NTNU – Trondheim
Norwegian University of
Science and Technology

Investment in hydropower plants under uncertainty

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Industrial Economics and Technology Management
Submission date: June 2013
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- uttak av masteroppgave

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Studieprogram	Hovedprofil
Industriell økonomi og teknologiledelse	**Investering, finans og økonomistyring**

3. Masteroppgave

Oppstartsdato	Innleveringsfrist
15. jan 2013	**11. jun 2013**
Oppgavens (foreløpige) tittel	
Investment in hydropower plants under uncertainty	
Oppgavetekst/Problembeskrivelse	
This thesis analyses investment in small hydropower plants. There are hundreds of such plants built in Norway the last 10-15 years, and the thesis will complete an existing dataset containing information about individual power plants. A theoretical model of the investment decision will be developed, and the data will be used to test the validity of the theory.	
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4. Underskrift

Student: Jeg erklærer herved at jeg har satt meg inn i gjeldende bestemmelser for mastergradsstudiet og at jeg oppfyller kravene for adgang til å påbegynne oppgaven, herunder eventuelle praksiskrav.

Partene er gjort kjent med avtalens vilkår, samt kapitlene i studiehåndboken om generelle regler og aktuell studieplan for masterstudiet.

Trondheim, 11.01.13

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Originalen lagres i NTNUs elektroniske arkiv. Kopi av avtalen sendes til instituttet og studenten.

Preface

This thesis serves as the final part of the Master of Science in Industrial Economics and Technology Management. It is a result of continuous working effort since January 2013.

The author would like to thank supervisor Professor Stein-Erik Fleten and co-supervisor Ph.D. Peter Molnar at the Norwegian University of Science and Technology for many helpful comments and suggestions. The author would also like to thank Ane Marte Heggedal, Kristin Linnerud and Trine Boomsma for allowing to build on their previous work with the data set and the real options model. In addition, the author is in debt to NVE and investors kindly providing the necessary information and Småkraftforeininga for the ability to participate in the congress Småkraftdagane which provided valuable and up-to-date insights into the industry of small hydropower plants.

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Abstract

Faculty of Social Sciences
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Master of Science

Investment in Small Hydropower Plants Under Uncertainty

by Maria Tandberg Nygård

Investment in renewable energy production in Norway is since the 1st of January 2012 granted subsidies through a market for elcertificates common with Sweden. The underlying purpose is to reach the Norwegian and Swedish government's goal of adding 26.4 TWh of renewable generation capacity within 2020. This thesis considers how the introduction of elcertificates has affected the expectations of investors investing in small hydropower plants in Norway. Data from 214 licenses granted from 2001 including 2008 are used to replicate the investor's decision problem. By taking a real options approach, investment timing and uncertainty in electricity and subsidy prices are considered. Solving for the required subsidy level for investment to be optimal, one can study the implicit expectation towards the elcertificates at the realized timing of investment. The analytical solution shows that the average investor expected subsidies in line with prices in the Swedish elcertificate market according to the optimal decision rule. Additionally, real options theory seems to better explain investment behaviour compared to the NPV rule, as investors were found to respond to subsidy uncertainty according to our predictions.

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Sammendrag

Fakultet for samfunnsvitenskap og teknologiledelse
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Sivilingeniør

Investering i småkraftverk under usikkerhet

av Maria Tandberg Nygård

Investering i fornybar energi i Norge har siden 1. Januar 2012 blitt tildelt subsidier gjennom et felles marked for elsertifikater med Sverige. Hensikten er å tilføre 26.4 TWh ny fornybar energi innen 2020, et mål satt av den norske og svenske regjeringen i fellesskap. Denne masteroppgaven omhandler effekten introduseringen har hatt på forventningene og investeringsoppførselen til småkraftinvestorer. Data fra 214 lisenser tildelt i tidsrommet 2001–2008 er brukt til å replikere investorens beslutningsgrunnlag. Ved å bruke en realopsjonsmodell tar vi hensyn til både valg av investeringstidspunkt og usikkerhet i forhold til inntekter fra salg av strøm og elsertifikater. Løser vi for subsidienivået som gjør det lønnsomt å investere, kan vi studere den implisitte forventningen til subsidier ved faktisk investeringstidspunkt. Den analytiske løsningen viser at investorene forventet subsidier på størrelse med de svenske elsertifikatene ifølge den optimale beslutningsregelen. I tillegg finner vi at realopsjonsteori gir en bedre forklaring av investeringsoppførselen enn NPV, da investorene responderte på usikkerheten som forespeilet.

Contents

Symbols

A	Scaling term in the Bellman solution	
B	After tax proportion of revenue	%
c_0	Annual maintenance cost at time 0	€/MWh/y
C	Discounted value of all maintenance cost	€/MWh/y
$F(P, S)$	Project value	€/MWh/y
I_0	Investment cost at time 0	€/MWh/y
I	Investment cost plus present value of maintenance cost	€/MWh/y
L	Threshold for size when evaluating taxes	MVA
P	Price of electricity	€/MWh
P^*	Price of electricity at optimal investment point	€/MWh
Q	Expected annual production	MWh/y
$Q(\beta_P, \beta_S)$	The fundamental quadratic equation	
R	Rated power	MW
S	Price of subsidy (i.e. elcertificates)	€/MWh
S^*	Price of subsidy at optimal investment point	€/MWh
T_P	Life time of the power plant	Years
T_{S_1}	Lag in revenue from subsidies	Years
T_{S_2}	Duration of subsidies	Years
$V(P, S)$	Expected present value of revenue	€/MWh/y
X	Constant term arising due to taxes	€/MWh/y
α_P	Electricity price drift rate	%
α_S	Subsidy price drift rate	%
β_P	Exponent of P in the Bellman solution	
β_S	Exponent of S in the Bellman solution	
δ	Lease rate	%
$\eta(P)$	Variable created for substitution	
$\rho_{P,S}$	Correlation between $\mathrm{d}z_P$ and $\mathrm{d}z_S$	

σ_P	Electricity price volatility	%
σ_S	Subsidy volatility	%
$\tau_{Economic\ rent}$	Tax rate for economic rent tax	%
τ_{Profit}	Tax rate for profit tax	%
$\tau_{Property}$	Tax rate for property tax	%
$\mathrm{d}t$	Increment in time	
$\mathrm{d}z$	Brownian motion	
i	Expected inflation rate	%
r	Required rate of return	%
r_C	Discount term	
r_P	Discount term	
r_R	Discount term	
r_S	Discount term	
r_{Norm}	Norm rent	%
r_{Debt}	Debt interest rate	%
$Upper\ Limit$	Upper limit for property value in property tax	€/MWh/y

Chapter 1

Introduction

In this thesis, 214 licenses to build small hydropower plants in Norway are examined. Knowing whether an investment decision for each license was made and when, we can by use of a real options model try to infer if the investors believed they would receive subsidies through elcertificates, or not. We do this by backing out the implied expectations to elcertificates at the time of investment assuming the investor follows the optimal decision rule in real options theory. As some investors might view the license as a now-or-never opportunity, we will in addition calculate the implied subsidy using the net present value (NPV) rule. We will compare the results and discuss which model seems to best represent the data.

Investment in small hydropower plants is in a special position, along with investments in wind power, because there has been political discussions about subsidies since 2001. Small hydropower plants are characterized by a maximum installed power of 10MW. The though was initially that the subsidies would be given through a market for elcertificates common for Norway and Sweden, but it was not before 2011 that the subsidies were passed by law in Norway. The market in Sweden was up and running from May 2003. The subsidies are a response to the EU directives 2001/77/EC and 2009/28/EC promoting the use of renewable energy sources, where only the latter was binding for the Norwegian government. In 2010, it materialized in an agreement between the governments in Sweden and Norway committing to increase the amount of new renewable energy with 26.4 TWh within 2020 using a common market for elcertificates (Ministry of Petroleum and Energy, 2010). By investigating licenses granted between 2001 and 2008 we precede the introduction of this market in Norway, which did not become active before 1st January 2012. The motivation for a common market, instead of two separate, was to achieve a more cost-efficient development through higher liquidity, lower price volatility and lower political risk.

All those years of political discussion led to policy uncertainty for the investors. Dixit and Pindyck (1994) state that "If governments wish to stimulate investments, perhaps the worst thing they can do is to spend a long time discussing the right way to do so.". Addressing this, the Minister of Petroleum and Energy promised a transitional agreement in a press release stating that all who invested after 1st January 2004 would be included in the subsidy scheme when introduced (Ministry of Petroleum and Energy, 2003). However, a few years later negotiations with Sweden broke down. In December 2007 negotiations were revitalized and in 2009 a second transitional agreement was promised by the Minister of Petroleum and Energy. Then, only plants built after 7th September 2009 would be subject to elcertificates.

During this period, investors in Norway had varying expectations to whether they would receive subsidies or not. Some were sitting on the fence waiting for a final confirmation, others invested knowing that their projects would be profitable regardless of any subsidy scheme. Others again invested believing they would receive subsidies based on the promised transitional arrangement. The goal of this thesis is to try to infer whether the investors who made an investment decision expected revenue from subsidies and if they responded to the uncertainty as predicted by theory.

To model the investment decision a real options model inspired by Boomsma and Linnerud (2013) is used. Using a real options model, we are able to incorporate uncertainties with respect to revenue and investment timing. We are also able to account for the value of waiting for more information. Both the price of electricity and the price of elcertificates are taken as stochastic, resulting in a two-factor model. The investment cost is modelled as constant and constitutes a sunk cost once the investment decision is made, as the investment decision is irreversible. The solution to the model has one degree of freedom, and can therefore only be solved by specifying one of the variables. We have chosen to specify the electricity price, making it possible to solve for the required subsidy level for investment to be optimal.

Even though few investors have heard about real options theory, it is not said that they do not behave accordingly. Over time, investors can develop their own decision rules which are similar to what predicted by theory. Kellogg (2010) state that real options is consistent with the existence of a strong incentive for firms to behave optimally. He finds that the cost of failing to respond to changes in volatility can be substantial. Thus, there are good motivation for taking a real options approach.

Real options theory start with Merton (1973) and Black and Scholes (1973) who were the first to link the financial options theory to decision making. McDonald and Siegel (1986) further described the value of waiting to invest in irreversible projects. There are mainly two methods in evaluating a real option (Dixit and Pindyck, 1994). The most common is the contingent claim analysis, which makes use of a replicating portfolio creating a risk-neutral investment. The other, is the dynamic programming method solved recursively. Dynamic programming is the choice of model here because it is impossible for a power producer to completely mitigate the risk, as revenue is depending on precipitation. Also, a market for elcertificate risk does not exist and entering bilateral agreement for the whole production would become very expensive. Thus, creating a replicating portfolio causes difficulties, even though it could be done by estimating an endogenous discount rate.

Limitations to the dynamic programming approach is the assumption of time consistency, that the investor has no incentive to deviate from the strategy that was calculated by the model before any decisions are actually made. This is called an ex ante approach and is closely connected to the assumption that decision makers are expected utility maximizers through the linearity properties of expectations. Rust (2006) points out that ”the linearity property of expected utility appears to be a key property that is violated in numerous experimental studies that have found that human decision making under uncertainty is inconsistent with expected utility maximization.”. Thus, dynamic programming will not always find the correct solution.

There are developed numerous applications of real options to the energy industry. Tourinho (1979) examines the option to wait in valuing natural resources. Brennan and Schwartz (1985) also use real options theory to evaluate natural resource investments and stresses the importance of treating output prices as stochastic when price swings are high. This is particularly the case for many natural resource industries, including electricity. Fernandes et al. (2011) give a summary of all papers involving real options theory applied to renewable energy resources.

Previous work on policy uncertainty include amongst others Rodrik (1991), Mauer and Ott (1995) and Hassett and Metcalf (1999) who examine investor behaviour under an uncertain reform or tax law change. Blyth et al. (2007), Yang et al. (2008) and EIA (2007) discuss policy uncertainty with respect to climate policy and its implications for the choice of power producing technology. These studies generally find that uncertainty act as a hefty tax on investment or as a risk premium for investors. Boomsma et al. (2012) analyse investment timing and capacity choice for renewable energy projects under different support schemes, namely feed-in-tariffs and renewable energy certificate trading. The approach is a three-factor contingent claim analysis used on a wind power case study. Adkins and Paxson (2013) derive the optimal investment timing and real option value for a renewable energy facility with price and quantity uncertainty, where there might be a government subsidy proportional to the quantity of production. Boomsma and Linnerud (2013) analyse the risk of a switch from the current support scheme at some random future point in time, using a case study for an onshore wind power project. Applying a two-factor model, they have the ability to model the support scheme as either price-driven (fixed price premium) or quantitative-driven (stochastic price premium).

The real options model in this thesis is applied to high quality data obtained from the regulatory database which is verified or updated through interviews. The dataset was originally gathered in 2011 and used by Heggedal et al. (2013). It is updated and extended by contacting the license holders that did not respond previously or had not made a decision to investment in 2011. The overall response rate is 99% (211 of 214 plants).

Empirical research on real options began with Paddock et al. (1988), Quigg (1993), and Moel and Tufano (2002). They all find empirical support for a model that incorporates the option to wait. Case studies on real options in the Nordic electricity market include Bøckman et al. (2008), Fleten et al. (2007) and Fleten and Ringen (2009), where the first focus on investment timing and optimal capacity choice for small hydropower projects.

The work closest related to this thesis is Heggedal et al. (2013) and Gravdehaug and Remmen (2011). Both applied a real options model to empirical data on licenses to build small hydropower plants in Norway and investigated whether policy uncertainty affected the timing of investment. Gravdehaug and Remmen (2011) had a smaller data set, with 74 licenses compared to 214. Both take the amount of subsidies and the electricity price as uncertain, but while Heggedal et al. (2013) and this thesis model revenue using Geometric Brownian motion (GBM), Gravdehaug and Remmen (2011) modeled it as Arithmetic Brownian motion (ABM). The solution in Heggedal et al. (2013) is found by simulation through least squares Monte Carlo, while Gravdehaug and Remmen (2011) reduces the two-factor model to a one-factor, as the first order homogeneous PDE for a two-factor problem has a known solution (McDonald and Siegel, 1986). This thesis thereby extend this area of research by applying an analytical solution to the two-factor investor's decision problem.

The main contribution of this thesis is that it is an empirical study in the stream of theoretical and case-study based papers on multi-factor real options models with Geometric Brownian motion diffusion processes. It follows recent progress in analytical and quasi-analytical solution methods by Gahungu and Smeers (2009), Rohlfs and Madlener (2011), Adkins and Paxson (2011) and Boomsma and Linnerud (2013). Also, to the best of our knowledge, few empirical studies have been conducted on investors' expectations under policy uncertainty. This contribution applies wider than just small hydropower plants, and could lead to insights in investment expectations under policy uncertainty with regards to all kinds of subsidies, not just elcertificates.

As the value of power plants is not available publicly, we do not completely know the firm's objective function and investor preferences. We therefore assume that the investor has rational expectations. The theories by Tversky and Kahneman (1975) on bounded rationality in behavioural economics explain why investor sometimes behave irrationally. They explain irrational behaviour with three heuristics that are commonly employed in judgement under uncertainty: i) assessment of representativeness, ii) assessment of availability and iii) adjustment from a starting point. Knowing that these heuristics are commonly employed, the assumption that investors are rational could affect our results. The method of structural estimation combats these pitfalls. Strebulaev and Whited (2012) claim that estimating structural models is useful because the connection between theory and tests of theory is extremely tight, thereby allowing a transparent interpretation of any result. Kellogg (2010) explain this further by stating "The use of this model allows me to do more than carry out a simple "yes/no" test of whether or not firms respond to changes in expected oil price volatility: I can also compare the magnitude of firms' responses in the data to the magnitude prescribed by the model.". There are mainly two approaches to structural estimation: Nested Fixed Point Algorithm (NFXP) (Rust, 1987) and Mathematical Programming with Equilibrium Constraints (MPEC) (Su and Judd, 2012). It is applied to real options theory in amongst others Morellec et al. (2008), Muehlenbachs (2009) and Kellogg (2010). Although a structural estimation approach would most likely improve our result, it is not applied here as it is outside of the scope of this thesis.

Throughout this thesis, the terms elcertificates, electricity certificates, green certificates, certificates and subsidies will be used all meaning the same. Readers must not make the mistake of misinterpreting the Guarantees of Origin as an elcertificate. A Guarantee of Origin is also traded in the market, but its purpose is merely as evidence to customers of the quality of the delivered electricity.

The thesis is organized as follows. Chapter 2 explain the purpose and mechanism behind elcertificates. Chapter 3 describe the investor's decision problem and the model using the real options framework. Chapter 4 present the data set and describe main findings. In Chapter 5, results from the real options model are discussed and Chapter 6 concludes.

Chapter 2

Elcertificates

This chapter focuses on describing the elcertificate as a policy instrument and the background for its existence. First, a review of the history behind the introduction of elcertificates will be given in Section 2.1. This will be followed by a description of the price determination and the market mechanisms in Section 2.2. Implications of the scheme for different types of renewable energy sources are discussed in Section 2.3.

2.1 The New Renewable Energy Target

As part of the EU directives 2009/28/EC and 2001/77/EC, Norway's and Sweden's governments have agreed to increase their countries overall renewable power production by 26.4 TWh within 2020. Put in perspective, the amount equals more than half of the current consumption for all Norwegian households (NVE, 2012). The increased production will be split equally when reporting to EU on the renewable targets. The elcertificates are introduced to address this goal by giving an economic incentive for investment. Jensen and Skytte (2003) found that it is always optimal to reach a renewable energy deployment goal by the use of green certificates.

A common market for elcertificates is now in place, but it has taken many years to get there. The market for elcertificates was established in Sweden May 2003. As from the beginning in 2001, the intention was that the market was to be common for Norway and Sweden. Negotiations broke down and consequently the market only included Sweden for many years. Subsequently, Norwegian legislators discussed not only subsidies through certificates, but alternatively a feed-in-premium in 2007. This was abandoned in 2008, as negotiations with Sweden were revitalized. A common market was finally determined in 2009, with start-up in 2012. As of 1st January 2012, Norwegian power producers and distributors have joined in and a common market is formed. A summary of publicly available information published by the Norwegian government during this period is presented in Table 2.1. It is reasonable to assume that investors were familiar with these statements.

But who is included in this subsidy scheme? All producers of *new* renewable energy are eligible to receive elcertificates, as long as they invest within a certain time frame. In Norway, all owners of hydropower plants who invest in new or upgraded capacity with initial building start after 1st January 2012, and before the end of 2020, are eligible. The investors will receive certificates throughout 15 years. In addition, some investors who invested prior to 2012 are subject to a transitional arrangement. For them, the number of years in operation before 2012 will be subtracted from the lifetime of the subsidies. The original transitional arrangement promised subsidies to plants built after 1st January 2004. However, in 2009 they reversed this, and the date was postponed to 7th September 2009. A few hydropower owners have gone into bankruptcy blaming the lack of subsidies. These days, the opposition promises to make amends with the investors who were cut out if they come to power, so the story is not finished yet.

To find the impact of the certificates for a single hydropower investor we can make a simple calculation of the present value of an annuity for 15 years after taxes. Here it is assumed that the revenue from elcertificates is 20 €/MWh, the profit tax rate is 28% and the after tax required return is 5%. To make the calculation independent of the size of the power plant, we calculate the present value on a per unit of production basis by dividing the investment cost with the expected annual production (e.g. €/MWh/y).

$$\begin{aligned} Revenue_{t=0}^{15} =& (1-\tau_{Profit})\frac{X_1}{r}\left[1-\frac{1}{(1+r)^n}\right] \\ =& (1-0.28)\frac{20}{0.05}\left[1-\frac{1}{1.05^{15}}\right] = 149.47 \end{aligned} \tag{2.1}$$

We find that the present value of the revenue from electricity certificates is approximately 150 €/MWh/y, which means that we can suffer an investment cost

Table 2.1: Publicly available information regarding hydropower subsidies published by the Norwegian government in the period 2002–2011

Year	**Information published by the government**	**Introduction year**
2002	The Ministry of Petroleum and Energy is positive to establishing an international certificate market and believe Norway should participate in it (Ministry of Petroleum and Energy, 2002).	-
2003	Parliament asks the Government to initiate a Swedish/Norwegian certificate market.	-
	The Petroleum and Energy Minister says power producers who initiate building after 1st January 2004 will have the opportunity to participate in the scheme, even though a scheme will be established afterwards (Ministry of Petroleum and Energy, 2003).	2004
2004	A draft on the Elcertificate Act is sent to external hearing. Start-up in 2006 is recommended by the Ministry (Ministry of Petroleum and Energy, 2004).	2006
2005	A common market is delayed one year (Ministry of Petroleum and Energy, 2005).	2007
2006	In the start of the year the negotiations break down. Already established policy instruments is said to be strengthened (Ministry of Petroleum and Energy, 2006a).	-
2007	A feed-in-premium will replace the certificate market. Hydropower will receive 5€/MWh for production representing the first 3MW of the installed capacity (Ministry of Petroleum and Energy, 2006b).	2008
2008	The feed-in-premium is put to hold and conversations with the Swedish government is revitalized (Ministry of Petroleum and Energy, 2007).	-
2009	The Swedish and the Norwegian government sign an agreement on the basic principles for the common market. Start-up is determined 2012 (Ministry of Petroleum and Energy, 2009a).	2012
	Transitional arrangements are decided to take place for power plants built after 7th September 2009. For power plants $\leq$ 1MW the previous date, 1st January 2004, is still maintained. The years prior to 2012 will be withdrawn from the 15 years of certificates (Ministry of Petroleum and Energy, 2009b).	
2010	The Swedish and Norwegian governments sign a protocol concluding the discussions on a system for renewable energy certificates (Ministry of Petroleum and Energy, 2010).	2012
2011	A draft on the Elcertificate Act was approved by the Council of State (Ministry of Petroleum and Energy, 2011).	2012

150 €/MWh/y higher than what was feasible before the subsidy scheme. This number coincides with figures released from Statkraft, one of Norway's largest hydropower producers. They indicate that they can increase their investment cost by 100 €/MWh/y compared to previous break-even points when including a subsidy price of 14 €/MWh for the future revenues, shown in Figure 2.1. For the uppermost plant displayed in grey (25MW/100GWh), the old break-even point **A** specified a maximum investment cost of 325 €/MWh/y given an expected future electricity price of 50 €/MWh. The new break-even point when we include subsidies **B**, lies at approximately 425 €/MWh/y. On the color scale on the x-axis it is indicated that an investment cost below 500 €/MWh/y is acceptable. Prior to the introduction of elcertificates, a project was said to be viable if the cost was below 375 €/MWh/y.

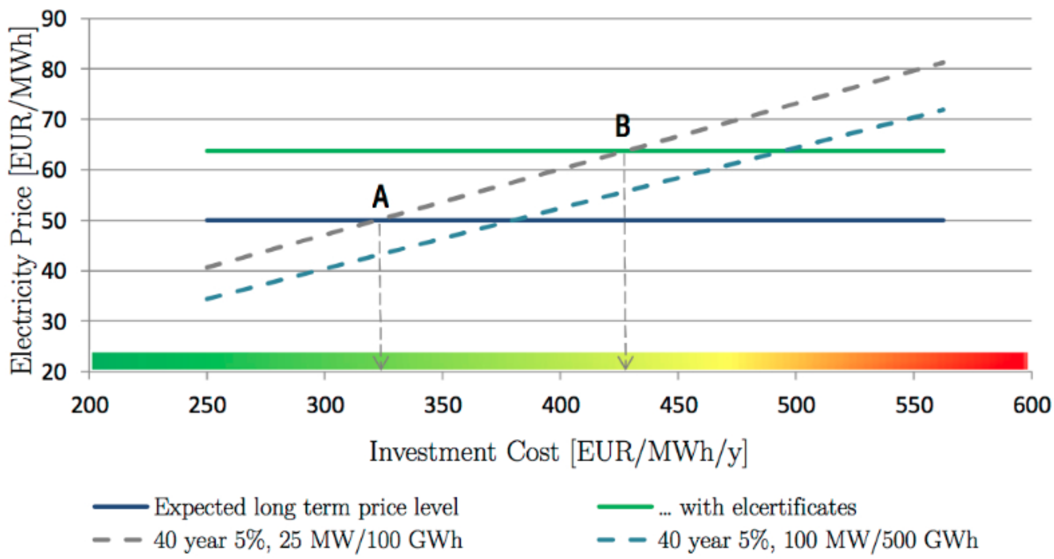


FIGURE 2.1: Break-even lines (dotted) for two large hydropower projects (Statkraft, 2012)

2.2 Price Determination

The economic principles behind the elcertificate market are similar to those for the electricity market. The Nordic electricity markets were liberalized during the 1990's and fully integrated from year 2000. Justification for liberalization was that economic efficiency would ensure that the most cost efficient plants were operating and invested in. Prices are determined in a common market through supply and demand, depending on a merit order curve. It should on average equal the long run marginal cost (LRMC) of investing in a new power plant (Wangensteen, 2012).

A detailed description of consumer-based tradable green certificate systems can be found in Schaeffer et al. (1999), Morthorst (2000), Amundsen and Mortensen (2001), Jensen and Skytte (2002), Jensen and Skytte (2003) and Fristrup (2003).

Morthorst (2003) discuss the separate introduction of an international tradable green certificate market into a liberalised power market. This is the way the market is arranged today. The thought is that the investor receives a twofold revenue - one part from sale of elcertificates and the other part from sale of electricity. Eligible power producers receive certificates according to their amount of production (e.g. MWh). Power distributors and some end users are mandatory buyers of certificates for a proportion of what they deliver or uses. Thus, the system is self-contained and requires no governmental support. Power distributors subsequently charge this on top of the consumer's energy bill. Consumers are on the other hand experiencing lower power prices due to the increased supply of energy. Producers who were already in the market before the scheme was implemented thereby experience lower revenue due to lower prices and end up as the ones paying for the scheme. In addition, some producers will find the price below their marginal production cost and reduce their production.

The proportional amount the power distributors have to buy is variable each year and given by the quota curve set by the Elcertificate Act §17, shown in Figure 2.2. This curve could be subject to changes, as the government could revise the scheme to make sure they reach the policy target. The quota is in fact the only possibility the government has for control. However, to reduce uncertainty for investors it is important that the changes are predictable, long-term and transparent.

The given quota makes sure that the average price in the market is determined based on the LRMC, as with electricity. The twist is that the total revenue from both electricity and elcertificates should equal the LRMC for investors. Market mechanisms are designed so that the price of electricity plus elcertificates will equal the LRMC needed to reach the target of 26.4 TWh in 2020. This long term equilibrium can be viewed as an anchor we expect prices will converge towards with time. This is illustrated in Figure 2.3.

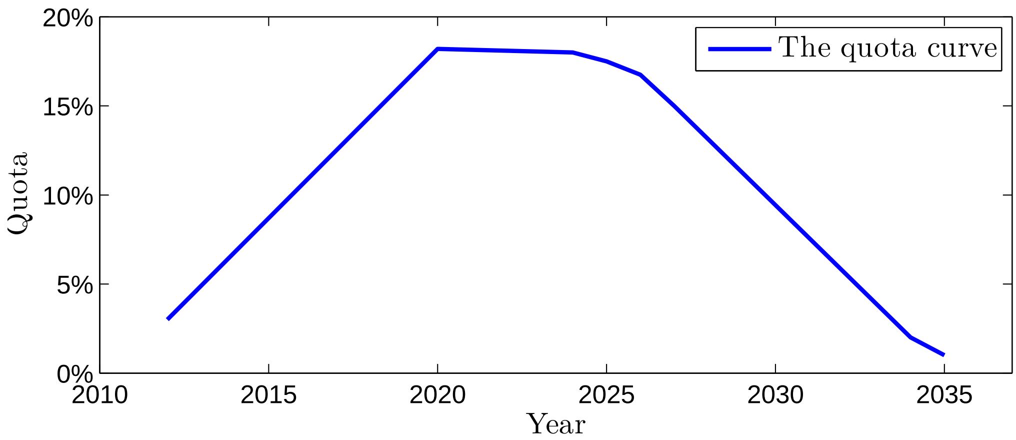


FIGURE 2.2: Power distributors' mandatory quota for elcertificates as a percentage of their distribution. Source: Elcertificate Act §17

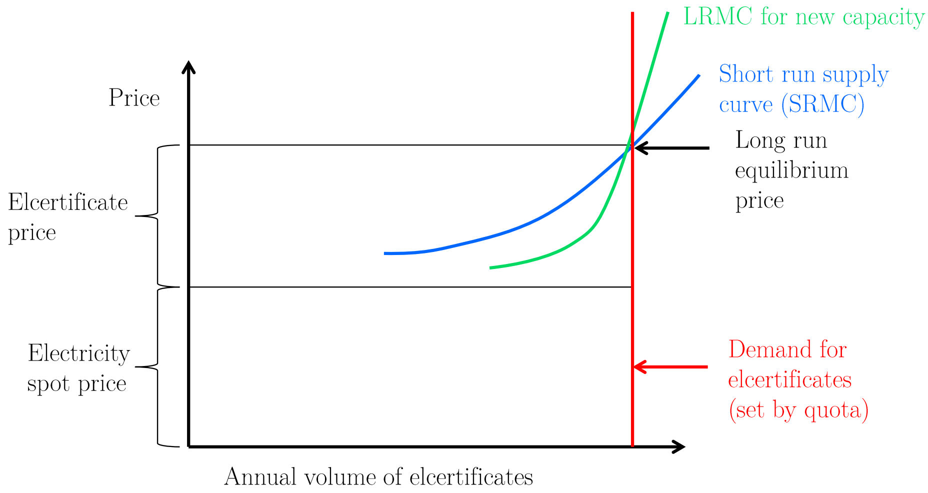


FIGURE 2.3: The price of elcertificates is determined by LRMC subtracted the electricity price (Morthorst, 2003)

Banking of elcertificates is allowed, enabling speculators to participate in the market and trade it like any other commodity. This is expected to improve market efficiency and reduce possibilities of arbitrage. Another feature of the principle of banking is that it reduces the volatility in the market, pointed out by Amundsen et al. (2006). They also point out that as banking is allowed, the relevant price should each year represent the LRMC of future production discounted by a required rate. The required rate is investor dependent, as the certificates are subject to wealth tax and should give a return equal to the investor's alternative cost of capital.

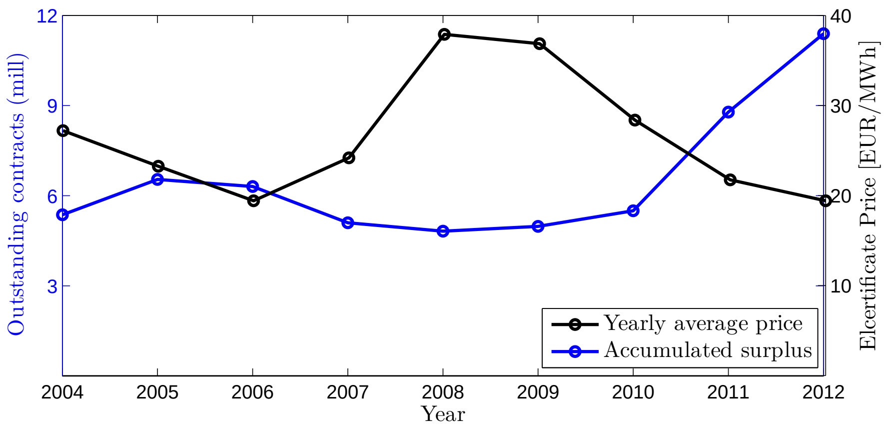


FIGURE 2.4: The price of elcertificates is determined by supply and demand. We can see that an excessive supply leads to lower prices. Source: Svensk Kraftmäkling (SKM)

Even though prices should equal the LRMC discounted by the required rate, it could deviate in the short run. Morthorst (2003) state that ”a number of reasons might exist that the expected equilibrium would not be fulfilled, among these most importantly that the volume of generated electricity would differ from the expected production.”. As both demand and supply of elcertificates are stochastic, the short term equilibrium depends on how much electricity is being consumed and produced. Supply and demand could also deviate due to changes in general market conditions or risk preferences. Then, the price is determined based on the short run marginal cost (SRMC) curve. When the expected amount of production is not met or overrun, it leads to a deficit or surplus of certificates in some years. When the surplus of certificates increases, the price generally falls as there is larger supply than demand. The relationship between price and accumulated surplus in Sweden is displayed in Figure 2.4.

This negative correlation (-0.65) between price and accumulated surplus is said to ensure the policy target to be met. If the price of certificates is too low to give incentive for new investment, the number of certificates supplied is unchanged given an equal amount of production. Simultaneously demand for certificates increases based on the quota curve, leading to a deficit of contracts and thereby rising prices. When the prices have risen enough, new investment will regain momentum.

Once a year at 1st of March, Statnett (the Norwegian transmission system operator) will compute the required contract volume for the producers. It is the distributors and end users own responsibility to have bought their required amount of certificates by the 1st of April. These contracts will then be taken out of the buyer's balance and nulled. If the buyer fails to meet his requirements, he will be fined. Thus, the fine imposes a price ceiling in the market. Nevertheless, trading occurs daily and the liquidity for both spot and forward contracts is said to be sufficient. Trades take place over the counter (OTC), often through a broker or by bilateral agreements. Recently, NASDAQ OMX opened an exchange for trading in future contracts as well. All trades are reported to national registers: NECS in Norway and Cesar in Sweden. Figure 2.5 show the daily close spot price quoted by the firm Svensk Kraftmäkling (SKM). The contract volume from a single power producer is often low and it is time consuming to monitor the market. Consequently, non-professional producers often have a distribution agreement with a more skilled agent. If the license holder of the small hydropower plant is professional, they are more likely to trade themselves.

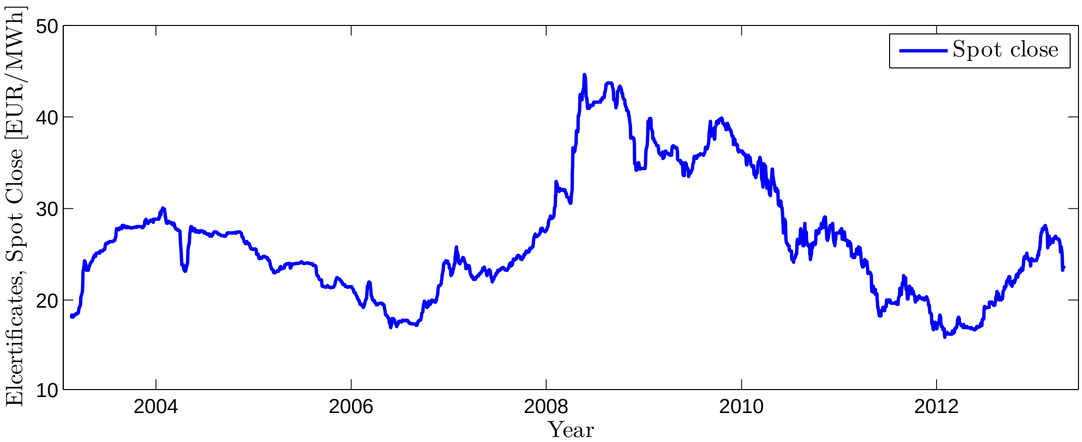


FIGURE 2.5: Price of elcertificates from 05.2003–03.2013. Source: Svensk Kraftmäkling (SKM)

2.3 What Resources Are Developed Under the Support Scheme?

By looking at the merit order of potential new production over the short term (10-15 years), we can predict what energy sources are developed under the certificate

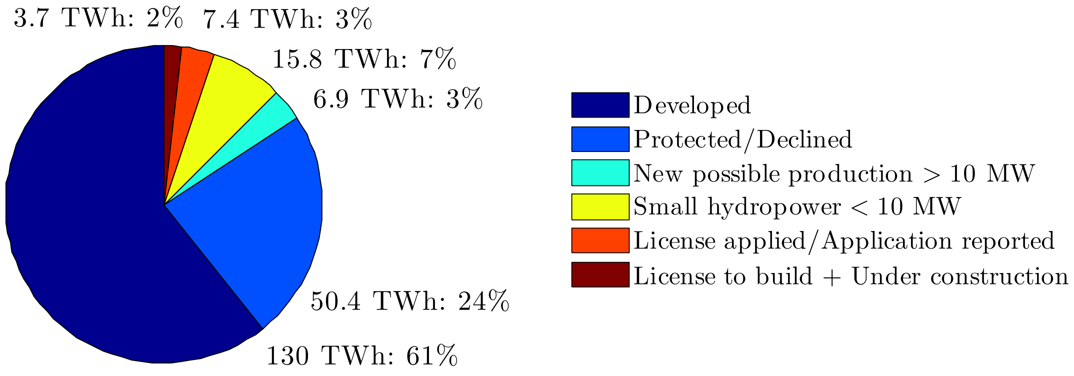


FIGURE 2.6: Potential for hydropower in Norway (NVE, 2012)

scheme. It is expected that wind power will be developed in both countries. In Norway more hydropower will be developed, while in Sweden bio power is expected to cover a large share of new production (Ministry of Petroleum and Energy, 2010). Bio power here is mainly reconstructing fossil fuelled plants into combined heat and power plants using wood as an energy source.

The potential for new renewable energy in both Norway and Sweden is vast. Still, there are many aspects which constrain a rapid development, including high development costs, exhausted transmission capacity and the time spent by regulators processing licenses. Ministry of the Environment (2012) notes that "How comprehensive the development of renewable energy becomes, depend on many factors, including preservation of nature, technological progress, development costs and future price- and market expectations by the participants.".

Recent figures from Norwegian Water Resources and Energy Directorate (NVE) show the overall hydropower potential in Norway, displayed in Figure 2.6. We here see that a large share of the undeveloped potential is protected and that the largest proportion of new possible production will come through small hydropower projects. A possibility study on future production in Norway performed by NVE and Enova in 2008 estimated that it will be possible to increase the production of renewable energy with approximately 30 TWh within 2020 (NVE, 2010b). The 30 TWh assume a split between hydropower and wind power of 13 TWh and 17 TWh respectively. Production from bio in Norway was not considered as it predicted to become a scarcity of this resource in future. This resource also receive less certificates per unit of production than hydro and wind, as it is not as environmentally friendly due to an energy efficiency of approximately 40%. In Sweden, bio power is already big and the third largest source of electricity behind hydropower and

Table 2.2: Potential and LRMC for the most cost efficient renewable energy sources in Norway (NO) and Sweden (SE) Sources: Statens energimyndighet (2007), NVE (2010b), EIA (2013), ICE Endex Wood Pellets

Energy source	**LRMC [€/MWh]**	**Potential, NO**	**Potential, SE**
Hydropower	32-48	13 TWh	0.5 TWh
Bio	54-64	-	3 TWh
Wind power onshore	59-89	17 TWh	10 TWh

nuclear power. The short term potential for new renewable energy consists of 3 TWh for bio and at least 10 TWh of new onshore wind power. Due to protection, the hydropower potential in Sweden is only 0.5 TWh (Statens energimyndighet, 2007). Offshore wind power was considered too expensive in both Norway and Sweden.

Hydropower is currently the most cost-efficient renewable energy source, with a LRMC in the range 32-48 €/MWh (NVE, 2010b). The second most cost efficient energy source is bio energy with a LRMC of 54-64 €/MWh (ICE Endex Wood Pellets, EIA (2013)). The LRMC of wind is predicted to be in the range of 59-89 €/MWh (NVE, 2010b). A summary of the short-term production potential and its LRMC is given in Table 2.2.

Based on the LRMC of the marginal production unit at 26.4 TWh, we can infer what the elcertificate price should be to give incentive to a required number of investors. By horizontally aggregating the potential production based on the LRMC from Table 2.2 we find the merit order of production, illustrated in Figure 2.7. Here we have assumed that the cost curves are linear, in practice they depend on the individual projects. At 26.4 TWh, it is calculated that wind power will be the marginal investment unit for Norway and Sweden combined. At current elcertificate price levels, only hydropower and bio power are economically viable. The required certificate price by wind power investors can be calculated as the difference between the LRMC and the electricity price. Looking at future and forward contracts we can get a picture of the future electricity and elcertificate price. We have chosen the 2016 contracts due to low liquidity further ahead. Setting the LRMC of wind to 72 €/MWh, and knowing that the 2016 future contract for electricity in May 2013 was traded at 34 €/MWh (ENOYR-16, NASDAQ OMX), the certificate price needed to trigger investment is 38 €/MWh. In May 2013, the forward for elcertificates with delivery in MAR-16 was traded at 23 €/MWh. We can therefore expect certificate prices to increase in future. However, the observation that future prices are far away from the target, indicates that investors do not forecast an elcertificate price of 38 €/MWh.

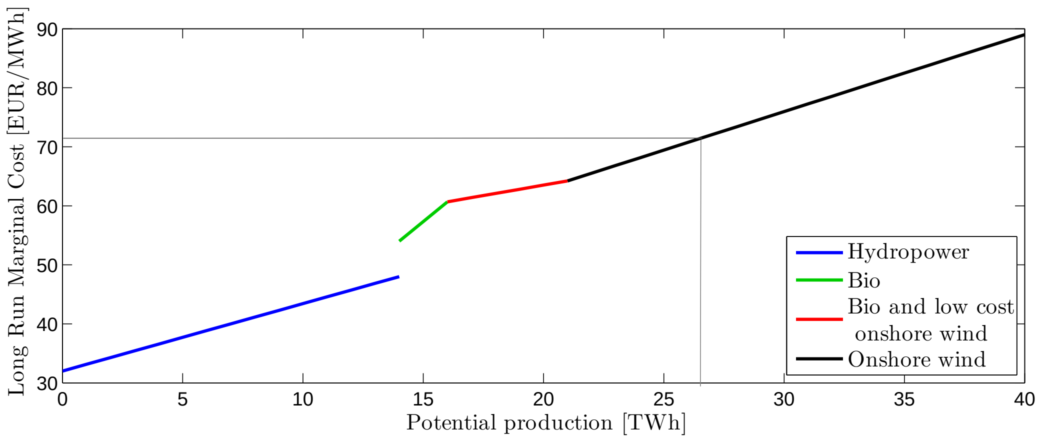


FIGURE 2.7: Merit order of potential production in Norway and Sweden [TWh] (Ministry of Finance, 2008). We see that the target of 26.4 TWh of new renewable energy is achieved at ∼72 €/MWh.

Chapter 3

Modelling the Investment Decision

To model the investment decision a real options model has been developed. In this chapter, the characteristics of the investment decision will be explained in Section 3.1, to provide a better understanding of the modelling choices which follows after in Section 3.2. The model will be illustrated and results from a parameter sensitivity analysis will be discussed in Section 3.3 and 3.4.

3.1 Characteristics of the Investment Decision

Developing a hydropower plant is a tedious process. A new investor has to follow many steps in a process which require a variety of skills. The first step is to develop a fundamental plan. Where do I situate the power plant, what dimensions are suitable, what are my costs and how much revenue can I expect? This forms the basis for an application which is sent to the regulator NVE. NVE process the application, making sure the power plant is according to the laws and preserve the natural environment. If a licence is granted, the investor continues with more detailed planning. In depth hydrology studies are evaluated and tenders are advertised, so that contractors can bid their price for doing the job. Also, the budget is updated and evaluated once more. Finally, after several years, the investor can make the final decision to invest.

There are several factors leading to profitability uncertainty which are relevant when making the investment decision. Interest rate risk, unforeseen building costs, variable price of electricity and subsidies, variable price of electricity distribution and illusive hydrology conditions. Nevertheless, many of these factors can be accounted for without increasing the costs substantially. The most prominent factors affecting profitability is the revenue from selling electricity and elcertificates. The reason for this is straightforward when looking at the characteristics of the investment and the timing of the cash flows. Investing in a hydropower plant requires a large up front expenditure to build the power plant, which later almost runs by itself with low operation and maintenance costs. The revenue stream is therefore approximately the selling price of electricity and elcertificates, and varies with production over time. The up front investment cost is large, and consequently make up a big consideration when making the investment decision. Though, it is easier to estimate than the future electricity price. It is therefore chosen to model both the electricity price and the price of elcertificates as uncertain and fluctuating over time, while the investment cost is modelled as constant.

If the investor has some leeway in the timing of the investment, he could sometimes gain additional value by waiting for more information. The investment decision can then be regarded as a real option to invest which is possible to exercise at any moment in time. In financial terms this characteristic pay-off structure is called an American call option. The investor should in such a case only invest when the alternative cost of terminating the option is accounted for.

Once the investor has obtained a license to build a hydropower plant, he has to invest within 5 years. Otherwise he must send in an application for prolonging the license for 5 new years. This is usually granted. Thereby we can assume that the license lasts forever and the investors can choose to invest at their own convenience. Thus, we assume the lifetime of the option to be perpetual. Sometimes financing opportunities are only valid for a short period of time. In such a case, the investor has to decide on a now or never basis. The value of the option to wait is zero when the investment can only occur on a now or never basis. Thus, the investor could, but only in this case, make a rational decision based on the basic Net Present Value (NPV) rule.

3.2 The Real Options Model

The real options model is a dynamic programming model inspired by Boomsma and Linnerud (2013). It is chosen to follow the terminology in Dixit and Pindyck (1994). Taxes are omitted for simplicity when first deriving the equations in Section 3.2.1. Nevertheless, its impact is added in the following Section 3.2.2.

3.2.1 Derivation of the Optimal Stopping Boundary

We want to define the optimal stopping boundary where the prices are sufficient for the investor to make an investment decision. For comparability between power plants, we evaluate the measures on a per unit of production basis (e.g. €/MWh). To obtain the total amount of profit, revenue or costs, one can multiply the respective amount with the expected annual production of the power plant, Q.

Both the price of electricity $(P_t)_{t\geq 0}$ and subsidies through the price of elcertificates $(S_t)_{t\geq 0}$ are taken as uncertain with respect to time t. They are modelled stochastically as Geometric Brownian motions (GBM):

$$\mathrm{d}P_t = \alpha_P P_t \mathrm{d}t + \sigma_P P_t \mathrm{d}z_{P_t} \tag{3.1}$$

$$\mathrm{d}S_t = \alpha_S S_t \mathrm{d}t + \sigma_S S_t \mathrm{d}z_{S_t} \tag{3.2}$$

Here, the α_P, α_S, σ_P and σ_S are constants and represent the trend parameter, also called the drift rate, and volatility for the price of electricity and elcertificates respectively. The last term in both equations, $\mathrm{d}z$, is a standard Brownian motion (BM). The two BMs are correlated, denoted as $E[\mathrm{d}z_P \mathrm{d}z_S] = \rho_{P,S}$.

When we consider the company as a price taker, the expected present value of the investment, V, is consequently a linear function of two variables following GBM. Using continuous compounding, the function for V becomes (derivation in Appendix A):

$$V(P,S) = r_P P + r_S S \tag{3.3}$$

where

$$r_P = \left(\frac{1 - \mathrm{e}^{-(r-\alpha_P)T_P}}{r - \alpha_P}\right), \; r_S = \left(\frac{\mathrm{e}^{-(r-\alpha_S)T_{S_1}} - \mathrm{e}^{-(r-\alpha_S)T_{S_2}}}{r - \alpha_S}\right) \tag{3.4}$$

Here we have discounted the future cash flows with the required rate of return of the project, r. As the subsidy is only granted for a given number of years, the lifespan of the revenue stream for electricity T_P and for the elcertificates T_{S_2} is different. We assume that revenue from sale of electricity is starting from time period 0. We have accounted for a delayed start-up of revenue from electricity certificates through T_{S_1}. The main reason for the delay is the time taken by politicians to introduce a subsidy scheme, further discussed in Section 4.2.

The net expected profit when you invest is found by the NPV rule: $V(P, S) - I$. The investment cost per unit of production, I, consists of the initial sunk cost taken on by building the plant I_0 and the present value of maintenance costs, C:

$$I = I_0 + C \tag{3.5}$$

Here, it is assumed that it is never optimal to shut down the plant, which is true for almost all hydropower plants, based on economic reasons. We can assume that the maintenance cost per unit of production, c_t, grows with the annual inflation rate, i, set at a constant rate reflecting the inflation target. Thus, the present value of the maintenance costs can be discounted to time 0:

$$C = \int_0^{T_P} c_t \mathrm{e}^{-rt} \mathrm{d}t = \int_0^{T_P} c_0 \mathrm{e}^{-(r-i)t} \mathrm{d}t = c_o r_C \tag{3.6}$$

where

$$r_C = \left(\frac{1 - \mathrm{e}^{-(r-i)T_P}}{r - i} \right) \tag{3.7}$$

We deviate from the terminology in Dixit and Pindyck (1994) by including the maintenance cost in I instead of V. Nevertheless, as the maintenance cost can be discounted back to time 0, it does not affect the investment decision whether it is included in V or I. For simplicity, it is therefore included in I, although it is not a part of the initial sunk cost I_0.

At each point in time, the investor could decide whether to invest or to keep the option alive. To be able to decide the optimal timing of the investment, we need to value the real option. It is optimal to exercise the investment option when its value, $F(V)$, is equal to the NPV. If the value of the option surpasses the NPV, it is optimal to postpone the investment and continue to hold the option. It is therefore common to refer to the option value as the continuation value. The value of the option is therefore the maximum of investing now, or the continuation value.

This is represented by the Bellman equation:

$$F(P,S) = max\left\{V(P,S) - I, \frac{1}{1+rdt}E\left[F(P+dP, S+dS)|P,S\right]\right\} \tag{3.8}$$

Because we have a perpetual option, we have time-homogeneity in the value process. Therefore, we can omit the t-subscripts. On the left hand side of the Bellman equation, we have the value of immediate exercising of the option. On the right, we have the continuation value: the discounted expected value of all future optimal decisions given the stochastic development. We can expand the expectation using Itô's Lemma, as in Karatzas and Shreve (1991). After some algebra, we arrive at a partial differential equation (PDE) which is valid for F(P,S) when continuation is optimal (i.e. $F(P,S) \geq V(P,S) - I$):

$$\frac{1}{2}\left(\sigma_P^2 P^2 \frac{\partial^2 F}{\partial P^2} + \sigma_S^2 S^2 \frac{\partial^2 F}{\partial S^2} + 2\sigma_P \sigma_S \rho_{P,S} PS \frac{\partial^2 F}{\partial P \partial S}\right) + \alpha_P P \frac{\partial F}{\partial P} + \alpha_S S \frac{\partial F}{\partial S} - rF = 0 \tag{3.9}$$

This equation is a second order homogeneous PDE. A first order homogeneous PDE for a two-factor problem has a known solution[1], shown in McDonald and Siegel (1986) and used in a similar problem in Gravdehaug and Remmen (2011). We can assume a generic solution similar to this, which is often called the Bellman solution as it is a solution to the Bellman equation:

$$F(P,S) = AP^{\beta_P} S^{\beta_S} \tag{3.10}$$

To check whether this is a possible solution, we insert it into the PDE in equation (3.9), rearrange and obtain the fundamental quadratic equation $Q(\beta_P, \beta_S) = 0$:

$$\begin{gathered} Q\left(\beta_P, \beta_S\right) = \\ \frac{1}{2}\left(\sigma_P^2 \beta_P(\beta_P - 1) + \sigma_S^2 \beta_S(\beta_S - 1) + 2\sigma_P \sigma_S \rho_{P,S} \beta_P \beta_S\right) + \alpha_P \beta_P + \alpha_S \beta_S - r = 0 \end{gathered} \tag{3.11}$$

This is the equation of an ellipse present in all four quadrants of the plane. When $\beta_P = 0$ or $\beta_S = 0$, we have the standard quadratic function in option valuation with a positive and a negative root comprehensively explained in Dixit and Pindyck (1994). The β's can not be negative as it will create an invalid option value if any the prices fall to zero. We therefore restrict the attention to those solutions that

[1] One can let $F(P,S) = Pv(p), p = \frac{P}{S}$ for some function $v(\cdot)$ and reduce the two-factor problem to a one-factor problem.

we find in the first quadrant:

$$\beta_P, \beta_S \geq 0 \tag{3.12}$$

The optimal stopping boundary is a solution plane consisting of a set of optimal values for S^* and P^*. Boomsma and Linnerud (2013) explain that "the prices at which it is optimal to invest, i.e. the investment triggers, define a one-dimensional subset of $P \times S$ space".

The project value when it is optimal to invest, is denoted $F(P^*, S^*)$ and varies along the boundary. It is also independent of time, as the PDE in Equation (3.9) is time-homogeneous. The optimal decision rule is consequently that we invest the first time P and S reaches the boundary P^* and S^* simultaneously.

To solve for the elements in $F(P, S)$ we need the corresponding boundary conditions. We have the value matching condition and the smooth pasting conditions defined at optimal investment point. Additionally, we should make sure that the value falls to zero when prices are zero. This is in fact already handled because if either P or S go to zero, the properties of the GBM ensure that value F will remain at 0 in future (Dixit and Pindyck, 1994).

$$F(V(0,0)) = 0 \tag{3.13a}$$
$$A(P^*)^{\beta_P}(S^*)^{\beta_S} = r_P P^* + r_S S^* - I \tag{3.13b}$$
$$A\beta_P(P^*)^{\beta_P - 1}(S^*)^{\beta_S} = r_P \tag{3.13c}$$
$$A\beta_S(P^*)^{\beta_P}(S^*)^{\beta_S - 1} = r_S \tag{3.13d}$$

By manipulation of the boundary conditions b)-d) shown in Appendix A we get an expression for the triggers:

$$P^* = \frac{\beta_P}{\beta_P + \beta_S - 1}\frac{I}{r_P}, \; S^* = \frac{\beta_S}{\beta_P + \beta_S - 1}\frac{I}{r_S} \tag{3.14}$$

Intuitively, the triggers increase with the investment cost and decrease with the discount rate. At this point, we have 5 unknowns $(A, P^*, S^*, \beta_P, \beta_S)$, but only four equations, (3.11) and (3.13 b)-d)). The solution thereby has one degree of freedom. Hence, in contrast to the standard real options problem, the value of the investment cannot be determined before prices actually reach the trigger. To find the required subsidy level for investment to be optimal, we choose to specify the electricity price. For a given price $P_t = P$, we introduce a new variable:

$$\eta(P) = \frac{I - r_P P}{r_P P} \tag{3.15}$$

From inserting this in the left side of Equation (3.14) we find that

$$\beta_S = \beta_P \eta(P) + 1 \tag{3.16}$$

The β's depend on each other, making the triggers dependent on each other. Using the expression for β_S, the optimal time to invest is the first time $S_t \geq S^*(P)$, where

$$S^*(P) = \frac{\beta_P \eta(P) + 1}{\beta_P(\eta(P)+1)} \frac{I}{r_S}, \ Q(\beta_P, \beta_P \eta(P) + 1) = 0, \ \beta_P, \beta_P \eta(P) + 1 \geq 0 \tag{3.17}$$

The expressions for $\eta(P)$, I and r_S can all be evaluated when we have chosen P. When we insert Equation (3.16) in the quadratic Equation (3.11) we arrive at (derivation in Appendix A):

$$\beta_{P,1,2} = \frac{-b \pm \sqrt{b^2 - 4ac}}{2a} \tag{3.18}$$

where

$$a = \frac{1}{2}\left(\sigma_P^2 + \sigma_S^2 \eta^2(P)\right) + \sigma_P \sigma_S \rho_{P,S} \eta(P) \tag{3.19a}$$

$$b = \frac{1}{2}\left(-\sigma_P^2 + \sigma_S^2 \eta(P)\right) + \sigma_P \sigma_S \rho_{P,S} + \alpha_P + \alpha_S \eta(P) \tag{3.19b}$$

$$c = \alpha_S - r \tag{3.19c}$$

conditional on

$$\beta_P, \beta_S \geq 0 \ \Leftrightarrow \ \beta_P, \beta_P \eta(P) + 1 \geq 0 \tag{3.20}$$

As we can not prove homogeneity of degree one, the sum of the β's must also be higher than one.[2]

$$\beta_P + \beta_S > 1 \tag{3.21}$$

We can find an expression for A by manipulation of the boundary conditions:

$$A = r_P^{\beta_P} r_S^{(1-\beta_P)} \beta_P^{-\beta_P} \beta_S^{(\beta_P - 1)} S^{*(1-\beta_P-\beta_S)} \tag{3.22}$$

[2]Recall that when $\beta_P = 0$, it is well known from the standard real options problem that the positive root of the quadratic equation satisfies $\beta_S > 1$, and vice versa when $\beta_S = 0$ then $\beta_P > 1$. Hence, the ellipse defined by $Q(\beta_P, \beta_S) = 0$ must always be above the line $\beta_P + \beta_S = 1$ in the first quadrant of the plane.

Substituting this in Equation (3.10) we have the final expression for the project value at the optimal stopping boundary.

$$F(P^*, S^*) = r_P^{\beta_P} r_S^{(1-\beta_P)} \beta_P^{-\beta_P} \beta_S^{(\beta_P-1)} S^{*(1-\beta_P)} P^{*\beta_P} \tag{3.23}$$

As mentioned before, due to the nature of the problem, we can not calculate the value of the option outside of this boundary. One can only evaluate the *expected* option value before reaching the triggers. Interested readers are referred to Gahungu and Smeers (2009) who estimates the expected option value using Monte Carlo simulation.

Inserting the triggers in the value matching boundary condition (3.13)b) we find an interesting notion:

$$F(P^*, S^*) = r_P P^* + r_S S^* - I = \left(\frac{\beta_P + \beta_S}{\beta_P + \beta_S - 1}\right) I - I \tag{3.24}$$

Because $\beta_P + \beta_S > 1$ when investment is optimal, the value of the option requires that the present value of income is *greater* than the costs. As usual in real options problems, uncertainty and irreversibility drive a wedge between compounded revenues and investment cost.

3.2.2 Including Taxes

Taxes are time varying, depending on revenue, depreciation and variable costs each year, such as maintenance costs and interest costs. Hydropower plants are subject to several taxes, all explained in Appendix B. A summary is given in Table 3.1.

In our model, the taxes come into play in $V(P, S)$ as they depend on the variables P and S. Additionally, we have to change the required rate to an after-tax required rate. If we subtract the full expression for the taxes in Equation (B.2) from Equation (3.3), the present value of revenue adjusted for taxes equals:

$$V(P, S) = (1 - (\tau_{Profit} + \tau_{Economic\ Rent}|_{R>L}))\,(r_P P + r_S S) - X \tag{3.25}$$

where τ_{Profit} is the profit tax rate and $\tau_{Economic\ Rent}|_{R>L}$ is the economic rent tax rate paid by plants with a size R above the limit L. If we set

TABLE 3.1: Summary of relevant taxes for small hydropower plants and historical rates in the period 2001–2012

Tax	**Description**	**Historical Rates**
Profit Tax	Profit tax is calculated as the earnings before taxes (EBT) multiplied by a rate τ_{Profit}.	$\tau_{Profit} = 28\%$
Property Tax	Municipalities have the opportunity to claim property tax. The rate $\tau_{Property}$ is multiplied by the market value of the power plant.	$\tau_{Property} = 0.7\%$
Economic Rent	Economic rent is a tax to collect super profits and only applicable for hydropower plants with power rating R above a threshold L. The rate $\tau_{Economic\ Rent}\|_{R>L}$ is multiplied with the revenue, subtracted maintenance cost, amortization and depreciation, property tax and free income. Free income is calculated as the average book value multiplied by a norm rate r_{Norm} set by the government.	2001–2007: 27%, 2008–2012: 30%, 2001–2003: $L = 1.5$MVA, 2004–2012: $L = 5.5$MVA
Natural Resource Tax	Natural resource tax is coordinated with the profit tax, such that an investor will never pay more than τ_{Profit} altogether. It is therefore omitted in the calculations. Similar to the economic rent, it is only applicable for hydropower plants with a rating R above a given threshold L.	1.625 €/MWh, 2001–2003: $L = 1.5$MVA, 2004–2012: $L = 5.5$MVA

$B = (1 - (\tau_{Profit} + \tau_{Economic\ Rent}|_{R>L}))$ we get:

$$V(P,S) = B\left(r_P P + r_S S\right) - X \tag{3.26}$$

The expression X is independent of the production and thereby constant for each power plant. It includes maintenance cost, amortization and depreciation, property tax, interest costs and free income based on the norm rate. We collect it in one term:

$$\begin{aligned} X =& \left(\tau_{Profit} + \tau_{Economic\ Rent}|_{R>L}\right)\left(-c_0 r_C - 2.5\% I_0 r_R\right) \\ &+ (1 - \tau_{Economic\ Rent}|_{R>L})\tau_{Property} Upper\ Limit\ r_R \\ &+ \tau_{Profit}\left[- r_{Debt} 75\% I_0 \left(r_R - \frac{5\%}{r}\left(r_R - T_P e^{-rT_P}\right)\right)\right] \\ &+ \tau_{Economic\ Rent}|_{R>L}\left[- r_{Norm} I_0 \left(r_R - \frac{2.5\%}{r}\left(r_R - T_P e^{-rT_P}\right)\right)\right] \end{aligned} \tag{3.27}$$

where

$$r_R = \left(\frac{1 - \mathrm{e}^{-rT_P}}{r}\right) \tag{3.28}$$

We see that if both tax rates τ_{Profit} and $\tau_{Economic\ Rent}|_{R>L}$ are set to 0, B equals 1. Then, the only adjustment we are left with is the property tax $\tau_{Property}$ in X. If this rate is also set to zero, $\tau_{Property}$=0, we arrive at the initial definition of the present value.

The new definition of the present value leads to changes in the boundary conditions. By following the steps in the previous derivation (specifying the electricity price and finding an efficient substitution by creating a new variable η) we find the new triggers. The new $\eta(P)_\tau$ adjusted for taxes is defined as:

$$\eta(P)_\tau = \frac{(X + I) - Br_P P}{Br_P P} \tag{3.29}$$

Then we can use the same substitution as previously for β_{S_τ} as the values for P^*_τ and S^*_τ are:

$$\beta_{S,\tau} = \beta_{P,\tau}\eta(P)_\tau + 1 \tag{3.30}$$

$$P^*_\tau = \frac{\beta_{P,\tau}}{\beta_{P,\tau} + \beta_{S,\tau} - 1}\frac{X + I}{Br_P},\ S^*_\tau = \frac{\beta_{S,\tau}}{\beta_{P,\tau} + \beta_{S,\tau} - 1}\frac{X + I}{Br_S} \tag{3.31}$$

As the expression for $\beta_{S,\tau}$ stays unchanged (except for a change of notation from $\eta(P)$ to $\eta(P)_\tau$), the solution to the fundamental quadratic $\beta_{P,\tau}$ stays unchanged. The expressions for the investment triggers adjusted for taxes P^*_τ, S^*_τ is different compared to the investment triggers without taxes, previously shown in Equation (3.14). Thus, the investment triggers are dependent on the tax regime. We know that $B \leq 1$, but the size of X could be either positive or negative. It is negative for our example power plant used in a sensitivity analysis in Section 3.4. The observed result when performing the sensitivity analysis is that the investment triggers have increased. Simultaneously, the project value at the trigger has changed. As we are indifferent to holding the option or investing, we can study the project value using the NPV approach or by calculating the option value. At the trigger, the NPV equals:

$$\begin{aligned} F(P^*_\tau, S^*_\tau) =& B(r_P P^*_\tau + r_S S^*_\tau) - (X + I) \\ =& \left(\frac{\beta_{P,\tau} + \beta_{S,\tau}}{\beta_{P,\tau} + \beta_{S,\tau} - 1}\right)(X + I) - (X + I) \end{aligned} \tag{3.32}$$

The overall impact of taxes on the project value at the trigger is ambiguous when

TABLE 3.2: Chosen parameters for a hypothetical power plant

Notation	**Parameter**	**Value**
I_0	Investment cost	350 €/MWh
c_0	Start value annual maintenance cost	9 €/MWh
α_P	Electricity price drift rate	2.5 %
α_S	Subsidy drift rate	2.5 %
σ_P	Electricity price volatility	15 %
σ_S	Subsidy price volatility	15 %
$\rho_{P,S}$	Correlation	-0.5
r	Required return	5 %
T_P	Lifespan of power plant	40
T_{S_2}	Lifespan of subsidies	15
T_{S_1}	Revenue lag of subsidies	1

looking at the NPV compared to Equation (3.24). B decreases the value of $F(P_\tau^*, S_\tau^*)$, while the new triggers and X increase the value. We therefore use the other approach and study the option value at the trigger. The expression for A_τ and $F(P_\tau^*, S_\tau^*)$ including taxes are both multiplied by B:

$$A_\tau = Br_P^{\beta_{P,\tau}} r_S^{(1-\beta_{P,\tau})} \beta_{P,\tau}^{-\beta_{P,\tau}} \beta_{S,\tau}^{(\beta_{P,\tau}-1)} S_\tau^{*(1-\beta_{P,\tau}-\beta_{S,\tau})} \tag{3.33}$$

$$F(P_\tau^*, S_\tau^*) = Br_P^{\beta_{P,\tau}} r_S^{(1-\beta_{P,\tau})} \beta_{P,\tau}^{-\beta_{P,\tau}} \beta_{S,\tau}^{(\beta_{P,\tau}-1)} S_\tau^{*(1-\beta_{P,\tau})} P_\tau^{*\beta_{P,\tau}} \tag{3.34}$$

Multiplying by B reduces the option value. Opposite, the trigger price S_τ^* has increased and increases the option value. The overall effect is therefore still ambiguous. To find the impact of the taxes, we must evaluate the expressions using a case study. A sensitivity analysis is therefore performed in Section 3.4.

3.3 Illustration of the Real Options Model

To get an impression of the behaviour of the real option model we use a case study for illustration. We here evaluate the exercise boundary and project value excluding taxes. The chosen parameters belong to a fictitious power plant and are displayed in Table 3.2. The investment cost represents the average power plant in our data set. The parameters are used when calculating the optimal stopping boundary for an electricity price ranging from 0 €/MWh to 50 €/MWh. For each electricity price, we find the minimum required subsidy level S^* for investment

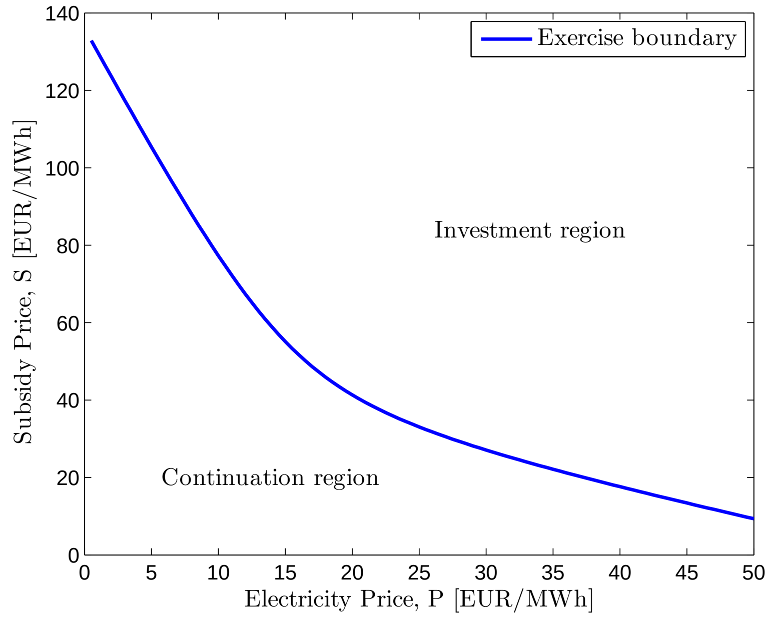


FIGURE 3.1: The optimal stopping boundary for an example power plant

to be optimal. The boundary is displayed in Figure 3.1 and we see that it is non-linear with respect to P and S.

The boundary divides the graph into two regions: the continuation region and the investment region. As long as the combination of a given electricity price and a given subsidy price is below this boundary, you should wait with the investment and continue to hold the option. Opposite, when the pair of electricity price and subsidy price is situated above the boundary, it is optimal to invest immediately. At the boundary, you are indifferent, as the option value is equivalent to the NPV. From Figure 3.1 we can infer that subsidies are required even when the electricity price is 50 €/MWh. Given the average price in May 2013 for the electricity future with maturity in 2016 (∼34 €/MWh, NASDAQ OMX) and elcertificate forward with maturity March-2016 (∼23 €/MWh, SKM), we would find ourselves situated just above the exercise boundary for this example power plant. Nevertheless, bear in mind that this is before we include taxes in the calculations.

We can evaluate the project value at the boundary. The result is displayed in Figure 3.2 and 3.3, using a range from 0 to 50 €/MWh for the electricity price and the corresponding optimal subsidy price from Figure 3.1. The project value is almost equal for the pairs [P=5,S=105] and [P=50,S=9]. From this we can infer that a high electricity price alone leads to a larger project value than a high

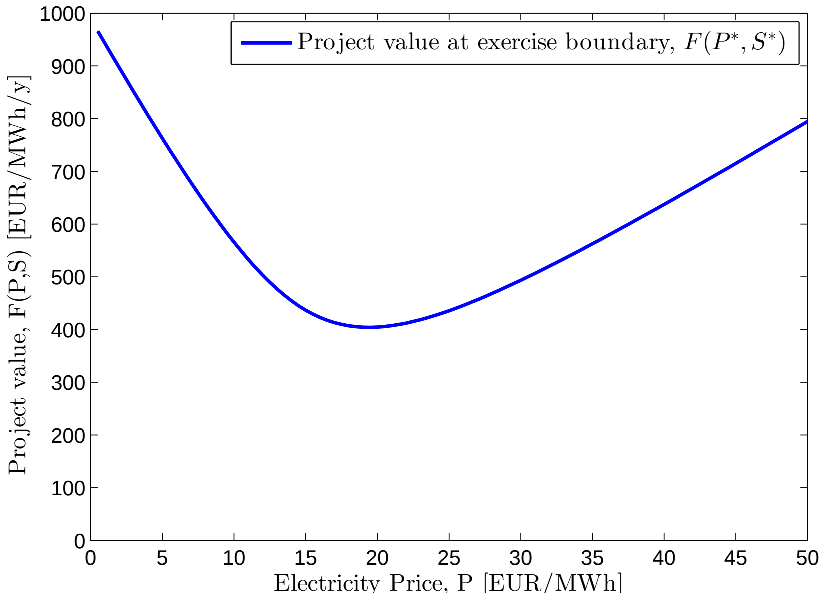


FIGURE 3.2: Project value at year 0 for an example power plant given a set of optimal electricity prices [0.05-50 €/MWh] and corresponding subsidy prices at the exercise boundary

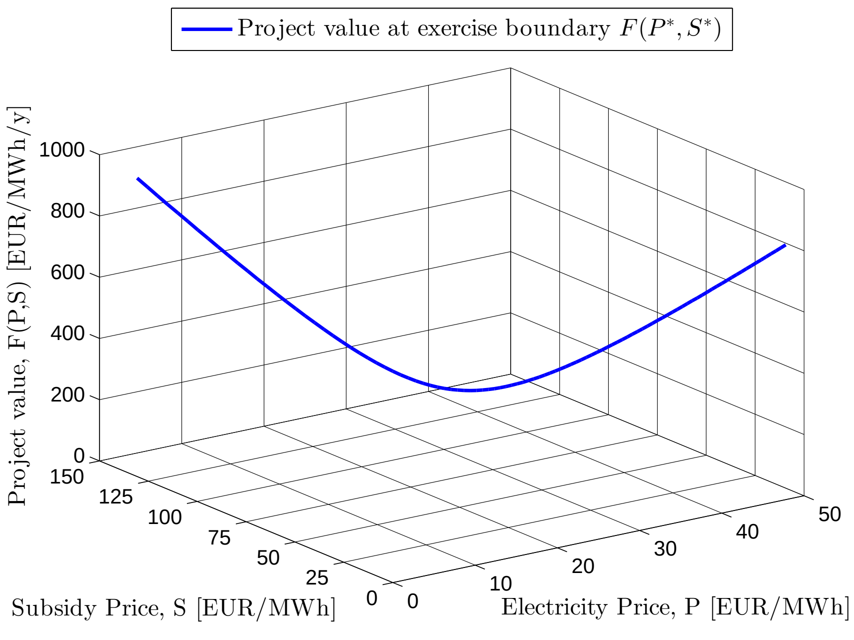


FIGURE 3.3: Project value at year 0 for an example power plant given a set of optimal electricity prices [0.05-50 €/MWh] and corresponding subsidy prices at the exercise boundary. The set of optimal prices lead to a varying project value at optimal investment point. When both prices are at a comfortable distance from 0, we are willing to invest with a lower present value of future pay-offs, due to an insurance-effect created by a negative correlation between the prices.

subsidy price alone, if the prices were equal. This is due to the bounded lifetime of the subsidy. For electricity certificates the lifespan is 15 years. Comparatively, the power plant has a revenue stream from sale of electricity over 40 years. We can also see that the project value is consistently greater than zero, a characteristic implied by the option from Equation (3.24). Because you have the opportunity to defer exercising, in some cases you do not invest even though you have positive NPV, because the value of the option is higher than the NPV.

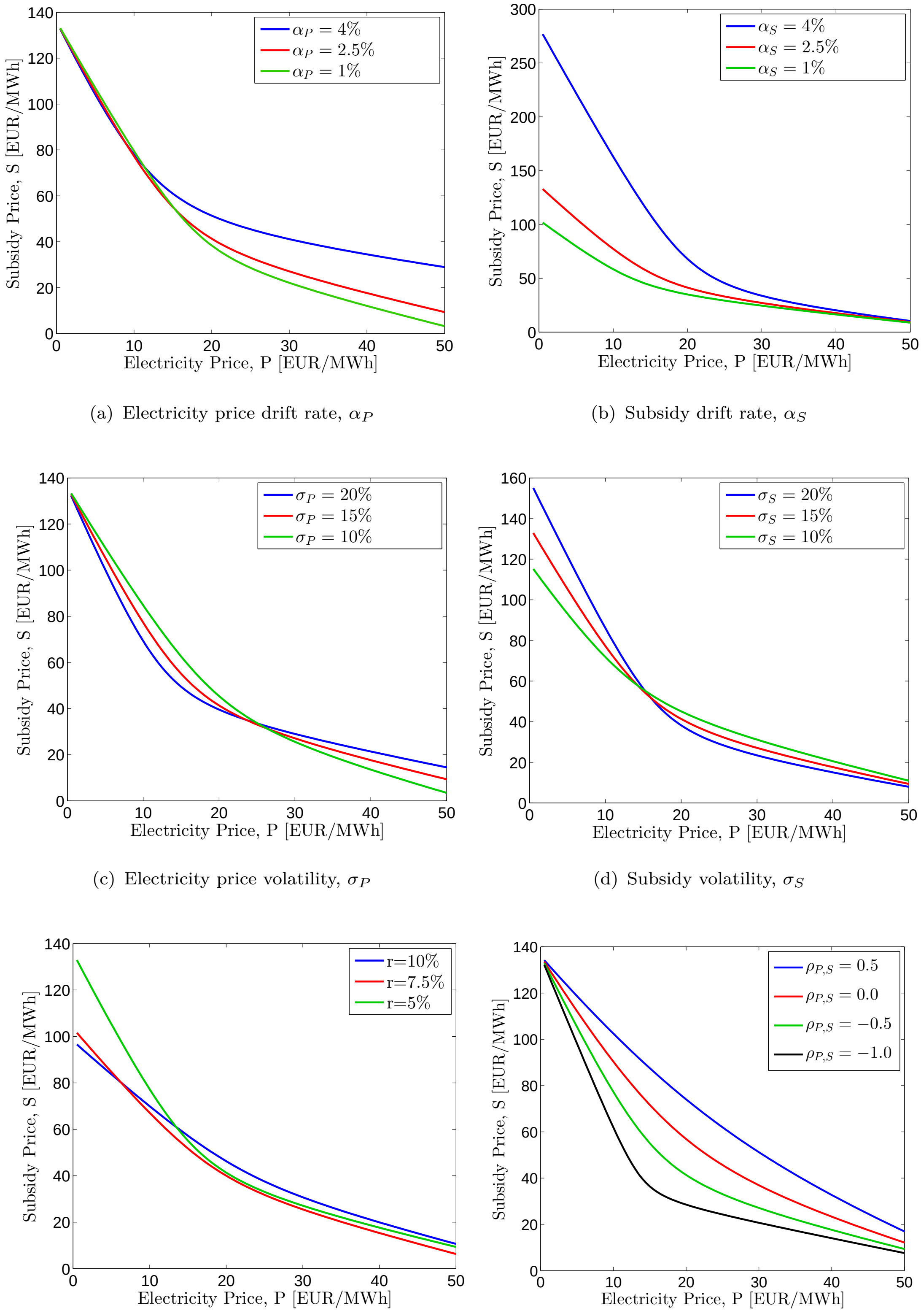
3.4 Sensitivity Analysis

Knowing how the parameter values affect the optimal stopping boundary is useful when interpreting the results. We therefore analyse the effect of varying one of the parameters from Table 3.2 at a time while keeping the others constant. Additionally, we investigate how the model responds when adding taxes.

3.4.1 Parameter Sensitivity

The results from the sensitivity analysis with respect to parameter values are displayed in Figure 3.4 and Figure 3.5. By looking at the illustrations, we first notice that none of the parameters have a linear relationship with respect to the electricity price. We second notice that the parameters with the largest impact on the exercise boundary is the investment cost, I_0, the drift rates, α_P and α_S, as well as the correlation $\rho_{P,S}$. We will now discuss the impact of the parameters, one by one, following the sequence of the illustrations.

From Figure 3.4(a) and Figure 3.4(b) we see that a higher drift rate leads to a higher trigger value. The reason for this is that a high drift rate implies that the prices will increase in the long run, making waiting more valuable. When looking at Figure 3.4(c) and Figure 3.4(d) we see that the choice of volatility has little impact compared to other variables. A possible explanation of this could be that the timespan of the revenue-stream is long. Even though the volatility does not seem to have much impact, it is mainly because of the chosen range of the y-axis. If we would have restricted the graph to a more realistic range of subsidy prices, the volatility would have shown more impact. We thereby support the usage of a two factor model instead of a one-factor model. Furthermore, a change in volatility has



(a) Electricity price drift rate, α_P

(b) Subsidy drift rate, α_S

(c) Electricity price volatility, σ_P

(d) Subsidy volatility, σ_S

(e) Required rate of return, r

(f) Correlation, $\rho_{P,S}$

FIGURE 3.4: Sensitivity analysis by varying one parameter at the time

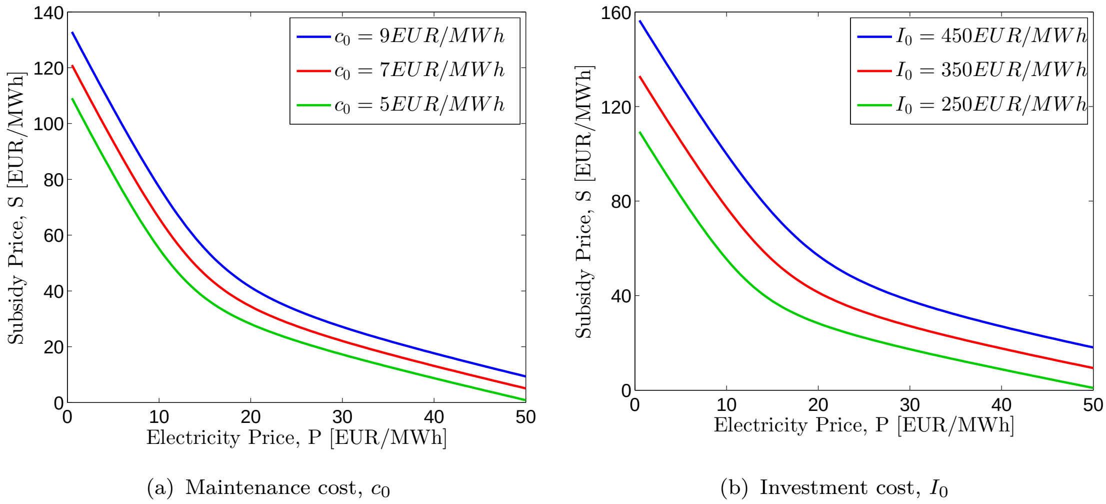


FIGURE 3.5: Sensitivity analysis by varying one parameter at the time

an ambiguous impact depending on the electricity price. For a given electricity price there seems to be a threshold where the impact of a marginal change in volatility changes direction. Actual electricity prices were mostly to the right of this threshold of approximately ∼20 €/MWh for the period 2001–2012. We can see that increasing electricity price volatility leads to a higher trigger value, while an increased subsidy volatility leads to a lower trigger. This has implications for the interpretation of the two-factor model. Compared to a one-factor model with a deterministic subsidy price ($\sigma_S = 0$), the two factor model predict a lower exercise boundary for the uncertain subsidy than the deterministic subsidy. Surprisingly, a two-factor model thereby gives a lower trigger than a one-factor model would have predicted.

From Figure 3.4(e) we see that the required rate r has a negative effect on the investment boundary when increasing the rate from 7.5% to 10%. When the interest rate increases, the future cash flows are discounted at a higher rate. Thus, the present value of revenue decreases and a higher trigger is required. However, if we reduce the interest rate from 7.5% to 5% the trigger also increase. This is due to the lease rate, δ. The lease rate is defined as the difference between the required rate and the drift rate, $\delta = r - \alpha$, and could be viewed as dividends foregone by not investing. A low lease rate makes it more optimal to wait, and increases the boundary. Consequently, the behaviour of the interest rate depends on how close the required rate is to the drift rate. The value of the correlation affects the curvature of the boundary, shown in Figure 3.4(f). If the prices are negatively correlated, the trigger is lower and the slope is curved. By being negatively correlated, we have an implicit insurance policy. If one of the prices decrease, in most cases, the other price will increase. Thereby we can take the risk of investing at a lower boundary.

In Figure 3.5(b) we see that the investment cost paid the first year has significant impact when determining the exercise boundary. When the investment cost increases, the exercise boundary is pushed outwards. It is natural that the investor requires a higher revenue when the cost increase. This logic applies to the maintenance cost in Figure 3.5(a) as well.

3.4.2 Tax Sensitivity

In Section 3.2.2 we derived the real options model including taxes. By looking at the equations, the impact on the triggers and project value was ambiguous. We therefore evaluate the trigger and the project value for the example power plant with and without including taxes. As most small hydropower plants do not pay economic rent, we have omitted this tax here, setting $\tau_{EconomicRent}$ to zero. We use a before-tax required rate for the trigger and project value when we omit taxes, while we use the after-tax interest rate otherwise.

From Figure 3.6 we see that incorporating taxes causes a similar effect as increased maintenance cost, or increased investment cost as in Figure 3.5. It has a negative impact on the required prices, raising the triggers. For example, our example power plant would not be built given the average future electricity price in May 2013(~34 €/MWh, NASDAQ OMX), unless we received a subsidy of 33 EUR/MWh. Given that the average price for the March-2016 elcertificate forward was just 23 €/MWh, we would not invest if we were faced with the decision today.

From Figure 3.7 we see that the required project value triggering investment is equal for the scenario including taxes up to a certain level of electricity price (P= 18 €/MWh). Above this price level, the required project value triggering investing is higher for the scenario without tax. The reason why the project value without tax increase more than the project value with tax in the latter case, is that the costs withdrawn are constants through X and I. The revenue is the variable entity. In the present value equation including taxes (3.32), the revenue

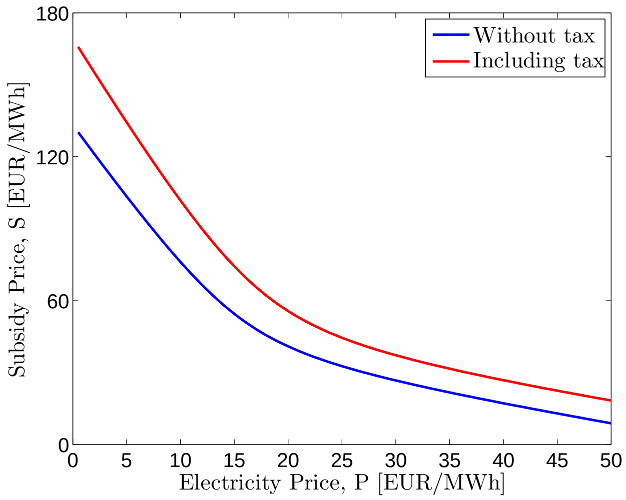


FIGURE 3.6: The optimal stopping boundary is increasing when we incorporate taxes

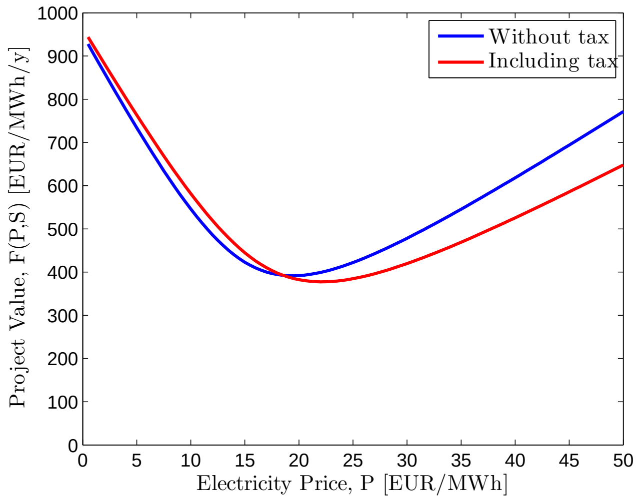


FIGURE 3.7: The project value at the optimal stopping boundary with and without taxes

is multiplied by B. Consequently, the project value grows at a slower pace with the parameter B as a buffer, when the subsidy price has marginal contributions.

Chapter 4

Data

We have updated and extended an existing dataset initially gathered by Heggedal et al. (2013). It consists of 214 licences to build small hydropower plants granted by NVE in the period 2001–2008. In this chapter's first Section 4.1, we will describe the collection process and the content of the dataset. It is worth noticing that the data has been collected in two stages, first from the regulatory database and thereafter through interviews with the license holders. The response rate from the interviews was 99%. Secondly, we will present the choice of parameters and assumptions plus its reasoning in Section 4.2. Lastly, we will present descriptive findings from the data in Section 4.3.

4.1 Gathering the Dataset

The dataset was gathered with the intention of replicating the investor's decision problem: Do I invest now or do I wait and see? This would be compared with the actual decision made. Necessary information comprised cost data, production size, important dates and the license holder's current status amongst others. Hence, the dataset should contain both quantitative and qualitative information, defined as a mixed approach. For description of features and advantages of using a mixed approach we refer to Creswell (2009).

The foundation of the dataset is data from the regulatory database kindly provided by NVE. They store detailed information concerning applications and licenses such as application date, license date, rated power, expected annual production, investment cost, filed complaints, ownership and in some cases cause of delays when the power plant for example face problems accessing the transmission grid.

Nevertheless, what the investor proposes in his application is only a draft. After a license is granted the investor have some leeway in the scope of the project. For example, an investor can increase or decrease the size of the turbine within $\pm 10\%$ without informing the regulator. Additionally, more detailed planning is performed after the license is granted. The common experience is that the actual investment cost increase compared to the initial application, due to a more profound planning and changed market conditions. The processing time for an application at the regulator could be several years due to a boom in interested investors and cost inflation in the industry has been high during the latest decade.

To minimize the impact of these uncertainties and improve the quality of the data it was chosen to interview the license holders. By supplementing the dataset with interviews we were able to obtain information about investors' expectations regarding subsidies and profitability, possible delays and whether the costs and size of the plant deviate from the original application. Additionally, we could learn the current status of the project, as well as discuss assumptions and parameters they have used in their own calculations. The interviews were mainly conducted by telephone and in some cases by e-mail when more convenient.

The dataset in Heggedal et al. (2013) had a respond rate of 85% (179 of 214) and were collected during 2011. The respond rate is now increased to 99% (211 of 214), after new attempts to contact the investors who did not respond previously. Additionally, we have contacted investors reporting they had not yet decided to invest when the original dataset was gathered in 2011. In total, 53 power plants have been updated in this round, making the total data set valid for the period 2001–2012. The survey we applied when updating and extending the dataset is attached in Appendix C.

We believe the quality of the data is high. A feature of the interview is that the interviewer can state his purpose and clarify any misunderstandings. We also believe that the data is neither understated nor overstated, as the investor have no gain from manipulating the results. The only way to get the desired qualitative information about expectations is through interviews.

In the three cases where we did not get a response we follow the approach in Heggedal et al. (2013), who relied on data from the regulatory database and information found on the internet. Such information could be local newspaper articles or tenders written by the license holder.

4.2 Assumptions and Parameters

To be able to calculate the value of the power plant we made assumptions where numbers are incomplete. Many of the decisions and calculations were made a decade ago. When speaking to the investors, some of them did not remember the exact numbers and made a guess. Others did not remember what was included in their numbers. To maintain consistency, we therefore made a few generalizing assumptions. We have also assigned values to parameters taken as input to the real options model.

We used a common rate for maintenance cost per unit of production for all the power plants in the data set. Maintenance cost for a hydropower plant usually consists of payments related to machine service, wages, insurance, transmission costs and rental payments for the right to use the river. As small hydropower plants are mainly run-of-river, they do not need production planning and constant surveillance. The maintenance cost is therefore low compared to the initial investment cost and is roughly calculated as 1% of the investment cost annually (NVE, 2011). Our belief is that the 1% does not cover insurance and transmission cost. We consequently chose to set the annual rate a bit higher than 1%, at 9 €/MWh in 2012, in line with Heggedal et al. (2013). In the years prior to 2012 we have deflated this measure so the annual maintenance cost follows the expected annual inflation rate of 2.5%. In cases where the license owner is also the land owner, the rental payments for the right to use the river should still be included as an alternative cost. He or she still has the opportunity to rent the rights to the river to others.

Hydropower owners are characterised by being either local land owners or larger companies owning several licenses. We choose to separate them in two groups: professional investors and non-professional investors. We define a professional investor as one that owns more than one license in our dataset.

When conducting the survey we strived to obtain the expected investment cost at the time the decision to invest was made. If a decision was not yet made, we tried to obtain the most current cost estimate. In the cases where the investor did not remember exactly the relevant cost, either the cost from the license application, or the actual incurred investment outlay is used. To get the relevant cost in each year in the investor possessed a license, the number we got from the investor is inflated or deflated according to the NVE Hydropower Index shown in Figure 4.1. Due to lack of data we have assumed that the growth rate in 2011 and 2012 is equal to the growth rate in 2010. The index is representative for a high pressure facility, with large tunnel costs and a usage time of 4 000 hours/year. It is calculated based on the average Norwegian hydropower plant, not just small hydropower plants. Still, we find it a good proxy and the best available for our purpose.

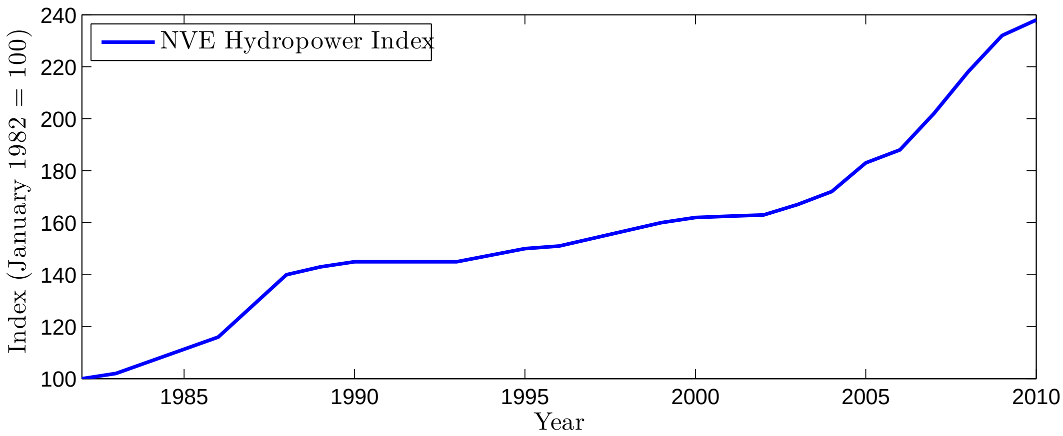


FIGURE 4.1: NVE's Hydropower Index (NVE, 2011)

NVE claim that it was a weak market in 2000–2005, resulting in a limited increase in prices in this period. However, the market experienced great activity domestically and internationally in 2006–2010 which led to a substantial price increase in some areas or industries (NVE, 2010a).

Revenue from operating a hydropower plant depends on the annual production. Future production depends on precipitation, but it is almost impossible to forecast hydrology years ahead. As a proxy for production we have used the expected annual production. The amount of production each year is thereby modelled as constant, while in reality it is an uncertain variable. Nevertheless, this assumption does not have a large impact on the results, as the average production will

Table 4.1: Expected year of introduction of subsidies and its corresponding lag in revenue T_{S_1}

Year	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Intro.	2004	2004	2004	2006	2007	2008	2008	2012	2012	2012	2012	2012
$T_{S,1}$	3	2	1	2	2	2	1	4	3	2	1	0

converge to the expected average production as the years of production increase. Additionally, as the pants are run-of-river they are often subject to a minimum required flow of water due to both biological and aesthetic reasons. This means that they cannot produce all the water that comes running in the river, but has to leave some of it outside of the pipes. When precipitation is high, power prices are generally low. As small hydropower plants usually operate without storage in dams, the average selling price for small hydropower plants could be lower than the average power price. When speaking to investors, they did not seem to experience a much lower average price. We have therefore not accounted for this in the model, but recognise that the power prices could be an upward bias.

Sødal (2006) study the effect of a construction lags on an uncertain, irreversible investment and find that the conventional effect on price uncertainty is weakened when there are lags. He believes the contrasting result arises due to the lag in revenue, and that the opportunity cost of waiting does not depend on the price during the delay, but the price in the future. This make the firm hurry in order to avoid learning of high prices while it is still out of the market. For small hydropower plants it is common that the building period stretches over 1.5 years. Revenues are thereby delayed, but for simplicity we assume that revenues from sale of electricity are continuous from the day the investment decision is made. Delay in revenue from elcertificates has been accounted for, as the delay is variable in the period between 2001–2012 and thereby have a bigger impact on the results. The delay is affected by both the time consumed by building the plant, and subsequently the time taken to process the application for the certificates, as you can only apply for certificates after the plant is in operation. Nevertheless, it is mainly the time needed for political decision making causing delay in revenues. Based on political statements in Table 2.1, the expected year and corresponding lag for introduction of subsidies is set in Table 4.1. It leads to a loss in revenue if you invest before the scheme is implemented. Electricity certificates are granted for a period of 15 years from the first day of production. Thereby, if you built your plant in 2010, you would only receive certificates for the period 2012–2025.

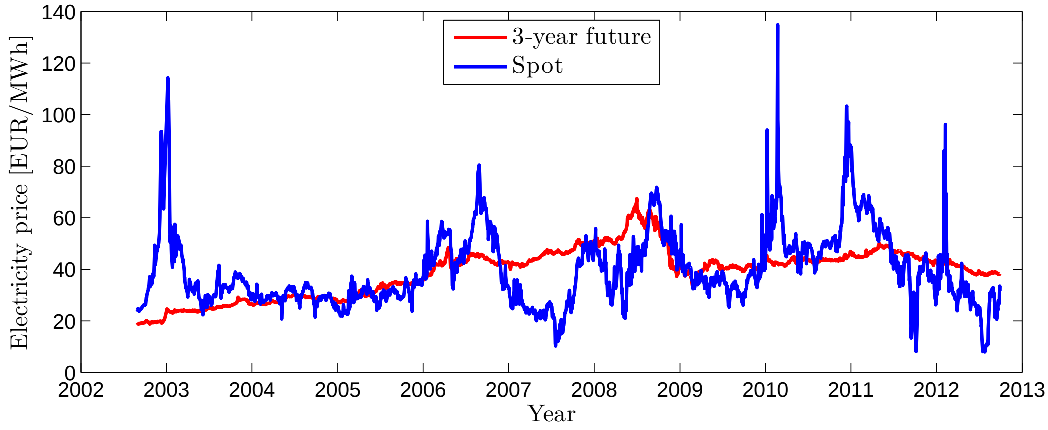


FIGURE 4.2: Comparison of the spot price and the 3-year future contract for electricity. Source: Nord Pool Spot, NASDAQ OMX

Electricity is continuously traded both on spot and future markets and the price is variable, displayed in Figure 4.2. Liquidity in the future market stretches out only 3 years ahead. Thereby, over the lifespan of the power plant the electricity price is uncertain. The volatility of the daily return on a 3-year forward contract in the period 2001–2012 is calculated to be 15.5% annually. For spot it is much higher, due to price spikes. For comparison, the volatility of the daily return for elcertificates on SKM Spot was 15.3% annually from 2003–2012. Some investors mentioned that they experienced a lower average price because of the geographical location of the power plant. The Nord Pool Spot operates with a system price, but will also quote area prices to deal with congestion management. In Norway, there are currently 5 price areas, NO1–NO5, but this has been subject to changes in the past as it depends on where the transmission capacity is exhausted. In Figure 4.3, the yearly average system spot price along with the quoted price for the areas is illustrated. Here we see that it is only the most current years when prices are diverging from the system price (2008,2010). This is caused by cold winters and all time high demands. Nevertheless, as the dispersion in the average prices is relatively small and not persistent with time, we have chosen to not account for this in the model.

In the real options model we have assumed that both electricity and electricity certificates follow GBM. This is to obtain a simple solution available to our problem. Electricity markets are characterised by high volatility and price spikes as well as seasonal patterns, shown in Figure 4.2. It has unique features compared to other energy commodities due to its non-storability further discussed in Eydeland

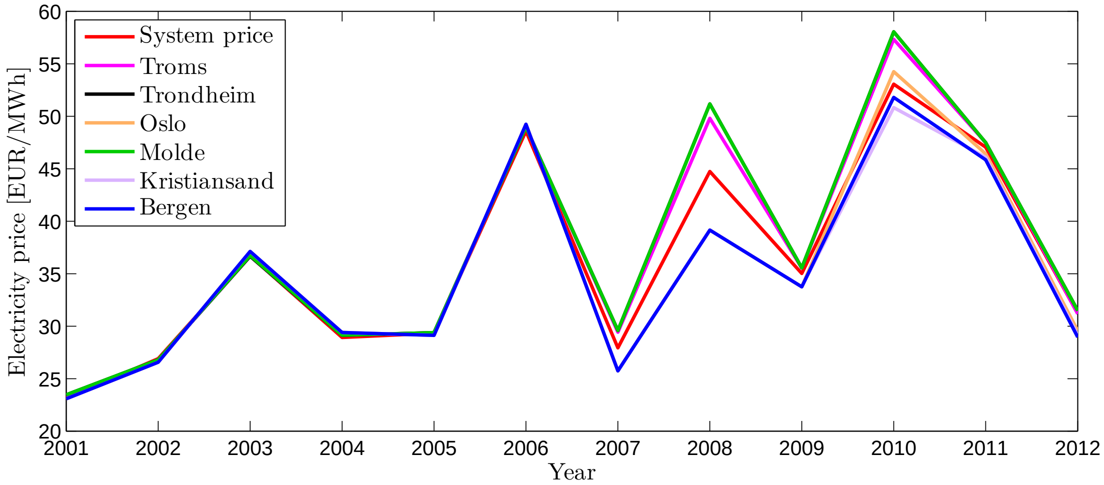


FIGURE 4.3: The average area prices in Norway each year compared to the system price. Source: Nord Pool Spot

and Geman (1999) and Lucia and Schwartz (2002). Based on these properties, many articles and books propose other processes than the GBM for modelling electricity prices. Both Weron et al. (2004) and Benth et al. (2008) recommend a mean reverting model with jumps for modelling electricity prices in the Nord Pool market. An empirical analysis by Koekebakker and Ollmar (2005) show less correlation between short-term prices and long-term prices in electricity markets than in other commodities markets. This support the two-factor model of commodity prices by Schwartz and Smith (2000) that allows mean reversion in short-term prices and uncertainty in the equilibrium level to which prices revert. Lucia and Schwartz (2002) have studied the Nordic electricity market using both a one-factor and a two-factor model and found that the two factor model have a better fit to the data. However, Schwartz and Smith (2000) argue that when considering long-term investments, the long-term factor is the decisive one. Similarly, Pindyck (2000) claims that when considering long-term commodity related investments, a GBM description of the price will not lead to large errors. Thereby, we find it reasonable to make the assumption that the electricity price follows GBM. As elcertificates are dependent on the electricity through the quota, we find it appropriate to use this model for elcertificates as well. The calculated starting prices each year for the electricity is displayed in Table 4.2 along with the drift rates for both electricity and the subsidy.

To the best of our knowledge, the only paper empirically testing the behaviour of electricity when including elcertificates is Heggedal et al. (2013). They find

Table 4.2: Starting values of the electricity price and drift rates

Year	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
P_0[a]	16.7	19.6	21.3	24.9	28.3	37.4	44.3	51.8	46.9	41.1	42.9	40.4
α_P[b]	5%	4%	4%	2%	1%	0%	-1%	0%	0%	1%	2%	2%
α_S[c]	2%	2%	2%	2%	3%	4%	0%[d]	2%	0%	1%	4%	4%[e]

[a] [€/MWh] The starting price of electricity is calculated using the discounted three-year future contract averaging prices over the first half of the present year and the last half of the previous year.

[b] The drift rate for the electricity price is calculated as the yearly average drift rate between two and three year future contracts.

[c] The electricity certificate drift rate is calculated as the annual required rate ensuring that the electricity certificates invoke wind power investment within 2020. The calculations are based on a LRMC of wind at 75 €/MWh, future price of electricity at 35 €/MWh, giving a required subsidy level of 40 €/MWh.

[d] The drift rate is set to 0% as a fixed feed-in-premium was promised in 2007 for the first 3MW in each power plant.

[e] The drift rate was calculated at 7%, but is set to 4% which is below the required rate of return, to ensure a positive lease rate and convergence to a solution.

that a deterministic process and a mean reverting process perform significantly better than regressions based on the stochastic GBM price process. This should be acknowledged when interpreting the results.

Simple linear correlation is likely to be an insufficient descriptor of the relationship between P and S. Bye (2003) perform simulations based on introduction of subsidies through certificates in the Norwegian power market. He finds that the behaviour of the sum of electricity price and the subsidy price is ambiguous, depending on the elasticities and the required amount of green energy, the quota. When new production is introduced to the market, the production volume increases causing a rightward shift in the supply curve. The demand function remains constant, thereby electricity price falls. Simultaneously, the elcertificate price increases as the higher production volume induces a high demand for certificates as the quota is production dependent. As long as the quota continue to increase with time, which it does in our case, new production will be added and this negative relationship will continue. Therefore, we would expect the relationship to be negative and we can make an assumption that the relationship is not far from linear without too much error.

The linear correlation between the prices was found to be close to zero, indicating no relationship at all. Nevertheless, investors might have had the expectation that the prices were in fact negatively correlated. We have therefore chosen to use

TABLE 4.3: Required rate of return and the norm rate for each year

Year	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
r	8%	8%	7%	6%	6%	6%	7%	7%	6%	6%	5%	5%
r_{Norm} [a]	10%	10%	10%	10%	9%	7%	7%	5%	5%	2%	2%	2%

[a] The norm rate is each year set by the government. It was from 2001–2007 set as the three-year average of interest rates on government bonds plus a risk adjustment of 4%. From 2008–2012, the 12 months Treasury bills without risk adjustment were used. The norm rate is set in arrears. We therefore included a 1 year lag, as this was the available information to the investor.

a correlation of -0.5 when finding our results. Lemming (2003) finds that in his framework, certificate prices and fluctuations in production from wind turbines will be negatively correlated and, as a result, certificate price fluctuations can actually help decrease the total financial risk. When there is low wind production, this production must be replaced by other renewable energy which is more costly and certificate prices increase. Thereby, revenue will be more stable for wind turbines. The same argument can be used with hydropower even though it constitutes a large share of the power production in Norway because the market is interconnected with Sweden, which has a larger share of non-renewable power like nuclear.

The cash flows in the model are taken as after-tax cash flows to total capital. The required return was calculated using the capital asset pricing model (CAPM) on an after-tax basis. As a proxy for the risk free rate we used the interest rate on 5-year government bonds from Norges Bank. The market premium was set to 5%. Using a beta of 0.7 recommended by Gjølberg and Johnsen (2009), we got the results displayed in Table 4.3. In the table we also include the norm rate, r_{Norm}, used to calculate free income relevant for the economic rent tax. In addition, we assume that the debt interest rate, r_{Debt}, is 4.5%.

The size of the power plant is an important feature when evaluating taxes. Currently, hydropower plant owners are subject to economic rent and natural resource tax when exceeding a labelled power of 5.5MVA, duly explained in Appendix B. Under normal operating conditions, most generators produce real power [MW] and reactive power [MVAr]. Easily explained, the reactive power is produced to compensate for losses in the lines during transmission. With a power factor[1] of 0.9 a production of 5.5MVA corresponds to an active effect of 4.95MW. But, as power factors are dependent on the operating state in the electricity grid, which

[1]The power factor is defined as the real power delivered to the load divided by the apparent or total power in the circuit (Saadat, 2011)

is variable, it can also be up to 1. Thereby, we can draw an equality between the labelled power and the real power as an assumption.

In the first round of interviews it was not asked whether the investors paid property tax. A feature of the property tax is that it is voluntarily claimed by the municipalities. In 2011, 73% of all municipalities in Norway claimed property tax (Advokatfimaet Lund & Co DA, 2012). Because of the opportunity of high revenues, municipalities containing hydropower plants usually claim this tax, as they are often located in rural areas without many other sources of tax revenues. We therefore assume that all hydropower plants pay property tax unless otherwise is clarified.

4.3 Descriptive Data

We here summarise the basic features of the collected data. Aggregated, the licenses comprise 672.9MW of generation capacity, 2.43TWh of expected annual production and an investment expenditure of €1,023 million (cost basis 2012). Put in perspective, this equals almost 2% of the annual power production in Norway (NVE, 2012).

Heggedal et al. (2013) found a distinction in the investment behaviour among professional and non-professional investors. The illustrations are therefore split into these categories where possible. In the data set there are 101 professional investors, and 113 non-professionals. 4 of the biggest companies with main focus on building small hydropower plants have created the Small Hydropower Alliance G4. The related companies are Småkraft, Norsk Grønnkraft, Fjellkraft and Elvekraft. Of the 101 professional licenses, they own 40. Non-professional investors could have less access to funding, be less diversified, have fewer available projects, be more risk averse and have less knowledge or information about regulatory processes. As noted by Bulan et al. (2009), most neoclassical models (such as CAPM) would predict that greater uncertainty caused by not diversifying leads to an increase in the non-professional investor's required rate of return.

In our data set, 201 power plants report a power rating $\leq$ 5.5MW, and 13 above. Of the latter, two of them are a sum of two power stations in the same river, and thereby each rating is actually below 5.5MVA per plant. Thus, they are free from natural resource tax obligations. Many of the licenses were initially given to plants with a larger size, but due to the natural resource tax, investors have scaled down their projects. 11 of the 13 plants above $\leq$ 5.5MW are owned by professional investors. Regarding the hydropower plants $\leq$ 1MW, 27 out of 30 are owned by non-professionals. The average size of the professional's power plants is 3.85MW. The average size of the non-professional projects is 2.51MW. There seem to be no particular pattern regarding the average size of investment each year, except for a high peak in 2004 when the average size of investment was 4.32MW. This exact year, the government eased the lower boundary for economic rent and natural resource tax from 1.5MVA to 5.5MVA.

The yearly distribution of the licenses and the decisions are illustrated in Figure 4.4. It is worth noting that the yearly number of granted licenses has increased drastically. The number of years from the license was granted to the actual investment decision was made, is displayed in Figure 4.5. Bear in mind that this is not adjusted for external delays such as filed complaints and transmission problems. The fact that almost half of the investors decide to invest in the same year they received the license show that many investors have already decided when entering the application. This was also an observation during the interviews. Some of them, when they were asked about the timing of their decision, stated that they decided when working on the application. It could be that they do not view the license as an option to invest. Disregarding the holdouts, the average time to decide was 1.5 years for professional investors, while only 0.92 years for non-professionals. Additionally, if we adjust for external events causing delay in the decision making process, the average time to decide was lowered to 0.94 years for professional investors and 0.53 years for non-professionals.

There are many explanations to why there are still 23 power plants who have not invested. We believe the main reasons are low profitability and grid-regulations. Some of the investors experience that they are not able or allowed to connect to the transmission grid. Others have lost interest in the project and do not have it as a priority at the moment. 10 of the 23 power plants who have not yet decided are $\leq$ 1MW. Moreover, they represent only 14% of the licences. Opposite, in the group of hydropower plants $\geq$ 5.5MVA only 1 of the 13 plants have not made an investment decision yet.

We find that the average investment cost per unit of production is higher on average for smaller plants, at 401 €/MWh/y. Compared to the total average of 347 €/MWh/y, it could be evidence for economy of scale. A scatter plot of

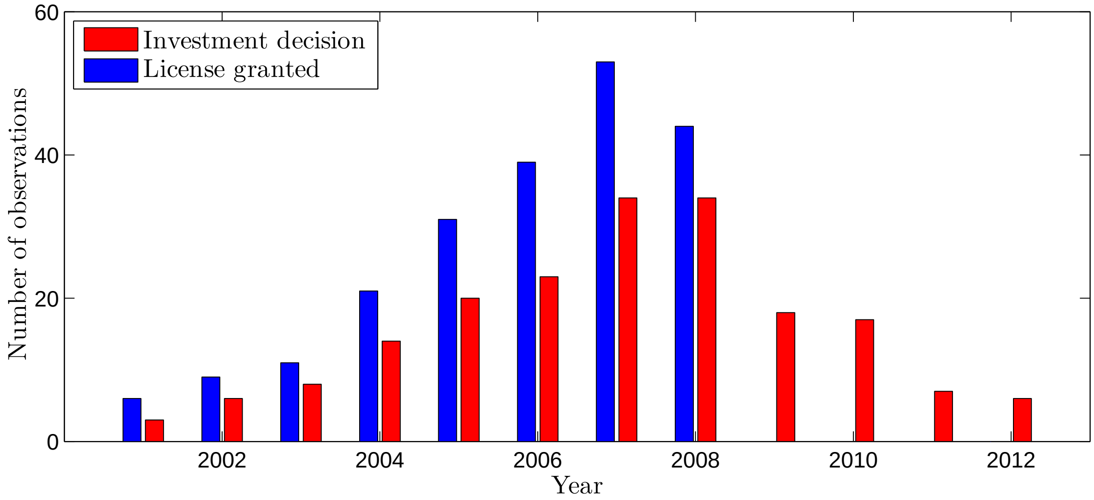


FIGURE 4.4: Number of licenses granted and number of investments each year

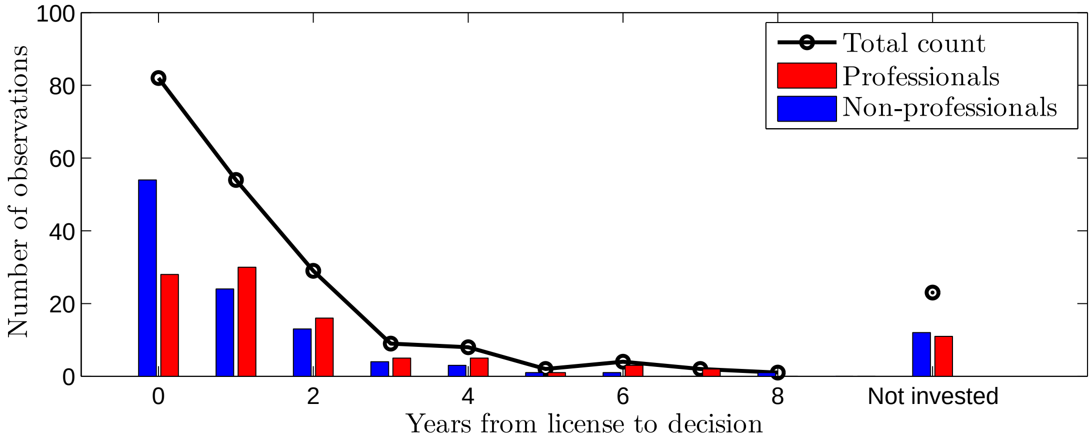


FIGURE 4.5: Number of years from a license was granted to a decision was made

investment cost per unit of production versus production size display a spurious relationship with a linear $R^2 = 0.008$.

An illustration of the average investment cost in each respective year, if investment was decided, is displayed in Figure 4.6. We here see that the average cost of the plants that is not yet invested in, is highest. It is also interesting that investments seem to follow a pattern of merit order, the more profitable plants are invested in first. This pattern is still present if we adjust for inflation. We acknowledge that there could be an upward bias in the average investment cost in the later years compared to the whole market, as we only investigate licenses granted to and including 2008. As the most profitable projects are invested in first, the plants

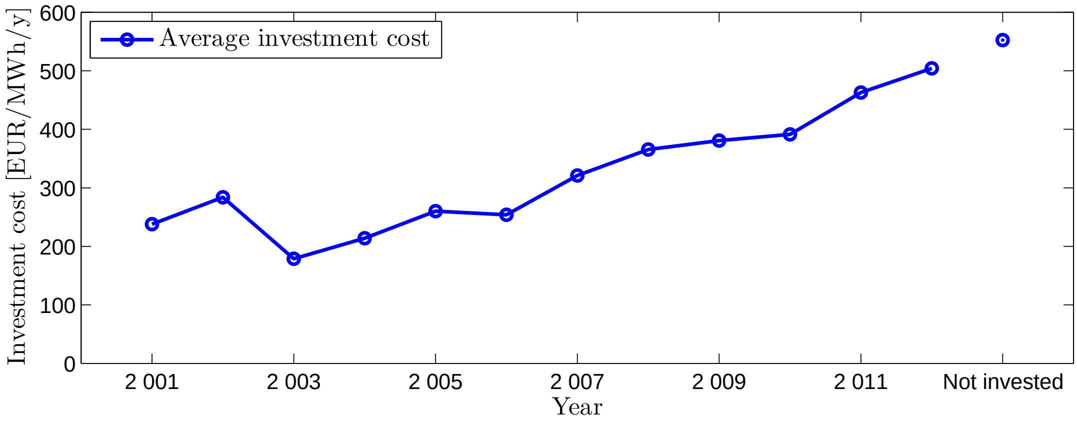


FIGURE 4.6: Average investment cost each year

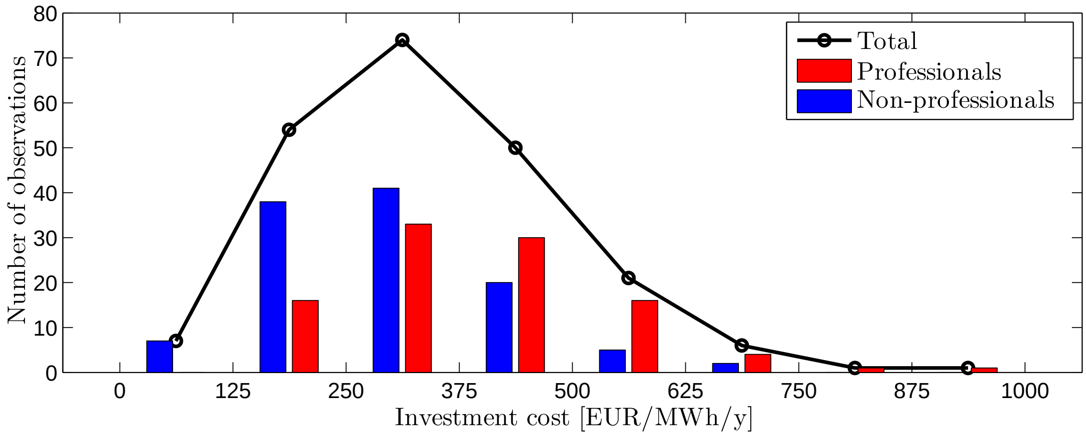


FIGURE 4.7: Distribution of investment cost

with high investment cost are postponed and thereby cause a biased sample in the later years.

In 2011, a time when the elcertificate scheme was determined, the upper limit for development costs was said to be 580 €/MWh/y (NVE, 2011). The distribution of the power plants' investment cost is displayed in Figure 4.7. We here use the investment cost from the year the decision was made, or if not yet decided, the inflated number corresponding to 2012. The qualitative result does not change much if we adjust all numbers to the same cost basis. Most of the power plants are distributed below the upper limit of 580 €/MWh/y. Non-professionals have a much lower average cost, at 294 €/MWh/y. Professionals average on 405 €/MWh/y. An explanation for this could be that the professional investors have more financial muscle and dare initiate more expensive projects. Additionally, projects where non-professionals face financing constraints, are often sold to professionals after the license is given.

Chapter 5

Results

In this chapter we first present the results from the real options model. Then, we compare this to results from the simpler NPV model. We will also discuss whether the models display rational investment behaviour. Subsequently, we perform a probit panel data regression to test whether the real options model is a good description of the investment behaviour.

5.1 Main Results

We have evaluated the real options model for each power plant in the years it possessed an active license to invest. The parameters are updated for each year, representing the available information presumably known by the investor, explained in Chapter 4. In the year the investor chose to invest (i.e. exercised the option), we calculate the implied subsidy level, S^*, required for investment to be optimal given the current electricity price.

We can only calculate the option value at the exercise boundary. Thus, we can not use our results directly in the years when the investor did not decide to invest. Nevertheless, we know that the investor would require a similar or higher subsidy level than that predicted at optimal investment point. We will therefore also try to infer something from the results in the years the investor did not invest and continued to hold the option. Here, we have excluded observations where the investor was held back by external reasons.

For comparison, we perform an analysis of the NPV without subsidies in the years the investor possessed an active licence. We also calculate the required subsidy level for the NPV to equal zero. A zero NPV is the optimal investment point following the NPV rule.

5.1.1 Results From the Real Options Model

The average implied subsidy price each year, in cases where the investor decided to invest, is displayed in Figure 5.1 and Table 5.1. It is compared to the average Swedish elcertificate price over the same period and the results from the real options model when the investor did not invest.

The required subsidy level when the investor did invest coincides very much with the elcertificate price in the years 2003–2010, while the required subsidy level is much higher in the years 2011 and 2012. As the market for elcertificates opened in 2003, there are no comparisons in 2001 and 2002, but relative to the years after, the required subsidy level is high. Both the magnitude of the subsidy and the evolution of the magnitude, apart from a slight hike in 2005, are similar to the price of elcertificates. This could indicate that investors had a long eye towards Swedish elcertificate prices when they invested. The predicted required subsidy level for the investors that did not choose to invest is generally higher than both the required subsidy rate for the investors that did invest and the elcertificate price.

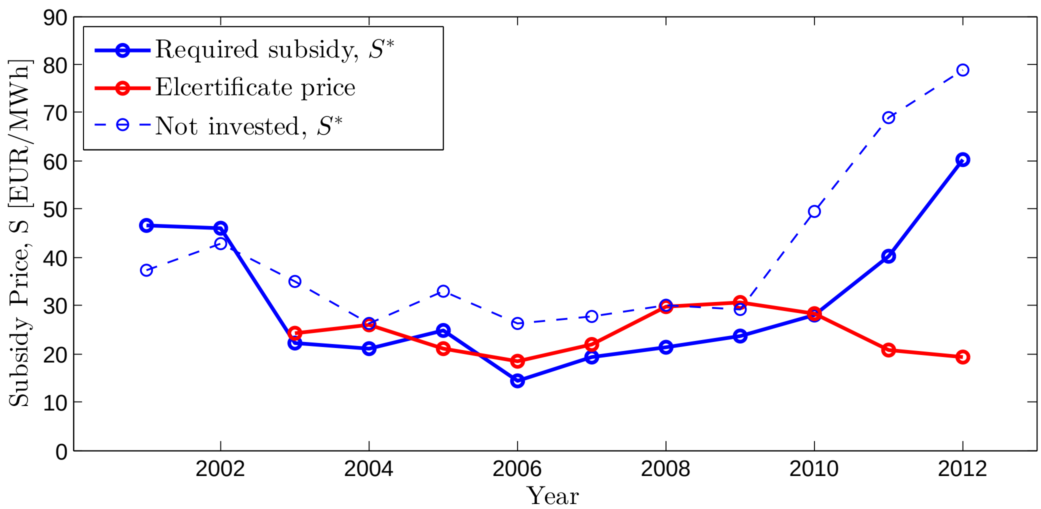


FIGURE 5.1: The average required subsidy level for investment compared to the elcertificate price. Source: Svensk Kraftmäkling (SKM)

This show rational investment behaviour in the sense that investors who deferred investing require higher subsidies than investors who did invest. Additionally, as the required subsidy level for the waiting investors is generally higher than the elcertificate price, it would not be optimal to invest if expectations were in line with the elcertificate price. The investor would consequently wait as predicted by real options theory.

From quotes gathered during the interviewing process, it is clear that investors had different expectations towards subsidies and that they varied with time. A full list of quotes is found in Appendix D. Based on the quotes and the political statements displayed in Table 2.1 we would expect the amount of implied subsidy to be higher in the years where political discussions were aspiring (2004–2005, 2009–2010) and lower in the years it was entrenched (2006–2008). Especially in 2007, when a much lower feed-in-premium of 5 €/MWh was to replace the idea of elcertificates, we would expect a lower level of implied subsidies. Although the general level of expectations towards subsides are lower in the years 2006, 2007 and 2008, it is about three times the level of the feed-in-premium. We therefore fail to see a corresponding magnitude in the responsiveness in the results. Nevertheless, talk about the feed-in-premium only lasted for approximately a year and we acknowledge that it could be difficult for investors to turn on the heel on a short notice. Through the incorporated lag in revenues from subsidies in Table 4.1, we also account for some of the political delay and thereby reduce the magnitude of the responsiveness. Furthermore, the promise of a transitional agreement from The Petroleum and Energy Minister in 2004 saying that all who invested would be included in the scheme in arrears, also oppose the effect. Consequently, as the results show a drop of almost 10 €/MWh in implied subsidies from 2005 to 2006, we believe that the political discussion had a negative and delaying effect on the investors, strengthening the real options assumption.

Explanation for the higher average level in the years 2001–2002 and 2011–2012 can be found by looking at the distribution of the required subsidy levels for those who chose to invest. In Figure 5.2 a scatter plot of all the observations is displayed, together with histograms. From this, we can see that the number of observations in the beginning and the most current years are much lower than the rest. The averages are therefore more sensitive to outliers. Furthermore, we only include licenses granted in the period 2001–2008 in our dataset. Our sample is therefore subject to a selection bias, as numerous licences were granted and exercised in the period 2009–2012 which is not part of our dataset. We believe the bias lead to a non-realistic high required subsidy rate in the later years, because the sample only consisted of the most unattractive and expensive projects, or else they would have been invested in previously.

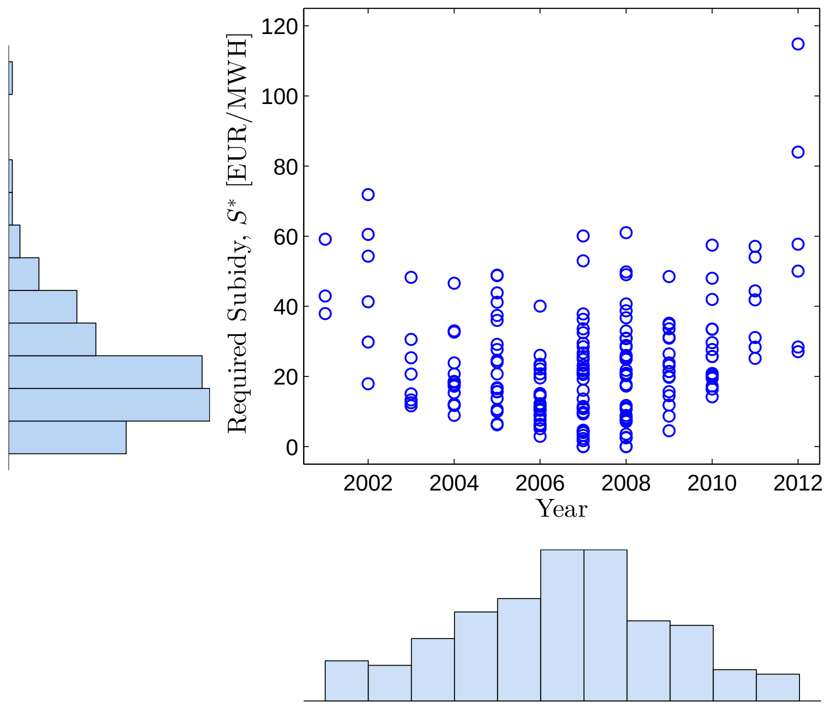


FIGURE 5.2: Scatter plot of the required subsidy level in the year the investor chose to invest, along with histograms

Looking at the sensitivity analysis in Section 3.4 and the state variables in Chapter 4 we can explain it further. In 2001–2002, the required return was at its highest, at 8%. Simultaneously, the power price was at its lowest at 16.7 €/MWh in 2001 and 19.6 €/MWh in 2002 and the electricity drift rates were at 4% and 5% respectively. Moreover, the investment cost per unit of production was at all-time high in 2011–2012 and the subsidy drift rates were at 4%, close to the required rate at 5%, giving a low lease rate. All of these aspects lead to an increased trigger according to the model, as discussed in the sensitivity analysis, with the investment cost and the electricity price as the largest determinants. The observation that investors did invest even though profitability was lower in 2001-2002 could be explained by noting that the spot price was much higher than the future prices used in the model. It could be that investors had good hopes for the far future and believed more in the level of the spot price than the future price.

5.1.2 Results From an NPV Approach

Results from the real options model indicate that investors on average expected a subsidy equal to the Swedish elcertificate price when they invested. However, one should be careful when interpreting the results as we assume that the investors are following the decision rule of real options. Both Gravdehaug and Remmen (2011) and Heggedal et al. (2013) find that for most Norwegian hydropower plants, the real options approach does not seem to better explain the investment behaviour than the NPV rule. Additionally, the short time spent by investors to make an investment decision could also contradict a real options approach. As explained in Section 4.3, they spend on average less than a year to decide after they receive a licence, after correcting for external delays. It could be that they do not regard the licence as an option to invest, but a now-or-never opportunity.

If a now-or-never approach is applied, the correct decision rule is the NPV rule. If we look at the NPV at the time of investment without including subsidies, we can study the investor expectations assuming that they follow the NPV rule. We find that 122 plants invested with positive NPV, 68 with negative, giving a total number of 190 investing. Separating the professional and non-professional investors we find that non-professionals invest at a higher average NPV than professional investors, indicating a higher required return predicted by Bulan et al. (2009). 45 professional investors invested with positive NPV and 44 with negative. 77 non-professionals invested with positive NPV and 24 with negative.

If we find the NPV per investment cost we get a proxy for the return on investment (ROI). ROI is defined as earnings, subtracted initial investment cost, divided by the initial investment cost. To account for the time value of money we replace the numerator, i.e. earnings subtracted initial investment cost, with the NPV. Thus, the ROI is already discounted using the required rate of return, which can be viewed as an alternative cost of capital. The resulting return of interest gives information about the profitability after the required return has been given to the investor.

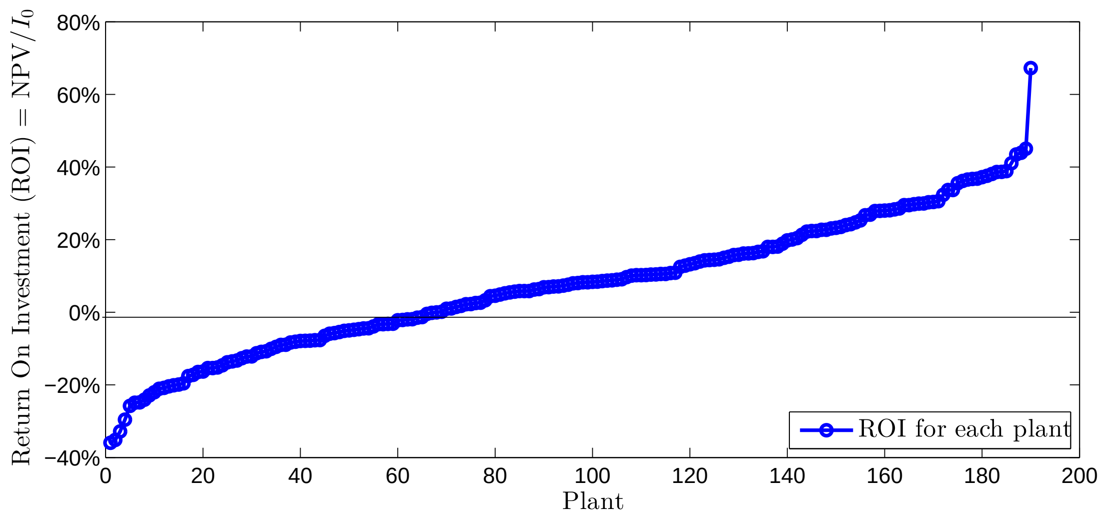


FIGURE 5.3: The distribution of ROI for power plants disregarding subsidies

The distribution of ROI for all the power plants that chose to invest is illustrated in Figure 5.3. The distribution exemplifies a smooth curve with only a few extreme points. This could evidence that the variation between plants are due to additional reasons we have not been able to model. One should therefore be careful and not draw too many conclusions from the plants with negative ROI, as there could be individual differences we have not been able to account for. For example, we have chosen to assume a common rate for maintenance cost and included property tax where otherwise was not clarified. In reality, it is therefore possible that they invested with positive NPV. Nevertheless, assuming that the additional reasons are evenly distributed across all plants we can use the NPV to find the implied subsidies.

The investor is indifferent to investing if the expected payoff is zero. Setting the NPV including subsidies to zero, we can find the minimum subsidy level required for investment:

$$S|_{NPV=0} = \frac{X+I}{r_S B} - \frac{r_P P}{r_S} \tag{5.1}$$

The results from this approach is displayed in Figure 5.4 and Table 5.1 together with the Swedish elcertificate price. We see that the minimum required subsidy level on average for those who invested is negative in most years, in 8 of 12. This is expected as the average ROI is positive looking at Figure 5.3. As the certificate price cannot be negative, we interpret the negative numbers such that the investor would be willing to invest even without subsidies. It is therefore a possibility that the investors did not expect subsidies at all when they invested. Reasons for this could be that the investors did not rely on the government's promises and only invested if they had positive NPV, even without subsidies. For example, some investors claimed "We did not dare to believe in revenue from elcertificates." and "We started production without even considering revenue from elcertificates. We have economy to manage without.". This show that investors could be risk averse (Pratt, 1964) and relying on subsidies before a scheme is implemented imposes a risk. Also, investors might not get the necessary financial support to make an investment decision with negative NPV, as banks do not grant loans based on uncertain expectations.

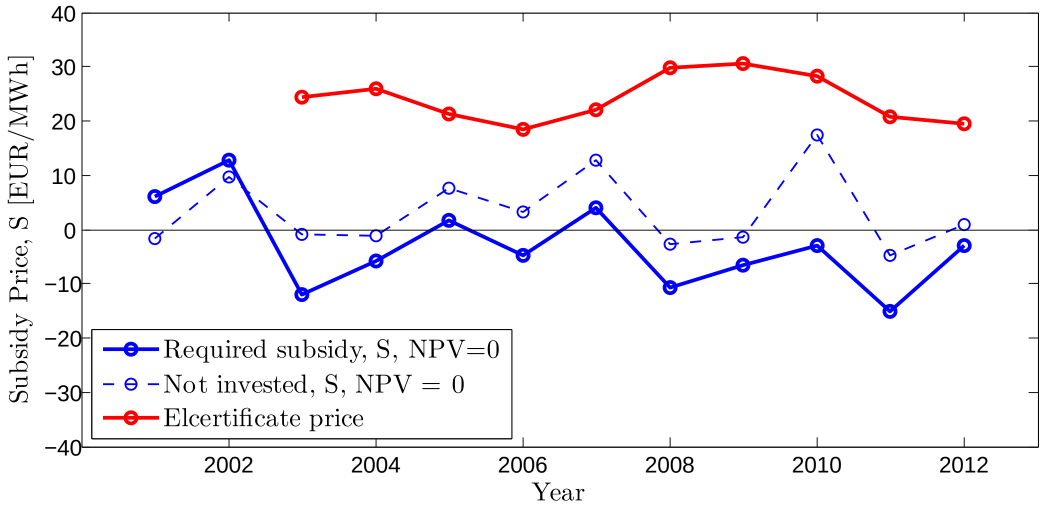


FIGURE 5.4: The average required subsidy level for investment to be optimal using the NPV rule, compared to the elcertificate price. Source: Svensk Kraftmäkling (SKM)

In 2001–2002, 2005 and 2007 the required subsidy level is positive, which imply that someone invested with negative NPV. This can be explained by three possibilities. The first, and the most likely according to us, is that the investors did actually expect subsidies. The second possibility is that the negative NPV could be caused by additional effects not captured by the model, while the third is that the investor did not expect subsidies and behaved irrationally.

We believe, based on the results and the quotes in Appendix D, that the investors who did invest actually expect subsidies, but did not incorporate them in full magnitude as they were risk averse. An investor who decided to invest in 2007 said for example: "We expected to receive elcertificates given promises that everyone who invested after 2004 would receive support, but we did not take it into account

Table 5.1: Expected subsidies implied by the real options model and the NPV calculations, along with the results when the investor deferred investment

Year	Elcert price	S^*	Not Invest S^*	$S\|_{NPV=0}$	Not Invest $S\|_{NPV=0}$
2001	-	46.7	37.2	6.2	-1.7
2002	-	46.0	42.8	12.8	9.7
2003	24.3	22.2	34.9	-12.0	-1.0
2004	26.0	21.1	26.3	-5.7	-1.2
2005	21.2	24.7	32.9	1.8	7.6
2006	18.4	14.4	26.2	-4.9	3.1
2007	22.0	19.4	27.7	4.0	12.8
2008	29.8	21.5	30.0	-10.6	-2.7
2009	30.6	23.6	29.2	-6.5	-1.4
2010	28.3	28.1	49.4	-3.0	17.4
2011	20.9	40.3	69.0	-15.0	-4.7
2012	19.4	60.3	78.8	-3.1	0.9

in expected revenues. Do never trust political promises.". Another who invested in 2009, just a few months before the new transitional agreement was set said "It was a big disappointment. We were sure we would receive elcertificates.".

The trend in the required subsidy follows the pattern we would expect according to the political statements in Table 2.1. We see that the investors are requiring a lower profitability in 2004 and 2005 compared to 2003, and the same goes for 2009 and 2010 compared to 2008. In 2006, when negotiations broke down, the profitability increased compared to 2005. The level of the required subsidy in 2007 also coincides with the outspoken level of the feed-in-premium of 5 €/MWh. On the contrary, the implied subsidy in 2001, 2002 and 2011 do not fit in this story. As mentioned, it could be that the hike in 2001–2002 was due to investors expecting an electricity price in line with the spot price, and not the future price, and the trough in 2011 we contribute to a selection bias. The interpretation that investors were investing with a positive NPV, but also followed the pattern of expected subsidies, points towards a behaviour according to the real options decision making rule.

In the cases where the license holder did not choose to invest, the required subsidy is positive on average. Thus, we have negative NPV on average and according to the NPV rule you should not invest if you have negative NPV. Thereby, the results display rational investment behaviour given that the investor did not rely on subsidies. Nevertheless, we can not rule out the plausible explanation that the investors were waiting for more information or better market conditions, in accordance with real options theory. The average required subsidy for the investors that did not invest is in fact negative in 6 out of 12 years, meaning that the NPV was positive half of the time. Thus, according to the NPV rule they should have invested. This speaks against the validity of the NPV in our case, and we therefore do not regard it as the best descriptor of the investment behaviour in our case.

5.1.3 Comparing the Results From the Two Approaches

The results show that the investor's expectation to subsidies is dependent on the applied model and its definition of the optimal decision rule. The real options model predicts that investors expected subsidies in line with the Swedish elcertificate price. If we follow the NPV decision rule, investors did on average not rely on subsidies. However, results from the investors that did not invest point towards that the NPV decision rule might not be a correct descriptor of the investment behaviour, as the NPV was positive in 6 out of 12 years. Results from the NPV calculations where the investor chose to invest could also support a real options decision rule, as the evolution in implied subsidies follow the predicted trend based on publicly available statements published by the government.

Based on the quotes in Appendix D we further strengthen our belief that the real options decision rule is a good descriptor of the investment behaviour, even though there were individual differences across investors. A scenario described in Heggedal et al. (2013) is that professional investors are behaving according the real options theory, while non-professionals according to NPV. We also find this pattern to some extent in our conversations with the investors.

We have analysed the implied subsidies while separating the results according to professionalism, both in the cases where the investor chose to invest, or not. The results are displayed in Figure 5.5 and 5.6 using the real options model and NPV calculations. Our first observation is that in all cases, irrespective of model choice or decision, the implied subsidies for the non-professionals are lower. This coincides with the observation that the average cost for non-professionals is lower than for professionals, thus, this was expected. Results from the real options model show marginal differences depending on professionalism. Our previous conclusions are therefore unchanged if we assume a real options behaviour. Results from the NPV calculations however, lead to new insights. Here, the professionals require subsidies in 6 of 12 years when they invested. Thus, we have further support for saying that investors required subsidies when investing. Non-professionals that did invest have a positive NPV in 9 of 12 years and we therefore cannot rule out the possibility that they invested depending on NPV. Non-professionals that did not invest have a positive NPV in 8 of 12 years, contradicting the hypothesis in Heggedal et al. (2013). Thus, our results infer that the non-professional investors that deferred investment behaved according to real options theory.

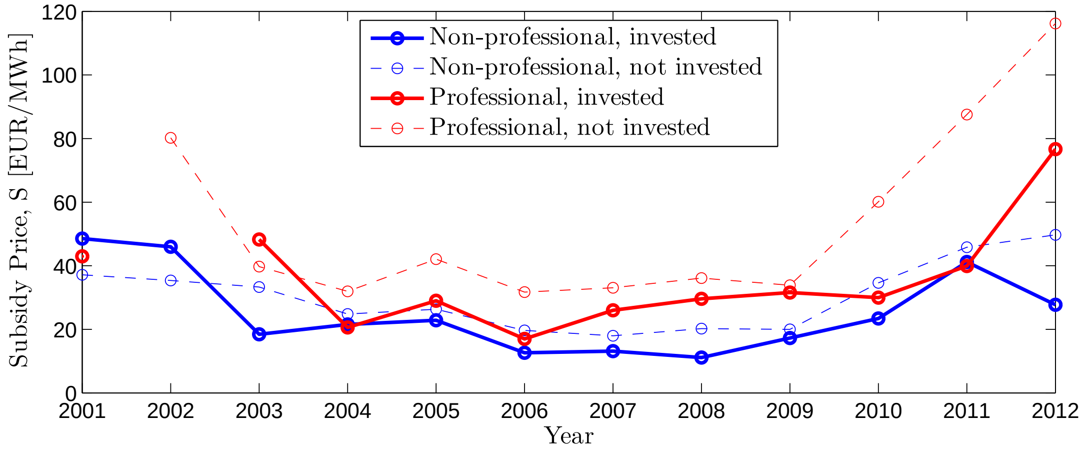


FIGURE 5.5: The average required subsidy level for investment to be optimal calculated using the real options model, split depending on professionalism

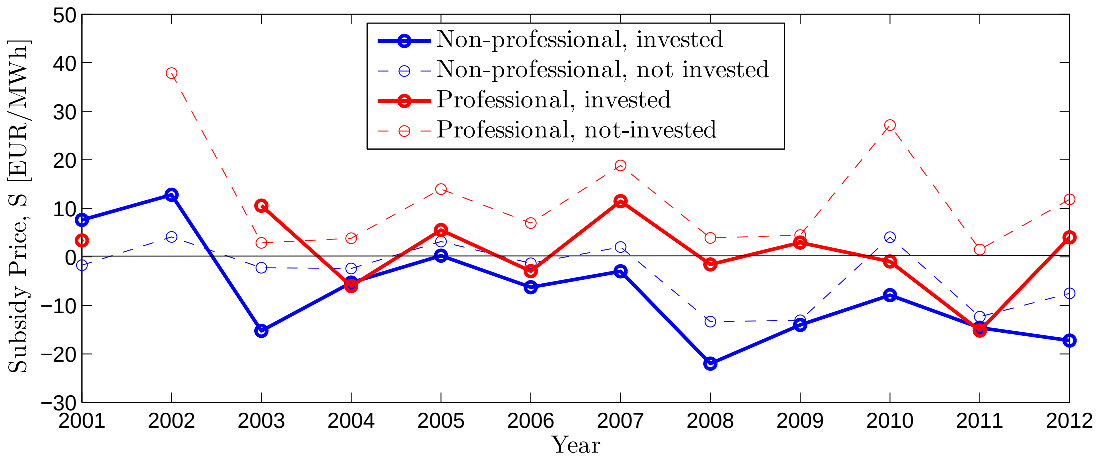


FIGURE 5.6: The average required subsidy level for investment to be optimal calculated using the NPV rule, split depending on professionalism

In summary, we believe that the results favour an investment behaviour predicted by real options theory over the NPV rule. This implies that the average investor was expecting subsidies when he or she invested. The magnitude of the subsidy however is debatable. The real options model predicted subsidies in line with the Swedish elcertificates, but few investors interviewed in this round proclaimed that they incorporated revenues from subsidies of that size. Our real options model may have overestimated the required subsidy as we assume a perpetual option. In reality, investors must start the development within year 2020 to receive subsidies. This year is consequently experienced as the final end of the license. Future work should therefore be done on incorporating a finite lifespan of the option. In addition, future work could incorporate a structural estimation model which will most likely give a more accurate description of this magnitude. Also, future work could be done on investigating our goal function. If our goal function is flat, the range of almost optimal implied subsidies can be wide, without leading to a large impact on the specified goal.

Recent numbers published by NVE show that there are currently 30 small hydropower projects under construction, while 307 projects with an active license are sitting on the fence (Europower, 2013). This further strengthen our belief that investors are behaving according to real options theory.

5.2 Model fit

To investigate the applicability of the real options model further, we perform a probit panel data regression with the investment decision as the dependent variable. As we can not decide the value of the option outside of the exercise boundary we can not test the real options model against the NPV. Instead, we follow the approach in Moel and Tufano (2002) where we find the impact the explanatory variables have on the investment decision. Then, we can compare this impact to what is predicted by the real options model in the sensitivity analysis in Section 3.4. If investors act in accordance with the real options model, then the decision to invest will be related to the market conditions according to the predictions.

5.2.1 The Probit Panel Data Regression

The probit analysis of the likelihood of an investment decision is computed using the probit model

$$Pr(y = 1) = \Phi(\beta_0 + \beta'\boldsymbol{x}) \tag{5.2}$$

where y is a dummy variable that equals one if the investment decision is made in a given year, and zero otherwise. $\Phi(\cdot)$ is the cumulative normal distribution, β_0 is the intercept, β' are the coefficients and $\boldsymbol{x}$ are the regressors.

The chosen independent variables were the ones predicted to have impact on the investment decision. In addition, we have chosen to control for other effects, such as the size of the power plant, whether the power plant is subject to economic rent tax, whether the investment decision was delayed by external factors and a linear trend.

The sensitivity analysis in Section 3.4 leads to the following predictions for the sign of the regression coefficients:

1. The expected investment behaviour with respect to the *electricity price* and the *elcertificate price* is that a higher price would increase revenues, and thereby the probability of investment (+).
2. We have also included the *product of the electricity and the elcertificate price*, to account for the parabolic shape of the optimal stopping boundary, displayed in Figure 3.1. The parabolic shape is caused by the predicted negative correlation between the variables. This parameter will only have an impact if investors behave according the real options model, as the NPV do not account for correlation. The expected impact would be that by including this variable, we would transfer the positive effect from the individual prices (+) over to their product and lose significance in those coefficients.
3. The *investment cost* has a negative impact on the investment decision: a higher cost will make it less desirable to invest (-).
4. From Figure 3.4(c) and 3.4(d) we see that increased volatility transfer into a two-fold response in the triggers, if we assume we are above some threshold for the electricity prices (approximately 20 €/MWh). As the electricity prices have been higher than this threshold in most of the years investigated, we expect the behaviour predicted by the sensitivity analysis to the right of this threshold. It is consequently expected an opposite investment behaviour

with respect to the volatilities. The trigger is expected to increase with increased *electricity price volatility* making it less probable to invest (-), while the trigger decreases with increased *subsidy volatility* making it more probable to invest (+). This difference is particular for this two-factor model. In a single-factor model, increased volatility always increases the value of the option and decreases the probability of investment.

5. The *rate of return*, r, has a dual behaviour depending on the size of the drift rate α. If the required rate increases, the future cash flows will be discounted harder. The present value of revenues then decrease, making it less likely to invest (-). However, if the drift rate and required rate are close, the lease rate is low. A low lease rate makes it more optimal to wait, and increases the boundary. Thereby, if you have a required rate which is close to the drift rate, increasing the required rate will increase the likelihood of investment (+). This is what causes the dual behaviour, making it hard to predict the expected sign of this parameter (+/-).
6. The same reasoning behind the threshold can be applied to the *drift rates*, the α's. Both drift rates increase the trigger to the right of the threshold making it less desirable to invest (-), but based on Figures 3.4(a) and 3.4(b) we expect a larger coefficient for the electricity price drift rate, α_P.

In addition, we have included some of the variables multiplied by a binary dummy for whether the investor is professional or not. We have done this for the electricity price, the elcertificate price, the product of the two prices, the investment cost and the volatilities. We expect these parameters to be significant if the investors behave differently depending on professionalism. It is important to note that for the non-professional investors, it is the original coefficient that is indicative. For professional investors, it is the sum of the original coefficients and the coefficient for the variable multiplied with the dummy. The latter coefficient represents the difference in behaviour of the non-professional and the professional investors.

The control variables are not used to infer the applicability of the real options model, but included to control for unobserved heterogeneity among power plants. Based on the findings in the descriptive data in Section 4.3, we expect that the *economic rent tax* and *external delay* should decrease the probability of investment (-). The *size* of the power plant has no particular expectation. The *linear trend* is included to account for a possible selection bias in 2009–2012. We assign the variables the numbers 1–4, depending on the year 2009–2012, and 0 otherwise.

In the regression, all data are taken as specified in Chapter 4 except for the volatilities. The volatilities in the real options model were set constant. In this analysis we have chosen to use the yearly average of the two-year rolling volatility for electricity and elcertificate price. In 2001 and 2002 we have used the elcertificate price and elcertificate volatility from 2003, to avoid losing observations in these years.

5.2.2 Results From the Probit Regression

The results are displayed in Table 5.2. The mean value of the observed independent variables in the regression is displayed in the second column. The average investment cost and size is here different compared to what was calculated from the original data set in Section 4.3. The reason for this is that we get additional observations when investors deferred investment, as we include all observations in each year the investor possessed an active license in the regression. Because the most expensive power plants are never subject to investment and the option is kept alive, we have more observations with high investment costs. The average investment cost is therefore higher. In the regression we have a total number of 565 observations, 190 observed investing and 375 observations where there was no investment decision. Of these, 140 observations experience delay due to external reasons and are prevented from making an investment decision.

The results in parenthesis are the p-values for the significance of the coefficient. If it is below 0.05 we know with statistically significance that the coefficient is different from 0 at a 95% confidence level. At a first glance it is easy to see that very few of the coefficients are significant. Lack of significance imply that the results are not robust, which could lead to a change in the sign of the coefficients depending on the specification of the regression. Inconsistency in the sign of the coefficient is for example observed for the variables for electricity price and elcertificate price. Finding that the regression is not robust could indicate that the regression lack a sufficient number of observations. Our data set could be too small to get any significant results. However, it could also imply that the regression is a poor fit and that the chosen independent variables are of low importance to the dependent variable.

We will further investigate the most important findings, but as they are not significant, we will be careful in drawing conclusions. To begin with, we can not say that the individual prices consistently show the effect predicted by the real

Table 5.2: Probit analysis of the likelihood of an investment decision, conditional on market conditions and investor characteristics. Number of observations: 565

Variable	**Mean value**	**Exp. sign**	**A**	**B**	**C**	**D**	**E**
Intercept			0.41	0.42	3.12	-2.42	-2.92
			(0.59)	(0.59)	(0.46)	(0.42)	(0.71)
El. price [€/MWh]	40.8	+	-0.02	0.04*	-0.01	0.00	0.02
			(0.20)	(0.02)	(0.90)	(0.96)	(0.93)
El. price×Prof.	21.8	+		-0.04	-0.05	-0.02	-0.05
				(0.18)	(0.19)	(0.52)	(0.28)
Elcert. price [€/MWh]	24.8	+	0.03	0.03	-0.07	0.11	0.15
			(0.16)	(0.29)	(0.68)	(0.11)	(0.67)
Elcert. price×Prof.	12.8	+		0.01	0.00	-0.03	-0.06
				(0.71)	(0.94)	(0.58)	(0.33)
El.×Elcert.'	1029.1	+			0.21		-0.11
					(0.59)		(0.89)
El.×Elcert.×Prof.'	555.8	+			0.08		0.13
					(0.56)		(0.38)
Invest.cost' [€/MWh]	534.8	-	-0.48*	-0.57*	-0.62*	-0.48*	-0.53*
			(0.00)	(0.00)	(0.00)	(0.01)	(0.01)
Invest.cost×Prof.'	302.8	-	-0.03	0.17	0.25	-0.11	-0.04
			(0.64)	(0.29)	(0.22)	(0.66)	(0.88)
El. volatility, σ_P	16%	-				1.65	0.81
						(0.76)	(0.90)
El. volatility×Prof.	8%	-				0.21	1.36
						(0.97)	(0.80)
Elcert. volatility, σ_S	13%	+				-6.87	-7.80
						(0.75)	(0.79)
Elcert. volatility×Prof.	7%	+				13.67	15.03
						(0.08)	(0.07)
Required return, r	6%	+/-				40.12	39.44
						(0.24)	(0.27)
El. drift, α_P	1%	-				-33.72	-35.10
						(0.61)	(0.66)
Elcert. drift, α_S	2%	-				24.38	24.85
						(0.40)	(0.43)
Size (MW)	3.0		0.11	0.13	0.14	0.11	0.11
			(0.15)	(0.09)	(0.08)	(0.19)	(0.20)
Economic rent tax	(1/0)	-	0.02	-0.30	-0.35	0.00	0.03
			(0.96)	(0.55)	(0.50)	(1.00)	(0.97)
External delay	(1/0)	-	-9.63	-10.18	-10.30	-10.53	-10.66
			(0.97)	(0.98)	(0.98)	(0.98)	(0.98)
Linear trend	(0,1-4)		0.32*	0.45*	0.48*	0.77	0.80
			(0.00)	(0.00)	(0.00)	(0.07)	(0.12)
Pseudo R^2			0.289	0.291	0.292	0.300	0.301

* Significance at a p-level below 0.05, ' Coefficient scaled by dividing observations by 100

options model. The coefficient for the electricity price and the elcertificate price are similar in magnitude, but the signs are alternating depending on the specification of the regression. However, we are getting a significant electricity price when including the electricity price multiplied by the dummy for professionalism in specification B. The sign of the coefficient is also positive, which is what we predicted. If we combine the coefficient for the Electricity price with the coefficient for the Electricity Price×Professional, we see that the sum is 0. This indicates that the professional investors invested independently of the electricity price, while non-professionals on the other hand paid attention to this variable.

Specifications C and E add the product of Electricity price×Elcertificate price. It has the predicted effect as it reduces the significance of the individual prices, but the sign is alternating. The investment cost has both the predicted sign and significance, while the investment cost multiplied with the dummy for professionalism neither have the predicted sign nor significance.

Adding further variables in specifications D and E have little effect on the pseudo R^2, which indicate that the variables are not improving the regression noteworthy. None of the variables for volatility, required rate or drift rate have significant results, and only the variables Elcertificate volatility×Professional, Electricity drift rate and Required return have a coefficient consistently coinciding with the prediction. The required return shows a behaviour which is predicted when the starting point of the drift rate is close to the required rate. The Elcertificate drift rate is consistently opposite to the prediction, which indicates that a higher drift rate leads to a higher probability of investing.

The p-value for the variable Elcertificate volatility×Professional is low and significant at a 90% confidence level. This indicates that the professional investors responded more to the evolution of the Swedish elcertficate prices than the non-professionals, predicted by Heggedal et al. (2013). It also implies that they were expecting subsidies as they responded to the Swedish elcertificate development.

The external delay variable act according to the predictions, but not the economic rent tax variable. The other control variables indicate that investors are more likely to invest as the years go by caused by the possible bias, and prefer larger power plants. The linear trend is significant in specifications A, B and C at a 95% significance level, and in D at a 90% significance level.

5.2.3 Comments to the Probit Regression Results

In summary, we have some support for saying that the investors act in accordance with the real options model and that investors behaved differently depending on professionalism. Simultaneously, as there is little significance we do not have enough support for concluding that this is the case. But whether this is because the investors do not follow the real options decision rule or due to an insufficient number of observations in the regression, we do not know. In the analysis made by Moel and Tufano (2002) there are 2056 observations from 285 gold mines, whereas we have 565 observations from 214 power plants.

The results from the regression indicate that the investment cost is the only important variable to the investors when they decide. This is debatable, and was not the impression we got when talking to the investors during the interviews. The data sample seems to be too small, as investors following the NPV rule also pay attention to the electricity price. We should therefore have expected a positive and significant coefficient for all specifications under this decision rule as well. Thus, one should not rule out the possibility that investors did follow the real options rule because we do not have strong evidence that the investors followed the NPV rule either. Nevertheless, we should not overlook the observation that the electricity price is significant in one of the specifications, where we separate out the effect of professional investors. It is clearly a difference in behaviour between the professional investors and the non-professionals. However, we find it difficult to believe that professional investors did not pay attention to the future electricity price. To test for this, we included the spot price as a variable in the regression, but it did not lead to significant results.

To improve the results from the regression, future work should focus on gathering more data from licences granted after 2008 and perform a more detailed analysis with respect to subgroups amongst investors. Additionally, it would be interesting to interview the investors about what proxies they use for the future electricity price.

The lack of significance in our results also has impact for the interpretation of the results in Heggedal et al. (2013). While we use the explanatory variables as the regressors, Heggedal et al. (2013) test their real options model using a logistic regression incorporating the real options value and the NPV value amongst others. We find our approach more transparent, as we are not bundling the impact of the variables into one unit. Our regression is thereby valid for both models, as they have similar input variables. Heggedal et al. (2013) found significant results for the hypothesis that non-professional investors behaved according to the NPV rule and that professional investors behaved according to the real options theory. In the light of our results, we should be somewhat sceptical to their significance levels, but we still believe their conclusion is valid for the investors that did choose to invest.

Chapter 6

Conclusion

In this empirical study, the investor behaviour in 214 small hydropower projects has been examined. Data from a previous study by Heggedal et al. (2013) has been extended and updated through interviews with investors (cf. Chapter 4).

The results show that the investor's expectation to subsidies is dependent on the applied model and its definition of the optimal decision rule. The two-factor real options model derived in Chapter 3 predicts that investors on average expected subsidies in the size of Swedish elcertificates (cf. Section 5.1.1). It also predicts that investors deferring investment would have required a subsidy larger than those who invested, displaying rational investment behaviour. Using a now-or-never investment approach, the NPV model predicts that investors did not expect subsidies on average (cf. Section 5.1.2). However, results from the investors that deferred investment show that the NPV decision rule might not be a good descriptor of the investment behaviour, as their NPV was positive in 6 of 12 years and thus should have invested according to this rule. Furthermore, we find that the evolution in implied subsidies follows the predicted trend based on publicly available information published by the government. Thus, our results infer that the average investor did expect subsidies when he or she invested and behave as predicted by real options theory.

Based on the quotes in Appendix D we further strengthen our belief that the real options decision rule is a good descriptor of the investment behaviour, even though we acknowledge individual differences across investors. A scenario described in Heggedal et al. (2013) is that professional investors are behaving according to real options theory, while non-professionals according to NPV. We support their findings, but only in the case where the investor chose to invest. Our results infer that non-professionals deferring investment also behave as predicted by real options theory.

Appendix A

Calculus

A.1 Proof of Present Value Calculation

Noting that the expectation of a variable following GBM is $\mathbb{E}[P_t|P_0 = P] = P\mathrm{e}^{\alpha_P t}$ (Dixit and Pindyck, 1994), we have:

$$\begin{aligned}
V(P,S) =& \mathbb{E}\left[\int_0^{T_P} \mathrm{e}^{-rt} P_t \mathrm{d}t + \int_{T_{S_1}}^{T_{S_2}} \mathrm{e}^{-rt} S_t \mathrm{d}t | P_0 = P, S_0 = S\right] \\
=& \mathbb{E}\left[\int_0^{T_P} \mathrm{e}^{-rt} P_t \mathrm{d}t | P_0 = P\right] + \mathbb{E}\left[\int_{T_{S_1}}^{T_{S_2}} \mathrm{e}^{-rt} S_t \mathrm{d}t | S_0 = S\right] \\
=& \int_0^{T_P} \mathrm{e}^{-rt} \mathbb{E}[P_t|P_0 = P] \mathrm{d}t + \int_{T_{S_1}}^{T_{S_2}} \mathrm{e}^{-rt} \mathbb{E}[S_t|S_0 = S] \mathrm{d}t \\
=& \int_0^{T_P} \mathrm{e}^{-rt} P \mathrm{e}^{\alpha_P t} \mathrm{d}t + \int_{T_{S_1}}^{T_{S_2}} \mathrm{e}^{-rt} S \mathrm{e}^{\alpha_S t} \mathrm{d}t \\
=& P \int_0^{T_P} \mathrm{e}^{-(r-\alpha_P)t} \mathrm{d}t + S \int_{T_{S_1}}^{T_{S_2}} \mathrm{e}^{-(r-\alpha_S)t} \mathrm{d}t \\
=& \frac{1 - \mathrm{e}^{-(r-\alpha_P)T_P}}{r - \alpha_P} P + \frac{\mathrm{e}^{-(r-\alpha_S)T_{S_1}} - \mathrm{e}^{-(r-\alpha_S)T_{S_2}}}{r - \alpha_S} S
\end{aligned} \tag{A.1}$$

A.2 Algebra to Find Optimal Investment Point

Rearrange Equation (3.13) c):

$$(S^*)^{\beta_S} = \frac{r_P}{A\beta_P (P^*)^{\beta_P - 1}} \tag{A.2}$$

Insert Equation (A.2) for $(S^*)^{\beta_S}$ in (3.13) b):

$$A(P^*)^{\beta_P}\left(\frac{r_P}{A\beta_P(P^*)^{\beta_P-1}}\right) = r_P P^* + r_S S^* - I \tag{A.3}$$

$$\Leftrightarrow P^* r_P\left(\frac{1-\beta_P}{\beta_P}\right) = r_S S^* - I \tag{A.4}$$

Solve for A in Equation (3.13) c) and d) and equate them:

$$\frac{\beta_P S^*}{\beta_S P^*} = \frac{r_P}{r_S} \Leftrightarrow S^* = \frac{r_P}{r_S}\frac{\beta_S}{\beta_P}P^* \tag{A.5}$$

Insert Equation (A.5) for S^* in Equation (A.4):

$$P^* r_P\left(\frac{1-\beta_P}{\beta_P}\right) = r_S\left(\frac{r_P}{r_S}\frac{\beta_S}{\beta_P}P^*\right) - I \tag{A.6}$$

By rearranging, we then obtain the expression for P^*:

$$P^* = \frac{\beta_P}{\beta_P+\beta_S-1}\frac{I}{r_P} \tag{A.7}$$

This we can use to find S^* by inserting it in Equation (A.5):

$$S^* = \frac{r_P}{r_S}\frac{\beta_S}{\beta_P}\frac{\beta_P}{\beta_P+\beta_S-1}\frac{I}{r_P} = \frac{\beta_S}{\beta_P+\beta_S-1}\frac{I}{r_S} \tag{A.8}$$

A.3 Finding β_P, Given the Electricity Price P

Remember the substitution:

$$\beta_S = \beta_P\eta(P) + 1 \tag{A.9}$$

Insert it in the fundamental quadratic from Equation (3.11):

$$\begin{aligned} Q\left(\beta_P, \beta_P\eta(P)+1\right) =& \frac{1}{2}(\sigma_P^2\beta_P(\beta_P-1) + \sigma_S^2(\beta_P\eta(P)+1)((\beta_P\eta(P)+1)-1) \\ &+2\sigma_P\sigma_S\rho\beta_P(\beta_P\eta(P)+1)) \\ &+\alpha_P\beta_P + \alpha_S(\beta_P\eta(P)+1) - r = 0 \end{aligned} \tag{A.10}$$

Simplify and collect the terms with β_P^2 and β_P:

$$\begin{aligned} Q\left(\beta_P, \beta_P \eta(P) + 1\right) = &\frac{1}{2}\left(\sigma_P^2 + \sigma_S^2 \eta^2(P) + 2\sigma_P \sigma_S \rho \eta(P)\right) \beta_P^2 \\ &+ \left(\frac{1}{2}(-\sigma_P^2 + \sigma_S^2 \eta(P) + 2\sigma_P \sigma_S \rho) + \alpha_P + \alpha_S \eta(P)\right) \beta_P \\ &+ (\alpha_S - r) = 0 \end{aligned} \tag{A.11}$$

Finally, solve the second-order equation for β_P:

$$\beta_{P,1,2} = \frac{-b \pm \sqrt{b^2 - 4ac}}{2a} \tag{A.12}$$

where

$$a = \frac{1}{2}\left(\sigma_P^2 + \sigma_S^2 \eta^2(P)\right) + \sigma_P \sigma_S \rho \eta(P) \tag{A.13a}$$

$$b = \frac{1}{2}\left(-\sigma_P^2 + \sigma_S^2 \eta(P)\right) + \sigma_P \sigma_S \rho + \alpha_P + \alpha_S \eta(P) \tag{A.13b}$$

$$c = \alpha_S - r \tag{A.13c}$$

Appendix B

Tax on Small Hydropower Plants

The present tax regime has been governing since 1997, although the rates have been changed a few times. The relevant laws are found in the Taxation Act §18 ”Special regulations for hydropower plants” and the Property Tax Act §8B ”Hydropower stations”. For readers interested in the impact of the different tax regimes on investment, I refer to Hall and Jorgenson (1967) for a broad introduction. More specifically, Baunsgaard (2001), Lund (2009), McPhail et al. (2009) and Otto et al. (2006) study how rent taxes may distort firms' operating and investment decisions. Frestad (2010) analyses how firms' financial strategies may be influenced by rent taxation. Bye and Bruvoll (2008) study the effects of aggregate taxes and subsidies.

The tax on small hydropower plants is a combination of several taxes:

$$\begin{aligned} Tax_t =& Profit\ Tax_t + Property\ Tax_t + Economic\ Rent_t \\ &+ Natural\ Resource\ Tax_t \end{aligned} \tag{B.1}$$

In addition to the elements in Equation (B.1), hydropower plant owners could be subject to municipal license fees and concessionary power as well as wealth tax. These elements are neglected further on due to a low impact on the overall decision making process. Losses can be carried forward and used in subsequent years for tax credits, which is incorporated in the calculations through the use of continuous compounding. We assume that the investor is in a tax position and can thereby neglect the large investment cost occurring the first year without affecting the results significantly. We conquer the tax equation by deriving each term separately in the following subsections. The final result is:

$$\begin{aligned}
Tax_0^{T_P} =& \tau_{Profit}\Bigg[r_P P + r_S S - c_0 r_C - 2.5\% I_0 r_R \\
& - r_{Debt} 75\% I_0 \left(r_R - \frac{5\%}{r}\left(r_R - T_P \mathrm{e}^{-rT_P}\right)\right)\Bigg] + \tau_{Property} Upper\ Limit\ r_R \\
& + \tau_{Economic\ Rent}|_{R>L} \Bigg[r_P P + r_S S - c_0 r_C - 2.5\% I_0 r_R \\
& - \tau_{Property} Upper\ Limit\ r_R - r_{Norm} I_0 \left(r_R - \frac{2.5\%}{r}\left(r_R - T_P \mathrm{e}^{-rT_P}\right)\right)\Bigg]
\end{aligned} \tag{B.2}$$

where

$$r_C = \left(\frac{1 - \mathrm{e}^{-(r-i)T_P}}{r - i}\right), \ r_R = \left(\frac{1 - \mathrm{e}^{-rT_P}}{r}\right) \tag{B.3}$$

B.1 Profit Tax

The first term is the profit tax. The profit tax is calculated as 28% of revenue after costs and interests are paid, commonly known as earnings before taxes (EBT):

$$\begin{aligned}
Profit\ Tax_t =& \tau_{Profit}[Revenue_t - (Maintenance\ Cost_t \\
& + Amortization\ and\ Depreciation_t + Interest\ Costs_t)]
\end{aligned} \tag{B.4}$$

The formulas for revenue and maintenance cost has already been derived in Chapter 3. Hydropower plants are subject to a linear amortization and depreciation over approximately 40 years. Machine-oriented equipment should be depreciated over 40 years, while pipes, dams, gates and power stations should be depreciated over 67 years (cf. Taxation Act §18-6). Based on conversations with NTE we estimate that 22% of the investment cost relates to pipes, gates and digging, while 75% relates to the actual power plant:

$$\begin{aligned}
& Amortization\ and\ Depreciation_t \\
& \quad = \left(22\% \frac{I_0}{67} + 75\% \frac{I_0}{40} + 3\% (5\%\ Balance\ Depreciation)\right) \\
& \quad \approx \frac{I_0}{40} = 2.5\% I_0
\end{aligned} \tag{B.5}$$

Interest costs is a fixed proportion of the remaining loan balance, depending on the loan interest rate r_{Debt}. In the small hydropower industry it is common to loan 75% of the investment cost, I_0. For simplicity we assume that the loan is a series loan, with equal down payments and duration of 20 years.

$$Down\ Payment_t = 5\% Loan\ Balance_0 = 5\% 75\% I_0 \tag{B.6}$$

$$Interest\ Cost_t = r_{Debt} Loan\ Balance_t = r_{Debt} 75\% I_0 (1 - 5\% t) \tag{B.7}$$

Now we can evaluate the profit tax in equation (B.4) with respect to the whole lifetime of the power plant.

$$\begin{aligned} Profit\ Tax_0^{T_P} =& \tau_{Profit} \Bigg[P \int_0^{T_P} \mathrm{e}^{-(r-\alpha_P)t} \mathrm{d}t + S \int_{T_{S1}}^{T_{S2}} \mathrm{e}^{-(r-\alpha_S)t} \mathrm{d}t \\ & - \int_0^{T_P} c_0 \mathrm{e}^{-(r-i)t} \mathrm{d}t - \int_0^{T_P} 2.5\% I_0 \mathrm{e}^{-rt} \mathrm{d}t \\ & - \int_0^{T_P} r_{Debt} 75\% I_0 (1 - 5\% t) \mathrm{e}^{-rt} \mathrm{d}t \Bigg] \end{aligned} \tag{B.8}$$

After solving the integrals and using partial integration we get:

$$\begin{aligned} Profit\ Tax_0^{T_P} =& \tau_{Profit} \Bigg[r_P P + r_S S - c_0 r_C - 2.5\% I_0 r_R \\ & - r_{Debt} 75\% I_0 \left(r_R - \frac{5\%}{r} \left(r_R - T_P \mathrm{e}^{-r T_P} \right) \right) \Bigg] \end{aligned} \tag{B.9}$$

B.2 Property Tax

The second term in the tax equation (B.1) is the property tax. The property tax is paid in addition to the income tax. It is voluntarily for the municipalities if they want to collect property tax, and they can choose a rate, $\tau_{Property}$, between 0.2% and 0.7%. The rate is multiplied by the market value in each year (cf. Property Tax Act §8B). For simplicity we assume that the investment cost is the market value. The market value is assumed to decrease over the years, and we apply the same linear depreciation as explained above.

$$Property\ Tax_t = \tau_{Property} Market\ Value_t \tag{B.10}$$

The market value decreases approximately linearly over 40 years.

$$Market\ Value_t = I_0(1 - 2.5\%t) \tag{B.11}$$

Over the lifetime over the power plant:

$$\begin{aligned} Property\ Tax_0^{T_P} =& \tau_{Property}\left(\int_0^{T_P} I_0(1-2.5\%t)\mathrm{e}^{-rt}\mathrm{d}t\right) \\ =& \tau_{Property} I_0 \left(r_R - \frac{2.5\%}{r}\left(r_R - T_P\mathrm{e}^{-rT_P}\right)\right) \end{aligned} \tag{B.12}$$

From 2004 the government introduced a maximum market value, $Upper\ Limit_t$, for power plants (cf. Property Tax Act §8B-1 (4)). The boundary was from 2004 including 2011 2.35 NOK/kWh/y (∼290 €/MWh/y) multiplied by the average annual production over the current and the past six years [1]. If the plant has been running for less than six years, then these years are used to calculate the average. In 2012 it was adjusted to 2.47 NOK/kWh/y (∼330 €/MWh/y). Most new power plants find themselves above this upper boundary, on the average 4 NOK/kWh/y (∼500 EUR/MWh/y)(Advokatfimaet Lund & Co DA, 2012). Additionally, there is a minimum boundary of 0.95 NOK/kWh/y (∼120 €/MWh/y), also present prior to 2004 and kept constant through the years. A simplifying approach could therefore be to assume that the power plant owners pay the maximum property tax over the whole lifetime.

$$\begin{aligned} Property\ Tax_0^{T_P} =& \tau_{Property}\int_0^{T_P} Upper\ Limit_t\mathrm{e}^{-rt}\mathrm{d}t \\ =& \tau_{Property} Upper\ Limit\ r_R \end{aligned} \tag{B.13}$$

B.3 Economic Rent

The third term in the tax equation (B.1) is the tax on economic rent. It is designed to tax super profits and only applicable to power plants $\geq$ 5.5MVA (cf. Taxation Act §18-3). This limit was raised from $\geq$ 1.5MVA in 2004 and temporarily lowered back to this level in 2008. As the temporarily lowering was reversed quickly and only lasted for a few months Ministry of Finance (2008), we have chosen to omit this in the calculations. The economic rent $\tau_{EconomicRent}|_{R>L}$

[1] Prior to 2008 the basis was not the average annual production over the current and past six years, but the same basis used to calculate the natural resource tax

currently equals 30%. Prior to 2008 this rate was 27% (Ministry of Finance, 2007). It comes on top of the profit tax, making the total tax rate on revenue 58%. The basis for the tax on economic rent is the normal market value of production subtracted maintenance cost, amortization and depreciation and property tax. In addition, one can subtract free income to make sure that normal profits below super profits are not taxed. The free income is calculated as the average book value on 1st Jan and 31st Dec multiplied by a prescribed norm rent, r_{Norm}. The norm rent is set by the Parliament each year in arrears based on Treasury Bills' trading history. A table of the historical norm rent is included in Chapter 4.

$$Free\ Income_t = r_{Norm} Book\ Value_{\frac{(t-dt)+t}{2}} = r_{Norm} I_0 (1 - 2.5\% t) \tag{B.14}$$

$$\begin{aligned} Economic\ Rent_t = \tau_{EconomicRent}|_{R>L}[&Revenue_t - (Maintenance\ Cost_t \\ &+ Amortization\ and\ Depreciation_t + Property\ Tax_t \\ &+ Free\ Income_t)] \end{aligned} \tag{B.15}$$

Over the whole lifetime of the power plant it is:

$$\begin{aligned} Economic\ Rent_0^{T_P} = &\tau_{EconomicRent}|_{R>L} \Bigg[P \int_0^{T_P} \mathrm{e}^{-(r-\alpha_P)t} \mathrm{d}t + S \int_{T_{S1}}^{T_{S2}} \mathrm{e}^{-(r-\alpha_S)t} \mathrm{d}t \\ &- \int_0^{T_P} c_0 \mathrm{e}^{-(r-i)t} \mathrm{d}t - \int_0^{T_P} 2.5\% I_0 \mathrm{e}^{-rt} \mathrm{d}t \\ &- \tau_{Property} \int_0^{T_P} Upper\ Limit_t \mathrm{e}^{-rt} \mathrm{d}t \\ &- \int_0^{T_P} r_{Norm} I_0 (1 - 2.5\% t) \mathrm{e}^{-rt} \mathrm{d}t \Bigg] \end{aligned} \tag{B.16}$$

And finally, by solving the integrals:

$$\begin{aligned} Economic\ Rent_0^{T_P} = &\tau_{EconomicRent}|_{R>L} \Bigg[r_P P + r_S S - c_0 r_C - 2.5\% I_0 r_R \\ &- \tau_{Property} Upper\ Limit\ r_R \\ &- r_{Norm} I_0 \left(r_R - \frac{2.5\%}{r} \left(r_R - T_P \mathrm{e}^{-rT_P} \right) \right) \Bigg] \end{aligned} \tag{B.17}$$

B.4 Natural Resource Tax

The fourth term in the tax equation (B.1) is the natural resource tax. As for the tax on economic rent, it is only applicable for power plants $\geq$ 5.5MVA (cf. Taxation act §18-2). The rate is 1.625 €/MWh multiplied by the average annual production over the current and the past six years. The natural resource tax is coordinated with the income tax, such that an investor will never pay more than 28% of income tax and natural resource tax altogether. By assuming that the investors pay full income taxes we can omit this tax in the calculations.

Appendix C

The Survey

1. Contact info	
Name:	
Telephone:	
Email:	
2. What is the status of your project today (February 2013)?	
a. Developed	
b. Under construction	
c. Detail planning	
d. Waiting – Uncertain profitability	
e. Waiting – Problem: Grid access	
f. Waiting – New application sent or is being considered	
g. Waiting – Problem: Neighbors or family	
h. Waiting – Other reason	
Comment:	
3. If 2.a) or 2.b): When was the decision to invest made? For example, when was the deal with the contractor signed?	
Month:	
Year:	
Comment:	
4. Have there been any delays? For example: filed complaint, problems with grid access or neighbors	
Comment:	

5. What was the estimated investment cost when the decision was made? Include cost of equipment and cost of grid connection	
[NOK/kWh]	
6. What is the installed capacity?	
[MW]	
7. What is the expected annual production?	
[GWh]	
8. When was/is production start?	
Month:	
Year:	
Comment:	
9. What is the expected annual maintenance cost of running the plant?	
[NOK/kWh]	
10. What is the expected economic life time of the power plant?	
Years:	
11. What taxes is your plant eligible to pay? For example: profit tax, property tax, natural resource tax (>5.5 MVA), tax on economic rent	
Comment:	
12. How did you create an image of the profitability of the project? For example: Net Present Value (NPV)	
Comment:	
13. Have you included income from green certificates in your calculations throughout the decision process?	
Comment:	

Appendix D

Quotes From the Survey

- *"Given that we invested in a plant above 1MW, we did not think that the elcertificates would be applicable for us. But we were hoping they would come."* – Decided to invest in 2005
- *"Yes, our project was only marginally profitable without elcertificates."* – Decided to invest in 2010, license was given in 2004.
- *"Of course elcertificates are of good help"* – Mini power plant built in 2005
- *"Promises of elcertificates made us revitalize the project." "Our expectations to elcertificates are at 20 €/MWh. We have included this in our calculations." "We have evaluated the profitability through NPV of cash flows to equity and to total capital."* – Considering investing in 2013
- *"It was a big disappointment. We were sure we would receive elcertificates."* – Started production in 2009
- *"We did not manage to become a part of the scheme. But it was not included in our calculations either."* – Decided to invest in 2006
- *"With current power prices and the developing trend it is absolutely crucial for the profitability that we receive elcertificates. Without them the project will not be profitable." "It was a big disappointment that we did not receive elcertificates on that power plant."* – Investor owning several licenses, decided to invest in one of them in 2007

- *"In the beginning we were very sceptical. It sounded great, but we will see. It could be that prices drop when many receives certificates." "We are situated within the NO5 area where power prices are low. It is therefore vital for us that we receive certificates."* – Decided to invest in 2010, license was given in 2007

- *"We have been waiting for the elcertificates. We are hoping for a price of 20 €/MWh and have included this in our calculations."* – Currently waiting for answer on an application to the regulators about amendments

- *"We started production without even considering revenue from elcertificates. We have economy to manage without."* – Decided to invest in 2009, license was given 2007

- *"We did not dare to believe in revenue from elcertificates. We have spreadsheets with and without this in the calculations." "We set a roof on the investment at 470 €/MWh/y."* – Decided to invest in 2007

- *"We expected to receive elcertificates given promises that everyone who invested after 2004 would receive support, but we did not take it into account in expected revenues. Do never trust political promises."* – Decided to invest in 2007

- *"Elcertificates have saved much of our bottom line economy." "We presented a scenario 1 and a scenario 2 to the banks." "Cash flow to equity was the most important analysis, but we also performed an NPV analysis." "We have been approved for elcertificates since late 2012 and signed a hedging agreement for the certificates for 3 years with a trading company."* – Decided to invest in 2008, started production in 2011.

- *"We were very cynical. We said that elcertificates, they don't exist, until it is actually implemented." "We expect a price of 20 €/MWh and have used this in our calculations." "We know several who invested already in 2004 based on the promises expecting 25 €/MWh. Some of them are on the edge of bankruptcy. It is of course a big disappointment when you expected to receive close to €4 million (25 €/MWh $\cdot$ 10 GWh/year = €0.25 million/year, multiplied by 15 years = €3.75 million)." "When we evaluate the profitability in a project we use the expected annual production as a base, then we find the return and compare this to our requirements. If it pays off, we invest. It* *is self-explanatory that no years equal the average, and the profitability will be poorer some years and better other years, but over a period of 10 years it will average out."* – Decided to invest in 2012, received license in 2008

- *"It is a clear goal for us to invest soon so we can enter the scheme."* – Investor currently delayed by transmission capacity

- *"Elcertificates was a prerequisite for our investment. We would not have invested without it." "We could have started the building one year earlier, but we chose to wait for the elcertificates and spent more time on detailed planning. It is important to acknowledge that a hydropower plant is a long term investment."* – Decided to invest in 2012

- *"None of our projects included revenue from elcertificates before they were implemented."* – Owner of several licenses

- *"If it wasn't for the elcertificates we would not have decided to invest in the power plant."* – Decided to invest in 2011

- *"We have been waiting for elcertificates. We see now that with current power prices we would not have managed without. It makes a huge difference."* – Started building in 2010, received license 2008

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