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Quantifying the uncertainty of wave energy conversion device cost for policy appraisal: an Irish case study

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Abstract

Wave Energy Conversion (WEC) devices are at a pre-commercial stage of development with feasibility studies sensitive to uncertainties surrounding assumed input costs. This may affect decision-making. This paper analyses the impact these uncertainties may have on investor, developer and policymaker decisions using an Irish case study. Calibrated to data present in the literature, a probabilistic methodology is shown to be an effective means to carry this out. Value at Risk (VaR) and Conditional Value at Risk (CVaR) metrics are used to quantify the certainty of achieving a given cost or return on investment. The certainty of financial return offered by proposed Irish Feed-in Tariff (FiT) policy is analysed. The influence of technological 'learning' is also discussed. The model presented identifies those rates of learning required to achieve cost-effective deployment under various cost certainty requirements. The corresponding cost reduction targets for developers are identified. Uncertainty is found to have a greater impact on the investment decision when learning progresses at a slower rate. This paper emphasises the requirement for a premium to account for cost uncertainty when setting FiT rates. By quantifying uncertainty, the presented methodology allows for the required premium to be identified.

Keywords: Wave Energy; Feasibility Analysis, Uncertainty, Renewable Energy Policy Appraisal, Statistical Simulation.

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1. Introduction

Many national and EU-level renewable energy policies incorporate the development and deployment of Wave Energy Conversion (WEC) devices (DCENR, 2010; DECC, 2011; EC, 2010, 2011; MI and SEI, 2005; Scottish Executive, 2005). With regard to novel technologies such as WEC devices, Dalton et al. (2010) have stressed the importance of reliable cost information to both inform deployment policy but also to aid private investment and device development decisions. Certain jurisdictions, such as Ireland, have put in place preliminary feed-in tariffs for initial devices (DCENR, 2014a), whilst tariffs for future deployment have yet to be finalised. It is the purpose of this paper to emphasise the importance of incorporating device cost uncertainty and allowing for such uncertainty when setting both initial and long-term tariffs. Not incorporating any potential risk premium required as a result of this uncertainty may result in ineffective policy, whilst an arbitrary risk premium may lead to over-remuneration, something which may be particularly undesirable given constrained public finances. A means to explicitly quantify the effects of cost uncertainty is required such that policymakers may identify with greater precision any potential risk premia that may be required when designing feed-in tariffs. This paper presents a means by which this may be carried out in order to inform effective policy both in Ireland and jurisdictions elsewhere.

The literature to date demonstrates considerable variability in cost estimates quoted. Economic evaluation of WEC-based generation commonly employs the Levelised Cost of Electricity (LCOE) metric. This is the 'ratio of total lifetime expense versus total expected output, expressed in terms of the present value equivalent' (Allan et al, 2011b; Nuclear Energy Agency and International Energy Agency, 2005). The LCOE is expressed as the total cost per unit of output (€/kWh or €/MWh), with a review of existing WEC device estimates provided in Table 1.

Abbreviations: AHTS: Anchor Handling Tug Supply; CER: Irish Commission for Energy Regulation; CVaR: Conditional Value at Risk; DECC: UK Department of Energy and Climate Change; DCENR: Irish Department of Communications, Energy and Natural Resources; ESBI: Electricity Supply Board International; FiT: Feed-in Tariff; IRR: Internal Rate of Return; kWh: Kilowatt Hour; LCOE: Levelised Cost of Electricity; MI: Irish Marine Institute; O&M: Operation & Maintenance; MVAC: Medium-Voltage Alternating Current; MW: Megawatt; MWh: Megawatt hour; PCM: Power Conversion Module; PV: Photovoltaic; REFIT: Renewable Energy Feed-in Tariff; SEAI (formerly SEI): Sustainable Energy Authority of Ireland; VaR: Value at Risk; WEC Device: Wave Energy Conversion Device.

Table 1: A Review of Existing Cost of Electricity Estimates for WEC devices

Author	Estimate (€/kWh)	No. Devices	Location	Device
Archetti et al. (2011)	0.64	21	Italy	Pelamis
Allan et al. (2011)	0.216	Unspecified	Scotland	Pelamis
Bedard (2006)	0.06-0.12	44	California	Pelamis
Carbon Trust (2006) [Initial]	0.175-0.644	Small Scale	UK	Unspecified
Carbon Trust (2006) [Post 13,000MW]	0.087-0.365	Unspecified.	UK	Unspecified
Carbon Trust (2011) [Initial]	0.433-0.547	10MW	UK	Unspecified
Dalton et al. (2010) [2004 Cost]	**0.05**	**100**	**Ireland**	**Pelamis**
Dalton et al. (2010) [2008 Cost]	**0.15**	**100**	**Ireland**	**Pelamis**
Dunnett and Wallace (2009)	0.16-0.26	15-27	Canada	Pelamis
ESBI (2005)	**0.105-0.185**	**26-209**	**Ireland**	**Pelamis**
O'Connor et al. (2013a)	**0.21**	**100**	**Ireland**	**Pelamis (1MW)**
O'Connor et al. (2013b)	**c.0.22-0.26**	**100**	**Ireland**	**Pelamis**
Previsic et al. (2004)	0.075-0.144	213	California	Pelamis
St Germain (2005)	0.087-0.111	15	Canada	Pelamis
SQW (2010)	**c.0.06-0.33**	**50 – 300MW**	**Ireland**	**Unspecified**
Teillant et al. (2012)	**0.213**	**100**	**Ireland**	**Unspecified**

Note: These values have been converted from their respective local currencies where required. Each conversion is carried out using the exchange rate observed on the date of article submission/publication or nearest date possible. These calculations are available from the author upon request.

Table 1 shows that considerable uncertainty surrounds LCOE estimates for WEC devices, with cost estimates ranging from €0.05/kWh-€0.64/kWh. The literature to date has quantified the extent to which variability of cost estimates may be explained by variations in WEC design (Dunnett and Wallace, 2009; Falcao, 2011; O'Connor et al., 2013a); variations in operational, maintenance and deployment characteristics (Dalton et al., 2011; O'Connor et al., 2013b); and differences in output across space (Archetti et al. 2011; Dalton et al., 2010; Dunnett and Wallace, 2009; ESBI, 2005). Alongside these factors, much variability may also be explained by uncertain input costs. Cost estimates to date have been calculated using prototype cost data (Dalton et al., 2010, 2011; Previsic et al., 2004) or extrapolation from the operating experience of similar industries (Teillant et al., 2012) with many of these studies thus including a cautionary note as to the uncertainty surrounding the assumed input values employed.

The influence of uncertain device costs, specifically the market price of steel and cabling, are important determinants of device cost (Dalton et al., 2010). Alongside this, Dalton (2012) and O'Connor (2013a) have discussed how uncertain learning rates are amongst the primary determinants of variability in project return. O'Connor et al. (2013a) quantified the change in cost due to different scenarios of device specification, cost reduction and operational conditions. Teillant et al. (2012) focuses on explicitly modelling the operational lifecycle of a WEC device installation and considered the variability of financial return with respect to changes in operational cost assumptions in an Irish context.

These studies and those quoted in Table 1 have identified the drivers of cost sensitivity and the range of potential cost values. A number of methods have been employed to quantify the impact each factor may have on LCOE estimates and device viability. The most basic approach has been to quote costs as a wide range of potential values (e.g. SQW, 2010). Although this may cover all potential cost values, this range may be quite wide and there is no further information as to the likelihood of achieving a given cost estimate. If a more narrow range of values is desired, most likely point estimates of each input parameter may be extracted from a stated range (e.g. Dalton et al., 2010; 2012). The reliability of such an approach in addressing uncertainty is predicated on the subjective accuracy of the point estimates chosen. The potential negative affect this may have is fully realised when one considers that although each assumed parameter may have a reasonable chance of occurring alone, the probability of a number of most likely parameters occurring together is less likely, culminating to form an expected cost based on an 'unlikely coincidence' of values (Hertz, 1964). A supplementary scenario or sensitivity analysis may estimate the cost/return under an alternative set of chosen circumstances, however the likelihood of the resulting alternate cost value occurring remains unknown. A third approach may choose a cost estimate from a stated range based on that value which may yield an adequate rate of return under a given public support mechanism (e.g. Allan et al., 2011). Although providing a benchmark for certain policy analyses, such an approach does not quantify the degree of uncertainty surrounding the estimate used.

Although these efforts provide insight into the variability surrounding a given cost value, the degree of confidence with which one may interpret a given value within such a stated range is still unknown. In the context of investment appraisal, quantification of uncertainty surrounding a cost estimate allows investors to identify how sensitive expected profits may be to deviations in assumed cost parameters. A prudent investor may abstain if there is sufficient possibility that financial return is inadequate under a given support mechanism. Quantifying this exposure under a given policy regime allows for the effectiveness of that policy to be gauged. Indeed, not recognising such uncertainty may affect the interpretation of results and the reliability of decisions (Mohamed & McCowan, 2001). Thus an updated, policy-specific analysis to quantify the impacts of cost uncertainty on WEC deployment and to explore fully the implications such uncertainty may have for decisions made by investors, developers and policymakers is required. Considering these motivational factors, this paper applies a probabilistic methodology to quantify the uncertain cost of a given WEC installation, focussing on the implications this may have for Irish policy as a case study of application. This method allows for the full range of potential uncertain values in favour of subjective point estimates to be employed, providing a more objective estimation of project profitability, whilst allowing for the simultaneous consideration of all potential sources of cost variability. A sensitivity analysis is carried out to elicit results under differing scenarios of installation size and rate of technological change, providing information for both developers and policymakers as to the rate of cost reduction and/or policy support required for feasible investment. Following the majority of the literature to date (Dalton, 2010; Dalton, 2012; O'Connor et al., 2013a, 2013b) the case study considered in this paper uses the Pelamis P1 device.

This paper proceeds as follows. Section 2 outlines the probabilistic methodology and indices of appraisal employed in this analysis. This is followed by an overview of the case study data and parameters employed in Section 3. The results of this analysis are presented in Section 4; Section 4.1 presents the results in relation to cost quantification, Section 4.2 assesses the uncertainty of the internal rate of return on investment, whilst Section 4.3 presents a sensitivity analysis. The purpose of the sensitivity analysis is to identify rates of cost and financial return under alternate assumptions of future cost reduction. These sections demonstrate the use of this probabilistic methodology for investors, developers and policymakers. Finally, concluding comments are offered in Section 5.

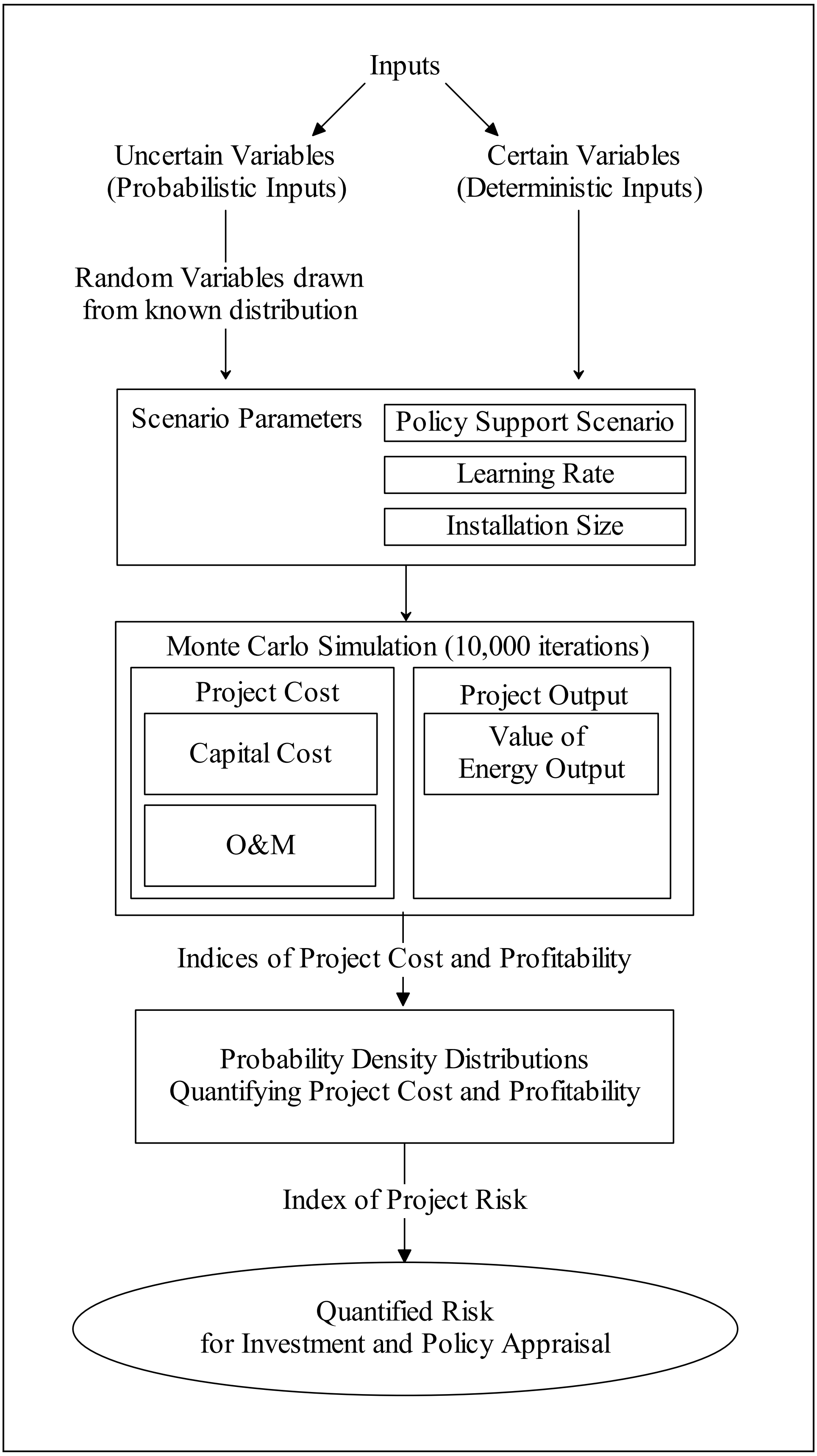
2. Material and methods

As noted in the Introduction, there is a need for an updated, policy-specific analysis to quantify the implications cost uncertainty may have for decisions made by investors, developers and policymakers. Montes et al. (2007; 2011) have reviewed methodologies to quantify the uncertainty of project profitability in the context of renewable energy investment, finding that methods of statistical simulation, such as Monte Carlo simulation, are most appropriate.

Gass et al. (2011), Darling et al. (2011) and Previsic et al. (2004) have applied probabilistic methodologies to quantify this cost uncertainty for renewable energy devices. Falconett and Nagasaka (2010) considered input and output variability for small-scale hydroelectric, wind energy and solar PV systems whilst Gass et al. (2011) incorporated the impact output variability may have on wind turbine investment. Darling et al. (2011) have carried out a similar probabilistic analysis for solar photovoltaic technology. Previsic et al. (2004) have applied Monte Carlo simulation to test the variability of WEC cost estimates in San Francisco. These studies have not applied these probabilistic techniques for feasibility analysis of WEC devices in Ireland, nor have they fully explored the implications such uncertainty may have for investment, development or policy evaluation. Furthermore, the probabilistic analysis carried out by Previsic (2004) was but a small component of that study, with data pertaining to a 2004 San Francisco installation. Much of this data has since been updated in subsequent studies (Dalton et al., 2010, 2012; O'Connor et al., 2013a).

Following the framework outlined by Falconett and Nagasaka (2010), Figure 1 illustrates the Monte Carlo simulation used in this paper. Simulation inputs may be either certain or uncertain, with uncertain inputs characterised by an expected distribution. For each scenario, 10,000 Monte Carlo simulation iterations are run, from which a probability density function, and thus the likelihood of cost/profitability, may be constructed. The Value at Risk (VaR) and Conditional Value at Risk (CVaR) methodology, as employed by Gass et al. (2011), is used to identify the probability that device cost (financial return) will be less (greater) than or equal to a stated probability threshold. A number of probability thresholds are chosen to account for various degrees of certainty that may be required by policymakers/investors in project evaluation. Each constituent element of the modelling process will now be outlined in greater detail.

Figure 1: Overview of Probabilistic Methodology



Note: Flowchart describing steps in probabilistic modelling process used in this paper

2.1 Scenario Parameters

We analyse WEC installations of 20, 50 and 100-unit capacity. When considering the financial viability of investment, a Feed-in Tariff (FiT) is a price support mechanism chosen in many jurisdictions that offers a guaranteed price per unit of electricity generated. This is the mechanism chosen to support renewable energy deployment in Ireland and is known as the Renewable Energy Feed-in Tariff (REFIT; DCENR, 2006; 2012). As such, project profitability will be assessed under a Feed-in Tariff price support mechanism in this chapter. Numerous feed-in tariff rates are assessed for the purposes of this analysis, including the rate of €0.26/kWh proposed by Irish policy for initial devices (DCENR, 2014a).

A 'learning rate' is commonly used to approximate the effect economies of scale and technological change may have on device cost (e.g. Dalton et al., 2010, 2012; Previsic et al., 2004; SQW, 2010). A learning rate or alternatively, an 'experience curve', calibrates an initial cost estimate to an empirically observed rate of cost reduction (Junginger et al., 2004).A full discussion of learning rates is offered by Junginger et al. (2004) and Hau (2006). Briefly, a learning rate may be characterised in terms of a scaling factor, *b*, which indicates the percentage scaling of cost with each doubling of capacity. Assuming cost reduction begins during the first time period, and denoting *p* as the percentage scaling of cost and *A* as the cumulative number of units installed at a given time, the learning rate may be defined in a continuous fashion by the following equation (Bhandari and Stadler, 2009; Dalton et al., 2010; Epple and Argote, 1990; Junginger et al., 2004);

$$p = A^{\frac{\ln(b)}{\ln(2)}} \qquad (1)$$

A lack of operating experience means that the scaling parameter *b* is unknown for WEC devices. The literature to date has employed expert estimates or extrapolated patterns of cost reduction observed for offshore wind and photovoltaic (PV) solar technology. Dalton et al. (2012) has stated that such values have ranged between 0.82 and 0.96 (Dalton et al., 2012; Previsic et al., 2004; SQW, 2010), whilst SQW (2010) have employed rates of learning of between 0.85-0.90. Following scenarios employed by Dalton et al. (2010), SQW (2010), and Carbon Trust (2006), a 0.90 rate of cost scaling is chosen for the central analyses of this chapter. Alongside this, a sensitivity analysis is carried out to assess results for cost scaling in the range of 0.82-0.95. This range is chosen as that which best represents the rate of cost scaling for most industrial products (Hau, 2006), the bounds provided by Dalton et al. (2012) and parameters employed by Previsic et al. (2004).

2.2 Indices of Project Cost and Profitability

The Levelised Cost of Electricity (LCOE) is employed to calculate project cost whilst the Internal Rate of Return (IRR) is calculated to measure profitability. The LCOE is a €/kWh metric calculated according to the following equation;

$$LCOE = \frac{\sum_{t=1}^{T} \frac{C_t}{(1+r)^t}}{\sum_{t=1}^{T} \frac{Y_t}{(1+r)^t}} \tag{2}$$

Where C_t represents the cost for period t and Y_t is the electricity yield at period t. Total cost and electricity yield (in kWh) is discounted and summed over T time periods of operation subject to the discount rate r. The discounted and summed value of lifetime cost is then divided by the discounted and summed electricity yield.

For a given LCOE, policy support offered must yield a certain return to be financially viable. A suitable tool for such appraisal is the Internal Rate of Return (IRR). The IRR may be considered as the discount rate r that allows the discounted returns to equal the discounted costs of a particular investment, calculated according to (4). A greater IRR indicates a greater return on investment, with an IRR value of 10% considered the ‘hurdle rate’ required to yield an attractive investment in technologies such as WEC devices (Dalton et al., 2010; SQW, 2010).

$$IRR = \sum_{t=1}^{T} \frac{[(kWh)(REFIT)]_t}{(1+r)^t} - \sum_{t=1}^{T} \frac{[Cost]_t}{(1+r)^t} \tag{3}$$

2.3 Index of Certainty

When interpreting the results, one must choose a point in the calculated probability distribution that indicates the profitability and/or cost of WEC deployment with an acceptable degree of certainty. Following Gass et al. (2011), the Value at Risk (VaR) and Conditional Value at Risk (CVaR) metrics are employed to carry this out. VaR may be interpreted as the value at which the probability of observing an event is equal to a β threshold probability (Rockafellar and Uryasev, 2002). By using this methodology, one can incorporate investor or policymaker's aversion to underestimating cost/overestimating profitability by choosing a β probability that represents an acceptable degree of certainty. CVaR augments this analysis by considering the entire tail of the profitability/cost distribution and measures the expected value of return, conditional on achieving a value beyond the β Value at Risk (Gass et al., 2011; Rockafellar and Uryasev, 2002). CVaR is thus a more prudent metric. Furthermore, CVaR does not rely on the assumption of normally distributed returns required for VaR (Gass et al., 2011).

The formula to calculate the CVaR from a given probability density function is outlined in great detail in Scaillet (2004) and Rockafellar and Uryasev (2000; 2002). CVaR calculations for cost are illustrated below in Equation 4:

$$CVaR = E\left(c \mid c \geq VaR_{\beta}\right) = \sum_{c}^{C}\left(p(c)c \mid c \geq VaR_{\beta}\right) \quad (4)$$

This metric is also used to determine the likelihood that the Internal Rate of Return, *irr*, is greater than or equal to an acceptable threshold using Equation 5:

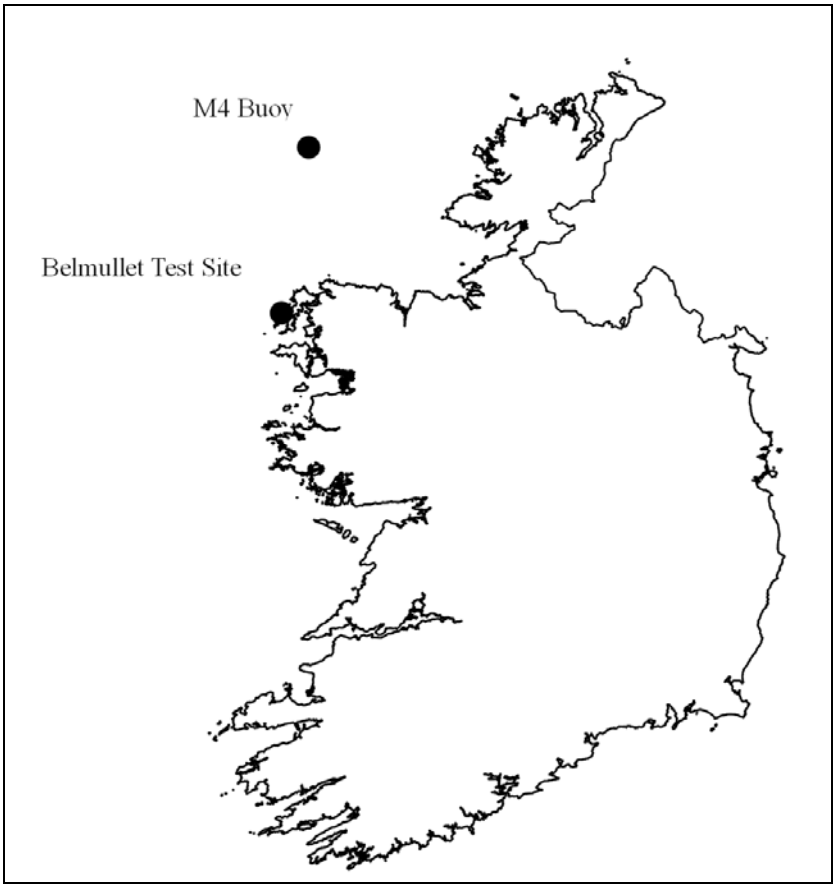
$$CVaR = E\left(irr \mid irr \leq VaR_{\beta}\right) = \sum_{irr}^{IRR}\left(p(irr)irr \mid irr \leq VaR_{\beta}\right) \quad (5)$$

where C is project cost; *irr* is project internal rate of return; $p(x)$ is the probability density function of parameter x; VaR is the minimum real value of project cost achieved with probability β.

3. Data

The productivity and cost of a wave energy installation is spatially heterogeneous and cost estimates must be interpreted in the context of the chosen location. This paper considers the cost of deployment off the north-west coast of Ireland. The specific location chosen is that of pre-commercial test site currently being developed at Belmullet, Co. Mayo (see Figure 2). Each of the model inputs for this scenario will now be outlined.

Figure 2: Belmullet Case Study Site and M4 Data Buoy Location



Data Source: Marine Institute (2011) and SEAI (2012)

3.1 Wave Energy Output

To model the output of a WEC device, one must obtain data detailing wave activity at a particular location and convert this to electricity output. To best approximate these conditions, and ensure consistency with existing Irish studies (Dalton et al., 2010; 2012; O'Connor, 2013a) 2008 wave energy data from the M4 buoy is used (Marine Institute, 2012; see Figure 2). The M4 buoy is one of the Irish Marine Institute's network of data collection buoys and is located near the considered Belmullet deployment site. 2008 represented the most complete annual profile from the data available, which recorded wave conditions in hourly intervals. The data had 127 missing observations which were interpolated by duplicating observations before/after any missing period such that all missing hours were accounted for. This profile of wave energy output is converted to electricity output using the Pelamis WEC power conversion matrix (Pelamis, 2012).

A WEC Power Conversion matrix characterises output at any one moment in time in terms of the significant wave height (H_s) and the wave energy period, T_e. The Pelamis WEC is the device to be analysed in this chapter as it has been employed in the majority of studies to date (Table 1). The Pelamis power matrix lists energy output in terms of significant wave height (H_s) and T_{pow}, the power period of a wave cycle. Dunnett and Wallace (2009) have defined T_{pow} as being the 'period of a single sinusoidal wave with the same power as the sea-state' and assumed that $T_{pow} = T_e$. The analysis presented in this chapter will follow this approach and make a similar assumption.

T_{pow} and T_e are not easy to observe and record in conventional data and, as such, simpler measures are recorded instead. The Irish Marine Institute records the mean zero up-crossing period, T_z. Dalton et al. (2012) illustrate that assuming a broad wave energy Bretschneider spectrum, the best suited function for deep sea long-fetch locations, T_z may be converted to T_e (and thus T_{pow}) using the following equation;

$$T_{pow} = T_e = 1.2T_z \qquad (6)$$

3.2 Cost Specification

Inputs may be categorised as manufacture/procurement cost, installation cost, operational and decommissioning costs and output. It is assumed that all manufacture/procurement and installation costs are incurred in the initial time period. Operation of the plant begins in the following year with O&M and insurance costs incurred annually throughout the 15 year operating lifetime of the plant. Decommissioning costs are incurred at the end of the life of the plant, in time period 15. Site-related infrastructural costs have been obtained from the Sustainable Energy Authority of Ireland (SEAI). This profile outlines costs used in the Belmullet test site and is thus representative of actual infrastructural costs at the chosen case study location. Device costs pertain to the Pelamis-P1 WEC, as this is the most mature device with the most comprehensive data available in the public domain. The Pelamis-P1 has also been used in many Irish studies to date (Table 1). Other infrastructural, component and installation data are sourced from the literature.

Table 2 shows that each uncertain parameter is classified as a probability distribution and each known parameter is classified as a point estimate. Each probability distribution is selected based on the most appropriate fit to expected values of each input and updated where required to represent 2010 cost values. This is carried out by converting to euro using the exchange rate at the time of each analysis, and adjusting for inflation if required.

Each input cost used in this paper is derived from industry interaction and a review of those present in the literature. The calculation of each parameter from these primary sources will now be discussed in detail.

The Pelamis WEC is comprised of two primary components; 3 Power Conversion Modules (PCM) and 4 tubular segments. PCM costs for the Pelamis P1 device are sourced from Previsic et al. (2004). Prices are updated to account for changes in price from 2003-2010 by using the Irish Wholesale Price Index for machinery and equipment manufacture (CSO, 2010). 2003 is chosen as the base year as much of the research carried out for the Previsic (2004) data is sourced from 2003 (DTI, 2003; Previsic, 2004). This results in 2010 a cost of €1,623,127 for 3 PCM modules[4]. This is considered as a central 'most likely' value. In the absence of alternative source of device cost variation, the uncertainty surrounding this estimate is considered by employing a triangular distribution, taking the range of minimum (-21%) and maximum (+31%) bounds quoted by Previsic et al. (2004).

The tubular segments for initial Pelamis WEC devices will be constructed from steel for initial installations (Previsic, 2004). Dalton et al. (2010) state that the 2008 cost per ton of finished and coated steel may be between €5,000-7,000/ton, with four segments, including end caps, totalling 289 tonnes. Since these values were estimated in 2008, the price of steel rose briefly in 2009. However, the cost returned to that of 2008 levels in 2011 (Indexmundi, 2012a), with O'Connor et al. (2013a) deeming these estimates appropriate for 2013 steel costs. Thus, it is assumed that the range quoted by Dalton et al. (2010) is sufficiently up to date for this analysis. Steel costs are parameterised by assuming that €6,000/ton represents the mean expected value. Any deviations beyond this are distributed according to a normal distribution, with all

[4] Previsic et al. (2004) have estimated that the cost of 3 PCM units totals $1,565,000 (€1,492,181; according to the Jan 2003 exchange rate of US$1 = €0.9534706331). NACE 29 (Machinery and Equipment) had an 8.775% increase in prices according to the Irish Wholesale Price Index (CSO, 2010), giving a 2010 cost of €1,623,127.

potential values falling within the €5,000-€7,000/ton range. This corresponds to a standard deviation of €333 per tonne.

Mooring line costs are taken from Allan et al (2011b), where the central value is converted to give a 2010 euro value of €552,165[5]. Given that these values were considered valid in 2011 they have not been updated for inflation. The variation surrounding this central estimate is assumed to follow a triangular distribution with minimum (54%) and maximum (118%) values corresponding to the range quoted by Allan et al. (2011b).

Once the electricity has been generated, it must be transported to the grid. It is assumed that 8.7km of export cable will be required, as this is the amount of cabling required for the deep sea test site at Belmullet (O'Connor et al., 2013a; SEAI, 2011). The type of export cable required varies depending on the capacity of the installation considered. Scenarios of 20, 50 and 100 unit Pelamis installations are considered for this study, with capacities of 15MW, 37.5MW and 75MW respectively. Sharkey et al. (2011) and O'Connor et al. (2013a) assume that 33-38kV Medium Voltage Alternating Current (MVAC) is sufficient for smaller WEC installations of 20MW or less, whilst O'Connor (2013a) assume 110kV cable is employed for installation sizes of 21-110MW. Thus, 38kV MVAC is employed for 20 unit installations, with 110kV cable installed for larger installations. The central cost values per unit of cable are derived from O'Connor et al. (2013a), where it is assumed that one kilometre of 38kV export cable costs €173,000, whilst one kilometre of 110kV export cable costs €288,000.

As CER (2005) discuss, the cost of this cable is subject to considerable uncertainty and fluctuation, with the primary driver of these costs being materials costs. This claim is enforced by Green et al. (2007), who state that one third of cable costs may be attributable to the price of copper on commodity markets. To account for this uncertainty a standard deviation of 27% of the copper component of cost is assumed.

[5] Allan et al. (2011b) employ a central mooring estimate of £362,240. The source for these cost estimations is Carbon Trust (2006) and as such, costs are converted to euro using the July 2006 exchange rate of GBP£1 = €1.449. This gives a 2006 euro value of €525,229 for the central estimate. This is updated according to the Wholesale Price Index for Machinery and Equipment where an increase of 5.1282% was observed to yield a 2010 Irish cost value of €552,165.

27% is chosen as this is the standard deviation of annual average copper prices observed since 2002 (Indexmundi, 2012b). A 27% change in copper price, when considered in the context of the effect it may have on overall cable cost, results in a standard deviation of €15,570/km for 38kV cable, and €25,920 per kilometre for 110kV cable. To improve the accuracy of simulation results, it is assumed that steel and copper commodity prices are positively correlated. The degree of correlation is estimated from market data, where average annual commodity prices have been observed to have a correlation coefficient of 0.647 (Indexmundi, 2012a; 2012b).

To facilitate the transmission of electricity from WEC devices, an offshore substation is required. O'Connor et al. (2013a) assume that an offshore substation for an installation of greater than 5 MW in size costs €60,000 per MW installed. This cost is included as a deterministic point estimate.

The cost of onshore works have been obtained from SEAI, pertaining to the costs for the first full scale installation at Belmullet, Co. Mayo, of 5MW capacity. These costs are parameterised as deterministic variables as they pertain to an actual installation. They are also assumed constant regardless of the scale of the installation.

The installation of cable is assumed to follow the same pattern as that assumed by O'Connor et al. (2013a), where 1km of untrenched, rock protected cable installation is required, at a total cost of €1,039,000. The remaining 7.7km will be installed by trenching. The calculation of installation costs for this 7.7km requires both an approximation of the number of days' work and the cost per day. Kaiser and Snyder (2011) outline the determinants of installation cost variability and give insight into the potential variability of days required. O'Connor et al. (2013a) report an expected value of €288,000/km for export cable installation for sites similar to the Belmullet site. This is combined with the variability in duration observed by Kaiser and Snyder (2011) to give an overall measure of export cable laying cost variability. Kaiser and Snyder (2011) report a median rate of installation at 0.73km/day. Converting the expected cost per km reported by O'Connor (2013a) to the expected cost per day using the findings of Kaiser and Snyder (2011), it is assumed that the present value expected daily cost for export cable installation at a site like Belmullet is €386,301/day. The rate at which cable is installed is simulated according to a triangular distribution fitted to the data observed by Kaiser and Snyder (2011), where the rate of installation ranges from 0.2km/day to 1.4km/day, with a median value of 0.73/day.

As similar vessels are employed, mooring and array cable installation are dealt with together in model specification. An Anchor Handling Tug Supply (AHTS) class vessel was used for prototype deployment in the UK (Previsic, 2004), and it is assumed that this class of vessel will be used for deployment in Ireland. The range of day rates for AHTS and the associated vessel spread from Kaiser and Snyder (2011) is employed, whereby a range of €17,596 - €52,824 per day is used. This is simulated according to a normal distribution, with a mean €35,228 and standard deviation €5,871. An estimated average installation time of 6 days (2 days for mooring and 4 for device installation) has been assumed, following RPS (2009). As there is no data outlining commercial-level device installation, this is taken as a central value with the associated distribution taken from AHTS installation activity outlined by Kaiser and Snyder (2011). Thus, a triangular distribution is assumed, with a central value of 6 days, a minimum value 0.52 times the central value (3.12) and a maximum value of 2.12 times the central value (12.72 days).

No empirical data explaining costs during the operational phase exist to date. The majority of recent studies have calculated O&M costs as % of capital costs (e.g. Allan et al., 2011; Dalton et al., 2010, 2011; O'Connor et al., 2013a; SQW, 2010). Thus, both annual insurance and operation and maintenance costs are assumed to range uniformly from 1-3% of total capital costs following the ranges quoted to date (Dalton et al., 2012; Dunnett and Wallace, 2009; Previsic et al., 2004; St Germain, 2005; SQW, 2010). Decommissioning costs are incurred in time period 15, and represent 10% of the total capital cost, as per the assumptions employed by Dalton et al. (2012).

Finally, it is assumed that the devices will have 75% availability when operational, following the assumption of O'Connor et al. (2013a) for Mature Technology Reliability in Ireland.

Table 2: Unit Costs for Typical Pelamis Wave Energy Installation

Parameter	Parameters					Source
	Min	Mean (SD if applicable)	Max	Distribution Type	Requirement	
A. Manufacture and Procurement						
PCM (3)	79%	€1,623,127	131%	Triangular	Total per WEC	A, B
Steel (per tonne)		€6,000 (€333)		Normal	280t	A, B
Mooring	54%	€552,165	118%	Triangular	Total per WEC	C
Admin, EIS and Onshore works	-	€5,682,925	-	Point Estimate	Total per installation	D
Export Cable (≤20MW)	-	€173/m (€15.57)	-	Normal	8.7km per installation	J
Export Cable (≥20MW)	-	€288/m (€25.92)	-	Normal	8.7km per installation	J
Offshore Substation	-	60,000/MW	-	Point Estimate	Total per installation	J
B. Installation						
Device/Mooring (per day)	-	€35,228 (€5,871)	-	Normal	-	E, F
Device/Mooring (no. days)	52%	6	112%	Triangular	-	F
Export Cable Lay (per day)	-	€386,301	-	Point Estimate	7.7km	E, J
Export Cable Lay (rate of installation)	27%	0.73km/day	191%	Triangular	7.7km	E
Untrenched Export Cable Lay and Rock Protection	-	€1,039,000	-	Point Estimate	1km	J
C. Operational & Decommissioning Costs (Calculated as % of Capital Expenditure [A+B])						
O&M	2%	-	5%	Uniform	per annum; for 15 years	G

Insurance	2%	-	5%	Uniform	per annum; for 15 years	G
Decommissioning	-	10%	-	Point Estimate	Time Period 15	G
D.Further Model Parameters						
Learning Rate	82%	90%	95%	Point Estimate Scenarios	-	A, B, F, G
Device Availability	-	75%	-	Point Estimate		J
Discount Rate	-	6%	-	Point Estimate	-	G
Corporation Tax	-	12.5%	-	Point Estimate	Per unit of profit	H

Note: Sources are as follows. A: Previsic et al., 2004; B: Dalton et al., 2010; C: Allan et al., 2011b; D: SEAI, 2011b; E: Kaiser and Snyder, 2011; F: SQW, 2010; G: Dalton et al., 2012; H: Department of Finance, 2011; J: O'Connor et al., 2013a.

4. Results and Discussion

4.1 Quantification of Cost Uncertainty

Assuming 100% availability, the annual energy output for one Pelamis P1 device using the methodology outlined in Section 3 is 2,500,480kWh. Scaled according to the 75% availability factor, this results in an annual output of 1,875,360kWh. 20, 50 and 100 unit steel-based Pelamis installations are considered for this analysis. Table 3 lists the distributional characteristics of project cost for each installation size and technology specification. The expected (mean) cost of electricity generated from small-scale installations of 20-unit size is €0.324/kWh, falling to €0.27/kWh and €0.244/kWh respectively for 50 and 100-unit installations. To incorporate aversion to risk and identify cost values at various degrees of certainty, LCOE estimates are also evaluated at various other probability thresholds using the VaR and CVaR methodologies. Results displayed in Figure 3 plot the VaR for each β threshold. Using the VaR criterion, the levelised cost of 20-unit installations will not be greater than €0.348/kWh at 95% probability according to the assumptions of this analysis. If a lower degree of certainty is preferred, the VaR at other thresholds may also be observed using the cumulative density functions of Figure 3. The CVaR methodology provides a more prudent measure, with results presented for 75, 85 and 95 percentile thresholds in Table 3. One can see that $CVaR_{95}$ is slightly greater than VaR_{95}, rising to €0.353/kWh from €0.348/kWh for 20-unit installations, for example. Overall, a premium of 5.5% is required when evaluating cost at $CVaR_{75}$ instead of the mean expected value, rising to 6.7% for $CVaR_{85}$ and between 8.9%-9.2% for $CVaR_{95}$. Interestingly, the proportional cost premia are relatively stable across installation scenarios. This is an important consideration for policymakers and investors when considering the impacts of uncertainty on investment performance and policy support.

The cost of electricity is inversely correlated with installation size, due to two factors. First, larger installations have the same range of fixed costs as smaller installations. These fixed costs are spread over a larger number of units, thus reducing the cost per unit of electricity. Second, a larger installation results in greater scope for cost reduction through ‘learning’. Indeed, these factors result in cost values for 50 unit installations being 16% less than 20-unit installations across all thresholds. If the first full-scale installation is of 100-unit structures, the cost of electricity falls by a further 9%.

Table 3: Levelised Cost (€/kWh)

Installation Size	Expected value (Mean)	$CVaR_{75}$	$CVaR_{85}$	$CVaR_{95}$
20 Units (15MW)	0.324	0.342	0.346	0.353
50 Units (37.5MW)	0.270	0.285	0.288	0.294
100 Units (75MW)	0.2444	0.258	0.261	0.267

Note: The ‘$CVaR_n$’ value represents the expected (mean) cost value greater than or equal to those at the n^{th} percentile.

Although each estimate found in the literature (See Table 1) is calculated under its own specific set of assumptions and circumstances, the probability calculated using this methodology allows one to apply the findings of previous research in the context of a given case study application. To illustrate, O’Connor et al. (2013b) state that if insurance costs are 1% of capital costs per annum, the LCOE for a 100 unit installation may be either c.22 or c.26c/kWh under respective scenarios of 1% or 3% O&M costs. However, O’Connor et al. (2013b) are unable to calculate the likelihood of achieving either value. This probabilistic framework provides this understanding. Under the assumptions of this paper (as opposed to those of O’Connor et al. (2013b)), the VaR criterion suggests that there is a 1.1% chance that the LCOE of 100-unit based installations will be less than or equal to €0.22/kWh. This rises to 92.13% for €0.26/kWh. Thus, the added value of this model is realised when one considers that the degree of risk associated with each cost value is now estimated. For a risk-averse investor who is basing an investment decision on either cost value, the stated probabilities for the €0.22/kWh estimate is likely to be too great a risk burden to incentivise investment. Furthermore, this probabilistic approach also allows for the probability of achieving intermediate cost values.

The results of Table 3 should be interpreted in the context of the Irish deployment scenario outlined in this paper. However, these results overlap with the Irish case study of O'Connor et al. (2013b). This provides a degree of validation for this model, as it can be seen that results of this paper correspond to those carried out for similar installation sizes, although under an alternate set of assumptions.

Figure 3: Cumulative Density Distribution of Pelamis Cost

Figure 3(a) 20 Unit Installation

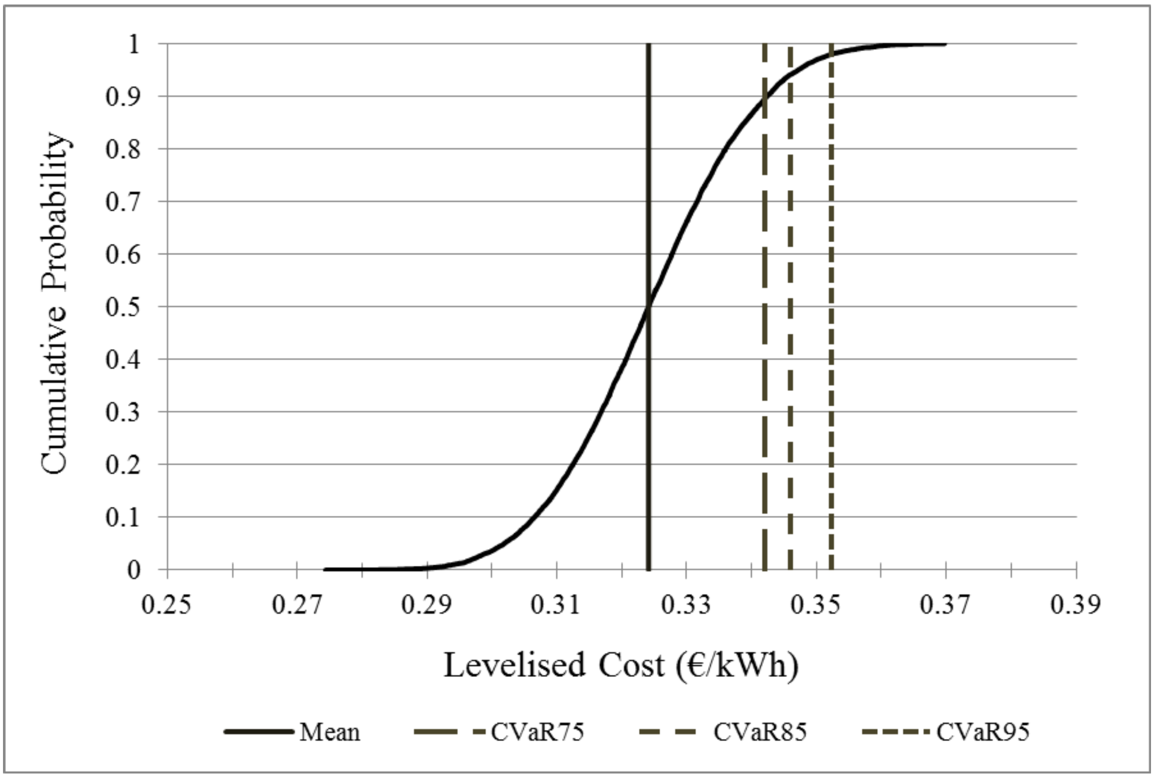


Figure 3(b) 50 Unit Installation

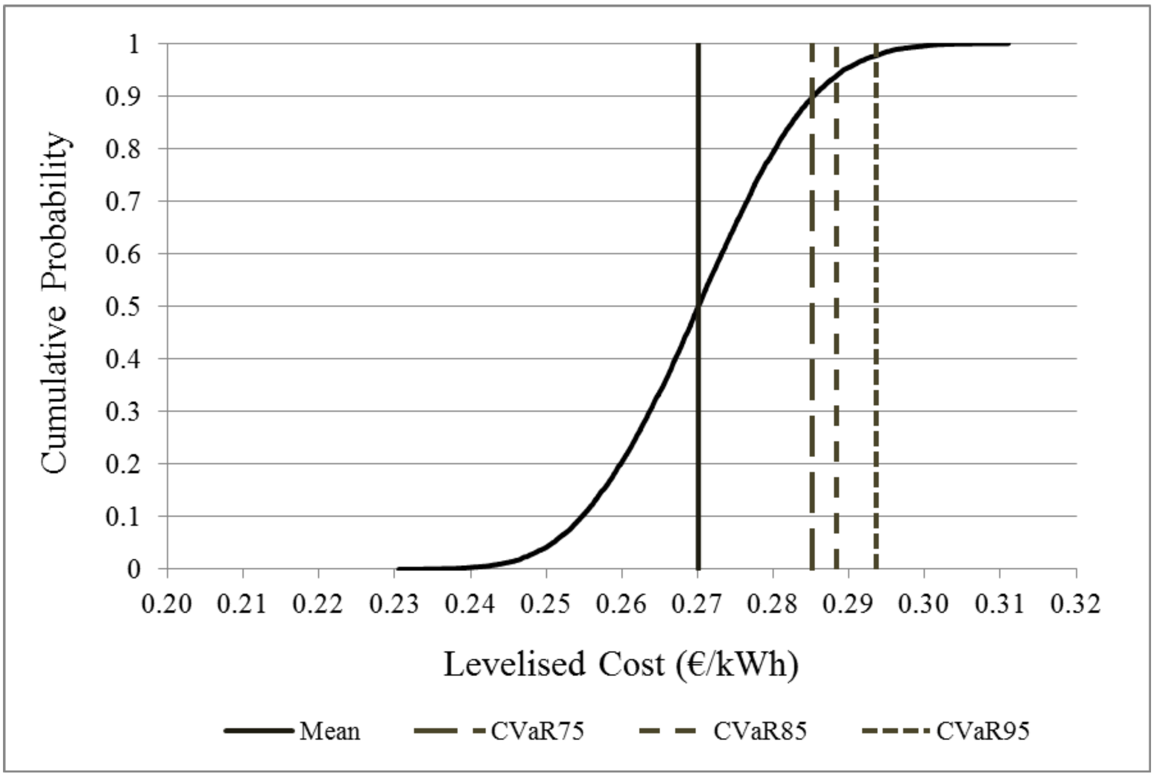
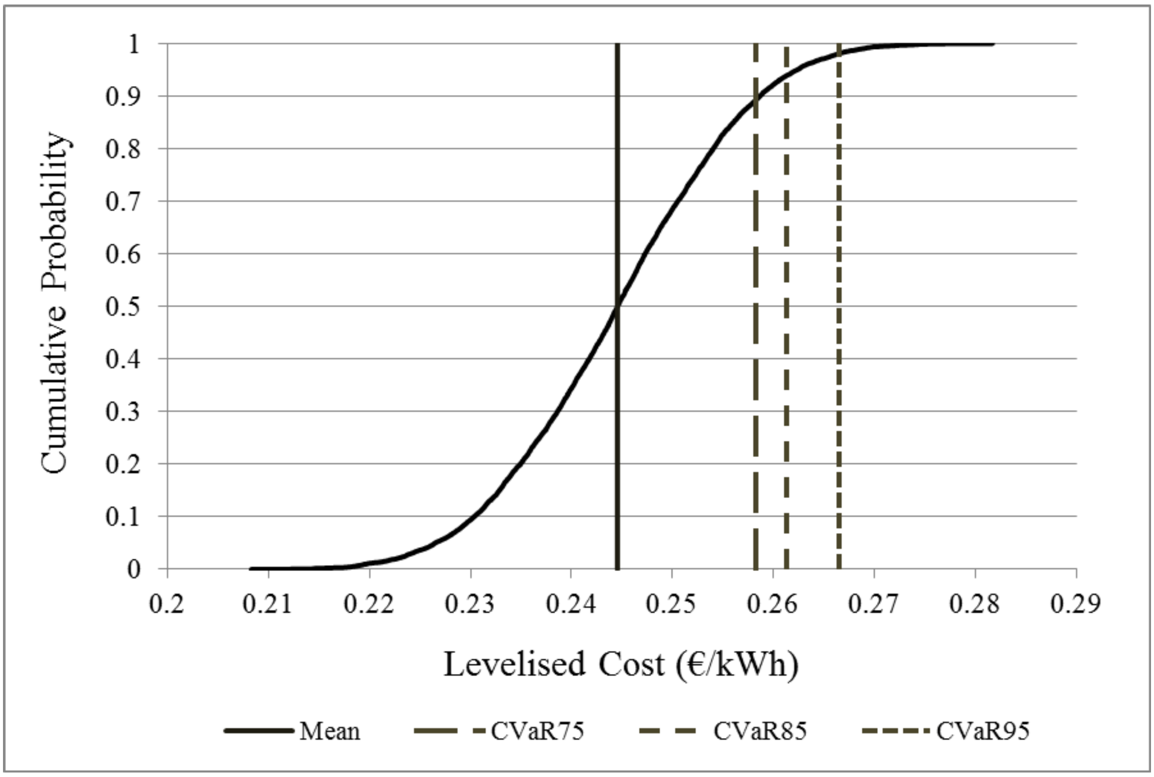


Figure 3(c) 100 Unit Installation



Note: Figures display cumulative probability of achieving a given levelised cost value. Each point on the curve represents the probability that cost will be less than or equal to that value. Vertical lines mark key CVaR levelised cost values quoted in Table 3. The point on each LCOE curve indicates the probability that LCOE will be less than or equal to this value. This value is analogous to the Value at Risk (VaR), whilst the cumulative probability is analagous to the β threshold.

4.2 Policy Appraisal in the Presence of Cost Uncertainty

4.2.1 Appraisal of Current REFIT Policy Proposals

Using the case study parameters presented, we will now use the probabilistic model for analysis of policy support mechanisms, quantifying the degree of certainty to which the proposed Irish REFIT of €0.26/kWh provides a positive rate of return on investment. Profitability values are evaluated at $CVaR_5$, $CVaR_{15}$ and $CVaR_{25}$ thresholds. These criteria analyse the weighted mean of IRR values less than or equal to the n^{th} percentile and may be interpreted as there being an n% chance that the IRR will be greater than or equal to the cost value quoted.

Table 4 shows that the threshold of risk aversion chosen has a greater impact on the magnitude of return than LCOE, with absolute premiums of 1.5-1.64%, 1.9-2% and 2.4-2.6% required when evaluating IRR at $CVaR_{25}$, $CVaR_{15}$ and $CVaR_5$ thresholds respectively. Cost uncertainty has a much greater proportional impact on smaller installation sizes, with IRR rates falling by 0.75%-122% for 20-unit installations. However, this falls as installation size increases, with 100-unit installations having increased IRR rates of 27-46% at the various thresholds of risk aversion.

Table 4: Internal Rate of Return: REFIT €0.26/kWh

Installation Size	Mean	$CVaR_{25}$	$CVaR_{15}$	$CVaR_5$
20 Units (15MW)	-0.0216	-0.038	-0.042	-0.048
50 Units (37.5MW)	0.0272	0.011	0.008	0.003
100 Units (75MW)	0.054	0.039	0.035	0.029

Note: $CVaR_n$ represents the expected (mean) IRR achieved for cost values less than or equal to those at the n^{th} percentile when a REFIT of €0.26/kWh prevails.

Similar to Figure 3, Figure 4 plots the IRR VaR for each probability threshold, where, although positive IRR values are prevalent for larger installations, the unlikely possibility of achieving 10% IRR under a €0.26/kWh REFIT can be clearly observed. Overall, Figure 4(a) shows that 20-unit installations have a 3.9% chance of having a positive IRR according to VaR criteria. Figures 4(b) and 4(c) show that 50 and 100-unit installations have greater potential to yield a positive IRR. It has been stated that an IRR of 10% is the rate required to incentivise investment (Dalton et al., 2010; SQW, 2010). Although there is a 99% chance or greater that 50 or 100-unit installations will yield a positive rate of return, there is <1% chance that this will exceed the 10% IRR required for viable investment. Analysing expected values in this context reveals that there is less than 1% chance that current REFIT policy is effective in incentivising deployment for all installation sizes.

These results quantify the effect cost variability may have on WEC project return and the impact this may have on the investment decision. This further demonstrates the added value offered by the developed probabilistic model of analysis. One can see that results are also sensitive to installation size, with these considerations thus important in designing an appropriate REFIT.

Figure 4: Cumulative Density Distribution of Internal Rate of Return

Figure 4(a) 20 Unit Installation

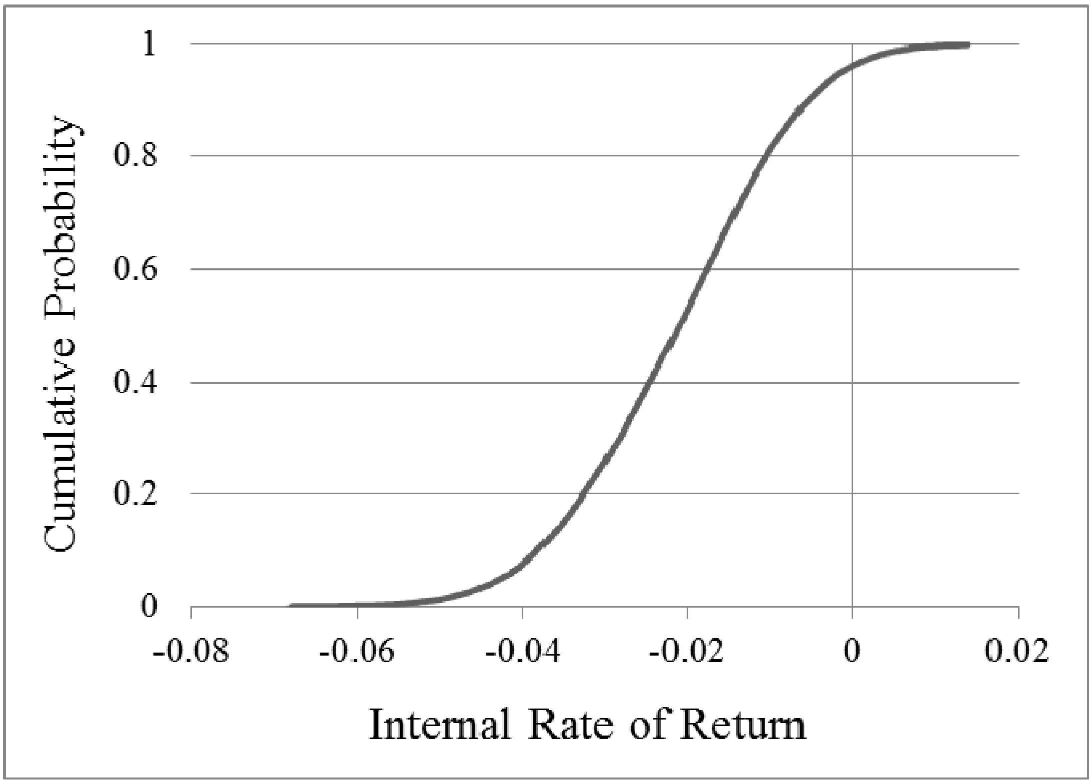


Figure 4(b) 50 Unit Installation

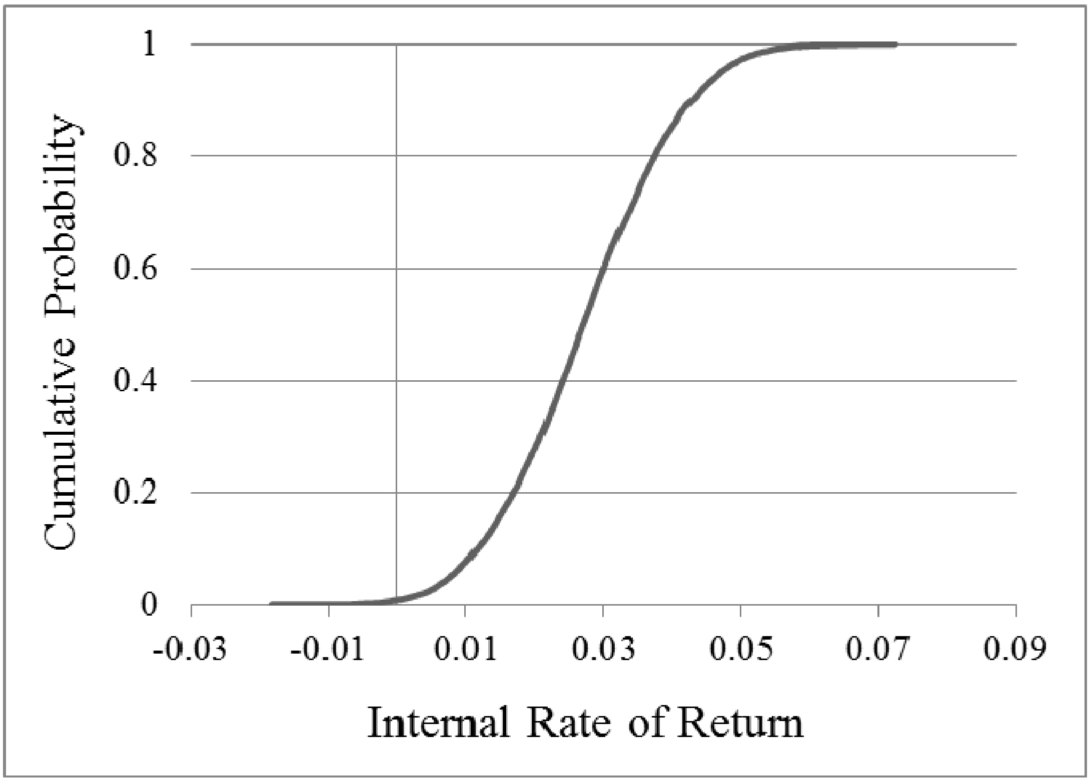
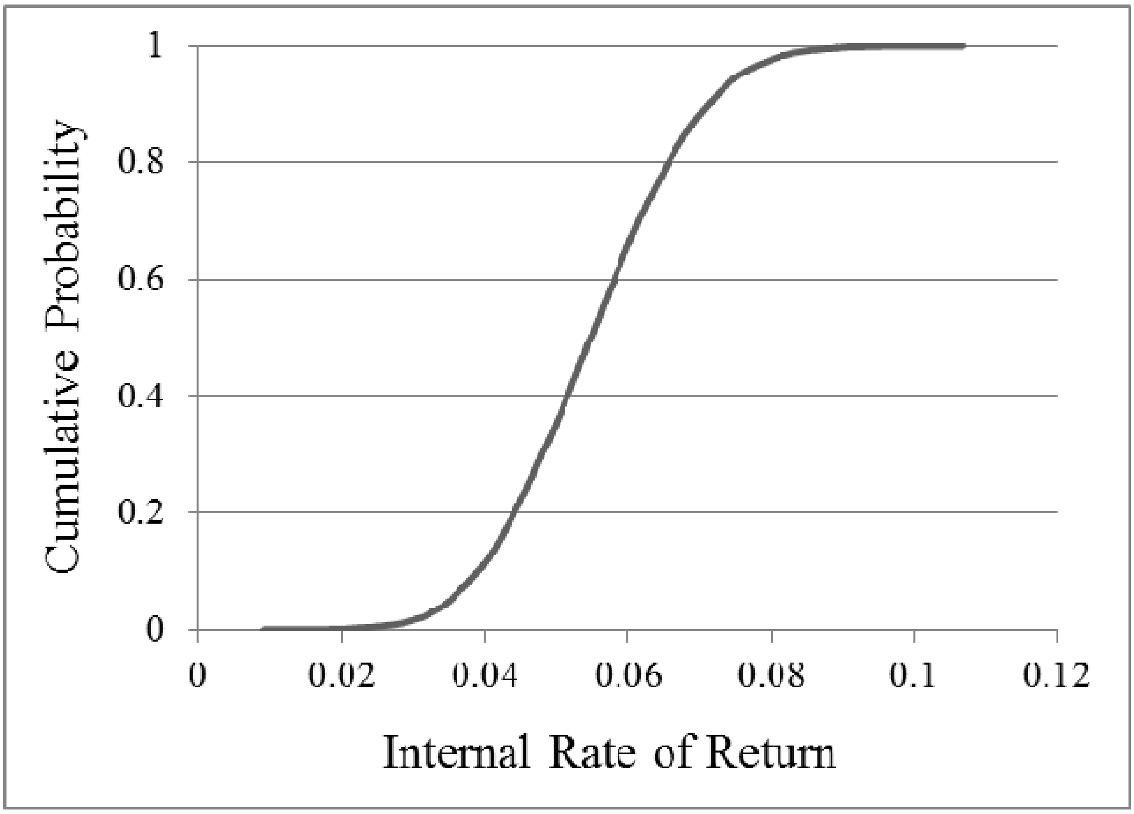


Figure 4(c) 100 Unit Installation



Note: Figures display cumulative probability of achieving a given Internal Rate of Return (IRR). Each point on the curve represents the probability that cost will be less than or equal to that value. The point on each IRR curve indicates the probability that IRR will be less than or equal to this value. This value is analogous to the Value at Risk (VaR), whilst the cumulative probability is analagous to the β threshold.

4.2.2 REFIT required for different installation sizes

Given the unprofitability of the proposed €0.26/kWh REFIT rate, this section analyses the minimum REFIT required to yield an IRR of at least 10% at each CVaR threshold. This allows one to identify the minimum cost required to incentivise deployment in an uncertain cost environment, with each CVaR threshold representing different thresholds of certainty required by investors. These results are presented in Table 5

Table 5: REFIT yielding an IRR of 10% or greater at various thresholds of certainty

Installation Size	Mean (€/kWh)	$CVaR_{25}$ (€/kWh)	$CVaR_{15}$ (€/kWh)	$CVaR_{5}$ (€/kWh)
20 Units (15MW)	0.42	0.44	0.45	0.46
50 Units (37.5MW)	0.34	0.36	0.37	0.38
100 Units (75MW)	0.31	0.33	0.34	0.34

Note: $CVaR_n$ represents the expected (mean) IRR achieved for cost values less than or equal to those at the n^{th} percentile.

Table 5 shows that, evaluated at the expected (mean) value, a REFIT of €0.42/kWh is required to ensure an IRR of 10% or greater for 20-unit installations, falling to €0.34/kWh and €0.31/kWh for 50 and 100-unit installations. In absolute terms, a REFIT premium of €0.02-0.04/kWh is required, depending on the scenario and degree of risk aversion. Given that the current REFIT for onshore wind is €0.069/kWh (DCENR, 2014b), with the majority of that funded by wholesale prices, this is not an insignificant amount.

Alongside quantifying the added premium required at different thresholds of certainty, this section highlights the importance of anticipating installation size for the setting of an appropriate policy. If installations of many different sizes are anticipated under the

REFIT scheme, a policy of support which discriminates by size may be appropriate. This may result in a REFIT which changes with time, if average installation size is anticipated to change with time. Alternatively, a constant REFIT for viable 100-unit investment may be offered for all installation sizes, with a supplementary capital grant to cover additional costs. These are but two suggestions to reconcile the different optimal REFIT rates of Table 5 within a tractable policy framework. A full cost/benefit analysis of potential price support mechanisms to overcome this problem, alongside the impacts on uncertainty and required risk premia, is outside the scope of this paper, but is a future potential application of this probabilistic cost model.

4.3 Influence of Learning on Device Cost and REFIT Requirement

As with all WEC feasibility analyses, results presented are highly sensitive to the assumed rate of cost reduction or 'learning'. This section identifies the implications this may have for both device developers and policymakers.

Table 6 lists the rate of learning required for a REFIT of €0.26/kWh to be effective. To achieve an expected (mean) IRR of 10% or greater, 20 unit steel-based devices require a rate of cost scaling considerably greater than the most likely range of 0.82-0.95 quoted by Hau (2006). For every doubling of capacity, this analysis suggests that the cost of a 20-unit installation must be scaled by a factor of 0.68, or 68%. This rate increases when uncertainty is taking to account.

The expected rate of cost scaling falls to 0.80 for installations of 50 unit devices. This is closer to the potential range of Hau (2006). The premium to account for uncertainty falls for 50 and 100 unit devices, with an added 2-3% rate of 'learning' required for both, depending on the degree of risk aversion present. The observed values for 100 unit steel-based devices are within the range of 0.82-0.95 cited by Hau (2006), however, they are still greater than the likely value of 0.90 commonly employed in the literature and may thus be considered optimistic. Interestingly, one can see that the required rate of cost scaling declines with each subsequent device specification. This reflects two factors. First, there are greater economies of scale to be achieved with larger installations, whereby constant infrastructural costs are spread over a greater output. Second, a larger installation size, and thus a greater level of cumulative installation, presents scope for a greater absolute change in cost. The impact of uncertainty, in absolute terms, seems to fall albeit at a potentially diminishing rate, for larger installation sizes. This illustrates the greater importance of incorporating uncertainty in small installation scenarios. Early deployment is likely to comprise smaller installation sizes (DCENR, 2014a; MI & SEI, 2005) and thus the findings of this paper may be more pertinent in such scenarios.

Table 6: Rate of Learning Required for IRR of 10% when REFIT of €0.26/kWh in place

Installation Size	Mean	$CVaR_{25}$	$CVaR_{15}$	$CVaR_{5}$
20 Units (15MW)	0.68	0.65	0.64	0.63
50 Units (37.5MW)	0.80	0.78	0.78	0.77
100 Units (75MW)	0.85	0.83	0.83	0.82

Note: The rate of learning represents the scaling of cost with every doubling of capacity.

Although the accepted convention within the literature, the quoting of cost reduction as a scale or percentage is somewhat abstract. In order to ground these parameters in measures of unitary cost, the rate of cost reduction required between the first and last unit deployed for each installation scenario is displayed in Table 7. Such information may provide cost targets for potential device developers to achieve profitable deployment, demonstrating an added use of this modelling framework. In the context of this analysis, the $CVaR_n$ threshold may be interpreted as a prudent cost value for a developer to aim for in order to achieve an appropriate rate of cost reduction. Thus, if a developer can produce the first/last device at a levelised cost less than or equal to the $CVaR_5$ value quoted in Table 7, there is a 95% chance of achieving an IRR of 10% or greater under the assumptions of this case study. The rate of cost reduction under a 0.90 rate of cost scaling is calculated also to provide a benchmark against which required rates of reduction may be compared to those expected.

Evaluated at $CVaR_5$, costs fall by 35% from the first to the last device under the benchmark 0.90 rate of cost reduction. However, in order to achieve cost-effective deployment costs must fall by between 51-68%. This highlights the considerable difficulty developers may face in achieving cost-effective deployment under currently proposed policy conditions, especially for lower installation sizes.

Table 7: Difference Between Levelised Cost of First and Last Unit due to Learning

Installation Size	Learning Rate	Mean Levelised Cost (€/kWh)		CVaR$_5$ Levelised Cost (€/kWh)		Rate of Cost Reduction
		Unit 1	Final Unit	Unit 1	Final Unit	
20 Units (15MW)	0.63	0.399	0.135	0.366	0.117	68.03%
	0.9	0.399	0.260	0.366	0.236	35.52%
50 Units (37.5MW)	0.77	0.359	0.153	0.328	0.137	58.23%
	0.9	0.359	0.234	0.328	0.213	35.06%
100 Units (75MW)	0.82	0.344	0.169	0.314	0.152	51.59%
	0.9	0.344	0.224	0.314	0.203	35.35%

Note: Unit cost values quoted are levelised cost estimates for first and last units of a given installation specification, evaluated at mean and CVaR$_5$ thresholds. Differences in these cost estimates are due to the assumed learning and resulting cost reductions through the cumulative installation of intervening units, evaluated at the CVaR value.

Table 8 displays the impact that sensitivity to learning may have on financial return and thus the required REFIT policy of support. For this analysis, the required REFIT is defined as that which yields an IRR of 10% at 95% probability, according to CVaR$_5$ criteria. Similar to the findings of Table 7, the required rate of REFIT is highly sensitive to the assumed rate of learning. For policymakers, this illustrates the degree to which correct prediction of the anticipated learning rate is especially important to yield an IRR of 10%. The premium for uncertainty declines as the rate of cost scaling approaches 1, indicating that accounting for potential uncertainty in cost values is of greater importance if cost reduction is likely to proceed at a greater pace.

Finally, it can be seen that the proposed REFIT rate of 0.26/kWh only provides an adequate rate of return under the extreme upper bound in cost scaling, at a learning rate of 0.82. This indicates that it is only under the most optimistic of deployment criteria that proposed Irish REFIT policy is adequate to yield an appropriate financial return for deployment.

Table 8: REFIT Required (€/kWh) for IRR of 10%

Installation Size	Learning	Mean	CVaR$_{25}$	CVaR$_{15}$	CVaR$_5$

20 Units (15MW)	0.82	0.35	0.37	0.37	0.38
	0.95	0.47	0.49	0.5	0.51
50 Units (37.5MW)	0.82	0.27	0.29	0.29	0.3
	0.95	0.4	0.43	0.43	0.44
100 Units (75MW)	0.82	0.24	0.25	0.25	0.26
	0.95	0.37	0.4	0.4	0.41

Note: 'Learning' refers to the rate of cost reduction for every doubling of capacity (cost scaling) employed in calculation. The 'REFIT required' is calculated as the REFIT rate required to yield a mean IRR value of 10% IRR for the lowest n^{th} percentile of simulated distributions.

5. Conclusion and Policy Implications

The economic evaluation of wave energy conversion devices has been limited to date by the uncertainty surrounding the true value of existing cost estimates. To incorporate the effect this uncertainty may have in policymaker, investor and developer decision-making, this paper has developed a tool to quantify the likelihood of achieving a given cost estimate. This model has been applied to a representative case study to further inform policymakers and investors as to the cost of wave energy devices in Ireland. The first goal of this paper was to quantify cost estimates for a central scenario of deployment. It was found that the expected levelised cost of electricity for 100 unit steel-based installations is €0.244/kWh. The uncertainty surrounding this estimation was quantified, with VaR and CVaR methodologies shown to account for risk in cost and policy appraisal. It was found that there is a 95% likelihood of achieving a cost value less than or equal to €0.267/kWh for 100-unit installations using the CVaR methodology.

The second goal of this chapter was to assess the certainty to which a feed-in tariff of 0.26/kWh provides an adequate return on investment, when investments are evaluated at their expected value or at a threshold accounting for uncertainty. This gives insight into the influence of cost uncertainty when policymakers are setting feed-in tariff rates. It was found that a tariff of €0.26/kWh is insufficient for all considered device specifications, with a REFIT of €0.42 required for 20-unit installations when evaluated at the expected mean value, rising to €0.46 when evaluated under $CVaR_5$ criteria. For 100-unit installations, expected mean and $CVaR_5$ criteria suggest values of €0.31/kWh and €0.34/kWh respectively. Thus, this methodology may identify the premium required to account for cost uncertainty. The third goal of this chapter was to explore the sensitivity of results to different rates of cost reduction or ‘learning’. The rates of learning required for feasible deployment under proposed REFIT policy were identified, whilst the REFIT rates required for feasible deployment under different rates of learning were presented.

Although cost estimates are still subject to uncertainty and thus to be treated with a degree of caution, this paper has presented a means to quantify this uncertainty through probabilistic simulation. This analysis recommends that prudent policy, cost and developer evaluation should incorporate cost variability into WEC project appraisal and has demonstrated how this may be done. For investors, a means to quantify the uncertainty of the investment environment allows for more informed investment decisions. For developers, this model has been applied to determine targets of cost reduction for feasible deployment. Furthermore, using the CVaR methodology allows for potential uncertainties to be incorporated in appropriate targets, such that prudent goals of cost reduction that account for potential cost uncertainties may be defined. Policymakers have been presented with a framework that quantifies the certainty with which a given measure will create the desired investment environment. This has contributed to the policymaker’s decision-making process in two ways. First, the need for a premium in FiT rates to account for cost uncertainty has been identified. Second, a means to efficiently specify this premium has been outlined.

A sensitivity analysis also identified the impact that greater levels of device learning may have for levelised cost estimates. Cost-benefit analysis of R&D investments to achieve such accelerated learning and application to alternate jurisdictions are further extensions.

The current economic climate is characterised by increasingly constrained public finances, alongside a global energy market characterised by increasingly uncertain fuel prices. Many jurisdictions, such as Ireland, have made considerable and continuing commitments to support WEC device deployment, despite these economic conditions. This paper has demonstrated the impact uncertainty may have on the policymaking process, outlining an appropriate modelling framework with which policymakers may take this into account. Quantifying the effects of cost uncertainty allows policymakers to identify with greater precision any potential premia that may be required, allowing for more efficient use of constrained public finances. Applied to an Irish case study, this provides a timely contribution by complementing existing cost estimates to better inform future policy processes in Ireland and elsewhere.

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