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The Profitability of Pre-Commercial Floating Offshore Wind Projects

A study of four funding mechanisms.

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Abstract

This thesis analyses the economic impact of different governmental support mechanisms on the investment in a pre-commercial floating offshore wind farm. An important contribution of this study is its investigation of funding regimes in the context of floating offshore wind and its analysis of the impact of subsidies from an investor's viewpoint, rather than from a social welfare perspective. Despite its potential to help meet the world's energy demand through clean electricity generation, thus mitigating climate change, floating offshore wind is not yet cost competitive with onshore wind generation or electricity generation from conventional sources. There is need for governmental support in order to encourage private investment to further develop the technology and achieve cost reductions through learning effects. This study investigates which type of support scheme is best suited to attract such investor support by evaluating the economic impact of four different funding mechanisms on a pre-commercial model floating wind farm. We analyse the market-based certificate scheme in Scotland and three different combinations of price-based mechanisms in Japan, France and Hawaii.

We find that a tradable green certificate scheme, as constituted by the Scottish example, is best suited to encourage investor support because it yields the most favourable return on investment. Notably, the Japanese feed-in tariff system constitutes an almost equal investment opportunity. The authors therefore recommend policymakers choose between a market-based certificate scheme and a non-market based feed-in tariff scheme the one that best suits the economic philosophy associated with governmental funding prevailing in their respective jurisdiction. If a feed-in tariff is chosen, we recommend policymakers phase out this support once floating technology has reached a certain level of maturity and replace it with a feed-in premium. This support encourages a better integration of floating offshore wind into the electricity mix and into the market.

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Abbreviations

ADEME	The French Environment and Energy Management Agency (Agence de l'environnement et de la maîtrise de l'énergie)
Capex	Capital Expenditure
CAPM	Capital Asset Pricing Model
CRI	Commercial Readiness Index
DECC	UK Department of Energy and Climate Change
DNV GL	Company (Det Norske Veritas & Germanischer Lloyd)
DPBP	Discounted Payback Period
DTU	Technical University of Denmark (Danmarks Tekniske Universitet)
DCNS	French industrial group (Direction des Constructions Navales)
DOE	US Department of Energy
EBIT	Earnings before taxes
EDPR	Renewable energy company (EDP Renováveis)
EIA	US Energy Information Administration
EU	European Union
EUR	Euro
EPA	US Environmental Protection Agency
EWEA	European Wind Energy Association
FEE	France Energie Eolienne
GBP	Great British Pound
GDP	Gross Domestic Product
GTC	Green tradable certificates
$GtCO_2e$	Gigatonne of CO_2 equivalent
GW/GWh	Gigawatt(s)/Gigawatt hour(s)
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
JPY	Japanese Yen
JWPA	Japanese Wind Power Association
LCOE	Levelised Cost of Electricity

MEDDE	French Ministry of Environment, Energy and the Sea (Ministère de l'Environnement, de l'Energie et de la Mer)
METI	Ministry of Economy, Trade and Industry
MITI	Ministry of International Trade and Industry
MW/MWh	Megawatt(s)/Megawatt hour(s)
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
OECD	Organisation for Economic Cooperation and Development
Ofgem	Office of Gas and Electricity Markets
Opex	Operational Expenditure
O&M	Operation and Maintenance expenditures
PPA	Power Purchase Agreement
PTC	Production Tax Credit
RECS	European Renewables Energy Certificate System
RO	Renewable Obligation (funding scheme in the UK)
ROC	Renewable Obligation Certificate
ROI	Return on Investment
ROS	Renewable Obligation Scotland
SCC	Social Cost of Carbon
SER	Syndicat des Energies Renouvelables
TLP	Tension leg platform (type of floating substructure)
TLWT	Tension leg wind turbine (type of floating substructure)
TRL	Technological Readiness Index
TW/TWh	Terawatt(s)/Terawatt hour(s)
UK	United Kingdom
US	United States of America

Table of Contents

List of Figures

List of Tables

CHAPTER 1: Introduction

The goal of this chapter is to provide an overview of the paper's subject matter. We start by introducing the reader to the topic and identifying the relevance of our paper, then continue by outlining our research question and the contribution our study can have to policy discussions on the topic, then outline the structure of our research and finally position our study within the literature.

1.1. Area of Research

In a quest for reducing greenhouse gas emissions to mitigate climate change as well as for increasing energy security and supply, a number of countries have, at least partially, moved towards renewable energies. One of the most recent developments in the field of renewables is the move towards floating offshore wind. This technology constitutes floating substructures, on top of which wind turbines are mounted. These structures can be deployed in water depths between 50m and 700m where conventional fixed-bottom turbines are no longer commercially viable (DNV GL, 2015; Zountouridou, et al., 2015). The advantage of deploying offshore wind turbines in deep waters is that out on the open water, wind speeds tend to be much higher and more constant than in coastal areas (Weinzettel, et al., 2009; Perveen, Kishor and Mohanty, 2014), allowing for a lot more energy to be generated than from fixed constructions Offshore floating wind thus offers great potential to play a significant role in many countries' and regions' renewable energy mixes (Green and Vasilakos, 2010).

But the floating offshore wind industry is still in its infancy with only five single floating prototypes installed worldwide. Two pre-commercial arrays comprised of several floating turbines are under way in Scotland, UK, with one already under construction and one in the advanced planning stage. More pre-commercial projects are expected to be deployed in the years leading up to 2020.

1.2. Relevance

High costs are currently the main obstacle for floating offshore wind development. The industry is under time pressure to reduce costs and prove that large-scale deployment is viable in the years leading up to 2050 and beyond. Indeed, Sun, et al. (2012) stress that unless significant cost reductions can be made in the next few years, floating offshore wind may lose its attractiveness to the market altogether. The next 5 to 10 years are therefore particularly crucial in demonstrating the economic viability and cost reduction potential of the technology (James and Costa Ros, 2015).

While the two pre-commercial arrays currently under development are a vital step in this process, the novelty of floating technology and the inherently high risk investors face, have kept investment in the industry very low so far. Governmental support is therefore necessary to make private investors' returns on floating projects more predictable. The support can aid the technology at its current stage by encouraging increased investor support. This in turn allows for floating technology to reach the commercial stage as well as realise the cost reductions necessary for it to develop into a widely applicable power generation option in the future. Governments need to provide sufficient and the right type of support to advance the development of floating structures and help the sector overcome technical and economic challenges. Only if sufficient and the right type of policy support is in place can commercial projects and new offshore designs become operational as soon as 2020. Otherwise the commercial phase of floating offshore wind may be more distant (James and Costa Ros, 2015).

There are various types of funding mechanisms in place in different countries, including renewable energy certificates, feed-in tariff schemes, capital grants and tax breaks, all of which offer different benefits by mitigating risks at different stages of a wind farm development process and thereby instilling investor confidence in different ways. The choice of policy support affects the long-term development of the floating offshore wind industry in a country (Blanco, 2009), and gaining a comprehensive understanding of funding schemes is thus vital in understanding potential future developments of the industry. An evaluation of policy instruments from investors' point of view has all too often been overlooked (Enzensberger, Wietschel and Rentz, 2002) and this thesis seeks to fill this gap by answering the paramount question facing the academic community and industry at this moment, which is what public policy incentive is best suited to attract private investor support to the floating offshore wind industry.

1.3. Research Question

In light of the previous arguments, this study aims to analyse the profitability of an investment in a pre-commercial model wind farm under various funding scenarios. We have therefore formulated our research question as follows:

What is the economic impact of different funding mechanisms on the investment in a pre-commercial floating offshore wind park?

Our study analyses which type of policy support is economically most attractive to investors. The outcome is meant to help policy makers choose the most effective funding scheme to facilitate the development of floating offshore wind by enticing investor support. By means of calculating a cash flow model and a series of economic indexes we will evaluate the profitability of a pre-commercial model floating offshore wind farm under four different funding regimes. This will provide a more figure-based aid to policy discussions. The authors of the paper believe that a more informed debate on funding mechanisms will help policy makers improve the effectiveness of their respective support schemes and thereby accelerate the development of floating technology in their respective markets.

1.4. Scope and Limitation

The possibilities for building on our topic are significant: A similar methodology could be utilised to analyse the effect of various combinations of these funding schemes on a pre-commercial array to see whether any combination is even better suited than a single support scheme. Once the industry evolves further, our methodology can be used to analyse the effects of different support schemes on commercial arrays and inform a debate on how floating wind can be steered to play a more significant role the electricity mixes of a given country.

It is important to understand that our study considers a pre-commercial floating wind park and that it therefore only presents a snapshot of the current situation. It will have to be replicated once the technology has reached commercial levels and always be adjusted to the prevailing funding schemes at any given time.

1.5. Structure

This paper is divided into seven chapters. **Chapter 1** provides an introduction to the topic and a context for our research question. It highlights the relevance of our thesis, and briefly positions our study relative to the existing literature. **Chapter 2** provides the background information needed to understand the issue at stake. We introduce the reader to the concept of climate change as well as the social and economic imperatives for reducing greenhouse gas emissions, and by extension the need for supporting renewable energies. We then continue by arguing for the development of wind energy, and floating technology in particular, assess the market potential for floating wind and analyse current industry challenges. Particular attention is paid to cost reduction challenges and the manner in which funding mechanisms can help overcome these challenges as this is the basis on which our research question has been formulated. **Chapter 3** outlines the techniques we have chosen to collect as well as analyse the data used in our study, and provides a critique of our data sources. In **Chapter 4** the setup of our pre-commercial model floating offshore wind farm cash flow model is explained, which forms the basis of our analysis. We then analyse the existing funding mechanisms in Scotland, France, Japan and Hawaii, and subsequently analyse the economic impact of each of the different funding regimes on our model wind farm in turn. Sensitivity analyses are carried out for each model. **Chapter 5** discusses our findings. We evaluate the profitability of our model under the different funding mechanisms, focusing on the economic impact of funding regimes on the pre-commercial array, and the risks involved. We draw a conclusion as to which funding mechanism results in the most profitable project, and develop a number of recommendations for policy makers. In **Chapter 6** we summarise our findings. **Chapter 7** concludes by outlining the limitations of our study, and presents recommendations for further research.

1.6. Literature Review

Floating offshore wind is subject to a significant amount of research in both the academic and the corporate world. The purpose of this section is to place our paper relative to existing literature and provide the reader with an understanding of how our study contributes to the academic field of floating offshore wind research.

None of the economic literature we found considers the economic effect of funding regimes on a floating offshore wind project from an investors' point of view. Academic literature related to energy policies tends to focus on the policy decision making process as a whole (San Cristóbal, 2011; Haralambopoulos and Polatidis, 2003), considers the impact of support schemes on a variety of renewable energy sources, with floating wind not being part of the consideration (Winkler, et al., 2016; Kozlova and Collan, 2016) or on renewable energy sources in general (Verbruggen and Lauber, 2012) rather than focusing on floating offshore wind, or simply examines the nature of funding (Bhattacharyya, 2013). When different funding schemes are contrasted, it is mostly done in a rather general fashion (e.g. Madlener, Gao and Neustadt, 2009; Verbruggen and Lauber, 2012) without paying attention to floating wind in particular. Even economic analyses of different funding schemes (Canton and Johannesson Lindén, 2010; Johnstone, Hascic and Popp, 2010) consider a variety of renewable energies and do not consider floating offshore wind. When literature is concerned with floating wind, it is often technical in nature rather than economic. Some examples include the analysis of the dynamics of a floating wind turbine (Antonutti, et al., 2014) or blade pitch control for turbines on floating platforms (Namik and Stol, 2011). Although cost structures have been compared before (e.g. see Levitt, et al., 2011), these studies only concern offshore wind and there is no evidence that floating offshore wind and the impact of funding schemes has been discussed in the amount of detail this paper sets out to do.

To our knowledge, none of the economic literature focuses on the economic aspects of funding mechanisms for floating offshore wind. An analysis of funding schemes for floating offshore wind in particular and how they could encourage capital investment is yet to be conducted.

Our paper suggests a new line of research, which is arguably of great interest to both the academic community and policy decision makers. The novelty of our research lies in examining floating wind from an economic point of view by capturing the effect of different funding mechanisms on a project's cash flows and a series of economic indexes that allow for evaluating the investment. This allows for comparing funding mechanisms in a way it has not been done before. We thereby hope to fill a gap in the literature and contribute to the inter-disciplinary approach that the floating wind industry currently needs by conducting an economic analysis on what type of funding is best suited to aid the development of the technology at its current stage.

Our paper will not only be useful for policy makers at the state government level, but also for those at regional government levels like the EU and similar administrative bodies that can incentivise floating wind development.

It is important to mention that while we made an effort to find as many relevant up-to-date academic papers as we could, many of the sources cited in this thesis are not academic sources but industry reports and analyses, and reports conducted by government-affiliated organisations as well as other interest groups. We have given priority to identifying and avoiding any potential bias in the sources throughout our research. Thus, figures derived from some of the reports are generally double-checked against publicly available data. We chose to use a variety of sources from academia and industry in order to provide a reliable, comprehensive analysis and present an up-to-date view on a quickly evolving technology. In order to complement our findings from academia and industry reports, we also conducted five in-depth interviews with experts from the offshore wind industry.

CHAPTER 2: Background and Theory

In this chapter we provide the reader with an introduction to the topic of climate change because the reduction of greenhouse gas emissions forms the basis of the rationale for supporting the development of floating offshore wind technology. We continue by outlining the reasons for supporting wind power over other types of renewables and provide a motivation for supporting floating offshore wind in particular. The market potential for floating offshore wind will subsequently be outlined, followed by a brief analysis of the main challenges facing the industry at this moment in time. Finally, bearing the previous sections of this chapter in mind, our thesis will be placed in the context of a previous study on funding mechanisms, outlining how this thesis will expand previous research.

2.1. Climate Change and the Case for Funding Renewables

The first step in understanding the rationale behind funding renewables energies – or respectively, taxing fossil fuelled energy generation – is understanding climate change. Its effects on economy and society ultimately provide the reason for supporting the development of clean energy sources over conventional forms of energy.

Greenhouse Gases and the Greenhouse Effect

Throughout the history of our planet, the Earth's climate has always been changing. This merits the question in what way the climate change that we currently experience is different and what impact this difference has on social and economic welfare on Earth. To this end, it is beneficial to first define climate change. The United Nations Framework Convention on Climate Change defines the phenomenon as a "change of climate, which is attributed directly or indirectly to human activity and alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods." (United Nations, 1992). The climate change we see today is largely attributed to the burning of fossil fuels such as coal, oil and gas, as well as the destruction of forests (European Commission, 2015a). 'Climate change' is generally used to refer to both the natural and the human-caused phenomenon that we have seen for over the last century. We will adopt the definition provided by the United Nations (1992) and use 'climate change' throughout the remainder of this thesis to refer to the climate change caused by human activity to avoid any misunderstandings. The climate change observed today is different from previous natural climate changes because the sharp temperature increase in the climate system began with the industrial revolution and present-day greenhouse gas emissions are the highest in history, unprecedented in the millennia before (IPCC, 2014a). This strongly suggests a correlation between human industrial activity and climate change.

Climate change is caused by the emission of a variety of greenhouse gases (GHGs), in particular carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone layer-depleting gases. Present in the lower atmosphere, these gases absorb the energy of the sun that is reflected off the surface of the Earth and re-emit the energy back to Earth. These gases affect climate millennia after their emissions (Montzka, Dlugokencky and Butler, 2011), and are therefore also referred to as 'stock pollutants' because they stay in the atmosphere for a long period of time, which causes their effect to accumulate as more of them accumulate in the atmosphere. In contrast to stock pollutants, so-called 'flow pollutants' only cause harm at the time of emission, being assimilated quickly by the environment (Grafton, et al., 2004). The different greenhouse gases absorbing the sunlight that used to be reflected back into space and releasing it back into the air on Earth is referred to as the greenhouse effect.

The greenhouse effect results in global warming, which in the long run leads to climate change. Climate change in turn has many different effects like increased droughts, floods, more extreme weather events, rising sea levels, the melting of glaciers and polar ice. Between 1880 and 2012 the average global surface temperature increased by 0.85°C (European Commission, 2015a). It is largely agreed that a global average temperature increase of 2°C compared to pre-industrial levels, would substantially increase the risk of large-scale, irreversible changes in the global environment (European Commission, 2015a).

However, based on current economic activity, global greenhouse gas emissions, excluding emissions from land use, land-use change and forestry, are projected to lead to an increase in average Earth temperature of over 2.5°C by 2060, and an increase of "well above 4°C" (Dellink, et al., 2014, p.8) by 2100.

Further damages to the environment and the Earth's natural capital can have severe impacts on human well-being and economic growth as well as limit the future prospects of either one (Dellink, et al., 2014). The following sections will discuss each of those aspects in turn, both of which, provide the rationale for supporting renewable energies over fossil-fuels.

The Social Cost of Carbon

The social cost of carbon (SCC) is generally defined as the cost of damage that is incurred by emitting one unit of CO_2 into the atmosphere. Understanding these costs is pivotal for the design of optimal climate policies because determining the correct price of carbon based on the SCC offers the suitable economic incentive for implementing energy policies, such as reducing current emission levels (Van den Bijgaart, Gerlagh and Liski, 2016) or establishing renewable energy standards (IPCC, 2014b). Calculating the SCC also offers an appreciation of the value of damages that can be avoided if carbon emissions are reduced (EPA, 2016). The SCC measure is aimed to be a comprehensive estimate of climate change-caused damages to net agricultural productivity, human health, property damages from increased flood risk, and changes in energy system costs such as reduced costs for heating and air conditioning.

There are a variety of models to assess SCC that vary in complexity and application (Van den Bijgaart, Gerlagh and Liski, 2016; IPCC, 2014a).

A number of studies have attempted to calculate a comprehensive social price of carbon, yielding different results. Van den Bijgaart, Gerlagh and Liski (2016), estimated SCC costs to have a median of 20EUR/tCO_2, a mean of 48EUR/tCO_2 and a 10% probability of the SCC exceeding 100EUR/tCO_2. They consider the mean of 48EUR/tCO_2 (about 53.81 USD) the relevant measure for policymaking. Other estimates were 42.68 USD/tCO_2 for a case with no controls and 40.11 USD/tCO_2 for a case with optimal controls in 2015, calculated in 2011 (Nordhaus, 2011), or in general around 40 USD per ton of carbon emitted in 2015 prices (Nordhaus, 2010). We can see that more recent estimates price the SCC higher than older sources. These figures provide a useful reference point for how much value is attached to the damages caused by emitting one tonne of CO_2 today. Crucially, they help understand that the SCC increases over time. This is also illustrated by the SCC estimates conducted by the EPA (2015) in Figure 0-1 in Appendix A and means that it is very crucial to combat climate change now in order to avoid even higher social and economic damages in the future.

Although different SCC assessment models vary with respect to their economic input parameters and degrees of uncertainty, the conclusion that we can draw from the leading economic models is that climate change, specifically a temperature increase of more than 2°C compared to pre-industrial levels, may have severe social and economic consequences. This is reason enough to justify immediate action to reduce emissions. In fact, because most models do not account for indirect risks inherent in climate change such as social unrest or disruptions in economic growth, it is likely that they might underestimate future climate change damages (Revesz, et al., 2014).

Uncertainties When Estimating SCC

In their critique of SSC assessment models, Revesz et al (2014) focus on three models that were used in a 2013 study by the US Government to estimate the SCC. Although their critique was composed with these specific models in mind, their assessment is nevertheless well suited to draw our attention to four major drawbacks of current models that result in the underestimation of present-day costs of damages caused by climate change: Firstly, economies and societies may be a lot more vulnerable to short-term weather variability in terms of crop growth and food security than models currently suggests. This would mean a higher costs associated with food shortages. Secondly, most models do not account for negative impacts on labour productivity, productivity growth, or the value of capital stock. These damages, however, could lower the economic growth rate and impact the global economy more strongly and for a longer period of time than the annual economic output currently suggested by the model. Thirdly, one core assumptions of the models is that the value people place on the Earth's ecosystems will stay constant over time. Yet, because it can be assumed that the services ecosystems provide will diminish as the planet gets warmer, the costs associated with future damage to ecosystems will be greater than they are today. Finally, in the analyses carried out by the US government the discount rate is kept constant to convert future damages into today's currency. But given the high uncertainty of future events as well as the fact that they happen very far in the future, a discount rate declining over time seems more suitable. This would lead to a higher present value of future climate change impacts and a higher social cost of carbon that the models currently represent (Revesz, et al., 2014). In their latest study on the matter, the US government corrected for this flaw and factored in a number of discount rates (EPA, 2015).

It becomes clear from these considerations that the above social cost of carbon estimates may be too low. This highlights again the importance for reducing carbon emissions through supporting renewable energies.

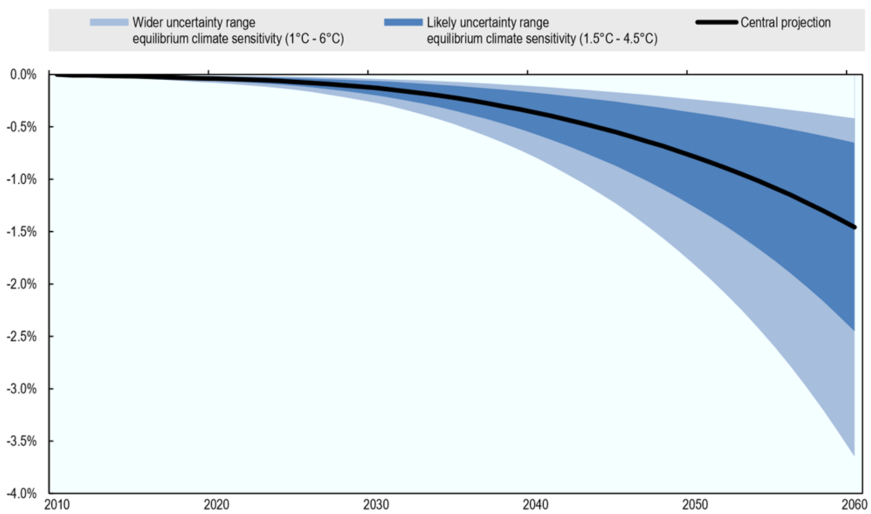
The Economic Cost of Carbon

To investigate the impact of climate change on economic growth, it might seem reasonable to turn to, for example, a standard neoclassical model of economic growth that captures growth as a function of saving, investment and capital accumulation. Unfortunately, such a model is not suited to capture the impact of climate change on economic growth rates because treating parameters that are effected by climate change as exogenous factors, makes it difficult to capture the impact of population growth, migration patterns, productivity levels and capital depreciation (Bowen, Cochrane and Frankhauser, 2012). Additionally, climate change also affects economic growth *rates*, not only output *levels*, only the latter of which is being captured by the standard neoclassical model. Climate change may alter the direction of economic growth: Severe weather events, for instance, can destroy productive assets or shift investment priorities from production to adaptation. Though a number of studies, many of which exhibit a neoclassical structure, have been carried out to assess the effect of climate change on growth, they have mostly evaluated level effects rather than growth effects (Bowen, et al., 2012). Exceptions constitute, for example, the studies by Frankhauser and Tol (2005) and Dell, Jones and Olken (2008) who appreciate that temperature increases may affect both the absolute output and an economy's ability to grow. With global warming impacting future welfare not only through level effects, anticipated future damages impact capital accumulation and people's propensity to save, which in turn affects the rate of economic growth. Climate change, impacts output more strongly than the direct 'levels' effect by causing reduced growth (Frankhauser & Tol, 2005), though both effects are small, meriting further research (Bowen, et al., 2012). Importantly though, even small effects on an economy's growth rate can have vast consequences over time. If the current temperature increase continues in the medium term, it can have severe results on economic growth nevertheless (Dell, et al., 2008). While a 1°C increase in mean temperature leads to a decrease in the per-capita income growth rate of 1 percentage point in the short run, it can lead to a 2.3 or even 3.2 percentage point decrease in the long run (Dell, et al., 2008; Dell, Jones and Olken, 2009).

Most studies tend to report these effects on growth, that is to say the economic cost of carbon, in terms of effect on GDP (Dellink, et al., 2014; Revesz, et al., 2014). Thus, they constitute a somewhat imperfect measure because they do not account for the impact on the well-being of society at large (Dellink, et al., 2014). We believe, however, that these economic models complement social cost of climate change considerations like the one above well and complete the picture of why advancing the development of renewable energies is necessary. Indeed, albeit providing by definition only part of the picture, economic models, precisely by expressing the impact of climate change in terms of GDP losses, are valuable in conveying the importance of climate change for economic policy makers (Dellink, et al., 2014). The findings of the study of Dellink, et al. (2014) reveal that the effect of climate change on economic output largely depends on one's assumptions about the relationship between carbon levels and global average temperature increases. While this may be a somewhat limited view because global warming is only part of the picture, some general conclusions can nevertheless be drawn: Using a variety of climate change impacts, their central projection sees a GDP decline of 1.5% by 2060 (Dellink, et al., 2014).

Figure 2-1: Change of global GDP under different uncertainty scenarios

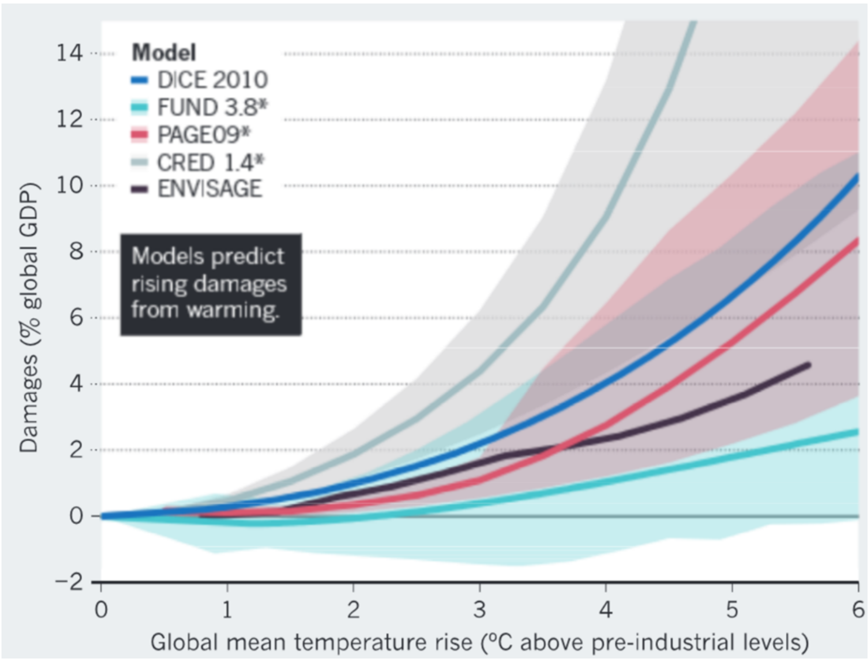
Source: Dellink, et al., 2014



This projection, however, is subject to a number of uncertainties associated with the economic and climate systems, the assessment of climate impacts and the way in which climate impacts feed back into the economy. The central projection is therefore expanded to include a likely range of annual GDP losses between 0.7% and 2.5% as well as a possibility range that could see global GDP losses of as low as 0.4% or as high as 3.6% (Dellink, et al., 2014). See Figure 2-1: Change of global GDP under different uncertainty for the change in global GDP from selected climate change impacts (Dellink, et al., 2014). Revesz et al (2014) present the following Figure 2-2 to illustrate the economic damages to global GDP, caused by climate change.

Figure 2-2: Projected Damages

Source: Revesz, et al., 2014



A study by the OECD (2015) projected a global annual GDP loss with a central projection of 2% by 2060 and a likely range between 1% and 3.3%. These relative wide ranges of likely GDP losses arise because the calculations bear an uncertainty associated with the equilibrium climate sensitivity (ECS), a measure reflecting the sensitivity of the Earth's climate to a doubling of CO_2 in the atmosphere. This calculation assumes a climate impact in the range of 1.5°C to 4.5°C. Assuming a wider range of 1°C and 6°C, GDP losses could amount to between 0.6% and 4.4% by 2060 (OECD 2015).

If the Earth's temperature rises above 4°C by 2100 compared to pre-industrial levels, GDP losses may accumulate to between 2% and 10% (OECD, 2015). If the average global temperature increases between 4°C and 5°C, it would mean dangerous changes to the world climate we know. Stern (2008) explains that at a time when temperatures were comparably high, though 5°C lower than today, ice melted and sea levels rose, causing England to separate from the European continent around 10,000 years ago. Similarly, further temperature changes can have consequences that even cause a transformation of the landscape we know today: A 5°C increase in mean global temperature, most of the world's ice would melt, including most probably the snow and glaciers of the Himalayas, resulting in a 10m sea level rise (Stern, 2008).

Although quantifying climate change in terms of average temperature increases makes it easiest for the general public to understand the concept, a focus on temperature distracts from a variety of other crucial elements that have critical social and economic consequences such as storms, floods, droughts and sea level rises (Stern, 2008). All of these events also result in GDP losses over the short and long-term (OECD, 2015).

Given these estimates of social and economic cost of carbon emissions, we can now see how reducing greenhouse gas emissions, limiting the use of fossil fuelled energy and instead supporting the development of renewable sources becomes both a social and economic imperative. There is a clear role for public policy to steer economic growth in the right direction in a world facing climate change (Bowen, Cochrane and Frankhauser, 2012).

Positive Impacts

There are a few positive aspects associated with global warming that are worth mentioning. A 1°C increase in average global surface temperature, would have an overall positive impact in OECD countries, including China and the Middle East, though negative effects on many other countries. Such a temperature rise would see their GDP increase by 2%, while a global average approach would mean a 3% GDP decrease (Tol, 2002a)., it is important to understand, that the impact of climate change, albeit being negative on average, may be both positive and negative, varying according to the time, region and sector that is under consideration (Tol, 2002b).

The Case for Renewables

Generating electricity from renewable energies constitutes one option for combating climate change in the energy sector. With their significantly smaller carbon footprint, renewables have the potential to mitigate climate change at least to some extent. Renewables can furthermore be utilised to meet both an increasing demand for electricity around the globe and hedge against fossil fuel price volatility.

The EIA (2015a) expects world energy consumption to increase by 56% until 2040 over 2010 levels. An increase in demand for electricity of this scope would result in an increased demand for coal, gas or nuclear power. But given the above detailed arguments against extensive further use of fossil fuels as well as the fact that fossil fuels reserves are depleting, the increased demand for electricity has to be generated from low-carbon technologies (Jacobsson and Karltorp, 2012). In addition, increasing the use of domestic renewable energy decreases dependency on fuel imports and inherently volatile prices (Krohn, Morthorst and Awerbuch, 2009). In 1983, J.K. Hamilton empirically formulated the vulnerability of an economic system to the oil price. Dramatic increases in oil and gas prices, such as those during the supply crisis of 1970s, affect the world economy dramatically. The so-called oil-GDP effect causes inflation and stifles economic growth. Krohn et al (2009) argue that there can be no doubt about the considerable effect of volatile fossil fuel prices on the world economy.

Enhancing energy diversity and bearing potential for hedging against the price volatility of fossil fuels (IEA, 2013; Krohn, Morthorst and Awerbuch, 2009), the development of renewable energies will help protect consumers from commodity price spikes and enhance national security (Saidur, et al., 2010).

Market Failures and the Rationale for Support Schemes

The emission of greenhouse gases is the single most important factor in causing climate change, prominently caused by a high consumption of fossil fuels in the energy and transportation sector. Unfortunately, the social and economic externalities detailed above are not internalised in the present prices of energy consumption (Stern, 2008). Producing electricity from renewable sources offers a number of benefits to mitigate climate change but, unfortunately, many alternative forms of energy are not yet cost-competitive with conventional emission-intensive sources. The high price discrepancy occurs, mainly because the above mentioned externalities are not fully internalised. This is the case even despite relatively recent efforts to internalise the costs of carbon emissions through measures such as the European Emissions Trading Scheme (Canton and Johannesson Lindén, 2010).

Having established a rationale for reducing pollution, our discussion begs the question by how much pollution should be reduced. Though in contrast to flow pollutants, for which one could find an economically efficient pollution, where the marginal cost of abatement equals the marginal benefits of polluting, the efficient level of a stock pollutant is not fixed, but instead a function whose values change over time (Grafton, et al., 2004). In order to combat climate change, emissions must be minimised to an efficient level by either regulating, prohibiting, or taxing the use of traditional sources of energy, or supporting the use of clean, renewables energies through support schemes. For examples of optimal taxation please see Diamond & Mirrless (1971a; 1971b), and for the taxation of fuels by means of a Pigouvian tax (King, 1986). Canton & Johannesson Lindén (2010) found that policies seeking to internalise environmental externalities are unlikely to make renewable power technologies competitive. As it is our declared aim to aid the development of renewable energies, we therefore argue for direct support schemes for renewable energies. Lehmann and Gawel (2013) support this view, concluding their study of renewable support schemes in relation to the EU emissions trading scheme by pointing out that only in a perfect world with a benevolent social planner providing perfect institutions would a carbon trading scheme suffice to internalise the externalities of pollution. In a non-perfect world as the one we live in, additional measures like support schemes for renewables are necessary.

The most prominent support schemes are feed-in tariffs, feed-in premiums and green certificates or green obligations. Other support instruments are tender, grants and other fiscal support mechanisms, though these tend to complement the three main funding schemes (Canton and Johannesson Lindén, 2010). Chapter 4 analyses the support schemes of the four jurisdictions under consideration.

2.2. The Case for Wind Power

This section introduces the reader in more detail to the concept of floating offshore wind technology and argues the case for why floating wind power should be supported above other renewable forms of energy. Biogas, onshore wind and small-scale hydro power can potentially compete with conventional energy sources such as nuclear, gas and coal if site conditions are favourable. Photovoltaic plants and offshore wind farms provide the largest potential for cost reduction (Canton and Johannesson Lindén, 2010). Wind power in particular plays an important role in meeting the great challenges posed by conventional fossil fuels (Jacobsson and Karltorp, 2012) because it is currently the most advanced of the renewable energy technologies (Dai, et al., 2015), whose development was mainly driven by concerns about energy security of supply and climate change concerns (Timilsina, van Kooten and Narbel, 2013; IEA 2013). The technology has achieved maturity in most energy markets and is the renewable source that has enjoyed the greatest growth over the past years (Saidur, et al., 2010). This development is due to levels of investment that have outperformed all other types of renewables, including solar power. Wind power offers a number of benefits over other forms of renewable energy, for example, being relatively inexpensive in comparison.

The capital cost of wind power has been declining steadily, primarily through competition and technological advances, now rendering onshore wind power cost-competitive with other forms of energy. Wind power has achieved cost parity with new coal- or gas-fired plants, in several EU member states and Australia, Brazil, Chile, Mexico, New Zealand, Turkey, South Africa, and the United States (REN21, 2015). To compare the costs of various forms of renewable energy, the industry uses the index of so-called levelised cost of electricity (LCOE). This index includes all potential expenses in building, running and dismantling a power plant over its life cycle. According to Abraham (2015), the average global LCOE for coal and gas is \$84 and \$98 per MWh respectively, while it is only \$83 for wind power. The US agency EIA (2015), suggests that the LCOE of wind power will be as low as 73.60 USD/MWh by 2020, which is lower than conventional coal (95.10 USD/MWh), advanced coal (115.70 USD/MWh), natural gas (between 75.20 and 113.5 USD/MWh), biomass (100.50 USD/MWh), solar PV (125.30 USD/MWh), solar thermal (239.7 USD/MWh) and hydro power (83.5 USD/MWh).

This may be the main reason why the installed capacity of wind power more than doubled worldwide between 2008 and 2013 (IEA, 2013). In 2014, 80 countries were using wind power on a commercial basis and wind generated more than 4% of worldwide electricity needs (World Wind Energy Association, 2015). In the EU, wind power installations have increased steadily since 2000 (EWEA, 2016a). In 2015 alone, the EU-28 member states installed a total of 13GW of wind power, constituting 44% of all new power installed. Here, public policy was a key driver in this development (EWEA, 2016c).

The Case for Offshore Wind Power

Although the majority of wind farm development so far has taken place onshore, the offshore wind sector has been growing significantly over the last few years. In addition to the wind power benefits mentioned above, the offshore environment offers four significant advantages.

Firstly, the wind resource in coastal regions and further offshore tends to be much stronger and more constant on average than on land (Schillings, et al., 2012; Bilgili, Yasar and Simsek, 2011). This is due to the absence of uneven terrain and other obstacles, both natural and man-made (Adelaja, et al., 2012). These higher wind speeds allow for more electricity to be produced by offshore wind farms. The capacity factor indicates the share of a wind farm's actual output relative to its potential output, the latter of which is given by the installed capacity (Snyder and Kaiser, 2009a; Green and Vasilakos, 2010). An onshore wind farm achieves capacity factors between 22% and 28.5% (Bilgili et al., 2011; Krohn, Morthorst and Awerbuch, 2009), while a fixed offshore turbine is on average achieves a capacity factor of 36% (Boyle, 2006). The absence of obstacles also means that offshore wind farms are less frequently affected by short-term wind speed variations (Dicorato, et al., 2011). This allows for wind energy production to be both smoother and more reliable, and makes the problem of intermittency more predictable, requiring less backup capacity and power deregulation.

Secondly, there are vast areas available offshore that are suitable for large-scale offshore wind projects (Bilgili et al., 2011). Space for wind deployment on land is limited by the lack of affordable land in close proximity of populated areas. This is not the case in open waters where higher-capacity power generation farms can be built (Bilgili et al., 2011; Castro-Santos and Diaz-Casas, 2015).

Thirdly, offshore wind farms have a higher potential to gain public approval than onshore wind farms. Installing an offshore wind farm at a sufficient distance from shore can nearly eliminate the issues of visual impact and noise (Norwea, 2014;

(Breton and Moe, 2009), which are often the reason for public opposition to wind farms (Bilgili et al., 2011).

Finally, offshore wind turbines can be bigger than those of land-based wind farms and thus command higher installed capacities. Because it is easier to transport and install very large turbines at sea than on land, there is “virtually no limit on the size of turbines” that may be installed offshore (Bilgili et al., 2011). This is a clear advantage over onshore constructions, which are often limited in size by road restrictions. Today, offshore turbines are usually in the range between 2MW and 5MW in capacity. But while in Europe the average offshore turbine in Europe currently has an installed capacity of 4.2MW (EWEA 2016a), prototypes of up to 8MW are already being tested (Kaldellis and Kapsali, 2013) and future turbines are likely to exceed 10MW. The limiting factor is only blade length, which is affected by gravity and material strength (Snyder and Kaiser, 2009b).

Although the costs of offshore wind development will be discussed detail below, the background analysis so far merits a brief mentioning of offshore wind farm costs at this point in the paper: An offshore wind park is generally more expensive than building a park with similar installed capacity onshore. These higher costs can be attributed to costly marine foundations, and a more pricy integration of an offshore wind farm in the electrical grid, which may require an upgrade on part of the weak coastal grid (Bilgili et al., 2011). Supply chain bottlenecks also contribute to higher costs: The limited number of installation vessels, the relatively time-consuming construction process at sea and limited access to the site due to weather conditions result in higher total costs (Green and Vasilakos, 2010; Bilgili et al., 2011). This cost increase can only partially be offset by the increased amount of electricity produced by an offshore farm. In 2013, the LCOE for electricity from an offshore wind farm was estimated to be about 140 €/MWh, while it was merely 81 €/MWh for onshore wind power (Siemens, 2014).

Nevertheless, significant cost compression and efficiency gains have been achieved so far, and given the positive cost developments onshore wind has achieved, one can assume that offshore wind will follow a similar trajectory. Krohn et al (2009) predict that the growing interest in offshore generation, in combination with scarcity of suitable onshore sites, will cause an acceleration of offshore wind power deployment. Some predict, that by 2020, about half of new investments into the wind energy market, worth €17 billion per year, will be placed in offshore wind (Krohn, Morthorst and Awerbuch, 2009). More offshore deployment will lead to further cost reductions. In 2013, IEA (2013) predicted the cost for onshore and offshore wind to decrease by 25% and 45% respectively by 2050. The main drivers for this trend are strong R&D efforts, improved design, materials, manufacturing technology and reliability. All of these will optimise wind power performance and the reduction of uncertainties. Offshore wind power may indeed have the potential to become less expensive than electricity from either onshore wind or fossil fuels.

Offshore wind has already become an integral part of long-term energy strategies in various countries and will play a significant role in meeting the world's energy demand (Bayati, Belloli, Ferrari, Fossati and Giberti, 2014). The UK for instance, is currently planning that offshore wind will account for one third of its generating capacity in the 2020s. So far, the industry is on track to achieve their cost reduction goals. Between 2012 and 2015 the cost of energy from offshore wind farms decreased by almost 11%, putting it ahead of schedule on the UK government's target cost reduction path that plans to reach £100/MWh by 2020 (ORE Catapult, 2015a). This confirms that offshore wind may play an even more prominent role in the future than it is foreseen today.

The Case for Floating Wind Power

Floating offshore wind is a relatively new technology: In 2009 and 2011, the first two demonstrator turbines were deployed in Norway and Portugal respectively. Today, a total of five single full-scale floating prototype turbines are operational. Despite the technology's current infancy, floating offshore wind is believed to constitute a vital part of the future offshore wind industry (Snieckus, 2015a). In addition to offering all benefits of wind power mentioned above, floating structures offer a number of important advantages of traditional offshore fixed-bottom structures. Firstly, floating structures can be installed in water depths that exceed 50 meters (Zountouridou et al., 2015), which is beneficial given that 95% of the world's ocean coastlines are too deep for bottom-fixed turbines (DNV GL, 2015). Because they are not restricted to shallow waters, floating wind farms enable a much larger choice of sites and gives access to an abundant wind resource with even higher and more constant wind speeds (Weinzettel et al., 2009); Perveen et al., 2014; Castro-Santos & Diaz-Casas, 2015). Better wind conditions result in an increased capacity factor, which in turn results in a significantly higher power output (Zountouridou et al., 2015). Because the amount of available energy in a given wind resource increases according to a cubic function, a doubling of wind speed increases the power output of a given wind turbine by the factor of eight (IRENA, 2012; Narbel, Hansen and Lien, 2014). This makes for a strong incentive to build wind farms in deep waters. Additionally, the steadier the wind profile the less fatigue is caused to the wind turbine itself, reducing downtime, and by extension operation and maintenance costs (IRENA, 2012).

Secondly, floating offshore wind turbines offer technical advantages over fixed constructions. Because their foundations are not placed on the seabed, floating constructions can reduce, possibly eliminate, the need for subsea piling operations (Reidy, 2008), which are both costly and arguably detrimental for Marine Mammals (ATKINS, 2014). The risks and costs associated with installing fixed offshore wind turbines at sea is also decreased because floating constructions can largely be assembled on land. The substructure is constructed and the turbine mounted onto it in a dock before the fully assembled wind mill is towed out to sea and fixed at site with mooring lines. This eliminates the need for specialist construction vessels required during the installation of fixed turbines (ATKINS, 2014; James and Costa Ros 2015; Reidy, 2008). Despite their design complexity, floating structures therein offer more flexibility in construction, installation, and decommissioning than fixed-offshore turbines.

At the moment, floating wind turbines are even more expensive to install than fixed-bottom structures. However, the only data available to assess the costs of floating offshore wind mills comes from a handful of prototypes. These do arguably not offer a sufficient reference point for the costs of floating offshore wind once it has been developed on a large scale. Substantial cost reductions are expected as the technology progresses to the commercial stage. In fact, the LCOE of a commercial scale floating wind power farm is expected to drop below that of fixed offshore wind farm and even that of gas plant: A study showed that a 500MW floating wind farm in water depths of 50m would achieve an LCOE of about £102/MWh, which is lower than the current average LCOE of fixed constructions in shallower waters (Arapogianni and Genachte, 2013), which is about £105/MWh (Ebenhoch, et al., 2015). The LCOE for floating offshore wind could even drop below £85 per MWh from the mid-2020s onwards (The Carbon Trust 2015; Energy Technologies Institute 2015; James and Costa Ros 2015).

Following five floating prototypes installed all over the world, two pre-commercial arrays are currently in the planning phase, aiming to demonstrate the commercial viability and cost reduction potential of the technology. The development of these and other projects at a greater scale is expected to result in learning and scale effects, reducing the cost of technology on the long term.

It becomes clear from the economic discussion in 2.1 and the rationale for floating offshore wind power in 2.2 that among all forms of renewable energy, floating offshore wind is one of the best technologies suited to combat climate change and mitigate its social and economic costs.

2.3. Floating Offshore Wind

This section introduces the reader to floating offshore wind and provides a rationale for why floating offshore wind merits special attention in terms of funding.

2.3.1. Market Potential

This subchapter complements the social and economic rationale for floating offshore wind presented above by outlining the vast potential for large-scale floating wind deployment. After a brief overview of the market potential around the world, this subsection evaluates the prospective of floating wind in four countries. These markets have been selected for in-depth research because they offer very favourable conditions for floating offshore wind development, have already installed a floating demonstrator or are in the process of developing either prototypes or pre-commercial demonstration projects. Assessing a jurisdiction's wind potential is also a vital first step in designing policies and strategies for offshore wind (Adelaja, et al., 2012) and this section therein serves as an important step in understanding the various funding mechanisms later on in the thesis. Importantly, the assessment of the markets with the most prominent wind potential will later inform our choice of jurisdiction-specific funding mechanisms that are applied to our model floating offshore wind farm.

The global market potential for wind power is significant. Literature indicates that the wind energy potential in deep waters around the world could provide the world with more electricity than there is currently demand for (Timilsina et al., 2013). The global potential of floating wind energy amounts to 7 TW (Snieckus, 2015a). With 3.4 GW of these expected to be grid-connected by 2030, Snieckus (2015a) speaks of the floating industry currently being on the verge of making a "great leap forward into industrial reality". It may therefore be argued that the floating wind industry could indeed become a "truly global market" (ORE Catapult, 2015b, p.5).

Concept development, research activities and pilot project funding is no longer limited to Europe. Currently, the US Department of Energy and the Japanese Ministry of Trade and Industry (MITI) are the most prominent non-European examples of governmental bodies that support the development of floating technology (DNV, 2012).

Potential in Europe

In Europe, the United Kingdom, France, Norway and Portugal offer great conditions for the application of floating offshore wind constructions. The offshore wind resource in the North Sea alone could produce energy that would meet the EU's present-day electricity consumption more than four times over (Arapogianni and Genachte, 2013). Further suitable areas can be found in the Atlantic and Mediterranean Sea (EWEA, 2013). Europe's currently installed offshore wind capacity of 11.03GW, including fixed offshore wind, meets about 1.5% of Europe's total electricity demand.

Europe is at the forefront of floating offshore wind. The world's first and second demonstrator were installed here and the first pre-commercial array is currently under construction. Indeed, floating offshore wind power has an immense potential to transform the energy mix in a variety of European countries. This may be the reason why the development of this technology is likely to play a role in the *Roadmap to a low-carbon economy in 2050* (Jacobsson and Karltorp, 2012).

Since 2012, the European offshore wind industry has grown substantially. While the accumulated offshore capacity amounted to 5 GW in 2012, the grid-connected wind turbines in Europe in April 2016 reached 11.03 GW (EWEA, 2016a). This translates to about 3,230 offshore turbines installed in 11 countries. New projects totalling 26 GW are already in the final planning stages. By 2020, the installed capacity may grow up to fourfold, compared to 2008 levels, up to 40 GW (Jacobsson and Karltorp, 2012), providing electricity to almost 39 million households. By 2030, the installed capacity could even reach 150 GW, at which point it would meet 14% of the European Union's total electricity consumption (European Wind Energy Association, 2013). Offshore wind could deliver 50% of the EU's electricity demand by 2050, with 40 GW installed in water depths that exceed 50 meters (EWEA, 2007). Floating offshore wind specifically has an immense potential to provide the continent with renewable energy (Arapogianni and Genachte, 2013).

Potential in the United Kingdom and Scotland

The United Kingdom has been the world leader in terms of installed fixed offshore wind capacity since 2008, their 5,098MW installed capacity, which generate about 15TWh per year, accounting for almost half of European offshore capacity (RenewableUK, 2016). While in 2010 renewable energies accounted for only 10% of UK gross electricity consumption, by 2020 the state aims to increase this share to 20%. Offshore wind is going to play a significant role in meeting these targets and may deliver up to 25% of the UK's renewable energy. This means that about 29GW of offshore wind capacity need to be built by 2020 (Delay and Jennings, 2008). By 2050, offshore wind deployment may reach 55GW (James and Costa Ros 2015).

Scotland, a country in the north of the UK, has particularly ambitious plans to become a "world leader in offshore renewable energy" (ATKINS, 2014). They plan to meet an equivalent of 100% of their demand for electricity with renewable sources by 2020, which would account for 30% of their overall energy consumption. If offshore wind deployment reaches 40GW UK-wide, the Energy Technologies Institute (ETI) expects up to 16GW of that to be delivered by floating offshore wind, the majority of which would be based in Scottish waters (RenewableUK, 2016).

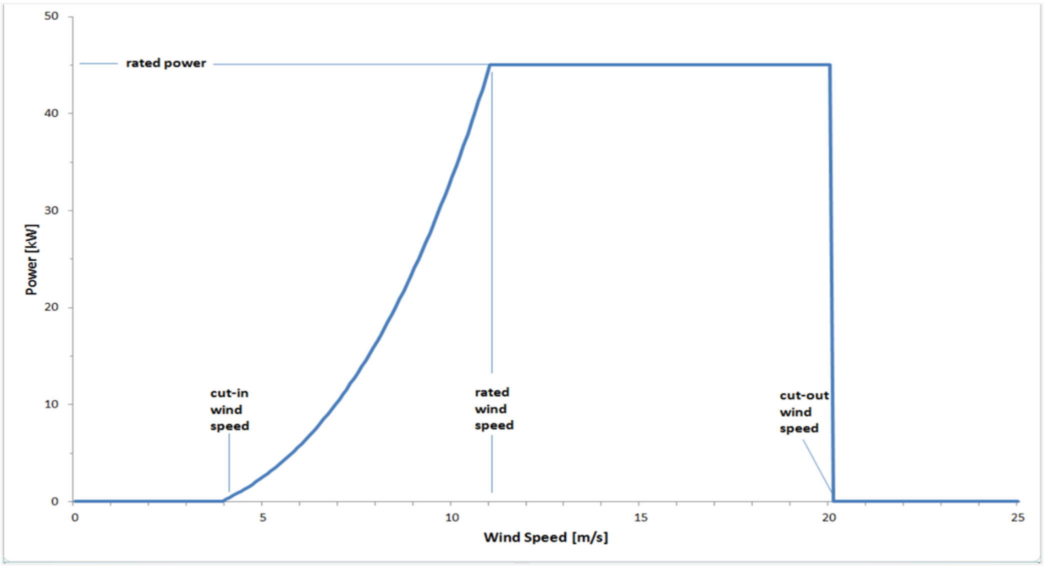
Water and Wind Potential in the UK and Scotland

Within the UK, Scotland specifically benefits from an excellent offshore wind resource (see Figure 2-4). Within 70 to 100km off the coast there are substantial wind, wave and tidal energy resources. The majority of its potential in the northern regions is at 50m - 100m depth at very strong average wind speeds.

Before we proceed, we provide a brief overview of the importance of wind speed on power output. The electricity output of a turbine strongly depends on the wind speed on site. See Figure 2-3 for an example of a typical power output curve that is plotted against wind speed.

Figure 2-3: Wind turbine power curve

Source: Science and Technology Facilities Council, 2016



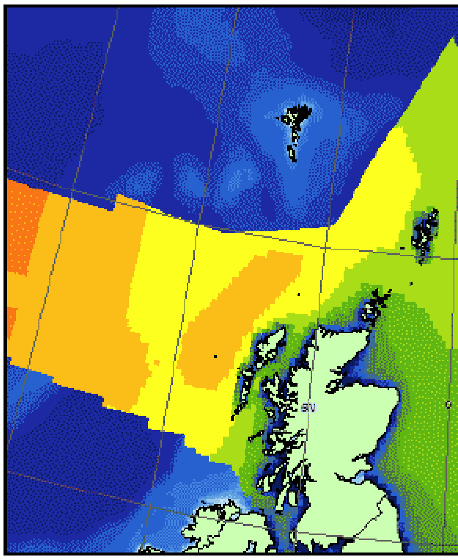
A wind turbine only starts to generate at about 4m/s, and should not generate at speeds above 20-25m/s for safety reasons and to avoid excessive wear and tear of the material. The ideal speed for a wind turbine depends on the turbine's capacity but generally falls between 11m/s and 14m/s.

The best mean wind speeds are measured in Scotland and off the south-west coast of the UK (James and Costa Ros, 2015). The winds over eastern Scottish waters are very high and reach average speeds of about 9.5m/s. This is due to their proximity to the track of the Atlantic depressions. In southern Scotland mean wind speeds tend to be less than 8.5m/s. The windiest waters in Scotland are located off the northern and western coasts. These areas are fully exposed to the Atlantic and closest to the passage of low pressure areas (The Scottish Government, 2010), as illustrated in Figure 2-4. Locations for floating wind farms in Scotland are therefore abundant and floating technology is essentially required to maximise Scotland's full offshore wind potential.

In addition to vast wind resources, Scotland benefits from an existing offshore infrastructure due to decades' worth of oil and gas exploration activities in the North Sea. Floating offshore wind development can thus benefit from established supply chains and port facilities, and may even benefit from technological synergies with the oil and gas industry, including offshore design, the fabrication and installation of the

Figure 2-4: Wind speed averages in Scotland

Source: The Carbon Trust, 2015



floating substructures, mooring lines and anchors. This type of collaboration could quickly reduce floating offshore wind costs.

Interestingly, floating wind projects in Scotland could benefit from the current trend among many oil and gas companies to diversify their portfolios, given the uncertain future of the North Sea oil and gas industry. Floating offshore wind could thus seem like a viable option for to preserve local jobs and maintain a strong market position (James and Costa Ros, 2015).

Current Projects in Scotland

The two most prominent projects currently developed in Scotland are the 30MW *Hywind Scotland* project, developed by Statoil, and the 48MW *Kincardine project*, which is explained in more detail in section 4.1.1. These projects are the world's first pre-commercial demonstrator arrays that aim to validate the cost reduction potential of floating wind from the prototype stage to the current pre-commercial demonstration array stage, as well as demonstrate cost efficient and low-risk solutions for future large-scale commercial parks (Statoil, 2014). In thus a pioneer in advancing floating offshore wind technology, Scotland takes a very important leadership role in the floating industry[1].

[1] Interview with Johan Sandberg of DNV-GL, 29.10.15, Appendix D.a, Lines 97-98

Potential in France

The European Wind Energy Agency (EWEA) ranked France to have the second largest wind potential in Europe, which is well spread across the country (EWEA, 2011). As of December 2015, 10.3GW of onshore wind power capacity were installed in France (The Wind Power Net, 2016). Despite the fact that no offshore wind mill has yet been built (Snieckus, 2016), the French Ministry of Environment, Energy and the Sea (MEDDE) sees potential in floating offshore wind to develop into a promising new industrial sector in France and utilise the potential of an estimated 200TWh per year. The strongest average winds are expected off the coast of Normandy, Brittany and Provence-Alpes-Côte d'Azur (MEDDE, 2016b). The French Environment and Energy Management Agency (ADEME) completes the first tender for floating offshore wind in April 2016 for both sites in the Mediterranean and the Atlantic Ocean. ADEME has set an aspirational target of 600MW capacity on floaters running by 2030 (Snieckus, 2015a).

Water and Wind Potential in France

3GW of offshore fixed wind capacity have been tendered so far in French waters. The French coastline is particularly suitable for floating wind structures (Snieckus, 2016) because the sea beds around the country's coasts quickly become very deep: Just 1km away from the port of Toulon in the Mediterranean Sea, for instance, the water is already 100 meters deep[1], rendering floating wind parks the best solution to tap into the Mediterranean offshore wind potential (Zountouridou et al., 2015). This is especially the case in the Côte d'Azur region where the industry has identified the wind-richest area in the country with several GW of floating offshore wind potential (Dodd, 2015). Given average wind speeds of about 9m/s there, it is likely that the first French floating offshore wind project will be installed in the Mediterranean Sea[2]. The Atlantic coast is an equally attractive area with large potential for floating offshore wind at similar average wind speeds (Dodd, 2015) though suitable areas tend to be further away from the shore and exhibit harsher wave and weather conditions. Several pilot projects for the Atlantic Ocean are already in their early planning stages.

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[1] Interview with Frederic Chino of DCNS, 23.09.15, Appendix D.b, Lines 60-63

[2] Interview with Frederic Chino of DCNS, 23.09.15, Appendix D.b, Lines 60-61

French companies like Alstom, EDF and GDF Suez to name but a few, have experience in electrical, steel, maritime as well as oil and gas works, and already actively participate in the international offshore wind market (Offshore Wind Biz, 2015). Despite the maturity of the French maritime and offshore industry, however, there is no uniform prospective on the extent to which the offshore industry's maturity would favour floating offshore wind development at this moment in time. While Snieckus (2016) argued that a number of shipyards on the French Atlantic coast rendered France well prepared for the assembly of floating offshore wind turbines, it is questionable whether France will be able to capitalise on this in the near future. In contrast to Norway and Scotland, France does not have the oil and gas infrastructure in place that could be used to kick-start a floating offshore wind industry[1]. Nevertheless, France has high ambitions to advance floating offshore wind and project developers actively press ahead with plans to develop the technology (James and Costa Ros, 2015).

Current Projects in France

Two French projects in particular are worth highlighting to give an idea of the current market development. One is a 6MW turbine installed on a semi-submersible platform, called *SeaReed*, that will be deployed 15km off the Atlantic coast of Groix, Brittany. This project, a joint endeavour by French power generation company Alstom, and DCNS, a company specialising in energy and owner of numerous naval dockyards, is in an early planning stage. The second project is called *FloatGen*, a 2MW turbine that is to be installed 19km off the Atlantic coast of Pays de la Loire by 2017. This project is a combination of a semi-submersible and a TLP floater. It was designed by French engineering company IDEOL, developed in collaboration with research facilities in Germany, and funded among others by the EU and ADEME (Snieckus, 2015a). Both projects have the ambition to upgrade their initially single wind mills to wind farms consisting of several turbines upon successful deployment of the respective demonstrator project (ORE Catapult, 2015b). French renewables developer Quadran is currently planning to collaborate with IDEOL to extend their floating offshore wind project to a fully commercial floating wind park of 500MW by 2020 (Quadran, 2016).

[1] Interview with Frederic Chino of DCNS, 23.09.15, Appendix D.b, Lines 96-99

An industry expert interviewed for this thesis, however, maintains that the first commercial wind park is not to be expected in French waters before 2022[1].

Potential in the United States and Hawaii

The majority of the American population lives along the East and the West coastlines of the country (EWEA 2013a), where the wind resource is generally abundant (Adelaja, et al., 2012). This proximity of demand to a relatively large wind resource has led the US Department of the Interior to estimate that the total US demand for electricity could be met with offshore wind that can be deployed close to population centres (DNV 2012). However, despite over 60% of the estimated wind resource in the US being located over deep waters on both coasts (DNV 2012), until today American wind power has been based entirely onshore. The total installed capacity amounted to 74GW in December 2015, which is about 20% of the world's total.

With regard to offshore wind in general and floating offshore wind in particular, the country lags behind developments in Europe and Japan (Sun, Huang, & Wu, 2012) as coal power still accounts for the majority of electricity production (Snyder and Kaiser, 2009b). Offshore wind in the US faces three main challenges: Firstly, it cannot compete with inexpensive coal power without state funding or a potential carbon tax on coal (Snyder and Kaiser, 2009b). Secondly, in contrast to densely populated Europe, relatively inexpensive onshore wind sites are still widely available in the US, which makes it unnecessary for the industry to move offshore at this moment in time. Thirdly, the current political environment does not favour offshore wind, neither fixed nor floating. The US Congress seems to be hesitant to amend the existing energy infrastructure in any way[2], and a long and uncertain permission process further hinders offshore wind development (DOE, 2015).

Hawaii was the first US state that declared its ambition to become energy-independent by 2045. This includes meeting 100% of the islands' electricity demand with renewable energy (State of Hawaii, 2015). In 2013, the state had to import 91% of the electricity it consumed (US Energy Information Administration, 2015). At the end of 2015, 202MW of onshore wind power were installed in Hawaii (Energy Hawaii, 2016), supply the state with only a negligible amount of its electricity needs

[1] Interview with Frederic Chino of DCNS, 23.09.15, Appendix D.b, Lines 70-72.

[2] Interview with Bonnie Ram of DTU, 09.12.15, D.c, Lines 9-13

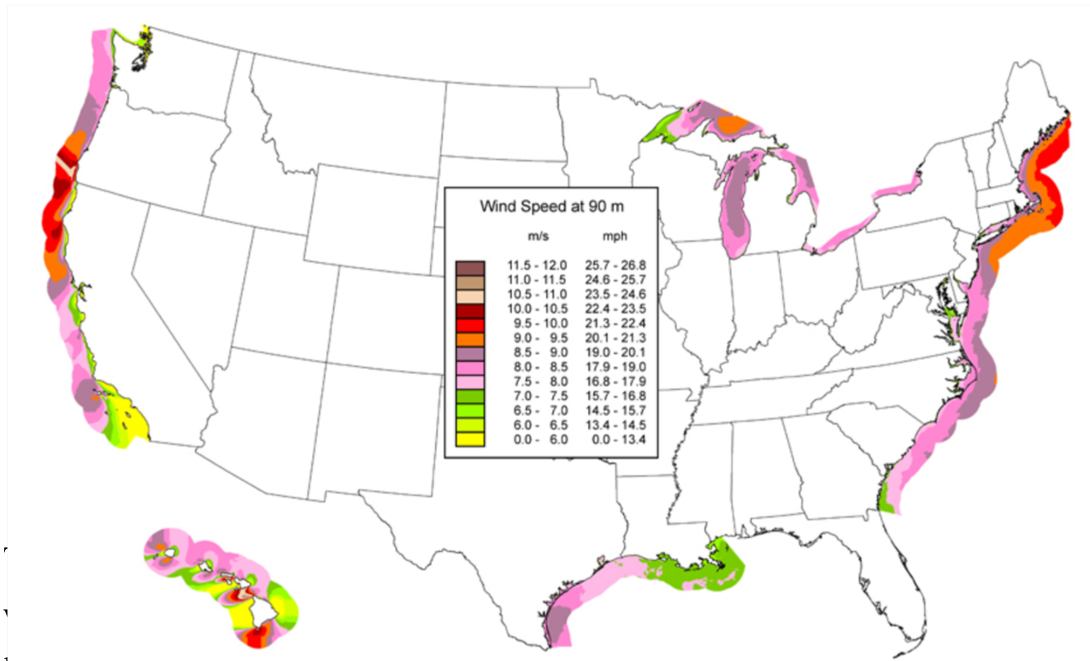
compared to photovoltaic and geothermal power. Hawaii largely depends on generating electricity with oil-fired power generators (Snieckus, 2015c), which drives electricity rates up to be about three times higher than those on the US mainland. Under these market conditions, even a technology as new as floating offshore wind has one of the best chances worldwide to reach grid parity. Additionally, floating structures would not take up any more of the already limited land resource available (Snieckus, 2015c).

Water and Wind Potential in the United States and Hawaii

The total wind potential off American coasts and on the country's lakes is estimated to amount to 3500GW, 1800GW of which could be tapped into using floating structures within 50 miles from the shore. A study by Musial (2010) found that 573GW of floating offshore wind capacity could be installed in Californian waters, 250GW in New England's waters and 459GW on the Great Lakes.

Figure 2-5: Wind speeds in the US at 90m height

Source: US Department of Energy, 2015



locations with high potential are on the East Coast, especially on the waters off the northern coastal states with average wind speeds of 9-10m/s and in the Great Lakes region with 8-9m/s average speed.

Hawaii has a strong offshore wind resource with an average wind speed of more than 8m/s. The water depth around the islands allow only for few fixed-bottom turbines. But, the potential for floating offshore wind on Hawaii is estimated to be 650GW, according to the National Renewable Energy Laboratory, which exceeds the island's electricity demand several times over (Snieckus, 2015c).

Current Offshore Wind Projects in the Unites States

The Department of Energy has set a target to deploy 10GW of offshore wind capacity by 2020 and increase this to 54GW by 2030 (Sun, et al., 2012). The first offshore deployment, a 30MW fixed-bottom wind farm that is currently being built off the coast of Rhode Island, is expected to be finalised by the end of 2016 (EIA, 2015c). Even though the American offshore wind industry is far behind its European counterpart, only building the first offshore wind park now, some developers already consider offshore floating wind projects. Principle Power, for example, plans to deploy a 30 MW floating offshore wind project off the coast of Coos Bay, Oregon, consisting of semi-submersible structures equipped with 6MW turbines (ORE Catapult, 2015b). In Maine, the DeepCwind consortium, coordinated by the University of Maine, is currently testing a prototype called *VolturnUS*. Two full-scale semi-submersible floaters, carrying a 6MW turbine each, are to be deployed at a demonstration site in 95m of water depth (ORE Catapult, 2015b).

Current Projects in Hawaii

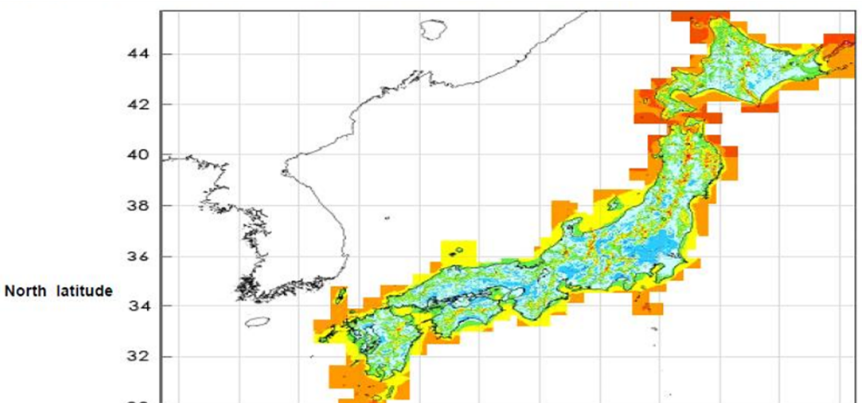
Two floating offshore wind projects, that are to be deployed about 20 kilometres off the Hawaiian island Oahu, are currently in the planning phase. The project developers, Danish Alpha Wind Energy and American Progression Energy, have proposed commercial scale projects of about 400MW and 816MW respectively (Kessler, 2016), both using semi-submersible designs. Construction could begin as early as 2020 (Snieckus, 2015c).

Potential in Japan

Japan has the third largest economy in the world and the second largest electricity market in the OECD (Govindji, James and Carvallo, 2014). Before the Fukushima nuclear accident, nuclear power was meant to account for 50% of Japan's electricity by 2030. After the accident, the government decided on an energy strategy that is meant to phase out nuclear power (The Japan Times, 2003) and focus on renewable energy (Tominaga, 2016). Today, the renewable sector is dominated by small hydro and biomass power plants, which account for 70% of total power generated in 2011. The overall share of solar and wind power in renewables is only 13% and 11% respectively (Govindji, James and Carvallo, 2014). In 2014, Japan had a total installed wind power capacity of 2,788MW, including 50MW from offshore wind turbines. The total electricity produced by wind energy (5.1TWh) corresponds to just over 0.5% of the country's total electricity demand (965.2TWh). This is relatively little, given that in European countries, the ratios of wind power to total power are much higher, amounting to 33% in Denmark and 8% in the UK (Ishihara, 2015). However, the Japanese government predicts that wind power could supply up to 20% of Japan's electricity demand by 2050 (MITI, 2016). The Fukushima accident and subsequent concerns about the safety of nuclear power plants has led Japan into taking economic risks and paying a high price for importing gas to meet electricity demand. Today, the country is merely 6% self-sufficient in terms of primary energy, which makes it especially vulnerable to external factors (Tominaga, 2016), electricity supply security having become one of the most pressing topics of political discussion (DNV GL, 2015). Japan therefore aims to increase self-sufficiency to 24.3% by 2030 (Tominaga, 2016). A ministry study showed that Japan could triple its renewable energy-generated electricity by 2030 (The Japan Times, 2015) and achieve up to 397GW by 2050 (DNV GL, 2015). The country will be one of the first markets to develop floating offshore wind at a commercial scale because of the lack of alternatives[1] and is expected to account for an increasing proportion of installed capacity (Japan Wind Power Association, 2016). 10GW of floating wind power are expected to be deployed by the early 2020s, with 36.2GW being the target for 2030 and 37GW for 2050 (Govindji, James and Carvallo, 2014).

Figure 2-6: Average wind speeds in Japan

Source: ORE Catapult, 2016



Water and Wind Potential

While Japan's space for onshore wind power deployment is severely limited, the country's waters offer plenty of space for offshore wind deployment. Given the limited space, onshore wind potential is estimated to be only about 280GW while the abundant offshore resource could generate up to 1,600GW (Ishihara, 2015), the large majority of which 1,170GW is over waters with depths of over 100m (EWEA, 2013; Arapogianni and Genachte, 2013). The wind speeds over these waters measure between 6 - 10m/s (see Figure 2-6).

Current Projects in Japan

Japan has already installed three single floating offshore wind prototypes, putting the country in a world leading position in regards to floating capacity installed. Japan's ocean floor falls rather steeply close to the shore, allowing for the first demonstrators, which are installed in 100m of water depth, to be only 15km away from the shore (Govindji, James and Carvallo, 2014). One of the first prototypes deployed in Japanese waters constitutes the first phase of the *Fukushima Forward* project, and is comprised of a semi-submersible structure carrying the wind turbine and a spar-buoy-based transformer station (ORE Catapult, 2015b). Another prototype has been installed near Kabashima Island in 2012 as part of the *Goto FOWT* project. In the project's second phase a 5MW turbine was installed in 2016 on an *Advanced Spar* floater (Fukushima Offshore Wind Consortium, 2016; Publicover, 2016). The *GotoFOWT* floater is particularly important as the floating offshore wind industry in

Japan is said to 'hinge' on this project (Snieckus, 2015a). Japan has been moving fast from the budget approval stage to the commissioning stage with three full-scale demonstrator projects in just 2 years[1]. The third fully commissioned demonstrator project was installed as part of the *WindLens* project by Kyushu University and has a total capacity of 0.006MW. This last project differs slightly from other projects we have discussed so far in that the floating substructure has two turbines mounted on to it; they have a capacity of 0.003MW (3kW) each (Govindji, James and Carvallo, 2014).

2.3.2. Industry Challenges

Having established the social and economic benefits, as well as the market potential of floating offshore wind in the previous sections, this section will provide an overview of the current status of the industry and highlight prevailing industry challenges. It highlights the need for our research at the current stage of floating offshore wind development and underscores our study's relevance for the academic community, policy makers and the wider floating offshore wind industry.

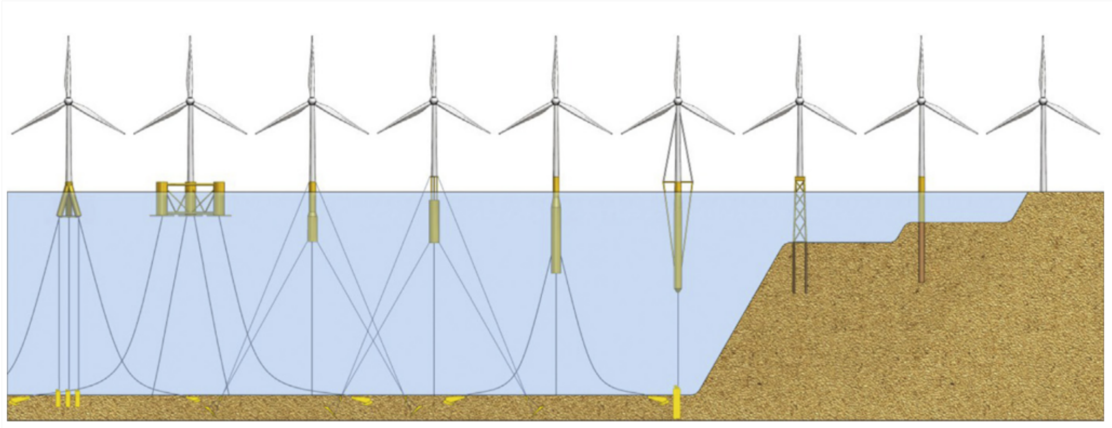
Substructures

This section provides the reader with a brief overview of the three most promising floating concepts. Currently, a number of structures are evaluated for floating wind farms, each of them offer different physical and economic benefits. Figure 2-7 shows the basic differences between fixed and floating substructures and the differences between various floating concepts that are under development. Illustrated from left to right are the TLWT, Windfloat, TLP, TLB X3, Hywind II, Sway, the Jacket and the Monopile structures. Only the spar-buoy (exemplified by Hywind II), the semi-submersible (exemplified by WindFloat) and TLP are presently under closer consideration for a pilot park (The Carbon Trust, 2015).

Figure 2-7: Illustration of substructure concepts

Source: Myhr, et al., 2014.

[1] Interview with Bonnie Ram of DTU, 09.12.15, Appendix D.c, Lines 135-136

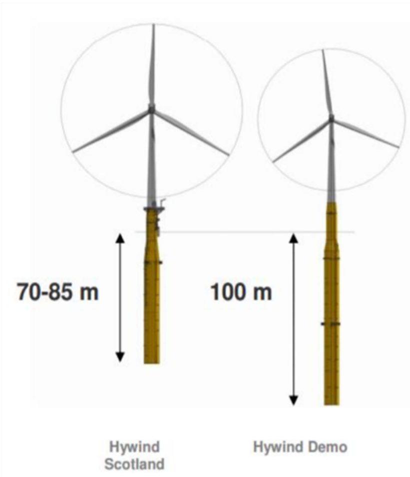


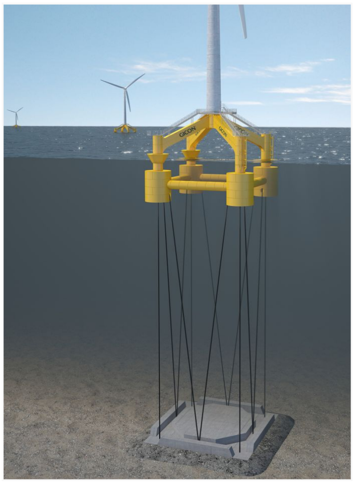
The Spar-Buoy

The spar-buoy floater (fifth from the right in the figure above) is an established design from the oil and gas industry. The technology has been proven both with offshore oil and gas platforms as well as the first floating wind demonstrators in Norway and Japan. The structure consists of one large monopile ballast tank that is filled with bulk and water to give a very low centre of gravity (Breton and Moe, 2009). The tank is fixed to the seabed with three chains or mooring lines. The floater's mass, together with a control system, dampens the impact of natural forces onto the wind turbine to a minimum. The large draught makes the structure very stable, rendering spar buoy concepts robust. A further advantage of the spar design lies in its simplicity and suitability for quick assembly. The structure thus offers a high potential for cost compression due to economies of scale. The spar buoy's weakness is depth. Measuring about 10-12m in width and about 85m in draught, this concept is only suitable for water depths greater than about 100 meters. The mean depth of the North Sea, for instance, is only about 90m. Other floater concepts are more flexible in their application because they can be installed in shallower waters. Derived from floating constructions in the offshore oil and gas sector, the spar buoy is considered the most mature concept, and has been used for two projects: Statoil's *Hywind* project in Norway and Toda's *Kabashima Island Spa*r in Japan. Projects utilising the spar concept that are currently constructed in 2016/17 include Statoil's *Hywind Scotland* and Marine United's *Advanced Spar* in Japan.

Figure 2-8: *Hywind* spar-buoy, *Windfloat* semi-submersible, *Gicon* TLP platform

Sources: Statoil, 2014; Principle Power, 2016; GICON, 2016





The Semi-Submersible

The semi-submersible floater concept is comprised of three ballast tanks, each of which contains bulk and water to achieve the desired buoyancy level in the water. The bulk tanks are joint with steel connectors and one of the ballast tanks carries the wind turbine. The triangular structure is fixed to the sea bed with four catenary mooring lines, one attached to each of the two ballast tanks not carrying the turbine and two attached to the ballast tank carrying the turbine. Each ballast tank is further equipped with a bottom plate for increased structural balance. Heave, pitch and rolling motions to the entire structure are balanced by transferring loads across the platform, and a hull-trim system repositions up to 200 tonnes of ballast water between the columns for further stability (Roddier, Cermelli, Aubault and Weinstein, 2010).

From an economic perspective, this structure is more complex than the spar concept and does not exhibit the best features for cost compression through simplification. The semi-submersible floating structure is rather heavy with a relatively high steel mass and many welded connections, increasing manufacturing complexity (Myhr, Bjerkseter, Ågotnes and Nygaard, 2014). The structure is also relatively vulnerable to extreme weather and wave conditions and possibly corrosion due to the large surface of the platform. One of the structure's advantages is its suitability for shallower waters than the spar buoy. A semi-submersible floater may be deployed in water depths of just 50m. Additionally, the structure, including the turbine, can be fully assembled and receive maintenance in a dry dock (ORE Catapult, 2015b).

Principle Power deployed a demonstrator project, *WindFloat I*, off the coast of

Portugal in 2011 (ATKINS, 2014) and Mitsubishi installed the second generation prototype off Japan in 2015. Alstom considers a similar semi-substructure structure with the *SeaReed* project in France. In addition, several pilot parks are in the planning phase, including the *Kincardine* pilot park off the coast of Scotland and a second project from WindPlus in Portugal. A second generation is planned to follow off the US states Hawaii and Oregon.

The Tension-Leg Platform

The tension-leg platform (TLP) concept is characterised by tensioned mooring lines that hold the structure in place and dampen the force of wind, waves and current. The structure may consist of either a comparably thin platform, four columns or a permanently submerged triangular stand. TLPs are very competitive, reducing heave and angular motions more effectively than the two previously mentioned concepts (Roddier et al., 2010). In order to minimize the amount of steel as well as the draught of the TLP structure, a tension load is created underneath the structure using tendons arms, a concrete base pate or an anchoring solution on the sea floor. The TLP concept allows for using a light and small structure that can be installed in very shallow waters with depths of merely 30m (ORE Catapult, 2015b). It is estimated that the substructure steel weight per MW will be a fraction of that of the competing spar buoy and semi-submersible concept on the market today[1].

The weakness of the TLP concept lies in its mooring requirements. The tension must constantly be adjusted to fit tidal variations and structural frequencies that cannot be damped by the structure itself (Roddier et al., 2010). Anchoring a structure under tension requires high vertical load anchors, which are more complex and more expensive than the mooring for the spar buoy and the semi-submersible[2], possibly outweighing the gains from an overall lighter structure. Furthermore, there is a significant operational risk that one of the mooring lines might fail, which could result in the loss of the entire structure (DNV, 2012). However, the cost savings in raw materials may allow for spending more on expensive mooring efforts, which reduces operational risks to a minimum. The tension-leg platform offers high potential for cost compression because the relatively simple floater is suitable for mass production and

[1] Interview with Johan Sandberg of DNV-GL, 29.10.15, Appendix D.a, Lines 103-120

[2] Interview with Johan Sandberg of DNV-GL, 29.10.15, Appendix D.a, Lines 134-137

automated manufacturing[1]. However, the structure could require more complex maintenance because some TLP designs such as the *PelaStar* cannot easily be towed to quayside or dry dock for repair.

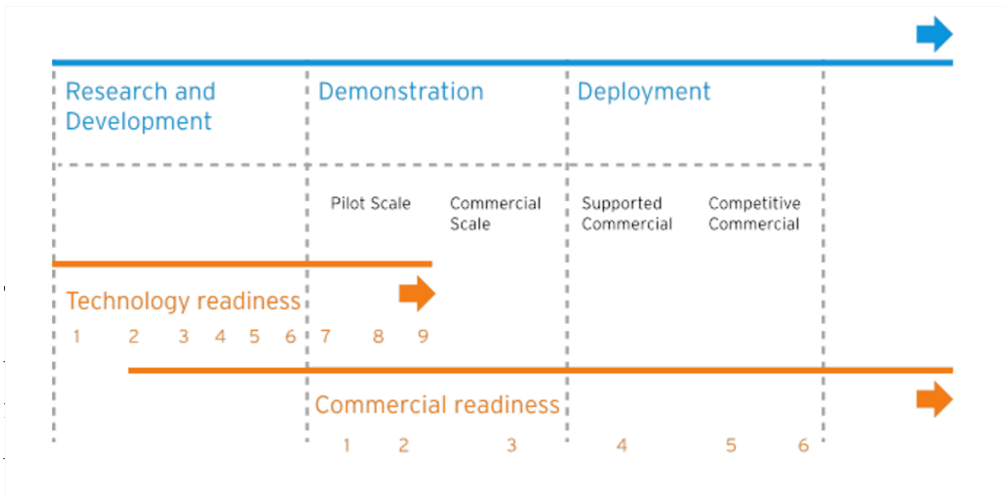
TLP designs currently under development include the *GICON SOF* and *FloatGen* prototype, which are scheduled for installation in the German Baltic Sea and off the French Atlantic coast in late 2016 (Gicon 2016; Floatgen, 2016). A third concept named *PelaStar* is also in development, but there are no current ambitions to build a commercial pilot park (Pelastar, 2016).

Technological Readiness

This subsection provides an overview of the current stage of technological development for floating offshore wind. Understanding the current development stage of the technology is very important when evaluating the necessity to advance support schemes at this moment in time. The technological and commercial readiness sections will be tied together in "The need for cost reduction" section.

Figure 2-9: Three stages of technological development

Source: Australian Renewable Energy Agency, 2014



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the Technology Readiness Level (TRL), a globally accepted benchmarking tool for both tracking the process of a technology as well as supporting its development from the early research stage (TRL 1) to system demonstration over all steps of expected conditions to the operational proof stage (TRL 9). As technology develops from TRL

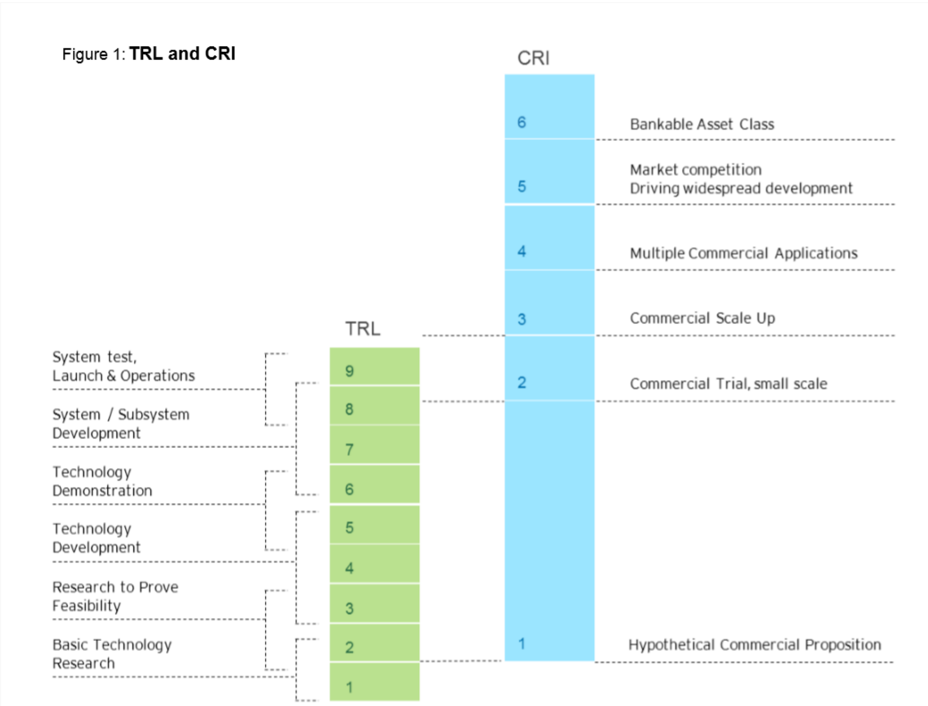
[1] Interview with Johan Sandberg of DNV-GL, 29.10.15, Appendix D.a, Lines 124-127

1 to TRL 9, investment must be used knowledgeably to develop the technology further, increase its deployment and improve its cost competitiveness.

There are currently over 30 floating concepts under development (ORE Catapult, 2015b), most of which still aim to demonstrate the fundamental functionality of the technology and are therefore on stages 0-6 of the TRL scale, see Figure 2-10. The two most advanced concepts are the spar buoy and the semi-submersible floater. Prototypes of both have already been deployed and demonstrated floating technology in its operational environment. Both substructures are currently in the transition phase between the demonstrator prototype stage and the first pre-commercial array stage.

Figure 2-10: The TRL and CRI indexes in comparison

Source: Australian Renewable Energy Agency, 2014



While most of the technological risk can be removed during the development process, considerable economic uncertainty and risk tend to remain during both the demonstration and deployment phase, which floating offshore wind currently finds itself in (ORE Catapult, 2015a). The economic risks at various stages of the development process are captured by the Commercial Readiness Index (CRI).

Commercial Readiness

A new technology always faces a multitude of barriers when first entering a market because these markets are home to proven technologies with set financing systems that are hard for new technologies to tap into. This poses a particular challenge to renewables in whose context capital costs and, by extension the access to capital, are a key barrier to accelerating deployment (AGREA, 2014). To account for the commercial aspect of a developing technology and complement the Technology Readiness Level framework that covers most technological risks, the Australian Renewable Energy Agency has developed the Commercial Readiness Index (CRI) for the renewable energy sector to capture the economic risks associated with an energy project in six stages. This framework helps evaluate industry barriers that a sector might be facing at various stages of the development process and enables governments and other funding bodies to channel support for new technologies in a way that best reduces risks and barriers at the various stages of the commercialisation process (Australian Government Renewable Energy Agency, 2016).

The two frameworks fundamentally complement each other. Figure 2-10 shows that CRI begins once the technology has proven its feasibility in the field (TRL 2). Importantly, CRI goes beyond the last TRL 9 stage when the technology is being commercially deployed and has become bankable (AGREA, 2014). According to the CRI index, the floating wind industry is currently between CRI 2 "Commercial Trial" and CRI 3 "Commercial Scale Up" (ORE Catapult, 2015a). At CRI 6, floating wind as an asset would be considered bankable because market and technology risk would no longer be the primary driver for investment decisions.

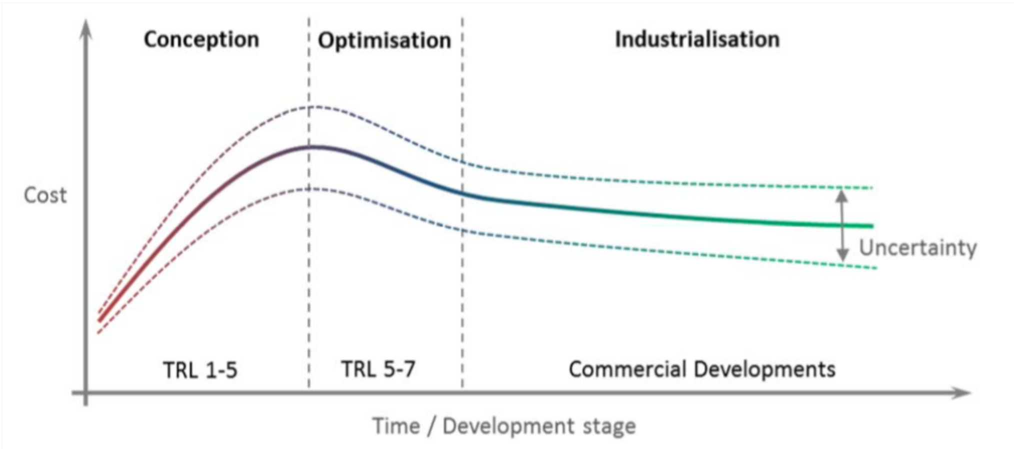
For a technology to develop sustainably from demonstration to scaling up, commercial readiness and finally to large-scale deployment, it is crucial that costs are reduced at every step of the process. Commercial potential is demonstrated by improving cost competitiveness, which will attract further investment that will ideally be sufficient to deliver sufficient volumes to generate learning. This in turn further improves the technology and leads to further cost reduction, thereby creating a virtuous cycle until the technology reaches the final commercial readiness level. Once the technology is commercially mature, it has to be developed further and cost reductions can be achieved by scaling up deployment (ORE Catapult, 2015a). Floating offshore wind thus currently finds itself in a crucial phase to reduce costs.

The Need for Cost Reduction

As a technology is developed and reaches different stages of maturity, it is expected to reduce certain costs. Figure 2-11 illustrates how costs are expected to develop over time as floating wind technology moves through the different development stages (James and Costa Ros 2015). So far, project costs have to come down sufficiently and in good time to prove commercial viability and to attract the attention of investors. If advanced sufficiently, the LCOE of floating offshore wind could drop below that of fixed offshore wind (DNV GL, 2015), also illustrated in Figure 2-12. Therefore, reducing costs is an imperative for the floating technology, in order to develop into the large-scale development phase and tap into its large potential in the near future.

Figure 2-11: The path of cost reduction

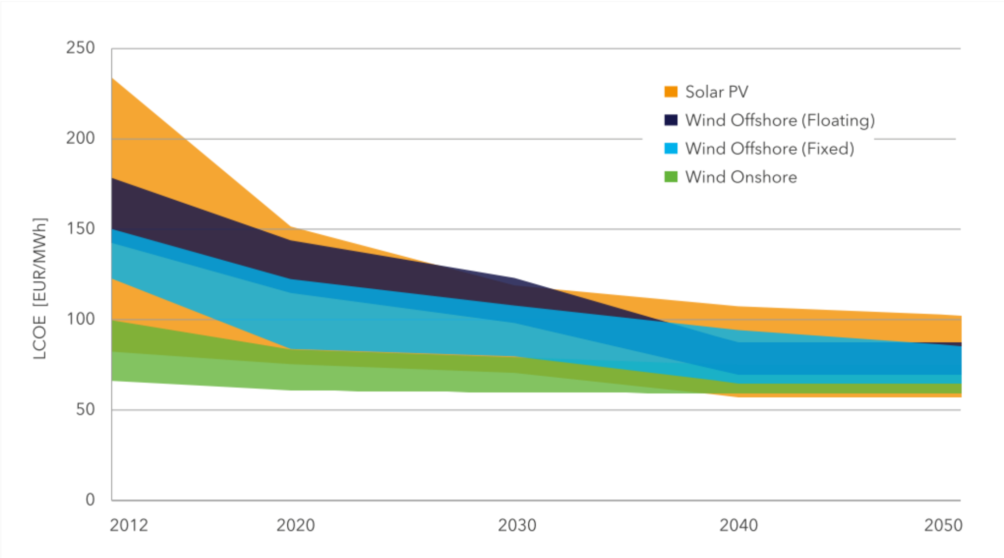
Source: Australian Renewable Energy Agency, 2014



As the industry currently finds itself in the "demonstration" phase, hoping to soon launch into the "cost compression" phase, floating wind is at a crucial point in its development phase to attract enough investment in time to make the technological advances and realise the cost reduction potential that are necessary now for the industry to develop into a high-energy delivering energy source toward the middle of the century. Sun et al (2012) stress that high costs are currently the main barrier facing further development. Despite its potential to achieve a lower LCOE than fixed offshore wind (see Figure 2-12), floating technology is under time pressure at this moment in time to prove its commercial viability until 2020 so the scaling up and cost reduction phase can take place between 2020 and 2030. The LCOE of floating offshore wind of about £85-£95/MWh has to be proven by 2050 (Buist, 2015) if the technology is to play a vital part in the UK energy mix up until and after 2050.

Figure 2-12: Evolution of LCOE for selected renewable technologies

Source: The Carbon Trust, 2015



Although achievements in cost reduction are desirable for all types of renewable energy, floating offshore wind is in a special situation: If cost reductions are not achieved within the next 5-15 years, the technology may lose its attractiveness to the market entirely (Sun et al., 2012), an aspect that is different for other renewables: Solar PV, fixed-bottom offshore wind or hydro power are not going to lose their attractiveness to investors entirely on a global scale if certain cost reduction targets are not met within the next couple of years. Floating offshore wind is therefore under unusual pressure to demonstrate its cost reduction and commercial development potential now.

In order to achieve the necessary cost reductions for floating offshore wind, Sun et al (2012) suggest to focus on learning effects and standardisation. The idea of learning effects is based on the empirical observation that the cost of a technology decreases constantly with every doubling of cumulative production. Learning effects will generally be between 7%-14% until 2050 for the whole offshore wind industry (DNV GL, 2015), where the cost of floating offshore wind will largely depend on the cost development of their fixed counterparts.

The Challenges of Floating Offshore Wind as a New Technology

Every new technology bears a substantial risk at first, simply due to its novelty to the market. The waters around Europe that are deeper than 50m constitute previously unexplored territory for the offshore wind industry, which causes concern among wind farm developers and entices some to stick to fixed-structure monopiles and jacket foundations; however, most of the global potential – apart from the North Sea – is in deeper waters and prototypes have proven the technology is both cost-effective and stable and both prototypes have survived storm conditions successfully (Kraemer, 2015). Buist (2015) refers to a report by The Carbon Trust when arguing that the perception that floating wind is a costly and immature technology were the biggest market barriers to cost reduction. The absence of commercial floating offshore wind farms makes it difficult for investors to compare the cost competitiveness of this new technology with that of established technologies as the currently existing prototypes are naturally high-cost investments and do not provide a useful reference point for commercial comparison with fixed bottom constructions.

At the current stage of early development, financial risk is fairly high (Ho and Mbistrova, 2015), among other reasons, because only limited data is available to forecast revenue streams. Investors therefore tend to refrain from investing in such novel technologies as floating offshore wind (Kraemer, 2015). But precisely at this development stage, substantial investment is crucial to advance the floating wind technology further, allow it to move into the cost compression phase, prove its commercial potential and give it the opportunity to develop into the vast energy source it has the potential to be. For example, to reach the UK's indicative target of 20% of renewables energies by 2020 the industry requires a £75bn investment, which is roughly equivalent to the North Sea oil and gas exploration industry peak (Delay and Jennings, 2008). To meet its deployment target of 40GW, the European offshore wind energy requires investments between €90bn and €123billion by 2020, which constitutes an increase in funding levels between 185% and 416%; even conservative estimates of 25GW offshore wind deployment would still require between €50bn and €69bn until 2020 (EWEA, 2013b). These vast sums can arguably only be attracted from private investors if governments provide policy support to make the currently relatively uncertain endeavour of a floating offshore wind project more predictable.

As other renewable energy investments, floating offshore is characterised by high upfront costs: 80% or more of the overall costs of a wind farm have to be invested into the installation and connection of the wind farm. This means the vast majority of costs are incurred before the wind farm even begins to generate power, and by extension return a profit to investors. Offshore wind power is in thus not only technologically challenging but also a capital-intensive and perceivably risky endeavour that requires particular financial and organisational resources that not all investors may have (Markard and Petersen, 2009).

Floating offshore therefore requires governmental support (James and Costa Ros, 2015) to counteract the risks that currently prevent investors from moving into the floating wind industry. Through establishing support schemes, governments can encourage private sector investment and significantly influence the development of new renewable energy technologies (Johnstone, Hascic and Popp, 2010). By supporting research and development, policy makers can help new technologies to achieve economies of scale and ultimately reduce the costs of renewables (Canton and Johannesson Lindén, 2010). Arguably, only with appropriate political and technological support can floating offshore wind develop into a crucial element of the global energy mix between 2030 and 2050 when it could be possible to build vast arrays that are located beyond the land horizon but nevertheless constitute a cost-effective and environmentally-friendly alternative to conventional types of energy, mitigating the social and economic costs of climate change (DNV GL, 2015).

2.4. The Fit of Our Analysis

As established above, in order to tap into the vast energy potential of floating offshore wind, the technology is currently under time pressure to prove the its cost reduction potential within the next decade so large-scale projects may be realised in the years leading up to 2050 and floating offshore wind does not lose its appeal to the market entirely. Because investors tend to be notoriously sceptical and hesitant to invest in novel technologies, the floating wind industry requires governmental support at its current development stage to aid its technological and commercial progress (DNV GL, 2015). Lessons can be learned from onshore wind, where policy support schemes have been vital in aiding the technological progress and economic development. Denmark and Germany are examples of countries where carefully constructed policy support schemes have helped to build a strong market early on, giving both countries a competitive edge in the current market (Markard and Petersen, 2009). Similarly, designated industry support can help floating offshore wind to realise its potential, further technological development and ultimately economies of scale through large-scale deployment (Blanco, 2009). A number of countries have devised such policy instruments to aid the development of renewables technologies, including capital loans or subsidies, tax incentives, tradable energy certificates, feed-in tariffs, preferred grid access and mandatory portfolio standards (Timilsina et al., 2013).

Having established the immense potential of floating offshore wind and the need for funding to allow the technology to progress quickly, the paramount questions facing the academic community and industry at this moment in time are therefore: First, how do the different funding mechanisms differ in their economic impact on a pre-commercial floating offshore wind farm? Second, is one support scheme better suited than another to advance floating wind technology by encouraging investor support? The evaluation of support schemes from investors' points of view has too often been neglected (Enzensberger, Wietschel and Rentz, 2002) and this thesis follows Enzensberger et al's (2002) suggestion to adopt a more comprehensive approach to policy design that takes into account the perspectives of a variety of stakeholders by precisely evaluating support schemes for floating offshore wind from an investor's perspective. To evaluate the correct level of funding, Canton and Johannesson Lindén (2010) develop a stylised partial equilibrium model of the electricity sector that seeks to maximise social welfare, taking into account the main support schemes (feed-in tariffs and green tradable certificates_ as well as energy security, and internalises pollution as an environmental externality (Canton and Johannesson Lindén, 2010). In their two-period stylised partial equilibrium model of the electricity sector, total welfare is given by consumer surplus, profit for electricity producers and externalities caused by polluting emissions and energy security. This formula is their point of departure for drawing a variety of policy conclusions for supporting renewable energies across the EU. One of their main findings is that, where possible, a green tradable certificate scheme should be preferred over feed-in tariffs and even feed-in premiums, because certificate schemes keep market distortions to a minimum and enable the trade of green electricity (Canton and Johannesson Lindén, 2010).

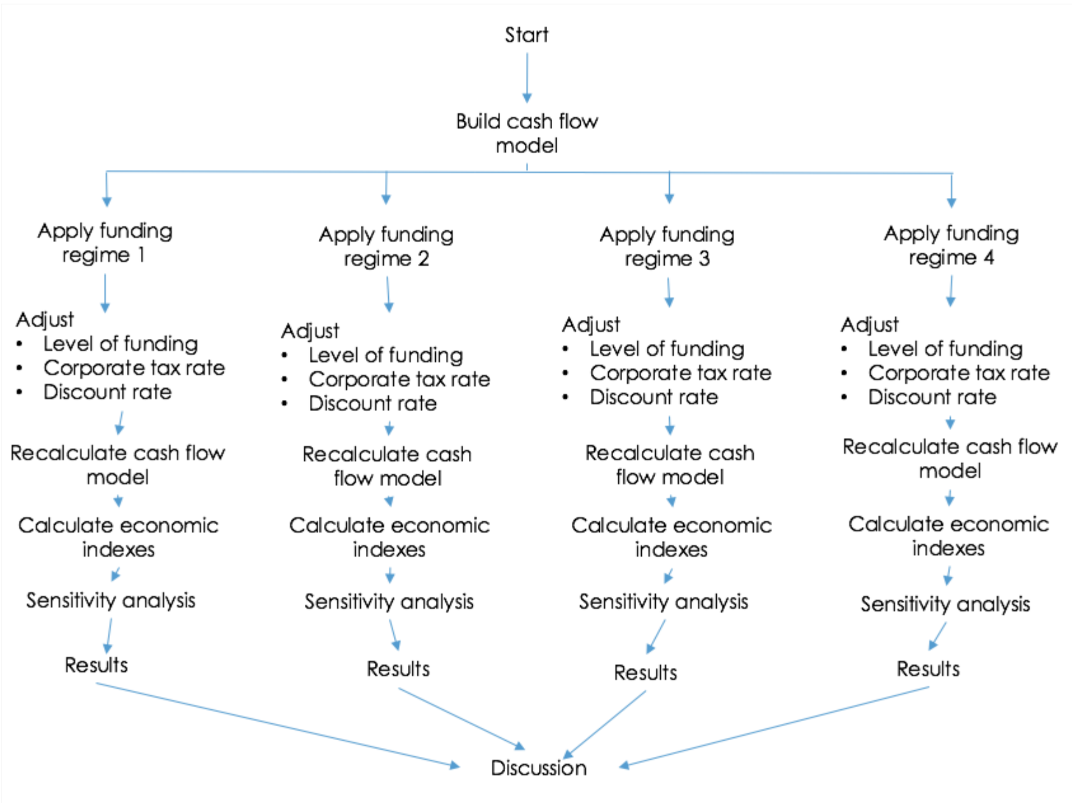
This model provides an important starting point for our analysis and partially inspired our study. We now evaluate whether their findings hold true in the specific case of floating wind, analysing specific support schemes for a model pre-commercial floating offshore wind farm and evaluating whether the ideal mechanism of funding from a society welfare point of view is also the most favourable funding regime from an investor's point of view.

In the following chapter we will introduce the reader to the methodology we employ to answer our research question. We carry out our analysis in Chapter 4, followed by a discussion of our findings in Chapter 5.

CHAPTER 3: Methodology

This chapter describes the methodologies employed to answer our research question. In this study, we compare the impacts of different funding mechanisms on the profitability of a floating wind project in order to evaluate under what funding regimes investors will be most likely to invest in a pre-commercial floating offshore wind farm. We use a cash flow model that serves as a basis for calculating a series of economic indexes to evaluate the project's profitability under each funding scenario: net present value (NPV), the internal rate of return (IRR), the return on investment (ROI), the levelised cost of electricity (LCOE) and the discounted payback period (DPBP). One cash flow model and one series of economic indexes are calculated for each of the four different funding scenarios selected. Our methodological approach is illustrated by Figure 3-1. Since each funding scheme supports the floating wind project at different stages, and thereby mitigates different risks, the discount rate is amended for each scenario to reflect the risk inherent in each support scheme under consideration as it is incurred by investors. To validate our findings, the model is subjected to a sensitivity analysis to evaluate the risk of uncertainty inherent in the

Figure 3-1: The path of our analysis



main parameters of each funding scheme model: the level of funding, the corporate tax rate and the discount rate. The four models as well as their economic indexes and sensitivity analyses are calculated in Chapter 4 and discussed in Chapter 5.

3.1. Cash Flow Model

Cash flow models have been used in the past to investigate the investment profitability of renewable energy projects (Gosens, 2015; Cucchiella, D'Adamo and Gastaldi, 2015) and this methodology is therefore suitable for our purposes. Our model floating offshore wind farm is based in Scotland because it is based on figures provided by the *Kincardine* project (see section 3.5). It was necessary to make an assumption as to what market the model wind farm would be located in to gather data on electricity prices and other market-specific parameters; in our calculations all of these are therefore Scotland-specific. One may thus think of our model as a Scottish pre-commercial floating wind farm that different funding regimes – inspired by real life funding mechanisms from all over the world – are applied to.

This subsection outlines the main income and cost parameters that together form the cash flow model, which in turn forms the basis for the economic index calculation.

3.1.1. Income Parameters

Income for floating offshore wind projects comes from the sale of electricity as well as from funding schemes.

The Sale of Electricity

The amount of electricity that can be generated by a floating offshore wind farm depends on the wind resource available on site, other site characteristics like wave height, the technical specifications of the wind turbines uses and power generation reductions (Blanco, 2009). The single most important factor that impacts the electricity generating capacity of a floating offshore wind farm is the capacity factor, which denotes the number of hours that a wind farm operates at full capacity (Krohn, Morthorst and Awerbuch, 2009; Blanco, 2009), explained in detail in section 4.1.2. Due to the variability of wind speed at a given site, which is dependent on the wind farm's location, seasons, day and night time, and downtime for maintenance, no wind farm will operate at full capacity at all times. From this it becomes clear that higher and more constant wind speeds lead to higher capacity factors. Because wind speed is such an important parameter for the amount of electricity that can be generated, micro-siting each wind turbine correctly is crucial for wind energy projects economics (Krohn, Morthorst and Awerbuch, 2009). For a scientific paper on the optimal layout of a wind farm see Gonzáles et al's (2010) paper on 'Optimisation of wind farm turbines layout using an evaluative algorithm'. The capacity factor fundamentally depends on the wind resource available at a given site. To give the reader an idea of the magnitude of capacity factors: Capacity factors for wind farm on land are around 25-30% (James and Costa Ros, 2015), the capacity factor for fixed offshore farms is about 36% (G. Boyle 2006)–40% (James and Costa Ros, 2015) and for floating offshore wind farms may be up to about 50%, as data from the *Hywind* project indicates. The actual amount of electricity that can be produced will furthermore depend on the inherent capacity of a given wind turbine and its generator. The electricity produced can be sold at the given wholesale electricity market price. Given that our pre-commercial model floating wind farm will be located in Scotland, we are concerned with the wholesale electricity prices in the UK.

Support from Funding Schemes

The second stream of income for a floating offshore wind farm comes from governmental subsidies. The most popular support schemes are feed-in tariffs, feed-in premiums, green energy certificate schemes like the European Renewables Energy Certificate System (RECS), and capital grants.

As part of a feed-in tariff scheme, the generator of electricity receives a fixed price for the power they generate over a set period of time. This price received per unit of electricity that is fed into the electricity grid and the price level is administered and guaranteed by the government, usually set so that the generator is able to make a reasonable profit given the reduced risk they now face (Cleijne and Ruijgrok, 2004).

In the case of a feed-in premium, the generator receives a set amount of money per unit of energy produced on top of the normal electricity price. Despite the reduced risk this poses because the generator will always receive at least the feed-in premium, the generator is nevertheless exposed to fluctuating prices and their inherent risk, which is very much in contrast to the feed-in tariff. As part of a green certificate scheme, one certificate is administered typically for one megawatt hour of renewable electricity produced and is intended to represent the environmental value of this renewable energy generated. Typically, electricity generators are then required to present a certain number of such green certificates given the total amount of electricity they supplied to customers, which increases the demand for renewable energy because generators are generally required to pay a fine for failing to present the required amount of renewable energy certificates. Alternatively, a slightly different quota scheme could see such certificates being sold to end customers who buy a guarantee that a certain amount of renewable energy is fed into the grid. Green certificates can thus be used to meet a renewable portfolio obligation or to provide end consumers of electricity with certified green electricity. In the EU the two predominant support mechanisms for renewables are feed-in tariffs and certificate based systems (Cleijne and Ruijgrok, 2004).

3.1.2. Cost Parameters

The costs incurred by a floating offshore wind farm are capital expenditures (capex) that are incurred at the outset of the project, operational expenditures (opex) and taxes that are incurred during the operational phase of the project, decommissioning costs and any costs associated with the funding received, for example, interest payments if the policy support constitutes a loan.

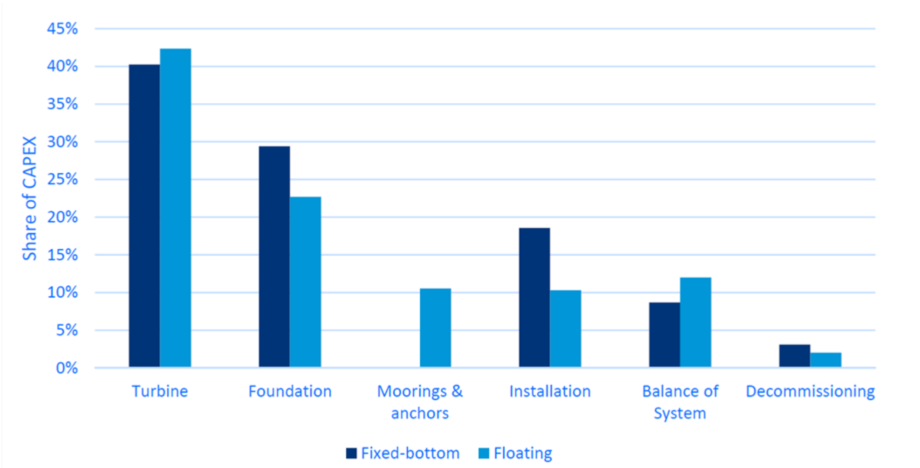
Capital Expenditure

The initial installation costs are generally referred to as the capital expenditure position (Gribben, Williams and Ranford, 2010). Capital costs are made up mainly of the upfront investment costs and include wind turbine generators, substructures, mooring lines, anchors, assembly halls, road construction and grid connection, project development and planning costs, installation, medium to high voltage substations if applicable, transportation, craning, assembly and tests, as well as the administrative, financing and legal costs that are incurred with respect to the installation process (ATKINS, 2014). This cost position is by far the biggest for any floating offshore wind farm developer, accounting for between 75% (Krohn, Morthorst and Awerbuch, 2009) and 80% (Blanco, 2009) of the total costs of a wind farm over its lifetime. IRENA (2012) even claims it can account for as much as 84% of total installed cost. This capital-intensity at the very outset of the project is in stark contrast to

conventional fossil fuel-based technologies, such as natural gas, where the capital costs only account for 30% to 60% because up to 40%-70% of the costs of those plants are related to fuel and O&M costs (Krohn, Morthorst and Awerbuch, 2009).
Floating offshore wind structures offer a few cost advantages when compared to fixed offshore projects. Floating project, for example, incur lower foundation costs as they require less steel than fixed projects, and generate lower installation costs (see Figure 3-2 below).

Figure 3-2: Cost breakdown for a typical fixed and floating wind farm

Source: The Carbon Trust, 2015



While assembling a fixed offshore turbine requires specialised heavy-lift vessels that can only operate under certain weather conditions, a floating turbine – especially a semi-submersible structure – can be fully assembled at a dock in the harbour and then towed out once fully erected by a standard tug boat that only costs about a third to hire than a specialist vessel (James and Costa Ros, 2015). Similarly, decommissioning floating offshore wind farms is much simpler and less costly than decommissioning fixed structures. This is reflected in the day rates for the vessels required to accomplish each respective installation and decommissioning: standard tug boats, which are sufficient to tow out fully erected floating turbines only incur about a third of the costs of the heavy-lift vessels required for fixed turbine installation and decommissioning (James and Costa Ros, 2015). In Chapter 4, we will detail the capital costs of our model floating offshore wind farm.

Operating Expenditure

Operational expenditures associated with floating offshore wind farms include most notably operation and maintenance (O&M) costs as well as cost elements related to insurance, scheduled and unscheduled maintenance, repair, spare parts, site rent, consumables, administration, and power from the grid (Krohn, Morthorst and Awerbuch, 2009). O&M costs only account for about 15%-25% of the total wind farm costs (Blanco, 2009; Krohn, Morthorst and Awerbuch, 2009; IRENA, 2012), and thereby constitute a rather small component compared to capital expenditures. Krohn et al (2009) state Spanish data indicates that about 60% of operational expenditure is spent on O&M of the turbine, labour costs and spare parts. The remaining 40% go in equal parts to insurance, land rental and overheads. Like capex, operational costs can vary significantly between countries, regions and even sites (Blanco, 2009): Some governments, for example, request continuous environmental evaluation and conservation studies, which can become an additional cost factor (Gribben et al., 2010). Other countries, such as France, place a special tax on all offshore wind turbines in operation. The distinct advantage of wind energy, compared to other forms of energy, with respect to operational expenditures is that once the installation process is complete and assuming that the wind resource has been calculated correctly, the generation costs for the entire project lifetime are predictable with reasonable certainty. This is, for example, why we did not add a contingency cost to our opex model figures, something we did for our opex cost estimates (see Chapter 4).

Opex will be adjusted to the inflation index just as other parts of the model will be indexed to inflation. For an explanation of the inflation rate, please see below (Section 3.1.3 Other Cash Flow Parameters).

Taxes

Generally, floating offshore wind and other renewable energy projects are required to pay taxes on their earnings. The formula for taxation is:

$$\text{Taxes payable}_t = \left(Income\ from\ electrictity_t + income\ from\ funding_t - opex_t - depreciation_t\right) \times T_c \tag{3}$$

Where,

t: any given year

T_c:corporate tax rate

Taxes will be adjusted for each funding regime because the authors view taxes as part of the funding schemes (see section 3.2).

Other Costs

The developer of a floating offshore wind farm may incur costs other than the three types mentioned above if, for instance, the funding scheme consists of a loan that needs to be paid back with interest over a certain amount of time.

Cost of Debt

Our model will not use debt financing. We do not ignore debt, but assume that every project considered needs a stately guarantor who guarantees the debt of the project, such as the infrastructure guarantee fund in the UK. For simplification purposes we will henceforth assume that projects are all equity-financed, because debt financing would complicate the model unnecessarily. This is an aspect the authors decided on after consulting a developer of an ongoing project in Scotland, who also suggested to keep debt considerations out of the analysis to construct the model only as complicated as necessary[1].

3.1.3. Other Cash Flow Parameters

Lifetime of the Project

Like the real *Kincardine* project, our model floating offshore wind farm will have a lifetime of 25 years. This is the industry standard for offshore wind projects (Shafiee, Brennan and Armada Espinosa, 2015).

Depreciation of Investment

Depreciation may be defined as the annual decrease in the value of an asset to its owner where value denotes the present value of all future cash flows under a certain asset (Kraus and Huefner, 1972). Depreciation essentially spreads the value of an

[1] Interview with Allan MacAskill, developer of *Kincardine*, 06.11.15 , Appendix D.e, Lines 28-31

investment over several years and is a widely used instrument to reduce one's taxable income in the first few years of a project. Importantly, it is merely an accounting measure to spread one's investment over a longer period of time with the main purpose to save taxes. The actual investment always has to be made at the beginning of a project, typically termed year 0. In the case of a floating offshore wind farm, depreciation is of interest because the vast majority of total costs (capex) is spent at the outset of the project. The way these capital expenditures are depreciated and the length of the depreciation period affect, for instance, the time when the developer starts to return a profit and is thus of great concern to investors.

In a firm's accounts, the value of the asset in question, in our case capex, in a given year is the asset's value of the previous year less the depreciation charge (Kraus and Huefner, 1972). Because our model floating wind farm will be based in Scotland, we will use the capital allowance system that is used in the UK to depreciate equipment, machinery, business vehicles, and so on for accounting purposes (Government of the United Kingdom, 2016a).

Discount rate

The discount rate reflects the perceived risk of a project, the regulatory and investment environment in each particular jurisdiction (Blanco, 2009). A common way for investors to account for higher risks is the use of higher discount rates when they lend money to new technologies. In the case of floating offshore wind, the immaturity of technology is the main source for risk exposure, where the higher discount rate is meant to offset the potential probability of project failure. The discount rate is estimated according to the financial return that investors require on the capital they provide. The return an investor expects to receive is again dependent on the risk they expect to be exposed to. When it comes to funding mechanisms, a feed-in tariff, for instance, is guaranteed by law over a fixed period of time and therefore holds less risk than a market-based certificate scheme that is subject to fluctuating prices.

In order to calculate the appropriate discount rate for our pre-commercial floating offshore wind farm, we use the Capital Asset Pricing Model (CAPM). The CAPM accounts for the relationship between investment risk and financial return in a simple calculation.

The formula for the CAPM is (Berk and DeMarzo, 2014):

$$E(r_e) = r_f + ß(risk\ premium) \tag{4}$$

Where,

$E(r_e)$: Expected return, the appropriate discount rate for our model

r_f: Risk-free rate, typically the yield of government bonds

ß: Risk beta, an adjustment for the risk of this type of technology

risk premium: The additional return required for bearing incremental risk in the financial market on top of the risk free rate

Inflation Rate

Current inflation rates are far below the respective targets of each of the countries whose funding regimes we consider in this study. Additionally, the estimated inflation rates for long-term projects differ substantially from country to country (Trading Economics, 2016a).

In alignment with the current monetary policies of the European Central Bank and the American Federal Reserve, inflation rates in all relevant Western economies for this study and Japan have been trending towards 0% this year (Trading Economics, 2016a). The US, where inflation has recovered from 0% to 1.4% this year, remains the exception.

Inflation forecasts for the different markets vary substantially. Projections for the US vary between 2%, 2.3% (Cleveland Fed, 2016) and 2.8% (Trading Economics, 2016b). Inflation rates for Japan and the EU are estimated at 1.8% and 2% respectively until 2020 (The Economist, 2016). Other sources suggest inflation rates as high as 3% for the UK, for example, starting from 2016 (Statista, 2015).

In the light of these quite different projections and the recent economic downturn in whose aftermath we have seen inflation rates close to zero, it is challenging to choose an appropriate inflation rate for long-term projects like our pre-commercial model wind farm. We decided to use the European Central Bank's (2016) long-term inflation target of 2% for our study since our model pre-commercial floating offshore wind farm is based in Scotland, an EU country, and we expect the inflation rate to tend again towards this target in the long run.

3.2. Application of Funding Mechanisms

After constructing the cash flow model, four different funding regimes are applied to the model in turn. These are:

1) A Scottish-style funding regime, using tradable renewable certificates
2) A Japanese-style funding regime, using a feed-in tariff scheme
3) A French-style funding regime, using a feed-in tariff scheme and a grant
4) A Hawaiian-style funding scheme, using a feed-in tariff scheme and production tax credit

These funding regimes were selected because they prevail in markets that currently either develop floating offshore wind projects or offer good conditions for future development. In order to provide an as accurate picture as possible of how different funding mechanisms from various markets around the world affect a model pre-commercial floating offshore wind farm in Scotland, we adjusted various factors associated with the funding regime when applying them to the Scottish wind farm model: The currency, the corporate tax rate and the discount rate. All of these changes are necessary in order to 'bring the funding regime to Scotland' and allow for a comprehensive comparison between the different mechanisms.

Adjustment of Currency

Our entire analysis is conducted in British Pound Sterling (GBP). The level of funding paid in the local currency under each funding regime is therefore converted to GBP using average exchange rate data of the past 10 years between GBP and the respective foreign currency. This data was derived from the US Foreign Exchange Service (US Forex, 2016), see Appendix A. The 10-year period was chosen because the authors believe the average exchange rate of the past 10 years to be more reflective of the actual value difference between the currencies than the current (April 2016) exchange rate. We suggest to use the average of 10 years to generate a true exchange rate that is not subject to short-term fluctuations.

Adjustment of the Corporate Tax Rate

The authors have adjusted the corporate tax prevailing under each of the different funding regimes to reflect the fact that funding mechanisms in every jurisdiction were designed with the respective corporate tax rate in mind and can therefore be regarded as ‘part’ of the funding mechanism. This becomes particularly evident in Hawaii where tax breaks are part of the support scheme. It makes sense to adjust the tax rate of the model under each funding regime respectively in order to reflect the impact of the support scheme entirely.

Adjustment of the Discount Rate

The discount rate in our model captures the risk inherent in each funding mechanism. Feed-in tariff schemes, for instance, constitute a more secure income for investors than a market-based certificate scheme that subjects the price investors receive for every MWh sold to market fluctuations. The discount rate can be used in order to quantify these differences in risk and is therefore adjusted for every funding regime. This way the cash flow model and economic indexes calculated will ultimately reflect each funding mechanism’s inherent economic risk to investors.

3.3. Economic Indexes

In order to assess the attractiveness of an investment in a pre-commercial floating wind farm to investors, we need to evaluate the economic profitability of this investment in the project under different support scheme scenarios. The economic indexes chosen to evaluate the economic attractiveness are net present value (NPV), internal rate of return (IRR), return on investment (ROI), levelised cost of electricity (LCOE) and discounted payback period (DPBP). All of these, except ROI, are considered the most important economic indexes when determining the economic feasibility of a floating offshore wind farm (Castro-Santos and Diaz-Casas, 2014; Castro-Santos and Diaz-Casas, 2015. ROI was chosen in addition to the indexes above because it captures the return an investor can expect under each funding regime and is therefore of great interest to our study. The indexes together deliver a comprehensive picture of the profitability of our model wind farm under each funding mechanism scenario. In this section of the chapter we will explain each economic index in turn and outline how they complement each other.

Net Present Value (NPV)

The net present value method is particularly well suited to determine the economic desirability of a project (Gosens, 2015) and constitutes the standard method for the financial evaluation of long-term investments in renewable energy projects (Cucchiella, D'Adamo and Gastaldi, 2015).

The NPV calculation includes the initial investment in a project as well as the running costs and revenues over time. The various cash inflows and outflows are adjusted for the time value of money and risk, which is reflected by the real interest rate. The basic assumption behind the time value of money concept is that money is worth more today than tomorrow because of the devaluation of money and the opportunity to earn bank interest. The NPV model uses the interest rate to calculate the present value of future cash flows.

The formula for the NPV is (Berk and DeMarzo, 2014):

$$NPV = -I + \sum_{t=1}^{T} \frac{Cash\ Flow_t}{(1+r)^t} \tag{5}$$

Where,

I: initial investment

T: total duration of the project

t: time period

Cash Flow_t: Free cash flow after taxation, depreciation

r: (real) discount rate

We assume that cash flows occur at the end of each time period considered. This is an assumption intended to simplify the model and limit excessive computations. Because our model is not attempting to maximise the NPV of each model per se, but rather to evaluate the relative differences between the different funding schemes, we believe that this assumption is reasonable.

The most challenging part of this index is the calculation of the real interest rate. The immaturity of floating wind technology and the lack of experience with offshore wind power projects in general across the 25-year life cycle are the main sources of uncertainty. Interestingly, a study by Narbel, et al. (2014) showed that capital-intensive technologies such as offshore wind are less affected by a presumptive future interest rate increase when compared to fuel powered plants because fuel powered plants incur more costs in the future than wind farms due to expenses for fuel while wind farms incur the vast majority of their costs at the outset of the project. Thus, an offshore wind power project is likely to be the more attractive investment when interest rates are low but expected to increase in the future, as it is currently the case with global interest rates. Fuel power plants on the other hand tend to be a more attractive investment when interest rates are high but expected to decrease because then it makes more sense to make use of currently prevailing high interest rates putting money in the bank and earning interest on it and spending it later, rather than spending it now.

Real Interest Rate

In order to calculate the net present value of each of our four funding regime models, we need to discount future cash flows with the real interest rate. This rate reflects the level of risk inherent in the project. The real interest may be defined as an ex ante rate, which subtracts the expected rate of inflation from the actual nominal rate (King and Low, 2014).

The formula for the real interest rate is (Berk and DeMarzo, 2014):

$$r = d - i \tag{6}$$

Where,

r: real interest rate

d: nominal interest rate / discount rate

i: inflation rate

The nominal interest rate is equal to the discount rate, which we calculate for each funding regime respectively. From this, the assumed inflation rate of 2% (see section 3.1.3) is subtracted and the resulting real interest is then used to discount future cash flows in every model to calculate the NPV.

Internal Rate of Return (IRR)

While the NPV method is straight-forward, it does not allow for determining the economic differences between two projects that have the same NPV but different cost requirements. The internal rate of return (IRR) complements the NPV parameters by providing some insight into the economic aspects of a project. This profitability index has been cited as one of the most meaningful to investors of renewable energy projects (Talavera, Nofuentes and Aguilera, 2010). IRR is defined as the interest rate that leads to a project NPV of zero. In other words, IRR is equal to the actual interest rate at which the upfront investment into a project is ought to be lent during the project's lifetime. Due to the nature of the NPV formula, there is no analytical way to calculate IRR so that NPV = 0 and an approximation of IRR has to be found through either trial and error or by means of a computer programme (Nofuentes, Aguilera and Muñoz, 2002). In our calculation we will use Microsoft Excel's IRR function. In general, higher project IRRs are preferred over lower IRRs.

Return on Investment (ROI)

Evaluating the efficiency of an investment, the return on investment (ROI) index constitutes a simple method to test for profitability (Berk and DeMarzo, 2014). ROI measures the amount of return on an investment relative to the costs of the project. The result is expressed as a percentage, which should be positive. Otherwise an investor will lose money when going through with the investment.

The formula for ROI is:

$$ROI = \frac{(Gain\ from\ investment - Cost\ of\ investment)}{Cost\ of\ investment} \tag{7}$$

The gain from investment in (7) is the sum of all discounted free cash flows over the 25-year lifetime of the project, accounting for operating costs, taxation and depreciation. The cost of investment is the initial capital expenditure in year 0 when the wind power plant is build. The operating costs are already accounted for in the 'gain from investment' position because they are part of the free cash flows calculated for each year.

Levelised Cost of Electricity (LCOE)

The levelised cost of electricity (LCOE) is a widely used benchmarking and ranking tool to evaluate and compare the cost of energy production of different sources of electricity (Branker, Pathak and Pearce, 2011). It denotes the cost of electricity over the entire life cycle of a power plant and is constituted by the ratio of the total costs to the total amount of electricity expected to be generated over the project lifetime (DECC, 2013). The LCOE calculation is based on discounting annual, quarterly or monthly cash flows to a common basis. The principal components of a wind farm's LCOE include capital costs, O&M costs and the expected annual power generation (IRENA, 2012). The LCOE of wind energy can vary significantly according to the quality of the wind resource, the investment cost, O&M expenditure, the cost of capital, and technological improvements leading to higher capacity factors (IEA, 2013). Using the correct rate to discount cash flows is crucial for the LCOE calculation (IRENA, 2012). In a case of debt financing, the weighted average cost of capital (WACC) would be used to discount the project's costs over time but because we consider a model without debt, we will use the normal discount rate calculated for each project respectively. The formula for LCOE is:

$$\mathrm{LCOE} = \left[\frac{\mathrm{R} \times \mathrm{c}_\mathrm{p}^\mathrm{i}}{\mathrm{H} \times \mathrm{f}_\mathrm{p}}\right] + \left[\mathrm{l} \times \left(\frac{\mathrm{c}_\mathrm{p}^\mathrm{o}}{\mathrm{H} \times \mathrm{f}_\mathrm{p}}\right)\right] \tag{8}$$

$$\mathrm{R} = \left[\frac{\mathrm{d} \times (1 + \mathrm{d})^\mathrm{T}}{(1 + \mathrm{d})^\mathrm{T} - 1}\right] \tag{9}$$

$$\mathrm{l} = \frac{\mathrm{d}(1 + \mathrm{d})^\mathrm{T}}{(1 + \mathrm{d})^\mathrm{T} - 1} \times \frac{(1 + \mathrm{e})}{(\mathrm{d} - \mathrm{e})} \times \left[1 - \left(\frac{1 + \mathrm{e}}{1 + \mathrm{d}}\right)^\mathrm{T}\right] \tag{10}$$

Where,

c_p^i: Initial installation cost i for plant p (in £/MW)

R: Capital recovery factory (in %)

c_p^o: O&M cost for plant p in year 1 (in £/MW)

l: Levelisation factor

f_p: Capacity factor for plant p (in %)

d: Discount rate (in %)

T: Plant life (in years)

e: Escalation rate (in %)

H: Hours per year

The equations were derived from the LCOE formulas presented by Narbel et al (2014). The recovery factor *R* (equation 9) is the share of the plant cost that the revenue from a year of operations must recover in order to balance out the project at the end of the plant life (Narbel, Hansen and Lien, 2014). This factor is calculated with a third formula (10) and accounts for increases in O&M costs over time as the plant ages. The escalation rate e is the rate at which O&M are assumed to grow every year. The first and second elements in the first formula (8) are each divided by the number of hours that the plant runs at full capacity every year to find the cost per hour of operation. The number of hours at which the plant runs at full capacity is calculated by multiplying the total number of hours in a year H by the capacity factor f_p. The capacity factor denotes the number of hours the plant runs at full capacity, and is expressed as a percentage of the total available production capacity.

The LCOE is primarily used for calculating the cost of a power plant and is a useful instrument to compare the cost of different energy sources. It allows for a clear comparison between the price of wind power and the price of other energy sources across countries and regions, as well as for a comparison between the costs of offshore fixed, offshore floating and onshore wind farms (IRENA, 2012). In our study this parameter allows for assessing the cost of one unit of electricity under different funding regimes.

Discounted Payback Period (DPBP)

The discounted payback period (DPBP) complements the previous indexes by indicating the time in which the initial investment of a project can be recovered from the cash inflows generated by the project (Zountouridou et al., 2015). One of the simplest investment appraisal techniques, DPBP constitutes the extended form of the simple payback period model, in contrast to the latter also accounting for the time value of money.

In contrast to the other indexes considered in this study, the DPBP technique focuses on capital recovery rather than project profitability (Zountouridou et al., 2015) and therefore does not account for the cash flows after the break-even point. In thus it complements the rest of the series of other economic indexes.

The formula is:

$$DPBP = A + \frac{B}{C} \tag{11}$$

Where,

A: last period with a negative cumulative cash flow

B: absolute value of cumulative cash flow at the end of period A

C: discounted cash flow during the period after A

3.4. Sensitivity Analysis

In order to demonstrate the magnitude of influence that certain parameters of the model (level of funding, taxes, discount rate) have in determining the outcome of the financial incentives' impact on the model, as evidenced by the main economic indexes, a sensitivity analysis is carried out. The value of these parameters might change according to governmental policies, technologies used, the risk perceived by investors, etc. A sensitivity analysis constitutes an appraisal of how a change in the above mentioned parameters influences our analysis and therefore aims to indicate the robustness of our results. Additionally, it allows for drawing more general conclusions from our results more reasonably later on.

The authors develop three scenarios: a base case scenario, an optimistic scenario and a pessimistic scenario. The base case is constituted by the numbers used for the general analysis. Following discussions, the authors decided to use +10% and -10% for the optimistic and pessimistic case respectively for the level of funding, and -10% and +10% for the optimistic and pessimistic case respectively for the tax rate and the discount rate.

The sensitivity analysis essentially constitutes a what-if scenario analysis and is calculated using Microsoft Excel's What-If Analysis tool. Only one parameter is changed at a time, keeping all other parameters at base case level, in order to generate meaningful sensitivity analyses for each major input factor. These analyses provide the authors with an understanding of how the variance in the different input parameters affects the results of the economic indexes. The outcomes were then used to create tornado charts in order to provide a meaningful illustration of the influence of one parameter's sensitivity on the model.

3.5. Data Collection and Critique

The pre-commercial model floating offshore wind farm used in this study is based on the *Kincardine* project, a pre-commercial floating offshore wind farm that is currently in its planning phase and scheduled to be operational off the coast of Scotland by the end of 2017. More specifically, our thesis uses current capex and opex estimates for the project as input parameters for our cash flow model, and by extension for the calculation of the various economic indexes. The rest of the data used throughout the study has been gathered through research.

Collection and Reasoning

The authors have chosen to base this study on the *Kincardine* project for two reasons: 1) *Kincardine* is one of the furthest advanced pre-commercial floating offshore wind farms currently under development worldwide, which is why the data can be argued to be reasonably close to what the actual costs of such a pre-commercial floating offshore wind farm will end up being. This is useful for further studies that can be conducted on the basis of our analysis and serve as a basis to start comparing costs of floating offshore wind projects over time. 2) *Kincardine* will be based on the semi-submersible structure *WindFloat*. In contrast to the spar buoy structure which is restricted to waters with depths of 100m or more, semi-submersible structures are more flexible in terms of their application. Most floating projects worldwide that are currently in the planning phase use semi-submersible structures. Given the cost differences between these two types of substructures, in analysing the profitability of a wind farm based on semi-submersible structures, our study is more widely applicable.

We were fortunate enough to receive our primary data for capital and operational expenditure from Allan MacAskill, developer of the *Kincardine* project. Other data needed was derived from publicly available data, other planned projects, cost projections from the literature or interviews conducted with industry experts. In addition to several conversations with Allan MacAskill, the authors also conducted interviews with David Stevenson (Head of Offshore Wind Policy, Scottish Government), Johan Sandberg (Service Line Leader Offshore Renewables at Det Norske Veritas), Frederic Chino (Ocean Energy Sales Department Manager at DCNS Group), Carlos Martin Rivals (Project Director of Windfloat Atlantic, EDP), Bonnie Ram (Senior Researcher, Department of Wind Energy, Technical University of Denmark) and Morton Dillner (Analyst at Statoil).

Critique

The data provided by Allan MacAskill is from mid-2014, which might be considered rather dated. Allan MacAskill, however, confirmed that the data was still valid and that it, in fact, in light of recent interest rate developments, constituted rather conservative estimates[1].

The cost estimates may furthermore be criticised because they are simplified and crude. They are only meant to be an estimate of the costs that will actually be incurred, hence the rather generous contingency estimate (see section 4.1.2). Because figures from similar projects are generally not publicly available for confidentiality reasons, we have no means of comparing theses estimates to others and must therefore take the Kincardine estimates at face value. It may be argued though that this is acceptable given that the goal of our study is to compare funding mechanisms relative to each other and not to give an as accurate as possible cost estimate of a pre-commercial floating offshore wind farm: For the purpose of this study, the authors therefore argue that even a simplified cost estimate of capex and opex is sufficient to produce reasonable results.

A further point of critique is that the cost estimates provided by Allan MacAskill for our pre-commercial model wind farm are quintessentially Kincardine-specific costs. This means that cost positions such as manufacturing and installation costs were estimated with the Scottish infrastructure in mind. The Scottish infrastructure though arguably offers relatively favourable conditions for floating offshore wind projects: Benefitting from decades of high-profile oil and gas exploration activities, Scotland's infrastructure with regards to docks, assembly halls, specialist vessel services, and so on is rather extensive. Less favourable conditions may prevail in other markets we have considered above. This means that our findings have to be taken with a grain of salt: Our findings reveal the most beneficial support structure for a pre-commercial floating offshore wind farm, even if the costs for installation or similar were higher in other markets because the relative differences between the funding mechanisms would still prevail as they do in our study. But that does not mean that if a country other than Scotland adopted this type of policy support, it could soon be on par with Scotland in the race for a first mover advantage in the floating offshore wind sector.

[1] Interview with Allan MacAskill from the Kincardine Project, 06.11.15, Appendix D.e, Lines 90-95

Scotland has not least been selected for the world's two first pre-commercial arrays due to its favourable infrastructure.

3.6. Limitations of Methodology

Some limitations of our study have been touched upon above during the discussion of the limitations inherent in our data. In addition to these, there are three limitation aspects associated with our methodology that the authors would like to draw the reader's attention to.

NPV

When interpreting our NPV results, one must keep in mind that our analysis fundamentally assumes that the project can become operational next year. But this may not be the case somewhere other than Scotland. In France, for instance, the first floating demonstrator prototype may not come online before 2022[1], which means that a pre-commercial array will be deployed even later than that. This highlights again that a country other than Scotland adopting the most favourable funding regime as revealed by our study would not necessarily accelerate its deployment of floating offshore wind prototypes and pre-commercial farms. If one were to calculate the case for a pre-commercial wind farm in France, one would have to discount the project further into the future to factor in that the French offshore wind sector lags behind the Scottish one.

LCOE

LCOE calculations usually do not account for risks or different methods of financing that may be available for different energy projects. We have partially solved the latter by starting out with a cash flow analysis, which could theoretically account for debt but since the authors have chosen not to consider debt-financing options, this point of criticism becomes negligible. While this then means that the LCOE calculations in our study are fine for the purposes of this paper, their applicability for future studies is necessarily limited. Our results should therefore not be taken at face value or extrapolated to indicate the global LCOE of a pre-commercial wind farm under

[1] Interview with Frederic Chino of DCNS, 23.09.15, Appendix D.b, Lines 60-61

certain funding schemes but instead always be viewed in context. Indeed, this is the case because the costs and amount of generated electricity tend to vary significantly in regards to location, generation capacity, complexity, efficiency, operation, plant lifetime and other factors (Branker, Pathak and Pearce, 2011). A further reason to always keep in mind the context in which certain figures have been derived is that LCOE only provides a ‘snapshot’ of a technology’s price at a certain moment in time and under specific circumstances while in reality market prices are dynamic (Branker, Pathak and Pearce, 2011).Given that LCOE is considered a benchmarking tool, the assumptions made about its cost factors are highly sensitive, even more so when considering its value several years into the future. It is therefore suggested that when evaluating policy alternatives, assumptions should be made as accurately as possible, using sensitivity analyses and justifications (Branker, Pathak and Pearce, 2011). The authors have done precisely that to counteract the potential disadvantage of LCOE that is its high sensitivity to certain assumptions. While a useful tool for comparing different technologies, the LCOE method does not say anything about the real revenues require to finance a project (Levitt, Kempton, Smith, Musial, & Firestone, 2011).

Debt Considerations

The authors have deliberately decided not to consider debt, unless it is part of a funding mechanism, as it would be, for instance, in the case of a government loan. This arguably makes the model less close to reality than it could be because in some cases a developer might take on debt to finance such a project. However, because the study at hand does not necessarily aim to provide figures that can be taken at face value but merely evaluate the relative differences of different funding schemes on a project, this criticism becomes negligible. Not considering debt keeps the model simple and does not distract from its main goal, which is to evaluate the economic impacts of different funding schemes on pre-commercial floating offshore wind farm relative to one another.

CHAPTER 4: Analysis

The analysis chapter will follow the structure that was outlined at the beginning of Chapter 3. We will analyse four funding mechanisms, but first we turn our attention to the cash flow model itself, which constitutes the basis for calculating the economic indexes for each funding regime. Then we turn to each funding regime and studying it in its economic and social context. Finally, we calculate the cash flow model, five economic indexes and conduct a sensitivity analysis under each regime.

4.1. Our Cash-Flow Model

The *Kincardine* project provides the basic figures for our cash flow model, particularly for capex and opex estimates. Before we begin our analysis we will provide a brief overview of the *Kincardine* wind farm project. We give a detailed account of the figures and use these to develop our basic cash flow model in 4.1.2. These numbers form the basis for the adjusted cash flow models, and economic index analyses conducted thereafter.

The Kincardine Project

The *Kincardine Offshore Windfarm* is a proposed demonstrator pre-commercial floating offshore wind farm with an installed capacity of 48MW, which will be located about 15km southeast off the coast of Aberdeen, Scotland. It is currently in the planning phase, and is expected to be operational and grid connected by 2017. The project is run by Kincardine Offshore Windfarm Limited (KOWL), a partnership between international engineering company Atkins and Pilot Offshore Renewables. The latter is a joint venture between Renewable Energy Ventures (Offshore) Limited and consultancy MacAskill Associates (ATKINS, 2014), whose director Allan MacAskill provided us with the capex and opex data of the project.

Aiming to prove floating wind technology's future technological and commercial feasibility, the *Kincardine* wind farm will consist of eight wind turbine generators mounted on semi-submersible *WindFloat* structures, with a capacity of 6MW each.

One of the world's first floating offshore wind arrays, *Kincardine* constitutes a pioneering effort in the field, aiming to prove the technology's commercial feasibility and future cost reduction potential.

4.1.1. Our Figures

All cash flow models are comprised of four main elements: capital expenditures, operational expenditure, capacity factor and funding mechanisms, including taxes. Capital expenditures, operating expenditures and capacity factor will stay the same throughout our analyses as they are project-specific and not affected by different funding regimes. First we outline the components of our basic cash flow model that forms the basis for the subsequent analysis. The funding regime of each of the four jurisdictions considered is then applied in turn, including the calculation of the five economic indexes and sensitivity analyses of the main model parameters.

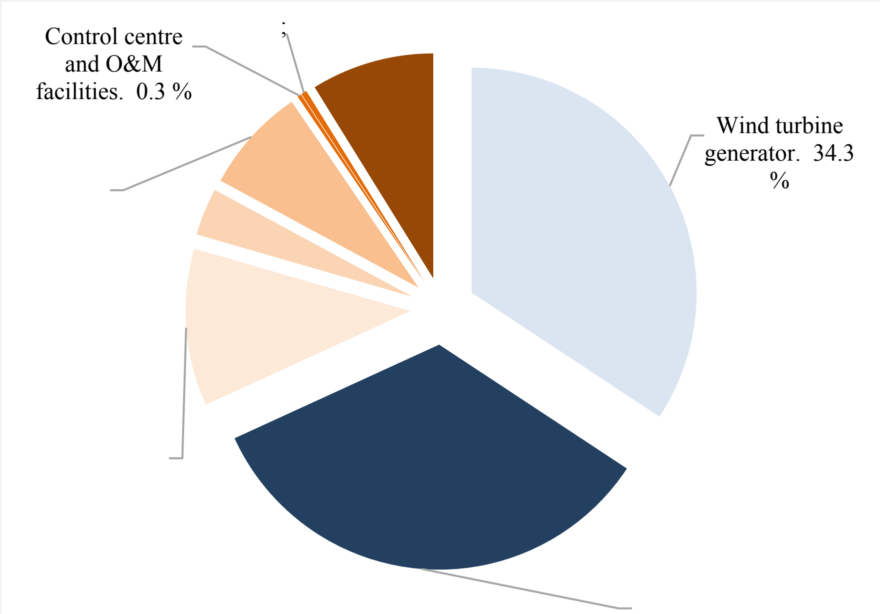
Capital Expenditure

Table 1 shows the capital expenditure figures used in our study. The developers of the *Kincardine* project are confident that the estimates below of turbines, moorings, electrical facilities and cables are correct. The industry has extensive experience with turbines, substations, grid connection and other elements of the capital expenditure position to provide reasonable estimates for these. However, the substructure and its installation constitute novel territory for the developers.

Table 1: Capital expenditures for our model

Wind turbine generator	£	62,474,783
Floating substructures	£	61,756,000
Installation of turbine and substructure	£	20,598,500
Onshore and offshore electrical facilities	£	6,214,212
Cables	£	13,835,000
Control centre and O&M facilities	£	500,000
Site and route surveys	£	750,000
Insurance and others	£	16,110,500
Total estimated wind farm cost	£	182,228,995
Contingency (20%)	£	36,447,799
Capex	£	218,686,794

Figure 4-1: Proportion of each cost position to the total expenditure



Reasonable estimates can nevertheless be made based on experience in dealing with semi-submersible structures in the oil and gas industry. The figures provided to us included a contingency factor of 30%. Contingency costs are a monetary measure that allows for factoring in the uncertainty inherent in capital cost calculations. The 30% figure was revised down after discussions with industry experts David Stevenson and Johan Sandberg. Based on their industry experience, both recommended a factor of 20% due to the relatively small size of the Kincardine project. The 20% figure also seems more reasonable in the current economic climate that has seen a decrease in commodity prices and increased competitiveness in offshore vessel market, compared to the price levels from mid-2014 when the above capex estimates were derived. Given that these price decreases make the capex estimate rather conservative, the authors assume a contingency of 20% to be reasonable. It is important to note that contingency remains a tool to account for commercial risk rather than to estimate costs. Given the novelty of floating wind technology, it is naturally difficult to estimate the accurate costs. We assume that cost estimates will become increasingly more accurate as the project progresses and approaches the construction phase.

There is the possibility of any possible links between capital expenditures and operating expenditures revealing themselves; this means that there might be opportunities to save operating expenditures if additional investments were made in capex today and vice versa.

Decommissioning costs

Decommissioning costs are part of the capital expenditure positions but have been excluded from the cost estimate above. The reason for this is that the decommissioning cost of the Kincardine project is assumed to be negligibly minimal, because the sale of raw materials, like steel from the decommissioned turbines, may indeed pay entirely for the removal of anchors and mooring lines or even incur a negative decommissioning cost, i.e. a profit on part of the project developer (Myhr, et al., 2014). Since this position is furthermore difficult to estimate at this moment in time and negligible in terms of size, it has been omitted from the analysis below for simplification purposes.

Depreciation of Investment

Because our pre-commercial model floating wind farm is based in Scotland, the study makes use of the capital allowance system employed in the UK to depreciate upfront investment for accounting purposes (Government of the United Kingdom, 2016a). Under the capital allowance system, a project developer may deduct a certain proportion of capex from their profit before taxes if the capex qualifies for annual investment allowance (AIA) under the capital allowance system (Government of the United Kingdom, 2016c). Given the amount of the above capex estimate, a developer may claim 'writing down allowances'. Under this allowance system, a proportion of one's investment can be deducted from taxes. In our case, we may deduct 18% of each year's capex from the taxable amount (Government of the United Kingdom, 2016b).

This means that given the total capital expenditure of GBP 218,686,794 in year 0, our tax shield TS during the first year of operation amounts to GBP 39,363,623:

$$TS_1 = £\ 218{,}686{,}794\ \times 18\% = £\ 39{,}363{,}623$$

Taxes are then paid on the remainder of our revenue, provided it is above GBP 0.

During the second year the following amount of the original investment remains for accounting purposes:

$$£\ 218{,}686{,}794 - £39{,}363{,}6223 = £\ 179{,}323{,}171$$

During the second year of operation, we therefore may deduct GBP 32,278,171 from our taxable income:

$$TS_2 = £\,179{,}323{,}171.10 \times 18\% = £\,32{,}278{,}171$$

This method is continually applied until the end of the project's lifetime. In the final year of operation, we may still deduct GBP 336,223 from our taxable income.

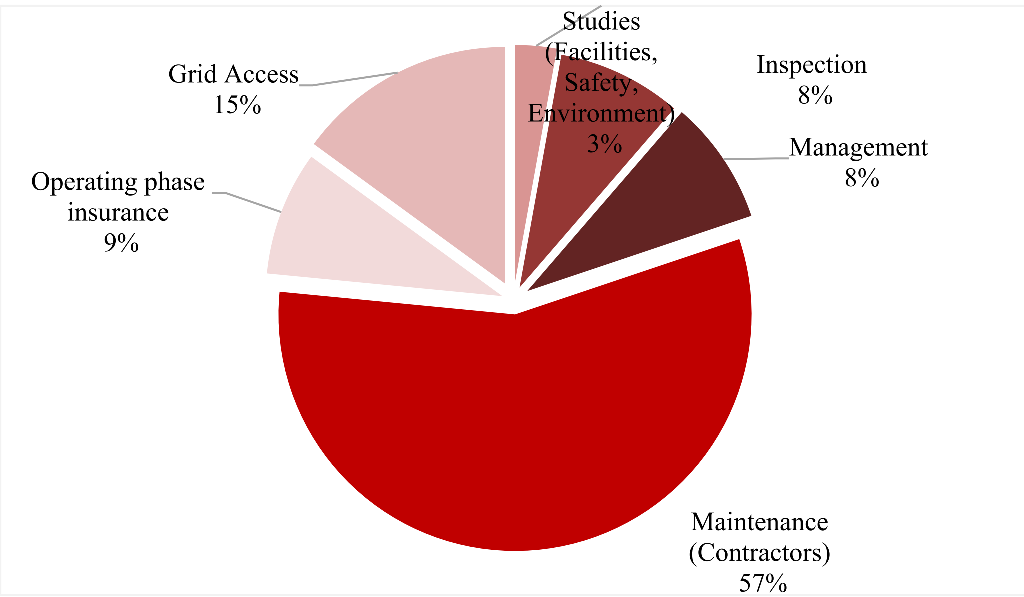
Operational Expenditure

The operational expenditure constitutes the annual costs incurred by the developer through operating and maintaining the wind farm. These estimates are the best cost estimate that can be derived at this moment in time, based on years of experience in the offshore wind industry. In year 1 of our cash flow model these costs will be:

Table 2: Operational Expenditures for Our Model

Studies (Facilities, Safety, Environment)	£	200,000
Inspection	£	600,000
Management	£	600,000
Maintenance (Contractors)	£	4,000,000
Operating phase insurance	£	600,000
Grid access	£	1,056,000
Opex	£	7,056,000

Figure 4-2: Proportion of each cost position to the total operational expenditure



In contrast to the capex estimates, in which the industry has partially experience, opex constitutes an entirely novel territory for the developers who have no experience in operating and maintaining floating offshore wind farms. However, the opex figures used in our model were previously confirmed by an independent consultant from BVG Associated as part of a consultancy report prepared for Kincardine Offshore Wind Limited (Kawale, 2015). For the purposes of our project, we will therefore assume that the above opex values are fairly accurate.

Capacity Factor

The wind resource available on site determines the net annual energy production of a wind farm, otherwise known as the capacity factor. This factor is given by the ratio of number of hours that the wind farm operates at full capacity over the total numbers of hours in a year (8760), and expressed as a percentage (Krohn, Morthorst and Awerbuch, 2009); Blanco 2009). Since our model floating offshore wind farm is based in Scotland and capex and opex estimates have been derived with the *Kincardine* project in mind, we will also assume the *Kincardine* project's capacity factor for our calculations.

In an environmental scoping report carried out for the Kincardine project, Atkins (2014) reported a mean annual wind speed of 9.33m/s for the Kincardine site, with a mean wind speed during the summer of 11.3m/s and 7.3m/s during the winter. James and Costa Ros (2015) estimate the capacity factor of a wind farm built at a site with mean wind speeds of 9.33m/s to be at about 44%. Wind data consultancy Oldbaum Services carried out a preliminary wind assessment analysis specifically for the *Kincardine* project in 2013. Their analysis was based on fourteen 6.15MW turbines and assessed a capacity factor of about 50% when including wake losses (Oldbaum Services, 2013). The number of turbines and layout have been revised since but the capacity factor estimated by Oldbaum nevertheless provides us with an indication of the capacity factors we might expect for the project. A reasonable assumption of the capacity factor of the Kincardine wind farm is therefore is 48.5%, which was confirmed by the project developer Allan MacAskill[1]. Given that our model wind

[1] Interview with Allan MacAskill, developer of *Kincardine*, 06.11.15 , Appendix D.e, Lines 73-75

farm has an installed capacity of 48MW and the estimated capacity factor is 48.5%, the total electricity generation amounts 203,932.8 MWh per year.

$$48MW \times 8760h \times 48.5\% = 203{,}932.8\ MWh$$

To not complicate the calculations in our thesis text, we have written 203,933 MWh per year in the text although we used 203,932.8 MWh for the calculations in our excel spreadsheets.

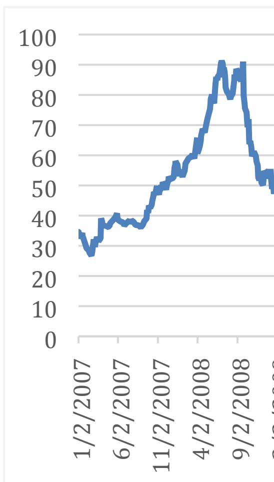
The Sale of Electricity

The wholesale electricity price used throughout our analyses is given by the wholesale electricity price in the UK, given that our model floating offshore wind farm is assumed to be located in Scotland.

The ICIS Power Index (IPI) provides homes and businesses with information about UK wholesale electricity market price trends. The IPI captures the average daily price for electricity delivered over the next summer and winter in GBP/MWh, which is weighted to account for the extra demand during winter. By accounting for the full year, the IPI aims to provide a more 'real' picture of energy price developments rather than short-term developments due to winters, colder weather or shorter days. Please see the below graph for the development of these average daily prices between 2007 and 2015 (ICIS, 2016). The average electricity price during this period, 2007 to 2015, was 49.33 GBP/MWh (ICIS, 2016).

Figure 4-3: Development of UK electricity prices 2007-2016

Source: ICIS, 2016



Electricity market prices depend largely on weather forecasts. Milder than usual temperatures in the winter of 2015 have supressed demand, keeping the market oversupplied. Long-term expectations suggest falling prices (ICIS, 2015). The graph shows that after the financial crisis of 2008/2009, electricity prices have been comparably stable, exhibiting the slightly falling trend already.

The wholesale price of 49.33 GBP/MWh is assumed to be the most accurate estimate of today's wholesale electricity price. This wholesale price is considered to be the present day electricity price, i.e. the electricity price in year 0, will be inflation adjusted for the first year of operation, year 1, and every year thereafter.

4.1.2. Discount rate for each funding regime

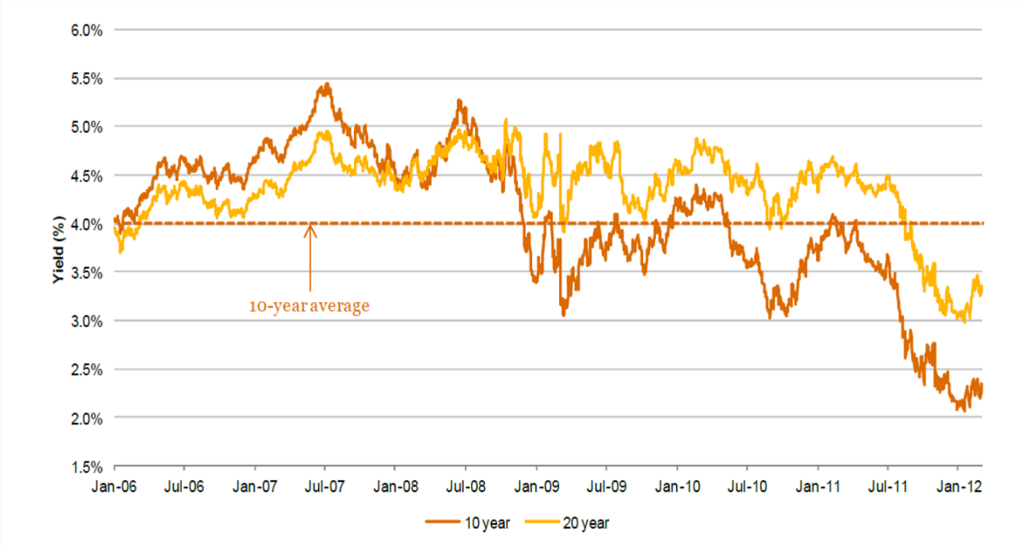
To calculate the appropriate discount rate for each funding regime, we use the capital asset pricing model (CAPM) formula. Each of its components, risk free rate, beta and the equity risk premium, will be calculated in turn.

The Risk-free rate

The risk free rate is typically given by the yield on government bonds. Since recently, the Scottish government holds the power to issue bonds but has yet to issue the first one (Moore, 2015). The authors will therefore calculate the cash flow models and economic indexes in this study using the yield on UK government bonds ('gilts') as an indicator of the risk-free rate. A gilt is a UK government liability that is issued by the Treasury Department in GBP and listed on the London Stock Exchange (United Kingdom Debt Management Office, 2016). Gilts can be issues for 2, 5, 10, 20 or 30 years and each type of gilt returns a different yield. Since our pre-commercial floating offshore wind farm is assumed to run for 25 years and there is no 25-year gilt, we need to use an approximation for the yield. As of today, a 30-year gilt generates a yield of 2.4% (Bloomberg, 2016) but in an offshore wind cost reduction study that included calculating the CAPM of offshore wind, PwC (2012) noted that current UK government bond yields saw a substantial reduction in 2011, following the introduction of the Bank of England's quantitative easing (QE) programme.

Figure 4-4: Evolution of UK government bond fields 2006-2012

Source: Bank of England, 2012



This means that present-day gilt yields are rather unrepresentative of the yield averages over the years before the QE programme.

The consultancy estimated the nominal yield of 20-year UK government bonds at 4.3% for the financial year 2020 but later used a risk-free rate of 4.5% to calculate the CAPM of a floating offshore wind project (PwC, 2012). It is difficult to assess how the yields of government bonds will develop in the future and hence what figure to use for long-term financial planning. It seems reasonable though to use a figure that is closer to the yield average than to the current 2.4%. We will therefore use PwC's figure of 4.5% as the risk-free rate for our discount rate calculations.

Risk beta

The beta adjusts for the risk of the type of the technology and funding mechanism under consideration and is therefore the only part of the CAPM formula that changes between the different funding regimes.

A risk beta for floating offshore wind in particular has not been calculated yet, so we will use beta calculations for offshore wind in general. This is reasonable given that even between offshore wind and onshore wind uncertainties are argued to be unlikely to increase the risk beta significantly (PwC, 2012). This means that we can assume with reasonable certainty that the beta difference between fixed offshore and floating offshore wind farms is also negligible.

Risk premium

The risk premium is the additional return required by investors to invest in equities rather than in risk-free government bonds. This premium has to be estimated over the long term as it cannot be derived from market data. In both academia and the industry one tends to use a combination of derivations from current market data and data of historical return to calculate a risk premium estimate (PwC, 2012). The long-term average of the risk premium for the world is estimated to be 5% (Cleijine and Ruijgrok, 2004). This seems to be congruent with data from ex-ante and ex-post estimates as well as recent regulatory decisions regarding the risk premium in the UK, and a longer term estimate of the risk-free rate (PwC, 2012). It has been argued in the literature that for future project calculations, given the increasingly interwoven nature of international capital markets, it makes more sense to use the world risk premium rather than country-by-country figures as the latter are influenced by country-specific historic events that are unlikely to repeat themselves (Dimson, Marsh and Staunton, 2003). It is therefore that we use the world average risk-free rate rather than the British risk-free rate.

Building the cash flow model

We assume that the first year of operation is year 1 of our cash flow model and that the entire capex position is incurred by the developers at the end of year 0. This means that we assume that the wind farm can be installed ‘overnight’. Naturally, this constitutes an enormous simplification as in reality it takes about two years to install an offshore wind farm. Nevertheless, for the purposes of our study this simplification has been deemed reasonable as it does not affect the result this study aims to reach.

4.2. The Scottish Funding Regime

This section involves treating our model floating offshore wind farm in Scotland with the Scottish funding regime. The authors first analyse the Scottish funding framework, then adjust the parameters that need adjusting, recalculate the cash flow model, then calculate the economic indexes and finally conduct a sensitivity analysis for the model wind farm under the Scottish funding scheme.

Background

For the UK, developing renewables is a matter of security of supply. As around a fifth of the state's existing electricity capacity will come offline as ageing coal and nuclear plants are decommissioned (The Crown Estate, 2015a), the government of the United Kingdom has committed to have renewables account for 15% of its primary energy demand by 2020. This goal aligns with the *EU Renewable Energy Directive* as well as with the UK's own *Energy Act* of 2013, in which the country committed to reduce emissions by 80% by 2050 compared to 1990 levels (The Crown Estate, 2015a). Offshore wind is expected to account for two thirds of this (The Crown Estate, 2016b), and together with other renewables it will account for around 30% of the UK's electricity supply (The Crown Estate, 2015). In the coming 20 years, the UK government plans to increase wind energy generation by a factor of 10 as part of legally binding European Union target for renewable energy (Scottish Enterprise, 2011).

Floating offshore wind could play a major role in the UK electricity mix, but this will fundamentally depend on the amount of total offshore wind power installed by 2050. There are three scenarios projecting the development of floating offshore wind by then. In the first scenario there are only 20GW of offshore wind power installed, and floating wind is unlikely to play a significant role. In scenario two, which could see 40GW of offshore wind being installed, floating wind would account for between 6 - 18 GW. Finally, in scenario three, under which 55GW of offshore wind power could be installed, floating offshore wind would account for significantly more of the installed capacity (James and Costa Ros, 2015).

Scotland is a country within the sovereign state of the United Kingdom and can, within the confinements of UK-wide devolution, pass its own legislation, separately from the British government in Westminster. Scotland can therefore set targets and pass legislation that is applicable in Scotland, but not elsewhere in the UK. More ambitious than the rest of the union, Scotland aims to produce 100% of its electricity demands from renewable energies by 2020 with offshore wind expecting to make the greatest contribution. This target is part of the country's longer-term vision to cut carbon emissions from electricity generation to 50g of CO_2 per kWh by 2030. This goal aligns with the independent advice issued by the UK Committee on Climate Change (The Scottish Government, 2013). The offshore wind potential in the Scottish territorial waters is immense and the Scottish Territorial Waters offshore wind programme will therefore play a substantial part in achieving these targets[1] and contribute to sustainable economic growth in Scotland (The Crown Estate, 2016b). GBP 100bn in investment are expected to flow into renewables between 2011 and 2021 (Scottish Enterprise, 2011). Scotland's *Offshore Wind Route Map* aims to increase the knowledge exchange between companies and the research base in order to help drive down the levelised cost of electricity, possibly leading to cost reductions up to 30% (The Scottish Government, 2013).

Currently, Scotland and France are the only countries that support floating offshore wind specifically, rather than just renewables or offshore wind in general. Under the Renewable Obligation Scotland (ROS), the Scottish government supports floating wind innovation and projects, which are both clearly distinct from the existing general offshore wind band under the ROS (detailed below), because it is believed that floating offshore wind constitutes an industry in which Scotland could gain competitive advantage by capitalising on its significant resource potential (The Scottish Government, 2013).

Renewable Obligation in the UK

In 2002, the UK government introduced their Renewable Obligation (RO) scheme to support the development of large-scale renewable energies, as opposed to small-scale generation of private homeowners, and provide investors in such technologies with long-term stability. This scheme constitutes the main funding mechanisms for large-scale renewable electricity production projects in the UK. It came into effect in England, Scotland and Wales in 2002. Northern Ireland followed suit in 2005 (Ofgem, 2015a). The RO scheme is set by the British Department of Energy and Climate Change (DECC) for England, Wales and Scotland and by the Department of Enterprise, Trade and Investment (DETI) in Northern Ireland, but administered by the Office of Gas and Electricity Markets (Ofgem). Ofgem assesses and accredits RO applications, ensuring that applicants meet the eligibility criteria to be granted accreditation under the RO.

[1] Interview with David Stevenson of the Scottish Government, 16.09.15, Appendix D.f, Lines 59-64

The RO regime is essentially a green tradable certificate (GTC) scheme, and in thus a quantity control policy (Madlener, Gao and Neustadt, 2009). Under a GTC scheme, governments set obligations to consumers or suppliers to obtain a certain share of their electricity from renewable sources. These certificates are issued to producers in accordance with their total amount of renewable energy produced. The certificates are traded and sold independently of the normal wholesale electricity market. Because suppliers need to obtain green certificates to fulfil their quota obligation, the GTC scheme ensures a demand for certificates (Canton and Johannesson Lindén, 2010).

The specified proportion of electricity generated from renewable sources that the suppliers have to provide customers with under each UK country's RO scheme is called the 'obligation' and is set at a new level each year. So far it has been increasingly annually (Government of the United Kingdom, 2015). There are three obligations: one for England and Wales, one for Scotland and one for Northern Ireland (Government of the United Kingdom, 2015). The Scottish obligation is examined in detail below.

Renewable Obligation Scotland

The Renewables Obligation for Scotland (ROS) is the Scottish Government's main funding scheme to support renewable energy generation projects in Scotland for 20 years of a project's lifetime. The scheme works in tandem with identical legislation in the rest of the UK: The scheme encourages renewable energy deployment by setting mandatory quotas for electricity generated from renewable sources relative to the total amount of electricity produced.

Electricity generation from renewable sources yields renewables obligation certificates (ROCs) and electricity suppliers are required to produce a certain number of ROCs as a proportion of the total electricity they supply to their customers in Scotland (The Scottish Government, 2016a). ROCs are traded among firms separately from electricity. The RO scheme thereby encourages the development of renewable energies because it provides generators with an income stream from the ROCs in addition to the income from selling electricity at the wholesale price (Bryan, Lange, & MacDonald, 2015). Suppliers need to submit their ROCs to a regulatory body to be in compliance with the mandatory levels of renewables generation. They can obtain ROCs either through purchasing electricity from a renewable energy producer or through purchasing ROCs on the market. If a supplier cannot present a sufficient number of ROCs to meet their obligations, a ROC equivalent must be paid into a buy-out fund at a buy-out price. The buy-out price is set every year by Ofgem (Ofgem, 2016a; Bryan et al., 2015). After the administrative costs of the scheme are deducted from the fund, the remainder is redistributed to the producers in proportion to the number of ROCs they produced in regards to their individual obligation. This aspect is unique to the RO scheme. The share of the fund that every supplier can expect should be equal to the difference between the market price for ROCs and the buy-out price as the regulatory bodies responsible for the scheme arbitrage these two price options (Bryan, et al., 2015).

In 2015 the buy-out fund for the total of the UK was £17,075,100 and £1,619,421 for Scotland (Ofgem, 2015b). The repay of the fund proportional to the ROCs produced discourages suppliers and utilities from simply paying the buy-out price because they are guaranteed an additional revenue stream on top of the sales from electricity production if they invest in renewable technologies (Bryan, et al., 2015).

Ofgem updates the renewable generation quota, the ‘obligation’, required by each supplier every year. Setting a new quota every year allows for reviewing prevailing conditions in the renewable energies market and reacting to them in a timely fashion. The obligation period always runs from 1 April until 31 March of the following year (Bryan, et al., 2015). Each supplier’s obligation is calculated by multiplying the total amount of electricity they supply in a given year (in MWh) by the obligation level set for a given year (ROCs per MWh) (Government of the United Kingdom, 2015). As in the rest of the UK, the level of obligations that suppliers have to fulfil has been increasing since the inauguration of the scheme in 2002. For the period running from 1 April 2016 to 31 March 2017, suppliers have to fulfil the obligation of 0.348 ROCs per MWh (The Scottish Government, 2016b). This means that suppliers are required to source 34.8% of all the electricity they supply to consumers from renewable energies. As an example, suppose that a supplier provides 900MWh of electricity in total in a given a year. Given the ROC level of 0.348 per MWh, 313.2MWh (900 x 0.348 = 313.2) out of the total 900 MWh they supply has to be sourced from renewables. Since the obligation level of 0.111 ROCs in 2010/2011 the obligation has been steadily increasing and will probably continue to do so until 2027. From then onwards, the Department of Energy and Climate Change (DECC) will set a fixed price for ROCs for the then remaining 10 years of the RO scheme at its long-term value and buy the ROCs directly from the generators. This is also set out in the White Paper on Electricity Market Reform and is subject to parliamentary approval. This measure is meant to reduce volatility in the final years of the scheme (Government of the United Kingdom, 2015).

Different forms of renewables are worth different numbers of ROCs per MWh. The scheme currently awards 2.5 ROCs/MWh to offshore test and demonstration sites that deploy innovative, new to market turbines and the deployment of innovative foundations. 3.5 ROCs per MWh are given out to floating wind pilot projects, which is 1.5 ROCs higher than what is currently awarded to bottom-fixed constructions. As of yet, however, no project has been able to take advantage of this support (James and Costa Ros, 2015). Both the *Hywind* project and the *Kincardine* project plan to make use of this support scheme with the former being the furthest advanced floating array project so far. Both support bands (2.5 ROCs for offshore test and demonstrator projects, and 3.5 ROCs for non-fixed turbines) have a capacity ceiling of 75MW. This cap was deemed sufficient for enough projects to be developed in order to advance the industry and yet low enough to limit the maximum additional cost of any support the Scottish Government might introduce following this scheme (The Scottish Government, 2013). For comparison, 0.9 ROCs/MWh are awarded to onshore wind projects, 2 ROCs/MWh to offshore wind and around 5 ROC/MWh to wave projects (Government of the United Kingdom, 2015). This technology banding approach constitutes one of the ways in which a GTC scheme may be amended to offset the fact that the GTC system does not work as well in practice as it does in theory (Verbruggen and Lauber, 2012): Ideally, a GTC scheme would reward generators of clean electricity by devising a market for certificates that generators can yield income from on top of the sales of electricity. In thus the scheme assumes that the wholesale electricity is competitive and that income from certificates should come in addition to wholesale electricity sale that is traded on a free, competitive power market. It may be argued that a certificate scheme is beneficial because it does not interfere with the allegedly competitive electricity market. But because this does not always hold in practice, banding, floor and ceiling prices, and quotas can be used to ensure that the certificate price remains within a certain range (Verbruggen and Lauber, 2012). This benefits electricity generators because it makes investors more willing to invest than they normally would: Under the imperfect information conditions of a not otherwise regulated green tradable certificate scheme, the uncertainty associated with the price of certificates is endogenous. The price at which certificates are traded at the market is dependent on both the cost structure of the generator under consideration and the cost structures of all their competitors. Therefore, risk-averse investors are not willing to invest because the expected return on investment is rather uncertain, depending on the cost structure of the firm they invest in themselves as well as the cost structures of all competitors (Canton and Johannesson Lindén, 2010). Through the technology banding approach, the Scottish government makes investors' expected return more predictable and thereby encourages more investment in floating offshore wind.

A developer of an offshore wind farm can receive support from the RO scheme for 20 years but only if the project starts to produce electricity before 31 December 2018. After this date, projects will no longer be eligible to ROC funding as the RO scheme is then replaced by the UK-wide Contract for Difference (CfD) scheme, a renewable portfolio standard, under which generators will sell electricity produced under a contract of Power Purchase Agreement to a licensed supplier. This scheme will provide developers with 15-year contracts and provides an indexed, regulated revenue for generators, protecting them from wholesale price risk where the clearing price would be determined in a competitive auction (The Crown Estate, 2016a). The RO scheme will thus no longer be available for applications after 31 March 2017. Projects that have been accredited before this date will continue to receive support for the first 20 years of the project's lifetime until 2037 when the scheme officially closes (Government of the United Kingdom, 2015).

ROCs are tradeable commodities and thus have no fixed price. The amount that an electricity supplier pays for such a certificate is a matter of negotiation between the supplier itself and the generator. For the purpose of financial planning, however, the long-term value of a ROC is constituted by the buy-out price (i.e. the payment the supplier avoids by presenting their required number of ROCs to Ofgem) plus 10% (Government of the United Kingdom, 2015). The buy-out price for the 2016-2017 obligation period is £44.77 per ROC (Ofgem 2016c). For long-term financial planning purposes, we hence calculate the following ROC value in year 0 of our NPV analysis:

$$\pounds 44.77 \times 110\% = \pounds 49.25$$

This value will be inflation-adjusted with 2% every year from year 1 of our cash flow model onwards until year 20 of our project (as the ROC scheme is only valid for the first 20 years of a project). This seems like a reasonable, even conservative, assumption for the long-term value approximation of ROCs as the inflation rate is slightly below the increase rate buy-out prices have seen in the past. For instance, the ROC buy out price for the obligation period of 2014/2015 was £43.3 per ROC while during 2015/2016 it was £44.33 per ROC (Ofgem, 2016c). This constitutes a 2.4% increase. Given the European Central Bank's (2016) long-term inflation target of 2%, and our assumption of an inflation value of 2%, the authors argue that the 2% inflation increase per year for the ROC value is reasonable.

DECC sets the level of renewable obligations required by suppliers every year using a fixed target, or a 'headroom' calculation, in accordance with the provisions stated in the Renewable Obligation Order 2009. 'Headroom' is the measure used to ensure that the price of ROC cannot drop too low. Because the value of a ROC is determined by the market, there is an inherent danger that supply of ROCs might exceed demand, which would cause the price to decrease. DECC therefore provides a set margin between the predicted generation (supply of ROCs) and the level of obligation (demand for ROCs), which helps reduce the likelihood of supply exceeding the obligation in any given year and thereby reducing the market value of a ROC. This 'headroom' measure increases investor confidence because it stabilises the ROC price and significantly increases the likelihood that there will always be a market for their ROCs (Government of the United Kingdom, 2015). This is a crucial element of the Scottish RO scheme because this price stabilising measure allows for long-term financial planning with ROC values, unlike the European guarantees of origin scheme (see below).

A Word on Renewable Energy Guarantees of Origin

As part of the EU's electricity tracking system, all member states are required to run and maintain a Renewable Energy Guarantees of Origin (REGO) scheme. As with the RO scheme, the REGO system aims to increase the contribution of renewable energies to total energy generation across the European Union. In contrast to the RO initiative, REGO permits the trade of renewable energy on an EU-wide scale (Ofgem, 2016b). The scheme aims to increase transparency of energy generation and gives consumers a choice between renewable and non-renewable energies. Trading takes place on a voluntary market (RECS International, 2016b). The Guarantees of Origin (GOs) can be purchased by consumers who wish for renewable energy to be fed into the grid and certify that the number of MWhs purchased by a consumer come indeed from renewable energies. In thus, the REGO scheme means an additional form of income for developers of renewable energy projects.

Problematically, GOs are subject to market demand and supply, thus there is no fixed price for these certificates (AIB, 2016), which makes financial long-term planning very difficult. In contrast to ROCs, demand and supply is not monitored. Additionally, there is no guarantee how many GOs will be bought in any given year and thus what the income stream to a developer might be. The regulatory body RECS International states that a Guarantee of Origin cannot be considered to be a reliable funding mechanism (RECS International, 2016a). Due to these ambiguities and difficulties, the Guarantees of Origin scheme will not be factored into our analysis in this thesis.

4.2.1. Adjusting the Cash Flow Model Parameters

Level of funding

Since this section concerns the Scottish funding mechanism, all monetary values are already given in pound Sterling. Therefore, no conversion is necessary.

Taxes

The corporate tax rate in the United Kingdom is 21% (HM Revenue and Customs, 2015). The taxable amount in our pre-commercial floating offshore wind model wind farm (EBIT) will therefore be taxed with this amount.

Discount Rate

To calculate the discount rate of the model wind farm under the Scottish funding regime, the authors modify the CAPM formula. The risk-free rate and the risk premium remain at 4.5% and 5% respectively. The beta, however, is adjusted to reflect the risk associated with the Scottish RO scheme.

The risk inherent in offshore wind projects has been decreasing in the past decade. While in 2004 the offshore wind beta under a green tradable certificate scheme was calculated to be 2.24 (Cleijine and Ruijgrok, 2004), in 2012, the equity beta for offshore wind projects reaching their final investment decision in 2011 was at only 1.0 (PwC, 2012). Since we assume that our project is not debt-financed, we are concerned with the asset beta. In a case of no debt, the equity beta equals the asset beta. We thus use PwC's equity beta estimate of 1.0 in our discount rate formula and arrive at a discount rate of 9.5%.

$$E(r_e) = r_f + ß(risk\ premium) \tag{4}$$

$$E(r_e) = \mathrm{d} = 4.5\% + 1.0\ (5\%) = 9.5\% \tag{4a}$$

This figure is in line with the cost of capital expected for new investments in offshore wind projects, which is generally in the range of 8-10% (Arapogianni and Genachte, 2013).

4.2.2. Inserting Values into the Cash Flow Model

Our model wind farm will receive income from the ROC scheme in addition to the income generated from selling electricity for the first 20 years of project lifetime. Given that the Scottish RO scheme sees 3.5 ROCs being awarded for every MWh of electricity produced from floating offshore wind and the current (year 0) ROC value of GBP 49.25, the income from ROCs would amount to 172.38 GBP/MWh.

$$3.5\frac{ROC}{MWh} \times 49.25\frac{£}{ROC} = 172.38\frac{£}{MWh}$$

This value will be inflation adjusted every year. This means that in year 1, the first year of operation, our model wind farm generates an income of

$$172.38\frac{£}{MWh} \times 1.02 = 175.82\frac{£}{MWh}$$

Given that our model wind farm produces 203,933 MWh of electricity, the total ROC scheme income for our cash flow model in year 1 is GBP 35,855,975.

$$175.82\frac{£}{MWh} \times 203{,}933MWh = £\ 35{,}855{,}975$$

In 2027 (year 11 of our cash flow model), DECC will fix the ROC price at a long term value to instil confidence in investors during the final 10 years of the scheme.

This long-term price is said to be the 2027 buy-out price, plus 10%. The ROC price will continue to be linked to inflation for the remaining 10 years of the scheme (DECC, 2011). We cannot know for sure what the long-term ROC value will be set at in 2027 but we assume that we can reasonably approximate the ROC price throughout the lifetime of our model by using the current buy-out price, plus 10% and adjusting it for inflation every year for the first 20 years of our cash flow model under the Scottish funding regime.

From year 21 of our cash flow model onwards, the project only generates revenue from the sale of electricity. See Appendix 0 for the detailed calculation of the cash flow model.

4.2.3. Economic Indexes

In this subchapter we exemplify the calculations of the economic indexes. In subsequent subchapters, 4.3 (Japanese funding regime), 4.4 (French funding regime), and 4.5 (Hawaiian funding regime), we assume that the formulae are known to the reader and merely present the results of our economic index calculations.

NPV

Investment I is given by the capital expenditure and thus amounts to GBP 218,686,794 (see section 4.1.1). The cash flows incurred every year are discounted using real interest rate r, which is given by

$$r = d - i \tag{6}$$

$$r = 9.5\% - 2\% = 7.5\% \tag{6a}$$

The model's cash flows every year are subject to inflation of the operational expenditure and the wholesale electricity price as well as the nature of the capital allowance tax shield and the lifetime of the ROS scheme, and are therefore different for every year t.

$$NPV = -I + \sum_{t=1}^{T} \frac{Cash\ Flow_t}{(1+r)^t} \tag{5}$$

$$NPV = -218{,}686{,}794 + \sum_{t=1}^{25} \frac{Cash\ Flow_t}{(1+7.5\%)^t} \tag{5a}$$

For our discounted cash flow calculations, please see Appendix 0. Discounting the cash flows generated each year according to the NPV model and adding them all to the initial capital expenditure yields the following result:

$$NPV = £\ 182{,}148{,}385$$

IRR

IRR is defined as the interest rate that leads to a project NPV of zero. As it is not possible to calculate the IRR precisely due to the nature of the NPV formula, one has to use trial and error to approximate the project's IRR. Microsoft Excel's built-in IRR formula is used for this study. The project's IRR amounts to 8.67%.

ROI

ROI measures the amount of return on an investment relative to the costs of a project.

$$ROI = \frac{(Gain\ from\ investment - Cost\ of\ investment)}{Cost\ of\ investment} \qquad (7)$$

$$ROI = \frac{(£380{,}058{,}440 - £218{,}686{,}794)}{£218{,}686{,}794} = 83.29\% \qquad (7a)$$

LCOE

In order to calculate the LCOE we first need to estimate the escalation rate e. The escalation rate captures the expected annual increase of annual O&M costs. The consultancy Ernst&Young estimate the escalation rate for offshore wind projects to be 3% (Narbel, Hansen and Lien, 2014). However, one can assume certain learning effects with some projections estimating a 10% decrease by 2050 (DNV GL, 2015). In reality, learning effects will probably be more pronounced during the first years of a project and flatten out towards the end. For simplification purposes we assume a linear learning effects rate in our calculation, or, in other words, an average of the total learning effects over the project's lifetime. With a 10% decrease over 35 years, this means a 0.3005% cost decrease per year. The escalation rate is therefore reduced to 2.7%:

$$e = 3\% - 0.3005\% = 2.6995\% \approx 2.7\%$$

In the comprehensive LCOE calculation we start out by calculating the appropriate capex denoted by c_p^i and opex denoted by c_p^o:

$$LCOE = \left[\frac{R * c_p^i}{H * f_p}\right] + \left[l * \left(\frac{c_p^o}{H * f_p}\right)\right] \quad (8)$$

where

$$c_p^i = \frac{£\ 218{,}686{,}794}{48\ MW} = 4{,}555{,}974.875\ \frac{£}{MW}$$

$$c_p^o = \frac{£\ 7{,}056{,}000}{48\ MW} = 147{,}000\ \frac{£}{MW}$$

Then we can continue with the calculation of the recovery factor R and the levelisation factor l as follows to arrive at an LCOE rate of 157.85 GBP/MWh.

$$R = [\frac{d * (1+d)^T}{(1+d)^T - 1}] \quad (9)$$

$$R = \left[\frac{9.5\% * (1+9.5\%)^{25}}{(1+9.5\%)^{25} - 1}\right] = 10.60\% \quad (9a)$$

$$l = \frac{d * (1+d)^T}{(1+d)^T - 1} * \frac{(1+e)}{(d-e)} * [1 - (\frac{1+e}{1+d})^T] \quad (10)$$

$$l = \frac{9.5\% * (1+9.5\%)^{25}}{(1+9.5\%)^{25} - 1} * \frac{(1+2.7\%)}{(9.5\% - 2.7\%)} * [1 - \left(\frac{1+2.7\%}{1+9.5\%}\right)^{25}] = 1.278 \quad (10a)$$

$$LCOE = \left[\frac{10.6\% * 4{,}555{,}974.875\ \frac{£}{MW}}{8{,}760 * 48.5\%}\right] + \left[1.278 * \left(\frac{147{,}000 \frac{£}{MW}}{8{,}760 * 48.5\%}\right)\right] = 157.85\ \frac{£}{MWh} \quad (8a)$$

DPBP

The Discounted Payback Period index shows that the accumulated cash flows of the model wind park break even with the initial investment cost between year 7 and year 8. The total accumulated cash flow at the end of period 7 is GBP -18,603,957, the absolute value of which is GBP 18,603,957. In the end of period 8, the discounted cash flow is GBP 21,030,375. This gives us a discounted payback period of:

$$DPBP = A + \frac{B}{C} \quad (11)$$

$$DPBP = 7 + \frac{£18{,}603{,}957}{£\ 21{,}030{,}375} = 7.88\ years \quad (11a)$$

Please see Appendix 0.a for the spreadsheet in which the cash flow model and economic indexes have been calculated for the floating offshore wind farm under the Scottish funding regime.

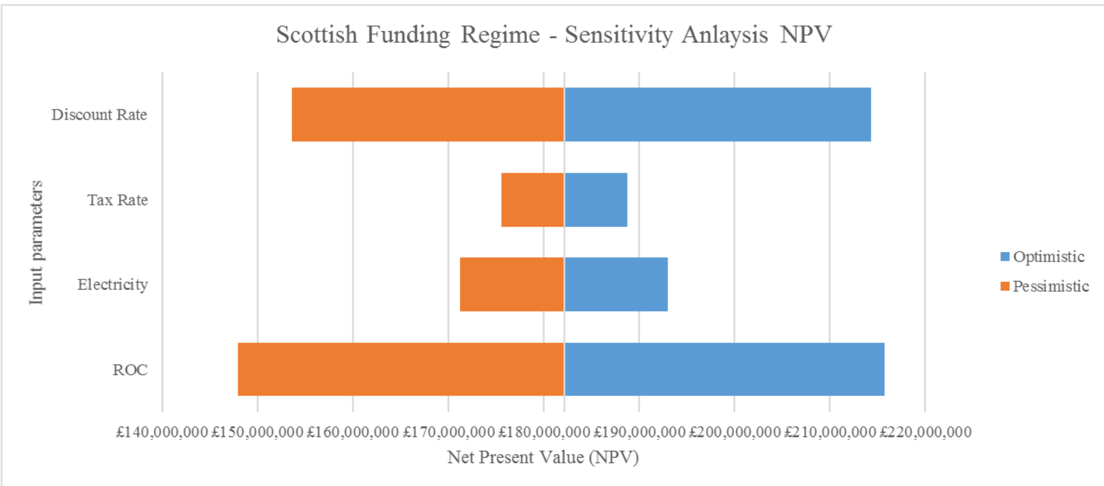
4.2.4. Sensitivity Analysis

As detailed in Chapter 3, the values for level of funding, discount rate, and corporate tax rate have been adjusted with +10%/-10%, -10%/+10% and -10%/+10% for the optimistic and pessimistic cases respectively. For a table listing the results of the sensitivity analysis of the model under the Scottish funding mechanism, please see Appendix 0.a. In the following illustrations Figure 4-5, Figure 4-6, Figure 4-7, Figure 4-8 and Figure 4-9 the reader can observe the results of our sensitivity analysis under the Scottish funding regime.

The first observation is that the ROC price is the single most important parameter influencing each of the economic indexes, except LCOE. The only input parameter relevant for the sensitivity analysis of LCOE is the discount rate.

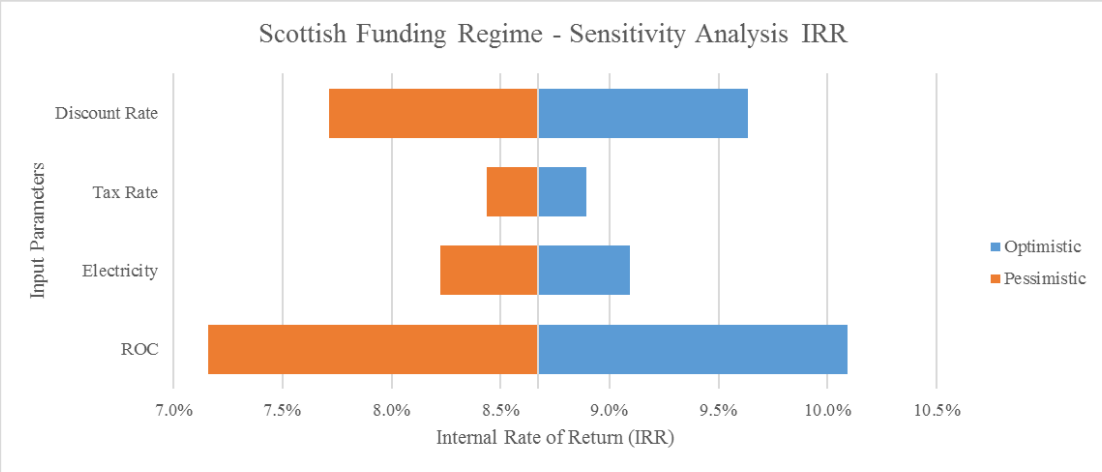
Figure 4-5 illustrates that the NPV value can vary substantially according to the ROC value. The sensitivity analysis show that the project could be up GBP 33 million more profitable or up to GBP 34 million less profitably under different ROC prices. The discount rate, albeit having less impact than the ROC value, still has a considerable effect on the NPV calculation.

Figure 4-5: Sensitivity of NPV



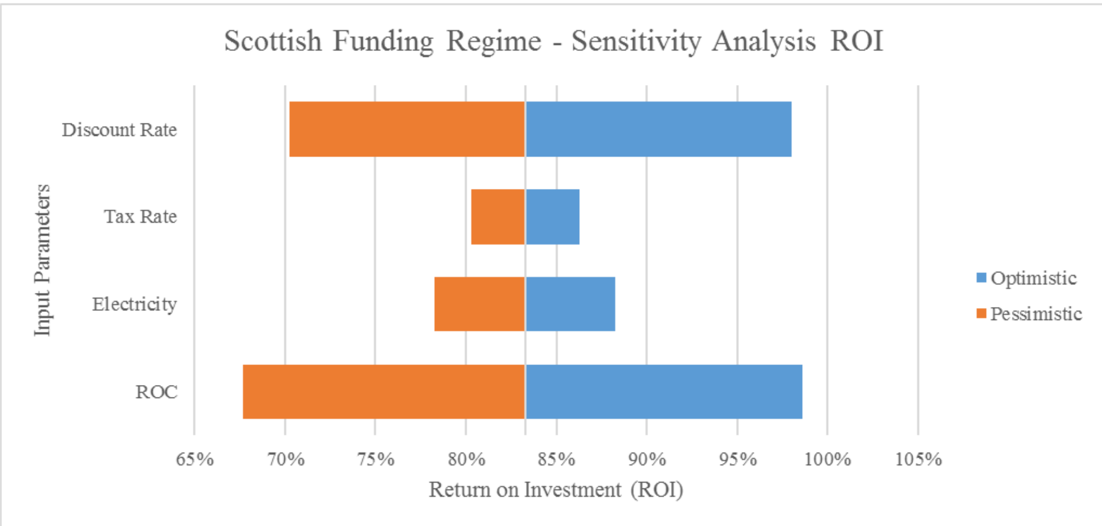
The impact of the ROC price is especially noticeable for IRR (Figure 4-6) and DPBP (Figure 4-9), where the ROC value has much greater impact than the discount rate, for example, compared to the NPV or the ROI sensitivity analyses. Figure 4-6 shows that the IRR can vary by about 1.5% depending on the ROC price scenario.

Figure 4-6: Sensitivity of IRR



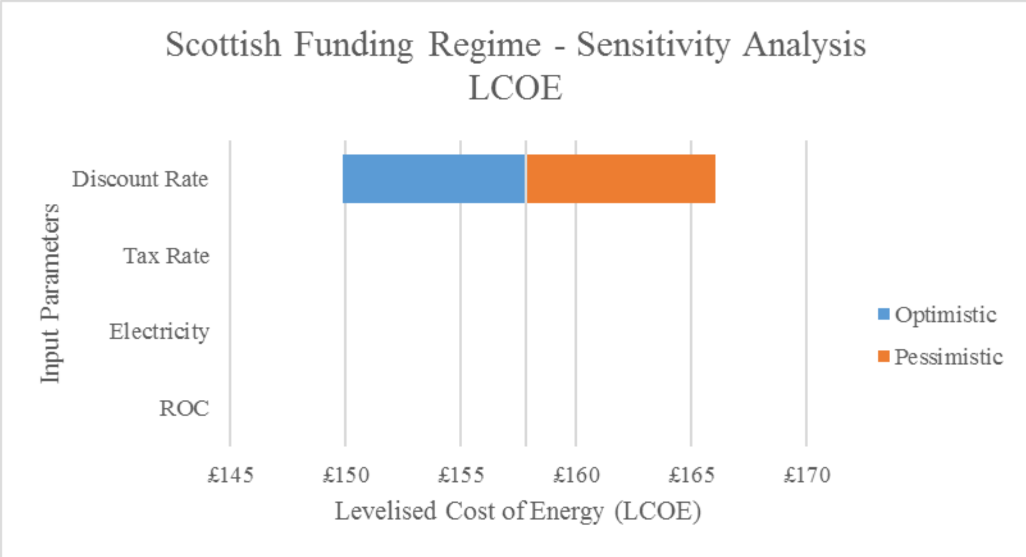
The discount rate has the second largest impact on NPV, IRR, ROI and DPBP.
The electricity rate, albeit having an effect worth noting, has a much smaller impact on these indexes than the ROC price or the discount rate. Figure 4-7 illustrates that the ROI can be as low as 67% or as high as 98%.

Figure 4-7: Sensitivity of ROI



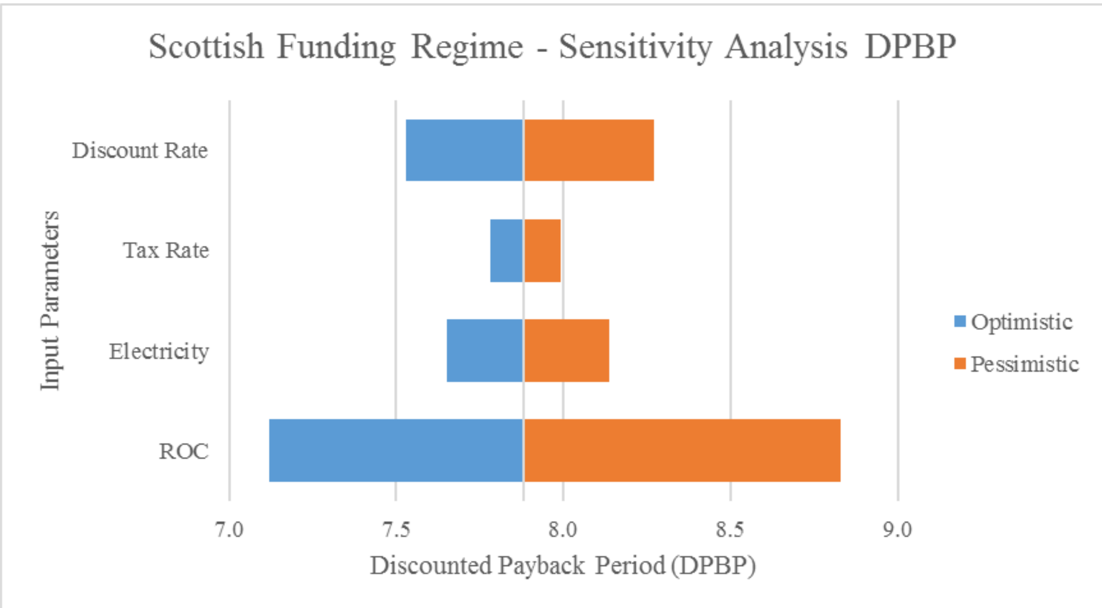
The only economic index that affects the LCOE is the discount rate, as becomes evident in Figure 4-8, because neither taxes nor income from electricity sales or ROCs are factored into the calculation of the LCOE. The sensitivity analysis shows that the LCOE may vary between about GBP 150 and GBP 166, depending on the discount rate, constituting a fairly large range of LCOE values.

Figure 4-8: Sensitivity of LCOE



Interestingly, the tax rate, although part of the funding mechanism as it has been argued for above, has the least impact on NPV, IRR, ROI and DPBP. Figure 4-9 shows that the impact of the tax rate for example on the DPBP index can only cause a delay or gain of 0.1 years until the investment is recovered.

Figure 4-9: Sensitivity of DPBP



4.3. The Japanese Funding Regime

This subsection analyses the Japanese funding regime, outlining the motivations behind the support as well as giving a detailed analysis of how the regime works, before adjusting the cash flow model accordingly, and calculating its economic indexes and their sensitivity analyses.

Background

After the introduction of the Renewable Portfolio Standard (RPS) in 2003 that saw Japan surpass its renewable energy development target of 1.35% for 2010 with renewables actually providing 4% of Japan's total electricity supply (Saidur, et al., 2010; IRENA, 2014), the island nation's share of renewable energy has been steadily increasing. In 2012, Japan had a total of 60.1GW of renewable energy generating capacity installed, which accounted for 12% of production. A new target aims to increase the share of renewables to 10% by 2020 (IRENA, 2014).

Having relied on nuclear power for as much as 30% of its energy demand in 2010, the 2011 Fukushima accident marked a turning point for Japan's energy plans. Currently, no nuclear power plants are under operation and plans to reconnect some of them again are opposed by as much as 60% of the population due to safety concerns following a series of earth quakes in April 2016 (Stapczynski, 2016).

For 2030, the Japanese Ministry of Economy, Trade and Industry (METI) has therefore set a more ambitious target share of 22-24% for renewable energies in the overall power mix. In contrast to many other countries' renewable targets, these clean energy proportions in the country's outlook constitute more of a minimum target rather than an ultimate level. The 2030 goal constitutes a slight upward revision from the country's fourth Basic Energy Plan, published in 2014, that aimed for renewables to supply 20% of electricity by 2030 (REN21, 2015), accounting then for 13% of the total primary energy supply (Govindji, James and Carvallo, 2014). The roadmap also sees a considerable decrease in the share of fossil fuels compared to current levels (Mancheva, 2015).

Perhaps surprisingly, given the country's considerable potential for offshore wind, solar power currently dominates Japan's renewable energy market, with the island nation constituting one of the biggest markets for photovoltaic power worldwide (ECE, 2016). Nevertheless, plans to develop wind power have been formulated: Japan aims to install a total of about 75GW of wind power by 2050, just under half of which is supposed to be accounted for by offshore wind, with floating wind power accounting for circa 17GW (Govindji, James and Carvallo, 2014).

The Japanese Feed-in-Tariff Scheme

The aforementioned Renewable Portfolio Standard (RPS) that was introduced in 2003 was replaced by a feed-in tariff scheme that came into effect in 2012 (Ishihara, 2015). Feed-in tariff schemes tend to be the most popular support scheme among renewable energy generators because they provide a guaranteed income for every unit of energy that is fed into the grid. Different tariff levels for different types of renewable energy are set by the government normally granted for periods between 10 and 20 years (Canton and Johannesson Lindén, 2010). Once the electricity is fed into the grid, the utility company will distribute it further. This means that the demand for their renewable electricity is secure. In this regard, feed-in tariffs offer both low price and low market risk, offering investors a secure return on investment. The legal assurance of a tariff applies as much to the grid operator as to all private or stately owned utilities, who are obliged to purchase renewable electricity at a given fixed price.

The Japanese feed-in tariff scheme aims to increase private investment in the renewables sector by offering relatively high fixed long-term rates for wind power, solar PV, small- and medium-scale hydropower, geothermal and biomass projects (Ishihara, 2015). The RPS, which in contrast to the feed-in tariff did not offer fixed prices, merely necessitated a supplier to source a certain share of energy from renewables and was only a temporary measure with the goal to source 12.2TWh from renewables by 2010, the equivalent of about 1.35% of total production (Maegaard, Krenz and Palz, 2016).

The new feed-in tariff scheme that offers a more secure income to developers is a longer-term support mechanism aimed at increasing the deployment of renewables. The support rates and periods vary between different technologies and are published by METI (Govindji, James and Carvallo, 2014). The scheme marks one of the commitments on part of the Japanese government since 2010 to promote R&D for deep offshore wind technology to capture the huge offshore wind potential in Japanese territorial waters (Saidur, et al., 2010).

Initially, onshore and offshore wind power projects received the same feed-in tariff of JPY 23/kWh but in March 2014, the Japanese government increased the feed-in tariff for offshore wind to 36 JPY/kWh, which is about 0.28 GBP/kWh. Although this tariff revision marks an increase of over 50% compared to the previous level, the subsidy has been criticised for being too low. Some developers claim a feed-in tariff of at last JPY 40/kWh is necessary to initiate the necessary industry growth (Govindji, James and Carvallo, 2014), and the Japanese Wind Power Association (JWPA) even commented that a reasonable tariff for offshore wind power should be no less than 50 JPW/kWh. Only then, they argue, would it be possible to raise the necessary funds to generate the "drastic expansion of offshore wind" that the government foresees (Offshore Wind Biz, 2014).

Following the introduction of the new feed-in tariff scheme in 2012, an additional 3.7GW of renewable capacity were installed. Solar PV power continues to dominate the market, accounting for 95% of the new renewable capacity installed between the introduction of the scheme in 2012 and 2014. The large share of solar PV over wind is said to be largely due to the shorter time to market solar power, partly because of faster fabrication and installation time but in Japan importantly also due to stringent environmental impact assessments that are required for wind power projects to proceed but not for solar PV projects (Govindji, James and Carvallo, 2014). Additionally, public acceptance and concerns about compensation for the fishery industry are big hurdles for offshore wind projects (Saidur, et al., 2010).

Both onshore and offshore wind projects in Japan benefit from relatively high feed-in tariff schemes when compared to the UK and other jurisdictions as will become clear throughout this study: While offshore wind projects in Japan receive JPY36/kWh for 20 years (Govindji, James and Carvallo, 2014), similar projects in the UK only receive 2 ROCs if the project under consideration uses fixed-bottom turbines and 3.5 ROCs if the project under consideration uses floating wind turbines, plus the whole sale electricity price.

4.3.1. Adjusting the Cash Flow Model Parameters

Level of Funding

In order to convert the feed-in tariff, given in JPY, into GBP, we use the average of the average yearly exchange rates between the two currencies for the last 10 years

(2007-2016), retrieved from the databank of the US Foreign Exchange Service, a source used by Bloomberg. According to this databank and the average yearly exchange rate we calculated, JPY 1 is worth GBP 0.0063332 (US Forex, 2016), see Appendix A. This means that the feed-in tariff of JPY 36/kWh equates to 0.228 GBP/kWh, or 227.9952 GBP/MWh. In our spreadsheet we use 228 GBP/MWh.

Taxes

Any taxable income (EBIT) of the pre-commercial model wind farm under the Japanese funding regime is taxed at Japan's corporate tax rate of 33.06% (KPMG, 2016).

Discount rate

To calculate the discount rate of the model wind farm under the Japanese funding regime, the authors maintain the above calculated risk-free rate and risk-premium at 4.5% and 5% respectively (see section 4.2.2) but adjust the beta.

The beta is adjusted to reflect the lower risk inherent in a feed-in tariff scheme, compared to a tradable green certificate scheme that is subject to market fluctuations. Different sources suggest reductions in beta between 10% (Cleijine and Ruijgrok, 2004) and 17% (PwC, 2012) when using a feed-in tariff regime compared to a green tradable certificate scheme. In order to capture the lower risk of a feed-in tariff scheme compared to a green tradable certificate scheme but not accidentally overstate the possible risk reduction, the authors use a reduction factor of 10% for the beta calculations under the feed-in tariff regime.

This brings the appropriate discount rate for the model wind farm under the Japanese funding mechanism down to:

$$E(r_e) = \mathrm{d} = 4.5\% + (1)(1 - 0.1)(5\%) = 9\% \qquad (4b)$$

4.3.2. Inserting Values into the Cash Flow Model

In the cash flow model of the wind farm, there will hence be an income of 228 GBP/MWh in year 0. Adjusting this for inflation means the wind farm obtains and income in year 1 of:

$$228\frac{£}{MWh} \times 1.02 = 232.56\frac{£}{MWh}$$

Given the expected production of 203,933 MWh per year, for the first year of operation the feed-in tariff yields an income stream of:

$$232.56\frac{£}{MWh} \times 203{,}933\,\frac{MWh}{yr} = 47{,}426{,}612\frac{£}{yr}$$

The income from the feed-in tariff scheme is adjusted for inflation until year 20 of the project because the feed-in tariff scheme only supports an offshore wind farm for the 20 years of its lifetime. For the remaining five years of the project, the wind farm generates income from selling electricity on the UK wholesale market. Here, the electricity price for year 21 of the project (2037) is estimated to be 74.77 GBP/MWh, assuming a 2% increase per year due to inflation.

The above calculated discount rate of 9% is used to calculate the real interest rate, which is used to discount the project's free cash flows for the NPV calculation.

4.3.3. Economic Indexes

The calculation of the economic indexes was explained in section 3.3 and exemplified in section 4.2.3. In this subsection we will therefore only present our results.

NPV

Given that the above calculated discount rate is 9%, the real interest rate used in the NPV model becomes:

$$r = 9\% - 2\% = 7\% \tag{6b}$$

The NPV of the model under the Japanese funding regime therefore becomes GBP 167,040,527.

IRR

The authors determine an IRR value of 8.23% for the pre-commercial wind farm under the Japanese funding mechanism, using Microsoft's Excel software.

ROI

The ROI in the case of the Japanese funding mechanism amounts to 76.38%.

LCOE

The basic LCOE parameters, c_p, c_0, H, f, and e, remain the same as in the previous LCOE calculation above in section 4.2.4. Only the discount rate changes, compared to the Scottish funding regime, to 9%. The LCOE we can obtain for the model under the Japanese support schemes is 153.63 GBP/MWh.

DPBP

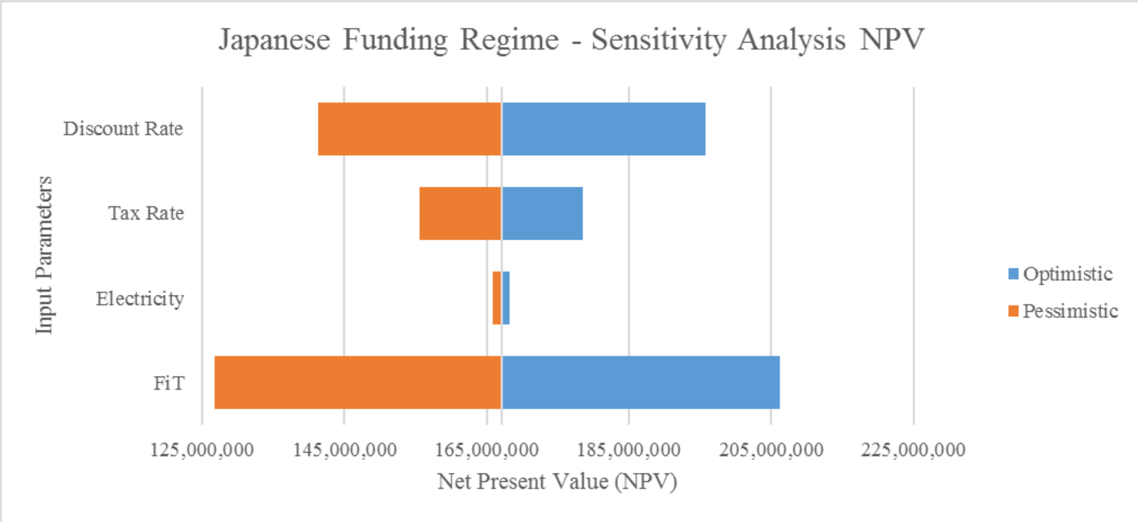
The cash flow model for the Japanese gives us a discounted payback period of 8.05 years.

Please see Appendix 0.b for the spreadsheet in which the cash flow model and economic indexes have been calculated for the floating offshore wind farm under the Japanese funding regime.

4.3.4. Sensitivity Analysis

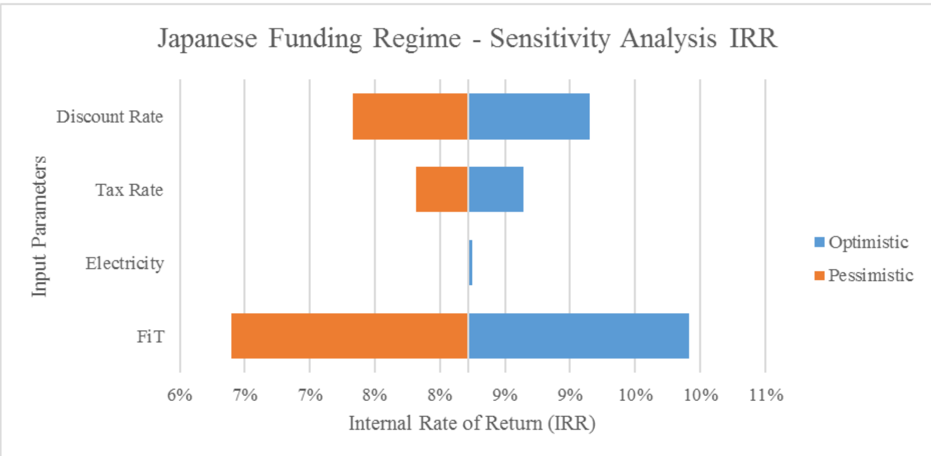
The values for the level of funding, discount rate, and corporate tax rate have been adjusted with +10%/-10%, -10%/+10% and -10%/+10% for the optimistic and pessimistic scenarios respectively. The following figures illustrate the results of our sensitivity analysis under the Japanese funding regime. The level of feed-in tariff has by far the greatest impact on the economic indexes. Its impact is even greater than that of the ROC funding under the Scottish model because the Japanese feed-in tariff accounts for a much greater part of the project's income than the ROCs under the Scottish scheme. This is because the feed-in tariff is higher than the income from ROC sales and because the feed-in tariff constitutes the only form of income during the first 20 years of the project while the income from ROCs under the Scottish scheme comes on top of electricity sales. The value of the project under the Japanese funding regime is therefore highly dependent on the tariff level and can be as low as GBP 127 million or as high as GBP 206 million under the pessimistic and optimistic feed-in tariff level case respectively.

Figure 4-10: Sensitivity of NPV



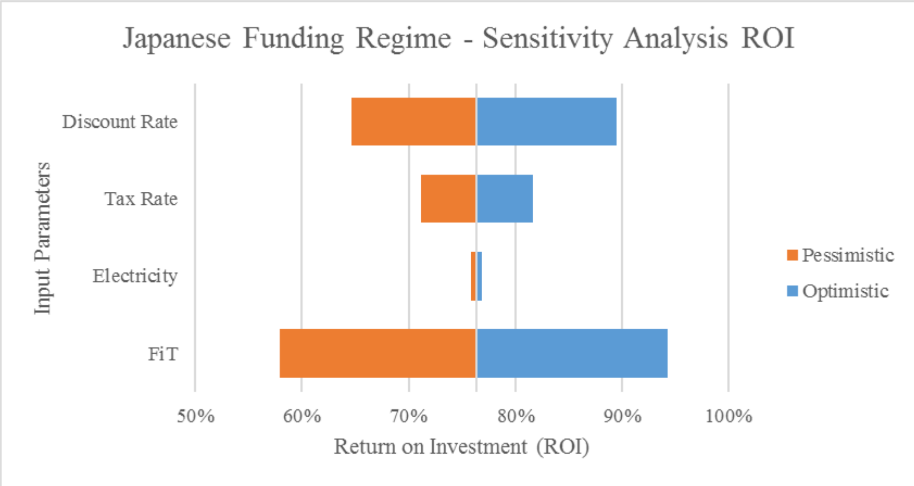
As it is the case under the Scottish support system, the level of funding, in this case the feed-in tariff level is the single most important input parameter for NPV, IRR, ROI and DPBP.

Figure 4-11: Sensitivity of IRR



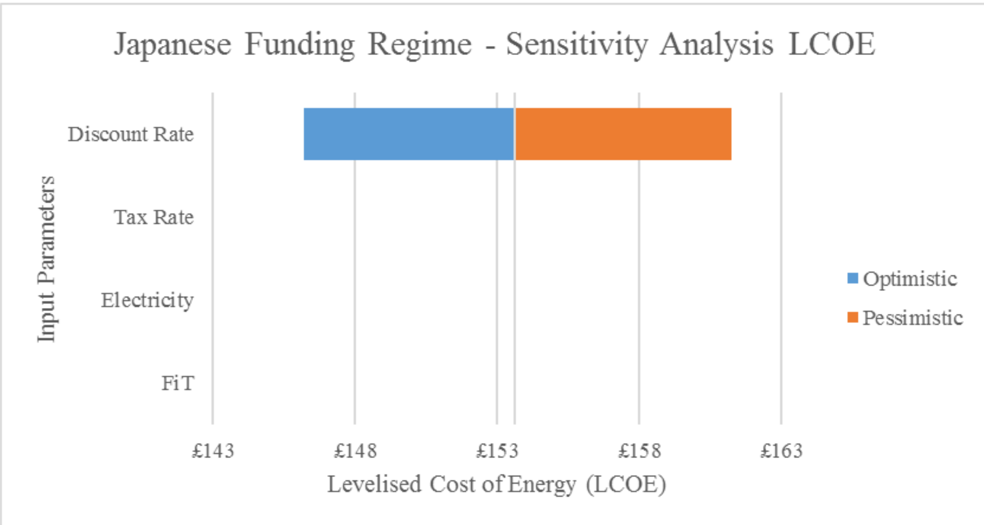
The discount rate has the second largest impact on the project, as is illustrated in Figure 4-10, Figure 4-11, Figure 4-12, Figure 4-13 and Figure 4-14. Under the pessimistic and optimistic case, the discount rate may bring the ROI to as low as 64% or as high as 89% respectively.

Figure 4-12: Sensitivity of ROI



The tax rate has a similarly small impact on the project indexes under the Japanese model as it has in the Scottish funding scenario. The ROI, as seen in Figure 4-12 only varies by a maximum of 5%, a much smaller amount it varies by than if the level of feed-in tariff or discount rate is changed.

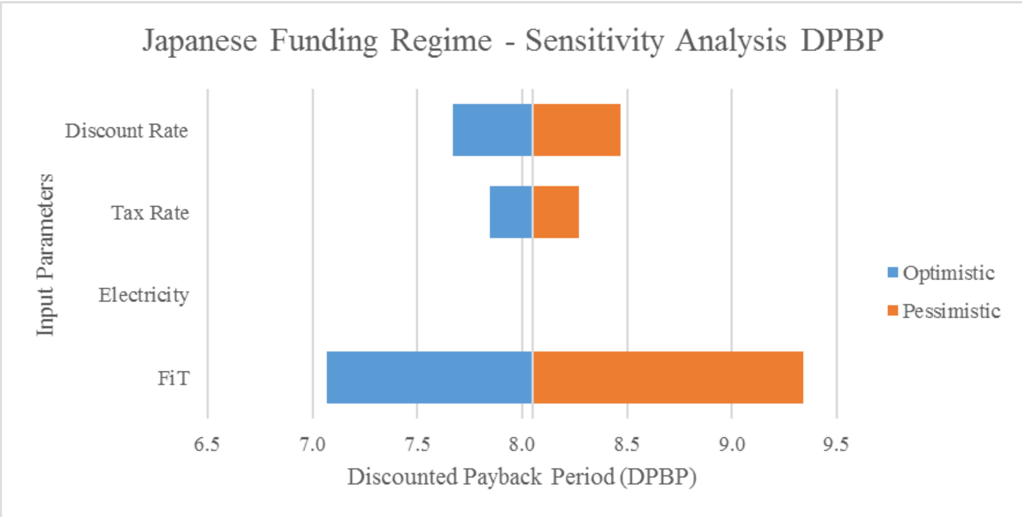
Figure 4-13: Sensitivity of LCOE



The discount rate has an equally substantial impact on the LCOE index in Figure 4-13 as it does under the Scottish funding regime. The LCOE values are estimated to vary between 146-161 GBP/MWh, according to the discount rate.

Finally, the electricity rate that is relevant for the last 5 years of the project life has a merely a minor impact on project profitability. In the DPBP index, there is no impact at all, because the project is paid back in full before the electricity price becomes relevant.

Figure 4-14: Sensitivity of DPBP



4.4. The French Funding Regime

The third part of our analysis will analyse the current funding regime in France and its motivations, and subsequently treat our model wind farm in Scotland with the French funding system.

Background

The French government has clearly stated their intention to become a country of "environmental excellence" with a strong focus on renewable energy (MEDDE, 2016c). The funding of floating offshore wind in France is part of a comprehensive funding strategy to achieve 40% renewable electricity by 2030 (Radowitz, 2015). Besides several governmental bodies and agencies, key players like the stately owned electricity supplier EDF and the renewable and wind energy associations SER and FEE are actively involved in the funding process. However, while fixed offshore wind projects are approaching commercial scale in other EU countries, multiple projects were tendered in France but never built. The French government and industry work on a variety of floating offshore wind projects, with the maritime sector mobilising strongly to develop the necessary supply chain, one of the French offshore wind industry's most significant shortcomings. As of today, France is merely at the beginning of building an offshore wind industry (Snieckus, 2016) and many challenges still lie ahead.

The French government has two main objectives for future energy development that motivate the country's renewable funding regime. The first goal is to reduce the share of nuclear power, and the second is to integrate a large proportion of renewable energy into the French energy mix. As of today, the main source of energy is nuclear power with a share of 75% (World Nuclear Association, 2016). The government plans to reduce this dependency down to 50% by 2025 (World Nuclear Association, 2016). Replacing about 30GW of nuclear power generation with renewables constitutes a great challenge. In order to reach this goal, France will either have to import renewable technology or strongly develop new renewable solutions of their own. Interestingly, the motivation for new sources of energy does not originate in the need for more energy. The electricity market is already satisfied, where the net export in the last five years accumulated to 55-70 TWh of electricity per year (World Nuclear Association, 2016). Therefore, the primary goal of the funding scheme is not to close a gap between demand and supply, but rather to give an incentive for change to an alternative source of electricity generation. Once a strong domestic industry has been established, the new technology could become a solid product for French export markets.

In contrast to the supply chain, the regulatory and supervisory environment is largely in place. MEDDE is the executive body that prepares and implements governmental policy. It is responsible for developing and implementing the French strategy against global warming in general, and for designing tax credits and feed-in tariffs for renewable energy in particular. In order to implement offshore wind power, the ministry authorises ADEME to locate potential sites and call for tenders. The call for tenders is only one of many activities of the agency. ADEME's primary goal is to finance renewable energy projects. Several French developers of floating offshore wind received funding in R&D, innovation and implementation. The goal of this publicly funded advisory body is generally to promote and establish sustainable development in energy generation and to mitigate climate change (ADEME, 2016). The Energy Regulation Commission (CRE) constitutes the regulatory governmental body that controls the French grid operators and is generally responsible to integrate renewable energy into the grid. Among other activities, CRE supervises the feed-in tariff and the non-discrimination of renewable power. Their key duties are to stabilise and guarantee access to the grid, to distribute electricity and to ease the operation of energy markets (CRE, 2016).

Another central role in the coordination of funding for renewables takes the largest, stately owned electric utility company Electricité de France (EDF), who is the main supplier of electricity to domestic homes in France. In collaboration with EDF, any developer of floating technology theoretically has access to an international market. This is because the utility company is one of the largest power producers in Europe with subsidiaries in America, Asia and Africa. Until today though, EDF's primary source of electricity generation is nuclear power, accounting for 82%. Only a minor 6% is generated from various renewables sources (EDF, 2016).

In contrast to the market-based funding regime in Scotland, the French state holds the executive and administrative power over the way funding is conducted, including the power to decide which project may be funded. Once a project is operational, the state also holds controlling power, because regulators CRE and EDF are stately-owned. Several lobby groups such as the French Renewable Energies Association (SER) and the French Wind Energy Association (FEE are aiming to challenge and facilitate the development of renewable energy. SER, for instance, is actively involved in the development of legislation, promoting certification and R&D programmes (SER, 2016). FEE speaks to public authorities as well as the press and civil society on behalf of the industry (FEE, 2016).

Feed-in Tariff and Grants

The feed-in tariff was introduced in 2001 and designed primarily to support wind power. It was modified in 2005 to include the support of solar photovoltaic and energy from biomass. The appropriate tariff for floating offshore wind projects will be between 170-220 EUR/MWh across the project life cycle of up to 20 years (Snieckus, 2016) but the final tariff level has yet to be decided.

France has centred its renewable energy strategy around a tendering procedure, which is supported by a feed-in tariff and in some cases by direct governmental funding. The first round of tenders for offshore wind was launched in 2011. It comprised 2GW capacity, where four sites off the Atlantic coast with roughly 500MW potential capacity each were announced. The winners included stately owned EDF, DONG Energy of Denmark and Alstom of France (Offshore Wind Biz, 2015). A second round followed and added another 1GW off the Atlantic coast in 2014. The third and most recent round is the first tender for floating offshore wind. In August 2015, ADEME published an appeal to submit applications for floating offshore wind pilot projects to aid the development and realisation of floating wind on three sites in the Mediterranean and a fourth site off the coast of the Bretagne region in the Atlantic Ocean (ADEME, 2015; Snieckus, 2016). During such a tender, any company can apply by presenting a concept and a timeline for their project. MEDDE set a target capacity, meaning the anticipated amount of MW installed (RES Legal, 2016). In the most recent tender case, the first floating offshore wind demonstration project was tendered was part of the *Investment for the Future* programme. The government tender consists of both grants and loans, funding projects with between 3-6 machines at a minimum of 5MW per turbine[1]. With every application for the tender, developers have to propose a business plan. The business cases will be evaluated in regards to risk, maturity and potential for commercial scale[2]. The funding programme includes the opportunity to first install a one-turbine prototype, based on whose success several other turbines are built in the same area to together from a floating wind farm. The programme provides a total of EUR 150 million, which will be distributed among eligible floating offshore wind projects.

EUR 50 million will be awarded to floating wind projects as a grant, and EUR 100 million in total will be given out as loans that are paid back during the operational phase (Snieckus, 2016). In practice, the funds are awarded to the generators by the utility and EDF handles the funding process throughout the project. Unique among the markets researched for this study, these grants and loans are awarded in addition to the above mentioned feed-in tariff, demonstrating a strong political motivation on part of the French government to push floating technology forward. The French government is eventually going to decide on the suitable feed-in tariff for the winning projects and a specific tax credit which could come as additional project support.

In order to receive project funding from the government, the project developer has to form an alliance with the maritime industry to build floating offshore wind structures[3]. The goal is that the maritime and the power industry gain knowledge from each other

[1] Interview with Frederic Chino of DCNS, 23.09.15, Appendix D.b, Lines 20-21

[2] Interview with Frederic Chino, 23.09.15, Appendix D.b, Lines 23-28

[3] Interview with Frederic Chino of DCNS, 23.09.15, Appendix D.b, Lines 83-88

and find synergies in this new industry. Creating a strong domestic offshore wind market in France is the primary goal of the French government's support, by which they hope to tap into new business opportunities, create employment in France and, in the long term, sustain energy independence in Europe. The French government also expects that the ROI will increase on export markets once France can export the know how gained at home (Dodd, 2015) In fact, floating offshore wind could be the chance for the French offshore industry to become a worldwide pioneer[1]. To this end, project developers are asked to team up with the utility company EDF that already has a worldwide presence. A small French developer that partners up with EDF for the French market may have a better chance to succeed in a foreign market, than to venture into the US and Japan by themselves. With a lead time to market of 5-8 years the French industry would have to accelerate their efforts very soon, given that 600MW of floating wind should be running by 2030. Half of this capacity is planned in the Mediterranean zone and half off the Atlantic coast (Snieckus, 2016). France needs to act fast because it may otherwise lose the chance to become the first mover in the floating offshore wind industry, which in turn would diminish the country's prospects to export floating wind know-how abroad. In order to realise this, the French industry would need to stick to a plan that would see the first pre-commercial farms in the water at the latest by 2020. The French idea is to address this issue of time pressure by accelerating turbine deployment through the combination of the sites for testing prototypes with the sites for future commercial projects[2]. This means that floating pilot projects would be developed where there is potential to develop a commercial farm soon after. Commercial projects of 20-40 turbines need to be operational by 2025 in order to sustain France's competitive advantage (Snieckus, 2016).

4.4.1. Adjusting the Cash Flow Model Parameters

The main difference between the French support mechanism and the Scottish and Japanese funding regimes analysed above is that under the French system governmental grants and loans are awarded to project developers in addition to a feed-in tariff.

[1] Interview with Frederic Chino of DCNS, 23.09.15, Appendix D.b, Lines 51-52

[2] Interview with Frederic Chino of DCNS, 23.09.15, Appendix D.b, Lines 32-33 and 55-56

Level of Funding

The final feed-in tariff level in France is yet to be announces later in 2016. However, the current tender suggests a rate of 170-220 EUR/MWh for up to 20 years[1] (Renews, 2015). Other than this range, we could not find any more precise information regarding the final tariff level. In our calculations we therefore use the average of this range, which is EUR 195:

$$\frac{€\,170 + €\,220}{2} = €\,195$$

In order to convert this tariff to GBP we take the mean of average yearly exchange rates between the two currencies for the last 10 years, retrieved from the databank of the US Foreign Exchange Service. According to this databank, EUR 1 is worth GBP 0.8065489 on average (US Forex, 2016), see Appendix A. This means that a feed-in tariff of 195 EUR/MWh is equal to 157.28 GBP/MWh.

During the construction phase of the wind farm, the French government awards roughly GBP 40 million (the EUR 50 million mentioned above) in total to several projects. After consulting with our expert Frederic Chino, we assume that our project will be awarded a governmental grant of GBP 13 million. This means that our capex position is reduced by GBP 13 million, bringing our total capex down to GBP 205,686,794. For our depreciation of investment calculation this means that the values will be different from the Scottish example above. See Appendix 0 for the excel spreadsheet of the cash flow model under the French funding mechanism and its depreciation of capital expenditure.

Taxes

Under the French funding regime, an offshore wind farm is subject to two different taxes. The first tax is the corporate tax rate on earnings, which is comparably high with 33.33% (KPMG, 2016). Additionally, fixed offshore wind farms are taxed with EUR 15,000 per MW/year installed to support coastal regions, which are directly affected by the wind turbines (MEDDE, 2016a). These special tax revenues are distributed to coastal community development, promoting fisheries and maritime

[1] Interview with Frederic Chino of DCNS, 23.09.15, Appendix D.b, Lines 7-8

activities. We assume the same taxation applies to our floating wind farm. Using the above mentioned exchange rate, the per MW tax translates to GBP 12,098/MW installed.

To what extent the new floating wind parks may be exempt from these taxes (see the above mentioned possible tax breaks) is unclear at this point in time. In our model, we therefore assume that floating wind will be taxed in the same way offshore fixed projects are taxed.

This means that in contrast to the previously analysed Scottish and Japanese funding regimes, the opex under the French support is GBP 7,636,715 in year 1. As before, this position will be inflation adjusted every year.

Discount Rate

The risk-free rate and the risk-premium remain the same as argued in 4.1.2 and are 4.5% and 5% respectively. Given the low risk inherent in a feed-in tariff scheme, the appropriate beta to use would 0.9 as we calculated in 4.3.1 for the Japanese feed-in tariff scheme. However, on top of the feed-in tariff, the French government also provides our project with a grant that substantially lowers the capital cost of our model wind farm. This is especially beneficial for the developer, and by extension investors, because the investment at the outset of the project constitutes such a large share of the total expense the wind farm incurs. The grant therefore leads to a further risk reduction for investors, which results in an even lower project beta. Data on estimates of such a beta reduction are notoriously hard to come by because investors tend to keep their risk estimates a secret. We can, however, make certain assumptions about this reduction. For example, the reduction in beta due to the government grant in addition to the feed-in tariff scheme should be less than the 10% used to capture the risk reduction of a feed-in tariff scheme as opposed to a green tradable certificates scheme. This is because the risk reduction constituted by the capital grant and government loan that are offered in addition to a feed-in tariff scheme lowers the risk to investors by less than a feed-in tariff scheme does compared to a green certificates scheme. How much risk exactly the additional government grant and loan actually mitigate has to be estimated based on market knowledge. For our purposes we assume a further beta reduction of 5%. This brings the beta for the project under the French funding regime down to:

$$\beta = 1 \times 0.9 \times 0.95 = 0.855$$

The discount rate thus changes to 8.78%.

$$E(r_e) = 4.5\% + 0.855(5\%) = 8.78\% \quad (4c)$$

4.4.2. Inserting Values into the Cash Flow Model

The regular income for our model wind farm under the French funding mechanism is based on the feed-in tariff of approximately 157.28 GBP/MWh in year 0. Adjusting this for inflation, as exemplified previously, gives us an income of 160.43 GBP/MWh in year 1 under the feed-in tariff scheme. Given the expected production of 203,933 MWh per year, the feed-in tariff yields an income stream of:

$$160.43\frac{£}{MWh} \times 203{,}933\frac{MWh}{yr} = 32{,}716{,}042\frac{£}{yr}$$

The repayment conditions of the governmental loan are not yet sufficiently defined for us to use in our study: Other than the fact that it has to be repaid at some time during the project's operational phase, no details are known regarding the interest to be paid, any possible time restrictions regarding the repayment of the loan sum or anything similar. Since these assumptions would be too speculative, we assume that our model floating offshore wind farm is awarded only a grant but not a loan.

4.4.3. Economic Indexes

The calculation of the economic indexes was explained in section 3.3 and exemplified in section 4.2.3. In this subsection we will therefore only list our results.

NPV

Given that the above calculated discount rate is 8.78%, the real interest rate used in the NPV model becomes:

$$r = 8.78\% - 2\% = 6.78\% \quad (6c)$$

The NPV of the model under the French funding regime therefore becomes GBP 51,850,188.

IRR

Using Microsoft's Excel software, the authors determine an IRR value of 2.87% for the pre-commercial wind farm under the French funding mechanism.

ROI

The ROI in the case of the French funding mechanism amounts to 25.21%.

LCOE

Given the discount rate of 8.78%, we can obtain an LCOE of 149.05 GBP/MWh for the model under the French support system.

DPBP

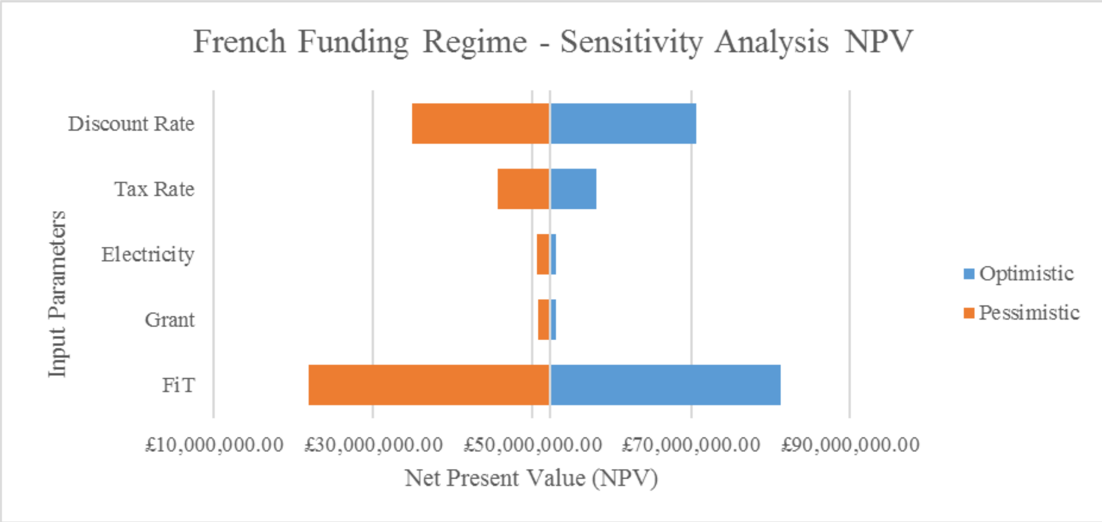
The cash flow model for the French funding regime gives us a discounted payback period of 13.62 years.

Please see Appendix B.c for the spreadsheet in which the cash flow model and economic indexes have been calculated for the floating offshore wind farm under the French funding regime.

4.4.4. Sensitivity Analysis

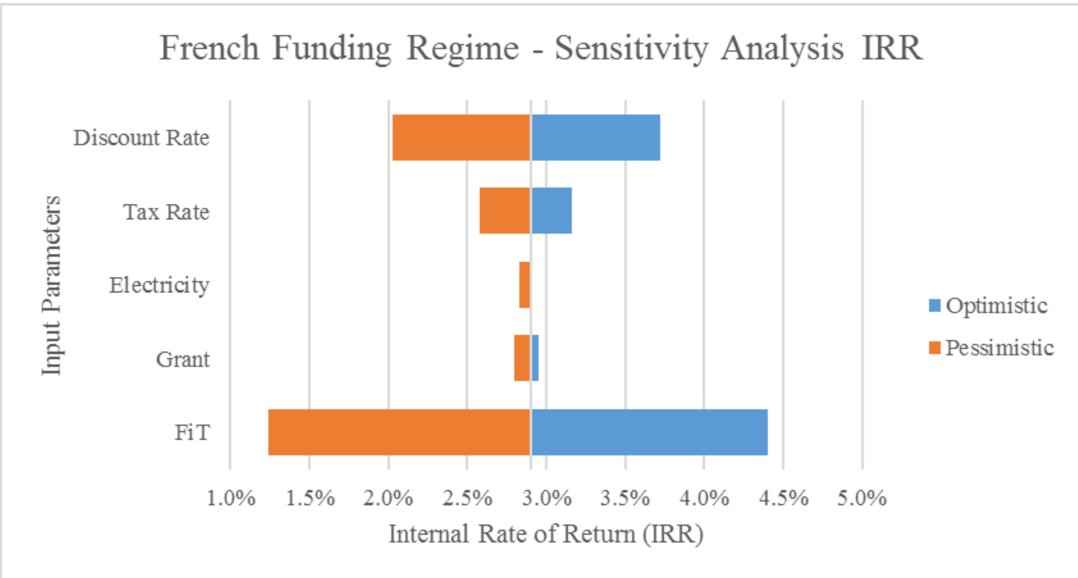
As detailed in Chapter 3, the values for level of funding, discount rate, and corporate tax rate have been adjusted with +10%/-10%, -10%/+10% and -10%/+10% respectively for the optimistic and pessimistic case respectively. The sensitivity analyses of the level of funding under the French regime, on top of the level of feed-in tariff, includes a sensitivity analysis of the level of governmental grant. In the following illustrations the reader can observe the results of our sensitivity analysis under the French funding regime. Just like we have seen in the case of the Scottish and Japanese funding regimes, the level of funding is also the most decisive factor on economic profitability for an investment under the French support mechanism.

Figure 4-15: Sensitivity of the NPV



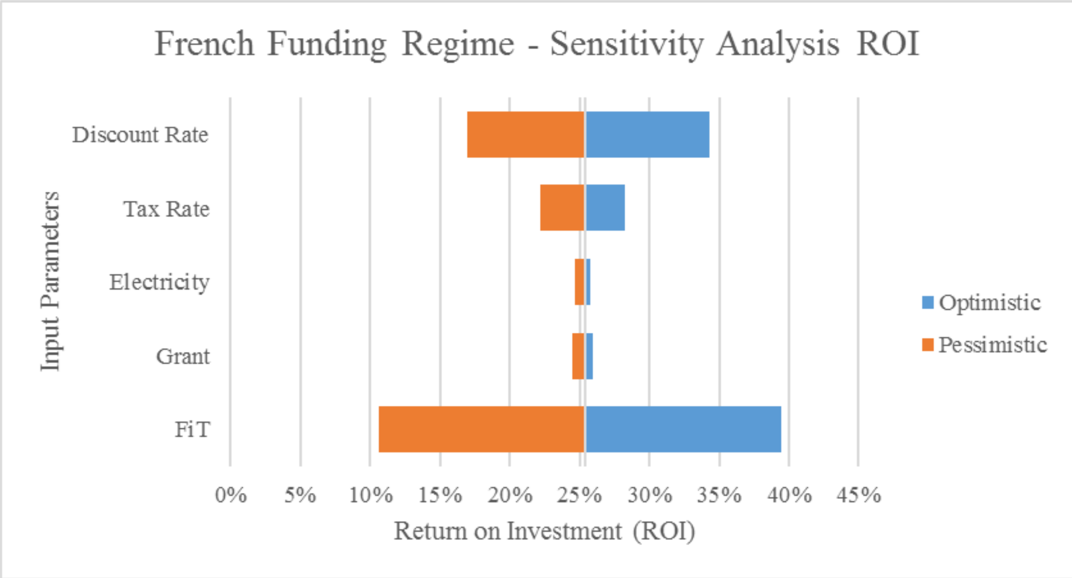
The level of the feed-in tariff has the highest impact on NPV, IRR, ROI and DPBP. As we can see in Figure 4-15, the project NPV value can be as low as GBP 22 million or as high as GBP 81 million depending on the feed-in tariff scenario.

Figure 4-16: Sensitivity of the IRR



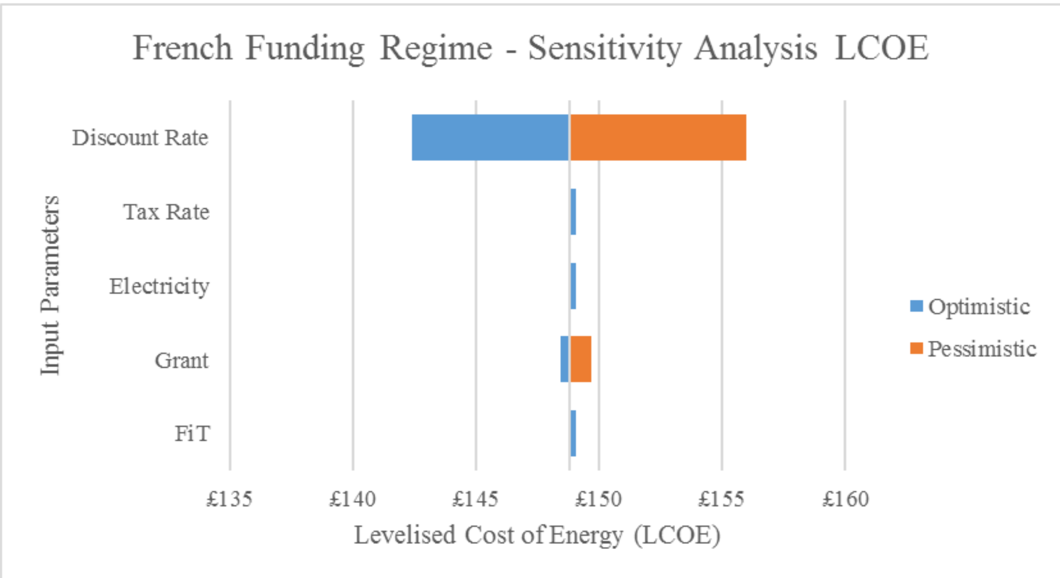
The discount rate has the second greatest impact on these four indexes, here illustrated with an impact on the IRR rate in Figure 4-16. The IRR rate, 2.87% at the base case, goes up to 3.72% or down to 2.03% under the optimistic and pessimistic discount rate respectively.

Figure 4-17: Sensitivity of the ROI



The tax rate has an even smaller impact on the NPV, IRR, ROI and DPBP under the French support system than under the Japanese one. The optimistic and pessimistic tax rate cases lead to changes in ROI of about 3%, while the tax rate leads to a change of about 3.5% in ROI under the Japanese support system.

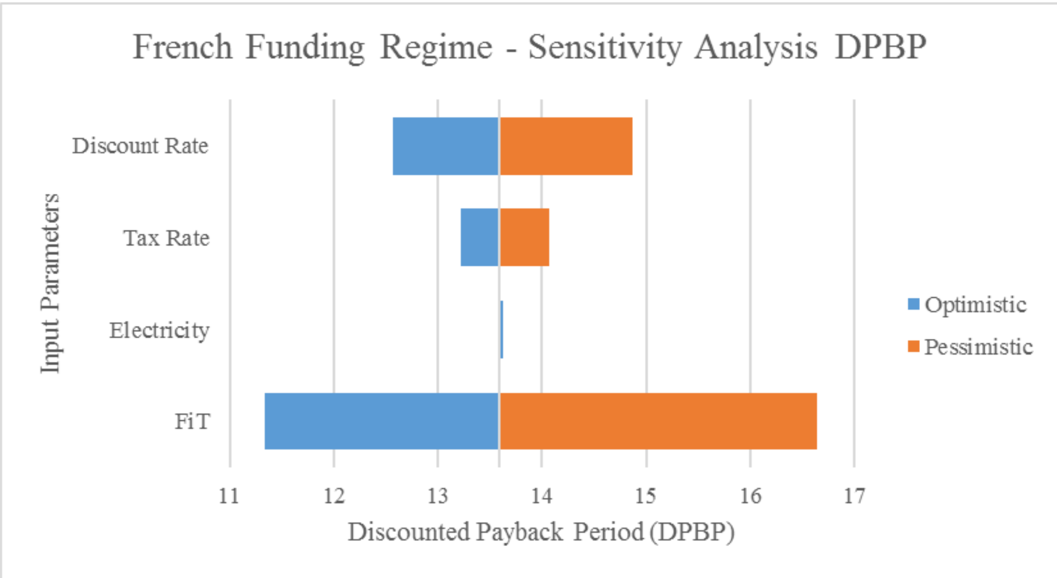
Figure 4-18: Sensitivity of the LCOE



The discount rate also has a considerable impact on the LCOE index in Figure 4-18. These values are estimated to vary between 142-156 GBP/MWh, which are comparably low values in comparison to all other LCOE sensitivity results. The French funding regime is the only one in which not only the discount rate but also a part of the funding regime itself, namely the governmental grant, has an impact on the LCOE. This is because the grant reduces the initial investment and is in thus factored directly into the LCOE calculation.

Finally, the electricity price again has a rather small impact on the economic indexes under the French support system because, as it is the case under the Japanese funding regime, the electricity price is only relevant for the final five years of the project.

Figure 4-19: Sensitivity of the DPBP



4.5. Hawaiian Funding Regime

This section first provides an overview of the Hawaiian funding regime and its motivation. Subsequently, the impact on our pre-commercial model floating offshore wind farm in Scotland is analysed.

Background

With 14% of its electric power being generated from coal and 70% from diesel, Hawaii is the most fossil fuel dependent state in the United States and therefore relies heavily on oil imports (Hawaii State Energy Office, 2015). The power production with diesel generators is expensive and results in the highest electricity prices in the United States, the average wholesale price of 0.1966 USD/kWh in 2015 being more than twice as high as the US average of 0.064 USD/kWh (EIA, 2015b). The motivation behind the Hawaii's renewable funding mechanism is therefore two-fold: The first goal is to replace the current oil-fired power generation with clean energy, and the second ambition is to become energy self-sufficient in order to rid themselves off a dependency on oil imports (Hawaii Powered, 2016).

The island state has rich renewable resources, including offshore wind. The Hawaiian government aims to produce 70% of their electricity from renewables by 2035, and 100% by 2045 (Hawaii Powered, 2016).

These targets mirror a growing political support across the United States to increase renewable power generation. President Barack Obama proposed that 80% of the nation's electricity should be generated from clean energy sources by 2035 (Arapogianni and Genachte, 2013). In contrast to the other jurisdictions reviewed in this study, however, the US does not offer federal funding for offshore wind power in particular, but only for renewable energy in general[1]. Funding in the US thus works very differently from European funding.[2] On top of this, funding at the federal level is generally very complex[3].

Policy makers in the Unites States value market-driven solutions over non-market support solutions, an aspect which resembles the Scottish funding philosophy. However, American policy makers also prefer state-specific rather than federal funding, an aspect in which they differ from their European counterparts. This is reflected by a general preference for, for instance, state-specific renewable tax credits over a federal carbon tax or a federal feed-in tariff (Snyder and Kaiser, 2009a). Different US states can therefore set targets for different renewable energies and support these as they see fit[4].

Generally speaking, state utilities and policy makers at the federal level and the US senate consider their responsibility primarily to ensure that the consumer is protected against higher commodity prices (Snyder and Kaiser, 2009a). The emphasis in the US lies on environmental concerns, operational safety and fair prices for consumers. This

[1] Interview with Carlos Rivals of EDPR, 18.09.15, Appendix D.g, Lines 54-56

[2] Interview with Carlos Rivals of EDPR, 18.09.15, Appendix D.g, Line 53

[3] Interview with Bonnie Ram of DTU, 04.12.15, Appendix D.c, Lines 39-41

[4] Interview with Carlos Rivals of EDPR, 18.09.15, Appendix D.g, Lines 54-56

stands in contrast to the European approach, where the focus is on encouraging investment into alternative sources of energy.

Despite the preference for the support of renewable energies in general, two federal agencies currently support the development of floating offshore wind in particular, the US Department of Energy (DOE) and the US Bureau of Ocean Energy Management (BOEM).

The DOE is largely responsible for guaranteeing energy security of supply, and supports science and innovation initiatives with the goal to move the US energy system as a whole towards clean energy technologies (DOE, 2016a). A significant portion of the *Recovery Act* from 2009 (ARRA) was dedicated to developing renewables, specifically offshore wind research and development (DOE, 2015). The *Offshore Wind Innovation and Demonstration Initiative* was the first DOE programme to support R&D funding of offshore wind. In 2012, this programme received USD 168m funding and currently supports seven offshore wind demonstration projects, three of which are floating concepts. The programme was recently extended until the end of 2016 (DOE, 2016b).

The BOEM is responsible for offshore wind specifically. The bureau issues leases for offshore projects, involving state and local governments in the process, with the main goal to ensure energy security of supply, considering the environment and fair returns for leases and grants (BOEM, 2016). In the case of the two recently proposed floating offshore wind parks on the Hawaiian Continental Shelf, the BOEM has published a Request for Information, RFI, to decide whether there is competitive interest in the project site, before the agency will issue the rights to lease and deployment (NREL, 2016). On the Hawaiian Islands, four electric utility companies serve different island or set of islands and are regulated by the Public Utility Commission (PUC).

Feed-in Tariff and Production Tax Credit

In the last decade state-specific Renewable Portfolio Standards (RPS) were meant to ensure a growing percentage of US electricity to be produced from renewable sources, with every state setting own targets for increasing the share of renewable electricity fed into the grid. 28 US states have adopted such RPS policies that require a certain percentage of renewable energy (Saidur, et al., 2010). A variety of state-specific

initiatives have since been added to support renewable energy development more effectively at a local level.
Hawaii, Vermont, Maine, California and Oregon, for instance, introduced feed-in tariffs to reach their renewable energy targets as set out under their respective RPS schemes (Lilley, Sheridan and Crompton, 2010; REN21, 2015). Hawaii, in contrast to most mainland states, has introduced a relatively high renewable feed-in tariff that supports all types of small and large-scale onshore and offshore wind power, as well as photovoltaic, biogas, geothermal and hydro power projects. The tariff for onshore wind power was 120 USD/MWh in 2015 with a limit on turbine size of 5MW (Hawaii Tax Office, 2016). The feed-in tariff for fixed offshore and floating wind projects is yet to be decided. No preliminary range in which the feed-in tariff may lie – as it is the case in France, for instance – has been published as of June 2016.
The tendering of sites for offshore wind is organised by so-called Request of Proposals. As part of this process, the government requires project developers to apply with their renewable energy projects for a combined capacity of 350MW to be developed on the islands by 2022 (Engerati, 2016). Danish wind developer Alpha Wind Energy and US developer Progression Energy have recently proposed floating offshore wind parks with a combined size of 812MW (Kessler, 2016). In this case a Request for Interest is issued, which is opens up the requested site for applications from other developers who can who can apply to compete with this proposal. It is expected that up to 1GW of wind power capacity will be installed in Hawaii by 2030, 800MW of which will be built offshore (Engerati, 2016).
Once a site is tendered, the project developer may choose between being awarded the Hawaiian feed-in tariff or alternatively can opt for negotiating a Power Purchasing Agreement (PPA) with a utility. The idea of PPAs as a market based solution is a widely accepted as an answer to insufficient federal or state support mechanisms[1]. A PPA constitutes a binding contract between a utility and a project developer as part of which the developer agrees to supply a certain amount of megawatt hours for a specific time period and the utility agrees to pay a certain price per megawatt hour. These contracts are very common and provide a stable income for generators. In this regard PPAs are similar to feed-in tariffs, except that tariffs mean an income that is protected by legislation while a PPA is an agreement between the generator and the

[1] Interview with Carlos Rivals of EDPR, 18.09.15, Appendix D.g, Lines 54-56

utility. This means that the price paid by the utility per megawatt hour is up to negotiation and not determined by the government. Although it is important to be aware of other financing options available to offshore wind generators under Hawaiian legislation, for our project we will assume that the project developer receives income under the feed-in tariff scheme.

Even though funding mechanisms are typically organised at state level in the United States[1], the federal government grants renewable energy projects a federal tax break, known as Production Tax Credit (PTC) in addition to state-level funding, in our case the feed-in tariff scheme. This credit is given in form of a reduced tax for a certain period of time for each MWh produced[2]. The PTC applicable to a wind park like our model floating wind farm allows the developer to deduct 23 USD/MWh for all MWhs produced from their taxable income and is valid for the first 10 years of operation. This value is valid for the year 2016 only and inflation-adjusted every year (DOE, 2016b). The PTC is going to be phased out for wind projects and other technologies where construction begins later than 31 December 2016. For wind power projects that commence construction in 2017, this means a reduction in the PTC amount of 20%. The PTC is gradually reduced for every year construction commences later than 2017 (DOE, 2016b). Because we assume that our project starts generating electricity in 2017, the PTC phasing out is not directly relevant for our profitability calculations. It is, however, an important aspect to keep in mind for wind developers operating under the Hawaiian funding regime.

The state government of Hawaii is currently in the process of discussing whether the federally regulated PTC is incentive enough or whether offshore wind parks should be exempt from taxation altogether (Hawaii State Energy Office, 2015). For our model wind farm we assume that taxes are paid because there is no further information on tax exemptions available, other than that talks about exemptions are being held.

In addition to the PTC, the federal government has launched several programs including the *Vision for 2025: A Framework for Change* and the *American Recovery and Reinvestment Act* (ARRA) (Saidur, et al., 2010).

[1] Interview with Morton Dillner of Statoil, 27.10.15, Appendix D.d, Lines 3-5

[2] Interview with Morton Dillner of Statoil, 27.10.15, Appendix D.d, Lines 6-8

4.5.1. Adjusting the Cash Flow Model Parameters

Level of Funding

The level of the feed-in tariff for offshore wind projects in Hawaii has not been decided yet. For the sake of our analysis, we assume that the authorities will choose a higher rate for floating offshore wind than for onshore wind power, which is currently funded with 120 USD/MWh (Hawaii State Energy Office, 2015). Due to the novelty of floating technology and its substantially higher investment cost compared to onshore wind, we assume that the government will propose a tariff that is closer to the actual wholesale power price in Hawaii, which was 196.6 USD/MWh on average in 2015, due to a high dependency on oil imports for power generation (EIA, 2015b). Because we have not further reference points other than the feed-in tariff for onshore wind and the wholesale electricity price, we assume that the feed-in tariff for our pre-commercial floating offshore wind farm under the Hawaiian funding scheme will be the average between the wholesale power price and the onshore feed-in tariff:

$$\$\,120\ \times 50\% + \$\,196.6\ \times 50\% = 158\frac{\$}{MWh}$$

In order to convert this tariff to GBP we use the mean average of yearly exchange rates between the two currencies for the last 10 years, retrieved from the databank of the US Foreign Exchange Service. According to this databank, USD 1 is worth GBP 0.618805 on average (US Forex, 2016), see Appendix A. This means that a feed-in tariff of 158 USD/MWh is equal to 97.78 GBP/MWh.

Taxes

Any commercial business in the United States has to pay both federal taxes and state taxes. The applicable tax rates for our model wind farm are 35% federal tax and 6.4% Hawaiian state tax respectively (Hawaii Tax Office, 2016; Department of Taxation, 2016). The combined tax rate of 41.4% is paid on all taxable income. During the first 10 years of operation, the project developer may deduct the PTC from this taxable income (DOE, 2016b).

Discount Rate

The risk-free rate and risk-premium remain the same as argued for in section 3.1.3. The risk beta is the same as in the Japanese model because, as in the case of the Japanese funding regime, the Hawaiian funding regime consists mainly of a feed-in tariff. The federal production tax credit does not influence the risk of the project revenue because, albeit changing the absolute level of profit investors receive, the tax credit does not make this revenue any more or less risky. Cases have been heard of where power generators could choose between the equivalent of a PTC and governmental grant (Saidur, et al., 2010), which suggests that PTCs and grants yield very similar outcomes in terms of gain, and therefore, by extension, constitute similar risks for investors. For our analysis this would mean that we would have to reduce the discount rate for the Hawaiian funding regime in the same way we did for the French funding regime. However, we argue that the discount rate under the Hawaiian funding regime should not be reduced. This is because governmental grants given to the project in year 0, that is at the outset of the project, are inherently less risky than future payments, governmental or otherwise, which may be subject to unforeseen policy changes. This is especially the case at the current time, given that the Hawaiian government plans to phase out support for wind projects such as the one considered in this study. For our thesis we therefore assume that the governmental grant under the French funding regime and the production tax credit under the Hawaiian scheme do not bear the same risk. Given these differences in risk, we believe that it is reasonable to use a higher discount rate under the Hawaiian funding regime relative to the French funding regime. Consequently, it follows that the discount rate under the Hawaiian scheme is 9%, as it is the case under the Japanese support scheme.

4.5.2. Inserting Values into the Cash Flow Model

The regular income for our model wind farm under the Hawaiian funding mechanism is based on our floating wind feed-in tariff level assumption of 97.78 GBP/MWh. As in our previous analyses, this is the feed-in tariff level we assume today, i.e. in year 0. Adjusting this for inflation, we obtain a feed-in tariff in year 1 of:

$$97.78\frac{£}{MWh} \times 1.02 = 99.74\frac{£}{MWh}$$

Given the expected production of 203,933 MWh per year, the feed-in tariff yields an income stream of GBP 20,339,360 during year 1 of the project lifetime:

$$97.78\frac{£}{MWh} \times 203{,}933\frac{MWh}{yr} = 20{,}339{,}360\frac{£}{yr}$$

As in the previous analyses, the feed-in tariff income will be adjusted to inflation every year. Similarly, to the above analysed funding regimes in other jurisdictions, we assume the feed-in tariff scheme ends after 20 years of operation on part of the project.

The PTC in 2016, i.e. year 0 of our cash flow model, amounted to 23 USD/MWh (DOE, 2016b), which, using the aforementioned exchange rate, equates to 14.23 GBP/MWh. It is inflation-adjusted every year, and is therefore already adjusted for the first year of operation of our cash flow model.

4.5.3. Economic Indexes

The calculation of the economic indexes was explained in section 3.3 and exemplified in section 4.2.3. As above, in this subsection we will therefore only list our results.

NPV

Given that the above calculated discount rate is 9%, the real interest rate used in the NPV model becomes:

$$r = 9\% - 2\% = 7\% \tag{6d}$$

The NPV of the model under the Hawaiian funding regime therefore becomes GBP –76,028,622.

IRR

Using Microsoft's Excel software, the authors determine an IRR value of –4.59% for the pre-commercial wind farm under the French funding mechanism.

ROI

The ROI in the case of the Hawaiian funding mechanism amounts to –34.77%.

LCOE

Given the discount rate of 9%, we can obtain an LCOE of 153.63 GBP/MWh for the model under the Hawaiian support system.

DPBP

The cash flow model for the Japanese gives us a discounted payback period of 155.57 years.

Please see Appendix B.d for the spreadsheet in which the cash flow model and economic indexes have been calculated for the floating offshore wind farm under the Hawaiian funding regime.

4.5.4. Sensitivity Analysis

As detailed in Chapter 3, the values for level of funding, discount rate, and corporate tax rate have been adjusted with +10%/-10%, -10%/+10% and -10%/+10% for the optimistic and pessimistic cases respectively. The sensitivity analyses of the level of funding under the Hawaiian regime, on top of the level of feed-in tariff, includes a sensitivity analysis of the level of production tax credit. The following figures illustrate the results of our sensitivity analysis under the Hawaiian funding regime. The effect of changes in the input parameters on the economic indexes are for the most part similar to those under the French and Japanese models. But in the case of the Hawaiian funding regime, no change in input parameters leads to a profitable project.

As has been observed in the previous three sensitivity analyses, the level of funding constitutes the input parameter with the most significant sensitivity, followed by the discount rate.

Though notably, even calculating the NPV under the Hawaiian regime with 110% of the above assumed feed-in tariff level would not render the project profitable, see Figure 4-20.

Figure 4-20: Sensitivity of the NPV

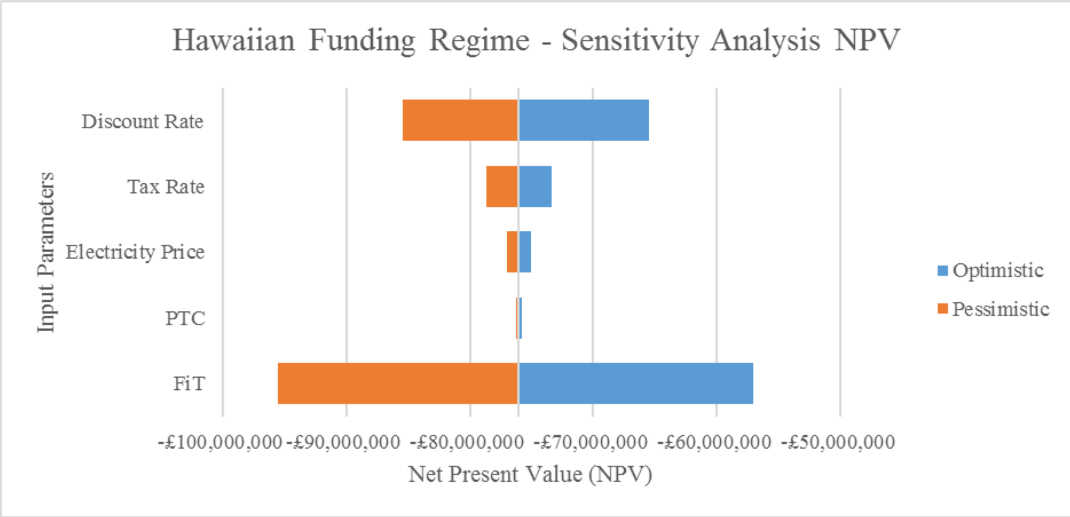


Figure 4-21 also shows that even under the optimistic scenarios of the input parameters an IRR of at most -3.38% could be achieved and Figure 4-22 illustrates that an ROI of at best -26% is possible.

Figure 4-21: Sensitivity of the IRR

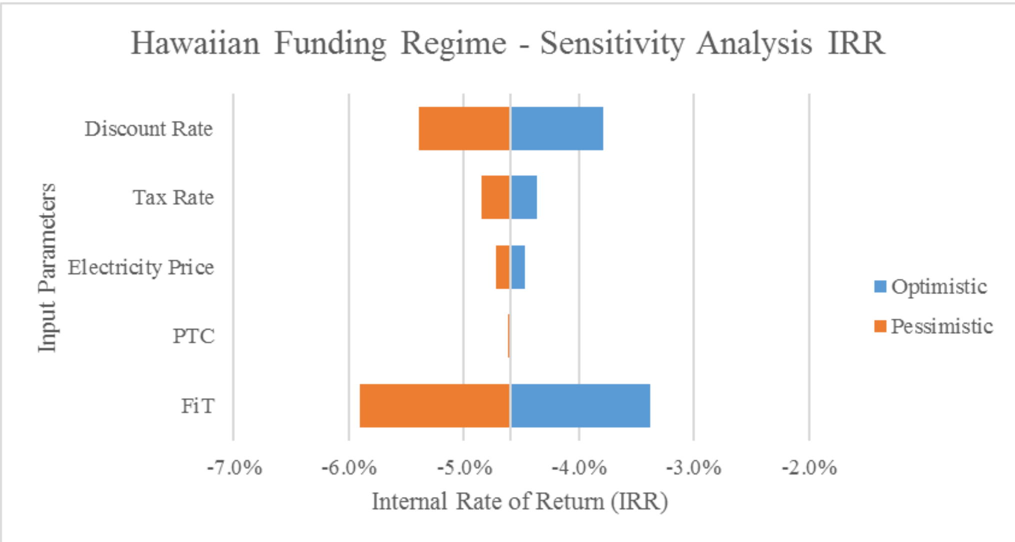


Figure 4-22: Sensitivity of the ROI

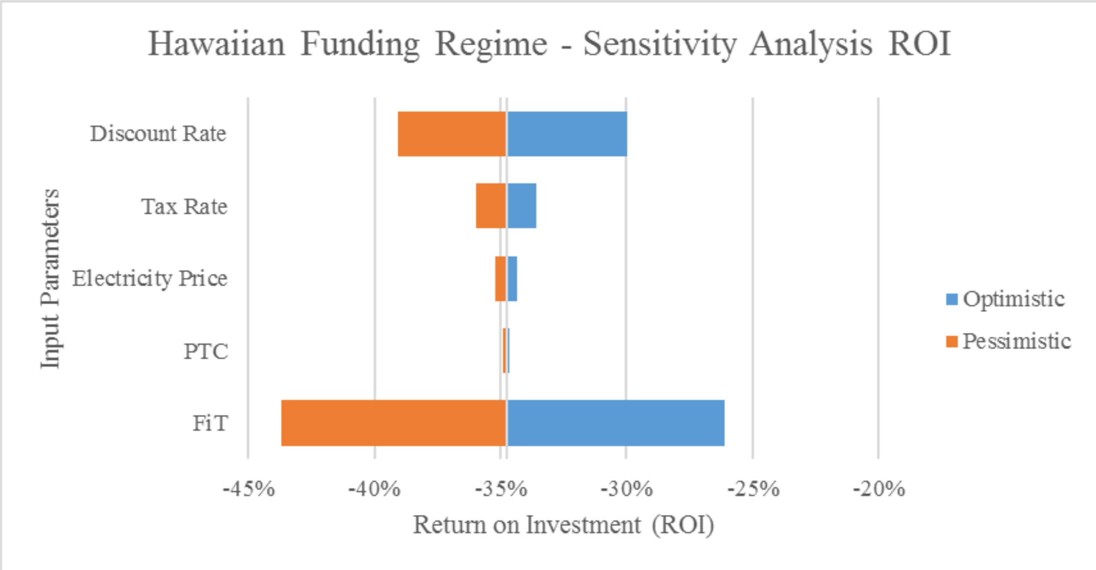
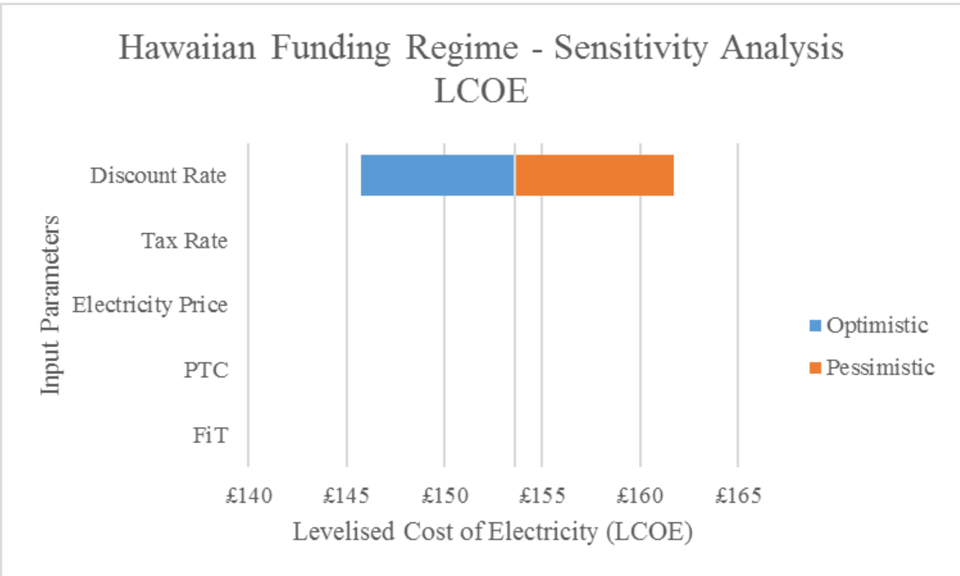


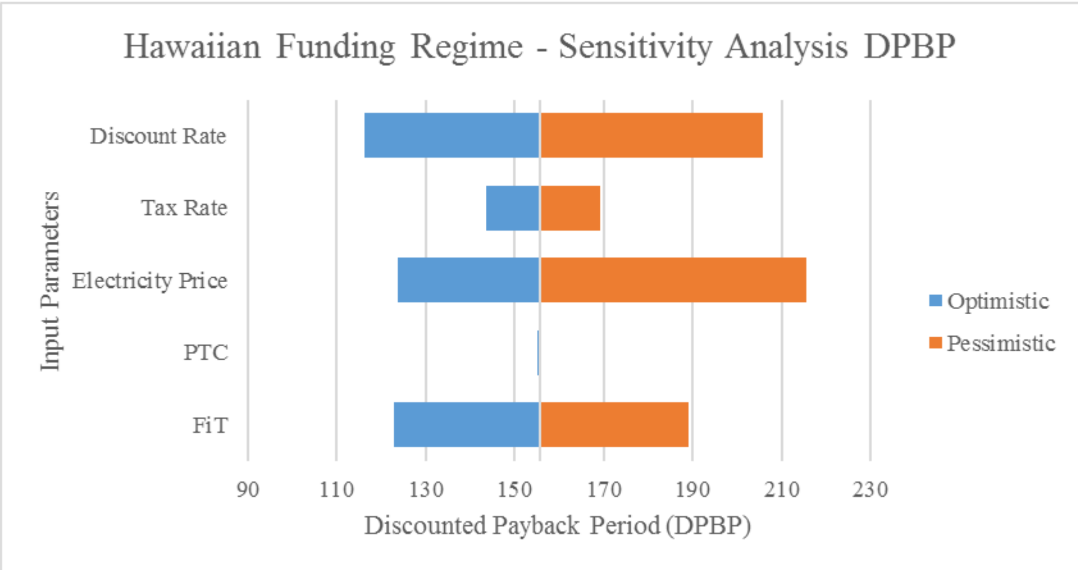
Figure 4-23: Sensitivity of the LCOE



A variability in the discount rate, as our analysis shows, has a similarly significant impact on the economic indexes as the ones derived under the Scottish, Japanese and French funding regimes and their sensitivity analyses. Interestingly, the economic indexes tend to be more sensitive to variabilities in the discount rate than to variabilities in the PTC, although the latter is part of the funding regime and in previous sensitivity analyses we could observe that the level of funding is the most significant input parameter in determining the profitability of our project. In the case of the Hawaiian funding regime, however, the PTC does not seem to have a significant impact on the economic indexes, compared to the other input parameters.

Given that the variability in the discount rate is the second most significant input parameter, it does not surprise to see that a sensitivity analysis of its impact on the LCOE yields a similar result than under the previous three sensitivity analyses in the sense that under the optimistic and pessimistic scenario the LCOE varies by about GBP 10, see Figure 4-23. The LCOE value under the Hawaiian regime may vary between 116 - 206 GBP/MWh, depending on what scenario of discount rate is chosen.

Figure 4-24: Sensitivity of the DPBP



When comparing the sensitivity analyses of the economic indexes, we can observe that the discount rate has the second biggest overall impact on NPV, IRR, ROI and DPBP. Interestingly, the change in discount rate has a stronger impact on the DPBP index than the level of funding as we can see in Figure 4-24. But a negative change in the electricity price has an even larger effect on the DPBP than a negative change in the discount rate or a negative change in the level of feed-in tariff. This effect of the discount rate on DPBP differs from the previous three sensitivity analyses, due to the on-going negative effect of a high discount rate so far in the future. A lower electricity price means that it takes disproportionately longer for the project to break-even. But because the project is unprofitable under the Hawaiian funding regime as it stands now, we will ignore the changes on discounted payback period in the sensitivity analyses and focus on the results that can help us determine recommendations for policy makers, as this is, by extension, the goal of this paper. From the different funding regimes' sensitivity analyses, it becomes evident that the level of funding is the most important factor when all input parameters' 10% changes are considered and is thus of greatest importance to investors. It is therefore important to set the level of funding in a way that will entice sufficient investor support.

4.6. Summary of Observations

From the different sensitivity analyses, it becomes evident that the level of funding is the most important factor in determining the results of the economic indexes. We can therefore conclude that it is important to set funding at a level that will entice sufficient investor support.

The following table provides an overview of the results of our cash flow and economic index analyses:

Table 3: Summary of all results from our five indexes

	Scottish	**Japanese**	**French**	**Hawaiian**
NPV	£182 148 384	£167 040 526	£51 850 188	-£76 028 622
IRR	8.67 %	8.23 %	2.87 %	-4.59 %
ROI	83.29 %	76.38 %	25.21 %	-34.77 %
LCOE	£157.85	£153.63	£149.05	£153.63
DPBP	7.88 Years	8.05 Years	13.62 Years	155.57 Years

We can see that the under the Scottish funding regime, the project obtains the most favourable values in terms of NPV, IRR, ROI and DPBP. In regards to these indexes, the Japanese funding regime provides comparably favourable outcomes. Interestingly, the French funding regime yields the lowest LCOE value for each MWh of energy produced from the model floating offshore wind farm. A discussion of these findings and an appreciation of the policy implications follows in the next chapter.

CHAPTER 5: Discussion

Based on the analysis and background information provided in previous chapters, we can now turn to interpreting our results, answering our research question and proposing suggestions to policymakers. To remind ourselves, the research question was:

- What is the economic impact of different funding mechanisms on the investment in a pre-commercial floating offshore wind park?

5.1. Economic Indexes

The table in section 4.6 provides an overview of the economic indexes obtained from our analysis in Chapter 4. These indexes capture the impact of the four different funding regimes on our model wind farm.

Given what we have said so far about the different funding schemes and the different risks inherent in each of them, it surprises to see that the Scottish funding regime yields a more favourable NPV, IRR, ROI and DPBP for our model floating offshore wind farm than the Japanese one. This is despite the fact that the Scottish scheme is market-based and through the market volatility of ROCs bears a greater risk for investors, leading to a higher discount rate for this funding regime. Nevertheless, compared to the NPV, IRR, ROI and DPBP under the French and Hawaiian regimes, the economic indexes under the Japanese support scheme are relatively close to those under the Scottish one. In this context, it is particularly interesting to see that the Japanese and Scottish support schemes yield so similar before-tax incomes for the model wind farm, 228 GBP/MWh and 222 GBP/MWh respectively, and merely differ in their tax rate and discount rate. These factors though differ considerably and are crucial in determining the profitability of the investment from investors' points of view. Yet, these factors seem to balance each other out, yielding similar NPVs for the Scottish and Japanese funding regimes. Normally, broad support schemes like green tradable certificates tend to encourage innovation into technologies that are fairly close to being competitive with conventional fossil fuels, i.e. not floating offshore wind, while targeted support schemes like feed-in tariffs and feed-in premiums are more adequate to support such expensive technologies (Canton and Johannesson Lindén, 2010). Yet, the Scottish green tradable certificate scheme, as it is currently designed, encourages more investor support into the rather expensive floating offshore wind technology than the Japanese feed-in tariff scheme.

It is perhaps the greatest surprise that, given these findings, our analysis confirms Canton and Johannesson Lindén's (2010) policy conclusion that a green tradable certificate scheme is the most beneficial type of support. This is although Canton and Johannesson Lindén (2010) evaluate support schemes from a total welfare point of view, factoring in the combined effect of consumer surplus, electricity producer profits, pollution externalities and energy insecurity, and we evaluate support schemes from an investor's perspective. This is perhaps a rather unexpected result, and one with a far-reaching meaning: We now know that it is possible for policymakers to combine total societal and market welfare considerations, including the aspects of energy security and the socially and economically motivated mitigation of climate change, with the motivation to support a promising, yet novel and therefore expensive, technology such as floating offshore wind through increased private investor support by designing one carefully crafted support scheme.

It is also interesting to see that the Japanese, French and Hawaiian support schemes yield such different NPVs, IRRs, ROIs and DPBPs relative to each other. This is noteworthy because all three schemes utilise feed-in tariff support as their main funding mechanism, a system that rewards a maximisation of total electricity production regardless of market demand. The Scottish scheme, by contrast, requires a certain level of output adjustment to market demand at any given time because generating too much electricity at times when the electricity price is low could lead to a loss for the generator.

The NPV under the French funding regime is substantially lower compared to the Scottish and Japanese scenarios. This discrepancy is mainly due to the combination of a relatively low feed-in tariff and a relatively high tax rate under the French scheme. France's feed-in tariff of 157.28 GBP/MWh in year 0 of our model is much lower than Scotland's income of 222 GBP/MWh from certificates and selling electricity, and Japan's feed-in tariff of 228 GBP/MWh. This discrepancy in regards to income is only exacerbated by the relatively high tax rate of 33.33% that developers have to pay under the French model, compared to 33.06% and 21% under the Japanese and Scottish regimes respectively.

The lowest NPV for our model wind farm is calculated under the Hawaiian funding regime, where the funding does not come even close to recovering the investment made in the project. The Hawaiian government has yet to decide on the tariff level at which to support offshore wind and has not yet published an expected range in which the final feed-in tariff might lie. The feed-in tariff assumed for our study is the average between the wholesale electricity price at 196.6 USD/MWh and the feed-in tariff for onshore wind power at 120 USD/MWh. One may argue that the feed-in tariff assumed in our model was estimated too low. However, even assuming a feed-in tariff at the level of the Hawaiian wholesale electricity price of 196.6 USD/MWh, which equates to 121.5 GBP/MWh, leads to a negative NPV. Unless the feed-in tariff for floating offshore wind on Hawaii is substantially higher than the Hawaiian wholesale electricity price or unless the project receives more tax breaks, this funding regime does not encourage investment in floating offshore wind at the current very early development stage.

Given the NPV values that were discussed above, it does not surprise that the Scottish funding regime also yields the most favourable IRR, 8.67%, compared to the other support mechanisms. Interestingly, as it is the case for the NPV, the IRR under the Japanese regime, 8.23% is only slightly less favourable than the one under the Scottish regime, which suggests that despite the differences in type of funding, inherent risk and tax rate between the two schemes, the yields generated under both schemes end up being similar enough overall to yield similar internal rates of return.
The IRR under the French regime is also substantially lower than under the other two regimes, yet relatively speaking higher when compared to the IRRs under the Scottish and Japanese regimes than a comparison among the three regimes' NPV values might let one expect. Nevertheless, the IRRs of these three support schemes are all below what investors may expect. In a report assessing the investment case of wind power, Deloitte (2015) simulated a financial wind project model and calculated an expected IRR of 9.4%. Even the Scottish support scheme's IRR of 8.76% falls behind this estimate. This means that even with access to the funding schemes discusses above, wind farms like our pre-commercial model wind farm may, due to its IRR, face some difficulties attracting sufficient investor support for the project to go ahead, particularly in the early stages of the project where investor funding is needed to during the installation and commissioning phase, before any funding can be received from electricity generation. It is possible thought that it might be acceptable for the

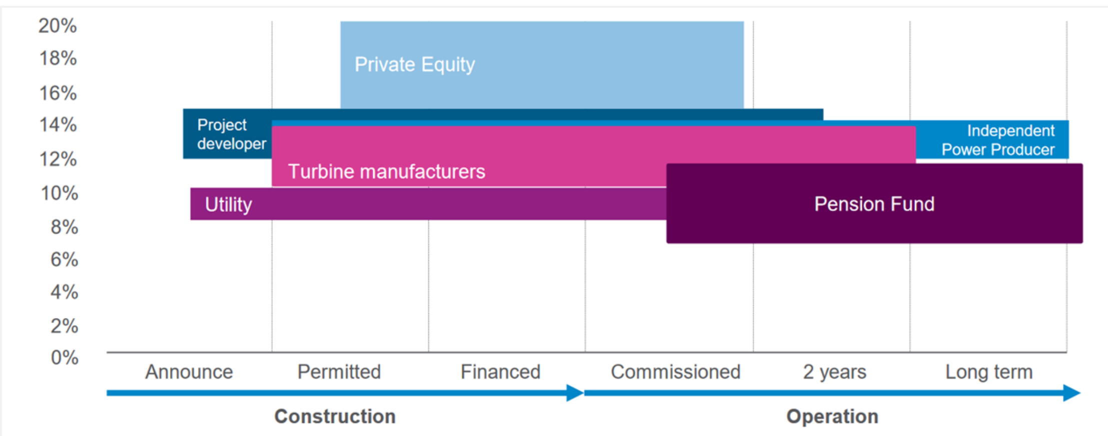
project under consideration to fall a bit short of IRR expectations, given that it is a pre-commercial floating project. Deloitte (2015) considers the investment case for wind in general, without specifying whether their considerations concern onshore or offshore wind. This means that the IRR of our model floating wind farm might fall behind general expectations due to the uncertainties associated with floating wind as a new technology, compared to offshore and onshore wind. But it may yield an acceptable IRR for floating offshore wind at the current stage of the development process.

The IRR comparison nevertheless helps understand why pre-commercial floating wind farms might face difficulties in attracting investor support and offers a possible explanation for why it took so long for the construction phase of the world's first two pre-commercial floating wind farms to come under way, which it did only now in 2016 although the first floating prototype was already operational in 2009.

In contrast to the IRR values, the ROI of the project under the Scottish, Japanese and French funding regimes is very favourable when compared to industry standards. With ROIs of 83.3%, 76.4% and 25.48 % under the Scottish, Japanese and French schemes respectively, the project offers returns far above industry standards, the commonly accepted ROI for offshore wind power being about 10% (Renewables International, 2013). Other sources suggest that investors generally expect returns between 8% and 20%, depending on who invests (UK Trade and Investment, 2014). Figure 5-1 shows that private investors, in this case denoted by 'Project Developer' and 'Private Equity', would expect returns of at least 12% or 16% respectively (UK Trade and Investment, 2014).

Figure 5-1: Entry and exit timings for selected equity investors

Source: UK Trade and Investment, 2014



The three above mentioned support systems offer multiples of the standard ROI, signalling a strong motivation to kick-start floating offshore wind industry. Especially the Scottish and Japanese funding schemes demonstrate how quickly these two governments would like to see the industry grow and mature in their jurisdictions. Given the very high ROI of the Scottish and Japanese support scheme, the French regime's ROI of 25.21% seems almost modest in comparison, and begs the question whether the Scottish and Japanese incentives may even be 'too generous', or, in case of the Japanese regime, even a waste of taxpayers' money. The Scottish market-based certificate scheme, in contrast to the Japanese one, is paid for by the power consumer. This consideration then already takes us beyond the question of the support schemes' impact on the profitability of the model wind farm for private investors and allows for a glimpse into the conclusions we might draw from our analysis for our policymakers. The French support scheme may be more sustainable than the Scottish and Japanese regimes because it less expensive for the public. According to our literature, the ROI under the French funding regime is still stronger than required to encourage early investment in this new technology.
The ROI of the model wind farm under the Hawaiian funding regime is entirely insufficient. The value of nearly -35% indicates that a developer would lose substantial amounts of money on an investment under this support mechanism as it currently stands.

It is interesting to see that although the Scottish funding regime seems to yield the most favourable values in regards to most of the economic indexes (NPV, IRR, ROI and DPBP), the Japanese funding regime generates a more favourable LCOE value for the project (153.63 GBP/MWh compared to the Scottish 157.85 GBP/MWh). Most surprisingly, when compared to the other indexes, is the fact that the French support mechanisms yields the most favourable LCOE value of all regimes under consideration, 149.05 GBP/MWh. The French funding scheme is hence best suited to effectively lower the cost of electricity, despite an additional special offshore wind tax. The direct governmental funding, in form of a grant is the reason for the lowest LCOE value under the French funding mechanism. We propose in our analysis that this direct support from the French government in combination with substantial project loans reduces the risk beta of the project. This is because the government

involvement promises stability to the prospective of these projects. We account for this with a slightly reduced risk beta, decreased by a factor of 0.9, which results in the lowest discount rate among all funding regimes, 8.78%.
The LCOE values we calculated for our project under the different funding regimes (157.85 GBP/MWh und the Scottish regime, 153.63 GBP/MWh under the Japanese, 149.05 GBP/MWh under the French, and 153.63 GBP/MWh under the Hawaiian) are substantially higher than the current LCOE targets of pre-commercial wind farms that are being developed in Scotland at the moment. The *Hywind* project, for example, aims to achieve an LCOE of less than 95 GBP/MWh (Hopson 2016). This, however, seems very optimistic, given that the average LCOE of an offshore bottom-fixed wind farm is currently about 120 GBP/MWh for commercial arrays (European Commission 2015b) and *Hywind* utilises the rather novel floating wind mills and is a pre-commercial array. The discrepancy between our calculations and the *Hywind* LCOE target might result from the fact that our calculations were conducted with conservative cost and discount rate assumptions in mind. For our study it is of prime interest how the impacts of several different funding mechanisms compare to each other. The results of previous indexes have shown that the Scottish funding scenario is the most profitable for an investor in regards to NPV, IRR and ROI. However, the LCOE under the Scottish funding scenario is with 157.85 GBP/MWh the most expensive cost per MWh in comparison to other support systems. The difference of 8.80 GBP/MWh between the LCOE under the Scottish and French funding mechanisms is due to the capital grant and the discount rate, which is 9.5% in the Scottish scenario and reflects the higher risk of a market based funding system, in comparison to the feed-in tariff in France and Japan. The Japanese and Hawaiian funding regime have a lower discount rate of 9%, which results in the same LCOE of 153.63 GBP/MWh. The difference between the Scottish and the Japanese mechanism for example is 4.22 GBP/MWh, which is still a substantial difference. As we can see, the LCOE allows a different perspective on the impact of a funding regime. It does not account for specific market or technology risks but the index indirectly reflects risks and uncertainties through the discount rate. These results show that direct governmental grants can effectively reduce the cost of energy further.

The results of the discounted payback period index show that the investment under the Scottish and Japanese mechanism will be paid back within 7.88 years and 8.05

years respectively. These economic index estimates are consistent with the results from NPV, IRR and ROI that make the Scottish support scheme the most favourable one by comparison. The DPBP index shows that in the Scottish and Japanese funding schemes the investment is recovered after only one third of the expected project lifetime. Due to the short payback period the project will reach the break-even point after about 8 years. This is a good sign, especially in a project such as a floating offshore wind farm, that carries high operational risks. When we consider the French support scheme, the investment in our wind farm model would break-even after 13.58 years. This is roughly six years later than in the previous Scottish and Japanese scenarios but this DPBP nevertheless renders the investment attractive. The investor receives a full return within half of the project life. Under the Hawaiian funding scenario, the payback index drastically exceeds the project life time of 25 years. This economic index illustrates once more that this floating offshore wind investment would fail to deliver the required return under the Hawaiian support mechanism.

At this point, our results already hint at the need for policy makers to consider different types of support for different stages of maturity for a wind farm. At the early stages of its development, it may need more generous support in order to attract investors to the technology in the first place and allow for cost reductions to be made as the technology progresses. At later stages, the funding may then be scaled back.

5.2. Sensitivity Analysis

Sensitivity analyses have been carried out for varying input parameters (level of funding, electricity price, tax rate, and discount rate) for the five economic indexes (NPV, IRR, ROI, LCOE and DPBP) for each funding mechanism.

From the sensitivity analysis above, it can be concluded that the profitability of an investment in a pre-commercial floating offshore wind farm under the Scottish funding regime is particularly susceptible to market fluctuations of the ROC price, and by extension any policy changes that may affect the long-term financial planning price. The second biggest risk for investors is constituted by the risk inherent in the funding mechanism, as captured by the discount rate. This suggests that in order to instil more confidence in investors in floating wind under this funding regime, the RO scheme should ideally be designed in a way that allows for the ROC price to be rather stable. The Scottish government partially addresses this issue by setting the level of obligations every electricity supplier has to present each year using a fixed target calculation. This fixed target, also termed 'headroom', sets a margin between the expected electricity generation in a given year (supply of ROCs) and the level of obligation (demand for ROCs), which reduces the risk of supply of ROCs exceeding demand. The risk of a price decrease is therefore reduced and this allows for more investor confidence in the price forecasts of ROCs as there will always be a market for them (Government of the United Kingdom 2015). Naturally, the price of ROCs nevertheless fluctuates but through the 'headroom' measure its price level is more predictable and this allows for factoring the ROC price into long-term financial planning considerations at a reasonable level. This stability aspect may also be interpreted as a mechanism that keeps the discount rate at relatively predictable levels. Here, the discount rate is a proxy of the inherent risk in each respective support scheme.

Robustness of our results

From the sensitivity analyses conducted above, we can infer some conclusions regarding the robustness of our results. Robustness generally refers to the potential for insight of an analysis despite some of the assumptions being altered. In other words, if actual values deviate from assumptions, the results will still have reasonable efficiency and a reasonably small bias.

Bearing this in mind, we can see that the results of our analysis regarding the relative differences between the different funding regimes is captured with reasonable accuracy: Even altering some of the basic assumptions of the models, a Scottish-style green tradable certificate scheme and a Japanese-style feed-in tariff scheme would remain the most favourable for investors, compared to the French-style combination of feed-in tariff and governmental grant or the Hawaiian-style combination of feed-in tariff and tax break. This means that our overall conclusion, that either a green tradable certificate scheme or a feed-in tariff scheme, modelled after the currently prevailing Scottish and Japanese funding regimes respectively, leads to the most profitable outcome, compared to the other two schemes.

Comparing the sensitivity analyses of the Scottish and Japanese support systems directly, however, one may argue that our results are not quite as robust. It has been established previously that the two schemes yield very similar results. An inadequate estimation of even only one of the values in either the Scottish or the Japanese funding scheme could therefore tip the comparison between these two schemes specifically in favour of one scheme or the other.

Let us consider this case briefly to gain a more profound understanding of the robustness of our results, specifically regarding the evaluation of these two funding regimes relative to one another. The assumptions we made regarding the Scottish certificate system that could change how it compares to the Japanese funding scheme are those regarding the long-term financial planning level of the ROC price and the discount rate; the corporate tax rate is certain and the electricity price only has a negligible effect on the economic indexes. Our assumptions for the Japanese feed-in tariff are associated with the discount rate. The tax rate and level of feed-in tariff are certain as they are set at these levels by law, and the electricity price merely has a negligible effect on the economic indexes. The ROC price was chosen as the input parameter to illustrate the robustness of our results, because it is the input parameter, whose assumed value can be compared to its actual value more easily than it is the case for the discount rate.

An overestimation of the long-term ROC price would mean that the Japanese feed-in tariff becomes more favourable to investors. This increased profitability is, however, arguably only modest change, especially when compared to the other two support schemes under consideration. If the ROC price turns out to be only 90% of what we estimated, the project's NPV under the Scottish funding regime would be reduced to about GBP 148 million (please see Appendix B.a). The NPV under the Japanese funding mechanism would still yield about GBP 167 million. A slight miscalculation can tilt the results of the economic analysis in favour of the Japanese scheme, when compared to the French and Hawaiian funding schemes. Nevertheless, the Scottish and Japanese support systems still yield the more profitable results. This holds, even if we assume we underestimated both the French and the Hawaiian feed-in tariff levels. Assuming 110% of the above estimated feed-in tariff levels for both the French and the Hawaiian funding regimes, the NPVs under these schemes (GBP 81 million and GBP – 94 million respectively) would still not come close to the Scottish and Japanese schemes. We can therefore determine that a slight error in our estimation of input parameters does not change the overall conclusion that can be drawn from our thesis. Thus, in any scenario, the Scottish and Japanese funding regimes yield the most profitable investment results, when compared to the French and Hawaiian funding regimes.

5.3. Policy implications

When evaluating the implications for policy makers from our analysis above, one must first bear in mind that there is no such thing as an optimal renewable energy policy instrument that may be used for all types of technology under all circumstances (Canton and Johannesson Lindén, 2010), and that policy instruments' effects on different types of renewable energy vary (Johnstone, Hascic and Popp, 2010). Our analysis is therefore only applicable to floating offshore wind farms at their present pre-commercial stage.

From our analysis of the economic indexes, it would seem that the most effective funding regime to encourage investor support in floating offshore wind are tradable green certificates, as exemplified by the Scottish funding scheme. This is a surprising result, given the generous Japanese feed-in-tariff and the lower risk to investors inherent in such a funding mechanism. A fixed price for every MWh of output produced that is guaranteed by law as it is the case under a feed-in tariff scheme provides investors with more security than a green tradable certificate scheme whose certificate prices are subject to market fluctuations. In our study this is reflected by the lower risk beta in the Japanese model. The Scottish and Japanese schemes follow quite different economic philosophies. Yet, both funding regimes yield quite similar and rather high economic indexes, especially when compared to the other two support systems under consideration in this study. Interestingly, in their study about the most favourable type of funding mechanism from a social welfare and environmental externality abatement point of view, Canton and Johannesson Lindén (2010) also reach the conclusion that green tradable certificate schemes are to be preferred over feed-in premiums and tariffs because the certificate schemes keep market distortions to a minimum. It surprises therefore that the option that Canton and Johannesson Lindén (2010) identify as the most beneficial for society and for the market also turns out to be the most beneficial for investors.

The difference between the Scottish RO and the Japanese feed-in tariff scheme is, however, in our analysis arguably merely marginal. We therefore consider both the Scottish ROC scheme and the Japanese feed-in tariff scheme as similarly beneficial in attracting investor support for floating offshore wind. Because the two regimes yield similar results, the authors suggest that policy makers choose between the feed-in tariff and a tradable green certificate scheme and select the support regime that best fits their country's economic philosophy. Some governments prefer to give more power to the market while others believe in the power of regulation. Scotland, for instance, has traditionally favoured more market-based support schemes while Japan seems to accept feed-in tariffs although these do not encourage electricity generators to respond to market demand at all. The countries' economic philosophies are so different that it would seem unreasonable to suggest that one scheme is superior to the other and, for instance, suggest that Japan should adopt a green tradable certificate scheme or that Scotland should adapt a feed-in tariff scheme. These suggestions would run contradictory to each country's economic philosophy and are therefore both unrealistic and unreasonable.

Whatever option policymakers ultimately decide on, however, it is crucial for them to appreciate how sensitive the economic indexes are to particularly the level of funding and the risk associated with the funding. The sensitivity analyses of the economic indexes indicate how sensitive the profitability of an investment in a pre-commercial floating offshore wind farm such as the one under consideration is to variations in the input parameters. This sensitivity in turn impacts the willingness of investors to invest. The level of funding should therefore be well chosen and the risk associated with the chosen support scheme should be minimised. This risk minimisation can, for instance, be achieved through a 'headroom'-type measure like the Scottish government has implemented for the ROS scheme or through long-term political commitment to renewable energies and their development that instils confidence in investors. If policymakers furthermore wish to decrease the risk incurred by investors, and thereby increase the attractiveness of investments in floating offshore wind farms, direct government funding in the form of grants (as was exemplified by the French support system above) can reduce the risk to private investors significantly. The tax rate, albeit considered part of the funding scheme, only has a minor impact on the economic indexes. The level of funding and the discount rate should therefore be of primary concern to policymakers when designing support scheme. The tax rate should, of course, nevertheless ideally be designed in a way that is as favourable to investors as possible. The tax rate would preferably be set at a level that balances the interests of investors against the interest of society at large. Going into more detail on this though would be beyond the scope of this study.

As established above, a feed-in tariff, if designed similarly to the Japanese example, can be almost as beneficial to investors as a green-tradable certificate scheme, as exemplified by the Scottish scheme. A country may choose to opt for a feed-in tariff over a green tradable certificate scheme because the former can, by directly favouring renewable electricity generation, motivate pollution abatement innovation more strongly. Somewhat paradoxically, utilities tend to prefer feed-in tariff schemes because these indirectly allow utilities to cause a certain amount of pollution when using fossil fuel-generated electricity (Madlener, Gao and Neustadt, 2009). Empirical studies have proven that feed-in tariffs can be very successful in developing renewable energies. But while feed-in tariff schemes provide a certain income for all units of electricity produced and have been very effective in encouraging all kinds of renewable energies in the past, if employed over a long period of time and encouraging a large share of renewable electricity production, they can lead to market disturbances because they do not encourage electricity producers to participate in balancing the market (Madlener, Gao and Neustadt, 2009; Canton and Johannesson Lindén 2010). We therefore suggest that jurisdictions which initially create a feed-in tariff scheme should opt for more market-based support schemes over the long run. This is because in the long run policy makers do not only have to take into account what funding regime would yield the greatest or most favourable return for investors but also consider the market realities of a scheme. Renewables have two main effects on electricity markets: The merit order effect and increased price volatility (J. Winkler, W. Gaio, et al., 2016). The merit order effect denotes the phenomenon of electricity price decrease that occurs when renewables are introduced to an electricity system. Renewable sources of energy take precedence over conventionally sourced energy, thereby receiving higher merit when fed into the grid. Renewable energy systems tend to have lower marginal costs than conventional electricity generation and are supported without market integration, which means that conventional energy sources with higher marginal costs are replaced by renewables in all hours in which renewable electricity is available. This in turn leads to an overall electricity price decrease. While this price development may be welcomed by consumers, it is unfavourable for investors of conventional power plants, flexibility options and renewables without support (Winkler, et al., 2016). This can lead to concerns about security of supply. Winkler, et al. (2016) point out that literature so far has not yet reached a conclusion as to whether the merit order effect will truly lead to longer-term price reductions. They do acknowledge, however, that at least in the short run, renewable sources of electricity have an effect on the electricity price and that this effect is determined by the choice of support schemes in place. Under a feed-in tariff scheme, electricity generation is maximised at all times, independently of the prevailing demand at a given time and independently of costs. A feed-in tariff thus can easily lead to over- or under compensation of generators. Under a quota or premium scheme, by contrast, the merit order effect is slightly reduced compared to the feed-in tariff scheme because generators are encouraged to respond, at least to some extent, to market conditions. At very low electricity prices, variable costs of generation are relevant for electricity generation and might become more economical to reduce generation.

An increased level of renewable energies on the grid also leads to increased price volatility (Winkler, et al., 2016). Small shares of renewable energy generation such as solar PV have no significant impact, because their generation pattern fits the demand curve well, with photovoltaics mainly producing electricity during peak demand times, for example around noon. By contrast, offshore wind power generates electricity relatively independent from day and night time and is less predictable. In order to account for this problem, some markets permit negative electricity prices, which are meant to encourage market agents to restructure the electricity system (Winkler, et al., 2016). Given these merit order effect and price volatility considerations, we can establish that if a feed-in tariff scheme encourages too much renewable energy deployment with generators producing electricity regardless of supply and demand, the electricity market as a whole will be disturbed.

The floating wind farms that are currently in the planning phase, however, are still small in size, which is the reason why their effect on the electricity price overall will be rather minimal. This assumption is confirmed by Winkler, et al. (2016) who argue that differences among support schemes are only truly pronounced in times of low demand and high supply of renewable energies. Wissen and Nicolosi (2007) complement Winkler, et al.'s (2016) point by arguing that a merit order model is only valuable to assess short-term effects of volatile source of energy on the electricity price but should not be used to evaluate a law that aims at dynamically increasing

renewable energies in a given market. For this type of evaluation, they recommend using a long-term electricity market model that factors in the use of existing capacity. Not accounting for long-term versus short-term effects of renewable energy sources can lead to a significant overestimation of the effect renewable energies may have on the electricity market. We can therefore conclude that in the short run, feed-in tariffs are the most effective option to encourage investment in floating offshore wind while keeping market disturbances to a minimum.
Despite its benefits, however, a price-based scheme like feed-in tariff requires a lot of money to fund, and tends to be mostly financed by tax revenue. In places where the economic or political cost of raising taxes is high – as it is in the United States and Scandinavia, for example – a quantity control policy like a GTC scheme may prove more economically viable (Madlener, Gao and Neustadt, 2009).

Whatever scheme is ultimately chosen by policymakers, we expect more renewables in general and more floating offshore wind in particular to enter the market in the future. An increasing amount of renewable energies on the grid then may lead to the aforementioned increased price volatility on the market, which should be taken into account by policymakers. Keeping a feed-in tariff for floating offshore wind at a time when large-scale deployment of the technology is underway could then destabilise the electricity market. We therefore argue for the sequencing of a variety of support schemes. Once the technology becomes more mature and a greater number of floating wind farms are deployed, the feed-in tariff should be changed to a feed-in premium scheme. The feed-in premium scheme provides generators of floating offshore wind with a guaranteed payment for every unit of electricity fed into the grid, on top of their normal electricity sale. The mechanism combines the advantages of a feed-in tariff with those of a market-based scheme: one the one hand, the feed-in premium provides a secure income and a secure demand for generators. On the other hand, the total price that electricity producers will obtain for every unit of electricity generated fluctuates according to the market price at any given time. Thus generators are enticed to adjust production to demand, which reduces the pressure on the electricity price. Our suggestion is supported by Winkler, et al. (2016) who argue that a feed-in premium constitutes a good compromise between the advantages of a tradable certificate scheme, market participation on part of the generators, and the advantages of a feed-in tariff scheme, a comparably low risk for plant operators. However, by a similar token, the risks inherent in a feed-in premium are an amalgam between those of a feed-in tariff and a green tradable certificate scheme, exposing generators, and by extension investors, to the electricity price risk (Canton and Johannesson Lindén, 2010). In part, our recommendations are in line with those by by Canton and Johannesson Lindén (2010) whose one policy conclusion is that a sequencing approach to funding mechanisms is suitable to best develop renewable energies further.

However, in part, our recommendation to policymakers to choose between a tradable green certificate scheme and a feed-in tariff scheme but to phase out the feed-in tariff at some point and replace it with a feed-in premium scheme also runs somewhat contradictory to another conclusion reached by Canton and Johannesson Lindén (2010). They argue that feed-in premiums should be preferred over feed-in tariffs at all times and that even the premium schemes should be limited in time, regularly reviewed, and ultimately replaced by a green tradable certificate scheme once the technology has become competitive. The discrepancy between their and our findings arises because our study evaluates funding schemes from an investor's point of view while Canton and Johannesson Lindén (2010) argue from a social welfare point of view.

CHAPTER 6: Conclusion

The research question of this thesis asks what economic impact different funding schemes have on the investment in a model pre-commercial floating offshore wind farm. In analysing this question, this study aimed to find out what funding scheme is best suited to attract investor support, and provide policymakers with a figure-based aid to policy discussions.

We gave a brief overview of the topic of climate change to highlight the economic and social imperatives for supporting renewable energy to mitigate the pollution from fossil fuels. The reader was subsequently introduced to the concept of floating offshore wind and its potential for mitigating climate change through clean energy production on a large scale. It is vital to prove this new technology's cost reduction potential within the next few years, because otherwise investors might lose interest in the technology altogether. Given that floating wind technology is still at a very early stage of its development process though, governmental support is necessary to encourage private investment in the sector. Following the prototype stage that started in Norway in 2009, one of the first two pre-commercial floating wind farms in Scotland is currently under construction, while the second pilot farm is already in the advanced planning stages. Based on the results of our analysis and the discussion above, a tradable green certificate scheme like the Scottish Renewables Obligation scheme and the Japanese feed-in tariff scheme yield the most favourable results for investors. Leading to similarly favourable profitability outcomes for investors, the Scottish GTC scheme even outperforms the Japanese scheme on all of the economic indexes. This is a surprising result, given that the Scottish market-based scheme is riskier for investors than the Japanese non-market based mechanism, an aspect that is the calculations reflect. The French scheme also yields positive results for investors, though less favourable than the Scottish or Japanese funding scenario. The Hawaiian support scenario yields negative results.

Given the similarity in profitability results between the Scottish and Japanese funding regimes, the authors' recommendation to policy makers is to design either a tradable green certificate system in the style of the ROC scheme or a feed-in tariff in the style of the Japanese regime, depending on which of the two best matches the economic philosophy of their jurisdiction. If a feed-in tariff is selected, we recommend replacing it by a feed-in premium once floating technology has achieved a certain level of maturity so as to encourage generators of green electricity to become active players on the electricity market. Additionally, direct government funding, as was exemplified in the French funding regime example, is well suited to bring down the risk for private investors, should policymakers wish to make investments in floating offshore wind even more attractive. This is reflected by the low interest rate under the French support system.

CHAPTER 7: Limitations and Further Research

Our study is merely a snapshot of the current situation and cannot be understood as a business case calculation, because it compares relative differences between funding mechanisms. However, our results can serve as an indicator for project profitability under different funding mechanisms. Our study could have gained a benefit from a research paper with focus on assessing the suitable discount rate for offshore wind and floating offshore wind in particular. A specific emphasis should be on evaluating the appropriate risk beta for this technology, because it has a critical impact on the net present value of a wind power project, but is not well explored at this point in time.

It is worth noting that our data is limited to one sample project, based on the *WindFloat* design, which is only one of many available floating technologies, all of which incur different costs.

A first replication of our study should consider data from multiple projects with different floating designs over a longer period of time and analyse an average impact of different funding mechanisms on multiple projects.

Furthermore, we suggest that a second complementary research should replicate our study design and analyse the business cases of a floating wind park in different jurisdictions. Capex and Opex would be adjusted according to country-specific conditions for example with respects to the cost of labour in O&M and the supply chain.

Finally, an additional study of the learning curve and cost development could be done in a further extension of our study once that large-scale floating wind farms become a possibility. It will be a fascinating research topic to evaluate the need for funding for commercial floating wind farms, which will be significantly different from pre-commercial farms.

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Appendix

A. Additional Figures

Figure 0-1: Social Cost of CO_2 per metric ton of CO_2, 2015-2050

Source: (EPA 2015)

	Discount Rate and Statistic			
Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th percentile**
2015	\$11	\$36	\$56	\$105
2020	\$12	\$42	\$62	\$123
2025	\$14	\$46	\$68	\$138
2030	\$16	\$50	\$73	\$152
2035	\$18	\$55	\$78	\$168
2040	\$21	\$60	\$84	\$183
2045	\$23	\$64	\$89	\$197
2050	\$26	\$69	\$95	\$212

[a] The SC-CO_2 values are dollar-year and emissions-year specific.

Figure 0-2: Long-term Exchange Rates (2007-2016)

Source: US Forex 2016

	A	B	C	D	E	F	G	H	I
1	**YEN-GBP**			**EUR-GBP**			**USD-GBP**		
2									
3	2007	0,004246		2007	0,684504		2007	0,499806	
4	2008	0,005301		2008	0,796053		2008	0,544573	
5	2009	0,006856		2009	0,891595		2009	0,641169	
6	2010	0,007385		2010	0,858538		2010	0,647491	
7	2011	0,007813		2011	0,867933		2011	0,623629	
8	2012	0,007913		2012	0,811205		2012	0,631109	
9	2013	0,006563		2013	0,849099		2013	0,63955	
10	2014	0,005746		2014	0,806492		2014	0,607353	
11	2015	0,005408		2015	0,726112		2015	0,654441	
12	2016	0,006101		2016	0,773958		2016	0,698929	
13									
14	AVERAGE	0,0063332		AVERAGE	0,8065489		AVERAGE	0,618805	
15									
16									

B. Calculation of Indexes

a. Scottish Model 1/2

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**Scenario 1 (Scotland): ROC certificates**													
2	**CAPEX**	Total			0	1	2	3	4	5	6	7	8	9
3	Wind turbine generator				62 474 783									
4	Floating substructures				61 756 000									
5	Installation of Turbine and substructures				20 598 500									
6	Onshore and offshore electrical facilities				6 214 212									
7	Cables				13 835 000									
8	Control centre and O&M facilities				500 000									
9	Site and route surveys				750 000									
10	Others				16 110 500									
11	Total estimated Windfarm Costs				182 238 995									
12	Contingency 20%				36 447 799									
13	**Total CAPEX**				**218 686 794**									
14	18% tax shield (Capital Allowance)	18 %	of declining balance			39 363 623	32 278 171	26 468 100	21 703 842	17 797 150	14 593 663	11 966 804	9 812 779	8 046 479
15														
16	**OPEX**													
17	Studies (Facilities, Safety, Environment)					200 000								
18	Inspection					600 000								
19	Management					600 000								
20	Maintenance (Contractors)					4 000 000								
21	Operating phase insurance					600 000								
22	Grid Access	22	£ per kW installed			1 056 000								
23														
24	**OPEX (inflation adjusted)**					**7 056 000**	**7 197 120**	**7 341 062**	**7 487 884**	**7 637 641**	**7 790 394**	**7 946 202**	**8 105 126**	**8 267 229**
25														
26														
27	**Sales Revenue**				0	1	2	3	4	5	6	7	8	9
28	Theoretical full utilization of 48MW capacity	420 480	MWh per year											
29	Capacity Factor	48,5 %												
30	Net energy production	5 098 320	MWh in total			203 932,8	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933
31														
32	(Year 1-25) Wholesale electricity price	49,33	£ per MWh			50	51	52	53	54	56	57	58	59
33	Income from selling electricity					10 261 205	10 466 429	10 675 758	10 889 273	11 107 058	11 329 200	11 555 784	11 786 899	12 022 637
34														
35	**Revenue from Funding Mechanism**													
36	ROC income per MWh	172,38	((£49.25/ROC) x 3.5 ROCs)			175,82	179	183	187	190	194	198	202	206
37	Total ROC Income					35 855 975	36 573 094	37 304 556	38 050 647	38 811 660	39 587 893	40 379 651	41 187 244	42 010 989
38														
39	**EBITDA**					**39 061 180**	**39 842 403**	**40 639 252**	**41 452 037**	**42 281 077**	**43 126 699**	**43 989 233**	**44 869 017**	**45 766 398**
40	Depreciation					39 363 623	32 278 171	26 468 100	21 703 842	17 797 150	14 593 663	11 966 804	9 812 779	8 046 479
41	**EBIT**					**- 302 443**	**7 564 233**	**14 171 151**	**19 748 195**	**24 483 927**	**28 533 035**	**32 022 429**	**35 056 238**	**37 719 919**
42	Tax payable					-	1 588 489	2 975 942	4 147 121	5 141 625	5 991 937	6 724 710	7 361 810	7 921 183
43	**Net Income**					**- 302 443**	**5 975 744**	**11 195 210**	**15 601 074**	**19 342 302**	**22 541 098**	**25 297 719**	**27 694 428**	**29 798 736**
44	Plus Depreciation					39 363 623	32 278 171	26 468 100	21 703 842	17 797 150	14 593 663	11 966 804	9 812 779	8 046 479
45	Less CAPEX				- 218 686 794									
46	**Free Cash Flows**				**- 218 686 794**	**39 061 180**	**38 253 915**	**37 663 310**	**37 304 916**	**37 139 453**	**37 134 761**	**37 264 523**	**37 507 207**	**37 845 215**
47	**Discounted Free Cash Flows**				**- 218 686 794**	**36 335 981**	**33 102 360**	**30 317 479**	**27 933 941**	**25 869 806**	**24 061 896**	**22 461 374**	**21 030 375**	**19 739 439**
48	Accumulated Discounted Free Cash Flow				- 218 686 794	- 182 350 813	- 149 248 453	- 118 930 974	- 90 997 033	- 65 127 227	- 41 065 330	- 18 603 957	2 426 418	
49														
50	Inflation rate	2,00 %												
51	Discount rate	9,50 %			CAPM	9,50 %								
52	Real interest rate	7,50 %												
53	Corporate tax rate	21,00 %												
54	Capital recovery factor	10,60 %												
55	Levelisation factor	127,80 %												
56	O&M escalation rate	2,70 %												
57	===============				221,71									
58	**IRR**	**8,67 %**												
59	**NPV**	**182 148 385**												
60	**ROI**	**83,29 %**												
61	**LCOE**	**157,85**	£ per MWh											
62	**DPBP (Discounted Payback Period)**	**7,88**	Years											

Scottish Model 2/2

O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	
6 598 113	5 410 452	4 436 571	3 637 988	2 983 150	2 446 183	2 005 870	1 644 814	1 348 747	1 105 973	906 898	743 656	609 798	500 034	410 028	336 223		
8 432 573	**8 601 225**	**8 773 249**	**8 948 714**	**9 127 688**	**9 310 242**	**9 496 447**	**9 686 376**	**9 880 103**	**10 077 706**	**10 279 260**	**10 484 845**	**10 694 542**	**10 908 433**	**11 126 601**	**11 349 133**		
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	
203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933		
60	61	63	64	65	66	68	69	70	72	73	75	76	78	79	81		
12 263 090	12 508 352	12 758 519	13 013 689	13 273 963	13 539 442	13 810 231	14 086 436	14 368 164	14 655 528	14 948 638	15 247 611	15 552 563	15 863 615	16 180 887	16 504 505		
210	214	219	223	227	232	237	241	246	251	256							
42 851 209	43 708 233	44 582 398	45 474 046	46 383 527	47 311 197	48 257 421	49 222 570	50 207 021	51 211 161	52 235 385							
46 681 726	**47 615 360**	**48 567 667**	**49 539 021**	**50 529 801**	**51 540 397**	**52 571 205**	**53 622 629**	**54 695 082**	**55 788 984**	**56 904 763**	**4 762 766**	**4 858 022**	**4 955 182**	**5 054 286**	**5 155 371**		
6 598 113	5 410 452	4 436 571	3 637 988	2 983 150	2 446 183	2 005 870	1 644 814	1 348 747	1 105 973	906 898	743 656	609 798	500 034	410 028	336 223		
40 083 613	**42 204 908**	**44 131 096**	**45 901 033**	**47 546 651**	**49 094 214**	**50 565 335**	**51 977 816**	**53 346 335**	**54 683 011**	**55 997 866**	**4 019 110**	**4 248 224**	**4 455 148**	**4 644 257**	**4 819 148**		
8 417 559	8 863 031	9 267 530	9 639 217	9 984 797	10 309 785	10 618 720	10 915 341	11 202 730	11 483 432	11 759 552	844 013	892 127	935 581	975 294	1 012 021		
31 666 054	**33 341 877**	**34 863 566**	**36 261 816**	**37 561 854**	**38 784 429**	**39 946 615**	**41 062 474**	**42 143 604**	**43 199 579**	**44 238 314**	**3 175 097**	**3 356 097**	**3 519 567**	**3 668 963**	**3 807 127**		
6 598 113	5 410 452	4 436 571	3 637 988	2 983 150	2 446 183	2 005 870	1 644 814	1 348 747	1 105 973	906 898	743 656	609 798	500 034	410 028	336 223		
38 264 167	**38 752 330**	**39 300 137**	**39 899 804**	**40 545 005**	**41 230 612**	**41 952 485**	**42 707 288**	**43 492 352**	**44 305 551**	**45 145 211**	**3 918 753**	**3 965 895**	**4 019 601**	**4 078 992**	**4 143 350**		
18 565 542	**17 490 600**	**16 500 325**	**15 583 346**	**14 730 546**	**13 934 546**	**13 189 316**	**12 489 875**	**11 832 065**	**11 212 367**	**10 627 776**	**858 164**	**807 895**	**761 708**	**719 034**	**679 423**		

b. Japanese Model 1/2

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**Scenario 2 (Japan): Feed-in Tariff**													
2	**CAPEX**	Total			0	1	2	3	4	5	6	7	8	9
3	Wind turbine generator				62 474 783									
4	Floating substructures				61 756 000									
5	Installation of Turbine and substructures				20 598 500									
6	Onshore and offshore electrical facilities				6 214 212									
7	Cables				13 835 000									
8	Control centre and O&M facilities				500 000									
9	Site and route surveys				750 000									
10	Others				16 110 500									
11	Total estimated Windfarm Costs				182 238 995									
12	Contingency 20%				36 447 799									
13	**Total CAPEX**				**218 686 794**									
14	18% tax shield (Capital Allowance)	18 %	of declining balance			39 363 622,92	32 278 171	26 468 100	21 703 842	17 797 150	14 593 663	11 966 804	9 812 779	8 046 479
15														
16	**OPEX**													
17	Studies (Facilities, Safety, Environment)					200 000								
18	Inspection					600 000								
19	Management					600 000								
20	Maintenance (Contractors)					4 000 000								
21	Operating phase insurance					600 000								
22	Grid Access	22	£ per kW installed			1 056 000								
23	Transmission charges													
24	**OPEX (inflation adjusted)**					**7 056 000**	**7 197 120**	**7 341 062**	**7 487 884**	**7 637 641**	**7 790 394**	**7 946 202**	**8 105 126**	**8 267 229**
25														
26														
27	**Sales Revenue**				0	1	2	3	4	5	6	7	8	9
28	Theoretical full utilization of 48MW capacity	420 480	MWh per year											
29	Capacity Factor	48,5 %												
30	Net energy production	5 098 320	MWh in total			203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933
31														
32	(Year 21-25) Wholesale electricity price	49,33	£ per MWh			50	51	52	53	54	56	57	58	59
33	Income from selling electricity					10 261 205	10 466 429	10 675 758	10 889 273	11 107 058	11 329 200	11 555 784	11 786 899	12 022 637
34														
35	**Revenue from Funding Mechanism**													
36	(Year 1-20) Feed-in tariff (FIT)	228	£ per MWh			232,56	237	242	247	252	257	262	267	272
37	Generated Value from FIT					47 426 612	48 375 144	49 342 647	50 329 500	51 336 090	52 362 812	53 410 068	54 478 269	55 567 835
38														
39	**EBITDA**					**40 370 612**	**41 178 024**	**42 001 585**	**42 841 616**	**43 698 449**	**44 572 418**	**45 463 866**	**46 373 143**	**47 300 606**
40	Tax shield					39 363 623	32 278 171	26 468 100	21 703 842	17 797 150	14 593 663	11 966 804	9 812 779	8 046 479
41	**EBIT**					**1 006 989**	**8 899 853**	**15 533 485**	**21 137 774**	**25 901 298**	**29 978 754**	**33 497 062**	**36 560 364**	**39 254 127**
42	Tax payable					332 911	2 942 292	5 135 370	6 988 148	8 562 969	9 910 976	11 074 129	12 086 856	12 977 414
43	**Net Income**					**674 078**	**5 957 562**	**10 398 115**	**14 149 626**	**17 338 329**	**20 067 778**	**22 422 933**	**24 473 508**	**26 276 713**
44	Plus Depreciation					39 363 623	32 278 171	26 468 100	21 703 842	17 797 150	14 593 663	11 966 804	9 812 779	8 046 479
45	Less CapEx				218 686 794	-	-	-	-	-	-	-	-	-
46	Free Cash Flows				- 218 686 794	40 037 701	38 235 733	36 866 215	35 853 468	35 135 480	34 661 442	34 389 737	34 286 287	34 323 192
47	**Discounted Free Cash Flows**				**- 218 686 794**	**37 418 413**	**33 396 570**	**30 093 813**	**27 352 439**	**25 051 111**	**23 096 382**	**21 416 200**	**19 954 931**	**18 669 542**
48	Accumulated Discounted Free Cash Flow				- 218 686 794	- 181 268 381	- 147 871 812	- 117 777 999	- 90 425 560	- 65 374 448	- 42 278 066	- 20 861 866	906 935	17 762 607
49														
50	Inflation rate	2,00 %												
51	Discount rate	9,00 %			CAPM	9,00 %								
52	Real interest rate	7,00 %												
53	Corporate tax rate	33,06 %												
54	Capital recovery factor (R)	10,18 %												
55	Levelisation factor (l)	128,49 %												
56	O&M escalation rate	2,7%												
57	==============													
58	**IRR**	**8,23 %**												
59	**NPV**	**167 040 527**												
60	**ROI**	**76,38 %**												
61	**LCOE**	**153,63**	£ per MWh											
62	**DPBP (Discounted Payback Period)**	**8,05**	Years											

Japanese Model 2/2

O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	
6 598 113	5 410 452	4 436 571	3 637 988	2 983 150	2 446 183	2 005 870	1 644 814	1 348 747	1 105 973	906 898	743 656	609 798	500 034	410 028	336 223		
8 432 573	**8 601 225**	**8 773 249**	**8 948 714**	**9 127 688**	**9 310 242**	**9 496 447**	**9 686 376**	**9 880 103**	**10 077 706**	**10 279 260**	**10 484 845**	**10 694 542**	**10 908 433**	**11 126 601**	**11 349 133**		
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	
203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933		
60	61	63	64	65	66	68	69	70	72	73	75	76	78	79	81		
12 263 090	12 508 352	12 758 519	13 013 689	13 273 963	13 539 442	13 810 231	14 086 436	14 368 164	14 655 528	14 948 638	15 247 611	15 552 563	15 863 615	16 180 887	16 504 505		
278	283	289	295	301	307	313	319	326	332	339							
56 679 192	57 812 775	58 969 031	60 148 411	61 351 380	62 578 407	63 829 975	65 106 575	66 408 706	67 736 881	69 091 618							
48 246 618	**49 211 551**	**50 195 782**	**51 199 697**	**52 223 691**	**53 268 165**	**54 333 528**	**55 420 199**	**56 528 603**	**57 659 175**	**58 812 359**	**4 762 766**	**4 858 022**	**4 955 182**	**5 054 286**	**5 155 371**		
6 598 113	5 410 452	4 436 571	3 637 988	2 983 150	2 446 183	2 005 870	1 644 814	1 348 747	1 105 973	906 898	743 656	609 798	500 034	410 028	336 223		
41 648 506	**43 801 098**	**45 759 211**	**47 561 709**	**49 240 541**	**50 821 982**	**52 327 658**	**53 775 385**	**55 179 856**	**56 553 202**	**57 905 461**	**4 019 110**	**4 248 224**	**4 455 148**	**4 644 257**	**4 819 148**		
13 768 996	14 480 643	15 127 995	15 723 901	16 278 923	16 801 747	17 299 524	17 778 142	18 242 460	18 696 489	19 143 545	1 328 718	1 404 463	1 472 872	1 535 392	1 593 210		
27 879 510	**29 320 455**	**30 631 216**	**31 837 808**	**32 961 618**	**34 020 235**	**35 028 134**	**35 997 243**	**36 937 395**	**37 856 714**	**38 761 916**	**2 690 392**	**2 843 761**	**2 982 276**	**3 108 866**	**3 225 938**		
6 598 113	5 410 452	4 436 571	3 637 988	2 983 150	2 446 183												
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
34 477 622	34 730 908	35 067 787	35 475 796	35 944 768	36 466 418	35 028 134	35 997 243	36 937 395	37 856 714	38 761 916	2 690 392	2 843 761	2 982 276	3 108 866	3 225 938		
17 526 675	**16 500 404**	**15 570 517**	**14 721 194**	**13 940 001**	**13 217 108**	**11 865 241**	**11 395 805**	**10 928 442**	**10 467 697**	**10 016 816**	**649 765**	**641 874**	**629 102**	**612 902**	**594 376**		

c. French Model 1/2

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Scenario 3 (France): Capital grant, GO certificates, FiT**												
2	**CAPEX**	Total		Phasing (Years)	0	1	2	3	4	5	6	7	8
3	Wind turbine generator				62 474 783								
4	Floating substructures				61 756 000								
5	Installation of Turbine and substructures				20 598 500								
6	Onshore and offshore electrical facilities				6 214 212								
7	Cables				13 835 000								
8	Control centre and O&M facilities				500 000								
9	Site and route surveys				750 000								
10	Others				16 110 500								
11	Total estimated Windfarm Costs				182 238 995								
12	Contingency 20%				36 447 799								
13	Direct governmental capital grant				13 000 000								
14	**Total CAPEX**				**205 686 794**								
15	18% tax shield (Capital Allowance)	18 %	of declining balance			37 023 622,92	30 359 371	24 894 684	20 413 641	16 739 186	13 726 132	11 255 428	9 229 451
16													
17	**OPEX**												
18	Studies (Facilities, Safety, Environment)					200 000							
19	Inspection					600 000							
20	Management					600 000							
21	Maintenance (Contractors)					4 000 000							
22	Operating phase insurance					600 000							
23	Grid Access	22	£ per kW installed			1 056 000							
24	OFFSHORE TAX	12	£ per kW installed			580 715							
25	**OPEX (inflation adjusted)**					**7 636 715**	**7 789 449**	**7 945 238**	**8 104 143**	**8 266 226**	**8 431 550**	**8 600 181**	**8 772 185**
26													
27													
28	**Sales Revenue**				0	1	2	3	4	5	6	7	8
29	Theoretical full utilization of 48MW capacity	420 480	MWh per year										
30	Capacity Factor	48,5 %											
31	Net energy production	5 098 320	MWh in total			203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933
32	(Year 21-25) Wholesale electricity price	49,33	£ per MWh			50	51	52	53	54	56	57	58
33	Income from selling electricity												
34													
35	**Revenue from Funding Mechanism**												
36	(Year 1-20) Feed-in tariff (FiT)	157,28	£ per MWh			160	164	167	170	174	177	181	184
37	Generated Value from FiT					32 716 042	33 370 363	34 037 770	34 718 525	35 412 896	36 121 154	36 843 577	37 580 448
38													
39	**EBITDA**					**25 079 327**	**25 580 913**	**26 092 532**	**26 614 382**	**27 146 670**	**27 689 603**	**28 243 395**	**28 808 263**
40	Depreciation (Tax shield)					37 023 623	30 359 371	24 894 684	20 413 641	16 739 186	13 726 132	11 255 428	9 229 451
41	**EBIT**					**- 11 944 296**	**- 4 778 457**	**1 197 848**	**6 200 741**	**10 407 484**	**13 963 471**	**16 987 967**	**19 578 812**
42	Tax payable					-	-	399 243	2 066 707	3 468 815	4 654 025	5 662 089	6 525 618
43	**Net Income**					**- 11 944 296**	**- 4 778 457**	**798 605**	**4 134 034**	**6 938 670**	**9 309 446**	**11 325 878**	**13 053 194**
44	Plus Depreciation					37 023 623	30 359 371	24 894 684	20 413 641	16 739 186	13 726 132	11 255 428	9 229 451
45	Less CAPEX				205 686 794								
46	Free Cash Flows				- 205 686 794	25 079 327	25 580 913	25 693 289	24 547 675	23 677 855	23 035 578	22 581 306	22 282 645
47	**Discounted Free Cash Flows**				**- 205 686 794**	**23 488 014**	**22 437 625**	**21 106 244**	**18 885 655**	**17 060 606**	**15 544 675**	**14 271 249**	**13 188 946**
48	Accumulated Discounted Free Cash Flow				- 205 686 794	- 182 198 780	- 159 761 155	- 138 654 911	- 119 769 256	- 102 708 650	- 87 163 975	- 72 892 726	- 59 703 779
49													
50	Inflation rate	2,00 %											
51	Discount rate	8,78 %		CAPM	8,78 %								
52	Real interest rate	6,78 %											
53	Corporate tax rate	33,33 %											
54	Capital recovery factor	10,00 %											
55	Levelisation factor	128,81 %											
56	O&M escalation rate	2,70 %											
57	===============												
58	**IRR**	**2,87 %**											
59	**NPV**	**51 850 188**											
60	**ROI**	**25,21 %**											
61	**LCOE**	**149,05**	£ per MWh										
62	**DPBP (Discounted Payback Period)**	**13,62**	Years										

French Model 2/2

O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	
6 205 883	5 088 824	4 172 836	3 421 725	2 805 815	2 300 768	1 886 630	1 547 036	1 268 570	1 040 227	852 986	699 449	573 548	470 309	385 654	316 236		
9 126 581	**9 309 113**	**9 495 295**	**9 685 201**	**9 878 905**	**10 076 483**	**10 278 013**	**10 483 573**	**10 693 245**	**10 907 110**	**11 125 252**	**11 347 757**	**11 574 712**	**11 806 206**	**12 042 330**	**12 283 177**		
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	
203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933		
60	61	63	64	65	66	68	69	70	72	73	75	76	78	79	81		
											15 247 611	15 552 563	15 863 615	16 180 887	16 504 505		
192	196	199	203	208	212	216	220	225	229	234							
39 098 698	39 880 672	40 678 286	41 491 852	42 321 689	43 168 122	44 031 485	44 912 115	45 810 357	46 726 564	47 661 095							
29 972 117	**30 571 559**	**31 182 991**	**31 806 650**	**32 442 783**	**33 091 639**	**33 753 472**	**34 428 541**	**35 117 112**	**35 819 454**	**36 535 843**	**3 899 854**	**3 977 851**	**4 057 408**	**4 138 556**	**4 221 328**		
6 205 883	5 088 824	4 172 836	3 421 725	2 805 815	2 300 768	1 886 630	1 547 036	1 268 570	1 040 227	852 986	699 449	573 548	470 309	385 654	316 236		
23 766 234	**25 482 735**	**27 010 155**	**28 384 925**	**29 636 969**	**30 790 871**	**31 866 842**	**32 881 505**	**33 848 542**	**34 779 227**	**35 682 857**	**3 200 405**	**3 404 303**	**3 587 099**	**3 752 903**	**3 905 092**		
7 921 286	8 493 396	9 002 485	9 460 696	9 878 002	10 262 597	10 621 218	10 959 406	11 281 719	11 591 916	11 893 096	1 066 695	1 134 654	1 195 580	1 250 842	1 301 567		
15 844 948	**16 989 340**	**18 007 670**	**18 924 230**	**19 758 967**	**20 528 274**	**21 245 624**	**21 922 099**	**22 566 823**	**23 187 311**	**23 789 761**	**2 133 710**	**2 269 649**	**2 391 519**	**2 502 060**	**2 603 525**		
6 205 883	5 088 824	4 172 836	3 421 725	2 805 815	2 300 768	1 886 630	1 547 036	1 268 570	1 040 227	852 986	699 449	573 548	470 309	385 654	316 236		
22 050 831	22 078 164	22 180 506	22 345 955	22 564 782	22 829 042	23 132 253	23 469 136	23 835 393	24 227 538	24 642 747	2 833 159	2 843 197	2 861 828	2 887 714	2 919 761		
11 447 988	**10 734 889**	**10 100 351**	**9 530 032**	**9 012 744**	**8 539 727**	**8 104 098**	**7 700 417**	**7 324 363**	**6 972 480**	**6 641 979**	**715 171**	**672 165**	**633 641**	**598 803**	**567 032**		
- 35 997 705	- 25 262 816	- 15 162 464	- 5 632 432	3 380 312													

d. Hawaiian Model

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**Scenario 4 (U.S. Hawaii): FiT, tax break**													
2	**CAPEX**	Total		Phasing (Years'	0	1	2	3	4	5	6	7	8	9
3	Wind turbine generator				62 474 783									
4	Floating substructures				61 756 000									
5	Installation of Turbine and substructures				20 598 500									
6	Onshore and offshore electrical facilities				6 214 212									
7	Cables				13 835 000									
8	Control centre and O&M facilities				500 000									
9	Site and route surveys				750 000									
10	Others				16 110 500									
11	Total estimated Windfarm Costs				182 238 995									
12	Contingency 20%				36 447 799									
13	**Total CAPEX**				**218 686 794**									
14	18% tax shield (Capital Allowance)	18 %	of declining balance			39 363 623	32 278 171	26 468 100	21 703 842	17 797 150	14 593 663	11 966 804	9 812 779	8 046 479
15														
16	**OPEX**													
17	Studies (Facilities, Safety, Environment)					200 000								
18	Inspection					600 000								
19	Management					600 000								
20	Maintenance (Contractors)					4 000 000								
21	Operating phase insurance					600 000								
22	Grid Access	22	£ per kW installed			1 056 000								
23	Transmission charges													
24	**OPEX (inflation adjusted)**					**7 056 000**	**7 197 120**	**7 341 062**	**7 487 884**	**7 637 641**	**7 790 394**	**7 946 202**	**8 105 126**	**8 267 229**
25														
26														
27	**Sales Revenue**				0	1	2	3	4	5	6	7	8	9
28	eoretical full utilization of 48MW capacity	420 480	MWh per year											
29	Capacity Factor	48,5 %												
30	Net energy production (MWh/yr)	5 098 320	MWh in total			203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933
31	(Year 21-25) Wholesale electricity price	49,33	£ per MWh			50	51	52	53	54	56	57	58	59
32	Income from selling electricity													
33														
34	**Revenue from Funding Mechanism**													
35	(Year 1-20) Feed-in tariff (FiT)	97,78	£ per MWh			99,74	102	104	106	108	110	112	115	117
36	Generated Value from FiT					20 339 360	20 746 147	21 161 070	21 584 292	22 015 978	22 456 297	22 905 423	23 363 532	23 830 802
37	(Year 1-10) Production Tax Credit (PTC)	14,23	£ per MWh			14,51	14,80	15,10	15,40	15,71	16,03	16,35	16,67	17,01
38	Generated Value from PTC					2 960 003	3 019 203	3 079 587	3 141 179	3 204 002	3 268 083	3 333 444	3 400 113	3 468 115
39														
40	**EBITDA**					**13 283 360**	**13 549 027**	**13 820 008**	**14 096 408**	**14 378 336**	**14 665 903**	**14 959 221**	**15 258 405**	**15 563 574**
41	Tax shield					39 363 623	32 278 171	26 468 100	21 703 842	17 797 150	14 593 663	11 966 804	9 812 779	8 046 479
42	**EBIT**					**- 26 080 263**	**- 18 729 143**	**- 12 648 092**	**- 7 607 434**	**- 3 418 814**	**72 240**	**2 992 417**	**5 445 626**	**7 517 095**
43	**PTC**					**2 960 003**	**3 019 203**	**3 079 587**	**3 141 179**	**3 204 002**	**3 268 083**	**3 333 444**	**3 400 113**	**3 468 115**
44	**Taxable income**					**- 29 040 266**	**- 21 748 347**	**- 15 727 679**	**- 10 748 613**	**- 6 622 817**	**- 3 195 843**	**- 341 027**	**2 045 513**	**4 048 979**
45	Tax payable					-	-	-	-	-	-	-	846 842	1 676 277
46	**Net Income**					**- 26 080 263**	**- 18 729 143**	**- 12 648 092**	**- 7 607 434**	**- 3 418 814**	**72 240**	**2 992 417**	**4 598 784**	**5 840 817**
47	Plus Depreciation					39 363 623	32 278 171	26 468 100	21 703 842	17 797 150	14 593 663	11 966 804	9 812 779	8 046 479
48	Less CapEx				218 686 794	-	-	-	-	-	-	-	-	-
49	**Free Cash Flows**				**- 218 686 794**	**13 283 360**	**13 549 027**	**13 820 008**	**14 096 408**	**14 378 336**	**14 665 903**	**14 959 221**	**14 411 563**	**13 887 296**
50	**Discounted Free Cash Flows**				**- 218 686 794**	**12 414 355**	**11 834 245**	**11 281 243**	**10 754 082**	**10 251 555**	**9 772 510**	**9 315 851**	**8 387 661**	**7 553 769**
51	Accumulated Discounted Free Cash Flow				- 218 686 794	- 206 272 439	- 194 438 193	- 183 156 950	- 172 402 868	- 162 151 313	- 152 378 803	- 143 062 952	- 134 675 291	- 127 121 522
52														
53	Inflation rate	2,00 %												
54	Discount rate	9,00 %		CAPM	9,00 %									
55	Real interest rate	7,00 %												
56	Corporate tax rate	41,40 %												
57	Capital recovery factor	10,18 %												
58	Levelisation factor	128,49 %												
59	O&M escalation rate	2,70 %												
60	================													
61	**NPV**	**- 76 028 622**	£											
62	**IRR**	**-4,59 %**												
63	**ROI**	**-34,77 %**												
64	**LCOE**	**153,63**	£ per MWh											
65	**DPBP (Discounted Payback Period)**	**155,57**	Years											

Hawaiian Model 2/2

O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	
6 598 113	5 410 452	4 436 571	3 637 988	2 983 150	2 446 183	2 005 870	1 644 814	1 348 747	1 105 973	906 898	743 656	609 798	500 034	410 028	336 223		
8 432 573	**8 601 225**	**8 773 249**	**8 948 714**	**9 127 688**	**9 310 242**	**9 496 447**	**9 686 376**	**9 880 103**	**10 077 706**	**10 279 260**	**10 484 845**	**10 694 542**	**10 908 433**	**11 126 601**	**11 349 133**		

O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	
203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933	203 933		
60	61	63	64	65	66	68	69	70	72	73	75	76	78	79	81		
											15 247 611	15 552 563	15 863 615	16 180 887	16 504 505		
119	122	124	126	129	132	134	137	140	142	145							
24 307 418	24 793 567	25 289 438	25 795 227	26 311 131	26 837 354	27 374 101	27 921 583	28 480 015	29 049 615	29 630 607							
17,35																	
3 537 478																	
15 874 845	**16 192 342**	**16 516 189**	**16 846 513**	**17 183 443**	**17 527 112**	**17 877 654**	**18 235 207**	**18 599 911**	**18 971 909**	**19 351 348**	**4 762 766**	**4 858 022**	**4 955 182**	**5 054 286**	**5 155 371**		
6 598 113	5 410 452	4 436 571	3 637 988	2 983 150	2 446 183	2 005 870	1 644 814	1 348 747	1 105 973	906 898	743 656	609 798	500 034	410 028	336 223		
9 276 732	**10 781 889**	**12 079 618**	**13 208 524**	**14 200 292**	**15 080 928**	**15 871 784**	**16 590 393**	**17 251 164**	**17 865 937**	**18 444 450**	**4 019 110**	**4 248 224**	**4 455 148**	**4 644 257**	**4 819 148**		
3 537 478																	
5 739 255	**10 781 889**	**12 079 618**	**13 208 524**	**14 200 292**	**15 080 928**	**15 871 784**	**16 590 393**	**17 251 164**	**17 865 937**	**18 444 450**	**4 019 110**	**4 248 224**	**4 455 148**	**4 644 257**	**4 819 148**		
2 376 051	4 463 702	5 000 962	5 468 329	5 878 921	6 243 504	6 570 918	6 868 423	7 141 982	7 396 498	7 636 002	1 663 912	1 758 765	1 844 431	1 922 723	1 995 127		
6 900 681	**6 318 187**	**7 078 656**	**7 740 195**	**8 321 371**	**8 837 424**	**9 300 865**	**9 721 970**	**10 109 182**	**10 469 439**	**10 808 448**	**2 355 199**	**2 489 459**	**2 610 717**	**2 721 535**	**2 824 021**		
6 598 113	5 410 452	4 436 571	3 637 988	2 983 150	2 446 183	2 005 870	1 644 814	1 348 747	1 105 973	906 898	743 656	609 798	500 034	410 028	336 223		
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
13 498 794	**11 728 640**	**11 515 227**	**11 378 183**	**11 304 522**	**11 283 607**	**11 306 735**	**11 366 784**	**11 457 929**	**11 575 412**	**11 715 345**	**3 098 855**	**3 099 257**	**3 110 751**	**3 131 563**	**3 160 244**		
6 862 102	**5 572 192**	**5 112 899**	**4 721 542**	**4 384 088**	**4 089 699**	**3 829 982**	**3 598 433**	**3 389 988**	**3 200 698**	**3 027 468**	**748 414**	**699 543**	**656 203**	**617 377**	**582 272**		
- 120 259 420	- 114 687 227	- 109 574 329	- 104 852 787	- 100 468 699	- 96 379 000	- 92 549 018	- 88 950 585	- 85 560 597	- 82 359 899	- 79 332 432	- 78 584 018	- 77 884 475	- 77 228 271	- 76 610 894	- 76 028 622		

C. Calculation of Sensitivity Analyses

The results of the sensitivity analyses below have been calculated using Microsoft Excel's What-If Analysis function. The way the function works requires entering the original value of the outcome (that is to say, the result of the economic index calculation when using the base case of the input parameter) at the top of a what-if analysis table. These cells are coloured in blue. The base, optimistic and pessimistic values for the input parameters are listed in the columns and the factoring of them in the calculation of the economic index in the respective column on their right. This means that the result of the base case value of each input parameter appears again next to the base case input value, as would be expected.

a. Scottish Model Sensitivity Analysis

Net Present Value

Calculation of base, optimistic and pessimistic cases

		NPV		NPV		NPV		NPV
	ROC Price	£ 182,148,385	**Electricity Price**	£ 182,148,385	**Tax Rate**	£ 182,148,385	**Discount Rate**	£ 182,148,385
110%	£ 189.61	£ 215,693,614	£ 54.26	£ 192,974,625	23.10%	£ 175,584,512	10.45%	£ 153,589,234
100%	£ 172.38	£ 182,148,385	£ 49.33	£ 182,148,385	21.00%	£ 182,148,385	9.50%	£ 182,148,385
90%	£ 155.14	£ 147,961,795	£ 44.40	£ 171,180,898	18.90%	£ 188,712,258	8.55%	£ 214,307,880

Summary of results

	ROC Price	Electricity Price	Tax Rate	Discount Rate
Optimistic	£ 215,693,614	£ 192,974,625	£ 188,712,258	£ 214,307,880
Base	£ 182,148,385	£ 182,148,385	£ 182,148,385	£ 182,148,385
Pessimistic	£ 147,961,795	£ 171,180,898	£ 175,584,512	£ 153,589,234

Internal Rate of Return

Calculation of base, optimistic and pessimistic cases

		IRR		IRR		IRR		IRR
	ROC Price	8.67%	**Electricity Price**	8.67%	**Tax Rate**	8.67%	**Discount Rate**	8.67%
110%	£ 189.61	10.09%	£ 54.26	9.09%	23.10%	8.44%	10.45%	7.72%
100%	£ 172.38	8.67%	£ 49.33	8.67%	21.00%	8.67%	9.50%	8.67%
90%	£ 155.14	7.16%	£ 44.40	8.22%	18.90%	8.89%	8.55%	9.64%

Summary of results

	ROC Price	Electricity Price	Tax Rate	Discount Rate
Optimistic	10.09%	9.09%	8.89%	9.64%
Base	8.67%	8.67%	8.67%	8.67%
Pessimistic	7.16%	8.22%	8.44%	7.72%

Return on Investment

Calculation of base, optimistic and pessimistic cases

		ROI		ROI		ROI		ROI
	ROC Price	83.29%	**Electricity Price**	83.29%	**Tax Rate**	83.29%	**Discount Rate**	83.29%
110%	£ 189.61	98.63%	£ 54.26	88.24%	23.10%	80.29%	10.45%	70.23%
100%	£ 172.38	83.29%	£ 49.33	83.29%	21.00%	83.29%	9.50%	83.29%
90%	£ 155.14	67.66%	£ 44.40	78.28%	18.90%	86.29%	8.55%	98.00%

Summary of results

	ROC	Electricity	Tax Rate	Discount Rate
Optimistic	98.63%	88.24%	86.29%	98.00%
Base	83.29%	83.29%	83.29%	83.29%
Pessimistic	67.66%	78.28%	80.29%	70.23%

Levelised Cost Of Electricity

Calculation of base, optimistic and pessimistic cases

		LCOE		LCOE		LCOE		LCOE
	ROC	£ 157.85	**Electricity**	£ 157.85	**Tax rate**	£ 157.85	**Discount rate**	£ 157.85
110%	£ 189.61	£ 157.85	£ 54.26	£ 157.85	23.10%	£ 157.85	10.45%	£ 166.04
100%	£ 172.38	£ 157.85	£ 49.33	£ 157.85	21.00%	£ 157.85	9.50%	£ 157.85
90%	£ 155.14	£ 157.85	£ 44.40	£ 157.85	18.90%	£ 157.85	8.55%	£ 149.89

Summary of results

	ROC	Electricity	Tax Rate	Discount Rate
Optimistic	£ 157.85	£ 157.85	£ 157.85	£ 149.89
Base	£ 157.85	£ 157.85	£ 157.85	£ 157.85
Pessimistic	£ 157.85	£ 157.85	£ 157.85	£ 166.04

Discounted Payback Period

Calculation of base, optimistic and pessimistic cases

		DPBP		DPBP		DPBP		DPBP
	ROC	7.88	**Electricity**	7.88	**Tax rate**	7.88	**Discount rate**	7.88
110%	£ 189.61	7.12	£ 54.26	7.65	23.10%	7.99	10.45%	8.27
100%	£ 172.38	7.88	£ 49.33	7.88	21.00%	7.88	9.50%	7.88
90%	£ 155.14	8.83	£ 44.40	8.14	18.90%	7.78	8.55%	7.53

Summary of results

	ROC	Electricity	Tax Rate	Discount Rate
Optimistic	7.12	7.65	7.78	7.53
Base	7.88	7.88	7.88	7.88
Pessimistic	8.83	8.14	7.99	8.27

b. Japanese Model Sensitivity Analysis

Net Present Value

Calculation of base, optimistic and pessimistic cases

		NPV		NPV		NPV		NPV
	FiT	£ 167,040,527	**Electricity Price**	£ 167,040,527	**Tax Rate**	£ 167,040,527	**Discount Rate**	£ 167,040,527
110%	£ 250.80	£ 206,153,479	£ 54.26	£ 168,162,444	36.37%	£ 155,609,263	9.90%	£ 141,364,038
100%	£ 228.00	£ 167,040,527	£ 49.33	£ 167,040,527	33.06%	£ 167,040,527	9.00%	£ 167,040,527
90%	£ 205.20	£ 126,773,356	£ 44.40	£ 165,918,609	29.75%	£ 178,471,791	8.10%	£ 195,757,575

Summary of results

	FiT	Electricity	Tax Rate	Discount Rate
Optimistic	£ 206,153,479	£ 168,162,444	£ 178,471,791	£ 195,757,575
Base	£ 167,040,527	£ 167,040,527	£ 167,040,527	£ 167,040,527
Pessimistic	£ 126,773,356	£ 165,918,609	£ 155,609,263	£ 141,364,038

Internal Rate of Return

Calculation of base, optimistic and pessimistic cases

		IRR		IRR		IRR		IRR
	FiT	8.23%	**Electricity Price**	8.23%	**Tax Rate**	8.23%	**Discount Rate**	8.23%
110%	£ 250.80	9.92%	£ 54.26	8.25%	36.37%	7.81%	9.90%	7.33%
100%	£ 228.00	8.23%	£ 49.33	8.23%	33.06%	8.23%	9.00%	8.23%
90%	£ 205.20	6.40%	£ 44.40	8.22%	29.75%	8.64%	8.10%	9.15%

Summary of results

	FiT	Electricity Price	Tax Rate	Discount Rate
Optimistic	9.92%	8.25%	8.64%	9.15%
Base	8.23%	8.23%	8.23%	8.23%
Pessimistic	6.40%	8.22%	7.81%	7.33%

Return On Investment

Calculation of base, optimistic and pessimistic cases

		ROI		ROI		ROI		ROI
	FiT	76.38%	**Electricity Price**	76.38%	**Tax Rate**	76.38%	**Discount Rate**	76.38%
110%	£250.80	94.27%	£ 54.26	76.90%	36.37%	71.16%	9.90%	64.64%
100%	£228.00	76.38%	£ 49.33	76.38%	33.06%	76.38%	9.00%	76.38%
90%	£205.20	57.97%	£ 44.40	75.87%	29.75%	81.61%	8.10%	89.52%

Summary of results

	FiT	Electricity Price	Tax Rate	Discount Rate
Optimistic	94.27%	76.90%	81.61%	89.52%
Base	76.38%	76.38%	76.38%	76.38%
Pessimistic	57.97%	75.87%	71.16%	64.64%

Levelised Cost Of Electricity

Calculation of base, optimistic and pessimistic cases

		LCOE		LCOE		LCOE		LCOE
	FiT	£ 153.63	**Electricity Price**	£ 153.63	**Tax Rate**	£ 153.63	**Discount Rate**	£ 153.63
110%	250.80	£ 153.63	54.26	£ 153.63	36.37%	£ 153.63	9.90%	£ 161.27
100%	228.00	£ 153.63	49.33	£ 153.63	33.06%	£ 153.63	9.00%	£ 153.63
90%	205.20	£ 153.63	44.40	£ 153.63	29.75%	£ 153.63	8.10%	£ 146.22

Summary of results

	FiT	Electricity Price	Tax Rate	Discount Rate
Optimistic	£ 153.63	£ 153.63	£ 153.63	£ 146.22
Base	£ 153.63	£ 153.63	£ 153.63	£ 153.63
Pessimistic	£ 153.63	£ 153.63	£ 153.63	£ 161.27

Discounted Payback Period

Calculation of base, optimistic and pessimistic cases

		DPBP		DPBP		DPBP		DPBP
	FiT	8.05	**Electricity**	8.05	**Tax rate**	8.05	**Discount rate**	8.05
110%	£ 250.80	7.07	£ 54.26	8.05	36.37%	8.27	9.90%	8.47
100%	£ 228.00	8.05	£ 49.33	8.05	33.06%	8.05	9.00%	8.05
90%	£ 205.20	9.34	£ 44.40	8.05	29.75%	7.85	8.10%	7.67

Summary of results

	FiT	Electricity	Tax Rate	Discount Rate
Optimistic	7.07	8.05	7.85	7.67
Base	8.05	8.05	8.05	8.05
Pessimistic	9.34	8.05	8.27	8.47

c. French Model Sensitivity Analysis

Net Present Value

Calculation of base, optimistic and pessimistic cases

		NPV		NPV		NPV		NPV		NPV
	FiT	£ 51 850 188	Grant	£ 51 850 188	**Electricity**	£ 51 850 188	**Tax rate**	£ 51 850 188	**Discount rate**	£ 51 850 188
110 %	173,01	£ 81 234 975	£ 14 300 000	£ 52 964 953	£ 54,26	£ 53 022 780	36,66 %	£ 45 672 755	9,66 %	£ 34 865 335
100 %	157,28	£ 51 850 188	£ 13 000 000	£ 51 850 188	£ 49,33	£ 51 850 188	33,33 %	£ 51 850 188	8,78 %	£ 51 748 880
90 %	141,55	£ 21 861 309	£ 11 700 000	£ 50 735 423	£ 44,40	£ 50 677 597	30,00 %	£ 58 027 621	7,90 %	£ 70 604 988

Summary of results

	FiT	Grant	Electricity	Tax Rate	Discount Rate
Optimistic	£ 81 234 975	£ 52 964 953	£ 53 022 780	£ 58 027 621	£ 70 604 988
Base	£ 51 850 188	£ 51 850 188	£ 51 850 188	£ 51 850 188	£ 51 748 880
Pessimistic	£ 21 861 309	£ 50 735 423	£ 50 677 597	£ 45 672 755	£ 34 865 335

Internal Rate of Return

Calculation of base, optimistic and pessimistic cases

		IRR		IRR		IRR		IRR		IRR
	FiT	2,87 %	Grant	2,87 %	**Electricity**	2,87 %	**Tax rate**	2,87 %	**Discount rate**	2,87 %
110 %	£ 173,01	4,40 %	£ 14 300 000	2,95 %	£ 54,26	2,91 %	36,66 %	2,57 %	9,66 %	2,03 %
100 %	£ 157,28	2,87 %	£ 13 000 000	2,87 %	£ 49,33	2,87 %	33,33 %	2,87 %	8,78 %	2,87 %
90 %	£ 141,55	1,24 %	£ 11 700 000	2,80 %	£ 44,40	2,83 %	30,00 %	3,16 %	7,90 %	3,72 %

Summary of results

	FiT	Grant	Electricity	Tax Rate	Discount Rate
Optimistic	4,40 %	2,95 %	2,91 %	3,16 %	3,72 %
Base	2,87 %	2,87 %	2,87 %	2,87 %	2,87 %
Pessimistic	1,24 %	2,80 %	2,83 %	2,57 %	2,03 %

Return On Investment

Calculation of base, optimistic and pessimistic cases

		ROI		ROI		ROI		ROI		ROI
	FiT	25,21 %	Grant	25,21 %	**Electricity**	25,21 %	**Tax rate**	25,21 %	**Discount rate**	25,21 %
110 %	£ 173,01	39,49 %	£ 14 300 000	25,91 %	£ 54,26	25,78 %	36,66 %	22,21 %	9,66 %	16,95 %
100 %	£ 157,28	25,21 %	£ 13 000 000	25,21 %	£ 49,33	25,21 %	33,33 %	25,21 %	8,78 %	25,16 %
90 %	£ 141,55	10,63 %	£ 11 700 000	24,51 %	£ 44,40	24,64 %	30,00 %	28,21 %	7,90 %	34,33 %

Summary of results

	FiT	Grant	Electricity	Tax Rate	Discount Rate
Optimistic	39,49 %	25,91 %	25,78 %	28,21 %	34,33 %
Base	25,21 %	25,21 %	25,21 %	25,21 %	25,16 %
Pessimistic	10,63 %	24,51 %	24,64 %	22,21 %	16,95 %

Levelised Cost Of Electricity

Calculation of base, optimistic and pessimistic cases

		LCOE		LCOE		LCOE		LCOE		LCOE
	FiT	£ 149,05	Grant	£ 149,05	**Electricity**	£ 149,05	**Tax rate**	£ 149,05	**Discount rate**	£ 149,05
110 %	£ 173,01	£ 149,05	£ 14 300 000	£ 148,41	£ 54,26	£ 149,05	36,66 %	£ 149,05	9,66 %	£ 156,00
100 %	£ 157,28	£ 149,05	£ 13 000 000	£ 149,05	£ 49,33	£ 149,05	33,33 %	£ 149,05	8,78 %	£ 149,09
90 %	£ 141,55	£ 149,05	£ 11 700 000	£ 149,69	£ 44,40	£ 149,05	30,00 %	£ 149,05	7,90 %	£ 142,39

Summary of results

	FiT	Grant	Electricity	Tax Rate	Discount Rate
Optimistic	£ 149,05	148,41	£ 149,05	£ 149,05	£ 142,39
Base	£ 149,05	149,05	£ 149,05	£ 149,05	£ 149,09
Pessimistic	£ 149,05	149,69	£ 149,05	£ 149,05	£ 156,00

Discounted Payback Period

Calculation of base, optimistic and pessimistic cases

		DPBP		DPBP		DPBP		DPBP		DPBP
	FiT	13,62	Grant	13,62	**Electricity**	13,62	**Tax rate**	13,62	**Discount rate**	13,62
110 %	£ 173,01	11,34	£ 14 300 000	13,50	£ 54,26	13,62	36,66 %	14,06	9,66 %	14,87
100 %	£ 157,28	13,62	£ 13 000 000	13,62	£ 49,33	13,62	33,33 %	13,62	8,78 %	13,63
90 %	£ 141,55	16,64	£ 11 700 000	13,75	£ 44,40	13,62	30,00 %	13,22	7,90 %	12,56

Summary of results

	FiT	Grant	Electricity	Tax Rate	Discount Rate
Optimistic	11,34	13,50	13,62	13,22	12,56
Base	13,62	13,62	13,62	13,62	13,63
Pessimistic	16,64	13,75	13,62	14,06	14,87

d. Hawaiian Model Sensitivity Analysis

Net Present Value

Calculation of base, optimistic and pessimistic cases

		NPV		NPV		NPV		NPV		NPV
	FiT	-£ 76 028 210	**PTC**	-£ 76 028 210	**Electricity Price**	-£ 76 028 210	**Tax Rate**	-£ 76 028 210	**Discount Rate**	-£ 76 028 210
110 %	£ 107,56	-£ 57 048 811	£ 15,66	-£ 75 792 996	£ 54,26	-£ 75 046 071	45,54 %	-£ 78 651 368	9,90 %	-£ 85 416 723
100 %	£ 97,78	-£ 76 028 210	£ 14,23	-£ 76 028 622	£ 49,33	-£ 76 028 210	41,40 %	-£ 76 028 210	9,00 %	-£ 76 028 210
90 %	£ 88,00	-£ 95 580 538	£ 12,81	-£ 76 262 601	£ 44,40	-£ 77 010 349	37,26 %	-£ 73 405 052	8,10 %	-£ 65 532 468

Summary of results

	FiT	PTC	Electricity Price	Tax Rate	Discount Rate
Optimistic	-£ 57 048 811	-£ 75 792 996	-£ 75 046 071	-£ 73 405 052	-£ 65 532 468
Base	-£ 76 028 210	-£ 76 028 622	-£ 76 028 210	-£ 76 028 210	-£ 76 028 210
Pessimistic	-£ 95 580 538	-£ 76 262 601	-£ 77 010 349	-£ 78 651 368	-£ 85 416 723

Internal Rate of Return

Calculation of base, optimistic and pessimistic cases

		IRR		IRR		IRR		IRR		IRR
	FiT	-4,59 %	**PTC**	-4,59 %	**Electricity Price**	-4,59 %	**Tax Rate**	-4,59 %	**Discount Rate**	-4,59 %
110 %	£ 107,56	-3,38 %	£ 15,66	-4,58 %	£ 54,26	-4,47 %	45,54 %	-4,84 %	9,90 %	-5,39 %
100 %	£ 97,78	-4,59 %	£ 14,23	-4,59 %	£ 49,33	-4,59 %	41,40 %	-4,59 %	9,00 %	-4,59 %
90 %	£ 88,00	-5,90 %	£ 12,81	-4,61 %	£ 44,40	-4,72 %	37,26 %	-4,36 %	8,10 %	-3,78 %

Summary of results

	FiT	PTC	Electricity Price	Tax Rate	Discount Rate
Optimistic	-3,38 %	-4,58 %	-4,47 %	-4,36 %	-3,78 %
Base	-4,59 %	-4,59 %	-4,59 %	-4,59 %	-4,59 %
Pessimistic	-5,90 %	-4,61 %	-4,72 %	-4,84 %	-5,39 %

Return On Investment

Calculation of base, optimistic and pessimistic cases

		ROI		ROI		ROI		ROI		ROI
	FiT	-34,77 %	**PTC**	-34,77 %	**Electricity Price**	-34,77 %	**Tax Rate**	-34,77 %	**Discount Rate**	-34,77 %
110 %	£ 107,56	-26,09 %	£ 15,66	-34,66 %	£ 54,26	-34,32 %	45,54 %	-35,97 %	9,90 %	-39,06 %
100 %	£ 97,78	-34,77 %	£ 14,23	-34,77 %	£ 49,33	-34,77 %	41,40 %	-34,77 %	9,00 %	-34,77 %
90 %	£ 88,00	-43,71 %	£ 12,81	-34,87 %	£ 44,40	-35,21 %	37,26 %	-33,57 %	8,10 %	-29,97 %

Summary of results

	FiT	PTC	Electricity Price	Tax Rate	Discount Rate
Optimistic	-26,09 %	-34,66 %	-34,32 %	-33,57 %	-29,97 %
Base	-34,77 %	-34,77 %	-34,77 %	-34,77 %	-34,77 %
Pessimistic	-43,71 %	-34,87 %	-35,21 %	-35,97 %	-39,06 %

Levelised Cost Of Electricity

Calculation of base, optimistic and pessimistic cases

		LCOE		LCOE		LCOE		LCOE		LCOE
	FiT	£ 153,63	**PTC**	£ 153,63	**Electricity Price**	£ 153,63	**Tax Rate**	£ 153,63	**Discount Rate**	£ 153,63
110 %	£ 107,56	£ 153,63	£ 15,66	£ 153,63	£ 54,26	£ 153,63	45,54 %	£ 153,63	9,90 %	£ 161,69
100 %	£ 97,78	£ 153,63	£ 14,23	£ 153,63	£ 49,33	£ 153,63	41,40 %	£ 153,63	9,00 %	£ 153,63
90 %	£ 88,00	£ 153,63	£ 12,81	£ 153,63	£ 44,40	£ 153,63	37,26 %	£ 153,63	8,10 %	£ 145,77

Summary of results

	FiT	PTC	Electricity Price	Tax Rate	Discount Rate
Optimistic	£ 153,63	£ 153,63	£ 153,63	£ 153,63	£ 145,77
Base	£ 153,63	£ 153,63	£ 153,63	£ 153,63	£ 153,63
Pessimistic	£ 153,63	£ 153,63	£ 153,63	£ 153,63	£ 161,69

Discounted Payback Period

Calculation of base, optimistic and pessimistic cases

		DPBP		DPBP		DPBP		DPBP		DPBP
	FiT	155,6	**PTC**	155,6	**Electricity Price**	155,6	**Tax Rate**	155,6	**Discount rate**	155,6
110 %	£ 107,56	123,0	£ 15,66	155,2	£ 54,26	123,7	45,54 %	169,2	9,90 %	205,9
100 %	£ 97,78	155,6	£ 14,23	155,6	£ 49,33	155,6	41,40 %	155,6	9,00 %	155,6
90 %	£ 88,00	189,2	£ 12,81	156,0	£ 44,40	215,5	37,26 %	143,6	8,10 %	116,1

Summary of results

	FiT	PTC	Electricity Price	Tax Rate	Discount Rate
Optimistic	123,0	155,2	123,7	143,6	116,1
Base	155,6	155,6	155,6	155,6	155,6
Pessimistic	189,2	156,0	215,5	169,2	205,9

D. Interview Transcripts

a. Johan Sandberg, Service Line Leader Offshore Renewables, Det Norske Veritas (DNV-GL)

Interview from the 29.10.2015

Sandberg: Norway with Statoil has already done Hywind and they have chosen not to take floating wind to the next step themselves. They say that other companies have to pay for the next development. That's why now Scotland is doing the next Hywind project.
I don't think that this is a good choice. I think Norway should have done this a long time ago and I am being quite open with that when I am interviewed by journalists. I have been quite critical with Norway that they have taken the chance to take Hywind to the next phase.

Question: What are the funding mechanisms for floating wind in Norway?

Sandberg: First of all, Norway is part of the Green Certificate Scheme with Sweden, so that is a subsidy scheme for renewable energy or basically any kind of energy that is not fossil or nuclear, so that is hydropower, biofuels, wind power, solar and everything similar. And the Green Certificate mechanism means that you are receiving Green Certificates when you are selling power to the grid. And Green Certificates is a market mechanism, so you sell them and you receive them when you produce power. So this means that they are technically neutral apart from fossil and nuclear energy. So you can build whatever renewable energy you want and you still receive the Green Certificates, but you will not receive anything more than these Certificates. The benefit from that is that you will always build the cheapest energy. The negative side of that is that you will never develop any new technology. Those are the two trade-offs. Because Sweden and Norway have entered into this agreement, it is almost impossible to do anything outside of it. Sweden is now looking into a separate subsidy scheme for offshore wind power, outside of the Green Certificate scheme. But they have not come close to that yet, they have done some investigations, but it is still a long way to go. Norway has not even considered that, it is not even on the agenda in Norway, they don't talk about that at all. But they have a different opportunity in Norway, which I think is very exciting. And that is the petroleum tax regime. You are paying 78% tax when you produce petroleum, which also means that if you make an investment you will withdraw that tax expense from your books. Basically anything that you invest in as an oil company is to 78% paid by the government with tax money that they don't receive. So any investment in oil and gas amounts only to 22% actual cost to the oil company compared to what it really costs. When we started to look at the oil and gas industry as a potential market for floating wind turbines, that was not to reduce emissions so much from oil and gas, but we thought it would reduce the costs of oil and gas. And the best funding mechanism you can have is a completely commercially driven market, where you don't rely on subsidies, research money or government intervention and political risk and so on. We wanted to prove that floating wind turbines could be a more cost effective solution for oil and gas than any other alternative. That is why we started this win-win project almost one year ago. The project is going really well and we get good results out of it. If we then get the oil industry to buy into this [technology on a large scale], then we suddenly have a commercial market for this, where we don't need support from the government.

Question: But this would primarily work for Norway?

Sandberg: You are absolutely right. In Norway you have a much higher tax, which means that you have a stronger business case. You also have a CO_2 tax in Norway, which comes on top of all other expenses. We have done this business case also for other markets, where you don't have these tax regimes and also there you receive a positive NPV and that's why we have several international oil companies in this project, not only Statoil but ENI from Italy, ExxonMobil from America, TBG from Germany, Nexen Petroleum from the UK. So we have a really international group of oil companies here, because it is not only working in Norway. That is really good news. If this is proved to work, we suddenly have a market for hundreds of wind turbines.
Win-win means wind power water injection, because that is what it is all about. We have identified the water injection process as the one process that is perfectly suited for floating wind. Because water injection does not need any backup power. Compared to the gas turbines that they have today, gas turbines inject water all the time, but it really does not matter if it injects water all the time, because even if you had a downtime of a week, this really does not affect production very much. The pressure in the reservoir will still be maintained even for several days and that is why it is very suitable for wind power.

Question: What is the motivation in Norway for floating wind?

Sandberg: The motivation is to create an export market for other parts of the world.

Question: When will the first oil rig be connected to a floating wind turbine?

Sandberg: I don't know. We have already started thinking about the next phase for our joint industry project. The project will be finished in February 2016. We need to think about how we move forward. The natural next step would be to build a prototype. Though we are not sure how it's going to be done, if the oil companies will do it themselves, if the supply chain will do it, or if the government will go in or some university will build it, but we are not going to build it. DNVGL does not build anything.

Question: Are there other final goals in Norwegian funding mechanisms?

Sandberg: The power price in Norway is 25øre/kWh and the Green Certificate Price is between 15-20øre/kWh. This means that the total income from a kWh is between 45-50øre/kWh, it is completely impossible to build anything apart from onshore wind power with that low price. You cannot build hydropower, coal, gas or nuclear or offshore wind with that price. Therefore, you need some other type of income and the only alternative is some kind of subsidy and I don't think Norway is going to give that [subsidy]. So then it does not really matter if you look at bank financing or private equity or whatever, because it is a negative cash flow you need a high power price.

Question: Would you then say Norway's funding scheme is ineffective?

Sandberg: I think that the Green Certificate scheme is not an effective funding scheme for floating wind or any type of new technology, that is very clear and I have been very open about this when I write articles. I think the Scandinavian countries should focus on developing new technology. Sweden is in a different situation, because Sweden needs to replace a whole lot of nuclear [power], then they need to build a lot of cheap energy and that's why they are building so much onshore wind power. This is a different situation and then the Green Certificate system works great. It is definitely working for that purpose.

Question: If Norway wants to export floating wind, the technology first needs to reach commercial scale?

Sandberg: Yes, exactly.

Question: Where will we see the first floating wind park, which are ambitious projects in your opinion?

Sandberg: I think there are a handful of markets where we will see turbines in commercial scale. The first one is Japan, which after Fokushima clearly is in a desperate situation. They have also been leading on floating wind last year and installed several prototypes and one of them is this huge 7MW turbine, which you have probably seen. The problem there is that Japan is a very isolated country when it comes to international collaboration. Even though we have been incredibly active in Japan, we have not been invited to give any advice on these structures. Therefore, the 7MW turbine [structure] is extremely large and extremely heavy. It is not commercial technology, it is not going to work [commercially], even if you increase the volume a lot. Maybe they have learned something from that and hopefully they can build a second generation that is much lighter and much cheaper. That is Japan.
Another market is America. Particular the West coast. Even when they have a lot of solar [power] and a lot of wind in California, they have extremely strong ambitions for renewables. I think they are probably going to be one of the first markets. I think we could see offshore floating wind parks along the whole West coast [including] Oregon, Washington State and California.
Then of course in Europe we have several markets. We have France, which is very exciting, they have the strongest ambitions at the moment. I think pretty much on the same level is Scotland. Scotland will be the first mover with Hywind, but then Scotland risks to be paying for the pilot, but then I am not sure if they will be able to build huge wind parks where they will get the benefits of that investment. Maybe they will, I certainly hope that they will. I think Scotland is taking a role that is extremely important and that is the leadership role. Fergus Ewing, the energy minister - I give him as much credit as I possibly can whenever I possibly can, because he is a fantastic person. He says that we are going to be the leaders in this and they are, if they actually get the benefit in the end, or if they have then paid a high proportion of costs, I am not sure. I think it is just incredibly important that they take the leadership because that is what the world needs now. Norway took the leadership for a while, when they build Hywind I and then they said, no, we are not going to build anything more, so that is where Scotland stepped in and I think that is incredibly good.
And then we have an interesting opportunity in countries where there is already a lot of wind power. That is Germany, Denmark and Holland, they have more shallow waters to choose from. I think it can be interesting to see, if we get the costs of floating turbines down, maybe they can even be cheaper than some of the bottom fixed projects, and then these countries would choose a deep rather than a shallow site for their projects. Another alternative is to able to build floating turbines on sites were originally assigned to bottom fixed turbines. I think that is a pretty dangerous path to go, because you will have to make compromises and sacrifices if you are going to install floating turbines on shallow water, this could be very expensive.

Question: Who will benefit from investments in this technology?

Sandberg: Everybody will benefit from the investments that Norway and Scotland have done. But I think that Hywind, which is the one we are talking about when we are talking about Norway and Scotland, they require deep water. Hywind requires at least 100m water depths. I think in countries like Holland, Germany and Denmark there is no such deep water. Those countries cannot benefit from Hywind; they can possibly benefit from other technologies such as Windfloat. Windfloat is now saying, we have designed our structure so that it can work on the existing sites that have already been announced. That is fine, but at the same time it is not the optimal design. The optimal design may be 100m or something like that. Therefore, Hywind is really good for deep water and Windfloat is good for shallow water. But if you could choose, I would probably choose a deeper site.

Question: How relevant is the TLP floater technology going to be?

Sandberg: First I was sceptical, but now I think that the TLP technology has the largest potential of all the structures. There has been some information leading to the media about our internal research project.

Question: What about the risk if a mooring breaks and your investment is completely lost?

Sandberg: There are still ways to have redundancy build into the mooring system so that this should not happen. The challenge though with TLPs is the mooring, that is correct. I think though that we can make the structure quite light with the TLP you can afford to have a more expensive mooring. As with everything, if you want to reach cost compression you need to reach industrialisation, mass production, automated manufacturing and all these things. I think that is where TLPs can be a very good opportunity. About 6months ago I was approached by the guy that used to be the CEO of SIEMENS wind power, his name is Hendrik Stiesdal, he founded the company that became VESTAS. He also founded SIEMENS wind power. He retired now. He came to me and said he has this dream of doing floating wind, now that he has done onshore and offshore wind. He approached me in march and we in DNVGL can verify this open source idea. We have been working with him ever since then to approve this idea and we are almost there now. We are going to present this in Paris in November and if all this works out the way we hope then this can be very cheap. Because it is open source, any university can go ahead and optimise the design and build it. Any developer can build it without any patent infringement. But we are just doing an overview of the structure as such, we are not approving in any high level of detail. The fundamental principles look very promising and we know the mooring is going to be very expensive, that is part of the package, but if you have double mooring lines, if you have redundancy on mooring, that is very expensive, but still maybe cheaper than other solutions.

Question: Which country has the most effective funding mechanism for floating wind?

Sandberg: Scotland for sure. They have maybe not the cheapest mechanism, they may end up paying a lot for it. But at the same time, things are happening and that is the whole point. France probably comes in second. They have a clear ambition and will probably build it. And they will probably do it more cost effective. But at the same time it is more uncertain.

Question: Because France is lacking offshore supply infrastructure?

Sandberg: That is more the technical risk. The technical risk you can always deal with in different ways. But France has much more a political risk. There are still some uncertainties about how much they are going receive and how secured this is on a political level. Scotland has a very stable condition and everybody agrees that this is a good idea, in France you have some kind of election and a politician changes his mind and then [the project] is gone. I have more faith in Scotland at this state.

Question: What about Japan's generous funding mechanism?

Sandberg: It is very generous, but still no-one is building there on any commercial scale. It is just like with us, we have all these incredibly positive signals coming from Japan, but when you actually go there and try to do it and try to realize your project it is extremely difficult.
It is a culture thing first of all, which is not meant negatively, but they are planning so long-term, that someone who is not Japanese, who does not have relationships that go long back, it is difficult to get approvals that you need and to navigate in the political landscape there. There are so many stakeholders that you need to work with for example the fishermen, it just takes a long time. I also think that the feed-in tariff that they have, which is a very generous with 36yen/kWh, there is no guarantee on how long you will receive it. There is political risk when they are adjusting the tariff from year to year. So I trust Scotland at the most, but we will see floating wind also in Japan. There was a bigger hype a couple of years ago, now it has cooled down a little bit. If we can see that technology matures in other markets maybe technology will wake up again and push this forward even more.
Thinks take a long long time in Japan. Western companies usually don't have that patience. So in Japan we will mainly see Japanese players. But we will also see Japanese players in Europe. Mitsubishi and Mitsui for example, Mitsue is very involved in Europe, even in Hywind. They are very keen to learn from the European projects.

b. Frederic Chino, Ocean Energy Sales Department Manager, DCNS Group

Interview from the 23.09.2015

Question: What funding mechanisms exist in France related to offshore floating wind?

Frederic: Considering fixed offshore wind in France we consider that fixed offshore wind is already in commercial size. There we have some call for tenders in France. There have been two calls for tenders within the last few years for several places in France. You can find those details in the web. Alstom with EDF has won some projects on the French coast and there was a second call mostly for NG the other utility that won the other side of the fields. There will be a third call for tenders that will be early next year, that is the call for tender that we call the third for fixed offshore wind. We don't know precisely where the French government will ask for new fixed offshore [fields], but if it is on the sea, the mechanism is mainly a feed-in tariff. I don't know what the feed-in tariff will look like but the previous support was about 205€ per MWh. This is the situation for fixed offshore wind.
Considering the floating wind turbine. There was a recent call for tender launched this summer, a call for tender from the French agency ADENE (French Agency for Energy, the governmental department to develop renewable projects). There is a call for tender, all the bidders will have to submit proposals for April 2016, so the race has already begun between utilities, all the stakeholders, project developers and all other parties to organise their answer. We are going to propose our solution, which we have developed with ALSTOM, the SeaReed technology. We have a product but we have also other competitors. The reason for this call for tenders, there will be grants and loans, let's say subsidies. And also. I don't know how to translate. There is a global envelope of 150million €. The third part of the envelope is dedicated to the subsidy. The subsidy will cover all projects, not specifically one project, all the projects that might be awarded. The two others thirds of the budget will be a kind of loan from the government that the awarded company has to pay back during a commercial project from these same players.

Question: What does the funding mechanism depend on and how much can I expect when I was to apply?

Frederic: This envelop is only for pilot farms. The framework is, to be able to propose 3-6 machines at a minimum production capacity of 5MW per turbine. There is through a window for a less powerful turbine, if the industrial of the project developer can explain that there is a real interest in the market. There is an example of a vertical axis turbine developer, this is a less powerful turbine, so there is a window for them but I am not sure they will be able to be awarded this project, because the market is more made for horizontal axis turbines with already proven turbine technology. There are many manufacturers that are ready to propose their turbine. The main object of this fund is to offer an opportunity to learn on the market for innovative solutions for the substructure, the pre-commercial arrays basically. So if you are a project developer, if you won and want to install in one of four pre-defined arrays, sites have been pushed but only four were selected, one on the Atlantic coast and three on the Mediatareen Coast. If you are a project developer, you have to decide in which one of the array you want to push your proposal. Let's assume you were to go for a site in the Mediterranean and you propose 5 machines with 6MW each, you propose a 30MW pilot farm. You will ask for those funds and this will only cover development and construction cost but this will not be enough to cover the costs of the whole project, that's why there is also a feed-in tariff which the French government is to decide on. I don't remember the minimum of the feed-in tariff, 170€ (its 150€) per MWh up 275€ per MWh. Your job as a project developer or a utility is to make your business plan, explaining that you ask for a subsidy which is only one third of the budget you will be able to ask for some part of the envelop of 50 million€. You can't obviously ask for the entire amount. You can say I ask for a certain part of the 50 million to be a loan and you may ask for a certain feed-in tariff. There is a minimum of 2 years to demonstrate and a maximum at the moment of 20 years. The French government already said that they prefer bidders to ask for longer demonstration phase. They give the opportunity to install a prototype. The prototype has been part of the final park that will eventually be build. We can imagine to build a first demonstration unit and one or two years later install the remaining 3-4 other machines to complete your pilot farm. If you want any subsidy for your pilot farm the French government explain that they will not give subsidies for only one prototype except it is the first unit of a pilot farm. The project is billed in advance and the government gives the money along with the fulfilment of milestones. Milestones are key to your payment and the government gives you the money all along the project. But if you don't get to the end of the project, they will ask you to return the funds that you received.

Question: At what stage does the government pay the developer?

Frederic: This depends on the team and who applies to the fund. The most relevant case in France is that the utilities are for the subsidies and the goal. The main issue is that the main part of the money that is received will be returned in the commercial phase and in the team, industrials are partnering with utilities but the return of investment will be due to other investments abroad, in the export market. The industrials make a lot of business with the utilities. We partner with EDF on the French market, we can also partner with EDF for a U.S or Japanese market opportunity in a market where EDF usually couldn't be a partner. The government either gives funds to the utility or to partners in the industry, that can give back the money earlier then the utility. It is important that the government gets their loans paid back as soon as possible.

Question: What motivation is underlying the funding mechanisms?

Frederic: The French government wants to help wind technology developers to move forward quickly, that is the main motivation. There will be some commercial projects following these pilot parks. We imagine that the first commercial project will happen in the Mediterranean Sea, because there is interesting potential, not only regarding the wind speeds, but the conditions are really ideal for floating wind. We call this Gulf Lion. On all this area, we have 40-50m depth, no other possibility for tidal, wave or other potential for generating electricity. The area is known to have good average wind speeds of about 9m/s which is very good. One of the issues is that you would want to develop a pilot farm where there is large commercial potential, so you you can quickly upscale from the first prototype. The government appreciates this. After the call for tenders has been issues this summer they expect proposals for April 2016 and they should announce the winners by the end of 2016 and start building in 2016. Considering the time that it the construction phase takes, there will most likely be no floating wind turbine before the end of 2019. This doesn't really depend on the readiness of the technology but the site readiness. Environmental surveys have to evaluate the sites. There is one site on which we have been working at Le Groix at the Atlantic Coast, here we already made surveys to have a time advantage, but nothing has been done for other sites in the Mediterranean. The administration and authorization process in France is quite long. We don't expect to deploy a machine before 2020 or 2021. You have to also make studies for the cabling and to get all permits is the 'critical way'[biggest challenge].

Question: Are you satisfied with the French support mechanism or could there be a better way?

Frederic: All the players want to compare the fixed and floating offshore wind market, we forget that the learning curve has to decrease [the costs], we are just at the beginning of the learning curve, to compare these two technologies already is quite a mistake. Unfortunately, part of the evaluation process from the French government is that you need to explain how you reduce the cost of the floating wind structure and in what term. That is difficult before you make your first power plant and we need a certain amount of experience to be able to determine when we will reach the same cost of energy of fixed offshore wind. It depends on the place where you place your turbine as well, it makes a great difference.
We need to improve the administrative process. We have been asking for an anticipation of all these environmental studies because this can be done before the final project development. So we can deploy the machines earlier, because the site can be ready on time. But this is not the only issue, there is the technology that is one problem, to have the site ready for operation is the second problem, to have the right infrastructure for the assembly of the machines is the third problem. So you don't have too many harbours in France that can support the building of such machines.

Question: Are funding mechanisms open for any foreign company?

Frederic: Yes, these funds are also available for foreign companies. For the French government it doesn't really matter who applies to the project the most important thing is the employment in France. Any company that can prove that their project is going to employ people during manufacturing the machines and the operating phase is qualified in order to create jobs in France.

Question: What criteria have to be fulfilled to qualify for the fund?

Frederic: In France for the time being there need to be investments into the infrastructure, into heavy cranes and machines. It is difficult to do these investments when you are only building 4-5 units. They know it is complicated to make all the parts in France for the pilot farm. The most important thing for them is to understand how you imagine the supply chain for commercial farms. I predict that together with ALSTOM we will be build the first commercial farm in France. It is quite clear that we cannot export complete machines out of the French harbours, these machines are quite huge and they will have to be somehow assembled close to the site. Our goal is to show however that the main part for the turbines of future French commercial floating parks is provided from France.

Question: How do you see the price development in the future?

There is the common European goal of 100€ per MWh. But we are not likely to reach this target in the next decade. I think we might be able to reach the target of 130€ per MWh.
We don't agree with everything [Carbon Trust], we don't agree with the targets, they are too optimistic. All these investments are not considered. There are constantly players entering the market that say they have found the miracle solution that will reduce the cost of energy with an innovative solution. These companies are mainly engineering companies that do not provide a commitment on the performance, the feasabity of the machines, they don't have the balance sheet to bear the risks of deploying these machines. Interestingly, the most mature solution is also the most robust solution and the most expensive solution, so the Carbon Trust paper admits that there is a cost for the most reliable machine. The most mature solution could be desirable to reduce risk. Deep studies have been done to determine all possible risks. It has become clear that companies that provide reliable solutions are marean experts and have a good financial balance sheet.

c. Bonnie Ram, Senior Researcher, Department of Wind Energy, Technical University of Denmark (DTU)

Interview from the 04.12.2015

Bonnie: My hair was getting grey seeing through offshore wind in the United States, so I thought I'd come to a country that already has some.

Question: We actually just did a talk on exactly that: Why is there no wind installed offshore in the US yet, so we are now a little bit informed actually.

Bonnie: I would love to hear your opinion!

Question: Well, it looks at least like the Jones Act seems to be the most prohibitive measure, and public policies, lobbyists, etc.

Bonnie: Yes, I would say the political environment, lack of climate policy, and a Congress that does not want to touch the existing energy infrastructure and the power of the existing energy infrastructure is underlying everything. The Jones Act to me is just a small [part]; I mean, yes, people are saying it's a huge barrier but in my opinion if we had a climate policy and we had an offshore wind policy – which we supposedly do if you look on the website [where you find all those lovely documents], which I looked at with many people in the Department of Energy about a "wind vision" and ow many gigawatts of offshore wind were imagined and are feasible. So all of these documents are easily [available], I don't know whether you guys have seen all that.
My opinion on why we have no offshore wind [in the United States] is really that it is a political problem.

Question: Okay, good. That's really interesting – it will put things a little bit into perspective because we thought there were more legislative problems [than political problems].

Bonnie: That's what it looks like from the outside but when you're in Washington [D.C.] you realise legislative problems can be solved very fast when there are political solutions.

Question: Okay, alright. Well, thank you very much already for that insight. That will be very helpful when we give policy recommendations to the US at the end of our paper hopefully.

Bonnie: [laughing] Yes.

Question: But beside the US – just so you know how we are going to approach this – we will look into Japan's funding mechanisms. We have been actually talking to people here from Statoil a little bit about the US but they had not too much to say. And then [we will be looking at] France, Portugal, and Scotland because of Allan [MacAskill is involved in the Kincardine project].

Bonnie: Yes, of course you have to do Scotland. Well, it's interesting that Statoil […] and I can understand why Statoil wouldn't be telling you much because they got kicked in the butt, you know. They had a proposal in Maine, you might have looked that up, called Hywind – they call it the same thing over here – but the Hywind project in Maine which was proposed – and they actually got some investment money from the US government – but then when the time came, there were too important decisions in the US when it came to offshore, and in particular to floating, which were those R&D investments; you might have found them on the Department of Energy website. There was one in 2012: US$28 million were allocated for seven projects, and then in 2014 that was down-selected to three projects. So those are some of the things you might want to look at.

Bonnie: Special project to look at: WindFloat in Oregon; WindFloat got money out of the Federal agency in 2014, which amounted to almost $47m over 4 years; also money given to the University of Maine, which is a whole different study; suggests a state-based case study because the funding at a federal level is very complex and "hard to unravel"; the political situation is very difficult to see through; two decisions in the last several years: WindFloat and UoM (pilot demonstration);

Question: What are the funding mechanisms available in the US?

Bonnie: There is a Renewable Energy Certificate [scheme] in New Jersey; that's a long political story, the certificates have been passed but it never actualised/ never applied to the project "Fishermen's energy"; this doesn't mean that it never will be actualised but it hasn't really helped the industry; so far there has been one OREC that has been applied to a real world project; for value of the OREC look on the web under the NJ PEC; there was a value assigned to it (in the links she sent us);

Question: Oregon doesn't have an offshore renewable energy scheme, do they?

Bonnie: No, they do not. It is not my understanding that the state is providing any funding mechanisms, however, what is very important in the US, there is political support in Oregon from the governor and other state officials not only to fund offshore wind but also ocean energy; Oregon and Washington state have tried to spur on some development in offshore renewable energy; there is a lot more political support there than in other states; Bonnie doesn't know of any state funding but thinks it's worth looking into; Allow Weinstein is very creative when it comes to getting funding and she was the one responsible for the first demonstrator project off the coast of Portugal; she never got it in the US but got it in Portugal from EDP and the EU

Question: If there was funding in the US, it would be in the form of PPAs, a utility company offering to buy energy at a higher price form the developer to make the project feasible?

Bonnie: Yes, so there would be a higher price offered to developers but with an OREC or an "invested tax credit" (ITC), which is the main mechanisms for offshore wind in the US – a federal tax credit; unfortunately, Congress can't manage to pass any long-term policy mechanisms; OREC is at the state level: offsets the costs, so the state would buy down the cost based on the developer price and the PPA, and in the ITC case, it's actually a 30% capex credit for the first 3GW of offshore wind; problem: ITC expired in December 2014 and they are looking to try to extend it again but not very hopeful; ITC not even active at the moment; despite a lot of bipartisan support, offshore is more seen of a "big reach" politically in the US, which is "very very different" from that in Europe; US energy policy: "all of the above", official name of it!; it has been tried to pass some carbon reduction policies but because Congress is so dysfunctional they can't pass any climate legislation; so they [Obama] had to do it through the back door: Clean Water Act, Clean Air Act, and other regulatory mechanisms that will increase the cost of operating fossil fuel plants; offshore wind debate in the US is very different from the situation in Europe because we have so many choices;

Question: Wouldn't it be fair to say, though, that if it is possible to increase the price for producing energy from conventional fuels, this benefits renewable energy sources because the prices paid for renewables in the PPAs are based on market prices of other fuel sources?

Bonnie: Yes, that's right but the process of rising prices in the US is very slow. What the clean air act means is that no more sources of coal are being sighted in the US; but all of the old plants are still operating and this still accounts for a great amount of our electricity; the only places where offshore wind might work is where you see some activity, both on the east and west coast be prices are higher in general; Massachusetts, Rhode Island, Main, New York: Higher electricity prices;
This is why offshore wind has been pushed in those regions; what you also have to consider is where offshore wind makes sense: If you have cheap gas or cheap onshore wind in a certain area, developing offshore wind doesn't make sense so the only argument for offshore wind is that in densely populated areas with high electricity / wholesale prices it makes the most sense to build there because there aren't any other options in New York, Massachusetts, etc. where you have no option for large scale renewable plants other than offshore wind;

Question: What do you think the value of the tax break is?

Bonnie: Huge signal, especially in the US! All types of support (FiT, renewable obligations, etc.) signal the market there is going to be this investment, there is going to be this opportunity for the private developers; problematically, many of those signals in the US are too short-term; for offshore wind, which takes a long time to develop/ many years, get permissions, etc.; this is why we are saying without an ITC of a big chunk of 30% there wouldn't be any incentive because the production tax credit (PTC) is designed for short-term gain, not a longer term; 4 year window (double check!!); tax break on capital expenses, not on production – this is what's needed in the US because we are so far behind in the deployment of offshore wind; we have no market for offshore wind, no pipelines; NPV analyses are great when you have a pipeline and you can really begin to see how it can benefit the next project

Question: So a multi-state approach to setting up a supply chain would be best?

Bonnie: The reason is that we realised without the market push [we can't establish an industry]; there needs to be a market first before you can set up a supply chain: who is going to buy a crane, a vessel, etc. if there is no market? Market activity in places like New York state, both Massachusetts and New York states are thinking about deploying large scale projects; they understand though that for an industry to develop there is need for a pipeline, not just a single project

Question: Do you have any idea of when that might be the case / be passed?

Bonnie: I have no idea. I know folks are working on that though, the Massachusetts state legislator is working on a bill right now and so is the New York state legislator.

Question: Do the wholesalers/utility companies also get a tax break on buying renewable energy?

Bonnie: I don't know how that works to be frank. The way ORECs and ITC are designed is for the developer, not for the utility unless the utility was also the developer, so in the case of the Delaware offshore wind project, which unfortunately fell through, that was NRG – NRG is the utility – and you might find that NRG bought the offshore wind lease from the developer who was doing all the permitting; they haven't done anything with it but if they did, they would be eligible

Question: Do you see a future for offshore wind in Hawaii maybe where electricity prices are very high?

Bonnie: There has been a lot of a talk & investment in the Hawaiian Energy plan, actually the department of energy had a special initiative; they were trying to spur on a clean energy revolution be the cost of energy is so high but I don't know what the reality of that is at the moment and how much they have accomplished so far be electricity prices are really high and Hawaii relies mostly on exports; same goes for Alaska, believe it or not: several of my colleagues are working on Alaskan power plants; a lot of the remote areas use diesel so they were trying to push a wind and solar option in remote areas; you are right in where it would most likely occur: in high electricity, more remote places or where wholesale prices are high; this is the key to understanding the situation in the US: you can dismiss the national level because Congress is dysfunctional and Obama can't pass any climate legislation, and you have to look at things on a state level because there is activity at the state level; activity is happening in certain states for a political and state-specific/regional reasons to encourage those kinds of developments

Question: We mentioned Statoil in Scotland before; where do you see the most development happening / the next full scale park, anywhere in the world?

Bonnie: I mean; a real surprise has been Japan. It is very fascinating to watch; they have moved ahead quite quickly; this shows again that if there is political support and there is a push to change something about their usual energy infrastructure – because their energy infrastructure is mostly based on nuclear, the Japanese had a political reason/motivation to make some kind of shift in investment and, boy, they got that into the water within two years! That has been quite an insightful example! Otherwise, China has been moving into offshore, though not so much floating at the moment, and I think in Norway, clearly there has been a sign of investment because the Norwegians have invested so much in offshore and floating because of floating and yet they are not so keen about deployment of wind in Norway, be it onshore or offshore; but I think the prospects of the Statoil initiatives in Norway and Scotland are quite high. That said, Principle Power is not far behind; they have a different type of floating structure and not so deep pockets if you will, you know, Statoil is a very rich corporation; and then with Norway's R&D matching that, PP has more challenges even though they have a utility helping them, they don't have a country behind them, like Statoil; except with some R&D, but even the R&D they get, $74m, for a floating commercial project is not exactly a lot as far as a major statement; Japan, Statoil activities and PP are the projects/activities to watch

It would be very interesting to see what Statoil thought the costs of their Maine project were going to be since they had one there; then you could compare Norway, Statoil and Maine; even if they gave you the range, that would be interesting because they had to calculate that without any tax credits or anything;

Question: The main problem, we have heard, in the US is the risk associated with the PPAs?

Bonnie: That's correct. The utilities don't want to pay. In Europe they already have the FiTs and the guaranteed price, which we don't [in the US] but it would have been interesting if they had calculated the ITC and their Hywind project in Maine; then you would have a "cool comparison" of three countries.

d. Morton Dillner, Analyst at Statoil

Interview from the 27.10.2015

Morton: There are no offshore wind farms in the US as of now. The first one is being developed on the North-east coast, in Massachusetts, Rhode Island by a company called Deep Water. This is a test park of five units, it is now being constructed and it is going to be operational by 2016. This test park has entered into a PPA with the state utilities. Beside that there is no project that has proceeded so far. When it comes to the funding mechanisms, they are typically state by state, there is no federal funding mechanism targeted at offshore wind. To develop offshore wind though you need funding by the state, the state that is next to the park that you are planning to develop. You get some sort of support from the government in form of production tax credits. This reduction is given to all renewable projects. This production tax credit is given in form of reduced tax for a certain period of time for each MWh produced. In addition, you can get loans. Once you have a federal loan it is much easier to get a loan from a commercial bank. It is a Kickstarter. This is also available. You also have some favourable tax depreciation rules targeted for renewable projects. This is called accelerated depreciation. I haven't been working with this very actively in the last years. But we had a project some years ago called Hywind Maine. Since then I have not been following the tax rules very closely. But you had the chance to accelerate project depreciation on capital expenditures.

Question: Could you say why Hywind Maine was cancelled?

Morton: There was a lot of uncertainty around the income side. We were about to enter a PPA and there was a lot of uncertainty about that, so we stopped the project. And in terms of developing Hywind we had been looking for Scotland as an alternative and then we chose to work with Hywind Scotland as the main project.

Question: What about Hawaii for future floating wind projects?

Morton: There is some leasing activity going on. In the US, the offshore wind permits are leased out by BOEM. They have started to process (applications) which will result in leasing anchorage outside of Hawaii. There are some strong drivers in Hawaii for renewables. They have stated to have 100% clean energy by 2030. They are currently relying on diesel. Diesel has a high CO2 content and is expensive. There are a few companies that have announced that they will look into Hawaii to develop offshore wind. There seems to be a growing interest among authorities and developers.

Question: What about the Jones Act?

Morton: You just need to deal with the Jones Act. The Act works such as, if you are using a non-US vessel you cannot enter a port in the US and then continue onto installing offshore wind farm units, that is not allowed, then it is interpreted as taking the vessel from one port to another one and that is not allowed for other than US vessels. Then you are violating the Jones Act. So, in order to use European ships in the US, you will need to not let those vessels into the ports first. You will need to transport equipment, import it directly from Europe to construction site and do the installation there and that can be done. If you look at the first wind farm, they are installing monopiles with a US company, the wind turbines are being installed by a European company EREVA. They are setup without going to port in the US. It makes things more challenging and can in some cases result in higher costs.

Question: If we were to focus on one location, which US state should we choose?

Morton: States where you see most activities when it comes to leasing in are Massachusetts, Rhode Island, New York, New Jersey. These are the ones I think have advanced the most in the US. In Oregon, there is one pilot that is being developed by Principle Power. This is a five or 6 units floating park. There are some challenges with a PPA with their utility. Floating is very little progressed on the east coast. The potential is there on both sides, but California especially has large potential for deep water wind. It is an interested state with a large power market and California is very ambitious with their renewable energy targets. This year they have announced that they are going to have 50% renewable power in their power mix by 2030. This is a very ambitious target. There are some strong drivers for green energy in California. California could be an interesting state. But there is no kind of special funding mechanism for offshore wind in any state. With the exception of the current PPA of Deep Water.

Question: How effective are PPAs?

Morton: I think PPAs are in general very effective, given that you are given enough support in order to make the project profitable, it is a very stable income. A PPA is a legally binding agreement. This gives some legal rights as well. This is a very good way of supporting offshore wind. You get a framework with a fixed price over a certain period of time. Green certificate systems also work well. There is one certificate system in New Jersey that simply hasn't been put into legislation. This system is called OREC, especially targeted to support offshore wind development, it was developed a few years ago, but it is very uncertain if it will ever be put into legislation. New Jersey has also deep waters and potential for floating.

Question: Can you elaborate on the different impact of a PPA or feed-in tariff on the NPV?

Morton: I don't think there is not much of a difference between PPA and feed-in tariff on the projects NPV, both kind of give you a fixed income per MWh.
A feed-in tariff is usually part of the legislation, while a PPA is contractually binding. The feed-in tariff might not give the same legal protection as when you have a contract. Countries however usually don't do retroactive changes because this is very damaging even though a feed-in tariff is not a contract, it has low risk.

e. Allan MacAskill of MacAskill Associates, Kincardine Project

Interview from the 6.11.2015

Question: Some assumptions in our thesis might be too strong, assuming the same price of electricity for example?

Allan: That's where you change [your approach], if we assume that the production stream is the same, the capital stream is basically the same, you may play around with the exchange rate because in our British project it is 6m pounds, it might be cheaper in Europe. I think that the difference is [in] the income stream, [so] that is your challenge. That is the price scenario you have will be different in every country. What you are trying to understand is which is most likely to progress the development.

Question: So the price of electricity is one of the country specific factors?

Allan: Yes, they are. In Britain it is a price specific system, they don't give you any grants, they just give you a high tariff. France gives you a lower tariff but a grant as well. Capital grant and a lower tariff. The different countries have different methods of funding the program. It is a mixture of capital grand push and income stream drag with higher tariff. It seems to me that you are looking at 4 different countries in theory. France, UK, US, Japan. Each country has a different set of methodology of incentivising pilot programmes of let's say 50 MW as a standard program. What you are trying to understand is which methodology gives the greatest incentive and the least risk. And it's a balance. The British system may give you a greater return on capital than let's say the French system, because you are getting 50m€ handed to you upfront. The risk that the owner is taking is lower. If you have a project that is 200m £, somebody gives you 25% as a capital grant, you only got to fund 150m £. And you got to pay this over the income stream, they give you a lower rate of return on that but the difficult thing is finding the 200m and if they have given you a quarter they have seriously reduced your challenges. So the government gives you a lower income stream, you get less reward on the grand scheme of things in terms of the long term on the project, but what you get is a lower risk profile. The question is, which methodology is more likely to encourage people to do pilot programs to make that step from demonstration to full commercial. In between you need these pilot programs. You can choose a number, 50MW, 30MW, that doesn't really matter, but you got 4 countries with different methods trying to encourage you to do this. And what you are trying to do is to find out which one gives you the most or most likely success.

Question: Will there be a difference in CAPEX as well?

Allan: No the CAPEX is the same. Pick a number, for example 200m. In France you start off with a grant of 50m grant that will be paid out to you during the CAPEX phase.
Banks are so conservative; they want a guarantee that the money will be given back to them. And if you are building something that has not been done before, it is a lot riskier and much less likely that the money is coming back. So the easiest way of doing a project is to finance it all by equity. A few companies would get together and get a 50m grant. To look into how debt financing would effect this might be simply too much work for your thesis. But debt is definitely something to worry about, because it complicates things dramatically. You don't have to ignore debt. You can say, what you need is a guarantor. In the UK, there is the infrastructure guarantee fund, they will guarantee the debt. I would not do an analysis about that. You could say the best solution is to lever the project. 200m £ is not exactly a huge project. You have big corporations behind it. If you build it, after 1-2 years the majority of risk is gone as far as the banks are concerned. After these years they can see an income stream and the construction and technical risk is removed and they borrow your money at LIBOR +2 or whatever. A conversation about debt is good, but keep it out of the analysis. Keep the economic model simple.

Keep it simple. Compare 4 different systems. How do those systems compare? What is the impact of them? What does it do in terms of risk profiles? What does it do in terms of income stream? The British system will give people the best returns, I think there is no doubt about that. But you got to find that extra amount of capital and you got to know if your project is going to work. If you got the French system, saying we take chunk of your capital risk, but we pay you less on a long term, that might be a better deal. You need to look into what the different deals result in and analyse and give your opinion to where the pros and cons are and there is no right or wrong answer, the answers will be driven by the political philosophy of the country and the government. Britain is a market lead economy. France is [deregulated].

Question: How do we consider the different revenue streams?

Allan: The income largely comes from the subsidy mechanism from the government. In some cases, it comes as a grant pre-generation, where they give you capital, pay your costs. You get two grants, one before you start the project to help you pay your CAPEX, then you get an income stream, which is basically a fixed fee for your income for the first 15-20 years. Britain for example, here you get 3.5 ROCs. A ROC this year is worth 43£ plus you sell the electricity. That is an open market. Currently a MWh is worth 40£. 3 times 43£ is guaranteed and 40 can go up to 60 or down to 35. Your actual float on the market is fairly limited. As a proportion of your income stream the amount that is actually being generated from the consumer is different. The bulk is paid by the subsidy carried by the state.

Question: How should we adjust two completely different electricity prices in two countries?

Allan: You have three components to your income. First you have capital grant, like negative cost, then you have income that comes post investment when you start to generate, that splits into two types, it can be pure subsidy and an agreed feed-in tariff. In Britain you have the ROC regime, not the CFD.

Question: Should we exclude the CFD?

Allan: Yes, exclude the CFD, the ROC regime is what is driving pilot programs. The ROC regime is a subsidy per MWh increasing with inflation (RPI). Then you also sell your electricity. The American system is a capital grant, then it is purely a tariff for the sale of electricity, the PPA. The reason American projects take a long time is that PPAs are regulated. This is a process where the public utility board has to verify that a PPA between a supplier and a generator is a fair price for the consumer. The problem is, when you make a fair price for the consumer based on what it costs to generate electricity with a legacy plant you isn't going to be doing a renewable project. In the US they have a tax incentive system. So they have 3 things, capital grant, PTA- tax credits basically where big companies can invest and get tax credit for that (the way i would deal with that is I would just add that as an income stream from tax credits), the last thing is that you sell your electricity. But you have to convince the public utilities board and they usually give a higher tariff that goes by quotas. You have then for example to produce a certain amount of electricity from renewables. For instance, the US military has a 50% renewable target by 2025. Different states have different incentive challenges and different rules. Some have high challenges but no rules. Others have stiff rules, but no challenges. Then you have to negotiate a PPA with someone which is passed by the public utilities which they agree to pay a higher price for that electricity for some reason but this has to be approved by the public utilities commission. That is the big challenge. If you look at the Windfloat Pacific project off Oregon the problem, there is that there is no PPA. Now what is going to happen is that the government is going to say that they insist that 15-20% electricity is coming from particular renewable sources. Oregon has the Columbia river with massive amounts of hydropower. They are probably going to create a system that generates a premium and people can sell their electricity at this premium because they have this renewable portfolio standard RPS. The governor of Oregon is trying to create a higher RPS to allow this Windfloat project to go ahead.

Question: When we are looking at funding mechanisms, what is the role of different electricity prices?

Allan: The electricity price is the core part of the funding mechanism. If you are on a Pacific Island you might not have to offer any incentives, because your alternative is generating power from diesel and you already have a high enough electricity price. What you are looking at is basically 2 things, what does it cost to run a basically 200m $ project, you may play around with the exchange rate and purchasing power parity. On the other end it may be up to how you get an income stream that covers it, that can come from capital grants, direct subsidies, the sale of electricity and any other benefits that an investor can get. From an economist view try to understand how these different risk profiles go and what impact they have on encouraging people to progress things that is the challenge that you are going to evaluate.
You also need to account for tax breaks. Oil companies quite like to have renewable energy, not because they love renewable energy but they love tax breaks. BP and Shell are major investors in wind in the US. By having wind projects, they pay less tax for their oil business. This makes wind parks an interesting investment. This is also the motivation why Statoil is coming to Scotland with the Hywind project.

Question: What do you know about the Hywind project manufacturing?

Allan: The floater is built in Spain, the assembly is done in Norway, Scotland will get to do the maintenance.
Comment on NPV: Building the NPV will help clarify what you are doing. Get a model and try to run it. Then you see the difference in NPV and IRR. You could also consider other measures that give you an idea of the risk using CAPEX...if you put 100m in it is a different risk than 150m. Having an identical project in an identical regime, what would the different incentive mechanism do to what you invest.

f. David Stevenson, Head of Offshore Wind Policy, Scottish Government

Interview from the 16.09.2015

Question: What do the funding mechanisms for floating offshore wind in Scotland entail?

David: Different financial incentives; most attractive incentive: Renewable Obligation Certificate, launched a couple of years ago; [originated?] from Statoil's Hywind project; Statoil said they would only continue if there were sufficient subsidies (?); 3.5 ROCs for floating offshore wind with quite a strict timeline obligation (will elaborate on later) – over and above traditional 2 ROCs which is available to fixed offshore wind; this is not directly funded by the Scottish Government, it is indirectly funded by Her Majesty's Treasury in London; Ofgem administers the RO scheme on behalf of the Treasury, how you trade your certificates; Renewable Certificate: you sell it to the electricity utility who use those certificates to prove that they fulfil their quota of renewable (certain percentage of the electricity they buy has to come from renewable sources)

Question: Are the certificates traded at market value or is there a set price for them?

David: market value figure form; depends on the electricity market; the scheme, depending on when you commission your technology, can last for up to 20 to 25 years; UK govt. now is letting this policy run out / scheme is coming to an end - UK govt has put legislation in place for that to close and be replaced by the Contracts for Difference process under the electricity market reform, which came into being last year under the *Electricity Act*; [in the light of this:] new [Conservative majority] government is looking to close down funding for onshore wind a lot sooner than originally anticipated; so far offshore wind is not impacted by that but there are still certain timelines for offshore wind – for enhanced ROCs for the floating technology you have your technology reaccredited / achieve presentation(?) of your floating technology by Ofgem by 31 March 2017; this means that you have to give assurance to Ofgem, your consent to build the project, you need to have confirmation that you have grid connection; documentation for all of that needed; grace period until 30 September 2018 – period on top of the 31 March deadline – allowing more time to developers to get the project physically into the water and start to generate; ROs can be only be traded up until 2037, even if you only started generating in the summer of 2018, giving you only 19 years – by contrast, if you started producing today you could trade 21 years' worth of ROs; so the ROs are not as favourable but still more favourable than CfD (Contract for Difference) under which you can only get 15 years of support → more incentive to get your project running under the ROC scheme; reason for many floating offshore wind projects being here; *Electricity Market Reform Act* passed last year [2014], prior to that David & Co had executive powers in Scotland to set their own broad bandings / bandage (?) and have done so with wave & tidal – while in England & Wales they would only get 3 ROCs for such power plants, in Scotland developers could get up to 5 ROCs; as of 2014, the UK govt withdrew power from the Scots to award those ROCs, so they no longer have that; schemes that the Scottish still have are mostly their traditional grand funding schemes, for instance, "Powers", prototype offshore wind turbine development scheme, worth £ 35m – if a turbine developer is looking to locate in Scotland, they can access this grant to do so; similar fund called "Skift"(Swift?) for foundation technology, which can also be accessed by developers looking to locate in Scotland; also: National Renewables Infrastructure fund (NRIF) – £75m, more for the development of harbours, for example, that turbine manufacturers need to access to get their equipment to their sites; also general R&D grants that companies can utilise; finally, REIF £103m renewable energy investment fund: loan fund (rather than a grant fund), so tends to be less popular – more info on interest rates etc. on websites,

Question: Elaborate more on ROCs

David: Ofgem (regulator) website for trading value of the certificates

Question: How much money can a developer expect from these grants? Is this may be linked to expected output, etc.?

David: The reason Scotland created these funds is to maximise our economic opportunities; it will be looked at what you are planning to do in Scotland, how many jobs you are going to create; what is the developer going to do for Scotland as a country [/how beneficial is his/her project to Scotland]; Scotland of course wants to maximise their offshore wind potential, increase the amount of electricity generated from renewable sources and source 100% of their electricity from renewables by 2020; this will be weighed against what the developer wants to achieve, how many jobs they want to create; things are assessed on a relative basis – there are no minimum requirements that a developer needs to fulfil; every project has its merit; if the project is credible and it has a benefit for Scotland, you will hopefully get a grant; the govt though does not want to be seen as the "public purse" paying for everything, there needs to be some private sector investment

Question: England does not support any FiT schemes, do they?

David: FiT support tends to be for smaller scale projects; but either way the UK govt decided to do away with that now and focus on Contracts for Difference process under the Electricity Market Reform that they did last year; all subsidy regimes like the FiTs, ROs, etc. have all been done away with and it is all under the CfD process now; different pots: Pot 1: Established technologies (e.g. onshore wind, hydro), then: Emerging technologies that would get higher tariffs: offshore wind, wave & tidal, Scottish ?? projects; different pots with different types of funding; overall aim: generate the most benefit for the public person; the consumer funds emerging technologies, R&D with a part/proportion of their electricity bill, proportion of their bill is used to fund new technologies; the govt tries to ensure that consumers get the maximum return for their "investment"; another aim of the government [for switching to CfD] was that the scheme should be easier to understand

Question: How effective do you think the UK's / Scotland's funding mechanisms are in advancing floating offshore wind?

David: If it wasn't for the ROC scheme, we wouldn't be talking to the project developers we are talking to now (e.g. Statoil and their Hywind project); it is "fairly obvious" that the ROC scheme is in thus successful; Energy Minister Fergus Ewing ran the consultation to see what a sensible banding would be (when Scotland still had those powers) to incentivise Statoil to move the single Hywind prototype from Norway to the next level; Scotland: deeper water, more challenging conditions that make floating more advantageous to them [than England]; in E&W there aren't many opportunities for floating wind farms, most offshore farms are fixed ones in relatively shallow waters where it's not very challenging to build; the only sites for floating offshore in E&W would be into the Atlantic, there are only a few pockets off the Welsh coastline [where floating offshore wind could be deployed];

Question: Despite all of these uncertainties, do you think it's realistic to bring the price per MWh down to £80?

David: Yes, floating offshore wind is not only being developed here [in Scotland] but also in France, the USA and Japan is especially keen to develop a lot of floating offshore wind projects by the end of the decade; we [in Scotland] are trying to ensure that offshore wind is viable not only for our own waters but that the R&D we develop here will help us work with countries like Japan, America to ensure that we are at the [economic] forefront of developing this technology; as we have done with oil & gas and wave & tidal, we are looking to spread our knowledge around the world. I think it is quite achievable to push the price of floating down to the £80 mark but of course you need a supportive environment and when you listen to people you need to be careful to distinguish between companies simply trying to promote their own technology (e.g. Statoil) and others;

Question: On a global scale the price can be brought down to £80 per MWh but Scotland will then not be at the forefront of that due to the great uncertainty?

David: No, no, we will still be at the forefront; certainly Statoil and the Kincardine project both submitted their marine consent application and both have a good chance of being deployed within the timeline; the timeline to achieve the ROC deadline is going to be a lot more challenging; but Scotland is in a good position: with two projects in the water, we have great opportunities to learn from them; this is beneficial not only to Scotland but to the world as we are developing this technology

Question: Out of the Kincardine and the Hywind projects, which one is further ahead?
David: Hywind is a bit further down the line because they have been developing their technology for some time; there is a difference between the two projects as to what marine consent they require due to their location; the Hywind project is beyond the 12 nautical mile line and is below 50MW, which means they only require a "marine licence", whereas the Kincardine project is within 12 nautical mile line, which means they need a Section 36 consent license as well as a marine license and the Section 36 license takes a bit longer to go through whereas the marine licence allows you to operate sooner and the process for it is a lot shorter; Hywind is thus going to be slightly ahead of the pack; we are fairly confident that they are going to be well within the ROC timeline of 2018 whereas Kincardine is slightly further behind, they submitted their application but Marine Scotland who officiates the application has a target of 9 months, so we are looking at April 2016 for when they get a determination on that; FiD? And then you need to plan when your project can get built, so we are looking at two to two and a half year until the project can actually physically be in the water.

g. Carlos Martin Rivals, Project Director of Windfloat Atlantic, Energias de Portugal Renewables (EDPR)

Interview from the 18.09.2015

Question: Could you please explain in your own words the funding mechanisms in Portugal?

Carlos: What I can share with you is what has been made public by the European Commission or the Portuguese government; NER300 is a European programme, there are different levels of support for different types of projects; in our case we receive €30m in total, which is subject to certain conditions, e.g. the total level of production, information sharing and certain deadlines, e.g. when the wind farm is operational

Question: Can you elaborate a bit on that? Is that 2017?

Carlos: End of 2018 because there was an extension agreed by the EC. Information sharing is basic stuff; production level: within five years, from 1 Jan 2019 onwards, we need to meet at least 75% of the target production of the wind farm that was included in the application of the wind farm; if we fall short, we lose the proportional part of [the grant];

Question: So the €30m is 100%?

Carlos: Yes, the €30m is 100%. Imagine we only reached 50% of the production, just to give you an example, the 30m would be reduced to 20m.

Question: The deal is for 25MW installed?

Carlos: Yes, there is a minimum of 25MW [to be reached]; this is a rule of the NER300.

Question: And you also receive support from the Portuguese government?

Carlos: Yes, so this [NER300] is at the European level. Then we get several support scheme at the Portuguese level; not all of this has been formally approved and published yet. What I can share with you is that [all these support mechanisms] are roughly equivalent a tariff of €168/MWh.

Question: So this constitutes a feed-in-tariff?

Carlos: Yes, this is a feed-in-tariff for 20 years, indexed to the inflation. But this is split into several tranches; the €168 do not constitute *one* formal-level FiT, it is an equivalent [of several support schemes]. You have different support schemes: You have some upfront investment support, and then part of the production receives a tariff and the other part of the production gets another tariff, so it's quite complex in terms of what you get for certain MWs produced; but eventually it will amount to a tariff of this level [€168/MWh];

Question: Is there any R&D support from the Portuguese government?

Carlos: No, that's all.

Question: Can you maybe elaborate on the motivation behind funding floating offshore wind from a Portuguese perspective?

Carlos: The thing about Portugal is that offshore wind here is very limited in terms of both existing projects and projects in the pipeline. So it's maybe not that comparable to other countries where you can have development on a bigger scale / large development, like in the UK. Basically, the only floating offshore wind project currently under development is ours and the support scheme is more general: it applies to other offshore renewable technologies as well [not just floating offshore wind]. In terms of installed capacity, so far there is only our prototype of 2 MW, which also receives the same tariff.

Question: What about the vision behind offshore wind in Portugal? In the UK, they strive to set up their own supply chain for the future of floating offshore wind. Are there similar plans for something like this in Portugal?

Carlos: The Portuguese government supports these projects because it is interested in developing a cluster but as of yet there is no clear roadmap for the number of MW Portugal plans to have installed by a certain date, and the support schemes are not designed to reach such a goal. Nothing of that kind has been approved yet. The tariff I am talking about today is limited to [projects with installed capacities of up to] 50MW and these are the only support schemes existing right now in the country.

There are no fixed offshore windmills installed in Portugal because there are no conditions for that; almost all waters surrounding the country are deep.

Question: Would it be fair to say that the offshore wind industry in Portugal relies a lot supply imports and outsourcing development? Portuguese companies are only responsible for the development that is relatively far upstream, and this is where WindFloat Portugal sees its market position in the future?

Carlos: You need to be aware of the various visions at play here: The country has a vision, there is a vision for the technology and the developer has a vision. I can't speak to the country's vision but there officially is an interest in developing floating offshore wind power in Portugal, simply because fixed offshore is not an option, but as I said there is no clear plan with regard to the number of MWs to be installed [by a certain date], locations for further development or the support schemes [designed to specifically aid this] – nothing has been defined yet. There is an intention but nothing has been formally approved yet in terms of what shape that would take. In terms of the technology, you know EDP, in which we have a stake. Principle Power, which is an American company, has a global perspective, they plan to sell their technology not only to Portugal. Kincardine has been consenting the project using WindFloat as a reference, so this is one example, and there are other prospective projects around the world that base their assumptions on WindFloat. EDP really focuses on the global market, not only on Portugal. From EDP's perspective, the focus is not so global because there are countries we are not considering but it is nevertheless international: Right now we focus on this project with WindFloat but we are looking at other places as well. You can't make a general statement about Portugal because it depends on who's talking about it.

Question: You mentioned the US. Can you tell us something about the situation in the US as well?

Carlos: Not really, no. I have some knowledge about the market but similar to the one you have, I guess. Judging from the questions you sent me, I assume you are wondering about the supporting schemes for wind projects. There was this news about a commission being created in Oregon for the development of offshore wind but officially nothing has been settled/approved yet in regards to support schemes. The market in the US works very differently from Europe: There is no such thing as FiTs in the US for any type for RE. Different states can set targets for different types of renewable to support them. In Idaho, for example, all utilities need to reach a certain percentage, say 25% as a minimum, of their electricity from renewable sources by 2020, let's say. So this forces the local utilities to contract renewable energy assets. Typically, they don't develop them themselves, they basically tender the capacity and the different developers in the state, potentially in other states, apply to supply the capacity tendered by the utility. On top of that, there are other support schemes: the second type of support scheme is a green certificate scheme exists in certain regions, which somehow allows ?? to comply with regulations, it's an equivalent system. Thirdly, you have federal tax breaks, which is called PTC, "production tax credit", which changes and is renewed every year. It is a grant. The PTC is an equivalent of a supporting subsidy; it is around $19/MWh. So this is typically the way it works: For an offshore project to be successful, they need local support. On a state or regional level there usually is some type of commitment from the authorities to support the development of offshore wind through some sort of target of installed offshore capacity. They would require the local utilities to source a certain amount from renewable sources by a certain date, say 50 MW of renewable source by 2025 or 2020. If that happens, you [as the developer] will negotiate with the utility. You have to negotiate what type of PPA level you can reach with the utility. It is very different from Europe, as I said. The state governments do not approve a feed-in tariff, they approve a mandate to the local utilities to purchase a certain amount of renewable energy and this amount of renewable power can be rendered towards specific technologies. In the past, for example, solar has received higher support than wind because it was more expensive through a higher number for green certificates and through specific targets state by state.

Question: Can you give us an example for one of your projects in the US and under what support scheme they fall?

Carlos: EDP does not have offshore wind developments in the US. As far as I know, there is no target approved yet for floating offshore wind in Oregon. This is what PP lobbies for; they want the state to set such a target, so they can negotiate a PPA with the local utilities. Otherwise you can also try to negotiate a PPA [without a renewable target or obligation having been set by the state government for the local utility] but then you [as a developer of renewables] are competing against all other forms of energy and that is very tough for a new technology like [floating offshore wind], if not even impossible.