Norwegian pumped hydro for providing peaking power in a low-carbon European power market – Cost comparison against OCGT and CCGT

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***Abstract*— This paper presents an analysis of the cost of providing peak generation from new OCGT, CCGT and Norwegian pumped hydro plants in a European power system with high penetration of wind and solar power. A method for calculation of the Levelized Cost of Peak Generation (LCPG) is proposed, which builds on the well-established metric Levelized Cost of Electricity (LCOE). Results from a case study shows that building new reversible pumping stations between existing reservoirs in the Norwegian hydro system are economical advantageous over new CCGT and OCGT plants in Northern Europe, taking into account additional costs of subsea cables across the North Sea and corresponding reinforcements of the mainland grid. The study also shows the importance of giving interconnectors access to capacity markets across borders to obtain as low cost as possible for firm capacity in a future European system dominated by variable renewable production.**

***Index Terms*— Capacity market, LCOE, Thermal power, Peak demand, Pumped hydro.**

I. Introduction

European climate and energy goals towards 2030 and 2050 imply massive integration of wind power and solar power, which are variable of nature and often difficult to forecast. To be able to operate the European power system in an efficient and secure manner in the future, it is necessary to exploit several means to provide sufficient flexibility in the system. An opportunity that has received increased attention the last years, is to expand the Norwegian hydropower system with new pumping facilities in order to contribute with significant balancing and peak load power in Continental Europe and UK.

The aim of this work is to study the costs of expanding Norwegian hydropower system to provide flexibility and peak power in a future European power market with high shares of variable renewable resources. A main question is whether new pumped hydro stations are attractive compared with new OCGT (Open Cycle Gas Turbines) and CCGT (Combined Cycle Gas Turbines), which are two other flexible alternatives with sufficient technological matureness.

Chapter II presents the methodology that has been developed for calculating the cost of meeting the peak demand in systems with high shares of renewable energy. The method is a modification of the well-established metric Levelized Cost of Electricity (LCOE) [1]-[4], which is introduced in the start of the section. The case study parameters and input data is given in Chapter III, while Chapter IV shows the results of an analysis where of new pumped hydro is compared with new CCGT and OCGT.

II. Methodology

A. Levelized Cost of Electricity (LCOE)

The Levelized Cost of Electricity Generation (LCOE) can be expressed as:

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} A_t (1+r)^{-t}}{\sum_{t=1}^{n} E_t (1+r)^{-t}} \tag{1}$$

where I_0 is the initial investment cost, A_t is the annual costs in year t, E_t is the annual power generation in year t, r is the discount rate and n is the operating lifetime of the power plant. The LCOE as defined here refers to the levelized cost of providing power from a single power plant, without taking into account transmission and distribution. In its general form in (1), E_t can change from year to year. This is especially important to consider for PV panels and other technologies that can experience a degradation in performance over its lifetime. For the technologies covered in this work, we assume constant expected annual power generation over the lifetime of the plant:

$$LCOE = \frac{I_0 \cdot \delta_{n,r}}{E} + \frac{A}{E} \tag{2}$$

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where the annuity factor $\delta_{n,r}$ is:

$$\frac{1}{\delta_{n,r}} = \sum_{t=1}^{n} (1+r)^{-t} = \frac{n}{1-(1+r)^{-n}} \tag{3}$$

The annual power generation can be expressed by the full load hours T_{fl} (excluding failures), the expected availability α and the installed power capacity. By using specific investment cost i [€/MW] and separating the variable costs into its components $c_{var,j}$ [€/MWh], the LCOE can be expressed as:

$$LCOE = \frac{i \cdot (\delta_{n,r} + OM)}{\alpha \cdot T_{fl}} + \sum_{j=1}^{J} c_{var,j} \tag{4}$$

where the annual Operation & Maintenance costs OM is given in percentage of the specific investment cost.

1) Natural gas power plants: The LCOE for natural gas fired power plants becomes:

$$LCOE_{ng} = \frac{i_{ng} \cdot (\delta_{n_{ng},r} + OM_{ng})}{\alpha_{ng} \cdot T_{ng}} + \frac{\left(p_{ng} + p_{CO_2} \cdot e_{ng}\right)}{\eta_{ng}} \tag{5}$$

where:

p_{ng}: Natural gas price [€/kWh$_{\mathrm{HHV}}$]
p_{co_2}: CO_2 price [€/kg$_{CO_2}$]
e_{ng}: Emission factor of natural gas [kg$_{CO_2}$/kWh$_{\mathrm{HHV}}$]
η_{ng}: Efficiency of natural gas power plant [kWh$_{\mathrm{el}}$/kWh$_{\mathrm{HHV}}$]

The price, emission factor and plant efficiency are all based on the Higher Heating Value (HHV) of the fuel.

2) Pumped hydro: The cost elements of pumped hydro (PH) differs substantially from natural gas. There are no direct fuel costs, but on the other hand there is a pumping cost which depends on the price for electricity and the round-trip efficiency of the PH plant. Investment costs are usually large, but this situation is somewhat different for Norwegian PH plants as identified by previous studies [5]. In these studies, a large (> 10 GW) potential for pumped hydro installations between existing reservoirs have been identified in the southern parts of Norway, close to existing and planned cable interconnectors. The investments costs of PH are therefore dramatically reduced compared to building a complelety new PH plant. Moreover, most of identified reservoirs in Norway have seasonal storage capacity, meaning that the probability of reaching the upper or lower limits due to a new pumping-generation regime is practically zero.

By including all required costs to develop a PH station between two existing reservoirs in i_0, and introducing the round-trip efficiency η_{ph} of the PH plant, the LCOE becomes:

$$LCOE_{ph} = \frac{i_{ph} \cdot (\delta_{n_{ph},r} + OM_{ph})}{\alpha_{ph} \cdot T_{ph}} + \frac{p_{pump}}{\eta_{ph}} \tag{6}$$

where p_{pump} is the average electricity price when the plant operates in pumping mode.

B. *Levelized Cost of Peak Geneation (LCPG)*

We now introduce a metric for the cost of providing electricity when fluctuating renewables and inflexible thermal generation cannot meet the demand, and denote this "Levelized Cost of Peak Generation" (LCPG). Traditionally, peaking power plants supplements base load power plants in hours with high demand. As more fluctuating wind power and solar power are introduced in the system, the need for peaking power changes. It is no longer the load itself that determines the need for peaking power, but the residual load. Residual load is normally defined as the remaining load after subtracting of fluctuating renewable power generation. We propose here to extend the definition of residual load to include all inflexible generation, including inflexible non-renewable generation if these sources are part of the studied system. With this definition, the peak generation must cover the residual load.

At large penetration levels, wind and solar power reduces electricity spot prices down to levels where the profitability of flexible generation is threatened. This is not only an issue for the owners of flexible generation, but also for the system operator, which must maintain security of supply. New capacity markets have therefore been considered or introduced in several European countries to deal with this potential problem. The resulting capacity prices should set so that sufficient amount of flexible generation is available in the system on an annual basis. In the longer run, the question is then how high the capacity prices should be to trigger new investments in flexible generation. The profitability of new flexible generation is consequently dependent on both prices for available capacity and prices for delivered energy. In this paper, we choose to use fixed scenarios for capacity prices, and calculate the resulting needed payment for delivered energy. This is what we has defined as the Levelized Cost of Peak Generation (LCPG). Alternatively, one could do the opposite and calculate the annual capacity payment needed to cover all costs, after subtracting the revenue from power sales.

1) Natural gas power plants: The equation for LCPG is based on the LCOE with an additional term for a possible annual capacity price p_{cap} [€/MWyr]:

$$LCPG_{ng} = \frac{i_{ng} \cdot (\delta_{n_{ng},r} + OM_{ng}) - p_{cap}}{\alpha_{ng} \cdot T_{ng}} + \frac{\left(p_{ng} + p_{CO_2} \cdot e_{ng}\right)}{\eta_{ng}} \tag{7}$$

The resulting LCPG can then be interpreted as the average price needed per produced MWh of peak generation, taken into account possible additional income from capacity markets. A crucial parameter in the equation is the Full Load Hours T_{ng}. This parameter should ideally be derived from detailed power market simulations, where the merit order determines whether the plant is in operation, and at which production level. In the case study in Chapter III we use a simplified method based on fixed scenarios for T_{ng}, but the methodology is not limited to this simplification.

2) Pumped hydro: The strategy for pumping and generation depends on several factors such as the reservoir levels, forecasts of power prices and forecasts of hydro inflow. In cascaded hydro systems, which are common in the Nordic countries, the optimal pumping/generation strategy of one lower/upper reservoir pair also depends on the reservoir levels and generation potential in other parts of the hydrological coupled area [6]. However, instead of performing detailed optimization and simulation studies, we use a simplified method as a first approach to calculate the LCPG of pumped hydro.

As a basis for the cost comparison between natural gas and pumped hydro, we use the Full Load Hours that is derived from the operation of the natural gas power plant. Hence, we assume that investing in a natural gas power plant (CCGT or OCGT) is the default choice for providing sufficient peak generation in the system. The Full Load Hours used in (7) is then the part of the time where peak generation is necessary, i.e. to cover the net load (Which is, by this definition, equal to the total Full Load Hours of the gas power plant). Consequently, this will be the same number of hours that peak generation is provided from the pumped hydro plant. Hence, the cost of peak generation between pumped hydro and thermal power can be compared on equal terms.

In addition to delivering the needed flexiblilty in critical hours as explained above, the pumped hydro power plant can be used for price leverage in the rest of the year, as long as the price difference is sufficenlty high to compensate for the pumping cycle losses[1]. So when comparing the cost of flexibility between pumped hydro and thermal power, we therefore need to subtract the revenuve gained from price leverage and other additional market interactions outside the hours when peak generation is needed to cover the load. Since we have defined the peak hours the hours where flexible generation is *needed*, which equals the Full Load Hours of the gas power plant alternative, the use of the gas power plant outside the peak hours is by definition zero.

To be able to provide substantial flexibility from Norwegian PH plants to European markets, new cable interconnectors in the North Sea are required, along with grid reinforcements at each side of the cable terminals. These costs must therefore be included in the cost estimate of the LCPG. It is also necessary to consider the availability of the cables to get a realistic picture of how much flexibility Norwegian PH can provide over the year.

By applying the assumptions given above, we can now derive an expression for the LCPG of pumped hydro:

$$\begin{aligned} LCPG_{ph} &= LCPG_{ph,plant} + LCPG_{ph,cable} \\ &+ LCPG_{ph,pump} + LCPG_{ph,gen} + LCPG_{ph,cap} \end{aligned} \tag{8}$$

where the subscripts denote he different cost components that contributes to the LCPG:

a) plant: Contribution from building and maintaining the pumped hydro plant:

$$LCPG_{ph,plant} = \frac{i_{ph} \cdot (\delta_{n_{ph},r} + OM_{ph})}{\alpha_{ph} \cdot \alpha_{cable} \cdot T_{ph,peak}} \tag{9}$$

where the denominator is the expected number of hours of the year where peak generation is provided, taking into account the availability of the plant itself and of the cable(s) that connects the Nordic and the Continental/UK markets. In accordance with the argumentation above, the hours where flexibility from pumped hydro is needed, $T_{ph,peak}$ is equal to the full-load hours of the default peaking alternative, i.e. T_{ng}.

b) cable: Contribution from building new sub-sea cable(s) and reinforcing the mainland grid:

$$LCFG_{ph,cable} = \frac{i_{cable} \cdot (\delta_{n_{cable},r} + OM_{cable} + GR \cdot \delta_{n_{grid},r})}{\alpha_{ph} \cdot \alpha_{cable} \cdot T_{ph,peak}} \tag{10}$$

where i_{cable} is the pumped hydro plant's share of the cable investment cost and GR accounts for any additional grid reinforcements needed on the mainland (in percentage of the cable investment). The lifetime of the sub-sea cable and AC-grid lines is n_{cable} and n_{grid}, respectively. Depending on the case study, the cable can be owned/operated by the owner owner of the pumped hydro plant or the TSO. In the latter case, the cable will also be used when not needed by the pumped hydro plant.

3) pump: Contribution from purchase of pumping power:

$$LCFG_{ph,pump} = \frac{p_{pump}}{\eta_{ph}} \tag{11}$$

4) gen: Negative contribution from generating power outside the peak hours:

$$LCFG_{ph,gen} = -(p_{gen} - \frac{p_{pump}}{\eta_{ph}}) \cdot \frac{(T_{ph} - T_{ph,peak})}{T_{ph}} \tag{12}$$

where p_{gen} is the average price obtained from the additional power generation.

5) cap: Negative contribution from capacity payments:

$$LCFG_{ph,cap} = -\frac{p_{cap}}{\alpha_{ph} \cdot \alpha_{cable} \cdot T_{ph,peak}} \tag{13}$$

where p_{cap} is the same price for capacity [€/MWyr] as in (7).

III. Case Study Data

A case study, which is used for comparing the cost of flexibility from pumped hydro with different natural gas technologies, has been developed as part of this work. The data for the natural power plants are based on Department of Energy and Climate Change in the UK (DECC) [3],[4]. To capture a sufficient range of flexibility options, three plant types are part of the study: CCGT, aeroderivative OCGT and F-class OCGT. Their plant parameters are given in Table II.

TABLE I. CCGT and OCGT Input Data

Parameter	CCGT	OCGT-1 (Aeroderivative)	OCGT-2 (F-class)
i_{ng} [€/kW]	718	705	377
n_{ng} [yr]	25	40	25
OM_{ng} [%]	3.9	3.5	3.4
η_{ng} [%]	59	35	35
α_{ng} [%]	92.8	94.7	91.9

The pumped hydro data are based on several studies on how to expand existing hydro systems in South-Western

[1] Pumping water in period t for generation in period t* is profitable if $p(t) < \eta_{ph} \cdot p(t^*)$

Norway with reversible pumps [5],[7]. New dams are therefore not necessary, which results in relatively low investment costs. For the calculation of LCPG of hydro power from Norway, data for subsea cable(s) and mainland grid reinforcements are required, as explained in the previous section. These data are based on [8]. Prices for CO_2 and natural gas are based on the "New Policies" scenario in IEA WEO [9]. The discount rate of all power plant investments is set to 10 % [3].

TABLE II. PUMPED HYDRO AND GRID INPUT DATA

Pumped hydro plant		Subsea cable and grid	
i_{ph} [€/kW]	400	i_{cable} [€/kW]	1153
n_{ph} [yr]	30	n_{cable} [yr]	40
OM_{ph} [%]	0.75	α_{cable} [%]	95.0
η_{ph} [%]	80	GR [%]	30
α_{ph} [%]	95.7	n_{grid} [yr]	70

IV. RESULTS

A. *Levelized cost of electricity (LCOE)*

First, we study the how the LCOE varies with the utilization of the flexible power plant, regardless of whether it is used as peaking, mid-merit or partly base load unit. Fig. 1 shows the resulting LCOE for load factors between 5 % and 40 %, which corresponds to 438 - 3505 Full Load Hours. It is evident that the electricity cost from Norwegian pumped hydro plants is clearly lower than the other flexible alternatives, even for average pumping prices of 50 €/MWh. The main reason for this is that no costly new dams are required, as explained in the earlier chapters.

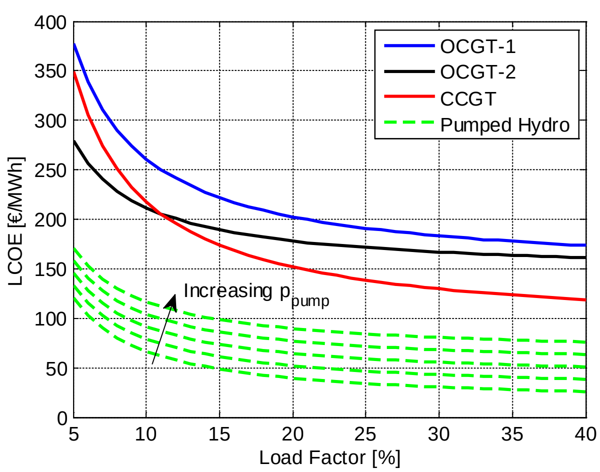

Figure 1. Levelized Cost of Electricity (LCOE) a function of load factor. Pumped hydro is plotted for average pumping prices of 10-50 €/MWh.

CCGT and F-class OCGT intersects at a load factor of 11 % (964 Full Load Hours), while aeroderivative OCGT is the most expensive alternative, even for very low load factors. However, requirements for dynamic response and issues related to wear and tear due to frequent power cycling of CCGT might favor aeroderivative OCGT although the LCOE results indicates the opposite. Detailed market simulations are required to determine the expected plant operation and corresponding effects on start/stop cycles. To give an indication, [10] estimates between 800 - 1800 full load hours (9-20 % load factor) for CCGT and pumped hydro in the area consisting of Germany, France, Benelux and Austria, based on different scenarios for RES integration levels in 2030.

B. *Levelized cost of peak generation (LCPG)*

To calculate the levelized cost of peak generation, we choose two fixed scenarios of 7 % and 20 % respectively for the load factor for peak generation. These values are based on assumptions for OCGT in [3] and [4], and are to be considered as first stage estimates since detailed market simulations eventually should be performed. However, based on existing studies that already exists on RES integration studies (see e.g. [10]), we consider that the 7 - 20 % is within the range of expected load factors for peak generation towards 2030-2050. As discussed in Chapter III, pumped hydro can obtain a higher utilization in the power market than CCGT and OCGT if the price variations in off-peak periods are sufficiently high. As a relatively conservative estimate, we here use 20 % as the total load factor for pumped hydro in total over the year, including peak periods and possible additional off-peak hours.

Fig. 2, shows how the LCPG of pumped hydro increases with increasing pumping price for 20 % load factor for peak generation. In this case, pumped hydro is only used in the peak hours. Thus, the revenue from generating power outside the peak hours is zero. When 10 % is used as discount rate for all assets, the peak power cost for pumped hydro intersects CCGT and OCGT at pumping prices of 20 €/MWh and 42 €/MWh, respectively. An alternative approach using 5 % discount rate for transmission system infrastructure[2], pumped hydro becomes the cheapest alternative even for 50 €/MWh pumping price.

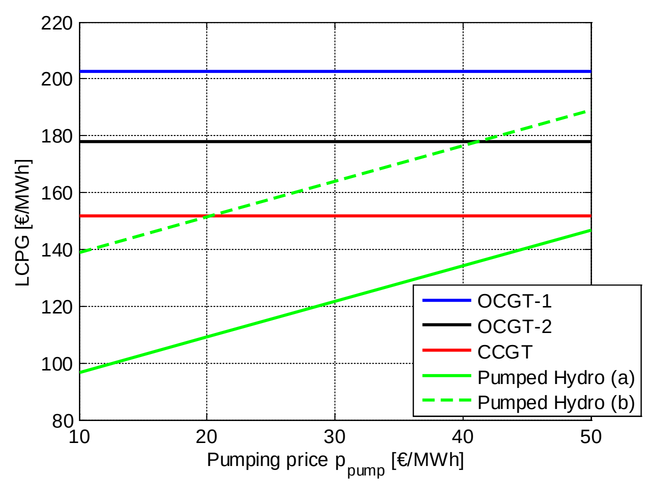

Figure 2. Levelized Cost of Peak Generation (LCPG) for 20 % load factor. (a) 5 % discount rate for cable and grid investments. (b) 10 % discount rate for cable and grid investments.

With 7 % load factor for peak generation, pumped hydro can obtain additional revenues from price leverage in off-peak periods, see (12). As explained above, the total load factor of pumped hydro is assumed to be 20 %. Fig. 3 shows

[2] For comparison, [8] uses 4 % for interconnector projects.

how the LCPG is influenced by this additional off-peak revenue for off-peak generation prices between 54 €/MWh and 86 €/MWh. These prices corresponds to p_{pump} / η_{ph} and $2 \cdot p_{pump}$ with a pumping price of 43 €/MWh. The pumping price is set to half of the calculated variable cost of CCGT, which we consider to be in the upper range of expected future pumping prices, see e.g. simulated spot price duration curves in [10] and [11]. If all required cable and grid investments are allocated to the pumped hydro project(s), an off-peak generation price of 82 €/MWh or higher is needed to be competitive with F-class OCGT. However, it is questionable whether all the needed grid investments should be covered by pumped hydro, since this new infrastructure also can give a benefit for other users of the grid. Fig. 3 therefore also plots the LCPG for cases where a part of the grid infrastructure costs is covered by other users.

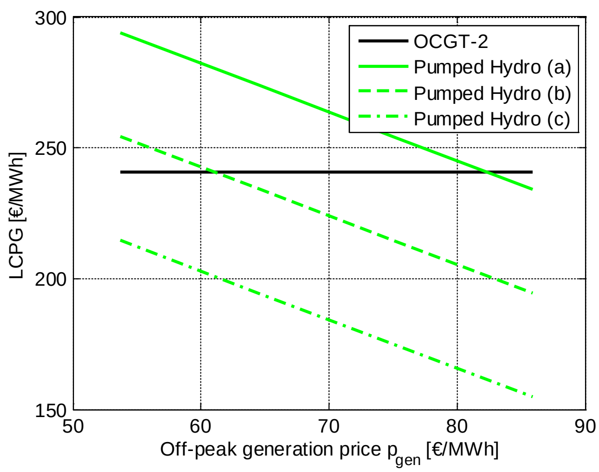

Figure 3. Levelized Cost of Peak Generation (LCPG) for 7 % load factor for peak generation. Pumped hydro is plotted for a fixed pumping price of 43 €/MWh and varying off-peak generation price. (a), (b) and (c) corresponds to 100,75, and 50 % of share of cable and grid costs allocated to pumped hydro.

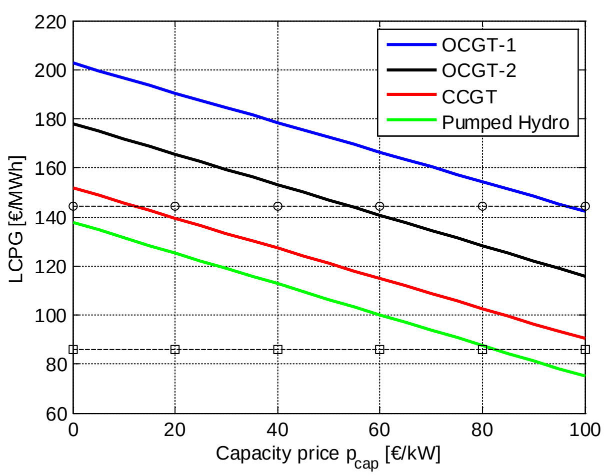

Figure 4. Levelized Cost of Peak Generation (LCPG) for 20 % load factor as a function of capacity price. Pumping price is set to 43 €/MWh. Dashed lines corresponds to variable costs of OCGT (circles) and CCGT (squares).

Finally, Fig. 4 shows how additional annual capacity payments influence the LPCG, for a case with 20 % load factor for all four flexible power plant types. For the scenario analyzed here, the LCPG for F-class OCGT is lower than its variable costs if annual capacity payments reaches 55 €/kW. The figure give an indication of how important it is for Norwegian hydro power to get access to European capacity markets to cover the costs for additional pumping/generation capacity and additional grid infrastructure that is needed to provide peak generation across the North Sea.

V. CONCLUSIONS

This paper has presented an analysis of the cost of providing peak generation from new OCGT, CCGT and Norwegian pumped hydro plants in a European power system with high penetration of wind and solar power. For this purpose, a method for calculation of the Levelized Cost of Peak Generation (LCPG) is proposed, which builds on the well-established metric LCOE. With the LCPG method, the peak periods are defined as the time of the year when non-flexible power plants cannot cover all the demand and the method account for possible capacity payments and additional revenue during off-peak periods.

Results from a case study gives clear indications that building new reversible pumping stations between existing reservoirs in the Norwegian hydro system can be economical advantageous over new CCGT and OCGT plants in Northern Europe, even when including additional costs of subsea cables across the North Sea and corresponding reinforcements of the mainland grid. A crucial factor in this equation is possible capacity payments in the European market. The study shows that it is important that interconnectors gain full access to capacity markets for utilization of the most economical viable sources of flexible power in Europe.

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