Aalto University
School of Science
Degree programme in Engineering Physics and Mathematics

Production Planning of a Pumped-storage Hydropower Plant

MS-E2108 Independent research projects in systems analysis
8.9.2015

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Contents

1 Introduction

This study describes the production planning of a hydropower plant operating in the deregulated Nordic electricity market. The project was initiated by a Finnish energy company to evaluate possible benefits of a pumped-storage hydro plant over a conventional hydropower plant. Planning was performed for both a conventional hydropower plant and a pumped-storage hydropower plant under the same market and environmental circumstances in order to evaluate the economical feasibility of pumped-storage under such conditions.

The problem was modeled as an iterative mixed integer programming (MILP) problem that aims to maximize total revenue gained over a given timespan. Hydropower production planning has been studied before: Conejo et al. [2002] describe a similar multi-plant production planning problem in a pool-based electricity market. Pursimo et al. [1998] also describe an optimal control approach to planning the production of a chain of hydro plants in the river Kemijoki. Wallace and Fleten [2003] also discuss a hydro unit commitment problem under uncertainty from a cost-minimization perspective. The model presented in this study considers a single plant in a deterministic setting. More importantly, in order to reflect the operation of a pumped-storage plant, the model extends conventional hydropower modeling to allow the plant to pump water into its upper reservoir. The model also accounts for start-up and switching costs.

The model was implemented using AMPL and the CPLEX solver. The model was used to compute revenue-maximizing hourly production amounts for a pumping plant and a conventional hydroplant the years 2013 and 2014. The case company provided input data that was used in the production planning process.

The rest of this study is structured as follows: the relevant principles of hydropower and deregulated energy markets are discussed in Section 2. The production planning model formulation is presented in Section 3. Finally results from the production planning process are summarized in Section 4.

2 Background

In this section, the fundamentals of hydropower production planning are discussed. First the central principles of hydroelectric power generation are discussed in Section 2.1. Then, both the international Nord Pool Spot and domestic balancing power markets are briefly introduced in Section 2.2. Approaches to pricing reservoir water are discussed in Section 2.3 and additional considerations related to pumped-storage hydropower are reviewed in Section 2.4. Finally issues in production planning of hydroelectric production is discussed in Section 2.5.

2.1 Hydropower

Hydropower is generated from the potential energy of falling water. A hydropower plant generates electrical power from falling water using a turbine and a generator. Water rotates the turbine through which it flows and the generator produces electrical energy using the rotational motion of the turbine.

The conversion of potential energy to electrical energy is expressed in (1), where E_d is the electrical energy produced via the water mass m falling the height (or hydraulic head) h under standard gravity g. η_d denotes the efficiency of the plant, i.e., the fraction of potential energy that the plant is able to turn into electricity. Typically η_d is around 0.9.

$$E_d = \eta_d mgh. \tag{1}$$

Alternatively, the electric power P generated by falling water is the time derivative of E. Here, Q denotes the flow of water per unit of time.

$$P_d = \dot{E}_d = \eta_d \dot{m} gh = \eta_d \rho Q_d gh. \tag{2}$$

In the context of electricity generation, energy is often expressed in megawatt-hours (MWh). Production is aggregated for given hours under consideration and thus it is common to correlate a given hourly mean flow $Q_{mean}(t, t+1)$ with corresponding mean power $P_{mean}(t, t+1)$. It follows that energy produced during that hour is

$$E(t, t+1) = P_{mean}(t, t+1) \cdot 1 \text{ hour}. \tag{3}$$

In addition, plant efficiency is not constant, but rather it is dependent on output power. Thus we write

$$\eta_d = \eta_d(P). \tag{4}$$

For convenience, a mean flow to energy curve (from here on referred to as the Q-P or Q-E curve) is estimated. For a single generator plant this curve is assumed to be concave, i.e., the efficiency curve reaches a global maximum at some optimal P and decreases when deviating further from optimal operation. Hence $P(Q)$ and $E(Q)$ are concave, which simplifies their inclusion in the optimization model.

2.2 Electricity Markets

Most of electricity produced in the Nordic countries is sold to the day-ahead market of Nord Pool Spot [2014]. A market clearing spot price for each hour is computed from production and consumption bids submitted by participants. The market is divided into areas, in which prices may deviate from a market-wide system price due to limited inter-area transfer capacity. For more information, see Nord Pool Spot [2015].

In addition to the Nord Pool Spot markets, the Finnish transmission system operator (TSO) Fingrid conducts balance management between production and consumption via intra-day balancing power markets. Power balance is managed via two markets: the balancing power market, where producing and consuming participants are offered respectively a premium or discount to the corresponding spot price for adjusting their original contribution, and the frequency-controlled reserves (FCR) market, where participants sell reserve capacity that can be automatically adjusted when frequency in the grid deviates from a specified range.

In this assignment only the Elspot and FCR markets were considered, because they are the only relevant sources of revenue for the plant in question. Also, accounting for other markets, such as the balancing power market, would require modeling of uncertainties related to the balancing demand and price.

2.3 Pricing of Water

In thermal energy production, the produced energy is priced according to marginal cost, i.e., the cost of producing an additional unit of energy. Assuming perfectly competitive markets and a strictly increasing marginal cost curve, such pricing maximizes profits, because marginal cost below sale price would indicate the existence of untapped profits and marginal cost above sale price would indicate that production is sold at a loss. (see Neame et al. [2003])

In hydroelectric production such an approach is not viable, because the marginal cost of production is essentially constant in the absence of fuel and other variable costs. When planning production under such circumstances a profit maximizing model would invariably discharge all water available in the upper reservoir, to the extent allowed by other constraints.

One possible pricing approach is to consider the alternative cost of water, which expresses the present value of expected profit from discharging a unit of water in the future. Hence when evaluating water value one needs to consider the expected future spot prices, inflows to the upper reservoir as well as physical plant and reservoir limits. For instance, the water value of a plant with a full upper reservoir is zero, because delaying production would force the plant to spill water. In essence, the plant should produce energy when the profit gained now would exceed the current water value and conversely delay production when the profit gained now is inferior to the current water value (Wolfgang et al. [2009]). This principle mostly holds for plants with a sufficient upper reservoir, because in reality, adhering to other environmental limits may also require the plant to keep discharging water, forcing it to offer electricity at zero pricing.

2.4 Pumped-storage Hydropower

Conventional hydropower plants employ a one-way turbine that only allows generation of electrical energy. However, with high enough a spot price volatility and limited reservoir levels, it may be profitable to reverse the process and convert electrical energy to potential energy via pumping so that it can be later sold back at a profit. Plants employing such strategies are called pumped-storage hydropower (or PSH) plants. Figure 1 illustrates these two plant types.

High efficiencies and comparably large storage capacity in water reservoirs make PSH plants attractive in compensating for abrupt consumption and production shifts. With increasing proliferation wind turbines that provide variable, weather-dependent amounts of power to the grid, PSH plants are seen as elastic participants that are able to swiftly adjust their operation schedule based on market conditions. Deane et al. [2010]

Pumping water using electrical energy is assumed to follow similar laws as when discharging water to produce energy. Namely, the pump converts elec-

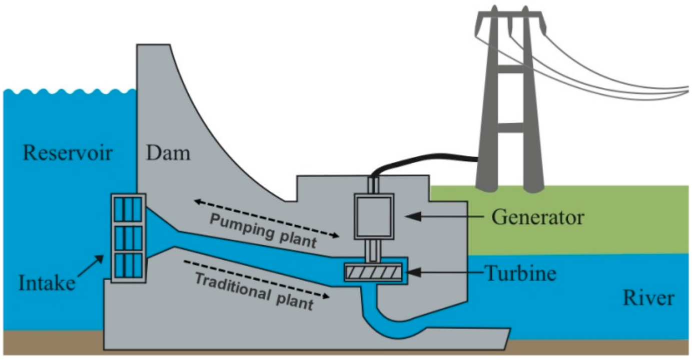

Figure 1: A diagram of a PSH plant. The turbine is used to both generate electricity via discharging water from the reservoir and to pump water to the reservoir by consuming electricity.

trical energy into potential energy with efficiency $\eta_p \in]0, 1[$:

$$mgh = \eta_p E_p.$$

As with η_d, η_p is also assumed to be power-dependent with similar properties. The round-trip efficiency is an efficiency measure for a PSH plant defined as the fraction of energy produced via discharge of a water unit and the corresponding electrical energy consumed to pump a unit of water into the reservoir:

$$\eta_{roundtrip} = \frac{E_d}{E_p} = \eta_d \eta_p$$

In addition, it should be noted that also the production efficiency n_d is smaller for a pumping turbine when compared to conventional hydropower turbines. In essence, the pumping turbine, if used only for production, would operate at an economical loss compared to a conventional turbine.

2.5 Planning Hydroelectric Production

In this assignment a simple hydroelectric plant with a small, regulated upper reservoir and an effectively unlimited lower reservoir is considered. The flows into the upper reservoir are given. A simple flow diagram of the reservoir and flows is shown in Figure 2. At a given hour t, V^t denotes the upper reservoir volume, Q^t_{in} denotes flows beside those from the plant into the reservoir, Q^t_d

denotes discharges through the plant, Q_p^t denotes pumping flows into the reservoir and W^t denotes flows from spilling.

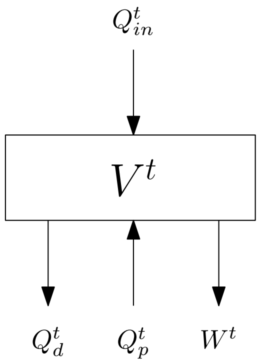

Figure 2: Flow Diagram

The plant is scheduled so as to maximize revenue under physical operational limits of the plant as well as limits posed by the upper reservoir.

A substantial issue in planning hydroelectric production is to evaluate residual value of water in the end of the planning period so as to prevent the model from discharging all available water by the end of the planning period. Ideally one would add the water value of the water remaining in the reservoir after the planning period to the objective function. However, computing water value even for a simple system of a single plant and reservoir is difficult, and several proxies and alternative approaches can be used to limit discharge when planning hydroelectric production. Førsund [2007] among others discuss such methods including the ones discussed below.

Rudimentary water value estimation One can estimate water value by multiplying the terminal reservoir level with a coefficient $\rho < 1$. This coefficient should reflect the possibility of the reservoir filling up and thus reducing the unit value of water as well as other limits forcing the plant to run inefficiently.

Fixed terminal reservoir The plan may be constrained to reach a fixed terminal reservoir level V_f. The terminal reservoir level should again reflect the alternative cost of water.

Increased optimization period The model may be optimized far in to the future so that only a small period in the beginning of the optimization period is used as a production plan. With a long enough optimization horizon, the terminal discharge effect should be mitigated within the beginning of the period.

In this project, a combination of the second and third methods was used. The planning interval was split into successive, partially overlapping subintervals and the plan was optimized for each subinterval so that the initial conditions were taken from the previous subinterval and the terminal reservoir level was constrained to a sensible level. Consequently, the aggregate plan was allowed to deviate from the constrained reservoir levels within each subinterval to the extent that the reservoir could be steered to the required terminal level during that interval. The rolling optimization method is further explained in Section 3.10.

3 Production Planning Model

The production planning problem is modeled as a mixed integer linear programming (MILP) problem that maximizes forecasted profits from the spot and frequency markets. Constraints are introduced in order to respect physical limitations, flow-power relationships, as well as switching between production, pumping and off-line modes. The constraints are grouped as follows:

Hydrobalance Reservoir level is determined by inflows and discharges.

Environmental regulations The plant needs to respect reservoir level regulations.

Plant operating ranges The plant variables need to remain within specified domains.

Flow-power mapping Piecewise-linear discharge-to-power and power-to-inflow mappings are modeled as constraints.

Mode switching Operating mode switching is tracked via binary constraints on operating modes.

Frequency Reserves The plant can reserve capacity to the frequency reserve markets during running hours.

Due to the hourly resolution of physical electricity markets, it is reasonable to model the production planning problem in an hourly resolution as well. In the following definitions, all references to time refer to hours and all quantities are treated as hourly means.

3.1 Notation

In production planning most decisions are modeled as a series of decision in time. Here such decision variables are denoted as y^t for a variable y at time t. The time frame is discrete and finite so that we denote the subject time frame as

$$\mathbb{T} = \{t \in \mathbb{Z} \mid t_0 \leq t \leq t_f\}.$$

The decision variables used in the model are listed in Table 1. While theoretically water flows should explicitly determine respective energies (and vice versa), here both are modeled as decision variables in order to simplify the optimization problem. Table 2 in turn shows input variables for the model. In addition, $E_{d,max}$ and $E_{p,max}$ are computed as

$$E_{d,max} = \mathcal{E}(Q_{d,max}) \tag{5}$$
$$E_{p,max} = \mathcal{Q}^{-1}(Q_{p,max}). \tag{6}$$

Additional variables and other notation are explained in the constraint definitions below.

For convenience, state x^t describing the plant operation at time t is defined as

$$x^t \triangleq \begin{bmatrix} Q_d^t & Q_p^t & W^t & V^t \end{bmatrix}.$$

Table 1: Decision Variables

E_d^t	$\triangleq$	Energy produced via discharge at time t	MWh
E_p^t	$\triangleq$	Energy consumed via pumping at time t	MWh
Q_d^t	$\triangleq$	Water discharge at time t	m^3/s
Q_p^t	$\triangleq$	Pumping inflow at time t	m^3/s
W^t	$\triangleq$	Spillage flow at time t	m^3/s
δ_m^t	$\triangleq$	Binary variable indicating if the plant switches operating modes at time t	
V^t	$\triangleq$	Upper reservoir volume at time t	m^3

Table 2: Input Variables

p_f^t	$\triangleq$	Forecasted spot price at time t.	€
p^t	$\triangleq$	Realized spot price at time t.	€
P_m	$\triangleq$	A fixed cost associated with switching operating modes.	€
P_{FCR-D}	$\triangleq$	Yearly market price of frequency controlled disturbance reserves	€
P_{FCR-N}	$\triangleq$	Yearly market price of frequency controlled normal operation reserves	€
V_l^t	$\triangleq$	Minimum upper reservoir volume at time t	m^3
V_u^t	$\triangleq$	Maximum upper reservoir volume at time t	m^3
Q_{in}^t	$\triangleq$	Upper reservoir inflow at time t	m^3/s
$Q_{d,max}$	$\triangleq$	The maximum discharge flow	m^3/s
$Q_{p,max}$	$\triangleq$	The maximum pump flow	m^3/s

3.2 Objective Function

The objective function to be maximized is the total revenue gained from both the spot and the frequency controlled reserves market less the cost incurred from switching operating modes.

$$\sum_{t \in T} p_f^t \cdot (E_d^t - E_p^t) - \delta_m^t P_m + \sum_{t \in T} [C_{FCR-D}^t P_{FCR-D} + C_{FCR-N}^t P_{FCR-N}] \quad (7)$$

3.3 Hydrobalance

In hydroplanning, all water flows should be accounted for and water should not vanish nor appear into the reservoir outside the accounted inflows and discharges. This requirement is modeled as the following constraint:

$$V^t = V^{t-1} + 3600 \cdot (Q_{in}^{t-1} - Q_d^{t-1} + Q_p^{t-1} - W^{t-1}) \quad \forall t \in (t_0 + 1) \dots t_f, \quad (8)$$

where the coefficient 3600 is used to convert flows in m^3/s to volumes in an hour m^3.

The initial and final reservoir levels are given as inputs to the model as V_0 and V_f respectively,

$$V^{t_0} = V_0 \tag{9}$$
$$V^{t_f} = V_f. \tag{10}$$

3.4 Environmental Limits

Regulated reservoirs have time dependent upper and lower limits for water level changes due to spring floods and preservation of biodiversity in the vicinity of the reservoir. Here these limits are accounted for with corresponding reservoir volumes.

$$V_l^t \leq V^t \leq V_u^t \quad \forall t \in T. \tag{11}$$

The plant also has hard limits on its spillage capacity.

$$W_l \leq W^t \leq W_u \quad \forall t \in T. \tag{12}$$

3.5 Q-E Profiles and Operating Modes

The discharge-to-output-power mapping is modeled as a concave, piecewise-linear function here denoted as $\mathcal{E}(Q)$. Such a fit for measured discharge and output power values is shown in Figure 3. Figure 4 shows the corresponding efficiency curve. As required, the Q-E-curve is concave and the efficiency curve has a unique maximum, decreasing steeply to its left and more gradually to its right. It is also assumed that the pump has a similar operational efficiency profile and hence the input-power-to-flow profile $\mathcal{Q}(E)$ is modeled as a similar concave, piecewise-linear function. Binary indicators "is discharging" and "is pumping" are introduced in order to indicate if the plant is discharging or pumping water at any given hour. M denotes a large positive constant. The constraint (17) forces the model to discharge water, pump water or to stay idle. These indicators are later related to mode switching costs and delays as well as FCR bidding opportunities.

$$E_d^t \leq \mathcal{E}(Q_d^t) + M \cdot (1 - \delta_d^t) \quad \forall t \in T \tag{13}$$
$$E_d^t \leq M \cdot \delta_d^t \quad \forall t \in T \tag{14}$$

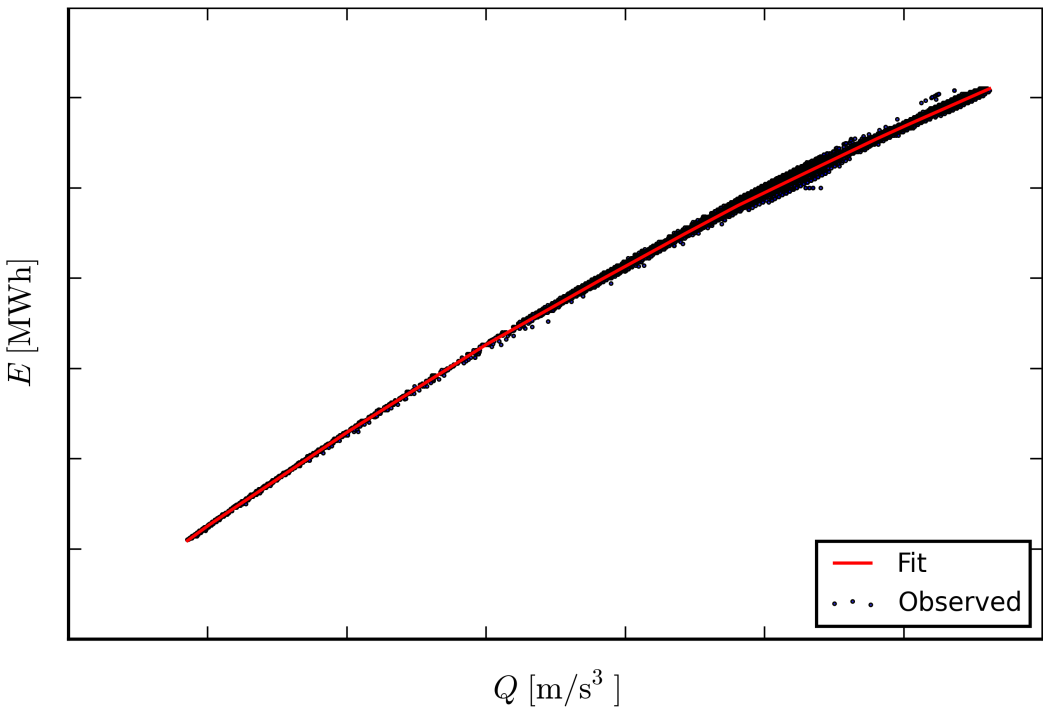

Figure 3: Piecewise-linear Q-E-curve fitted against measured discharge and power output.

$$Q_p^t \leq \mathcal{Q}(E_p^t) + M \cdot (1 - \delta_p^t) \quad \forall t \in T \tag{15}$$
$$Q_p^t \leq M \cdot \delta_p^t \quad \forall t \in T \tag{16}$$

$$\delta_d^t + \delta_p^t \leq 1 \quad \forall t \in T \tag{17}$$

In addition, hard flow limits and mode indicators are combined into constraints forcing both discharge and pump flows to within hard limits during operation and to zero during off-line hours.

$$\delta_d^t \cdot Q_l \leq Q_d^t \leq \delta_d^t \cdot Q_u \quad \forall t \in T \tag{18}$$
$$\delta_p^t \cdot Q_l \leq Q_p^t \leq \delta_p^t \cdot Q_u \quad \forall t \in T \tag{19}$$

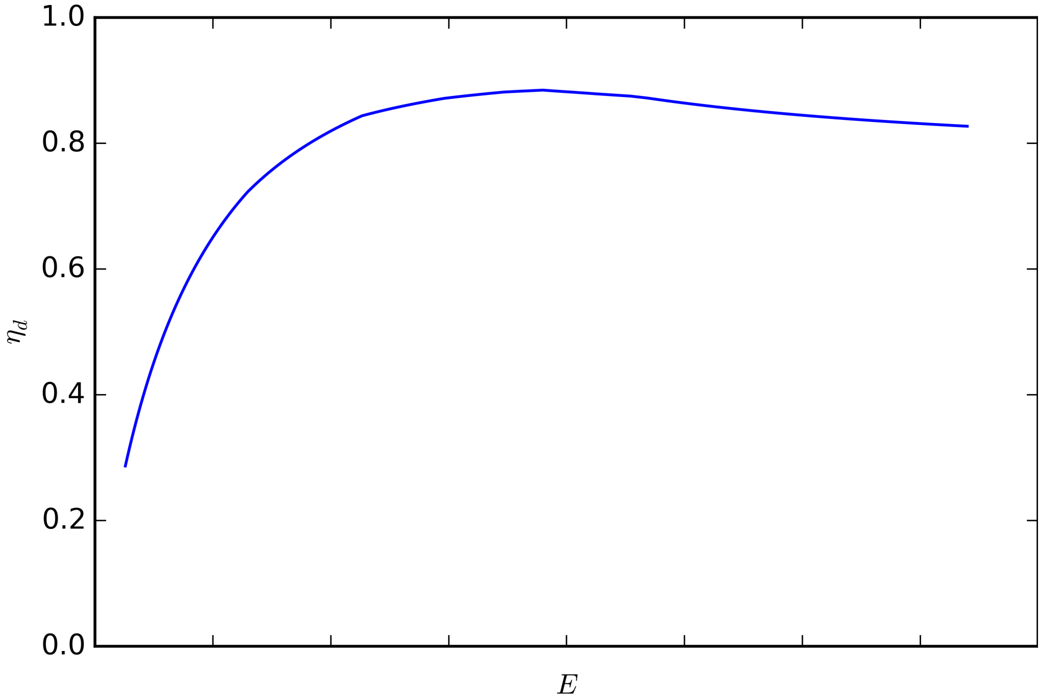

Figure 4: Theoretical efficiency curve corresponding to the piecewise-linear Q-E-curve in Figure 3

3.6 Mode Switching Costs and Delays

A fixed cost P_m is associated with starting either the pump or the turbine. The binary decision variables δ_m^t in the objective function account for each mode change and the following constraints are introduced to force the variable to one each time the plant switches modes. The binary variables $\delta_{d,\uparrow}^t$ and $\delta_{p,\uparrow}^t$ are used to indicate if either the turbine or pump is started at hour t.

$$\delta_{d,\uparrow}^t \geq \delta_d^t - \delta_d^{t-1} \qquad \forall t \in T \qquad (20)$$
$$\delta_{p,\uparrow}^t \geq \delta_p^t - \delta_p^{t-1} \qquad \forall t \in T \qquad (21)$$
$$\delta_m^t \geq \delta_{d,\uparrow}^t \qquad \forall t \in T \qquad (22)$$
$$\delta_m^t \geq \delta_{p,\uparrow}^t \qquad \forall t \in T \qquad (23)$$

In addition to mode switching costs, the model also accounts for ramp-up and ramp-down delays as reduced maximum discharge and pump flows for hours when either mode is switched on or off. It is assumed that the plant could linearly ramp up to or down from the maximum capacity Q_u in t_{switch} minutes. The modeled mode switch delay is defined in (24). The definition violates linearity due to multiplication of decision variables and is therefore not suitable as a constraint in the MILP model. The constraints in (25) - (27) force the corresponding decision variables to take values according to (24). Equivalent non-linear equality constraints and substituted linear inequality constraints are introduced for discharge stops as well as pump starts and stops,

$$Q^t_{start,d} = \delta^t_{d,\uparrow} \cdot Q^t_d \cdot t_{switch}/60/2 \quad \forall t \in T. \tag{24}$$

$$Q^t_{start,d} \leq M \cdot \delta^t_{d,\uparrow} \qquad \forall t \in T \tag{25}$$
$$Q^t_{start,d} \leq Q^t_d \cdot t_{switch}/60/2 \qquad \forall t \in T \tag{26}$$
$$Q^t_{start,d} \geq Q^t_d \cdot t_{switch}/60/2 - M \cdot \delta^t_{d,\uparrow} \qquad \forall t \in T \tag{27}$$

Using the mode switch delays defined above effective upper limits for Q^t_d and Q^t_p are defined as the hard upper limit Q_u less delay losses due to either starting or stopping.

$$Q^t_d \leq Q_u - Q^t_{start,d} - Q^t_{stop,d} \qquad \forall t \in T \tag{28}$$
$$Q^t_p \leq Q_u - Q^t_{start,p} - Q^t_{stop,p} \qquad \forall t \in T \tag{29}$$

3.7 Frequency Controlled Reserves

The plant may also participate in the frequency controlled reserves market. Reserve capacity may be sold to the frequency controlled disturbance reserves (FCR-D) and to the frequency controlled normal operation reserves (FCR-N). Selling to these reserves does not incur flows but large production amounts limit the amount of headroom, i.e., the unused capacity available for use in the FCR, that can be sold to either reserve. According to Fin [2015, Appendix 2], the capacity sold to normal operation reserves needs to be adjustable in both directions, i.e., during discharge hours the plant needs to be able to both increase and decrease production, and during pumping hours the plant needs to be able to both increase and decrease consumption by the sold reserve capacity. Selling capacity to the disturbance reserves in turn only obliges the plant to be able to increase its production or decrease its consumption by the set amount.

Due to rapid shifts required from FCR capacity it is also assumed that the plant needs to be on-line for all hours sold to the FCR market as well as that the plant may not switch modes to accommodate frequency correction.

To determine available capacities for a given hour t four auxiliary variables are introduced. $C^t_{d,\uparrow}$ and $C^t_{d,\downarrow}$ indicate the headroom available in either direction during discharge hours. $C^t_{p,\uparrow}$ and $C^t_{p,\downarrow}$ indicate the same quantities for pumping hours, i.e.,

$$C^t_{d,\uparrow} \leq \delta^t_d \cdot M \qquad \forall t \in T \tag{30}$$
$$C^t_{d,\uparrow} \leq E_{d,max} - E^t_d \qquad \forall t \in T \tag{31}$$
$$C^t_{d,\downarrow} \leq \delta^t_d \cdot M \qquad \forall t \in T \tag{32}$$
$$C^t_{d,\downarrow} \leq E^t_d \qquad \forall t \in T \tag{33}$$

$$C^t_{p,\uparrow} \leq \delta^t_p \cdot M \qquad \forall t \in T \tag{34}$$
$$C^t_{p,\uparrow} \leq E_{p,max} - E^t_p \qquad \forall t \in T \tag{35}$$
$$C^t_{p,\downarrow} \leq \delta^t_p \cdot M \qquad \forall t \in T \tag{36}$$
$$C^t_{p,\downarrow} \leq E^t_p \qquad \forall t \in T. \tag{37}$$

Here $E_{d,max} = \mathcal{E}(Q_u)$ and $E_{p,max} = \mathcal{Q}^{-1}(Q_u)$ with $\mathcal{Q}^{-1}$ denoting the inverse of $\mathcal{Q}$. In essence, the quantities indicate the maximum energy output produced via discharge and maximum energy input consumed by pumping respectively.

With these auxiliary headroom variables defined, the FCR capacity constraints are defined as follows. It is assumed that the plant has a limited capacity that can be sold to the FCR markets at any given time.

$$C^t_{FCR-N} \leq C_{FCR-N,max} \tag{38}$$
$$C^t_{FCR-D} \leq C_{FCR-D,max}. \tag{39}$$

The headroom variables are then used to limit the hourly FCR capacity sales according to limits described above. The Big M Method is used here to target either discharge or pump capacity accordingly.

$$C_{FCR-D}^t \leq C_{d,\uparrow}^t + M \cdot \delta_p^t \qquad \forall t \in T \tag{40}$$
$$C_{FCR-D}^t \leq C_{d,\downarrow}^t + M \cdot \delta_p^t \qquad \forall t \in T \tag{41}$$
$$C_{FCR-D}^t \leq C_{p,\uparrow}^t + M \cdot \delta_d^t \qquad \forall t \in T \tag{42}$$
$$C_{FCR-D}^t \leq C_{p,\downarrow}^t + M \cdot \delta_d^t \qquad \forall t \in T \tag{43}$$

$$C_{FCR-N}^t \leq C_{d,\uparrow}^t - C_{FCR-D}^t + M \cdot \delta_p^t \qquad \forall t \in T \tag{44}$$
$$C_{FCR-N}^t \leq C_{p,\downarrow}^t - C_{FCR-D}^t + M \cdot \delta_d^t \qquad \forall t \in T \tag{45}$$

3.8 Traditional Turbine Operation

For comparison purposes the same model can be used to find optimal production plans for a plant without a pump. To facilitate this a simple additional constraint is added to disallow pumping,

$$\delta_p^t = 0 \quad \forall t \in \mathbb{T}. \tag{46}$$

Additionally, as mentioned in 2.4, it is typical that the Q-E curve $\mathcal{E}$ needs to be re-evaluated for the traditional turbine, too.

3.9 Summarized MILP problem

With objective function and constraints defined above, the MILP problem can be now expressed in a summarized form:

$$\begin{aligned} \underset{Q_d, Q_p, W}{\text{maximize}} \quad & (7) \\ \text{subject to} \quad & (8) - (45) \end{aligned} \tag{47}$$

3.10 Rolling Optimization

In order to force the model to maintain sensible water levels in the long term, the production planning problem is split into partially overlapping subintervals $\mathbb{T}_i$ and solved iteratively (see Figure 5). Excluding the last, possibly truncated interval, the subintervals are equal in length and equally spaced.

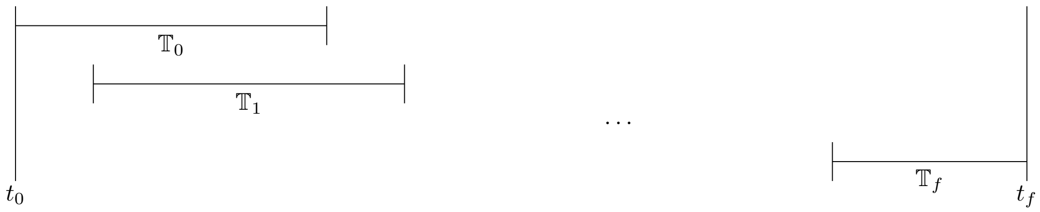

Figure 5: The rolling optimization process

After each iteration the time frame is shifted forwards by τ hours and the initial conditions x_t are fixed to reflect the state reached by the plan up until the beginning of the new interval. By specifying the final reservoir condition (10) for each $\mathbb{T}_i$ the production planning process can be forced to also reach sensible water levels in the short term. The method is detailed more precisely in Algorithm 1.

$\hat{t}_0 \leftarrow t_0$;
while $\hat{t}_0 < t_f$ **do**
    $\mathbb{T}_i \leftarrow \{\hat{t}_0 \ldots \min\{\hat{t}_0 + \Delta t, t_f\}\}$;
    Solve (47) for $\mathbb{T}_i$;
    Fix $x_{\hat{t}_0+\tau}$;
    $\hat{t}_0 \leftarrow \hat{t}_0 + \tau$;
end

Algorithm 1: The iterative solving method

4 Results and Discussion

Year long simulations for 2013 and 2014 were conducted on the model with a pumping and non-pumping configuration in order to compare both setups in terms of profitability. Both years were planned using the rolling optimization approach by finding a plan for a two week subinterval and advancing by a day in each iteration.

Inflows were given as realized values. While realistically reservoir inflows exhibit uncertainty, it was assumed that they are accurately known for two

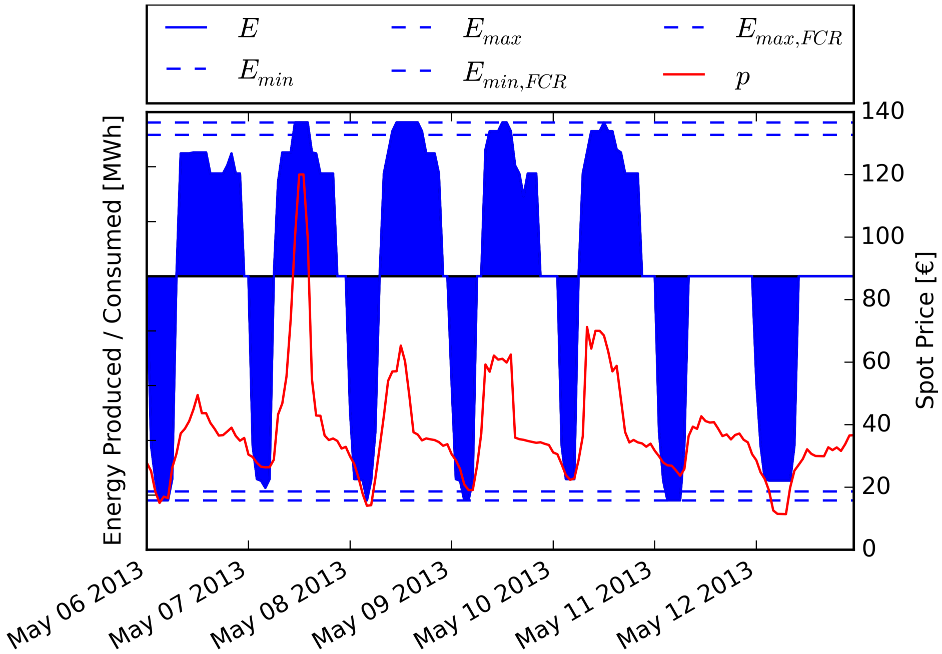

Figure 6: A model generated schedule for 6.5.2013 - 12.5.2013. The plant targets high spot prices for production hours and low prices for consumption hours.

weeks in advance. Revenue was maximized against forecasted spot prices but finally also compared to realized spot prices.

Years with different fundamental properties were selected in order to compare the PSH plant's relative performance under different circumstances. The selected years exhibit differences in spot prices as well as inflow levels. In 2013, there was approximately 21% less natural inflow and approximately 14% higher spot prices in comparison to 2014. It was hypothesized that the PSH plant might perform relatively better during dry years when discharge capacity is not saturated for long periods of time. This hypothesis was validated by the production planning process: in 2013 the PSH plan pumped 12.8% more water in comparison to the plan computed for 2014. However, the qualitative results for both years were altogether similar, and hence the figures and discussion below focus on the year 2013.

Figure 6 shows a week long example of the model-generated PSH plan against realized spot prices. The plan targets high-priced hours for production and low-priced hours for consumption. FCR capacity is traded for expanded production or consumption only during the most expensive or cheap hours respectively. This is expected, because the additional profit or reduction in

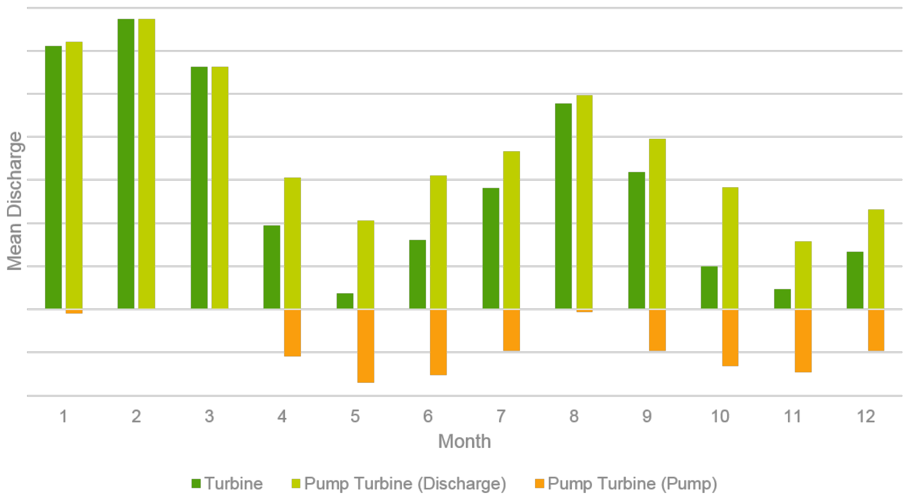

Figure 7: Mean discharge flows for the conventional and PSH plants in 2013. Pumping and corresponding additional discharge by the PSH plant are scheduled from April to July and September to December.

cost obtained during full operation needs to outweigh the alternative cost of shifting that production to hours with more headroom and a lower price. In the week long period the plant consistently runs when the spot price is higher than approximately 40 €/MWh and pumps when the price is lower than approximately 30 €/MWh.

In addition, a notable aspect in the production planning example is the comparison between Monday the 6th and Saturday the 11th. The spot price profiles for both days are very similar with Monday's prices being only slightly higher. Nevertheless, due to starting costs the plant is planned to run all day Monday and to idle on Saturday.

Figure 7 shows the monthly mean discharge flows in 2013 for both configurations. With equal terminal reserve constraints it is clear that both setups should have equal net flows in total. Interestingly, the PSH plant scheduled significant pumping flows only for the periods from April to July and September to December. Spring floods are the dominant reason for inexistent pumping during the first quarter of the year; very large inflows and limited maximum reserve capacity forced full discharge plans for that period. This underlines the need to examine such plans in the long term.

Figure 8 shows the mean hourly production of the pumping and non-pumping plants. The PSH plant tends to consume energy during the night and produce

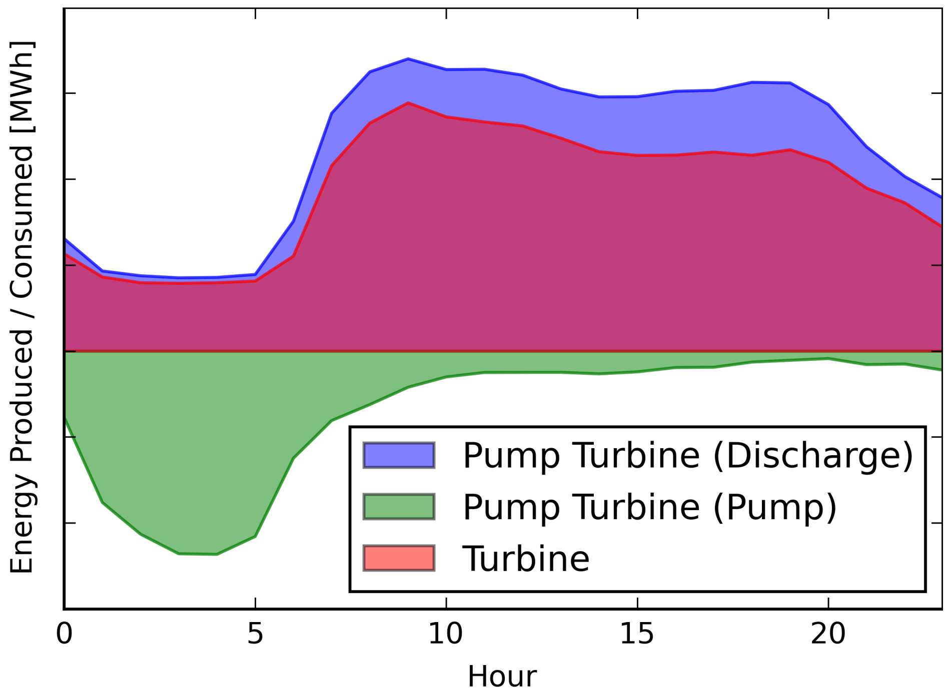

Figure 8: Mean hourly production for the turbine and pump turbine configurations in 2013. The PSH plant is able to generate more energy during the test period due to night-time pumping.

energy via additional discharge during the day. Optimally the PSH plant should target the highest paying hours for added discharge, but due to limited discharge and pumping capacity the plant needs to discharge additional water during non-optimal hours.

The profitability of a pumping plant versus a conventional hydropower plant is not self-evident. On one hand, the pumping plant might be able to allocate additional peak-hour production using water pumped during cheap hours, while on the other hand, the pumping turbine is less efficient, causing an efficiency loss in comparison to a conventional turbine. Revenues from the FCR market constitute another differentiating factor in revenues between the two turbine types: a PSH plant remained in operation (discharging or pumping) for more than 50% of the planning period, while the conventional plant was scheduled to operate significantly less than half the time. This allowed the PSH plant to sell significantly more capacity into the FCR market. Clearly the economics of a PSH operation are dependent on both the spot market volatility as well as the prices in the FCR market; the PSH operation benefits from both high spot volatility and high FCR prices.

The model presented in this study provides detailed decision support for an investment decision between the two turbine alternatives. While being useful as such, the model could be expanded in various ways. The technical accuracy could be improved by modeling the turbine efficiency curves quadratically instead of using a piecewise-linear approximation. In general, while nonlinear optimization problems in general are harder to solve, efficient approaches to quadratic problems are available. The model is also deterministic in its approach, and thus does not capture the stochastic nature of its key inputs, i.e., water inflows and spot prices. To further improve the results gained from the model, scenario based or robust optimization could be utilized. Finally, running the model for other kinds of hydropower plants, one could possibly make generalizations of the technical characteristics that affect profitability of pumping hydropower and market conditions that would favor PSH plants over conventional hydropower.

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