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Economic analysis of large-scale pumped storage plants in Norway

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Abstract

The European power system needs to develop mechanisms to compensate for the reduced predictability and high variability that occur when integrating renewable energy. Construction of pumped storage plant (PSP) is a solution. In this article an economic analysis of large-scale PSP in Norway is made considering sales of energy. The analysis is carried out with a power market model and a 2030 projection of the Northern Europe power system. The effect of varying the PSP capacity and transmission capacity between Norway and Europe is studied. A substantial increase in transmission capacity from Norway to Europe is needed for PSP to be profitable for the owners and the Scandinavian socio-economic surplus. 14100 MW transmission capacities and 950 MW new PSP capacity give the highest socio-economic surplus in this analyse, which increase by 800 M€/year compared with expected 2030 capacity on transmission and PSP.

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Keywords: Pumped storage plant; power system; renewable energy; energy storage; green battery

1. Introduction

There are ambitious plans for the shaping of the future power system, aiming at less emission and better utilization of resources, as well as increased robustness and flexibility. To reduce emissions renewable sources must be integrated in the power system and EU-27 has alone planned to facilitate 500-600 TWh renewable energy within 2020 [1]. Certain challenges occur when renewable energy production is integrated in the power system, since electric power has to be used and produced at the same time. Most renewable energy sources are not as predictable

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as the traditional energy sources. If possible, the power system has to store energy in periods with "excess supply" and produce in periods with "undersupply" [2], but storage of electrical energy is prohibitively expensive for larger quantities. An example of the challenge has been assessed in Portugal where production from renewable energy goes from 70% of the total production to only 3% in 12 hours [3]. With current storage technology, only hydro reservoirs and compressed air energy storage can store enough energy for long periods with large capacities.

The potential to store energy in Norway is high since the country has numerous and large reservoirs with significant head. Today Norway has nearly 50% of the total reservoir capacity in Europe, about 85 TWh [4, 5]. Because of this the European Network of Transmission System Operator for Electricity (ENTSO-E) has asked Norway and Statnett (Norwegian transmission system operator) to verify the potential of building 14 000 MW pumped storage plant (PSP) in Norway. Study by SINTEF has calculated that the technical potential as balancing power in Norway is at least 20 000 MW by 2030 [6]. However, the economic uncertainty is high and today only a few PSP exist in Norway. A project by Sira Kvina was cancelled in 2011 because of high uncertainty in future income [7].

In this analysis emphasis is on economic and operational feasibility of PSP expansion. Technical, environmental and practical challenges are neglected.

This paper gives a description of models that are used in the analysis, and how these work. A brief explanation of the data set and the method of analysis follow. The final part of the article consists of results and conclusion.

Nomenclature

af	Annuity factor from NPV [1]
C	Cost [€]
CS	Consumer surplus [€]
CR^{Europa}	Congestion rent between Norway and Germany, Netherland and UK [€]
$Ep(t)$	Energy price at time t [€/MWh]
$\overline{Ep}$	Average energy price [€/MWh]
M	Million
N_{years}	Number of years
$N_{time\ step}$	Number of time steps
$P(t)$	Generation on PSP for a given time t on the new PSP [MWh]
$P(t)^{Pump}$	Pumping on PSP for a given time t on the new PSP [MWh]
PS	Producer surplus [€]
SD	Standard deviation of DA-prices [€/MWh]
SES	Socio-economic surplus [€]
$SPSP$	Surplus to pumped storage plant owners [€/MW]
TP	Total capacity on the new PSP [MW]
TP_{Pump}	Total pump capacities on the new PSP [MW]
UT_{Pump}	Utilization time of pump [h]

2. Method

The following section describes the principles of the analysis. The EMPS-model and the prototype ReOpt (both shortly explained below) developed by SINTEF Energy Research are used for optimization and simulation, where ReOpt gives the final results. The data set describes the Northern Europe power system and its projections for 2030.

2.1. EMPS-model

The EMPS-model [8] is a well-established model for analyzing hydro-thermic power systems. Input to the EMPS-model is time series of the stochastic variables inflow, wind and temperature and a detailed description of thermal power plants, hydro power plants, firm- and flexible demands, and capacity and loss on transmission corridors between regions. The objective of the model is to maximize the socio-economic surplus using the so-called water value method. The water values essentially represent the shadow costs of the reservoir constraints. The problem is solved in two steps; strategy and simulation. The first step is an optimization to calculate water values for an aggregate regional hydro system resulting in a strategy for how to use the water in the best possible way. The simulation part is solved by split the main problem in weekly decision problems, sub problems, where the different weeks are connected by reservoir level and water values from the strategy. Simulation results are power prices, reservoir level, exchanges between areas, production on each power station and more. Learn more about the EMPS-model in [8, 9].

2.2. ReOpt

The ReOpt model [10] performs a (linear) re-optimization of the weekly decision problem using target reservoirs obtained from the EMPS-model. It is a well suited model to analyze power systems with a large amount of unregulated energy sources. The only difference between the two models is the way they handle the simulation problem. The EMPS-model solves the detailed hydro scheduling problem by use of a heuristic detailed drawdown model. Relevant for the present analysis, with this approach PSP only have the possibility for seasonal pumping. ReOpt formulates the detailed scheduling problem as a linear programming (LP) problem where PSP can operate with full flexibility within the week. Long time, seasonal, pumping is also included in ReOpt through the target reservoirs from the EMPS-model.

2.3. Data set of Northern Europe

The data set describes the Scandinavian countries; Norway, Sweden, Denmark and Finland, in detail and partially describes the Baltic countries; Estonia, Latvia and Lithuania. Germany, Poland, Netherland and UK are described exogenously while Russia and other countries in the east are modeled as thermal power plants and consumers with fixed price-production curves. In total there are 32 regions with 15 regions in Norway, four in Sweden, two in Finland, four in Denmark, and one region in the other countries and the data set includes over 1000 hydro power plants. The transmission grid is represented as in a transport model with connectivity between regions limited by a fixed capacity, and with line losses. The exogenous areas are described by a fixed price, which is a major assumption in the analysis. The price series are calculated in the BID model (Power Market model of Pöyry, a consultancy) [11], where all of Europe is described and these prices are approximated values for 2030. Compared with day-ahead prices today are the prices similar.

Historical weather data from 1962 to 2008 are used, where each week consist of 56 time steps (3 hour in each). Demand in Scandinavia and Baltic is represented with fixed and price dependent demands. The total transmission capacity from Norway to other countries is 11 800 MW with 4 900 MW to Germany, Netherland and UK. This data set is referred to as "Base case".

No parts of the power system are constrained in terms of maximal change of generation and transmission. Hydropower plants have a maximum and minimum discharge and a maximum and minimum level in reservoir.

2.4. Test case

A lot of factors affect the utilization and profitability of PSP. The main factors are transmission capacity, total PSP capacity, hydropower plant capacity, amount of renewable energy, demand, flexibility for production and demand, fuel prices and emission fees. If PSP shall be utilized and profitable the pump and production price must have a price arbitrage, which is at least the same as the efficiency loss in the PSP cycle (minimum 20 %) [12]. In the analysis are variating total capacities on PSP and transmission tested, to check how it impacts the socio-economic surpluses and surplus to the PSP owners. Other factors are kept constant and are based on projections for 2030.

The new PSP capacities which are tested are 0, 950, 6 650, 9 500 and 14 250 MW, and are based on the 15 most relevant PSP projects in Norway with a capacity of 950 MW on each PSP. 14 PSP are located at southwestern part of Norway and the 15th in Central Norway. The pump efficiency is 90% and the production efficiency is depending on what values the original hydro power plants have. Most of the productions efficiencies are between 80 and 92%.

The total transmission capacities for the various cases to Germany, Netherland and UK are shown in Table 1. Since power prices in Germany, Netherland and UK are assumed exogenous, these will not change with increasing transmission capacity, which is a major assumption in this analysis. That is a rough approximation with large capacity and Norway can be a transfer point in this case. All combinations of PSP capacities and transmission capacities are calculated, a total of 25 cases. 0 MW new PSP capacity and 4 900 MW transmission capacity are equal to the "Base case".

Table 1 List of transmission capacities from Norway to Germany, Netherland and UK.

Total transmission capacity	4 900 MW	7 700 MW	10 500 MW	14 100 MW	18 300 MW
Germany	1 400 MW	2 800 MW	2 800 MW	5 000 MW	6 400 MW
Netherland	700 MW	700 MW	2 100 MW	2 100 MW	2 800 MW
UK	2 800 MW	4 200 MW	5 600 MW	7 000 MW	9 100 MW

2.5. Economic evaluation

In this analysis the standard deviation of the simulated power prices in south Norway, consumer-, producer- and socio-economic surpluses in Scandinavia are compared as well as the utilization time of PSP and surpluses to PSP owners. All the results are compared to "Base case" and therefore "Base case" is by definition equal to zero.

When comparing the results, costs must be taken in to account. Costs are included in the comparing of the socio-economic surpluses, producer surpluses and surplus to PSP owners. The relevant PSP projects are calculated to have investment costs between 0.25 and 0.5 M€/MW [13] and total investment costs for the different PSP capacity are 0 M€, 343 M€, 2 413 M€, 3 133 M€ and 5 251 M€ respectively.

Transmission costs from Norway to Germany, Netherland and UK, including ACDC-rectifier, are approximated to be 1.231, 1.275 and 1.694 M€/MW [2] with an approximately distance from Norway to Germany at 520 km, Netherland 550 km and UK 840 km. The total investment costs in transmission are 0 M€, 4 065 M€, 8 220 M€, 13255 M€ and 19 400 M€ respectively. The investment cost for transmission is split equally between both parts which also the congestion rents are. The net present value method is used with discount rate at 4% [7] to account for differences in life time. The life time on PSP is approximately 60 years and transmission lines 40 years [14].

All the results are compared as a function of transmission capacity and represented as continuous functions, but in practice they are interpolated between discreet points. The discreet points are results from equation (1) to (6) for each case. These equations simplified the results from ReOpt, and investment cost.

Equation (1), (2) and (3) are the annual averages changes in consumers-, producers- and socio-economic surpluses in the Scandinavian), respectively. They are all referred to "Base case", but (2) and (3) include some additional parameters. In (2), change in producer surplus, are PSP investment cost included. Equation (3) finds changes in socio-economic surplus and including PSP investment, half the investment cost of transmission and half of the congestion rent between Norway, and Germany, Netherland and UK. The reason why only half the investment cost and half the congestion rent are included is because the focuses are on the Scandinavian socio-economic surpluses.

Utilization times in (4) represent how many hours per year the PSP have to operate at full pumping to pump the whole energy volume in an average year. The last equation, (5), is average yearly surplus for PSP owners represent per MW. It is represent per MW because it is easier to compare the results. Revenue comes from production, and pumping and investment are the costs.

$$\Delta CS = CS_{Case} - CS_{Base\ case} \tag{1}$$

$$\Delta PS = \left(PS_{Case} - \frac{C_{PSP,\ Case}}{af_{PSP,\ Case}} \right) - PS_{Base\ case} \tag{2}$$

$$\Delta SES = \left(SES_{Case} - \frac{CR_{Case}^{Europa}}{2} - \frac{C_{PSP,Case}}{af_{PSP,\,Case}} - \frac{C_{Transmission,\,Case}}{af_{Transmission,\,Case} \cdot 2} \right) - \left(SES_{Base\ case} - \frac{CR_{Base\ case}^{Europa}}{2} \right) \tag{3}$$

$$UT_{Pump} = \frac{1}{TP_{Pump}} \left(\frac{1}{N_{years}} \sum_{1 \le t \le N_{time\ step}} \left(P(t)_{Case}^{Pump} \right) \right) \tag{4}$$

$$\Delta SPSP = \frac{1}{TP} \left(\frac{1}{N_{years}} \sum_{1 \le t \le N_{time\ step}} \left(DA(t)_{Case} \cdot P(t)_{Case} - DA(t)_{Base\ case} \cdot P(t)_{Base\ case} \right) - \frac{C_{PSP,\,Case}}{af_{PSP,\,Case}} \right) \tag{5}$$

3. Result

The main results of the analysis are present in following section and are illustrated graphically in Fig. 1 (a) and (b), Fig. 2 (a) and (b), and in Fig. 3 (a) and (b), where (a) is at the left hand side and (b) at the right hand side in the figures. These figures are respectively based on standard deviation of the prices in southern Norway for the whole time period and equation (1), (2), (3), (4), and (5). The discrete points are result from ReOpt**.**

The different surpluses are directly impact by the power prices and to give an idea in how the power prices in southern Norway change in the different cases the standard deviation of power prices with different capacities on PSP and transmission are shown in Fig. 1 (a). Increased transmission capacity makes the Norwegian power prices more equal to the prices in Germany, Netherland and UK, where the price variation are higher. As shown in Fig. 1 (a), increase PSP capacity gives a decrease in standard deviation.

In Fig. 1 (b) results for the consumers are shown. The consumer will reduce their surplus by increasing the transmission capacity and they will get a growing surplus by increasing the PSP capacity. The figure shows that transmission capacity affects the surpluses more than the PSP. Notice the green line with 950 MW PSP at 4 900 MW transmission capacity in Fig. 1 (b) where the line is lower than the other lines. This due to a flat optimum where there is little impact on the result whether it is the consumers or the producers who receive the profit. This is also shown in Fig. 2 (a) where the green line is higher at 4 900 MW transmission. An interesting point is shown at 18 300 MW transmission capacity where the lines meet in one point. This happens because more transmission capacity influences the consumer surplus little or nothing. The producer will get a benefit opposite to the consumers

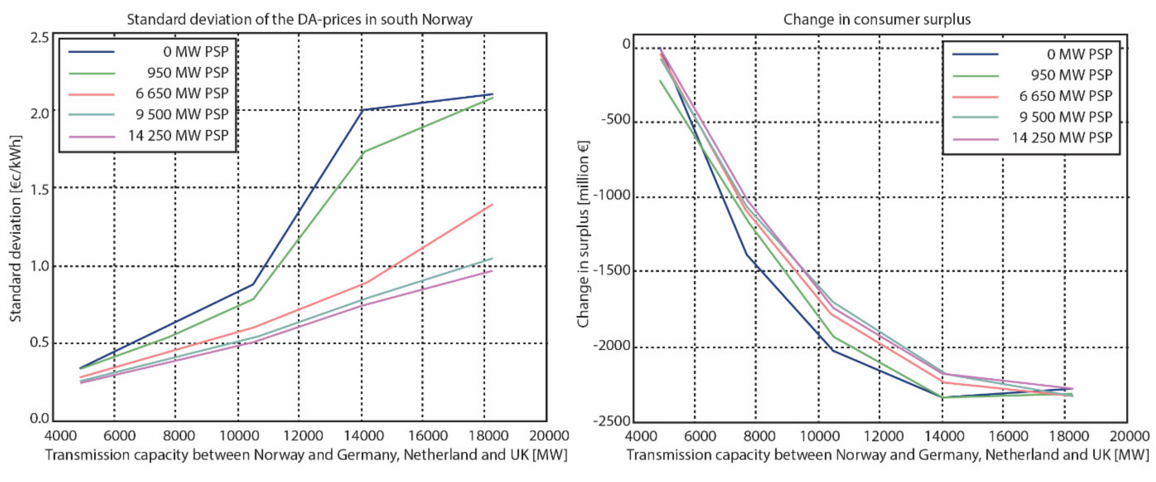

Fig. 1 (a) Standard deviation of the DA-prices in southern Norway; (b) Average yearly change in consumer surplus compared with "Base case".

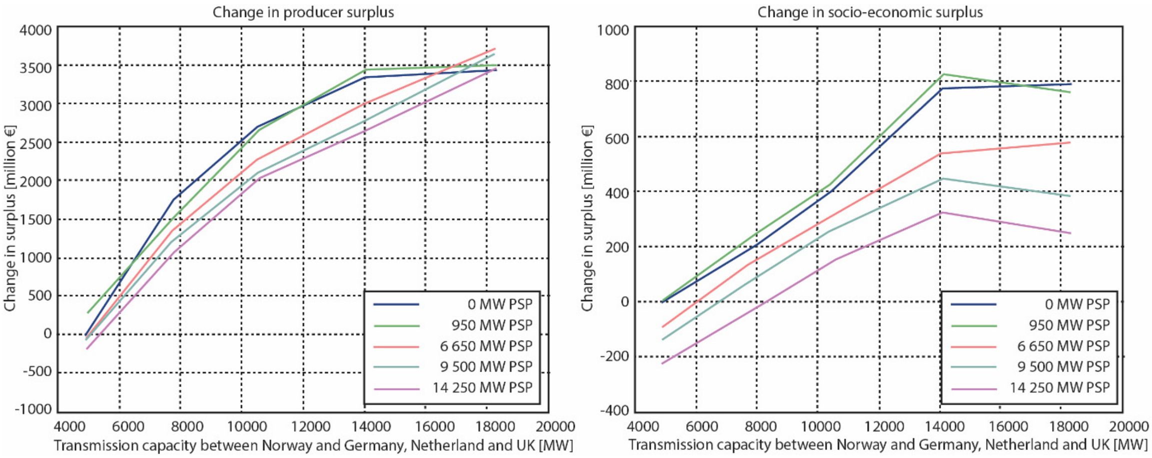

Fig. 2 Change in average yearly surplus compared with "Base case"; (a) producer surplus; including investment cost on the PSP, (b) socio-economic surplus in Nordic countries; including investment cost on PSP, half the cost of the transmission and half of the congestion rent.

as it is shown in Fig. 2 (a) where more transmission increases the surplus.

The socio-economic surplus, in Fig. 2 (b), increases at every case below 14 100 MW and is for 4 out of 5 PSP capacities reduced for higher values. With more flexibility in the power system all theoretical information shows that socio-economic surplus should increase. The reason why the results are apparently inconsistent is the way they are represented. Here is the investment costs of PSP, half the investment cost of the transmission and half of the congestion rent between Norway and Germany, Netherland and UK included. That is also why the changes some places are negative. The socio-economic surplus shows that the best solution for the Scandinavian countries is to use the existing hydropower plants and reservoirs or only invest in one PSP. Like the results in Fig. 2 (b) analyses by Statnett has concluded that Norway must pay the costs for the PSP and other countries will get the benefits.

Surplus to the PSP owners is shown in Fig. 3 (b) and the figure shows that a lot of new transmission capacity is required before it will be interesting to build PSP in Norway. The figure shows that 9 500 MW gives higher surplus for PSP owners than 950 and 6 650 MW PSP at low transmission capacities which is not obvious. The explanation is in the fact that different numbers refer to different investment objects. The hydropower plants have different investment costs, different efficiency of production and are located in different price areas.

At low transmission capacities the utilization of pump is low, which correspond with the low standard deviation

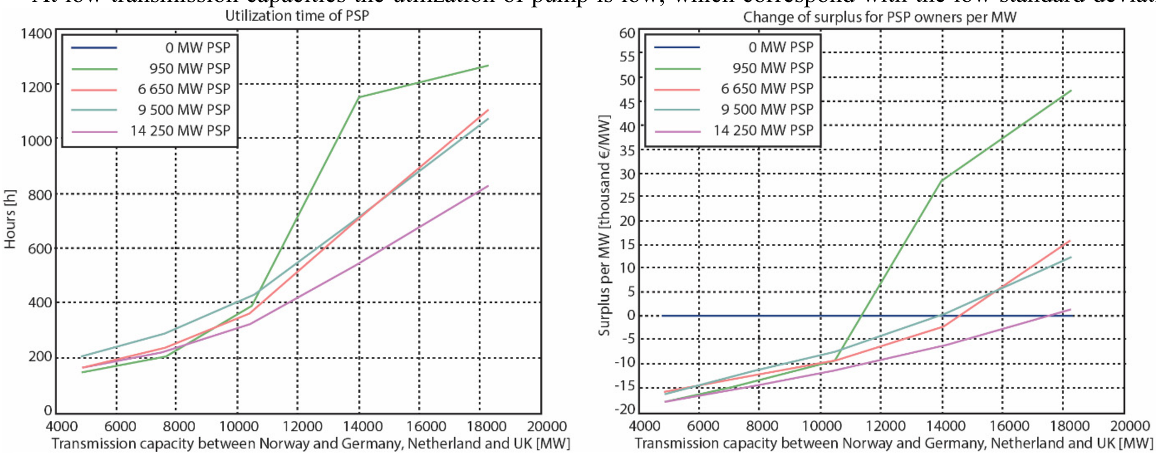

Fig. 3 (a) Utilization time of the pump part on the PSP; (b) Change of average yearly surplus per MW to the PSP owners; including the investment cost of the PSP, compared with "Base case".

in Fig. 1 (a), and most of the incomes are more efficient use of the inflow. With higher transmission capacities the PSP have a high utilization as shown in Fig. 3 (a), but the revenue is nearly zero. The revenue is low because the high PSP capacity arbitrages away its own profitability. With the 18 100 MW transmission the surplus to PSP owners with 6 650 MW, 9 500 MW and 14 250 MW are low although the utilization time is relative high and total transmission capacity are much larger than the PSP capacity e.g. 6 650 MW PSP, 18 100 MW transmission and a utilization time around 1100 hours. There are several of reasons why this happened and the most obvious ones is the existing hydropower system in the Scandinavian having high flexibility and use of fixed prices in Germany, Netherland and UK. The flexibility is high because the total storage capacity in Norway is large, 85 TWh, and the model has no ramping and time delay constrains. Fig. 3 (a) shows a high surplus for the PSP owners with 950 MW and thus the fixed prices are not a limit for surplus. With further investment in transmission capacity the surplus to the PSP owners gradually increase at the same level, but as Fig. 2 (b) shows the socio-economic surplus have reached a break-even point where investment cost of transmission are equal or higher than the increase in revenue.

It should be noted that this conclusion is strongly influenced by the fact that the full cost of the PSP investment is borne by investor, while a significant share of the benefits occurs in continental Europe. It is not realistic to assume that investors make a multi-billion Euro investment with revenues based on expected spot prices. Better business models, where a significant share of the cost is covered by the continental part, could lead to different conclusions. If the PSP owners not have to cover all the costs zero on the y-axis in Fig. 3 (b) will start at a lower level, where the reduction is equal to the cost covered by the other part. Then the PSP will be profitable for the owners at lower transmission capacity and investment in PSP becomes more likely. The average investment cost on PSP is 16.3 thousand €/MW/year and e.g. the other part cover 50 % of the cost zero will start at -8.15 in Fig. 3 (b). The PSP capacity 950 MW, 6 650 MW and 9 500 MW will then be profitable for PSP owners with around 11 000 MW transmission capacity.

4. Conclusion

The potential to construct large-scale PSP in Norway is in principle feasible, but it is not necessary the best solution. With today's power market and power system the best solution for the Scandinavian countries regarding the socio-economic surplus is to use the high flexibility in the existing hydropower plants and reservoirs, and develop little or no new PSP. The reason why large-scale PSP will give a small profit is because the large PSP capacity will depress the high and increase the low power prices, arbitraging away its own profitability. As expected the results also show that consumers will lose and the producers will gain a benefit if large-scale PSP should be constructed in Norway. Even with more than 11000 MW of exchange capacity to the European continent, only about 950 MW of PSP would be profitable and increase the yearly income by 800 M € compared to no investment.

Further work should consider a more detailed power system model, as not all real constraints are represented in the present study. More constraints could result in more sustained price differences and thus increased profitability. Also, the inclusion of Intraday and especially real time balancing markets will most probably increase PSP profitability. Finally and most importantly, research should focus on business models that better distribute costs and risks between PSP investors and continental parties.

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