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POLICY PAPER

The Effect of REFIT on Irish Wholesale Electricity Prices*

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Abstract: This paper evaluates the likely effect of REFIT, the Irish scheme to support renewable electricity generation, on the wholesale price of electricity. The cost of REFIT is passed on to Irish consumers. Here we calculate that, when there are 4,071MW of on-shore wind in the Republic of Ireland, the cost of the REFIT scheme is between 5 per cent and 10 per cent of the gross wholesale price of electricity. Off-shore wind has higher levels of support than on-shore wind, as do technologies that are still in development such as wave and tidal. When off-shore wind, wave and tidal are added to the system, the cost of REFIT increases significantly. We argue that wave and tidal should be sustained with a different scheme that provides capital grants, and that off-shore wind that is channelled to exports should not be supported by Irish consumers.

I INTRODUCTION

The promotion of renewable energy resources has increased recently in response to more stringent European legislation and greater environmental awareness. In 2009 the European Commission approved the 20-20-20 plan. One of the goals is for 20 per cent of all energy use in the European Union to come from renewable resources by 2020. For Ireland this

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has translated into a requirement that renewables provide 16 per cent of total energy demand by 2020. Most of the responsibility of meeting this target will fall on electricity generation, given the limited renewable resources available to fuel other sectors such as heating and transport (the focus on renewable resources in electricity generation applies to other countries as well, such as the UK; see Newbery, 2010). The renewable energy target is legally binding, and should Ireland not achieve this target domestically, it will have to pay for the statistical transfer of renewable energy from other member states.

In order to reach the 16 per cent economy-wide target, the power sector will have to generate about 40 per cent of electricity demand using renewable resources, primarily wind. This target is consistent with Irish government plans, as set out in 2007, Department of Communications, Marine and Natural Resources (DCMNR, 2007) and amended in 2008, Department of the Environment, Heritage and Local Government (DEHLG, 2008). The method chosen to incentivise investment in renewable electricity generation is a system of support payments. The cost of the scheme is passed on to Irish consumers in the form of a Public Service Obligation (PSO) levy, which includes not only payments for renewable energy, but also payments to peat generating plants and plants that were built to maintain electricity reliability standards. The level of the PSO levy is set by the Commission for Energy Regulation (CER) so as to recover the additional costs to suppliers as a result of purchasing energy from these sources (CER, 2010).

The price of electricity is important to consumers and policymakers. There have been extensive discussions of electricity prices during the past couple of decades. There is concern about how they affect residential consumers (and energy poverty) and the competitiveness of exporting companies (for recent examples see Sustainable Energy Ireland (SEI), 2010 and Diffney *et al.*, 2011). This paper estimates how the Renewable Energy Feed-In Tariff scheme (REFIT) influences wholesale electricity prices in 2020. We compare the cost of electricity for different levels of renewable generation as fossil fuel prices change. This paper focuses exclusively on payments related to renewable generation and does not address the other components of the PSO. We calculate the cost of REFIT for 2020 and find that the effect of the scheme depends greatly on exogenous factors such as the price of fossil fuels. When fuel prices are high the scheme is less costly, adding up to 6.8 per cent to wholesale electricity costs. On the other hand, when fuel prices are low, the wholesale price of electricity increases by up to 17.2 per cent due to the REFIT scheme.

Previous research shows that wind generation can be used to hedge against high fossil fuel prices (Berry 2005; Diffney *et al.,* 2009). Graves and Litvinova (2009) find that the hedging properties tend to be more valuable in the long run, when financial hedges are unlikely to be available.[1] The work undertaken in this paper shows that the REFIT scheme maintains renewables' hedging properties when it passes the cost on to consumers, although in a somewhat dampened form.

Many papers have analysed the effect of increased wind penetration in Ireland (for examples see DCENR and DETINI, 2008; Denny and O'Malley, 2006). A few papers study the cost of renewable support schemes, but mostly focus on evaluating the least-costly type of scheme. Huber *et al.* (2007) determine the optimal type of support needed to ensure that the Irish renewable targets are met (at the time 20 per cent renewable generation by 2020). They find that over the 2006-2020 period, feed-in-tariffs provide the required level of renewable generation at minimum cost to society. Butler and Neuhoff (2008) study the effect of support schemes for wind generation, focusing on the UK and Germany and determine that the German feed-in-tariff is cheaper than the system of quotas used in the UK. Doherty and O'Malley (2011) evaluate the cost of REFIT for Ireland on the basis of a probability distribution of forecasts of future electricity prices. Based on their assumptions, they find that the subsidy to wind generation is about €23 per MegaWatt-hour (MWh) produced by wind.

Section II introduces the renewable support scheme and describes how it works. Section III presents the model used for the analysis and outlines the main assumptions used in the simulations. Section IV presents the results of the simulation. Given the uncertainty that exists in energy markets we provide the results for a series of different fuel price scenarios. Finally, Section V summarises the results and concludes.

II REFIT SCHEME

In the Republic of Ireland, investment in new renewable electricity generation is supported by the Renewable Energy Feed-In Tariff (REFIT) scheme, which guarantees a minimum price for renewable electricity to investors. This scheme replaces the Alternative Energy Requirement scheme (AER).[2] The first phase of REFIT was announced in 2006 and provides support for wind generation, hydro and biomass for up to 15 years. The level of support

[1] The authors also conclude that in areas where wind does not blow at times of peak demand (for example, areas where the annual peak coincides with extensive use of air conditioning) hedging through renewable resources will only be economic if fossil fuel prices are expected to be high.

[2] The AER accounted for about 532MW of wind investment support, designed to last 15 years. The last round of competitive tendering under the AER took place in 2005.

increases with inflation (measured by the Consumer Price Index) if inflation is positive.

Table 1 shows the levels of support for all categories for 2006 and 2010, where the 2010 figures are equal to the 2006 figures adjusted for inflation, based on the Consumer Price Index (CPI).[3] The REFIT payment is composed of three parts. The first part is independent of the market price of electricity obtained in the compulsory pool Single Electricity Market (SEM, described in more detail below). In Table 1 it is defined as "Fixed Payment" and is paid for each MegaWatt-hour (MWh) of electricity produced by generators. The second part is a reference price (equal to €66.35/MWh in 2010). If the price obtained on the market is smaller than the reference price, a payment is made for the difference between the two. Finally the third part is the technology difference payment, paid in addition to the reference price for all renewables other than large scale wind, to compensate these suppliers for the higher costs of generation from other technologies. Large scale wind refers to any wind farm with an installed capacity larger than 5 MegaWatt (MW).

In Table 1 the "Guaranteed Price" is the sum of the reference price and the technology difference payment for all technologies. For renewable generators that fall within the first phase of REFIT (from now on referred to as REFIT I), the technology difference payment is paid independently of the market price.

Table 1: *Level of Support for Renewables in REFIT I, €/MWH*

	2006		*2010*	
	Fixed Payment	*Guaranteed Price*	*Fixed Payment*	*Guaranteed Price*
Large scale wind		57		66.353
Small scale wind		59		68.681
Hydro	All receive 15% of 57	72	All receive 15% of 66.353	83.814
Biomass – LFG		70		81.486
Biomass – other		72		83.814

Source: DCMNR (2006) and DCENR (2009). www.dcenr.gov.ie/Energy/Sustainable+and+Renewable+Energy+Division.

In 2009 the Department for Communications, Energy and Natural Resources extended the support to additional categories of renewable

[3] The adjustment is upwards only, so guaranteed prices did not decline following the negative CPI in 2009.

generation (DCENR, 2009). We refer to this second phase of the scheme as REFIT II. Support prices for bio-energy were subsequently revised, raising the price level for smaller generating units and lowering it for non-CHP anaerobic digestion.

Table 2: *Support for Renewables in REFIT II, €/MWh*

	2010	
	Fixed Payment	*Guaranteed Price*
Off-shore wind*		140
Wave and Tidal*		220
Anaerobic Digestion CHP ≤500kW		150
Anaerobic Digestion CHP >500kW	All receive	130
Anaerobic Digestion non-CHP ≤500kW	15% of 66.353	110
Anaerobic Digestion non-CHP >500kW		100
Biomass CHP ≤1500kW		140
Biomass CHP >1500kW		120

* Off-shore wind and wave and tidal energy support prices are not linked to CPI.

Table 2 reports the level of support suggested for REFIT II. The payment is again made of three parts. The fixed payment is identical to REFIT I and is equal to 15 per cent of the support per MWh given to large scale on-shore wind installations. The reference price for REFIT II is higher than the price given to any technology in REFIT I. In addition, there is the technology difference payment which varies by renewable resource. The sum of reference price and the technology payment is reported in Table 2 as "Guaranteed Payment".

There are a couple of significant differences between REFIT I and REFIT II, in addition to the different prices. First, the guaranteed prices in REFIT II for off-shore wind, wave and tidal energy are not indexed to the CPI, so their real value decrease over time in line with inflation. Biomass support prices are indexed to CPI. In addition, in REFIT I the technology difference payment is paid independently of the market price, whereas in REFIT II it is not paid if the market price is high enough.

The scheme allocates the payments through a somewhat complicated procedure. Due to historic circumstances, the money does not go directly to renewable generators, but is instead paid to supply companies who have entered into long term contracts with the generators. In 2006 the electricity market in Ireland worked on the basis of bilateral contracts between generators and suppliers to final consumers. Generators had to put in place 15-year agreements with suppliers (called Power Purchasing Agreements or PPAs). The payment therefore was set up to go to the companies supplying final consumers, to compensate them for the difference in cost between buying from renewable generators and buying from conventional generators. Since the advent of the Single Electricity Market (SEM) in November 2007, the Irish electricity market has moved away from bilateral contracts.

The SEM is a wholesale market that encompasses both the Republic of Ireland and Northern Ireland. It is structured as a compulsory pool market with capacity payments. All generators (with an installed capacity larger than 10MW) must bid their short-run costs into the pool.[4] In general, in each period generators are ranked according to their bid and the cheapest plants needed to meet demand are dispatched. As an exception to this rule, a small number of plants have been designated priority dispatch generators, and are chosen to generate regardless of their bid. Every generator producing electricity during the period receives the bid of the marginal plant (i.e. the most expensive plant needed to meet demand). In addition generators receive capacity payments, designed to remunerate them for their capital investment and thereby cover their long run costs.

The change in market structure eliminated bilateral contracts between generators and suppliers for all generators with a capacity larger than 10MW. The REFIT programme, however, still requires these bilateral contracts and is set up to compensate what is essentially now a middleman: the supplier to final consumers. The middleman is delegated to bid the power generated by the renewable generator into the pool.

In practice, therefore, the middleman or supplier enters into a PPA with the renewable generator, generally for 15 years, the length of time for which the REFIT will be paid. The agreement specifies the amount that the supplier will pay the generator for each unit of electricity produced. Over the course of a year the generator using renewable technology r produces n^r MWhs and receives the amount per MWh negotiated in the PPA. The supplier pays the price agreed in the PPA and receives the wholesale price W_h achieved in the market in the half hour of generation, and the three components of REFIT for each MWh of n^r. The guaranteed price components of REFIT are calculated using the average wholesale price per MWh received by the supplier over the course of the year, $\overline{W}$.

$$F = (0.15 \, x \, P^{REFIT_l}) \tag{1}$$

$$ME = \begin{cases} (P^{REFIT_j} - \overline{W}) & if \quad P^{REFIT_j} > \overline{W} \\ 0 & \quad\;\; otherwise \end{cases} \tag{2}$$

[4] Generators with an installed capacity smaller than 10 MW have the option of bidding in the pool or operating outside of the market with bilateral agreements.

$$TD^r = \begin{cases} (G^r - P^{REFIT_I}) & if \quad P^{PPA} \geq G^r \\ (P^{PPA} - P^{REFIT_I}) & if \quad P^{REFIT_I} \leq P^{PPA} < G^r \\ 0 & if \quad P^{PPA} < P^{REFIT_I} \end{cases} \qquad \text{(REFIT I)} \quad (3a)$$

$$TD^r = \begin{cases} (G^r - \overline{W}) & if \quad P^{PPA} \geq G^r \geq \overline{W} \\ (P^{PPA} - \overline{W}) & if \quad \overline{W} \leq P^{PPA} < G^r \\ 0 & if \quad P^{PPA} < \overline{W} \end{cases} \qquad \text{(REFIT II)} \quad (3b)$$

Equation (1) shows how the fixed payment F is calculated: P^{REFIT_I} is the REFIT I reference price, or the reference price in the first phase of REFIT. As mentioned above, the fixed payment per unit of renewable energy is independent of the market price.

Equation (2) calculates ME, the market equalisation payment: if the average wholesale market price $\overline{W}$ is smaller than the reference price P^{REFIT_j} (where j indexes either I or II, the first and second phase respectively), the supplier receives the difference between the two prices.

Finally, the technology difference payment TD^r depends on the REFIT phase. Equation (3a) shows that for technologies that fall under REFIT I, it is independent of the market price. It only depends on P^{PPA}, the price per MWh specified in the contract between generator and supplier; G^r the relevant technology reference price for each generation type r; and the appropriate REFIT reference price. For technologies that fall under REFIT II, the technology payment also depends on the average wholesale price $\overline{W}$. As the market price increases, any additional payment to the supplier decreases.

The PPA price will depend on the negotiating power of the generator and the supplier. In practice it is unlikely that the PPA price would be lower than the technology-specific reference price G^r. Even when $G^r = P^{PPA}$ the supplier still receives the fixed payment and any positive difference between the market price and the guaranteed price, unless any or all of this amount is negotiated away by the generator.

Summarising, the total yearly REFIT payment paid to a supplier who has entered into PPA i with a generator using technology r can be defined as:

$$REFIT_i^r = (F + TD^r + ME)n_i^r$$

where F, ME and TD^r are described in Equations (1)-(3) above, n_i^r is the amount of electricity produced under PPA i in the given year, and r indexes the technology.

The formal need for a PPA in the REFIT scheme does not affect the amount that consumers eventually have to pay, but it does influence the returns to generators. The contract terms in the PPAs will depend on their negotiating power vis-à-vis the supplier. There is evidence that some generators have set up a new company that sells exclusively to their plant in order to avoid negotiating with independent (and possibly powerful) suppliers.[5] This set up increases transaction costs (either by the cost of setting up the company or by the cost of negotiating with limited power with a supplier).

The cost of the scheme is then passed on to Irish consumers in the form of a Public Service Obligation (PSO) payment. The PSO levy is charged to all electricity customers as an additional cost in the electricity bill. The PSO is used to compensate suppliers for additional costs incurred not only as a result of supporting renewable electricity sources, but also indigenous fuels (mostly peat) (CER, 2010). In this paper we limit our attention to PSO payments related to renewable sources.

III MODEL AND ASSUMPTIONS

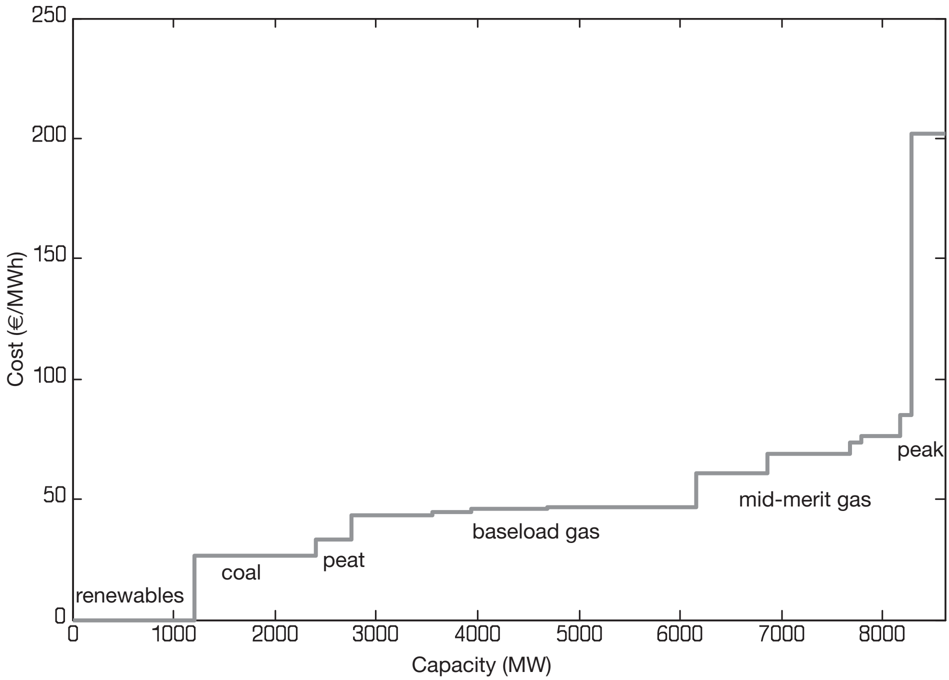
We calculate the cost of REFIT for 2020. The year 2020 is chosen because it is both far enough in the future to allow for the deployment of significant additional infrastructure, and close enough that the majority of exiting thermal plants are expected to still be operating. Moreover, there are well-defined targets for renewable energy in 2020.

Section II explains why defining the wholesale electricity price in each half hour of the year is necessary to measure the total cost of REFIT. We use IDEM, the Irish optimal Dispatch of Electricity Model, to determine the wholesale price. This model stacks all the plants in the All-Island market according to their bid price in each half hour to build a merit order curve, such as the one displayed in Figure 1, which builds the merit curve for the All-Island market and reflects fuel prices at the end of 2007.[6] The merit order varies as fuel prices or the cost of carbon change. If coal becomes more expensive than natural gas, coal plants will tend to be dispatched after natural gas plants and will move to the right in Figure 1. Wind generation is assumed to have a bid price of 0, since wind itself is free. Electricity demand

[5] The Statutory Instrument 444 of 2009 (http://www.irishstatutebook.ie/2009/en/si/0444.html) shows several instances where the generator and the supplier share very similar names. This is the case for many small scale wind farms, but also for a few large scale ones.

[6] At the end of 2007 the price of carbon in the EU Emissions Trading System was essentially 0.

Figure 1: *Merit Order Dispatch Curve for the Island of Ireland, End of 2007*



is exogenous, which is equivalent to saying that it does not change in response to electricity price changes.

IDEM determines the least costly way to meet demand in each half hour. The most expensive plant needed to meet demand sets the marginal price, which is paid out to all generators producing electricity during that period. The marginal price essentially reflects the cost of fuel and carbon needed to generate the last MWh of electricity.

Since wind generation is assumed to have a short-run cost of zero, more wind tends to put downward pressure on electricity prices, up to a point. Wind generation is by its own nature variable. When wind dies down thermal plants (typically fuelled by natural gas or coal) must be available to pick up the slack in order to maintain a reliable electricity system. It takes several hours for a thermal plant to warm up to the point where it can generate electricity. To take this feature into account, we assume that a certain number of thermal plants must always be on at their minimum stable capacity. The number of plants that are constrained on depends on the time of the year and the level of electricity demand and is determined on a monthly basis by the model. When thermal plants are constrained on and would not otherwise have been dispatched by the market, they do not bid their marginal cost into the market; rather, they are compensated for this generation through constraint payments which equal their marginal cost, regardless of market prices. At times the need to constrain on thermal plants to maintain reliability might also cause the curtailment of available wind generation. Wind curtailment is recognised by the system operators to be a likely event (EirGrid and SONI, 2010). In this study, to avoid unrealistic cycling of the Moneypoint coal plants in the medium fuel price scenario, we force the model to adopt the same constrained-on thermal plants as in the high fuel price scenario.

Ireland is connected to Great Britain by an existing electricity cable between Northern Ireland and Scotland. In addition, contracts have been signed for the building of an East-West Interconnector between Ireland and Wales. In this study we assume that there will be a further interconnector in place by 2020, bringing the total electrical connection between Ireland and Great Britain to 1400MW. Without this additional interconnection, wind generation would have to be curtailed in order to allow baseload thermal plants to run and maintain a reliable electricity system (Diffney *et al.*, 2009). We assume that the fossil fuel prices are the same for Great Britain as for Ireland. The relevant British price is estimated on the basis of a model similar to that for Ireland.[7] We also assume that the plant generation portfolio in Great Britain stays constant at its 2014 level as described in National Grid (2008).[8]

In calculating the total REFIT payments we make several simplifying assumptions. First of all we assume that all REFIT I payments go to large scale wind. Wind represents about 99 per cent of all generation in REFIT I and large scale wind accounts for about 90 per cent of wind generation.[9] Second, for REFIT II we focus on changes in off-shore wind and ocean energy capacity. Third, we avoid having to estimate the negotiating power of generators and suppliers by assuming that there is a single generator/supplier unit that

[7] We abstract from the actual arrangements of the British market, which is governed by BETTA (British Electricity Trading and Transmission Arrangements) and is based on voluntary bilateral agreements between generators, suppliers, traders and customers.

[8] The British system is much larger than the Irish one. Consequently the commissioning or decommissioning of a few plants has a much smaller effect on the system price. Only a large increase in the deployment of wind in Great Britain would significantly affect REFIT payments in Ireland, by making Irish wind less profitable. Great Britain has plans to increase its renewable generation to about 30 per cent of total electricity, mostly by increasing offshore wind (HM Government, 2009). However, many analysts believe that a large deployment of offshore wind by 2020 is unlikely due to the many technological and economic challenges Great Britain faces in meeting its renewable electricity target (see for example Wood and Dow, 2011; Chazan, 2010). The current economic climate makes large investments in the short to medium term less likely.

[9] Volumes are calculated on the basis of the description of renewable generators in Schedule 3 of the Statutory Instrument 444 of 2009 (http://www.irishstatutebook.ie/2009/en/si/0444.html)

receives the REFIT payment. This does not affect the REFIT cost to consumers. These assumptions allow us to simplify the calculation of the REFIT payment system. The only prices that remain relevant are the wholesale price of electricity and the REFIT prices relevant to each technology.

The market equalisation payment from Equation (2) and the technology difference payments described in Equations (3a) and (3b) in Section II can be combined into one equation:

$$GPay^r = \begin{cases} (G^r - \overline{W}) \cdot n^r & if \quad G^r \geq \overline{W} \\ 0 & otherwise \end{cases} \tag{4}$$

GPay^r is the guaranteed payment to technology *r*, and the wholesale price per MWh for half-hour *h*, W_h, is defined as follows:

$$W_h = SMP_h + CapPay_h + ConstrPay_h \tag{5}$$

SMP is the System Marginal Price, determined in the pool market. *CapPay* represents Capacity Payments to renewable generation, based on the amount of electricity generated by these plants. Additionally, if wind or wave generators are curtailed at any time (for example to allow thermal plants to continue generating at their minimum stable capacity) they receive constraint payments *ConstrPay,* based on the amount they would have generated had they not been constrained.

The total cost of REFIT depends on many factors, but the most prominent are the actual amount of renewables on the system, and the price of fossil fuels and carbon dioxide permits. To evaluate the cost of REFIT to final consumers we consider two different levels of wind penetration on the Island of Ireland for the year 2020: 2,000MW or 6,000MW of wind. Of on-shore wind 2,000MW are likely to be reached without any further incentives, so this scenario can be interpreted as a baseline. 6,000MW of wind are likely to be sufficient to meet the target of generating 40 per cent of all electricity from renewable sources, as set out in DCMNR (2007) and modified by the Carbon Budget 2009 (DEHLG, 2008). In addition, we analyse a scenario using the wind, wave and tidal generation portfolio outlined in Ireland's National Renewable Energy Action Plan (NREAP, 2010). The plan suggests generation capacity for Ireland (excluding Northern Ireland) of 4,094MW of on-shore wind, 555MW of off-shore wind, and 75MW wave capacity. For this study, we increase on-shore wind capacity in Northern Ireland proportionately to increases in Ireland, after the horizon of the EirGrid Generation Adequacy Report (EirGrid, 2009). Including this on-shore wind capacity for Northern Ireland increases total on-shore wind capacity in this scenario to 6,034MW. We abstract from payments to small scale wind, biomass and hydro in 2020. This is clearly a simplification, although the effect of these renewable technologies on REFIT payments is likely to be much smaller than the combined effect of wind and ocean energy.[10]

Table 3 summarises the assumptions for the different scenarios in 2020, distinguishing between the amount of renewables on the island as a whole and in the Republic of Ireland. The installed capacity reported in Table 3 includes the capacity of windfarms that fall under a previous AER scheme, although the AER capacity is excluded from the calculation of REFIT payments. The AER supported 532MW of investment in wind power. Towards the end of 2009 there were 1,167MW of wind in the Republic of Ireland, 237MW of hydro (most of it installed decades ago) and 34MW of biomass capacity (EirGrid, 2009). We assume that electricity demand growth in the Republic of Ireland averages 0.8 per cent per year, in line with the World Recovery scenario from Bergin *et al.* (2009).

Table 3: *Renewable Scenarios, Installed Capacity (MW) in 2020*

	All-Island On-shore Wind	*Republic of Ireland On-shoreWind*	*Republic of Ireland Off-shore Wind*	*Republic of Ireland Wave & Tidal*
1. Low wind	2,000	1,357	–	–
2. High wind	6,000	4,071	–	–
3. High mixed renewables	6,034	4,094	555	75

Table 4 outlines the assumptions on fuel prices. We report the price of oil mainly for reference purposes. Its level has limited direct effect on the Irish electricity system, but we assume that the price of natural gas is linked to oil prices. Most of the Irish plants run on natural gas (in 2008 it fuelled 55 per cent of generation; see SEI, 2009). The price of coal is less volatile and we assume it is constant across the different fuel scenarios.

The cost of carbon dioxide permits traded in the European Union Emissions Trading Scheme is set at €30/tonne of CO_2, measured in 2008 currency.

We assume that on-shore wind has an average (ex ante) load factor of 33 per cent at installed capacity of 2,000MW (1,357MW in the Republic of Ireland, referred to as ROI from now on). This is equivalent to saying that it

[10] There is little additional development expected in future years for hydro generation. Biomass generation on the other hand may increase significantly over time, especially if more fossil-fuelled plants move to cofiring with biomass. However, the scale of biomass penetration is likely to be much smaller than wind in Ireland.

Table 4: *Fuel Price Assumptions for 2020, Measured in 2008 Currency*

	Low Fuel Price	*Medium Fuel Price*	*High Fuel Price*
Oil ($/barrel)	57	87	107
Natural gas (€/MWh)	17	26	32
Coal (€/MWh)	10.2	10.2	10.2

can achieve electricity output in line with its stated capacity about a third of the time during a year. This load factor reduces to 30 per cent at 6,000MW (4,071MW ROI) as optimal windfarm locations become scarcer. Wind generation in this study is based on the 2008 historic wind profile. Over 2005 to 2008, the wind load has varied between 29 per cent and 33 per cent (EirGrid, 2009). In 2010 Ireland experienced particularly low levels of wind, with an average load of about 23 per cent (EirGrid, 2011). We normalise the wind profile to have a 31 per cent load in our main analysis, and run sensitivity tests around this assumption. In particular, we vary the total level of wind by scaling the original wind profile to 23 per cent and 33 per cent, the minimum and maximum observed between 2005 and 2010.[11] Second, we vary the distribution of wind across the year, using the wind profile for 2007 scaled to 31 per cent.

For the 'Mixed Portfolio' scenario we also need assumptions on the load factor and generation profile of ocean energy. There is currently very limited 'hard' data for these forms of generation. The load factor for off-shore wind is set at 35 per cent reflecting the fact that wind tends to blow more off-shore. These assumptions are in line with assumptions in the current literature (The same factor of 35 per cent is set for the combination of wave and tidal generation. Tidal generation generally operates with a substantially lower load factor of approximately 22 per cent, Denny, 2009). However, wave and tidal receive the same level of support under REFIT, and are treated as one in this paper. The relatively high load factor used here can, therefore, be attributed to all of the ocean generation capacity coming from wave, and none from tidal.

For lack of data on the load curves of off-shore wind, wave and tidal, we assume that on-shore wind, off-shore wind and wave and tidal are perfectly correlated, so that when on-shore wind dies down, so do the other options. This is clearly a simplification driven by the lack of publicly available hourly data

[11] We also vary the distribution of wind across the year, using the wind profile for 2007 scaled to 31 per cent. This change, however, has a minimal effect on the results (not reported, but available from authors).

on off-shore wind and wave generation for Ireland. Stoutenburg *et al.* (2010) show that for California, the correlation between offshore wind and wave is generally below 50 per cent.[12] Electricity generation at different wind farms is likely to be less correlated the further the wind sites are from each other and the more different the surrounding topography is (Hoogwijk *et al.*, 2007). Lack of data prevents us from taking this aspect explicitly into consideration in the model. If we allowed off-shore wind, wave and tidal to generate electricity at different times than on-shore wind, we would expect a slightly lower system marginal price in the market with the 'mixed renewables' option. This would be potentially accompanied by somewhat higher REFIT payments if curtailment of renewable generation were more limited. We expect differences with the reported results to be fairly small, in part due to the limited amount of ocean energy in the Mixed Portfolio scenario.

We assume a future inflation rate of 2 per cent per year, in line with the inflation targets stated by the European Central Bank. As a sensitivity analysis, we also evaluate the results when inflation is 4 per cent, approximately equal to the growth of the Irish consumer price index between 2006 and 2008. Note that the inflation-adjusted payments are linked to inflation only if it is positive. This means that the minimum average yearly inflation that the REFIT scheme will reflect is zero, even if there is deflation. An assumption on inflation is necessary to determine the guaranteed price that applies to REFIT II renewables in 2020.

Table 5: *Level of Support in 2020, Measured in 2020 and 2008 Prices, €/MWh*

REFIT II Guaranteed price	*2020 Prices*	*2008 Prices*
Off-shore Wind	140	108.2
Wave & Tidal	220	170.0

IV RESULTS

The cost of REFIT is calculated for all the wind, wave and tidal renewables installed in the Republic of Ireland. Renewable generation located in Northern Ireland provides electricity within the same All-Island market, but is subject to a separate renewable support scheme.[13]

[12] Dalton *et al.* (2010) build a time series for Ireland using proprietary data based on the Pelamis, a specific wave device.

[13] Renewables in Northern Ireland are supported by NIRO (Northern Ireland Renewable Obligations), which is tied to the system of Renewable Obligation Certificates in Great Britain.

Table 6 shows how REFIT affects the cost of electricity in 2020 when fuel prices are at their medium level (corresponding to €26/MWh for natural gas in 2008 currency). It compares the cost of the REFIT scheme for three different scenarios. In the first column there are 2,000MW of wind island-wide, of which 1,357MW in the Republic of Ireland. Of these 1,357MW, 825MW are supported through the REFIT scheme (the remaining 532MW fall under the previous AER scheme). The second column reports the case where there are 6,000MW of on-shore wind on an all island basis, of which 4,071MW in the Republic of Ireland (3,539MW in REFIT). Finally the last set of four columns disaggregates the cost of having a mixed portfolio of renewables by renewable technology. In this case there are 6,664MW of renewables on the island as a whole and 4,724MW in the Republic of Ireland. REFIT supports 3,562MW of the 4,094MW of on-shore wind in this scenario. Fixed payments for the amount of capacity subject to REFIT are calculated as shown in Equation (1). The payments that depend on guaranteed prices are calculated as shown in Equation (4) and summed over the different existing technologies.

Not surprisingly, as more renewables get on the system their cost in terms of REFIT increases. Note that the REFIT cost increases a bit less than the increase in installed capacity. When a lot of wind is deployed, a small proportion of it is curtailed to allow a few thermal plants to generate at their minimum stable capacity and therefore maintain reliability of the system.

Table 6: *REFIT Costs in 2020 (€ Million, 2008 Currency), Medium Fuel Price*

	All On-shore		*Mixed Portfolio*			
All-Island capacity	*2,000MW*	*6,000MW*	*6,664MW*			
ROI capacity	*1,357MW*	*4,071MW*	*On-shore (4,094MW)*	*Off-shore (555MW)*	*Wave & Tidal*	*Total (75MW)*
REFIT capacity	825MW	3,539MW	3,562MW	555MW	75MW	
Fixed payment	22.8	88.0	90.0	15.8	2.1	108.0
Guaranteed price payment	–	42.0	–	73.4	23.8	115.1
Total	22.8	130.0	90	89.2	25.9	205.2
Total: €/MWh consumed	0.74	4.25	2.94	2.92	0.85	6.70

For medium fuel prices, on-shore wind receives the bulk of its REFIT compensation from the fixed payment portion of the scheme. The guaranteed price is often below the estimated market price, contributing very little to on-shore wind compensation. Also note that as more wind is deployed, the average price of electricity decreases. Wind has very low variable costs of electricity generation, due to wind being free in and of itself. This means that when more wind generation is available, it displaces more expensive thermal power and, therefore, on average decreases the cost of electricity in each half hour. Off-shore wind, wave and tidal receive a far greater proportion of their compensation from the guaranteed price portion of the scheme.

Table 7: *REFIT Costs in 2020 (€ Million, 2008 Currency), Low Fuel Price*

	All On-shore		*Mixed Portfolio*			
All-Island Capacity	*2,000MW*	*6,000MW*	*6,664MW*			
ROI Capacity	*1,357MW*	*4,071MW*	*On-shore (4,094MW)*	*Off-shore (555MW)*	*Wave & Tidal*	*Total (75MW)*
REFIT capacity	825MW	3,539MW	3,562MW	555MW	75MW	
Fixed payment	22.8	87.4	89.9	15.8	2.1	107.9
Guaranteed price payment	26.4	123.9	123.7	95.3	26.7	245.7
Total	49.2	211.3	213.7	111.1	28.8	353.6
Total: €/MWh consumed	1.61	6.90	6.98	3.63	0.94	11.55

When the price of fuel decreases, the price of electricity in the Single Electricity Market also decreases and the cost of REFIT increases for all options, as shown in Table 7.

Conversely, when the fuel price increases, the cost of REFIT decreases, although because of the effect of the fixed payment, the reduction is less than proportional to the increase in the shadow price. The exception is the case with low wind generation capacity installed; here the low levels of ‘free’ wind generation do not reduce shadow price sufficiently to require any guaranteed price payment, even in the medium fuel price scenario. The only REFIT contribution is the fixed payment, so a move to higher fuel prices does not change the overall REFIT cost. With high fuel prices most of the cost is due to the fixed payment component of the REFIT scheme, as shown in Table 8. This also suggests that the hedging properties of renewables are somewhat dampened by the REFIT scheme.

One interesting point to make here, that we will return to later, is that wave and tidal account for less than 2 per cent of total renewable generation capacity, but are responsible for between 8 and 13 per cent of the total PSO cost. They receive an average yearly payment per MW of installed capacity equal to €385,000 when fuel prices are high, €345,000 with medium fuel prices and €322,000 when fuel prices are low.

Table 8: *REFIT Costs in 2020 (€ Million, 2008 Currency), High Fuel Price*

	All On-shore		*Mixed Portfolio*			
All-Island Capacity	*2,000MW*	*6,000MW*	*6,664MW*			
ROI Capacity	*1,357MW*	*4,071MW*	*On-shore (4,094MW)*	*Off-shore (555MW)*	*Wave & Tidal*	*Total (75MW)*
REFIT capacity	825MW	3,539MW	3,562MW	555MW	75MW	
Fixed payment	22.8	88.0	90.0	15.8	2.1	108.0
Guaranteed price payment	–	-	–	60.5	22.0	82.6
Total	22.8	88.0	90.0	76.4	24.2	190.6
Total: €/MWh consumed	0.74	2.87	2.94	2.50	0.79	6.23

We have shown how different levels of renewable energy influence the REFIT payment under a number of different scenarios. In the following paragraphs we discuss how the REFIT payments affect consumer prices. We compare the size of REFIT per MWh consumed with the wholesale cost of electricity. The gross wholesale price is composed of the shadow price, capacity payments, possible constraint payments, plus uplift and balancing costs. We do not model the uplift and balancing payments, but assume that they will average €8 per MWh, based on the costs reported in MMU (2009). The constraint payment here refers to payment given to renewables (wind and wave) if they are curtailed, and to thermal plants should they be constrained on to avoid cycling.

As mentioned earlier, the REFIT payment is eventually funded by consumers through the PSO payment. The PSO payment is calculated here as the total REFIT payment divided by the amount of MWhs consumed during the year. This closely approximates the actual calculation of the PSO, which apportions a slightly higher share of REFIT costs to the residential sector and a slightly smaller one to the non-residential sector.

Table 9: *2020 Average Wholesale Electricity Price (All Island) €/MWh, 2008 Currency*

	All On-shore (4,071MW, of which 3,539MW REFIT)		
	Low Fuel Price	*Medium Fuel Price*	*High Fuel Price*
Shadow Price	45.1	56.8	64.0
Capacity & Constraint Payments	15.0	18.7	17.5
Uplift and balancing costs	8.0	8.0	8.0
Total gross wholesale	68.1	83.5	89.5
REFIT PSO	6.90	4.25	2.87
PSO as % gross wholesale	9.8%	5.1%	3.2%

Table 9 analyses the size of PSO payments with respect to the average yearly gross wholesale price for 2020 when there are 6,000MW of on-shore wind on the island as a whole and 4,071MW of on-shore wind in the Republic of Ireland. Table 9 shows that as the fuel prices increase, the cost of REFIT decreases, as expected. When moving from low to medium fuel price, the price of natural gas (the fuel that is most important in the Irish electricity system) increases by 53 per cent and the PSO cost decreases by about 48 per cent. When moving from medium to high fuel price the cost of natural gas increases by 23 per cent and total PSO cost decreases by about 37 per cent. We don't expect the cost of the PSO to decrease linearly with the increase in fuel costs for several reasons. First of all, the electricity half hourly cost is determined by the merit order and this involves a calculation that is inherently non-linear. Second, the REFIT scheme itself is non-linear due to the fixed payment component. The last row of Table 9 measures the size of the PSO relative to wholesale costs. When fuel prices are low the PSO is 9.8 per cent of gross wholesale prices. This decreases to 5.1 per cent with medium fuel prices and 3.2 per cent with low fuel prices.

Table 10: *2020 Average Wholesale Electricity Price (All Island) €/MWh, 2008 Currency*

	All On-shore (1,357MW, of which 825MW REFIT)		
	Low Fuel Price	*Medium Fuel Price*	*High Fuel Price*
Shadow Price	46.4	59.8	69.1
Capacity & Constraint payments	16.0	19.5	17.4
Uplift and balancing costs	8.0	8.0	8.0
Total wholesale	70.5	87.4	94.5
REFIT PSO	1.61	0.74	0.74
PSO as % gross wholesale	2.3%	0.9%	0.8%

Table 10 describes the size of the PSO payment in the scenario with 2,000MW of wind on the island (and 1,357 MW in the Republic of Ireland). The size of the PSO payment decreases as expected. The PSO is between 0.8 per cent of gross wholesale cost (high fuel price) and 2.3 per cent (low fuel price).

Table 11 shows that PSO costs increases when the renewables are both on-shore and off-shore. This is hardly surprising given the higher guaranteed payments to off-shore renewables. For this scenario, the PSO is between 6.8 per cent and 17.2 per cent of the gross wholesale price, depending on the fuel price level.

Table 11: *2020 Average Wholesale Electricity Price (All Island) €/MWh, 2008 Currency*

	Mixed Portfolio (On-shore, Off-shore, Wave and Tidal)		
	Low Fuel Price	*Medium Fuel Price*	*High Fuel Price*
Shadow Price	44.3	57.4	65.9
Capacity & Constraint payments	14.8	18.8	18.0
Uplift and balancing costs	8.0	8.0	8.0
Total gross wholesale	67.1	84.2	91.9
REFIT PSO	11.55	6.70	6.23
PSO as % gross wholesale	17.2%	8.0%	6.8%

The absolute size of the scheme might be politically relevant, in part due to the current financial constraints facing Ireland. The Appendix includes the detailed breakdown of the calculation of total wholesale costs and how they compare to total REFIT costs. Table 12 summarises the overall cost of REFIT for all scenarios. Table 12 also allows us to compare the PSO costs of an on-shore only portfolio with a similar portfolio including off-shore wind, wave and tidal generation. The move to a mixed portfolio results in an increase in the PSO cost of 67 per cent when fuel prices are low, 58 per cent with medium fuel prices and 117 per cent with high fuel prices. This is due to the much higher guaranteed price for off-shore and wave generators.

The large relative increase in the PSO when moving to more off-shore renewable generation causes a few concerns. If off-shore wind is successful and adopted at high rates, it will become quite expensive for the final consumer. This is before accounting for the cost of undersea cables, necessary to connect off-shore resources to the main grid. There are no consensus estimates for the cost of off-shore cables, but it is likely to be much larger than on-shore cables. Wave and tidal are not mature technologies. They have not been deployed at a large commercial scale yet. The results presented in Table 11 show that sustaining these technologies through REFIT has a relatively large impact on consumers. At the same time the REFIT payment is unlikely to foster the development of this technology. For each MW of installed wave or tidal renewable generation, companies receive €322,000 to €385,000 per year from REFIT, as discussed above. For comparison, the Wave Hub project in Cornwall (UK) has cost up to now about £42 million (about €48 million at current exchange rates) for a capacity of 20MW.[14] In general, tying funding to

[14] Numbers reported in www.oceanpowermagazine.net/2010/11/05/wave-hub-%E2%80%98plugged-in%E2%80%99-and-open-for-business/

Table 12: *REFIT PSO Total Payment in 2020, €, 2008 Currency*

	Low Fuel Price Million	*Medium Fuel Price Million*	*High Fuel Price Million*
All on-shore (1,357 MW, of which 825MW REFIT)	49	23	23
All on-shore (4,071 MW, of which 3,539MW REFIT)	211	130	88
Mixed portfolio (on-shore and off-shore wind, wave and tidal – 4,724 MW, of which 4,192MW REFIT)	354	205	191

generation is not optimal at the development phase of a technology, since the trial projects are going to produce very little electricity.

We run a few sensitivity tests to incorporate the effect of the variability of wind. We report the results for the low and high fuel price scenarios. Reducing the wind load from 31 per cent to 23 per cent decreases REFIT PSO costs by a similar proportion: 23 to 26 per cent, due to lower generation from renewables (see Table 11). Similarly, increasing the wind load to 33 per cent results in proportionately (6 to 7 per cent) higher PSO, except in the case of the all-onshore portfolio with high fuel prices. Here, the additional generation from wind brings the average price of electricity below the threshold for market equalisation payments, resulting in a PSO cost 13 per cent higher than the base-case wind level. We should note that while the PSO costs decrease when wind is blowing less, the costs to the system as a whole increase. Electricity that is not generated by wind needs to come from more expensive fuel sources. In fact, when wind blows only 23 per cent of the time on average, the shadow price increases by 2 to 4 per cent with respect to the case when wind is blowing 31 per cent of the time, as can be seen in Table 14. When wind blows more (33 per cent of the time) the shadow price decreases by about 1 per cent.

Varying the time during the day and the year that wind blows also has some effect on REFIT payments, although overall quite small: using the 2007 wind profile instead of the 2008 wind profile – but maintaining the load at the 31 per cent level – varies PSO costs between –2 and +4 per cent. Inflation rates affect estimates of PSO costs only through the guaranteed price paid to offshore wind and ocean energy suppliers in the case of the mixed generation portfolio. Increasing the average yearly inflation rate to 4 per cent, rather than the 2 per cent assumed in the base case results in a 12 per cent reduction

Table 13: *Wind Profile and Wind Load Factor Sensitivity: REFIT PSO Cost (€ /MWh, 2008 currency)*

	Wind Profile		*2008*		*2007*
	Wind Load Factor	*31%*	*23%*	*33%*	*31%*
Mixed portfolio	High fuel price	6.23	4.73	6.65	6.32
	Low fuel price	11.55	8.91	12.42	11.98
4,071 MW on-shore	High fuel price	2.87	2.15	3.23	2.86
	Low fuel price	6.90	5.12	7.35	6.79

Table 14: *Wind Profile and Wind Load Factor Sensitivity: Shadow Price (€/MWh, 2008 currency)*

	Wind Profile		*2008*		*2007*
	Wind Load Factor	*31%*	*23%*	*33%*	*31%*
Mixed portfolio	High fuel price	65.92	67.44	65.22	65.36
	Low fuel price	44.27	45.51	43.75	43.92
4,071 MW on-shore	High fuel price	63.99	66.35	63.38	64.32
	Low fuel price	45.06	45.76	44.81	45.02

Table 15: *Inflation Rate Sensitivity: REFIT PSO Cost (€/MWh, 2008 currency)*

		2%	*4%*
Mixed portfolio	High fuel price	6.23	4.86
	Low fuel price	11.55	10.19
4071 MW on-shore	High fuel price	2.87	2.87
	Low fuel price	6.90	6.90

in the real cost of the REFIT PSO in the low fuel price scenario, and a 22 per cent reduction in the high fuel price scenario (see Table 13).

It would be interesting to measure how REFIT affects final retail prices, but that is beyond the scope of the current paper. It would involve estimating the costs of the additional electricity transmission and distribution lines needed to accommodate the amount of renewable in each scenario and the size of the retail margin.[15] The cost of undersea cables needed to connect off-shore wind farms, wave and tidal generation to the grid is undoubtedly large, but still uncertain. There is also uncertainty on the size of the retail margin in

[15] The retail margin is added to the wholesale cost of electricity by the company that provides the electricity meters and the billing services.

Ireland, which will depend on the number of players in the retail sector and on its level of regulation, issues that are beyond the scope of this paper.

We can, however, measure the historic relationship between wholesale and final retail prices. In Ireland in 2008 wholesale costs (including capacity payments, uplift and dispatch balancing costs) accounted for slightly less than 60 per cent of the final residential cost of electricity and about 80 per cent of the final industrial cost in the Republic of Ireland.[16] Using these wholesale to retail price shares and the size of the PSO measured in the presence of a mixed renewable portfolio as shown in Table 11, the PSO would be between 4.1 per cent and 10.3 per cent of the final retail electricity price for the residential sector and between 5.4 per cent and 13.7 per cent for industry.

V CONCLUSION

In this paper we have estimated the cost of REFIT, the Irish renewables support scheme, for the year 2020. We have compared the cost of REFIT for three levels of renewable generation. Fuel prices are historically very volatile, so we have also evaluated the sensitivity of the results to different fuel price levels. The REFIT payment to renewable generation includes a fixed component and a minimum price guarantee. The fixed component is paid any time generators produce electricity and is independent of the return that generators achieve on the market. The guaranteed price component is only paid if the generators do not receive a high enough price (i.e. the guaranteed price level) on the market.

A few studies have shown that wind generation may have hedging qualities. When fuel prices are high, wind generation dampens the price of electricity. When fuel prices are low, the price of electricity is going to be a bit larger when more wind is on the system (if the capital costs of wind are to be covered). This is true in this study as well. The REFIT scheme, however, dampens the hedging qualities of wind slightly, due to the presence of fixed payments. Fixed payments essentially increase the cost of renewables on the system independent of the price of conventional fuels.

Adding more wind to the electricity system is not costless. The introduction of large amounts of intermittent generating capacity on the Irish system imposes costs in the form of curtailing wind generators at times where too much wind energy would be generated to allow a stable system and also of more fluctuations in the output of conventional thermal plants. Increasing

[16] Final industrial and residential costs for the Republic of Ireland come from IEA (2009). The estimate of the cost of electricity in the SEM is reported in MMU (2009).

wind generation also increases the need for more transmission and distribution lines. Moreover, if there is a lot of wind on the system the price of electricity will be lower when the wind blows. This means that returns to wind generators will get lower as more wind generation is established. We take into account the curtailment costs of wind in this study, but not the costs of transmission and distribution and the effects of lower electricity prices on wind generators' returns to investment. In general, this means that as more wind farms are connected to the grid they will decrease the average generation (and returns) of previously existing wind farms. This is what is normally referred to as a 'negative externality'. Each single wind farm will, therefore, have a higher incentive to start producing than the benefit it brings to the system as a whole

We find that when there are only 2,000MW of wind on the All-Island system, the price of REFIT is fairly small, between 0.8 per cent and 2.3 per cent of the wholesale electricity price. When there are 6,000MW of wind, a level that is consistent with reaching the goal of meeting 40 per cent of electricity demand through renewables, REFIT costs between 3.2 per cent and 9.8 per cent of the gross wholesale price. REFIT costs decrease when wind is blowing less (23 per cent of the time instead of the baseline 31 per cent) and increase when it is blowing more, more or less in proportion to the additional amount of renewables generation. It is important to note that the wholesale price itself decreases with more renewables, by about 5 per cent when fuel prices are high.

The REFIT costs are approximately between 2 per cent and 6 per cent of residential retail prices. They are between 2.5 per cent and 8 per cent of business retail prices, since the wholesale price of electricity is a larger share of the final retail price for businesses than for residential customers. Note that we expect transmission and distribution costs to also increase in 2020, and the costs will be higher the more renewables are on the system. As mentioned above, we do not estimate the cost of additional distribution and transmission lines in this study

Combining on-shore, off-shore, wave and tidal generation significantly increases REFIT costs over an on-shore only portfolio. The analysis in this paper excluded the costs of reinforcing and expanding the transmission and distribution grid. There are no consensus estimates for the cost of off-shore cables, but they are likely to be much larger than on-shore cables, further increasing the differences between the on-shore and the off-shore scenarios.

We argue, therefore, that if Ireland is able to meet its renewables obligations using only on-shore wind, it is the least costly solution for final consumers. If, on the other hand, on-shore wind will not deliver enough capacity to meet the State's international obligations, there will be a need to turn to off-shore sources of electricity. In general, if off-shore wind is deployed widely, its costs are going to be high for the Irish consumer. At the same time, it appears unlikely that the electricity system will be able to accommodate much additional off-shore wind at low cost. There has been much discussion recently of developing Ireland's off-shore electricity resources for export. This may well be optimal from a European (and specifically UK) point of view, if it is cheaper to develop these resources in Ireland than in the UK. However, it is clear that Irish consumers should not be called to fund and guarantee this business venture.

For wave and tidal, the usefulness of a REFIT scheme is even less clear. Those technologies are not at a deployment level yet. This means that a scheme such as REFIT is not sufficient to encourage research and development in the area. Instead, a competitive process of research grants should be set up to fund this type of development. A competitive grant scheme would allow more research and not weigh too heavily on consumers and businesses. It would also have the advantage of capping liabilities for the taxpayers (or consumers) who are ultimately going to fund it. Finally, the fixed portion of the REFIT payment is a pure subsidy, not linked to market conditions. As it is set up, this element of the REFIT scheme dampens the hedging quality of wind generation and adds to the cost to final consumers. It should therefore be eliminated, leaving REFIT as a pure price guarantee scheme.

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APPENDIX

Table A1: *2020 Total Wholesale Electricity Price (ROI), €, 2008 Currency*

	All On-shore (4,071MW, of Which 3,539MW REFIT)		
	Low Fuel Price Million	*Medium Fuel Price Million*	*High Fuel Price Million*
Shadow Price	1,379	1,739	1,959
Capacity & Constraint Payments	460	573	537
Uplift and Balancing Costs	245	245	245
Total Gross Wholesale	2,084	2,557	2,741
REFIT PSO	211	130	88

Table A2: *2020 Total Wholesale Electricity Price (ROI), €, 2008 Currency*

	All On-shore (1,357MW, of Which 825MW REFIT)		
	Low Fuel Price Million	*Medium Fuel Price Million*	*High Fuel Price Million*
Shadow Price	1,422	1,832	2,116
Capacity & Constraint Payments	490	598	531
Uplift and Balancing Costs	245	245	245
Total Wholesale	2,157	2,674	2,892
REFIT PSO	49	23	23

Table A3: *2020 Total Wholesale Electricity Price (ROI), €, 2008 Currency*

	Mixed Portfolio (On-shore, Off-shore Wind, Wave and Tidal)		
	Low Fuel Price Million	*Medium Fuel Price Million*	*High Fuel Price Million*
Shadow Price	1,355	1,757	2,018
Capacity & Constraint Payments	454	575	552
Uplift and Balancing Costs	245	245	245
Total Gross Wholesale	2,054	2,577	2,815
REFIT PSO	354	205	191