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King Abdullah Petroleum Studies and Research Center

# Comparing Renewables Support Policies: Quantifying the Trade-Offs

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*December 2015 / KS-1527-DP021A*

## About KAPSARC

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# Key Points

Policies to support wind energy development are most effective when they deliver power at the lowest cost per unit of added capacity and per unit of delivered electricity. Our analysis uses real Spanish onshore wind project data to identify which approaches deliver the lowest cost to society.

Taking into account the capital intensity of renewables and current market conditions, we find that investment credits provide the most cost-effective and least uncertain outcome in terms of cost for ratepayers.

However, an investment credit is front-end loaded and burdens the public finances. Perhaps a more acceptable approach would place a surcharge spread across the entirety of consumer bills. The resulting revenues could be securitized by project developers, reducing their cost of capital almost to the level of sovereign risk.

# Summary

The adoption of renewable energy technologies has been routinely promoted as a means of enhancing energy security, environmental sustainability, national industries and green jobs, among other things. However, with recent economic constraints on taxpayers and electricity ratepayers, some developed economies are re-evaluating their policy support for renewable energy.

The aim of our research is to provide a better understanding of the relationship between renewable technologies and to identify the best financing method, from the perspective of both investors and society (taxpayers/ratepayers). Spain makes a good wind energy case study, given its history of subsidizing renewables. In Spain, feed-in tariffs drove significant deployment of renewable technologies, particularly wind turbines. However, concerns about policy costs grew as renewables development accelerated beyond expectations and the economy slowed. Feed-in tariffs provide guaranteed revenue for investors at a project level, but the aggregate cost of the policy is variable for ratepayers, depending on the evolution of market prices and the level of utilization of the supported technology.

This uncertainty over the total costs for the ratepayer became a major concern at a time of economic stagnation and declining electricity consumption. This was because the cost of the feed-in tariff was allocated across a declining quantity of electricity supply, ratcheting up the unit price payable by ratepayers. Spain's energy policy resulted in the implementation of many renewable energy projects, but this came at a considerable political cost, which led to policy changes during the period 2006–2013.

Our analysis uses real wind project data, addressing data granularity issues that have hampered other analyses, to compare feed-in tariffs with other types of subsidies. These include a feed-in premium, a production tax credit and an investment credit to clarify which option would be the most cost-effective in achieving the policy goal of increasing the amount of energy generated from wind turbines.

We find that, given the capital intensity of renewable technologies and current market conditions, the most cost-effective option, and the one that minimizes the additional electricity price volatility experienced by ratepayers, is an investment credit. This cuts the initial cost of developing a project and can be set at a level that yields the same returns for investors as other policy options—including feed-in tariffs, feed-in premium and production tax credits—but results in lower costs to taxpayers under a range of possible electricity price scenarios.

> An investment credit policy is a cheaper policy under a vast majority of scenarios for electric power prices, though it provides the same financial returns to project developers as a feed-in tariff, a feed-in premium or production tax credit.

> This is because of the discount rate applied to future payments. Society (taxpayers or ratepayers) typically requires a lower discount rate than private investors.

Despite the investment credit appearing more attractive from a societal perspective, it has the disadvantage of being front-end loaded and requiring public finance at a time when such funds are already stretched. By contrast, feed-in tariffs, feed-in premiums and production tax credits are spread over the life of the project. An option to make an investment credit program more politically palatable, though, would be to transfer the burden to consumers. A predictable surcharge on consumers' electricity bills could be securitized by project developers, reducing their cost of capital to a level almost equivalent to sovereign risk.

# Introduction

Countries around the world are promoting the adoption of renewable energy technologies as a means of enhancing energy security, environmental sustainability, national industries and green jobs, among other things. Given the recent economic slowdown in many developed countries, some governments are re-evaluating their policy support for renewable energy. This is the case for some European countries, including Spain.

In Spain, policymakers adopted a feed-in tariff as the main form of subsidy and this drove significant deployment of renewable technologies. However, concerns about policy costs grew as more wind and solar were deployed and the economy slowed. Spain was emblematic of the tension between renewable energy deployment, costs, and the risk to ratepayers associated with market price volatility. Feed-in tariffs provide a guaranteed revenue to investors but the total cost of the policy is variable for ratepayers. As a result, this uncertainty in total costs for the ratepayer becomes a major concern in a scenario of economic stagnation and decline in electricity consumption, such as Spain experienced from 2008–2013.

One of the problems in designing public interventions is the lack of granular cost information available for policymakers, as Menanteau et al (2003) indicates. Financial incentives to promote renewable technology can become too little or too much when this information is incorrectly estimated. This research aims to provide a better understanding of the relationship between renewable technologies and the best financing method, from the perspective of both investors and society (taxpayers/ratepayers). Spain provides a useful case study, particularly with respect to wind energy. As of 2013, it ranked fourth in installed wind capacity after China, the U.S. and Germany, according to the BP Statistical Review of World Energy (2014). Although Spain's energy policy successfully drove deployment of a great deal of renewable energy, it came at a cost, which led to several policy changes during the period 2006-2013.

This study uses real wind project data, addressing granularity issues, to compare the feed-in tariff with other subsidy types, including a feed-in premium, a production tax credit and an investment credit, in order to clarify which option is the most cost-effective. The paper uses data from 318 onshore wind projects installed in Spain between 2006 and 2013, totaling more than 10 GW. The use of real project data reveals valuable insights about the relationship between financial conditions and capacity factors that are normally omitted from more theoretical approaches.

Our research concludes that, given market conditions, the most cost-effective policy option for society arises from an investment credit, meaning that it minimizes the net present cost of the policy. The cost structure of renewable technologies, being capital intensive, requires private investors to make large financial outlays upfront. Private investors typically have a higher cost of capital than sovereign borrowers and the provision of a capital contribution that reduces the initial investment outlay helps these investors more than it costs the government, or taxpayers.

Despite imposing a lower overall cost, investment credits are politically difficult because they require an upfront payment, normally from the treasury and, in recent years, from public balance sheets that are already stretched. By contrast, feed-in tariffs, feed-in premiums and production tax credits are paid by electricity consumers as a series of payments over the life of the project, obscuring the total cost of such policies. The question is: how much more should society pay than it needs to for the political expediency of moving a liability from one part of the public balance sheet to another?

# Scenario Definition and Methodology

## Description of Policy Instruments

This paper considers four subsidy types:

- Feed-in tariffs (FIT)
- Production tax credits (PTC)
- Feed-in premiums (FIP)
- Investment credits (IC)

For the purpose of this analysis, PTC and FIP are treated equally since they are both an output subsidy on a euro (€) per megawatt hour (MWh) basis. Although other policy options exist, including soft loans and various taxes, we have excluded them from the scope of this paper.

The FIT used in this analysis is a guaranteed minimum fixed price (in real terms) for the electricity produced over the life of a wind project. If the market price is greater than the FIT, then the owner of the wind facility receives the market price. If the price of electricity is lower, investors receive the FIT price. This type of policy generates an asymmetric, though appetizing, risk/reward for investors and creates a positive environment for investors. On the other hand, the burden for electricity ratepayers is variable and ultimately depends on the dynamics of electric power market prices.

FIP and PTC are considered as one policy in this analysis. The subsidies are similar, in that both, if set at the same level, produce the same subsidy in euros per MWh under all market conditions – because an FIP/PTC is a fixed amount that is added to the market price.

An IC is a percentage discount on the initial investment that is given to reduce the costs of a technology. For example, a 10 percent IC for a €1 million wind project would result in a €900,000 cost for the developer, while the government would shoulder the remaining €100,000. An IC can also be applied on a fixed, €/MW basis (i.e. lump sum). Intuitively, if the IC is set too high it may reduce the financial incentive for developers to minimize costs as the government will bear a disproportionate share of the risk, i.e. the combination of the IC and subsequent reductions in taxes because of the higher cost base.

## Description of the Methodology

A cost-benefit analysis was conducted to compare the total discounted revenue and total discounted costs over the lifetime of each of the 318 projects studied. This analysis took the perspective of private investors, then calculated the incremental cost of policies to taxpayers and/or electricity customers.

The levelized cost of electricity (LCOE) represents the 'cost' metric of the cost-benefit analysis. It illustrates the stream of equal payments distributed over each unit of expected energy production. The levelized avoided cost of electricity (LACE) is the revenue metric in the analysis. It is the estimate of the revenue available to a given resource, distributed over each unit of expected energy production. Calculations for both LCOE and LACE are adapted from Namovicz (2013) and are a standard approach in the literature (see Appendix I for additional details). The difference between LACE and LCOE is the net value, which is the incremental annual cost to the government (taxpayers) in order to break even. LCOE and LACE were calculated for each of the 318 projects.

To calculate the cost-effectiveness of Spanish wind projects, a number of data sources were combined. Financial leverage, capacity factors, locations, CAPEX, and number of projects were sourced from Bloomberg New Energy Finance (BNEF). Wholesale prices were sourced from both the Iberian market operator and the Comision Nacional de los Mercados y la Competencia (the Spanish regulator) and used to compare the costs of policies relative to the market. The Spanish regulator also reports information on electricity produced from wind and financial support given to wind projects. Interest rates for long-term bank loans come from the Bank of Spain.

We used a hurdle rate for the cost of equity of 8 percent (in real terms) for the project developers. The government discount rate used was 3.7 percent, constant in real terms over the period of analysis. This discount rate is similar to that used in macroeconomic models for Spain, such as Martin-Moreno et al (2014). The operating life of all projects is taken as 20 years. We treated all debt as being structured as amortized loans in which there are equal payments over the period of the loan.

We have made a simplifying assumption that developers apply the same hurdle rate to return on equity regardless of the financial leverage of a project. Projects that can support greater leverage are able to do so because there is less volatility in their revenues and their cost of capital is lower. Some combination of the interest rate on the debt being lower or the proportion of debt being higher can be applied when revenues are more certain. That assumption is probably valid when developers are bidding competitively to access projects, because they are more likely to pass on the benefits of reduced risk to the ratepayer or taxpayer.

The capacity factor of each wind project is estimated based on project-level BNEF and Spanish regulator information.

All costs for projects in the analysis, which fall within a period of 8 years, have been translated to constant euros, with 2014 being the base year.

# Description of the Wind Project Database

The dataset includes financial and operational information on 318 onshore wind projects implemented in Spain between 2006 and 2013. Projects selected for the dataset were limited to those with installed capacity of 15 megawatts (MW) or more. The projects represent 10,732 MW of installed capacity, some 83 percent of the total 12,885 MW installed during the 2006–2013 period according to the BP Statistical Review of World Energy 2014. To assess the cost of each project, we used the weighted average cost of capital (WACC) as the real discount rate. The average WACC of projects in the analysis is 6 percent.

From 2006 to 2013 the number of wind projects commissioned per year declined from 58 to five projects (Table 1). New capacity additions declined from 1,896 MW to 190 MW per year as a result of the government's reduced support for wind projects.

For each individual project we have calculated the LCOE depending on capacity factor, leverage, WACC, fixed costs and operational costs. With this information we were able to construct a supply curve ranking the wind projects from least to most expensive. Figure 1 presents the supply curve with each project's LCOE and the cumulative capacity in megawatt hours. Figure 1 is not a conventional supply curve, since it does not link production of electricity and marginal costs of production. Instead, the curve represents the long run cost of constructing and operating the various projects over their 20-year useful lives. The average LCOE for Spanish commissioned wind projects in our dataset is €84/MWh, while the median is €77.5/MWh.

LCOE varies by geography, as a result of the different conditions in different locations. We plotted the projects on a map, as shown in Figure 2. The capacity of each project is represented by the size of the dot, while the band in which the LCOE falls is represented by the color of the dot. The lighter the green, the lower the unit cost of the electricity provided by the project and the darker the red, the higher the unit cost provided by the project. The lowest cost projects are in the north and southeastern parts of Spain. On the other hand, the center of the country has poorer wind resources, and projects there are more expensive per unit of generation.

**Summary of Key Data**

| Year | Number of Projects | Total Installed (MW) | Investment (EUR thousand/MW) | Debt Level | Capacity Factor |
|---|---|---|---|---|---|
| **2006** | 58 | 1,896 | € 1,263 | 50.8 percent | 26.7 percent |
| **2007** | 64 | 2,145 | € 1,311 | 43.5 percent | 23.9 percent |
| **2008** | 69 | 2,166 | € 1,353 | 49.0 percent | 24.8 percent |
| **2009** | 54 | 2,004 | € 1,452 | 42.0 percent | 22.7 percent |
| **2010** | 29 | 937 | € 1,587 | 48.1 percent | 25.7 percent |
| **2011** | 26 | 986 | € 1,365 | 46.7 percent | 21.7 percent |
| **2012** | 13 | 408 | € 1,260 | 59.4 percent | 23.2 percent |
| **2013** | 5 | 190 | € 1,230 | 45.6 percent | 19.2 percent |
| **Total** | 318 | 10,732 | | | |
| | | **Average** | € 1,361 | 47.1 percent | 24.3 percent |
| | | **Minimum** | € 1,214 | 10 percent | 11 percent |
| | | **Maximum** | € 1,600 | 85 percent | 46 percent |

*Table 1 - Summary of Key Data*

*Source: KAPSARC based on BNEF and Bank of Spain data*

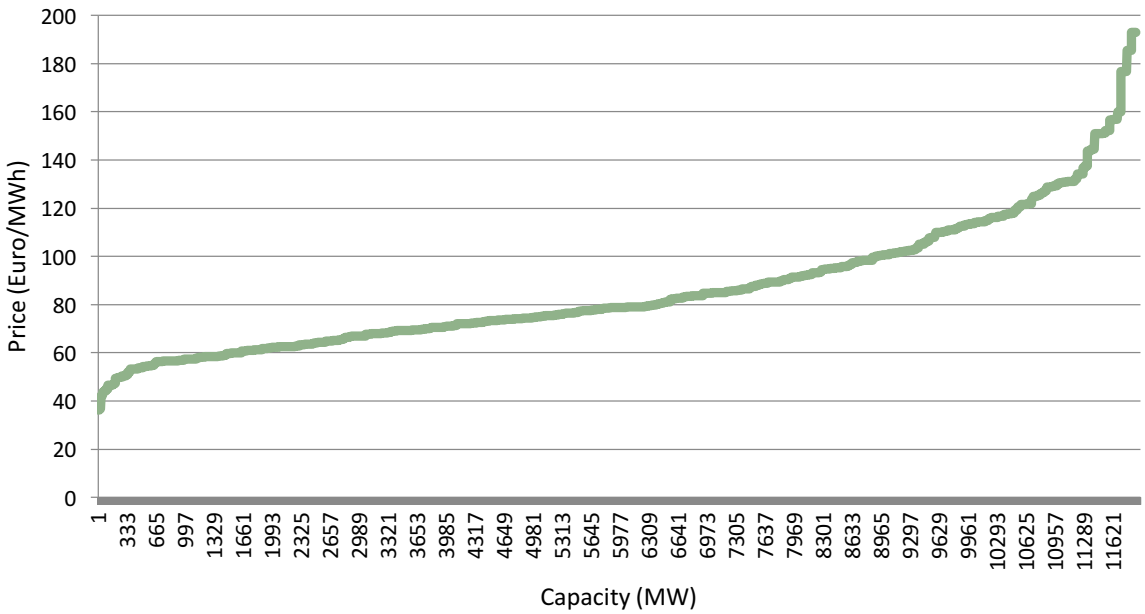


*Figure 1 - Supply Curve*

*Source: KAPSARC based on BNEF and Bank of Spain data*

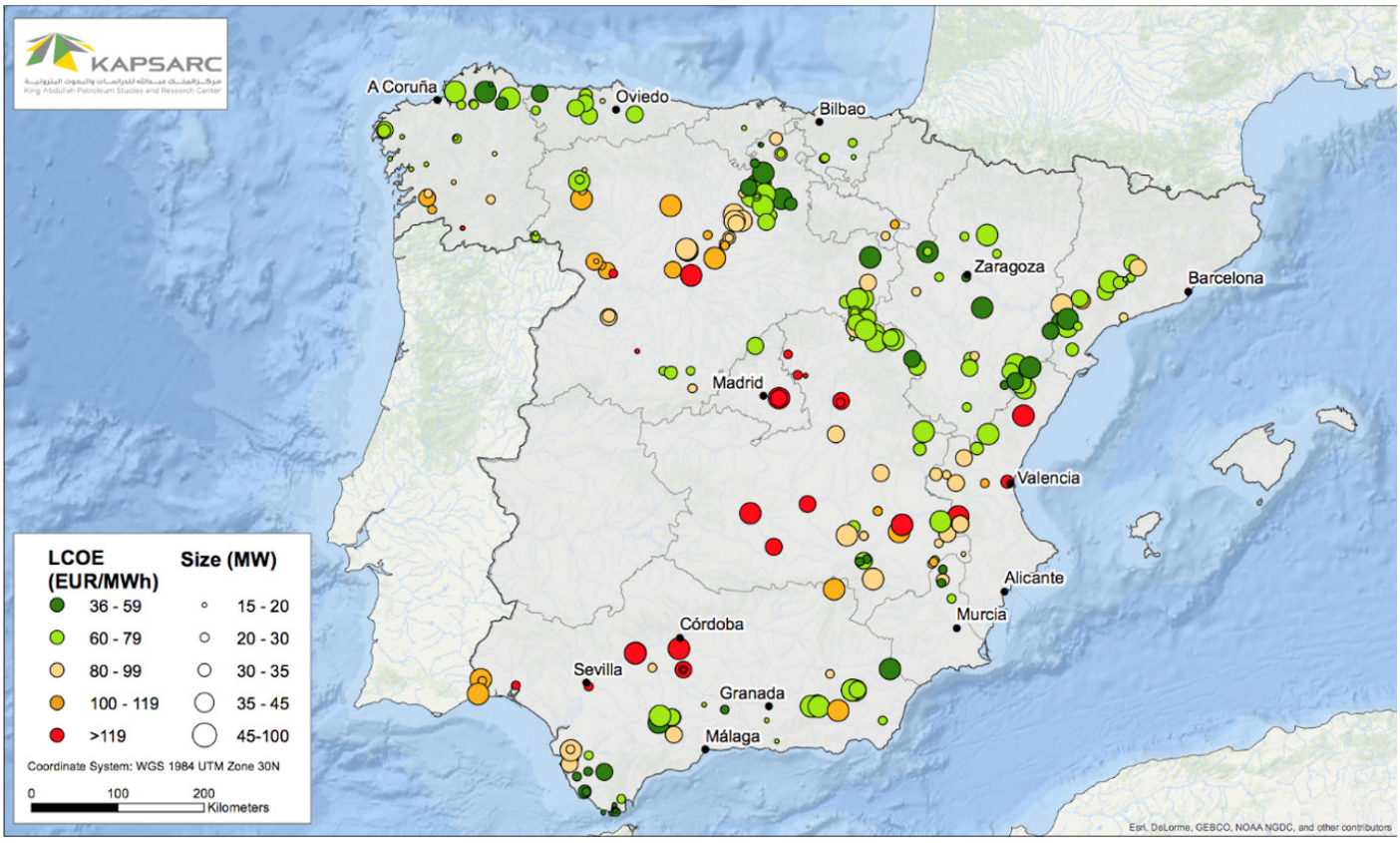


*Figure 2 - Map of Spanish Wind Projects*

*Source: KAPSARC based on BNEF data*

# Analysis and Results

## Market Conditions. No Policy Scenario

The wholesale electricity market in Spain is liberalized. The market price there is set in a day-ahead market and depends on the expected supply and demand during the day. In addition, there is a real-time market to sell and buy electricity during the day, allowing fine-tuning of prices and quantities.

Electricity prices are very volatile from hour to hour and daily average prices in Spain can fluctuate widely. Between 2006 and 2014, the real daily price of electricity ranged from a minimum of €0/MWh to over €106/MWh (Figure 3). The average daily price over this period was €47.6/MWh, with a standard deviation of €15.3/MWh. Around 76 percent of the daily price observations fall within the price interval €33.4/MWh to €63.9/MWh (average +/- one standard deviation).

To begin examining the cost-competiveness of the wind projects, we evaluated their LCOE against potential revenues in a baseline 'no-subsidy' market scenario. The real price of electricity in this scenario is a constant €48/MWh over the 20-year study period.

Using the baseline market scenario as a proxy for unit revenues allows for a clearer picture of the competitive situation of wind technology in Spain. If we compare the LCOE of the projects (project supply curve) with their potential levelized revenues, we find that only 200 MW out of 10,732 MW have a positive net present value. In other words, only 1.9 percent of the total installed capacity is potentially economic under market conditions. In fact, the cumulative net present value (NPV) of the projects in Spain is minus €7.80 billion. The average NPV scaled per installed capacity is minus €0.73 million/MW.

Ultimately, the NPV of each individual project depends on the final price of electricity. As prices increase, the NPV of the projects improves. In particular, if the real price of electricity were to reach €78/MWh, the cumulative NPV of the 318 projects would be zero. However, this is a very unlikely scenario because only 3.7 percent of the prices observed in the period 2006–2014 were greater than €78.

We use this understanding of the market and the projects in the database to evaluate the consequences of the three classes of incentive described earlier.

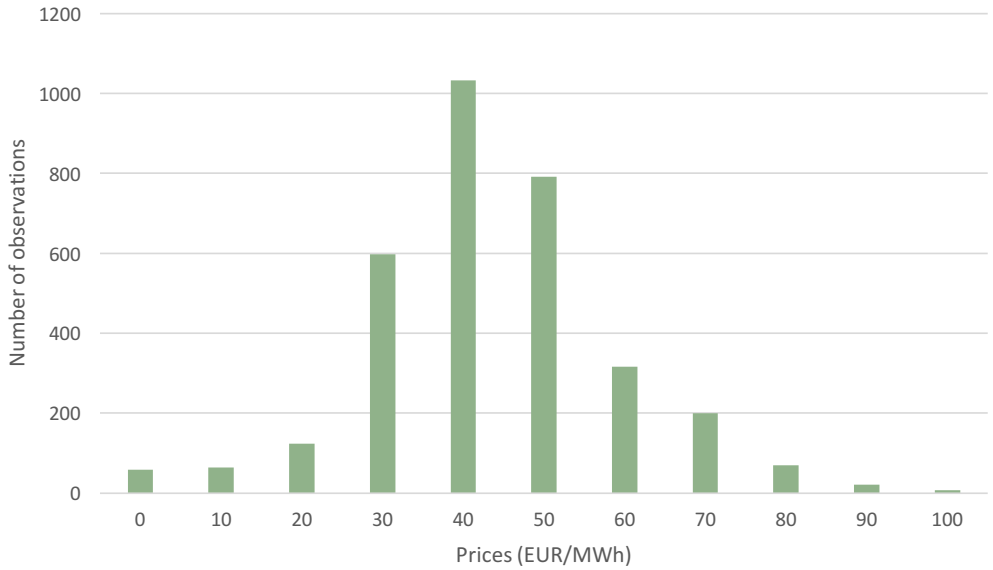


*Figure 3 - Histogram of Real Prices (Euro/MWh)*

*Source: KAPSARC analysis based on Bloomberg data*

## Feed-in Tariff

The FIT level was derived from the reports by the Spanish regulator for the period 2009–2014. It was based on the average amount assigned in Spain from 2006–2013, which was €83/MWh.

In this FIT scenario, 6,120 MW of the installed capacity remains economic – i.e. maintains a positive NPV. The cumulative NPV of the project cash flows is €1.3 billion. These results are constant provided the market price stays in the range €0-€83/MWh because wind projects receive constant revenue from the FIT at those price levels. As electricity prices increase beyond €83/MWh, the NPV and the proportion of wind capacity that is economic increases.

The discounted cost of the policy to ratepayers is the obverse of the NPV protection provided to investors, but discounted to the government cost of capital rather than the project WACCs. The cost of the policy is greatest if the market price of electricity is €0. This is because then the difference between the market price and the level of support for the policy is at its maximum. The incremental cost of the policy falls to €0 if the market price exceeds €83/MWh. In the baseline market scenario of €48/MWh, the incremental cost to ratepayers of the FIT is €11 billion (€1.0 million/MW). The FIT policy option puts the risk on the government or ratepayers, depending on which is funding it, but provides certainty for investors because of the revenue stability afforded by the price floor.

The remainder of our policy scenarios are based on the 6,120 MW of cumulative economic capacity calculated under the FIT scenario. This provides a comparison of 'apples-with-apples' for different policy subsidies. In these alternative scenarios, the cumulative capacity figure provides the policy target. In this way, we can understand the costs to taxpayers and ratepayers and the revenue to investors required to achieve the desired total installed megawatts.

## Feed-in Premium or Production Tax Credit (FIP/PTC)

In our analysis, we selected a fixed amount of €35/MWh as a baseline FIP/PTC subsidy amount. This is because a €35/MWh subsidy on top of a €48/MWh baseline market price yields equivalent results in terms of achieving the target benchmark 6,120 MW of economic projects.

Unlike an FIT, an FIP/PTC policy option shifts the cost risks from the government/taxpayer to the investor. In this case, the cost of the policy to the taxpayer does not change, remaining at €11 billion (€1.0 million/MW), regardless of the price. On the other hand, revenue, and thus NPV for investors, fluctuates with prevailing market prices. The NPV of the projects increases as prices increase, but the investors are faced with volatility in the outcome, which would increase the cost of capital for the project compared with the FIT policy. This is why, in principle, an FIP/PTC is less attractive to investors than an FIT, if set at a level that yields the same average price but with less certainty. Dinica (2006) points out that risk is as important as expected yield in order to support renewable technology.

Assuming no change in the WACC, under the baseline market scenario the NPV of the target benchmark projects would be €1.3 billion. This is identical to the FIT. An FIT of €83/MWh and an FIP/PTC of €35/MWh produce exactly the same results if the market price is €48/MWh, when there are no differences between the volatilities of the cash flows under the two arrangements. The cumulative NPV of the total projects is zero at a market price of €43/MWh. However, the uncertainties regarding the cost for policymakers and the benefits for investors are different; we ran sensitivities to illustrate the impact of a change in the cost of capital in terms of increasing the level of the subsidy and, thus, the cost of the policy.

The FIP/PTC shifts risks toward investors and so an increase in their WACC can be expected. Higher volatility of income implies that investors will seek higher yields and lenders will require higher interest rates. However, there is insufficient data to assess these impacts at the level of individual projects.

To examine what might be the impact of such an increase, we applied a uniform increase of 1 percent to the WACC. This increases the average LCOE of Spanish wind projects by €5/MW. Under the new conditions, the baseline subsidy required to achieve the target (6,120MW) increases to €40/MWh, resulting in a 15 percent (€1.7 billion) increase in policy costs. In the worst case, increasing the WACC by 2 percent results in an additional 31 percent (€3.5 billion) cost for the policy.

## Investment Credit

Both FIT and FIP/PTC subsidize the revenue side of the equation. An alternative approach is to subsidize the costs of installing wind turbines. Two approaches to this are:

- A fixed IC measured in €/MW installed, calculated to be a percentage of the expected costs but carrying the risk that technology cost reductions do not get passed on to the taxpayer.
- A fixed percentage of the actual costs incurred by the developer, carrying the risk of cost overruns in a project being passed on to the taxpayer.

The latter approach is more typical and an IC of 53 percent results in the target benchmark of 6,120 MW of economic projects, meeting the hurdle return on equity. The cost of this policy would be €8.4 billion (€0.80 million/MW), 20 percent less than the revenue subsidy approach. In other words, covering a little over half of the developers' expected costs through an IC can achieve the same benchmark level of economic wind capacity at a lower cost than an FIT or FIP/PTC. This policy eliminates much of the volatility in the cost of supporting the policy because it is exposed only to fluctuations in costs – that may be generally subject to downward pressure as technology improves – rather than the more volatile electricity market prices.

An IC results in an overall, but not uniform, downward shift of the wind supply curve. There is a general flattening of the curve, because higher cost projects (in €/MW terms) and those with lower capacity factors, and thus higher WACC, have greater LCOE reductions than cheaper projects with lower WACC.

Despite being cheaper than an FIT and FIP/PTC, an IC can be a less attractive option for policymakers: because the IC is paid up front directly from the treasury and is counted in current public spending. By contrast, FITs and FIP/PTCs are typically funded by electricity ratepayers over the life of the projects (20 years in this analysis). From an investor perspective, an IC appears more risky because the return is dependent on electricity prices and volatility drives up the cost of capital.

The cumulative NPV of the projects analyzed is €0.6 billion under the baseline market prices scenario. This compares with €1.3 billion for the FIT and FIP/PTC cases. The reduction results from the flattening of the supply curve and illustrates the consequences of an IC, based on a percentage of development costs providing an incentive for costlier projects with lower capacity factors.

Besides the FIP/PTC, we also tested the sensitivity increases in the WACC. A one percent increase across the board results in a need for a credit that is 57 percent higher, increasing the cost of the policy by 7 percent (€0.6 billion). An increase of 2 percent results in an increase of 12 percent (€1 billion) in the cost of the policy.

Using the alternative of a fixed IC of €792,000/MW of installed capacity partly corrects this unintended result. This approach would achieve the target cumulative capacity of 6,120 MW. As a policy, the fixed IC would be cheaper than the fixed percentage IC to the extent of €0.94 billion – 11 percent lower. However, the increased cost of debt that results from exposure to revenue volatility is at least partially offset by the reduction in the financing required, assuming that developers do not change their expectations of return on equity.

## Comparison of Policies

We then conducted a more comprehensive analysis, evaluating the 318 projects and policies using four different market prices. The total discounted cost of the projects in our analysis amounted to €20.3 billion. The cumulative NPV of the projects in the dataset, using the average real electricity price of €48/MWh observed between 2006 and 2014, is negative €7.8 billion. Only 1.9 percent of installed capacity was economic without financial support.

Table 2 shows the cost of the policies in each of the four market price scenarios, discounted

| Price (€/MWh) | Percentile of Scenario Price within 2006-2014 Observation (percent)* | Policy Option | | |
|---|---|---|---|---|
| | | FIT (€83/MW) | FIP/PTC (€35/MW) | IC (53 percent) |
| **0** | 99.9 percent | 26.1 | 11.0 | 8.4 |
| **48** | 50.5 percent | 11.0 | 11.0 | 8.4 |
| **56** | 25.8 percent | 8.4 | 11.0 | 8.4 |
| **83** | 1.9 percent | 0.0 | 11.0 | 8.4 |
| **100** | 0.2 percent | 0.0 | 11.0 | 8.4 |

*Table 2 - Cost of Policies (EUR billion)*

*Source: KAPSARC Analysis*
*The sample covers 318 Spanish wind projects, representing 10,732 MW.*
** Instances when observed 2006-2014 prices exceed reference prices in column 1.*

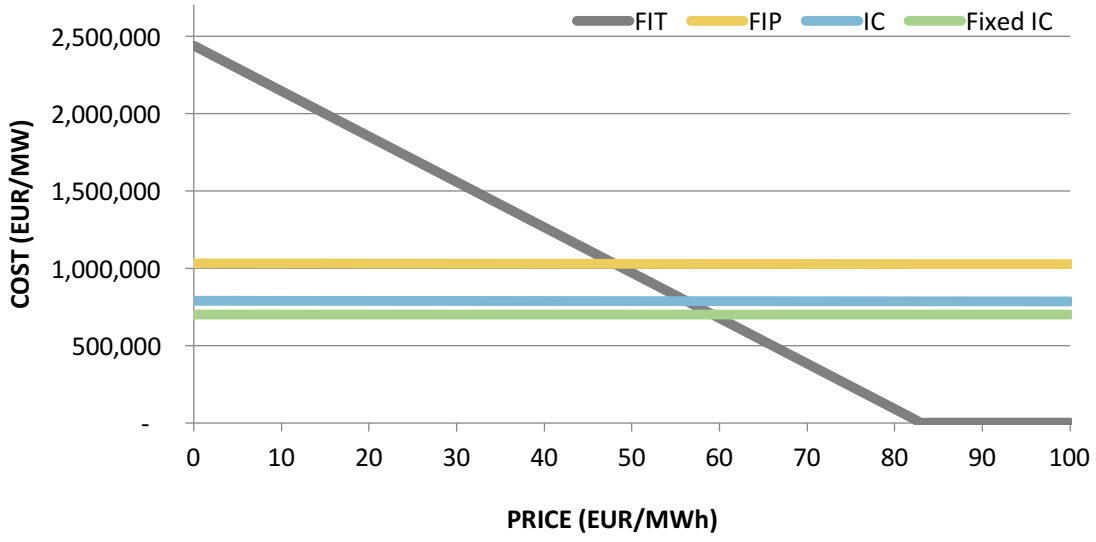


*Figure 4 - Total Cost of Policies on Government (Taxpayers)*

*Source: KAPSARC Analysis*

at the government cost of capital, and Figure 4 illustrates the cost of the policies per installed MW. It demonstrates that:

- For an electricity market price below €48/MWh, an FIT is the most expensive subsidy (typically paid by the ratepayer).
- Between €48 and €56/MWh an FIP/PTC is the most expensive subsidy (typically paid for by the taxpayer).
- If the real-terms electricity market price is consistently above €56/MW, the FIT is the most economic subsidy, with the cost falling to zero when the electricity market price exceeds €83/MWh.
- The IC is the most cost effective policy for electricity market prices below €56/MWh.

Under most anticipated electricity market prices, the FIT is the most expensive policy. This is not a surprise as Schmalensee (2011) finds a similar result. He points out that the FIT policy "is almost certain not to minimize the cost of achieving a program's goals."

For taxpayers, an IC is the most appealing policy option because it represents the minimum financial burden at which the policy targets are achieved. Only if policymakers expect a market price that is systematically above €56/MWh would they then prefer a FIT policy option. This scenario seems to be very unlikely given the average prices over the period 2006–2014, that wind tends to operate in off-peak periods, and that increasing amounts of wind power, with zero cost dispatch, will make it more likely that market prices fall to zero more often. Even considering the WACC, increased due to the higher risk for investors, the IC still remains the lowest cost policy option for society under most scenarios.

Table 3 shows the total NPV of the portfolio of projects for the different policy scenarios – including a 'no-subsidy' scenario – and market conditions from an investor's perspective. For investors, an FIT is the most appealing policy option if market prices average less than €48/MWh. An FIT policy is attractive to investors because of the price certainty it provides.

If market prices average more than €48/MWh, the FIP/PTC would be the policy preferred by investors. The expected cumulative NPV under an IC scheme is similar to a FIP/PTC. Figure 5 represents the NPV/MW under different policy options, with prices ranging from €0/MWh to €100/MWh.

In general terms, investors would prefer an FIT because of the constant positive return even in low market price scenarios. Investors that expect prices for electricity to be systematically over €48/MWh would prefer an FIP/PTC, given the higher return for the investment. In this analysis, an IC would not be preferred by investors under any price condition.

| Price (€/MWh) | Percentile of Scenario Price within 2006-2014 Observation (percent)* | Policy Option | | | |
|---|---|---|---|---|---|
| | | FIT (€83/MW) | FIP/PTC (€35/MW) | IC (53 percent) | Market 'no subsidy' |
| **0** | 99.9 percent | 1.3 | -11.2 | -11.9 | -20.3 |
| **48** | 50.5 percent | 1.3 | 1.3 | 0.6 | -7.8 |
| **56** | 25.8 percent | 1.3 | 3.4 | 2.7 | -5.7 |
| **83** | 1.9 percent | 1.3 | 10.4 | 9.8 | 1.3 |
| **100** | 0.2 percent | 5.7 | 14.9 | 14.2 | 5.7 |

*Table 3 - Cumulative NPV (EUR billion)*

*Source: KAPSARC Analysis*
*The sample covers 318 Spanish wind projects, representing 10,732 MW.*
** Instances when observed 2006-2014 prices exceed reference prices in column 1.*

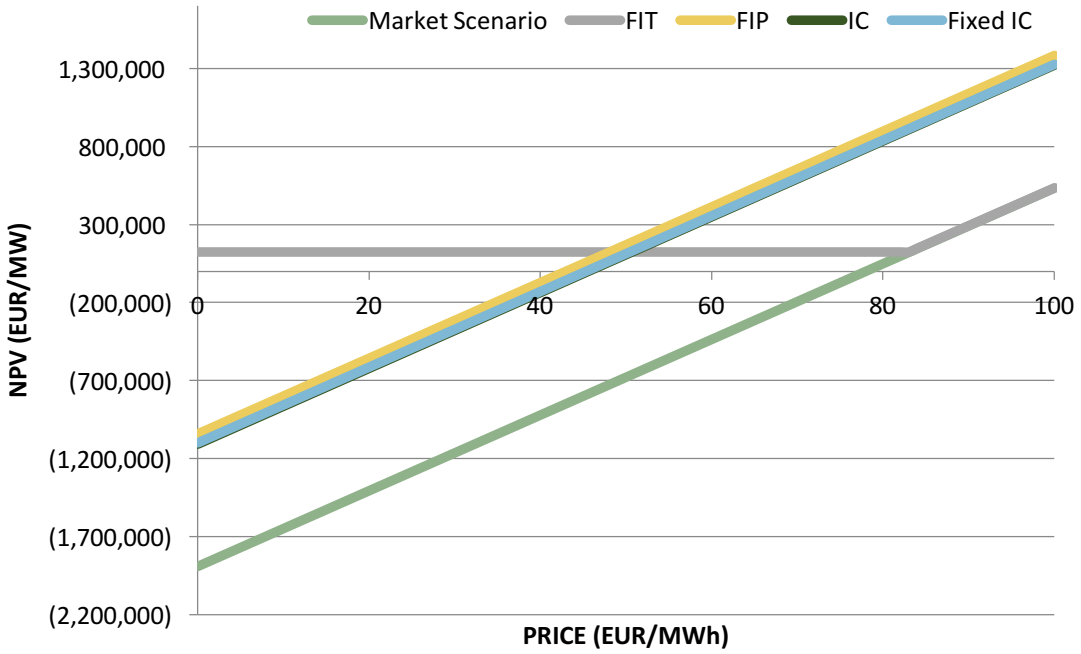


*Figure 5 - Total NPV of Projects under Policy Options*

*Source: KAPSARC Analysis*

# Conclusions

In this paper, we analyzed the costs to providers of subsidies (ratepayers and taxpayers) and values to project developers (investors) of different policy options for promoting wind energy. We used a dataset of 318 real Spanish onshore wind projects commissioned between 2006 and 2013. These projects represent 10,732 MW of installed capacity, which is 83 percent of the total of 12,885 MW installed during the same period.

The dataset revealed the relationship between financing structure and capacity factor that is often omitted in theoretical approaches. In particular, projects with higher capacity factor tend to be financed more through debt than equity and, in circumstances where the hurdle rate of return to the equity investor is constant, enjoy lower average costs of capital.

The supply curve that we created from the dataset ranks the wind projects from lowest to highest LCOEs and was steeper than initially expected, due to the positive relationship between capacity factor and leverage. The bulk of the projects in our dataset have an LCOE between €59/MWh and €99/MWh, with an average LCOE of €83/MWh.

Renewable technologies are capital intensive, so the most cost-effective option for society to promote wind technology, without risking total costs fluctuating with electricity prices, is an IC. This is because an IC cuts the initial cost of developing a project borne by the investor and requires a lower average electricity market price to meet the equity return hurdle.

Based on our analysis, a percentage IC costs taxpayers 31 percent less than an FIT or FIP/PTC policy under a baseline scenario of electricity prices in Spain. An IC is cheaper than a FIT and FIP/PTC because the discount rate that investors apply to future payments is higher than that required by society (taxpayers or ratepayers).

Investors prefer an FIT because the volatility associated with market prices is minimized. In addition, if the policy is successful in bringing about more development of zero marginal cost power, investors are protected against the danger of electricity market prices falling in real terms, in the absence of a market redesign.

It is perhaps counterintuitive that society may extract value even from an expensive policy that promotes renewable energy. The consequence might be that market prices are driven down to a point where owners of conventional fossil fueled generation are ‘contributing’ their equity to ratepayers through prices that are too low to recover their capital investment. This would result in lower overall electricity prices until additional investment in new capacity was required. How much investors would need to be paid to take on such an investment risk is, however, open to debate.

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## About the Project

The goal of this project is to understand how policy can expedite renewable energy transitions in a cost-effective way, while allowing competitive national industries to develop. In line with this objective, a wide range of policy instruments, designed and implemented to promote renewable energy, are being assessed. Furthermore, the project takes a holistic approach by analyzing how the competitive dynamics between renewable technologies and incumbent technologies evolve.

# Appendix 1

## Description of Methodology

The levelized cost of electricity (LCOE) is representative of the 'cost' metric of a cost benefit analysis. The formula used in this analysis is adopted from Namovicz (2013). It illustrates the stream of equal payments normalized over expected energy production. For clarity, the LCOE is defined according to the formula below:

$$lev\ cost = \frac{(fixed\ charge\ factor * capital\ costs + fixed\ O\&M)}{annual\ expected\ generation\ hours} + variable\ O\&M$$

where the variable O&M refers to operation and maintenance costs, which are constant in real terms (or increase with inflation). The cost of fuel is not represented in the formula above because it is set to zero since wind does not use fuel. The annual expected generation hours is defined by the product of the capacity (MW) of individual projects, the capacity factor, and the number of operating hours in a year (8760). The fixed charge factor, also known as the capital recovery factor, is the discount rate levelized over the life of the project. It is defined by the following formula:

$$fixed\ charge\ factor = discount\ rate + \frac{discount\ rate}{(1 + discount\ rate)^{financial\ life} - 1}$$

The levelized avoided cost of electricity (LACE) represents the 'revenues' metric in the CBA, and is also adopted from Namovicz (2013). It is the estimate of the revenues available to a given resource, which is normalized over the expected energy production period. The LACE equation is depicted below:

$$lace = \frac{\sum_{t=1}^{y}(marginal\ gen\ price_t * \ dispatched\ hours_t)}{annual\ expected\ generation\ hours}$$

where the total marginal generation price is normalized over the number of dispatch hours added. In our case, the marginal generation price corresponds to the level of the FIT, FIP-PTC, or market price (depending on the policy). Other potential revenues such as capital credits or capacity payments are not considered. The LCOE and LACE of each the wind projects was calculated. The LACE was first calculated by using market prices without subsidies; this is to calculate the cost effectiveness in a range of marking price environment.

The incremental cost of each subsidy to the government was calculated by multiplying the government discount rate, which was assumed as 3.7 percent, by the annual incremental value of each subsidy type normalized over the market price. Each cost was scaled to individual project size by multiplying the size by annual generation.

# Appendix 2

## A Review of Renewable Energy Policy in Spain 2006 - 2013

As a result of the increase in wind power generation, the cost of the financial support increased. Spanish power generation from wind represented 20 percent of total electricity generation in 2013, ranking third in the world after Denmark (32 percent) and Portugal (22 percent). At the beginning of the economic crisis in 2008, financial support for wind amounted to €1.2 billion per year. By 2013, the level of support doubled to €2.4 billion according to the Spanish Regulatory Body. IEA/IRENA (2015) indicates that the increase in subsidies in a fragile economy forced a change in the Spanish government's renewable energy outlook. A shift towards a less favorable legal framework for developers began to emerge in 2010. As a result of this change in the regulatory environment, new installations of wind capacity almost fell to zero in 2013.

Key regulatory policy changes in the period 2006 – 2013 include:

- Royal Decree 661/2007. Superseded Royal Decree 436/2004. The new Decree established a system of feed-in tariff and feed-in premium, but with a lower level of public support than the previous Royal Decree 436/2004. (See Asociacion Empresarial Eolica – Association of Spanish Wind Companies – (2007) and IEA/IRENA Joint Policies and Measures database).

- Royal Decree 6/2009. Established that future renewable energy power projects must be pre-registered before they can be eligible to receive public support. (See Asociacion Empresarial Eolica (2010) and IEA/IRENA Joint Policies and Measures database).

- Royal Decree 1614/2010. A maximum financial support was established for wind generators, in particular electricity production. Wind generators that exceeded the limit were not entitled to financial support. (See Asociacion Empresarial Eolica (2011 and 2012) and IEA/IRENA Joint Policies and Measures database).

- Royal Decree Law 1/2012. New renewable facilities that are developed do receive financial support. (See Asociacion Empresarial Eolica (2013) and IEA/IRENA Joint Policies and Measures database).

- Royal Decree Law 15/2012. Imposed a 7 percent tax on electricity generation, including renewables sources. (See Asociacion Empresarial Eolica (2013) and IEA/IRENA Joint Policies and Measures database).

- Royal Decree Law 2/2013. The removal of feed-in premium from the incentive options for wind power generators. This is a retroactive law as all facilities, either old or new, were impacted. (See Asociacion Empresarial Eolica. (2014)).

- Royal Decree Law 9/2013. The feed-in tariff system is replaced by an investment incentive. This new incentive was designed to guarantee a return on investment similar to that of a 10-year sovereign Spanish bond plus 300 basis points. This is a retroactive law that affects all renewable energy plants. (See Asociacion Empresarial Eolica (2014) and IEA/IRENA Joint Policies and Measures database).

The evolution of the regulation on wind energy explains the stagnation of Spanish wind projects in 2013. It seems that the economic recession changed the perception of the Spanish Government on renewable energy and currently it is less likely to favor wind projects.

# Notes

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