Investment in Wind Power Development
- A Comparative Study Between Norway, Denmark, and Sweden

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Investment in Wind Power Development - A Comparative Study Between Norway, Denmark, and Sweden

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ABSTRACT

This study analyses and compares the historical foundation of how governmental policies and policy instruments have shaped the development of onshore wind power in the three Nordic countries Norway, Denmark, and Sweden. In Denmark and Sweden, wind power has emerged as an important contributor to reduce pollution and global warming. In Norway, however, wind power has not developed to the same extent. This in spite of considerable potential and climate policies promoting use of electricity from renewable sources.

This analysis indicates that clear political ambition and generous financial support have been important factors in increasing the share of wind power in Denmark and Sweden. In comparison, the Norwegian policy has been vaguer, not stating specific goals in favour of wind power. The long lead time to get a licence from the authorities has also been an obstacle for the investors' willingness to invest in this market.

More specifically, institutional and policy-related differences across the countries are explored by assessing the profitability of a simulated project. This project is considered in Norway, Denmark, and Sweden to yield net present values (NPV) of -€26 245 604, -€13 500 032, and -€24 322 229, respectively. The analysis suggests the negative NPVs to result from the low electricity prices, in addition to low financial support and high investment costs. The country-specific differences are mainly due to the size of the upfront investments needed. Denmark – flat, with little height variation, provides good geographical conditions for development of wind power; in addition, Denmark has an historical advantage, hence the lower investment cost.

The overall results show that a wind farm project will financially perform differently in the three represented countries. However, there is considerable uncertainty associated with these results. Sensitivity analyses show the electricity price to be the most critical variable affecting the NPV. Monte Carlo distributions paint a good picture of the uncertainty associated with these projects, thus, the uncertain variables must be closely monitored.

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LIST OF ABBREVIATIONS

NVE	Norwegian Water Resources and Energy Directorate (Norges vassdrags- og energidirektorat)
MPE	Ministry of Petroleum and Energy (Olje- og energidepartementet)
FIT	Feed-in Tariff
FIP	Feed-in Premium
TGC	Tradable Green Certificate
TW	Terrawatt
MW	Megawatt
KW	Kilowatt
O&M	Operational and Maintenance cost
NPV	Net Present Value
LCOE	Levelized Cost of Energy
CAPM	Capital Asset Pricing Model
WACC	Weighted Average Cost of Capital
MC Simulation	Monte Carlo Simulation

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1 INTRODUCTION

Renewable energy sources have been given increased attention in recent years, due to heightened public awareness of environmental challenges such as pollution and global warming. Correlatively, new policies consistently promote the development of renewable energy technologies, and wind turbines are installed across the globe at an increasing rate. Due to its low greenhouse gas footprint, wind power contributes to the «green shift», curbing our reliance on fossil fuels, in a world where energy demand is still growing.

Wind power is a capital-intensive source of electricity, highly dependent on political support. In Europe especially, implementation of strong policies throughout the 1990s and 2000s has contributed to investors increasingly providing capital for wind power projects; including countries such as Denmark and Sweden. Today, the share of wind power in Sweden and Denmark are 6 520 MW and 5 228 MW. Norway however, has a significantly lower share with an installed capacity of 765 MW (IEA, 2016a). This in spite of the Norwegian Government promoting increased production of electricity from wind power through financial support.

This study investigates and compares onshore wind power development conditions in the three Nordic countries Norway, Denmark, and Sweden from the perspective of a private investor. It highlights policy and political support-related differences between the countries in a historical perspective. Furthermore, an analysis of revenues and the costs needed to develop, install, and operate a wind power project is conducted, exemplified through a simulated reference project. The following research statement is addressed:

Investment in Wind Power – A Comparative Study Between Norway, Denmark, and Sweden.

The purpose is to investigate why wind power in the Norwegian market has not developed to the same extent as in its neighboring countries. This despite Norwegian authorities having set ambitious goals for the overall climate policy and the development of electricity from wind power. By assessing historical differences and the profitability of a simulated project placed in Norway, Denmark, and Sweden, this study seeks to highlight the most critical factors causing the differences. This can help shed light on how Norwegian policy should be adapted to promote investment in wind power.

The remainder of the study is structured as follows: Chapter 2 will examine political targets from a global perspective and the background of wind power, considering technical and economic aspects. Further, the historical foundations of wind power development in the global, Norwegian, Danish, and Swedish energy markets is presented. Chapter 3 assesses previous research on how governmental policies and policy instruments promoting renewable energy have shaped the development of wind power, mainly in the three Nordic countries. Chapter 4 describes the theoretical models and analyses tools relevant to assess investments in wind power. Chapter 5 summarises the data set needed to conduct the NPV-analyses; and Chapter 6 discusses findings and results, as well as research limitations. Lastly, Chapter 7 gives the final conclusions, as well as suggestions for further research.

2 BACKGROUND

This chapter provides a political and technological overview, and considers the economics and cost classifications of wind power. A historical background of global developments is provided, before the three Nordic countries' general planning and regulatory frameworks, as well as financial supports, are presented.

2.1 Political Targets

Reduction of greenhouse gas emissions has become a major objective in most countries' energy and environmental policies. Looking at the framework for renewable energy, it usually contains government measures to improve the competitiveness of this industry. There are several reasons for supporting renewable energy, such as environmental and climate considerations, security of supply and reduced import dependence, and industry and business development.

Safe access to affordable energy is a prerequisite for economic stability and growth. The energy crisis in 1973 and 1978 highlighted the OECD countries' strong dependence on oil imports. The lack of competition and resource shortage in the oil market combined with high oil prices helped to focus on security of energy supply. Supply security and reduced dependence on imports are still a key issue for most countries (Fornybar, 2016).

Even though the use of oil and gas will continue to increase in the nearest future, the growth in renewable energy will be percentually higher (IEA, 2013a). Developing technologies that are capable of utilising national energy resources is a key measure to reduce import dependence. In most technology areas, the cost of new capacity is falling with increased production. This is due to increased efficiency, large scale production and learning effects (Fornybar, 2016).

The first legally binding global climate agreement, The Paris Agreement, came into force in November 2016, stipulating that the world should be emission-free by 2050 (GWEC, 2015; Regjeringen, 2016). The Global Wind Energy Council expects wind power to play an important part in achieving this goal, accounting for as much a 20% of the global electricity production in 2016, up from 7% at the end of 2013 (GWEC, 2016a).

The EU has increased its commitment to renewable energy and energy efficiency. Its so-called 20-20-20 targets within 2020 are (Fornybar, 2016):

- 20 percent of EU's energy production should come from renewable energy sources
- 20 percent increased energy efficiency from 1990 levels
- 20 percent reduced greenhouse gas emissions from 1990 levels

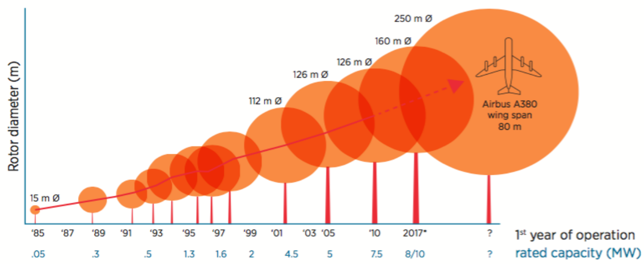
In order to achieve these targets, each member country is obliged to increase its renewable share. Wind power is a renewable energy source that can help to achieve these goals (Fornybar, 2016).

2.2 Wind Power

Electricity from wind is generated by transforming the kinetic energy of moving air into electrical energy by use of wind turbines (IRENA, 2016). These are often juxtaposed in so-called wind farms, most of which are connected to a power grid, which transmits the generated electricity to the end user.

The size of wind turbines has increased over the past 30 years. Larger turbines harness stronger winds, allowing them to produce more energy per unit of installation area. In addition, larger swept-areas enable more efficient production with higher wind speeds (IRENA, 2016). The historical growth of wind turbines, alongside projected future dimensions, is illustrated in Figure 1 below. The figure shows that the largest available wind turbines produce 8,0 MW. However, average capacity of newly installed wind turbines is now in the 1,5-3,0 MW range (Broehl, Labastida, & Hamilton, 2015; European Wind Energy Association, Europakommisjonen, & Intelligent Energy Europe, 2009).

Figure 1 - Growth in Capacity and Rotor Diameter of Wind Turbines



Source: (IRENA, 2016)

In the wind power industry, it is common to denote production from a wind turbine with "full load hours". Full load hours are a theoretical simplification of real production, given by Equation 1 below. This indicates how many hours the turbine must go on full power to produce the production target for a single year (NVE, 2016a). Normally, a turbine starts producing at a wind speed of 3-4 m/s and achieves maximal production around 11-15 m/s. With wind speed higher than 15 m/s, the turbine blades' rotational speed is automatically adjusted to avoid overload (NVE, 2015). Hence, the most attractive locations for wind power development projects are those with high and stable wind speeds throughout the year.

$$Full\ Load\ Hours = \frac{Annual\ production\ (MWh)}{Installed\ capacity\ (MW)} \tag{1}$$

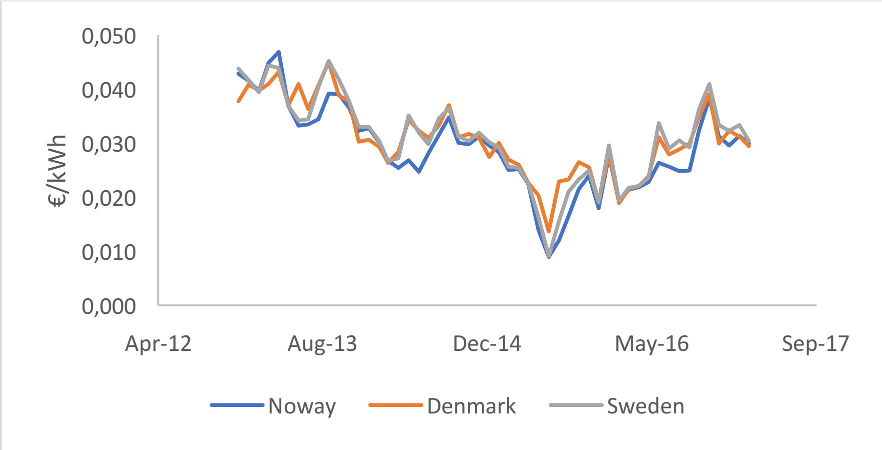
Full load hours have increased in recent years due to increased technology- and industry knowledge, as it depends on technology, resources, and efficient operation of the wind farm. Variables that contribute to high full load hours are large rotor diameters, small generators and high average wind at the site (NVE, 2016a).

2.3 Economics of Wind Power

2.3.1 Electricity Prices and Policy Instruments

Norway, Denmark and Sweden are all part of Nord Pool, the leading electricity market in Europe. Figure 2 below illustrates historical country-specific power prices from this market. It is evident that the price differences between the countries have been minimal over the past years. Furthermore, the figure shows that electricity prices are volatile and fluctuate with seasons.

Figure 2 - Historical Power Prices (Elspot) for Norway, Denmark and Sweden



Source: (Nord Pool, 2017b)

There are a number of mechanisms governments can utilise to promote the development of renewable energy resources. The main ones are listed in Table 1 below. Of these policy instruments, the financial support, such as Feed-in tariffs (FIT), Feed-in premium (FIP), Tradeable green certificates (TGC), and Capital subsidies are the most commonly used.

Table 1 - Overview of Policy Instrument

Feed-in Tariffs (FIT)	The producer gets a fixed price per unit of electricity fed into the power grid.
Feed-in Premium (FIP)	The producer gets a fixed premium on top of the electricity market price per unit of electricity fed into the power grid.
Tradable Green Certificates (TGC)	Electricity generators using renewable technology receive a certificate for each MWh of electricity generated. Further, these are sold to the electricity suppliers.
Capital Subsidies	Percentage subsidy on the initial investment that is given to reduce the costs of a technology, i.e., a direct subsidy.
Long-term Contracts	A contract to purchase electricity coming from wind power.
Priority Access	A guaranty that the wind power producers will have access to sell their electricity in the market place at all times.
Tax Credits	Some or all expenses associated with wind installation can be deducted from taxable income.
Financial Incentives	Investment support as a percentage of total costs, or as a predefined amount per installed kW.

Source: Adapted from (Bean, Blazquez, & Nezamuddin, 2017; European Wind Energy Association et al., 2009; IEA, 2015b; Timilsina, Cornelis van Kooten, & Narbel, 2013)

2.3.2 Cost of Wind Power

The total cost of wind power consists of direct costs, indirect costs and externality costs (see Table 2). From the perspective of a private investor, direct costs consist of investment costs, operational and maintenance costs (O&M), and decommissioning cost (Timilsina et al., 2013). These can account for as much as 80% of the economic total life cycle costs (Blanco, 2008), with the most significant factor being upfront costs needed to install the wind turbines (IRENA, 2012). Indirect costs consist of system costs, capacity factor and turbulence effects from other turbines (Timilsina et al., 2013). These comprise the remainder of the economic total life cycle costs (Blanco, 2008). Finally, externality costs refers to impacts on the noise pollution, adverse health effects, loss of visual amenities, impacts on wildlife and falling ice (Timilsina et al., 2013).

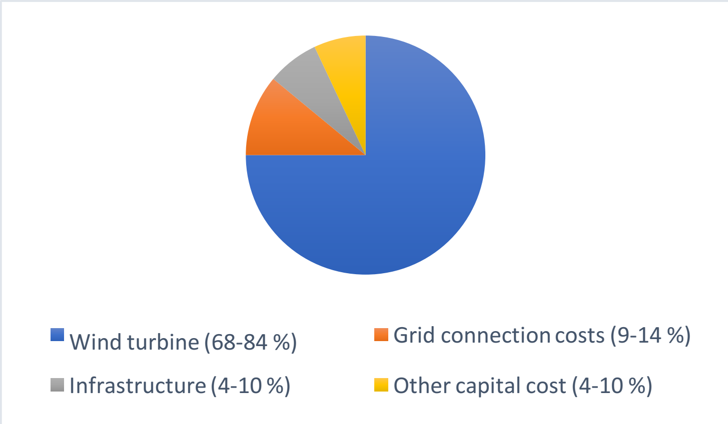
Table 2 - Costs of Wind Power

Direct Costs	Indirect Costs	Externality Costs
- Investment costs - Operational and maintenance (O&M) costs - Decommissioning cost	- System costs - Capacity factor (based on wind speeds and turbine availability factor) - Turbulence effects from other turbines	- Noise pollution - Adverse health effects - Loss of visual amenities - Impacts on wildlife - Falling ice

Source: Adapted from (Timilsina et al., 2013)

The investment cost for installing wind turbines can be broken down as shown in Figure 3 The cost of the wind turbine itself (production, transportation, installation) constitutes the largest share, at 68-84%, followed by grid connection costs (cabling, electrical work/lines, connection points, substations, and buildings) at 9-14%. Infrastructure (e.g. building roads) and other capital costs (development/engineering, licensing, permits) represent 4-10% each (IRENA, 2016).

Figure 3 - Investment Cost Breakdown for Typical Onshore Wind Power Project



Source: Adapted from (IRENA, 2016)

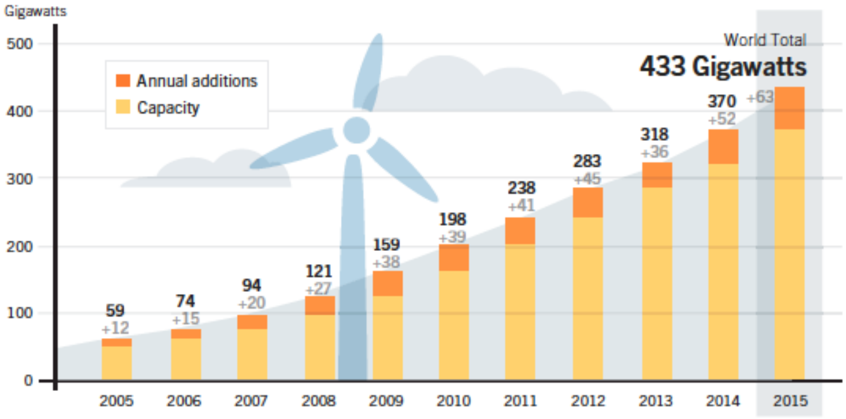
O&M costs can be split into fixed costs and variable costs. The fixed costs typically comprise wages, insurance- and administration costs, and service contracts for regular maintenance. The variable costs include unscheduled maintenance and replacement components (IEA, 2011b).

As a wind farm project reaches the end of its operational life, various options exist, including decommissioning, repowering or overhaul of the wind farm. If the land lease come to an end, decommissioning is most likely. This cost is related to total project costs and depends on the number of wind turbines installed and the geographical location (Aldén et al., 2014; Deloitte, 2014).

2.4 Wind Power in Global Energy Markets

Figure 4 below shows the annual wind power additions and capacity from a global perspective. In 2015, wind power was the leading source of new power generating capacity in Europe, the United States and Canada. As a result, more than 63 GW of wind power was added, reaching a total installed capacity of approximately 433 GW (REN21, 2016).

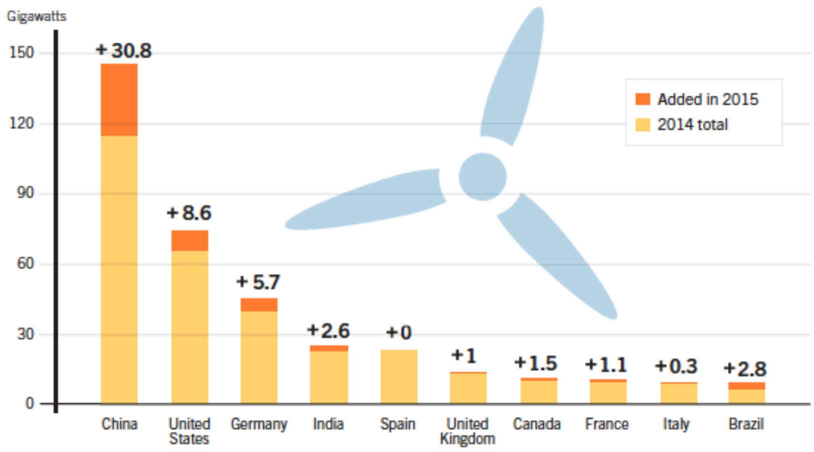
Figure 4 - Wind Power Global Capacity and Annual Additions, 2005-2015



Source: (IRENA, 2016)

Figure 5 below lists the top 10 countries with the highest wind power capacity in 2015. As can be seen, China dominates the global market; while Germany has the highest installed capacity in Europe, followed by Spain, the United Kingdom, France and Italy. In the EU, capacity in operation at the end of 2015 was enough to cover an estimated 11,4% of electricity consumption in a normal wind year (REN21, 2016).

Figure 5 - Wind Power Capacity and Additions, Top 10 Countries, 2015



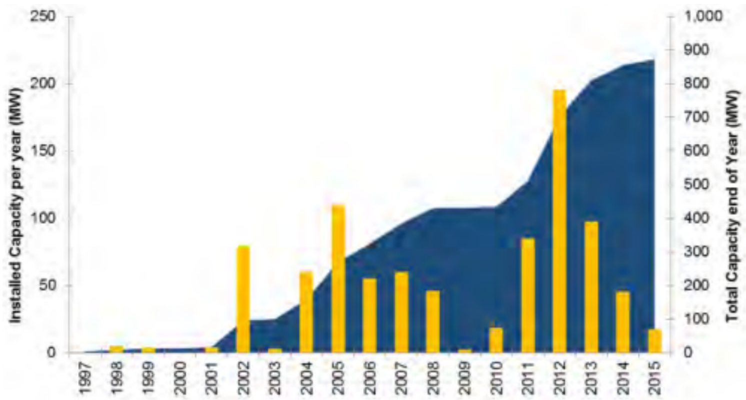
Source: (IRENA, 2016)

2.5 Wind Power in the Norwegian Market

Norway's electricity production is predominantly based on hydropower and is already a low-carbon market, with 96% of the electricity generated coming from hydropower (IEA, 2011c). However, when water reserves are too low, power is imported from coal-fired plants to meet the demand, resulting in emittance of CO_2. The Norwegian Government has committed to reduce greenhouse gas emissions by 30% by 2020, from 1990-levels, and become carbon neutral by 2050; wind power is seen as a potential contributor to achieving this goal (IEA, 2011c).

Norway has considerable potential of wind power production, both onshore and offshore. The Norwegian Water Resources and Energy Directorate (NVE) has calculated the onshore wind power potential to be approximately 250 TWh, all external factors excluded (Hofstad, Mølmann, & Tallhaug, 2005). Although the Norwegian Government advocates for increased investment in renewable energy, wind power production remains limited. As shown in Figure 6, the overall wind power production was 761 MW at the end of 2015, representing 1,4% of all electricity generated (GWEC, 2016a; NVE, 2017).

Figure 6 - Installed Wind Power Capacity in Norway



Source: (IEA, 2016b)

2.5.1 Wind Power Planning and Permitting

To construct and operate a wind farm, a licence from the authorities is needed. NVE is responsible for licence distribution in Norway, and reports to the Ministry of Petroleum and Energy (MPE). A licence is issued, on the basis of financial viability and environmental impact assessment, and gives the right, but not the obligation, to build and operate a wind farm for 25 years (Vindportalen, c). The lead time is extensive compared to Denmark and Sweden. According to Riksrevisjonen (2014) the process took 66 months on average between 2009-2013, while the average time in Denmark was 34 months, and in Sweden 14 months (Agency, 2015; Riksrevisjonen, 2014).

2.5.2 Financial Support

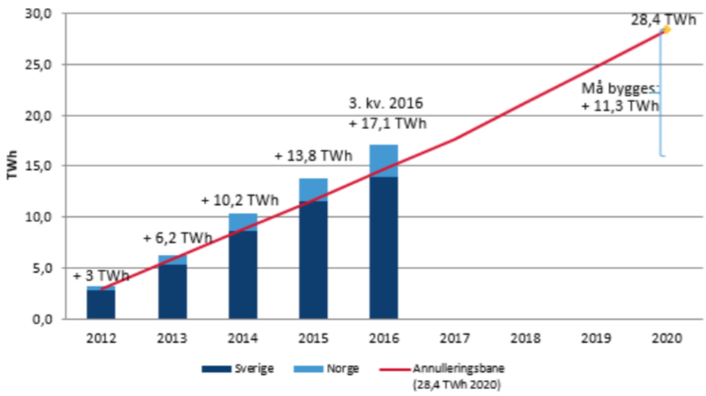
A climate policy was introduced in the late 1990s promoting energy efficiency and use of renewable sources. In 1999, the Norwegian Parliament set a target of 3 TWh onshore wind power produced to be reached by the end of 2010 (St.meld. nr. 29 (1998-99), 1999). NVE established direct investment support to achieve this goal, and in 2001, Enova (a state enterprise that was established by the Norwegian Parliament in 2001 to contribute to the conversion of energy consumption and energy production) took over the management of capital distribution.

Between 1999-2005, the supporting framework was limited, resulting in the realisation of only a few projects. Most of these were financed due to the Netherlands allowing foreign power plants to respond to national obligations for renewable energy (Enova, 2014). In 2006-2007, no projects were realised due to the uncertainty around future investment support, but in 2008, the Norwegian Energy Fund was allocated new capital. This led Enova to launch a new wind power program, contributing to the realisation a total of 1 TWh new wind power between 2008-2010 (Enova, 2014). Nonetheless, Norway did not reach the 2010-target and ended on approximately 1,6 TWh, mostly due to high project cost and low electricity prices (IEA, 2011c).

In accordance with EU's Renewable Energy Directive, there is set a Norwegian target increasing the energy coming from renewable sources to 67,5% by 2020, and as a contribution to meet this goal Norway entered the TGC market with Sweden in January 2012. The aim of the TGC market is to increase the combined electricity production from renewable sources by 28.4 TWh by 2020. Norway and Sweden is responsible for financing 13,2 TWh and 15,2 TWh respectively, regardless of where development and production takes place. Approved production put into operation by 2020 will receive TGC for 15 years (IEA, 2011c, 2015b; NVE, 2016c; Statnett, 2009).

Today, the Swedish market represents a larger part of the TGC market as shown in Figure 7 below. Market size, lower cost level, and maturity cause the differences. In addition, the regulatory frameworks has been more favorable in Sweden, especially for tax depreciation (Enova, 2014; NVE & Energimyndigheten, 2016).

Figure 7 - Installations Under the Joint TGC System



Source: (NVE & Energimyndigheten, 2016)

2.5.3 Depreciation

The common certificate market with Sweden has not boosted investment in wind power production in Norway. Although the two countries have virtually the same certificate price and electricity price, different tax depreciation rule has contributed to make Swedish projects more profitable. Formerly, the depreciation for Norwegian wind power plants corresponded with the expected economic lifetime of the assets. In Sweden, the assets for wind power farms depreciate consistently over a five-year period, i.e., the book value of the assets decrease to zero in 5 years (EFTA Surveillance Authority, 2016).

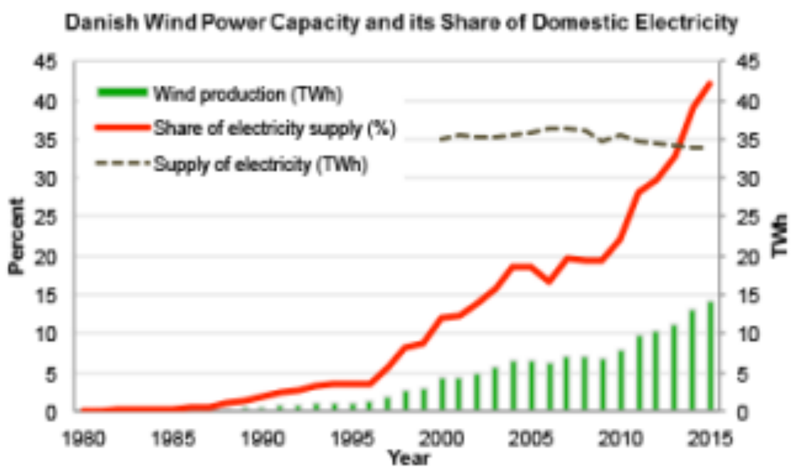
In July 2016, the Norwegian Government introduced a more favorable depreciation rule like the existing Swedish rule, which is expected to confer an economic advantage for wind power farm investors. The advantage consists in faster depreciation of the investments increasing the present value of the deductions from taxable income (EFTA Surveillance Authority, 2016; Prop. 120 LS (2014–2015), 2015).

2.6 Wind Power in the Danish Market

Denmark has a long history of wind energy, going hundreds of years back. However, the real commercialisation of the technology started after the oil crisis in the 1970s, when the country's first energy plan was implemented, in order to safeguard against future crises. At that time, 90% of Denmark's energy supply depended on imported oil (Vestergaard, Brandstrup, & Goddard, 2004).

Wind energy, and its efficient use, have played a central role in Danish energy policy for more than three decades. In 2015, the total installed wind capacity was 5 228 MW, accounting for approximately 42% of Denmark's electricity generation (GWEC, 2016b; IRENA & GWEC, 2012). According to Energinet (2016), this is the highest proportion ever achieved by a country. The Danish Government has set a target of 50% electricity production coming from wind power by 2020. This as a part of its long-term strategy to receive a 100% renewable energy mix in the electricity sector by 2035 (IEA, 2012). As shown by Figure 8 below, the share was approximately 2% in 1990 and 43% in 2015.

Figure 8 - Installed Wind Power Capacity in Denmark



Source: (IRENA & GWEC, 2012)

2.6.1 Wind Power Planning and Permitting

In Denmark, the respective municipalities are responsible for decisions regarding onshore wind turbine developments. The respective municipal plan sets out potential sites for wind turbines and a project developer must then apply for a licence to develop/operate a wind farm. On average, it takes 34 months from the application is submitted until it is approved/rejected. Public involvement is seen as important in Denmark, and as such, the approval process includes both public consultations and a public meeting. The level of public involvement in the past has led to a high degree of public acceptance for wind turbines, and the local community is often the driving force behind the developments (Agency, 2015; IEA, 2011a).

Moreover, the developer is obliged to sell shares constituting at least 20% of the project value (cost price). These can be bought by any citizen of age, who lives within 4,5 km. of the site. Another common way of local ownership is wind turbine cooperatives, meaning turbines are owned by private households. Local private ownership is argued to have contributed to the high level of social acceptance of wind power (Agency, 2015).

2.6.2 Financial Support

Denmark was the first European country to introduce large subsidies aimed at increasing the share of wind power in the energy mix. Since 1979, wind power projects have been given capital subsidy. This was introduced at a rate of 30%, and gradually reduced to 10%, before it was revoked in 1988 (Meyer, 2004). In 1993, Denmark introduced FIT, amounting to approximately 0,3 DKK/kWh. In addition, wind projects received a refund from the Danish carbon tax and a partial refund on the energy, which effectively doubled the income for the first five years. FITs were replaced by TGC in 2003 (Bolinger, 2001).

Between 2004-2008, the electricity market stalled before a FIP framework was introduced. Between 2009-2012 the premium added to the market price accounted for 0,25 DKK/kWh for the first 22 000 full load hours. In addition to this, the producer got a compensation of 0,023 DKK/kWh to cover balancing costs (GWEC, 2010). As wind conditions vary and are difficult to predict, deviation between expected and actual production can occur. In case of deviation, the wind power manufacturer must enable/disable another production or trade in the marketplace to produce the right level of output. Hence, balancing cost refers to the increased cost of maintaining system balance (EWEA, 2015).

Onshore projects receive (as per May 2017) a premium on top of production costs of 0,25 DKK/kWh for the sum of 6 600 full load hours, set to zero if the electricity price and the premium exceeds 0,58 DKK/kWh. Plus, 0,013 DKK/KWh for covering the balancing costs for 20 years from the date of connection (Lov om fremme af vedvarende energi, 2017).

2.7 Wind Power in the Swedish Market

Following the 1970s oil crisis, Sweden started to search for alternative energy sources. At that time, oil supplied more than 75% of Sweden's energy demand; today, approximately 20% - a reduction mainly due to the reduced usage of oil for residential heating (sweden.se, 2016). The Swedish Government has invested heavily in renewable energy sources over the past 40 years. This resulted in having a 50% share of electricity coming from renewables in 2012 (Swedish Cleantech). Further, the Swedish Government has set an energy goal of 100% renewable electricity production by 2040 (Government Offices of Sweden, 2016).

Figure 9 shows the installed wind power capacity in Sweden from 1991-2015. Between 2007-2015, the electrical supply from wind power expanded rapidly, resulting in a total increase of approximately 5 250 MW. In 2015, the total installed wind capacity was 6 000 MW, representing 12,2% of Sweden's electricity consumption. The Swedish Government has set a target for increasing wind power production to 30 TWh by 2020; 20 TWh onshore and 10 TWh production offshore (IEA, 2016a).

Figure 9 – Installed Wind Power Capacity in Sweden

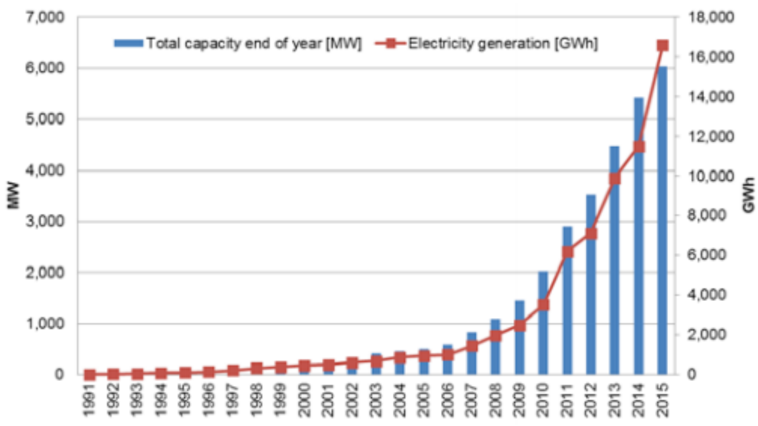


Figure 1. Installed wind power capacity in Sweden 1991 to 2015

Source: (IEA, 2016b)

2.7.1 Wind Power Planning and Permitting

The Swedish local municipalities are included in all types of wind power development, either as a consultant or as the final decision maker, depending on the height and quantity of the installed wind turbines. For small and medium-sized installation, the municipalities are responsible for granting permits. Wind turbines taller than 150 m, or wind farms with more than six turbines taller than 120 m, need a permit according to the Swedish Environmental

Code. However, the municipalities must also approve the project, and have veto power with respect to establishment (Stockholm Environment Institute, 2013). According to Riksrevisjonen (2014), it takes on average 14 months to reach a decision in a wind power application (Riksrevisjonen, 2014).

2.7.2 Financial Support

Since 1994, small-scale renewable energy production was given tax credits of 0,1-2,0 SEK/kWh (IEA, 2014). This practice was replaced in 1998 by FIPs of 0,09 SEK/kWh (IEA, 2016b). In May 2003, a system of TGC came into force, aiming to ensure a predetermined market for renewable power sources, and promote a cost effective competition between the different types of renewable energy sources (IEA, 2015b; Meld St. nr. 2002/03:40, 2003).

2.8 Cross-country Comparison

Table 3 summarises the differences in installed capacity, financial support and the average lead time in the three countries, as explained above. As can be seen from the table, there are large differences between the country's installed capacity, as well as the average lead time. The differences between TGC and FIP and how they impact the simulated project will be further addressed later in this study.

	Installed Capacity at the End of 2015	*Financial Support*	*Average Lead Time*
Norway	761 MW	TGC	66 months
Denmark	5 228 MW	FIP	34 months
Sweden	6 000 MW	TGC	14 months

Table 3 - Wind Power Development, Policy and Planning in the Nordic Countries

3 PREVIOUS RESEARCH

Most of the current research on policy instruments promoting renewable energy development highlights the results of specific financial support mechanisms (Toke, Breukers, & Wolsink, 2008). However, M. Petterson et al (2010) finds that the financial support design only partly explains the differences in national wind power capacity, and that success cannot necessarily be transferred across borders. Hence, the similar financial support will yield different results, depending on local conditions (Pettersson et al., 2010).

3.1 Investment in Wind Power

Compared to Denmark and Sweden, Norway has the most favourable wind conditions, but still the lowest investment in wind power. Blindheim (2016) concludes that the Norwegian renewable politics has not contributed to enhance investments in wind power. He argues that policy changes would contribute significantly to develop the wind power markets in Norway (Bernt Blindheim, 2016).

Another important factor is investors' access to capital. The Norwegian electricity market is dominated by publicly owned power companies who own about 90% of the total production capacity (Olje- og energidepartementet, 2013). This ownership structure, coupled with limited investment funds, have contributed to the prioritisation of hydropower, which gives greater value to the local owners; the tax regime for hydropower ensures significant revenue to the municipalities. Wind power on the other hand does not contribute accordingly (Bernt Blindheim, 2016). Disregarded these conditions, profitable projects will usually be financed either by borrowing or other types of investors equity, such as foreign power companies or pension funds.

3.2 Wind Power Planning and Permitting

In a comparative study M. Pettersson et al (2010) analyses institutional and legal differences in wind power planning and permitting. They found that the Danish and the Norwegian planning system give better integration of wind power policy at a local level compared to Sweden. Both the Danish and the Norwegian system have a hierarchical structure of the planning process. In Denmark, the national planning system is vertically integrated and includes a designation of areas for wind power purposes in the local plans. The Norwegian system is also vertically integrated in the sense that the Norwegian Government set goals and guidelines for the planning and location of wind turbine installation. These are further integrated at the regional and local level. In Sweden, however, the strong municipal position through municipal monopoly prioritising local impacts (e.g., visual interference), ignoring national and global energy policy objectives, is seen as a barrier for development (Pettersson et al., 2010). Buen (2006), however, finds that policies in Norway have been weaker and less stable over time compared to Denmark. In Norway, development has been motivated by short-term views rather than long-term stimulation (Buen, 2006).

Blindheim (2015) argues that the Norwegian licensing process is difficult to understand from the investor's point of view, which in turn could influence the willingness to go into, remain and invest in the market (Bernt Blindheim, 2015). Riksrevisjonen (2014) has investigated the licensing process in Norway for the period 2010-2013. Table 4 shows average lead time in Norway, Denmark and Sweden. The analysis mentions lack of grid capacity as a bottleneck causing the long lead time in Norway. Additionally, the guidelines and routines for early rejection of unrealistic wind power cases are emphasised as an important factor leading to an inefficient system (Riksrevisjonen, 2014).

Table 4 - Average Lead Time

Norway	66 months
Denmark	34 months
Sweden	14 months

(Agency, 2015; Riksrevisjonen, 2014)

3.3 Financial Support

Toke et al. (2008) argue that the country's financial support contribute to differences in wind power development. Literature suggests that FIT and FIP, as seen in Denmark, are the most effective policies to stimulate rapid development of renewable energy (Toke et al., 2008). This is further supported by the European Commission (2008) concluding that “well-adapted feed-in tariff regimes are generally the most efficient and effective support schemes for promoting renewable energy” (European Commission, 2008). It is argued that FIT and FIP create lower risk for the investor and greater predictability of future cash flows (Couture & Gagnon, 2010; Mitchell, Bauknecht, & Connor, 2006).

Menanteau et al. (2003), however, claims that TGC as seen in Norway and Sweden, is more efficient than FITs and FIPs because it facilitate for the cheapest renewable energy technology and best locations to be developed first (Menanteau et al., 2003). The main drawback with this financial support is the volatility of the certificate price and its negative effects on investors, which happens if the market is limited and lacking liquidity due to a small number of participants (Morthorst, 2000).

In a comparative study of the cost of renewable energy policy options in Spain, Bean et al. (2017) find the use of capital subsidy to be the most effective option for society to promote wind technology without risking total costs fluctuating with electricity prices. They argue that a capital subsidy yields the same results as other financial support options, such as FITs and FIPs, but at a cheaper cost. However, FITs and FIPs are still the preferred options for private investors, given lower volatility and greater predictability of future cash flows (Bean et al., 2017).

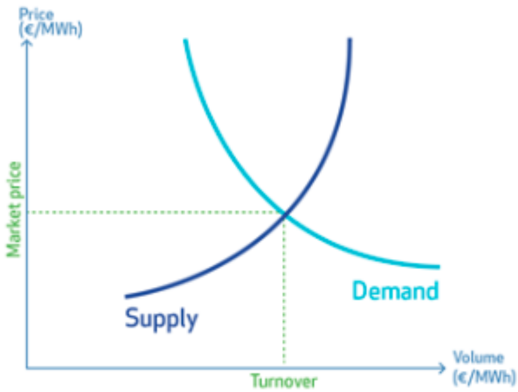
4 THEORY AND MODELLING TOOLS

This chapter presents theories and modelling tools forming the further analytical basis of this study. First, the price formation in the electricity market is presented. Second, the experience curve, demonstrating how costs decline with cumulative production. Third, the Levelized Cost of Energy model, comparing energy generating technologies. Fourth, Net Present Value analysis - demonstrating the profitability of an undertaking, used to rank projects against each other. Last, the theory of risk analysis including sensitivity analysis and Monte Carlo simulation is presented; these are important supplements to the profitability analysis, accounting for uncertainties and risks not included in the NPV model.

4.1 Price Formation in the Electricity Market

The Nord Pool market offers both day-ahead and intraday markets to its customers. The day-ahead market is the main arena for trading, where price is given by a balance of demand and supply, as shown in Figure 10.

Figure 10 - Price Formation in Elspot Market



Source: (Nord Pool)

The day-ahead market is ensured balanced by the supplementary intraday market. For example, if a wind power plant cannot produce because of too low wind speeds, or because too high wind speed forces the plant to stop the production, imbalance occurs. By allowing adjustment of the bids closer to delivery time, the Nord Pool market is brought back in balance. Hence, as more wind power enters the grid, the intraday market becomes more important. Compared to the day ahead market where the prices are set based on the supply and demand, the price in the intraday market are set based on the best prices. That means the highest buy price and the lowest sell price (Nord Pool).

Forward and futures contracts are common mechanisms to manage risk associated with electricity prices. A forward contract is an agreement to buy or sell an asset at a certain future time for a certain price. A futures contract is a standardised agreement to buy or sell an asset at a certain future time for a certain price (McDonald, 2014). Figure 11 shows how the contract prices are determined by the intersection of the aggregated supply and demand curves. The aggregated curves include all purchase and sell orders for each delivery hour for a bidding area (Nord Pool). Norway, Denmark and Sweden are all part of the Nordic bidding area.

Figure 11 - Price Formation of System Price

Source: (Nord Pool)

4.2 Experience Curve

The overall learning effect gained from technology improvements and experience can be explained by the aggregated experience curve. This presents how costs decline with cumulative production. The Experience Curve may apply at a company level, industry level, as well as a combination of the two. In this study, the Experience Curve is assumed to apply at an industry level. In reality, the aggregated experience curve consists of individual learning systems. As an example, wind turbine technology can be divided into learning systems for design and development, and installation. These can again be divided into learning within design of rotor blades, towers and nacelles, and for learning in the construction of foundations, infrastructure, network connection and cabling (NVE, 2015). If the intention is to better understand which parts of the production chain that drives the cost of wind power, it would be necessary to break up the aggregated experience curve into these different learning systems. However, this study focuses mainly on the overall cost.

The experience curve is expressed as follows (Bye, Greaker, & Rosendahl, 2002):

$$k(t) = K_0 \times x(t)^{-E} \tag{2}$$

$k(t)$ = cost per unit at time t, where t is the number of years
$x(t)$ = cumulative production at time t
K_0 = cost per unit for the first unit (when the accumulated production = 1)
E = degree of learning

In logarithmic form, Equation 2 above is expressed as follows:

$$\ln k(t) = \ln K_0 - E \times \ln x(t) \tag{3}$$

In this form, the experience curve is illustrated as a straight line in a graph with logarithmic axes. However, this does not take into account that learning and experience may, in reality, decrease over time. The slope of the experience curve, called Progress Ratio (PR), expresses the development of cost reduction for wind power technology:

$$PR = \frac{K_0 \times [2 \times x(t)]^{-E}}{K_0 \times [x(t)]^{-E}} = 2^{-E} \tag{4}$$

PR = progress ratio
K_0 = cost per unit for the first unit (when the accumulated production = 1)
$x(t)$ = cumulative production at time t
E = degree of learning

The PR is used to find the learning rate (L = 1- PR), which expresses the percentage fall in unit costs when the accumulated production doubles, i.e. the «improvement of the wind technology» (NVE, 2015). For instance, a PR of 0,9 gives a learning rate of (L = 1-0,9 = 0,1) 10%.

4.3 Levelized Cost of Energy

Levelized Cost of Energy (LCOE) is a commonly used measure to calculate the cost of electricity produced by a generator, and enables a financial comparison of various energy generating technologies of different time periods and capacities (Dyesol, 2011; Renewable Energy Advisors, 2017).

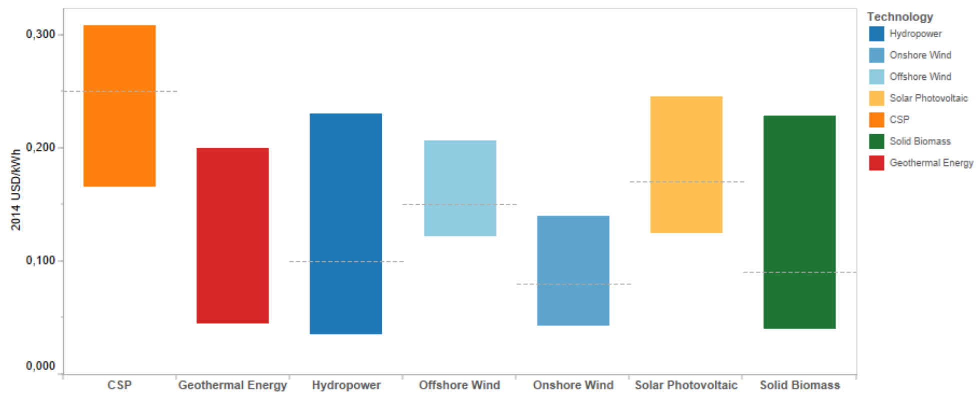
LCOE is calculated by summing all the discounted costs incurred, divided by the units of energy produced, over the lifetime of the project, (Dyesol, 2011):

$$LCOE = \frac{\sum_{t=0}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+r)^t}} \tag{5}$$

I_t : Investment and development costs
M_t: Operating and maintenance costs
F_t: Energy and fuel costs
E_t: Energy produced
n: Economic lifespan measured in years
r: Discount rate

One can argue that the profitability of wind power has been caused by generous financial support. However, as this technology matures, the support will be reduced, and wind power will be directly exposed to market competition. This makes it interesting to assess the cost competitiveness of wind power compared to other available sources of power generation. Figure 12 below shows the LCOE of renewable technologies in Europe in 2014. Although building a wind farm is capital intensive, wind power had the lowest LCOE on average indicating that wind power had the highest likely returns for the investors (IRENA, 2014).

Figure 12 - LCOE for Different Energy Generating Technologies in Europe



Source: (IRENA, 2014)

Theoretically, LCOE can be used to compare the simulated project in the represented countries having the same conditions and restrictions. LCOE gives the value of the unit-cost of wind power in net present value terms, which again can be compared to the electricity price. If the electricity price exceeds the LCOE, the project is said to have reached grid parity (Vindportalen, b). Reaching grid parity, the technology is considered profitable without investment subsidies (Renewable Energy Advisors, 2017). However, LCOE does not quantify the value of the simulated project. Hence, for this study Net Present Value will provide a better model assessing the profitability of these projects.

4.4 Net Present Value

Net Present Value (NPV) is regarded as the most representative measure of financial performance considering both the investment size and the time value of money. NPV is related to net cash flows and discount rate and is calculated as follows (Duffy, Rogers, & Ayompe, 2015):

$$NPV = F_0 + \frac{F_1}{(1+r)^1} + \frac{F_2}{(1+r)^2} + \cdots + \frac{F_N}{(1+r)^N} = \sum_{n=0}^{N} \frac{F_{n,n}}{(1+r)^n} \qquad (6)$$

$F_{n,n}$ = net cash flow in year n

N = project lifespan

d = annual discount rate

A wind power project is attractive to the investor when the NPV is positive, giving a return greater than the required discount rate. This would be equivalent to receive the NPV in cash today (Berchtold, 2007).

Generally, long-term cash flow models can be limited, resulting in inaccurate future estimates. However, cash flows from wind power projects are often relatively accurate, due to investment cost being front-loaded and mean wind speed are known early on. In addition, wind power projects have low variable O&M costs, no carbon emissions costs or fuel costs (IEA, 2011b).

4.4.1 Cash Flow

In financial appraisal of wind power projects, cash flows are the most important inputs and can be categorised into three categories: investment cash flows, cash inflows and cash outflows. The sum of the three cash flows is the net cash flow (Duffy et al., 2015). Incremental cash flows are considered, meaning that sunk costs and opportunity costs are ignored:

$$F_{\mathrm{n},n} = F_{\mathrm{i},n} - F_{\mathrm{o},n} - F_{\mathrm{c},n} \tag{7}$$

$F_{\mathrm{n},n}$ = net cash flow in investment year *n*

$F_{\mathrm{i},n}$ = cash inflows in year *n*

$F_{\mathrm{o},n}$ = cash outflows in year *n*

$F_{\mathrm{c},n}$ = investment cash flow in year *n*

For a wind power project the cash inflow results from the sale of energy and financial support granted, while cash outflows result from investment costs, O&M costs and decommissioning cost. Moreover, the positive tax effects of depreciation must be included.

4.4.2 Depreciation

Depreciation has an impact on cash flows and is an important consideration in capital-intensive investments such as wind power project. The value of the wind turbine diminishes throughout its lifespan, becoming worthless at the end of its operational life. As the annual depreciation can be written off against corporate tax liabilities, it results in increased project cash flows in the relevant year. By comparing Norwegian and Swedish wind power projects, Enova (2014) found that depreciation resulted in a tax benefits amounting to 0,04-0,06 NOK/kWh in disfavor to Norwegian projects, equivalent to approximately 15% higher production per wind farm (Enova, 2014).

4.4.3 Discount Rate

The cost of capital for a project is the return necessary to attract investors, and should be consistent with the riskiness of the investment. When discounting the cash flow paid to equity and debt holders, the weighted average cost of capital (WACC) should be used. This approach reflects the average risk of the investment (Berk & DeMarzo, 2013):

$$WACC = \left[\frac{E}{E+D} r_E\right] + \left[\frac{D}{E+D}(1 - T_c) r_D\right] \tag{8}$$

r_E = returns on equity
r_D = the returns on equity
E = amount of equity
D = amount of debt
T_c = corporate tax rate

In order to find the required return on equity, the Capital Asset Pricing Model (CAPM) is the most common method used in practice. CAPM assumes that the players in the financial markets want to diversify to the point where they are left with systematic risk (the risk that cannot be diversified away). In this way, the cost of capital required by an investor will only reflect the systematic risk (Berk & DeMarzo, 2013):

$$r_E = r_f + \beta(r_m - r_f) \tag{9}$$

r_f = the risk-free rate
β = systematic risk
$r_m - r_f$ = market risk premium

Government bonds are often used as the risk-free rate. Theoretically, this is only correct if there is no risk of default and no risk of reinvestment related to this bond. Moreover, the duration of the bond matters, and the time-horizon should be the same as for the cash-flow. Further, (r_m –

r_f) equals the additional rate of return on investment over the risk-free rate; i.e., the extra return demanded by investors for taking on a risky project (Berk & DeMarzo, 2013).

In the CAPM model, the risk component measures the projects volatility in relation to the market, i.e. the project's sensitivity to the market risk is defined as (Berk & DeMarzo, 2013):

$$\beta = \frac{Corr(r_x, r_m) \times SD(r_x)}{SD(r_m)} \tag{10}$$

$Corr(r_x, r_m)$ = correlation of the investment in relation to the market
$SD(r_x)$ = volatility of the investment
$SD(r_m)$ = volatility of the market.

In practice, Equation 10 assumes that the company is publicly traded and relevant market data is available. However, if the company is not publicly traded, a common method is to look at comparable companies operating in the same market as a benchmark. In this case, regression betas from other publicly traded companies in the same market are collected. These are further used to estimate an unlevered beta for the undertaking being analysed, reflecting its operating leverage (Damodaran, 2012):

$$Unlevered\ \beta_{buisness} = \frac{\beta_{comparable\ companies}}{\left[1 + (1-t)\left(\frac{D}{E} ratio_{comparable\ companies}\right)\right]} \tag{11}$$

If β equals 1, the investment has the same systematic risk as the market, while a β equal to 2 indicates that the investment has twice as much systematic risk as the market. Further a β of -1 indicates that the investment has a reverse relation to the market – doing better when the market declines.

4.5 Sensitivity Analysis

Electricity generation projects require significant irreversible capital investments. They also encompass uncertainties from changing technologies, fluctuating demand, liberalisation of electricity markets, and stricter environmental protection regulations (Khindanova, 2013). These risks are not considered in common capital budgeting methods such as NPV analyses. To get an overview of the most critical aspects of a project, a sensitivity analysis should be conducted. The sensitivity analysis shows how the NPV varies with changing underlying assumptions (Berchtold, 2007). To run a sensitivity analysis, the first step is to identify the expected cash flow by establishing a base-case scenario reflecting the most probable outcome. Further, optimistic and pessimistic outcomes are considered, before the fluctuations of the NPV is investigated for inaccurate forecasts and risk analysis/mitigation.

Such an analysis can provide a good overview of which variables need close monitoring (Brealey, Myers, & Allen, 2007). However, the method does not take into consideration interrelating underlying variables. For example, the TGC price may be correlated to the electricity price.

4.6 Monte Carlo Simulations

A Monte Carlo (MC) simulation considers multiple sources of uncertainty and their interrelationship. The simulation involves *"describing uncertainty of inputs with probability distributions, repeated generation of random values from the input distributions and simulations of the output"* (Khindanova, 2013). This results in a probability distribution of the output. The distribution permits a deeper investment appraisal compared to a single point estimate of the output, such as a sensitivity analysis. MC simulation enables to estimate not only a standard deviation, but also additional risk measures (skewness and behavior in the distribution tails) and probabilities of extreme output values (Khindanova, 2013). With this in mind, a MC simulation should be conducted as a supplement to the sensitivity analysis.

5 THE DATA SET

Following the theoretical presentation of the NPV-analysis, this chapter introduces the simulated project for analysis. Subsequently, underlying assumptions and inputs used are presented. The inputs included in this financial analysis are costs and revenues, depreciation and taxation, and discount rate. The International Energy Agency's Wind Task 26 – a case study report describing the cost elements of typical wind energy facilities in the members' countries – is used as a basis. The report consists of average numbers for wind farm projects planned or commissioned in 2008 and 2012 which can be compared across the three countries. This makes Wind Task 26 a good basis for the analysis.

5.1 The Simulated Project

The number of wind turbines in a wind farm commonly varies from project to project, and country to country. The average number of wind turbines in a wind farm was in 2012 in Norway 24, in Denmark 4, in Sweden 41. In Denmark, there exists many cooperatives owning a single wind turbine or two, which lowers the average country-specific number (IEA, 2011b, 2015a). For this financial analysis, the simulated project consists of 10 wind turbines with a capacity of 3 MW each, giving a total installed capacity of 30 MW. The lifespan of the project is set to 20 years – the expected technical lifetime of a wind turbine (NVE, 2015).

5.2 Assumptions

The assumptions made for the NPV-analysis are listed below:

- The investment cost is paid as a whole at the beginning of the project, i.e. year 0. The economic calculations (depreciation, etc.) thus starts from year 1
- Inflows and outflows happens once a year.
- There are no reinvestments during the analysis period.
- All variables used in the analysis are given in nominal numbers.
- All currencies are converted into euros (€).

5.3 Revenue Estimates

5.3.1 Annual Production

The annual level of production varies considerably from year to year due to variations in meteorological conditions. Nevertheless, the expected annual production is found by rearranging Equation 1 presented in Chapter 2:

$$Annual\ Production\ (MWh) = Full\ load\ hours \times Installed\ capasity\ (MW) \qquad (12)$$

Table 5 below list the full load hours from Wind Task 26. The average Norwegian wind power farm in normal operation in 2008 produced 2 800 full load hours, in Denmark 2 963, and in Sweden 2 600 (IEA, 2011b, 2015a). Table 5 shows an increase in full load hours for both Norway and Denmark in 2012 suggested to stem from technology improvements and better industry knowledge. The full load hours in Sweden in 2012 is not included in Wind Task 26, it has hence extrapolated based on the average growth of the other countries.

Considering further technology improvements, the full load hours averages are expected to be higher today compared to the 2012-numbers. However, in some countries there are resource scarcity i.e. sites with the best wind resources have already been developed. This does not hold for Norway, where the country's geography indicates high potential of developing more wind farms. Hence, Norway is expected to have the highest increase in the full load hours from 2012-2017, adjusted to 3 200 in this study. For the wind farm in Denmark, full load hours are set to equal the 2012-number of 3 000, which assumes that areas with the highest annual average wind speeds already have been developed. Lastly, full load hours for the Swedish project is adjusted to 2 900 indicating a slightly growth from 2012.

Based on full loads hours and the chosen wind-farm capacity of 30 MW, the annual production for the simulated projects in Norway, Denmark and Sweden are calculated to be 96 GWh, 87 GWh, and 90 GWh, respectively.

Table 5 - Wind Power Projects Features in Norway, Denmark and Sweden

		Norway			Denmark			Sweden		
		2008	*2012*	*2017e*	*2008*	*2012*	*2017e*	*2008*	*2012e*	*2017e*
Production	*full load hours*	2 860	2 963	3 200	2 700	3 000	3 000	2 600	2 800	2 900

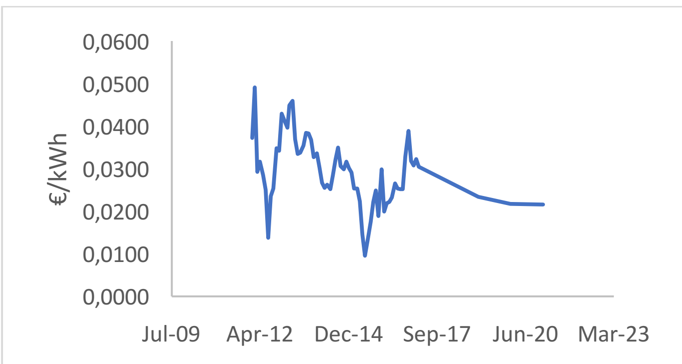
Source: Adapted from (IEA, 2015a) & (IEA, 2011b)

5.3.2 Electricity price

Figure 13 below illustrates historical system prices of electricity (the reference price for all financial instruments) and forward prices on the Nordic power exchange. As shown, these have fluctuated from 0,049 €/kWh in 2012 to 0,010 €/kWh in 2015. In addition to market demand, these prices depend on climatic conditions (temperature, precipitation, and wind), as well as the interconnections between countries and economic growth (Statnett, 2014).

The three forward contracts included in Figure 13 are obtained from NASDAQ OMX (2017,03.04). These contracts shape a downward sloping forward curve, also known as backwardation. The rational expectation theory seeks to explain this phenomena, stating that the future price is equal to the future spot price. Hence, the decline is an expectation of lower price, due to lower demand or higher supply, in the future. In other words, the market expects a future decrease in the system price (McDonald, 2014). In this study, the electricity price is assumed to follow the price developments indicated by the forward prices - thus to stabilise at 0,022 €/kWh. Thus, the electricity price will only increase with the inflation in the countries being analysed, through the lifespan of the projects.

Figure 13 - Historical System Prices and Forward Prices



Source: (Nord Pool, 2017b) & (NASDAQ OMX, 2017,03.04)

5.3.3 Financial Support

Norway, Denmark and Sweden have structured their financial support through different mechanisms. Today, Denmark uses an FIP structure with a premium of 0,034 €/kWh for the first 6 600 full load hours, with an upper limit for the unit compensation (price + premium) of 0,074 €/kWh. The producer further gets a compensation of 0,002 €/kWh to cover balancing costs (converted to EUR using the exchange rate at 04.05.17 (XE Live Exchange Rates, 2017)).

Norway and Sweden however, are part of a common TGC market. Figure 14 below shows historical prices of the TGC, and the forward prices traded on Svensk Kraftmäkling. These are converted into EUR using a historical average of the exchange rate over the past 10 years (Ref. Appendix B). The trend shows a decline from 0,035 €/kWh in January 2009 until the current price of 0,008 €/kWh. This corresponds to a percentage decline of 78%, which can be explained by a lot of foreign investment capital. International investors are increasingly entering licence projects in Norway and Sweden, despite the low combined sum of power prices and TGC prices. Some argue that if the TGC market is not expanded, over-investment may lead to surplus of certificates with following price collapse (Norwea, 2016).

The forward contracts prices indicate that the price of the TGC is expected to remain stable around the current level. For the simulated projects, TGC prices are set to 0,007 €/kWh in 2017 for Norway and Sweden and will further increase by the general rate of inflation through the lifespan of the projects.

Figure 14 - Historical Spot Prices and Forward Prices for TGC

Source: (Svensk Kraftmâkling, 2017a) (Svensk Kraftmâkling, 2017b)

5.3.4 Summary of Revenue Estimates

The revenue is given by the total energy sales in one year and can be calculated as follows:

$$Revenue = (Price + Financial\ support) \times Annual\ production \qquad (13)$$

The total price is the sum of the estimated electricity price, and the additional financial support achieved through TGC in Norway and Sweden, and through FIP and the compensation to cover balancing cost in Denmark. These variables are summarised in Table 6 below.

Table 6 - Factors Affecting Revenue

	Norway (2017e)	*Denmark (2017e)*	*Sweden (2017e)*
Annual Production (kWh)	96 000 000	90 000 000	87 000 000
Electricity Price (€/kWh)	0,022	0,022	0,022
TGC Price (€/kWh)	0,007	-	0,007
FIP (€/kWh)	-	0,034	-
Compensation to Cover Balancing Cost (€/kWh)	-	0,002	-

5.4 Cost Estimates

5.4.1 Investment Cost

In the NPV-analysis, the upfront investment cost is not subject to discounting. Hence, the investment cost has a direct effect on the NPV. This, in addition to its relative size, makes the investment cost the most important one. As shown in Table 7, Sweden had the highest investment costs in 2008 of 1 591 €/kW. Albeit Swedish wind farms constituted the highest number of wind turbines, the high investment cost suggest that economies of scale were not leveraged. In Norway, the investment cost increased from 1 386 €/kW in 2008 to 1 592 €/kW in 2012 due to, at least in part, to the financial support given. As the financial support increased in 2008, the developers did not have the same incentive to keep the costs low compared to projects sanctioned earlier (IEA, 2015a).

Denmark had the lowest investment costs both in 2008 and 2012 of 1 475 €/kW and 1 273 €/kW respectively. In Denmark, the grid companies pay the costs of connecting the wind turbines to the power grid as long as the area is regulated as a wind turbine area. This reduces the overall project costs for the developer substantially. Also, Denmark is a flat country with little height variation, resulting in more favorable geographical conditions compared to Norway and Sweden. This, as well as a strong, local turbine manufacturing industry and an experienced project development sector, has contributed to lower investment costs (IEA, 2011b).

Normally, the cost of technology declines as it matures, and experience and competition increase. This applies for wind technology as well (NVE, 2015). Cost decline is estimated using the experience curve. As can be seen from Table 7 below, investment cost for Sweden in 2012 are lacking. This has therefore been estimated before including Sweden in the estimation from 2012-2017.

Table 7 - Investment Cost for Wind Power Projects Features in the Nordic Countries

		Norway		*Denmark*		*Sweden*	
		2008	*2012*	*2008*	*2012*	*2008*	*2012*
Investment Costs	*€/kW*	1 386	1 592	1 475	1 273	1 591	N/A

Source: Adapted from (IEA, 2015a) & (IEA, 2011b)

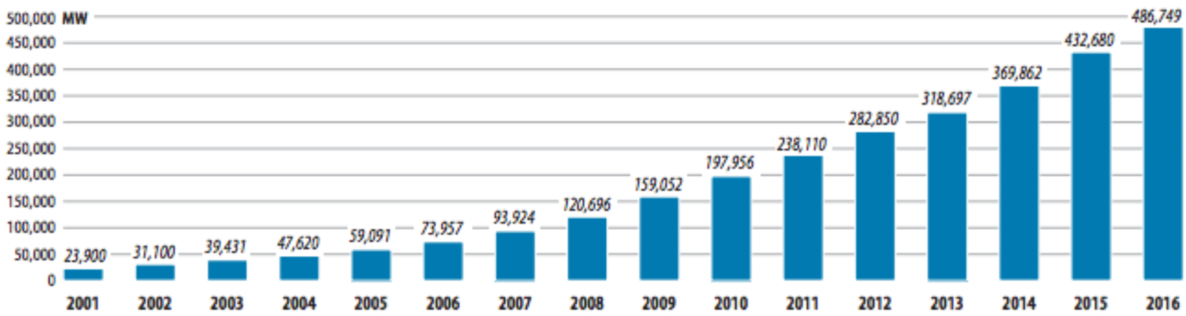
5.4.1.1 The Experience Curve

As shown in Equation 2 in Chapter 2, the accumulated production x(t) at time t, and the degree of learning, E forms the basis of the experience curve. The degree of learning, E is calculated using the learning rate. The most relevant is to look at the global market, in accordance with NVE recommendations, arguing that wind power is a global industry where turbine prices converge, and technological diffusion occurs rapidly between countries manufacturers and installers. As the learning curve should reflect the global market, the accumulated wind power should do the same (NVE, 2015).

5.4.1.2 The Global Accumulated Wind Power Capacity x(t)

The global accumulated production is assumed to equal the global accumulated installed wind capacity. As shown in Figure 15 below, the cumulative capacity has increased significantly over the past sesquidecade. From 2012 to 2016 the cumulative installed capacity increased from 282 850 MW to 486 749 MW, with the annual growth rate varying between 32% and 12%. Based on annual growth rates, the average annual increase in cumulative capacity between 2008-2012 and 2012-2017 is calculated to be 24% and 15% respectively (Ref. Appendix C).

Figure 15 - Global Cumulative Installed Wind Power Capacity 2001-2016



Source: (GWEC, 2016b)

5.4.1.3 The Learning Rate (L):

The appropriate learning rate for manufacturing and installation of wind turbines is given by existing literature. Based on a review of historical and projected learning rates, NVE (2015) uses a constant learning rate of 10% for 2014-2020 (NVE, 2015). Lemming et al. (2008), basing their research on historical development of capacity and costs, concludes using the same 10% in their calculations (Lemming et al., 2008). This study hence assumes a learning rate of 10%.

5.4.1.4 The Degree of Learning (E):

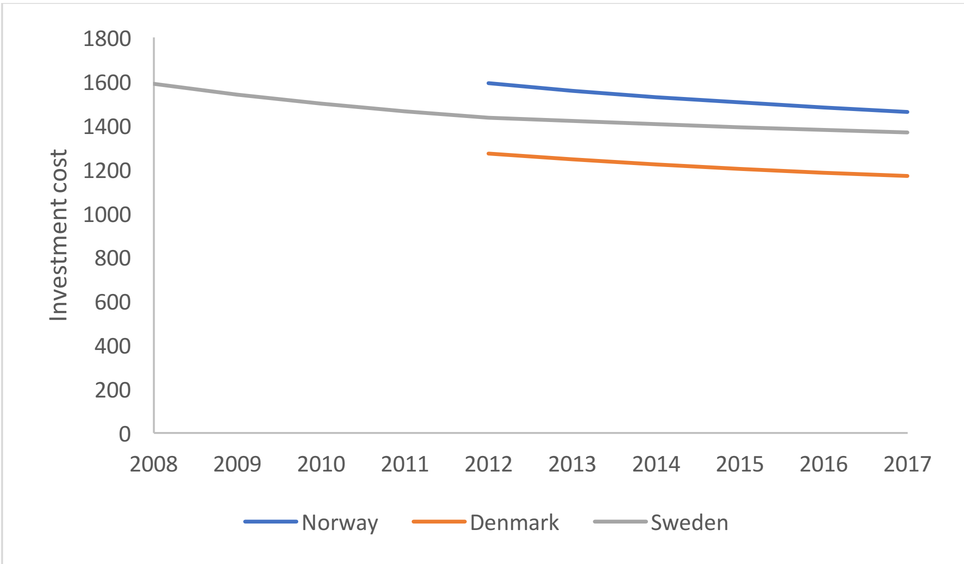
Equation 14 gives the degree of learning (E)

$$E = \frac{\ln(PR)}{\ln(2)} \tag{14}$$

Employing learning rate of 10% gives a PR ratio of 0,9. Hence, the degree of learning (E) equals 0,152 annually for 2008-2016. The low degree of learning indicates a small drop in the unit cost when the accumulated production doubles.

The investment cost in 2017 is calculated by including the accumulated wind power capacity x(t) and the degree of learning (E) in Equation 2, and plotted graphically, as displayed in Figure 16 below (for detailed calculation, see Appendix C). The investment cost in Sweden decrease by 9,72% from 2008-2012, giving an investment cost of 1 436 €/kW in 2012. Furthermore, there is a total decrease in Norway, Denmark and Sweden of 8,15%, 8,15% and 3,73% in the period 2012-2017, giving an investment cost of 1 462 €/kW, 1 169 €/kW and 1 367 €/kW respectively.

Figure 16 - The Reduction in Investment Cost due to the Degree of Learning



5.4.2 Operational and Maintenance Costs

O&M costs are normally low at the beginning of the turbine's lifetime, increasing as the wind turbine matures; the older the turbine, the more maintenance it needs to operate with full effect. It is common to set an average cost based on output produced (kWh). As O&M costs are not easily available and project data are lacking, the estimates from Wind Task 26 presented in Table 8 are highly uncertain. They are based on pre-construction estimates and/or survey-data rather than real numbers.

In Wind task 26, the O&M costs are separated into fixed and variable costs for Sweden, but not for Norway and Denmark. In Sweden, the fixed and variable O&M costs were reported to amount to 0,4 €ct/kW and 1,10 €ct/kWh respectively. However, a fixed O&M costs of 0,4 €ct/kW gives a yearly cost of €120 for a wind turbine with a capacity of 30 MW – highly unlikely, given that O&M usually covers wages, insurance- and administration costs, and service contracts for scheduled maintenance.

O&M costs are not easily separated and are commonly quoted as a total of €/kWh. Hence, this study presents the two combined. A compensation of 0,4 €ct/kWh is added to the variable O&Ms cost for Sweden, giving a total O&M costs of 1,50 €ct/kWh. Further, the O&M cost for Sweden in 2012 is calculated based on the average decline in the O&M costs in Norway and Denmark in the period 2008-2012 of 2,59%. The average annual decline in the three countries is calculated (Ref. Appendix D), and assumed to apply until 2017. Hence, the O&M costs for Norway, Denmark and Sweden are estimated to be 1,5 €ct/kWh, 1,20 €ct/kWh, and 1,04 €ct/kWh, respectively. These O&M costs increase with the general rate of inflation over the lifespan of the projects.

Table 8 - O&M Costs for Wind Power Projects Features in Norway, Denmark and Sweden

		Norway		*Denmark*		*Sweden*	
		2008	*2012*	*2008*	*2012*	*2008*	*2012*
Fixed O&M Costs	*€/kW*	N/A	N/A	N/A	N/A	0,004	N/A
Variable O&M Costs	*€ct/kWh*	2,00	2,00	1,35	1,28	1,10	N/A

Source: Adapted from (IEA, 2015a) & (IEA, 2011b)

5.4.3 Decommissioning cost

In Wind Task 26, decommissioning cost is only estimated for Sweden in 2008. As can be seen in Table 9 this amounts to approximately 0,1% of the total investment cost. This is further used to calculate decommissioning costs for the three simulated projects: 1,46 €/kW, 1,17 €/kW and 1,37 €/kW for Norway, Denmark, and Sweden, respectively.

Table 9 - Decommissioning Cost for Wind Power Projects Features in the Nordic Countries

		Norway		*Denmark*		*Sweden*	
		2008	*2012*	*2008*	*2012*	*2008*	*2012*
Decommissioning Cost	*€/kW*	N/A	N/A	N/A	N/A	1,60	N/A

Source: Adapted from (IEA, 2015a) & (IEA, 2011b)

5.4.4 Summary of Total Costs

Table 10 below summarises the cost estimates for a typical wind farm project in the three countries in 2008, 2012 and 2017 (for detailed calculations, see Appendix C and D).

Table 10 - Wind Power Projects Features in Norway, Denmark and Sweden

		Norway			*Denmark*			*Sweden*		
		2008	*2012*	*2017e*	*2008*	*2012*	*2017e*	*2008*	*2012e*	*2017e*
Investment Cost	*€/kW*	1 386	1 592	1 462	1 475	1 273	1 169	1 591	1 436	1 367
O&M Costs	*€ct/kWh*	2,00	2,00	1,5	1,35	1,28	1,20	1,5	1,46	1,41
Decommissioning Cost	*€/kW*	1,39	1,59	1,46	1,48	1,27	1,17	1,60	1,44	1,37

Source: Adapted from (IEA, 2015a) & (IEA, 2011b)

5.5 Taxation and Depreciation

Two taxes are relevant to consider when operating a wind farm: corporate tax and property tax. The former is calculated from the taxable income – the profits after deduction of operating costs, tax depreciation, property taxes and interest costs. The corporate tax rates in Norway are 25%, Sweden 22%, and Denmark 22% (KPMG).

Property tax is paid to the municipality in which the wind turbine operates, and is collected in some municipalities in Norway and Sweden. In Norway, the individual municipality decides whether or not to claim property tax, and the size of it. In Sweden, the property tax is fixed at

0,2% of the appraised value and is based on installed capacity, adjusted for full loads hours, and maturity of the wind turbine; i.e., the property tax over the lifespan of a project will decline (Svensk Vindenergi, 2017; THEMA Consulting Group, 2015).

This study disregards property tax from its calculation, because not all municipalities in Norway collects it, the tax rate in Sweden is relatively small and will decline over the project's lifetime, and there is no property tax in Denmark. It is therefore concluded that it is negligible for the purview of this study.

As previously mentioned, depreciation leads to reduced income taxes. As presented in Chapter 2, Norway has adopted the same depreciation rule as Sweden where the wind power farms depreciate as a straight line over five years. Denmark, however, has balance depreciation at a rate of 15% (Skat, 2017).

5.6 Discount Rate

WACC should be used when calculating the discount rate, giving insight in the cost of funding from both debt and equity holders. To estimate WACC, required returns on equity and debt, and the ratio between them, has to be found.

The required return on equity represents the costs needed to attract equity holders to the investment. CAPM gives this return, including the risk-free rate, the beta and the market risk premium. Assuming the government as a default-free entity, 10-year government bonds give the risk-free rate. The risk-free rate used is the average rate over the past decade, assuming that the risk-free rate is practically random in a larger perspective. Thomson Reuters (2017) gives average risk-free rates for Norway, Denmark and Sweden at 2,68%, 2,05%, and 2,05 %, respectively (Thomson Reuters, 2017). The detailed overview of the return on obligations the last decade is shown in Appendix A.

To get the nominal risk-free rate, the expected inflation is added. In Norway, the annual growth in the price of goods and services is 2,50% (Norges-bank, 2017), whilst in Denmark and Sweden this rate is 2,00%, reflecting the annual growth in the Eurozone (Danmarks Nationalbank, 2017; Sveriges Riksbank, 2017). This gives a nominal risk-free rate for Norway, Denmark and Sweden of 5,18%, 4,05%, and 4,05%, respectively. Further, the unlevered beta is assumed to be 0,44 for the three represented countries. This is calculated by Damodaran (2017) as the average unlevered beta for the renewable energy sector in Europe (Damodaran, 2017). Further, the market risk premium is common for the whole market and not affected by industry or company-specific differences. According to studies done by PwC, the risk premiums have been stable over the past decades at 5,20%, 5,60%, and 6,50% for Norway, Denmark, and Sweden (PWC, 2015, 2016a, 2016b). Hence, the return on equity for Norway, Denmark and Sweden are calculated to be 7,47%, 6,51% and 6,91% respectively.

The required return on debt represents the cost needed to attract debt holders to the investment. In Norway, the return on debt for wind power projects is approximately 4,50-6,00%, depending on the riskiness of the investment (Deloitte, 2014). This study assumes the required return on debt in Norway to be 5%. In Denmark, the return on debt for wind power projects has been uniform around 4,50-5,50%, unchanged from 2008 (IEA, 2015a; Noothout et al., 2016), and this study assumes the rate at 5,00%. Whereas in Sweden, it ranges between 4,50-6,00% (IEA, 2015a; Noothout et al., 2016), and is set to 5,50% for this study.

The financing structure affects how the return of equity and debt are weighted for different wind power projects. Damodaran (2017) analyses 48 different companies in the European renewable energy sector for their debt/equity ratio; the average being 54,68/45,32 (Damodaran, 2017). However, this average considers companies operating with all renewable energy sources, not only wind power. It will therefore be more appropriate to look at studies focusing exclusively on wind power. A report by Deloitte (2014) states that Norwegian wind power projects are financed with approximately 50-70% debt, where onshore projects are typically in the upper range (Deloitte, 2014). The debt/equity ratio in Norway is therefore set to 60/40. The report Wind Task 26 (2015a) shows that the debt/equity ratio in Denmark has been stable around 80/20 in the period 2008-2012 (IEA, 2015a). This is supported in a 2016-report by Noothout et al. (2016), which concludes with a ratio between 70/30-100/0 (Noothout et al., 2016). In this study, the debt/equity ratio in Denmark is set to 80/20. In Sweden, the debt/equity ratio for a typical wind power project was 87/13 in 2008 (IEA, 2011b). Noothout et al. (2016), however, states this has since changed to fall in the range of 60/40 to 50/50. A debt/equity ratio of 60/40 is therefore set for Sweden (Noothout et al., 2016).

Table 11 summarises all the inputs used in the calculation of WACC, and shows the nominal after tax WACC to be 5,24%, 4,42% and 5,34% for the Norwegian, Danish, and Swedish simulated projects. However, to adjust for the longer lead times in Norway and Denmark, an additional risk supplement is added to this discount rates. As Norway has the longest licence processing time, the additional risk supplement is set to be 0,3%, resulting in a WACC of 5,54%. In Denmark, the risk supplement is set to 0,1%, resulting in a WACC of 5,34%. The discount rate is assumed fixed for the whole duration of the projects.

Table 11 - Wind Power Financing Terms in Norway, Denmark and Sweden in 2017

	Norway	*Denmark*	*Sweden*
Inflation	2,50%	2,00%	2,00%
Risk Free Rate (real)	2,68%	2,05%	2,05%
Risk Free Rate (nominal)	5,18%	4,05%	4,05%
Unlevered Beta (β)	0,44	0,44	0,44
Market Risk Premium (rm –rf)	5,20%	5,60%	6,50%
Return on Equity (r_E)	7,47%	6,51%	6,91%
Return on Debt (r_D)	5,00%	5,00%	5,50%
Equity Share	40,00%	20,00%	40,00%
Debt Share	60,00%	80,00%	60,00%
Corporate Tax Rate	25,00%	22,00%	22,00%
WACC (nominal, after tax)	5,24%	4,42%	5,34%
Risk Supplement	0,3%	0,1%	-
WACC (including risk supplement)	5,54%	5,34%	5,34%

6 RESULTS AND DISCUSSION

This chapter considers the results from the analyses of the simulated project in the three Nordic countries. Section 6.1 presents the results from NPV-analysis, Section 6.2 presents the results from the sensitivity analysis, while the results from the Monte Carlo simulations are presented in Section 6.3. Lastly, Section 6.4 covers a discussion of these findings.

6.1 Net Present Value Analysis

6.1.1 Norway

Table 12 below presents the accumulated cash flow for the simulated project in Norway (for detailed calculations, see Appendix E). As shown, it yields an NPV of -€26 245 604. The negative NPV indicates that the present value of the combination of the electricity price and the income from the TGC system is not enough to cover the present value of the installation/operating costs. Hence, the simulated project appears to be unprofitable. This can be attributed to the high initial investment in year 0, and the methodology of the discounted cash flow model; the revenue becomes small when discounted over 20 years.

As can be seen from Table 12, the Norwegian project will not be in a tax position during the 20-year period, given the underlying assumptions. This is because the loss carryforward that occurs during the first 5 years exceeds future taxable income (for detailed calculations see Appendix E).

Table 12 – NPV-Analysis for the Norwegian Project

Years	*2017* (0)	*2018-2027* (1-10)	*2028-2037* (11-20)
Initial Investment (€)	- 43 865 400		
Electricity Price (€)		23 661 542	30 288 775
TGC Price (€)		7 528 673	4 521 582
O&M Costs (€)		- 16 132 870	- 20 651 437
Decommissioning Cost (€)		-	- 43 800
Depreciation (€)		- 32 899 050	-
EBIT (€)		15 057 345	14 115 120
Tax (€)		-	-
Net Present Value (€)	- 26 245 604		

6.1.2 Denmark

The country-specific accumulated cash flow is shown in Table 13 below (for detailed calculation see Appendix E). The simulated project in Denmark with the above assumptions, is shown to have an NPV of -€13 500 032. Like Norway, it appears to have a negative NPV and not to be profitable. However, unlike the Norwegian project, the Danish project is in a tax position. As demonstrated in Table 13 below, the tax amounted to €217 549 for the first ten years and €813 669 for the next ten years. Nevertheless, this is an insignificant amount which do not have a big impact on the NPV.

Table 13 – NPV-Analysis for the Danish Project

Years	*2017* (0)	*2018-2027* (1-10)	*2028-2037* (11-20)
Initial Investment (€)	-35 075 763		
Electricity Price (€)		20 715 181	22 882 447
Feed-in Premium (€)		6 732 000	-
Balancing Cost (€)		1 800 000	1 800 000
O&M Costs (€)		-11 299 190	-12 481 335
Decommissioning Cost (€)		-	-35 100
Depreciation (€)		-21 127 682	-5 179 140
EBIT (€)		17 947 991	12 166 012
Tax (€)		-217 549	-813 669
Net Present Value (€)	-13 500 032		

6.1.3 Sweden

Table 14 below summarises the accumulated cash flow analysis for the simulated project in Sweden (for detailed calculations see Appendix E). The NPV is calculated to -€24 322 229, and alike the other projects, it is unprofitable.

Table 14 demonstrates that the Swedish project will not be in a tax position during the 20-year period, given the underlying assumptions as the loss carryforward for the first 5 years exceeds the future taxable income.

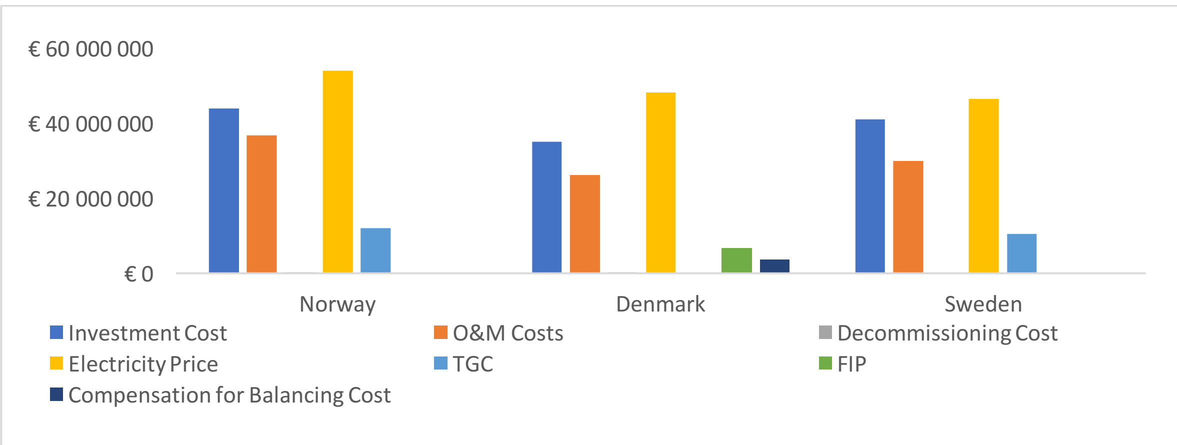
Table 14 – NPV-Analysis for the Swedish Project

Years	*2017* (0)	*2018-2027* (1-10)	*2028-2037* (11-20)
Initial Investment (€)	-41 018 404		
Electricity Price (€)		20 767 152	24 823 026
TGC Price (€)		6 607 730	3 773 105
O&M Costs (€)		-13 351 109	-15 958 612
Decommissioning Cost (€)		-	-41 100
Depreciation (€)		-30 763 803	-
EBIT (€)		14 023 773	12 596 418
Tax (€)		-	-
Net Present Value (€)	-24 322 229		

6.1.4 Cross-country Comparison

Figure 17 below summarises the accumulated income and costs throughout the projects lifespan. As shown, the simulated project in Norway has the highest installation cost and O&M costs, followed by Sweden. The Norwegian project also has the highest revenue from sale of electricity, as well as higher revenue from TGC than Sweden, due to highest production. When comparing this additional income from TGC with the FIP from the first 6 600 full load hours in Denmark, Figure 17 shows that TGC gives higher compensation throughout the project's operating lifespan. However, unlike the other countries, Danish wind farm projects are granted compensation to cover balancing costs.

Figure 17 – Cross-country Comparison of the NPV-analysis



6.2 Risk Analysis

Risk analyses are performed using Excel with the add-in @RISK, and takes into account the correlation between the variables presented above. Based on historical data, the electricity price and the price of the TGC are found to positively correlate at 0,4 (Ref. Appendix F), meaning that if the electricity price increases, the price of the TGC increases as well. Further, a positive correlation at 0,4 is assumed between the investment cost and the O&M costs. The investment cost and the decommissioning cost are perfectly correlated (correlation of 1,0) because the decommissioning cost is 0,1% of the initial investment.

6.2.1 Sensitivity Analysis

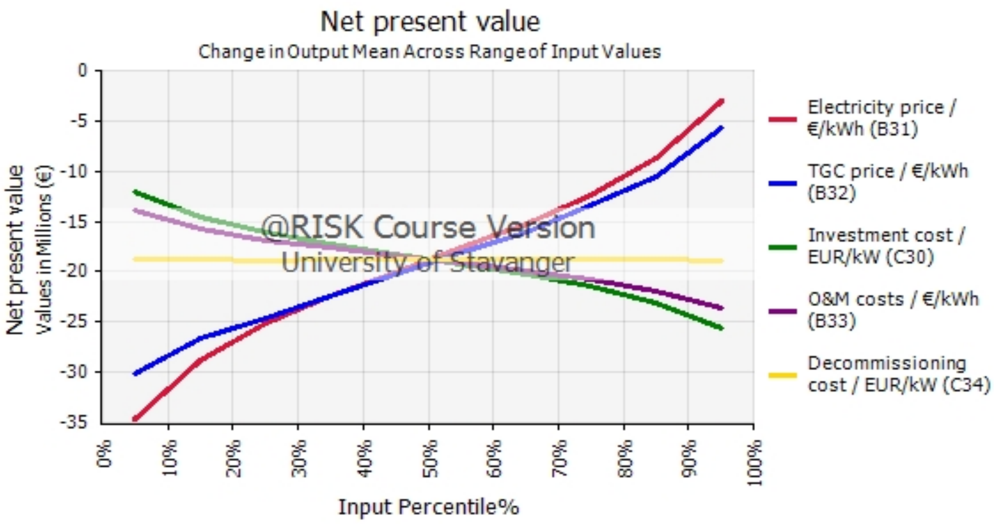
Even though the calculated NPV presented above is informative, the method assumes a static world without uncertainty, and where annual cash flows are given by fixed production levels, revenues and costs. In reality, these may vary, and it is thus important to emphasise the uncertainty of the variables included in the calculations. A sensitivity analysis shows which variables the projects are most sensitive to changes in, and have to be closely monitored in further analysis and risk assessment.

6.2.1.1 Norway

Figure 18 below shows the level of change in the benchmark NPV as the input variables change +/- 50%, ceteris paribus. The steeper the curve, the greater impact the input value has on the NPV. The five variables analysed are the electricity price, TGC price, investment cost, O&M costs and decommissioning cost.

The most critical variable is shown to be the electricity price. Nonetheless, a 50% increase in this variable alone does not make the NPV positive. The results also indicate that a change in the TGC price will have a great impact on the NPV. A change in the decommissioning cost, however, will only have a small impact on the NPV as it is such a small cost 20 years into the future.

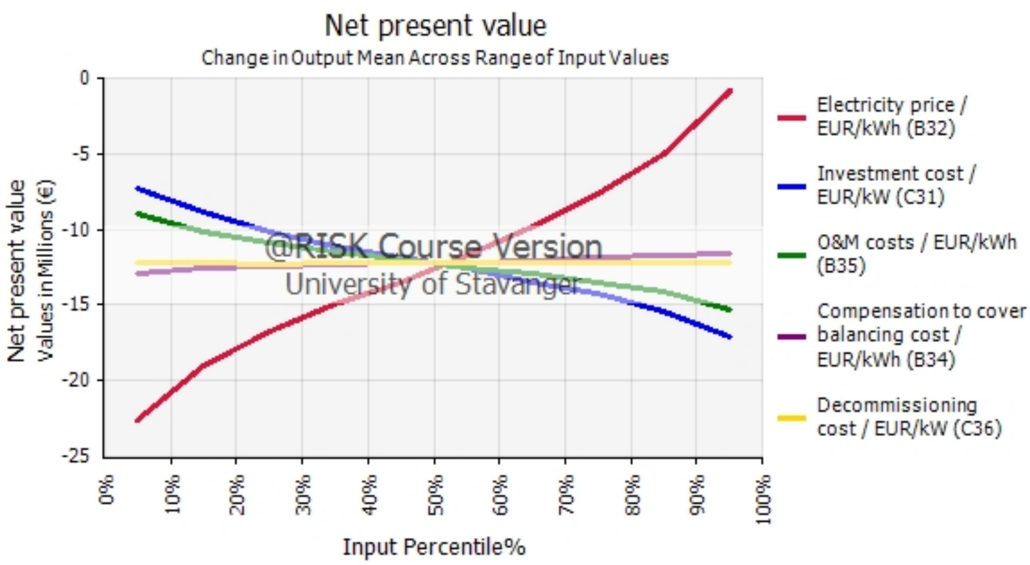
Figure 18 - Sensitivity Analysis of the Norwegian Project



6.2.1.2 Denmark

Figure 19 below shows the level of change in the benchmark NPV for the Danish project. In addition to the aforementioned variables, the compensation to cover balancing costs is considered. However, a change in this variable does not yield a big impact due to the low compensation given. The electricity price is the most critical variable affecting the NPV, followed by the investment cost and the O&M costs.

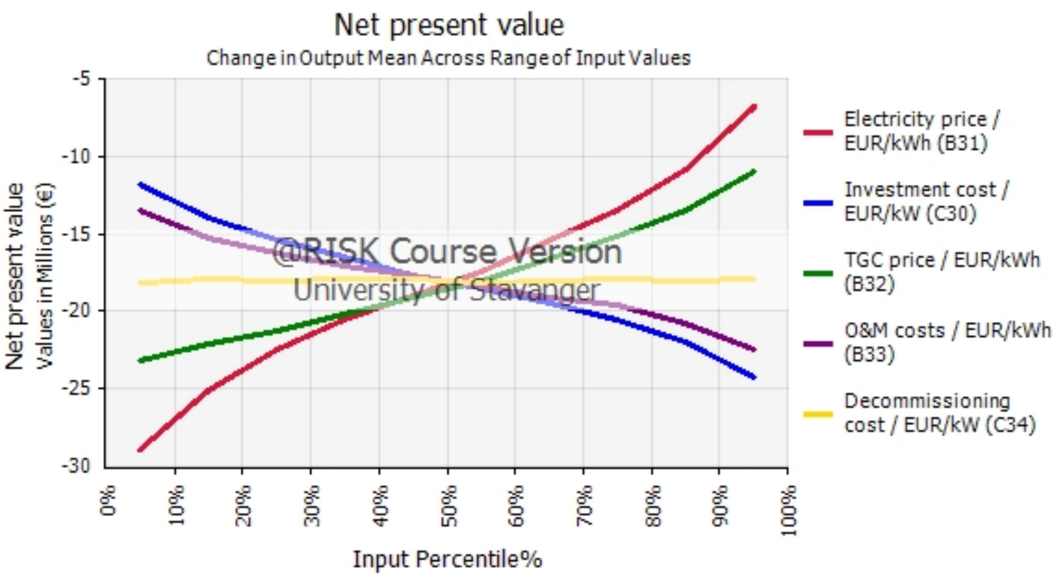
Figure 19 - Sensitivity Analysis of the Danish Project



6.2.1.3 Sweden

Figure 20 shows the sensitivity analysis for the Swedish project. Electricity price and the TGC price yields the most impact, however, none of these variables alone can contribute to make the NPV positive considering a range of +/- 50%.

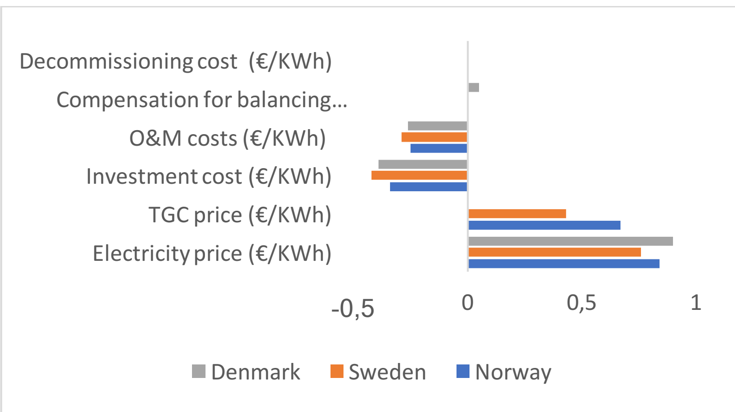
Figure 20 - Sensitivity Analysis of the Swedish Project



6.2.1.4 Cross-country Comparison

Figure 21 shows the comparison of the results for the three countries, and demonstrates how each of the input variables correlate with the NPV. Hence, the electricity price has the largest effect on the NPV for all the three countries. This is followed by the TGC price for Norway and Sweden. Of the costs, the investment cost is the most critical.

Figure 21 - NPV Correlation Coefficients for the Input Variables



6.2.2 Monte Carlo Simulation

Unlike the sensitivity analysis, the Monte Carlo (MC) simulation imitates a real-world situation, where more than one of the inputs change simultaneously. The simulations are based on repeated random sampling, in order to produce a distribution of possible outcomes. In the simulations, triangular distributions are used, specified by the minimum possible value, the most likely value, and the maximum possible value. This implies that the likelihood increases consistently as the estimates approach the mode from either side (Albright, Winston, Broadie, Lapin, & Whisler, 2012).

The parameters used are presented in Table 15 below, and a 20% over/under budget is considered for the cost variables. For the change in income variables, historical prices are applied to predict future outcomes; as formerly presented, the electricity price has ranged between 0,01 and 0,04. As the electricity price can change beyond the price level of the forward contracts presented earlier, the historical range is used as a basis. The price of the TGC, however, will probably not be as high as its historical level. The TGC price has fallen significantly from 0,035 €/kWh in 2009 to 0,016 €/kWh in 2012 (when Norway became a part of this scheme), to 0,008 €/kWh today. Hence, the future TGC price is assumed to be between 0,005 €/kWh and 0,025 €/kWh.

The FIP in Denmark is assumed to remain stable and constant for the next three years, as FIP is only given for the first 6 600 full load hours, and given the yearly production of 3 000 full load hours, this corresponds to the first 2,5 years.

Table 15 - Input Variables in the MC Simulations

	Norway			*Denmark*			*Sweden*		
	Minimum	*Most likely*	*Maximum*	*Minimum*	*Most likely*	*Maximum*	*Minimum*	*Most likely*	*Maximum*
Investment Cost (€/kW)	1 170	1 462	1 755	935	1 169	1 403	1 094	1 367	1 641
Electricity Price (€/kWh)	0,010	0,022	0,040	0,010	0,022	0,040	0,010	0,022	0,040
TGC Price (€/kWh)	0,005	0,007	0,025				0,005	0,007	0,025
Compensation for Balancing Cost (€/kWh)				0,001	0,002	0,003			
O&M Costs (€/kWh)	0,012	0,015	0,018	0,010	0,012	0,014	0,011	0,014	0,017

Decommission-ing Cost (€/kW)	1,17	1,46	1,75	0,94	1,17	2,40	1,09	1,37	1,64

Sensitivity to the discount rate is calculated systematically with three simulations/100 000 iterations each. Table 16 below lists the discount rates used in the analysis for the three countries. As should be noted, the discount rate in simulation two is the same as for the NPV-analysis above.

Table 16 - Discount Rate Considered in the MC Simulations

	Norway	*Denmark*	*Sweden*
Simulation 1	2,59%	2,03%	2,36%
Simulation 2	5,24%	4,42%	5,34%
Simulation 3	7,77%	6,08%	7,07%

6.2.2.1 Norway

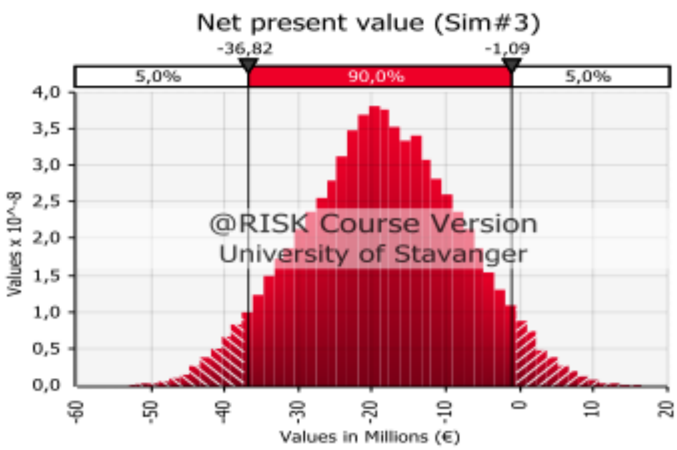
The results from the MC simulation of the Norwegian project are listed in Table 17 and the NPV-histogram from simulation 2 with the discount rate of 5,24% shown in Figure 22 below. For this rate, the simulation resulted in an interval of the NPV between -€53 272 601 and €16 490 986. However, these outcomes indicate the extreme positions, and are therefore considered to be unrealistic. More likely, the NPV is 90% probable within the range of -€36 815 521 to -€1 091 754. The average NPV of the distribution is found to be -€18 791 762, and the median value -€18 781 181.

Table 17 also shows how the NPV changes with the discount rate: The upper level of the NPV-interval changes when changing the discount rate in positive or negative direction. The lower level, however, does not change much.

Table 17 - Summary Statistics for Net Present Value for Norway

Simulations	*Simulation 1*	*Simulation 2*	*Simulation 3*
Discount Rate (%)	2,59	5,24	7,77
Minimum (€)	-54 545 114	-53 272 601	-52 499 559
Maximum (€)	29 215 292	16 490 986	7 600 366
Average (€)	-12 792 187	-18 791 762	-23 029 245
Standard Deviation (€)	13 048 987	10 737 210	9 162 422
Skewness	-0,038	-0,027	-0,018
Kurtosis	2,701	2,693	2,692
Median (€)	-12 796 462	-18 781 181	-23 007 316

Figure 22 - Net Present Value Histogram for the Norwegian Project



To comment on whether the NPV is normally distributed or not, the Jarque-Bera test is employed. According to this test, there are two conditions describing the symmetry of measurements in a probability distribution. The first factor is skewness – a measure of symmetry known to be zero at normal distribution. For the second simulation, presented in Table 17 and Figure 22, the skewness is -0,027. A negative skewness means that most of the results from the 100 000 iterations are higher than the average NPV of -€18 791 762. The second factor describing the distribution symmetry is the kurtosis result, which provides a measure of the weight in the tails of a probability density function. If a population is normally distributed, the kurtosis should be 3. For simulation 2, the kurtosis is 2,693, meaning that the distribution is somewhat steeper than a normal distribution producing fewer and less extreme outputs. Hence, the two factors conclude that the distribution from the MC simulation is not normally distributed (Newbold, Carlson, & Thorne, 2010).

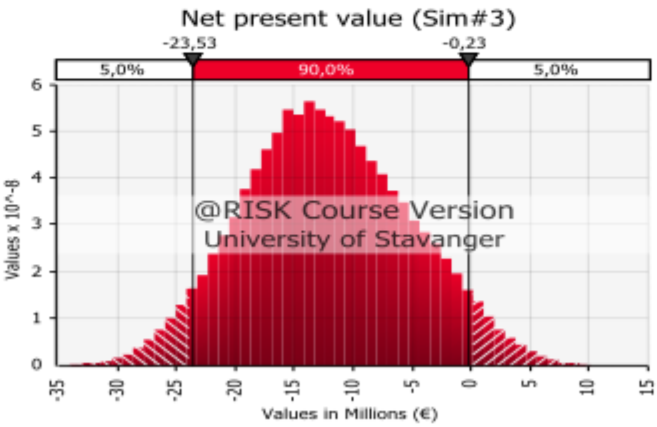
6.2.2.2 Denmark

The results from the MC simulation for the Danish project are listed in Table 18 below, and the NPV histogram with the discount rate of 4,42% (simulation 2) is shown in Figure 23. According to this simulation, the value of the NPV is 90% probable within the range of -€23 528 852 to -€232 776 €. The average NPV is found to be -€12 203 841, and the median value -€12 499 173. The skewness in Denmark is positive at 0,112 and the kurtosis is 2,624. According to the Jarque-Bera test, the distribution in this simulation is not normally distributed and that most of the results from the 100 000 iterations are lower than the average NPV of -€12 203 841.

Table 18 - Summary Statistics for Net Present Value for Denmark

Simulation	*Simulation 1*	*Simulation 2*	*Simulation 3*
Discount Rate (%)	2,03	4,42	6,08
Minimum (€)	-33 128 878	-34 115 516	-34 633 068
Maximum (€)	18 668 859	10 130 062	5 620 003
Average (€)	-7 811 609	-12 203 841	-14 563 597
Standard Deviation (€)	8 394 019	7 022 191	6 307 169
Skewness	0,148	0,112	0,089
Kurtosis	2,595	2,624	2,646
Median (€)	-8 286 598	-12 499 173	-14 775 535

Figure 23 - Net Present Value Histogram for the Danish Project



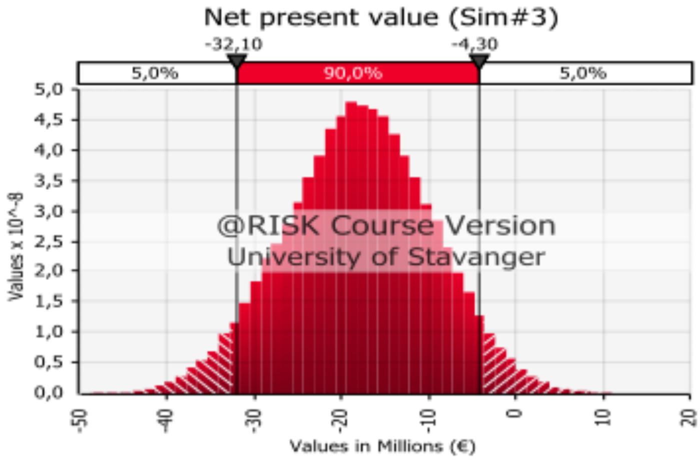
6.2.2.3 Sweden

The results from the MC simulation for the Swedish project are listed in Table 19 below and the NPV histogram with the discount rate of 4,42% is shown in Figure 24. For this particular discount rate (simulation 2), the results indicate that the NPV is 90% probable within the range of -€32 102 899 to €4 295 668, the average of the distribution is -€18 011 030, and the median value -€17 920 566 €. Table 19 shows the skewness for simulation 2 to be -0,051 and the kurtosis 2,811, hence the distribution from the MCS is not normally distributed and most of the results from the 100 000 iterations are higher than the average.

Table 19 - Summary Statistics for Net Present Value for Sweden

Simulation	*Simulation 1*	*Simulation 2*	*Simulation 3*
Discount Rate (%)	2,36	5,34	7,07
Minimum (€)	-49 439 673	-48 849 719	-48 645 505
Maximum (€)	23 298 812	11 085 067	5 757 730
Average (€)	-11 751 214	-18 011 030	-20 761 243
Standard Deviation (€)	10 324 376	8 381 080	7 563 197
Skewness	-0,062	-0,051	-0,044
Kurtosis	2,816	2,803	2,800
Median (€)	-11 672 149	-17 920 566	-20 679 057

Figure 24 - Net Present Value Histogram for the Swedish Project



6.3 Discussion

The main objective of this study is to investigate why electricity from wind power in the Norwegian market is not developed to the same extent as in its neighboring countries. In particular, it focuses on factors affecting investment attractiveness in the Norwegian wind power market compared to Denmark and Sweden. In reviewing institutional and legal differences in the three Nordic countries, combined with a financial analysis of a simulated reference project, the research statement in Chapter 1 can be addressed:

Environmentally friendly use of electricity has been of importance in Norway, Denmark, and Sweden following the oil crisis in the 1970s. However, electricity coming from wind power has developed differently among these countries. Denmark has, compared to Norway and Sweden, a long history of wind power, and has historically given generous financial support to projects, aiming to increase the share of wind power (mostly through FIT or FIP frameworks). Denmark has also communicated a clear political ambition to increase electricity coming from wind power, while the formulations in Norway and Sweden has been more vague, not stating specific goals. Norway has a strong tradition of hydropower, which can be an explanatory factor causing the difference in the ambitions regarding wind power development. Finally, wind power projects in Denmark has been integrated into the society through cooperatives and power generation for own consumption, which has in turn enabled a high level of local acceptance towards wind turbines, stimulating development.

In 2016, Sweden produced more electricity from wind power than Denmark. However, while installed capacity in Denmark has grown steadily over the past 25 years, the installed capacity in Sweden has only increased considerably since 2003. This was the year Sweden introduced the TGC system. Norway entered this market in 2012, and although the intention was to distribute production between the countries, Sweden has attained a greater portion of the growth. One can argue this imbalance is due to a more favorable depreciation rule in Sweden, lower cost levels, and greater market size and maturity. However, the depreciation rule in Norway was improved in 2015 and is now similar to the Swedish rule. This could provide a more equal distribution of the TGC market in the future. Nonetheless, TGC is technology neutral and not given directly to the development of wind power, but facilitate for the cheapest renewable energy technology to be developed first. Hence, the Norwegian renewable policy must contribute to enhance investment in wind power to the same extent as investment in hydropower, if Norway wishes to develop on the same level as its neighbours. This will in turn allow the construction of new electricity based on the most profitable technology. As shown in Chapter 4, wind power is cost-competitive, and was in 2014 in Europe the technology with the lowest LCOE on average.

Apart from the aspects discussed above, long lead times can be regarded as an obstacle for investors' willingness to invest in wind power, as it is reflected in higher required return, affecting the financial performance of the project. The higher the required return, the less competitive the project becomes. Norway has the longest lead time of 66 months on average. Both in Denmark and Sweden, the permitting is handled by municipalities which can contribute to make the process less complex and more effective.

The NPV-analysis of the simulated projects resulted in an NPV in Norway of -€26 245 604, Denmark -€13 500 032, and Sweden -€24 322 229. One can argue that the negative NPVs are due to low electricity prices and high investment costs. In addition, the financial support is currently low compared to earlier years. To illustrate, the price of the TGC, as seen in Norway and Sweden, has declined significantly. In Denmark, the FIP has also been reduced, and today the premium is only given for the first 6 600 full load hours. As can be seen from the NPV-analysis, this reduction has resulted in making the TGC more effective, providing a higher accumulated income over the lifespan of the project. However, in Norway and Sweden, the income from TGC will not offset the overall loss caused by the fall in electricity prices. Thus, this financial support does not appear to be a strong enough incentive alone, to invest in wind power.

As can be seen from the NPV-analysis, the Norwegian project yields an NPV of €12 745 573 less than the Danish project. The difference is largely caused by the higher upfront investment cost of €8 789 637. In addition to Denmark having a historical advantage in the wind industry (compared to Norway and Sweden) it is a flat country with little height variation, resulting in good geographical conditions for the development of wind power. These advantages lower the costs associated with installing and operating a wind farm, hence the cost level in Denmark being lower than in the two other countries.

The sensitivity analysis reveals that the three projects depend on the same variables, the most critical being the electricity price. It is indicated that when developing a wind farm, the project developers should, if possible, try to reduce the amount of uncertainty related to it. A way of doing this is by entering into a financial contract where the electricity price is already set. Such a contract may also apply to the O&M costs.

The Monte Carlo simulations emphasises the uncertainties of the projects and gives a probability distribution of possible outcomes. This distribution paints an illustrative picture of the uncertainty associated with wind power projects. The MC simulation indicates a large spread in possible outcomes. However, the simulation supports the conclusion from the NPV analysis, that the simulated project is most likely to have a negative NPV in the three represented countries. Thus, when planning a wind farm, the uncertainty variables must be closely monitored.

6.3.1 Research Limitations

In aligning reality and theory, some simplification and assumptions are made, which leaves room for uncertainty. For the scope of this study, the electricity price and the TGC price in 2018 (year 1) is assumed to equal the average price of three and five forward contracts. These prices are assumed to grow at the general rate of inflation; however, as shown earlier, there have been historical fluctuations in both electricity price and TGC price. It would therefore be reasonable to argue for fluctuations over the lifespan of the project.

Furthermore, the NPV-analysis use figures from Wind task 26, where full load hours and cost figures are average numbers from projects planned and performed in 2008 and 2012, representing a "typical" project for the countries. However, the actual cost and full load hours are site- and project-specific; for instance, a large wind power project will probably benefit from economies of scale. The financing structure will also vary between projects. Thus, the chosen debt/equity ratios may prove to induce a high level of uncertainty, as well as for the cost of equity and the cost of debt. These uncertainties combined will in turn affect the discount rate and the financial performance of the project. Therefore, the data presented is illustrative for the overall country-specific conditions and should only be regarded with this in mind.

A potential weakness with the Monte Carlo simulation is that the range in each of the variables can be set too wide or too narrow. The simulation further does not take into account possible variations in costs and income during the 20-year period, as the analysis is constructed in such a way that a change in one of the parameters will lead to a change in year 1, with a subsequent growth equal to the inflation over the next 20 years.

7 CONCLUSION

Following the discussion above, it is evident that there are several reasons why wind power in Norway has not developed at the same extent as in Denmark or Sweden. In Denmark, a robust and consistent political system favouring wind power has been essential in strengthening its dominance. In Sweden, the main cause of rapid growth is the TGC-system. In Norway, the low share of wind power can be explained by vague political ambitions and political uncertainty surrounding the schemes of financial support. This can be partly attributed to the country's strong tradition of hydropower, which one can argue functions as a distracting factor. If Norway wishes to develop to the same level as its neighbours, the Norwegian renewable policy must contribute more to enhance investment in wind power. Also, improving policy stability, and speeding up the permitting process, may contribute to increased development going forward.

Although Norway has been a part of the Swedish TGC system since 2012, the market has not developed accordingly. This can be explained by the different depreciation rule and higher cost level, favouring wind power projects in Sweden. However, the recently improved depreciation rule in Norway could provide a more equal distribution of the TGC market in the future.

The higher cost level in Norway is illustrated in the NPV-analysis, causing the simulated project to perform worst with an NPV of -€26 245 604; this in spite of Norway having the best wind conditions, as reflected in higher full load hours. In Denmark and Sweden, the same project yields NPVs of -€13 500 032 and -€24 322 229, respectively. Although the simulated project performed better in these countries, neither demonstrates sufficient cash flow from revenue and financial support to meet the financial requirements to be developed. Thus, lower costs and/or higher income are necessary to yield a positive NPV.

7.1 Suggestions for Further Research

With technical solutions being investigated, to combine wind- and hydropower for stable production throughout the year, further research should be conducted as to how this may impact the wind-development sector from a political and financial perspective.

Case study of politics – why have politicians not done more to increase wind power development? – interviews. What are the different political parties doing? What was the rationale of the old system? How do they see development in Norway since 2012 as a result of the change. What are Denmark and Sweden currently doing to increase wind power?

Case study of companies – Interviews - what do you think about the political scheme in Norway? Test conclusions – is this one of the main factors?

Deeper study of electricity prices – what determines it, and project it for the future, with all variables/predictions in mind.

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9 APPENDICES

Appendix A – Discount Rate

Risk-free Rate

	SE GVB 10Y	*NO 10Y*	*DK 10Y*
2008 Q2	4,21	4,71	4,53
2008 Q3	4,13	4,74	4,57
2008 Q4	3,22	4,13	4,04
2009 Q1	2,89	3,82	3,51
2009 Q2	3,46	4,13	3,67
2009 Q3	3,40	4.17	3,71
2009 Q4	3,26	4,06	3,62
2010 Q1	3,28	3,88	3,51
2010 Q2	2,82	3,40	2,99
2010 Q3	2,56	3,27	2,54
2010 Q4	2,90	n/a	2,75
2011 Q1	3,35	n/a	3,23
2011 Q2	3,06	3,56	3,18
2011 Q3	2,24	2,73	2,53
2011 Q4	1,76	2,48	2,05
2012 Q1	1,85	2,34	1,86
2012 Q2	1,59	2,12	1,44
2012 Q3	1,42	2,01	1,27
2012 Q4	1,50	2,10	1,45
2013 Q1	1,90	2,41	1,66
2013 Q2	1,82	2,22	1,54
2013 Q3	2,36	2,85	1,95
2013 Q4	2,37	2,89	1,88
2014 Q1	2,25	2,87	1,73
2014 Q2	1,92	2,75	1,48
2014 Q3	1,56	2,36	1,40
2014 Q4	1,16	1,97	1,04
2015 Q1	0,66	1,38	0,40
2015 Q2	0,70	1,64	0,71
2015 Q3	0,73	1,59	0,93
2015 Q4	0,79	1,55	0,86
2016 Q1	0,87	1,35	0,63
2016 Q2	0,70	1,29	0,39
2016 Q3	0,16	1,07	0,08
2016 Q4	0,42	1,53	0,32
2017 Q1	0,67	1,67	0,45
Average	**2,05**	**2,68**	**2,05**

(Thomson Reuters, 2017)

Appendix B – Forward Prices

Forward Prices – Electricity (€/MWh)

Product Series	*Bid* (€/MWh)	*Ask* (€/MWh)	*Last* (€/MWh)
ENOFUTBLYR-18	23,31	23,40	23,40
ENOFUTBLYR-19	21,55	21,65	21,65
ENOFUTBLYR-20	21,45	21,70	21,60

(NASDAQ OMX, 2017,03.04)

Forward Prices - TGC (SEK/MWh)*

Product	*Bid (SEK/MWh)*	*Ask (SEK/MWh)*	*Close (SEK/MWh)*
Spot	70,0	75,0	71,0
Mar-18	70,0	75,0	73,5
Mar-19	65,0	70,0	69,0
Mar-20	65,0	70,0	67,5
Mar-21	65,0	70,0	66,5
Mar-22	60,0	70,0	66,0

(Svensk Kraftmâkling, 2017b)

*Converted from SEK to EUR by using the average 10-year historical currency:

Date	*EUR per SEK*
31.12.2007	0,106017326
31.12.2008	0,091168259
31.12.2009	0,097503315
31.12.2010	0,110966664
31.12.2011	0,111752832
31.12.2012	0,116492566
31.12.2013	0,112909947
31.12.2014	0,105799793
31.12.2015	0,108971529
31.12.2016	0,104348743
Average	*0,106593097*

(XE Live Exchange Rates, 2017)

Appendix C – Investment Cost

Inputs

Learning rate (L)	10%
PR	0,9
Degree of learning	-0,152

Increase Cumulative Capacity

Year	*Cumulative Capacity*	*Increase %*
2008	120 696	
2009	159 052	32%
2010	197 956	24%
2011	238 110	20%
2012	282 850	19%
2013	318 697	13%
2014	369 862	16%
2015	432 680	17%
2016	486 749	12%

Average Increase in Cumucaltive Capacity

Years	*Average Increase %*
2008 - 2012	24%
2012 - 2016	15%

Norway

Year	*Learning Rate (L)*	*Degree of Learning (E)*	*Growth Rate (x(t))*	*x(t)*	*Investment Cost (€/kW)*
2012				1,00	1 592
2013	10%	-0,152	15%	1,15	1 559
2014	10%	-0,152	15%	1,30	1 530
2015	10%	-0,152	15%	1,45	1 505
2016	10%	-0,152	15%	1,60	1 482
2017	10%	-0,152	15%	1,75	1 462

Denmark

Year	*Learning Rate (L)*	*Degree of Learning (E)*	*Growth Rate (x(t))*	*x(t)*	*Investment Cost (€/kW)*
2012				1,00	1 273
2013	10%	-0,152	15%	1,15	1 246
2014	10%	-0,152	15%	1,30	1 223
2015	10%	-0,152	15%	1,45	1 203
2016	10%	-0,152	15%	1,60	1 185
2017	10%	-0,152	15%	1,75	1 169

Sweden

Year	*Learning Rate (L)*	*Degree of Learning (E)*	*Growth Rate (x(t))*	*x(t)*	*Investment Cost (€/kW)*
2008					1 591
2009	10%	-0,152	24%	1,24	1 540
2010	10%	-0,152	24%	1,48	1 499
2011	10%	-0,152	24%	1,72	1 465
2012	10%	-0,152	24%	1,96	1 436
2013	10%	-0,152	15%	2,11	1 420
2014	10%	-0,152	15%	2,26	1 406
2015	10%	-0,152	15%	2,41	1 392
2016	10%	-0,152	15%	2,56	1 379
2017	10%	-0,152	15%	2,71	1 367

Appendix D – O&M Costs

Decline in O&M Costs

	Decline (2008-2012)	*Annual Decline*
Norway	0	0
Denmark	-0,052	-0,013
Sweden	-0,026	-0,006

Average Decline in O&M Costs (Norway and Denmark)

-0,0259

Appendix E – Net Present Value Analysis

Norway

Inputs

Annual Production (kWh)	96 000 000
Capacity (kW)	30 000
Investment Cost (€/kW)	€ 1 462
Electricity Price (€/kWh)	€ 0,022
TGC Price (€/kWh)	€ 0,007
O&M Costs (€/kWh)	€ 0,015
Decommissioning Cost (€/kW)	€ 1,460
Inflation	2,50%
Tax	25,00%
WACC	5,24%

Depreciation

Year	*Depreciation*
1	€ 6 579 810
2	€ 6 579 810
3	€ 6 579 810
4	€ 6 579 810
5	€ 6 579 810
Sum	€ 32 899 050

Wind turbines, grid installations and foundations are depreciated on a straight line over five years. This is assumed to amount 75% of the investment cost.

Cash Flow Analysis (Norway)

Year	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
Investment cash flow										
Investment cost	-43 865 400									
Cash inflows										
Electricity price		2 112 000	2 164 800	2 218 920	2 274 393	2 331 253	2 389 534	2 449 273	2 510 504	2 573 267
TGC price		672 000	688 800	706 020	723 671	741 762	760 306	779 314	798 797	818 767
Total cash inflow		**2 784000**	**2 853 600**	**2 924 940**	**2 998 064**	**3 073 015**	**3 149 840**	**3 228 586**	**3 309 301**	**3 392 034**
Cash outflows										
O&M costs		-1 440 000	-1 476 000	-1 512 900	-1 550 723	-1 589 491	-1 629 228	-1 669 959	-1 711 707	-1 754 500
Decommission cost										
Total cash outflow		**-1 440 000**	**-1 476 000**	**-1 512 900**	**-1 550 723**	**-1 589 491**	**-1 629 228**	**-1 669 959**	**-1 711 707**	**-1 754 500**
Tax effects										
Profit before depreciation and tax	-43,865,400	1 344 000	1 377 600	1 412 040	1 447 341	1 483 525	1 520 613	1 558 628	1 597 594	1 637 533
Depreciation		-6 579 810	-6 579 810	-6 579 810	-6 579 810	-6 579 810				
Loss carryforwards		-5 235 810	-5 202 210	-5 167 770	-5 132 469	-5 096 285	-	-	-	-
Taxable income		-	-	-	-	-	-	-	-	-
Tax		-	-	-	-	-	-	-	-	-
Net cash flows after tax	**-43 865 400**	**1 344 000**	**1 377 600**	**1 412 040**	**1 447 341**	**1 483 525**	**1 520 613**	**1 558 628**	**1 597 594**	**1 63 7533**
Net present value	***- 26 245 605***									

	10	11	12	13	14	15	16	17	18	19	20
Investment cash flow											
Investment cost											
Cash inflows											
Electricity price	2 637 599	2 703 539	2 771 127	2 840 405	2 911 415	2 984 201	3 058 806	3 135 276	3 213 658	3 293 999	3 376 349
TGC price	839 236	860 217	881 722	903 765	926 359	949 518					
Total cash inflow	**3 476 835**	**3 563 755**	**3 652 849**	**3 744 170**	**3 837 775**	**3 933 719**	**3 058 806**	**3 135 276**	**3 213 658**	**3 293 999**	**3 376 349**
Cash outflows											
O&M costs	-1 798 363	-1 843 322	-1 889 405	-1 936 640	-1 985 056	-2 034 682	-2 085 549	-2 137 688	-2 191 130	-2 245 909	-2 302 056
Decommission cost											-43 800
Total cash outflow	**-1 798 363**	**-1 843 322**	**-1 889 405**	**-1 936 640**	**-1 985 056**	**-2 034 682**	**-2 085 549**	**-2 137 688**	**-2 191 130**	**-2 245 909**	**-2 345 856**
Tax effects											
Profit before depreciation and tax	1 678 472	1 720 434	1 763 444	1 807 531	1 852 719	1 899 037	973 256	997 588	1 022 527	1 048 091	1 030 493
Depreciation											
Loss carryforwards	-	-	-	-	-	-	-	-	-	-	-
Taxable income	-	-	-	-	-	-	-	-	-	-	-
Tax	-	-	-	-	-	-	-	-	-	-	-
Net cash flows after tax	**1 678 472**	**1 720 434**	**1 763 444**	**1 807 531**	**1 852 719**	**1 899 037**	**973 256**	**997 588**	**1 022 527**	**1 048 091**	**1 030 493**

Taxable Income After Depreciation and Loss Carryforwards (Norway)

Year	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
Taxable income after depreciation, but before loss carryforwards	-	-	-	-	-	1 520 613	1 558 628	1 597 594	1 637 533
Loss carryforwards	-5 235 810	-5 202 210	-5 167 770	-5 132 469	-5 096 285	-	-	-	-
Sum loss carryforwards	-5 235 810	-10 438 020	-15 605 790	-20 738 259	-25 834 544	-24 313 932	-22 755 304	-21 157 710	-19 520 177
Taxable income after depreciation and loss carryforwards	-	-	-	-	-	-	-	-	-

Year	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
Taxable income after depreciation, but before loss carryforwards	1 678 472	1 720 434	1 763 444	1 807 531	1 852 719	1 899 037	973 256	997 588	1 022 527	1 048 091	1 030 493
Loss carryforwards	-	-	-	-	-	-	-	-	-	-	-
Sum loss carryforwards	-17 841 705	-16 121 271	-14 357 827	-12 550 296	-10 697 577	-8 798 541	-7 825 284	-6 827 696	-5 805 169	-4 757 078	-3 726 585
Taxable income after depreciation and loss carryforwards	-	-	-	-	-	-	-	-	-	-	-

Denmark

Inputs

Annual Production (kWh)	90 000 000
Capacity (kW)	30 000
Investment Cost (€/kW)	1 169
Electricity Price (€/kWh)	0,022
FIP (€/kWh)	0,034
Compensation to Cover Balancing Cost (€/kWh)	0,002
O&M Costs (€/kWh)	0,012
Decommissioning Cost (€/kW)	1,169
Inflation	2,00%
Tax	22,00%
WACC	4,42%

FIP

Year	*Full Load Hours*
1	3 000
2	3 000
3	600

FIP = 0,034 €/kWh for the first 6 600 full load hours.

Depreciation (Denmark)

Year	*Depreciation*	*Rest*
		€ 26 306 822
1	€ 3 946 023	€ 22 360 798
2	€ 3 354 119	€ 19 006 678
3	€ 2 851 001	€ 16 155 677
4	€ 2 423 351	€ 13 732 325
5	€ 2 059 848	€ 11 672 476
6	€ 1 750 871	€ 9 921 605
7	€ 1 488 240	€ 8 433 364
8	€ 1 265 004	€ 7 168 359
9	€ 1 075 253	€ 6 093 105
10	€ 913 965	€ 5 179 139
11	€ 776 870	€ 4 402 268
12	€ 660 340	€ 3 741 928
13	€ 561 289	€ 3 180 639
14	€ 477 095	€ 2 703 543
15	€ 405 531	€ 2 298 011
16	€ 344 701	€ 1 953 310
17	€ 292 996	€ 1 660 313
18	€ 249 047	€ 1 411 266
19	€ 211 689	€ 1 199 576
20	€ 1 199 576	0

Wind turbines, grid installations and foundations are depreciated with a rate of 15% annually. This is assumed to amount 75% of the investment cost.

Cash Flow Analysis (Denmark)

	0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
Investment cash flow										
Investment cost	-35 075 763									
Cash inflows										
Electricity price		1 980 000	2 019 600	2 059 992	2 101 192	2 143 216	2 186 080	2 229 802	2 274 398	2 319 886
Feed-in premium (FIP)		3 060 000	3 060 000	612 000	-	-	-	-	-	-
Balancing cost		180 000	180 000	180 000	180 000	180 000	180 000	180 000	180 000	180 000
Total cash inflow		**5 220 000**	**5 259 600**	**2 851 992**	**2 281 192**	**2 323 216**	**2 366 080**	**2 409 802**	**2 454 398**	**2 499 886**
Cash outflows										
O&M costs		-1 080 000	-1 101 600	-1 123 632	-1 146 105	-1 169 027	-1 192 407	-1 216 255	-1 240 581	-1 265 392
Decommission cost										
Total cash outflow		**-1 080 000**	**-1 101 600**	**-1 123 632**	**-1 146 105**	**-1 169 027**	**-1 192 407**	**-1 216 255**	**-1 240 581**	**-1 265 392**
Tax effects										
Profit before depreciation and tax	-35 075 763	4 140 000	4 158 000	1 728 360	1 135 087	1 154 189	1 173 673	1 193 546	1 213 817	1 234 493
Depreciation		-3 946 023	-3 354 120	-2 851 002	-2 423 352	-2 059 849	-1 750 872	-1 488 241	-1 265 005	-1 075 254
Loss carryforwards		-	-	-1 122 642	-1 288 264	-905 660	-577 199	-294 695	-51 188	-
Taxable income		193 977	803 880	-	-	-	-	-	-	-
Tax		-4 2675	-17 6854	-	-	-	-	-	-	-
Net cash flows after tax	**-35 075 763**	**4 097 325**	**3 981 146**	**1 728 360**	**1 135 087**	**1 154 189**	**1 173 673**	**1 193 546**	**1 213 817**	**1 234 493**
Net present value	***-13 500 032***									

	10	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
Electricity price	2 366 283	2 413 609	2 461 881	2 511 119	2 561 341	2 612 568	2 664 819	2 718 116	2 772 478	2 827 928	2 884 486
Feed-in premium (FIP)	-	-	-	-	-	-	-	-	-	-	-
Balancing cost	180 000	180 000	180 000	180 000	180 000	180 000	180 000	180 000	180 000	180 000	180 000
Total cash inflow	2 546 283	2 593 609	2 641 881	2 691 119	2 741 341	2 792 568	2 844 819	2 898 116	2 952 478	3 007 928	3 064 486
O&M costs	-1 290 700	-1 316 514	-1 342 844	-1 369 701	-1 397 095	-1 425 037	-1 453 538	-1 482 609	-1 512 261	-1 542 506	-1 573 356
Decommission cost											-35 100
Total cash outflow	-1 290 700	-1 316 514	-1 342 844	-1 369 701	-1 397 095	-1 425 037	-1 453 538	-1 482 609	-1 512 261	-1 542 506	-1 608 456
Profit before depreciation and tax	1 255 583	1 277 095	1 299 037	1 321 418	1 344 246	1 367 531	1 391 282	1 415 507	1 440 217	1 465 422	1 456 030
Depreciation	-913 966	-776 871	-660 340	-561 289	-477 096	-405 532	-344 702	-292 997	-249 047	-211 690	-1 199 577
Loss carryforwards	-	-	-	-	-	-	-	-	-	-	-
Taxable income	-	-	-	-	-	951 408	1 046 580	1 122 511	1 191 170	1 253 732	256 453
Tax	-	-	-	-	-	-209 310	-230 248	-246 952	-262 057	-275 821	-56 420

1 255 583	1 277 095	1 299 037	1 321 418	1 344 246	1 158 221	1 161 034	1 168 555	1 178 160	1 189 601	1 399 610

Taxable Income After Depreciation and Loss Carryforwards (Denmark)

Year	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
Taxable income after depreciation, but before loss carryforwards	193 977	803 880	-	-	-	-	-	-	159 239	341 617	500 224	638 697	760 128	867 150	961 999	1 046 580	1 122 511	1 191 170	1 253 732	256 453
Loss carryforwards	-	-	-1 122 642	-1 288 264	-905 660	-577 199	-294 695	-51 188	-	-	-	-	-	-	-	-	-	-	-	-
Sum loss carryforwards	-	-	-1 122 642	-2 410 906	-3 316 566	-3 893 765	-4 188 459	-4 239 647	-4 080 408	-3 738 790	-3 238 566	-2 599 870	-1 839 741	-972 591	-10 592	-	-	-	-	-
Taxable income after loss carryforwards	193 977	803 880	-	-	-	-	-	-	-	-	-	-	-	-	951 408	046 580	1 122 511	1 191 170	1 253 732	256 453

Sweden

Inputs

Annual Production (kWh)	87 000 000
Capacity (kW)	30 000
Investment Cost (€/kW)	1 367
Electricity Price (€/kWh)	0,022
TGC Price (€/kWh)	0,007
O&M Costs (€/kWh)	0,014
Decommissioning Cost (€/kW)	1,367
Inflation	2,00 %
Tax	25,00 %
WACC	5,34 %

Depreciation

Year	*Depreciation*
1	6 152 761
2	6 152 761
3	6 152 761
4	6 152 761
5	6 152 761
Sum	30 763 803

Wind turbines, grid installations and foundations are depreciated on a straight line over five years. This is assumed to amount 75% of the investment cost.

Year	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
Investment cash flow										
Investment cost	-41 018 404									
Cash inflows										
Electricity price		19 14 000	1 952 280	1 991 326	2 031 152	2 071 775	2 113 211	2 155 475	2 198 584	2 242 556
TGC Price		609 000	621 180	633 604	646 276	659 201	672 385	685 833	699 550	713 541
Total cash inflow		**2 523 000**	**2 573 460**	**2 624 929**	**2 677 428**	**2 730 976**	**2 785 596**	**2 841 308**	**2 898 134**	**2 956 097**
Cash outflows										
O&M costs		-1 230 502	-1 255 112	-1 280 214	-1 305 819	-1 331 935	-1 358 574	-1 385 745	-1 413 460	-1 441 729
Decommission cost										
Total cash outflow		**-1 230 502**	**-1 255 112**	**-1 280 214**	**-1 305 819**	**-1 331 935**	**-1 358 574**	**-1 385 745**	**-1 413 460**	**-1 441 729**
Tax effects										
Profit before depreciation and tax	-41 018 404	1 292 498	1 318 348	1 344 715	1 371 609	1 399 041	1 427 022	1 455 563	1 484 674	1 514 367
Depreciation		-6 152 761	-6 152 761	-6 152 761	-6 152 761	-6 152 761				
Loss carryforwards		-4 860 263	-4 834 413	-4 808 046	-4 781 151	-4 753 719	-	-	-	-
Taxable income		-	-	-	-	-	-	-	-	-
Tax		-	-	-	-	-	-	-	-	-
Net cash flows after tax	**-41 018 404**	**1 292 498**	**1 318 348**	**1 344 715**	**1 371 609**	**1 399 041**	**1 427 022**	**1 455 563**	**1 484 674**	**1 514 367**
Net present value	***-24 322 229***									

Cash Flow Analysis (Sweden)

Year	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
Investment cash flow											
Investment cost											
Cash inflows											
Electricity price	2 287 407	2 333 155	2 379 818	2 427 415	2 475 963	2 525 482	2 575 992	2 627 512	2 680 062	2 733 663	2 788 337
TGC Price	727 811	742 368	757 215	772 359	787 806	803 563					
Total cash inflow	**3 015 219**	**3 075 523**	**3 137 033**	**3 199 774**	**3 263 770**	**3 329 045**	**2 575 992**	**2 627 512**	**2 680 062**	**2 733 663**	**2 788 337**
Cash outflows											
O&M costs	-1 470 564	-1 499 975	-1 529 975	-1 560 574	-1 591 786	-1 623 621	-1 656 094	-1 689 216	-1 723 000	-1 757 460	-1 792 609
Decommission cost											-41 100
Total cash outflow	**-1 470 564**	**-1 499 975**	**-1 529 975**	**-1 560 574**	**-1 591 786**	**-1 623 621**	**-1 656 094**	**-1 689 216**	**-1 723 000**	**-1 757 460**	**-1 833 709**
Tax effects											
Profit before depreciation and tax	1 544 655	1 575 548	1 607 059	1 639 200	1 671 984	1 705 424	919 898	938 296	957 062	976 203	954 628
Depreciation											
Loss carryforwards	-	-	-	-	-	-	-	-	-	-	-
Taxable income	-	-	-	-	-	-	-	-	-	-	-
Tax	-	-	-	-	-	-	-	-	-	-	-
Net cash flows after tax	**1 544 655**	**1 575 548**	**1 607 059**	**1 639 200**	**1 671 984**	**1 705 424**	**919 898**	**938 296**	**957 062**	**976 203**	**954 628**

Taxable Income After Depreciation and Loss Carryforwards (Sweden)

Year	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
Taxable income after depreciation, but before loss carryforwards	-	-	-	-	-	1 427 022	1 455 563	1 484 674	1 514 367
Loss carryforwards	-4 860 263	-4 834 413	-4 808 046	-4 781 152	-4 753 719	-	-	-	-
Sum loss carryforwards	-4 860 263	-9 694 675	-14 502 721	-19 283 873	-24 037 592	-22 610 570	-21 155 007	-19 670 333	-18 155 966
Taxable income after loss carryforwards	-	-	-	-	-	-	-	-	-

10	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
1 544 655	1 575 548	1 607 059	1 639 200	1 671 984	1 705 424	919 898	938 296	957 062	976 203	954 628
-	-	-	-	-	-	-	-	-	-	-
-16 611 311	-15 035 763	-13 428 704	-11 789 504	-10 117 520	8 412 097	-7 492 198	-6 553 902	-5 596 840	-4 620 637	-3 666 009
-	-	-	-	-	-	-	-	-	-	-

Appendix F – Correlation

Correlation - Electricity Price and TGC Price

	TGC price	*Electricity price*
TCG price	1	0,412550273
Electricity price	0,412550273	1

Regression Statistics

Multiple R	0,412550273
R-squared	0,170197728
Adjusted R-squared	0,156594412
Standard deviation	0,003556783
Observations	63
P-value	0,000779597

P-value = 0,0008 < alpha = 0,05, hence the correlation is significant

Correlation – Investment Cost and O&M Costs

	Investment Cost	*O&M Costs*
Investment Cost	1	0,4
O&M Costs	0,4	1

Correlation – Investment Cost and Decommissioning Cost

	Investment Cost	*Decommissioning Cost*
Investment Cost	1	1
Decommissioning Cost	1	1

Appendix G – Monte Carlo Simulation

Norway

Risksimtable Values for the Discount Rate

2,59%	5,24%	7,77%

Parameters for Triangular Distributions

Inputs	*Minimum*	*Most likely*	*Maximum*
Investment Cost	€ 1 170	€ 1 462	€ 1 755
Electricity Price	€ 0,010	€ 0,022	€ 0,040
TGC Price	€ 0,005	€ 0,007	€ 0,025
O&M Costs	€ 0,012	€ 0,015	€ 0,018
Decommissioning Cost	€ 1,169	€ 1,460	€ 1,754

Denmark

Risksimtable Values for the Discount Rate

2,03%	4,42%	6,08%

Parameters for Triangular Distributions

Inputs	*Minimum*	*Most likely*	*Maximum*
Investment Cost	€ 935	€ 1 169	€ 1 403
Electricity Price	€ 0,010	€ 0,022	€ 0,040
Compensation to Cover Balancing Cost	€ 0,001	€ 0,002	€ 0,003
O&M Costs	€ 0,010	€ 0,012	€ 0,014
Decommissioning Cost	€ 0,935	€ 1,170	€ 1,403

Sweden

Risksimtable Values for the Discount Rate

2,36%	5,34%	7,07%

Parameters for Triangular Distributions

Inputs	*Minimum*	*Most likely*	*Maximum*
Investment Cost	€ 1 094	€ 1 367	€ 1 641
Electricity Price	€ 0,010	€ 0,022	€ 0,040
TGC Price	€ 0,005	€ 0,007	€ 0,025
O&M Costs	€ 0,011	€ 0,014	€ 0,017
Decommissioning Cost	€ 1,093	€ 1,370	€ 1,640