



# Master's degree thesis

**LOG950 Logistics**

**“Geiranger Case Study”**

**– A cost-benefit analysis of the energy  
investment options in Møre og Romsdal**

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## **Preface and acknowledgements**

This thesis is the last part in the LOG950 master program at Molde University College. The work on this thesis has been a lengthy process and somewhat difficult at times, but highly interesting and rewarding. All in all, this has been an exciting journey of learning for me, both professionally and personally.

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---

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## Executive Summary

The power situation in Central-Norway and in Møre og Romsdal in particular is characterized by a **capacity shortage**. Growth in consumption from energy demanding industries and lack of investments in transmission or production capacity has led to a negative energy balance in the region. This strained power situation has proved to be challenging in periods with little precipitation and cold weather and has resulted in consequences for general consumers and industries in the region, especially relating to supply security, regional price differences and competitive disadvantage.

The power situation in Møre og Romsdal is the starting point and relevance of this thesis, where a case study named the “**Geiranger Case**” attempts to address the main problems and explore the various investment alternatives that might improve or solve this capacity shortage. The main theoretical framework of the thesis is **cost-benefit analysis (CBA)**. This is an economic framework that address the investment alternatives from an economic approach, and identifies benefits and costs that can be priced or not, and compares these. The main parameters for comparison in the energy sector have been identified to include investment and operating costs. Disruption costs measured by KILE and other aspects of supply security, transmission losses and bottlenecks, system technical effects and a well-functioning market as well as environmental impacts. The aspect of time was also identified as an important factor in the investment decision.

The analysis of the Geiranger case study has looked at investment alternatives within transmission, production and end-user measures. The concession given overhead transmission line **Ørskog-Fardal** was used as the zero alternative in the thesis, and also included in the analysis were four other investment alternatives. These were a *redevelopment* alternative that entailed a voltage upgrade on the existing 132 kV line Ørskog-Sykkylven-Haugen, a *subsea cable* on the route Ørskog-Store-Standal, a *conventional gas-fired power plant with quota duty* and a *gas-fired power plant with CO<sub>2</sub> capture and storage (CCS) from day one*. The main findings from the impact assessment were that the four alternatives had higher investment costs than the zero alternative and the same or worse impacts on supply security. The most similar alternative to the concession given line is the redevelopment alternative, which has the same

characteristics if it can be implemented in 2015 expect an additional 360 MNOK investment cost and improved impacts on the environment. Alternatives that was assumed to be implemented later than the zero alternative, did not receive identical time benefits, in terms of reducing disruption costs, transmission losses and bottlenecks, improving regional price differences and connecting small power producers in Sogn og Fjordane. The gas-fired power plant alternatives did not have a benefit of connecting small power producers. The alternative with the least impact on the environment was found to be the subsea cable, which however has an additional cost of 2, 4 billion NOK and a later implementation time. If general consumers were to cover this additional “environmental cost”, a cost of 83 NOK per year for 25 years if considered a national public good would have to be paid or 650 NOK per year for 25 years if considered a regional public good. A summary of the findings from the case study is illustrated in table 0.1.

**Table 0-1: Compilation of investment alternatives relative to the zero alternative Ørskog-Fardal**

	<b>INVESTMENT COST</b>	<b>COMPLETION</b>	<b>SUPPLY SECURITY</b>	<b>ENVIRONMENT</b>
<i>Zero alternative (Ørskog-Fardal)</i>	<b>2600 MNOK</b>	2015	<b>Good</b> Improves supply security in Central-Norway and Sogn.	<b>Poor</b> Significant impacts on the environment, with aesthetic effects on high-value fjord landscapes
<i>Redevelopment (Ørskog-Sykkylven-Haugen)</i>	<b>Additional 360 MNOK</b>	2016 (2015)	<b>Same/worse</b> Waiting until 2016 and using current line has insignificant impact.	<b>Better</b> Utilizes existing route and thus makes no “new” footprints, except larger masts and a new transformer station
<i>Subsea cable (Ørskog-Store-Standal)</i>	<b>Additional 2400 MNOK</b>	2017	<b>Same/worse</b> Waiting until 2016 and lengthier repair times has little impact.	<b>Better</b> Less aesthetic impacts as two-thirds of the line is located subsea, but local impacts associated with landing facilities
<i>Gas-fired power plant with quota duty</i>	<b>Additional 200 MNOK</b>	2015	<b>Same/Worse</b> Will not improve supply security in Sogn	<b>Better/worse</b> Less aesthetic affects, however environmental costs associated with emissions
<i>Gas-fired power plant with CCS</i>	<b>Additional 2200 MNOK</b>	2018	<b>Same/Worse</b> Waiting has little impact, but will not improve supply security in Sogn	<b>Better</b> Less aesthetic affects and deals with the costs associated with emissions

The **findings** of the thesis suggest that a single conclusion as to the most economically investment alternative in the Geiranger case cannot be drawn. The reason for this is that a ranking between the investment alternatives is not possible based on the CBA methodology. The zero alternative does however come out as having the most positive NPV from the investigated alternatives, and the subsea cable as the most environmentally friendly from the independent studies of environmental effects. A ranking of the transmission alternatives would mean a valuation of the WTP for the protection of environmental values, in which there is a lack of relevant information in the academia. The thesis also investigated two production alternatives, which included a conventional gas-fired power plant with quota duty and a gas-fired power plant with  $CO_2$  capture and storage from day one. The thesis concluded that both these alternatives cannot run a commercially profitable operation without government support, even though the requirements for CCS are relaxed.

The thesis further suggested that there can be a value of waiting for more information in terms of developments within consumption and investigating the public's WTP in the environmental questions. There are however also benefits included in this thesis that favor investment alternatives that can be quickly implemented, such as connecting small power producers of renewable energy in Sogn og Fjordane, reducing the costs associated with supply security and reducing or eliminating the regional price differences between Central-Norway and the rest of the country.

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## Glossary and list of abbreviations

<b>BKK</b>	Term used to describe the area surrounding Bergen peninsula
<b>CBA</b>	Cost-Benefit Analysis
<b>CCS</b>	$CO_2$ capture and storage
<b><math>CO_2</math></b>	Carbon dioxide
<b>Economics</b>	English name for the Norwegian term “Samfunnsøkonomi”
<b>GW</b>	Gigawatt, or one watt * $10^9$
<b>IEA</b>	International Energy Agency
<b>IM</b>	Industrikraft Møre
<b>IRR</b>	Internal Rate of Return
<b>KILE</b>	Quality-adjusted income limits of not delivered energy
<b>KILE-rate</b>	Specific (normalized) interruption cost for an interruption with a given duration, Krone/ kW
<b>kV</b>	Kilovolt (1000 volt)
<b>kW</b>	Kilowatt, or one watt * $10^3$
<b>kWh</b>	Kilowatt-hour = one kilowatt * one hour
<b>NOK</b>	Norwegian kroner
<b>Nord Pool</b>	Norwegian Power Exchange
<b><math>NO_x</math></b>	Oxides of nitrogen
<b>NPV</b>	Net Present Value
<b>NVE</b>	Norwegian Resources and Water Directorate
<b>OED</b>	Olje- og Energidepartementet (Norwegian Ministry of Petroleum and Energy)
<b>PV</b>	Present Value
<b><math>Sm^3</math></b>	Standard cubic feet
<b>SV</b>	Statens Vegvesen (Norwegian Public Road Administrator)
<b>TCM</b>	European $CO_2$ Test Center Mongstad
<b>TSO</b>	Transmission System Operator
<b>TW</b>	Terawatt, or one watt * $10^{12}$
<b>TWh</b>	Terawatt * one hour
<b>WTA</b>	Willingness to accept
<b>WTP</b>	Willingness to pay

## 1. Introduction

The demand for power in Norway and the rest of the world has grown rapidly in the last decade, and is expected to continue to grow in the future. Norway is one of the most energy demanding countries in the world, which is reflected in its high consumption per inhabitant. This dependence on energy in the modern world means that society is highly reliant on **reliable and secure electricity** supply. This is evident both within the private sphere, where important household functions are dependent on electric power, and in the rest of society, where imperative social functions are dependent on a stable power supply (Hervik et al., 2011a). *“The loss of electricity supply could thus after some time create significant problems for affected households and halt vital social functions”* (Hervik et al. 2011; p. iv)<sup>1</sup>. Recent years has further shifted the focus from cost efficiency to supply security in the power system, as a result of the recent power disruptions in Europe.

The current electric power situation in Norway is compromising a reliable and secure electricity supply, due to lack of investments into production and transmission infrastructure to meet demand. The situation is particularly difficult in Møre og Romsdal in Central-Norway and BKK<sup>2</sup> in Western-Norway. New investments will however often have negative impacts on the **environment**, to a varying degree depending on the transmission choice and routing alternatives. Hervik et al. (2011) write that the most cost effective routing alternatives for the network owner will often be located close to populated areas, and thus more people are exposed to the environmental impacts. A problem is thus often apparent, that the alternative with the lowest market costs will have the highest environmental costs.

The environmental problem has been evident from the debate concerning the overhead transmission lines that were concession given in Central and Western-Norway, between Sima-Samnanger and Ørskog-Fardal. Opponents have particularly suggested the use of subsea cables instead of overhead transmission lines as a more environmentally friendly alternative. The

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<sup>1</sup> Translated by author

<sup>2</sup> Term used to describe the area surrounding Bergen peninsula

proposed line **Sima-Samnanger** received so much negative media attention, that 4 expert committees were given the responsibility to assess the feasibility of a subsea cable by the government. The reason was that opponents feared that the overhead transmission line would affect the internationally recognized landscape in Hardanger. These committees gave their final recommendations in February 2011. Committee 4 (Hervik et al., 2011a) looked at the economic<sup>3</sup> impacts of the subsea cable alternative<sup>4</sup>, and concluded that no rankings were possible between the two. The two alternatives were seen as equal in terms of supply security and both had tradeoffs in terms of either higher investment costs for the subsea cable or higher environmental impact for the overhead transmission line. A ranking would thus denote a valuation of the willingness to pay for the protection of natural values against the high additional costs associated with cabling (Hervik et al., 2011a). Satisfactory information of WTP was not available and thus not applied in the analysis. A month after the committees submitted their reports to OED (01.03.2011), the government decided to uphold its original decision and subsequently maintained the concession to build the overhead line between Sima-Samnanger.

The findings from the “*Hardanger*” report and the decision reached for the BKK and the Sima-Samnanger line will be relevant to the investment choices in Møre og Romsdal and the proposed line **Ørskog-Fardal**. Disputes over this line has also been evident, particularly due to the impact of the line on the world heritage listed fjord “Geirangerfjorden”. To avoid a similar situation as in the Hardanger scenario described above, Statnett has currently applied for a subsea cable on some of the route, namely Ørskog-Store Standal. Other alternatives are also under consideration, as the proposed line is under complaint handling with the Norwegian Ministry of Petroleum and Energy.

The situation in Møre og Romsdal is the starting point and relevance of this thesis. The main goal of this paper is to assess the investment alternatives in the region from a socioeconomic standpoint, through a case study called *Geiranger*. The analysis method is a cost-benefit analysis (CBA) and is described later in this thesis. The analysis by Hervik et al. (2011) of the *Hardanger*

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<sup>3</sup> In Norwegian: “Samfunnsøkonomi”

<sup>4</sup> Refer the following link for the complete report by committee 4:

[http://www.regjeringen.no/pages/15604222/Utvalg\\_IV.pdf](http://www.regjeringen.no/pages/15604222/Utvalg_IV.pdf)

*case* will serve as a benchmark of how to carry out the CBA and is also a mean of comparing the results. Below is a description of the research problem that the thesis will aim at answering.

### ***1.1. Research problem***

The first and principal step in the research process is to select and properly define the research problem. The research problem must be formulated, so it can become susceptible to research according to Sanjeev (2010). A research problem is one that aims at finding the best solution for a given problem in the context of a given environment (Sanjeev, 2010). The formulation of the research problem in this thesis is based on the introduction and background to the topic, which reflects on the difficulties in making energy investments which must consider the requirements of supply security as well as impacts on the environment. The problem therefore intends to answer the following question:

*“What is the most economic electric power investment  
that balances the long-term impacts on the environment  
against the short-term requirements of  
reliable and secure electricity supply?”*



## ***1.2. Structure of the thesis***

This thesis is divided into five main chapters, which will be built up to include methodology, a theoretical outline, the case analysis and some conclusions and recommendations. The structure of the thesis is illustrated in figure 1.1. A brief description of the contents in each chapter is described next.

### ***Chapter 1***

Chapter 1 gives an overview and background of the topic and an introduction to the research problem.

### ***Chapter 2***

The main goal of chapter 2 is to give a brief description of the methodology to be applied in the thesis. This includes a definition of the term, formulation of the research questions, description of the research design and a classification of data and sources.

### ***Chapter 3***

Chapter 3 is the theoretical framework and provides the main building blocks for chapters 4 and 5. This chapter is further subdivided into three main elements. The first section is a thorough description of cost-benefit analysis (CBA), including its definition and purpose, theoretical foundations and main steps. Next, an examination of CBA in the energy sector is carried out, which will be a key input to the case study in chapter 4. This section includes a description of the electricity market, key parameters, practical implementation and a framework for measuring benefits and costs. Last, an outline of the main critiques of CBA is presented together with alternative socioeconomic methods. This chapter will answer research question *i*, presented in chapter 2.1.

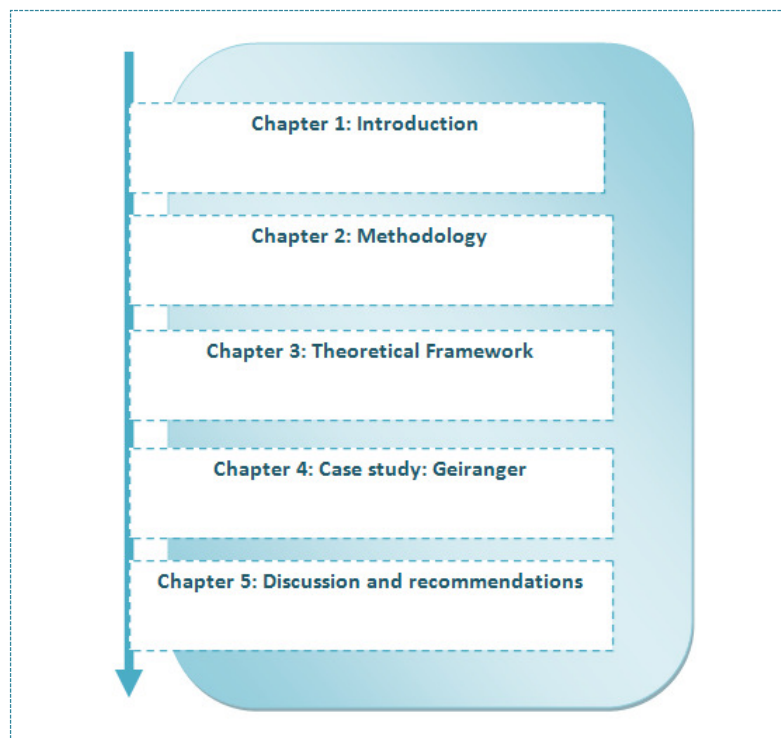
### ***Chapter 4***

The main work of the thesis will be carried out in chapter 4 and is the case study of the power condition in Møre og Romsdal, named the Geiranger case. The chapter will be based on the framework presented in chapter 3 and will include a background to the energy problems in Møre

og Romsdal, named problem and purpose specification. Next, the possible investment alternatives are specified together with a limitation of those alternatives that will be further analyzed in the next section. The third section will specify the impacts of the investigated alternatives before a compilation and assessment is made. A conclusion of the findings will also be given. This chapter will answer research question *ii* (refer chapter 2.1).

### **Chapter 5**

The aim of chapter 5 is to summarize the main theoretical foundations of CBA in the energy sector in chapter 3 and the finding from the case study in chapter 4 in an attempt to answer the research problem presented in chapter 1.1. The chapter will discuss the answers to the research problems and give recommendations further research in the area.



**Figure 1-1: Structure of the thesis**

## **2. Methodology**

This chapter will give a portrayal of the methodology to be applied in this thesis, which can be defined as a structured method to reach a certain goal. Johannessen et al. (2004) write that methodology is about how one should proceed to obtain information about reality as well as how to analyze this information so it gives a new insight in economic conditions and processes. This chapter is divided into four main subjects. Firstly, the chapter will express the research questions to be applied in the thesis. Secondly, the research design is described, including an exploration of case study research. Thirdly, a classification of the data to be used in the thesis is outlined. Lastly, the terms validity, reliability and objectivity is described.

### ***2.1. Research questions***

Research questions can be defined as inquiries that are asked with certain goals in mind, and in such a precise way that social science methods can answer them (Johannessen et al., 2004). Well defined research questions helps to refine and give direction to the analysis and contribute to an economization of the projects recourses according to Johannessen et al. (2004).

The research questions in this thesis have been formulated with the aim of having sufficient information to answer the research problem outlined in chapter 1. The following research questions have been developed:

- i. What are the main theoretical buildingblocks of CBA and which buildingblocks of this theory is applicable to the energy sector?*
  - a. What elements are monetized and which are quantifiable described?*
  - b. How is supply security quantified?*
  - c. How is environmental impacts valuated and how can the visual impacts of overhead transmission lines be quantified?*

- ii. *What are the characteristics of the power situation in Central-Norway and is an overhead transmission line the most economic investment choice in this region?*
  - a. *What other alternatives are feasible to solve the power situation in the long-run?*
  - b. *Are projects that are environmentally less intrusive priced higher in the market also in the Geiranger case?*

The above questions will be answered in chapters 3 and 4 in the thesis. Question i will be answered based on the descriptions of the theoretical framework in chapter 3. Chapter 4 will give an exploration of the Geiranger case and thus intuitively answer research question ii.

## **2.2. Research design**

Research design is a framework in which data is collected and analyzed with the aim of answering the initial questions of the study (Yin, 2009). “*Decisions regarding what, where, when, how much and by what means concerning an inquiry or research study constitute a research design*” (Sanjeev, 2010; p.36).

There is numerous approaches research design, which is often divided into quantitative and qualitative design methods. **Quantitative methods** involves the generation of data which can be subjected to analysis in a formal and rigid manner (Sanjeev, 2010). This category of research can be subdivided into *inferential*, *experimental* and *simulation* approaches to research. Refer Sanjeev (2010) for a more detailed description of these methods. **Qualitative methods** are characterized by the lack of one distinct analytical direction, and are mostly concerned with subjective assessment of attitudes, opinions and behavior according to Sanjeev (2010). This means that qualitative methods can be conducted in a variety of ways. One widely applied qualitative method is case design or case studies. Although both quantitative and qualitative methods are used for data collection in case studies, the latter will normally predominate in the study of processes (Gummesson, 2000).

This thesis will utilize the **case study** method, by identifying the investment environment in Central-Norway with an in depth analysis of several investment alternatives in Møre og Romsdal that might affect Geirangerfjorden, thus named the Geiranger case study. Case study research is an empirical research method, and Yin (2003; 2009) write that the benefits of using this method are that it can deal with a variety of sources of evidence, observations and documents and in that sense paint a small picture reality. A case study investigates a contemporary phenomenon within its real-life context, assuming that the contextual conditions are highly pertinent to the phenomenon of study (Yin, 2009).

There are various characteristics of case study approaches, comprising of explanatory, exploratory and descriptive (Yin, 2003). The thesis will utilize an **exploratory case study** approach, with the reasoning that the case study will be used to explore situations in which the interventions being evaluated has no clear, single set of outcomes (Yin, 2003). The explanations that are built will be founded in well-known theories, as described in chapter 3. This technique can lead to recommendations for future policy actions (Yin, 2009), which is the aim of this paper and thus a relevant method to be applied for the thesis.

### ***2.3. Classification of data and sources***

The task of collecting data begins after the research problem and research questions have been defined and the design of the study planned. The method of data collection is dependent on the type of data which is needed, and a distinction can generally be made between primary and secondary data. **Primary data** is defined as new data which the researcher has collected and thus happen to be original in character (Sanjeev, 2010). **Secondary data** is on the other hand data which has already been collected by someone else and thus already passed through the statistical process (Sanjeev, 2010). This thesis will employ data from secondary sources, which are both quantitative and qualitative in nature. Quantitative methods are mostly relevant to compare the economic aspects of the various alternatives, as these are more easily quantifiable in monetary terms. Some aspects will be based more on qualitative theories and judgments and conversations with key informants.

Some of the main data sources needed in the thesis can include the following, but are not limited to:

❖ **Documentation**

- Documentation from sources such as:
  - ✓ The Norwegian Water Resources and Energy Directorate
  - ✓ The Norwegian Ministry of Petroleum and Energy
  - ✓ Statnett
  - ✓ Istad
- Hardanger case information from expert committees
- Academic papers
- Textbooks

❖ **Archival records**

- Statistical data
- Maps and charts
- Reports

❖ **Key informants**

- Conversations with supervisor Arild Hervik
- Istad Kraft
- Other persons/ groups that may be of relevance

## **2.4. Validity, reliability and objectivity**

These terms are used to reassure a level of quality in the data and sources of data described above. The terms are most often used for quantitative research, but also important to consider in all research approaches. Validity, reliability and objectivity will be important considerations in this thesis and thus below is a brief description of each.

**Validity** indicates the degree to which an instrument measures what is suppose to measure and in that sense, how well the data represents the phenomenon of study (Sanjeev, 2010, Johannessen et al., 2004). One can make a distinction between three types of validity, namely content validity, criterion-related validity and construct validity. Sanjeev (2010; p.89) defines the three types as follows: *“Content validity is the extent to which a measuring instrument provides adequate coverage of the topic under study. Criterion-related validity relates to our ability to predict some outcome or estimate the existence of some current condition. Construct validity is the most complex and abstract. A measure is said to possess construct validity to the degree that in conforms to predict correlations with other theoretical propositions”*.

**Reliability** is related to the survey data and a measuring instrument is said to be reliable if it provides consistent results (Sanjeev, 2010). This means that two or more researchers studying the same phenomenon with comparable purposes should in principle reach the same results, thus be replicable (Gummesson, 2000). Reliability is not as vulnerable as validity according to Sanjeev (2010), it is however easier to assess.

**Objectivity** is about how the researcher relate to the phenomenon of study, which should be neutral and value free (Johannessen et al., 2004). Objectivity is therefore of basic importance *“because it determines the data which are collected, the characteristics of the data which are relevant, relations which are to be explored, the choice of techniques to be used in these explorations and the form of the final report”* (Sanjeev, 2010; p.101).

### 3. Theoretical Framework

This chapter of the thesis will give a thorough description of the theoretical framework that is important to conduct the analysis of the case study in the next chapter. Cost-benefit analysis (CBA) is a widely used method to assess economic profitability of a project or public investment, and thus an important tool also for assessing investments within the energy sector in Norway. The chapter is divided into three main parts, as illustrated in figure 3.1 below. First, the main concepts within the CBA framework are described, including its definition and purpose, its conceptual foundations and its main steps. Second, the application of CBA in the energy sector is described. This section highlights the main methodologies relevant to the case study in chapter four, including a short description of the electricity market, the key parameters influencing the economic investment decision, practical implementation of CBA and lastly a framework for illustrating benefits and costs in energy projects is developed. The third section of this chapter attempts to highlight the main critiques of CBA, with a summary of alternative methods.

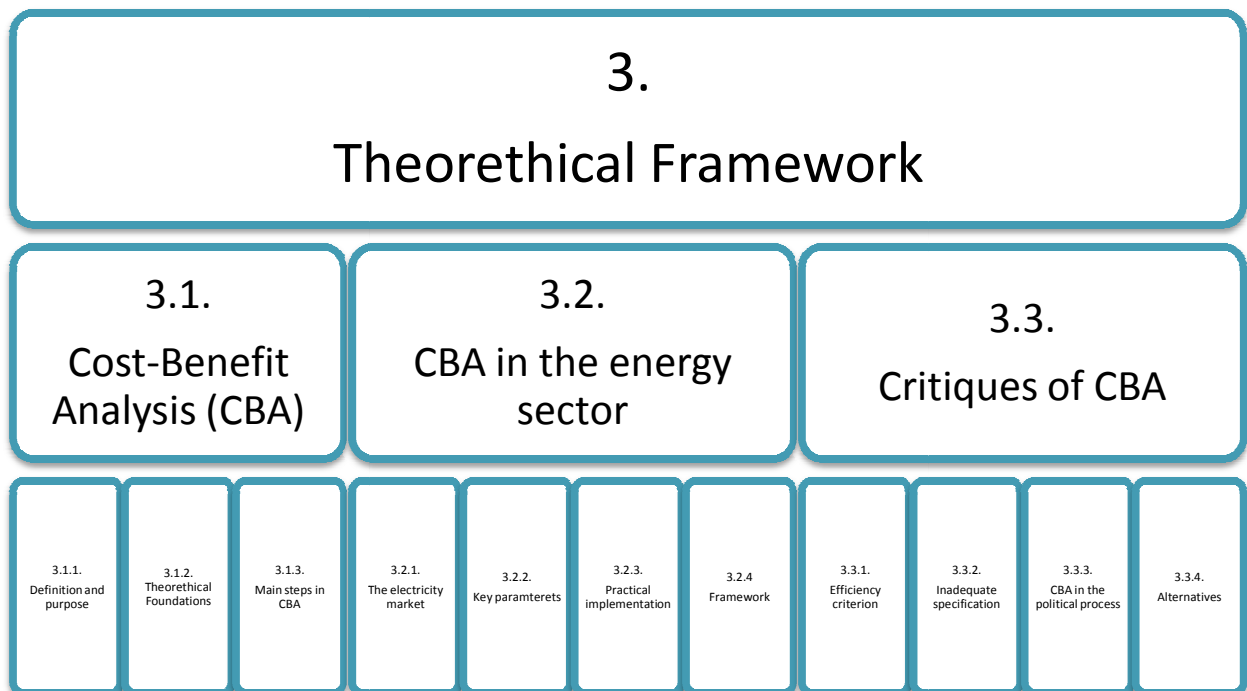


Figure 3-1: Main subjects in the theoretical framework



### **3.1. Cost-Benefit Analysis**

The CBA methodology has advanced over the years, with increased acceptance from both various disciplines and government agencies (Hanley and Spash, 1993). The use of CBA started in the US in the 1930s and advanced in the 1960s when the Minister of Transport in the UK adopted and promoted this method (Boardman et al., 2011). The CBA tool then spread around the world, and is applied in many different circumstances for many different purposes. A cost-benefit analysis is especially relevant for investments that are of public interest, as costs and benefits to society as a whole are considered. This is one of the reasons why many government agencies require the use of CBA in regulatory changes (Boardman et al., 2011). The Norwegian government has provided the public with a manual of how to conduct CBA, which is further used when assessing public policy projects (Finansdepartementet, 2005). This handbook, together with the textbooks of Boardman et al. (2011) and Nas (1996) are the main sources of literature applied when exploring CBA in section 3.1.

#### **3.1.1. Definition and purpose of CBA**

Finansdepartementet (2008) writes in their handbook that the main purpose of economic analysis is to map, visualize and systematize the consequences of a governmental policy and reform, before the decision is made. There are various tools used in assessing the economic profitability of a project, such as multi-criteria analysis (MCA) and cost-benefit analysis (CBA).

CBA is probably the most applied method and can be characterized as a policy assessment method that attempts to quantify in monetary terms the value of all consequences of a policy to the society (Boardman et al., 2011). The definition used in Nas (1996) is quoted as it gives a clear explanation of the term: *“Under the CBA methodology, all potential gains and losses from a proposal are identified, converted into monetary units and compared on the basis of decision rules to determine if the proposal is desirable from society’s standpoint”* (p. 1-2).

There are in practice four main types of cost-benefit analysis, which are described in Boardman et al. (2011). Firstly, there is the **ex ante** CBA, which is conducted before a decision is made.

This is the most common type, as the results of the analysis will be useful as part of the decision foundation and contributes to making it verifiable (NOU, 1998a). Next, CBAs may also give useful information after the project is conducted, and is called **ex post** CBA. This CBA will be useful for evaluating the project, where mistakes from the project can be highlighted for future projects (NOU, 1998a). This type of analysis contributes to “learning” not only about the particular intervention, but the class of such interventions. The third type of CBA, is named **in medias res** analyses, and is conducted during the course of the life of the project. The main purpose of this type of analysis is to highlight whether or not to continue the project, as well as costs and benefits can be predicted for future ex ante analyses. The last type of CBA is the **comparative** CBA. This type compares ex ante CBA with an ex post (or in medias res) CBA for the same project, and is most useful as a general mechanism for learning about the efficacy of CBA as a decision making and evaluative tool.

### ***3.1.2. Theoretical foundations of CBA***

Microeconomic theory, welfare economics and finance makes up the basic conceptual foundations of CBA (Boardman et al., 2011, Nas, 1996). The basic principles in microeconomics are dealing with social welfare and efficient allocations of resources, which are the roots of CBA. A public project is likely to affect the welfare of three main groups according to Nas (1996). These are individuals that are beneficiaries of the project, taxpayers who provide the funding for the project and those who incur losses as the project is implemented. The main task for those conducting a CBA is thus to identify these affected parties, calculates losses and gains and then identify whether the project is feasible from the standpoint of society (Nas, 1996).

The main concepts of the microeconomic theories of CBA are described in more detail in this section and can be divided into eight subsections. Firstly, economic efficiency and Pareto optimality are described as these concepts forms the basis for the CBA decision rule, which is explained next. Third, the concept of net benefits is described, which is based on willingness to pay and opportunity costs. Next, the concept of time is described and some measures of socioeconomic profitability outlined. Then, the discount rate is explained and how to define the correct one is assessed. The sixth concept is the presence of market failures and imperfections

and the next is the valuation of non-market goods. Lastly, the concept of option value is defined and described briefly.

### **3.1.2.1. Economic efficiency and Pareto optimality**

One of the main goals of CBA is to have an efficient resource allocation. Efficiency can be broadly defined as “*a situation in which resources, such as land, labor, and capital, are deployed in their highest valued uses in terms of the goods and services they create*” (Boardman et al., 2011; p. 27). A central concept within welfare economics is allocative or **Pareto efficiency** (Nicholson, 1990). Pareto optimality is a standard of efficiency that describes the conditions that are essential to attain optimality in resource allocation. It is defined as “*a state of economic affairs where no one can be made better off without simultaneously making at least one other person worse off*” (Nas, 1996; p. 11).

To describe Pareto efficiency, the thesis will adopt the explanations and illustrations from Boardman et al. (2011), refer the figure below. The figure illustrates a situation which involves the allocation of a fixed amount of money between two people. Each person can receive any amount of money, from \$25 to \$100, depending on how they agree to split the money between them. Point **a** (\$25, \$25) can be called the status quo, and gives the amount the two people would receive in an agreement about splitting the \$100. The triangle **abc** is called the *Pareto frontier*, because it represents a situation where it gives each person at least as much as the status quo, without making the other person worse off. This means that the status quo is not Pareto efficient and movements within the triangle abc are called **Pareto improvements**. One can thus conclude that an allocation of resources is Pareto efficient when no further Pareto improvements can be achieved, and one person’s gain does not make the other person worse off.

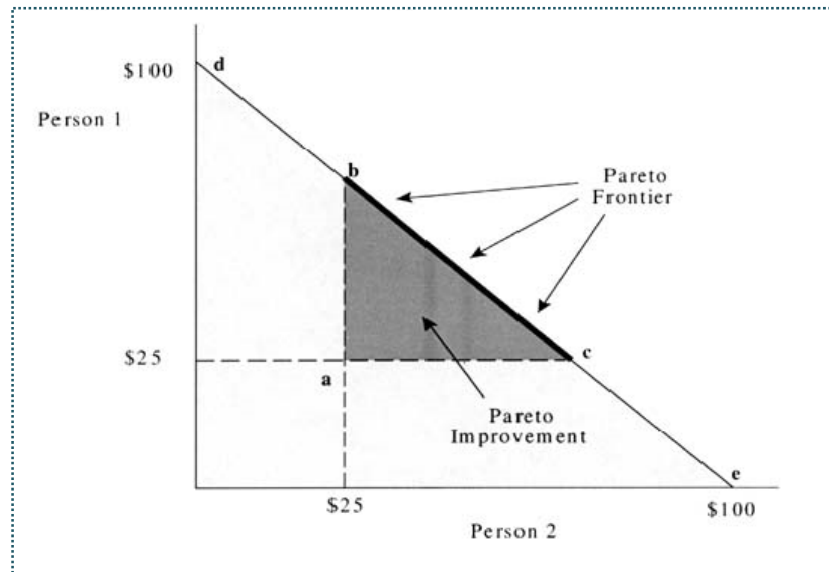


Figure 3-2: Pareto Efficiency (Modified after Boardman et al. 2011; p. 28)

The figure above gives a simple illustration of how Pareto efficiency works in theory. However, this concept might be easy to understand and uncontroversial when all information is available, but few projects do in reality achieve Pareto-efficient allocations (NOU, 1997). This is the reason why CBA utilizes a decision rule that is based on the theory of Pareto efficiency, but that does not hold all its assumptions.

### 3.1.2.2. CBA decision rule

CBA utilizes a decision rule that might have less conceptual appeal than the Pareto efficiency, but much greater feasibility according to Boardman et al (2011). This rule is called the *Kaldor-Hicks* criterion and is much more flexible for a CBA, as it justifies any reallocation of resources as long as it raises net social benefits (Nas, 1996). The criterion forms the basis for the *potential Pareto efficiency rule*, which states that “as long as net benefits are positive, it is at least possible that losers could be compensated so that the policy potentially could be Pareto improving” (Boardman et al., 2011; p. 32).

Projects that satisfy the Kaldor-Hicks criterion will in theory coincide with projects that have a positive aggregated willingness to pay. There are various justifications for applying the potential Pareto efficiency rule in cost-benefit analyses and Boardman et al. (2011; p.32) suggests the following four:

- I. *By always choosing policies with positive net benefits, society maximizes aggregate wealth.*
- II. *It is likely that policies will have different sets of winners and losers, thus costs and benefits will tend to average out across people so that each person is likely to realize net positive benefits from the full collection of policies.*
- III. *The rule stands in contrast to the incentives in representative political systems to give too much weight to costs and benefits that accrue to organized groups*
- IV. *If a more equal distribution of wealth or income is an important goal, then it is possible to redistribute costs and benefits after a large number of policies have been adopted*

### **3.1.2.3. Net benefits**

Net benefits are the “*difference between the annual benefit stream and the annual cost stream*” (Nas, 1996; p.121). Benefits can be defined as increases in human well-being or utility, while costs can be seen as reductions in human well being (Pearce et al., 2006). Benefits can be measured by either willingness to pay (WTP) or opportunity costs. WTP is the method for valuing the outputs of a policy and the opportunity cost is the method for valuing the resources required to implement the policy (Boardman et al., 2011). Confer the figure below for an illustration of the elements that make up net benefits.

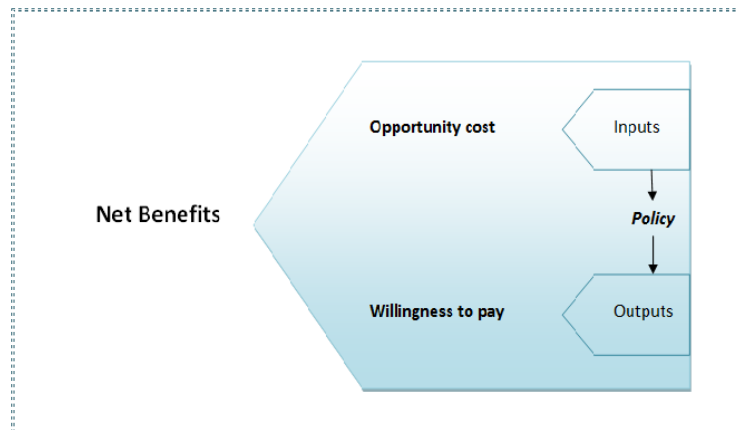


Figure 3-3: Categorization of Net Benefits of Projects (Modified after Boardman et al. 2011; p. 29)

- ***Willingness to pay***

The main principle behind using willingness to pay, is that the monetized value of a positive effect should be equal to the amount the population is willing to pay (WTP) to achieve it (Finansdepartementet, 2005). Willingness to pay is based on people's preferences and income, which can be illustrated in the demand function of each consumer. The collected demand functions are known as the joint demand function (NVE, 2003). An economic viable project is thus an indication that the majority of the inhabitants is willing to pay at least as much as the policy costs. There may occur situations where the willingness to pay is larger than the total costs, but the project may not be desirable from the society's standpoint. Finansdepartementet (2005) write in their handbook that there may be three reasons for this. Firstly, it may not be possible to measure all the impacts in NOK in a good way. Secondly, it is possible that the willingness to pay does not capture the welfare effects in its entirety and lastly, the policy makers may in addition to WTP be interested in how the effects are distributed across the society.

- ***Opportunity costs***

The implementation of a policy almost always requires the use of some inputs that could be used to produce other things of value (Nicholson, 1990). The concept of opportunity costs are used in CBA to place a monetary value on the inputs required to implement the policies and forms the

cost element in the analysis (Boardman et al., 2011). The opportunity cost is thus the value that the society must forgo to use the input to implement the policy.

Although the definition of the concept appears simple, it is sometimes problematic to determine the opportunity cost or alternative cost. The simplest valuation of the opportunity cost are in those cases where the resources are traded in a free market, without price distortions and with an optimal distribution of incomes (NOU, 1997). The process becomes somewhat more difficult when the resources are not traded in a free market economy and thus the prices will not necessarily reflect the true value of the alternative uses of these resources. Further, some situations occur where it will not be possible to determine the cost components and the alternative is to conduct an impact assessment (NOU, 1997). In an impact analysis the costs and benefits are described in physical sizes, and based on this information the decision maker can form a picture of how much resources that is expected to be utilized (NOU, 1997).

#### **3.1.2.4. The time dimension**

Costs and benefits rarely occur at the same time, thus a method to compare costs and benefits in different years are necessary. The most common methods to accomplish this are described next in this section, and include net present value, internal rate of return and the benefit-cost ratio. These three methods all represent measures of economic profitability.

- **Net Present Value (NPV)**

This is the most common method, and involves calculating the yearly benefit and cost elements into a present value. This measure compares whether the sum of discounted gains exceeds the sum of discounted losses (Hanley and Spash, 1993). Discounting reflects that a Krone today is not worth the same as a Krone tomorrow (NOU, 1997). The annual costs can be discounted separately and be deducted from the present value (PV) of the benefit stream, or alternatively, the net benefits can be discounted to find the NPV (Nas, 1996). Either way, the outcome will be the same.

A general formula for calculating the NPV was given in NOU (1998) and is as follows:

$$NPV = -I_0 + \sum_{t=0}^n \frac{U_t}{(1+k)^t}$$

Where  $I_0$  is the investment costs that is assumed to accrue in year 0,  $U_t$  is the project surplus in year  $t$ ,  $k$  is the discount rate that is assumed to be constant in the analysis time horizon, and  $n$  is the number of years the project lasts.

The project or alternative is profitable when the NPV is larger or equal to zero. When there are several projects, the alternative with the largest NPV is generally chosen (Boardman et al., 2011).

- **Internal Rate of Return (IRR)**

The internal rate of return, or breakeven discount rate, is the rate at which the NPV is equal to zero. The IRR can be found by solving the equation below (Adopted from NOU, 1997).

$$-I_0 + \sum_{t=0}^n \frac{U_t}{(1+p)^t} = 0$$

In practice, the NPV and IRR methods will provide the same results (NOU, 1998a). Boardman et al. (2011) suggest that “*IRR may be used for selecting projects when there is only one alternative to the status quo*” (p. 158). The IRR relative to the appropriate discount rate indicates whether the project should be chosen or not, thus if the IRR is greater than the discount rate one should proceed with the project, if not, one ought not to (Boardman et al., 2011).

There are several limitations to the use of IRR. Firstly, there may not only be one discount rate at which the NPV is zero. Secondly, IRR is a percentage and not a monetary value, thus caution should be applied when selecting a project from a group of projects that vary in size (Boardman et al., 2011). Nevertheless, if it is unique, the IRR express valuable information to decision



makers or other analysts who want to know how sensitive the results are to the discount rate (Boardman et al., 2011).

- ***Benefit-Cost Ratio***

Analysts often evaluate projects based on the benefit-cost ratio. A benefit-cost ratio can be employed to establish the viability of a project during any given year or over a time span (Nas, 1996). The ratio can generally be defined as described below (Adopted from NOU, 1997).

$$\frac{C}{B} = \frac{\text{Present value of the gross benefits generated by the project}}{\text{Present value of the gross costs related to the project}}$$

The rule is that the ratio should be larger than or equal to one, which basically means that the present value of the benefits should be larger than the present value of the costs to be profitable (NOU, 1997). One could also choose the largest ratio when comparing projects that are mutually exclusive (Pearce et al., 2006).

Although popular and simple to use, there are some well documented problems with using the benefit-cost ratio. First, the rule is highly sensitive to how costs and benefits are defined (Pearce et al., 2006). Another problem is that the ratio rule is incorrect when applied to mutually exclusive contexts. Boardman et al. (2011) also state that the cost-benefit ratio may be prone to manipulations. Due to the limitations and critiques of this ratio, Boardman et al. (2011) recommend that “analysts avoid using benefit-cost ratios and rely instead on net benefits to rank policies” (p. 34). NPV will therefore be used in chapter 4 of this thesis to rank investment alternatives.

### **3.1.2.5. Discounting and the choice of discount rate**

The choice of discount rate will often have a large impact on whether a project is profitable or not and is thus also one of the most debated issues in CBA. “*Discounting refers to the process of assigning a lower weight to a unit of benefit or cost in the future, than to that unit now*” (Pearce et al., 2006; p. 184). The further into the future the benefit or cost arises, the lower the weight attached to it. There are two main reasons why benefits and costs in a CBA are discounted. Firstly, the future is associated with **uncertainty**, thus one cannot place the same weight on future factors as elements in period 0, since there will be a large amount of factors that can possibly change in a period of say 25 years (Nilsen, 2003). Secondly, financial capital will be tied up when investing in a project, which can represent an **alternative cost**, such as investing the capital in other projects or in a bank (Nilsen, 2003).

The discount rate should reflect what it will cost from a socioeconomic standpoint to tie up capital in long-term applications and one can thus see the discount rate as a form of calculation price (NOU, 1998a). The discount rate consists of two elements

- A risk-free rate (risk-free alternative cost)
- A risk premium (compensation from carrying risks)

NOU (1997) suggests that the Norwegian **risk free rate** should be around 3, 5 % per year. This rate may however be too low for projects that have a higher risk than regular projects. NOU (1998a) state however that the risk associated with future inflation may point to a lower long-term risk-free interest rate. The risk-free interest rate was in 2004 almost 2% lower than in 1997 (NOU, 1997), which indicates that the time is right for adjustment of the discount rate level (Hervik, 2004). Investments into the electric power system are examples of projects with higher risk than normal, and thus the discount rate should reflect some risk premium. The **risk premium** is dependent on a variety of factors and should reflect the risk associated with the particular project, such as cyclical sensitivity and the share of fixed costs (Finansdepartementet, 2005). Hervik (2004) reported in 2004 that there is currently a trend in the international science literature to scale down the risk premium.

- ***The discount rate in energy projects***

The discount rate to be used in energy projects in Norway is dependent on the size of the investment. With large or important individual projects, separate estimates for the discount rates should be made (NVE, 2003). For smaller project, standardized interest rates are used that are divided into pre-defined risk classes. Within each risk group a discount rate of 4, 6 or 8% is used, which is based on a risk free rate of 3,5% and a risk dependent premium of 0,5, 2,5 or 4,5% (NVE, 2003). This rate is in compliance with the practice other countries, where most government agencies today suggest a base-case discount rate of 7 per cent (Nas, 1996). Various authors are on the other hand now discussing whether this discount rate is too high, refer (Hervik, 2004, Jenssen et al., 2004, Andersen and Skjeret, 2003). Hervik (2004) argue that there are currently many conditions that suggest that the **discount rate should be somewhat adjusted downward**. In his report from 2004, Hervik analyzed the discount rate to be used specifically in power grid investments, and concluded that a discount rate of 6% would be a fair estimate, however 5% would also not have been unreasonable (Hervik, 2004). In their socioeconomic analysis of network investments in Hardanger, Hervik et al. (2011a) used a discount rate of 4 %. Based on the foregoing discussion, the thesis will use a discount rate of 6% in the CBA in chapter 4. A lower estimate of 4% will be used for sensitivity analysis.

- ***The discount rate in long-term projects***

A main argument relating the choice of discount rate is the length of the analysis period. Projects with a long duration will be highly dependent on the size of the discount rate to determine its profitability (Dalen et al., 2008). Examples of economic profitability studies with lengthy time horizons are investments in transportation infrastructure, some investments in the petroleum industry as well as investments in climate politics and environmental measures (Dalen et al., 2008). Various authors (Dalen et al., 2008, Boardman et al., 2011) therefore suggests that the discount rate should time declining. Boardman et al. (2011) suggests that for long lived projects, *“benefits and costs should be discounted at 3, 5 percent for the first 50 years, at 2,5 percent for years 50-100, 1, 5 percent for years 100-200, 0, 5 percent for years 200-300, and 0, 0 percent for years more than 300 in the future”* (p.156).

### **3.1.2.6. Market failures and imperfections**

A key principle in the economic welfare theory is that an economy with perfect competition in all markets, under certain conditions, will achieve an efficient allocation of society's resources (NOU, 1997). In practice however, these conditions may not be met and there will be a market failure. Markets may fail to achieve economic efficiency in the real world, as a result of imperfections in the markets, as the inability to provide for public goods, the presence of externalities, information asymmetry, public goods and tendencies of imperfect competition are examples of (Nas, 1996). Boardman et al (2011) affirm that market failures are an important concept for CBA, "*as their presence provides the prima facie rationale for most, although not all, proposed government interventions that are assessed through CBA*" (p. 78).

- **Public goods**

Nas (1996) write that public goods have two fundamental characteristics: "*(a) they are nonrival in consumption, and (b) exclusion is either impossible or very costly*" (p. 31). Nonrival consumption occurs when one person can consume a commodity without preventing others from consuming the same commodity. Exclusion indicates that if a good is supplied to one consumer, it is available to all consumers. This phenomenon is sometimes referred to as "*jointness in supply*" (Boardman et al., 2011). Goods that contain both these characteristics are referred to as "pure" public goods, where an example might be a country's national defense. Some goods are not pure public goods, as consumption might be dependent on how many people who use it, such as a road (NOU, 1997). Such goods can be called "rivalry" public goods (Boardman et al., 2011).

Optimal supply of pure public goods should be determined in a way that the total willingness to pay for an additional unit, is equal to the marginal costs of producing this unit. In effect, the consumers have different marginal WTP, but the access is equal to everyone (NOU, 1997). This is the opposite situation than for private goods, where the price of the good is the same, but the consumption is normally diverse. The characteristics associated with public goods, connote that if the good is going to be produced, the government needs to intervene by either producing the good itself or subsidizing its production (Boardman et al., 2011, NOU, 1997).

- **Externalities**

Externalities are costs and benefits imposed on third parties, where the effects are not conveyed through the price mechanism (Nas, 1996). This makes it difficult to elicit prices and willingness-to-pay for these externalities. There can generally be both positive and negative externalities, which represent benefits or costs to society. Positive externalities is a situation where there is an underutilization of resources and an example may be subsidizing programs that benefit a local neighborhood. Common negative externalities are often impacts on the environment, such as air and water pollution (Boardman et al., 2011). Firms are generally not held accountable for such negative costs to society and individuals subject to the externality may not be compensated for the harm imposed on them (Nas, 1996). In many circumstances, the handling of negative externalities are left to the public to deal with (NOU, 1997)(NOU, 1997)(NOU, 1997)(NOU, 1997). This might be through measures such as environmental taxes (Finansdepartementet, 2005)

The reason for including externalities in CBA is to account for over- or underestimations of costs or benefits of a project and to reflect that there is a discrepancy between private and public costs of resource employment. The reason is that these externalities will not commonly be part of private profitability calculations, and must therefore be included in economic profitability computation (NOU, 1997).

### **3.1.2.7. Valuing non-market goods**

Many of the impacts addressed in a cost-benefit analysis is intangible in nature and are not traded in actual markets (Pearce et al., 2006). As mentioned earlier in this thesis, it is difficult to observe peoples willingness to pay in these non-markets. In these conditions, the cost-benefit literature provides several direct and indirect approaches to value goods that carry non-market characteristics (Nas, 1996). These can broadly be divided into three main methods, which are revealed preference methods, stated preference studies and benefit transfers.

**Revealed preference methods** are based on observed behaviors, where individuals reveal their preferences without having to be asked (Boardman et al., 2011). These methods estimates

willingness to pay for changes in provision of non-market goods or willingness to accept compensation for such changes, through a direct survey approach (Pearce et al., 2006). See the table below for a summary of the most common revealed preference methods. **Stated preference** methods are more indirect methods that involve people disclosing their preferences through actual choices (Boardman et al., 2011). This is achieved by measuring demand for complementary goods to deflect demand for other goods. General stated preference methods are also summarized in the table below.

The third way of valuing non-market goods, involves using shadow prices from secondary sources (Boardman et al., 2011). Shadow prices, also called “**benefit transfers**”, are used when observed prices fail to reflect the social value of a good or when observed values do not exist. Some shadow prices mentioned by Boardman et al. (2011) includes the value of a statistical life, the value of a life-year, the cost of crashes and the cost of injuries, the cost of crime, the value of time, the value of recreation, the value of nature, the value of water and water quality, the cost of noise, the cost of air pollution, the social cost of automobiles and lastly the cost of taxation. The value and appropriateness of shadow prices will depend on the number of studies carried out, as well as the closeness of that study to the study where transfers of data will be carried out.

**Table 3-1: Summary of revealed and stated preference methods**

Revealed Preference Methods	Stated Preference Methods
❖ Hedonic Pricing Method (HPM)*	❖ Contingent Valuation Method (CV)*
❖ Travel Cost Method (TCM)*	❖ Choice Modelling (CM)
❖ Defensive Expenditure Method	
❖ Market Analogy Method	
❖ The Trade-Off Method	
❖ Intermediate Good Method	
❖ Asset Valuation Method	

\*These methods are the most common valuation methods and will be described in more detail below

- **Hedonic Pricing Method**

The hedonic pricing method (HPM), sometimes called hedonic regression method (Boardman et al., 2011), approximates the value of a non-market good by observing the behavior in the market for a related good (Pearce et al., 2006). *“The starting point for the HPM is the observation that the price of a large number of market goods is a function of a bundle of characteristics”* (Pearce et al., 2006). To find the implicit price of each of these characteristics, HPM uses statistical techniques. There are two types of markets that are of particular interest in non-market evaluation, namely property markets and labor markets. As with other valuation methods, there are several limitations with the HPM. Hanley and Spash (1993) write that these include the omitted variable bias, multi-collinearity and restrictive assumptions. There are further problems with choosing the functional form, how to segment the market and separating between expected and actual characteristics levels (Hanley and Spash, 1993).

- **Travel Cost Method**

The travel cost method (TCM) has been developed to value the use of non-market goods, predominantly geographical areas and locations used for recreational purposes (Pearce et al., 2006). *“The TCM seeks to place a value on non-market environmental goods by using consumption behavior in related markets”* (Hanley and Spash, 1993; p. 83). The consumption behavior is assessed through the costs of using the service, such as travel costs, entry-fees, on-site expenditures and outlay on capital equipment necessary for consumption (Hanley and Spash, 1993). Due to the characteristics of the method, TCM estimates user values, but not non-user values. There are several limitations to TCM, where one is that the method only provides an estimate of the WTP for the entire site rather than for specific features of a site (Boardman et al., 2011). Further, measuring the cost of a visit to a site may prove difficult, there might be an issue with multi-purpose trips, the journey itself may have a value and equipment that are expensive are needed to participate in the recreational activity (Boardman et al., 2011). Other technical problems may also arise when using this approach according to Boardman et al. (2011), such as truncation (the sample is drawn from only those who visit the site, not from a larger population),

the omitted variables problem and lastly the derivation of the market demand curve assumes that people respond to changes in price regardless of its competition.

- **Contingent valuation method**

The contingent valuation method (CVM) is used when there is no existence of observable behavior to disclose individual preferences. *“It consists of a survey technique in which the analyst, by asking willingness to pay or willingness to accept types of questions, collects information on individual preferences regarding a project outcome or a welfare change”* (Nas, 1996; p. 111). A typical instrument used in these surveys provides detailed questions stated under various response alternatives, contingent upon a hypothetical market environment (Nas, 1996). Refer Hanley and Spash (1993) for a detailed description of the application of the CVM. Although the CVM is a widely accepted method for valuing non-market goods, the method is prone to various types of biases (Nas, 1996, Hanley and Spash, 1993, Boardman et al., 2011). Hanley and Spash (1993) write that biases may result from a number of causes, such as strategic bias, design bias and mental account bias.

### **3.1.2.8. Option Value**

This chapter has previously discussed economic profitability in terms of a positive NPV. If the investment leads to irreversible impacts however, the NPV is no longer a sufficient measure to determine whether the projects are profitable or not (Finansdepartementet, 2005). Irreversible decisions can be defined as choices made now which commits resources or generates costs that cannot subsequently be recovered or reversed (Pearce et al., 2006). Pearce et al (2006) further write that in this context of uncertainty and irreversibility *“it may pay to delay making a decision to commit resources”* (p. 145). The alternative costs with lost decision flexibility is related to the possibility to delay a decision in order to obtain a more positive NPV (NOU, 1998a)(NOU, 1998a)(NOU, 1998a). This value gained from delay is the option value or quasi option value. If the project is implemented, this would mean that the option is subsequently expired (NOU, 1998a).



Another important element that brings forward the importance of option value, occurs when there is a great deal of uncertainty surrounding central factors that are essential to the profitability of the project (Finansdepartementet, 2005). If by waiting one can receive increased information of these factors, it will be profitable to make the decision at a later stage to avoid loss scenarios (Finansdepartementet, 2005).

In practice, the option value is calculated by estimating the NPV of a project at different implementation times (NOU, 1998a)(NOU, 1998a)(NOU, 1998a). Prompt implementation would be correct if the NPV is sufficient to also cover the alternative cost by eliminating the alternative cost of the option to wait (Finansdepartementet, 2005).

### 3.1.3. Main steps in CBA

This part of the chapter is dedicated to listing and describing some of the main steps of CBA. There is not a consensus in the number of steps to be involved in the analysis by various authors (Nas, 1996; Finansdepartementet, 2005; Boardman et al. 2011, Hanley and Spash, 1993), although they often entail the same information and specifications. This thesis will use the guidelines of Finansdepartementet (2005) and the steps are listed in the table below and then described.

**Table 3-2: Main steps of a CBA (Modified after Finansdepartementet (2005))**

<b>Problem and purpose specification</b>	<ul style="list-style-type: none"> <li>- What is the problem?</li> <li>- What is the purpose of the proposed alternatives?</li> </ul>
<b>Specification of measures/ alternatives</b>	<ul style="list-style-type: none"> <li>- Which alternatives are considered?</li> <li>- Describe the alternatives and how they are intended to be implemented</li> <li>- Consider the implementation time and possibilities for flexible solutions</li> </ul>
<b>Specification of impacts</b>	<ul style="list-style-type: none"> <li>- Identify and describe benefits and costs of each alternative</li> <li>- Quantify benefits and costs in the form of physical sizes</li> <li>- Value impacts in a monetized value where appropriate</li> <li>- Explain the utilized data sources, assumptions and methods</li> <li>- Explain the total uncertainty attached to the project</li> </ul>
<b>Compilation and assessment of the socioeconomic analysis</b>	<ul style="list-style-type: none"> <li>- Calculate socioeconomic profitability for each alternative</li> <li>- Consider the impacts that was not monetized</li> <li>- Conduct sensitivity analyses and scenario analyses</li> </ul>

- Consider whether it is possible to reduce the risks
- Account for distributional effects
- Make recommendations

### **3.1.3.1. Problem and purpose specification**

This step is made up of two main elements according to Finansdepartementet (2005). Firstly, an elaboration of the problem including a description of the current situation and development without measures in this area is given. In this section, a description of the background as well as the justification for the policy is explained (Finansdepartementet, 2005).

The zero alternative is also described in this first step, which can also be named “counterfactual” or “status quo” (Boardman et al., 2011). The zero alternative may involve “doing nothing”, but it may also include the costs and benefits that transpire as a result of keeping today’s situation operational in the future (NVE, 2003).

The second element within this step involves a clarification of the purpose of the policy and which goals that are aimed to accomplish (Finansdepartementet, 2005). Within this step, NVE (2003) suggests that all assumptions that may affect the results of the analysis are declared, such as the reference time period (start point for the analysis), physical life time and analytical period.

### **3.1.3.2. Specification of alternatives**

This step of a CBA is based on answering which alternatives or policies to be considered, together with a description of how they are planned executed (Finansdepartementet, 2005). The most critical phase of CBA is a methodical analysis of all relevant alternatives, which can involve alternatives with different physical measures or use of alternative instruments. Finansdepartementet (2005) write that “*a thorough job in this phase of the study is decisive for a good analysis*” (p. 14). It is advantageous to study as many alternatives as possible as a main

rule, however this might be very resource-intensive as there in principle are numerous alternatives to choose from (NVE, 2003).

Once all the alternatives are considered, descriptions of each of them are necessary. It must be clear at this phase what the alternatives or policies involve and how they can practically be achieved (Finansdepartementet, 2005). It is also important to assess whether alternatives with obvious limitations should be eliminated before they are analyzed further. Examples of limitations include budgetary, technical, temporal, legal, distributional or political constraints (Finansdepartementet, 2005).

This second stage of a CBA also involves answering whether the time of implementation can be changed, as well as the possibility for flexible solutions (Finansdepartementet, 2005). Mainly uncertainty about future benefits and costs may make it beneficial to postpone an alternative or implement it stepwise. This was discussed previously in this thesis as option value, refer to section 3.1.2.8.

### **3.1.3.3. Specification of impacts**

This stage involves identifying the physical impact categories of the proposed alternatives, catalogue them as benefits and costs, quantify these in the form of physical sizes and monetize these (Boardman et al., 2011, Finansdepartementet, 2005). “*The main reference in identifying costs and benefits is the Kaldor-Hicks efficiency standard*” (Nas, 1996; p. 60). Impacts may change depending on who has standing, so it is important at this stage firstly to identify and decide whose benefits and costs should be included in the analysis (Boardman et al., 2011). The standing can be either local, national or global, however most governments consider national benefits and costs (Boardman et al., 2011). The question is however relevant, especially when considering impacts that may be of global concern, such as environmental impacts.

The step of specifying the impacts involves various aspects, which Finansdepartementet (2005) divides into five subsections. These are: identify and describe benefits and costs of each alternative, quantify benefits and costs in the form of physical sizes, value impacts in a

monetized value where appropriate, explain the utilized data sources, assumptions and methods, explain the total uncertainty attached to the project. The three first elements are described in more detail next, where the author believes that descriptions of assumptions and uncertainties are self-explanatory and thus need no further elaboration.

- **Identify and describe benefits and costs of each alternative**

All the relevant effects from the proposed alternatives are at this phase described, with the null alternative as the starting point. The benefits and costs are expressed, including those that cannot be quantified in physical sizes or valued in Kroner (Finansdepartementet, 2005). The impacts that are to be evaluated can be divided into two main elements, as illustrated in the figure below:

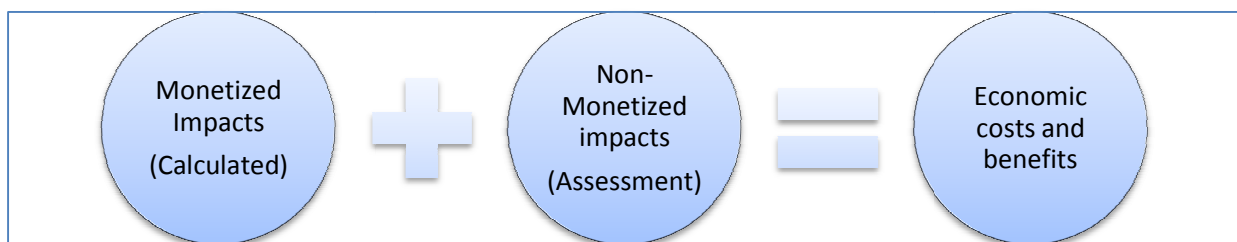


Figure 3-4: Cost and benefits in a CBA

The analyst is at this stage only interested in project costs and benefits that affects the utility or individuals with standing (Boardman et al., 2011). If possible, the affected groups should be specified and to what extent these are affected. This identification will allow the visualization of the distribution profile of the alternatives, which then will be useful when the distributional effects are to be specified (Finansdepartementet, 2005).

In order to treat something as an impact, the analyst must know that *“there is a cause-and-effect relationship between some physical outcome of the project and the utility of human beings with standing”* (Boardman et al. 2011; p. 8). Some impacts may have an obvious relationship between cause- and effect, while other may not be so apparent. This may make the demonstration of the cause-and-effect relationship difficult, and it often requires reviews of scientific and social science research.

- ***Quantify benefits and costs in the form of physical sizes***

A suitable unit for calculating the impacts are at this phase identified in physical sizes (Finansdepartementet, 2005). The choice of impact categories is dependent on “*data availability and ease of monetization*” (Boardman et al., 2011; p. 9).

The impacts are then as far as possible quantified in each time period for every alternative, which will be measured against the changes relative to the zero alternative or status quo (Finansdepartementet, 2005). Examples of physical sizes in energy projects are ton of emissions emitted, TWh of electricity delivered, reductions in transmission losses etc (NVE, 2003).

- ***Value effects in a monetized value where possible***

As discussed in the conceptual foundations of CBA earlier in this chapter, the main principle for valuing a positive effect is that the monetized value is equal to what the population is willing to pay to achieve it and the value of the resources used in the alternative, is equal the opportunity cost of these resources in its best possible application (Finansdepartementet, 2005). To monetize means to value in dollars (Boardman et al., 2011), or for the purposes of this thesis, monetization's are made in Norwegian Krone (NOK).

If the project is operating in a perfect market, these prices are equal to the market prices. Obtaining price information is thus easy for tangible elements, such as capital equipment, labor, and land (Nas, 1996). If market failures occur however, as discussed previous in this chapter, the market price cannot be used as a correct measure of benefits and costs in a CBA. Intangible elements of this kind are thus likely to misrepresent true market values (Nas, 1996). To obtain the true value of these goods, the willingness to pay for a certain good can be found through a variety of valuation techniques and methods (Finansdepartementet, 2005). If there is uncertainty attached to some of the quantifiable measures, Finansdepartementet (2005) recommends that expected value are used.

It is important to remember that changes in transfers that does not represent changes in the economic costs are not included in the analysis (Finansdepartementet, 2005). Transfers can be defined as reallocations of benefits or costs between different groups in the society.

#### **3.1.3.4. *Compilation and assessment of the socioeconomic analysis***

This stage of a cost-benefit analysis is important, as it compares the different impacts of each alternative and makes a final conclusion of the work. This step of CBA is six fold, and starts with a calculation of economic profitability for each alternative, then a consideration of the impacts that were not monetized, a sensitivity analysis must next be conducted before considerations whether it is possible to reduce some of these risks are made. Lastly, the stage involves accounting for distributional effects and making recommendations. These subsections are described to a greater extent next.

- ***Calculate socioeconomic benefit or costs for each alternative***

The NPV is used to compare and sum the benefits and costs measured in NOK that accrue each year, as recommended by the Finansdepartementet (2005). One key decision in this step is to choose the appropriate social discount rate. For some governmental funding, the discount rate is already mandated by a government agency with authority. NVE (2003) recommends using a discount rate of 4, 6 and 8 % respectively, se section 3.1.2.5 for a more detailed description of this topic.

- ***Assess effects that cannot be monetized***

In this section, the analyst is to give a systematic description of the effects that are not professionally or desirable to value in NOK (Finansdepartementet, 2005). Some environmental goods may be easier to value in physical sizes than monetize and some ethical dilemmas may be more suitable to discuss more theoretically than to monetize (Finansdepartementet, 2005).

- **Conduct sensitivity and scenario analyses**

There will always be some uncertainty present in a CBA in terms of the predicted impacts and the values assigned to them. The reason is that what seems reasonable today may turn out to be infeasible tomorrow, due to changes within production technology or priorities of public institutions (Nas, 1996). Another cause is that several assumptions are made in estimating costs and benefits in the analysis, such as externalities, the discount rate and the lifetime of the project (Nas, 1996). Boardman et al (2011) emphasize that the purpose of sensitivity analysis “is to acknowledge the underlying uncertainty” (p. 177). The goal will thus be to express how sensitive the predicted net benefits and costs are to changes in assumptions (Boardman et al., 2011). For example, the discount rate has some uncertainty related to it. If 4 % is chosen as the central case, 2% and 6% may be chosen as variations of the discount rate in the sensitivity analysis (Pearce et al., 2006). The main assumptions are varied based on judgment, literature survey or assigned probabilities using past data (Nas, 1996). There are however practical limits to the amount of sensitivity analysis that is feasible, as potentially every assumption in a CBA can be varied (Boardman et al., 2011). *“If the sign of the net benefits does not change, when we consider the range of reasonable assumptions, then our results are robust, and we can have greater confidence in them”* (Boardman et al., 2011; p. 177). After the sensitivity analysis have been carried out, the outcomes are then reported and possible areas of improvement are pointed out (Nas, 1996).

- **Consider whether it is possible to reduce the risks**

Although there will always be some uncertainty present in a CBA, the job of the analyst is to address whether some of these uncertainties may be reduced or eliminated completely. To avoid uncertainty and risks, Finansdepartementet (2005) suggests making decision such as:

- Avoiding irreversible decisions
- Conduct pilot studies
- Add flexibility measures at the start of the project
- Avoiding using untested technology in a large scale



- ***Account for the distributional effects of each alternative***

A socioeconomic analysis will always be concerned about who accrue the costs and benefits, and ask “who wins and who loses”. In true Pareto efficiency, there will be no winners and losers. CBA does however use the Kaldor-Hicks efficiency standard, which means that some will receive benefits and some will receive costs. The “who” can according to Pearce et al. (2006) be different income groups, ethnic groups, geographical located groups etc. It might also be relevant to consider whether the costs and benefits are allocated to businesses or private persons (Pearce et al., 2006). This section thus means that the analyst should describe the distributional effects of each alternative in detail, thus giving the decision maker the best possible framework for evaluating the project (Finansdepartementet, 2005).

- ***Make recommendations***

In this last section, the analyst will attempt to rank the various alternatives and suggest which alternative is the most economically feasible (Nas, 1996). Generally, the project with the largest NPV is recommended. There might however be factors that does not make this feasible, such as not being able to monetize important impacts of an alternative, a large number of uncertainty factors or other important reasons (Boardman et al., 2011). It is however important to stress that analysts “*make recommendations, not decisions*” and that “*CBA is only one input*” to the political decision-making process, focusing on efficient allocation of society’s resources (Boardman et al. 2011; p. 15).

## ***3.2. CBA applied in the energy sector***

Making socially optimal decisions is a key aspect when investing in the energy sector. A main reason for this is that electricity can be seen as a public good and thus needs to ensure reliability, sufficient capacity to meet the demand from customers as well as consider the externalities posed by development and operation of the network (Førsund, 2007). The management of energy in Norway is designed to allocate resources with respect to economic profitability (NVE, 2003). It is expected that the Norwegian Resource and Water Directorate (NVE)<sup>5</sup> as the management authority in the Norwegian energy sector, conducts assessment of investment alternatives that considers the impacts on society. In fact, the Norwegian energy law aims at balancing advantages and disadvantages in energy project and states that production, transformation, transmission and distribution of energy is conducted in a way that is economically rational, thus considering the interests of all public and private interests (OED, 2010). The authority has given out a handbook of how to perform CBA in this sector (NVE, 2003), mainly based on NOU (1997) and Finansdepartementet (2005). There are some key characteristics of this sector, which are of relevance to the case study in this thesis, thus consequently some key aspects of CBA within the energy sector is explored and described in this section of the chapter. The topics included are a description of the electricity sector, explanations of the key parameters in the sector relevant for CBA, practical implementation of CBA in the energy sector and a framework for measuring costs and benefits.

### ***3.2.1. Electricity sector***

Investment in the electricity sector includes activities within power grid, power production and end user consumption (NVE, 2003). This can be illustrated by a figure simply illustrating the electricity market and the industry structure, refer figure 3.5.

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<sup>5</sup> Norges Vassdrags- og Energidirektorat (NVE)

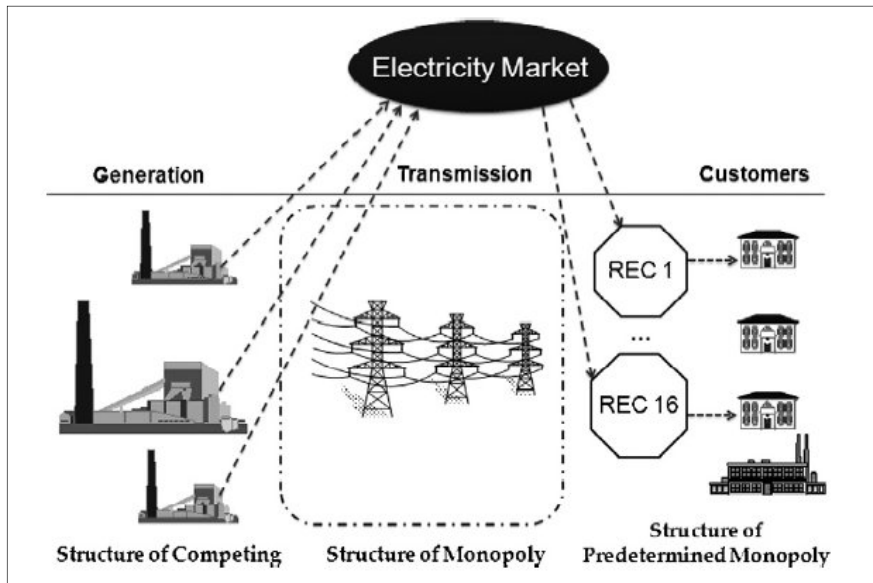


Figure 3-5: The Electricity Market (Khosroshari et al., 2009)

### 3.2.1.1. Electricity Market

Norway's electricity sector is integrated in the Nordic and European networks. The Norwegian electricity market is one of the most market driven in Europe and involvement from the government is still strong, in the form of public ownership and regulation (IEA, 2001). Below will be a brief description of the elements that constitutes the electricity market, including the policy and regulatory framework and the wholesale power exchange and trade.

- **Policy and regulatory framework**

The Energy Act of 1990 has provided the governmental framework for the reorganization of the power supply sector in Norway. The act has enabled competition within generation and trading of power and also allowed production and electricity prices to be fully determined by the market mechanisms (IEA, 2005). The aim of the act is according to IEA (2001; p. 59) as follows:

- *“Level the price of power in various regions*
- *Improve the efficiency of power production and grid operation*
- *Give consumers the correct signals to save energy*
- *Provide incentives for the optimal selection of investments according to profitability”*

Bye et al. (2010) further states in their report about the Norwegian power system that the goal of organizing energy in a market is to achieve economic optimal long-term development and short-term efficiency of the power system.

**The Ministry of Petroleum and Energy (MPE)**<sup>6</sup> has the overall administrative responsibility of the energy sector, and their main responsibilities in relation to the electricity sector are ensuring sound management of water and hydropower resources, from both an economic and environmental standpoint. The administrative powers under the Energy Act are largely delegated to the **Norwegian Water Resources and Energy Directorate (NVE)**, with responsibilities involving management of river systems that is coherent and environmentally sound, and promoting efficient electricity trading and energy use as well as cost-effective energy systems.

- ***Wholesale power exchange and trade***

#### **Wholesale power exchange**

Norway is part of the Nordic electricity market, which is a highly integrated system with a cross-border trade and a common power exchange named **Nord Pool**. The electricity market reform started with deregulation of the electricity market in Norway in 1991, and then subsequent expansions were made including Sweden, Finland and Denmark (Amundsen and Bergman, 2007). Today, Nord Pool has more than 350 participants in one or more of its markets, including producers, distribution companies, large industrial enterprises and other large units (NordPool, 2011a). Nord Pool organizes four market services, which are **Elsport** (spot market for physical contracts), **Elbas** (physical market for balance purposes), **Eltermin** (financial market) and **Eloptions** (clearing service).

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<sup>6</sup> Olje- og Energidepartementet

## **Trade**

Norway plays an integrated role in the regional electricity trade system within Northern Europe, and the flexibility which hydro capacity in particular provides, enables the Nordic market according to (IEA, 2005). Norway has a shifting role within the trade environment, from acting as a net exporter in wet years to a net importer in dry years. This flexibility is enabled through the low marginal cost of hydro generation (IEA, 2005). Norway has increasingly become a net importer of electricity in recent years however, as a result of growing domestic demand and limited development in new generating capacity. Trade in electricity has according to IEA (2005) *“brought efficiency and reliability benefits to Norway and the Nordic region including the deepening of wholesale competition, more efficient utilization of existing infrastructure enabling capital expenditure on new generating plants to be deferred, increasing the potential for efficient sharing of capacity reserves and facilitating greater use of imports to ensure reliable electricity supplies during dry years”* (p. 170).

## **Regulatory market**

Nord Pool has NVE as the regulatory authority. The system operator Statnett uses the regulatory market, in order *“to maintain a stable frequency and a continuous balance between production and consumption of power in the country”* (IEA, 2001; p. 74). To achieve this goal, Statnett will monitor and analyze the trade in the regulatory market to detect disparity between planned production and expected consumption. Special conditions will be prosecuted and reported to NVE, who are able to conduct measures to improve the situation (Statnett, 2009).

### 3.2.1.2. Generation

Up until beginning of the 1990s, Norway had a stable capacity in production capacity, since then however, there has been a halt in new generating developments combined with a growth in consumption (Statnett, 2005a). This has generated a shortage in production capacity, and Statnett write that we can expect to see considerable investments in the coming years (Statnett, 2005a). Energy produced in Norway is produced mostly from hydroelectric power, where gas power and thermal power also exists in smaller scales. Hydropower plants in Norway accounts for nearly 99% of total production in Norway, in a year with normal precipitation. At the beginning of 2008, 121.8 TWh power was produced from hydropower in a normal year (OED, 2008). Norway has further installed capacity of 385MW from wind power stations, 645MW from gas-fired power plants and 240MW from other thermal power plants<sup>7</sup>. From the ten largest power plants in Norway, hydropower accounts for nine of these (OED, 2008). Refer figure 3.6.

Power station	Power type	County	Max capacity MW	Mean annual production GWh/year
Kvilldal	Hydropower	Rogaland	1 240	3 517
Tonstad	Hydropower	Vest-Agder	960	4 169
Aurland I	Hydropower	Sogn og Fjordane	675	2 407
Saurdalm *	Hydropower	Rogaland	640	1 291
Sy-Sima	Hydropower	Hordaland	620	2 075
Rana	Hydropower	Nordland	500	2 123
Lang-Sima	Hydropower	Hordaland	500	1 329
Tokke	Hydropower	Telemark	430	2 221
Kårstø	Thermal power	Hordaland	420	3 400**
Tyin	Hydropower	Sogn og Fjordane	374	1 398

\* Pump-fed power station  
 \*\* For gas-fired power stations, the figure quoted is maximum production capacity (see the box on page 18)

Figure 3-6: The 10 largest power stations in Norway (OED, 2008)

<sup>7</sup> Thermal power plants: power stations that produce electricity from fossil fuels, biofuels or nuclear power

- **Hydropower**

Hydropower is the most important energy source for Norway. One can distinguish between small and large hydropower plants. **Small hydropower plants** comprise of facilities with installed capacity up to 10 MW. **Large hydropower plants** have capacity greater than 10 MW, and these are the most developed facilities in Norway. The Nordic system is a mixed hydropower and thermal power system, where in 2009 hydropower accounted for around 56%, thermal power 40% and wind power 3% (NordPool, 2011c).

Hydro production is highly constrained by water inflow, where reservoir capacity is the most important costs factor due to the need for huge reservoirs (Midttun, 1998), and variations in output are dictated by fluctuations in the level of precipitation. The majority of hydro stations are located in the western and northern parts of Norway, while the principal markets are in the south-eastern Norway. “[..... *Consequently, transmission lines are long and have to cross wide fjords and mountains*” (IEA, 2001; p. 61).

#### **Development potential**

New hydropower capacity is going to be restricted to relatively small developments, as most of the hydropower resources has already been developed and most of the remaining resources are protected against development (IEA, 2001). The below figure demonstrate Norway’s hydropower potential (2008), which clearly illustrate the share of developed and protected resources.

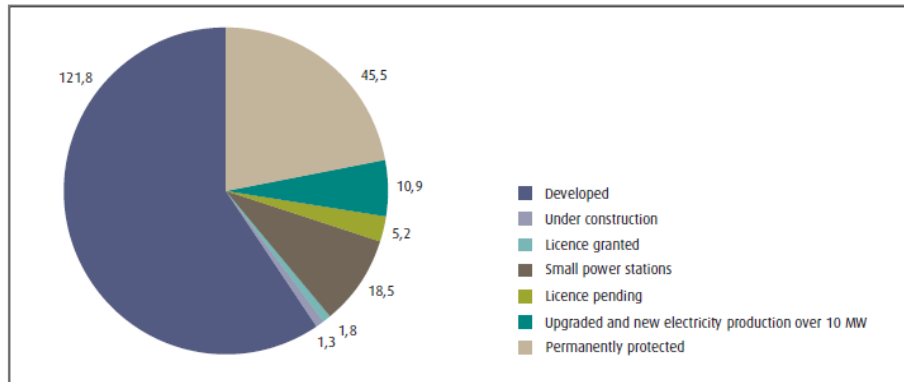


Figure 3-7: Norway's hydropower potential (OED, 2008)

- **Wind power**

Wind power in Norway has historically not been extensively developed, which can be seen in light of the country's reliance on hydropower. With the decreased potential for developing hydropower, wind power has become increasingly interesting for electricity production. At the end of 2007, installed wind power capacity in Norway was 385 MW with a total production of 899 GWh (OED, 2008). More capacity have been added after this, as NVE awarded licenses to 18 new projects with a combined installation of around 1400 MW in 2008 (OED, 2008).

#### Development potential

Wind power technology has developed in recent years and thus increased unit performance according to OED (2008). Wind mills have in that sense become more efficient, and the production costs are estimated to be between NOK 0.45 and 0.60/ kWh at sites with good wind conditions and moderate construction costs (OED, 2008). In the current market environment however, wind power development is not considered commercially viable without some form of financial support (IEA, 2001). The government has however put increased emphasis on developing renewable energy such as wind power, e.g. report no. 29 (1998-1999) to the Storting on Norwegian energy policy set a target of building wind power stations with a generating capacity of 3TWh by 2010 (OED, 2008). Refer section 3.2.2.4 of this thesis for a description of the political instruments to motivate investments in wind power.



- ***Gas-fired power***

Gas-fired power is a general description of all production of electricity and/or heat, that uses natural gas (OED, 2008). Gas-fired power production in mainland Norway is only developed in a small extent. NOU (1998b) write that the only gas-fired power facility without pure emergency aggregates is a 35MW gas turbine facility at Kårstø. Another gas-power facility is located at Melkøya in connection to development of the “Snøhvit” field. Gas turbines are more widely used in the petroleum operations at the continental shelf however, both for engine operation and power production (NOU, 1998b).

#### **Development potential**

The most appropriate energy source for power production in Norway is natural gas, when comparing it against other fossil fuels according to NOU (1998b). Gas power has low emissions of  $CO_2$  compared to coal power, and it also is competitive in the current European market.

One large limitation is however that there is not a political agreement with regards to developing new gas-fired power plants. The current government is opposed to building new gas-power, which does not possess technology that can capture and store  $CO_2$  (CCS). There is however disagreements in regards to these CCS requirements, where supporters of gas power argue that Norwegian production will reduce the total Nordic emissions of  $CO_2$ , especially when Norway is increasingly becoming a net importer of electricity (NOU, 1998b). Opponents argue that building new gas-fired power plants will contribute to global emissions and that the gas can be utilized in a more environmental sense in other countries and for other purposes. One of the main reasons why gas-fired power has aroused so much opposition is that the current power production based on hydropower is practically free of emissions, and thus gas-fired power production would increase the national  $CO_2$  emissions significantly (NOU, 1998b). Another main limitation of developing gas power in Norway is that it is not commercially profitable under the current operational and political conditions (Hervik et al., 2011a).

- **Ownership**

Most of the generation capacity within electricity in Norway has not been privatized as a result of liberalization, which is evident as local authorities and country councils own more than 50 % of the production capacity (Regjeringen, 2007). The central government, through Statkraft AS, has a share of around 30% and only 13% is owned by private companies (IEA, 2001). The ten largest production companies in the country accounts for almost 70 % of the total mean production, and about the same proportion of installed capacity (Regjeringen, 2007).

### **3.2.1.3. Transmission**

The legal basis for regulation of grid management and operation is provided by The Energy Act (IEA, 2001). *“The objectives are to control monopoly operations to safeguard consumer rights, and to ensure efficient development of the grid”* (IEA, 2001; p. 64). This section of the paper will consequently describe Norway’s infrastructure characteristics, the system operation, network pricing and regulation as well as developments of the power grid.

- **Infrastructure**

Production and consumption of electricity is linked together through the power grid, which consists of power lines, cables, transformers and various other components (Bye et al., 2010). The electricity grid is split into three levels, namely the main or central grid, the regional grid and the distribution network. The **central grid** is nationwide, as well as comprising of foreign connections that open up import and export possibilities. The voltage in the central grid consist of mostly lines and cables with 420 and 300 kV, and some 132 kV lines (Bye et al., 2010). The **regional grid** connects the central grid and the distribution grid, while the **distribution grid** brings power to the end-consumers. This grid consists of a medium voltage distribution network (11 and 22 kV) as well as a low voltage distribution grid (230 and 400 V). The total extension of the Norwegian power grid is approximately 330 000 km (Bye et al., 2010). The primary role of the transmission network is to ensure that consumers at their locations are supplied with power produced by generators, typically located at different geographical patterns (Førsund, 2007).

Refer figure 3.5 for an overview of the main transmission lines and interconnectors in Norway as well as important “cross-sections”<sup>8</sup>.

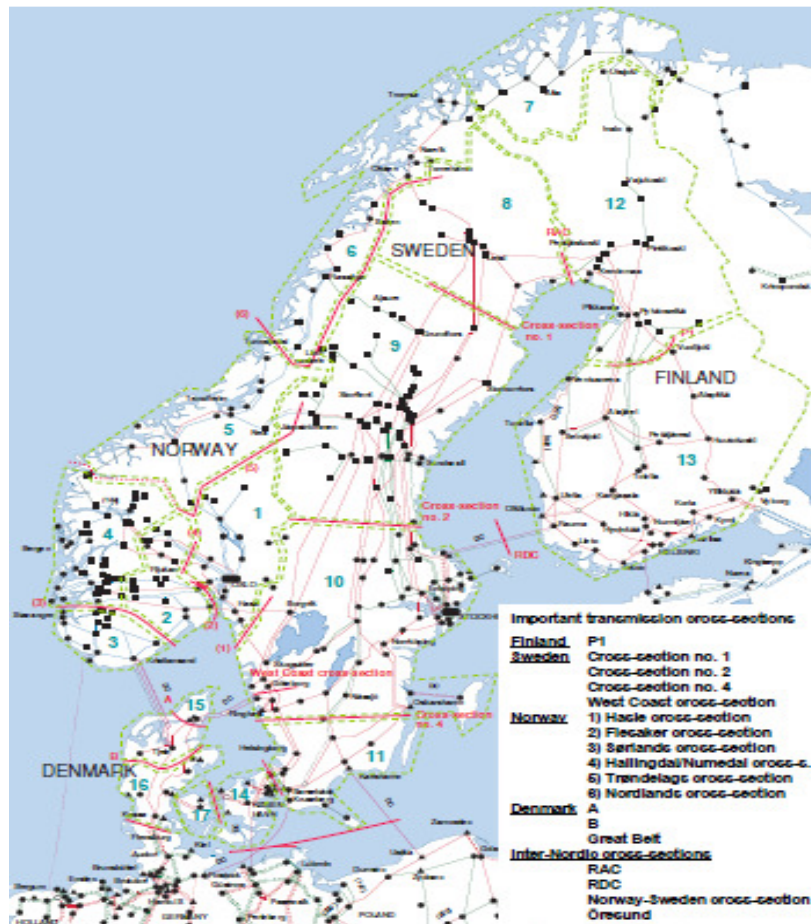


Figure 3-8: Norwegian Transmission Network (Nordel as seen in Bye et al., 2010)

- **System operation**

Statnett is the Norwegian Transmission System Operator (TSO) of the electric power system. The role of Statnett is to facilitate a well-functioning power market, where all players have access. A well-functioning market means that power supply is reliable and secure. An important

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<sup>8</sup> Cross-section is the name of transfers between large geographical areas, such as West- and East of Norway. The cross-section will normally consist of two or more power lines which will partly go in parallel. The term is called “Snitt” in Norwegian.

part of Statnett's responsibilities is thus to maintain the security of electricity supply, which presupposes secure access of energy, sufficient effect (capacity) as well as reliable components and facilities. Refer section 3.2.2.1 for a thorough discussion of the concept of supply security. Another relevant responsibility for Statnett is to manage congestion and long-term bottlenecks in the transmission network, which will be discussed further below.

### **Congestion management**

Bottlenecks within the transmission system, both domestically and internationally, are managed through a combination of regional price setting and countertrading (IEA, 2005). **Price areas** are formed when supply is not able to meet demand in a region, and this mechanism will be used to reduce the demand for electricity in a limited geographical area. The price difference between the price areas represents the "congestion rent". **Countertrading** is used to deal with intra-regional congestion, "*which involves Statnett paying generators to increase or reduce output in order to balance the regional market*" (IEA, 2005; p. 154/155). The additional costs resulting from countertrading are borne by Statnett, and should act as a financial signal to pursue investments in order to eliminate regional and intra-regional congestion.

### **Establishment of Elspot areas**

The TSO should create Elspot areas in order to deal with bottlenecks in the regional- and central grid. There are in principle two main reasons for creating Elspot areas according to Bye et al. (2010), which are "long and lasting bottlenecks" and "energy shortage in a limited geographical area". The creation of distinct areas does not in principle create different price areas, however price differences occur when the transmission capacity between areas limits the flow of energy between these regions. In the beginning of 2010, Statnett created two new price areas, as a result of bottlenecks and energy shortage. Before this, Norway has generally been divided into three main Elspot areas, however new Elspot areas indicate a situation of harder utilization of the transmission network with a lack of investments into new transmission capacity (Bye et al., 2010).

- **Network pricing and regulation**

The Energy Act requires the grid owner to make transmission and distribution services available to all participants in the market, including the same access conditions (IEA, 2005). Discrimination between grid customers are thus not acceptable, and consequently tariffs are set throughout the grid in a system known as point tariffs (IEA, 2005). NVE provides the regulation framework for operators of the transmission and distribution grid, and involve developing and charging income caps as well as setting a framework for overall network pricing. These two main concepts are described next.

#### **Income caps**

NVE is responsible for regulating the activities of network operators and they determine company specific income caps to ensure efficient development of the grid and reasonable charges for customer. These income caps are set for a minimum of five years and are reduced each year by 1, 5% on the basis of a general efficiency requirement as well as an individual efficiency requirement between 0% and 5, 2%. *“The efficiency requirements do not make it obligatory for the companies to become more efficient, but their rate of return rises if they can reduce their costs”* (IEA, 2005; p. 156). The income cap system acts as an incentive for reliable delivery of transmission and distribution services, through a mechanism that “punishes” interruptions with a reduction in revenues.

#### **Network pricing**

All customers that are connected to a grid pay a charge called point tariff, which is for the electricity fed into or tapped from the grid (IEA, 2005). This charge is meant to encourage efficient utilization and development of the grid. The charge paid by the customers goes proportionally to the central grid and the regional grid. The charges for the distributional grid is normally higher than for the regional or central grid, reflecting cost differences of operating these networks. These charges are fourfold and include the transmission tariff, an energy charge, a capacity charge and a fixed charge (IEA, 2005). The **energy charge** is variable and reflects the quantity of energy that is fed into or drawn from the network. The **capacity charge** is based on the difference between the regional and Nordic system marginal spot price, which occurs when

spate price zones are formatted as a result of congestion. The **fixed charge** is not dependent on the amount of electricity that is tapped from the grid and thus network companies will normally charge the same amount in the input tariff as the central grid.

#### **3.2.1.4. Customers**

Customers or end-user can be defined as anyone who buys electricity for their own use. Small and private users normally buy electricity via an intermediary such as a trading company or a distribution utility, while larger end-users often buy directly in the wholesale market (IEA, 2001). All end users are free to choose which electricity supplier they wish to use.

- **Retail prices**

The total electricity price for end-consumer consists of the wholesale price of electricity, network charges and taxes (IEA, 2005). The charges faced by households are considerably higher than industrial prices according to IEA (2005); this is mainly a reflection of the additional costs of distribution charges. Household consumers can choose between various types of contracts for electricity. The most common is based on a variable price, another type is based on fixed price contracts and the third type of contract is based on the spot price movements with a fixed retailer margin (IEA, 2005). Industrial consumers, especially within energy-intensive industry, often have long-term contracts with Statkraft on terms fixed by the Storting<sup>9</sup>. These agreements will however expire by 2012. The sector also meets its requirements from its own power plants' long-term commercial contracts and purchases on the spot market (IEA, 2005).

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<sup>9</sup> The Norwegian Parliament

### ***3.2.2. Key parameters in the electricity sector***

Parameters such as security of supply, system-technical effects and a well functioning market, dependability in the network and impacts on the environment all influence the investment decision in the electricity sector. These parameters are thus fundamental in the cost-benefit analysis. Balancing these constraints is not an easy task, however necessary to achieve economic development in the energy sector. These main elements will accordingly be discussed more in detail, as to demonstrate how they impact on CBA within the energy sector.

#### ***3.2.2.1. Security of energy supply***

- ***Definition and importance***

Security of energy supply can be defined as a continuous availability of energy, in sufficient quantities and at reasonable prices (Balat, 2010). Supply security has physical, economic, social and environmental aspects or risks according to Costantini et al. (2007). **Physical** disruptions can arise when an energy source is exhausted or production is stopped, either temporarily or permanently (Costantini et al., 2007). This system failure may occur as a result of weather conditions, lack of capital investment or generally poor conditions of the energy system (Egenhofer, 2004). **Economic** disruptions originate when there are erratic fluctuations on the world markets in the price of energy products (Costantini et al., 2007). Fluctuation can be caused by for example a threat of a physical disruption of suppliers, or anticipation of such disruptions, as well as lack of investment or insufficient contracting (Egenhofer, 2004). Instability of energy supplies may further cause severe **social** disruptions. This is due to the demand and dependability for energy in today's society, where instability will have a large impact on both private and commercial interest (Costantini et al., 2007). The last element in the definition, **environmental** disruptions, is concerned with the damage to the ecosystems caused by the energy chain.

One can further distinguish between short-term and long-term energy security. The former is concerned with disruptions and mitigation of these or rises in prices. Long-term security consider the energy system as a whole, and as such the causes of disruptions together with the availability of sufficient energy to allow stable and economic development (Kruyt et al., 2009, Costantini et al., 2007).

The past couple of years have shifted the focus from cost efficiency to supply security in the power system (Statnett, 2005a). The reason can be seen as a result of the recent supply disruptions in Europe, which highlighted the importance of supply security and as such brought forward a political debate about the causes and risks and how to overcome these. These disruptions was caused by for example grid failure, a lack of reserve capacity or oil product shortages as a result of refinery blockages (Egenhofer, 2004). There are various well-known examples of countries that have experienced blackouts, the Californian Power Crisis, transitory electricity shortages in the Nordic power market in the winter of 2000 and the power failures that arose in many parts of Europe as a result of the heavy storms around Christmas 1999 (Egenhofer and Legge, 2001). The Californian power crisis was in part due to mishandled regulation, while in the Nordic region, lack of peak capacity was the root and in France the vulnerabilities of a centralized power system was the source of the power cuts (Egenhofer and Legge, 2001). In Norway, the biggest challenge to supply security is the big variations in precipitation and the ability of the power system to deal with this (Statnett, 2005a). The winter of 2002/2003<sup>10</sup> put further forward the political debate in Norway as to the importance of supply security (IEA, 2005).

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<sup>10</sup> This winter was characterized by extremely low reservoir levels (a 70 year low) as a result of an extremely dry autumn coupled with very low winter temperatures. This particularly unusual combination put the market under extreme pressure, threatening supply security. Estimates published by the Norwegian Ministry of Petroleum and Energy suggest that this combination of conditions is only likely to occur once every 100 to 200 years in Norway.



- **Network and supply security**

Network infrastructure is essential to deliver energy supplies to customers. Electric power infrastructures have in Norway and other parts of the world been forced to operate almost at their full capacities due to the environmental and/ or economic constraints to build new generating plants and transmission lines. Bye et al (2008) report that decreasing investments in new capacity increases the vulnerability as excess capacity in normal inflow situations has vanished. Such events of energy shortages have raised concerns about security of supply (Bye et al., 2010). It is the transmission system operators (TSO) that are responsible for the safe and efficient operation of the transmission grid, which involves ancillary services, balancing the market as well as facilitating the spot market (Egenhofer and Legge, 2001). Also the long-term development of the transmission grid is a key task, which must be enforced by government through obligations and incentives in an appropriate regulatory framework (Egenhofer and Legge, 2001). A general approach could entail making TSOs liable for non-delivery (Egenhofer and Legge, 2001), which is in place in Norway and based on the KILE costs (which will be discussed later in this section). A key concern in grid development is to assess to what degree the society is prepared to accept outages. Traditionally, grid planning and load limitations have been based on the **N-1 criterion**, which means that “*a system must be able to tolerate the breakdown of one component without causing an outage in the electricity supply*” (Statnett, 2005; p. 7).

### **3.2.2.2. Consequences of supply interruptions**

There is a consensus within the literature that the costs of supply disruptions go beyond the economic measures of national accounts. The reason is that “*energy use pervades daily life in such a constant and ubiquitous way that it is very difficult to distinguish among all the short- and long-term negative effects*” (Costantini and Gracceva, 2004; p. 1). Supply interruptions can be separated into either short-term, medium-term or long-term, where the subsequent consequences will often be highest for long-interruptions, however less likely to occur (Costantini et al., 2007).

Various studies have attempted to identify the consequences of disruptions and the values that society places on these. There is no consensus on valuating supply interruptions, and one important constraint is that the consequences differ depending on the situation. de Nooij et al. (2007) report that there may be reasons why the consequences of one supply interruption differ from the consequences of others, which will be summarized in the table below.

**Table 3-3: Consequences of supply interruptions (de Nooij et al., 2007)**

<b>There are different types of electricity users</b>	Interruptions in hospitals, industrial plants and private households have very different consequences.
<b>The perceived reliability level</b>	“The vulnerability conflict”: the higher the perceived reliability, the less firms and households are inclined to take precautionary measures, and thus the greater the damage caused by the interruption.
<b>The moment when the interruption occurs</b>	The season, the day of the week and the time of day determine which activities are interrupted.
<b>The length of the disruption</b>	The length determines the costs. Some damage will occur instantaneously (e.g. loss of computer files), some are proportional to the length of the disruption (e.g. loss of working hours, while other starts only after a while (e.g. spoilage of food in refrigerators).
<b>Whether notification of the interruption was given</b>	A notification before an interruption lowers the consequences of that interruption.
<b>Whether the disruption is structural or incidental</b>	The effects if interruptions are smaller when it is structural, as people prepare more when they are interrupted regularly, even though they are not warned beforehand.
<b>The source of the outage</b>	If the outage is caused by a failure in the network, the price effects will mostly be small, whereas if the outage is caused by the fact that the production capacity is smaller than the demand, prices tend to rise strongly.

### 3.2.2.3. Measuring supply security

Many individuals in society considers supply security of power to be very important, however the value that society place on it is not a certain factor. Normally this information could be derived from a market, though there is no market in which power-supply interruptions are traded (de Nooij et al., 2007). As improvements in supply security will come at a cost, these costs must consequently be paid by the society according to Damigos et al. (2009), “*either through increased electricity bills or through public financing*” (p. 2008). These investments must therefore be based on CBA principles such as non-market costs and benefits, i.e. the value placed on interruptions avoided by the consumers (Damigos et al., 2009).

In the lack of a market to determine the costs of supply interruptions, economists and academics have developed several methods for calculating the effects of a supply disruption (Billinton et al., 1993). These might be surveys and interviews (stated preferences), the production-function approach, market behavior (revealed preferences) and case studies (de Nooij et al., 2007). Hofmann et al. (2010) makes a classification of different types of costs associated with quality problems in electricity supply, which includes total socio-economic costs, private customer costs and costs to the rest of society. Figure 3.9 is from this study.

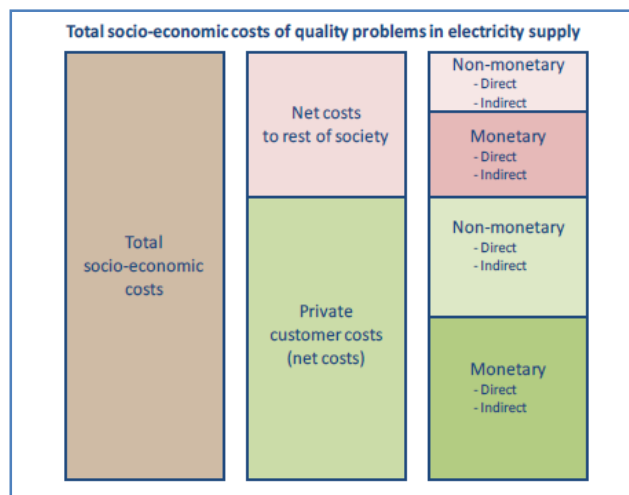


Figure 3-9: Categorization of different cost terms relating to supply security (Hofmann et al., 2010)

- **KILE-rates**

The **KILE-rates** used in Norway to measure supply quality represents the costs associated with disruption to end-consumers or what can be called the *priced-effects* in a CBA (Hervik et al., 2011a). These charges are calculated based on the estimated costs of hypothetical commotion to end-users as well as their willingness to pay to avoid disruptions, normalized with interrupted power effects (Sintef, 2011). The KILE-rates does however not catch up the entire impacts of supply security, this is especially the case for direct and indirect costs on society (Sintef, 2011). These are the *non-priced* effects that need to be also included in a CBA. Examples are spillover effects and consequential costs as a result of effects on other infrastructure services due to disruptions or that larger geographical areas are affected simultaneously. Adapting the cost figure from Hofmann et al. (2010), the KILE costs measures the indicated costs:

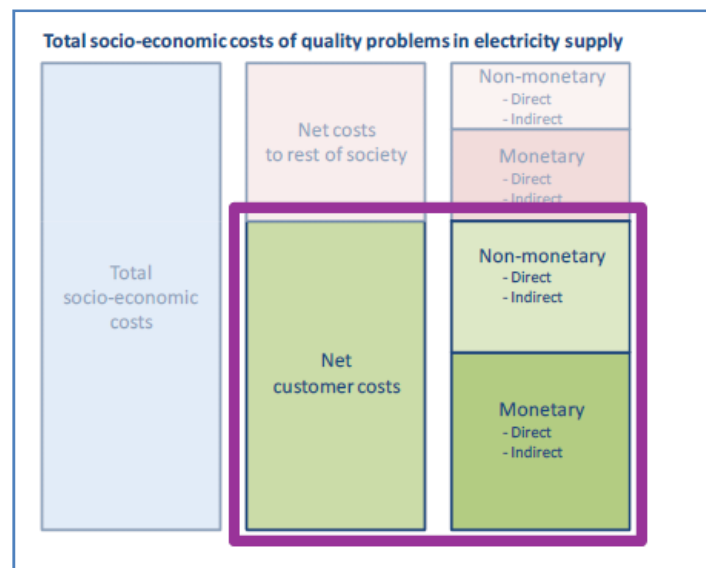


Figure 3-10: What costs the KILE-rates cover (Sintef, 2011)

#### **3.2.2.4. System-technical effects and a well functioning market**

It is important to consider in a CBA how investments into the energy sector impacts flexibility in relation to other developments, investments and plans (Hervik et al., 2011a). In this context, system technical effects as well as a well-functioning market are important parameters according to Hervik et al. (2011).

- **System technical effects**

The system technical effects involve the plans for new developments within production that requires grid connection, the age of the transmission network as well as planned investments into the transmission network within and outside the country (Hervik et al., 2011a). These parameters are interlinked with the political goals of the country. Norway has had an increased focus on supply security as well as sustainability in their energy politics. The main goals of the government which are relevant to the analysis in chapter 4 can be summarized as follows:

- The Norwegian government's climate politic objective is to reduce national greenhouse gas emissions. This is reflected in Norway's commitment to the **Kyoto protocol**, which requires Norway to reduce its greenhouse gas emissions (IEA, 2001). In the period 2008-2012, Norway decided to exceed the previous goal and reduce national emissions with further 10%.
- The government is actively involved in developing future-oriented technologies for **CO<sub>2</sub> management**. Norwegian projects will thus focus on capture and storage of CO<sub>2</sub>, and one important project in that sense is the project at Mongstad. The main goal at Mongstad is to develop knowledge and possible technologies for capture, storage and transport of CO<sub>2</sub>, which in the future can become a full-scale facility.

- The government targets the development of renewable energy, through the “green certificate”<sup>11</sup> agreement with Sweden. **Green certificates** will provide extra payment to the generators of new renewable energy, in addition to the value of the electricity itself, which primarily will consist of wind power and small hydropower plants (Statnett, 2005a). A certificate scheme will thus give an economic advantage to renewable energy, as non-renewable energy producers will be faced with tax charges linked to pollution (Statnett, 2005a). The scheme means that substantial investments need to be made into the central grid and thus also needs to see investment in new electricity production on context with the need for new grid investment (Statnett, 2005a).
  
- A central element in the government’s energy politic is to streamline and limit the energy usage. Norway has the highest electricity consumption per inhabitant in the world, as a result of power intensive industries and a high utilization of electricity for heating. One action to achieve this goal was to create **Enova**, a governmental agency motivating sustainable energy usage and production. Enova manages the energy fond, and their main goals are to reward:
  - Effective use of energy
  - Increased use of renewable sources
  - A well-functioning market for effective and environmentally friendly solutions
  - Increased knowledge in society for effective and environmentally sound energy practices
  
- NVE announced in 2007 a full rollout of **advanced metering systems (AMS)** for all end user, which will allow for a more thorough and correct information about the consumers own electricity consumption (OED, 2008). Full implementation of AMS has not been achieved; however the government is working on this goal as part of their energy efficiency measures and NVE reports a suitable time-horizon for full rollout would be around 2013 (OED, 2008).

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<sup>11</sup> Norway and Sweden signed an understanding in September 2009, establishing the principles for further development of common renewable energy in electricity generation as from 2012

- **Well-functioning market**

A well-functioning market can be characterized as a market where there is balance between the power supplied to the power grid and the demand for power (OED, 2008). Domestic power balance is defined as “*the relationship between production and total consumption of power*” (OED, 2010; p. 22). One of the reasons why the electricity market was deregulated according to OED (2008) was to achieve this balance through increasing efficiency in the electricity market, increase efficiency in the distribution and transmission sector and increase efficiency in capacity expansion. To achieve a well-functioning market, the most important mechanism is the price. The reason for this is that:

- Prices give correct investment signals for all types of investments within consumption, production and the power grid (Hervik et al., 2011a).
- Prices and distinct Elspot areas communicate more correct price signals to the market, which reflects the physical scarcity of energy or long-term bottlenecks in the transmission network (Bye et al., 2010)

Although prices may assist in creating a well-functioning market, investments considered in a CBA must also consider how a project may influence regional price differences, other parts of the energy system and implementation time. Consequently regional differences in prices, network and dependability and time is shortly described next.

#### **Regional differences in prices**

The current Norwegian market operates with five price areas. There are two main reasons why Elspot areas are created, firstly due to “long and lasting bottlenecks” and “energy shortage in a limited geographical area” (Bye et al., 2010). As discussed earlier in this thesis, long-term bottlenecks may lead to price differences in these price regions. Hervik et al. (2011) write that long-term differences in electricity prices may lead to distributional consequences and create a competitive disadvantage for businesses in regions with higher prices.

### **Network and dependability**

The energy system is network based, which means that what occurs in one part of the system will affect other parts. This has also implications on the economic profitability of a project, as this might be dependent on the existence of other projects within the network (NVE, 2003). There can in principle be infinite dependence relationships between different measures and projects within the energy system, where the profitability in each alternative may depend not only on which other projects that will be carried out, as well as the order in which they are conducted (NVE, 2003).

#### **3.2.2.5. Environmental effects**

Environmental costs is an important part of an economic analysis, and specially within the energy sector (NVE, 2003). NVE (2003) suggest including environmental impacts in the form of *natural intrusion, aesthetics and emissions*. Different energy projects carry varying impacts on the environment. Production of fossil and gas energy is mostly connected to emission costs, while projects within lines, cables and water and wind production are mainly associated with natural impacts and aesthetics (NVE, 2003). It is not obvious which environmental impacts that is least desirable.

NVE does however not find that there are sufficient robust estimates of environmental costs that can be used in their analyses. This is mainly due to the lack of studies of environmental costs to be able to generalize. This means that only environmental effects that can be valued in NOK can be included in the CBA. Non-valuable effects to the environment, must be treated on the “outside” of the pure calculations, either in terms of indexes or through a qualitative assessment or description (NVE, 2003). Although there are currently a lack of generalized costs in the Norwegian energy sector, the impacts on the environment in the form of natural destruction or aesthetics can in theory be valued in several ways. One way is to use some of the methods describes earlier in this section, including revealed and stated preference methods. NVE (2003) also suggests that the Life Cycle Assessment (LCA) method may be appropriate.



This section will be dedicated to show the relevant studies concerning environmental valuation in the Norwegian energy sector. It will first give an overview of the findings of these studies, before a more detailed description is given about the studies that attempt to elicit information about willingness to pay to avoid the aesthetic effects of transmission lines. As the thesis will use a more qualitative description of the environmental impacts, Statens Vegvesen's valuation method will be described last.

- **Relevant studies of environmental valuation in the Norwegian energy sector**

Several studies have attempted to value environmental goods in the energy sector, and these can be divided into either environmental costs from water power, wind power, network measures or emissions (NVE, 2003). The relevant costs that have been identified from these valuation studies will be summarized here, as they may be of relevance for analysis of the Geiranger Case in the next chapter. The following table is based on the information provided in NVE (2003), with additions where necessary, and lists the present studies of environmental costs, and the estimates these provide.

**Table 3-4: Summary of studies on environmental costs in the Norwegian energy sector**

	<b>Water Power</b>	<b>Wind Power</b>	<b>Network measures</b>	<b>Emissions (<math>CO_2</math>)**</b>
<b>Studies transferable to the Norwegian energy sector</b>	Navrud et al. (2003)	ExternE Project (EU)	Gurholt (1998) – pilot study for Navrud Navrud (2002) (Magnussen and Navrud, 1995)	SFT Navrud TØI Cicero Extern E Project
<b>Current cost estimates</b>	1,9-5,0 øre*/kWh	0,4-2 øre/kWh	Willingness to pay per household (1km) to avoid a power line: 700-1400 NOK/ year	30 – 1100 NOK/ ton

\* 1 NOK = 100 øre

\*\* Only  $CO_2$  costs included in this table, although these studies also show the environmental costs of  $CH_4$ ,  $N_2O$ ,  $CF_4$ ,  $C_2F_6$ ,  $SF_6$  and HFK - 134a.

- ***Willingness to pay to avoid the aesthetic effects of transmission lines***

In an international setting, there are some studies that have investigated the environmental impacts of high voltage transmission lines. The techniques used in these studies are mainly hedonic pricing and contingent valuation (survey methods described in section 3.1.2.7). The findings from these studies suggests that there is a negative effect of transmission lines on property values as well as a positive WTP to avoid these impacts (Giaccaria et al., 2010). Consensuses on the monetary value of these are however not reached. Refer appendix 1 for a summary of the previous monetary valuations of transmission lines externalities from international studies. None of the monetary values indentified in these studies are however transferrable to CBA studies conducted in Norway, as the characteristics are not similar.

In the Norwegian setting, there are a couple of studies that attempt to reveal WTP to avoid the aesthetic effects of transmission lines. Refer table 3.4 above for a list of these studies. Two other studies were discussed in the report by the expert committee to the government in February this year (Hervik et al., 2011), and these will briefly be summarized here. The first one is by **Navrud (2008)** and the study considered whether the increased costs of cable instead of overhead transmission lines can be socioeconomic feasible. To answer this imperative question, the authors used CV to elicit household's willingness to pay for the added costs, in terms of increased electricity bills. The study found that people in general was willing to pay something to have some or all of the power line buried as a cable, in fact a total of 76,8% of the 538 answered this. This is further affirmed by the study, which found that the WTP per household varies from around 500-1999 NOK per year for the whole stretch of the power line. Another important finding in this study is that people who live close to the power lines, suggests that underground cables are more preferable to overhead transmission lines, especially when the question is whether to build new lines or not. The second study was by **Magnussen et al. (2009)**, which used the CV method to map the environmental impact of a power line in the county of Trøndelag (Hervik et al., 2011a). This study valued aesthetic effects of power lines going trough natural areas outside densely populated areas. Magnussen et al. concluded that the WTP to avoid the aesthetic effects of transmission lines going through a mix of landscape types is around 1000 NOK per household each year.

Although all the Norwegian studies have found a positive WTP to avoid the aesthetic effects of transmission lines, these monetary values may not be appropriate to transfer to other Norwegian CBA studies (Hervik et al., 2011a). New studies with more accurate estimates are needed to be able to conduct benefit-transfer of these estimates<sup>12</sup>. The reason is that consumer preferences may have changed since the study was conducted and there may be different characteristics of the environmental good that is being valued (Hervik et al., 2011a). These uncertainties come in addition to the uncertainties present in the original studies. Even though the monetized values cannot be transferred to the Geiranger case in chapter 4, the studies give an indication of the size of the economic value of avoiding the aesthetic effects of overhead transmission lines by households.

- ***Statens Vegvesen's valuation method of environmental goods***

As the monetary estimates from the studies described above is not transferrable to other studies, a more qualitative approach is necessary to evaluate the environmental effects of transmission lines and other investment alternatives in the energy sector. Neither Finansdepartementet (2005) nor NVE (2003) has developed a framework for valuing-non-market goods. Statens Vegvesen<sup>13</sup> has however developed such a structure in their handbook for impact assessments, which will briefly be described in this section.

Statens Vegvesen separates non-priced or external effects into five separate subjects, including landscape, community and recreation, natural environment, cultural heritage and natural resources (SV, 2006). Each of these is analyzed in terms of three criteria which are central in the framework developed by Statens Vegvesen. These are value, scope and impact and will consequently be discussed next.

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<sup>12</sup> Refer appendix 1 in Hervik et al. (2011) for a detailed description of the studies presented in this section and the explanations of benefit-transfer

<sup>13</sup> The Norwegian Public Road Administrator

## Value

Value is a term that is meant to describe how valuable an area or environment is. The criteria for valuation for each subject are set on a gliding scale from a small to a large value. The assessment is then shown on a figure where the value is marked with an arrow, refer figure 3.11 below. The criteria for valuation coordinated, which means that a value for one subject is comparable to the same value for another subject. After placing the value of a subject on the scale, the valuations are then justified.

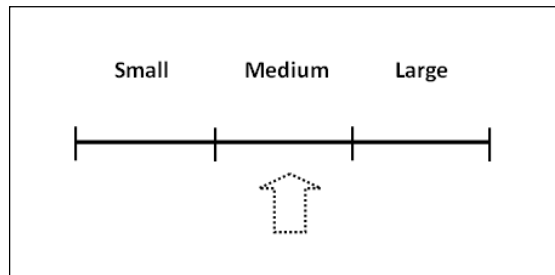


Figure 3-11: Valuation criteria (Modified after SV, 2006)

## Scope

The term scope means a valuation of which changes and the degree of these the project is assumed to lead to for the different subjects. The scope of the project is compares against the zero alternative in the CBA and is set on a scale ranging from large negative, medium negative, small/none, medium positive and large positive. As with the valuation above, the scope of the project is marked on a gliding scale, as illustrated in the figure below. A justification for the evaluations for each subject is then subsequently made.

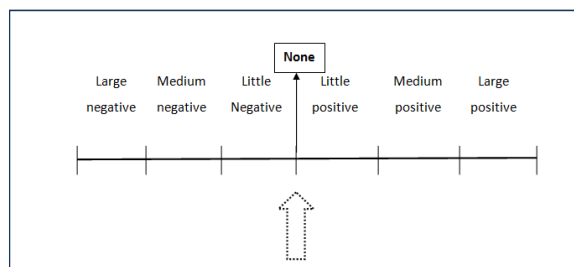


Figure 3-12: Scope criteria (Modified after SV, 2006)

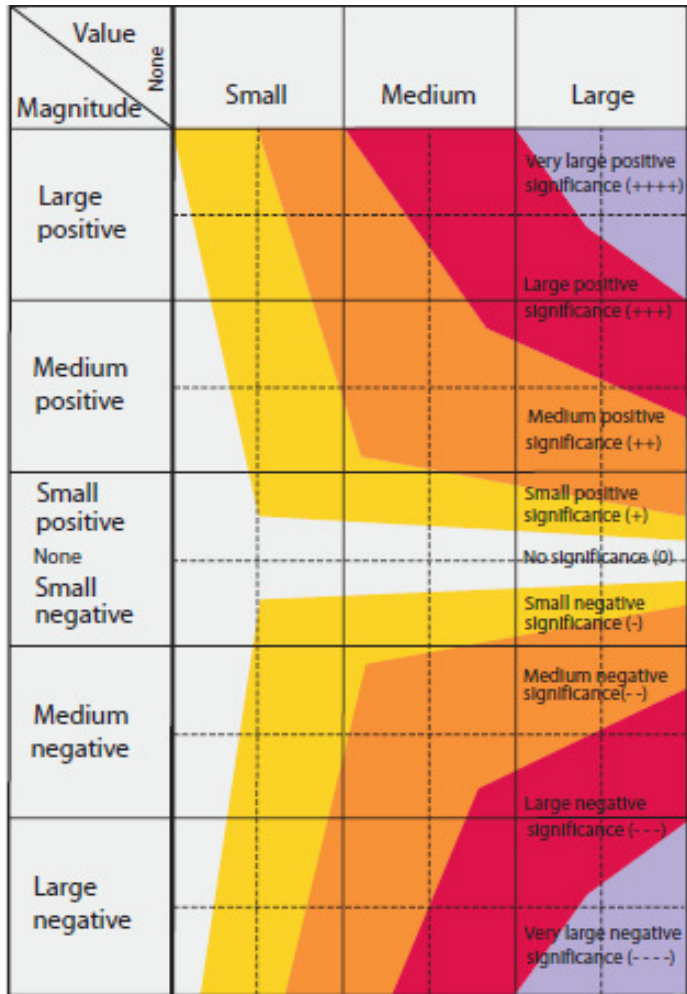
## **Impact**

When defining the impact, the advantages and disadvantages of a given project are compared. The impact assessment is made on a nine-fold scale, ranging from large negative to large positive impact. The impact assessment is made in the following way according to SV (2006).

- Explain the impact for each subject that is affected by the project
- Give a total impact assessment for each alternative project, based on the consequence matrix. Refer figure 3.13 below.
- An analysis is then made whether the impacts in total are positive or negative compared to the zero alternative
- Any mitigation measures or other information that might be relevant to the choice of project is also included

## **Consequence matrix**

Once each project is analyzed in terms of value, scope and impact, the impacts can be set in a matrix as illustrated in the figure below. Impacts are in this matrix presented on a scale divided into nine segments ranging from very large positive to very large negative. The impacts for each project can then be compared against each other, to identify which has the most and least favorable non-priced effects. Most environmental impacts of energy projects are ranked using this terminology from Statens Vegvesen and the nine consequence segments.



Symbol	Description
++++	Very large positive consequence
+++	Large positive consequence
++	Medium positive consequence
+	Small positive consequence
0	No consequence
-	Small negative consequence
--	Medium negative consequence
---	Large negative consequence
----	Very large negative consequence

Figure 3-13: Consequence matrix of non-priced effects (SV, 2006)

### 3.2.3. Practical implementation of CBA in the energy sector

There are some guidelines provided by NVE (2003) on how to conduct CBA on energy projects. This section will be used to summarize some of the main elements from the handbook which are of relevance to the thesis, including investments in production of electricity and policies in the transmission network (in that order). This section will only provide a short table with a summary of the key elements, for a further description see NVE (2003).

Table 3-5: Summary of practical guidelines for conducting CBA in the energy sector

	Production of electricity	Transmission Network
<i>Description of the project and the alternatives</i>	<ul style="list-style-type: none"> <li>- Production capacity</li> <li>- Uptime (hours of operation)</li> <li>- Possible distribution facilities are explained with capacity and extent</li> <li>- Triggering factors for this alternative</li> <li>- Geographical location</li> <li>- Transmission conditions in the network</li> </ul>	<ul style="list-style-type: none"> <li>- Geographical location</li> <li>- Existing consumption and production</li> <li>- Current supply facilities</li> <li>- Triggering factors for this alternative</li> <li>- Current network level</li> <li>- Connection points</li> <li>- Type of facility</li> <li>- Voltage level</li> <li>- Thermal transmission capacity</li> </ul>
<i>Assumptions</i>	The physical lifetime for gas power is normally set to <b>40 years</b> , with an analysis period of <b>25 years</b>	Physical lifetime is <b>50 years</b> and economic lifetime of 30 years. Analysis period of <b>30 years</b> .

<p><i>Elements included in the benefit side</i></p>	<ul style="list-style-type: none"> <li>- Delivered electricity</li> <li>- Contribution to the control rate</li> <li>- Positive external effects</li> <li>- Salvage value</li> </ul> <p>There are normally no positive external effects of a gas power plant that is not reflected in the market</p>	<ul style="list-style-type: none"> <li>- Yearly reduction in disruption costs</li> <li>- Yearly reduction in costs from network losses and bottlenecks</li> <li>- Salvage value</li> </ul> <p>Sources to find data about disruption costs:</p> <ul style="list-style-type: none"> <li>• Statnett's yearly statistics for operation disruptions</li> <li>• SEfAS (2002) to find the associated costs (in no other data from the customer in that particular area is conducted)</li> </ul>
<p><i>Investment and operating costs</i></p>	<ul style="list-style-type: none"> <li>- Investment costs</li> </ul> <p>The prices will be based on market prices, exclusive fiscal fees. If these costs are not available, NVEs handbook 2/2002 can be used.</p> <ul style="list-style-type: none"> <li>- Operating costs</li> </ul> <p>If not sufficient data is available, and assumption of operating costs without fees can be set to <b>1%</b> of the investment costs</p>	<ul style="list-style-type: none"> <li>- Investment costs</li> </ul> <p>The prices will be based on market prices, exclusive fiscal fees. If these costs are not available, publication 26/1998 can be used.</p> <ul style="list-style-type: none"> <li>- Operating costs</li> </ul> <p>If not sufficient data is available, and assumption of operating costs without fees can be set to <b>1,5 %</b> of the investment costs</p>



### 3.2.4. Framework for measuring costs and benefits

Based on the theories described in section 3.1 and 3.2 in this chapter, a framework to be used in chapter 4 to analyze impacts of the investment alternatives are developed in this section. The framework divides the costs and benefits of the CBA into economic, social and environmental aspects in the decision making. A time horizon is also added to illustrate the trade-off between social requirements and long-term effects on society. The time dimension further exemplifies that an investment decision that is timely to implement, will have costs attached to it (discussed more in chapter 4) as well as an option value. Refer figure 3.14 for a graphic description of the framework.

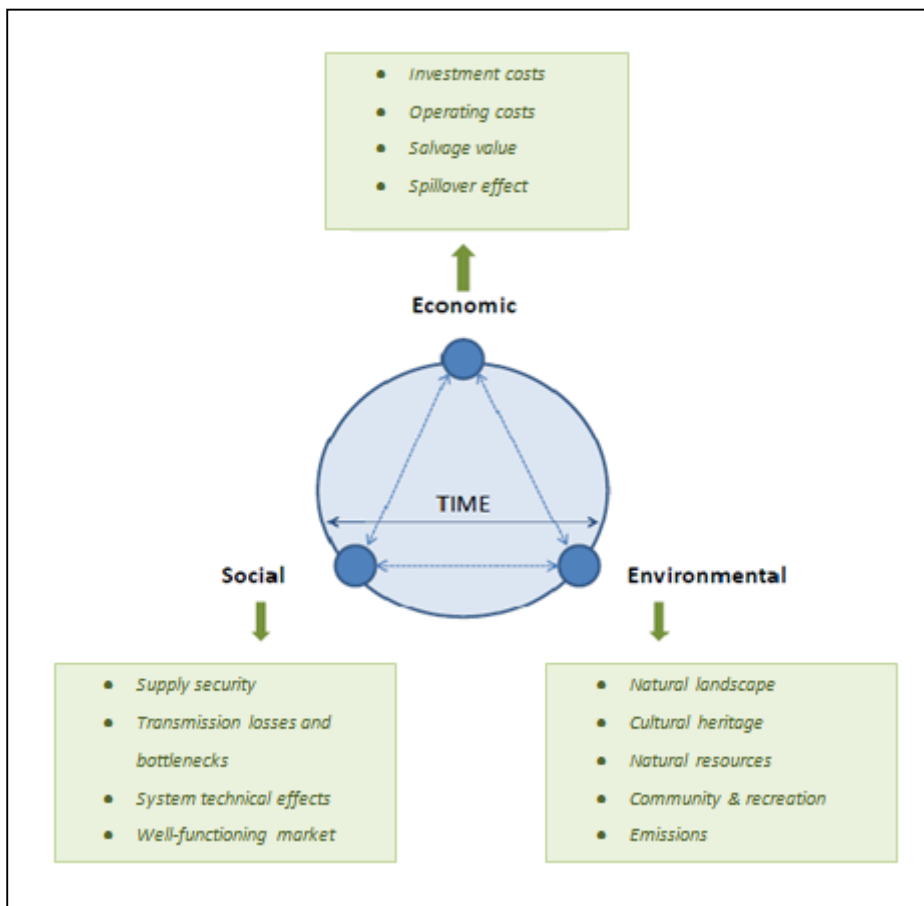


Figure 3-14: Framework for measuring costs and benefits

The costs and benefits listed above can be further divided into priced-effects and non-priced effects. Especially difficult to monetize are those impacts on the environment, as discussed in section 3.2.2.5. Refer table 3.15 below for an illustration of those alternatives that will be priced in the analysis in chapter 4, and those that will only be qualitatively described.

**Table 3-6: Priced and Non-priced effects (Modified after Hervik et al., 2011)**

<b>Priced effects</b>	Investment costs and operating costs
	Salvage value
	Supply security: outage costs measured with KILE
	Transmission losses
	Bottleneck costs
	Delivered electricity*
	Emissions*
	Time costs/ benefits
<b>Non-priced effects</b>	Spillover effect
	Security of supply
	System-technical effects
	Well-functioning market
	Environmental impacts

\*Benefits related to production alternatives

### ***3.3. Drawbacks/ critiques of CBA***

There are some disadvantages to CBA as an analytical method, which are important to highlight also as this method will be applied in chapter 4 of this thesis. The critiques of CBA can be broadly divided into three main arguments and include criticism of the efficiency considerations as the underlying normative approach, criticism of the insufficient specification of CBA and criticism of using CBA in the political decision making process (Hansjürgens, 2004). These will be discussed in turn next.

#### ***3.3.1. Criticisms of the underlying efficiency criterion***

Critiques of the CBA is forefront by skepticism over the general approach of weighting up various aspects to come to a general conclusion (Hansjürgens, 2004). Boardman et al. (2011) state that some people do not agree that there can be a tradeoff between some people's benefits and another person's costs. Another main principle behind this skepticism is that it rejects the principle of weighting up human life, health and the environment against economic concerns (Hansjürgens, 2004). Further, some may disagree about the more practical issues, as to what impacts will actually occur over time, how to monetize these as well as how to make tradeoffs between the present and the future (Boardman et al., 2011). A more broad criticism is the rejection of the efficiency rule altogether, as its only concern is efficiency and not other considerations (Hansjürgens, 2004). "*The consequence from criticism of the efficiency norm is that ranking whenever there is more than one alternative is rejected*" (Hansjürgens, 2004; p. 245). This is because different values suggest that various issues cannot be weighted up, and thus must be left side without being weighted up. The concerns that are placed under these headings are mostly based on ethical and moral reasons according to Hansjürgens (2004).

### ***3.3.2. Inadequate specification of CBA***

This criticism of CBA is more at a technical level. The first objection within this limitation is according to Hansjürgens (2004) that uncertainty is prevalent in the data collected and the valuation of these data. One large part of the data that is highly prone to uncertainty is valuing non-market and environmental goods. Issues such as the ethical dilemma of placing a monetized estimate on these goods, environmental complexity, the rights of future generations and the impact from the social discount rate as well as uncertainty and irreversibility arise in CBAs that try to incorporate environmental goods (Hanley and Spash, 1993). Secondly, arbitrariness in data selection and conception is a further limitation of CBA, and can be argued as there is often only one person or group carrying out the analysis and may focus on certain aspects, while others are neglected or deliberately ignored (Hansjürgens, 2004). A third technical limitation is that it may not be possible to quantify and monetize all relevant impacts as costs and benefits (Boardman et al., 2011). A last element within inadequate specification can involve the fact that there are no clear guidelines that explain what the relevant alternatives of an analysis are, and what can be considered a zero alternative (NVE, 2003).

### ***3.3.3. CBA in the political process***

Some argue that the CBA is an expression of economic value imperialism and that “*the values of a small but influential minority are imposed on the majority of the population*” (Hansjürgens, 2004; p. 247). This argument is further suggesting that it is the industry that represents an especially powerful interest group which will be strengthened by carrying out CBA (Hansjürgens, 2004). Another aspect important to consider when using CBA in the political process is that effects of regulation can often be appraised in the form of quantifiable data, while effects on humans and the environment can often only be made by qualitative information (Hansjürgens, 2004). A third aspect within the political limitations is that collecting information is highly time consuming and may slow down the regulatory process. Information about non-market goods are often the root to delays and thus policy makers must often make a trade-off

between the need for increased information and the time and resources required (Hansjürgens, 2004).

### ***3.3.4. Alternatives***

Sometimes it is not feasible to carry out cost-benefit analysis of a project as a result of its limitations, thus other methods may give a more appropriate result. This paper will not discuss these methods in detail, confer (Boardman et al., 2011, Hanley and Spash, 1993)for further elaboration of these methods.

Below is a simple list suggesting some alternative methods to CBA.

- ❖ Cost-effectiveness analysis (CEA)
- ❖ Qualitative CBA
- ❖ Multi-criteria analysis (MCA)
- ❖ Distributionally Weighted CBA
- ❖ Environmental impact assessment (EIA)

## 4. Case study: Geiranger

This chapter will utilize the theories described in chapter 3 in a case study, that aims at conducting a practical CBA of the power investment choices in Møre og Romsdal. Central Norway and particularly Møre og Romsdal is faced with a situation of energy shortage, as a result of growth in consumption from power intensive industries combined with lack of investments into the power system. Investment considerations are thus currently on the political agenda and the choices made to solve the situation will need to be considered from an economic standpoint.

The name of the case study is Geiranger. The reason for this name is that the original solutions for solving the energy deficit in the region were to build an overhead transmission line, which opponents feared would impact the world heritage listed fjord in Geiranger. The economic costs and benefits will however not only be discussed from the viewpoint of Geiranger, but the rest of the county and country. The aim of the thesis is to bring forward and organize relevant information concerning the power situation in Møre og Romsdal and the various investment alternatives that might solve the situation in the long-run. The case study analysis will follow the main steps suggested by Finansdepartementet (2005), which were discussed in section 3.1.3 of this thesis. A summary of these four steps is illustrated in the figure below.

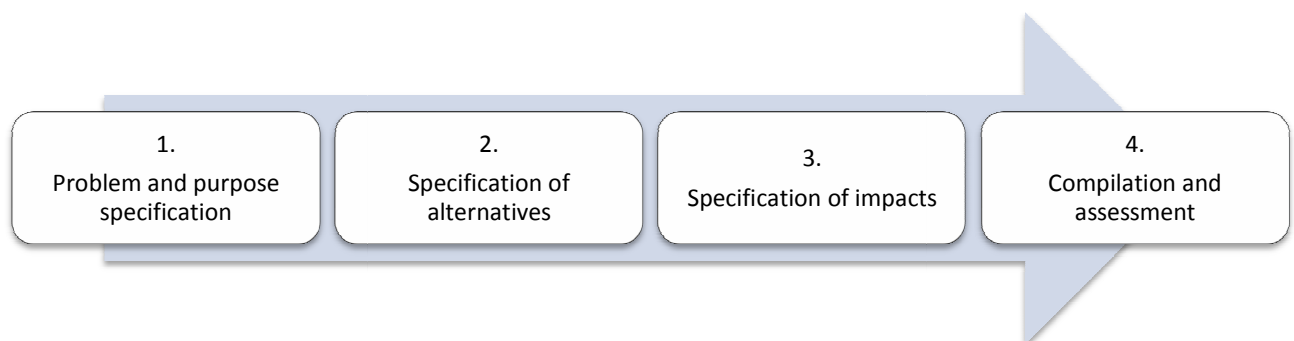


Figure 4-1: Steps of CBA in the Geiranger case study

## **4.1. Problem and purpose specification**

This first part of the analysis will highlight the main elements that are of relevance to the case study. First, a background of the power problem in Central-Norway and Møre og Romsdal are given. Then a description of the power balance in the region is discussed, addressing current and future consumption, production and import. Third, a discussion of the main problem areas is given, including transmission losses and bottlenecks, outage conditions, regional price differences and competitive disadvantage. Next, the zero alternative is described in detail. Lastly, the main assumptions for the CBA analysis of the Geiranger case are explained.

### **4.1.1. Background**

The region of Central-Norway comprises of the counties Møre og Romsdal and Trøndelag (north and south). It is especially the development in Møre og Romsdal that has influenced and will continue to influence the power situation in Central-Norway (Ericson and Halvorsen, 2007). The reason for this is that Møre og Romsdal has in recent years experienced a large growth in electricity consumption, largely from power intensive industries such as Ormen Lange, Hydro Aluminum and Hustad Marmor. It is also expected that this growth in consumption will continue in the coming years (Ericson and Halvorsen, 2007). In addition to this trend, there is large uncertainty as to when and if new production or transmission capacity will be expanded.

The result of consumption growth and lack of capacity investment has lead Central-Norway into a situation with a potential threat of a power crisis. Ericson and Halvorsen (2007) define a power crisis as “*a situation where the system security is threatened and physical rationing is needed*”<sup>14</sup> (p. 36). There are in theory two types of supply security issues that might lead to a power crisis, called either short-run system operating reliability or long-run resource adequacy/ capacity<sup>15</sup> (Joskow, 2005). **Operating reliability** refers to attributes of the system in the short-run. Problems exists when there is difficulty with the continuous supply of power in real time, which

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<sup>14</sup> Translated by author

<sup>15</sup> These two terms are in Norwegian named ”Effekt” and ”Energi” problems/ shortage

occurs when production and import of energy to an area cannot cover the immediate demand (Ericson and Halvorsen, 2007)(Ericson and Halvorsen, 2007. **Resource adequacy or capacity problems** on the other hand refers to the long-term performance attributes of the system in attracting investments at the right time and at the right locations. Problem occurs when there is scarcity in the availability of energy over a period of time, and occurs when the total consumption over a period exceeds the production and import possibilities to an area. Central-Norway can be characterized as an area with the possibility of a capacity crisis due to the scarcity of available energy over a longer period of time, which will be elaborated in section 4.1.2.

The scarcity of energy in Møre og Romsdal is highly a result of lack of investments into the transmission network in recent years as a lack of investments in production capacity. Sandsmark and Hervik (2008) reports that the transmission capacity in the region has been highly utilized and there have been long situations of bottlenecks. In fact, there has been a lack of investments into the power grid network in the last 50 years (Istad, 2010). It was known in advanced that large investments in power intensive industries would create a serious unbalance in the regional power market, if not new production capacity was established or extensive transmission line construction was initiated (Sandsmark and Hervik, 2008).

#### ***4.1.2. Power balance in Møre og Romsdal***

To assess the possibilities of a power crisis in Central-Norway, the power balance in the county must be assessed to identify the balance between consumption, production and import. Power balance is characterized as when production plus net import is equal to the consumption in the region. Next is a description of current and future consumption and production in Møre og Romsdal as well as the expected power balance if no investments are made.



#### **4.1.2.1. Consumption**

- **Current consumption**

The power consumption in Central-Norway has seen a strong growth from power intensive industries, as discussed earlier in the thesis. The consumption within power intensive industries has grown with 89% from 2002 to 2009 and these businesses alone contributed in 2009 to 62% of the total consumption of 10, 4 TWh in the county (Istad, 2010). The power consumption in 2009 is shown in the below table.

Table 4-1: Power consumption in Møre og Romsdal 2009

<b>Consumption</b>	<b>General Consumers<sup>16</sup></b>	<b>Power demanding industries<sup>17</sup></b>	<b>Total</b>
<b>2009</b>	4 TWh	6,4 TWh	10, 4 TWh

- **Future consumption growth**

Istad (2010) uses a basis growth scenario of general consumers of 0, 8 per cent as well as an alternative low growth scenario of 0, 1 per cent. The difference between these two scenarios constitutes very little difference according to Istad (2010). Further growth from power intensive industries will continue, where the expected growth from 2009 to 2015 and 2025 is 1, 8 TWh and 2, 4 TWh respectively (Istad, 2010). These numbers include resumed operation of SU3 at Hydro Aluminum, increased load at Ormen Lange (including a sub water compression plant from around 2016) and Hustadmarmor, as well as a possible establishment of an ironwork facility at Tjelbergodden. There are currently no prognosis for power demands from Nyhamna (except Ormen Lange) and other places in Møre og Romsdal in connection to future expansion of oil- and gas fields (Istad, 2010).

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<sup>16</sup> Electricity consumers excluding power intensive manufacturing and extraction (power demanding industries)

<sup>17</sup> Hydro Aluminium (Sunndalsøra), Hustadmarmor (Fræna), Statoil (Tjelbergodden) and Ormen Lange (Aukra)

Table 4-2: Predicted consumption growth in Møre og Romsdal until 2025

Future Consumption	General Consumers		Power demanding industries	Total
2009	4TWh		6,4TWh	10, 4 TWh
	0,1%	0,8%		
2015	4, 02 TWh	4,19 TWh	8, 2 TWh	12, 4 TWh*
2025	4, 06 TWh	4,54 TWh	10, 6 TWh	15, 2 TWh*

\* Based on the basic growth scenario

From the table above, it is evident that the future growth in consumption is mainly from power intensive industries. Using the basic growth scenario, the total consumption in the region will be 12, 4 TWh and 15, 2 TWh in 2015 and 2025 respectively.

#### 4.1.2.2. Production

- **Current production**

In a year with normal precipitation, the total production capacity in the county is 7, 1 TWh. Total production of power in 2009 was 6, 9 TWh (Istad, 2010). Since 2009, production has been expanded with 0, 1 TWh due to new small power production facilities. The maximum capacity of all the power producing facilities is 1620 MW, which may not always be available due to a share of unregulated production (Istad, 2010). Hydropower and wind power plants without storage make up this proportion of unregulated production. The figure below illustrates power production in Møre og Romsdal in 2009.

Table 4-3 Power production in Møre og Romsdal in 2009

	Total Production
2009	6, 9 TWh

- **Future production growth**

There are extensive, yet uncertain, plans for establishment of new production capacity in Møre og Romsdal. Possible projects are illustrated in the figure below and consist of projects within hydro, gas and wind power.

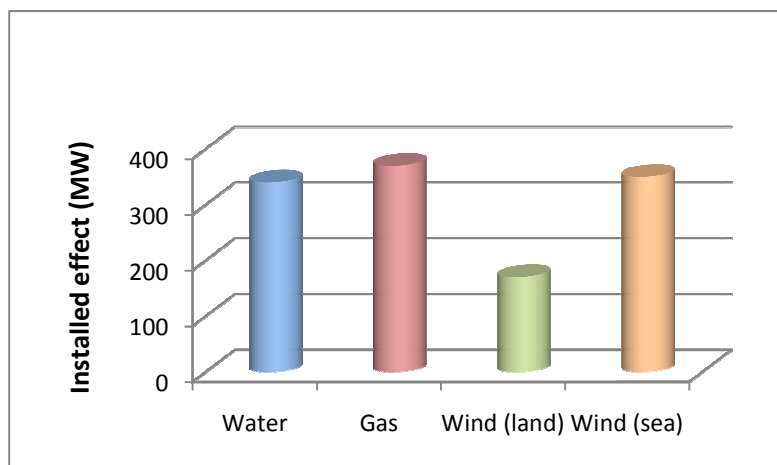


Figure 4-2: Planned new production capacity (Modified after Istad, 2010)

The planned projects within hydro power will give a yearly production capacity of 1, 2 TWh, and the projects within wind power a yearly capacity of 1, 4 TWh (Istad, 2010). There is one possible project within gas power, which will give a yearly production capacity of more than 3 TWh (Istad, 2010). Whether new capacity is actually realized however, is dependent on concessions as well as an environment that provides sufficient profitability for investment. It is therefore great uncertainty related to future production capacity growth (Istad, 2010).

#### **4.1.2.3. Power balance**

Møre og Romsdal had a good balance between consumption and production a few years back. The growth in consumption and lack of investment in production has shifted this balance however, and the county experiences a threat to this balance. In a normal situation, the import capacity to the region will be sufficient to cover this deficit. Due to uncertainties in the system, such as the large share of hydro power generation in the region (approx. 90%) and the associated

stochastic inflow variability, the supply security is a main concern (Sandsmark, 2008). Including import capacity, the energy deficit in Møre og Romsdal was **3, 7 TWh** in 2009, assuming average output (Istad, 2010).

This deficit is expected to continue to grow, especially without investments in transmission or production capacity. The figure below shows an assembly of historical development and prognosis for power consumption in the scenarios 2015 and 2025. In the figure, also the current production capacity and likely future developments within production are shown. The red line illustrates middle production.

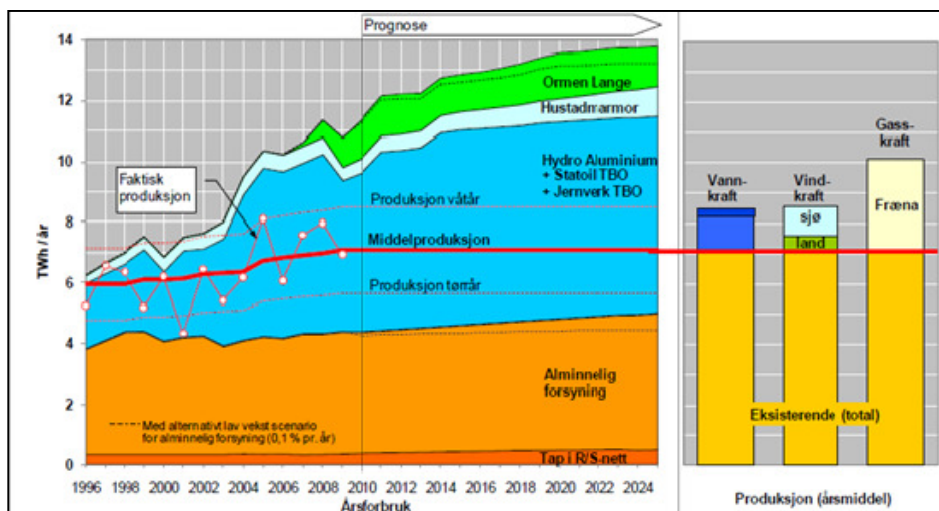


Figure 4-3: Future power balance estimates for Møre og Romsdal (Istad, 2010)

As illustrated in the above figure, if no new production capacity is realized, the energy deficit will continue to grow. In the scenarios 2015 and 2025, the estimated deficit will be **5, 5 TWh** and **8, 3 TWh** respectively. These estimates from Istad (2010) do however not take into account the market response to this deficit, such as a reduction in consumption due to prevailing high electricity prices.

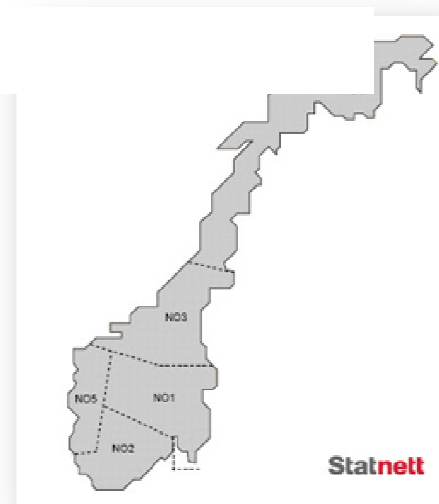
### ***4.1.3. Consequences of energy shortage in Møre og Romsdal***

The increasing constrained power balance in Central-Norway has resulted in the need for increased transmission transfer into the region. Istad (2010) write that the challenges will mostly be related to years with little precipitation and water in the reservoirs, where the need for import to the region will be greater than normal. In such situation, the capacity will be heavily utilized and impact the regions energy system. The consequences of such pressure on the transmission lines will mainly be regional price differences, transmission losses, bottlenecks, disruption costs and competitive disadvantages for businesses. These aspects are discussed next.

#### ***4.1.3.1. Regional price differences***

In a situation of scarcity of capacity over a longer period, Central-Norway will be established as its own price area (NO3). The reason why Central-Norway has become its own price area in some time periods, is to give price signals to the market participants that reflects the physical shortage of energy, which hopefully will lead to energy savings and change the power flow and thus strengthen supply security (Sandsmark and Hervik, 2008).

In 2010, Norway was divided into five price areas. Norway is normally divided into only 2 or 3 price areas, and the creation of three new areas is highly unusual (Bye et al., 2010). Refer figure 4.4 for an illustration of the five Elspot areas, as of March 2010. The results of having price areas are that the spot prices in the different regions will not necessarily be the same and thus create regional price differences. Figure 4.5 illustrates the differences in spot prices between the different bidding areas in Norway in the period from January 2010 to January 2011.



Regional Elspot areas (Statnett)

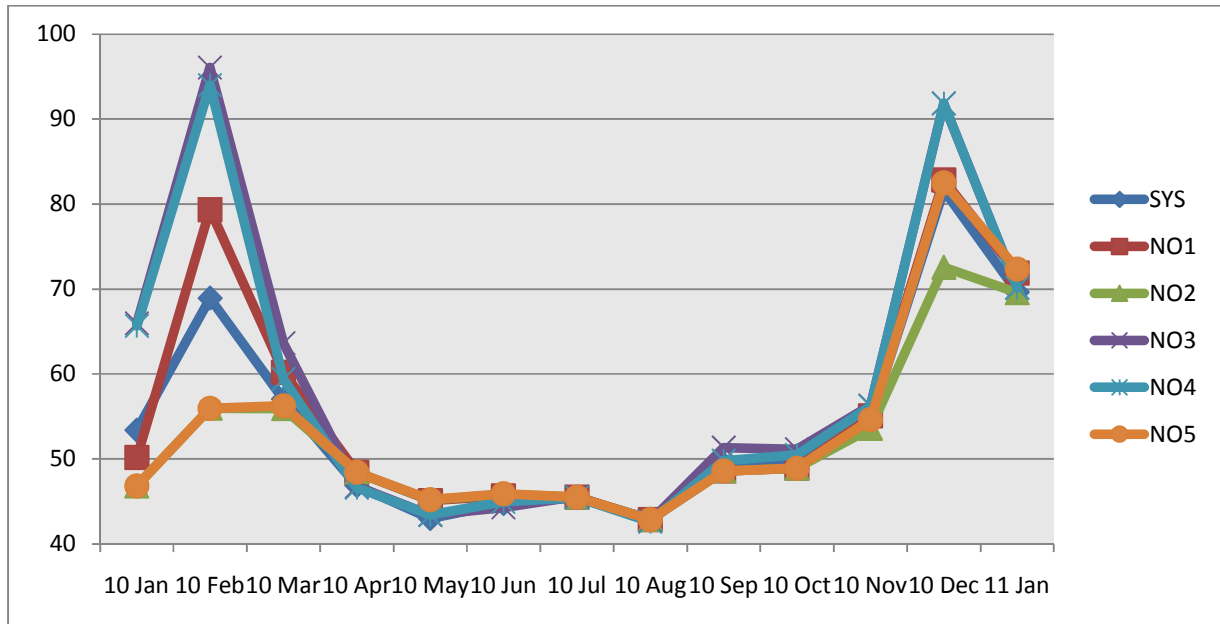


Figure 4-5: Average monthly prices for the Elspot areas NO1 to NO5 (NordPool, 2011b)

As seen from the above figure, there have been periods with large price differences between the price areas. This is especially the case during the winter months, from November to March. To study the effect the different power prices has had on residents, public operations, business and industry in the region, a table that illustrate the average yearly spot price for the five different Elspot areas from January 10 to January 11 has been made. Refer table 4.4 for an illustration of these average spot prices and the difference compared to the system price.

Table 4-4: Average yearly spot price for the different Elspot areas (NordPool, 2011b)

	SYS	NO1	NO2	NO3	NO4	NO5
<i>Average price øre/ kWh</i>	0, 544	0, 557	0, 523	0, 592	0, 585	0, 534
<i>Difference to average system price</i>		- 0, 013	0, 021	-0,047	- 0, 041	0, 010

As illustrated in the table above, Central-Norway had the highest spot prices of the five Elspot areas in the period from Jan 10 to Jan 11. This was also the result in the report by Sandsmark and Hervik (2008), which found that Central-Norway had the highest spot prices in the period October 07 to September 08. This study will use the methodology from the study by Sandsmark

and Hervik (2008) to calculate the additional costs in Central-Norway compared to the rest of the country as a result of the regional differences in spot prices. Employing 10 TWh<sup>18</sup> in consumption for general consumers, the addition cost in Central-Norway compared to the system price is almost 476 MNOK. The table below illustrates these price differences for general consumers in the different Elspot areas, using the average price in January 2010 to 2011. (All prices and percentages are rounded to the nearest whole number).

**Table 4-5: Regional price differences for general consumers in Central Norway**

	<b>Additional cost compared to system price</b>	<b>Additional cost compared to NO1</b>	<b>Additional cost compared to NO2</b>	<b>Additional cost compared to NO4</b>	<b>Additional cost compared to NO5</b>
<i>Central-Norway</i>	476 MNOK	343 MNOK	688 MNOK	66 MNOK	579 MNOK
<i>Percentage increase</i>	8 %	6 %	12 %	1 %	10 %

It is evident from the table that the household consumers for general consumers in Central-Norway have almost 12% higher energy costs than the consumers in Southern-Norway (NO2) and around 10 % higher costs than consumers in Western-Norway (NO5). The smallest difference in prices is from those consumers in Northern-Norway (NO4). These regional price differences clearly illustrate the costs or inequity to society of not investing in capacity to improve the energy deficit in Central-Norway. This could be considered benefits to energy investments that would reduce and or eliminate this difference and also kept in mind when considering investment alternatives that are timely to implement. The estimate of 476 MNOK is used in section 4.3 MNOK, as an estimate of yearly benefits of a new investment in the energy system that would reduce or eliminate these price differences.

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<sup>18</sup> 10 TWh consumption is based on approx. 4TWh consumption in Sør-Trøndelag, 2TWh consumption in Nord-Trøndelag and 4 TWh consumption in Møre og Romsdal. Refer appendix 2.

#### 4.1.3.2. Transmission losses

Transportation of power will always lead to losses in the different components of the power system, and the losses will amplify with increasing utilization. As Møre og Romsdal is an energy deficit area with high utilization of the network, there are increased losses in these networks (Istad, 2010). Feeding new production into the network, will give corresponding loss gain reports Istad (2010). Figure 4.6 is adapted from the power system study by Istad in 2010, and illustrates the average marginal loss rates for extraction per year in Møre og Romsdal in the years 1998-2009. The figure shows the loss rates for three selected points in the central grid, which are respectively the blue, red and green line. The figure also illustrates the power deficit in the corresponding year, which is exemplified by the purple line.

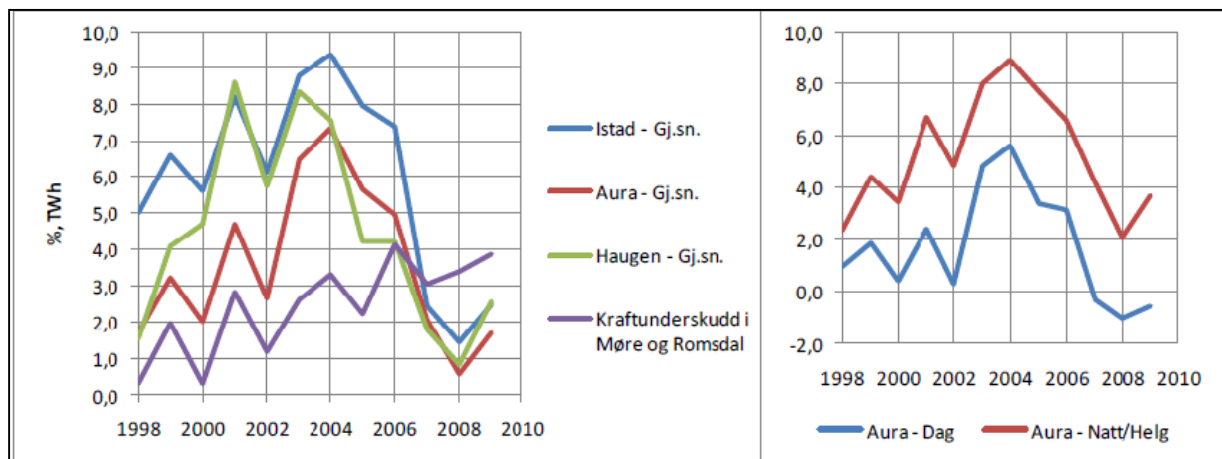


Figure 4-6: Transmission loss conditions in Møre og Romsdal from 1998-2009 (Istad, 2010)

Møre og Romsdal has experienced very large marginal loss rates, as evident from the above figure. There has however been an improvement in the last years, and Istad (2010) reports that the reason for the decreasing loss rates can be a result of the development of two new 420 kV transmission lines in 2004 and 2006 respectively and the restructuring of the procedures for calculating the marginal loss rates as of 2007.

The costs associated with these losses is dependent on the price of power and the marginal loss component is calculated as  $\text{output} / \text{input} * \text{marginal loss rate} * \text{power price}$  for each hour (Istad,



2010). With an example of an power price of 40 øre/kWh, the marginal loss component will be 4 øre/ kWh with a marginal loss rate of 10% (Istad, 2010). The marginal loss rates are administratively limited to 10% until 2009 and 15% from 2010 (Istad, 2010). Statnett (2007) calculate the saved transmission loss costs in relation to a new 420 kV transmission connection in the region to amount yearly benefits of 52 MNOK. This estimate is further used in section 4.3 of this thesis.

#### **4.1.3.3. Bottlenecks**

Bottlenecks occur when the transmission network is not able to transmit sufficient electric power. This can either arise when the desired consumption in an area exceeds possible generation and import capacity, or when the preferred generation in a region exceeds consumption and export capacity. As Central-Norway is a capacity deficit area, bottlenecks occur as a result of higher consumption than generation and import capacity. Statnett (2007) reports that the transmission capacity in Central-Norway has had a high utilization and experienced periods of bottlenecks, especially in periods where demand is high and there has been little precipitation. Statnett (2007) estimates the yearly benefits of reduced bottlenecks in relations to investments in the transmission network in Central-Norway to total 111 MNOK. This estimate is used further in this thesis.

#### **4.1.3.4. Disruption conditions**

The interruption conditions are central when quantifying the supply security and are often measures by KILE. These conditions can be described by aspects such as number of interruptions each year, duration of disruptions and non-delivered energy (Istad, 2010). The disruption condition in Møre og Romsdal has worsen since 2001. In the period between 2001 and 2003, the region experienced many errors that caused transmission breakdowns and industry was also affected (Istad, 2010). The share of non-delivered energy from 2005 to 2006 in Møre og Romsdal was much higher compared to the rest of the country. The left-sided figure below demonstrates historical disruption conditions for the region in terms of non-delivered energy (ILE) as a percentage of delivered energy (LE). The red line is the conditions for Møre og

Romsdal, while the green line illustrates the conditions for Norway. The figure on the right side shows the costs associated with these disruptions distributed on end-user groups in Møre og Romsdal, together with the total percentage compares to the rest of the country (right).

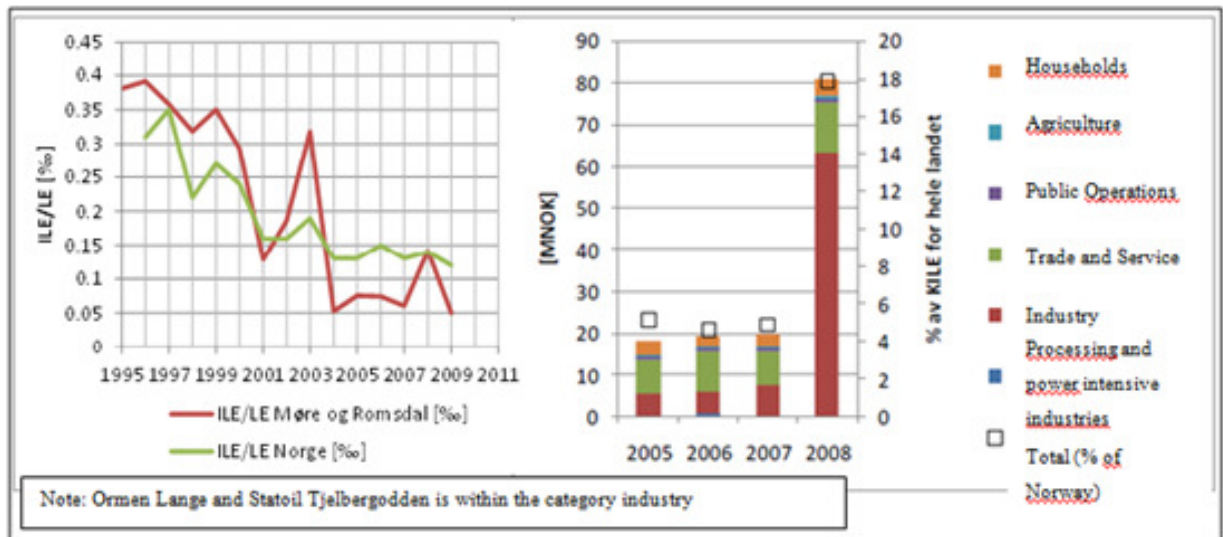


Figure 4-7: Quality of delivery and supply security (Modified after Istad, 2010)

The costs of disruptions were 80 MNOK in 2008 for Møre og Romsdal, which represented 18% of the total KILE costs in Norway. The marked increase in disruption costs and ILE/ LE in 2008 is a result of a long-term disruption at Ormen Lange, which alone gave interruption costs over 50 MNOK (Istad, 2010). If no new measures to improve the situation in Møre og Romsdal is made, these disruptions and the associated costs are likely to increase in the future. The yearly benefits of disruptions costs used in section 4.3 in the thesis will be based on the average disruption costs from 2005 to 2008, which is 35 MNOK. There is however some uncertainty related to this estimates, as no more relevant data sources have been found.

#### 4.1.3.5. Competitive disadvantage

The industry in Møre og Romsdal is dependent on a stable access to power at a predictable price. Sandsmark and Hervik (2007) write that the industry in the region has experienced challenges, as a result of limited transmission capacity to and from the region as well as increasing energy

deficit. The energy deficit is a main concern, as the power intensive industries in Møre og Romsdal are experiencing a growth in demand for their products, which will continue in the coming years. Further expansion of these industries are however limited as much by the lack of available power as the price of power according to Sandsmark and Hervik (2007). There are plans for industrial development both within the petroleum industry and power intensive industries, which however requires more access to power than what is currently available in Central-Norway (THEMA, 2011b).

Power-intensive industry can in principle be affected by a strained power situation in four different ways according to THEMA (2011):

- *“Sustained high energy prices reduces the profitability of industrial production*
- *Large variation in the power prices creates unpredictable conditions for investments and operation*
- *Reduced supply security created direct costs in terms of lost production and possible damage to equipment*
- *Lack of opportunities to expand power consumption to realize commercially profitable projects” (p. 45)<sup>19</sup>*

The report by THEMA (2011) writes that the power deficit has put industry and other business development on hold in Central-Norway. Investments for around 90 billion NOK is dependent on a strengthened power supply to be able to be realized, where 40 per cent of these investments accrue Norwegian actors (THEMA, 2011b).

Hervik state that there is also an economic cost of not being able to expand businesses in their best alternative use (Pers. Comm., 03.05.2011). As described above, there are numerous projects that are commercially profitable that have to delay or end due to energy shortage in Central-Norway. One example of this is Ormen Lange<sup>20</sup>, who is dependent on available power to be able

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<sup>19</sup> Translated by author

<sup>20</sup> Ormen Lange is the second largest gas-field at the Norwegian continental shelf. For more info, refer: [www.hydro.com](http://www.hydro.com)

to expand their operation at Nyhamna by 2016-2018. The plan is to invest billions at this port to be able to create a landing facility for Linnorm and Luva, two gas-fields located at Haltenbanken (Torvik, 2011). If these investment plans cannot be realized as a result of energy shortage in the region, Ormen Lange will need to diverge from the commercially profitable project and thus an **additional cost** of choosing another less attractive investment alternative will occur (Pers. Comm. Arild Hervik, 03.05.2011). There will also be competitive disadvantages for local businesses if the investment plans are not realized, who would originally benefit from investments at Nyhamna (Torvik, 2011). Although not monetized in this thesis, THEMA (2011) further reports that a delay of 1-3 years of a new transmission line such as Ørskog-Fardal, can lead to a loss in present value of around 0,7 – 2,7 BNOK, as a result of the delay of the expansion of the Luva and Linnorm projects with related infrastructure.

#### **4.1.3.6. Short-run measures**

The supply security in Central-Norway has been strengthened in later years by measures such as installation of capacitor banks, temperature upgrades, system protection and investments in the local and regional grid (OED, 2011). The power line connection to Sweden has furthermore been upgraded. These measures are however not sufficient to cope with the power situation in years with little precipitation. Statnett therefore have put three measures in place, in an attempt to solve the situation in “dry years”. These measures are special and put in place to maintain supply security in the region (OED, 2011)(OED, 2011). First, as discusses in section 4.1.3.1, Central-Norway has been separated into its own **price area**. The rationale is to exploit the import capacity as well as to raise the price in strained power situations in order to reduce demand. Second, Statnett has bought **energy options** which can be used in the case of a severe supply shortage, for the purposes of reducing electricity demand. Companies that sign these contracts entitle Statnett to order a demand reduction in return for a certain payment (Sandsmark, 2008). Third, two **mobile gas-fired power plants** have been built, which can be operated in extremely stressed power situations. The total capacity of these plants are 300 MW (Istad, 2010). These are located at Tjelbergodden and Nyhamna and can be utilized if the power situation in the region is strained and there is a possibility of rationing. In 2010, these plants were given a temporary permit to be utilized also in the event of an operational disturbance or difficult operating

situation in Central-Norway. These three measures which were presented in Statnett's "SAKS-list" are however not sufficient to improve the situation in the region long-term, thus other more extensive investment alternatives have been considered. These are discussed more in detail in the next sections of this analysis.

#### ***4.1.4. Long-run measures: Zero alternative***

In order to improve the situation in Møre og Romsdal in the long-run, investment in new production or transmission capacity needs to be made. Statnett has therefore decided to build a new overhead transmission line between Ørskog and Fardal. A concession application for this new line was sent to NVE in 2007, and subsequently approved in 2009. The case was however appealed and is now being complaint handled by OED, where a final decision is expected to be reached during 2011. This overhead transmission line is nonetheless used as the zero alternative in this analysis and will be the basis for which other investment alternatives are compared.

The concession-given overhead transmission line between Ørskog-Fardal will be around 250-300 km long. The line will go from Ørskog transformer station in Ørskog municipality to Fardal transformer station in Sogndal municipality. The line is split into three sections, namely:

1. Ørskog-Leivdal (around 90-99 km)
2. Leivdal-Moskog (around 84-119 km)
3. Moskog-Fardal (around 76-80 km)

Refer (Statnett, 2007) for a detailed description of these three sections in the concession application. Figure 4.8 also illustrate the localization of these three sections.

The below table (4.6) illustrates the main specifications of the proposed transmission line between Ørskog and Fardal.

Table 4-6: Zero alternative specifications

<i>Length</i>	250-300 km
<i>Voltage</i>	420 kV
<i>Implementation time</i>	2015
<i>New transformer stations</i>	Sogndal Høyanger Moskog Ålfoten Ørsta
<i>Mast technology</i>	Steel masts <sup>21</sup>

#### **4.1.4.1. Rationale for building a new overhead transmission line**

The proposed new transmission line is necessary to secure electricity supply in Central-Norway according to Statnett (2007). This is a result of increased energy shortage in Møre og Romsdal combined with plans of new power production in Sogn og Fjordane. The current power grid infrastructure will thus not be able to serve the growing demand for importing power into the region. A new line will therefore enable greater transportation of power to and from the county, as well as improve the supply security in Sogn og Fjordane and locally in Sunnmøre. The new line will in addition facilitate expansion of wind power and small water power plants in Sogn og Fjordane and Sunnmøre, which the current transmission network is too weak to handle (Statnett, 2009).

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<sup>21</sup> Refer appendix 3 for pictures of the masts that will be used for this project

#### 4.1.4.2. Localization

The below figure illustrate where the proposed line Ørskog-Fardal will be located. The red line demonstrates the localization of the proposed new line. The red circles show the placement of the proposed new transformer stations.



Figure 4-8: Map of the zero alternative (Statnett, 2010)

#### **4.1.4.3. Technical dimensions**

The 285 km transmission line will consist of around 800 masts. There will be five new transformation stations, located in Sogndal, Høyanger, Moskog, Ålfoten and Ørsta. There will be conducted redevelopment of Fardal transformation station in Sogndal and removal of 110 km existing steel mast cords. When NVE gave this alternative concession, they set conditions that camouflage-colored masts were to be used, as well as composite insulators on certain routes (Statnett, 2010). The proposed new line also requires other measures to the current power grid infrastructure according to Statnett (2007):

- *Demolition of the 300(132) kV-line between Fardal-Stølsdalen*
- *Reconstruction of the 132 kV-line between Fardal-Mel*
- *Reconstruction of the 300 kV-line between Leirdøla-Fardal*
- *Reconstruction of the 132 kV-line between Høyanger-Moskog*



#### ***4.1.5. Assumptions of the Geiranger case analysis***

This section of the thesis will highlight the main assumptions of the analysis of the Geiranger case.

- ❖ From the assessment of the power situation in Møre og Romsdal in section 4.1.2, it is assumed that consumption from households will have a steady growth of 0,8 % (low-growth scenario of 0,1 %). Industry consumption is expected to play an important role in the region and grow to 8,2 TWh and 10,6 TWh in 2015 and 2025 respectively.
- ❖ The impacts from the various investment alternatives in section 4,3 will be based on a national and not a global standing. This means that the question of local versus global emissions will not be discussed in this thesis.
- ❖ The reference time of the CBA is set to 2011
- ❖ The analysis period is set to 25 years for all the alternatives
- ❖ The base discount rate is set to 6 per cent (refer chapter 3.1.2.5 for a discussion on the discount rate)
- ❖ The long-term price of electricity is set to 40øre/kWh (Pers. Comm. Arild Hervik, 03.05.2011)
- ❖ The long-term price of gas is set to 84 øre/sm<sup>3</sup> (Svendsen et al., 2005)<sup>22</sup>

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<sup>22</sup> The price of gas is highly related to the long-term prices of crude oil. The gas price of 84 øre/sm<sup>3</sup> is based on a long term price of crude oil of 30USD/ barrel (Svendsen et al. 2005). It is important to highlight that there is no unified market price for gas in the Norwegian or European market. Refer appendix 4 for an overview of the varying gas prices depending on the crude oil price.

## 4.2. Specification of alternatives

This part of chapter four will be dedicated to analyzing the various investment alternatives that may solve the potential power crisis in Møre og Romsdal and Central-Norway, in addition to the zero alternative. There are in theory a variety of alternatives that can be considered to improve the situation in Central-Norway; however this analysis will focus on those alternatives that will secure energy to the region in the long-run. In the choice between various investment alternatives, some measures will be complementary while others are directly supplements (Sandsmark and Hervik, 2008). One clear supplement is the choice between production and new transmission capacity.

Below is an exploration of various alternatives in addition to the zero alternative, which was discussed in section 4.1.4. The alternatives are divided into three areas, namely transmission, production and end-user measures. Refer figure 4.9 for an overview of these investment choices, which will consequently be discussed next.

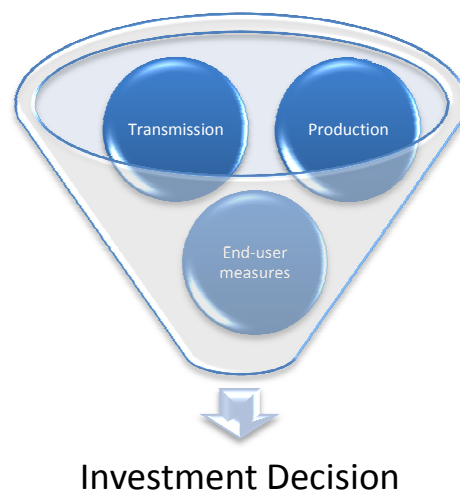


Figure 4-9: Investment alternatives in the Geiranger Case

### **4.2.1. Transmission**

There are three relevant transmission alternatives of improving the power situation in Møre og Romsdal, which include the zero alternative, an alternative that involve redevelopment of the existing overhead transmission line between Ørskog-Ørsta and a subsea cable between Ørskog and Store Standal. Below is a description of the latter two. Other transmission alternatives and routing options are not considered in this thesis.

#### **4.2.1.1. Redevelopment of existing overhead transmission line**

As the zero alternative currently is under complaint handling, the OED has asked Statnett for a study of two different alternatives on the transmission route between Ørskog-Ørsta. One of these includes a new main alternative, which entails a new transformer station and corresponding redevelopment of the existing power grid. The main aspects of this project are that a new transformer station is built in Sykkylven combined with voltage upgrade of the existing 132 kV line Ørskog-Sykkylven-Haugen (Ørsta) (Statnett, 2010). The below table illustrates the main specifications of the proposed redeveloped line between Ørskog and Fardal.

**Table 4-7: Specifications of the redevelopment alternative**

<b><i>Length</i></b>	250-300 km
<b><i>Voltage</i></b>	420 kV
<b><i>Implementation time</i></b>	2016 -
<b><i>New transformer stations</i></b>	Sogndal Høyanger Moskog Ålfoten Ørsta Sykkylven
<b><i>Mast technology</i></b>	Steel masts

- **Rationale for this alternative**

The zero alternative has received many complaints, which are mainly related to the aesthetic impacts of a new transmission line. All of the independent studies conducted in relation to this line have further found that the environmental consequences are rigorous. This makes the rationale for the redevelopment alternative, which in theory will make no new “interruptions” to the landscape. Less environmental footprints are thus made compared to the zero alternative, as the redeveloped line will go in the existing route Ørskog-Sykkylven-Haugen (Statnett, 2007). The rationale for the zero alternative of solving the energy situation in Møre og Romsdal is similar for this alternative, as it has the same specifications in terms of capacity and ability to connect renewable energy sources from Sogn og Fjordane.

- **Localization**



Figure 4-10: Map of the redevelopment alternative (Statnett, 2010)

The above figure exemplifies the route of the proposed redeveloped transmission line. The blue line is where the redeveloped line will go in parallel with the existing 132 kV overhead line. The red circles demonstrate the new transformer stations in relation to the Ørskog-Fardal project, where the redeveloped transmission line will introduce an additional station compared to the zero alternative. This is the transformer station in Sykkylven.

- **Technical dimensions**

To be able to redevelop the current 60 km long 132 kV steel mast line Ørskog-Fardal-Haugen, a new 420/ 132 kV transformer station in Sykkylven needs to be built. This is according to Statnett (2010) necessary in order to secure supply to Sykkylven and Stranda. Other technical dimensions are similar to those described for the zero alternative. The proposed redevelopment line also requires other measures to the current power grid infrastructure according to Statnett (2010), which are listed below:

- *New 420/132/22 kV transformer station in Sykkylven municipality, with two alternative locations. (Alt.1: Aurdalen, alt. 2: Vikedalen)*
- *Redevelopment of existing 132/22 kV transformer station in Sykkylven (Haugset), including movement of its function to a new 420/ 132 kW transformer station in Sykkylven municipality*
- *Restructuring of existing 132 kV Stranda-Sykkylven to a new transformer station in Aurdalen or Vikedalen*
- *Adjustment of prior authorization given alternative pathways at Store Standal, Stavset and Vindsneset*
- *New transformer station T2 at Ørskog transformer station and two new connections between Ørskog and Giskemo transformer stations in Ørskog municipality*
- *Redevelopment of the existing 132 kV facility at Ørskog transformer station*

#### 4.2.1.2. *Subsea cable between Ørskog and Store Standal*

During the complaint handling of the Ørskog-Fardal project, Statnett was asked to also study the alternative of a subsea cable between Ørskog and Store Standal (Statnett, 2010). The reason for this requests where that complaints of the zero alternative promoted a subsea cable, which would have higher consideration for nature, tourism and recreation. Statnett has studied the use of cables on several sections, and the oil and energy department asked in 2009 for a specific study of the use of cable in the Hjørundfjord near Ørskog. The subsea alternative involves a new 420 kV- cable between Ørskog and Store Standal, which consists of 4 km cabling underground and 40 km subsea cabling (Statnett, 2010). The maximum depth in the sea is estimated to be around 630 meters. Refer table 4.9 for a summary of the specifications of a subsea cable alternative.

Table 4-8: Subsea cable alternative specifications

<i>Length subsea cable</i>	40 km
<i>Length underground cable</i>	4 km
<i>Voltage</i>	420 kV
<i>Implementation time</i>	2017 +
<i>New transformer stations</i>	Ørskog Ørsta
<i>Landing facilities</i>	Ørskog Store Standal
<i>Cable technology</i>	Oil cable

- ***Rationale for investing in subsea cable***

The choice of subsea cable over overhead transmission lines will normally be motivated by the negative landscape effects as well as aesthetic effects that overhead transmission lines bring. The main argument for the subsea cable between Ørskog and Store-standal is that no masts on this

route are built, thus avoiding the visual impacts from the zero alternative. Regjeringen (2010) write that a subsea cable is considered the best alternative when it comes to environmental gains, and thus needs to be considered against the zero alternative. The subsea cable has therefore a broad support amongst the local residents and politicians in the region (Regjeringen, 2010).

- **Localization**

The map below illustrates the location of the proposed subsea cable between Ørskog and Store Standal, as exemplified by the dotted line. The blue line demonstrates where the 420 kV line between Store Standal and Ørskog will be located. It is presupposed that the cabling starts in the Ørskog transformer station and the onshore facility will be placed at Store Standal.



Figure 4-11: Map of the subsea cable alternative (Statnett, 2010)

- ***Technical dimensions***

The technical dimensions of subsea cords are highly complex, and much of the debate is outside the scope of this thesis. Refer (Multiconsult, 2007, Norconsult, 2010, Eriksson et al., 2011) for a thorough analysis of the technical dimensions involved in the choice of subsea cables. This section of the thesis will highlight some of the technical aspects that are of relevance for the CBA analysis.

Direct current (DC) power is the only option for a cable project that will transfer more than 1 000 MW in a distance like Ørskog-Fardal (Multiconsult, 2007). Norconsult (2010) has assumed the use of 6 cords (2 cable sets) in their cable study, which will be able to offer increased supply security in the case of an error on one of the cable sets. The analysis by Norconsult, considered the use of both oil and PEX (plastic insulated) cables for the cabling in the Geiranger case. Norconsult (2010) recommends the use of oil cable in the Hjørundfjord, with the reason that the oil cable technology is well known and tested for facilities up to 40 km. Further, it is the only technology which is commercially feasible in a time frame within 3-5 years and PEX cables are only marginally less expensive (5%) than an oil cable (Norconsult, 2010).



### **4.2.2. Production**

New production in Møre og Romsdal will reduce the losses within the transmission network and improve the security of supply. Statnett (2005) suggests in their report about power in Møre og Romsdal that production of energy close the large electricity consumers would be more economically efficient than solving the gap through investments in new transmission lines. When investing in production technology, both renewable and non-renewable technologies are available. This section will firstly discuss the renewable energy potential that exist in Central-Norway, and secondly discuss the relevant alternative of non-renewable investments through a gas-fired power plant.

#### **4.2.2.1. Renewable energy sources**

The potential for renewable energy in Central-Norway is large and it is an important political goal to be able to incorporate this capacity into the electric-power network. The reason for this is that water and wind power is renewable energy, which will thus be helpful in the Norwegian effort to reduce greenhouse gases (OED, 2008).

There are two aspects relevant in the discussion of investing in production of renewable energy sources. Firstly is the potential of production in Central-Norway, which will assist in the power balance in the region. Next is the potential in Sogn og Fjordane, which can be imported to Central-Norway and add production capacity in the region. These potentials have not been realized as a result of lack of capacity in the current transmission network. The table below illustrates the potential in Central-Norway and Sogn og Fjordane for renewable energy production. Included in the table are only those projects that have received concession by NVE, and comprise of micro, medium and larger power production facilities.

Table 4-9: Hydro and wind resource potential in Central-Norway and Sogn og Fjordane (NVE, 2011)

	Wind Power (Production capacity in TWh)	Hydro Power (Production capacity in TWh)	<i>Total production capacity potential (TWh)</i>
<b>Central-Norway</b>	5, 41	1, 93	<b>7, 34</b>
<b>Møre og Romsdal</b>	1, 55	0, 93	<b>2, 48</b>
<b>Sogn og Fjordane</b>	0, 17	1, 915	<b>2, 085</b>

As exemplified in the above table, there is a lot of unrealized potential of power production, where the capacity in Sogn og Fjordane and at Sunnmøre cannot be connected to the power grid due to lack of capacity (Statnett, 2010). But these can be incorporate into the power system in the coming years, if new transmission capacity will be realized. These projects can however not alone provide a solution for the power balance in Central-Norway in the long-run, and they are therefore not included further in this thesis as an investment alternative that can replace the zero alternative. It is however important at this stage to highlight that if no investment in capacity are made in the coming years so that these projects can be realized, it will represent an economic cost.

Connection of small power producers in Sogn og Fjordane can in light of the above discussion be seen as a benefit for all the transmission alternatives in the cost-benefit analysis. This is affirmed by Hervik et al. (2011), who state that there are economic gains associated with network investments that enable new renewable energy sources. Due to lack of sufficient data, one can assume that all the small-power producers will be profitable with the current assumption of long-term electricity prices, except the wind-power producers (Pers. Comm. Arild Hervik, 03.05.2011). This means that if a new transmission line can connect all the water-power producers from Sogn og Fjordane from table 4.10, they will produce 1,915 TWh yearly, with a profit margin of 10 øre/kWh<sup>23</sup>. The net benefit can accordingly be calculated to total:

$$\text{Net benefit} = 1,915 \text{ TWh} * 0,1\text{NOK/ kWh} = \underline{\underline{191, 5 \text{ MNOK}}}$$

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<sup>23</sup> The profit margin is based on a long-term price of electricity of 40øre/kWh minus long-term operating costs of 30 øre/ kWh (Pers. Comm. Arild Hervik, 03.05.2011). Green certificates are not included in this calculation.

#### 4.2.2.2. Gas-fired power plant

The strained power situation in Møre og Romsdal can make for possibilities of new power production in the region, such as gas power. Much of the reasoning for favoring a gas power plant over investments in transmission, is that local production will be close to the main consumers in the region and thus the region will not be dependent on importing large quantities of power.

Industrikraft Møre has received a concession to build a gas power plant in Elnesvågen, with 450 MW and production capacity of 3,7 TWh per year (Faanes, 2010). This gas power plant will be used in this thesis as the alternative for gas power production, and other locations and gas power plants are therefore not investigated in this thesis<sup>24</sup>. A standard gas power plant will take around 30 months to build, and because a pipeline from Ormen Lange as well as a concession is in place, delays are not likely to be present. The thesis will thus assume that completion of a gas power plant in Fræna can be achieved within 3-4 years, thus at the latest in 2015 if a decision is in 2011. The specifications of the proposed gas power plant in Elnesvågen are summarized in the table below.

Table 4-10: Specifications of the gas power plant alternative (IM, 2006a)

<i>Size</i>	450 MW
<i>Yearly operation time</i>	8300 hours
<i>Production capacity</i>	3,7 TWh
<i>Implementation time</i>	2015
<i>Efficiency level</i>	58%
<i>Gas consumption (approx)</i>	600 Million Sm <sup>3</sup>
<i>Yearly emissions of CO<sub>2</sub></i>	1 250 000 ton
<i>Potential CO<sub>2</sub> capture</i>	1 000 000 ton

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<sup>24</sup> Tjeldbergodden is another potential location for a gas-power plant in Central-Norway. Statoil has previously applied for a concession of a gas power facility there. Another relevant gas-fired power plant is at Skogn in Nord-Trøndelag (Industrikraft Midt-Norge), which could contribute with 8-9 TWh yearly power production.

- **Rationale for investing in a gas-fired power plant**

The strained power situation in Møre og Romsdal opens up possibilities for power production in the region. Statnett reports that the realization of a gas power plant will delay the need for a transmission line between Ørskog-Fardal until 2020. (Statnett, 2005b). Further, as the gas power plant will be localized close to the main concentration of consumption in the region, “*the cost of connecting the plant up to the main grid will in addition be substantially less than in the case of other possible locations in Central Norway*” (Statnett, 2005b; p. 13). As with the transmission alternatives, a local gas-fired power plant will lead to improved supply security as well as reduced network losses.

- **Localization**

Industrikraft Møre has chosen a location in Elnesvågen for the gas power plant, as it will be located close to energy demanding industries in the municipality. In their impact assessment from 2006, Industrikraft Møre write that the motive for Fræna as the municipality was to achieve a coordination of industrial synergies within operation as well as future business development and facilitation for possible future use of gas in the area (IM, 2006a). Refer picture 4.11 for an illustration of where the proposed gas-fired power plant will be located.



Figure 4-12: Location of a power plant in Elnesvågen

- **Technical dimensions**

The planned gas-fired power plant in Elnesvågen will be a combined-cycle power plant with catalytic  $NO_x$  purification, and facilitation for  $CO_2$  management at a later stage. The figure below exemplifies the specifications of a combined-cycle power plant. Refer IM (2006a) for further specification of the technical dimensions of such a facility.

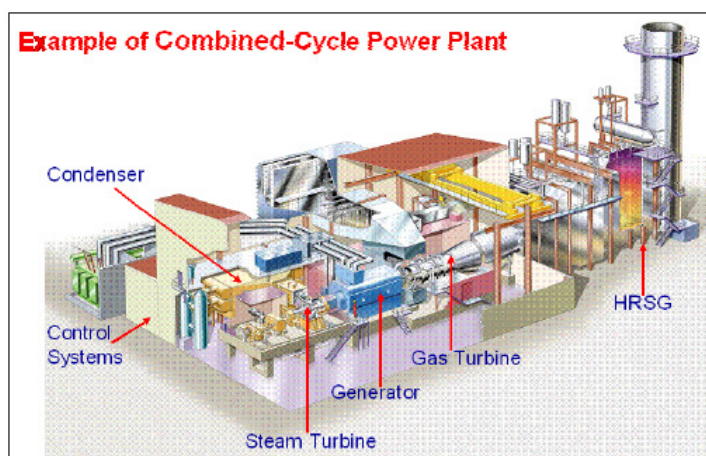


Figure 4-13: Example of a combined-cycle power plant

The size of the proposed power plant is dimensioned for up to 450 MW, which is meant to serve the power needs of Ormen Lange at Nyhamna in the size of 250 MW as well as general consumption in the region. Natural gas to be used in the gas power plant will come from Ormen Lange and transportation of this gas will be conducted in a sea and land cable from Nyhamna (IM, 2006a). It will be Industrikraft Møre AS who will be the developer of the project, where a gas pipeline from Ormen Lange to the gas power plant will be an integrated part of the project. It will however be Naturgass Møre AS who will build the pipeline and will function as the owner and operator of this (IM, 2006a).

- **Dealing with  $CO_2$  emissions**

There are in theory two options for the proposed gas-fired power plant in Elnesvågen, which entail a gas-fired power plant with quota duty or a full-scale cleaning and storage facility of  $CO_2$ .

These alternatives are practically and politically more complicated, as evident in the discussion below.

#### **Gas-fired power plant with quota duty**

The concession that Industrikraft Møre has received to build a gas power plant in Elnesvågen, has in place requirements from the government for  $CO_2$  capture and cleaning from first day of operation, and the government will not provide financial aid to this (Istad, 2010). There have been requirements from several parties that the emission requirements are changed, so that the conditions will be similar to the ones at Kårstø (Faanes, 2010). This would mean that the gas power plant is prepared to deal with  $CO_2$  cleaning at a later stage, when the technology is commercially available. The thesis will look at an alternative where this is approved by the government, and  $CO_2$  emissions are dealt with by buying emission quotas. The thesis will assess this alternative, although Industrikraft Møre for the moment has chosen to lay down the work on the project, as a result of lack of government support (Dagsrevyen, 22.02.2011).

#### **Gas-fired power plant with full scale $CO_2$ management**

As Industrikraft Møre does not find it commercially feasible to invest in a gas-fired power plant with  $CO_2$  management from day one, an alternative approach may be to opt for government support in capturing and storing  $CO_2$ . This alternative has been heavily debated in the media. Supporters of this alternative state that the “moonlanding”<sup>25</sup> projects should be moved from Mongstad to Elnesvågen, as this will be a more economical solution. The local newspaper reported in March that there was new hope for the gas power plant in Elnesvågen, as the government has opened for  $CO_2$  cleaning in other places than at Mongstad (Romsdals Budstikke, 04.03.2011). The thesis will also analyze this alternative, which would mean in practice that government funding for some of the investment costs and operation costs are provided by the government.

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<sup>25</sup> Term used for the European  $CO_2$  Test Center Mongstad (TCM). The test center is a cooperative project between the Norwegian government and Statoil (energy company), where the aim is to establish the world’s largest  $CO_2$  capture and storage (CCS) project in conjunction with a projected combined heat and power plant.

### **4.2.3. End-user measures**

A third investment alternative is for the government to invest in and promote end-user measures. End-user measures may be used to reduce electricity consumption in three distinct ways according to Bye et al. (2010). Firstly, consumers may use another form of energy (substitution), they may move consumption in time and lastly by using less energy in total. NOU (1998) separates ENØK-measures (energy economizing) in two distinct elements, either *energy efficiency* or *energy savings*. **Energy efficiency** is a description of a method to get more out of each energy unit used. Flexibility and higher energy productivity are key aspects to achieve this. **Energy saving** involves limiting the use of energy. The possibility to reduce the use of electricity in particular is significant, and can be achieved through changes in attitudes, habits and routines.

ENØK measures can be accomplished by the industry sector as well as the residential/commercial sector according to IEA (2005). The industry sector may economize on energy use through industry networks and projects. The residential sector are most influenced by ENØK measures and may save energy in the form of building codes, information, advice and campaigns as well as training and education (IEA, 2005). An important topic within end-user measures are hourly metering and billing, such as **AMS** (advanced measuring systems). These measures will provide high flexibility in the short-run.

End-user measures is an important part of the government's energy policy, and unlike large investment projects, there are no public objections against encouraging investments in energy efficiency (Egenhofer and Legge, 2001). Although ENØK thus is an important long-term focus, the effect of end-user measures on the power balance in the region will thus be relatively small, especially compared to the time frame of other investment alternatives. This is because electricity consumption within general supply is only 38% of total consumption, and this share is further falling (Istad, 2010). As end-user measures will not be sufficient to deal with the energy deficit in Central-Norway, this option is thus not analyzed further as an alternative in the CBA.

#### ***4.2.4. Summary of alternatives to be included in the analysis***

Section 4.2 have discussed and analyzed alternatives within transmission, production and end-user measures that might assist in solving the possible power crisis in Central-Norway. Some alternatives have been dismissed as an investment alternative, due to the small impact it will have on the power balance in the region. These are investments in renewable energy sources and end-user measures. Although not analyzed further in the thesis, their impacts on other investment alternatives are evident, in particular the potential renewable energy production in Sogn og Fjordane. The investment alternatives that might solve the power balance in the region are fourfold, and are listed below.

- ❖ Overhead transmission line between Ørskog-Fardal (zero alternative)
- ❖ Redevelopment of existing overhead transmission line (Redeveloped transmission line)
- ❖ Sub water cord
- ❖ Gas-fired power plant
  - a. With quota duty
  - b. With full scale  $CO_2$  management from day one



### 4.3. Specification of impacts

This part of the chapter will look at the impacts of the identified alternatives in section 4.2.4. To identify which impacts to assess, the framework from section 3.2.4 of the thesis will be utilized. The framework divided the costs and benefits into economic, social and environmental impacts as well as including a time dimension and these are briefly replicated in the table below.

Table 4-11: Impacts assesses for the investment alternatives

<b>Economic</b>	<ol style="list-style-type: none"> <li>1. <i>Investment and operating costs</i></li> <li>2. <i>Salvage value</i></li> <li>3. <i>Spillover effect</i></li> </ol>
<b>Social</b>	<ol style="list-style-type: none"> <li>4. <i>Supply security</i></li> <li>5. <i>Transmission losses &amp; bottlenecks</i></li> <li>6. <i>System technical effects and a well functioning market</i></li> <li>7. <i>Delivered electricity (gas-fired power plant)</i></li> </ol>
<b>Environmental</b>	<ol style="list-style-type: none"> <li>8. <i>Environmental impacts (Based on studies using Statens Vegvesen's valuation method)</i></li> </ol>
<b>Time</b>	<ol style="list-style-type: none"> <li>9. <i>Time costs</i></li> </ol>

The above impacts will be discusses in order for the four different investment alternatives, independent of whether they can be monetized or not. When the impacts can be priced, they will be quantified in physical measures and monetized.

### 4.3.1. Zero alternative

The impacts of the zero alternative is analyzed in this section and will be mainly discussed and summarized from the concession application from 2007 from Statnett, as well as some independent studies relevant to this alternative. Some of the numbers may have been revised and updated, and when feasible these are included in the thesis. The impacts are described in the order of table 4.11 and monetized where possible.

#### 4.3.1.1. Investment and operating costs

- **Investment costs**

Statnett write in the concession application in 2007 that the total investment costs of the proposed Ørskog-Fardal transmission line will be around 2 billion NOK. These costs include the investment costs, technical measures as well as remedial actions that needs to be conducted. Refer table 4.12 for a breakdown of the investment costs associated with the zero alternative.

Table 4-12: Zero alternative investment costs

Measures	Costs MNOK
New 420 kV-line (longest route alternative)	1160
Ørskog transformer station	80
Moskog transformer station	170
Fardal transformer station	345
Demolition Fardal-Stølsdalen	25
New 132 kW-line Sande-Høyanger	50
Environmental/ remedial measures	100
<b><i>SUM investment costs (2006)</i></b>	<b><i>1930</i></b>

The costs identified in Statnett (2007) were from 2006 and these numbers can be transformed to 2011 NOK, to be measurable to the costs of the other alternatives. The total investment costs for the zero alternative used in the thesis will thus be 2583 MNOK or rounded up to 2, 6 billion NOK (Based on a discount rate of 6%).

- **Operating costs**

There is not sufficient data available as to what the operating costs of the zero alternative will include and total. The thesis will therefore use the guidelines presented by NVE (2003) and set the operating costs without fees to 1, 5% of the investment costs. The yearly operating costs of the zero alternative can be calculated as:

$$\text{Yearly operating costs} = 2,6 \text{ BNOK} * 1,5\% = \underline{\underline{39 \text{ MNOK}}}$$

Present value of the operating costs after 25 years of operation, can then be calculated to total 228 MNOK.

#### **4.3.1.2. Salvage value**

The physical lifetime transmission network is 50 years whereas the analysis period is 30 years according to NVE (2003). The thesis has set the analysis period of 25 years for all alternatives. This means that some of the investment costs can be recovered, as the analysis period is shorter than the physical lifetime. The salvage value is calculated as the amortized value of the remaining value of the facility, between the analysis period and the physical lifetime, computed after a linear depreciation of the projects physical lifetime (NVE, 2003). Refer formula below.

$$\text{Salvage value} = \text{Investment} * \frac{(\text{Physical Lifetime} - \text{Analysis Period})}{\text{Physical Lifetime}}$$

This means that the salvage value of the zero alternative is 1300 MNOK ( $2600 \text{ MNOK} * (25/50)$ ). The salvage value will be recovered in year 25, and thus the present value of this amount can be calculated to amount 303 MNOK in year 2011.

#### **4.3.1.3. Spillover effect**

The common approach in the central grid is to make investments into overhead transmission lines, as discussed earlier in the analysis. The choice of the zero alternative will thus not have any direct effect on other projects in terms of changes in policy. One implication of choosing overhead transmission lines in this investment decision is that it gives a signal to electricity consumers and the market that this is the preferred alternative compared to other investment alternatives.

#### **4.3.1.4. Supply security**

One of the main rationales for investing in a new overhead transmission line between Ørskog and Fardal was to improve the supply security Central-Norway and especially in Møre og Romsdal. Statnett (2007) found in their concession application that the proposed transmission line will give supply security benefits in terms of having a transmission grid that can handle the increasing import demand in the region and improve electricity supply also in Sogn og Fjordane and locally at Sunnmøre. Next is a description of the monetized benefits associated with the proposed overhead transmission line.

- **Disruption costs**

The monetized effects of supply security are disruption costs measured by KILE. The estimate of these costs were discussed in chapter 4.1.3.4, and assumed to total yearly benefits of 35 MNOK as a result of the proposed transmission line Ørskog-Fardal. Due to lack of sufficient data, this estimate is used in the thesis. The present value of the monetized supply security is around 204 MNOK.

#### 4.3.1.5. *Transmission losses and bottlenecks*

The yearly benefits of reducing transmission losses and bottlenecks in relation to a new overhead transmission line between Ørskog-Fardal were estimated in the concession application of this line to total 52 MNOK for reduced losses and 111 MNOK for reduced bottlenecks (Statnett, 2007). These figures will be used in the analysis, only transformed to 2011 NOK, refer table 4.13 for a summary of these benefits and the calculated present value.

Table 4-13: Transmission losses and bottleneck benefits of the zero alternative

<b>Benefit</b>	(MNOK)
Reduced losses in the network	66
Reduced bottlenecks	140
<b><i>Total yearly supply security benefit</i></b>	<b>206</b>
<b><i>Present value</i></b>	<b>1200</b>

#### 4.3.1.6. *System technical effects and a well functioning market*

- ***Political goals***

One of the main reasons for choosing to solve the power situation in Møre og Romsdal by expanding the transmission network, is due to political goals in terms of renewable and clean energy. The argument supporting investment in transmission capacity on Statnett's homepage is threefold (Statnett, 2011b). Firstly, new power grid infrastructure is necessary to transport new production of renewable energy to the consumers. Facilitating renewable energy will in turn enable a reduction of power that increases emissions of  $CO_2$ , which is of political interest both nationally and in the EU. Secondly, new transmission networks will provide the petroleum sector with clean energy, which are one of the largest contributors of  $CO_2$  in Norway. Thirdly, there has been an increased focus on wind power production in the latter years, which needs to be connected to the central grid to meet the power demand from consumers.

- ***Network and dependability***

Grid reinforcements will be able to resolve the challenges in Central Norway, through the supply of more energy to the region. Statnett (2005a) does however report that in a situation of power shortfall, a solution that comprise of grid reinforcements alone may create new challenges in other areas. In addition to major investments in grid capacity, extensive measures will also be needed to secure stability and reliability in the grid (Statnett, 2005a). Investing in grid reinforcements may thus not be an optimal situation of solving challenges such as energy shortfalls, as the costs will be rather high and security of supply will be weakened (Statnett, 2005a).

#### ***4.3.1.7. Environmental impacts***

This section will discuss the environmental impacts that are posed on the region as a result of the proposed overhead transmission line between Ørskog and Fardal. Firstly, the value of the environment is discussed before a discussion of the consequences of the new line is made.

- ***Environmental value***

The fjord **landscape** in Western part of Norway is highly valuable both on a national and international scale. UNESCO placed both Geirangerfjorden in Storfjorden and Nærøyfjorden in Sognefjorden in their world heritage list in 2005 (Tangeland et al., 2006). The **tourism industry** is of high importance in the areas where the proposed new transmission line will pass. Tangeland et al. (2006) classifies the area as a tourism destination with international importance. The region entails some of the country's most attractive fjord destinations. These are primarily Geirangerfjorden, Hjørundfjorden, and the middle part of Sognefjorden. The region is to an increasing degree marketed in terms of nature- and landscape qualities and there is a high likelihood that the significance of tourism will increase both on absolute and relative terms (Tangeland et al., 2006).

The **recreation** interests in the area are comprehensive and varied. The largest recreational areas are Sunnmørsalpene, Ålfotbreen and Naustdal-Gjengedal. There is in addition to this, a variety of recreational areas in the communities, such as Leikanger, Førde, Nordfjordeid, Stranda and Ørsta. The region is not very different than other parts of the country, in terms of value of **holiday homes**. Tangeland et al. (2006) state that there is a medium large value of holiday homes in the areas, primarily in connection to areas such as Sunnmørsalpene and Jølservatn. Other areas also have low to medium value.

The most valuable **cultural areas** in the region are mainly related to agricultural activities and dairy farming (NIKU, 2007). Technical monuments and infrastructure as well as residential areas are also evident in the region, where the proposed transmission line will be routed. The largest values are connected to mountain and summer farms which partly are actively used as grazing areas and as yet little affected by natural intrusions such as those associated with overhead power lines (NIKU, 2007). The **biological values** in the region are associated with pine forests, bogs and deciduous forests (Fjeldstad and Larsen, 2010). The fjord slopes act as important wildlife areas for deer in the region and there is in addition values attached to raptors. The region also encompasses populations of golden eagles, sea eagles and owls, which are all highly vulnerable to collisions with power lines (Fjeldstad and Larsen, 2010).

- ***Environmental consequences***

Many independent reports have evaluated the environmental impacts from the proposed 420 kW transmission line between Ørskog and Fardal (Zero alternative). Statnett (2007) reports that the proposed new line will affect 15 municipalities, including Ørskog, Sykkylven, Ørsta, Volda, Eid, Bremanger, Flora, Naustdal, Førde, Jølster, Gaular, Høyanger, Balestrand, Leikanger and Sogndal. Below is a table that summarizes the environmental consequences on these municipalities and the environment, based on the individual reports by ASK (2010), NIKU (2010), Fjeldstad and Larsen (2010), Tangeland et al. (2006), SWECO (2010) and Multiconsult (2010).

Table 4-14: Environmental consequences from the zero alternative

Subject	Consequence/ impact	Comment	Study
<i>Natural landscape</i>	Large negative ---	There are significant national values on the west side of the Hjørundfjorden, where the zero alternative is routed. This is the reason why the line has a large negative consequence.	(ASK, 2010)
<i>Cultural heritage</i>	Medium negative consequence --	The line has receives a negative medium consequence, as the line will not redevelop some of the existing line. This leads to a parallel routing with the existing 132 kV line, which have a negative impact on Standaldalen and Follestaddalen.	(NIKU, 2010)
<i>Biodiversity</i>	Medium negative consequence --	The zero alternative affects conservation objectives for the reserves and conservation areas, especially large are the conflicts in relation to forest reserves and planned landscape conservation areas.	(Fjeldstad and Larsen, 2010)
<i>Community and heritage</i>	Very large negative consequence ----	New solutions may to some extent reduce the negative impacts. The negative impact is related to the parallel routing with the existing 132 kV line at the east side of the Hjørundfjord, where important recreational interest lies. The routing on the west side of the Hjørundfjord is especially negative for tourism.	(Tangeland et al., 2006) (SWECO, 2010)



<i>Agriculture</i>	Small/ medium negative consequence -/--	The zero alternative have an impact on the agriculture, as the transmission line will occupy productive forest land. This area is however moderate in relation to the total forest resources in the region.	(Multiconsult, 2010)
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As illustrated from the table above, the environmental consequences from the proposed new transmission line is significant. This is a result of the high value that the region place on its environment, which is evident in the public's reactions to the proposed overhead transmission line Ørskog-Fardal, together with the impact posed by the new line. The studies that investigated the various subjects natural landscape, cultural heritage, biodiversity, community and heritage and agriculture all found that the consequence of the proposed new line would range from medium to very large negative consequence. The main reason for this consequence is a result of the routing of the concession given line on the west side of the Hjørundfjord, where significant values in natural landscape, cultural heritage biodiversity and community and heritage lie. The west side of the fjord is associated with the entrance to the internationally renowned Geirangerfjorden. Another reason for the significant impact is that the zero alternative will be parallel with the existing 132 kV line at the east side of the fjord, and thus confiscate large areas and impact on recreational areas and agriculture.

#### 4.3.1.8. Time

The zero alternative have been studied for many years now, thus the planning process is to a large extent over. This means that implementing a new overhead transmission can be quickly realized, once a decision has been made. Statnett reports in their homepage (Statnett, 2011a) that the aim is completion of the proposed Ørskog-Fardal line by 2015. To be able to reach this goal however, Statnett needs a final conclusion that the entire line can be built as an overhead transmission line by 2011. In April 2011, a partial concession was given by OED to start building sub-parts of the line already in 2011 (OED, 2011). If the line is implemented in 2015, the transmission line will encompass benefits of being a timely alternative and monetized benefits as illustrated in table 4.5. Other non-monetized benefits which are realized include an improvement for regional businesses to invest in expansions or developments in the region, due to access to more power.

Table 4-15: Time benefits of zero alternative

<b>Yearly benefits</b>	<b>MNOK</b>
Disruption costs	35
Transmission losses and bottleneck costs	206
Eliminating costs of regional price differences	476 <sup>26</sup>
Connecting small power producers in Sogn og Fjordane	191, 5 <sup>27</sup>
<b><i>Total yearly benefits</i></b>	<b><i>908, 5</i></b>
<b><i>Present value of benefits (total after 25 years)</i></b>	<b><i>5292</i></b>

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<sup>26</sup> Costs used is the addition regional cost in Central-Norway compared to the system price, refer chapter 4.1.3.1.

<sup>27</sup> For background on this cost estimate, refer section 4.2.2.1.

#### 4.3.1.9. *Net present value of monetized impacts*

The impacts characterized in the above section have been monetized where possible. This section is dedicated to finding the net present value of these impacts and to assess whether the monetized impacts outweigh the costs. The below figure summarizes the benefits and costs and gives the net present value of the zero alternative.

**Table 4-16: Net present value zero alternative**

<b>Costs and Benefits</b>	<b>MNOK</b>	<b>Present value (MNOK)</b>
Investment costs	(2600)	(2600)
Operating costs	(39)	(228)
Salvage value	1300	303
Disruption costs (KILE)	35	204
Transmission losses and bottleneck costs	206	1200
Eliminating/ reducing regional price differences	476	2773
Connecting small power plants in Sogn og Fjordane	191,5	1116
<b><i>Net present value</i></b>		<b>2768</b>

As seen from the above table, the net present value of the zero alternative is positive, which indicates that from the monetized effects, there are more benefits than costs. This thesis has included the estimated benefits of improving supply security, eliminating and reducing regional price differences and connecting small power producers in Sogn og Fjordane.

### **4.3.2. Redevelopment alternative**

This part of chapter 4 will look at the impacts from the redevelopment alternative. Some of the impacts will in this project be identical to the ones discussed above in the zero alternative, some differences are however evident. The most crucial differences are related to investment costs and the effects on the environment. Below is a description of the impacts that are different to the zero alternative, which will also be monetized where possible.

#### **4.3.2.1. Investment and operating costs**

- **Investment costs**

The investment costs of the redevelopment alternative will be somewhat higher than for the zero alternative. The additional costs compared to the zero alternative will be around 360 MNOK, depending on the location of the stations (Statnett, 2010). This means that the total investment costs of the redevelopment alternative will be around 2960 MNOK (2600 MNOK + 360 MNOK). Refer figure 4.17 below for a description of the additional costs associated with the redevelopment alternative, compared to the zero alternative.

**Table 4-17: Investment costs of the redevelopment alternative (Modified after Statnett, 2010)**

<b>Measures</b>	<b>Costs MNOK</b>
New Sykkylven station, including reorganization of local networks	250
Expansion of Ørskog transformer station	80
Demolition of 132 kV- line Ørskog-Sykkylven-Haugen	30
<b><i>SUM additional costs from redevelopment</i></b>	<b>360</b>
<b><i>Total investment costs</i></b>	<b>2960</b>

- **Operating costs**

There is for the redevelopment alternative also not sufficient data available as to what the yearly operating costs will be. The thesis will further use the guidelines presented by NVE (2003) and set the operating costs without fees to 1, 5% of the investment costs. The yearly operating costs of the redevelopment alternative is consequently estimated to total 44, 4 MNOK. The present value of the operating costs after 25 years is calculated to total 259 MNOK.

#### **4.3.2.2. Salvage value**

The physical lifetime and analysis period of the redevelopment alternative is identical to the zero alternative, and is thus subsequently 50 and 25 years respectively (NVE, 2003). The salvage value can be calculated for this alternative is calculated based on the formula by NVE (2003), and the recovered value is as follows:

$$\text{Salvage value} = 2960 \text{ MNOK} * \frac{(50-25)}{50} = \underline{1480 \text{ MNOK}}$$

This value will be recovered in year 25, and thus the present value of this amount can be calculated to amount 345 MNOK in year 2011.

#### **4.3.2.3. Spillover effect**

The redevelopment does not have any spillover effect connected to it, as it will represent the same outcome in terms of policy as the zero alternative.

#### **4.3.2.4. Security of electricity supply**

- **Disruption costs**

The characteristics of the proposed redeveloped line between Ørskog and Fardal possess the same ability as the zero alternative to improve the supply security in Central-Norway, and the thesis will thus originally adopt an equal monetized value for supply security for these two alternatives. The reduced disruption costs were estimated to have a yearly benefit of 35 MNOK with a present value of 204 MNOK. Refer section 4.3.2.8 for a description of how a later implementation time of the redevelopment alternative will reduce this benefit.

- **Non-monetized impacts**

The zero alternative and the redeveloped line will have roughly the same impacts on non-monetized supply security. The main difference is that the redevelopment alternative will make use of the existing 132 kV connection between Ørskog and Haugen, which might influence supply security to a smaller extent. The reason is that if there is a long-term disruption or error on the proposed 420 kV line, the current 132 kW line will be able to transfer some power to the stations Ørskog and Ørsta (Statnett, 2007). This will however be only marginal in relation to maintaining a sufficient supply security in Central-Norway.

#### **4.3.2.5. Transmission losses and bottlenecks**

The benefits of reducing transmission losses and bottlenecks will be assumed to be the same for the redevelopment alternative as the zero alternative, with transmission loss costs of 66 MNOK and bottleneck costs of 140 MNOK. The redevelopment line will thus accrue yearly benefits of 206 MNOK, with a present value of 1200 MNOK. If the transmission line is realized a year or two later than the zero alternative, the benefits will be reduced in these years, as discussed in section 4.3.2.8.

#### 4.3.2.6. **System technical effects and a well-functioning market**

The redevelopment will be able to achieve the same political goals as the zero alternative and possess the same characteristics in terms of network and dependability.

#### 4.3.2.7. **Environmental impacts**

The proposed new overhead transmission line that will utilize the existing location of the 132 kW transmission line, entail some distinct environmental advantages compared to the zero alternative. Especially the new transformer station in Sykkylven is seen as a pure environmental measure, as it will not have any considerably larger benefit for the power system (Statnett, 2010). The environmental value of the landscape will be similar to the zero alternative, as it will be located in the same region. This value was described in section 4.3.1.6.

- **Environmental consequences**

The independent studies of the redevelopment alternative have found that it possess some distinct benefits to the environment compared to the zero alternative. The findings of these studies are summarized below and given a degree of consequence after Statens Vegvesen's valuation method.

**Table 4-18: Environmental consequences of the redeveloped alternative**

<b>Subject</b>	<b>Consequence/ impact</b>	<b>Comment</b>	<b>Study</b>
<i>Natural landscape</i>	Medium/ large negative consequence --/--	The impact is dependent on transformer choice. Redevelopment of the existing Haugset transformer station seen the alternative with the lowest impact. The study concludes that this alternative will keep the landscape more or less unchanged compared to the current situation.	(ASK, 2010)

<i>Cultural heritage</i>	Small/ medium negative consequence -/--	With redevelopment of the existing 132 kV transmission line and a transformer station in Sykkylven, the routing on the west side of the Hjørundfjord is avoided which is generally considered to be positive for the cultural heritage in the region.	(NIKU, 2010)
<i>Biodiversity</i>	Small/ medium negative consequence -/--	The construction of a new transformer station in Sykkylven means that a 420 kV line on the west side of the Hjørundfjord is avoided, which means that impacts to wildlife in particular are reduced/ avoided. The impacts on the east side of the fjord will however increase, and will pass among other the Gjevenesstranda nature reserve.	(Fjeldstad and Larsen, 2010)
<i>Community and heritage</i>	Medium/large negative consequence --/---	The impacts locally are considered to be larger for the redeveloped alternative, however regionally it is seen as an advantage over the zero alternative especially as tourism attractions on the west side of the Hjørundfjord will not be affected.	(SWECO, 2010)
<i>Agriculture</i>	Small/ medium negative consequence -/--	Voltage upgrade of the existing line instead of a new route, means that less area and useful forest land is utilized	(Multiconsult, 2010)

As seen from the above table, the environmental consequences of the redevelopment alternative is ranked from small to negative consequence, and all subjects graded above the zero alternative. The reason for being considered a better alternative is that an existing route is used, thus utilizing the existing environmental footprint. The redeveloped 420 kW transmission line will moreover have a positive environmental effect on those residents who currently live close to the 132 kW



line, as the new line will go higher up in the terrain and thus have a greater distance to the residence (Statnett, 2010). Further, the routing of the redevelopment alternative will be moved to the east side of the Hjørundfjord, and thus avoid the environmental impacts associated with the routing on the west side of the fjord as with the zero alternative.

#### **4.3.2.8. Time**

By redeveloping the existing transmission line Ørskog-Sykkylven-Haugen, the current 132kV line must be removed before the 420 kV line is developed. This means that this project will take longer time than the zero alternative, as the line must be completed from one side towards Sykkylven, before the wire is removed at the other end (Statnett, 2010). This is because a power supply line to Sykkylven needs to be maintained in the construction phase. This analysis assumes that an additional year is needed for the redevelopment of the existing line, and thus this project might be completed in 2016. It is realistic that the line is completed by 2015, however the thesis will assume a lengthier implementation time to illustrate the effect of this on the benefit side of the investment. This additional implementation time will have impact on the benefit side of the alternative, by reducing the value of supply security, regional price differences and connection of power plants in Sogn og Fjordane by 1 year. Refer table 4.19 for a summary of the monetized value of these benefits and the reduction in the value of the benefits (time costs).

**Table 4-19: Time costs of redevelopment alternative**

<b>Yearly benefits</b>	<b>MNOK</b>	<b>Present value if realized in 2016</b>	<b>Time costs</b>
Disruption cost	35	169	35
Transmission losses and bottlenecks	206	994	206
Eliminating costs of regional price differences	476	2297	476
Connecting small power producers in Sogn og Fjordane	191,5	924,5	191,5
<b>Total</b>	<b>908, 5</b>	<b>4384, 5</b>	<b>908, 5</b>

#### 4.3.2.9. Net present value of monetized impacts

The priced effects that have been described for the redevelopment alternative will be summarized and the economic performance will be calculated in this section. The priced effects is somewhat similar to the zero alternative, however the investment cost is 360 MNOK higher and there is some costs associated with a later implementation date for the redevelopment alternative. Refer figure 4.20 for a rundown of the monetize effects of this investment alternative.

Table 4-20: Net present value of redevelopment alternative

Costs and Benefits	MNOK	Present value (MNOK)
Investment costs	(2960)	(2960)
Operating costs	(44,4)	(259)
Salvage value	1300	345
Disruption costs (KILE)	35	169
Transmission losses and bottlenecks	206	994
Eliminating/ reducing regional price differences	476	2297
Connecting small power plants in Sogn og Fjordane	47	924
<b>Net present value</b>		<b>1510</b>

As seen in the table above, the net present value for the redevelopment alternative is positive. The NPV is not as high as the zero alternative, nevertheless a solid alternative which have more favorable environmental impacts. If the line can be implemented in **2015** and not 2016 as assumed in this thesis, the NPV will be significantly larger at **2419 MNOK**. If this would be the case, the only main difference between the redevelopment alternative and the zero alternative in terms of monetized impacts would be the additional investment cost of 360 MNOK.

### 4.3.3. Subsea cable

An alternative to the overhead transmission line between Ørskog-Fardal is to build a subsea cable. The initial argument for this project is that it will minimize the environmental impacts, through being less visible in the natural landscape. The costs associated with a subsea cable is however significantly higher than a transmission line, and the main reason for opposition. This section of the thesis will have an in depth analysis of the impacts associated with building a subsea cable as a substitute of the zero alternative. The discussion follows the steps in table 4.11.

#### 4.3.3.1. Investment and operating costs

- **Investment costs**

The investment costs for the proposed cable facility is around 2400 MNOK more than the zero alternative (Statnett, 2010, Norconsult, 2010). This means that the estimated total investment costs of the zero alternative is 5020 MNOK. The uncertainty in this price estimate is however high and will depend on the competitive situation among the suppliers and the cost of raw materials. Norconsult (2010) propose that the accuracy of this estimate is between +/- 25%, while Statnett (2010) estimates the accuracy to be around -10% to + 30%. The breakdown of the additional investment costs is summarized in the table below.

Table 4-21: Total investment costs subsea cable alternative (Modified after Statnett, 2010)

Measures	Costs MNOK
Cable and installation costs	1912
Compensating reactors	220
Construction and facility	188
Contractor costs	100
<b><i>Additional investment costs of the subsea cable</i></b>	<b>2420</b>
<b><i>Total investment costs of the subsea cable</i></b>	<b>5020</b>

- **Operating costs**

The operating costs of the subsea cable are assumed to be 1, 5% of the investment costs, as for the other investment alternatives into the transmission network (NVE, 2003). Using this guideline from NVE (2003) as a result of lack of data, the yearly operating costs of the subsea cable alternative will be 75, 3 MNOK. Present value after 25 years of operating cost is calculated to total 439 MNOK.

#### **4.3.3.2. Salvage value**

The physical lifetime and analysis period of the subsea cable can also be assumed to be identical to the zero alternative, and is thus subsequently 50 and 25 years respectively (NVE, 2003). Using the formula presented in this thesis, the recoverable value of the subsea cable calculated to be

$$\text{Salvage value} = 5020 \text{ MNOK} * \frac{(50-25)}{50} = \underline{\underline{2510 \text{ MNOK}}}$$

This value will be recovered in year 25, and thus the present value of this amount can be calculated to amount 585 MNOK in year 2011.

#### **4.3.3.3. Spillover effect**

The spillover effect will probably be most evident in the subsea cable alternative, due to the current governmental policy. The current Norwegian power grid infrastructure consists of 2/3 of overhead transmission lines. The use of cables in the central grid is thus not a common approach, especially when the voltage level increases. The consideration of cables is however included when the regional and central grid is developed, but underground and subsea cable is mostly relevant on limited distances with significant conservation interests or large esthetic disadvantages on 66kV and 132kV transmission lines (OED, 2010). It can also be considered for routes with large environmental gains with 300 and 420kV (OED, 2010). Deciding on a subsea

cable in the Ørskog-Fardal project would mean that a change in policy is required, which may affect the decision on other investment projects in the central grid. If there is a spillover effect on the Ørskog-Fardal project on other similar investment, it will represent significantly higher investment costs. Hervik et al. (2011) conclude in their report on investment alternatives in Hardanger that the investment costs with increased used of cables in the energy policy in the period between 2011-2020 is somewhere in the range between 15 and 30 billion NOK. This is based on the assumption that cabling is eight times more expensive per kilometer than overhead transmission lines.

#### **4.3.3.4. Security of electricity supply**

It is important to reflect on the security of electricity supply when considering a subsea cable. The monetized effects can be concluded to be similar to those of the zero alternative, however the non-priced effects will be somewhat more complex. Below is a discussion of supply security aspects regarding the subsea cable.

- **Disruption costs**

The characteristics subsea cable possess an unchanged ability as the zero alternative to improve the supply security in Central-Norway, and the thesis will thus originally adopt an equal monetized value for supply security for these two alternatives. The benefits of reduced disruptions costs are thus set to 35 MNOK, with a present value of 204 MNOK. The later implementation date of the subsea cable will reduce these benefits however, as discussed in section 4.3.3.8.

- **Non-monetized effects**

Although the cable will improve the current power deficit in the region, some technical aspects that affect the supply security compared to the zero alternative exists. The main element relates to errors and repair time, and is discusses in more detail in the next section.

### **Errors and repair time**

There are few errors on oil cable facilities according to Statnett (2010), the repair time will however be significantly longer compared to an overhead transmission line. This is because an overhead transmission line normally can be repaired in a couple of hours, as the placement of the error is often easily accessible and the material is standard stock item. Cables on the other hand, need to be removed from the sea, which will be more difficult the deeper it lies. This operation is further dependent on special equipment and vessels, which there are not so many of globally (OED, 2010). Normal repair time lies between 2-6 months (Statnett, 2010). Statnett and OED use the extreme case of the cable in the Oslo fjord as an example of the repair time of a sub water cable, which took 18 months to repair (Statnett, 2010, OED, 2010). The proposed subsea cable in Geiranger is however planned with two sets of cables, where the network connection will be able to operate with half capacity until the error is repaired. This does however mean that the transmission need will not be met at any time, which subsequently will put restrictions on the power system. Statnett (2010) considers the likelihood of errors on both cable sets in Geiranger as very small.

#### ***4.3.3.5. Transmission losses and bottlenecks***

The subsea cable will be an improvement to the existing central grid in Central-Norway and this investment will also reduce transmission losses and bottlenecks in the region. The thesis assumes identical yearly reduction for the zero alternative and the subsea cable and thus the benefits are 206 MNOK yearly, with a present value of 1200 MNOK.

#### ***4.3.3.6. System technical effects and a well-functioning market***

Ørskog-Fardal will be the most important transmission connection between Central and South of Norway according to Statnett (2010). Cabling this line will offer some significant system-technical challenges and disadvantages and impact on how well the market will function.

A cable facility will according to Statnett (2010) generate a far greater **reactive effect** than a overhead transmission line. This must be compensated by a reactor facility, in order to keep the voltage from the 420 kV power grid at the correct level. It is suggested that a fixed reactor and two adjustable reactors in the transformer stations at Ørskog and Ørsta.

A great deal of **system-related uncertainty** is present in cable cords at the length planned in the Hjørundfjord. These uncertainties are among others related to the threat of resonance fluctuations and surges at the input- and output links of the cable connections (Statnett, 2010). Resonance can in addition to creating system technical problems in the existing power grid, also limit the possibilities for cabling other routes (Statnett, 2010).

Subsea cables will be more **difficult to integrate** into the current power system according to OED (2011). The reason is that subsea cables will be more heavily loaded than overhead transmission lines, thus additional equipment will be needed before installation. Another argument put forward by OED (2011) is that increased use of cables in the power system leads to greater distance between the connection points, which mean that more grid capacity is needed to be able to connect small power plants and larger hydro- and wind power facilities. Without the development of such capacity, a subsea cable will hinder power developments in Sogn og Fjordane and at Sunnmøre.

#### **4.3.3.7. Environmental impacts**

The main rationale for choosing a subsea cable over the zero alternative, is that a cable will have less aesthetic effects on the environment than an overhead transmission line. The value of the region in and around Geiranger has been described earlier in this analysis, and will be the same for the subsea cable alternative. The consequences of the proposed cable in the sea are elaborated further below.

- **Environmental consequences**

The consequences of the subsea cable is summarized in table 4.22 and based on the independent studies (ASK, 2010; NIKU, 2010; Fjeldstad and Larsen, 2010; SWECO, 2010(Multiconsult, 2010).

**Table 4-22: Environmental consequences subsea cable**

<b>Subject</b>	<b>Consequence/ impact</b>	<b>Comment</b>	<b>Study</b>
<i>Natural landscape</i>	Medium negative consequence --	There will be visible impacts on the natural landscape where the coupling facility will be placed in Store-Standal as well as from the routing junction from the concession given solution to the coupling facility. The cabling from Ørskog to Store-Standal will have no visual interventions to the natural landscape.	(ASK, 2010)
<i>Cultural heritage</i>	Small negative consequence -	The cable alternative will primarily have consequences for Store-Standal, where possibly a coupling facility will be located. The cable will not affect any registered or well known cultural heritages on the route Store-Standal-Ørskog. It will however be unfortunate for cultural heritage on the transmission route Store-Standal-Haugen, which will be parallel with the existing 132 kV line.	(NIKU, 2010)
<i>Biodiversity</i>	Small negative consequence -	A subsea cable will have little impact on important sites of natural environment onshore. The subsea cable will however have some of the route in an overhead line, which has a negative impact on biodiversity.	(Fjeldstad and Larsen, 2010)



<i>Community and heritage</i>	Medium/large negative consequence --/---	The assessment here is not easy, as this alternative is not significant to community and heritage in Sykkylven. The cable will however have a very large negative impact in the area of Ørsta. The consequence in the study is thus seen from a regional perspective.	(SWECO, 2010)
<i>Agriculture</i>	Insignificant/small negative consequence 0/-	The subsea cable will exploit much less area that can be otherwise be used for forest and farmland, as around two-thirds of the cable will be under water. There will be some area used in the transmission line Ørsta-Store-Standal, thus an insignificant to small consequence is given.	(Multiconsult, 2010)

As seen from the above table, the subsea cable alternative is considered a less intrusive investment choice from an environmental standpoint, with small to medium/large consequence rankings. The reason that the subsea cable will have a medium to large negative consequence in the subject community and heritage, is that the wires must be routed all the way down to the fjord and landing stations must be placed at each side of the fjord. These facilities will be located in densely populated areas and may be perceived as large interventions in small communities. Nevertheless, two-thirds of the route will be placed under water and therefore have no visual impact on any of the subject categories described above.

#### **4.3.3.8. Time**

A cable facility between Ørskog and Store Standal is implementable within a time frame of around 4 years (Norconsult, 2010). This estimate is dependent on the use of oil cables and that there is sufficient production capacity when the decision is reached. Statnett (2010) does however report that if a decision is reached in 2011, it will not be realistic to assume completion until earliest 2016. But a later completion date cannot be excluded, due to the complexity of and lack of experience associated with such a project (Statnett, 2010). Hervik et al. (2011) write in

their report about Hardanger, that a subsea cable will take an addition five years compared to the overhead transmission line. Based on these arguments and the uncertainty surrounding the completion date of the subsea cable, the thesis assumes that a subsea cable can be completed in 2017. The thesis further assumes that there will not be sufficient difference between the subsea cable and the zero alternative when it comes to the possibilities of connecting small power plants and possibilities for improving supply security and reducing regional price differences. The later implementation of the subsea cable compared to the zero alternative will however reduce the positive impact from these benefits by 2 years. This is replicated in the table below.

**Table 4-23: Benefits of subsea cable and time costs**

<b>Yearly benefits</b>	<b>MNOK</b>	<b>Present value if realized in 2017</b>	<b>Time costs</b>
Disruption costs	35	141	63
Transmission and bottleneck costs	206	833	367
Eliminating costs of regional price differences	476	1926	847
Connecting small power producers in Sogn og Fjordane	191,5	775	341
<b>Total</b>	<b>908, 5</b>	<b>3675</b>	<b>1618</b>

#### **4.3.3.9. Net present value of monetized impacts**

Below is a summary of the benefits and costs associated with the subsea cable alternative. Evident from the discussion in section 4.3.3, is that a subsea cable represents much higher investment costs than the zero alternative.

Table 4-24: Net present value of subsea cable alternative

Costs and Benefits	MNOK	Present value (MNOK)
Investment costs	(5020)	(5020)
Operating costs	(75,3)	(439)
Salvage value	2510	585
Disruption costs	35	141
Transmission losses and bottlenecks	206	833
Eliminating/ reducing regional price differences	476	1926
Connecting small power plants in Sogn og Fjordane	191,5	775
<b>Net present value</b>		<b>(1199)</b>

As exemplified in the table above, the economic costs are much higher than the benefits of the subsea cable alternative. The main reason is the high investment cost as well as the estimated later implementation time. Consumers have come forward in the media and favored this solution, as it is more environmentally friendly than the zero alternative. The additional investment costs of 2400 MNOK for the subsea cable compared to the zero alternative would however have to be covered by general consumers. It is evident in the theory that consumers have a positive WTP to avoid the aesthetic effects of overhead transmission lines, refer discussion in chapter 3.2.2.5; however there is not sufficient data to determine this WTP for the Geiranger case. One can however calculate how much each consumer would have to pay each year, if this alternative was chosen. The environmental cost by choosing the subsea cable can be calculated by dividing the additional investment cost on the relevant consumers. If the subsea cable is considered a national solution, the additional cost of 2400 MNOK will on average total 83 NOK<sup>28</sup> per household per year for 25 years. If the subsea cable is considered a regional solution, the additional cost divided by the population in Central-Norway will amount around 650 NOK<sup>29</sup> per household per year for 25 years.

<sup>28</sup> Assuming 2,2 million households in Norway (www.ssb.no)

<sup>29</sup> Assuming 292 000 households in Central-Norway (www.ssb.no)

#### ***4.3.4. Gas-fired power plant with quota duty***

The gas-fired power plant with quota duty is what Industrikraft Møre has applied for in their concession application of 2006. This section of chapter 4 will explore and discuss the economic specifications of this alternative, including costs and benefits that can and cannot be monetized. The impacts associated with a gas-fired power plant are somewhat different than those related to investment into the transmission network. Especially relevant to power production is the benefits received from production of energy and the costs associated with emissions of greenhouse gases (NVE, 2003). This discussion will like the other investment alternatives follow the steps of figure 4.13.

##### ***4.3.4.1. Investment and operating costs***

- ***Investment costs***

The investment costs of the proposed gas-fired power plant in Elnesvågen consist of a standard power plant including the pipeline connecting the facility to the gas supplier and to the customer network. Total investment costs are estimated to be 2091 MNOK (IM, 2006a). This investment costs can be calculated to total around 2800 MNOK in 2011 NOK. The costs associated with building a gas power plant will depend on the technical solution chosen and selected suppliers. The estimated costs used in this paper, are from IM (2006) on a power plant with an installed effect of 450 MW, based on prices from turbine suppliers, Aker-Kværner ASA, Norsk Hydro ASA, Norske Shell AS, SFT and Point Carbon AS. Some of the costs might have changed since the concession application, but the thesis will be based on these numbers.

- ***Operating costs***

Operating costs can be divided into maintenance costs, feeding costs to the transmission network, costs of producing electricity and pollution costs. These costs are discussed below and then summarized.

### **Maintenance and feeding costs**

Industrikraft Møre calculated the *maintenance costs* on the facility and the pipeline to total 110 MNOK in 2006 (IM, 2006a). This sum totals 148 MNOK in 2011 NOK. In addition to these costs, Industrikraft Møre (IM, 2006) will also have to pay *yearly feeding costs* to the transmission network of 3, 6 MNOK (based on a tariff of 0, 1 øre/ kWh). This feeding fee can be calculated to total around 152, 8 MNOK in 2011 NOK. The net present value of the maintenance and feeding costs after 25 years can be calculated to total 890 MNOK.

### **Production of electricity**

Another high cost element associated with a gas-fired power plant, is the cost of gas that is needed to produce electricity. The cost of gas is difficult to determine and will impact on the profitability of the proposed gas fired power plant. The thesis assumes a long-term price of gas of 0, 84 NOK/ $sm^3$  and that the proposed power plant will need around 615 million  $sm^3$ / year. The cost of producing electricity can then be calculated to total around 516, 6 MNOK yearly, with a present value of 3009 MNOK.

### **Pollution costs**

Some environmental impacts can be monetized and given a value from society's viewpoint, and for the gas power plant alternative these impacts are related to emissions. Probably the most fundamental consequences of building a gas power plant is the air emissions, which means increases in national  $CO_2$  and  $NO_x$  emissions in particular. These two costs will be elaborated further.

EU's quota system has made it possible to set a price on  **$CO_2$  emissions**. The price on a quota explains in principle the costs of reducing emissions of  $CO_2$  with one unit, and creates an international market where quotas are traded (IM, 2006a). This means that when there is one ton emissions in Norway, this will be offset with one ton reduced emissions another place in the world (IM, 2006a). The gas power plant planned at Elnesvågen will emit around 1 250 000 ton of  $CO_2$  without capture. IM (2006) calculated a price of yearly emissions of 200 million NOK,

assuming a long-term  $CO_2$  price of 20 Euro per ton<sup>30</sup> (1 euro = 8 NOK). This sum gives a present value of 1165 MNOK.

Industrikraft Møre's gas power plant will emit around 67 tons of  $NO_x$  per year. The socioeconomic cost of this can be estimated by using the government fee of  $NO_x$ , which is 15 NOK per kilo or 15 000 NOK per ton. Then the price of emissions will be in excess of 1 MNOK per year of the proposed gas power plant (IM, 2006a). Present value of this yearly cost can be calculated to total 5,9 MNOK.

### Summary of operating costs

The below figure illustrate the sum of the yearly operating costs associated with the gas-fired power plant. These costs are dependent on the assumption of the cost of gas, as well as the quota costs.

**Table 4-25: Operating cost of gas-fired power plant with quota duty**

<b>Yearly operating cost</b>	<b>MNOK</b>
Maintenance and feeding costs	152,8
Production of electricity	516,6
Pollution costs	201
<b><i>Total operating cost</i></b>	<b><i>870,4</i></b>
<b><i>Present value of operating costs</i></b>	<b><i>5070</i></b>

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<sup>30</sup> The current price level of  $CO_2$  is around 10-15 Euro per ton. There is uncertainty surrounding the long-term price of  $CO_2$ , however Klimakur 2020 put a carbon price of 40 Euros as the basis for 2020, with 20 Euros as the low-cost and 60 Euros as the high-price alternative. Refer RINGLUND, G. B., ROSLAND, A. & BJØRKUM, I. 2009. Vurdering av framtidige kvotepriser. In: KLIMAKUR2020 (ed.) *En rapport fra etatsgruppen Klimakur 2020*. Oslo.

#### **4.3.4.2. Salvage value**

The physical lifetime of a gas power plant is 40 years whereas the analysis period is 25 years (NVE, 2003). This means that some of the investment costs can be recovered, thus the recovered value of the gas-fired power plant in Elnesvågen is as follows:

$$\text{Salvage value} = 2800 \text{ MNOK} * \frac{(40-25)}{40} = \underline{\underline{1050 \text{ MNOK}}}$$

The value of the salvage value which will be accrued in 25 years is in 2011 worth around 245 MNOK. In addition to the salvage value for the gas power facility, one can also assume that there will be a salvage value from the mobile gas power plants located in the region, as they will become redundant if a new gas power plant is built (IM, 2010). If one assume that the salvage value of these are also 37, 5%, and the investment costs of these were 2100 MNOK, the salvage value can be calculated to be around 788 MNOK. This is 184 MNOK in 2011. The total salvage value of the gas-fired power plant can thus be calculated to total 429 MNOK in 2011.

#### **4.3.4.3. Spillover effect**

The current government will not give concession to any new gas-fired power plant without CO<sub>2</sub> capture and storage. Allowing Industrikraft Møre to build a conventional gas power plant without CO<sub>2</sub> management would mean a change in this policy and affect other projects that want to invest in gas-fired power. Another spillover effect of increased usage of gas is the impact it has on the central grid. Statnett (2005b) write that the effects of direct usage of gas as a substitute for electric households and industry could be significant for the development of the central grid in the long-term. The spillover effects of this is however difficult to quantify.

#### **4.3.4.4. Supply security**

An increase in local production, such as the gas power plant in Fræna will be able to reduce the energy deficit in Møre og Romsdal as well as reduce the need for transmission in the network, both within and outside the region. Below is a description of the monetized and non-monetized supply security benefits of the proposed gas-fired power plant with quota duty.

- **Disruption costs**

The monetized effects of supply security for the proposed new power plant in Elnesvågen will be assumed to be similar to the ones of the zero alternative. This is because not sufficient data has been found that have calculated the specific supply security benefits of the gas-fired power plant. The yearly saved disruption costs used for this alternative are therefore 35 MNOK, with a present value of 204 MNOK.

- **Non-monetized effects**

As discussed above, the monetize effects of new power production in Møre og Romsdal will lead to reduced disruption costs. New production also has other supply security benefits, which are not so easy to monetize. Statnett (2005b) write in their report that the proposed gas-fired power plant will maintain the supply in Central-Norway, as well as give lower prices in the region and lower price differences in other regions. New power production will further contribute to an improved national balance and somewhat lower prices generally in the power system (Statnett, 2005b).

#### **4.3.4.5. Transmission losses and bottlenecks**

Statnett points out that new production close to the site of the consumers can reduce grid losses and bottlenecks (Statnett, 2005a). Due to lack of sufficient data, the thesis have assumed that the gas-fired power plant can obtain the same yearly benefits as the zero alternative and thus set the benefits to be 206 MNOK, with a present value of 1200 MNOK.



#### **4.3.4.6. System technical effects and a well-functioning market**

- **Political goals**

One of the main reasons why the proposed gas-fired power plant in Elnesvågen has not received a concession with quota duty is the political agenda on the **management of CO<sub>2</sub>**. OED (1999) reports that: *“Any future applications for construction of gas-fired power plants should be treated according to the Energy Act and Pollution Control Act. Based on an overall assessment, the Government will oppose construction of gas power in Norway that is not based on CO<sub>2</sub> cleaning. This assessment emphasizes the need for stimulation of new technology and the need to implement the necessary changes in energy consumption and production<sup>31</sup>”* (Section 3.3.2). This White Paper on energy policy clearly state that a conventional gas-fired power plant with quota duty is not part of a well-functioning electricity market. Another political agenda is the **Kyoto protocol**, which has been discussed earlier in this thesis. A new gas-fired power plant in Elnesvågen would increase the national emissions of CO<sub>2</sub> and reduce the possibility of Norway reaching its target.

- **Commercially unprofitable**

A gas power plant will be able to reduce the energy deficit in the region, however might struggle in periods where the demand for electricity is lower and less expensive power is available in the market. Hervik et al (2011) write that it will thus be difficult to achieve a commercially profitable operation, especially without support from the government. Support from the government is however not feasible or highly demanding due to the political agenda as well as the rules for state aid (Hervik et al., 2011). A possible solution to this problem is to conduct a similar scheme for tendering new electricity production as **CADA** (Capacity and Differences Agreement) in Ireland (Sandsmark and Hervik, 2008). A scheme which is approved by the European Commission, refer (EC, 2003). The directive by the European Commission gives producers of electricity the possibility of conducting tendering when the concession process is

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<sup>31</sup> Translated by author

not sufficient to improve supply security (Sandsmark and Hervik, 2008). A number of assumptions must however be met in order to achieve an equivalent agreement in Central-Norway (Hervik et al., 2011a).

- ***Network investment***

Localization of new production in Central-Norway, such as gas-power, would according to Statnett (2005a) mean a considerably reduced need for investment in the grid in the region. Due to heavy increase in consumption by energy demanding industries, transmission reinforcements have been planned. These grid reinforcements could be reduced or postpone the need for these investments and the zero alternative could be delayed until 2020 (Statnett, 2005a). Industrikraft Møre estimates that there is a benefit of around 500 MNOK from saved investments in the power grid, as a result of local power production. The proposed gas-fired power plant would however not facilitate connection of small energy producers in Sogn og Fjordane. Choosing this alternative would consequently mean that a transmission connection to Sogn would be necessary to connect these producers, in addition to the gas-fired power plant.

#### ***4.3.4.7. Delivered electricity***

The willingness to pay for electricity is dependent on income and demand, where the latter is dictated by the time of day as well as seasons, temperature and activities (NVE, 2003). The amount of delivered electricity will be the income side of the investment, and will be dependent on the future price of electric energy. Delivered electricity is on the benefit side of the gas-fired production facility according to NVE (2003). The yearly operating time at the proposed gas-fired power facility in Elnesvågen is around 8300 hours, which give a yearly power production around 3, 7 TWh. If one assumes that the long term price of electricity will be around 0, 40 NOK/ kWh, the benefit of delivered electricity from the gas-fired power plant can be estimated to be around 1480 MNOK. This benefit will however be charged with a 60 % electricity tax, less 10% for the electricity that will be lost in the transmission network (NVE, 2003). The total yearly benefit will can then be calculated to be around 680 MNOK. Refer the table below for an illustration of the assumptions and income from delivered electricity.

Table 4-26: Delivered electricity from a gas-fired power plant with quota duty

<i>Yearly power production</i>	3,7 TWh (3700 000 000 KWh)
<i>Long-term price of electricity</i>	0, 40 NOK/ KWh
Benefit from delivered electricity	1480 MNOK
Electricity tax	(800 MNOK)
<b><i>Net benefit of delivered electricity</i></b>	<b>680 MNOK</b>
<b><i>Net present value of delivered electricity</i></b>	<b>3961 MNOK</b>

#### **4.3.4.8. Environmental impact**

There are various effects on the environment as a result of developing a gas power plant. Some of these impacts have been monetized and accounted for under operating costs, such as  $CO_2$  and  $NO^x$  emissions. Emissions of  $CO_2$  is often the main concern relating gas-fired power, though other impacts must also be accounted for. This section will elaborate on the non-priced environmental consequences associated with the proposed gas-fired power plant in Elnesvågen.

- ***Environmental consequences***

Industrikraft Møre has conducted an impact study from the proposed gas-fired power facility in Elnesvågen (IM, 2006). There has not been independent studies conducted, such as with the transmission alternatives. The impacts from the gas power plant is however more important in terms of calculating and accounting for the emissions that occur as a result of producing electricity. Another aspect is further that the gas-power plant is built in an existing industrial site, and thus has not impacts on residential areas and tourism destinations in the same manner as transmission lines. Below is a short summary of the findings from IM (2006).

Table 4-27: Environmental consequences gas-fired power plant with quota duty

	<b>Impact</b>	<b>Consequence</b>
<i>Natural landscape</i>	The planned facility will be placed in an industrial site, next to Hustad Marmor AS in Elnesvågen. The largest element of the gas-fired power plant will be the chimney, which will be approx. 50-60 meters high. A further 50-60 meters in height must be added, if and when a CO <sub>2</sub> capture facility is developed. The height of the facility means that the power plant is highly visible in the landscape and will be visible from parts of the population in Elnesvågen. Will however not appear dominant.	Small negative consequence
<i>Natural resource/ biodiversity</i>	There are several protected areas and a large number of registered important habitats for biological diversity. These are however not impacted.	Insignificant consequence
<i>Community and heritage</i>	The area where the gas-fired power plant is planned built is regulated as an industrial site. The whole area is thus fully investigated by archaeologists and released by heritage authorities.	Insignificant consequence
<i>Noise-pollution</i>	The conclusion from the impact assessment is that the gas power plant can be built within the given noise limits in the area. This does however presuppose that noise-reducing measures are put in place together with a favorable noise utilization of the industrial site.	Insignificant consequence
<i>Sea-pollution</i>	The main emissions to the sea are temperate seawater. The normal temperature of the cooling water will be in the region of 13-16 degrees, and will not give rise to malformation or unacceptable biological effects in the fjord.	Insignificant consequence

#### 4.3.4.9. Time

This thesis has assumed that the proposed gas-fired power plant with quota duty can be realized in 2015 if a decision is reached in 2011. This means that this alternative will receive the same time benefits as the zero alternative in that respect, in terms of supply security and reducing or eliminating the regional price differences. The benefit that the proposed gas-fired power plant will not solve, is the connection of small power producers in Sogn og Fjordane. The time benefits of the power plant are illustrated in the table below.

Table 4-28: Time benefits of gas-fired power plant with quota duty

<b>Yearly benefits</b>	<b>MNOK</b>
Disruption costs	35
Transmission losses and bottlenecks	206
Eliminating costs of regional price differences	476
<b><i>Total yearly benefits</i></b>	<b><i>717</i></b>
<b><i>Present value of benefits (total after 25 years)</i></b>	<b><i>4177</i></b>

#### 4.3.4.10. Net present value of monetized impacts

The impacts characterized in the above section have been monetized where possible and these are summarized in the table below to assess whether a gas-fired power plant with quota duty will have more economic benefits than costs. These calculations are merely based on the monetized impacts of the alternative.

Table 4-29: Net present value of the gas-fired power plant with quota duty

Costs and Benefits	MNOK	Present value (MNOK)
Investment costs	(2800)	(2800)
Operating costs	(870, 4)	(5070)
Salvage value	1838	429
Disruption costs	35	204
Transmission losses and bottlenecks	206	1200
Delivered electricity	680	3961
Eliminating/ reducing regional price differences	476	2773
<b>Net present value</b>		<b>697</b>

As seen from the above table, a gas-fired power plant with quota duty has a positive NPV, when included economic benefits in addition to business benefits. There are however limitations in associated with this NPV, which stems from the fact that gas-fired production is not commercially profitable during current business environment and climate politic (refer section 4.3.4.5). There will thus be an additional cost represented to this alternative, as the plant would need some governmental support to cover normal business operation. The reason is that the investors of a gas-fired power plant will not receive the social benefits of the investment, but be dependent on the price paid for gas and the income received from electricity. Refer table 4.30 for an overview of the volatility of the NPV to the changing prices in gas and electricity.

Tabell 4-30: NPV with changing gas price and electricity price conditions

		<i>Price of electricity</i>		
		<i>20 øre/kWh</i>	<i>30 øre/kWh</i>	<i>40 øre/kWh</i>
<b>Price of gas</b>	<i>47øre/ Sm<sup>3</sup></i>	47 MNOK	1142 MNOK	2025 MNOK
	<i>66 øre/ Sm<sup>3</sup></i>	(632 MNOK)	359 MNOK	1346 MNOK
	<i>84 øre/Sm<sup>3</sup></i>	(1281 MNOK)	(290 MNOK)	698 MNOK
	<i>102 øre/Sm<sup>3</sup></i>	(1921 MNOK)	(929 MNOK)	58 MNOK
	<i>120 øre/Sm<sup>3</sup></i>	(2564 MNOK)	(1573 MNOK)	(586 MNOK)

Table 4.30 illustrate that the economic performance of the gas-fired power plant is highly dependent on a high long-term price of gas of 40 øre/  $Sm^3$  to be able to be beneficial to society. If the electricity price is 30 øre/kWh, the gas price must be under 84 øre/ $Sm^3$  and under 66 øre/ $Sm^3$  if the electricity price is under 20 øre/kWh.

#### ***4.3.5. Gas-fired power plant with CO<sub>2</sub> management***

Management of CO<sub>2</sub> including cleaning and storage is a rather new technology, which is currently being tested in Norway and globally. The European Union has committed itself through the Kyoto protocol to facilitate technological development of CO<sub>2</sub> cleaning technologies, transportation systems and storage. Similar technologies are also being developed in Australia and Canada (KON-KRAFT, 2002). In the US, CO<sub>2</sub> has been transported in pipes from different states around Texas and used for pressure support for onshore oil wells for several years (KON-KRAFT, 2002). This technology has created a value for CO<sub>2</sub> that offsets the cost of power losses and cleaning costs. In Norway, alternative methods for CO<sub>2</sub> management are currently under development. Common for these are however that it will be a lengthy process to develop commercially sustainable solutions and the current technologies are mostly available for smaller power facilities (OED, 2008).

This section will discuss the economic aspects of a gas-fired power plant with CO<sub>2</sub> management. Only those aspects which are different to a conventional gas-fired power plant will be elaborated on, including investment and operating costs, salvage value, delivered electricity, time and net present value of monetized impacts. Refer section 4.3.4 for a review of the other impacts. A section which discusses governmental funding of a full-scale CO<sub>2</sub> management facility is also included in this section of the analysis. The main assumption behind the discussion of a full-scale gas power production facility with CO<sub>2</sub> cleaning and storage in Elnesvågen, is that the government will fund some of the costs and in that respect choose to move the “moonlanding” project from Mongstad to Elnesvågen.



#### 4.3.5.1. Investment and operating costs

- **Investment costs**

Investment costs related to a CO<sub>2</sub>-capture facility were in 2006 around 1 billion NOK, and are based on “The Co2 Capture Project” (IM, 2006a). Industrikraft Møre AS and Aker Kværner ASA have in their “Just Catch” program a goal of halve these costs to around 500 MNOK. In addition, other costs must be added on, thus a Co2 capture program in relation to Industrikraft Møre AS and the gas power plant can be estimated around 1, 5-2 billion NOK (IM, 2006a). The thesis will assume that the additional investment costs of a CO<sub>2</sub> capture facility will be 1500 MNOK, which makes the total investment cost of a gas-fired power plant in Elnesvågen 3591 MNOK, with a value in 2011 NOK of around 4800 MNOK.

- **Operating costs**

Operational costs of the CO<sub>2</sub>-capture facility is estimated to be between 150-200 MNOK (IM, 2006a). These estimates have an accuracy of +/- 40%. Using the top of the estimate of 200 MNOK in operating costs, this has a value in 2011 of 268 MNOK. These operating costs will be in addition to the operating costs of the conventional gas-power plant, except the costs of pollution. Refer table 4.30 for a rundown of the operational costs associated with a gas-fired power plant with CO<sub>2</sub> management.

Table 4-31: Yearly operating costs of gas-fired power plant with CO<sub>2</sub> management

<b>Yearly operating cost</b>	<b>MNOK</b>
Maintenance and feeding costs	152, 8
Production of electricity	516, 6
CO <sub>2</sub> -capture facility	268
<b>Total operating cost</b>	<b>937, 4</b>
<b>Present value of operating costs</b>	<b>5460</b>

#### 4.3.5.2. Salvage value

If one assumes similar recovered value calculations for a conventional gas-fired power plant as with the gas-fired power plant with CO<sub>2</sub> management, the salvage value of the latter is as follows:

$$\text{Salvage value} = 4800 \text{ MNOK} * \frac{(40-25)}{40} = \underline{1800 \text{ MNOK}}$$

The value of the salvage value which will be accrued in 25 years is in 2011 worth around 420 MNOK. One can also presuppose for this gas power plant alternative that there is a salvage value from the mobile gas power plants located in the region of around 788 MNOK. This is 184 MNOK in 2011. The total salvage value of the gas-fired power plant can thus be calculated to total 604 MNOK in 2011.

#### 4.3.5.3. Delivered electricity

Common to all processes that can remove CO<sub>2</sub> are that they are energy demanding and lead to reduced efficiency in power production (KON-KRAFT, 2002). Industrikraft Møre reports that the electric power consumption from the CO<sub>2</sub>-capture facility will be around 20 MW, thus 4,4 % of total capacity. Assuming this estimate, a gas-fired power plant with CO<sub>2</sub> management will produce around 3,5 TWh yearly. Based on the same assumptions as for the conventional gas-fired power plant, the net benefit of delivered electricity can then be calculated to total:

**Table 4-32: Delivered electricity from gas-fired power plant with CO<sub>2</sub> management**

<i>Yearly power production</i>	3,5 TWh (3500 000 000 KWh)
<i>Long-term price of electricity</i>	0,40 NOK/ KWh
Benefit from delivered electricity	1400 MNOK
Electricity tax	(756 MNOK)
<b><i>Net benefit of delivered electricity</i></b>	<b>644 MNOK</b>
<b><i>Net present value of delivered electricity</i></b>	<b>3751 MNOK</b>

#### 4.3.5.4. Time

A conventional power-plant was in this thesis assumed to be implemented in 2015, if a decision was reached in 2011. A gas-fired power plant with CO<sub>2</sub> management from day 1 is a much more timely process. Although Siemens can deliver a gas-fired power plant with CCS by 2015<sup>32</sup>, the political decision process will probably add some time to the planned implementation. It is difficult to predict the length of this process, thus the thesis assumes that the capture facility can be implemented 3 years after the zero alternative. The implementation time is then set to the beginning of 2018. The conventional power plant had time benefits of improving supply security and regional price differences of 256 MNOK and 476 MNOK yearly, with a present value of 1492 MNOK and 2773 MNOK respectively. These benefits are reduced with a delayed implementation of 3 years and the time benefits and costs are summarized in table 4.32.

**Table 4-33: Time benefits from a gas fired power plant with CO<sub>2</sub> management**

<b>Yearly benefits</b>	<b>MNOK</b>	<b>Present value if realized in 2018</b>	<b>Time costs</b>
Disruption costs	35	116	88
Transmission losses and bottlenecks	206	681	519
Eliminating costs of regional price differences	476	1574	1199
<b>Total</b>	<b>717</b>	<b>2371</b>	<b>1806</b>

<sup>32</sup> Refer discussion in Romsdals Budstikke (18.05.2011), “En landsdel på vent”, p. 35

#### 4.3.5.5. Net present value of monetized impacts

Below is a summary of the monetized effects of the proposed gas-fired power plant in Elnesvågen, with a  $CO_2$  capture facility.

Table 4-34: Net present value of gas-fired power plant with  $CO_2$  management

Costs and Benefits	MNOK	Present value (MNOK)
Investment costs	(4800)	(4800)
Operating costs	(937,4)	(5460)
Salvage value	2588	604
Disruption costs	35	116
Transmission losses and bottlenecks	206	681
Delivered electricity	644	3751
Eliminating/ reducing regional price differences	476	1574
<b>Net present value</b>		<b>(3534)</b>

The values presented in the table above, illustrate that the economic costs associated with a  $CO_2$  capture facility clearly outweigh the benefits. The NPV is largely negative, and is a result of the high investment costs and operating costs associated with this alternative. With the current costs of  $CO_2$  capture and storage technology, gas-fired power production will have much higher costs than benefits, from the priced-effects. The profitability is expected to increase in the coming years however, as research in the area is rather new and continued research will bring down the costs (OED, 2008). Profitability will also increase if one can achieve deposition on  $CO_2$  (OED, 2008). The implementation time assumed in this thesis is highly uncertain. If a decision to build and support a CCS facility in Elnesvågen is reached in the near future by the Government, it may be possible to be implemented by 2015. The NPV of this alternative will in that scenario be less negative, **-1708 MNOK**. Although implemented in 2015, the CCS facility in Elnesvågen would need some governmental support to be realized.

#### **4.3.5.6. Governmental financial support**

For the proposed gas-fired power plant in Elnesvågen, the realization of a full-scale  $CO_2$  cleaning and storage facility is dependent on support from government, and possibly a change in policy. The reason why the government might want to change its policies and fund such a project will be to motivate development of  $CO_2$  technology. The government has pointed out that the “moonlanding” project is not a determined place, but a political and technological task to promote  $CO_2$  management technology that will be more profitable than pollution. It has been argued recently therefore that the gas-fired power plant in Elnesvågen should also become a test center for  $CO_2$  technology development, and the government wrote in 2010 as follows:

*“If the power-plant in Elnesvågen with full scale  $CO_2$  management is to be financed by the developer alone, the financial risk will be so large that the project cannot be realized. The leader of the Low Emissions Committee, Professor Jørgen Randers, recently introduced the idea of moving step 2 of the governments ‘moonlanding’ project for capturing and storing  $CO_2$  from Mongstad to a new project. In that respect, the plans of Industrikraft Møre in Elnesvågen is a relevant alternative. This would then avoid the cost, security and technology challenges related to building a  $CO_2$  capture facility in a gas power plant that is already in operation. This might be a serious solution with respect to the challenges at Mongstad and the supply situation in Central-Norway” (Stortinget, 2010) <sup>33</sup>*

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<sup>33</sup> Translated by author

#### **4.4. Compilation and assessment of the cost-benefit analysis**

This section is divided into three main parts. Firstly, the economic benefits and costs of all the investment alternatives are compiled and discussed. This is conducted by firstly addressing the priced effects and then the non-priced effects. A consequence matrix then illustrates the main conclusions from the priced and non-priced effects. The second part of this section is a sensitivity analysis, which addresses the uncertainty elements of the analysis. Thirdly, a conclusion is given based on the findings from the Geiranger case study.

##### **4.4.1. Economic costs and benefits**

###### **4.4.1.1. Priced effects**

The monetized effects that the thesis identified in section 4.3 of this thesis will be summarized and assessed in this part. These include the investment and operating costs, salvage value, supply security and time benefits. For the gas-fired power plant, delivered electricity is another monetized benefit. One of the main impacts which affect the net present value of the various alternatives is the implementation time. Refer figure 4.14 for a timeline of the estimated implementation time for the different alternatives.

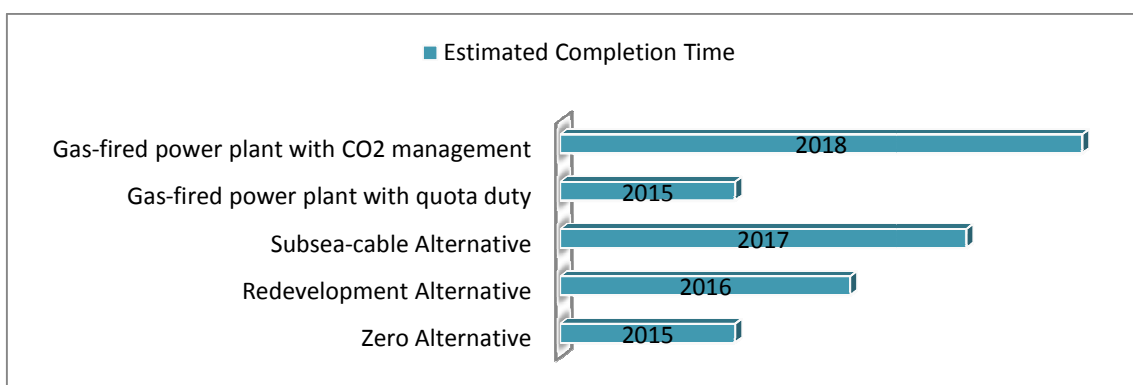


Figure 4-14: Timeline for the different investment alternatives

As exemplified by the timeline, the alternatives that are assumed quickest to implement are the zero alternative and the conventional gas-fired power plant. These have higher time benefits in terms of being able to reduce supply security and regional price differences from 2015. The zero alternative will also connect small power producers from Sogn og Fjordane, which is another benefit which will be realized from 2015. The other alternatives lose 1- 3 years of these benefits, which represent significant values. (Also benefits accrued in earlier years have higher values than benefits in later years). For a summary of the monetized impacts of all alternatives and comparison of the NPV values, refer table 4.34. All numbers are in million NOK.

**Table 4-35: Summary of priced effects for all investment alternatives**

	<b>0-alternative</b>	<b>Redeveloped transmission line</b>	<b>Subsea-cable</b>	<b>Gas-fired power plant with quota duty</b>	<b>Gas-fired power plant with CO<sub>2</sub> management</b>
<b>Costs</b>					
Investment costs*	(2600)	(2960)	(5020)	(2800)	(4800)
Operating costs	(39)	(44, 4)	(75, 3)	(870, 4)	(937, 4)
Time cost*	X	(908,5)	(1618)	x	(1844)
<b>Benefits</b>					
Salvage value*	303	345	585	429	604
Disruption costs	35	35	35	35	35
Transmission loss & bottleneck costs	206	206	206	206	206
Delivered electricity*	x	x	x	680	252
Regional price differences and renewable energy producers	668	668	668	476	476
<b>NPV</b>	<b>2768</b>	<b>1510 (2419)**</b>	<b>-1199</b>	<b>696</b>	<b>-3534</b>

\*One time sum (not yearly)

\*\*If redevelopment alternative is realized in 2015

The calculations above illustrate the main monetized effects of the various investment alternatives and based on these estimates find that three of the alternatives have positive net present values. These are the zero alternative, the redevelopment alternative and the gas-fired power plant with quota duty. If the assumption of completion in 2016 for the redevelopment alternative is changed to 2015, the only cost changing it from the zero alternative is the 360 MNOK higher investment cost. The gas-fired power plant also have a positive NPV, however as discussed earlier it will be an additional cost to this alternative, as it would need governmental support to be a commercially viable facility. So is the case for a gas-fired power facility with  $CO_2$  management. The subsea cable has a negative NPV, which is mainly a result of the higher investment cost and later implementation time than the zero alternative. If the consumers WTP would have been known, these costs might have been covered and resulted in a different NPV. The calculation earlier in this thesis concluded that the amount consumers would have to pay to cover the additional investment costs was 83 NOK per year for 25 years if considered a national public good and 650 NOK if considered a regional public good.

The priced-effects do not give any final answer to the most preferable investment choice, as there are many parameters that have not been considered. However, based merely on the NPV and the impacts from the priced-effects, the alternatives can be ranked in the following order:

- Zero alternative
- Redevelopment alternative
- Gas-fired power plant with quota duty
- Subsea cable
- Gas-fired power plant with  $CO_2$  management

#### **4.4.1.2. Non-priced effects**

There are numerous impacts that has not been monetized in this analysis, but qualitatively described where possible. Highly relevant to the energy debate is the environmental impacts, which have partly only been monetized for the gas-fired power plant alternatives. The non-priced impacts are compiled in the table below, to give an overview of these impacts for the various alternatives.



Table 4-36: Summary of non-priced effects of all investment alternatives

	<b>0-alternative</b>	<b>Redeveloped transmission line</b>	<b>Subsea-cable</b>	<b>Gas-fired power plant with quota duty</b>	<b>Gas-fired power plant with CO<sub>2</sub> management</b>
<i>Spillover effect</i>	<b>None</b> In compliance with current transmission investment practices	<b>None</b> In compliance with current transmission investment practices	<b>High</b> Not in compliance with current practices, spillover effect on other investment projects	<b>Medium/high</b> Not in compliance with current regulation of CO <sub>2</sub> management for gas-fired power facilities, requires change in policy and thus affect other projects	<b>None</b> In compliance with current regulation of CO <sub>2</sub> management for gas-fired power facilities
<i>Supply security</i>	<b>Good</b> Improves supply security in Central-Norway and Sogn	<b>Same/ worse</b> Will not keep an additional connection (132kV) to assist in errors on the 420 kV line. This only have a marginal effect on supply security however.	<b>Same/worse</b> Later implementation time and the duration of repairing errors on the line is longer and more complex	<b>Same/Worse</b> Will not strengthen supply security in Sogn, as a new connection is not built	<b>Same/Worse</b> Will not strengthen supply security in Sogn, as a new connection is not built
<i>System-technical effect and a well-functioning market</i>	<b>Good</b>	<b>Good</b>	<b>Acceptable</b> A subsea cable has a greater reactive effect, more system-related uncertainty and more difficult to integrate	<b>Same/ worse</b> A gas-fired power plant is commercially unprofitable under current business and political environment – will need government support. Increase national emissions of CO <sub>2</sub> impact on Kyoto targets.	<b>Same/ worse</b> Will need government funding to be realized
<i>Natural landscape</i>	<b>Large negative</b> Ranked as the worst of the transmission alternatives	<b>Medium/large negative</b> Ranked as the best of the transmission alternatives (if Haugset station is chosen)	<b>Medium negative</b> Ranked over the zero alternative, however below the redevelopment alternative (Haugen)	<b>Not significant</b> Industrial site. The largest visual element is the chimney which is 50-60 meters. Will not appear dominant in relation to other industrial sites.	<b>Not significant</b> The chimney will be an additional 50-60 meter in height
<i>Cultural heritage</i>	<b>Medium negative</b> Ranked as the worst of the transmission alternatives	<b>Small/ medium negative</b> Ranked over the zero alternative	<b>Small negative</b> Ranked as the best of the transmission alternatives	<b>Not significant</b> Industrial site	<b>Not significant</b> Industrial site

<i>Biodiversity</i>	<b>Medium negative</b> Ranked as the worst of the transmission alternatives	<b>Small/ medium negative</b> Ranked over the zero alternative	<b>Small negative</b> Ranked as the best of the transmission alternatives	<b>Not significant</b> The main impact is cooling water, but will not give rise to unacceptable biological effects	<b>Not significant</b> The main impact is cooling water, but will not give rise to unacceptable biological effects
<i>Community and heritage</i>	<b>Very large negative</b> Ranked as the worst of the transmission alternatives	<b>Small/ medium negative</b> Ranked over the zero alternative (regional perspective – not local)	<b>Medium/large negative</b> Ranked as the best of the transmission alternatives. Very negative from a local perspective in Ørsta however.	<b>Not significant</b> Industrial site	<b>Not significant</b> Industrial site
<i>Agriculture</i>	<b>Small/ medium</b> Ranked as the worst of the transmission alternatives	<b>Small/ medium negative</b> Ranked over the zero alternative	<b>Insignificant/ small negative</b> Ranked as the best of the transmission alternatives	<b>Not significant</b> Industrial site	<b>Not significant</b> Industrial site

The valuation of the non-priced effects clearly illustrate that there are many important characteristics of the investment alternatives that cannot be monetized. As the table illustrate, all the investment alternatives have acceptable levels of supply security, compared to the zero alternative. The system technical effects and elements for a well functioning market are somewhat different however. The zero and redevelopment alternatives both have good scores under this heading. The subsea cable is also similar, however will be somewhat more difficult to integrate in the current power grid network. Both the gas-fired power plants will need government support to operate profitable and without CCS, a gas fired power plant would need changes in current government policy to be realized. From an environmental viewpoint, the subsea cable has the best valuation from the transmission alternatives, especially in relation to the aesthetic impacts. The gas-fired power plant with quota duty cover its negative impact in the priced-effects, thus both the production alternatives have a better environmental impact than the zero alternative in that respect. A ranking based on the non-priced effects is difficult; however it is evident that the alternatives which were ranked low based on the NPV have much better valuation on the non-priced effects. It is also difficult to rank the transmission and production

alternatives against each other, as this would require a weighting of emissions versus aesthetic effects. This discussion is outside the scope of this thesis.

#### 4.4.1.3. Consequence matrix

The consequence matrix summarizes the main elements from the priced and non-priced effects that illustrate the main differences of these alternatives. The alternatives are in this table compared against the zero alternative, based on investment costs, completion time, supply security and environmental impact.

Table 4-37: Consequence matrix

	INVESTMENT COST	COMPLETION	SUPPLY SECURITY	ENVIRONMENT
<i>Zero alternative (Ørskog-Fardal)</i>	<b>2600 MNOK</b>	2015	<b>Good</b> Improves supply security in Central-Norway and Sogn.	<b>Poor</b> Significant impacts on the environment, with aesthetic effects on high-value fjord landscapes
<i>Redevelopment (Ørskog-Sykkylven-Haugen)</i>	<b>Additional 360 MNOK</b>	2016 (2015)	<b>Same/worse</b> Waiting until 2016 and using current line has insignificant impact.	<b>Better</b> Utilizes existing route and thus makes no “new” footprints, except larger masts and a new transformer station
<i>Subsea cable (Ørskog-Store-Standal)</i>	<b>Additional 2400 MNOK</b>	2017	<b>Same/worse</b> Waiting until 2016 and lengthier repair times has little impact.	<b>Better</b> Less aesthetic impacts as two-thirds of the line is located subsea, but local impacts associated with landing facilities
<i>Gas-fired power plant with quota duty</i>	<b>Additional 200 MNOK</b>	2015	<b>Same/Worse</b> Will not improve supply security in Sogn	<b>Better/worse</b> Less aesthetic affects, however environmental costs associated with emissions
<i>Gas-fired power plant with CCS</i>	<b>Additional 2200 MNOK</b>	2018	<b>Same/Worse</b> Waiting has little impact, but will not improve supply security in Sogn	<b>Better</b> Less aesthetic affects and deals with the costs associated with emissions

#### **4.4.2. Sensitivity analysis**

As discussed in section 3.1.3.4, there will always be some uncertainty present in CBA in terms of the predicted impacts and the values assigned to them. The uncertainty relating to these in the thesis can be rather high, as much of the impacts and values are either obtained from secondary sources or estimated based on secondary sources. The goal of carrying out a sensitivity analysis is therefore to see how sensitive the estimated benefits and costs are to changes in assumptions.

##### **4.4.2.1. Discount rate**

The level of discount rate used in this thesis has been set to 6 per cent as a basis alternative. The discussion in section 3.1.2.5 did however suggest that the level of discount rate should be lower. Based on personal communication with Hervik 03.03.2011, the thesis will test the robustness of the analysis by changing the discount rate to 4 per cent for the various alternatives.

**Table 4-38: NPV with a discount rate of 4 per cent**

	<b>Zero alternative</b>	<b>Redevelopment</b>	<b>Subsea cable</b>	<b>Gas-fired power plant (quota)</b>	<b>Gas-fired power plant (CO<sub>2</sub> management)</b>
<b>NPV 4 %</b>	5857,10	4579,96	1698,68	2567,41	-2646,51

As evident from the above figure, all the alternatives have a higher NPV with a discount rate of 4 per cent. This is a result of benefits and costs have a higher value in later years with a lower discount rate, thus benefits which accrue each year will more outweigh the investment costs. Boardman et al. (2011) write that the estimates are robust as long as the signs of the alternatives do not change. In the calculations from the Geiranger case, the sign of the subsea cable alternative changes to a positive sign, with a lower discount rate. This is because the high investment costs have a higher value compared to the benefits with a higher discount rate. This means that there is some uncertainty relating to the NPV calculations of this alternative in the thesis. The ranking of the alternatives based on the NPV do however not change with a lower discount rate.

#### 4.4.2.2. Analysis period

The analysis period in this thesis was set to 25 years. The lifetime of the transmission grid is however estimated to 30 years and 40 years for production facilities (NVE, 2003). The thesis will thus use another analysis period to see the sensitivity of this assumption. Hervik et al. (2011) use an analysis period of 35 years in their Hardanger analysis and thus this period will be used in this section. When such a lengthy analysis period is used, the salvage value is excluded from the calculations. Refer figure 4.38 to see the changes of the calculated NPV.

Table 4-39: NPV with an analysis period of 35 years

	Zero alternative	Redevelopment	Subsea cable	Gas-fired power plant (quota)	Gas-fired power plant (CO <sub>2</sub> management)
<b>NPV 6% disc./ 35 years</b>	228,16	-1057,90	-3927,91	-1087,16	-5228,19
<b>NPV 4% disc./ 35 years</b>	2908,62	1605,90	-1421,36	536,21	-4539,33

When using the 6 per cent discount rate with an analysis period of 35 years, the NPV of the various investment alternatives changes. The redevelopment alternative and the gas-fired power plant with quota duty change their sign to negative, which indicates that their calculation is prone to some uncertainty. The zero alternative is the only investment option with a positive NPV with an analysis period of 35 years and it does not change the sign, thus it is most robust alternative. If the discount rate is lowered however, the NPV results are not drastically different from the original estimates. The lower discount rate gives benefits during the 35 year lifetime higher values than the 6 per cent discount rate, thus the NPV's are positive for the zero alternative, redevelopment alternative and gas-fired power plant with quota duty.

#### 4.4.2.3. Priced-effects

The thesis has attempted to quantify impacts such as regional price differences, connecting small power producers in Sogn og Fjordane and the costs of delaying the implementation time. These estimates are however in theory part on the non-priced effects of supply security. If these benefits are not included in the analysis, the net present value of the various alternatives will be as follows:

Table 4-40: NPV with varying assumptions of priced-effects

	Zero alternative	Redevelopment	Subsea cable	Gas-fired power plant (quota)	Gas-fired power plant (CO <sub>2</sub> management)
<b>NPV excluding all</b>	-1120,36	-1469,81	-3469,80	-2076,26	-4501,29
<b>NPV excluding renewable + time</b>	1652,33	1302,87	-697,12	696,43	-1728,55
<b>NPV excluding regional + time</b>	-4,88	-354,33	-2354,32	-2076,26	-4501,23
<b>NPV excluding regional + renewable</b>	-1120,36	-2378,31	-5087,80	-2076,26	-6307,23

If neither the benefits of regional price differences, connecting small power producers or time are included in the calculations, the alternatives all have negative NPV. In fact, if the estimate of eliminating or reducing regional price differences is not included, the alternatives do not have a positive net present value. The thesis have estimated a number for the benefits of regional price differences, but is uncertain and cannot conclude that any of the investment alternative will reduce or remove the inequity of price differences for 25 years. The sensitivity analysis above does however illustrate that the benefit of this assumption, is an important reason to invest in new transmission or production capacity in the region.

### **4.4.3. Conclusion**

One cannot draw a single conclusion as to the most economically profitable investment alternative in the Geiranger case. This assumption is consistent with the chronicle by Karine Nyborg<sup>34</sup> in Dagens Næringsliv in regards to concluding that an investment alternative is economically profitable based on the CBA methodology. The CBA of the Geiranger case and the possible investment choices in this thesis does however give an indication of the economic considerations in such a complex investment environment and it also highlights the economic benefits and costs that decision makers need to consider.

The thesis has analyzed three transmission alternatives, which include the zero alternative, the redevelopment alternative and the subsea cable. A ranking between these three is not possible based on the CBA. The zero alternative however comes out as having the most positive NPV from the investigated alternatives, and the subsea cable as the most environmentally friendly from the independent studies of environmental effects. The redevelopment alternative has an additional investment cost of 360 MNOK and seen as a less intrusive line in the environment than the zero alternative. The new transformer station in Sykkylven in relation to this alternative will have no system technical effects to the power system and is thus considered a pure environmental measure. A ranking of the transmission alternatives would mean a valuation of the WTP for the protection of environmental values, in which there is a lack of relevant information in the academia. One can however conclude that the transmission investment alternatives with the lowest market costs in the Geiranger case also have the most impact on the environment.

The thesis further investigated two production alternatives, which included a conventional gas-fired power plant with quota duty and a gas-fired power plant with  $CO_2$  capture and storage from day one. These alternatives are not dissimilar to the zero alternative when it comes to supply security, however will not have the benefit of connecting small power producers in Sogn og Fjordane. Both these alternatives cannot run a commercially profitable operation without government support however, even though the requirements for CCS are relaxed. The thesis

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<sup>34</sup> Dagens Næringsliv (06.05.2011), "Lønnsomt, og så?"

cannot rank transmission versus production alternatives based on the CBA, because this decision must also be seen as a trade-off between aesthetic effects and the costs of pollution. The thesis has found no studies that have investigated the public's opinion in these questions<sup>35</sup>.

There can be a value of waiting for more information in terms of developments within consumption and investigating the public's WTP in the environmental questions. The complex investment environment, characterized by irreversibility, the order of investments, stochastic inflows to the water power plants, environmental conflicts and an uncertain framework, may make the value of waiting for more certain information significant for potential investors (Sandsmark and Hervik, 2008). There are however also benefits included in this thesis that favor investment alternatives that can be quickly implemented, such as connecting small power producers of renewable energy in Sogn og Fjordane, reducing the costs associated with supply security and reducing or eliminating the regional price differences between Central-Norway and the rest of the country. Industries in the region are also currently suffering from a lack of energy investments, and would benefit from a timely alternative, which would motivate investments and reduce competitive disadvantages as a result of price differences.

The goal of OED is also to make an investment that is timely and completed by 2015. In April 2011, the ministry adopted a resolution for sections of the proposed zero alternative, which means that the sections Sogndal-Moskog as well as the south side of the Hjørundfjorden to Ørsta will be realized independent of the decision of other investment alternatives on the remaining sections<sup>36</sup>. The construction will start in late summer of 2011 and the approved section will consist of around half of the route between Ørskog-Fardal. This decision illustrates the lack of governmental dedication for a gas-fired power plant in Elnesvågen, with neither quota duty nor CCS. The realization of such production potential in the region is thus not likely to be realized in the near future.

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<sup>35</sup> This discussion is also outside the scope of this thesis

<sup>36</sup> Refer to the governmental press release:

<http://www.regjeringen.no/nb/dep/oed/pressesenter/pressemeldinger/2011/delvedtak-for-420-kv-kraftlinje-mellom-o.html?id=639863>



## 5. Discussion and recommendations

This chapter represents the last part of the thesis and is divided in to three main parts. First, this chapter will attempt to discuss the findings from chapter 4 and answer the research problem. The main limitations of the study are highlighted next, before recommendations for further research are made.

### 5.1. *Research problem discussion*

Based on the foregoing chapters, this section will answer the research problem presented in the introduction of the thesis. The question was as follows: *“What is the most economic electric power investment that balances the long-term impacts on the environment against the short-term requirements of reliable and secure electricity supply?”*

There is unfortunately no easy answer to this research problem. The reason for this is that the CBA framework does not alone represent all parameters relevant to make this trade-off between the environment and reliable and secure electricity supply. One large problem is that investment and operating costs as well as some aspects of reliability and security of electricity supply can be given a value in terms of priced effects, while environmental values can only be quantified in non-priced effects. There are methods that attempt to monetize the value of the environment and the value of for example avoiding the aesthetic effects of overhead transmission lines. Sufficient information can however not be drawn from these studies, that a generalized conclusion in terms of environmental value can be provided. The Geiranger case in this thesis and the Hardanger case by Hervik et al. (2011) have therefore not sufficient information to make a conclusion of the ranking of environmental investment alternatives such as a subsea cable. The Hardanger case did however conclude that the additional cost of a subsea cable must be covered by consumers, where general consumers would have to pay 90 NOK per year for 35 years to cover this “environmental” cost, if considered a national public good. The Geiranger case found similar result, with a yearly cost of 83 NOK for 25 years to cover the additional cost of a subsea cable. Relevant WTP studies for these two regions would however be necessary to conclude whether

consumers would be willing to pay these costs to save the regions of an overhead transmission line.

Based on the above discussion, it can therefore be relevant to suggest that more comprehensive research is carried out, that attempts to map the public's willingness-to-pay in different regions for avoiding the aesthetic effects of overhead transmission lines. Perhaps, some landscapes and regions will have a higher WTP, as a result of their national and international importance. Surely, Geirangerfjorden and Hardangerfjorden are examples of such landscapes. One can therefore ask the question of how valuable a landscape must be before it is "worth saving". Possibly a list, comparable to "Samla Plan<sup>37</sup>", could be mapped. This would give the public a voice in the debate and allow them to state which landscapes they would be willing to conserve for future invasion. Such a plan would also define a cohesive framework for valuing landscape in electric power investment decision.

There is also another relevant discussion from the research problem, which is the time aspect of an investment decision. Central-Norway is currently in a stressed power situation with capacity constraints in terms of available energy. Investment alternatives that can be realized at the same time as the zero alternative or sooner, have valuable contributions to supply security, renewable energy production, regional price differences and industries. The findings in the Hardanger case also suggested that a timely investment alternative would have added benefits, although the implementation time was not crucial and projects that could be realized within 2018- 2020 was also realistic solution to the power situation in BKK. The added benefits of a quick realization must be weighted up against the value of waiting for more information. A project invested in now, might have irreversible long-term impacts on the environment and thus a conclusion of an investment alternative must be carefully considered based on all these non-quantifiable parameters. It is not always economic to choose an investment alternative that have low market costs and high environmental costs or vice versa. Decision makers needs a holistic view of all projects and also consider the distributional effects of an investment alternative as well as other

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<sup>37</sup> Samla Plan is an overall plan for the Norwegian rivers, which was established in the 1980s. The aim was to regulate hydro power production by developing a unified national governmental management of the country's waterways. The framework was led by the Ministry of Environment. ([www.nve.no](http://www.nve.no))

parameters not covered in the CBA methodology. Cost-benefit analysis does however provide an in depth analysis of available information and analysis of economic costs and benefits based on this information, which will provide the decision makers with more knowledge in the area under investigation. A CBA also give a theoretical analysis of emphasized impacts, whether monetized or not, with a description of the positive and negative impacts and the uncertainty surrounding these.

## **5.2. Limitations**

This section will state the limitations of this thesis, which is based on the knowledge, time and available resources of the author. Below is a description of the main limitations and challenges that occurred in the process of the thesis.

One of the main limitations of the thesis was the availability of sufficient and transparent data and information in regards to the Geiranger case. This meant that data used by for example Statnett was not explained or the background to the data was not available to the public. This has resulted in the data used in the analysis are mainly taken directly from these secondary sources, or estimated based on the available information. The reliability and validity of the data is could therefore not be checked.

Another limitation was the CBA calculations itself. The cost-benefit analysis in chapter 4 is a somewhat simplified model, which attempts to illustrate how CBA can be applied and illustrate which parameters that is relevant to consider in an investment environment such as the energy sector. A more holistic model would be necessary to verify the conclusions in this thesis. The findings do however correspond with the work of Hervik et al. (2011), which indicates that there is some theoretical foundation in the conclusions.

Due to the time and resources of this thesis, as well as the knowledge of the author, there are perhaps some aspects that has not been discussed or sufficiently explored in the thesis, which might be relevant aspects of a cost-benefit analysis. The conclusions and findings of the thesis are thus based on the information and theories described in the previous chapters.

Last, another limitation in this thesis was the language. Although the author is familiar with writing in English, the Norwegian terminologies have proved somewhat difficult to translate at times. Therefore, if no apparent English terminology was available, direct translation has been applied.

### ***5.3. Recommendations for further research***

During the work on this thesis, some issues and topics were identified which could be the focus of further research. This section will therefore highlight some of these possibilities, which are briefly listed below.

- The CBA conducted in this thesis has been a simplified model of the real-world context and has taken a broad view attempting to cover all the main aspects relevant to the CBA. Further research might go more in depth in one or more aspects of the investment decision and thus be able to have a more comprehensive analysis of certain investment criteria.
- One of the main challenges with working on the thesis was the ability to value environmental impacts from the investment alternatives. Previous WTP studies did not provide sufficient information to make them transferable to the Geiranger case. Further research might therefore focus on estimating the willingness-to-pay for “environmental solutions” in the energy sector, for specific regions and landscapes that can be transferred to other studies and research
- More applied CBA methodology within the Norwegian setting and the energy sector could be a valuable contribution to the research area, which the thesis found was a limiting factor when searching academic literature.

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## 7. Appendices

### 7.1. Appendix 1: Environmental studies of impacts from overhead transmission lines

Appendix 1 is a summary of the environmental studies of impacts from overhead transmission lines, from 1967 to 2005.

Author	Technique	Corridor width	Results
Kinnard (1967)	Interviews to owners	4 categories. The more distant houses are at 61m (200 feet)	Low reduction in real estate values (around 3%)
Clarke and Treadway (1972)	Hedonic price	-	Significant reduction for residential houses but not for commercial activities
Doyer <i>et al.</i> (1978)	Interviews to owners	1 mile	Real estate value reduction around 16% and 29% depending on the distance from the HVTL
Colwell and Foley (1979)	Hedonic price	122m (400feet)	No effects for houses within 60m, reduction only for houses within 15m.
Colwell (1990)	Hedonic price	122 m (400feet)	Reduction in real estate values related to the proximity of houses to the HVTLs
Kung and Seagle (1992)	Hedonic price	-	No effect with statistical support, about 72% of the owners declare the HVTL has not influence on real estate values
Deaney and Timmons (1997)	Hedonic price	-	Reduction up to 10% depending on the distance from the HVTL
Hamilton and Schwann (1995)	Hedonic price	200m	Reduction between 1.1% for house at 200 meters from the lines and 6.3% for those at 100 meters
Callanan and Hargreaves (1995)	Hedonic price	300 m	In proximity of a tower ( $\leq 10$ meters) the reduction can reach 27.3% of the real estate value.
Bond and Hopkins (2000)	Hedonic price	400 m	The effects on the real estate values are not significant in statistical terms
Des Rosters (2002)	Hedonic price	488 m	Reduction up to 20% for houses very close to HVTLs
Haidler <i>et al.</i> (2001)	Hedonic price	3000 m	Average reduction of 4 - 6.2% for properties within 1km from HVTLs. Little evidence of impact on property values at distance $>500$ m.
Rosato <i>et al.</i> (2004)	Contingent Valuation	1500 m	Average WTP around 530 € per household. No statistical relation between distance and WTP
Atkinson <i>et al.</i> (2004)	Choice Experiments	500m-5 km	Compare 5 different structures for HVTL and estimate household WTPs for each tower design between 1.85£ and 2.03£
Tempesta and Marzetti (2005)	Contingent Valuation	-	Median WTA around 200€, median WTP around 80 € per person. Do not investigate the relationship between WTP/WTA and proximity to the HVTLs

Source: (Giaccaria *et al.*, 2010)

## 7.2. Appendix 2: Electricity consumption in Central-Norway (2009)

**Produksjon og forbruk av elektrisk kraft.**

Fylke	Maks. ytelse (MW)	Produksjon		Kull- olje- industriell brensel	Anvendelse				
		2006 (GWh)	2008 (GWh)		I alt (GWh)	Borgerne og annen industri (GWh)	Andre nærings- og transport (GWh)	Husholdning og forbruk (GWh)	
								I alt (GWh)	Komm. (GWh)
Bæverfjord	547	4725	4 364	3044	376	426	1246	1421	6542
Akershus	183	506	364	107	778	336	3571	3978	7950
Oslo	15	31	52	62	8023	366	4624	3181	6861
Hordaland	54	3527	2465	-	3444	606	947	1498	6453
Oppland	1523	5737	7 385	21	2452	606	1182	1447	6885
Buskerud	202	9558	13 205	1263	4197	546	1406	2136	7182
Vestfold	4	15	17	118	3419	538	1062	1189	7157
Telemark	2573	11271	15 354	3262	2782	321	304	1387	7405
Aust-Agder	1173	4720	5 341	219	1506	164	536	812	6300
Vest-Agder	203	8740	11 511	3474	2165	366	602	1194	6008
Agderne	4004	14032	13 544	5228	6151	546	2072	3776	6724
Hordaland	4166	16775	17 516	3085	9030	3206	2656	3198	7220
Sør- og Tvedestrand	362	14726	15 225	4679	1822	286	577	822	6002
Møre og Romsdal	1544	6025	7 306	6111	3022	78	1130	1857	6887
Sør-Troms	122	5495	4 321	1516	3980	406	1634	1836	5829 <sup>1)</sup>
Vest-Troms	751	3036	2 374	1440	1163	310	672	1113	5829 <sup>1)</sup>
Nordland	3204	15202	15 225	4527	4153	636	1511	2141	8031
Troms	576	2886	2 670	862	2116	184	1086	1448	6776
Finnmark	612	2714	1155	-	1328	194	506	175	3021
Svalbard	20	38	79	-	83	28	16	22	-
<b>Totalt</b>	<b>30262</b>	<b>132762</b>	<b>142703</b>	<b>48213</b>	<b>11970</b>	<b>11185</b>	<b>27252</b>	<b>37023</b>	<b>77938</b>

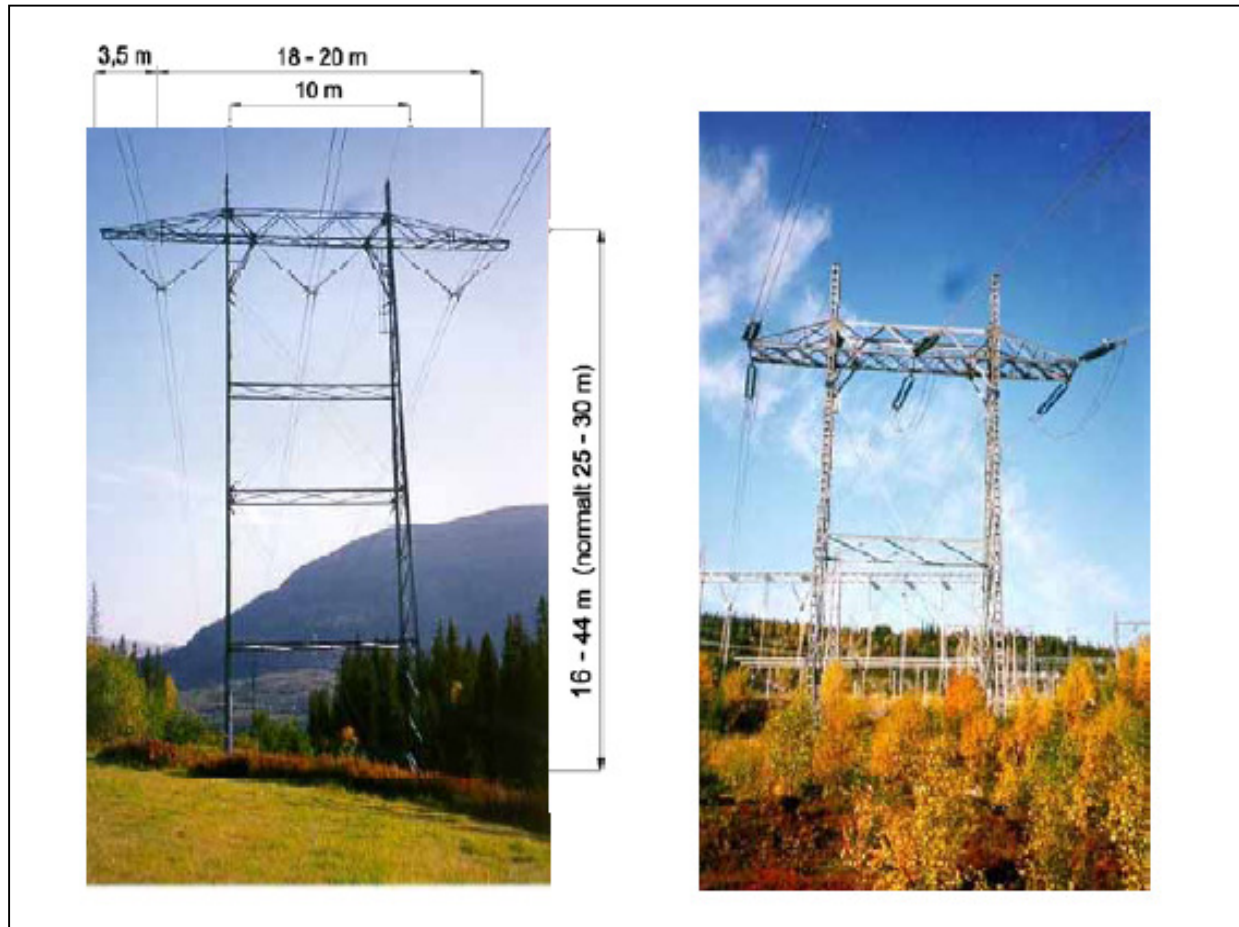
<sup>1)</sup> Tinnokleppfyllene samlet

Source:

<http://www.nve.no/Global/Energi/Analyser/Energi%20i%20Norge%20folder/Energi%20i%20Norge%202010%20utgave.pdf>

### 7.3. Appendix 3: Steel masts

Appendix 2 demonstrates the steel masts that will be used in the Ørskog-Fardal project. The left picture is of a support mast which will be the standard mast for the project. The right picture show a mooring mast, which will be used when needed to absorb large forces.



Source: (Statnett, 2007)

#### **7.4. Appendix 4: Gas-price with varying crude oil price**

Appendix 3 illustrate the gas price (øre/ $Sm^3$ ) with varying oil price. The long term crude-oil price was estimated in Svendsen et al., (2005) to be 30 USD/barrel.

<b>Crude oil price (USD/barrel)</b>	<b>18</b>	<b>20</b>	<b>25</b>	<b>30</b>	<b>35</b>	<b>40</b>
Gas price (Kårstø, Kollsnes and Tjelbergodden)	39	47	66	84	102	120

Source: (Modified after Svendsen et al., 2005)

### 7.5. Appendix 5: NPV calculation with a discount rate of 4 per cent

<i>MNOK</i>	<b>Zero alternative</b>	<b>Redevelopment</b>	<b>Subsea cable</b>	<b>Gas-fired gas quota</b>	<b>Gas-fired gas Co2</b>
<i>Investment costs</i>	-2600	-2960	-5020	-2800	-4800
<i>Operating cost</i>	-39	-44,4	-75,3	-870,4	-937,4
<i>Salvage value</i>	303	345	585	429	604
<i>Disruption costs</i>	35	35	35	35	35
<i>Transmission losses and bottlenecks</i>	206	206	206	206	206
<i>Regional</i>	476	476	476	476	476
<i>Renewable</i>	191,5	191,5	191,5		
<i>Del. Electricity</i>				680	644
<i>Sum ben-cost</i>	869,5	864,1	833,2	526,6	423,6
<i>4 % disc</i>	8154,101489	8103,460721	7813,682991	4938,412702	3972,486936
<i>Time cost</i>		-908,5	-1680		-2423
<b>NPV</b>	<b>5857,101489</b>	<b>4579,960721</b>	<b>1698,682991</b>	<b>2567,412702</b>	<b>-2646,513064</b>