Optimal investment timing and capacity choice for pumped hydropower storage

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Abstract

Pumped hydropower storage can smooth output from intermittent renewable electricity generators, facilitating their large-scale use in energy systems. Germany has aggressive plans for wind power expansion, and pumped storage ramps quickly enough to smooth wind power and could profit from arbitrage on the short-term price fluctuations wind power strengthens. We consider five capacity alternatives for a pumped storage facility in Norway that practices arbitrage in the German spot market. Price forecasts given increased wind capacity are used to calculate profit-maximizing production schedules and annual revenue streams. Real options theory is used to value the investment opportunity, since unlike net present value, it accounts for uncertainty and intertemporal choice. Results show that the optimal investment strategy under the base scenario is to invest in the largest available plant approximately eight years into the option lifetime.

Keywords: Pumped hydropower storage, real options, wind power integration, European Energy Exchange, mutually exclusive options

1 Introduction

Wind power capacity in Germany is expected to grow in the coming decades far beyond its current value of 27 GW. The German Advisory Council on the Environment projects that installed wind capacity could reach 113 GW by 2050 (SRU, 2010), and the German Federal Ministry for the Environment estimates that wind capacity could reach 94 GW by 2020 and 147 GW by 2050 (BMU, 2010). Since wind power is nondispatchable, energy storage large enough to absorb excess wind power and release it at hourly and daily timescales can facilitate the integration of wind capacity into electricity grids by shaping power output to better match load and relieving ramping demands on other generators. The storage facilities would profit from providing this service through price arbitrage and participation in ancillary service markets. A certain degree of daily arbitrage revenue, largely due to demand-correlated price fluctuations, is possible in the current market. Increased wind capacity, however, could cause a shift in generator mix that would increase price volatility and therefore arbitrage opportunity (Nicolosi and Fürsch, 2009).

Storage technologies large enough to perform daily balancing of intermittent renewables include batteries, compressed air energy storage (CAES), and pumped hydropower storage. Batteries have the advantage of flexible siting, but at present cost and scale discourage their use for applications requiring storage capacity on the order of GWh. CAES can balance wind power at daily timescales; the 290 MW CAES plant in Huntorf, Germany, built in 1978, is increasingly used for this function (Gyuk, 2003). Demonstrated CAES designs, however, use natural gas to reheat the expanding air during the generation phase. While the heat rate of CAES is approximately 4,300 BTU/kWh, which compares favorably with that of the most efficient combined-cycle gas turbines currently deployed at 5,690 BTU/kWh, CAES still produces significant carbon emissions and is vulnerable to price fluctuations in the natural gas market. Pumped hydropower storage, although feasible in fewer areas of the world than CAES, has the advantage of low carbon emissions and independence of fossil fuel prices. Pumped storage plants ramp quickly and have low startup costs in both pumping and generation mode, and their efficiencies are comparable to those of other storage technologies (Hadjipaschalis et al., 2009). They are thus well suited to balancing wind power fluctuations at hourly through weekly timescales.

Germany has 7 GW of pumped storage production capacity with 0.04 TWh reservoir capacity (SRU, 2010), and an additional 4.5 GW hydropower capacity without pumping utilizing 0.3 TWh of reservoir capacity (Lehner et al., 2005). These resources alone are inadequate to support substantial added wind capacity. In a feasibility study of 100 % renewable electricity in Germany by 2050, SRU found that requiring Germany's electricity system to be entirely independent would require the use of expensive CAES plants in addition to pumped storage to balance wind. The study found that connection with Northern Europe would allow Norway's 27 GW of hydropower production capacity and 84 TWh of storage capacity not only to replace domestic CAES as the most cost-effective method of balancing wind power but would also enable construction of more wind capacity in Germany (SRU, 2010). The need for daily balancing of wind will likely be signaled by increased short-term price volatility in the German market, creating opportunities for Norwegian hydropower storage facilities to profit through arbitrage.

Loisel et al. (2010) analyze CAES and pumped hydropower storage as methods for future wind power integration in Europe and find that the main roles of the storage systems are wholesale price arbitrage and wind power curtailment avoidance. While the value of storage in the near future may not compare favorably with other wind-smoothing technologies such as gas turbines, Loisel et al. (2010) find that evolving regulatory and market conditions could make large-scale storage economically viable in the future. Deane et al. (2010) review existing and planned pumped storage plants in the European Union, the United States, and Japan, and find that between 2009 and 2017 over 7 GW of pumped hydropower storage will be built in Europe. Of this capacity, 2,140 MW will be located in Switzerland at a cost of 0.75 million euro per MW, 1,430 MW in Austria at 0.74 million euro per MW, and 1,000 MW in Germany at 0.70 million euro per MW. The costs for all proposed hydropower storage plants in the review range from 0.47 million to 2.17 million euro per MW.

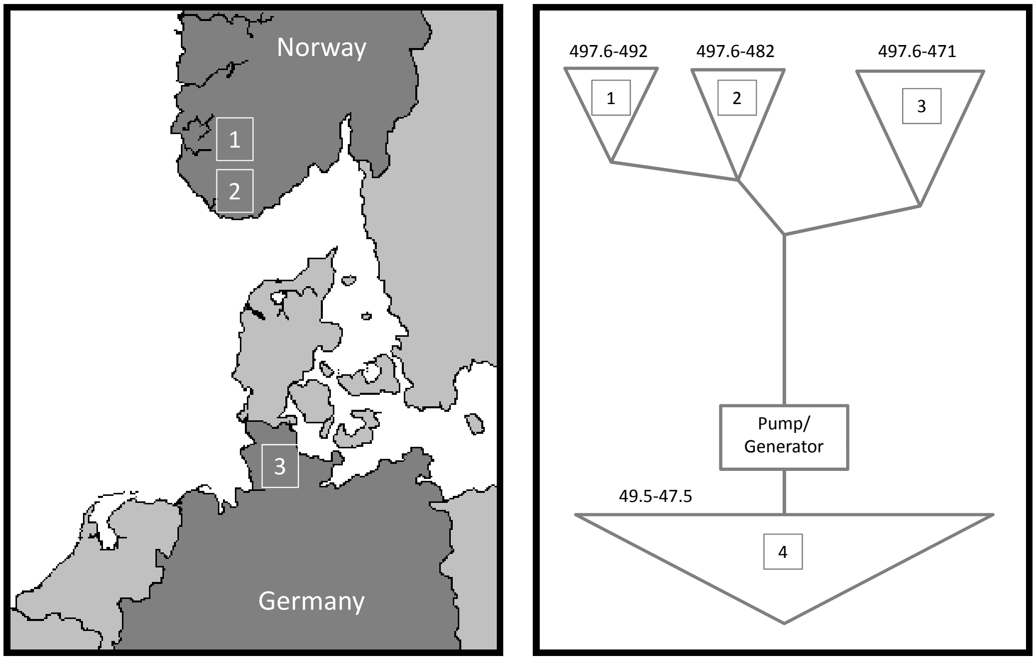
Schill and Kemfert (2011) use a game-theoretic Cournot model to examine the strategic use of energy storage in the German electricity market. Results of the study suggest that oligopolistic ownership of storage would result in underutilization, since the owner would have the incentive to withhold storage capacity to maintain short-term price volatility and thus arbitrage opportunities. This effect, however, disappears under the assumption of dissipated ownership of storage assets. Schill and Kemfert (2011) also find that owners of other generators operating in the German market with enough capacity to have market power are unlikely to invest in storage, since its smoothing effect on prices would reduce the profitability of conventional generation.

Current energy storage facilities in Germany appear not to be a relevant source of market power.

We investigate how a pumped hydropower storage system, modeled after the proposed upgrade to the Tonstad hydropower plant in southern Norway, can operate in the German market to maximize profit given expectations of increasing spot price volatility. By optimizing the production schedule of the pumped storage plant for profit, calculating the annual revenue stream, and applying a real options analysis, we find the optimal investment timing and capacity choice for the pumped storage system.

The investment opportunity considered is a unique, previously secured right to construct a pumped storage facility in Norway which operates solely on the German power market, enabled by an HVDC connection from the facility to the North Sea coast and a subsea HVDC connection to Germany, the cost of which our model incorporates. Diagrams of the geography and operation of the facility are shown in Figure 1. The system operates only in the German European Energy Exchange (EEX), which has more volatile electricity prices than NordPool, the Scandinavian power market. Norwegian power producers are considering connecting a pumped hydropower storage facility with EEX because connection with the Nordic system would require significant investments in the domestic grid in southern Norway. Construction plans for transmission would take a long time to be finalized, and in the meantime the pumped hydropower storage facility could reap the benefits of interconnection with the German system only.

Profitability of the investment opportunity rests largely on the effect of increased wind capacity on spot price volatility, which is subject to conflicting effects that operate over different timescales. Weigt (2009) finds that given a static generation portfolio, wind power suppresses average short-term price volatility. Accounting for changes in generator mix due to the increasing share of wind generation over time, Nicolosi and Fürsch (2009) find that increased renewable energy penetration will result in more volatile residual demand (demand minus renewable power output) such that the market share of thermal base load generators shrinks and that of peak load generators grows. Since wind power has negligible marginal cost and peak load power plants tend to have high marginal cost, the shift in generation portfolio will increase volatility in spot prices (Nicolosi and Fürsch, 2009). Connolly et al. (2011) examine profitability of a pumped storage system performing daily arbitrage and find that accurate long-term price projections are not necessary to maximize profit, but that profit varies widely from year to year such that realized NPV is highly uncertain.



(a) Geographical layout of investment opportunity. (b) Pumped hydropower storage facility.

Figure 1: (a): Diagram of the investment opportunity. A pumped hydropower storage plant, modeled after the planned upgrade to the Tonstad power plant, is located at (1). The facility is connected through an HVDC transmission line to the coast (2), where the subsea HVDC cable starts that traverses the North Sea to Germany (3). (b): The pumped storage facility has upper reservoirs (1), (2) and (3) and lower reservoir (4). The numbers above the reservoirs indicate the meters above sea level between which the water levels can vary. In generation mode water is released from the upper reservoirs through the tunnel, and in pumping mode the flow direction is reversed.

NPV analysis alone is often used to evaluate investment opportunities in energy projects. Real options theory, however, offers the advantage over NPV of comparing the current project value with the expected value of postponing investment, enabling calculation of optimal investment strategy with respect to either time or expected profit. Although delaying investment sacrifices immediate revenue, factors that encourage waiting include an expected rise in future profitability, uncertainty that will resolve in the future, and discounting of capital costs.

Décamps et al. (2006) value the option to invest irreversibly in one of two mutually exclusive projects, and find intervals of output price for which investment versus waiting is optimal. In particular, a waiting region exists at prices above which it is optimal to invest in one project and below which it is optimal to invest in the other, for the purpose of gathering more information before making the investment decision. This solution improves upon that of Dixit (1993), who argues for a single threshold value below which to postpone investment and above which to invest in the most valuable project. The simulation-based method of Longstaff and Schwartz (2001), implemented in the current study, also evaluates an option on a choice among multiple projects and produces a value function in the manner of Décamps et al. (2006).

The only other study of which we are aware that uses real options to value pumped hydropower storage is Muche (2009), in which the option value of a pumped hydropower storage plant is calculated as the arbitrage revenue averaged over a set of simulated price paths given optimal unit commitment for each path. This option value is compared with arbitrage revenue calculated from a single expected price path, which contains no price spikes and shows less short-term price volatility than individual simulated paths. The real option is framed as an option to operate the pumped hydropower storage plant flexibly in response to actual prices, which renders the plant valuable; it is contrasted with an unrealistic scenario of prices that vary deterministically with time and do not spike, resulting in a negative NPV for the pumped storage plant. While our analysis also rests on modeling profit of a pumped hydropower storage plant given simulated price paths, our option valuation technique optimizes investment timing and capacity choice.

The remainder of this paper is organized as follows: Section 2 presents the valuation framework, which consists of a price model and a pumped storage dispatch model used for calculation of NPVs, which in turn serve as an input to a real option valuation. Section 3 presents a numerical example with data from the Tonstad power plant in southern Norway, Section 4 presents results, and Section 5 concludes and provides recommendations for future work.

2 Valuation Framework

The valuation framework consists of three parts: a price model, a model for pumped hydropower storage scheduling, and a real options valuation. The price model uses bootstrapping methods to simulate future spot prices that serve as input to the pumped storage scheduling optimization. The optimal production schedule of the pumped storage facility is found by maximizing revenue over successive one-week time intervals. Annual revenue calculated from the production schedules serve as input to the real options valuation, which in turn yields the optimal investment timing and project size. Figure 2 gives an overview of the valuation framework, and a detailed explanation of each component follows.

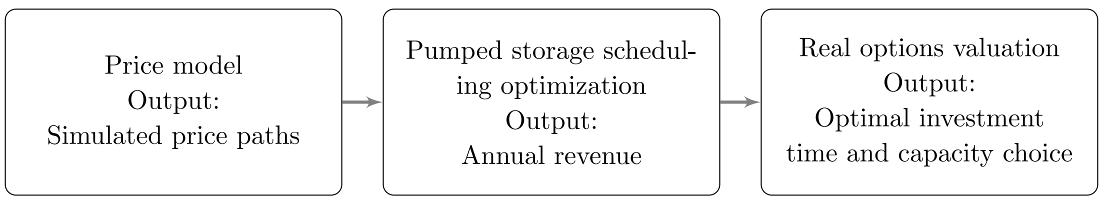


Figure 2: Structure of the analysis.

2.1 Price Model

Since short-term price volatility rather than mean price drives the arbitrage revenue of a pumped hydropower storage system, the aim of the price model is to capture the change in price volatility over time.[1] An assumed three-year construction lag, ten-year option lifetime, and 40-year project lifetime require each simulated price path in the option valuation to span 53 years. The price path simulation begins by randomly sampling 53 years of data, in yearly increments with replacement, from 2003-2010 German EEX historical prices. The pumped storage plant is assumed to be a price taker in the German system. The price in hour i of year y ($2011 \leq y \leq 2063$) of each sample path is then adjusted to reflect the increased price volatility (defined as price standard deviation) due to greater market share of wind power. The adjusted price $\hat{p}_{y,i}$ for hour i in year y is calculated as

$$\hat{p}_{y,i} = \mu_{y,j} + (p_{y,i} - \mu_{y,j}) \cdot \beta_{y,j}, \tag{1}$$

where $\mu_{y,j}$ is the mean historical price for month j in sampled year y, $p_{y,i}$ is the historical price for hour i of sampled year y, and $\beta_{y,j}$ scales the standard deviation of prices in month j of year y.[2]

[1] Additional revenue streams would be available to the facility through participation in ancillary service markets. Here we consider only arbitrage revenue in the spot market.

[2] The mean prices $\mu_{y,j}$ are calculated monthly, since increasing price volatility around a daily mean would ignore that periods of high and low wind can last longer than a day, and adjusting prices around a yearly mean could mask finer-scale fluctuations and artificially suppress or elevate prices that are low or high for longer periods of time due to seasonal or macroeconomic effects.

$\beta_{y,j}$ is calculated as

$$\beta_{y,j} = \frac{1 + (y - 2010) \cdot (b_j + \sigma_j \cdot \epsilon)}{(1 + k)^{y-2010}}, \tag{2}$$

where b_j is the mean annual percentage-point increase in price volatility in month j since 2010, σ_j represents uncertainty around that value, ϵ is a standard normal random variable, and k is the annual inflation rate taken as 2 %, the annual inflation target for the European Union (European Central Bank, 2011).

Baseline values for b_j and σ_j were calculated from 2010 yearly Phelix futures prices for peak and base load power for 2011 through 2016 (Phelix, 2011).[3] Peak load contracts are for delivery from 08:00 to 20:00, Monday through Friday, and base load contracts are for delivery of constant power. These data were used to calculate off-peak prices, since the increase in the difference between peak and off-peak prices (henceforth termed the intraday price difference) is proportional to the increase in price standard deviation. The nominal mean intraday price difference increased by 8 percentage points annually above the 2011 value (Figure 3), and this increase was adjusted downward for inflation by 2 % per year to convert to real prices (Equation (2)). We calculate σ in Equation (2) as the annual growth in the standard deviation of the intraday price difference in the futures market, equal to 2.8 percentage points per year.

The monthly parameters b_j and σ_j were then calibrated according to the average wind capacity factor in Germany, which is near 30 % in the winter but only 15 % in the summer. Given a static generation portfolio, wind power in Germany has historically suppressed price volatility the least in the summer, when capacity factor is lowest (Weigt, 2009). We therefore scale b_j and σ_j to be inversely proportional to wind power capacity factor in month j but have a mean over all twelve months equal to the yearly values calculated from the futures prices.

The Phelix yearly futures markets have low trading volume and almost none more than three years in advance. When no volume is traded, the price is approximated as the mean of estimates elicited from market participants so does not reflect market conditions as well as prices from actual trades. Low trading volumes for contracts with delivery years in the future contributes to the substantial uncertainty in the change in intraday price differences. Further, yearly futures prices for trades in late 2011 show a weaker increase in intraday price differences than the 2010 prices on which we base our primary results. We address these factors

[3]Phelix refers to the physical electricity index in the EEX power spot market for Germany and Austria.

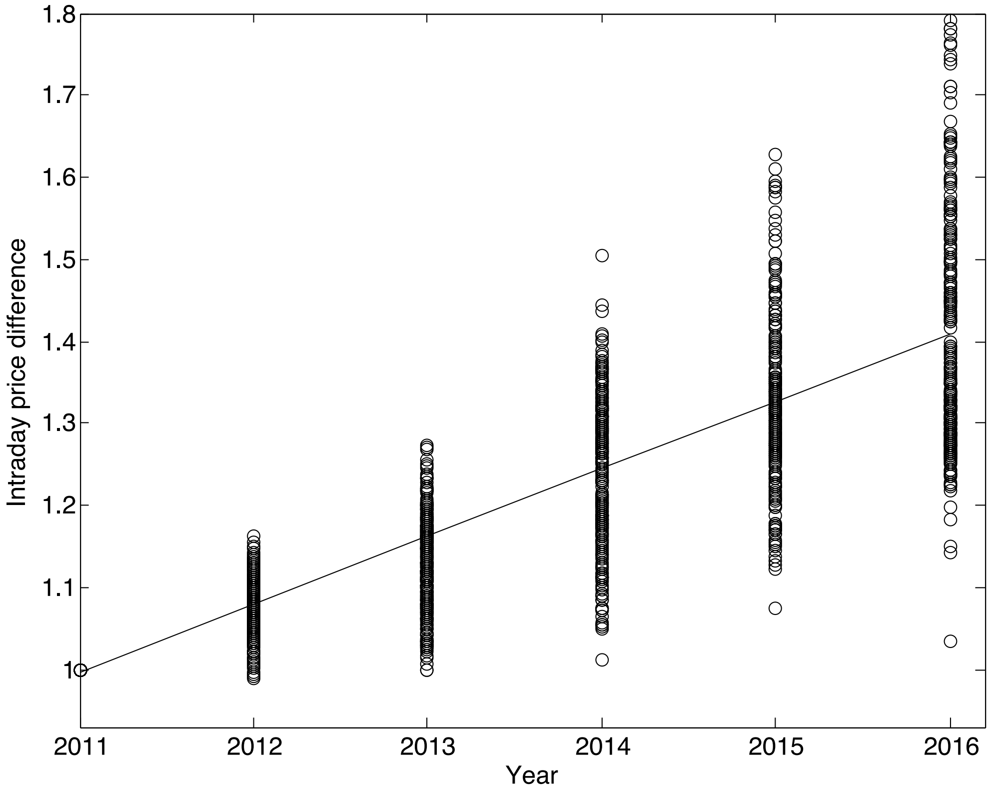


Figure 3: Futures prices for 2010 trades show increasing intraday price difference (proportional to the increase in standard deviation), which creates increasing arbitrage opportunities for pumped storage systems. Each data point represents the intraday price difference in the yearly futures market for contracts traded on a single day divided by that difference for 2011 futures that day. The uncertainty in this value grows for delivery dates from 2011 through 2016.

through a sensitivity analysis in Section 4. Figure 4 shows simulated trajectories of the expected real change in intraday price difference for a range of nominal yearly growth rates for intraday prices (with $b = 0.08$ as the base scenario), which form the basis of the sensitivity analysis.

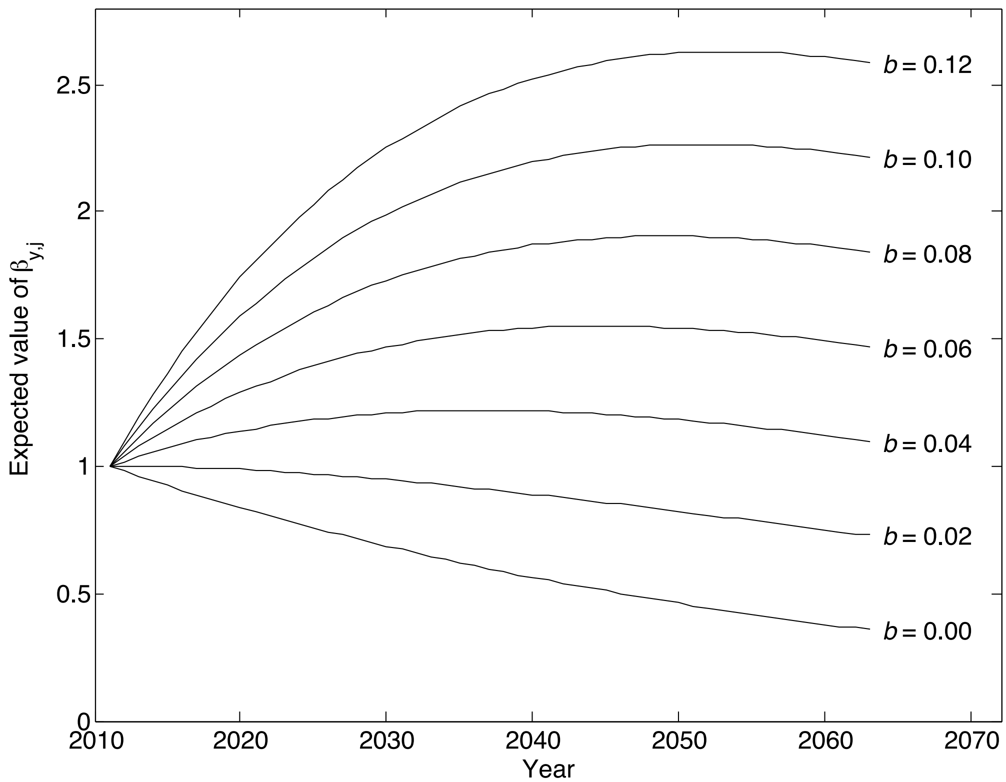


Figure 4: Simulated trajectories of expected future short-term price volatility by year with $b = 0.08$ (calculated from the futures market data) as the base scenario. β scales the real growth in short-term price volatility from 2011 values and b is the nominal annual percentage-point growth in price volatility.

2.2 Pumped Storage Scheduling Model

The pumped storage scheduling model generates the optimal production schedule and expected revenue given hourly spot prices. Operation of the pumped storage system is optimized over a planning horizon of $n = 168$ hours (one week). For hours $i \leq m = 24$, the spot price p_i is known, and for the remaining hours $m < i \leq n$ the spot price is approximated as the mean price for the corresponding hour one week earlier and two weeks earlier and is denoted by $\bar{p}_i$. Optimizing production over a week instead of a day gives the system the flexibility to store energy on weekends, for example, when prices are lower and produce energy at times of week when prices are higher. Operating the system for a single day before re-optimizing allows new price information to be incorporated on a daily basis without assuming future knowledge of prices beyond a day. Since generators make price-dependent bids, scheduling based on a day of known prices is approximately equivalent to scheduling based on knowledge of the price distribution, which is a weaker assumption than perfect price knowledge and produces nearly the same results.

The following linear program maximizes profit for one week:

$$\max\left(\sum_{i=1}^{m} p_i \cdot \left[E_i \cdot (1-h) - S_i \cdot \frac{1}{1-h}\right] + \sum_{i=m+1}^{n} \bar{p}_i \cdot \left[E_i \cdot (1-h) - S_i \cdot \frac{1}{1-h}\right]\right) \tag{3a}$$

subject to

$$0 \leq R_0 + \sum_{i=1}^{k}\Big(S_i \cdot \eta_S - \frac{E_i}{\eta_E}\Big) \leq R_{\max} \text{ for all } k \leq n \tag{3b}$$

$$\sum_{i=1}^{n}\Big(\frac{E_i}{\eta_E} - S_i \cdot \eta_S\Big) = R_0 - f \cdot R_{\max} \tag{3c}$$

$$R_0 + \sum_{i=1}^{n}(S_i \cdot \eta_S - \frac{E_i}{\eta_E}) = f \cdot R_{\max} \tag{3d}$$

$$0 \leq S_i \leq S_{\max} \tag{3e}$$

$$0 \leq E_i \leq E_{\max} \tag{3f}$$

Parameters and variables in the pumped storage scheduling model are summarized in Table 1. $E_i \leq E_{\max}$ is the energy produced by the plant at efficiency η_E in hour i, $S_i \leq S_{\max}$ is the energy stored at pump efficiency η_S in hour i, $R_{\max}$ is the capacity of the reservoir in MWh, R_0 is the reservoir level at the beginning of the week in MWh, h is the transmission loss, and f is the target fractional reservoir level at the end of the optimization period. Constraint (3b) ensures that the reservoir level neither exceeds the maximum nor drops below zero and (3c) ensures that the calculated reservoir level at the end of the optimization period is equal to $f \cdot R_{\max}$, in order to avoid an unrealistic plan of completely emptying the reservoir at the end of each period (for sufficiently long planning horizons, this constraint would not be necessary).

Profit earned during a period of $m = 24$ hours is calculated as

$$\sum_{i=1}^{m} p_i \cdot \left[E_i^* \cdot (1-h) - S_i^* \cdot \frac{1}{1-h}\right] \tag{4}$$

in which E_i^* and S_i^* are the optimal amounts of energy produced and stored. We assume maintenance is conducted during times when the opportunity cost of operation is negligible, and we multiply revenue by a factor of $1 - a = 0.95$ to account for unplanned outages.

Table 1: Parameters and variables in pumped hydropower storage scheduling. Subscript i denotes quantities that may change hourly.

Symbol	Explanation	Value	Unit
p_i	Simulated spot price	-	euro/MWh
$\bar{p}_i$	Forecasted (rolling-average) price	-	euro/MWh
m	Length of operation period (known prices)	24	h
n	Length of optimization period	168	h
E_i	Energy produced	-	MWh
E_i^*	Optimal energy produced	-	MWh
$E_{\max}$	Maximum generator capacity	480-2,400	MW
η_E	Generator efficiency	0.9	-
S_i	Energy stored	-	MWh
S_i^*	Optimal energy stored	-	MWh
$S_{\max}$	Maximum pump capacity	480-2,400	MW
η_S	Pump efficiency	0.80	-
f	Target fractional reservoir level at end of week	0.5	-
$R_{\max}$	Maximum reservoir capacity	75,000	MWh
h	Transmission loss factor	0.05	-
a	Total unplanned outages of plant and cable	0.05	-

Startup costs, reduced generator efficiency at full power, and head effects are ignored. Implementing approximations of these effects significantly increased computation time but reduced profit by less than 1 %. The location of the pumped storage plant within a large reservoir system would relax reservoir capacity constraints due to greater flexibility in the system as a whole; however, the plant may be subject to occasional restrictions such as forced operation to avoid spillage. These effects are discussed further in Section 4.

2.3 Real Option Valuation

Classical methods of project planning dictate that investment should be made if expected NPV is positive. This investment strategy ignores the value of postponing investment in a positive-NPV project in anticipation of resolution of uncertainty or expected future change in conditions determining the project value. For projects in which these factors are substantial, real options captures the value of flexible decision making and intertemporal choice. The method is based on comparing the current NPV with the expected value of postponing investment (the continuation value), and investing only if the former exceeds the latter. A holding cost, which we do not incorporate, would decrease the value of postponing investment and accelerate investment timing.

Since the pumped storage investment opportunity is characterized by sunk costs, irreversibility, and a time interval during which investment is possible, we model it as a Bermudan call option.[4] We calculate the value of the investment opportunity expiring T years in the future as

$$ROV = \max_{t \leq T} \left(\mathbb{E}[e^{-r \cdot t} \cdot (PV_t - F)], 0 \right) \tag{5}$$

where ROV is the value of the investment opportunity with expiration time T, PV_t is the present value of revenue when the option is exercised at time $t \leq T$, F is the investment cost, r is the discount rate, and $\mathbb{E}$ is the initial expected value operator. If the NPV at the optimal investment time is positive, then the option value equals the NPV and the investment should be made; if the NPV is negative, the option is worthless.

The method used to value the real option to invest in the pumped storage system is Least Squares Monte Carlo (LSM), proposed by Longstaff and Schwartz (2001). Unlike the methods of Dixit and Pindyck (1994) and Décamps et al. (2006), based on partial differential equations, or the lattice method of Cox et al. (1979), LSM is free from the assumption that revenue streams follow a prescribed stochastic process. Since LSM is simulation-based, it can accommodate exotic option characteristics such as multiple project choices, dynamic uncertainties, and disjoint exercise intervals.

Starting with the option value at the expiration time T (equal to the NPV since postponing investment is worthless), the LSM procedure iterates backward over the option lifetime to find the expected value of investing and that of continuing to hold the option at each time step. The expected value of continuation at time t is found by regressing the maximum values of investing at a later time on basis functions of the simulated present values at time t. If the NPV exceeds the expected continuation value for a given simulation, t becomes the optimal investment time for that simulation, and the backward iteration continues.

Longstaff and Schwartz (2001) argue that the choice of basis function in the regression has little

[4] A Bermudan call option allows the owner to purchase an asset for a given exercise price at given points in time during the option lifetime. Here, the asset value is the present value of revenue to the pumped hydropower storage system, the exercise price is the investment cost, and the option can be exercised yearly. The option valuation method used in this study requires discrete exercise times, although an investment decision could be made more frequently than once per year, this frequency is adequate to yield insight into our problem.

effect on results. Clément et al. (2002) show that LSM converges almost surely under general conditions, and Gamba (2002) extends LSM to value mutually exclusive investment alternatives and shows that the convergence results of Clément et al. (2002) apply. We use basis functions given by

$$\mathbb{E}[Y|X] = \sum_{i=0}^{k} \alpha_i \cdot X^i \tag{6}$$

in which X is the current present value for a single project (which, in our numerical example, is correlated with the other project values with $\rho > 0.99$), Y is the discounted continuation value, and the α_i are estimated regression parameters. We find that basis functions of higher order than $k = 3$ do not improve results.

The option value at the initial time is calculated as the mean over all simulations of the discounted payoff of investing at the expected optimal time. In summary, the aim of the valuation framework is to conduct a real options analysis for the investment opportunity at hand. Annual revenue from operating the pumped hydropower storage facility serve as input to the real options analysis and is found by first simulating future spot prices (as outlined in Section 2.1) and then calculating profit-maximizing production schedules (as outlined in Section 2.2).

3 Numerical Example

The investment opportunity considered is a unique, previously secured right to construct a pumped storage facility, modeled after the Tonstad power plant in southern Norway, which operates solely on the German power market through an HVDC connection. Upriver of Tonstad, there are three reservoirs which are small compared to others in the system and serve mainly as short-term storage for the existing power plant. These form the upper reservoir capacity in this analysis (see Figure 1). We assume the pumped storage plant has no inflow and operates in isolation from the rest of the reservoir system. Since the reservoirs already exist and do not require adaptation, their cost is set to zero.

The cost of securing the investment option is negligible since there is no permitting fee, the current Tonstad plant owner Sira Kvina already possesses the majority of the necessary land rights, and the cost of assembling an application is approximately 130,000 euro. Although the success of obtaining a permit is uncertain, incorporating this uncertainty would require a two-stage option valuation framework that is outside the scope of this analysis.

The investor can choose among pumped storage plants of capacities between 480 and 2,400 MW, in 480 MW increments (the proposed upgrade to Tonstad is 960 MW, consisting of 2×480 MW pump/generator units). The projects are mutually exclusive with no option to upgrade a smaller project to a larger project. Although the pumped storage system is considered an upgrade to the existing Tonstad plant, it would involve the construction of a new water tunnel and the installation of new machinery such that its cost is commensurate with building an entirely new plant. The investment opportunity includes construction of a HVDC transmission line from the power plant to the coast and a subsea HVDC cable between Norway and Germany. We assume that the investor can purchase HVDC transmission of equal capacity to the pumped storage plant and that the cost is proportional to that of the proposed 1,400 MW NorGer cable between Norway and Germany (NorGer, 2009). Since licenses issued by the Norwegian Water Resources and Energy Directorate last five years with the possibility of a five-year extension (NVE, 2010), we assume the investment opportunity lasts ten years beginning in 2011. We later examine the effect of extending the investment window to 20 years. Revenue begins three years after construction costs are incurred, and the lifetime of the power plant and the HVDC cable is set to 40 years.

Table 1 presents parameters and variables for the pumped storage plant used in the numerical example. Capital cost amounts to 0.66 million euro per MW of installed capacity for the pumped storage plant and transmission to the Norwegian coast, and with the subsea HVDC cable the cost becomes 1.71 million euro per MW. We neglect economies of scale with respect to capacity, which could shift decisions toward larger projects. Capital costs include expenses related to financing during the construction period. We assume a before tax, real discount rate of 6 %, in accordance with the Norwegian government's discount rate for high-risk projects (NDR, 2011). Since discount rate is uncertain a sensitivity analysis is presented in Section 4.

The cost excluding the subsea cable is less than the estimates for the planned pumped storage plants in Switzerland (0.75 million euro per MW), Austria (0.74 million euro per MW), and Germany (0.70 million euro per MW). The amount of pumped storage capacity available in each of these countries, however, is less than the 2,400 MW modeled as the largest option for the Tonstad upgrade.

4 Results

Under the base scenario of a nominal growth rate in short-term price volatility of 8 percentage points annually, a profit-maximizing investor following a strategy based solely on NPV would invest immediately in the largest available project since initial expected NPV is 880 million euro. Valuing the flexibility to postpone the investment decision up to ten years in order to resolve uncertainty and reap possible future gains shows that the investment opportunity is worth 1.1 billion euro, 25 % more than if investment were restricted to a now-or-never decision in the first year. At the beginning of the option lifetime, the expected optimal strategy is to wait approximately eight years and then invest in the largest available project, with revenue streams beginning three years later.

The NPV of the maximum-value project and the continuation value at each year of the ten-year option lifetime for the base scenario are shown in Figure 5. As the option nears expiration, the ability to delay investment adds less value to the opportunity, and the continuation value becomes equivalent to NPV at the optimal investment time (approximately the eighth year).[5] The threshold NPV curve shows the NPV above which investment would be optimal at each timestep. Since only expected NPV can be observed, this curve cannot directly form the basis for an investment decision rule and the optimal strategy must be updated as more information becomes available. The trend of the threshold NPV curve illustrates that investment in earlier years would be optimal only if current NPV is significantly higher than the expected NPV, but as the option nears expiration, the value of holding the option decreases and investment is optimal at lower NPVs. After the optimal investment time, the required NPV for investment is lower than the average NPV in the given year. The threshold NPV and continuation value both drop to zero in the last year of the option lifetime, since in that year the investment opportunity is now-or-never and investment is optimal if the NPV of the maximum-value project is positive.

[5] Continuation values appear to increase with time because they are discounted to the time of investment; if values were discounted to a uniform time they would of course decrease, reflecting the reduced flexibility as the option nears expiration.

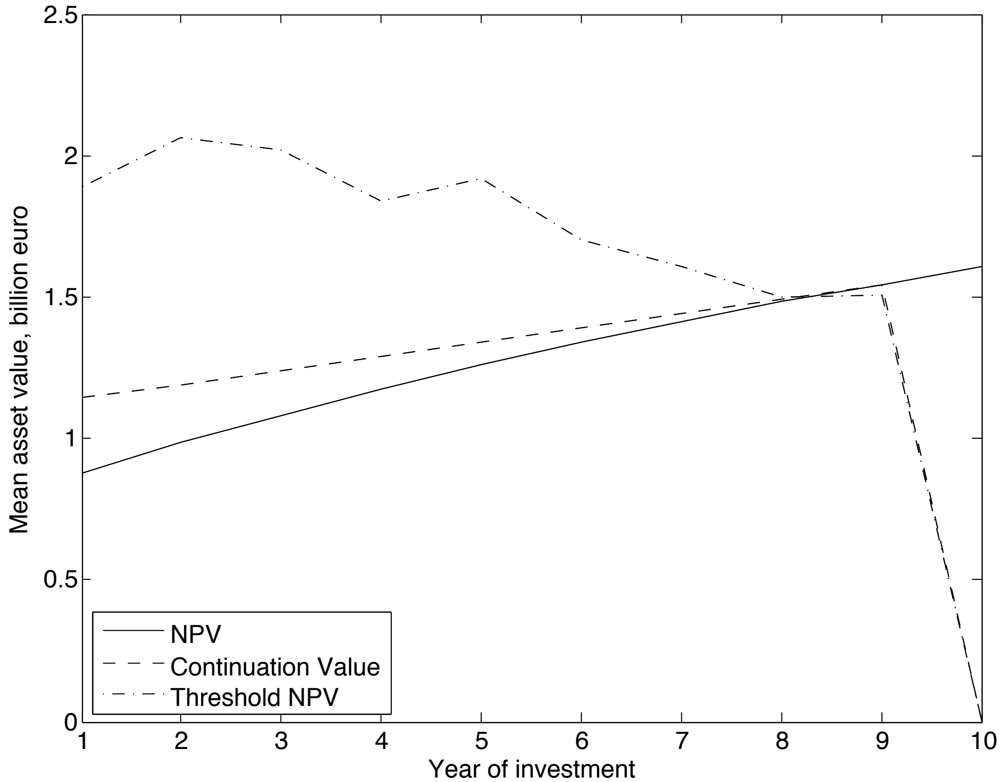


Figure 5: NPV, continuation value (the expected value of postponing investment), and threshold NPV for the base scenario over the course of the ten-year option lifetime. The threshold NPV refers to the NPV above which investment would be more profitable than postponing at each timestep if current NPV could be observed. In the eighth year, the expected optimal investment time, this value is equal to the mean NPV. The downward trend of the curve shows that as the option nears expiration, the value of waiting decreases and investment is optimal at lower NPVs.

Figure 6 shows the NPV of each project and the continuation value (the expected value of postponing investment) for the base scenario at the expected optimal investment time (the eighth year). If the present value of the 2,400 MW project is greater than 5.7 billion euro (the value at which maximum NPV and continuation value intersect), investment would be more profitable than continuing to hold the option.

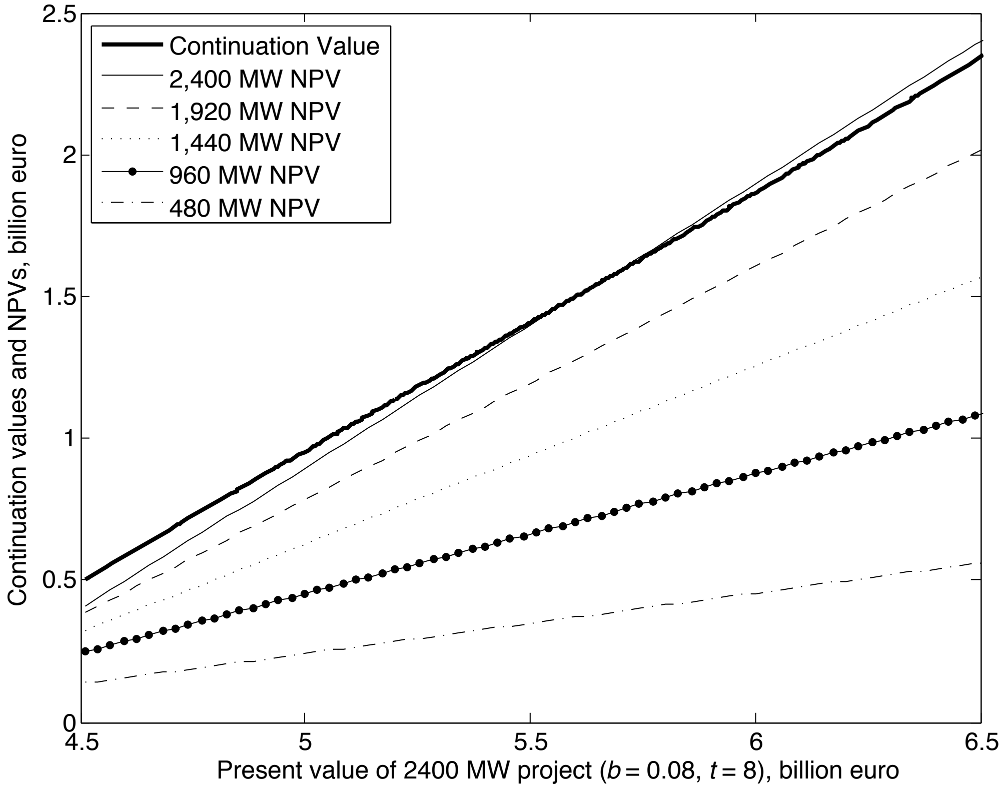


Figure 6: Continuation value (expected value of postponing investment) and NPVs of each project at the optimal investment time (eighth year of the option lifetime) under the base scenario. All project values are plotted against the 2,400 MW present value to obtain a consistent basis for comparison; since all projects see the same price streams, their present values are almost perfectly correlated. The NPV of the 2,400 MW project dominates those of the other projects.

Since profitability of the pumped storage plant is driven by price arbitrage, option value increases with growth in short-term price volatility (b in Equation (2)). Table 2 gives the NPV, option value, mean investment time, and optimal project size for the range of growth rates in short-term price volatility presented in Figure 4.

Table 2: Results for a range of growth rates in intraday price differences (base scenario in bold).[6]

Value of b	0.00	0.02	0.04	0.06	**0.08**	0.10	0.12	0.14
NPV (million euro)	−530	−380	−190	65	**880**	1,900	3,000	4,100
Option value (million euro)	0	0	0.77	240	**1,100**	2,100	3,200	4,200
Mean investment time (year)	-	-	8.5	9.9	**8.4**	7.1	6.0	5.2
Project size (MW)	-	-	480	2,400	**2,400**	2,400	2,400	2,400

Greater increase in short-term price volatility promotes early investment in large projects since revenue grows quickly in early years and is large enough to overcome a high capital cost. With earlier optimal investment times, the option to postpone adds less value relative to the initial NPV. For nominal growth rates in price volatility of 8 percentage points and higher, almost all simulated NPVs are positive and NPV grows linearly with the growth rate; at lower values of the growth rate, the linear relationship does not hold.

In the base scenario, the only realized capacity choice is 2,400 MW such that the investment decision is binary: either invest in the largest project or not at all. If there is little or no increase in nominal short-term price volatility above historical values (0 or 2 percentage points), then arbitrage revenue cannot overcome investment cost and the option is worthless. For a yearly increase in short-term price volatility of between 4 and 6 percentage points, on the other hand, investment can be optimal in a small project if present values are low, a large project if present values are high, and not at all if present values are near their mean, resulting in a discontinuous investment region. Figure 7 shows all NPVs and the continuation value for nominal intraday increase of 6 percentage points in the ninth year of the option lifetime, when investment in the 480 MW project is optimal at low present values, investment in the 2,400 MW project is optimal at high present values, and a waiting region exists at intermediate present values. Value is created through the option to postpone the investment decision until it becomes clear which project is more profitable.

[6] b is the mean nominal yearly increase in price standard deviation. Mean optimal investment time and the most frequent optimal project size are calculated from only those scenarios for which investment in any project during the option lifetime is profitable (excluding scenarios in which no investment occurs).

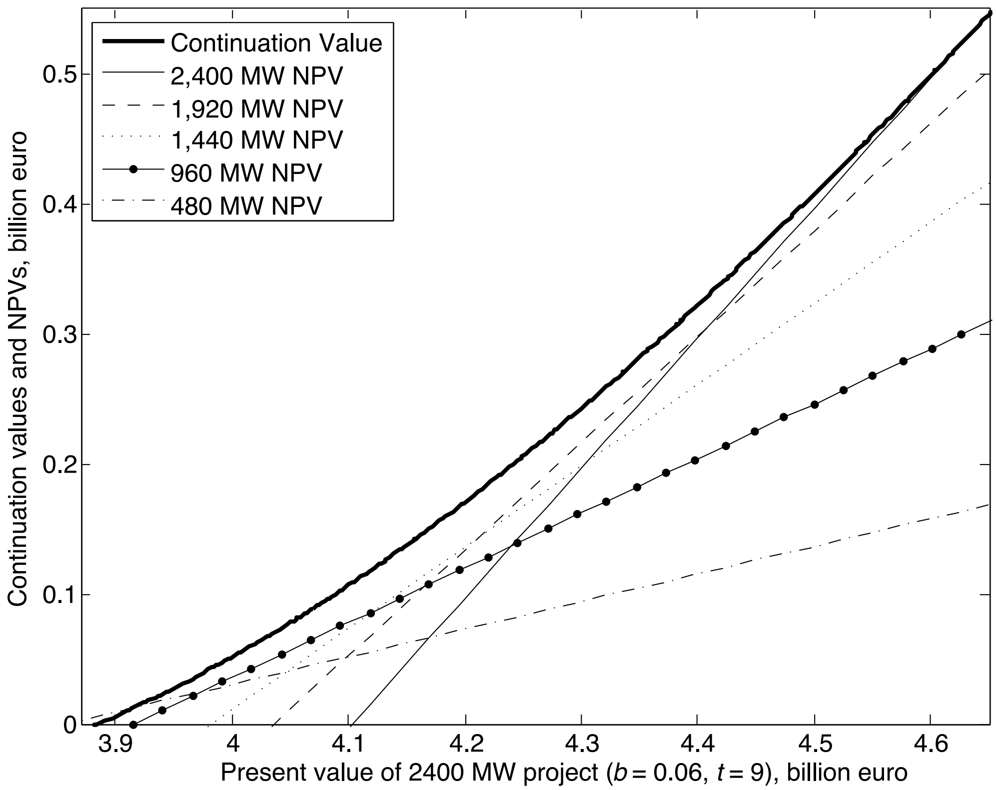


Figure 7: Continuation value and NPVs of each project at $t = 9$ years for a nominal increase in short-term price volatility of 6 percentage points. Two investment regions occur: at low present values, investment in the smallest project is optimal, and at high present values investment in the largest project is optimal.

To examine the effect of the assumed functional form for β, the base case was run with (1) β modeled as a discrete-time Brownian motion with drift and (2) no uncertainty in the nominal annual growth in price volatility ($\sigma = 0$). The first case reflects an assumption that is more common in real options analysis but does not fit the futures market data used to construct β in Section 2.1. In the second case, the price paths vary only according to the sampled historical data they contain. Option values using the alternative functions for β are the same as the base case to two significant digits. Optimal investment time for (1) is 8.6 years and for (2) is 8.7 years into the ten-year option lifetime, compared with 8.4 years under the base case, and 2,400 MW remains the optimal capacity choice in all cases. With $\sigma > 0$, short-term price fluctuations create more volatile revenue streams and thus a greater spread in optimal investment time. With investment time curtailed to 10 years, more variability in optimal investment time tends to slightly reduce its mean, counter to the common real options effect of delaying investment under greater uncertainty. Results are thus robust to the functional forms for β examined.

The investment cost estimate used in this study, based on communications with Sira Kvina personnel, is nearly 70 % higher (inflation-adjusted) than that on the 2007 permit application for the same sized plant (Sira Kvina, 2007). Since this estimate is uncertain, a cost sensitivity analysis was conducted for the base scenario (Table 3). Reducing cost by 10 % or 25 % substantially increases NPV, accelerates the optimal investment time, and reduces the added value of the option to postpone investment. Raising costs by 10 % or 25 %, on the other hand, delays the optimal investment time such that the high capital cost is maximally discounted. Updating the cost estimate for future economic conditions would allow optimal investment timing to be refined.

Table 3: Sensitivity of base scenario results to investment costs.

Deviation from base scenario investment costs	−25 %	−10 %	**0 %**	+10 %	+25 %
NPV (million euro)	1,900	1,300	**1,100**	490	90
Option value (million euro)	1,500	1,700	**1,400**	850	430
Mean investment time (year)	4.7	7.2	**7.8**	9.4	10
Project size (MW)	2,400	2,400	**2,400**	2,400	2,400

In reality, the project could be initiated after the end of ten-year option lifetime. To examine the effect of the assumed investment window, the option lifetime was extended to 20 years with the last ten years of revenue approximated as the mean of the final year of simulated annual revenue. For the longer option lifetime, the option value in the base scenario increases by less than 10 % and the optimal investment time is the tenth year, showing that results are robust to option lifetime. Since short-term price volatility experiences nearly no growth after 2040 (see Figure 4), as the option lifetime progresses there is less incentive to postpone investment and face more heavily discounted revenue.

Considering how power plants of different sizes utilize the reservoir capacity, Figure 8 shows two weeks of operation of the pumped storage facility for the five power plant size alternatives. Larger power plants use a wider range of the reservoir capacity than smaller power plants and are more constrained by capacity limits. When the reservoir level for a large power plant reaches the upper or lower bound on reservoir capacity, expanding the capacity would increase profitability. All power plants profit from both intraweek and intraday price arbitrage, as evidenced by the weekly and daily periodicities in the reservoir levels.

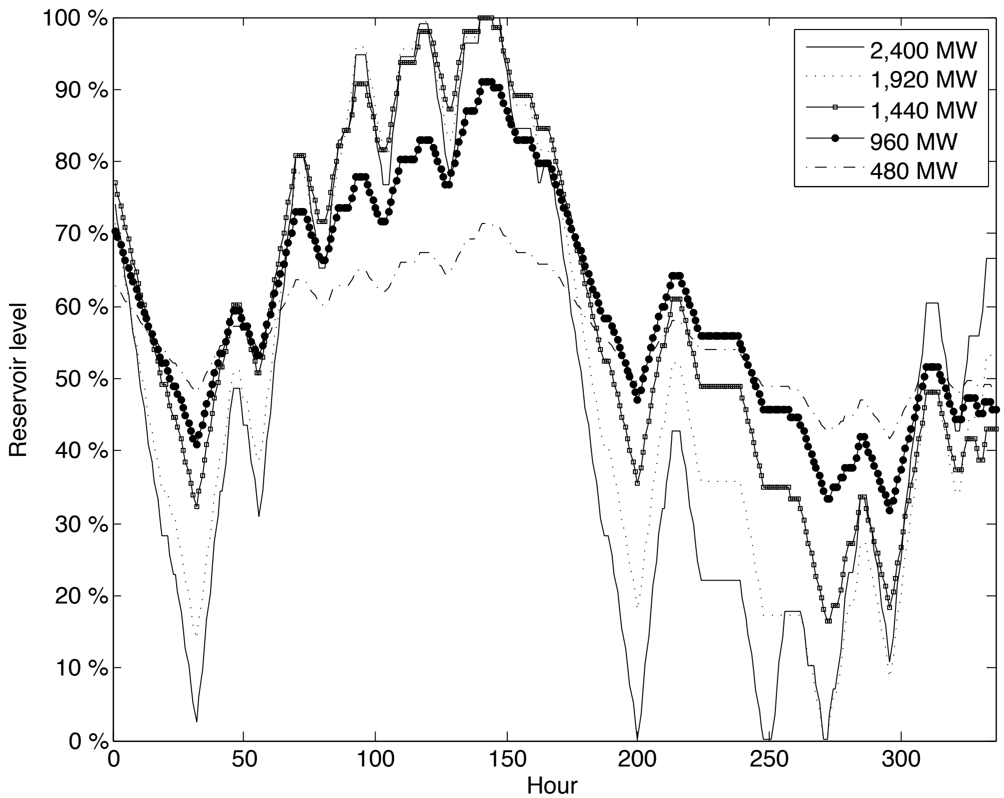


Figure 8: Reservoir level during two weeks of operation for all five pumped storage capacity alternatives. Reservoir capacity constrains operation, and therefore reduces profit, most frequently for larger plants. Water levels show both daily (24 h) and weekly (168 h) periodicity.

Examining sensitivity of profit to reservoir capacity, Figure 9 shows how the revenue from a 960 MW and a 2,400 MW pumped hydropower storage facility would change with 25 % and 50 % reductions and increases in storage capacity. While expanding the reservoir capacity leads to a small increase in revenue, decreasing the capacity by an equivalent amount results in a greater loss. Larger power plants are more affected by changes in reservoir capacity since they operate more frequently near the reservoir limits, as shown in Figure 8. The optimal generator capacity under the base scenario (2,400 MW) is unaffected, and the investment time is pushed back one year to the ninth year of the option lifetime only for the smallest reservoir capacity. Investment timing and capacity choice are thus robust to reservoir capacity.

Reservoir capacity available to the pumped storage plant depends on the operation of interconnected

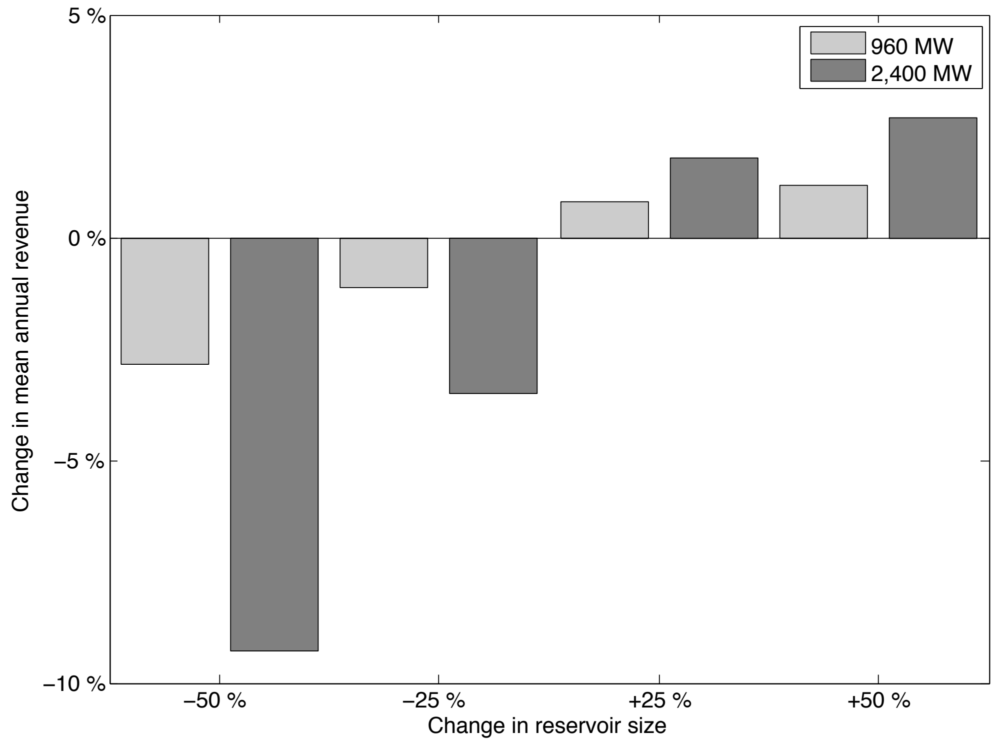


Figure 9: Sensitivity of profit to reservoir size for the 960 MW plant (proposed as the Tonstad upgrade) and 2,400 MW plant (the optimal size in the current study). Increasing reservoir size by 50 % results in only a 3 % profit increase for the 2,400 MW plant and a 1 % increase for the 960 MW plant. Decreasing reservoir size by 50 %, in contrast, leads to a 3 % drop in profit for the 960 MW plant and a 9 % drop for the 2,400 MW plant.

reservoirs in the system, and consistent operation of the pumped storage plant and existing hydropower plants would create more flexibility in the system as a whole. The assumed reservoir capacity could therefore artificially restrict the operation of the pumped storage plant in a way that constrains profitability of both the pumped storage and the rest of the system. Evaluating the benefit of additional flexibility to the system as a whole is beyond the scope of this analysis.

Figure 10 illustrates the sensitivity of the option value to discount rate. Under the base scenario, the option is worth less than 100 million euro at discount rates of 8 % or more and becomes worthless at a discount rate of 11 %. A 6 % discount rate is common for energy project planning in Norway, but investors in riskier projects use up to 10 %.

The effect of discount rate on optimal investment time is nonlinear for the base scenario, with investment in the tenth (final) year at a discount rate of 2 % but dropping steadily to the seventh year at a discount rate of 5 % and rising again to the final year at discount rates of 7 % and above. Since price volatility increases with time, a low discount rate encourages waiting to capture greater revenue. A mid-range discount rate encourages accelerated investment so that revenue streams are discounted less heavily, and at high discount rates revenue in the future is no longer sufficient to overcome high up-front capital cost so investment is postponed to maximally discount capital cost. The optimal project size shrinks as discount rate increases as well, from 2,400 MW at discount rates from 0 to 7 % steadily down to 480 MW at 10 %, reflecting the dominance of low capital cost over large revenue streams as discount rates increase. In summary, if investors decide the project is risky enough to warrant a higher discount rate, optimal investment is later and in a smaller project than if the standard 6 % discount rate is used.

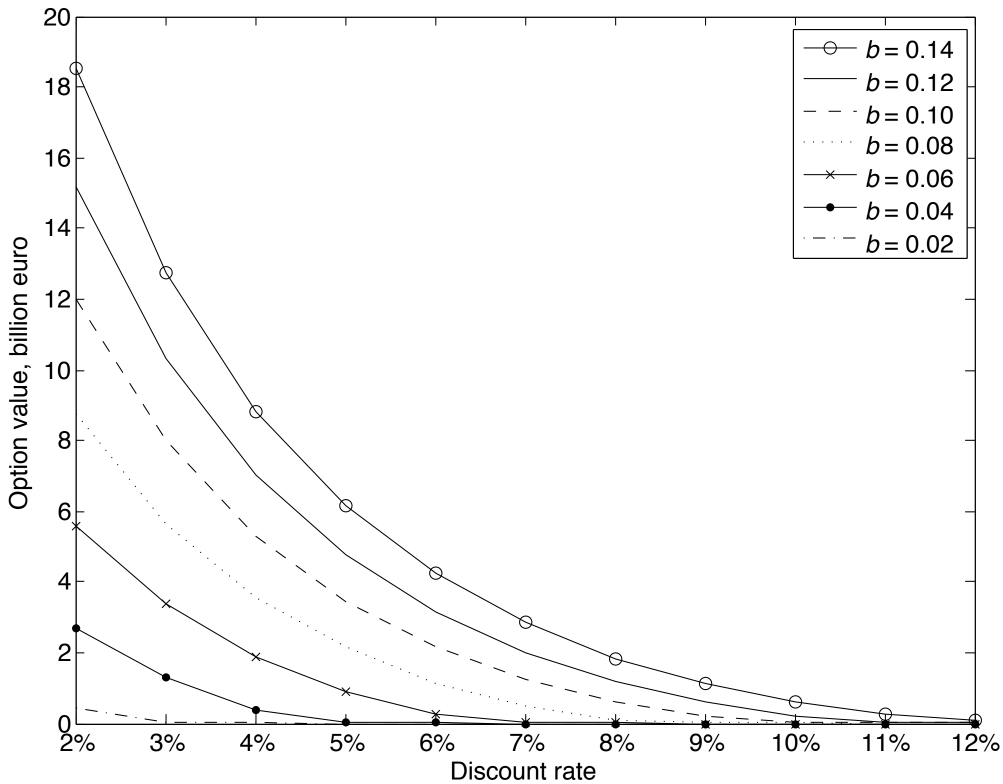


Figure 10: Sensitivity of option value to discount rate. The high up-front capital cost and relatively long project lifetime render profitability highly sensitive to choice of discount rate.

5 Conclusions and Further Work

Under a base scenario of growth in price volatility derived from the EEX futures market, a prospective investor in a pumped hydropower storage facility in Norway seeking to profit from arbitrage in the German market should hold the option for approximately eight years and then invest, updating the strategy as more information becomes available. The option to postpone investment provides substantial added value, due to both deterministic growth in price volatility as well as greater uncertainty in revenue combined with the ability to avoid investment if a project proves to be unprofitable. Progress toward resolving uncertainty on the price effect of wind will enable investors to refine optimal investment strategies.

The sensitivity analyses illustrate ways in which resolution of uncertainty could change the optimal investment strategy. While the optimal project size is robust to cost and reservoir capacity, it decreases with decreasing growth in short-term price volatility and increasing discount rates. Optimal investment time is pushed forward with larger growth in short-term price volatility, lower cost, and larger reservoir sizes, whereas higher discount rates have nonlinear effects on investment timing. Consistent across sensitivity analyses was the result that the option to postpone investment created value above that captured in an NPV analysis.

The effect of increased wind power penetration on short-term price volatility will depend on factors such as the viability of base load generators in the changing market, the amount of new transmission capacity integrating European electricity markets, the price of natural gas, and the greenhouse gas regulatory regime. We have encountered neither explicit modeling of these effects nor price scenarios from bottom-up models that sufficiently capture uncertainty, have fine enough time resolution, and have long enough time span for use in this study. Updating the price model used in this work with better information on the listed effects will strengthen the conclusions, and is left for future work.

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