Natural gas power generation | naturalgas | % | 7.837 | 0.242 | 7.296 | 8.246 |

Note: $FIP\_onshorewind\_i$ and $FIP\_offshorewind\_i$ illustrates the maximum incentive level under the FIP. In this case, we assume that wind power projects receive the maximum incentive, which is the initial reference tariff for the entire 20 -year operation period.

Table A2. Unit root test

| | Variables in levels | | Variables in first difference | |
|---|---|---|---|---|
| | ADF | KPSS | ADF | KPSS |
| ln_solar | -5.358*** | 0.175 | -3.826** | 0.123 |
| ln_onshorewind | -2.687 | 0.382* | -4.647*** | 0.043 |
| ln_offshorewind | -2.956 | 2.360 | -4.056*** | 0.092 |
| ln_capsolar | -3.019 | 2.240 | -7.306*** | 0.024 |
| ln_caponshorewind | -5.975*** | 0.138 | -15.44*** | 0.019 |
| ln_capoffshorewind | -2.506 | 0.504** | -4.878*** | 0.066 |
| ln_FIP_solar | -2.466 | 1.480*** | -4.438*** | 0.106 |
| ln_FIP_onshorewind | -1.501 | 1.370*** | -5.449*** | 0.090 |
| ln_FIP_offshorewind | -1.632 | 1.090*** | -5.644*** | 0.110 |
| ln_FIT_solar | -2.127 | 3.570*** | -4.292*** | 0.124 |
| ln_FIT_onshorewind | -1.994 | 4.260*** | -11.34*** | 0.067 |
| ln_demand | -2.443 | 0.086 | -3.954** | 0.035 |

Note: The unit root tests of Augmented Dickey-Fuller (ADF) and Kwiatkowski-Phillips-Schmidt-Shin (KPSS) confirm that all the variables' order of integration do not exceed the value of one (I(0) or I(1)). ***, **, * indicate rejection of the null hypothesis at 1%, 5%, and 10%, respectively.

Table A3. Cointegration test result.

| | Power generation | | | Newly approved installation capacity | | |
|---|---|---|---|---|---|---|
| | ln_solar | ln_onshore wind | ln_offshore wind | lncap_solar | lncap_onshore wind | lncap_offshore wind |
| F-test statistics | 12.271 | 9.140 | 4.710 | 4.281 | 3.392 | 4.349 |
| Asymptotic Critical Values | | | | | | |
| | 99% level | 99% level | 95% level | 95% level | 90%level | 95% level |
| I(0): | 3.74 | 3.74 | 2.86 | 2.62 | 2.26 | 2.86 |
| I(1): | 5.06 | 5.06 | 4.01 | 3.79 | 3.35 | 4.01 |

Note: The table shows F-test of joint significance of variables. We conclude that the variables are cointegrated, regardless of whether they are stationary or not, if the observed test statistic exceeds the upper critical band. The results suggest evidence of a long-run relationship between the variables.

Table A4. Feed-in tariff rates (€/kWh) and degression rates (%)

| Solar PV | | Degression rate | < 10kW | [10kw, 40 kW) | [40kW,1MW) | [1MW,10MW) | ≥ 10MW |
|---|---|---|---|---|---|---|---|
| EEG 2012 | | | | | | | |
| 2012/4/1 | | - | 0.1950 | 0.1850 | 0.1650 | 0.1350 | 0.1350 |
| 2012/5/1 | △ | 1.00% | 0.1931 | 0.1832 | 0.1634 | 0.1337 | 0.1337 |
| 2012/11/1 | △ | 2.50% | 0.1790 | 0.1698 | 0.1515 | 0.1239 | 0.1239 |
| 2013/2/1 | △ | 2.20% | 0.1664 | 0.1579 | 0.1408 | 0.1152 | 0.1152 |
| 2013/5/1 | △ | 1.80% | 0.1563 | 0.1483 | 0.1323 | 0.1082 | 0.1082 |
| 2013/11/1 | △ | 1.40% | 0.1407 | 0.1335 | 0.1191 | 0.0974 | 0.0974 |
| 2014/2/1 | △ | 1.00% | 0.1355 | 0.1285 | 0.1146 | 0.0938 | 0.0938 |
| EEG 2014 | | | | | | | |
| 2014/8/1 | | 1.00% | 0.1275 | 0.1240 | 0.1109 | 0.0883 | |
| 2014/9/1 | △ | 0.50% | 0.1269 | 0.1233 | 0.1104 | 0.0879 | |
| 2014/10/1 | △ | 0.25% | 0.1266 | 0.1230 | 0.1101 | 0.0877 | |
| 2015/10/1 | △ | 0.00% | 0.1231 | 0.1196 | 0.1071 | 0.0853 | |
| EEG 2017 | | | | | | | |
| 2017/1/1 | | 0.00% | 0.1230 | 0.1196 | 0.1069 | 0.0851 | |
| 2017/2/1 | △ | 0.00% | 0.1230 | 0.1196 | 0.1069 | 0.0851 | |
| 2017/5/1 | △ | 0.25% | 0.1227 | 0.1193 | 0.1066 | 0.0849 | |
| 2017/8/1 | △ | 0.00% | 0.1220 | 0.1187 | 0.1061 | 0.0845 | |
| 2018/8/1 | △ | 1.00% | 0.1208 | 0.1175 | 0.1050 | 0.0837 | |
| Onshore wind | | | Initial value | Basic value | | | |
| EEG 2012 | | | | | | | |
| 2012/4/1 | | - | 0.0893 | 0.0487 | | | |
| 2013/1/1 | ∗ | 1.50% | 0.0880 | 0.0480 | | | |
| EEG 2014 | | | | | | | |
| 2014/8/1 | | | 0.0890 | 0.0495 | | | |
| 2016/1/1 | | 1.20% | 0.0879 | 0.0489 | | | |
| 2016/4/1 | | 1.20% | 0.0868 | 0.0483 | | | |
| 2016/7/1 | | 1.20% | 0.0858 | 0.0477 | | | |
| 2016/10/1 | | 1.20% | 0.0848 | 0.0472 | | | |
| EEG 2017 | | | | | | | |
| 2017/1/1 | | | 0.0838 | 0.0466 | | | |
| 2017/3/1 | △ | 1.05% | 0.0829 | 0.0461 | | | |
| 2017/10/1 | | 2.40% | 0.0740 | 0.0403 | | | |
| 2018/1/1 | | 2.40% | 0.0722 | 0.0393 | | | |
| 2018/4/1 | | 2.40% | 0.0705 | 0.0384 | | | |
| 2018/7/1 | | 2.40% | 0.0688 | 0.0375 | | | |
| 2018/10/1 | | 2.40% | 0.0672 | 0.0366 | | | |
| Offshore wind | | | Initial value | Basic value | | | |
| EEG 2012 | | | | | | | |
| 2012/4/1 | | | 0.1500 | 0.0350 | | | |
| 2018/1/1 | ∗ | 7.00% | 0.1395 | 0.0326 | | | |

Note: △ denotes tariff reduction rates are monthly reduction rate until next announcement; ∗ represents yearly reduction rates. EEG 2012 period: 1/1/2012 - 7/31/2014, EEG 2014 period: 8/1/2014 - 12/31/2016, EEG 2017 period: 1/1/2017 - 10/1/2018.

Table A5. Feed-in Premium reference tariff rates (€/kWh)

| | EEG2012 | | EEG2014 | | EEG2017 | |
|---|---|---|---|---|---|---|
| Rooftop/BIPV | | | | | | |
| < 30kW | 0.2874 | | 0.1315 | | 0.1270 | |
| 30 - 100kW | 0.2733 | | 0.1280 | | 0.1236 | |
| 100kW - 1MW | 0.2586 | | 0.1149 | | 0.1109 | |
| 1-10MW | 0.2156 | | 0.0923 | | 0.0891 | |
| Ground-mounted solar PV | | | | | | |
| < 10MW | 0.2156 | | 0.0923 | | 0.0891 | |
| | Initial value | Basic value | Initial value | Basic value | Initial value | Basic value |
| Onshore wind | 0.0893 | 0.0487 | 0.0890 | 0.0495 | 0.0838 | 0.0466 |
| Offshore wind - 1 | 0.1500 | 0.0350 | 0.1540 | 0.0390 | 0.1540 | 0.0390 |
| Offshore wind - 2 | | | 0.1940 | 0.0390 | 0.1940 | 0.0390 |

EEG 2012 period: 1/1/2012 - 7/31/2014, EEG 2014 period: 8/1/2014 - 12/31/2016, EEG 2017 period: 1/1/2017 - 10/1/2018.

Table A6. Feed-in Premium reference tariff degression rate (%)

| issue date | reduction rate | issue date | reduction rate | issue date | reduction rate |
|---|---|---|---|---|---|
| PV | | Onshore wind | | Offshore wind | |
| EEG 2012 | | | | | |
| 2012/01/01* | 9.00% | 2013/01/01* | 1.50% | 2018/01/01* | 7.00% |
| | | | | | |
| EEG 2014 | | | | | |
| 2014/09/01△ | 0.50% | 2016/1/1 | 0.40% | 2018/1/1 | 0.50% |
| | | 2016/4/1 | 0.40% | 2020/1/1 | 1.00% |
| | | 2016/7/1 | 0.40% | 2021/01/01* | 0.50% |
| | | 2016/10/1 | 0.40% | | |
| | | | | | |
| EEG 2017 | | | | | |
| 2017/02/01△ | 0.50% | 2017/3/1 | 1.05% | | |
| | | 2017/4/1 | 1.05% | | |
| | | 2017/5/1 | 1.05% | | |
| | | 2017/6/1 | 1.05% | | |
| | | 2017/7/1 | 1.05% | | |
| | | 2017/8/1 | 1.05% | | |
| | | 2017/10/1 | 0.40% | | |
| | | 2018/1/1 | 0.40% | | |
| | | 2018/4/1 | 0.40% | | |
| | | 2018/7/1 | 0.40% | | |
| | | 2018/10/1 | 0.40% | | |

Note: △ denotes tariff reduction rates are monthly reduction rate until next announcement; * represents yearly reduction rates. EEG 2012 period: 1/1/2012 - 7/31/2014, EEG 2014 period: 8/1/2014 - 12/31/2016, EEG 2017 period: 1/1/2017 - 10/1/2018.

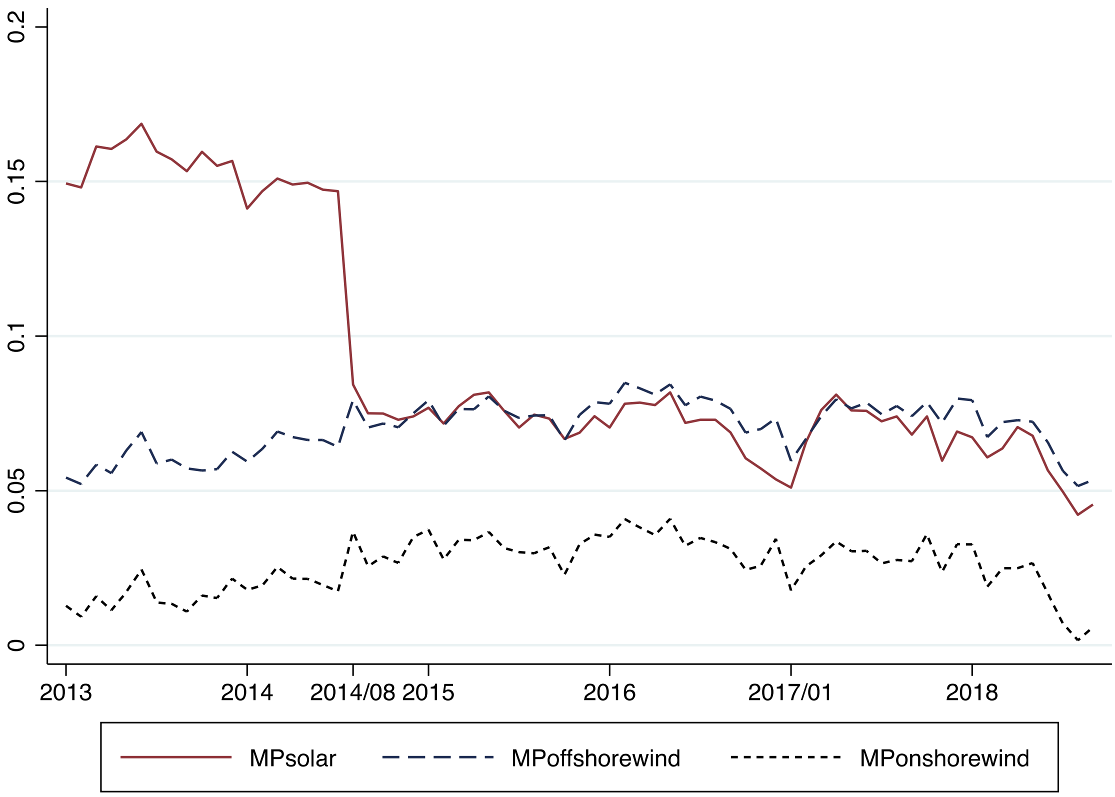


Figure 4: Amount of market premium (€/kWh) under the sliding FIP scheme