An Option Analysis of the European Union Renewable Energy Support Mechanisms

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Abstract

We examine the economic efficiency of incentive mechanisms used to promote Renewable Energy (RE) across the European Union (EU) by looking at returns to investors along with any negative externalities or social costs. Using electricity price data from 2009 to 2013, we evaluate the RE support mechanisms adopted by some of the largest EU economies. We explain the limitations of various metrics used to inform incentives for RE and propose an alternative metric reflecting investor requirements. Our results show that while the EU schemes were effective in delivering RE capacity, the incentives provided were overly generous and economically inefficient. To assess the indirect costs of RE in liberalized electricity markets we employ real option theory to quantify the costs of hedging and pricing the exposure faced by conventional fossil fuel generators required to accept RE under dispatch priority. We find that the cost of hedging against random RE output under dispatch priority is expensive while increasing RE in liberalized markets, by depressing prices and increasing price volatility, may place greater burden on conventional, dispatchable generators. As support for RE is presented as a public good, we argue that economically efficient RE support mechanisms require recognizing both their direct and indirect costs.

Keywords: Renewable Energy, Feed-in tariffs, Investor Returns, Real Option Theory

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1. Introduction

Reducing the usage of fossil fuels through supporting wind turbines, solar cells and other renewable technologies is a key objective of energy policy in many regions of the world. For example, the largest 19 European countries more than doubled their renewable output between 2004 and 2013 but popular concerns have been raised about the affordability of renewable energy (RE) from the standpoint of consumers, business and industry (FT, 2015). In 2009 the total direct support for RE had risen to €17bn, whereas about €27bn was spent on subsidies to solar and wind powered electricity generation by 2012 (Ecofys, 2014). The capital costs of RE are falling but, because the output is both random and only available less than one-quarter of the time, its costs per unit of output are high. Without incentives, private investors would not be interested in building it, putting the nature and size of such subsidies at the heart of the affordability debate. Therefore, it is important to understand how support mechanisms should be designed, their costs calibrated and their impact measured. Using standard financial and economic theory, we evaluate the widely used RE support mechanisms, as adopted by the largest economies of the European Union (EU) but excluding the United Kingdom (which has been covered in our previous research), to address their economic efficiency as manifested in both the returns to investors in RE and negative externalities in the form of social costs. We use the value of incentives paid to investors to analyze the financial performance of RE under the various support mechanisms found across a number of EU countries. We use representative plants, costs, localized operating characteristics, such as solar irradiance and historic country level electricity price data from 2009 to 2013. To examine the negative externalities of such investments, we employ financial option theory to measure the indirect costs of RE comparing them with the private benefits earned by investors. We also consider how changes to option parameters may impact the value of support for RE. Germany, Italy and Spain have recently reduced their support schemes, lending weight to the growing perception that the costs and the consequences, as originally conceived, were inadequately anticipated (Gipe, 2012 and FT, 2015). As terminology, we follow the public finance literature in defining "externalities" as "situations where consumption benefits are shared and cannot be limited to a particular consumer, or where economic activity results in social costs which are not paid for by the producer or consumer who causes them." (Musgrave & Musgrave, p. 42, 1989). The positive externalities of RE in reducing the social costs offossil fuels are not treated in this research. The direct and indirect costs we quantify of RE may be acceptable in whole or in part as a means of reducing the social costs of CO2, although estimates of the latter vary widely and greatly exceed those observed in the EU emissions trading market (EPA, 2015; Moore & Diaz, 2015). Lastly, although the term "option" is often used in the policy literature to refer to public choices, we employ this term as in "option theory" to refer to the valuation of state-contingent assets or liabilities, as found in the finance literature (Hull, 2013) and as applied to the optimization of energy assets such as power stations (Eydeland and Wolyniec, 2002).

The paper is organized as follows: in section 2 we provide perspectives on the topic of RE support mechanisms and then turn to the efficiency of support mechanisms as covered in the public finance and environmental economics literature. Section 3 explains how we use financial option theory to model the exposure created through dispatch priority, as afforded to renewable generation, to address the issues raised in the literature review on the economic efficiency of RE incentive mechanisms, social costs included. In section 4, we present measurements of the financial performance of RE generation, both in terms of private benefits and social costs in order to observe the calibration of incentive support mechanisms in liberalized, traded markets for electricity. The concluding section relates our findings to some of the broader concerns and critiques of EU energy and environmental policies.

2. RE as Public Good

According to public finance theory the nature and size of public goods need to be decided through collective or social decision making rather than through market processes (Musgrave and Musgrave, 1989). RE is supported as a public good to correct the negative externalities associated with fossil fuels such as green-house gases (GHG), especially as effective taxation of CO_2 has proven difficult. To maximize social benefits and reduce social costs, various incentive mechanisms have been put forward to encourage investment in RE, particularly in wind turbine or photo voltaic electricity generation. But how may one quantify the social benefits of reducing GHG and determine by how much RE should be supported? Formally, the decision on how much of a public good should be produced requires finding the level of production which maximizes the difference between marginal social benefits and marginal social costs (Samuelson, 1954). Given the global nature of GHG and atmospheric warming, it is difficult to apply this rule for how much RE is required. But as governments have objectives for RE investment and de-carbonization, such as the latest 2015 UN targets, we ask how large these incentives should be to achieve the objectives while ensuring allocative efficiency, i.e. aligning private benefits with social costs.

2.1 Support Mechanisms and Instruments for RE

Various support mechanisms for RE have been tried. Compared to conventional methods of generating electricity, RE is more capital intensive but it has lower operating and maintenance costs and no fuel costs. In competitive markets for electricity as found in Europe, North America and elsewhere, on a Levelized Cost of Electricity basis (or LCOE, as in Capital Costs ÷ Output), RE generation struggles to compete with incumbent methods of producing electricity because its costs are spread over much smaller output. Although the fixed costs of RE, particularly solar PV, have been falling, the problem lies with the number of hours over which RE generates electricity. For comparison, using North American prices for natural gas, it has been shown that cutting the utilization of a Combined Cycle Gas Turbine (CCGT) from 80% to 40%, only increases the cost of electricity from 5.2 US cents per KWh to 7.2 US cents per KWh (Biasi, 2013). In contrast, typical wind and solar plants may only generate electricity about 25% of the time, resulting in substantial capital costs being spread over fewer hours, or higher LCOE. With conventional forms of energy like gas and coal plants, the mixture of fixed and variable costs means that, even with reduced hours, their LCOE may yet be competitive. These disadvantages facing RE mean that incentives are required to yield an adequate return to capital, although there is no consensus on what works best (Stokes, 2013). The common solution - financial support mechanisms for RE- has led to many issues and problems. The alternative of putting a price on CO_2 and changing the merit order of dispatchable electricity generation has been attempted but, for many reasons, has been unsuccessful (Haar and Haar, 2006).

In traded electricity markets the support mechanisms usually involve removing or modifying the various risks faced by renewable investors through combinations of guaranteed prices above a floating price, a fixed premium or uplift to a floating electricity price, and/ora transfer of risks to other parties or the greater system (Ayoub and Yuji, 2012). Indirect support may also be derived through the possibility of revenue from trading RE certificates (Ragwitzer et al., 2007). While the merits of various RE support schemes continue to be debated, in the view the US Department of Energy National RE Laboratory, tariffs are suited to deregulated generation markets (Couture, et al., 2010). According to other research, feed-in tariffs, as found in Denmark, Germany and Spain, have worked better than quota programs in delivering an RE supply (Green and Yatchew, 2012). In summary, there has been varied research into the effectiveness of policies in promoting renewable targets but no consensus has emerged. Given the levels of renewable investment now achieved in Europe, North America and elsewhere, the focus of debate has shifted to the costs and efficiency of delivery mechanisms as explained below.

2.2 Allocative Efficiency and RE

The premise that the deregulated and privatized markets for electricity require sufficient incentives to attract investors begs the question of how to ensure economic efficiency in delivering policy goals. Various approaches have been used to promote RE investment while avoiding waste through setting an appropriate returns to investors in RE. Some methods are cost and revenue based and use LCOE; other methods calibrate incentives according to the avoided fossil fuel generation cost to capture the value of RE in society (US DOE – EIA, 2014). In other settings, trying to provide a reasonable return to project costs has been employed. To avoid supra-normal returns, it also has been proposed to rely upon market forces in the form of auctions as a means to calibrate RE incentive and avoid economic rents (Held et al. 2014). Calibrated in different manners and often revised, the variety of such methods suggests a lack of consensus on how to deliver supply, align social costs with private benefits to promote economic efficiency while avoiding economic rents.

Adding a margin to the LCOE to set incentives and anticipate revenues for RE has been a common approach, although not without controversy. In Ontario, Canada, a debate on using LCOE to set incentives was settled by calibrating it to the support levels of Germany (Gipe, 2007). However, the use of LCOE has resulted in numerous instances of excessive returns to investors. For example, a study of wind parks in Portugal found that owners of such RE were over-compensated under the feed-in tariff scheme (Pena et al. 2014). The Portuguese Authorities used a LCOE model to determine what they felt would be the necessary and sufficient level of support. But the RE investment under the Portuguese scheme soared. According to research, under the 2005 legislation, €4.1bn was spent on feed-in tariff supports while the 2013 legislation required another €840mil of public spending on wind energy supports (ibid, 2014). In other countries, including Italy and Spain, the use of LCOE led to an unexpected surge in renewable investment that required hasty actions to reduce incentives. There appears to have been a divergence between how policy makers view subsidies, such as feed-in tariffs,or feed-in premiums[3] and how markets and investors value them (Michaelowa and Hoch, 2013). The design of incentives through the application of LCOE has yielded strong investment, suggesting that incentive schemes may have been too generous and ignored indirect impacts, such as system costs. Exacerbating matters, under most schemes, LCOE-based incentives were set according to the size of the facility with the smaller, less efficient plant being offered higher subsidies. Apart from the economically perverse impact of such an approach, this may have contributed to fraud as many sites were intentionally "de-rated" to qualify for higher incentives (Garman and Ogilvie, 2015).

Using LCOE for measuring the value of RE in liberalized traded markets for electricity is problematic in several other respects. In using LCOE one is treating electricity as a homogenous good and power supply from different fuels and technologies as commoditized perfect substitutes. This ignores temporal and spatial issues and their consequent system impact (Eldenhofer et al. 2013). Applying a discounted life-time fixed and variable cost of a generation technology, as used for conventional technology, is not suitable for measuring the economic attractiveness of RE (Joskow, 2011). Unlike conventional dispatchable energy generation from fossil fuels, the RE output is random and, because electricity cannot be stored, the time of day when it is supplied or dispatched determines its value (Joskow, 2011 and Hirth et al.2015). Moreover, RE is intermittent and requires conventional

[3] Feed-in tariffs and feed-in premiums are both forms of incentive mechanisms for RE. In the former a specific price is guaranteed while in the latter a percentage premium is added to the market price. Both forms result in an incentive premium for producers of RE.

operators to accommodate their random output. The metric LCOE does not address this issue either. For example, using the LCOE approach, some researchers compared the value conferred through the feed-in tariff against the wholesale traded electricity price, providing a measure of Net Present Value (NPV). The returns were adequate, but the impact upon the grid and overall system was not addressed (Movilla and Blazquez, 2013). Using LCOE to inform a return on capital for RE ignores the benefits to investors of dispatch priority in liberalized electricity markets. The LCOE ignores the indirect costs imposed upon incumbents and the system. Understanding the economic efficiency of RE support mechanisms and whether the returns are "fair" requires recognizing the market setting and the exposure created. Lastly, RE as distributed generation requires additional high voltage transmission connections to join a national or regional grid (Lang and Lang, 2012).

By contrast, value-based approaches attempt to account for how RE interacts with conventional forms of electricity generation in liberalized traded markets for electricity and have been used to augment the LOCE approach. Known as the Levelized Avoided Cost of Energy (LACE), this is intended to measure the value of RE to society or to a centralized utility or grid operator according to the savings from displacing fossil fuels. As a metric to calibrate RE tariffs and incentives this approach has been promoted by the US Department of Energy and has been used recently in Portugal. As a policy metric, LACE is under evaluation but has not yet gained acceptance (Bolinger, 2013; US DOE EIA, 2014). Depending upon how it is applied, this may include from when and from where RE is fed into the grid. Avoided cost may provide a proxy measure for the annual economic value, or savings of a candidate project summed over its financial life, converted to an annuity. Calibrating RE incentives in this manner incorporates savings to the grid from *not* generating electricity using conventional incumbent plants, but ignores the impact upon individual utilities of reducing output and even capacity. These savings (computed using LACE) may be compared with the LCOE to set incentives for a RE project. Although economically intuitive, applying LACE requires system knowledge and deciding *what is* the marginal plant. Further, it assumes an operating regime which can vary widely with market conditions. In sum, LACE is useful in theory but hard to apply in practice.

To calibrate the sufficient level of subsidies and incentive schemes to spur investment in RE yet avoid excess returns, we propose below using an investor's perspective. To promote economic efficiency, we also need to examine any indirect costs given the nature of RE and the market setting. The intermittency of RE and the lack of dispatchability need to be considered in how we value and subsidize renewables because in traded, liberalized markets, the price of electricity depends on when it is produced and it is usually priced hourly or half-hourly. The correlation between output and prices found in traded electricity markets, means that the random nature of RE output may increase price volatility, depress prices and alter plant merit order according to marginal pricing. Such results have been documented in research on the Spanish power market by Ballester and Furio (2015) and Hirth

(2013), while others have questioned if liberalized traded power markets are suited for a large renewable base (Gelabert et al.2011). As the proportion of RE in total system capacity expands, the value of the feed-in tariff relative to the market price grows, making it worth more, like a put option increasingly in-the-money, while the fall in prices hurts incumbent generators. Lastly, introducing RE into a liberalized market may also interact in unexpected manners with other incentive mechanisms. For example, by depressing electricity prices, RE may discourage conservation and efficiency programs (Borenstein, 2012). For all these reasons, encouraging renewable energy in liberalized markets requires understanding its value and impact. Only with accurate valuation of RE, including both direct and indirect costs, can we ensure that incentives mechanisms are calibrated to use resources efficiently. In addition to looking at RE from an investor's perspective, we introduce a new way of capturing and measuring the indirect costs of RE according to how the consequent exposures may be hedged. Comparing these results with the returns enjoyed by investors allows us to understand the impact of RE in liberalised markets, along with how incentives could be calibrated to promote economic efficiency.

3. Methods, Model and Data

To determine the appropriate level of RE incentives we analyse the value derived from operating RE in an integrated, liberalised traded market for electricity. We begin with an investor perspective and consider, empirically, the returns earned under the various incentive schemes offered in the EU. Secondly, we ask whether from the standpoint of economic efficiency, incorporating the full impact of RE in liberalized markets, the return provided to investors has been generous. Thirdly, we consider if such returns to RE investors embody all direct and indirect costs from the operation of renewable generation. And, fourthly, as the priority dispatch of renewable electricity into an integrated liberalised system may make markets more volatile and reduce prices, we ask how could the impact in terms of system cost, exposure and economic efficiency be appraised. These aspects are discussed below.

3.1 RE in Liberalized Markets

Setting the right incentives for RE in liberalized, traded markets for electricity presents many challenges. In the 1990s most programs to deregulate and liberalize electricity markets gave a prominent role to trading. Through the interaction of supply and demand markets were balanced and reliability ensured, with the marginal price set by the most productive or thermally efficient plants, the Combined Cycle Gas Turbines. Organized around a centralised grid, which owns the high-voltage transmission systems and sub-stations, fossil fuel generators compete on short-run marginal costs. In liberalised electricity markets wholesale electricity prices are made as often as at 48 times per day, reflecting the metering requirements of the largest users. Through system planning that ensures the right mix of flexible and less flexible plants, grid operators use balancing and trading markets to cover demand prediction errors, unexpected weather or unplanned outages, while longer-term contracts with suppliers are used to avoid supply disruptions and ensure adequate reserve margins.

Introducing RE into the above market structure presents challenges as it cannot be dispatched on demand but generates when the wind blows or the sun shines. For this reason, renewables are given "dispatch priority": when they are generating, other plants with flexible and controllable output must reduce their output. Dispatch priority creates short-term balancing costs for the grid and incumbents, plus long-term costs such as the need for grid connections and investment in more dispatchable generation as back-up. The average thermal efficiency of incumbent plants may be reduced and the frequency of unexpected outages and break-downs may grow. Such negative externalities represent tangible costs which need to be incorporated into how we value and incentivize RE. Renewables have negligible short run marginal costs and higher fixed costs but setting economically efficient incentives requires including the benefits enjoyed from the non-internalized costs - the externalities - which they impose upon incumbent dispatchable generators, the grid, the overall energy supply system and, ultimately, society's stakeholders. Setting incentive mechanisms for renewables (such as feed-in tariffsor feed-in premiums), while excluding free-riding (not paying for the common resource of dispatchable back-up generation and grid management), means the true returns to RE are under-estimated and, ultimately, resources wasted.

3.2 The Indirect Costs of Renewable Energy

The operators of RE plants receive an incentive price for what they generate but simply comparing the value of their revenues against the costs of investments does not tell full story. Rather, in addition to the private return to investors, one should take into account the indirect costs of RE schemes. In the EU, the RE purchase obligation upon grid operators and integrated utilities means that, whenever the sun shines or the wind blows, output must be reduced and all other dispatchable plants must be re-prioritized or even shut-down. Typically, a renewable owner/operator will enter into a supply contract with a renewable aggregator or integrated utility resembling a contract for differences (CfD) between the premium price paid according to the feed-in tariff and the market price. The cost of accepting intermittent renewable output under dispatch creates an exposure for the buyer and, ultimately, society. Under most schemes, if hourly prices exceed the tariff the renewable operator must return the excess (Murphy, 2011). It is difficult to measure the system cost of exporting renewable energy to incumbent utilities and the grid under dispatch priority but we can use financial option theory to quantify the exposure created, through what it would cost to hedge the non-internalized costs or negative externalities. In power markets option theory has been applied to model flexible, dispatchable plants (Blake et al. 1999; Eydeland and Wolyniec, 2012 and Johnson et al. 1999).

Through applying option theory we can quantify the indirect cost of exposure to renewable energy from a purchaser's and, ultimately, system perspective.

In agreeing to take renewable electricity, the buyer is liable for the difference between the market and the incentive price (the effective CfD). This creates an exposure ultimately imposed upon the greater system. This exposure can be hedged hypothetically by purchasing a strip of put options (the right to sell) with strike prices equal to the feed-in tariff price. Although purchasing individual half-hourly options to hedge against this exposure is not possible in practice, the theoretical price of the option represents the cost for accepting such risk by the purchaser and is, ultimately, borne by the system. As a strategy on the part of utilities obliged to purchase RE, we assume risk neutrality, although assuming risk aversion would only make the cost of accepting such risk greater (Dupuis, 2016). If market prices fall, the exposure arising from the CfD grows, but through using put options that confer the right to sell at the incentive price, a purchaser of RE could, hypothetically, hedge the exposure because the price of the put option embodies this volatility. Therefore, we argue that the price of the put option represents the cost of taking RE under the purchase obligation ultimately borne by society's stakeholders, as it is equal and opposite in value to neutralize the exposure.

To price the exposure from the difference between market price and that of RE, through for example a feed-in tariff, we compute the value of put options using the Black & Scholes (1973) formula with strike prices set at the levels paid for such energy, as these could be used to neutralize the cost of having to purchase electricity above the market price. In summary, the combination of dispatch priority and incentive pricing enjoyed by renewable operators creates an exposure for the buyer and, ultimately, for the system or grid which can be priced and, hypothetically, hedged using put options. In using option theory, we assume that market prices and volatility of market prices reflect available information, *including* the risk and exposure from renewable generators exporting electricity under dispatch priority. Given that the trading of electricity on exchanges and over-the-counter involves merchant generators, integrated utilities, banks and trading houses, we believe this assumption is reasonable. Other approaches have been considered to quantify the exposure to RE, such as comparing it with the LCOE but, as already explained, this excludes any indirect costs of RE. One researcher has used a statistical approach to value the CfD against futures markets but the lack of liquidity and risk aversion rendered such results tentative (Kristiansen, 2004). By employing option theory to measure the cost of RE externalities, we can compare the indirect costs of RE with the returns earned by investors. Furthermore, understanding the option model parameters also allows us to appreciate how the growing presence of RE may affect the value of such RE investments and their economic impact.

3.3 Data

Turning to data, information was collected from 2009 to 2013 for the following: (i) effective support prices for RE for the major countries of the EU, excluding the UK; (ii) day-ahead wholesale prices for electricity within these countries; (iii) day-ahead price volatility in the same countries; (iv) daily sun irradiation by countries to calculate output per square meter of investment[4]; (v) country specific monthly average capacity factors for wind turbines and photo-voltaic facilities[5] and (vi) costs per installed MW of renewable investments. Data from the Council of European Energy Regulators (CEER) were used for support levels by country and technology, per MWh and appear in Table 1 below (where programs were not in place or output was negligible, cells are empty).

Table 1. RE Incentives

RENEWABLE ENERGY SUPPORT PRICES BY TECHNOLOGY (EUROS/MWh)					
COUNTRY	YEAR	SOLAR PV	SOLAR OTHER	WIND OFFSHORE	WIND ONSHORE
BELGIUM	2009	€ 465.39		€ 107.00	€ 95.28
	2010	€ 420.67		€ 94.88	€ 94.88
	2011	€ 407.42		€ 100.94	€ 94.58
	2012	€ 375.89		€ 107.00	€ 86.29
	2013	€ 369.07		€ 104.89	€ 84.19
FRANCE	2009	€ 449.97		€ 130.00	€ 41.48
	2010	€ 496.03		€ 130.00	€ 82.00
	2011	€ 477.22		€ 130.00	€ 82.00
	2012	€ 451.69		€ 127.20	€ 82.00
	2013	€ 435.99		€ 127.20	€ 82.00
GERMANY	2009	€ 411.04		€ 81.07	€ 41.05
	2010	€ 387.92		€ 41.05	€ 41.05
	2011	€ 353.82		€ 84.13	€ 45.43
	2012	€ 319.69		€ 127.20	€ 62.04
	2013	€ 291.54		€ 135.50	€ 65.63
ITALY	2009	€ 434.88			€ 217.45
	2010	€ 406.80			€ 220.00
	2011	€ 367.20			€ 220.00
	2012	€ 335.55			€ 224.80
	2013	€ 306.88			€ 79.74
NETHERLANDS	2009	€ 309.08	€ 68.04	€ 84.21	€ 65.01

[4]http://www.pveducation.org/pvcdrom/properties-of-sunlight/calculation-of-solar-insolation
[5]http://www.munich.climatemps.com/sunlight.php

	2010	€	389.68	€	68.04	€	89.29	€	81.16
	2011	€	385.88	€	68.04	€	94.37	€	68.47
	2012	€	245.40	€	68.04	€	99.45	€	65.68
	2013	€	220.53	€	68.04	€	99.32	€	60.34
SPAIN	2009	€	429.37	€	290.90	€	95.00	€	79.08
	2010	€	399.93	€	290.90	€	95.00	€	79.08
	2011	€	356.76	€	290.90	€	91.04	€	79.08
	2012	€	349.08	€	290.90	€	90.34	€	79.08
	2013	€	389.79	€	269.56	€	89.75	€	79.08
STATISTICAL SUMMARY (Over Countries and Years)	Minimum	€	220.53	€	68.04	€	41.05	€	41.05
	Maximum	€	496.03	€	290.90	€	135.50	€	224.80
	Average	€	381.34	€	177.34	€	102.23	€	92.60

Source: CEER , Annual Reports, www.CEER.eu/portal/page/portal/EER

Buyers of renewable energy under dispatch priority are exposed at hourly frequency, but only day-ahead prices at daily frequency are available and were sourced from Bloomberg. The Solar Electricity Handbook (2015) and several websites were checked for sun irradiation. Data from the International Energy Agency (IEA) and the US Department of Energy, Energy Information Agency (US DOE) were consulted for capacity factors of both wind and photo-voltaic electricity generation (International Energy Agency, 2010, 2013). Both official, EIA and IEA and commercial sources were examined for the price per installed unit of wind and solar capacity, with the World Energy Outlook for 2014 proving the most useful (US DOE EIA 2002, 2007, US DOE EIA 2014, World Energy Outlook, 2015). To adjust for the time-value of the cash flows arising from renewable generation a weighted average cost of capital (WACC) of 10% was assumed as it reflects the average opportunity cost of capital among Europe's major integrated energy utilities (while we note the return on capital employed for Europe's integrated utilities was averaging around 8%). As a hurdle rate, given the nature of the cash flow arising from renewable electricity generation, a discussion of whether a different rate should be applied, appears below. To calibrate the option pricing model, country specific rolling 30-day, and day-ahead price volatilities (as computed from base load day-ahead power prices on the high-voltage grid) were taken from Bloomberg, as summarized below.

Table 2

Country	Price Index (Bloomberg Mnemonic)	Day-ahead Rolling 30 Day Price Volatility (2009-2013 Averages)
Belgium	ELBBDAHD Index	158%

France	PWNXFRAV Index	411%
Germany	ELGBDAHD Index	358%
Italy	OMLPDAHD Index	211%
Spain	GMELITBS Index	326%
The Netherlands	AELCTDAY Index	249%

Source: Bloomberg

Although the above volatilities may already appear high compared to other commodity market, they reflect the unique characteristics of electricity markets (Auibe, et al 2013 and Hardle et al, 2010). As inputs to the option pricing formulas, they were scaled-up by about 20% (the square root of 1/24) to represent the within-day hourly exposure to intermittent renewable energy output.[6] Option strike prices were set at the support prices as shown above. As required by the option pricing formula, the risk free rate was assumed to be 2%. Using the option pricing software DerivaGem, Version 3.00, at daily frequency, we computed the cost of hedging exposure to intermittent renewable energy at the various incentive prices (www.pearsonhighered.com/hull, 2015).

4. Model Setup and Results

We begin by examining the returns earned by investors in RE using a return on capital employed measure, specifically:

$$ROCE\ (\%) = \frac{Earnings\ before\ Interest\ and\ Tax}{Capital\ Employed} \qquad (1)$$

Capital Employed is the capital required to purchase renewable generation capacity and excludes funding liabilities. As operating costs of renewable plant are low for wind turbines, especially during the first ten years of operation, and even lower for photo-voltaic (estimated at just 1%), earnings were not adjusted for such costs. ROCE shows whether a business can create value exceeding its WACC. Examining the profitability of renewable investments using ROCE is not common but, arguably, it represents how investors would appraise such opportunities. (To validate the ROCE results, we also extended the 2009 to 2013 results to 2029 and computed an Internal Rate of Return by comparing the initial investment against the historic and projected revenues. Assuming a twenty year life span for the investments, the IRR results resemble the ROCE results.) The revenue stream was time value adjusted using the assumed 10% WACC.

To analyse the value in RE, we computed a ROCE using the total amount received for generated output by an owner/operator. Sellers of RE receive the product of the i) volume of electricity sold/generated and ii) the support/incentive price through the feed-in tariff scheme. The latter is the sum of the wholesale market price for electricity and the incentive premium. Therefore, buyers of RE

[6] See the Appendix for the Option Pricing Formula and computation of the hourly volatility parameter.

are exposed, at half-hourly frequency, to the difference between the support price and the wholesale price. Using the feed-in tariffs for each of the six countries, we have averaged the returns to sellers over the last five years of available data and compared them to the capital employed by those sellers.

The results appear below in table 3.

Table 3. ROCE for select EU Countries (%)

RETURN ON CAPITAL EMPLOYED				
COUNTRY	**SOLAR PV**	**SOLAR THERMAL**	**WIND OFF-SHORE**	**WIND ON-SHORE**
BELGIUM	26%	n.a.	12%	33%
FRANCE	36%	n.a.	16%	25%
GERMANY	25%	n.a.	11%	14%
ITALY	50%	n.a.	n.a.	68%
SPAIN	48%	36%	11%	32%
THE NETHERLANDS	20%	4%	11%	24%
AVERAGE	34%	20%	12%	33%

Source: Internal Model Calculations

Our calculations show that returns to RE owners and operators were very attractive. Solar photo-voltaic technology earned the highest return on capital employed followed by on-shore wind energy. The average ROCE for solar photo-voltaic exceeds 30%, while for on-shore wind generation the ROCE was also high. In Italy, for example, the returns to solar and wind were spectacular. Across the EU, only Spain made noteworthy investment in solar thermal technology and the ROCE results exceeded 30%. Compared to a WACC of 10%, as used to discount the time value of future earnings, ROCE results greatly exceeded the assumed cost of capital. Given the guaranteed off-take, dispatch priority afforded to RE investors, the credit quality of counter-parties purchasing the generated electricity and the government backing to incentive prices, the returns provided to investors were generous and surprising. As the relationship between incentive prices and ROCE is linear, cutting incentives in half would still have generated returns equal to, or exceeding, the WACC in the six EU countries analysed. While for wind on-shore, apart from Germany, cutting the incentives in half would have still produced ROCE exceeding the assumed cost of capital. In summary, although the various programs across the EU were *effective* in getting RE plant built, the cost of incentives were economically inefficient offering supra-normal returns for essentially risk-free investments.

We now turn to measuring the exposure created by the operation of RE and faced by its grid operators, integrated utilities and society. Under dispatch priority, buyers of RE must pay the difference between the feed-in tariffs, as guaranteed under the various country schemes, and the wholesale market price. But the buyers do not know when intermittent wind-generated electricity will occur or when, during day-light hours, solar electricity will be generated. Therefore, we seek to quantify the expected cost imposed upon buyers of renewable energy from this exposure to intermittent output. In wholesale electricity markets, options are traded for day-ahead delivery, balance of week delivery, balance of month delivery, etc. No options are actually traded allowing one to hedge exposure at half-hourly frequency. The fact that such options are not available means that the expected cost remains with the buyer of RE and, ultimately, all other stakeholders. We quantified this expected cost using option theory under a hypothetical hedging programme which neutralises the exposure. At day-ahead frequency, using the scalar adjustment noted in section 3.3 for five years, the prices of put options were computed using the standard put option model and parameters (Hull, 2013).

To appreciate the profitability for RE shown above, we quantify the externality per MWh of capacity from the operation of RE and compare it to what was earned per MWh of installed capacity. As in table 4 below, it would cost the buyers of RE on average nearly *twice* as much to hedge the exposure arising from the difference between the feed-in incentive prices to what the RE owner/operator received. For example, while the renewable operator with solar PV earned €342,100 per MW of capacity, it would cost buyers of such RE €669,598 to hedge the exposure. For on-shore wind, the externality is the difference between €228,082 and €441,827.

Table 4. Revenues versus Hedging Costs (in €)

FIVE YEAR AVERAGE ANNUAL REVENUE PER MW OF CAPACITY VERSUS HEDGING COSTS				
COUNTRY	**SOLAR PV**	**SOLAR THERMAL**	**WIND OFF-SHORE**	**WIND ON-SHORE**
BELGIUM				
RE Owner/Operator Revenue	€ 256,891		€ 236,124	€ 229,284
Cost to Buyer to Hedge	€ 558,305		€ 494,240	€ 431,982
FRANCE				
RE Owner/Operator Revenue	€ 363,390		€ 311,525	€ 174,308
Cost to Buyer to Hedge	€ 788,972		€ 632,533	€ 348,868

GERMANY				
RE Owner/Operator Revenue	€ 250,184		€ 217,322	€ 99,099
Cost to Buyer to Hedge	€ 532,015		€ 451,584	€ 232,130
ITALY				
RE Owner/Operator Revenue	€ 503,184			€ 476,839
Cost to Buyer to Hedge	€ 858,351			€ 946,254
SPAIN				
RE Owner/Operator Revenue	€ 483,132	€ 359,723	€ 223,374	€ 223,374
Cost to Buyer to Hedge	€ 839,326	€ 617,290	€ 444,620	€ 375,802
THE NETHERLANDS				
RE Owner/Operator Revenue	€ 195,819	€ 42,147	€ 223,345	€ 165,587
Cost to Buyer to Hedge	€ 440,620	€ 86,489	€ 446,541	€ 315,923
FIVE YEAR AVERAGE ANNUAL REVENUE PER MW OF CAPACITY VS.HEDGING COSTS				
AVERAGE (Belgium, France, Germany, Italy, Spain, The Netherlands)	**SOLAR PV**	**SOLAR THERMAL**	**WIND OFF-SHORE**	**WIND ON-SHORE**
RE Owner/Operator Revenue	€ 342,100	€ 200,935	€ 242,338	€ 228,082
Cost to Buyer to Hedge	€ 669,598	€ 351,889	€ 493,904	€ 441,827
AVERAGE DIFFERENCE	67%	56%	71%	66%

Source: Internal Calculations

As shown in table 4, the costs of hedging one's exposure greatly exceed the gains from renewable operation. The result is intuitive: under risk neutrality, intermittent output would be hedged for every half hour of the year, although RE is generated during a small part of the year, as determined by the weather. Moreover, setting the incentive prices so high makes the required put options deeply in-the-money and expensive. The costs of hedging solar PV generation are greater in the Southern countries of Europe than in the North due to the more hours over which exposure is created. Although buyers of RE are only exposed to purchasing energy from solar facilities during day-light hours (compared to wind turbines which must be hedged throughout the day), the higher incentives provided for the former makes the cost of hedging its exposure generally greater.

We have assumed risk neutral behaviour: utilities would hedge all exposure if options were available. Although such means of neutralizing their exposure are not available, we have used the hypothetical option valuation to measure the exposure faced. But even as a strategy, if individual utilities were risk tolerant and only hedged a proportion of exposure according to their unique commercial and financial objectives, such possibility is irrelevant because they still face the expected objective cost of having to accept RE at incentive prices. In summary, through the imposition of unhedgeable expected costs on utilities and, ultimately, the society, RE investors effectively enhance their already favourable returns. If roughly half of the expected costs imposed upon dispatchable generators (and the society) were shifted back to RE owner/operators, their attractive returns would be eliminated, hence this supports the case for reducing the incentives.

5 Conclusions

In this article we made two sets of observations based upon empirical research and analysis. The first concerns the financial performance from operating or owning a RE facility; the second draws attention to the negative externalities arising from RE. We calculated the financial performance of various renewable technologies across the key EU countries using a ROCE approach. We observed that ROCE results, under the various RE subsidies, were high. At a time when Europe's major energy utilities were earning less than their cost of capital, investors in RE earned strong returns while taking little, if any, risk. Research into the indirect costs of RE begins with acknowledging that dispatch priority creates a cost for conventional generators and ultimately all stakeholders, as they are forced to reduce capacity, re-prioritize their plant and pay the difference between the feed-in tariff and the wholesale price. To measure this cost we used option theory on the grounds that, through purchasing options, the cost of random RE output to a purchaser could be neutralized. Although options at half-hourly frequency are not traded, the price of an option represents the cost of neutralising the risk. We found that hedging against having to take RE is expensive because the feed-in tariff prices are at a large premim to the wholesale prices, making such options deeply in-the-money. Moreover, a lot of options would need to be purchased as wind turbines can generate at any time throughout the day and solar PV during any day-light hour. According to our research and analysis, if a utility were to hedge against the cost of taking RE, it would cost nearly twice as much as what the RE owner-operator received. This difference represents the external costs of RE imposed upon utilities and ultimately passed through to consumers and society. If such costs from RE were shifted back to renewable owners, then it would have been unlikely for green technology to develop. As a Pigouvian means of redressing the social costs of CO2, the above results *might* be acceptable in whole or in part, although this raises many issues around equity in how such burden is shared. A useful area for future research could be to compare our direct and indirect cost results with recent estimates of the social cost of CO2.

It has been suggested that the presence of renewables may lower prices and contribute to price volatility because prices and volumes are generally positively correlated (Hirth, 2013 and Gelabert et al, 2011). RE contributes to price volatility while lowering average prices of electricity because their short run marginal costs are negligible. Further, RE may create system wide costs as more thermal plants are paid to be on stand-by or run at minimum stable generation, lest the wind stops blowing or clouds appear. RE may also increase the frequency of ramping-up and ramping-down output, increasing system instability (Perez-Arriaga and Battle, 2012). Although no sensitivities to option parameters were computed, from the insights of option theory, we see that if electricity markets were to become more volatile, through the growing presence of RE generation, the cost of hedging the exposure to RE would increase. Further, with variable cost of operating RE practically zero, the operation of RE may depress electricity prices by increasing the spread between the feed-in tariff and the market price and raise the cost of hedging against such an exposure. Not only does RE impose costs upon incumbents, the system and society but, with growing investment and output, the mark-to-market value of their CfD arrangements gain value and their negative externalities increase. Lastly, as the proportion of RE output in any market grows, the scope for portfolio diversification benefits to utilities will be diminished and, thereby,will require ever larger reserve margins to ensure system stability and keep the lights burning.

In rolling-out RE support schemes using feed-in tariffs, the countries of the EU were driven by effectiveness in getting capacity up and running. But, when measured by the returns provided to RE investors, many schemes across Europe werewasteful and inefficient. While the EU has encouraged a single market for electricity through inter-connectors and uniform grid codes, member countries individually designed incentives for RE. Rather than driving costs downwards through competition between potential suppliers, the myriad of incentive schemes across the EU led to competition between countries vying for new capacity through offering the most favourable returns. Instead of investing in solar PV in places with the greatest sunshine, virtually every country attempted to attract RE investment to meet targets regardless of geography. In 2010, Belgium, Italy and Spain offered around €300 per MWh for solar PV-generated electricity, while sunny Greece paid nearly €500 per MWh. Altogether, this piece-meal approach contributed to economic inefficiency and waste. According to work for the EU Commission, in 2012 alone, the total support to solar and wind generation had risen to around €27 billion and over €33 billion was dispensed through feed-in tariffs and feed-in premiums (Ecofys, 2014). Measured on a per MWh basis, hundreds of Euros were being spent for each unit of electricity produced, while prices of electricity were stable to declining.

Why was such economic inefficiency accepted and belatedly scrutinized? At a time of economic recession, amidst the financial crises, supporting RE arguably became a mixture of industrial and fiscal policy. ‘RE can create jobs’ remains a common refrain, but this ignores the impact on consumers spending power and on the international competitiveness of European industry. On top of the direct costs of RE, the feed in tariff schemes impose indirect costs on incumbent dispatchable plants managing random output. In addition to the opportunity cost of moth-balling brand new CCGT plants, the adverse impact of random RE output, doubtlessly contributed to the half-a-trillion Euro fall in the capitalization of Europe's utilities (The Economist, 2013). To the extent that such costs were not absorbed by utility shareholders in lower returns or by employees in lower wages, they would have been passed forward to consumers. In summary, although the EU was successful in getting RE built, the direct costs of incentivizing RE, plus the indirect costs to society, have been huge and difficult to justify from the standpoint of economic efficiency.

APPENDIX: Black–Scholes equation for European Style Options[7]

The Black–Scholes equation is a partial differential equation, which describes the price of the option over time. The equation is:

$$\frac{\partial V}{\partial t} + \frac{1}{2}\sigma^2 S^2 \frac{\partial^2 V}{\partial S^2} + rS\frac{\partial V}{\partial S} - rV = 0$$

The Black–Scholes formula calculates the price of European put and call options. European style options may only be exercised at maturity as opposed to American style options which may be exercised any time during the life of the contract. This price computed using theformula shown below is consistent with the Black–Scholes equation as above since it can be obtained by solving the equation for the corresponding terminal and boundary conditions.

Thus the formula for the value of a call option conferring the right to purchase for a non-dividend-paying underlying stock in terms of the Black–Scholes parameters is:

$$C(S,T) = N(d_1)S - N(d_2)Ke^{-r(T-t)}$$

$$d_1 = \frac{1}{\sigma\sqrt{T} - t}[\ln\left(\frac{S}{K}\right) + \left(r + \frac{\sigma^2}{2}\right)(T-t)]$$

$$d_2 = d_1 - \sigma\sqrt{T} - t$$

The price of a corresponding put option conferring the right to sell, based on put–call parity is:

$$P(S,t) = Ke^{-r(T-t)} - S + C(S,t)$$

$$P(S,t) = N(-d_2)Ke^{-r(T-t)} - N(-d_1)S$$

For both equations, as above:

- *N( )*is the cumulative distribution function of the standard normal distribution

[7] As covered in Chapter 15, Hull, 2015.

- T-$t$is the time to maturity
- $S$is the spot price of the underlying asset
- $K$is the strike price
- $r$is the risk free rate (annual rate, expressed in terms of continuous compounding)
- $\sigma$is the volatility of returns of the underlying asset

Volatility can be defined as the standard deviation of the return provided from holding the instrument or security for one year when the return is expressed using continuous compounding. Thus $\sigma^2\Delta t$ is approximately equal to the variance of the percent change in the security price in time Δt and $\sigma\sqrt{\Delta t}$ is approximately equal to the standard deviation of the percentage change in the security price at time Δt.

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