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Economic Benefit of New Capacity in the Central Grid

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Problem Description

There are plans for large investments in the Norwegian central grid. Such investments depend on the power balance in different part of Norway and the total balance in the country. Calculation of the economic benefit for such investments represents a challenge. In this work we are making use of existing tools (Samlast) to estimate the economic benefit of grid investments. We are going to investigate grid investments under different scenarios concerning power generation, for instance increased contribution from renewable sources such as wind.

The following tasks are included:

1. Describe the basic elements in an estimation of the benefits (to society) of investing in new capacity in central grid. Literature survey.
2. Describe the analytic tools used in this project.
3. Analyse grid investments under a scenario involving ambitious development of renewable power in Norway.
4. Evaluate/discuss the results and suggest further work.

Assignment given: 15. January 2009
Supervisor: Ivar Wangensteen, ELKRAFT

Abstract

Norway and the EU have in recent years established ambitious goals to increase the share of renewable energy in their consumption. On account of these goals, a large-scale wind power development can be expected in northern Norway and Sweden. This development may be financed both by Norway and by countries with less wind resources in order to meet the energy goals imposed upon them. An increased power surplus is dependent on TSOs abilities to transmit increased amounts of power through the Nordic grid.

A scenario of likely power market conditions in year 2025 is used as a basis. The scenario has a high expectancy of new wind power as well as strong grid investments compared to the level in 2009. This thesis assumes an additional increase in annual renewable power production of 22 TWh, divided into 16 TWh in northern Norway and 6 TWh in northern Sweden. Results show that this amount of new power cannot be implemented without large grid investments. The Energy and Power Flow model is utlized to simulate the Nordic power flow for different levels of grid investments.

Two grid solutions are proposed that allow the production increase while maintaining an acceptable state of system operation. The first uses DC transmission from Rana to Oslo in order to control power flow through Norway. An additional AC line from Kobbelv to Ritsem allows import from Sweden to the DC line. The second grid solution uses AC line upgrades throughout Norway ensuring two 420 kV lines from Ofoten to Kristiansand. Due to lower impedances in the Swedish grid, a large amount of the Norwegian production flows into and through Sweden. This solution requires a new line from Kobbelv to Ritsem and Rätan to Borgvik in order to solve resulting Swedish transmission congestion.

Both grid solutions require a new DC cable from southern Norway to Germany in order to export most of the new power production. These cables require a number of supporting line upgrades in the region. Power producers schedule according to the new market situation, allowing a very high export during daytime and a low export during night.

The increased power production in northern Norway and Sweden replaces other production. A high amount of gas and coal power is replaced in continental Europe. No hydropower, wind power or nuclear power is replaced. The DC and AC grid solutions allow European reductions corresponding to 19,3 % and 16,6 %, respectively, of the expected Norwegian CO_2 – emissions in year 2025.

The cost of each grid solution is calculated to 22 760 MNOK and 19 310 MNOK. Annual system increases in valued socio-economic benefit outweigh the grid investment costs of each option by 3 300 MNOK and 3 370 MNOK per year of the period of analysis. The total cost of new power production must not exceed these values for such a decision to be socio-economically beneficial. Due to the high increases in calculated socio-economic benefit, a recommendation for further analysis is made.

Acknowledgements

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Trondheim, 11th of June 2009

Ingar Dalen

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1 Introduction

There is a growing global concern about the dependency many economies have on carbon – based power production. An increasing interest for renewable power has manifested itself throughout the past few years in the power development goals of many countries. Few areas in the world have better wind power conditions than the coast of northern Scandinavia. On account of this development, large scale investments in renewable power may be expected in the region.

This thesis is based on the assumption that these investments will have taken place within year 2025. Such a development will depend greatly on the Transmission System Operators (TSO) abilities to transmit increased amounts of power through the Nordic grid. Given a power surplus in Norway, long distance transmission capacities may be necessary in order to reach consumers with less renewable resources.

The main consideration of this thesis is the future development of the Nordic transmission grid. Adequate transmission capacity must be provided for the increase in renewable production. The thesis aims first of all to give an understanding of how calculations of economic benefit for central grid investments are performed. Existing analytic tools and simulation software are then utilized to model the power system. On the grounds of these calculations and simulations, the future development of the Nordic transmission grid can be analyzed.

Expectations in future market conditions must be considered before additional grid investment projects are proposed. The following analysis will reveal what affect large levels of renewable power in northern Scandinavia will have on the Nordic power system as a whole. Obtaining an understanding of the power flow changes and resulting regional power prices is essential for such an analysis. The impact of the renewable power on existing power production can then be found, revealing what socio-economic benefits can be expected.

2 Power market theory

2.1 Calculation of socio-economic benefit

A main strategy for TSOs is the socio-economic long term development of the electric grid. In Norway the main TSO, Statnett, is bound by government regulations. These are meant to encourage socio-economic beneficial investments with a basis in corporate profitable evaluations. [1] A large amount of factors have to be taken into account in order to determine the socio-economic benefit of a grid investment.

The balancing price of a power system is found as the crossing point between supply and demand. In a system with sufficient transmission capacity, the system price is the balancing market price that will be seen by all areas of the system. This is illustrated in Fig. 2-1, where P_0 is the system price and X_0 is the quantity of power that will be produced at this price. In the figure, the supply curve shows the marginal cost of supplying power. The demand curve shows the marginal willingness to pay for that power.

Producer surplus is defined graphically by the area above the supply curve that lies below the power price in a specific area. Similarly, consumer surplus is defined as the area below the demand curve that lies above the area price. The socio-economic benefit of the system is the sum of the consumer and producer surplus in all areas. Fig. 2-1 assumes a simplified system with no transmission limits and a perfectly competitive market.

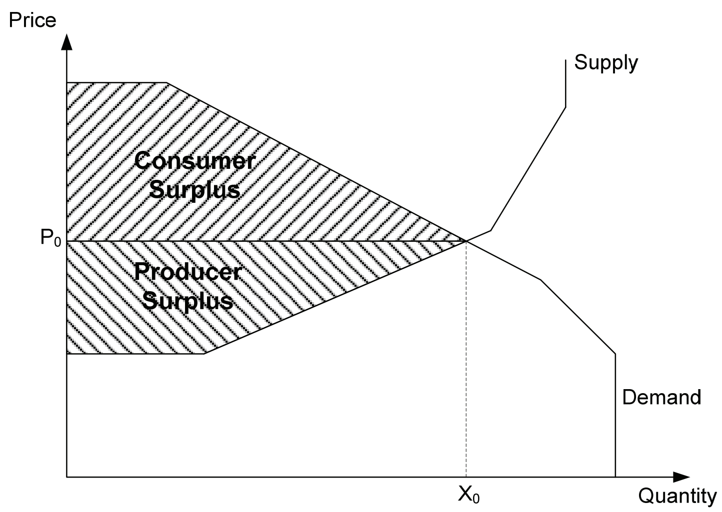


Fig. 2-1 - Consumer and producer surplus

In this simplified example, the system is made up of one power surplus area and one power deficit area. These areas are represented by Fig. 2-2 and Fig. 2-3, respectively. A loss free transmission line with no transmission limit is assumed. The system demand curve for such a case is simply the sum of the two area demand curves. Likewise the system supply curve is the sum of the two area supply curves.

In an example with no transmission between the two areas, prices and power quantities produced in each area would be as shown in Fig. 2-2 and Fig. 2-3. Area B has both a higher demand and power supply cost than area A. As a result, the area price also becomes much higher than area A. The transmission line benefits the consumers in the power deficit area, and benefits the producers in the power surplus area.

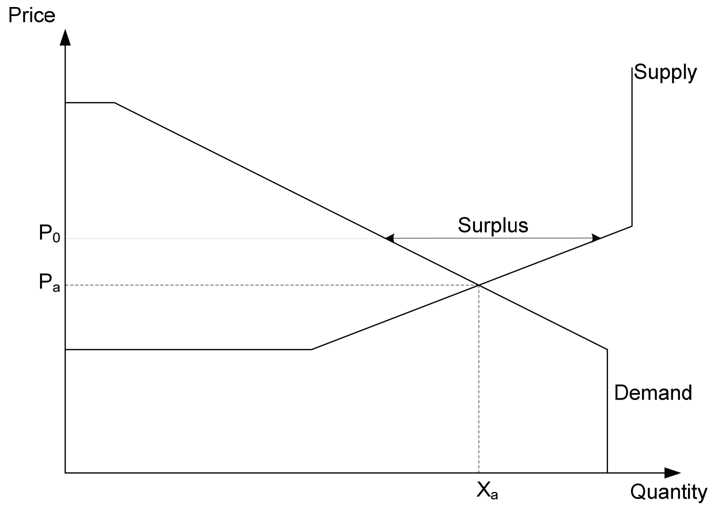


Fig. 2-2 – Area price for surplus area A

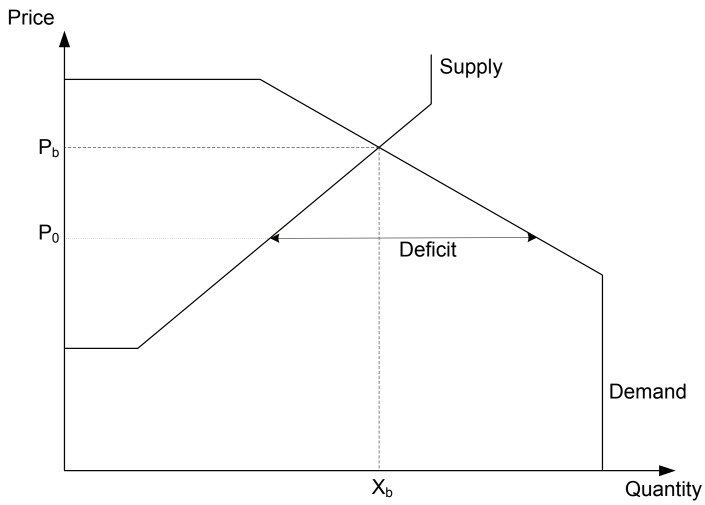


Fig. 2-3 – Area price for deficit area B

When transmission lines connect the two areas, power may flow between them. This power exchange has no affect on the system price, which remains the same as before. The only power prices that will change are the area prices. Area B, shown in Fig. 2-3, is an area with a power production deficit. This area is therefore dependent on power transmission from other areas to attain an area price equal to the system price. Transmission capacity into area B is added in Fig. 2-4. This results in a change in the demand curve, which is moved left as shown in the figure. The area price is lowered from P_b to P'_b. Producer surplus is decreased while consumer surplus is increased.

When a transmission grid becomes congested, bottlenecks occur. Bottlenecks in the transmission into a deficit area cause prices to increase, and producers in the deficit area can benefit greatly from the situation. Transmission profits made from congestion are found by multiplying the difference between nodal prices with the flows of power between injection and delivery points on the network. Grid companies transferring power from a cheaper, neighboring area will benefit as they make a profit from the price difference. This is on the expense of the consumers.

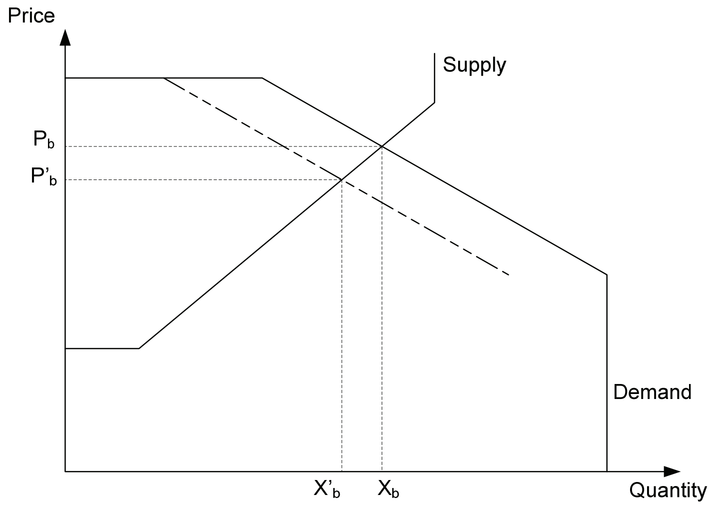


Fig. 2-4 – Consequence of increased transmission for area B

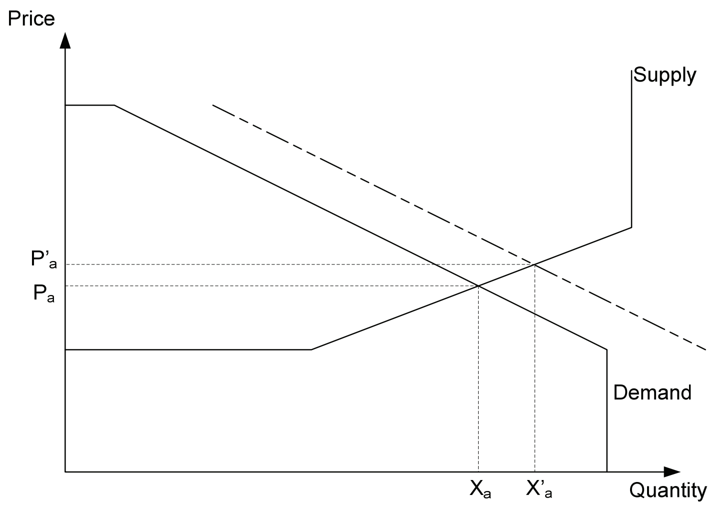


Fig. 2-5 – Consequence of increased transmission for area A

Fig. 2-5 shows the impact that increased transmission has on the power surplus area A. This area must export an amount of power in order to attain an area price equal to the system price. As a result of the increased transmission capacity, the demand curve is moved left as shown in the figure. The area price increases from P_a to P'_a. This signifies an increase in producer surplus and a resulting decrease in consumer surplus. If bottlenecks prohibit power transfer from the surplus area, excess power must be sold in the surplus area itself. This gives an area price lower than the system price, benefiting consumers on the expense of the power suppliers.

The consequence of grid congestion is illustrated in Fig. 2-6. In this graph, the net surplus curve for area A is found by subtracting demand from supply in the area:

Surplus A = $S_a - D_a$

Similarly the net deficit curve for B is found by subtracting supply from demand:

Deficit B = $D_b - S_b$

In Fig. 2-6, a transmission capacity only equal to X_1 is available. The enclosed areas A and C represent increased welfare for market participants. Enclosed area B represents the rent income of the congestion, which is made by the transmission grid owner. This rent income is found by the difference in area prices P'_a and P'_b multiplied with the transferred quantity. Area D represents the welfare loss due to insufficient capacity. This loss is a direct result of insufficient transmission capacity.

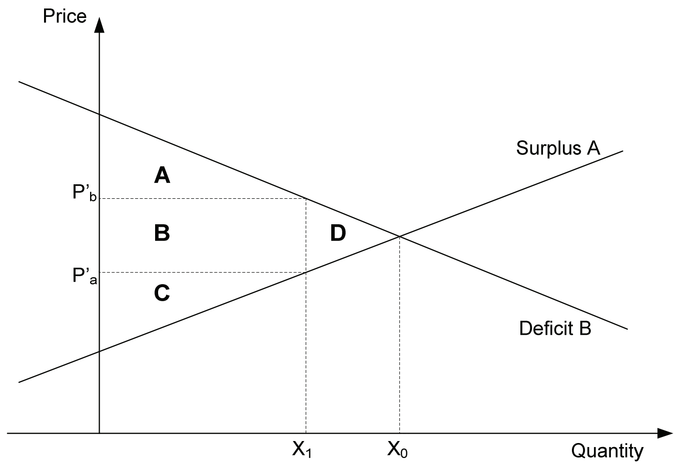


Fig. 2-6 –System benefits and losses

Increasing the capacity reduces the welfare loss. This is shown in Fig. 2-7 where transmission capacity is increased from X_1 to X_2. The shaded area shows the increased rent income for a grid owner, made by the difference in new area prices P'_{a2} and P'_{b2} multiplied with the capacity change. Enclosed areas A and C are increased by the new price values P'_b and P'_a, respectively. The size of enclosed area B is decreased by the new price values, giving a reduction in profits for the grid companies.

An existing grid company that invests will have an increase in profits equal to the shaded area and a decrease in profits equal to the reduction in area B. If the capacity increase is made by a new grid company entering the market, this participant will only make the profit shown by the shaded area. All previously existing grid companies will in this case only experience the reduction in profits. Increase in socio-economic benefit is found as the sum of congestion rent increase and welfare gain increase. Ideal transmission capacity in the system would have been X_0, completely removing the welfare loss.

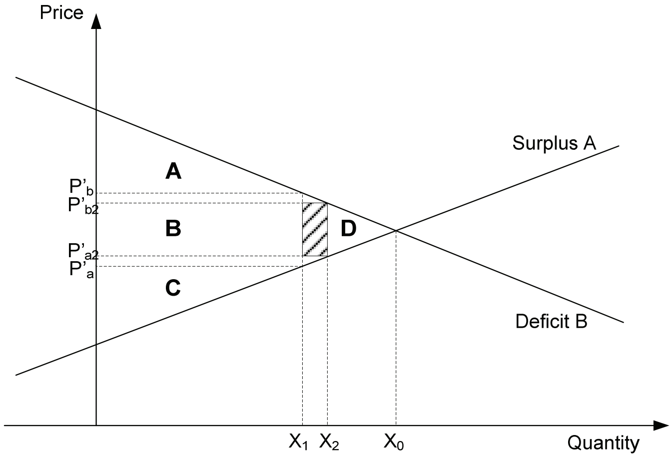


Fig. 2-7 – System benefits and losses with capacity increase

A corporate profitable investment is not necessarily socio-economically beneficial, and vice versa. There are two main reasons for the difference. Market failure can cause production and consumption that is not optimal for the market. The other difference is made up of the consumer surplus, which is the part of the total benefit that does not benefit the producer. [2]

[3]

2.2 TSO handling of transmission bottlenecks

Bottlenecks limit the flow of electricity and may threaten system stability. Bottlenecks are found in most large power transmission systems and may be handled in several ways. A unified handling strategy for solving these problems, however, does not exist. [4] Even in the Nordic area, TSOs do not agree on the best handling of bottlenecks in their grids.

One method of solving bottleneck problems is using the buy-back procedure. [3] This requires the System Operator (SO) to interact actively on both sides of bottlenecks. In order to keep all power flow within available limits, the SO will pay for production increase on the deficit side of the bottleneck at a high cost. The same amount of power is then sold as a consumption increase at a lower price on the surplus side. This results in one single market price for the entire system and leads to a net cost for the SO. Fig. 2-8 illustrates the welfare loss, A, and buy-back costs B and C. Total costs become the square in the figure given by areas A, B and C. The procedure is used in both the Swedish and Finnish grids.

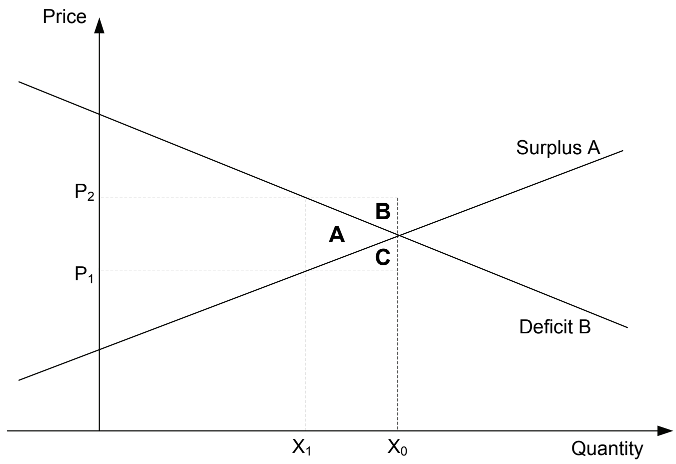


Fig. 2-8 – Costs of the buy-back procedure [3]

Another way to manage transmission congestion is through area pricing. This procedure splits up the system into smaller areas that are divided from each other by bottlenecks. Each of these areas is given a power price depending on the local supply and demand curves. The socio-economic aspect of area pricing is described in chapter 2.1. A trading surplus is made from the power transfer from low to higher priced areas, giving the SO a net income. In the Nordic area, this method of congestion management is used as a complement to the buy-back procedure. In Norway, this policy has resulted in the three current price areas NO1, NO2 and NO3.

In the long term, large consumers will prefer locating in areas with low prices. Likewise, new producers will prefer locating in areas with high prices. In this way, area pricing is a method of giving incentives for the free market to solve bottlenecks. These incentives will not be given by the buy-back procedure, where market participants do not see the correct power price in their area. Area pricing comes at the cost of uneven market conditions due to regional price differences. A motivation for the buy-back procedure may be solely to avoid these differences, providing equal market opportunities for all consumers.

2.3 Consequences of the reserves market

In a large power system, electricity is generated and consumed continuously. Electricity is also consumed at the same moment that it is generated. It is therefore necessary that load and generation are equal at all times, in order to ensure a reliable power supply with a stable voltage and frequency.

In the Nordic power market [5] Nord Pool AS operates Elspot, a market designed to meet these demands. It is a day-ahead market, allowing trade of power contracts for the following day. The contracts must each be at least of one hour duration, and the trade results in physical delivery of power. This is in contrast to other types of financial power contracts such as forwards and options, which do not result in physical delivery.

The Elspot market offers many advantages over the bilateral market that it often operates in competition with. Standardized contracts with neutral and transparent prices are some of these advantages. Nord Pool serves as a reliable counterparty for all participants, and the market serves as a grid congestion management tool. This allows both area pricing and the buy-back procedure to take place a day in advance.

One problem with the Elspot market is that it does not consider changes in the market between trade and delivery. When the Elspot market closes for trade the day before delivery, a new market opens for trade up to one hour before delivery. This is called the Elbas market and is currently only available in Finland, Sweden and Eastern Denmark.

The balancing market is a tool for SOs to balance power generation to consumption up to 15 minutes in advance. It allows for a final generation adjustment and provides a price for the participants' power imbalances. A bid in the balancing market is divided into two categories. A bid for upward regulation pays for increased generation or reduced consumption in the area. Downward regulation is used when bidding for decreased generation or increased consumption. The regulation pricing in Norway differs from the other Nordic countries, but all aim to ensure that no profit is made from imbalances.

In the Nordic power system, the balancing market represents the secondary reserve of the power market. The primary reserve is automatic and instantaneous, but can often only maintain the necessary capacity for a short amount of time. The secondary reserve must therefore restore balance between supply and demand before the available primary reserve has finished. These reserves are part of the Norwegian ancillary services which are required to ensure a high level of quality on the supply of power.

In Norway, power suppliers are obliged to offer capacity to the reserves market in critical situations. In practice, this means that the power suppliers must have reserve power in case they are called upon. They are not allowed to operate at maximum production. They receive an economic compensation for this spare capacity, in addition to payment if the capacity is bid upon and must be supplied.

The price settlement for reserves and the resulting system power price [3] in a simplified system is shown in Fig. 2-9. Six generating units are shown, each with a different marginal cost. With no requirement for capacity reserve, the market price would have been c_5 in the figure, where demand crosses the supply curve. When reserve capacity is included in the calculations, the market price becomes p_s.

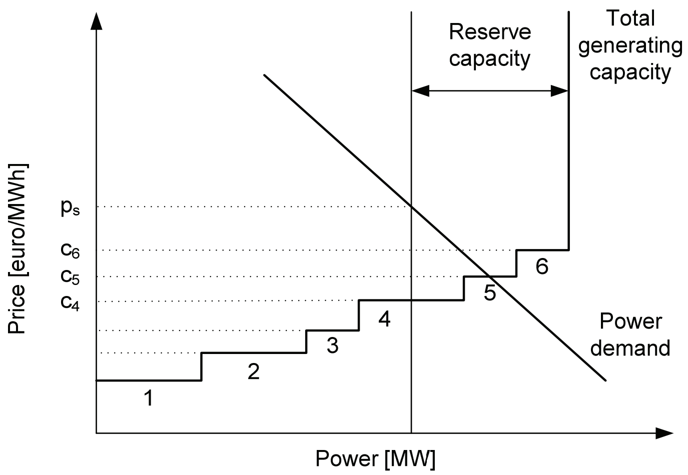


Fig. 2-9 – Price settlement for capacity reserves

The capacity price can be considered to be the price of capacity reserves that leads to the economically optimal solution. Assuming the reserve capacity shown in the figure, with a marginal cost of only c_4, the capacity price becomes:

$p_c = p_s - c_4$

In the optimal solution, units with the lowest operation costs are in active operation. These units are represented by 1, 2 and 3 on the supply curve. The unit(s) with higher operation costs, represented by unit 6 on the curve, is used as standby. Generating unit 4 becomes the balancing unit, which is indifferent between being in active production and standing by. This unit will run on part load, balancing the system. The altered system price, as a result of the reserves market, is the price that consumers pay for this ancillary service.

3 Analysis of central grid investments

3.1 Alternative methods of investment

Power system investments are normally constructed and upgraded in steps rather than linearly. This is due to both practical and economical aspects. Once constructed, the systems have a long life span and the investments are to a large extent economically irreversible. There are large costs and little income in removing an investment, such as a high voltage line or a power plant, once constructed. When considering the necessity of such an investment, all possible alternatives should be analyzed first. Alternatives often used to solve power deficits in an area include:

- Improvement of grid connections towards other areas
- Reduction of area consumption
- Increase of area production

Within these main alternatives there are a number of internal alternatives that also must be considered. [1] These include time and geographic location of investments, voltage levels, types of transmission systems, thermal transmission capacity and connection nodes. The situation development without the investment, the reference alternative, may also be disputable and have many alternatives in itself.

One investment may greatly affect the benefit of another investment. Each of two planned transmission lines out of a surplus area might be beneficial and profitable on its own. When both are built simultaneously, neither may be profitable. Another example is construction of a power plant without sufficient grid capacity to transfer produced power to consumers. Such a lack of project coordination would also result in economic losses. Coordination of projects and the order in which they are constructed are both issues that are vital to the economic results.

In cases where investments do not affect the power prices, market prices can encourage socio-economic decisions. TSOs profit on the price difference between the areas that lines are operated between. A new line between areas with different power prices will therefore be encouraged by the market as long as the price difference is not removed when building the line.

In cases with poor transfer capacity, investments in new production can cause or solve bottlenecks depending on their location. Investing in increased production in an area with high demand and little supply may decrease the need for grid reinforcement. Potentially, all grid bottlenecks into the area may be solved. The local production increase may also have a positive impact on both the system stability and reliability of supply. If the production increase does not take place, a new line may be necessary to solve these problems. Expensive grid investments can in this manner be avoided.

In practice such options may not be considered, as the market will not reward such an investment. The new power producer receives no compensation for saving the TSO an expensive line investment. Local power prices are likely to be reduced towards the price level in the neighboring areas. This represents a profit reduction for all existing power suppliers. When the total socio-economic benefit is not considered, many beneficial investment options may be neglected.

Fig. 3-1 shows a socio-economic investment analysis in a power deficit area. Currently, the power capacity is at a value C_1. The demand curve in the area gives a price value P_1 for the power supplied. It is assumed that the next step of construction for increased power capacity lies at value C_2, achieved either by grid expansion or new power production. The power price after the investment, found by the new crossing point between supply and demand, will only be P_2.

As a result of the investment, consumer benefit is increased by the area below the demand curve between C_1 and C_2. The price of the investment is found as the area below P_{inv} that lies between the values C_1 and C_2. Socio-economic benefit will be increased by area A and decreased by area B. No investment will be done from a socio-economic point of view if B is larger than, or as in this case equal to, A. The most ideal investment would be to only expand capacity to the value C_{inv} where the investment power price crosses the demand curve. Such an ideal investment is rarely possible. [1]

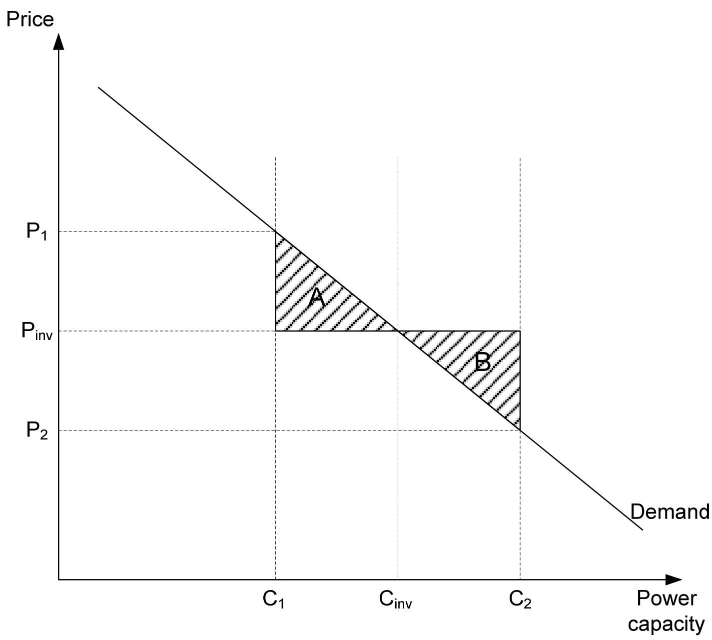


Fig. 3-1 – Socio-economical analysis of investment

Any investment power cost of less than P_{inv} will cause an increase in A and a decrease in B, thus making the investment beneficial. This is regardless of the type of investment, whether it is a grid expansion or new power production. While both types of investment may be beneficial, one may be better than the other. It is therefore important to consider all types of investment in the analysis, so that the most beneficial decision can be made.

An optimal market will ensure a price that gives balance between supply and demand, ensuring power delivery through the price mechanism. However, a market can only function optimally when all participants are faced with correct prices. All forms of market failures, giving participants other prices than the optimal ones, causes a loss in welfare for the society. For a free market model to make socio-economic decisions without control or incentives, the following criteria would be necessary:

- All investments are reversible
- Reliability of supply is guaranteed
- Market prices always reflect shadow prices of power at the correct time and place
- Transmission capacity is always optimal given supply and demand at a given time
- Perfect competitive conditions
- Power grid is always built to the point where the marginal cost of increasing capacity is equal to the markets marginal willingness to pay

[1]

Many of these criteria are unrealistic in most situations. Economic incentives that are direct and situation specific could be used to compensate for these flaws. Yet no single incentive regulation mechanism can be developed to govern transmission investments. Nor will they evolve socio-economically through competitive markets alone. Market driven transmission investment may be an addition to regulated transmission investment, but is not an adequate substitute. [6]

3.2 Types of grid investments and transmission companies

Competitive markets for electricity are dependent on a transmission network with good performance attributes. It enables demand and supply to be matched over a large geographic area by allowing decentralized suppliers and consumers to trade. Competition is increased by allowing consumer access to a number of suppliers.

Before an investment is made, it is important to know its exact purpose and what problem it will solve. The economic and reliability goals of a transmission investment must be considered by the TSO. For this purpose, transmission investments are often divided into a number of different categories. These categories include:

- **Generator connection investments** are made in order to allow generators access to the wholesale market. These investments alone do not ensure adequate capacity to transmit power from the generator to any supplier on the grid.
- **Distribution network connection investments** are the consumer counterparts of generator connection investments, ensuring consumers access to the wholesale market. Such interconnections will only be made by a distribution company if there is capacity in the grid to supply the energy demanded by the new load.
- **Intra-TSO transmission network upgrade investments** refer to investments made within a single TSO. These will often mainly focus on congestion costs. The investment analysis involves a cost-benefit evaluation of the investment and its profits compared to the alternative congestion and cost losses.
- **Inter-TSO economic investments** cover investments between two or more TSOs. The intention of such an investment is to both increase transfer capacity and reduce congestion. The difference between this investment and that of the intra-TSO is the fact that market, regulatory and transmission investment frameworks may differ between the TSOs involved. This may lead to very different incentives for and evaluations of economic investments.
- **Interconnection investments to support inter-TSO transmission links** allow for better utilization of the inter-TSO link. This is achieved by improving network congestion levels internally in each of the linked grids, allowing them to deliver and withdraw more power from each other.
- **Reliability transmission network investments** focus on improving the reliability of a network. More than often, such investments will also have an impact on both congestion and area prices. Likewise, other types of investments often have impacts on the reliability of the network.

[6]

There are many types of transmission network organization structures. Conflicts of interest can arise when TSOs are vertically integrated into both generation and marketing activities. The operating and investment decisions made by the TSO may be influenced by their impacts on the transmission network profits. Categories of TSO structures include:

- **Full vertical integration** is found where one company has an integrated responsibility covering the entire span from power production and transmission to wholesale marketing. In such a company only a small portion of the total income is made from power transmission. As a consequence, transmission matters may not be the primary focus of attention.
- **Independent transmission** companies only have transmission network functions. Generation and marketing functions are performed separately by a different company. Therefore conflicts of interest described earlier do not exist, and the company focuses more primarily on transmission services. The independent transmission company will still be integrated vertically to include system operation, network maintenance and network investment.
- **Independent system operator** (ISO) is a model characterized by separating the SO from all other functions. The ISO has no generation, marketing or transmission assets. Its sole responsibility is security of supply by ensuring power balance and sufficient capacity margins.

[6]

TSOs in Norway are bound by Norwegian grid regulation ensuring that they consider the total socio-economic consequences of their investments. The Norwegian central grid is operated by an independent transmission company as described above. This allows such considerations to be performed without conflicts of interest for the TSO. A Norwegian TSO must consider the socio-economic benefits of completely removing a grid bottleneck and thereby removing a potentially profitable price difference. Such an investment is not profitable in a free market and would therefore be unlikely to happen if the central grid was completely unregulated. [1]

3.3 Costs and benefits of investments

An investment in the central grid may have a large impact on a number of elements. All relevant effects from an investment should be quantified and valued in order to perform a thorough analysis. The reference alternative is used as a reference when the impacts are calculated. For an investment to be beneficial, the positive change in socio-economic benefit must be higher than the total cost. The benefit includes reduction in the following elements as a result of the investment:

- Costs from grid congestion
- Cost of losses
- Grid outage costs

It is important to note that an investment in one area may simply move a bottleneck from one line to another, not necessarily relieving or even reducing the problem. An analysis of costs and benefits must cover a large part of the system in order to detect such unwanted power flow movements.

The total cost of an investment include the initial investment cost as well as operation and maintenance costs. Another element to consider is the yearly reduction in outages, giving a reduction in outage costs. Depending on the period of analysis and life span of the investment, there may also be a salvage value to consider. The outage reduction and salvage value should be subtracted from the project costs before comparing them to the change in socio-economic surplus.

All costs can be discounted to a certain year. Most elements in the analysis are uncertain, even when using calculated future scenarios as shown in Chapter 5.2. For compensation a risk addition to the discount rate is then applied to account for systematic risk involved in the project. This is the risk connected to the general economic development during the period of analysis. Unsystematic risk, the risk specific to the project, is included in the sensitivity analysis rather than included directly in the calculations.

Not all elements can be quantified or valued. Environmental consequences are often difficult to value. Power lines may cause damage to both flora and fauna. Human habitants in close proximity to the lines may also be affected from fear of health problems due to electromagnetic fields. Scenery may be reduced, directly causing fall of real estate values. Areas used for power lines may also occupy land otherwise used for recreation.

Increased system stability in the case of several faults occurring simultaneously is another element that normally is not valued. Industrial interests should also be considered. If a grid investment is a necessity for increased industrial activity or power production this should be noted in the analysis. An investment may also improve the admission into the market for free entry and trade, improving the confidence in the market. Invaluable and unquantifiable elements may be vital to the evaluation of a project and must therefore be considered alongside the valued cost calculations.

[7], [8]

4 Analytic tools

4.1 Powel Market Analyzer (PMA)

The PMA model, also known as EMPS (EFIs Multi-area Power Scheduling model), is a power market simulator that optimizes the utilization of systems based on hydro and thermal power. [9] It uses stochastic calculation methods in order to schedule and simulate system performances, and is designed for use in systems with large quantities of hydropower production. Through analysis and simulation, the model evaluates both seasonal and multi-year management of regional water reservoir levels. The evaluation takes into account a number of key aspects of a power system, including firm power obligations, transmission limitations, inflow statistics and trade options. [10]

The basis of the PMA model is an OPS (One area Power Scheduling) model [11], illustrated in Fig. 4-1. This model simulates water inflow to reservoirs and hydropower production in one single area. In order to do this, all reservoirs in the area are considered one single reservoir equivalent. No transfer limitations or line losses are calculated or used within the area. This is illustrated in the figure, with a lossless busbar. OPS areas are defined from practical criteria such as hydrology, so that rivers with several hydroplants are typically modeled within a single area. It is important that there are no large grid bottlenecks within one OPS area, which would make the equivalent unrealistic. [9]

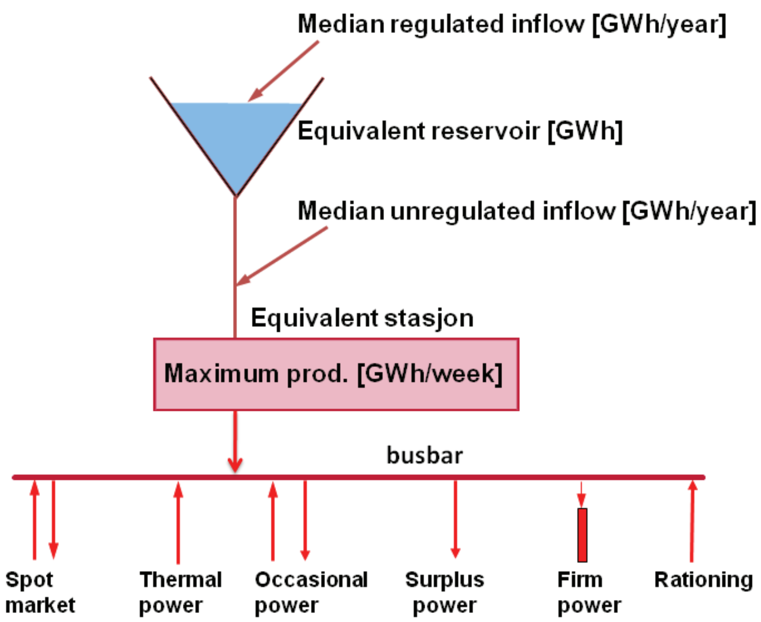


Fig. 4-1 – Equivalent diagram [9]

The PMA model considers a series of OPS areas connected together by a grid, as shown in Fig. 4-2. For this project, 20 interconnected areas are used to simulate a part of the European power system. Names of the numbered areas in the figure, as well as the countries represented by them, are given in Table 4-1.

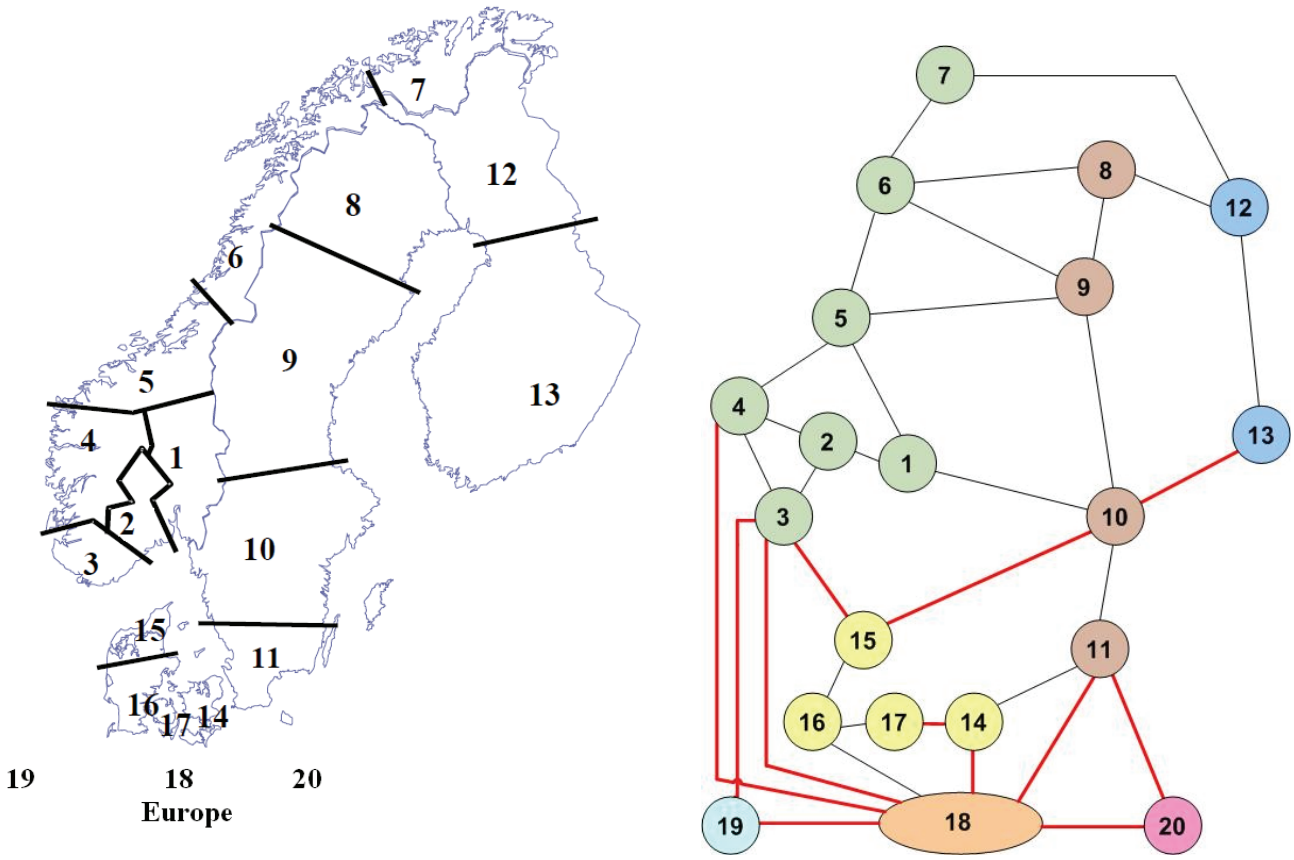


Fig. 4-2 – Connection between OPS and PMA. Principle figure (left) and actual area connection (right) [9]

Table 4-1 – OPS areas used in simulation

Area number	Area name	Country
1	NORGEOST	Norway
2	NORGESENT	Norway
3	NORGESYD	Norway
4	NORGEVEST	Norway
5	NORGEMIDT	Norway
6	NORGENORD	Norway
7	NORGEFINN	Norway
8	SVER-SNO1	Sweden
9	SVER-SNO2	Sweden
10	SVER-SNO3	Sweden
11	SVER-SNO4	Sweden
12	FIN-NORD	Finland
13	FIN-SYD	Finland
14	DANM-OST	Denmark
15	JYLL-NORD	Denmark
16	JYLL-SYD	Denmark
17	FYN	Denmark
18	TYSKLAND	Germany
19	NEDERLAND	Netherlands
20	POLEN	Poland

The grid between areas is given as a file, MASKENETT. This file contains data regarding transfer restrictions between each area, transmission costs and line losses in percentages. Only areas connected through this file are able to trade electrical power during model simulation. The map on the left side of Fig. 4-2 shows the geographical principle of the area connection, while the diagram on the right shows the actual connections used in this project. In the diagram, DC transmission lines are given in thick red lines while AC transmission lines are given in thin black lines.

The PMA model can be divided into two main elements. The program part performs all calculations, while a data set provides values for all necessary variables. Input data found in the data set include:

- **Inflow statistics** that are observed for a number of years for reservoirs in each area. For simulations used in this project, these statistics are given for all years from 1950 to and including 2000. This gives a total of 51 years of statistics.
- **Hydropower production system description** given for all stations expected to be in operation at the period of analysis. The description includes production dependent information such as reservoir capacity, hydraulic connections, energy equivalent of water used and a number of restrictions.
- **Thermal power production system description** given for all stations expected to be in operation at the period of analysis. A prognosis of fuel costs and station efficiency is used in the calculation of the production cost of power. Station operating availability and power restrictions are also included.
- **Power transfer capabilities** providing all connections and restrictions in transmission between OPS areas in the system.
- **Prognosis of firm power demand** for all areas. Yearly consumption and its variation throughout a week for different price periods are included.
- **Spot price market options** covering both domestic and foreign markets. This includes demand prognosis for different prices and the variation of demand throughout a week.

[10]

It is important that the entire power system is modeled in order to achieve reliable simulation results. All Scandinavian countries and Denmark are modeled in detail. The rest of Europe is also modeled in order to include external affects on the Nordic market, although more simplified. It is represented by the countries Germany, Netherlands and Poland. These are each represented by an empirically based supply curve and load variations for different load periods. [12] No grid is provided internally for either of these countries.

Wind power production may also be included in the data set. Wind power parks are modeled as hydropower stations with unregulated inflow and no reservoir capabilities. As with water, historical wind series are used to model the “inflow” to the turbines.

In the model, power demand is divided into firm power and price-dependant power consumption for each area. Firm power consumption is mainly modeled with no price elasticity. It is represented by yearly power volumes with different weekly consumption profiles. Within each week another profile divides the weekly consumption into 5 different load periods. The price-dependant consumption is represented by consumption volumes for each price range at given time periods.

The time resolution of the model divides the week unevenly into the 5 load periods, depending on the determined number of hours for each. The load periods used in this project are shown in Table 4-2. A characteristic of using these load periods is that the hours in them are not sequential. For example, one “Peak” load period will consider the load between 08 and 13 o’clock for all days during one week.

Table 4-2 – Week division into load periods

	Load period	Number of hours
1	**Peak**	25
2	**Daytime**	35
3	**Morning/Evening**	25
4	**Night**	49
5	**Weekend**	34

The PMA program consists of two separate parts. One part calculates the general strategy of the model simulation, while another part implements the main simulation using the strategy found.

Strategy part

Although the water flowing through a hydropower plant in itself is not paid for, the marginal cost of hydropower generation is not zero. The water is a limited resource and can be stored in reservoirs. The water value is the expected value of the next stored marginal kWh of water to be drawn from a reservoir. This value will depend on the alternative cost of covering a future load with production from another plant. Reservoirs allow for water storage during periods with low power prices, and production during periods with high prices. The water value must therefore be known in order to achieve optimal production scheduling. This is calculated before simulation of the power system.

The strategy part of the PMA model calculates a water value matrix [13] for each area in the modeled system, disconnected from the other areas. This is done using a backward stochastic dynamic programming algorithm as illustrated in Fig. 4-3, using the single reservoir equivalent for each area. In the figure the reservoir equivalent is divided into 51 discrete points, one point per 2% reservoir filling. The columns give the water values for each week throughout a defined number of years. After an initial guessed value for the previous week, water values are calculated for each discrete point. A number of realizations of stochastic inflow are used. These are given as Q in the figure, followed by week number and inflow alternative. Values for the first and last week are compared, and the values for the first week are entered into the last week until they are equal to a degree of accuracy.

The objective is to find the operation strategy that minimizes the operation cost for a period of analysis. This is achieved by a sequence of stored, spilled and turbined water volumes. The system interconnections are then taken into account by modifying the demand and spot-market options for each area. [10]

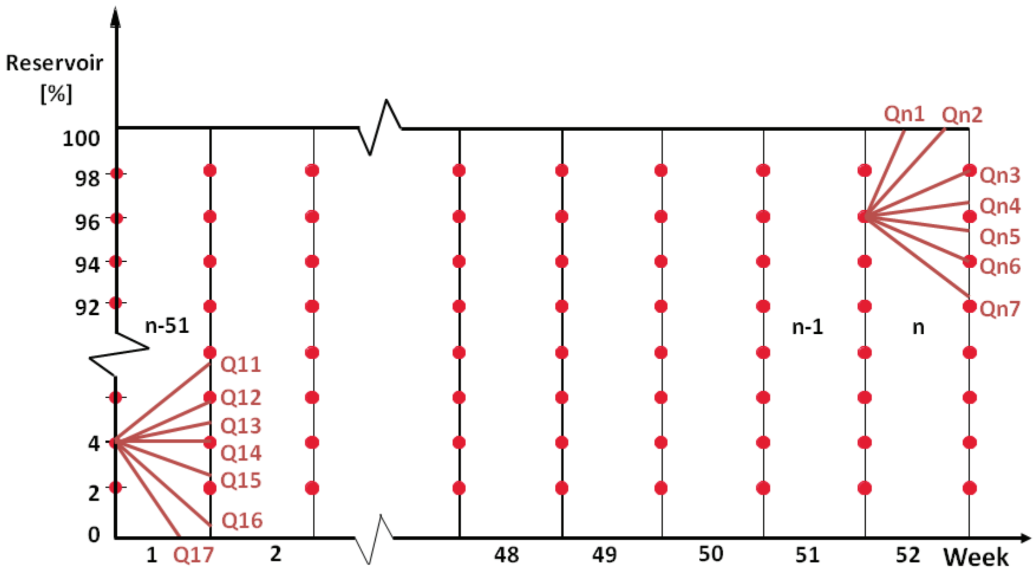


Fig. 4-3 – Water value calculation [13]

System behavior is simulated using the water values calculated, in order to improve them. Historical inflows into the reservoirs in each area are used in the calculations. Energy production in each area, energy exchange between areas and utilization of spot market options are found. In this way water storage capacities, uncertainties in future inflow and development in the modeled power market are all considered. The new data is then used in the first step again, continuing to iterate until a stable solution is found. The stable solution is stored as a single water value matrix for each area. [10]

Simulation part

In the simulation part of the PMA model, the physical and economic consequences of the strategy determined are simulated for inflow alternatives given by a sequence of hydrological years. [13] It is divided into two main sections: the single reservoir area productions decision section and reservoir drawdown section (RDS).

The single reservoir area productions decision section formulates an optimization problem using the calculated water value matrixes from the strategy part. The optimal solution of area hydropower production is found and stored.

The reservoir drawdown section uses the optimal solution found to assign the calculated power productions to the various hydropower stations expected to exist in the period of analysis. For each power plant the algorithm takes into account water storage capacity, production capacity and production efficiency. The algorithm also considers restrictions and concession claims for the system. Each area is calculated in a sorted sequence, beginning with the areas with lowest freedom for power operation. Production is corrected for areas that cannot fulfill the single reservoir area productions decision. This creates new optimal production decisions used for calculation in the other areas. [10]

The PMA is purely a market model, recreating the power market as described in Chapter 2. There is, however, no function in the model to recreate the reserves market. Therefore the model only uses area pricing in order to balance the system and solve transmission bottlenecks.

A cross point between supply and demand is found for each load period. The simplified transmission grid used by the model does not consider impedances on individual lines. Any physical load flow that defies the power market is therefore not considered by the model. The model assumes a free and optimal market, and the results give an approximated optimal utilization of the hydropower production and transmission.

Market conditions concerning the United Kingdom are not included in any of the data sets for base scenarios in this project despite the fact that two of them include a DC connection to England. For simplicity, this line has been modeled to area 18, Germany, instead. The data sets assume that the market conditions that are modeled in Germany are sufficiently generalized to also adequately represent the UK.

For the period of analysis, results are given for each of the five different load periods each week. During simulation of 52 weeks using 51 years of historical inflows, the model will calculate results for 13 260 load periods. The results given for each area include:

- Hydro production
- Thermal production
- Purchase / sale at spot market
- Power exchange with other areas
- Firm power demand delivery
- Spot price for power
- Reservoir levels

[10], [14], [15], [16]

4.2 Energy and Power Flow (EPF) model

The EPF model, also known as Samlast, is an integration of the PMA model and load flow analysis on a detailed electricity grid. It is designed for evaluation of large-scale hydro-thermal power systems and allows for calculation of variables such as power productions, losses and benefits during the period of analysis. It consists of three interconnected parts:

- The PMA model
- A load flow algorithm (Optlast)
- Algorithm for grid overload and loss handling

[16]

The PMA model is run as described in chapter 4.1, with the same input variables. Water values are calculated for each area in the strategy part. In the simulation part the optimal solution of hydropower production is found and stored by the single reservoir area productions section. The reservoir drawdown section assigns production to specific stations. A first calculation of power production for each plant is provided here.

In addition to these variables, the EPF model requires a number of data given in separate text files. While MASKENETT is used by the PMA model, the EPF model requires more detailed grid data in addition. This is given as a separate file with a number of nodes with connected lines between them. These lines have specified impedances and maximal current flow, but only cover the central grid. No lines below 132 kV are detailed with specific impedances. It is important to note that as the system model is simplified, not all areas have grid data included. This is neglected in areas where this simplification has a minor influence on the internal power flow between areas of analysis. Other input files include:

- **STYREDATA** is the main input file for management of the EPF model. It reads the detailed grid data file from its source. This file also states main commands such as the maximal number of iterations allowed in EPF and the type of load flow to be performed (AC or DC).
- **EFI-MODRED** contains information on handling of the exchange between market areas with and without grid data. All DC transmission links are stated in this file.
- **EFI-KOBLING** includes data used for the load-flow calculation, such as base power reference and slack generator tolerance.
- **EFI-SNITT** creates a link between the OPS areas and the detailed grid data. It specifies which lines divide the system into separate areas. The lines are referred to the detailed grid of the EPF model while the areas are referred to MASKENETT.
- **EFI-FAST** links the distribution of area load in the market to the individual busbars in the grid model.
- **EFI-PROD** gives data on the connection between individual hydropower plants and busbars.
- **EFI-PREF** assigns power injection or consumption to busbars according to the buying and selling possibilities modeled for thermal power plants.
- **KOMBSNITT** states transmission limits through specified individual lines. These values are used in the algorithm for grid overload handling.

[17]

After the PMA model has finished its calculations, results are transferred into a load-flow algorithm called Optlast. This includes hydropower and thermal power production, as well as market utilization and firm power demand. A load flow analysis is performed, satisfying Ohm's and Kirchoff's laws for the transmission network. A reference node specifying U and δ is set, along with a number of P-Q and P-U nodes. Power flow equations are formulated for each specified P and Q, as shown in equations (4.1) and (4.2). A non-optimized load flow is first performed using the Newton-Raphson iterative method, satisfying the equations.

$$\mathrm{P}_{\mathrm{sp}} - \mathrm{P}\left(|\mathrm{U}|,\ \delta\right) = 0 \tag{4.1}$$

$$Q_{\mathrm{sp}} - Q\left(|\mathrm{U}|,\ \delta\right) = 0 \tag{4.2}$$

P – Active power
Q – Reactive power
U – Voltage
δ – Voltage angle

The optimal load flow [18], minimizing the operating costs as a function of the power flow in the system, may be solved by finding the optimal set of control variables. The equations (4.1) and (4.2) may be collected in a vector $\underline{g}$ as follows:

$$\underline{\mathrm{g}}\left(\underline{\mathrm{x}}, \underline{\mathrm{u}}, \underline{\mathrm{p}}\right) = 0 \tag{4.3}$$

$\underline{x}$ – State variables

$\underline{u}$ – Control variables

$\underline{p}$ – Parameter values

When all voltages are found, active and reactive power for all nodes can be calculated. This is achieved by manipulating equation (4.4) into equations (4.5) and (4.6), and solving them.

$$S = U \cdot I^* \tag{4.4}$$

S – Apparent power
I – Current

$$P_i = \sum_j |U_i| \cdot |U_j| \cdot |Y_{ij}| \cdot \cos\left(\delta_i - \delta_j - \theta_{ij}\right) \tag{4.5}$$

$$Q_i = \sum_j |U_i| \cdot |U_j| \cdot |Y_{ij}| \cdot \sin\left(\delta_i - \delta_j - \theta_{ij}\right) \tag{4.6}$$

P_i – Active power in node i
Q_i – Reactive power in node i
Y_{ij} – Admittance between nodes i and j
Θ_{ij} – impedance angle of Y_{ij}

Depending on the settings applied in STYREDATA, the load flow is either a simplified DC equivalent, or a more time-consuming AC load flow. Overloading of lines due to thermal and stability considerations is not taken into consideration at this point. A price-area algorithm is applied to the results of the load-flow calculation. A quadratic loss function is found by calculating the approximate power losses related to power transmission. This function is then made linear in order to find the actual losses.

The power transmissions calculated by Optlast are often different from the ones calculated by the PMA model. This is due to the consideration of individual line values in Optlast, and can cause line overloads during simulation of the EPF model. In order to solve these overloads, an algorithm for grid overload and loss handling compares calculated power transmission with capacities listed in KOMBSNITT. It is assumed that if the market model distributes a production and consumption that cannot be solved without overloads in the physical grid, the model has not adequately represented the market. The market conditions must therefore be adjusted for the overloads to be solved.

All overloads that are found in Optlast exert power transmission restrictions that are implemented back into the PMA model. This is done in a corrective loop rerunning the PMA model, producing a new power flow within the predefined limits. The new calculation of power flow considers the area prices that are found in the last calculation of the reservoir drawdown section in the PMA. A total of 13 260 load-flow solutions are found. With an average of 5 iterations per load period, the number of calculations amounts to more than 60 000. The EPF model therefore consumes more time and computer resources than the PMA model. [10]

4.3 Grid overload handling

The transmission limits considered by the EPF model must all be manually calculated and implemented. Power transmission limits in one direction may also be different from the limits in the other direction. As mentioned before, these limits are stated for specific lines and sections in the KOMBSNITT file.

A main challenge when handling overloads is the fact that AC power cannot be controlled directly, but will always follow the electric path of least impedance. In the market model PMA, line overloads do not exist. The model may calculate transmission through a line that is equal to its capacity limit. If this capacity is not sufficient, the excess power will be transmitted through other paths between the areas. Otherwise, consumption will increase or production decrease, solving the problem. The simulated transmission will never exceed the capacity limit between areas. As no line impedances are given, an overload cannot be calculated by the model.

In a real power system overloads exist and represent a typical load flow problem. The EPF model uses the calculated production and consumption values calculated by the PMA model. As impedances are considered in the EPF model, the power may flow in a very different manner than expected by the PMA model calculations. As a consequence of this, more power may flow through certain lines than was expected when the market conditions were calculated. This transmission may exceed the capacity limits given to the PMA model, causing overloads.

When an overload occurs between two areas, the EPF model will decrease the transmission capacity between these areas when rerunning the market model. The market model will consequently recalculate how much power can be exported from the surplus area, and reassess the market conditions accordingly. With a reduced transmission capacity the market model may either decrease production on the surplus side of the bottleneck, or reduce power prices causing increased consumption. This is done in the expectancy that less power surplus causes less export, thus solving the overload.

This solution has two main problems. First, the power flow causing the overload may be produced in a different area than the one on the surplus side of the bottleneck. Only decreasing production in the area on the surplus side, and not the area actually producing the surplus power, may not solve the problem. Secondly, as all the areas in the Nordic grid are interconnected, there is normally more than one path between two areas.

If there is free transmission capacity on other paths, the market model will calculate power export through these channels instead of the overloaded line. Production in the surplus area may in this case not be changed no matter how much transmission capacity is reduced on the overloaded line. The market model will not consider which path has the least impedance. The problem can be shown by Fig. 4-4. In this example an overload has occurred between areas 6 and 8, illustrated by the line marked in red. If there is free transmission capacity from area 6 to 8 either directly or through area 5 and 9, the market model will use these transmission channels and not reduce any production in area 6.

When the same production values again are used in the load flow algorithm, it will calculate the same power flow as before. Thus the same overload will occur again. This type of problem may not be solved no matter how many iterations are applied by the model.

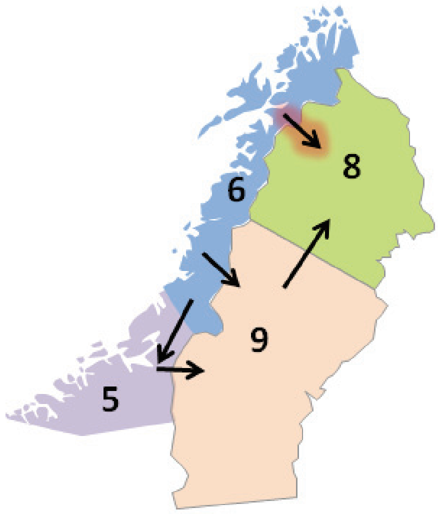


Fig. 4-4 – Market flow after overload in transmission between areas 6 and 8

In order to solve such problems, one must limit the ability of the market model to allow power flow in paths around the overloaded line. This is done manually in the KOMBSNITT file. The user must state, for each group of lines that are examined, which of the OPS areas the market model is to reduce production in when overloads occur. When overload occurs on a section of lines, power production is reduced or consumption increased in the areas stated. In the above example, production may be set to be reduced in both areas 6 and 7 whenever overload occurs between areas 6 and 8. This manual method of manipulating the modeled market is a tool that enables the model to take realistic action when encountering overloads. These actions are meant to replicate what the TSO would do when faced with the same overload situation.

The inter-TSO economic investments described for all scenarios in Chapter 5.2 are all DC connections. Simulated power flow through DC connections is equal to the market model flow given by the PMA model. This is due to the fact that power flow through DC connections is regulated by DC converter settings. As this power is controlled, it is not included in the load flow calculation of the EPF model.

4.4 Calibration of models

Model calibration has a significant impact on the results achieved from the simulations. The calibration aims to ensure that all simulations are realistic. The behavior of power producers, consumers and TSOs under the given conditions should be anticipated as realistically as possible. It is a tool for correcting reservoir drawdown and resulting area price development that is unlikely to occur. Both individual conditions in each of the areas as well as their impact on each other must be considered when evaluating the realism of the calibration results.

Both the PMA and the EPF model must be calibrated [17] in order to achieve realistic simulation results. Calibration is performed in order to find optimal transfer capacities for use in the water value calculations. This will allow for optimal weekly reservoir levels ensuring the best economic result for the simulations. The models do not have an adequate automatic calibration process that will ensure optimal results. The process must be done manually, altering three vital parameters of the model. These parameters consist of:

- Loop-back factor
- Form factor
- Elasticity factor

The quantity of firm power contracts used in the water value calculation is considered in the loop-back factor. Increasing this factor will cause an increase in the water values themselves. Strategically the model will ensure higher reservoir levels as a result. This is the parameter that has the most influence on the calibration.

Load distribution throughout the year is taken into account by the form factor. A factor of 0 is defined as a constant, or flat, load distribution. Increasing the factor increases winter consumption and decreases the summer consumption correspondingly. A high form factor will give high reservoir levels at the start of the drawdown season and low reservoir levels at the start of the filling season.

Water values are also influenced by the price-dependent market not only in its own area, but also all connected areas. The elasticity factor gives a value for this, describing the price elasticity of the system. A decrease in elasticity factor will reduce the curves for supply and demand, causing less sample space for the simulated reservoir levels. All percentage curves will as a result be pushed closer to each other.

Fig. 4-5 shows the main structure of the PMA model and how calibration of it can be performed. During startup, SAMINN transfers input data to files that can be read by the model. STFIL then inputs simulation control data, and starts a separate OPS model water value calculation for each area of the simulated system. SAMSIM represents a simulation without detailed reservoir drawdown, while it is included in SAMTAP. KOPL will rerun the model back to before the OPS calculations if the water values do not converge, changing firm power values slightly each time. When this has completed, a manual check of results may be performed by the user. It is at this point the three calibration parameters may be altered manually. The model is then looped back to before STFIL and rerun, and new results can be evaluated by the user once they converge.

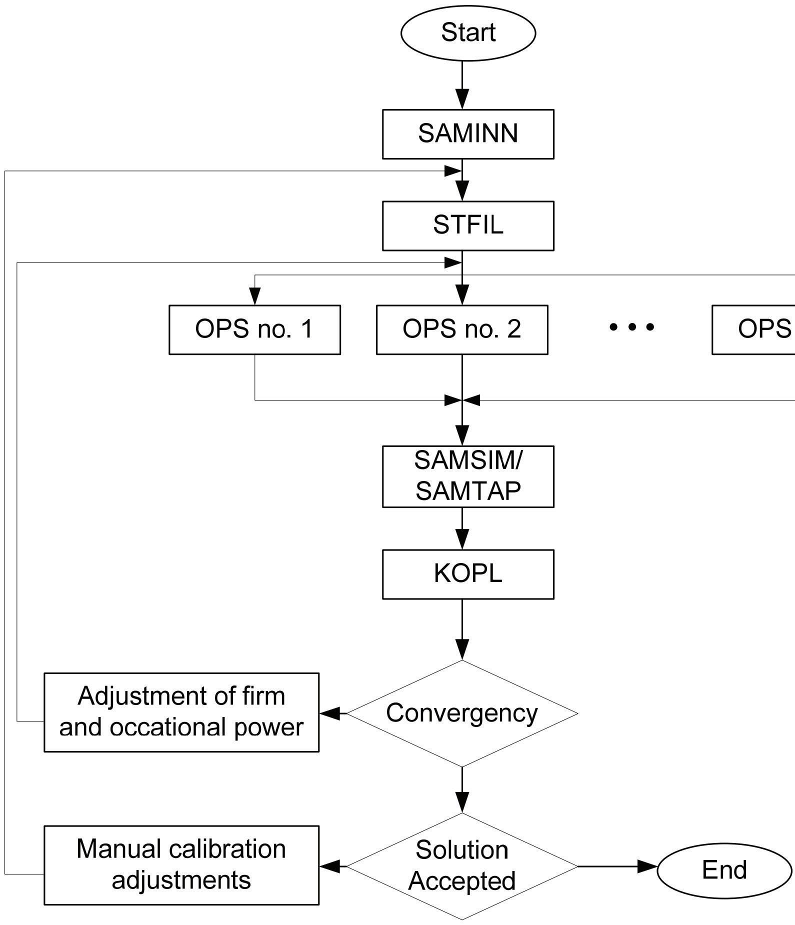


Fig. 4-5 – Calibration of the PMA model [17]

The main calibration signifying the largest change is done graphically, viewing the reservoir levels of the simulated areas. A simulation is first run without reservoir drawdown, using SAMSIM. As this calculation does not include reservoir drawdown, the calculation time is significantly shorter than SAMTAP. The reservoir level graphs are tuned manually to gain the desired curves. Ideal reservoir filling curves may differ from area to area, which must be taken into account when considering the graphs. Generally the curves should avoid risk of both overflowing and emptying the reservoir. The model may also be calibrated to desired area price curves instead of reservoir levels.

After the main graphical calibration has been achieved, a new simulation can be run with reservoir drawdown included, using SAMTAP. This may cause the curves to vary from the original calibration, so they again must be altered into acceptable values. Detailed results of the simulation may be used for fine tuning of the model in the final calibration. The results giving the lowest running costs for the system as a whole will give the best calibration.

Calibration of the EPF model is similar. After inspection of the resulting reservoir levels and area prices after simulation, parameters are changed and the simulation rerun. The same result criteria are considered for the EPF model as for the PMA model. The loop will continue until the user accepts the results that the model has calculated.

For the purpose of calibration, reservoir level data is presented with percentage curves in order to gain a realistic view of the statistics the data represents. Each curve has a percentage possibility that the result will be less than what the curve itself indicates. Percentage curves re given for 0, 25, 50, 75 and 100 %. The result is referred to the 50 years of historical data that is used by the model. Therefore the 25 percentage curve for reservoir filling will have a 25 % possibility that the reservoir level will be lower than shown by the curve.

The 0 percentage curves are always the lowest curves, and show the reservoir development assuming the driest and coldest of the historical weeks. The 100 percentage curves are the highest curves in the graphs, and show the development assuming the historical weeks with the highest inflow. The median curve for all the historical data is shown in the same graph, given by the color black.

In one of the simulated data sets, area 5 had a reservoir curve as shown in Fig. 4-6 before calibration. The 100 percentage curve indicates overflow from weeks 24 to 47, and the 0 percentage curve falls dangerously close to zero during spring. The values used for this area before the calibration was performed are shown in Table 4-3.

As seen from Fig. 4-6, the 100 percentage curve represents the chance of an area price higher than 12 eurocent/kWh during spring. This high price spike is a result of the 0 percentage curve of the reservoir level. When the reservoir level drops towards zero, prices are increased in order to decrease consumption. Such a high power price will have a large impact on all consumers, especially high power consuming industry. Taken that this price is significantly higher than the production cost of power, socio-economic benefit is reduced.

All water that is spilled from a reservoir has no value for the producer. Therefore, prices drop towards zero when there is an increasing chance for overflow. This is illustrated by the 0 percentage curve for prices dropping to zero during weeks 29 to 33, the same time period most reservoir level percentage curves are at their highest. When power prices drop below the production cost producers are faced with a loss, also causing a reduction in socio-economic benefit.

Table 4-3 – Model values before calibration

Area number	Loop-back factor	Form factor	Elasticity factor
5	0.750	0.686	1.000

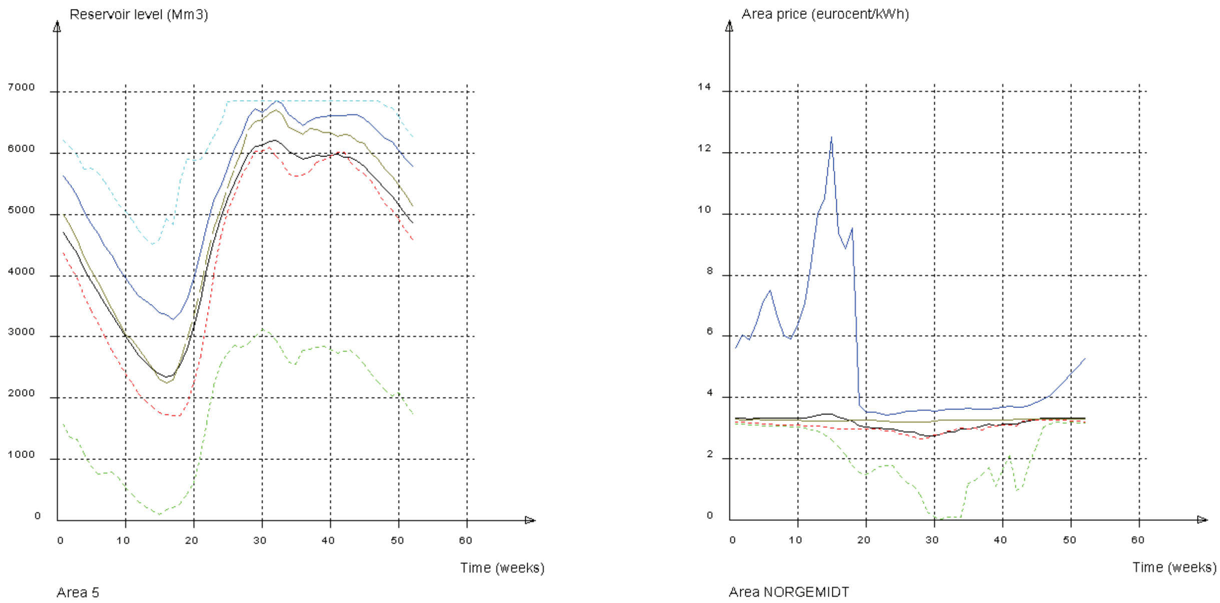


Fig. 4-6 – Reservoir levels (left) and area price (right) for mid-Norway before calibration

In order to improve the area conditions shown by Fig. 4-6, area 5 is calibrated as given in Table 4-4. The elasticity factor is reduced in order to reduce the area of possible outcomes, seen as the space between the percentage curves. Further, the loop-back factor is increased for the model to increase the reservoir levels slightly. The result on the reservoir level is shown in Fig. 4-7. None of the percentage curves indicate any overflow at any point. Also, the 0 percentage curve does not drop as close to zero as before the calibration.

Table 4-4 – Model values after calibration

Area number	Loop-back factor	Form factor	Elasticity factor
5	0.800	0.686	0.300

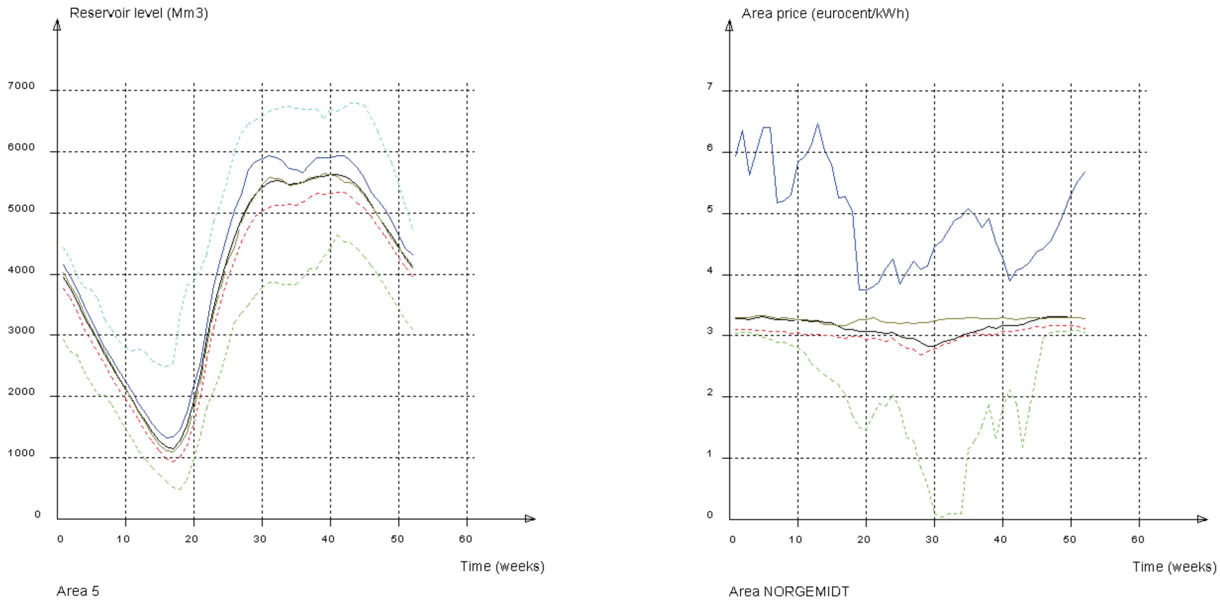


Fig. 4-7 – Reservoir levels (left) and area price (right) for mid-Norway after calibration

Calibrating the model produces different area price curves, also given in Fig. 4-7. Although still comparably higher during spring, the 100 percentage curve is more constant than before the calibration. The large price spike seen before has been removed. This is a direct result of the reservoirs having a lower chance of being emptied. The strategy part of the model no longer needs to increase prices to avoid this situation.

There is still a risk of power prices dropping to zero in Fig. 4-7. The 0 percentage curve is only slightly improved from before the calibration. Producers in the area risk operating at a loss under these conditions. Local conditions must be taken into account when considering this result. The mid-Norway region has limited reservoir sizes and in this data set, poor grid connections to neighboring areas. Excess water can only be stored to a certain extent, and grid congestion may limit the power transmission out of the area. A risk of low prices during late summer may be unavoidable without grid reinforcement.

As calibration aims to improve the water value calculations, they are only relevant for areas that are modeled with hydropower production. All such areas in all data sets used in this thesis are calibrated using the same method as described above. Adjustments are made where necessary to avoid large spikes or drops in area prices. Areas 14 to 20 are not modeled with hydropower production and are therefore not calibrated.

The general tendency of low reservoir levels during spring, seen in Fig. 4-6 and Fig. 4-7, is a typical characteristic of the Norwegian hydropower system. Most of the large hydropower producers in Norway receive inflow from catchments at medium or high elevation. Precipitation in such areas comes as snow during winter. This snow cannot be utilized by the power stations until it melts. Reservoir levels will therefore become increasingly low during and after winter, until spring flood. When spring flood occurs, the snow melts and precipitation resumes as rain. Inflow during this period is much higher than the rest of the year, refilling the reservoirs.

The highest reservoir levels are generally found during late autumn, clearly seen in the calibrated curves. This depends on geographic location and elevation of catchments as well as the specific temperature and inflow each year. Area prices follow the reservoir levels, giving high prices at low levels and low prices at high levels. These prices represent the assumed risk of reservoir emptying and flooding, respectively. This connection between reservoir levels and area prices is often clearly visible in Norway due to the high dependency on hydropower.

4.5 Model improvements provided by EPF version 7.6

The EPF model is continuously under development in order to achieve more realistic results. In the project “Economic benefit of new capacity in the central grid” during autumn 2008, an analysis was made for a grid investment between areas 4 and 5. Simulations were performed using two different data sets, by means of EPF model version 7.4. For each data set, simulations were made of the system both with and without the investment. The resulting power flow and socio-economic benefit of the simulations were then compared.

Changes in transmission, congestion and area prices found by the analytic tools were consistent with the theory presented in the project report. However, the increases in socio-economic benefit were not consistent with theory in one of the data sets, data set 1. A large decrease in benefit was calculated both for the Nordic area and the system as a whole. As a result, the calculated benefit of that simulation was disregarded and a number of probable causes of the error were presented. These include model disturbances, and the apparent failure of the program to solve certain power flow problems caused by transmission limits. It was assumed that the power flow results were realistic although the socio-economic benefit had been calculated unrealistically.

This project utilizes EPF model version 7.6, which has a number of improvements compared to version 7.4. This version implements an improved method of solving power flow problems caused by transmission limits. A more realistic method of calculating socio-economic benefit has also been applied, taking into consideration reservoir level differences before and after simulation.

The simulation results for each version can be shown in Table 4-5 for data set 1 and Table 4-6 for data set 2. The tables show the increase in benefit by the investment for each data set and model version. The increase is found by subtracting the total benefit after the investment by the total benefit before. All values are given in million Euros per median year of simulation.

Table 4-5 – Socio-economic benefit increase using data set 1

Model version	Area 5	Norway	Nordic area	System
V.7.4	0,38	10,91	**-22,59**	**-22,75**
V.7.6	6,37	15,76	8,05	8,5

Table 4-6 – Socio-economic benefit increase using data set 2

Model version	Area 5	Norway	Nordic area	System
V.7.4	74,09	22,41	20,54	19,37
V.7.6	91,59	53,16	19,12	16,43

The results using version 7.6 give increased socio-economic benefits in all areas shown by the tables above. The decreases in benefit previously found using version 7.4, shown in bold, are corrected by the new model version. All results appear to be reasonable. Benefit increase in Norway is found to be 15,8 million Euro using data set 1 and 53,2 million Euro using data set 2.

Power flow between areas 4 and 5 is calculated and presented in Fig. 4-8, for data set 1. Changes for all load periods are similar to the ones shown below, for load period 1. The results of both EPF versions are shown in each figure. The graphs show that calculated transmissions are very similar throughout most of the year. This shows that the improvements made in the EPF model have not had a large impact on the main transmission calculations.

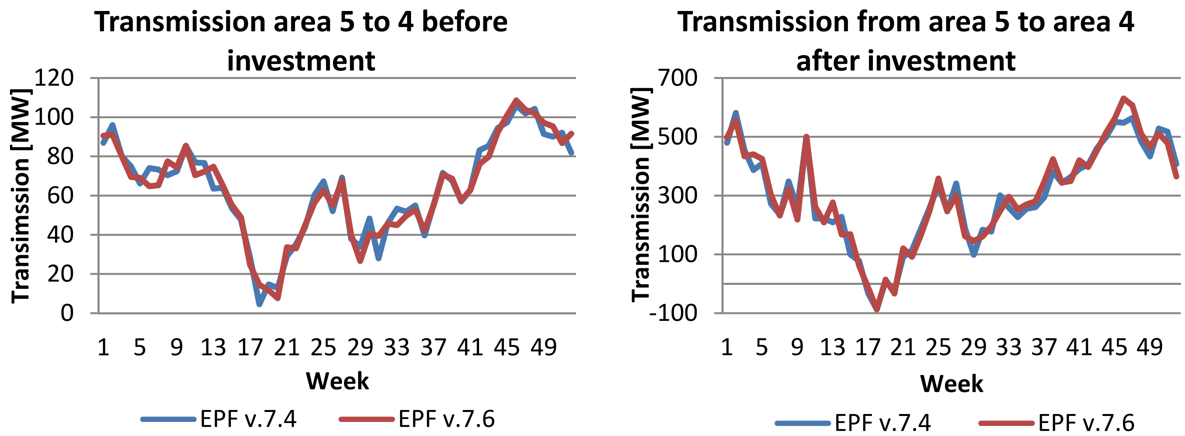


Fig. 4-8 – Transmission using data set 1, transmission limit 100 MW (left) and 1400 MW (right)

The power prices in area 5 before and after the investment are shown in Fig. 4-9. Prices are shown for load period 1. The graphs both show that the power price is reduced in area 5 when simulating with the new model version. This price reduction causes an increase in consumer benefit in the area. The increase is small, as the price reduction is only 0,5 EUR / MWh.

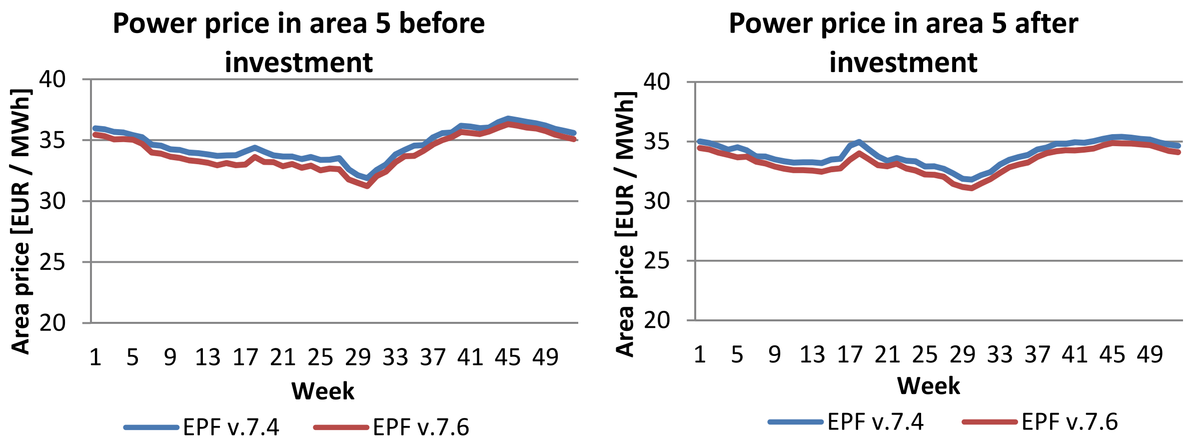


Fig. 4-9 – Area price using data set 1, transmission limit 100MW (left) and 1400 MW (right)

The graphs that are compared use identical data sets, and the only change between the simulations is the model upgrade. All result changes are therefore solely due to the improvements in the new version of the EPF model. The slight changes in transmission that are proposed by the new model version have an impact on the prices. The socio-economic benefit is highly affected by such price changes. In addition, the program calculating this benefit has been rewritten, solving earlier calculation flaws. EPF model version 7.6 proves to improve the models ability to calculate the benefit realistically.

5 The Nordic power system

5.1 Background: renewable power goals

"What is important is to make progress toward an economy that is less dependent on carbon."
EU Commission President Jose Manuel Barroso, 10. January 2007 [19]

Through the past decade there has been a growing concern for the consequences of both CO_2-emissions and the dependency on carbon that is found in many economies. Security of supply, climate changes and rising fuel prices are important factors. As a result of this, the EU has decided to increase renewable power production considerably. A goal has been set that by year 2020, 20 % of all the energy consumed within the EU should come from renewable sources. This percentage level is more than three times higher than the renewable energy consumption in year 2008. The EU goal also states that greenhouse gas emissions are to be cut by at least 20 % below 1990 values by year 2020. [19], [20], [21]

According to the Intergovernmental Panel on Climate Change, [22] global emissions must be cut by 80 % within 2050 in order to limit climate changes to sustainable levels. One can expect that this will lead to even more ambitious emission reduction goals between the years 2020 and 2050.

There are many areas within the energy sector where the proportion of renewable energy can be increased. For economic reasons it is favorable to do so within the power sector. The amount of renewable power produced in the EU must be increased to roughly 35 % within year 2020 in order to meet the goal that is set. From the 2008-level of 15 %, this demands a large increase in renewable power over a short amount of time. [20]

A characteristic of many forms of renewable power is its low operating costs once built. Wind and water are not subject to purchasing costs such as is the case with coal and gas. The marginal cost of power generation from such sources is therefore very low compared to other types of power generation commonly used in Europe. This is illustrated in Fig. 5-1, where the marginal cost of wind and hydropower generation is lower than all other forms of energy production represented.

As explained in Chapter 2, production units with the lowest marginal cost of generation are put into operation before units with higher marginal costs. An increase in hydro- or wind power production will therefore not cause existing renewable power stations to be shut down. Nuclear power also has a low operating cost and is likewise unlikely to be shut down. New renewable power that is built is more likely to replace coal, oil and gas power production, which have higher operating costs.

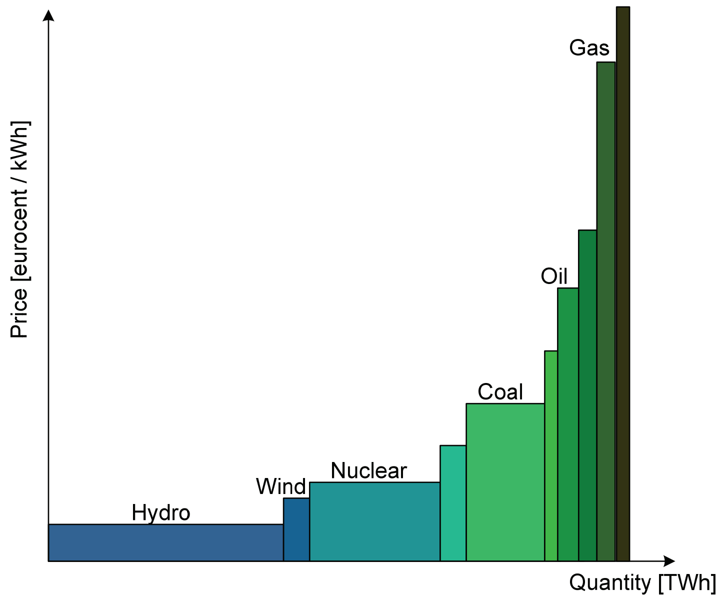


Fig. 5-1 – Marginal cost of power generation in the Nordic system

The Norwegian power production is mainly based on hydropower, and renewable sources cover more than 98% of the total national production. In the Nordic power system, approximately 52% of the total power production is based on renewable energy in an average year. [23] The Nordic countries are therefore already a large contributor to the average amount of renewable energy in Europe. There is very little production in Norway and Sweden that would be shut down by increased renewable power investments. Given sufficient transmission capacity and a net power surplus, these investments can replace carbon-based production in continental Europe.

Norway has excellent conditions for both hydro and wind power. While most of the hydro resources have already been utilized, little wind power has so far been developed in Norway. Theoretical power available from wind is a factor of its velocity to the third power:

$$P = 0.5 \cdot \rho \cdot A \cdot V^3 \tag{5.1}$$

P= Power [W]
ρ = Air density [kg/m^3]
A = Rotor area [m^2]
V = Wind speed [m/s]

The high wind speeds found around the Norwegian coast compared to areas in central Europe therefore give potential for a much higher power output per wind turbine. The strong winds found at the coast of northern Norway provide especially good wind power conditions. Despite increased wear on the turbines due to the harsh climate, wind parks in this area are expected to be much more economical than in areas with less wind.

As of 2008, there is a power surplus in Norway. No power deficit is expected in the future. [23] There is no coal and very little gas production that can be replaced by new wind power. With unchanged power prices, new power produced would not be consumed in Norway. If increased production causes a reduction in power prices, consumption is likely to increase moderately in the southern region of the country. Either way, the majority of new power produced is likely to be exported for consumption abroad.

Without subsidies, wind power is not profitable in Norway. [24] Together, the cost of investment and maintenance exceed the revenue made from power sales in today's power market. Without significant technological advances, subsidies are therefore necessary if any new wind investments are to be made. For the Norwegian government, subsidizing wind power which is made solely for export can be difficult to justify without a political purpose.

It is expected [21] that the EU goals also will become valid for Norway. As the goal of 20 % renewable energy in EU is an average, the requirement for Norway may be much higher. A calculation performed by Point Carbon has concluded that the EU may demand a 15 % increase in the share of renewable energy in the Norwegian consumption. An important part of meeting this demand will be by increasing the renewable production for export.

For European countries that have few renewable resources, the goals determined by the EU may be difficult to achieve. Countries which exceed their goals for renewable energy may therefore sell Guarantees for Origin (GO). [20] These may be purchased by countries that have not met their goals, instead of producing the renewable power themselves. With GO, European countries with little renewable resources can pay for renewable power in countries with more resources, such as Norway or Sweden.

It is therefore possible for large-scale wind power development in Norway to be made within year 2025. This development may be financed both by Norway and by countries with less wind resources in order to meet the EU energy goals. A requirement for such development will be the TSOs abilities to transmit this power to the consumers in continental Europe. With grid congestion problems already today, this will require massive transmission capacity investments.

5.2 Base scenario assumptions on future market conditions

Investments in power systems generally have a long life span, typically 40 – 70 years. When calculating the benefit for such investments, market conditions for the entire period of analysis must be taken into consideration. Politics within energy and environmental issues, new technologies and global economical growth are examples of elements that may greatly alter the future benefits of an investment. These elements are often very unpredictable, giving an element of risk in the investment.

In order to reduce this risk, TSOs develop scenarios of likely market conditions for a number of years into the future. Simulating the system with variables fitting each of these scenarios can give an indication of how large the span between likely worst- and best-case market conditions will be. For reliable results, scenarios must be internally consistent, considering all consequences of all presumptions.

Statnett creates and revises such scenarios each year. A series of scenarios with prognosis for electric production and consumption have been developed to simulate the needs for Norwegian grid development until the year 2025. In 2008, four such scenarios were presented. These scenarios [23] are used in this project, providing a basis of expectancy for the year 2025. This basis of expectancy is useful in comparison to additional market condition assumptions that are considered in the project.

For all 4 scenarios, data sets are provided for the analytic tools that are described in Chapter 4. These data sets are based on a common data set that reflects the given grid and market condition in 2008. They are therefore directly comparable with each other. From the common data set, individual changes have been made on each of the data sets according to the scenario they represent. The scenarios are given as follows:

"Standstill" scenario

Global economy is declining and oil prices are low. The weaker economy and cheap fossil fuels result in little interest in development of renewable power. Therefore only a very small amount of increased wind- and hydropower is developed. General consumption increase will be low, while increased and decreased industrial consumption will on a national basis even each other out. The Norwegian power system as a whole will remain in balance with no large change in either consumption or production. The only new inter-TSO economic investment made from Norway is Skagerrak 4, connecting to Denmark.

"Wind and Consumption growth" scenario

The global economy continues growing at the same rate as it was in the beginning of 2008. Oil prices are in accordance with the International Energy Agency's expectancies. Renewable energy ambitions are high and wind power is subsidized well. With improved technology, wind power is developed in a much larger scale than today. Climate changes cause increased water inflow into reservoirs, allowing for more hydropower production. The increased power production causes lower power prices and a resulting increase in general consumption. A moderate power surplus will be created in Norway and the national electric grid is strengthened considerably. Inter-TSO economic investments are made towards Denmark (Skagerrak 4), England (Norge-England) and Netherlands (Nordned II).

“Export and Trade” scenario

A high oil price and strongly growing global economy is expected. Combined with high prices on power generation based on fossil fuels, this will motivate renewable energy. Measures taken in energy efficiency allow for a general consumption which does not greatly exceed that of 2008. High power consuming industry will increase their consumption greatly as a result of the increase in global economy. Due to high costs, a corresponding consumption reduction will take place in the wood processing industry. Expansions of current power production, increased water inflow and thorough development of renewable energy in Norway will give a high power surplus in Norway. This surplus allows for large scale trade with other countries. Inter-TSO economic investments are therefore made to Denmark (Skagerrak 4), England (Norge-England), Netherlands (Nordned II) and Germany (Nordlink).

“Expectancy” scenario

This is considered the most likely scenario, and is a synthesis of the other three scenarios. Oil prices, global economy and general consumption evolve as expected in “Wind and Consumption Growth”. While water inflow increases, wind power is not greatly expanded. Power production and international trade reaches a high level, but not as high as in the “Export and trade” scenario. Inter-TSO economic investments are made to Denmark (Skagerrak 4) and Germany (Nordlink).

The data sets for each of the scenarios consider the Nordic power market with different expectations. In turn these different expectations have a large impact on the simulation results. The expectations of power consumption, production and resulting balance is shown in Table 5-1. High fossil fuel and CO_2 quota prices cause high power prices in countries with large quantities of thermal power. In turn this leads to increased power export from Norway and a high motivation for development of renewable power.

Table 5-1 – Power consumption, production and balance for all data sets

		Expectancy	Standstill	Wind and Consumption Growth	Export and trade
Production	**[TWh]**	154,4	143,3	163,3	158,1
Consumption	**[TWh]**	143,7	142,9	155,6	145,4
Power balance	**[TWh]**	10,7	0,4	7,7	12,7

As each of the scenarios have different grid expectations, transmission limits between certain areas also differ. Both thermal and stability conditions differ between the scenarios, depending on the expected level of investment. Additional limits apply for groups of intersections due to stability and overload concerns.

It is of interest to see how increased power production north in both Norway and Sweden will impact the power flow of the Nordic grid. To simulate such a situation, a number of planned wind parks and small hydropower stations are assumed built within 2025. This will create a large power surplus in the region, allowing for a high power export. For this assumption, conditions in the “Wind and Consumption Growth” scenario offer logical expectations for grid and market conditions. The scenario is chosen due to both its high expectancy of new wind power as well as the strong grid investments that are anticipated.

5.3 Base grid and market conditions

The ”Wind and Consumption Growth” base scenario for year 2025 assumes that large changes have been made in the Norwegian power and transmission system compared to year 2009. The changes include increased consumption, production and transmission capacities. The median area prices for Norway and Sweden during peak load are shown in Fig. 5-2. The analytic tools described in Chapter 4 are used to provide the results shown by the graphs. One can see that there are large price differences between north and south in both countries, throughout most of the year. It is therefore apparent that transmission congestion may be a problem with this grid solution.

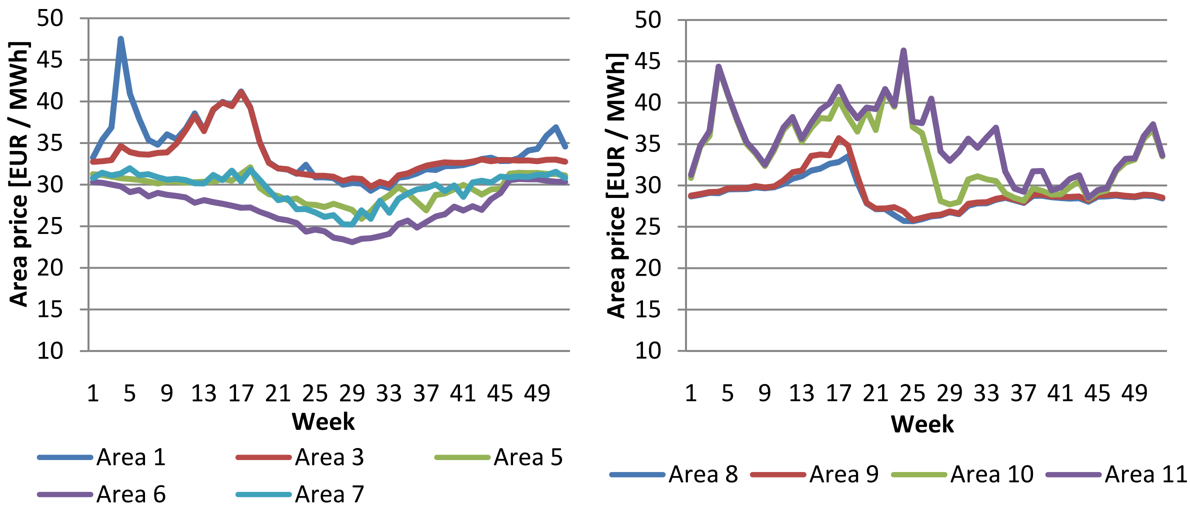


Fig. 5-2 – Area prices in Norway (left) and Sweden (right), peak load period

In Sweden, congestion appears mainly between areas 9 and 10. This causes similar power prices in the areas above the congestion, as well as in the areas below the congestion. A large amount of the total power production in Sweden is produced in areas 8 and 9, while there is little consumption in these areas. This is visible as these two areas have lower area prices than areas 9 and 10, where the main Swedish power consumption occurs. Transmission congestion prevents power produced north in Sweden to be transmitted south. Therefore, prices in the producing areas drop while prices in the consuming areas rise.

The Norwegian area prices do not appear to be grouped as clearly as in Sweden, but there is still a price division present. As in Sweden, there is little consumption north in Norway compared to the southern regions. There are large amounts of power that is produced north in Norway that therefore must be transmitted to the consumers in south. Throughout most of the year, the southern areas have a common price that is higher than the prices in the northern areas. This is the same problem as is found in Sweden. As prices in areas 5 and 6 are similar, the main congestion appears to occur between mid- and southern Norway.

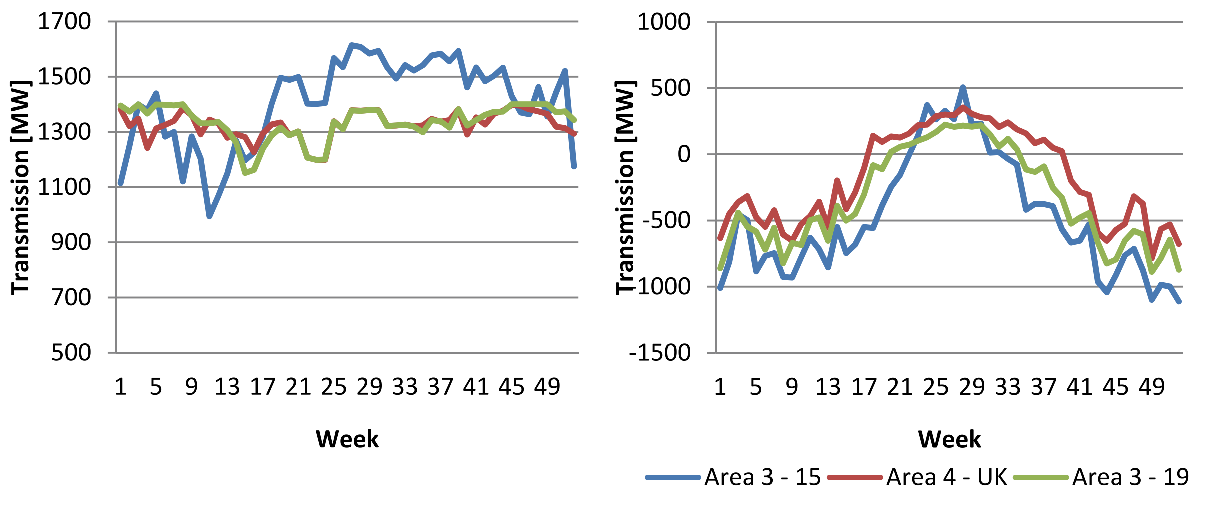
Apart from a few price spikes, the prices are relatively constant throughout the year. The prices are not low enough to indicate a high probability for overflow. Similarly they are not high enough to indicate a high probability for rationing. The price spike in area 1 in week 4 is due to a simulated increase in firm power consumption in this week, only to represent the coldest week of each winter. It shows that although such a week will cause an increase in prices, power rationing will not be necessary.

Norway covers most of its electric power consumption with regulated hydropower. This is not the case in continental Europe where thermal power is dominant. Thermal power generation usually requires many hours or days to start or stop, which can be a problem due to daily load variations. If thermal power generation is dimensioned to match consumption during daytime, there is a large excess of power during night. This creates very high power prices during day and low prices during night.

Regulated hydropower has the advantage that it can be started and stopped in minutes, and the energy can be stored for a long time depending on the reservoir size. Norway is therefore able to export power to continental Europe during daytime when prices are high, and import power at night when prices are low. Norway can make a large profit from this trade. It is also beneficial for European countries as Norwegian export during day allows them to operate fewer thermal power stations, thus reducing the profit loss during night.

The base scenario assumes a total of three DC links from southern Norway to other European countries. The transmission through these cables is given in Fig. 5-3. In the figures, the term “UK” is used instead of “area 18” to avoid confusion between the Norway – England and Norway – Germany lines, as they both connect to area 18. The left figure shows that during peak load, the cables to area 19 and UK are utilized close to their capacities. The cable to area 15 also has a high transmission, but it is lower than the capacity limit through most of the year. During nighttime, the transmission changes direction into Norway throughout most of the year. The figure shows that Norway participates, and has an important role, in the regulation of European thermal power.

Power export from southern Norway to continental Europe
Base scenario, load periods 1 (left) and 4 (right)



Transmission capacities [MW]:

Area 3 – 15	:	1640 / 1640	DC
Area 4 – UK	:	1400 / 1400	DC
Area 3 – 19	:	1400 / 1400	DC

Fig. 5-3 – DC cable transmission, peak load period (left) and nighttime (right) in base scenario

5.4 Transmission section capacities

Grid transmission limits exist due to both the current capacity through each line, also known as thermal conditions, and stability concerns. The N-1 criteria used by Statnett states that a failure on any one line should not cause the fall-out of another. A line may therefore not be loaded as much as its nominal capacity, in order to ensure the stability of the system.

Certain groups of lines, creating sections, have a limit on the level of total transmission that can pass through them in order to avoid overload problems. The sections considered in this project that have capacities altered are shown in Fig. 5-4. A stability analysis of all considered grid conditions is not included in this project. Transmission limits that are necessary to ensure the stability of the system are based on calculations performed by Statnett.

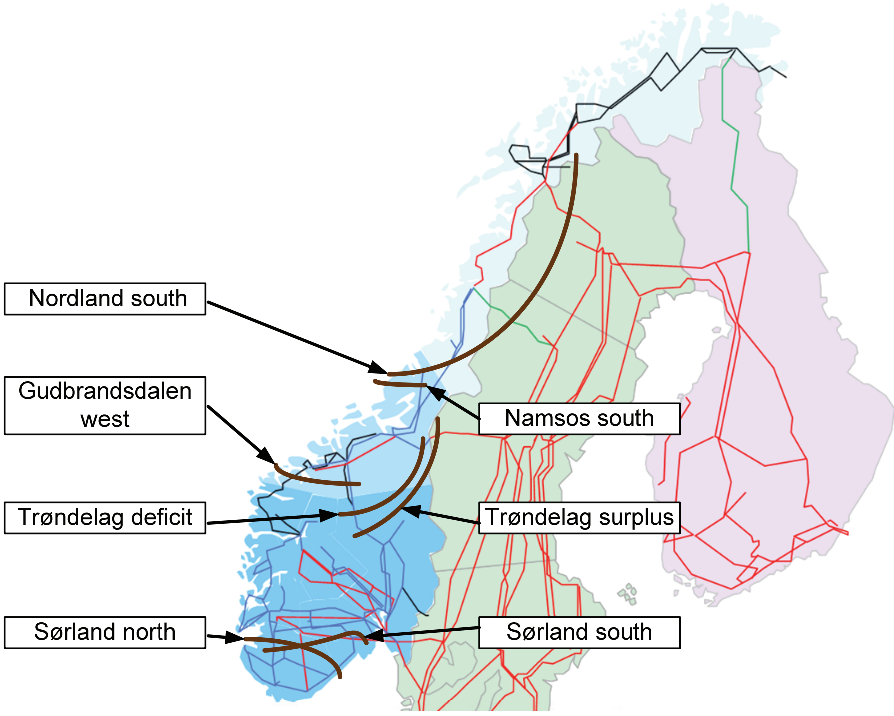


Fig. 5-4 – Lines defining transmission sections

For the base scenario conditions, section transmission limits are implemented with values shown in Table 5-2. Limits are given for both directions of the defined sections, first in the direction that the section name indicates. Therefore the Nordland section south is defined as all lines transmitting power south from Nordland, into Sweden and mid-Norway.

Table 5-2 – Section transmission capacities

Section transmission limits implemented in base scenario conditions			
Section transmission capacities [MW]:			
Nordland section south	2 500 / –	Trøndelag section surplus	800 / –
Namsos section south	– / –	Sørland section south	3 400 / –
Gudbrandsdalen section west	– / –	Sørland section north	3 300 / –
Trøndelag section deficit	800 / –		
Explanation: – is used to indicate sections where a limit is not necessary because the respective lines are not overloaded in the current situation.			

5.5 Additional project assumptions

The “Wind and Consumption Growth” scenario has been chosen as a logical base scenario due to its high expectancy of new wind power and strong grid investments. The assumptions included in this scenario must be considered before additional changes are implemented into it. Compared to the situation in 2008, the “Wind and Consumption Growth” scenario assumes a hydropower production increase of 12 TWh. Another 13 TWh of onshore wind power is expected, as well as another 6 TWh of offshore wind power. It is important to note that these increases in production are spread throughout the country and not all positioned in the north of Norway. Due to increased consumption, the scenario assumes a positive power balance of only 7 TWh.

In addition to the inter-TSO economic investments mentioned before, a number of intra-TSO transmission network upgrade investments are also assumed made in the base scenario. Voltage upgrades and other investments ensure a 420 kV connection covering the entire length of Norway, from Kristiansand in south to Varanger in north. The expected Norwegian grid in 2025, compared to the grid in 2008, is shown in Fig. 5-5.

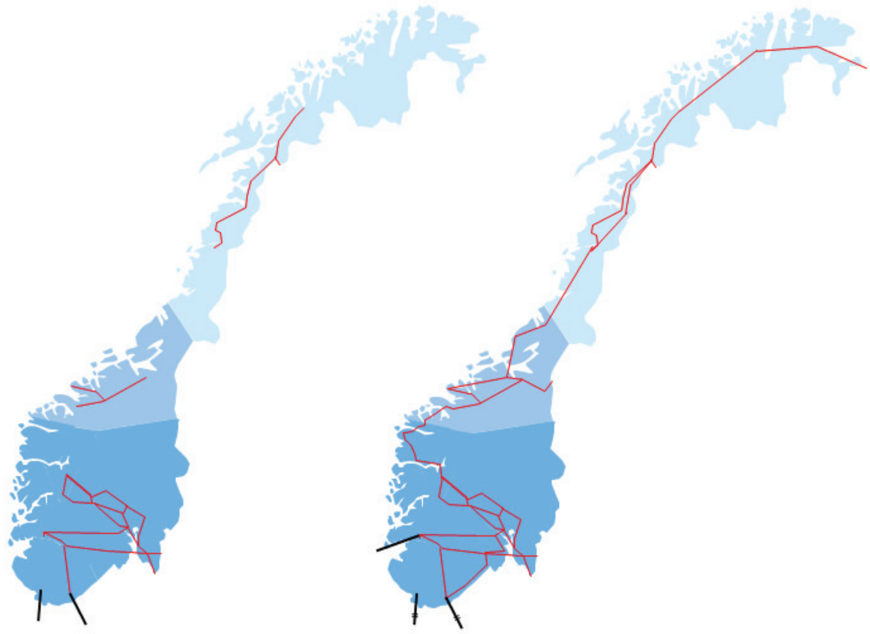


Fig. 5-5 – 420 kV grid in 2008 (left) and in the expected scenario for 2025 (right)

Only DC lines (black) and 420 kV AC lines (red) are included in the figure. Most of the new investments are made at 420 kV level, and the figure therefore gives a good indication of where the transmission capacity has been improved. The 420 kV line that is built through area 7 reduces losses in the region significantly, improving conditions for new power production. Similarly, the 420 kV line upgrades connecting area 5 to areas 4 and 6 allow for a much higher power flow through Norway than today. The three new DC cables from southern Norway allow increased export and trade with other European countries.

This thesis assumes a power production increase that by far exceeds the expectations of the base scenario. None of the new power stations that are assumed built have received building concessions to date. They are, however, all theoretically realistic projects that have published investment plans. These projects have been chosen as they offer a degree of realism into the simulations. If a large amount of new power production is to be built in northern Norway and Sweden, these projects may be the most likely plans to be considered. The increased wind power production is shown in Table 5-3, Table 5-4 and Table 5-5.

Table 5-3 – Assumed new wind power projects in area 6 [25] , [26]

Regional area	Installed capacity [MW]	Yearly production [GWh]
Vannøya	750	2 500
Sleneset	225	675
Sjonfjellet	436	1 304
Selvær	450	1 600
Seiskallåfjellet	147	440
Kvalhovudet	33	100
Kovfjellet	57	170
Stortuva	69	207
Sum area 6	2 170	7 000

Table 5-4 – Assumed new wind power projects in area 7 [27]

Regional area	Installed capacity [MW]	Yearly production [GWh]
Skjøtningberg	400	1 200
Nordkyn	750	2 600
Dønnesfjord	100	300
Laukvikdalsfjellet	70	280
Rákkocearro	350	1 100
Sum area 7	1 670	4 280

Table 5-5 – Assumed new wind power project in area 8 [28]

Regional area	Installed capacity [MW]	Yearly production [GWh]
Markbygden	2 000	6 000
Sum area 8	2 000	6 000

In addition to the wind power projects, an increased amount of small hydropower production is expected in area 6. This amount corresponds to 5 TWh per year. As such an amount of power will require a significant amount of small hydropower stations, a list of all individual plants that are expected is not given. They are assumed built in proximity to the regional areas Kolsvik, Marka, Glomfjord and Svartisen. A visual representation of the geographic locations of all new power stations is given in Fig. 5-6.

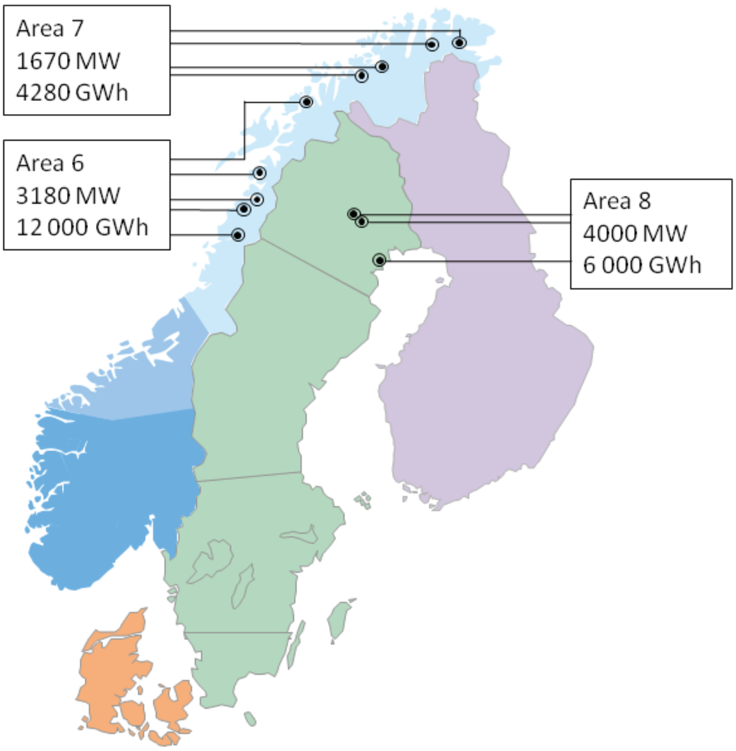


Fig. 5-6 – Geographic locations and maximum values for new power production

In total, the projects listed above expects a total yearly production increase of 22 300 GWh more than the base scenario. This is divided into 16 300 GWh in Norway and 6 000 GWh in Sweden. The increase is of such a size that the grid is unlikely to provide acceptable power transmission without large improvements. Grid improvements are likely to be necessary in order to for this amount of new production to be socio-economically viable.

5.6 Proposed grid options

The main goal of the grid development is to find an optimal transmission solution for the new power production. This solution should solve transmission bottlenecks to the extent possible and cause a minimum of losses during the transmission. Area prices should not drop low enough to cause large amounts of increased consumption. The solution should ideally allow renewable power to directly replace carbon-based production. Over the period of analysis considered, the grid development should provide a socio-economic benefit.

The large amount of renewable power that is assumed to be built will put a large strain on the expected central grid in 2025. As the consumption is expected to take place in continental Europe, the power must be transmitted through Norway and Sweden. In 2025, Sweden is expected to have four 420 kV lines spanning the length of the country while Norway is only assumed to have one. The impedance of the Swedish central grid will consequently be much lower than the Norwegian equivalent. A large amount of the new power will be likely to flow towards and through Sweden. If a majority of the power is to be transmitted through Norway, it will require either controlled DC transmission or a large reduction of the Norwegian central grid impedance.

There are several ways to approach the transmission problem. Transmission network upgrade investments can be made both in Norway and Sweden. New inter-TSO economic investments can be made between the countries, allowing more power trade. Both AC and DC line investments are possible. Additional DC cables connecting southern Norway to continental Europe may also be built in order to export power through Norway. Such DC transmission links may require interconnection investments to support them, allowing power to flow freely to the DC cables.

One transmission option is to decrease the impedance of the Norwegian grid by upgrading to two 420 kV lines through most of the country. This will require large investments connecting to both north and south of mid-Norway. A series of line voltage upgrades can be performed from Rana to Klæbu, seen left in Fig. 5-7. South of mid-Norway, line upgrades can be made from Sunndal over Dovre to Oslo. This is shown right in the figure. The proposed investments are given by the color brown. Together, these transmission investments will allow increased transmission capacity into and through mid-Norway. As the central grid impedances consequently will be decreased, more transmission is expected.

If only the Ofoten – Klæbu line is upgraded, there will be a strong grid connection to mid-Norway from the north. Without the Sunndal – Oslo line upgrade, transmission congestion will occur when power from northern Norway flows south. The high impedance of the lines connecting mid-Norway to southern Norway will also cause less power flow in Norway. It is therefore assumed that these investments are made together in order to maximize their affect on the Norwegian power flow. The 420 kV upgrades should allow for a large amount of the new power production to flow through Norway from north to south.

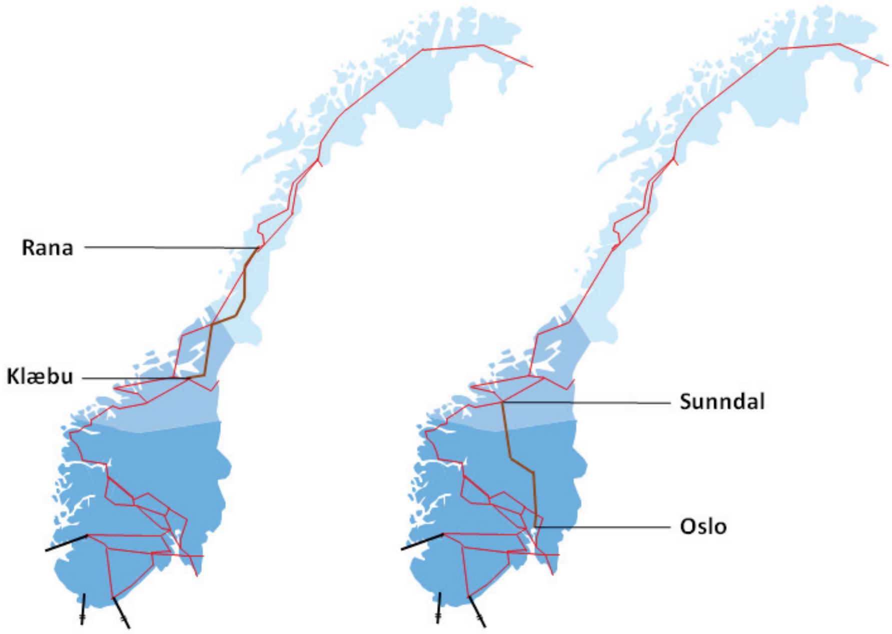


Fig. 5-7 – Line voltage upgrades Rana – Klæbu (left) and Sunndal – Oslo (right)

Two 420 kV lines through Norway are not likely to reduce the Norwegian system impedance to the Swedish level. An increased transmission causing overloads in the Ofoten – Ritsem line to Sweden may force a production decrease in Northern Norway in order to solve the overloads. Such a scenario must be avoided to justify any grid development through Norway. A new 420 kV line from Kobbelv to Ritsem will increase the transmission capacity between the countries, potentially solving the problem.

An advantage of AC line upgrades through mid-Norway is that both new power consumers and producers can connect to the 420 kV lines at any of the transformer stations along the line. The upgrade will also improve power stability and security of supply in the area. Upgraded lines may be built in the same tracks as the older lines, reducing the increase of visual pollution and forest clearing.

A method of avoiding conflicts between market and power flow in Norway, is by means of controlled DC transmission. Over long distances, DC transmission can also have lower losses than AC transmission. It may therefore be beneficial to build a DC line from northern Norway to a region south of mid-Norway, as seen in Fig. 5-8. As the increased production is not assumed to be consumed in mid-Norway, no converter stations will be built in that area. Existing power flow through mid-Norway is also expected to flow through the DC line. This should resolve congestion problems locally while allowing transmission through the area with fewer losses than before.

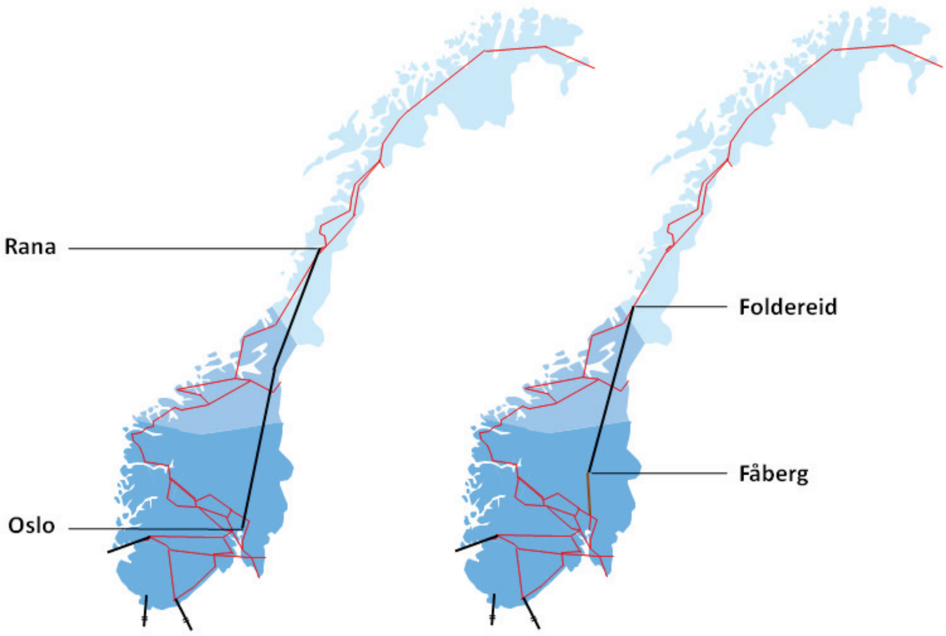


Fig. 5-8 – DC transmission options Rana – Oslo (left) and Foldereid – Fåberg (right)

A DC line may be built from Rana to Oslo as shown left in the figure above. This should reduce AC losses in areas 1, 5 and 6. Another option is to build the line just past area 5, from Foldereid to Fåberg, as given right in the figure. Such an option may only reduce AC losses in area 5, and will require a 420 kV line investment from Fåberg to Oslo. Both alternatives aim to control the flow of power through Norway and thus reduce the flow into Sweden. It is important to note that although the alternatives should reduce grid losses when production is unchanged, the expected annual increase of 22 TWh through the grid will certainly increase the total losses.

DC cables could remove the visual pollution from these investments. However, it is both impractical and uneconomical to dig a cable trench through hundreds of kilometers of Norwegian inland. Overhead DC lines will therefore be assumed utilized for this option.

In the year 2025, power export will be possible from southern Norway by DC cables to Britain, Netherlands and Denmark. Export to Sweden will be possible by AC lines. This may not be sufficient to handle the increased amounts of power. In such a case, power prices may be lowered in Norway as a whole. Due to its price elasticity, consumption will increase. A DC cable to Germany may decrease congestion in existing lines and allow power prices to remain at a higher level. A new cable to Germany may be built from Tonstad, allowing more export. Such a cable will require supporting voltage upgrades in the area in order to enable power flow to and from the cable. This is shown in Fig. 5-9.

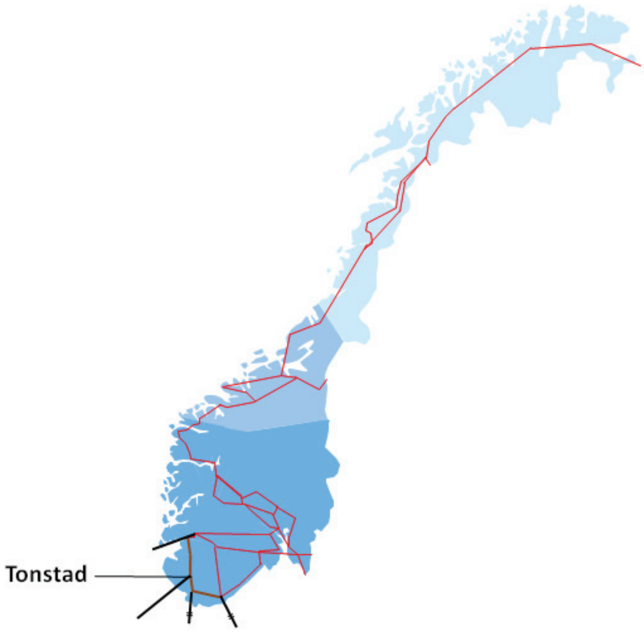


Fig. 5-9 – DC cable to Germany with supporting interconnection upgrades

A new DC cable to continental Europe from southern Norway is not likely to be an adequate solution on its own. The main transmission problem is the power flow from north to south within Norway. The DC cable will only be considered if congestion occurs in the existing export channels from the region. This investment may therefore only be built in addition to, and not instead of, other investments that allow power flow into southern Norway.

Instead of making a number of large grid investments through Norway, a solution may be to deliberately transmit most of the new power through Sweden. This will require a large transmission capacity increase from area 6 into area 8. A number of new lines are also likely to be necessary within Sweden in order to transmit the power southwards. Finally, the existing export channels from southern Sweden to continental Europe may also need upgrades. A Norwegian TSO is likely to prefer investments in Norway rather than investments abroad. If the Swedish alternative requires a similar amount of investments as in Norway without significant advantages, it will therefore be discarded.

6 System analysis

6.1 Method, goal and scope of analysis

The Nordic power system is modeled and simulated using complex analytic tools. These are thoroughly described in Chapter 4. The main manual modifications that are made to the data sets, in order to include the assumed market conditions, are explained in Appendix A.1. A very large amount of result data is available for each simulation. For practical reasons, only a selection of the most significant results is presented to illustrate the main points of interest for this analysis.

An overview of the different grid options and increased production options modeled and simulated with the EPF model is presented in Table 6-1. A notation is assigned to each grid and production option. When referring to a grid solution option that includes one or more of these investments, the respective notations are used. For example, *2025-123-cd* will refer to a copy of the "Wind and Consumption Growth" data set for year 2025, modeled with new lines between Kobbelv – Ritsem and between Borgvik – Rätan. The production increase corresponds to 12 000 GWh in area 6, 4 300 GWh in area 7 and 6 000 GWh in area 8.

Table 6-1 – Grid and production options

Scenarios and assumptions which are modeled and simulated using the EPF model			
Scenario:			
2025: Wind and Consumption Growth, year 2025			
AC grid options and transmission capacities [MW]:			
ab:		**d:**	
Line upgrades Klæbu – Rana and Sunndal – Oslo		New line Borgvik – Rätan	
Transmission areas 6 – 5	3 000 / 3 000	Transmission areas 9 – 10	9 000 / 9 000
Transmission areas 1 – 5	1 000 / 2 000	**e:**	
Gudbrandsdalen section west	2 150 / 2 150	New line Fåberg – Oslo	
Namsos section south	1 900 / 1 900	**f:**	
Trøndelag section deficit	– / –	Line upgrades sørlandssnittet	
Trøndelag section surplus	– / –	Transmission areas 3 – 4	3 500 / 3 500
c:		Sørland section north	4 500 / –
New line Kobbelv – Ritsem		Sørland section south	4 500 / –
Transmission areas 6 – 8	2000 / 2000		
Nordland section south	4000 / –		
DC cable and line capacities [MW]:			
X:			
New line Rana – Frogner	2000		
Y:			
New line Foldereid – Fåberg	2000		
Z:			
New cable Tonstad – Germany	1400		
Production capacities [GWh]:			
1: Power increase in area 6:	12 000		
2: Power increase in area 7:	4 300		
3: Power increase in area 8:	6 000		

A DC line and AC line upgrades through Norway are two separate and very costly grid strategies that are both intended for the same purpose. Building both is likely to be a drastic over-investment compared to the expected power increase, and would in such a case not be beneficial. These two strategies, if found necessary, are therefore only considered as alternatives to each other. The goal of the analysis is to see what effect each grid strategy has on the power system and what level of additional investments are necessary in order to achieve an acceptable system situation.

All graphs, unless stated otherwise, are given for load period 1 which is defined as peak load. It is important to note that load period 1 is the period in which the power system is generally most prone to congestion and thus differences in area prices. This amount of congestion can only be expected for a few hours each day. This load period is generally chosen in order to see the main bottleneck problems in the system.

Weekly average values are often considered unsuited for comparison as they include all load periods. If transmission increased in one load period and decreased in another, the weekly average would remain unchanged. Weekly averages are especially unsuited for transmission graphs where the direction of load flow changes between load periods. This would hide important information which is otherwise available when only considering one of the load periods at a time.

6.2 The necessity of new transmission investments

All increased production considered in this analysis is unregulated, meaning that it cannot be stored. This unregulated energy, in form of water and wind, is highly variable. All overflow of water and its wind equivalent is considered to have no value. The new power stations assumed built in areas 6, 7 and 8 will produce power when wind and water is available regardless of market conditions and load periods.

The areas affected can use this production for base load. As unregulated production varies throughout a year, the areas become dependent on regulated power to even out the production according to the given load. In areas 6, 7 and 8 this is done by means of reservoirs, where water can be stored at times of high unregulated production and then used at times of low unregulated production. The three areas that are faced with a large increase in power production have very different reservoir storage capacities. While areas 6 and 8 have many large multi-seasonal reservoirs, this is not the case in area 7.

Another method used to even out the power supply is to export power during surplus and import during deficit. Area 8 is, with three 420 kV lines, well connected to area 9 which also has a large reservoir capacity. Area 6 is only connected by a single 420 kV line each to areas 8 and 5. Area 7 is again only connected by a 420 kV line to area 6. The weaker connections between areas 7 – 12 and 6 – 9 have high impedances and low capacities. They are therefore of minor importance for power export and import in this situation.

As the areas have very different conditions regarding both reservoir and transmission capacities, they are affected differently by the increases in production. In areas 6 and 7, the new production by far exceeds both consumption and reservoir storage capacities. Transmission from area 7 to 6 does not exceed the capacity, while congestion occurs in the lines out of area 6. Power is produced to avoid overflow, but there are no export channels or consumers for the new power. Power prices therefore drop towards zero, causing increased consumption to cover the new production. This is illustrated in Fig. 6-1. High levels of congestion are shown by the lines marked in red.

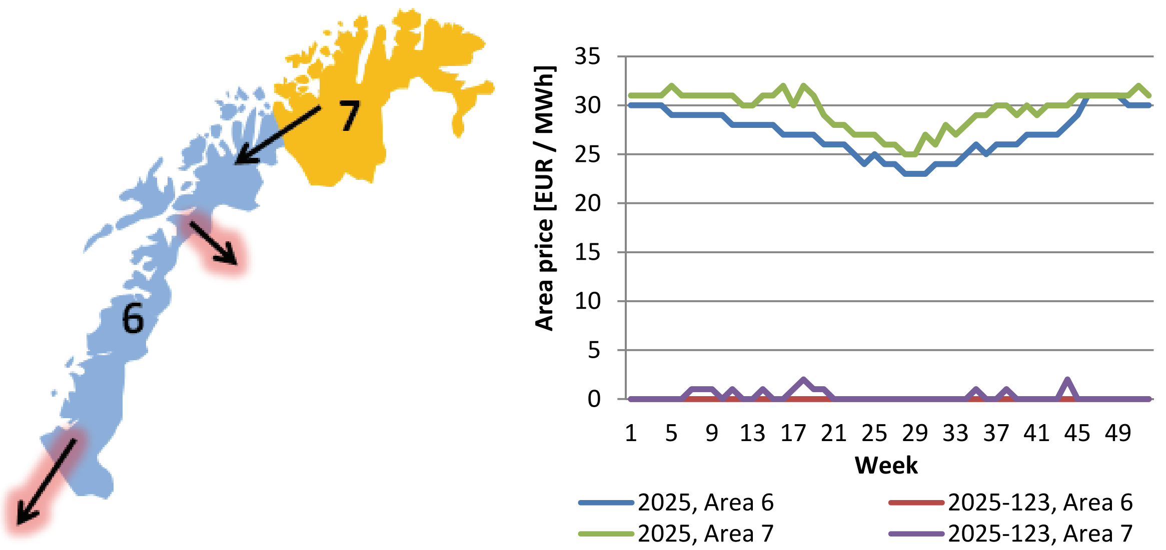
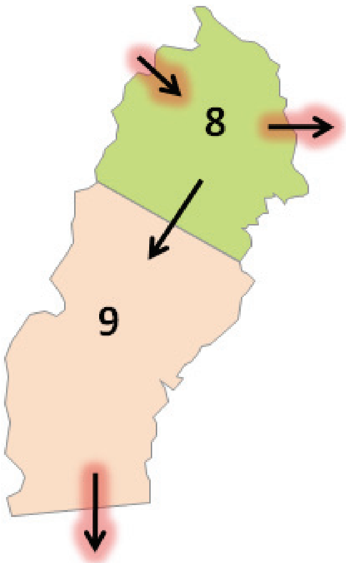


Fig. 6-1 – Power flow and congestion (left) causing reduced power prices (right) in areas 6 and 7. Shown without grid upgrades, before and after increased production

In Sweden, areas 8 and 9 are mildly isolated in a similar way as areas 6 and 7 during load period 1. While power flows freely between areas 8 and 9, congestion prevents large power export from the two areas during peak load. Together, the two Swedish areas have a larger reservoir storage capacity than the Norwegian areas. In addition, more new power is assumed built in Norway than in Sweden. The Swedish areas are therefore able to decrease more regulated power production when congestion is highest. Due to these factors the area prices in northern Sweden, shown in Fig. 6-2, do not fall towards zero as in Norway. They are still decreased considerably, allowing consumption to increase.



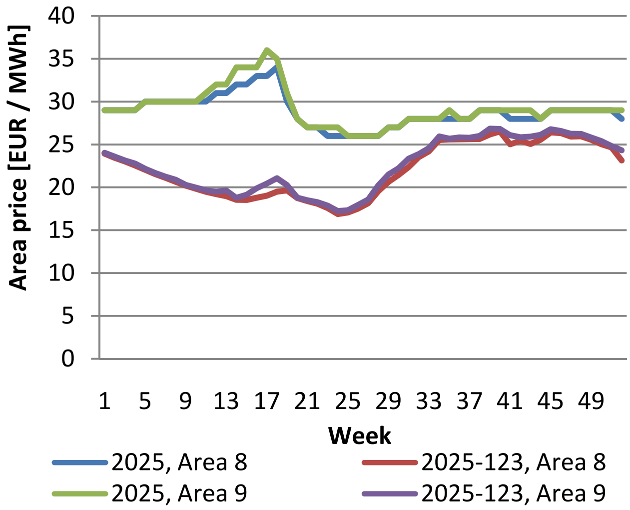


Fig. 6-2 – Power flow and congestion (left) causing reduced power prices (right) in areas 8 and 9. Shown without grid upgrades, before and after increased production

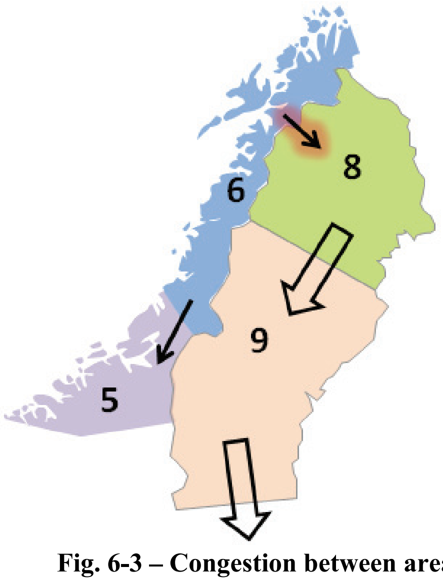
With this grid solution, congestion prevents export of the new power from northern Norway. The affect of increased production is only to decrease power prices and increase consumption locally. Large-scale increased export of renewable power to continental Europe, which is assumed to justify the new production, does not occur. A power producer will not consider investing to the point where power prices fall towards zero. A large production increase in these areas is therefore not possible under these grid conditions.

6.3 Norwegian transmission challenges

If there were no connections to Sweden from northern Norway, increasing power flow through Norway would only be a matter of increasing the transmission capacity. However, the Swedish central grid has much lower impedance than its Norwegian counterpart. Electric power follows the path of least impedance, which from northern Norway is through the Swedish central grid.

The grid connection between areas 6 and 8, the Ofoten – Ritsem line, currently only has a capacity of 600 MW. This capacity limit causes congestion towards Sweden during peak hours even in the base scenario without any new production. In order to avoid overloads on the line, production must be limited in northern Norway during this load period. This causes a production schedule that is not optimal for the system. With less power being produced during peak load, transmission through Norway is decreased as well as the transmission to Sweden.

The problem is illustrated in Fig. 6-3, where the line marked in red indicates a high level of congestion before investment. Production in area 6 during peak load is shown before and after a new line is made between the areas. The transmission capacity to area 8 is increased to 2 000 MW by the new line, made between Kobbelv and Ritsem. At this point all congestion is solved between areas 6 and 8 in the base scenario conditions, therefore much fewer restrictions are implemented on the production. The reservoir drawdown is allowed to increase in the beginning of the year, giving a more optimal solution.



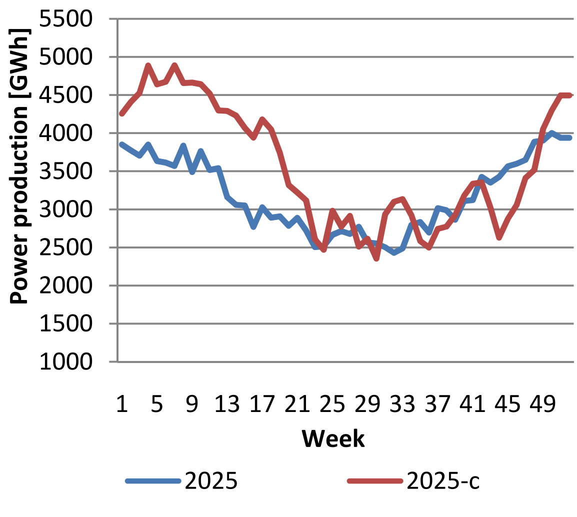


Fig. 6-3 – Congestion between areas 6 – 8 (left) cause power production limits in area 6 (right)

By allowing a higher power production in areas 6 and 7, more power flows through Norway as well as into Sweden. The graph in Fig. 6-4 shows that transmission into area 5 is increased during the same weeks that production is increased in area 6. This power continues to flow to southern Norway through area 5 as shown left in Fig. 6-4. The figure illustrates that increasing transmission capacity to Sweden is a method of allowing increased transmission through Norway.

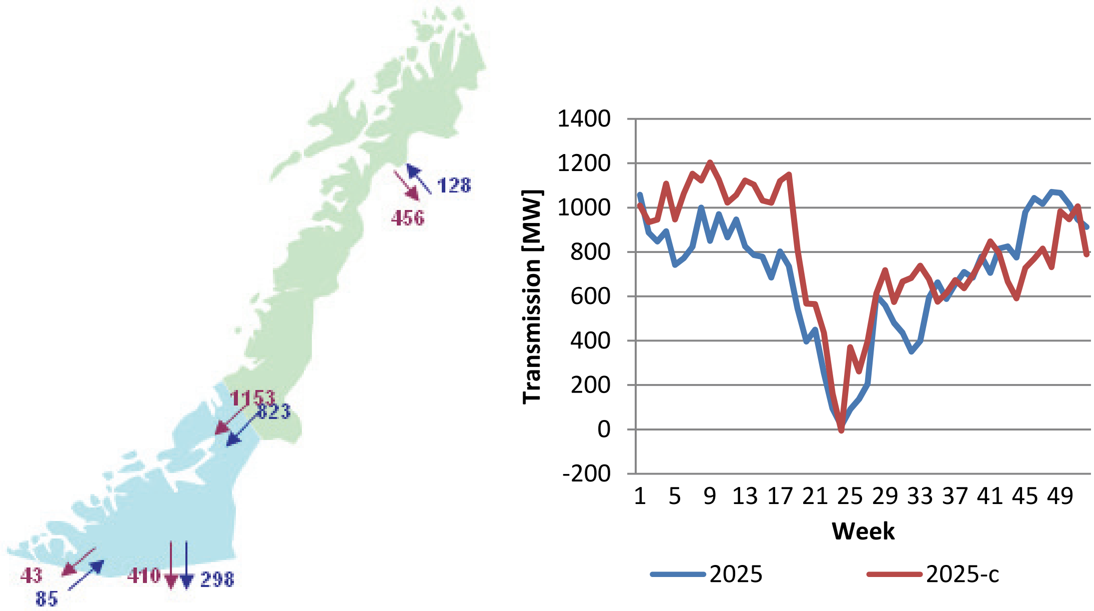


Fig. 6-4 – Power flow changes due to new Kobbelv – Ritsem line. Regional transmission in week 7 (left) and annual transmission between areas 5 – 6 (right)

In the base scenario, the problem of limited production in northern Norway is only present during peak load when export is highest. By changing the production schedule to other load periods, the power price is only marginally affected. When new unregulated power stations are introduced, this problem occurs at all load periods. The unregulated water and wind cannot be stored, yet a large power surplus will overload the Ofoten – Ritsem line. As a result, shown left in Appendix Fig. A 2-1, the power price drops to zero even though massive upgrade investments have been made in Norway.

The upgrade investments in Norway have not greatly improved the area prices compared to the ones that are found in Fig. 6-1. The drop in power prices is necessary in order to increase consumption, thus reducing the power surplus and solving the line overload. A situation with such low power prices is unrealistic and will not occur. In order for a large power surplus to be created in northern Norway, the grid investments in Norway are therefore not sufficient. Without a power surplus, transmission through Norway cannot occur no matter how much transmission capacities are increased.

One solution might be to upgrade the Norwegian central grid to a level where the impedance is lower than in Sweden. This represents an unrealistically high level of investments with a cost far beyond that of a new line to Sweden, and is therefore not considered. Another solution is to use controlled DC transmission to make power flow through Norway.

The right figure in appendix Fig. A 2-1 shows the resulting power prices in areas 6 and 7 when a DC line is built from Rana to Oslo. The line impedances between Rana and Ofoten are considered small, allowing power to flow towards the DC terminal as intended. Power prices therefore remain at reasonable levels. However, power production is still limited during load period 1. This is shown left in Fig. A 2-2, where production in area 6 is increased after the Kobbelv – Ritsem line is built. Additionally, as shown in Fig. 6-8, increased trade with Sweden in this area eases Swedish congestion problems. This is due to a weekly average power import from Sweden towards the new DC line, shown right in Fig. A 2-2. A capacity increase from area 6 to area 8 is therefore considered beneficial for both grid options.

The benefit of the Kobbelv – Ritsem line can also be illustrated as shown in Fig. 6-5, where two levels of grid reinforcements with new power capacity included are compared with the base scenario. The figure shows, for area 6, that both grid solutions allow a large increase in power production without a collapse in the power prices. The same is shown for area 7 in Appendix Fig. A 2-3. These two grid upgrade options, both including the Ofoten – Ritsem line, each prove to allow a power surplus in Norway with power prices and consumption remaining at reasonable levels.

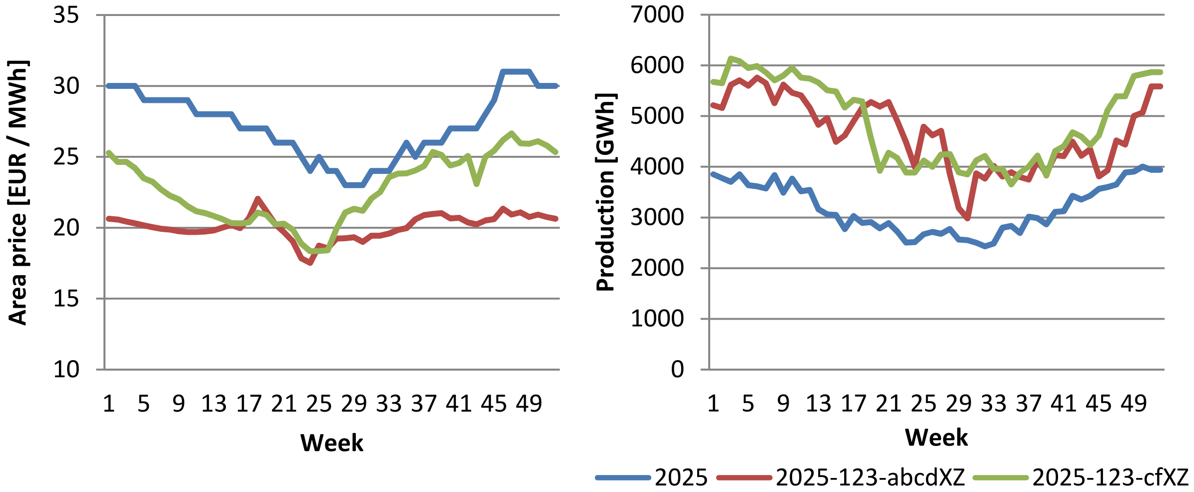
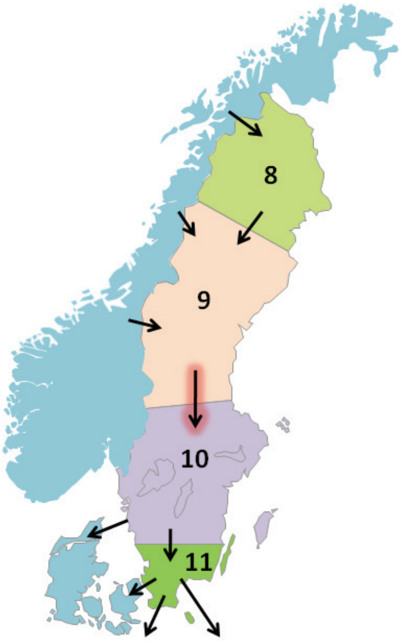


Fig. 6-5 – Power price (left) and production (right) in area 6

6.4 Swedish transmission challenges

The increased power surplus in Norway and Sweden causes increased power transmission through both countries. A part of the Norwegian surplus will also flow through Sweden, as explained in Chapter 6.3. This increased transmission adds to the congestions already found in the base data set, which is described in Chapter 5.3. The problem is illustrated in Fig. 6-6, where power from Norway flows into areas 8 and 9. This power flow, combined with the Swedish power, creates congestion between areas 9 and 10 as it seeks southwards towards consumers. The graph shows how congestion causes very high price differences between northern and southern Sweden. The low power prices in northern Sweden cause an increase in consumption which reduces the power surplus.



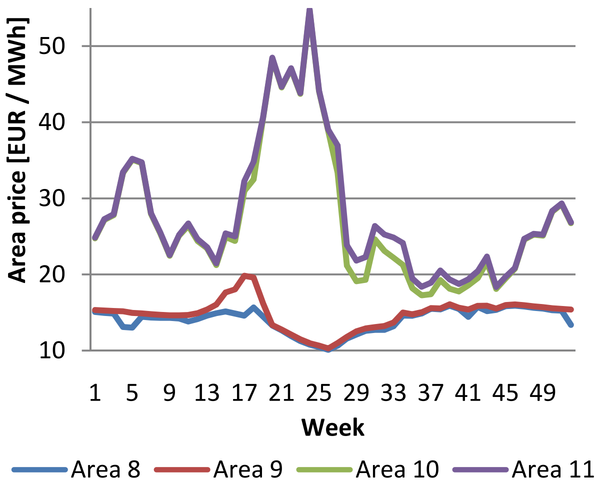


Fig. 6-6 – Swedish transmission congestion (left) and area prices for *2025-123-abc* (right)

A new line between Borgvik and Rätan in mid-Sweden, increasing transmission capacity between areas 9 and 10, solves much of the congestion. Fig. 6-7 (left) shows that the congestion that is not solved, is now spread over the whole country. The price difference between north and south is much smaller than before, which indicates that the power surplus is transmitted through the country and causes little congestion. This can be seen right in Fig. 6-7, where transmission from area 9 to 10 is greatly increased through most of the year.

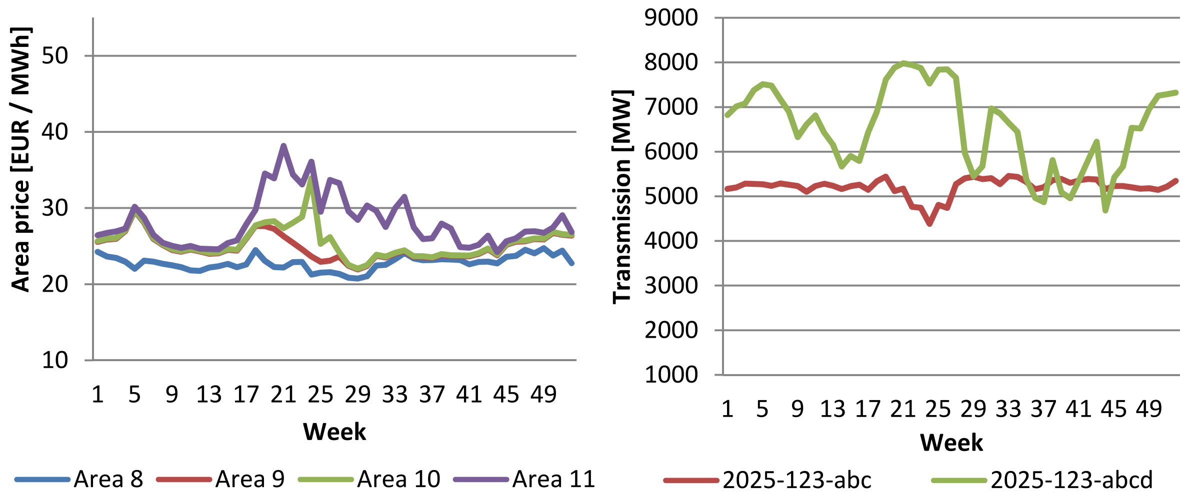


Fig. 6-7 – Swedish power prices for *2025-123-abcd* (left) and transmission between areas 9 - 10 (right)

The DC line solution used in *2025-123-cfXZ* allows for more of the new power production to flow through Norway and therefore relieve some of the Swedish bottleneck problems. Congestion is only marginally increased from the level of the base scenario, as seen left in Fig. 6-8, and power prices in areas 8 and 9 do not drop as low as in the *2025-123-abc* grid solution. A large power surplus is created in both northern Norway and Sweden. Transmission capacity increases in mid-Sweden are not considered necessary with this grid solution.

This is mainly due to the Kobbelv – Ritsem line which helps the congestion problem in Sweden by increased power trade with Norway. Without this line, internal area price differences become very high in Sweden, as seen right in Fig. 6-8, and a new line in mid-Sweden might be necessary.

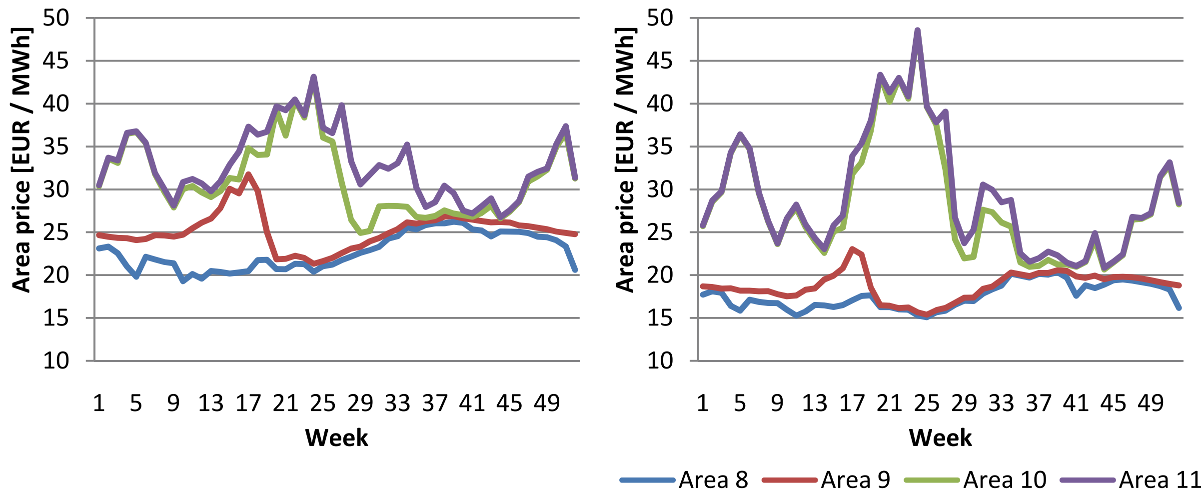


Fig. 6-8 – Swedish area prices for grid *2025-123-cfXZ* (left) and *2025-123-fXZ* (right)

A strategy meant to intentionally divert as much power flow through Sweden as possible is also simulated. The new production is first added. Extensive AC line investments are then implemented from areas 6 to 8 and through Sweden to area 11, to the degree that no congestion occurs in any of these sections. With no investments made in Norway, drastic problems in the Norwegian transmission occur. More power flows from Norway towards Sweden causing congestion from areas 5 and 6 into area 9. The power that does not flow towards Sweden causes congestion southwards from area 6 into 5 and further into area 1. An illustration is given left in Fig. 6-9, where bottlenecks are marked in red.

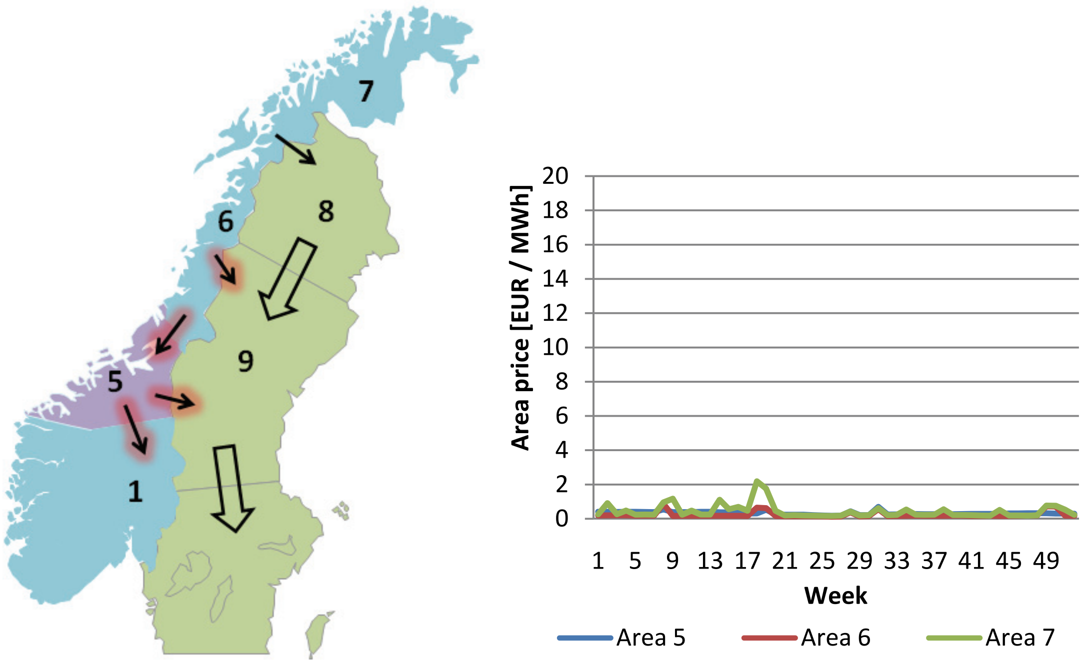


Fig. 6-9 – Bottlenecks and resulting area prices when all congestion is solved from area 6 to 8 and through all areas in Sweden

The right figure shows the resulting power prices in mid- and northern Norway. The congestion in Norway and on the lines to Sweden causes a collapse of power prices in areas 5, 6 and 7. This represents unrealistic system conditions and will not occur. A number of investments in the sections marked in red would be necessary in order to avoid the collapse in prices and thus provide a possible state of system operation. In total, this will require a far larger amount of investments than previously discussed options. The strategy for investments solely into and through Sweden is therefore dismissed.

6.5 Power export to continental Europe

As power production always must match power consumption at any given time, export channels are necessary in order to create a power surplus in Norway and Sweden. Without any export, consumption will simply increase to match the increased production due to price reductions. Norway and Sweden are directly electrically connected to continental Europe only by means of DC transmission. The DC transmission cables shown in Fig. 6-10 are the only means to export large amounts of power to continental Europe and Britain. A power surplus in the two countries is therefore dependent on the export capacity of these cables.

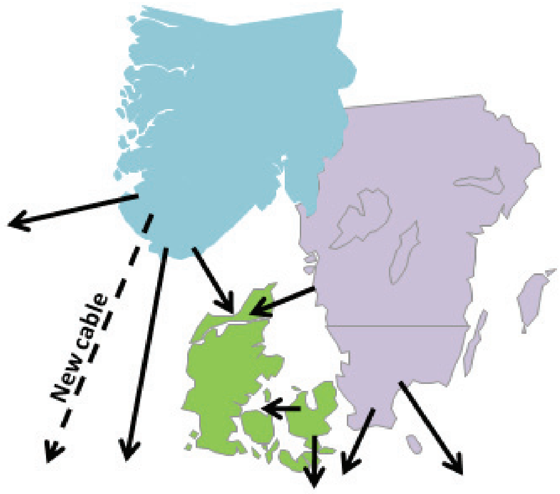


Fig. 6-10 – DC lines directly connecting Norway and Sweden to continental Europe

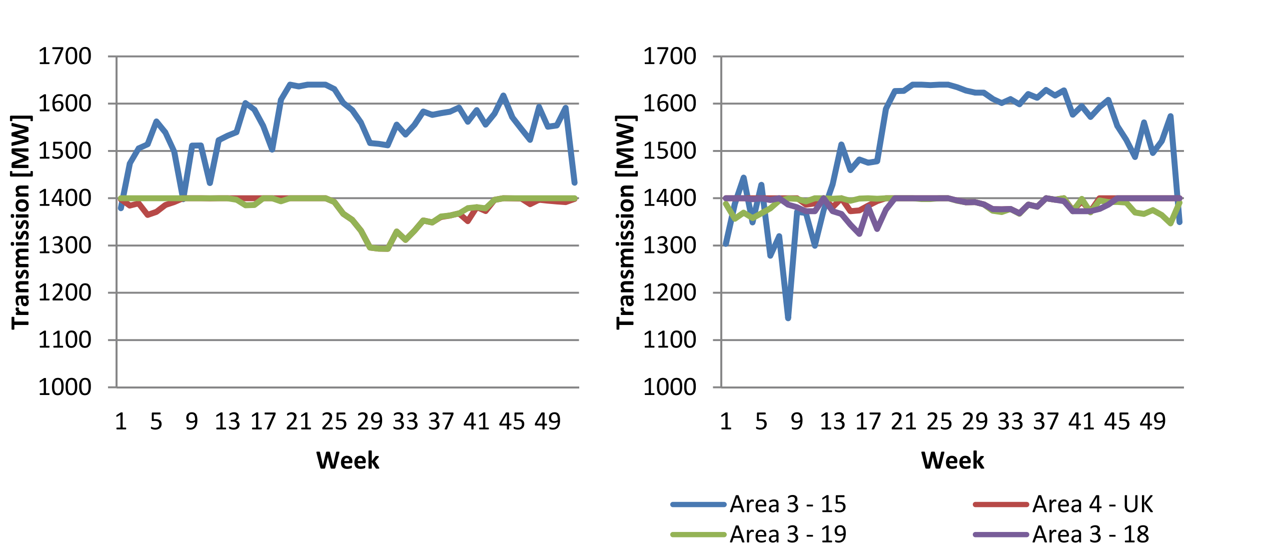
A new DC cable from area 3 in Norway to Germany is dependent on supporting grid upgrades in southern Norway in order to enable power to flow to the DC terminal. Without such supporting upgrades, unrealistically large congestion problems occur from areas 2 and 4 into area 3. These investments are only beneficial when built together, and are therefore also only considered built together.

When the DC line solution *2025-123-cfXZ* is used to control power flow through Norway, this power is exported from southern Norway. The increased trade with Germany slightly increases power prices south and west in Norway, shown in Appendix Fig. A 2-4, although they are still lower than in the base scenario. Although consumption therefore is marginally decreased compared to the *2025-123-cX* option, this does not lead to a large increase in the power surplus in itself.

The resulting total power surplus in southern Norway is not enough to allow a full utilization of the new DC cable at all load periods without reducing the utilization of the other three DC links. However, the cable is not meant for full export during all load periods. As described in Chapter 5.3, Norway participates in the day-night regulation of the European power system. Therefore, when the new cable is added, Norwegian power producers will change their production schedule in order to maximize export during daytime when European power prices are high. This will in turn maximize the profits of the power producers.

DC link transmission values for peak load hours before and after the new cable to Germany are shown in Fig. 6-11. The graph shows that the utilization of existing DC links is, on average, not reduced by the new cable. All cables are utilized at or close to their transmission capacities, except the cable to Denmark which is utilized a little less in both situations. This is the case for load periods 1, 2 and 3, which are the load periods where continental Europe experiences the highest power prices. The total power export during these three load periods is therefore increased on average by close to 1 400 MW.

Power export from southern Norway to continental Europe during load period 1
Grid options *2025-123-cX* (left) and *2025-123-cfXZ* (right)



Transmission capacities [MW]:

Area 3 – 15	:	1640 / 1640	DC
Area 4 – UK	:	1400 / 1400	DC
Area 3 – 18	:	1400 / 1400	DC
Area 3 – 19	:	1400 / 1400	DC

Fig. 6-11 – Norwegian DC power export with grid options *2025-123-cX* (left) and *2025-123-cfXZ* (right)

The Norwegian power surplus is, as mentioned, only marginally increased by the new cable due to minor price changes. The increased export during day, measured in turbined reservoir water, must be compensated by decreased export or increased import during another period of time. This is done during load periods 4 and 5, as shown in Fig. A 2-5, when European power prices are the lowest. More water is turbined during daytime on weekdays and less water is turbined during night and weekends. Total power production throughout an average year is therefore close to unchanged.

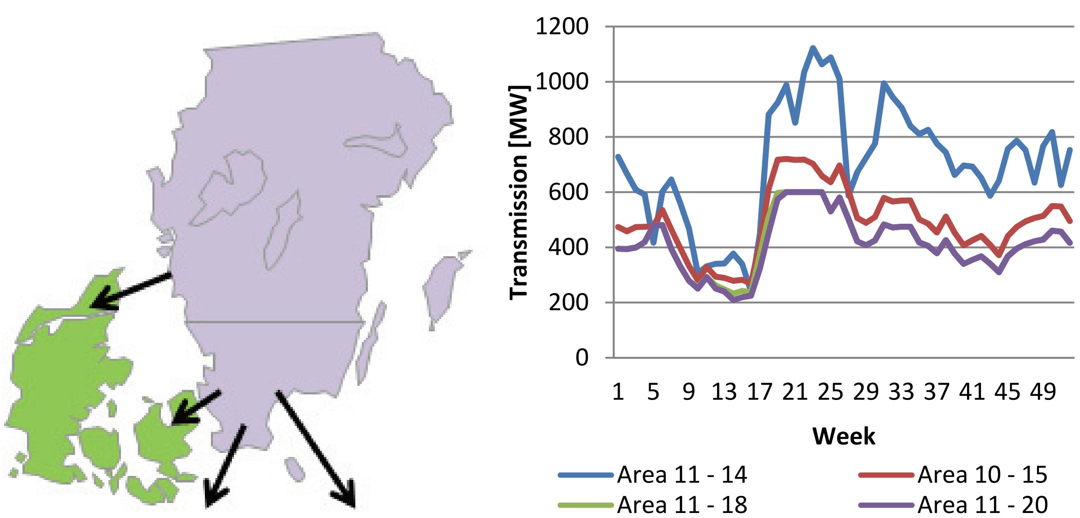
Compared to the day-night regulation performed in the base data set, shown by Fig. 5-3, one can see that average export throughout both day and night is increased. This is expected because of the new production surplus in areas 6, 7 and 8 that needs to be exported.

The effects of the new DC cable in the *2025-123-abcdfZ* grid option is the same as described above for the *2025-123-cfXZ* option. The new DC cable to Germany is utilized well during the first three load periods. This is illustrated in Fig. A 2-6 for load period 1. During night export is decreased and import increased as shown in Fig. A 2-7 for load period 4.

The cable improves the day-night regulation of the European power system in both grid options. As area prices in southern Norway are increased, the price differences between north and south in Norway also increase. This is shown in Fig. A 2-8 and Fig. A 2-9. The total difference between north and south is still lower than the base scenario, as much congestion has been solved. The figures show that the regions south of area 6 have very little congestion as the area prices are very closely grouped. This is also the case for areas 6 and 7. Norway is effectively split into two very distinct price areas defined by the border between areas 5 and 6.

When more power flows through Sweden, power export from southern Sweden will increase. The Swedish export channels have free capacity for this increased export. This is shown for the AC line option *abcd* in Fig. 6-12, where transmission is far below the transmission limits most of the year even in load period 1. The DC line options give lower power transmission levels through Sweden and therefore need less export capacity from southern Sweden than the *abcd* option. Increased transmission capacity from southern Sweden is therefore not considered necessary for either grid solution.

Power export from southern Sweden to continental Europe during load period 1
Grid option *2025-123-abcd*



Transmission capacities [MW]:

Area 11 – 14	:	1300 / 1700	AC
Area 11 – 18	:	600 / 600	DC
Area 10 – 15	:	720 / 720	DC
Area 11 – 20	:	600 / 600	DC

Fig. 6-12 – Swedish power export to continental Europe in *2025-123-abcd* option

6.6 Resulting power flow

The strategy of DC transmission through Norway is expected to decrease power export from area 6 to 8, thus allowing a high transmission through Norway. The AC strategy, on the other hand, intends for a higher power export to area 8 and therefore gives a higher transmission through Sweden. The simulation results, given in Fig. 6-13 for Norwegian transmission and Fig. A 2-10 for Swedish transmission, prove that the power flows as expected. For Norway, the graph shows the added transmission both between areas 6 – 5 and 6 – 1. The figures are shown with two lengths of DC line, where both types give higher transmission through Norway and lower transmission through Sweden than the AC option.

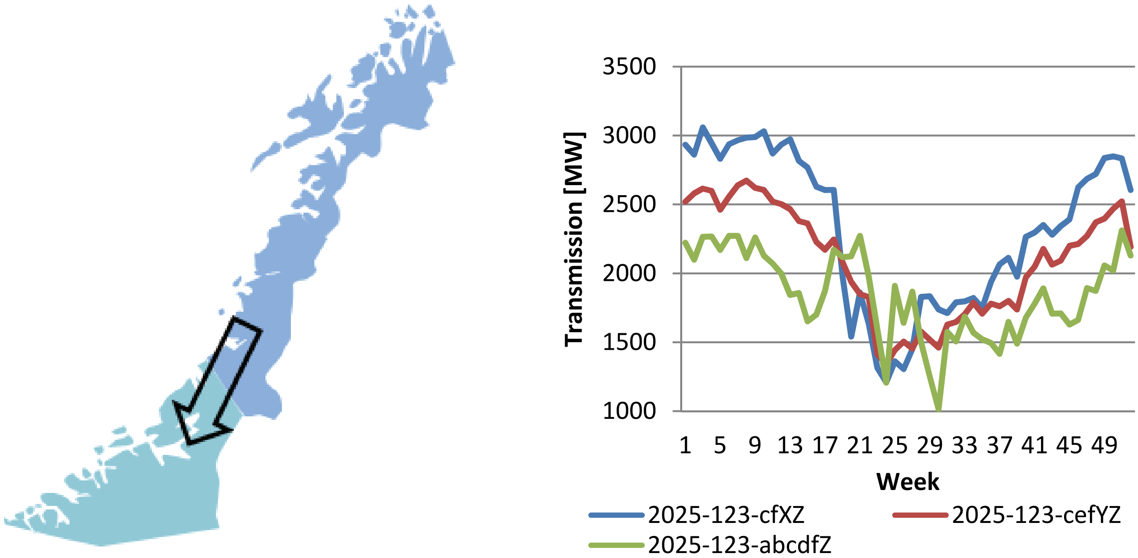


Fig. 6-13 –Transmission southwards in Norway from area 6

The figures also show that the length of the DC cable has a large influence on the power flow through both countries. This is due to the fact that Rana is, both electrically and geographically, much closer to Ofoten than Foldereid is. The line impedances from Ofoten to Foldereid are therefore much larger than the impedances to Rana. Power will flow to the DC terminal from the producers where the path between has the least impedance. The electrically closest producers will therefore be most affected. When the terminal is positioned in Foldereid, power flow north in area 6 is less affected and more power flows through Sweden. Positioning the DC terminal in Rana causes less transmission into Sweden as the DC line controls the flow of power from power producers north in areas 6 and in area 7 through Norway.

When transmission into Sweden from area 8 is high, an amount of this power flows back into Norway in area 1 after flowing through Sweden. As the total transmission through Norway from area 6 is higher with the DC terminal in Rana, a higher power surplus is given in Oslo at the other end of the DC line. Due to this surplus, power import from Sweden, shown in Fig. 6-14, is reduced.

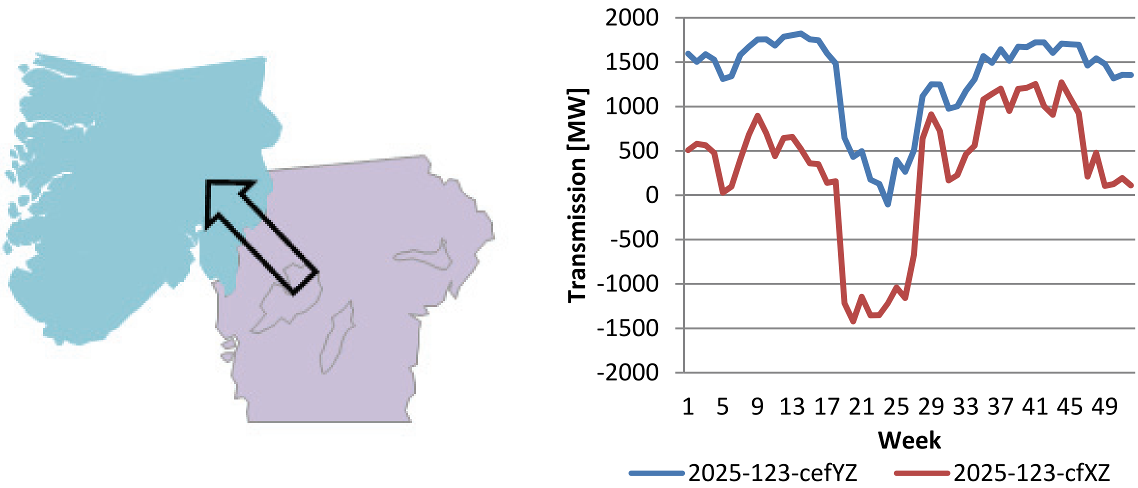


Fig. 6-14 –Transmission from area 10 to 1

When power transmission is increased through Sweden, this causes congestion as described in Chapter 6.4. This is illustrated in Fig. A 2-11, where the shorter DC line causes similar Swedish congestion to that of the *2025-123-fXZ* grid option. The DC line from Rana – Oslo is therefore considered much more beneficial than if it was built from Foldereid – Fåberg.

6.7 Consequences on existing power generation

The grid solutions described in previous chapters have proven to allow a high power surplus in both Norway and Sweden, and transmission through the countries. As the power is exported, production can be decreased in neighboring countries where the marginal cost of power generation is higher. As production levels change, so do grid losses and consumption in each area. The *cfXZ* grid option appears to be the most promising grid solution involving a DC line through Norway. For this option, the total changes in production, consumption and grid losses per area in an average year are shown in Fig. 6-15. The same values for the most promising grid solution with AC grid upgrades, *abcdfZ*, are given in Fig. A 2-12.

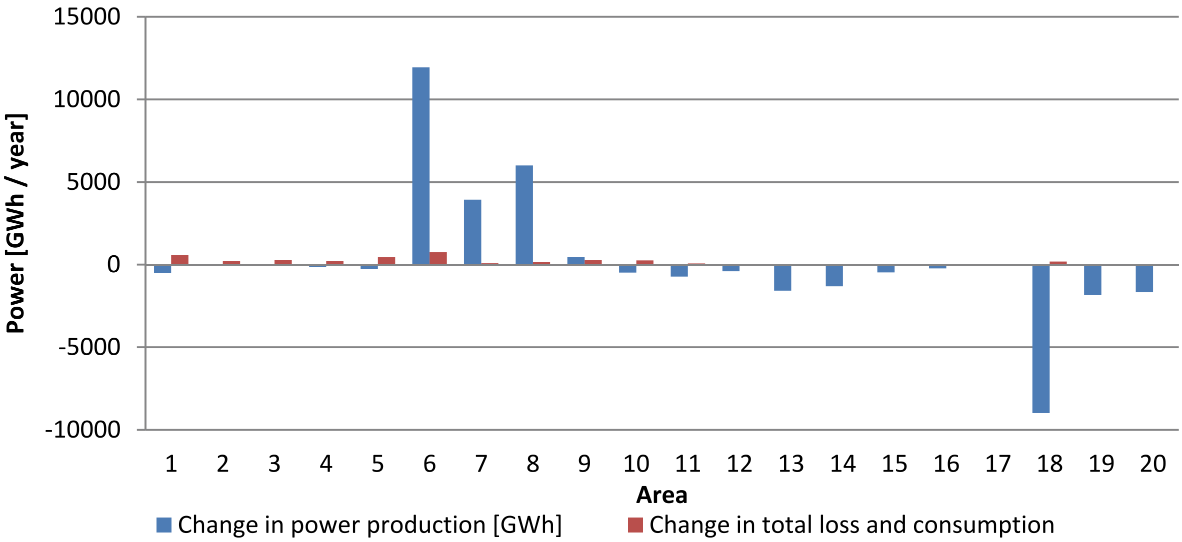


Fig. 6-15 – Production, consumption and loss differences (2*025-123-cfXZ* minus base scenario)

The increase in grid losses is a direct result of increased transmission through the grid. In the DC line option, *cfXZ*, a large amount of power is transmitted through Norway. The main loss increases are therefore seen in areas 1 and 6 where the DC terminals are positioned. Minor grid loss increases are also found in areas 5, 8 and 9 due to increased AC transmission. In the AC grid upgrade option, *abcdfZ*, more power flows through Sweden, giving larger grid losses in areas 9 and 10. Higher grid losses in Norway are also found in this option.

Total amount of new power production that is utilized in areas 6, 7 and 8 can be seen in both graphs to be roughly 22 000 GWh. One can see from the production values that increased consumption and grid losses only cover a small amount of the new production. Most of the new production replaces power in other countries.

The type of production that is replaced in each country is shown in Fig. 6-16 and Fig. A 2-12 for grid options *cfXZ* and *abcdfZ*, respectively. The results are similar. They show that a moderate amount of gas power is replaced in Sweden while coal power is replaced in Denmark and southern Finland. In Germany, Netherlands and Polen both coal and gas power is replaced. The largest coal and gas power reductions are by far in Germany, where more than half of the total reductions take place.

One can see that 1 500 GWh more coal power is replaced in the *cfXZ* option. This is due to the high power flow through Norway, where the existing hydropower is not replaced by the new wind power. The power then flows to continental Europe, replacing a large amount of coal power. 1 300 GWh more gas power is replaced in *abcdfZ*, as more power flows into southern Sweden with this solution. Gas power has a higher marginal cost than wind power and thus a higher amount of gas power is replaced in Sweden.

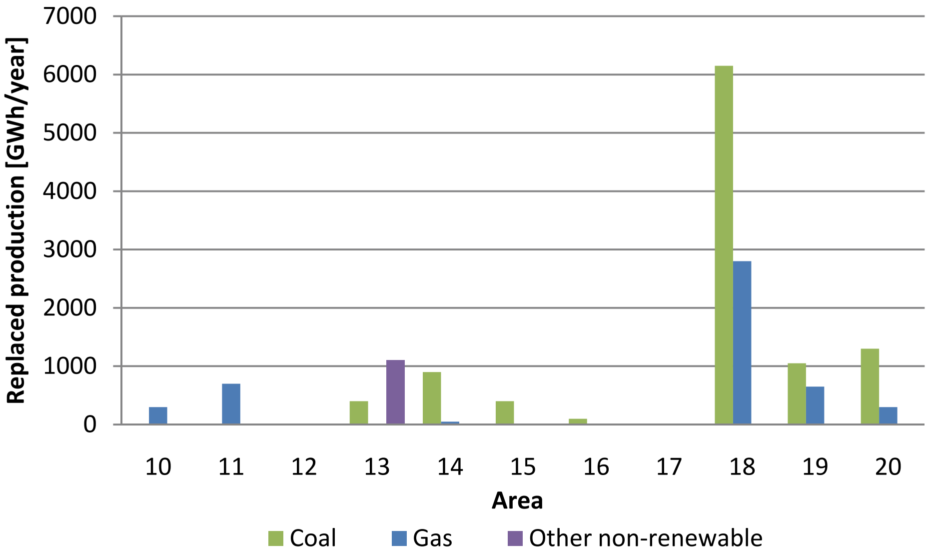


Fig. 6-16 – Replaced power production (production values of base scenario minus *2025-123-cfXZ*)

CO_2 is produced by burning fuel when producing power from most non-renewable sources. The emission amounts, given per kJ and MWh, that are assumed by the base data set are presented in Table 6-2. The numbers assume 100 % production efficiency, which is highly unlikely. The actual quantity of CO_2 – emissions per MWh therefore depend on the efficiency of each specific power station.

Table 6-2 – CO_2 – emissions

Power production type	CO_2 [kg/kJ]	CO_2 [ton/MWh]
Combined heat and power	25	0,0900
Coal	95	0,3420
Gas	57	0,2052
Light oil	75	0,2700
Oil	78	0,2808

The quantity of reduced power in each power station is multiplied with the amount of CO_2 released per MWh of the power production type. The resulting quantity of CO_2 is then divided by the efficiency of each station. This gives the total reduction of CO_2 – emissions per power station compared to the base scenario, given in millions of metric tons per year. These are added together for each area and presented in Fig. 6-17 for the *cfXZ* option, where a reduction of 10,9 $MtCO_2$ / year is achieved. In the *abcdfZ* option, shown in Fig. A 2-14, a reduction of 9,4 $MtCO_2$ / year is made. This corresponds to a respective 19,3 % and 16,6 % of the expected [29] Norwegian CO_2 – emissions in year 2020, which is 56,5 $MtCO_2$/year. The emission reductions mainly take place in Germany, but are also high in Denmark, Poland and Netherlands.

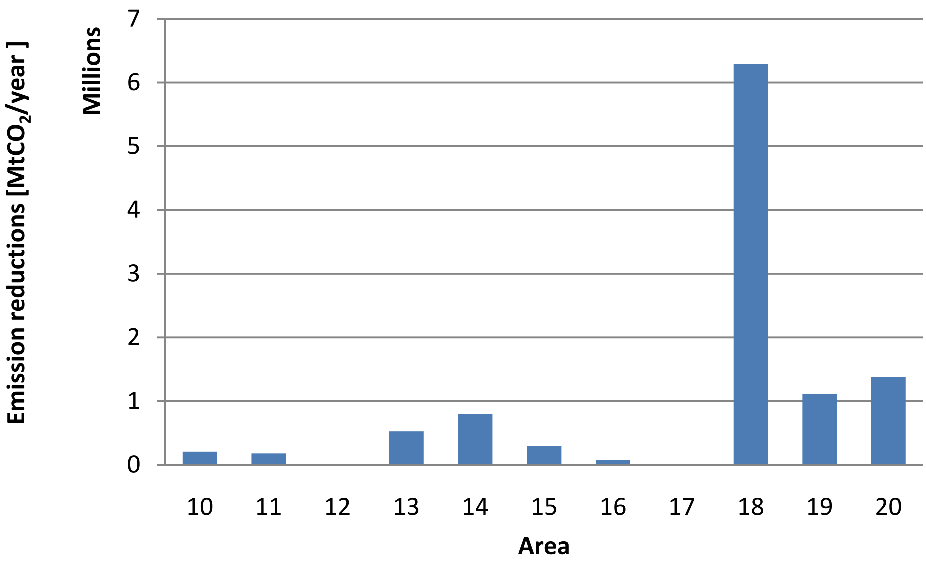


Fig. 6-17 – CO_2 – emission reductions (base scenario values minus *2025-123-cfXZ values*)

The "Wind and Consumption growth" scenario expects an average CO_2 – quota price of 200 NOK per ton in year 2025. An assumption is made that the CO_2 – quota price reflects the actual reduction in socio-economic benefit due to the emission. It is also assumed that this price is paid by all CO_2 emitting market participants in year 2025. By these assumptions, the reductions in CO_2 – emissions amount to an increase in European socio-economic benefit of 2 180 MNOK / year and 1 880 MNOK / year for the grid options *cfXZ* and *abcdfZ*, respectively.

7 Socio-economic analysis

7.1 Technical and economic investment evaluation

In order to compare the simulated levels of investments, all aspects of each alternative must be considered. The impact that each alternative has on the Nordic power flow is an important part of this, but is not sufficient in itself. An economic evaluation of each of the alternatives must also be considered. In order to make a thorough economic evaluation, a technical evaluation is necessary.

A detailed technical evaluation of all proposed investments is a large task that is not included in this thesis. General and simplified per unit costs are used that do not consider specific local conditions. Tables of per-unit costs for investments are provided from [7] and [30]. The intention is to give a general idea of how each option that is considered can be realized, and what scope of costs it represents.

Line lengths are dependent on the chosen line paths between each connection point. The line lengths considered in this evaluation are therefore only approximate and will depend on local conditions. All line masts, transformer stations and components are assumed built in average difficult terrain. Only line and transformer station investments are included. Generator connection investments are assumed as part of the power station investments and are not considered in this analysis.

Steel masts, as shown in Fig. 7-1, with 420 kV duplex lines of type FeAl 2x481 Parrot are used for all new lines and line upgrades. In some cases a line upgrade may only represent a change of the physical lines without making any changes to the existing masts. Where this is not possible, it may be necessary to construct new masts. In order to use the same line path and minimize visual pollution, the old masts may be torn down to make room for the new line. Such considerations are not made in this evaluation. The cost of line construction with new masts is used for both new lines and line upgrades. Upgraded lines are assumed to be in the same condition as new lines when put into operation.

The Kobbelv – Ritsem line is expected to be 100 km long. Its expected line specifications and thermal transmission capacity are calculated below. The same calculations are made for all lines. Specifications, as well as investment costs, that can be expected for the individual lines in all the described AC grid options are given in Appendix A.3. All costs are given in 2005 – values.

$$R = 0,018\ \Omega / \text{km} \cdot 100\ \text{km} = 1,8\Omega$$
$$X = 0,322\ \Omega / \text{km} \cdot 100\ \text{km} = 32,2\Omega$$
$$C_j = 8,58\ \text{nF} / \text{km} \cdot 100\ \text{km} = 0,858\,\text{mF}$$
$$C_d = 11,56\ \text{nF} / \text{km} \cdot 100\ \text{km} = 1,156\,\text{mF}$$
$$I_{th} = 3088A$$

C_j	=	Capacitance to earth (per phase)
C_d	=	Operational capacitance (per phase)
I_{th}	=	Thermal capacity (referred to 20°C air temperature)

$$P = U \cdot I \cdot \sqrt{3} - I^2 \cdot R \cdot \sqrt{3} \tag{7.1}$$

$$P = 420\,kV \cdot 3088\,A \cdot \sqrt{3} - (3088\,A)^2 \cdot 1,8\Omega \cdot \sqrt{3} = 2217\,MW$$

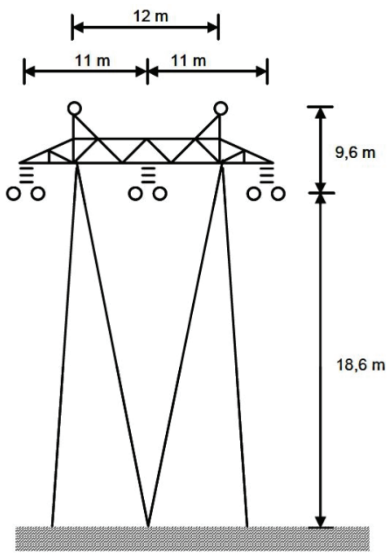


Fig. 7-1 – Steel mast overview schematic for 420 kV duplex lines [7]

Table 7-1 shows the assumed average cost of all station expansions. 1 000 MVA autotransformers for 300 / 420 kV are assumed utilized at all transformer stations, with 0,04 % active and 1,534 % reactive losses. Busbars and switchgear are air isolated. A transformer shaft with necessary protection and cable routing between transformer and switchgear is used. An additional construction cost of 15 MNOK is assumed adequate for necessary building expansions and unforeseen costs in each station.

Table 7-1 – Transformer costs

Line connection	Cost [MNOK]
Transformer (1 000 MW)	18,5
Double busbar with circuit breaker	8,8
Transformer shaft	4
Cable routing (50m)	3,1
Construction	15
Total cost	49,4

HVDC overhead lines are uncommon in the Nordic grid. There are no similar lines to the proposed Rana – Oslo line in Norway that can give an indication of the actual investment costs. It is assumed that these lines can be fitted on similar steel masts as are used for 420 kV AC transmission. While DC transmission requires only two lines instead of three as AC transmission requires, the per kilometer cost of each DC line may be higher due to the high capacity that is expected of this line. A simplified assumption made in this evaluation is therefore that the DC overhead lines that are considered have the same total investment cost per kilometer as the 420 kV duplex AC lines that are considered. This corresponds to 3,6 MNOK per kilometer.

Converter stations and underwater HVDC cables already have an important and established role in the Nordic power system. The investment costs for such installations are big and depend on a large amount of variables. Published investment costs for the existing NorNed cable [31] are used in this evaluation to estimate converter and cable costs. In the NorNed investment, cable and installation costs were at 2 300 MNOK while converter stations including construction cost was 1 390 MNOK. These costs are given in 2004 – values.

The proposed cable to Germany will only be marginally shorter than the existing NorNed cable, but the capacity will be 2,3 times higher. Generally, per unit costs of investment often decrease as capacities increase. The cost of both converter stations and cable is therefore assumed to be 2,2 times higher than the existing NorNed cable. The Rana – Oslo line will have a 3,3 times higher capacity than the existing cable. In this case, the cost of converter stations is assumed to be 3,1 times higher. An additional 20 % is added to these costs to account for administrative fees, technical support, insurances and unforeseen events.

Line investment costs are added from the tables in Appendix A.3. Other cost are calculated as explained above. The investment costs for each of the two main grid options are presented in Table 7-2 and Table 7-3.

Table 7-2 – Investment costs for grid option *cfXZ*

Investment	Cost [MNOK]	Referred year	Comment
HVDC cable	6 070	2004	Norway – Germany
Converter stations	3 670	2004	For HVDC cable
Converter stations	5 170	2005	For HVDC line
Total 2004-values	14 910		
AC line	360	2005	
Transformer stations	350	2005	7 station expansions
HVDC line	3 310	2005	Rana – Oslo, 920 km
Total 2005-values	3 770		

Table 7-3 – Investment costs for grid option *abcdfZ*

Investment	Cost [MNOK]	Referred year	Comment
HVDC cable	6 070	2004	Norway – Germany
Converter stations	3 670	2004	For HVDC cable
Total 2004-values	9 740		
Transformer stations	990	2005	20 station expansions
AC lines	5 540	2005	
Total 2005-values	6 480		

7.2 Calculated difference in benefits

A socio-economic benefit is calculated by the analytic tools used, for each simulated grid and production option. This benefit is calculated purely on the market conditions in each simulation, based on the methods described in Chapter 2. The most realistic way to find the benefit of the grid investments would be to subtract the socio-economic benefit after the grid options with the situation before, without changing any other factors. However, the situation with a production increase and no grid investments was found to be an unrealistic system situation that will not occur. This situation is therefore unsuited for comparison.

In order to find the increase in benefits, the benefit found in the base scenario is subtracted from each grid scenario with new production included. The difference found gives the total benefit of both new production and grid reinforcements together. As new production and grid reinforcements are investments that will take place depending on each other, this is considered to be a logical comparison.

The calculated socio-economic benefit of increased production with the *cfXZ* and *abcdfX* grid solutions is given in Fig. 7-2 and Fig. A 3-1, respectively. The results are similar, and show large benefit increases for Norway, particularly in the northern region. Area 9 makes a profit on congestion in the base scenario, and the grid options improve the congestion. The profit made of congestion is therefore decreased and area 9 has a reduction in benefits after the investments. This is only a local reduction, as the benefit increases greatly in the other Swedish areas.

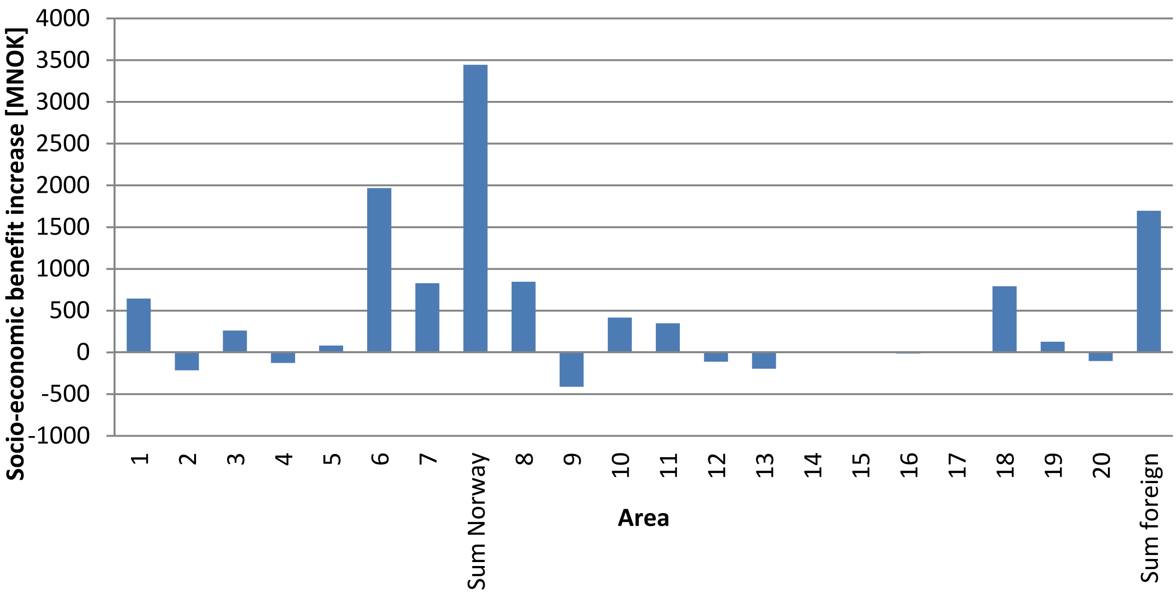


Fig. 7-2 – Socio – economic benefit of *2025-123-cfXZ* minus benefit of base scenario

The total increase in socio-economic benefit for the system as a whole amounts to 5 140 MNOK / year for *2025-123-cfXZ* and 4 930 MNOK / year for *2025-123-abcdfZ*. One can see from the figures that the increase in benefit in Norway stands for more than two thirds of the total benefit increase in the system.

7.3 Discounted costs and benefits

The costs and benefits can all be discounted [32] to 2025 – values. As a simplification, all investments are assumed made and finished in year 2025. The capitalization factor, $\lambda_{R,N}$, given in (7.2), can be used to find the equivalent investment cost from a number of annual costs. In order to find the equivalent annual cost of the investment, the annuity factor $\varepsilon_{R,L}$ is used. This formula is given in (7.3).

$$\lambda_{R,N} = \left[\frac{1-(1+r)^{-N}}{r} \right] \tag{7.2}$$

$$\varepsilon_{R,L} = \left[\frac{r}{1-(1+r)^{-L}} \right] \tag{7.3}$$

N – Duration of analysis [years]
L – Physical lifetime of investment [years]
R – Discount rate

The general economic life span [8] of overhead lines using steel towers is 70 years, while for transformer stations it is 50 years. HVDC converter stations have a life span of 40 years, and this is also used for the HVDC cables. The period of analysis used in this calculation is 30 years, beginning in year 2025. This is shorter than the life span of the investments because of the difficulty in predicting the state of the market situation more than 30 years ahead. Also, as a result of the discount rate, present value of costs and benefits after 30 years will be much smaller than those found during the period of analysis. Neglecting these costs and benefits will therefore not have a large impact on the final results.

The discount rate is assumed to be a risk free rate of 4 % with a risk addition depending on the type of investment made. The risk addition for investments in the central grid is 3 %. [8] By adding these together the total discount rate becomes 7 %. This is in accordance with a recommendation [33] made by the Institute for Research in Economics and Business Administration on the level of discount rate used for central grid investments and cross-border DC cables.

From formulas (7.2) and (7.3), the capitalization and annuity factors used for calculation are:

$$\lambda_{7\%,30} = \left[\frac{1-(1+0,07)^{-30}}{0,07} \right] = 12,4 \qquad \varepsilon_{7\%,40} = \left[\frac{0,07}{1-(1+0,07)^{-40}} \right] = 0,0750$$

$$\varepsilon_{7\%,50} = \left[\frac{0,07}{1-(1+0,07)^{-50}} \right] = 0,0725 \qquad \varepsilon_{7\%,70} = \left[\frac{0,07}{1-(1+0,07)^{-70}} \right] = 0,0706$$

Costs and benefits of grid option *cfXZ*

The Norwegian Consumer Price Index (CPI) [34] is used to find the 2009 – value of the investment costs. These costs are assumed to be of the same value in 2025 as they are in 2009, and are presented in Table 7-4. The average CPI values for years 2004 and 2005 are used together with the CPI in April 2009. The multiplication factors used are given below:

2009 – values from 2004 – values: $\frac{125,4}{113,3}$

2009 – values from 2005 – values: $\frac{125,4}{115,1}$

Table 7-4 – Initial investment costs for option *cfXZ*

Investment	Cost [MNOK]	Economic life span
HVDC cable	6 720	40
Converter stations cable	4 060	40
Converter stations line	5 720	40
Transformer stations	390	50
AC line	380	70
HVDC line	3 610	70
Initial investment cost	20 880	

The salvage value of the investment after the period of analysis must also be considered. This is done by multiplying the investment cost with both the capitalization factor and the respective annuity factor. Present values (year 2025) of the investment costs are given in Table 7-5.

Table 7-5 – Investment costs after considering salvage values for option *cfXZ*

Investment	Cost [MNOK]
HVDC cable	6 250
Converter stations cable	3 780
Converter stations line	5 320
Transformer stations	350
AC line	330
HVDC line	3 160
Total investment cost	19 190

Maintenance and operation costs of grid investments are assumed [2] to be 1,5 % of the investment cost, per year. These annual costs are:

$C_m = 19\,190 \text{ MNOK} \cdot 0{,}015 = 288 \text{ MNOK}$

The value (year 2025) of all annual maintenance costs within the period of analysis is:

$C_{m,0} = C_m \cdot \lambda_{7\%,30} = 288 \text{ MNOK} \cdot 12{,}4 = 3\,570 \text{ MNOK}$

Value for investment and maintenance costs:

$C_{tot} = C_{inv} + C_{m,0} = 19\,190 \text{ MNOK} + 3\,570 \text{ MNOK} = 22\,760 \text{ MNOK}$

For this investment to be justified, the total increase in socio-economic benefit must be higher than the total costs. Per year, the increased benefit must at least be equal to:

$$C_{year} = \frac{C_{tot}}{\lambda_{7\%,30}} = \frac{22\ 760 \text{ MNOK}}{12,4} = 1\ 840 \text{ MNOK}$$

As the total system increase in socio-economic benefit has been found to be 5 140 MNOK per year, the total annual system increase in benefits of the *2025-123-cfXZ* option outweighs the grid investment costs by 3 300 MNOK.

Costs and benefits of grid option *abcdfZ*

The value of the investment costs are found for year 2025 as described before, and are presented in Table 7-6.

Table 7-6 – Initial investment costs for option *abcdfZ*

Investment	Cost [MNOK]	Economic life span
HVDC cable	6 720	40
Converter stations cable	4 060	40
Transformer stations	1 080	50
AC lines	6 040	70
Initial investment cost	17 900	

The salvage value of the investment after the period of analysis is considered as described before. Present values (year 2025) of the investment costs are given in Table 7-7.

Table 7-7 – Investment costs after considering salvage values for option *abcdfZ*

Investment	Cost [MNOK]
HVDC cable	6 250
Converter stations cable	3 780
Transformer stations	970
AC lines	5 280
Total investment cost	16 280

The annual maintenance and operation costs are calculated:

$C_m = 16\ 280 \text{ MNOK} \cdot 0{,}015 = 244 \text{ MNOK}$

The value (year 2025) of all annual maintenance costs within the period of analysis is:

$C_{m,0} = C_m \cdot \lambda_{7\%,30} = 244 \text{ MNOK} \cdot 12{,}4 = 3\ 030 \text{ MNOK}$

Value for investment and maintenance costs:

$C_{tot} = C_{inv} + C_{m,0} = 16\ 280 \text{ MNOK} + 3\ 030 \text{ MNOK} = 19\ 310 \text{ MNOK}$

For this investment to be justified, the total increase in socio-economic benefit must be higher than the total costs. Per year, the increased benefit must at least be equal to:

$$C_{year} = \frac{C_{tot}}{\lambda_{7\%,30}} = \frac{19\ 310\ \text{MNOK}}{12{,}4} = 1\ 560\ \text{MNOK / year}$$

As the total system increase in socio-economic benefit has been found to be 4 930 MNOK per year, the total annual system increase in benefits of the *2025-123-abcdfZ* option outweighs the grid investment costs by 3 370 MNOK.

An overview of the valued elements that are calculated is presented in Table 7-8 for both grid options.

Table 7-8 – Overview of valued and calculated elements

Result category	*2025-123-cfXZ*	*2025-123-abcdfZ*
Initial investment costs	20 880 MNOK	17 900 MNOK
Investment costs considering salvage values	19 190 MNOK	16 280 MNOK
Maintenance costs	3 570 MNOK	3 030 MNOK
Total investment and maintenance costs	22 760 MNOK	19 310 MNOK
Emission reductions	10,9 $MtCO_2$	9,4 $MtCO_2$
Socio-economic value of reductions	2 180 MNOK	1 880 MNOK
Increase in annual socio-economic benefit	5 140 MNOK	4 930 MNOK
Total annual costs	1 840 MNOK	1 560 MNOK
Annual increase in benefit minus total costs	3 300 MNOK	3 370 MNOK

A number of factors that are not considered create a large uncertainty regarding costs. Geographic conditions as well as the total investment size and specific contract agreements are important regarding costs. The current market conditions, including the level of competitiveness, will also have an impact. Compensation to land owners and interest rates during construction are not included in costs. The investments can be made by Statnett alone or in cooperation with other TSOs, splitting the costs and incomes. The latter is particularly relevant for inter-TSO investments and investments outside Norwegian territory.

7.4 Other elements of consideration

A number of socio-economically important factors are not directly taken into consideration by the calculations. These are elements that are difficult to quantify or value. In case of line faults, the improved grid solutions are expected to improve the system stability and the security of supply. Competitive conditions will also improve, improving the Nordic power market as a whole and the confidence in it.

The new market conditions cause decreased power prices in northern Norway, a region prone to depopulation in recent years. The lower power prices may give incentives for new industry to establish in the area. In time, increased industrial activity and the new jobs that come with it may increase the area's population.

The environmental impacts of the grid options are also difficult to value. When upgrading 300 kV lines to 420 kV, it is assumed that the existing paths will be used as frequently as possible. This will result in a minimum of increased visual disturbances. No new transformer stations are built, but the number of expansions may cause local scenery reductions.

All new lines bear the risk of impacting nearby inhabitants, local scenery, vegetation, animal and bird life. Besides forest clearing around the lines, additional roads may be necessary to transport components. Especially the Rana – Oslo line, stretching close to half the length of Norway, may have a notable impact on the national socio-economic benefit. Cables may be used instead of lines in certain areas to reduce this impact, but this will again have large consequences on the economy of the grid solution.

During the construction period, increased activity on and around the line paths and transformer stations may cause local noise and visual pollution. The high investment budget will also employ a number of contractors during this period, which may have a positive impact on Norwegian economy.

In dry years with little precipitation, the improved import capacity and increased production will reduce the risk of power rationing in Norway. Similarly, in years with high levels of precipitation the improved export capacity will allow for a better utilization of water and wind resources than before. These elements are, to a degree, valued in the calculated benefits. On average, the new market conditions should lead to more stable power prices not only in Norway, but also in the other Nordic countries. Less uncertainty regarding future power prices may be considered a benefit for both producers and consumers, but is not valued in these calculations.

8 Discussion of results

The transmission system investments assumed made by year 2025 in the “Wind and Consumption Growth” scenario provide Norway with a stronger central grid than that of 2009. The analysis of the base scenario reveals that due to changed market conditions, congestion occurs during certain load periods despite the improved transmission capacities. Adding transmission of 22 TWh / year through a system that is already strained is likely to cause massive congestion problems. The simulations in Chapter 6.2, with increased production and no new grid investments, confirm the expectations when power prices fall towards zero in northern Norway. The possibility of adding such quantities with unregulated power in this region without further grid investments is therefore dismissed as unrealistic.

It is a known fact that Sweden has a much stronger central grid than Norway. The fact that power flows through the path of least impedance is basic electrical theory. It is logical that a power increase in Norway would strain the Ofoten – Ritsem line, and the results in Chapter 6.3 show that either production must be decreased or consumption increased in order to solve this problem. These results were expected from the theory presented, and prove the necessity of investing in a new line in this area, such as the Kobbelv – Ritsem line. Norwegian AC line upgrades alone are not sufficient.

The fact that the Swedish grid has lower impedance than its Norwegian counterpart does not necessarily mean that it has more free transmission capacity. The base scenario analysis showed congestion even before the production increase. Congestion levels generally increase with increased transmission. It is therefore natural that a grid solution intending to allow high levels of increased transmission through Sweden will require higher transmission capacities. The results in Chapter 6.4 correspond well with this theory and show that a line investment between Rätan and Borgvik solves the problem.

A high level of line investments in Sweden and no investments in Norway causes more power flow towards Sweden, which is expected due to the decreased line impedances. As not all new power flows towards Sweden, congestion is increased in Norway as well as in lines into Sweden. The possibility of line investments through Sweden without investments through Norway is therefore found to be unrealistic.

Simulation results in Chapter 6.5 illustrate well the day-night trade from southern Norway to Europe and how power producers will adapt to a new cable. Production and export is maximized during daytime in order to maximize profits, as expected. The overall export increase compared to the base scenario is a logical consequence of the increased power production.

While AC transmission follows Ohm’s and Kirchoff’s laws, DC transmission can be controlled. As the results in Chapter 6.6 show, a DC line therefore allows for a higher transmission through Norway than the proposed AC upgrades. With more power flowing through Norway, less power flows through Sweden and grid investments within Sweden are not necessary. It is also logical that less power import is necessary into southern Norway from Sweden when transmission is higher internally through Norway.

As intended, the increased power production in northern Norway and Sweden replaces production in other areas. As expected, no hydropower, wind power or nuclear power is replaced. The main CO_2 – emission reductions take place in continental Europe, which corresponds to the location of the high amounts of coal power that is replaced.

Discussion of benefits

Coal power causes higher CO_2 – emissions than gas power. It is therefore logical that more emissions are replaced in *2025-123-cfXZ*, where the most coal power is replaced, than in *2025-123-abcdfZ*. This emission reduction, alone amounting to an increase in socio-economic benefit of 2 180 MNOK per year in *2025-123-cfXZ*, can be considered to be a political justification for the assumed increase in renewable power production.

The socio-economic benefit increase as a result of market condition improvements is large both for the system as a whole and particularly for Norway. This benefit includes the income of the new power producers, which explains some of the increases in benefit for areas 6, 7 and 8. CO_2 – quota prices are included in the price of power production in the calculation of benefits. The socio-economic benefit of emission reductions is therefore also included.

Most of the emission reductions take place in Germany, therefore most of the benefits of these reductions are also found there. As production is reduced in Germany, the income from German power production is also reduced. This benefit is moved to Norway and Sweden where production is increased. The total increase in benefits found in Germany is therefore smaller than the calculated increase due to reduced emissions in the country.

The total socio-economic benefit should exceed the total costs of both grid and power station investments in order for the new market situation as a whole to be beneficial. This thesis assumes that the power stations will be built due to political purposes in any case, and their costs are therefore not considered. The increase in power surplus cannot be realized without grid reinforcements. One can therefore argue that the benefit increase from improved market conditions can be attributed the grid investments. If the implementation of new power is to be considered alongside the grid solutions, investment costs of power production must also be included.

The investment costs are assumed to be the same in 2025 as in 2009 due to the fact that future inflation is unknown. It is possible that these costs may be much higher in 2025. The costs of both the NorNed investment and the per unit costs used may also be unsuited for comparison due to a number of reasons. Components necessary in order to control reactive power, such as reactor plants and condenser banks, are not considered. The investment and maintenance value of such components are therefore not included. In addition to this, a number of elements apply that are not quantified or valued. A much more thorough technical analysis would be necessary to conclude the actual costs of these investments.

The grid option in *2025-123-cfXZ* allows for the highest emission reductions and the highest increase in total benefits, but is more expensive than the *2025-123-abcdfZ* option. The calculated differences between these options are considered to be within plausible error due to simplifications and non-valued elements. In order to decide which of these two options is the most beneficial, a more detailed technical analysis would be necessary.

One can argue that there is less uncertainty associated with AC line upgrades than a new DC line of such a length. The socio-economic value of using the same line paths as existing lines and thus minimizing visual pollution can also be expected to be high. In addition, the AC alternative will allow new consumers and producers to connect to the 420 kV lines at any of the transformer stations along the line. This can be considered to be an incentive to encourage new industry and power producers in the center of Norway. For these reasons, the *abcdfZ* grid option is likely to be preferable.

Main sources of modeling errors

The EPF models ability to simulate the power system is mainly dependent on three important factors. First, the data set used must give accurate values for the system that is to be represented. Errors and simplifications in the data set may cause the model to simulate a system that is operating under unrealistic conditions.

The model calculates water values a long time into the future. In that time many unpredictable variables can have changed. The historic inflow values used may no longer apply due to physical changes in an area or waterway. There may also have been a change in precipitation due to climate changes after the inflow was observed. The base scenario used expects a 3 TWh inflow increase due to climate changes, but this prediction may be incorrect. Invalid inflow statistics will cause an incorrect system representation, thus providing a wrong result to the intended simulation.

Secondly, the model is dependent on user knowledge of both the model itself and the power system it is to simulate. This is due to the number of manual operations that must be performed by the user in order to achieve useful results. Manual calibrations are unlikely to result in optimal values, but are considered adequate when performed well. A poor calibration is synonymous with a poor market representation. A poor choice of areas and lines used in overload handling will not enable the model to realistically replicate TSO reactions. Such factors may result in an unrealistic system simulation.

Finally, the effect of model simplifications on the simulation is of great importance. Grid maintenance and line upgrades may affect the operational time of certain lines throughout a year. This may again affect the power flow of the system, but is not considered by the EPF model. Ramping restrictions when switching the direction of power flow through DC lines and cables are not considered. The fact that a DC load flow is calculated instead of AC may also reduce the accuracy of the calculations.

Due to the time resolution of the EPF model, no distinction is made between each of the weekdays, or the sequential load development throughout a week. A consequence of this is that many restrictions are not considered. For a small hydropower plant with limited reservoir capacities, the model may assign a larger reservoir level difference between day and night than what is practically possible. Only the reservoir level before and after each week is taken into account when considering the restrictions.

As the hours in the load periods used are not sequential, start and stop costs of thermal plants are not implemented in the model. Such plants are often put into operation during daytime, when prices are high due to the peak load. The costs of starting and stopping the plants may cause higher daytime prices than if there were no such costs involved. In the Norwegian power system most production is hydropower, where start and stop costs are negligible. This element may cause an inaccuracy in the modeling of neighboring countries with high amounts of thermal power.

Additional errors due to system predictions

A critical assumption in this analysis is the expected power market conditions in year 2025. While the chosen scenario “Wind and Consumption Growth” offers a logical starting point based on the goals described in Chapter 5.1, the market conditions may also evolve differently than expected. One may argue that the base scenario in itself, even without additional production, is an ambitious expectation when it comes to new renewable power.

It is also important to point out that the period of analysis for the scenarios only covers up to the year 2025. The analyzed investment has a period of analysis covering 30 years from 2025, reaching 2055. No detailed scenario predictions are given on the expected market conditions between years 2025 and 2055. However, as described in Chapter 5.1, the emission reductions expected to be necessary before 2050 are much larger than the goals for 2020. More renewable power, and the means to transmit and export it, is likely to become increasingly important and valuable during this period.

All new production and grid investments are in this thesis assumed to take place in the beginning of year 2025. As the investments are dependent on each other to make a gain in socio-economic benefit, it is considered very likely that they will be coordinated and finished shortly after each other. They may, however, be built in steps rather than all at once as assumed in these calculations. Due to the investment sizes, it is also likely that they will require many years to complete.

9 Conclusion and recommendations

A number of grid solutions are simulated and analyzed, assuming 22 TWh increased annual production compared to scenario expectations. Of these, two are found to provide what is considered to be within acceptable system operation. These are the grid options provided by *2025-123-abcdfZ* and *2025-123-cfXZ*, explained in Chapter 6.1. Without grid investments, a realistic state of system operation cannot be achieved.

System bottlenecks are reduced to levels below the base scenario. The new production is transmitted to the export channels in southern Norway and Sweden at acceptable loss levels. Power export to continental Europe is increased, causing a reduction in carbon-based power generation. All changes in production, consumption, transmission and area prices appear to be logical within the theory presented. The level of simplifications and possible errors in the power flow simulations are considered to be acceptable within the scope of this analysis.

The calculated increase in socio-economic benefit greatly outweigh the costs for both of the chosen grid options. A high increase in benefits is supported by the improved market conditions seen in the results. If a political decision is made to implement the regional production increases that this thesis has analyzed, the proposed grid solutions will be very beneficial. One may anticipate that this political decision is dependent on an expected increase in socio-economic benefit. In such a case, the cost of new power production must not exceed 3 370 MNOK per year within the period of analysis. Due to large simplifications in cost calculations and the number of unvalued elements, this value must be considered to be very approximate.

The results of this thesis confirm that a large power surplus in northern Norway and Sweden is possible while maintaining an acceptable state of system operation, within the proposed grid solutions. A high reduction in European emissions can be made that will be a large contributor to achieving existing energy development goals. The high increase in calculated socio-economic benefit, especially in Norway, indicates that further analysis should be made.

Further work will benefit from a more detailed technical and economic evaluation. Cost estimates for renewable power investments should also be included. Further analysis should consider more closely the stability concerns due to both the increased production and new power lines. This consideration should include the possible implementation of components such as capacitor banks, reactor plants and series capacitors to control reactive power flow. Different production varieties than the quantities and locations used in this project should also be analysed. Other scenarios than the one analyzed in this thesis should be included, considering a variety of different market expectations for 2025 and onwards.

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A.1 Data set modifications

This thesis is based on the assumptions made in the scenario "Wind and Consumption Growth 2025". All simulations are therefore based on a corresponding data set for this scenario. All simulated grid and production conditions are implemented into copies of this base data set. This allows for a directly comparison between all simulation results.

All new power stations are included into the data sets with their respective installed capacities and yearly production capacities. Wind parks are modeled as hydropower plants with unregulated inflow, which is defined by a database on historical wind data in each area. The small hydro plants are also modeled with unregulated inflow, defined by a similar database on historical water inflow. The impedance of generator connection lines is assumed minimal and neglected. All production is therefore connected directly to the geographically nearest central grid bus bar of the respective stations. These connections are stated in the EFI-PROD-1 and EFI-PROD-2 files.

In order to upgrade the voltages of lines in the data set, existing lines are first removed. Transformers for the new voltage level are then added at the connection nodes. Finally, new lines are added with their new impedances and thermal capacities. All these changes are made in the detailed grid file of the data set. Data for new lines and line upgrades are entered in KOMBSNITT and MASKENETT. When these investments cross area borders, EFI-SNITT must also be edited accordingly. Data for the new DC lines are entered in MASKENETT, EFI-MODRED and EFI-PREF. The DC lines are also manually entered as trading options in each of the areas they connect to. Sections in KOMBSNITT for stability considerations and handling of overloads are changed according to the new system requirements for each option.

The new production which the system is simulated with, particularly before grid upgrades are introduced, puts a very large strain on the load flow calculations in the model. The load flow algorithm must solve equations where many of the 13 260 load periods represent extreme transmission conditions far above nominal values. New AC lines provide capacitances and inductances that may create reactive power flow, also straining the system. An AC load flow considers both active and reactive power flow and is prone to convergence problems under these conditions.

In practice, TSOs will take measures to control the flow of reactive power to avoid stability concerns. These are not made automatically by the EPF model, and have not been implemented as part of this analysis. A DC load flow [9], which only considers active power and the voltage angle, is therefore used in order to avoid convergence problems during simulation. The model uses a predefined voltage vector when calculating the DC load flow in order to achieve results that are as realistic as possible. This analysis mainly considers changes in system conditions before and after investments. For this purpose, a DC load flow is considered to represent a good approximation to an AC load flow.

A.2 Analysis results

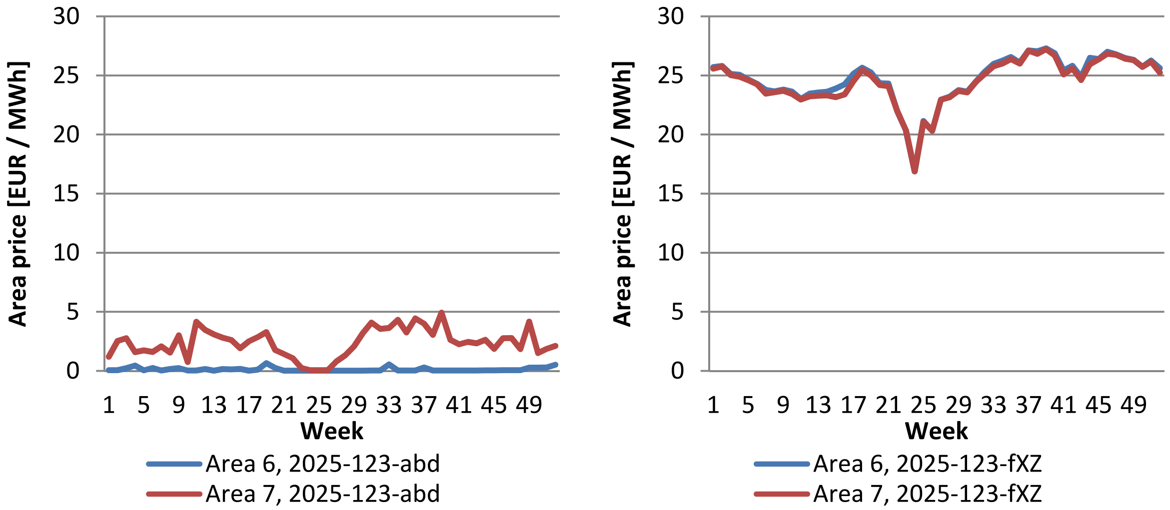

Fig. A 2-1 – Power prices for areas 6 and 7 given grid options without Kobbelv – Ritsem line

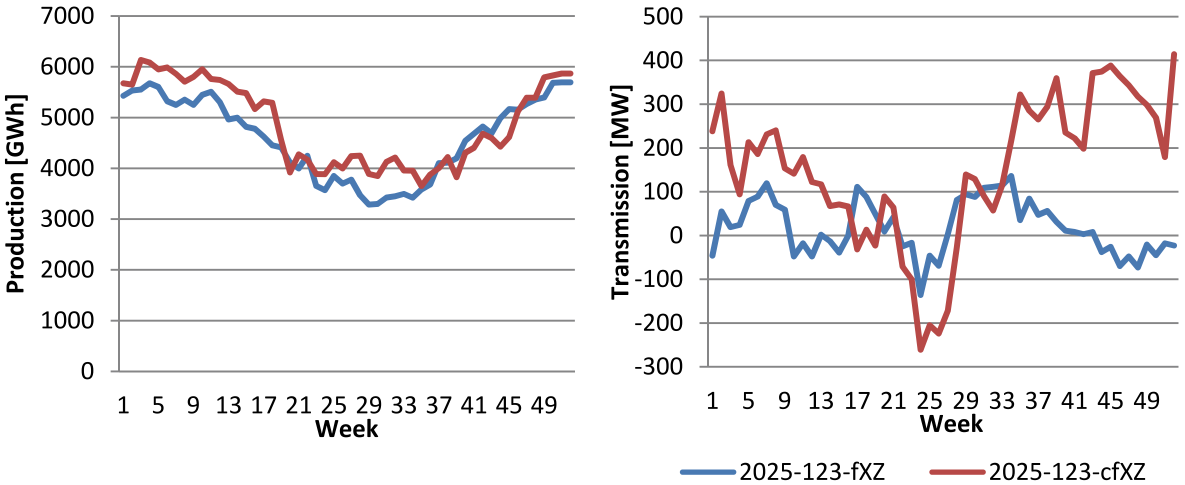

Fig. A 2-2 – Power production in area 6 (left) and average weekly transmission from area 8 to 6 (right) with and without Kobbelv – Ritsem line

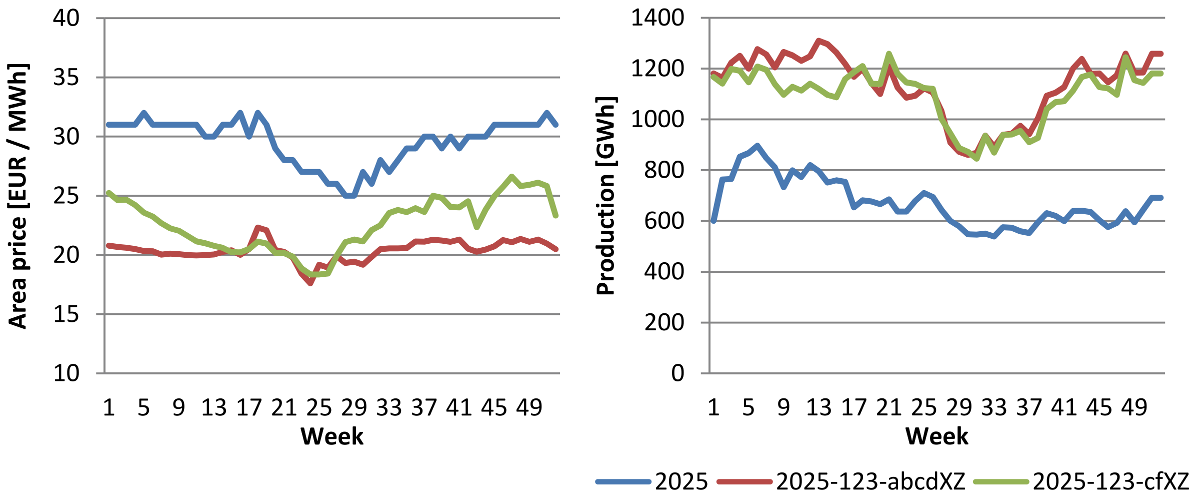

Fig. A 2-3 – Power price (left) and production (right) in area 7

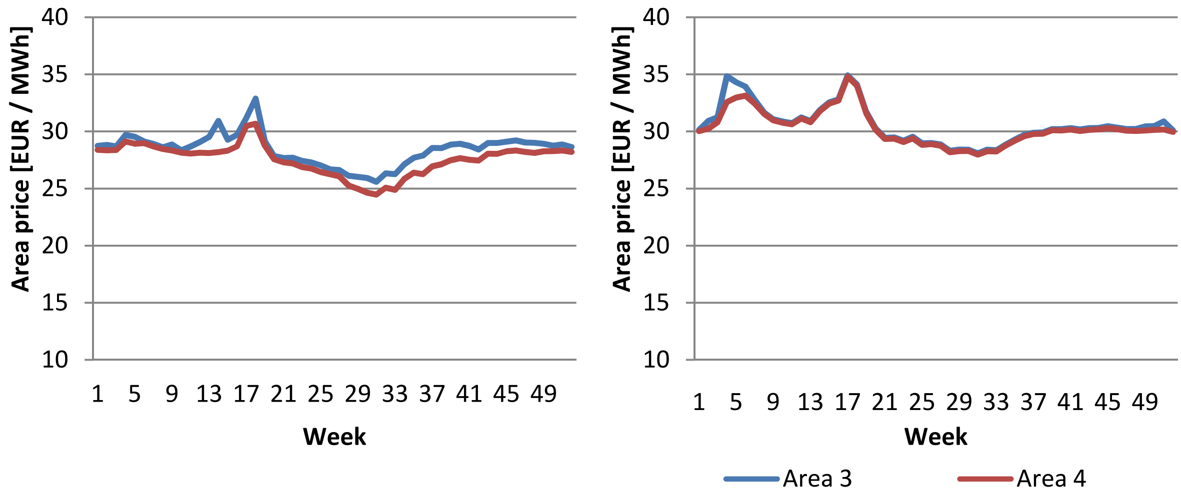

Fig. A 2-4 – Area prices in southern Norway with grid options *2025-123-cX* (left) and *2025-123-cfXZ* (right)

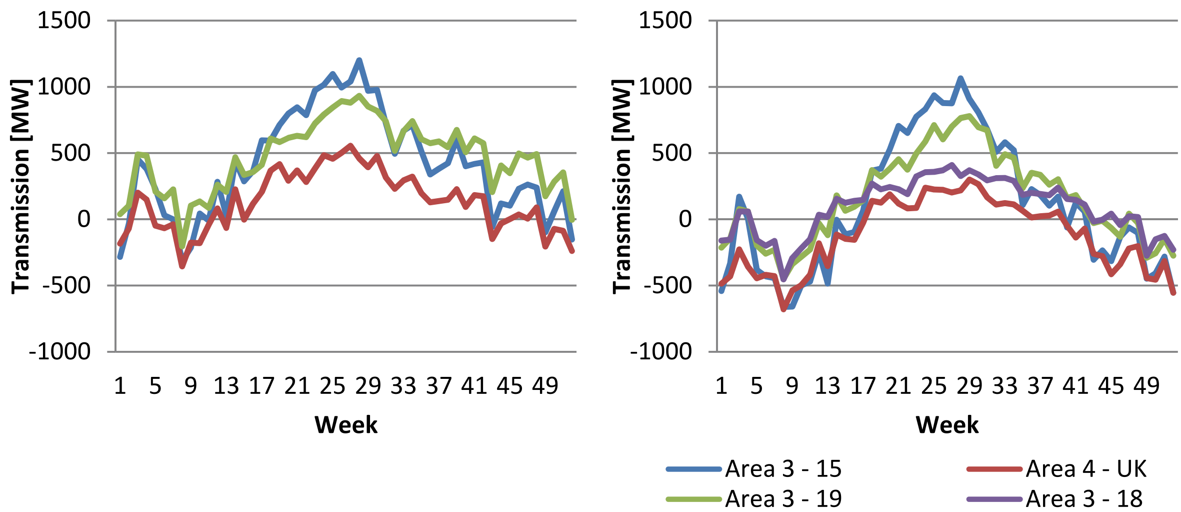

Fig. A 2-5 – Norwegian DC power export with grid options *2025-123-cX* (left) and *2025-123-cfXZ* (right), load period 4

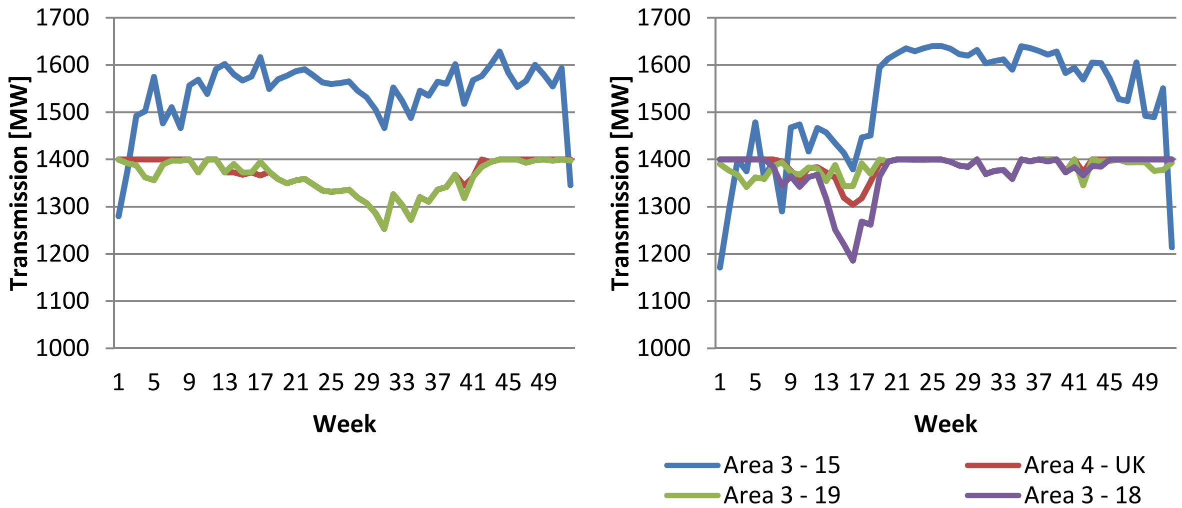

Fig. A 2-6 – Norwegian DC power export with grid options *2025-123-abcd* (left) and *2025-123-abcdfZ* (right)

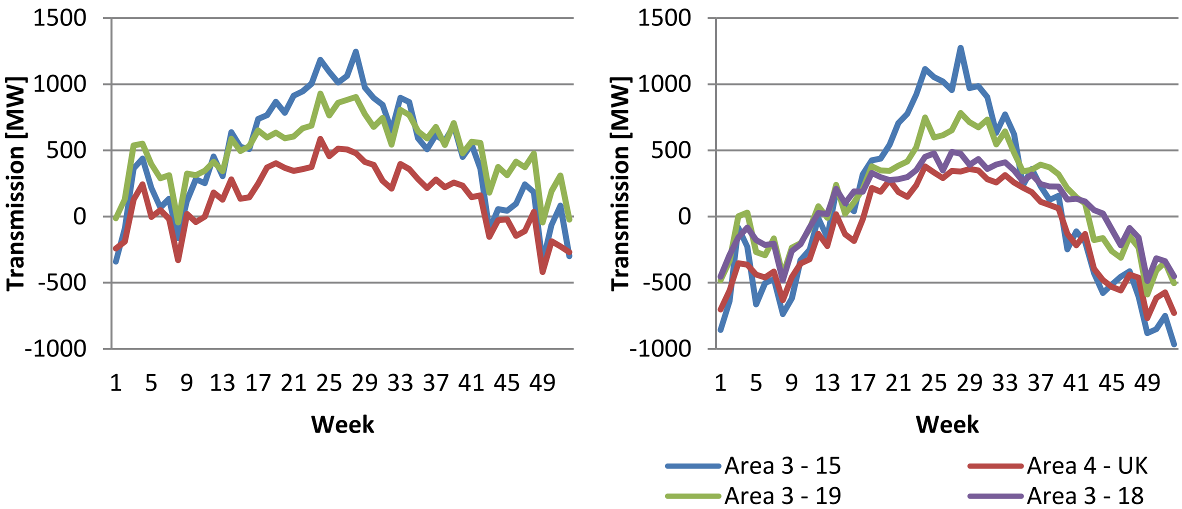

Fig. A 2-7 – Norwegian DC power export with grid options *2025-123-abcd* (left) and *2025-123-abcdfZ* (right), load period 4

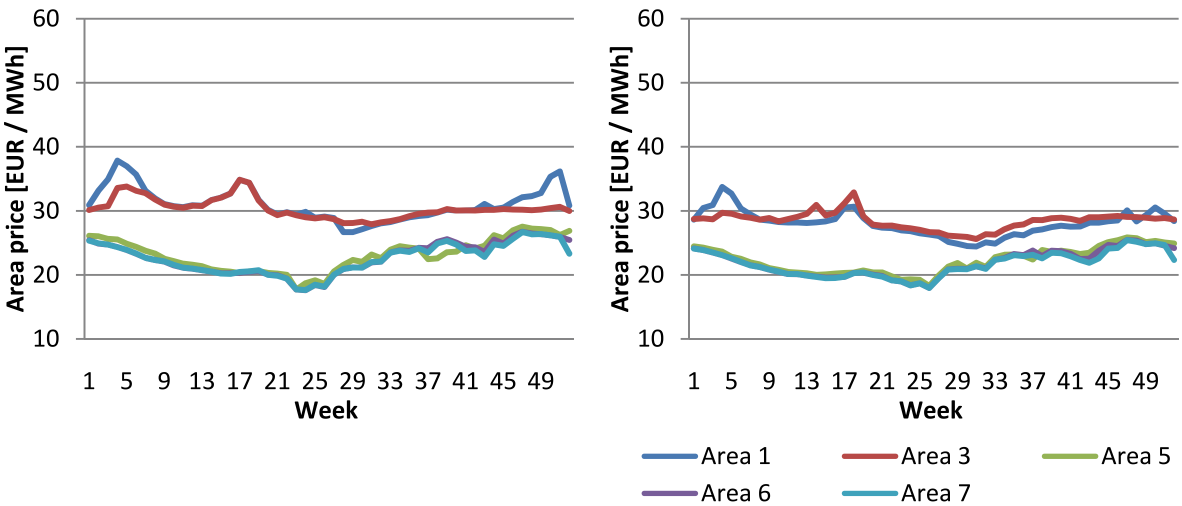

Fig. A 2-8 – Area prices in Norway for *2025-123-cfXZ* (left) and *2025-123-cX* (right)

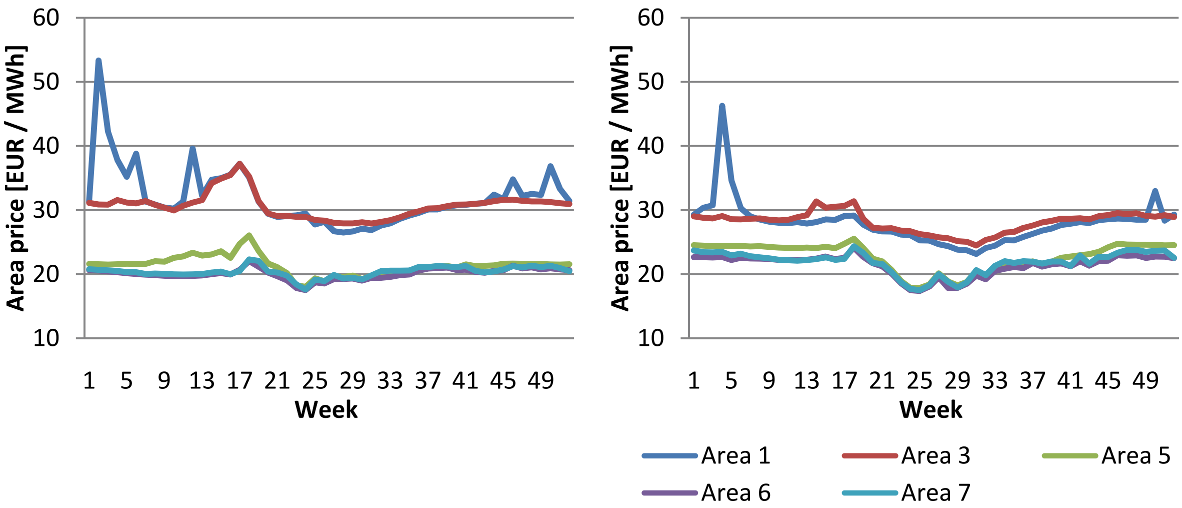

Fig. A 2-9 – Area prices in Norway for *2025-123-abcdfZ* (left) and *2025-123-abcd* (right)

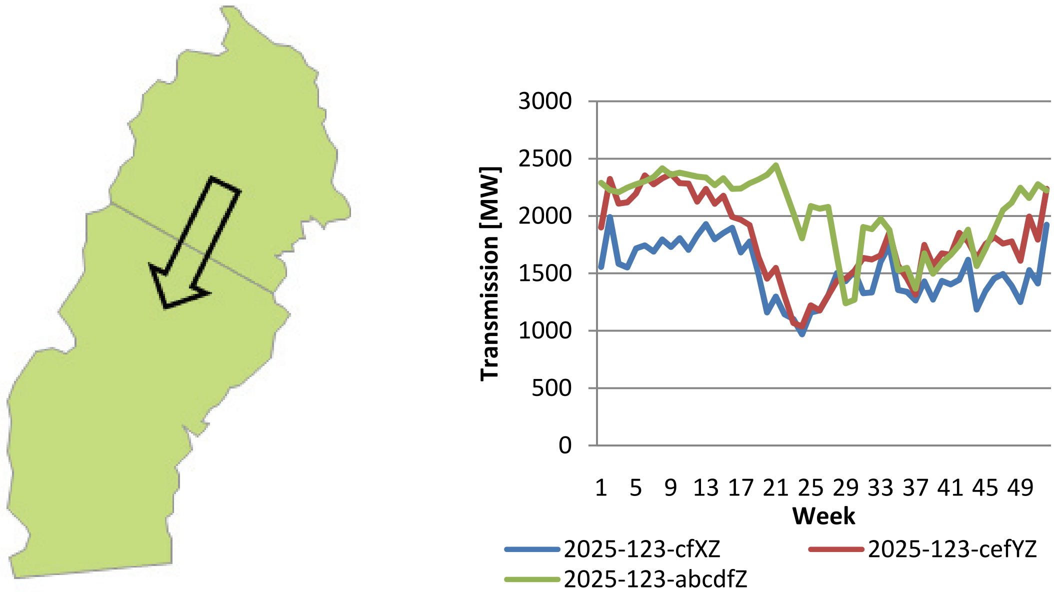

Fig. A 2-10 –Transmission from area 8 to 9

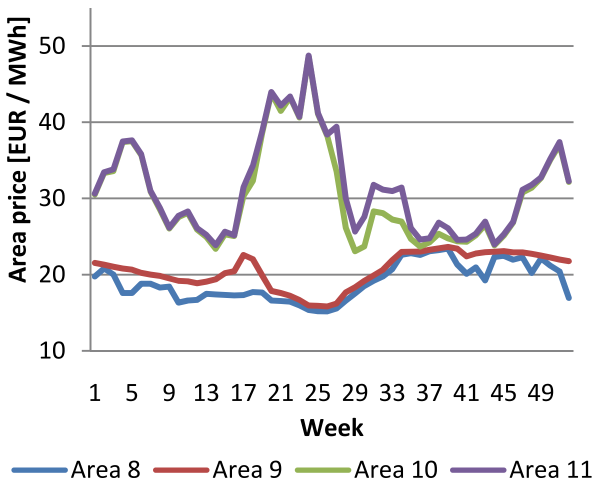

Fig. A 2-11 – Swedish area prices for grid *2025-123-cefYZ*

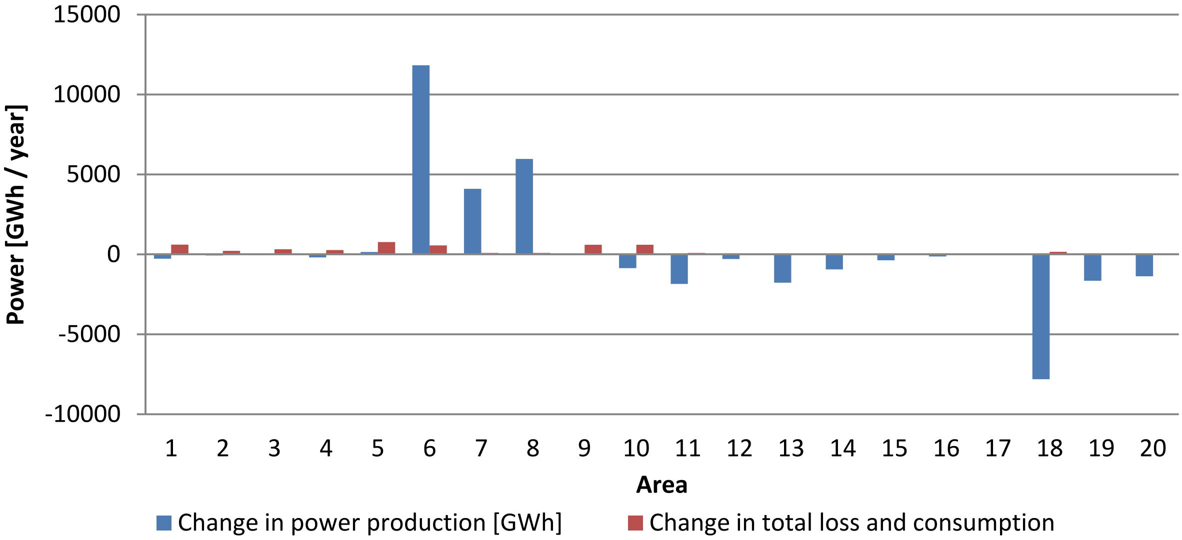

Fig. A 2-12 – Production, consumption and loss differences (*2025-123-abcdfZ* minus base scenario)

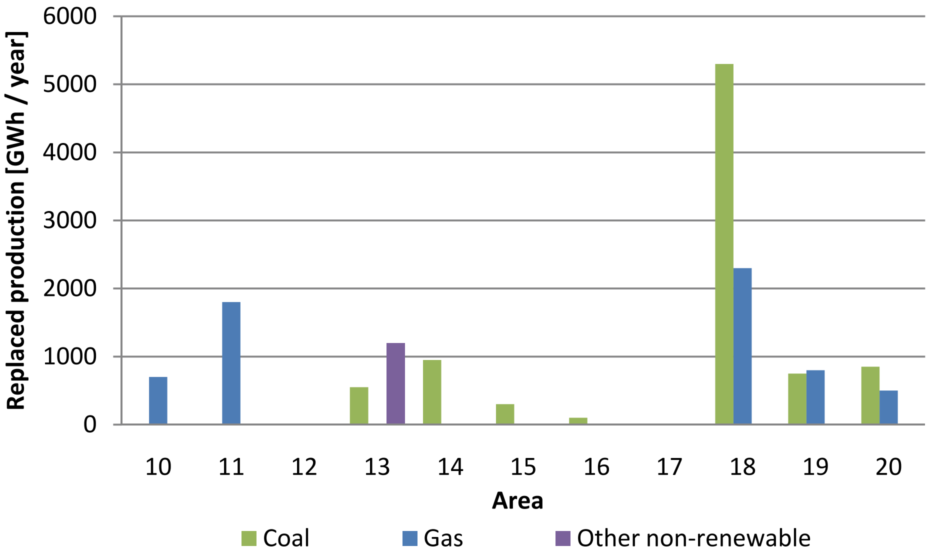

Fig. A 2-13 – Replaced power production (production values of base scenario minus *2025-123-abcdfZ*)

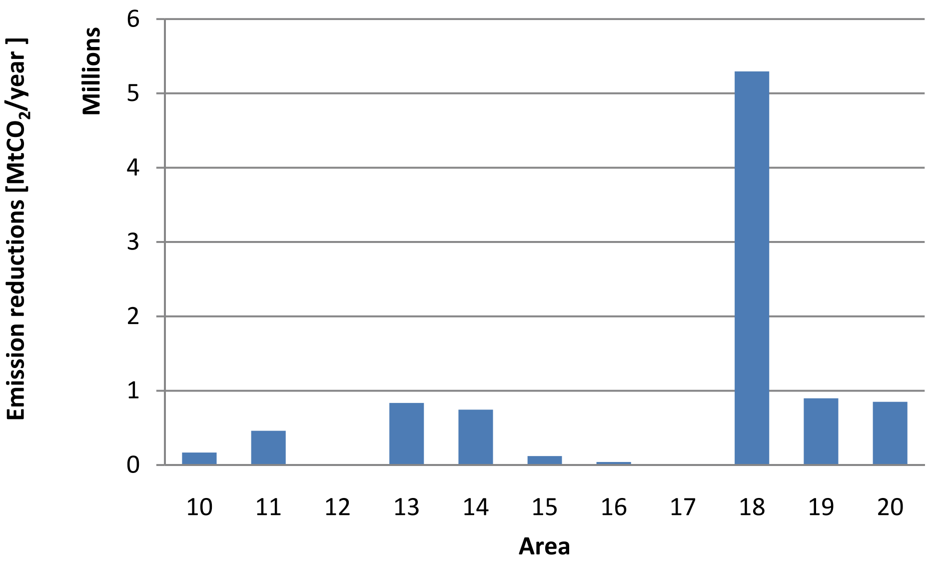

Fig. A 2-14 – CO_2 – emission reductions (base scenario values minus *2025-123-cfXZ* values)

A.3 Costs and benefits

Table A3-1 – Line specifications and costs for grid option *a*

Line connection	Length [km]	R [ohm]	X [ohm]	C_i [mF]	C_d [mF]	I [A]	Thermal capacity [MW]	Cost [MNOK]
Namsos – Tunnsjødal	80	1,44	25,76	0,6864	0,9248	3 088	2 223	288
Tunnsjødal – Namskog	40	0,72	12,88	0,3432	0,4624	3 088	2 235	144
Namskog – Nedre Røssåga	160	2,88	51,52	1,3728	1,8496	3 088	2 199	576
Klæbu – Verdal	90	1,62	28,98	0,7722	1,0404	3 088	2 220	324
Verdal – Ogndal	35	0,63	11,27	0,3003	0,4046	3 088	2 236	126
Ogndal – Namsos	65	1,17	20,93	0,5577	0,7514	3 088	2 227	234
Total								1 692

Table A3-2 – Line specifications and costs for grid option *b*

Line connection	Length [km]	R [ohm]	X [ohm]	C_i [mF]	C_d [mF]	I [A]	Thermal capacity [MW]	Cost [MNOK]
Fåberg – Frogner	190	3,42	61,18	1,6302	2,1964	3 088	2 190	684
Fåberg - Ø. Vinstra	100	1,8	32,2	0,858	1,156	3 088	2 217	360
Ø. Vinstra – Vågåmo	50	0,9	16,1	0,429	0,578	3 088	2 232	180
Vågåmo – Aura	100	1,8	32,2	0,858	1,156	3 088	2 217	360
Total								1 584

Table A3-3 – Line specifications and costs for grid option *c*

Line connection	Length [km]	R [ohm]	X [ohm]	C_i [mF]	C_d [mF]	I [A]	Thermal capacity [MW]	Cost [MNOK]
Kobbelv – Ritsem	100	1,8	32,2	0,858	1,156	3 088	2 217	360
Total								360

Table A3-4 – Line specifications and costs for grid option *d*

Line connection	Length [km]	R [ohm]	X [ohm]	C_j [mF]	C_d [mF]	I [A]	Thermal capacity [MW]	Cost [MNOK]
Borgvik – Rätan	360	6,48	115,92	3,0888	4,1616	3 088	2 139	1 296
Total								1 296

Table A3-5 – Line specifications and costs for grid option *e*

Line connection	Length [km]	R [ohm]	X [ohm]	C_j [mF]	C_d [mF]	I [A]	Thermal capacity [MW]	Cost [MNOK]
Fåberg – Frogner	190	3,42	61,18	1,6302	2,1964	3 088	2 190	684
Total								684

Table A3-6 – Line specifications and costs for grid option *f*

Line connection	Length [km]	R [ohm]	X [ohm]	C_j [mF]	C_d [mF]	I [A]	Thermal capacity [MW]	Cost [MNOK]
Feda – Tonstad	50	0,9	16,1	0,429	0,578	3 088	2 232	180
Tonstad – Tjørhom	30	0,54	9,66	0,2574	0,3468	3 088	2 237	108
Tjørhom – Lyse	35	0,63	11,27	0,3003	0,4046	3 088	2 236	126
Lyse – Saurdal	55	0,99	17,71	0,4719	0,6358	3 088	2 230	198
Total								612

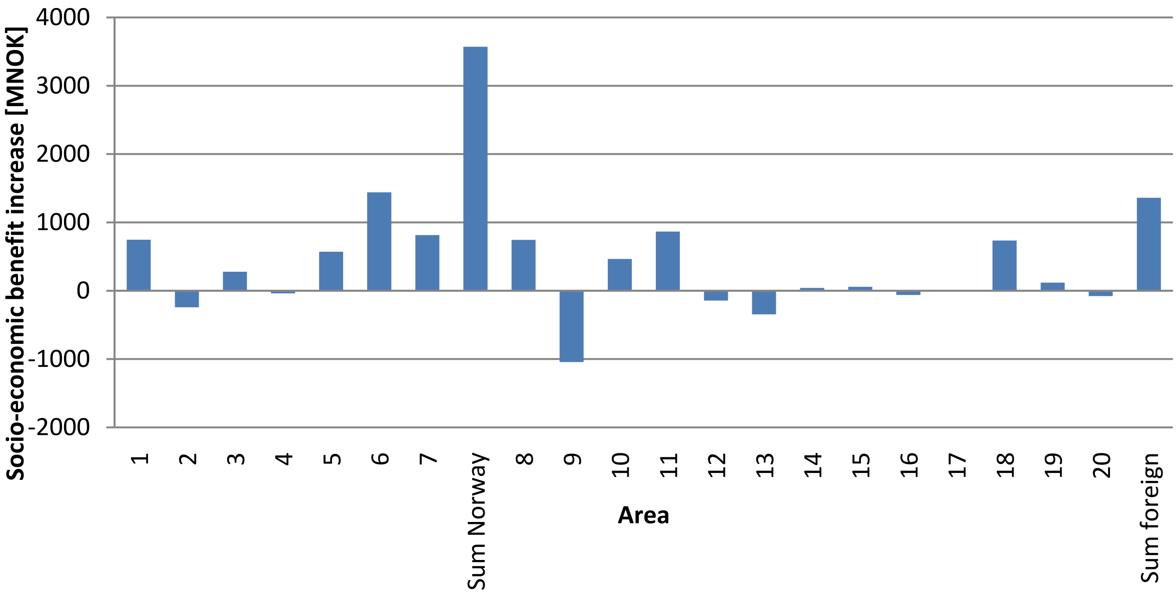

Fig. A 3-1 – Socio – economic benefit of *2025-123-abcdfZ* minus benefit of base scenario