Bidding into balancing markets in a hydro-dominated electricity system

Preliminary Draft
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Abstract

In an electricity system, demand and supply have to be balanced in real time. Therefore, balancing power and energy are procured in the balancing markets. The market outcomes may significantly differ from one country to the other dependent on the underlying generation technologies and market design. In this paper, we have a look at the balancing market prices of a hydro-dominated electricity system using Switzerland as a case study. By using a short-term hydropower operation model and a set of Swiss hydropower plants, we are able to identify a competitive benchmark for Swiss balancing market prices defined by the opportunity costs of hydropower for providing balancing power. Our results show that Swiss balancing market prices are influenced by several drivers but do not hint at any market imperfections.

1 Introduction

In an electricity system, physical electricity demand and supply have to be balanced in real time to keep the frequency stable. To ensure this system balance, balancing power and energy are procured by the transmission system operators (TSOs) in the balancing markets. On the supply side, multiple firms or plants of one or several technologies are providing balancing power. In a system with a high share of conventional power plants like Germany, most of the balancing supply is provided by conventional plants. Thus, prices for balancing power and energy are defined by conventional power plants. In a system with a high share of renewable energies, however, balancing requirements are also provided by renewable energies. Since renewable technologies are dependent on natural circumstances like weather or hydrology but have variable cost of zero or close to zero, balancing prices may differ from conventional systems (Ocker, 2017; Ocker et al., 2016). In addition, renewable energies may have an impact on the need of balancing power requirements (Hirth and Ziegenhagen, 2015).

In this paper, we have a look at the balancing market prices of a hydro-dominated electricity system. By taking Switzerland and its secondary reserve (Sekundärregelleistung (SRL)) market as a case study, we want to derive a competitive benchmark for the balancing market prices for an electricity system with a high share of hydropower. To do so, we use a short-term hydropower operation model and apply it to set of Swiss hydropower plants and cascades. By starting with a simplified basic model and extending it by short-term trading options, technical plant characteristics and uncertainty in the day-ahead market prices, we are able to identify drivers of the opportunity cost of hydropower for providing balancing power and thus the balancing market prices in a hydro-dominated system. Our results show that opportunity costs for providing balancing power are mainly driven by cascade structure and the size of the balancing market bid. In addition, our results show that short-term trading options, head effects as well as uncertainty in day-ahead market prices all can have an impact on the overall costs for providing balancing power. Comparing costs of hydropower for providing balancing power with the observed balancing market prices leads us to the conclusion that Swiss balancing market prices are justified by costs of hydropower.

The remainder of the paper is structured as follows: in section 2, we have a look into literature on balancing markets. In section 3, the model and data used in this paper are explained. In section 4, the opportunity costs of hydropower for providing balancing power are illustrated. Section 5 discusses the results and concludes.

2 Balancing markets and hydropower in the literature

Literature on balancing markets is diverse. Since balancing market are still highly heterogeneous in its market design across countries (see, e.g., Ocker et al., 2016) a lot of studies in literature addressing different national balancing market designs (e.g., Müsgens et al., 2014; Ocker, 2017), the harmonization of market designs (e.g., Dallinger et al., 2018; Ocker et al., 2018a) , the integration of balancing markets (e.g., Farahmand and Doorman, 2012) or if the market design is suitable for VRE participation (e.g., Fernandes et al., 2016). Regarding VRE, other studies focus on the interaction of an increasing share of VRE and the balancing requirements and costs (e.g., Gianfreda et al., 2018; Hirth and Ziegenhagen, 2015; Holttinen et al., 2011; Ocker and Ehrhart, 2017) or hydropower's ability or value in contributing to balance an increasing share of VRE (e.g., Dujardin et al., 2017; Graabak et al., 2019).

Literature more relevant to this study deals with balancing market auctions in terms of the bidding behaviour of market actors and the resulting balancing market prices. Thereby, Kirsch and Singh (1995) analyse efficiency properties and incentives of different auction formats for ancillary services showing that only uniform pricing auctions which minimize revealed social costs are efficient. Just and Weber (2008) analyse the German balancing market prices deriving the balancing market logic and the prices from the trade-off between balancing and spot markets. Rammerstorfer and Wagner (2009) study the policy reform of the German balancing market in 2006 and its impact on the balancing price dynamics. According to their results, the reform led to a decreasing price level and volatility and an increase in the degree of integration between spot and balancing market. Heim and Goetz (2013) study price increases in the German balancing market by having a look at the market structure and bidding strategies. They find evidence that increase in balancing prices resulted from collusive behaviour and show that pay-as-bid auctions do not necessarily reduce strategic behaviour like capacity withholding or collusion building. Müsgens et al. (2014) study the economics and design of the German balancing markets. Their results show that both scoring and settlement rules as well as rational bidding ensures simultaneous efficiency of balancing and spot markets. Ocker (2017) analyse seven European balancing market auctions by first, theoretically describing the optimal bidding strategies (i.e., profit maximizing bids) for each market and second, empirically test if the optimal bidding strategies can be observed in reality. However, in five out of seven markets, theory does not match the empirical data. Empirical results for Switzerland especially highlight the high volatility of the balancing market prices resulting from the hydro-dominated electricity system in Switzerland. Empirical results for Germany by Ocker and Ehrhart (2017) show that balancing suppliers coordinate on a price level which is higher than the completive level and that suppliers take into account previous auctions prices in their power bids. Due to the mismatch between empirical auction results and theoretic predictions, Ocker et al. (2018b) further analyse deviations from optimal bidding strategies in the German and Austrian balancing markets. By taking into account price expectations based on historic market outcomes in their theoretical model, they formulate a theoretical bidding strategy which matches empirical balancing market results in this markets. Build upon this, Ocker et al. (2018a) analyse if a change from pay-as-bid to uniform pricing as proposed by the European

Commission would incentivise suppliers to reveal their true costs. However, their results show that under both pricing regimes (i.e., pay-as-bid and uniform pricing) suppliers do not reveal their actual cost.

Regarding hydropower, Gebrekiros et al. (2013) analyse the bidding in the balancing market for hydropower units. By having a look at the Norwegian market they determine the bidding price for balancing power based on the opportunity costs in the day-ahead market. By taking into account the discharge-power output relationship of hydro units, they show that deviations from optimal operating points due to balancing power provision will reduce profit. This loss in profit represents the cost for balancing power of hydro units. Similar to Gebrekiros et al. (2013), Aasgard and Roti (2016) study the opportunity-cost-pricing of different types of balancing products for a hydropower system. Their results show that for the Norwegian balancing power products especially spinning reserve (primary and secondary reserves) can be costly to provide by hydropower plants since they can significantly restrict the production schedule. In addition, they show that symmetric products (i.e., primary reserves in the Norwegian market) are more expensive due to additional restrictions for hydropower plants resulting from the symmetric nature of the product.

Additional studies, which have a look at hydropower and balancing markets, analyse the profit potential of balancing markets from a hydropower perspective. Examples of such studies are Chazarra et al. (2016), Fodstad et al. (2018) or Schillinger et al. (2017). Chazarra et al. (2016) present a detailed optimization model to derive the optimal generation schedule of a hydropower cascade that maximizes its profit on the Spanish energy and balancing markets. Their results show that hydropower can significantly increase their income when selling in the day-ahead and balancing market compared to pure day-ahead market participation. Similarly, Fodstad et al. (2018) find a theoretical potential for added value when selling energy in multiple markets relative to day-ahead sales only. Their results for market data from Norway, Sweden and Germany show that especially flexible plants can benefit from multi market participation. Schillinger et al. (2017) find a similar result for Swiss hydropower. While there might be a significant potential for additional revenues by balancing markets in theory, the authors highlight the limitations of such additional incomes resulting from uncertainties and balancing market characteristics.

With this paper, we contribute to the literature which has a look at the balancing markets (especially balancing market prices) of an electricity system dominated by hydropower instead of conventional (fossil fuel) technologies. To do so, we use a similar approach as Gebrekiros et al. (2013) or Aasgard and Roti (2016) to derive opportunity cost prices for balancing power but focus on the Swiss electricity market and the Swiss balancing market design.

3 Modelling framework

3.1 Model

Participation of power plants or firms in the balancing markets changes the optimal generation schedule on the spot market. Because of this, balancing market prices can be derived from the opportunity cost of power plants or firms on the spot market (see, e.g., Aasgard and Roti, 2016; Gebrekiros et al., 2013; Just and Weber, 2008; Müsgens et al., 2014; Ocker et al., 2018b). In this paper, we focus on the opportunity costs for balancing power of a hydropower dominated electricity system. Therefore, we use a short-term hydropower operation model to derive the optimal generation schedule for hydropower plants on the spot market as well as deviations from this schedule due to balancing market participation. The example in figure 1 shows the basic logic of the approach used in this paper.

Figure 1. Basic logic of the approach used in this paper.

The logic illustrated in Figure 1 relates to a symmetric balancing market. On the spot market, a profit maximizing storage hydropower plant only produces in a few high price hours since it is limited in terms of energy by the water stored in the reservoir. How much it can produce in such high price hours is constrained by the turbine capacity which is in the example in Figure 1 assumed to be 100MW (left figure). If the hydropower plant is now bidding 10MW in the symmetric balancing market in addition to spot market participation, it has to adopt its spot market generation schedule. First, the hydropower plant has to run at least at 10MW in each hour of the underlying tendering period in order to reduce its generation output by 10MW if negative energy is requested by the TSO. Second, the hydropower plant can only produce 90MW instead of 100MW in high price hours in order to reserve 10MW in case positive energy is needed to balance the system (right figure). These changes in the profit maximizing generation schedule correspond to a symmetric balancing market as the SRL market in Switzerland. The difference in revenues between the two generation schedules represent the opportunity cost for providing balancing power (Aasgard and Roti, 2016; Gebrekiros et al., 2013). In this paper, we analyse this opportunity costs in relation to the actual balancing market prices. By starting with a simplified basic hydropower operation model and extend it by short-term trading option, technical plant details (i.e., head effect) and price uncertainty we are able to identify the opportunity costs for balancing power for a set of Swiss hydropower plants as well as its drivers. Regarding the drivers, we only have a look at the individual effect of these drivers on the opportunity cost for providing balancing power rather than a combination of these effects. The model details are described below. All

models have a resolution of one hour (15 minutes in case the intraday market is considered) and are solved for time horizon of one week while each week of the year is solved. Solving the model on a weekly instead of a yearly time horizon results from the time intensive solution process when taking into account technical plant characteristics and uncertainties. The basic model as well as the model which takes into account short-term trading options could also be solved on yearly basis. By solving the model for a weekly instead of a yearly time horizon small deviations from the yearly optimal generation schedule can occur (see appendix A3.1). Due to the limited foresight when solving the model on a weekly time horizon, the future value of water is taken into account. The future value of water is derived from more long-term models (see, e.g., Gebrekiros et al., 2013). In our case, we derive the water values from a simplified yearly hydropower operation model. All models are coded in GAMS 25.1.3 and solved using the CPLEX 12.8 solver.

3.1.1 Basic Model

The basic model represents a simplification of the model described in Schillinger et al. (2017). While in Schillinger et al. (2017) balancing market aspects are explicitly model, we just consider deviations in the spot market schedule due to balancing market participation in this model. The basic model assumes perfect foresight and neglects head effects. Thus, the basic model is deterministic and linear. The objective of the plant operator is to maximize its weekly revenue in the day-ahead market R_{DA} defined by the day-ahead market price p_t and the generation $G_{t,i}$ of each turbine i. To take into account the future value of water the storage level $S_{t^{end},r}$ and the water value $wv_{t^{end},r}$ for each reservoir r at the end of the week t^{end} are taken into account. Deviations which occur when solving the basic model on a weekly instead of a yearly time horizon are illustrated in the appendix (A3.1).

$$\max R_{DA} = \sum_{t,i} p_t G_{t,i} + \sum_{r} S_{t^{end},r}\, wv_{t^{end},r}$$

The generation of each turbine is defined by the water to energy conversion factor η and the water which is discharged through the turbine $D_{t,i}$. In the basic model, no head effects are considered so Eta is assumed to be constant.

$$G_{t,i} = \eta_i D_{t,i} \qquad \forall t, i$$

The storage level in each hour for each reservoir is defined by the storage level of the previous hour, the natural water inflows into the reservoir $i_{t,r}$, the water which is going out of the reservoir either by discharging $D_{t,\underline{i}}$ or spilling $Spill_{t,\underline{i}}$ it via the turbine below the reservoir $\underline{i}$ and the water which is ending up in the reservoir by discharge or spill from a turbine above the reservoir $\overline{i}$. Water delay within a cascade is not considered in this paper.

$$S_{t,r} = S_{t-1,r} + i_{t,r} - \sum_{map_{\underline{i},r}} D_{t,\underline{i}} - \sum_{map_{\underline{i},r}} Spill_{t,\underline{i}} + \sum_{map_{\overline{i},r}} D_{t,\overline{i}} + \sum_{map_{\overline{i},r}} Spill_{t,\overline{i}} \qquad \forall t, r$$

The generation of each turbine is constrained by the turbine capacity g_i^{max} as well as the minimum generation level g_i^{min}. In our case the minimum generation is assumed to be zero.

$$g_i^{min} \leq G_{t,i} \leq g_i^{max} \qquad \forall t, i$$

If a hydropower plant bids capacity into the weekly symmetric SRL market bid^{srl}, it has to run at least at that capacity at all hours of the week in order to reduce its generation if negative energy is required by the TSO. In addition, the difference between the turbine capacity and the capacity offered has to remain free to be able to increase generation if positive energy is needed to balance the system. If a whole cascade is bid into the balancing market, this constraint accounts for the total cascade generation and not the generation of the individual plants.

$$g^{min} + bid^{srl} \leq G_t \leq g^{max} - bid^{srl} \qquad \forall t$$

In order to be able to deliver what was bid into the balancing market in terms of energy, water has to be reserved in the reservoir. In the weeks before the week for which capacity is bid into the balancing market, the storage at the end of the week has to be at least such that the plant has enough water available to run at the offered capacity level for the whole week for which balancing power was bid and at the same time is able to increase its generation by the offered capacity (i.e., $2 * bid^{srl}$). However, since the reservoir gets natural water inflows in the future i_{rr}^{future}, the required storage level is corrected by that amount. In case of a hydropower cascade, we assume that just the biggest storage reservoir of the cascade (rr) has to fulfil this storage constraint.

$$S_{t^{end},rr} \geq \left(\frac{2\, bid^{srl}}{\eta_i}\right) t^{end} - i_{rr}^{future} \qquad \forall rr$$

In the week for which balancing power was bid into the SRL market, the storage level has to be big enough to increase the generation by the offered capacity for the remaining time of the week taking into account the future inflows of the week.

$$S_{t,rr} \geq \frac{bid^{srl}}{\eta_i} (t^{end} - t) - i_{rr}^{future} \qquad \forall t, rr$$

In addition to the storage constraints resulting from balancing market participation, the storage is constrained by its minimum and maximum storage level.

$$s^{min} \leq S_{t,r} \leq s^{max} \qquad \forall t, r$$

The storage level in the first hour is given either by historic data, if it is the first week of the year or in any other week of the year, by the storage end level of the previous week.

$$S_{t=1,r} = s^{start} \qquad \forall t = 1, r$$

To derive the opportunity cost for providing balancing power in a specific week, we first run the model for each week of the year while the plant or cascade is optimized on the day-ahead market. Second, we run the model for each week of the year while for one week capacity is bid into the balancing market and the corresponding generation schedule for the day-ahead market of this and all other weeks of the year has to be adopted. By comparing the yearly revenue without and with balancing market participation in a specific week, we are able to calculate the opportunity costs of that week by the yearly revenue difference.

3.1.2 Short-term trading options

In our basic model, we only consider trade on the day-ahead market. However, storage hydropower plants as flexible technologies are also traded on more short-term markets like intraday markets. This can change the generation schedules and revenues of hydropower (see, e.g., Fodstad et al., 2018) and correspondingly the opportunity cost for providing balancing power. Therefore, we extend the basic model by taking into account trade on the intraday market in addition to the day-ahead market. The objective of the hydropower plant operator is thus to maximize its revenues over both markets R_{DA+ID} while generation is split between the day-ahead $G_{t,i}^{DA}$ and the intraday market $G_{t,i}^{ID}$.

$$\max R_{DA+ID} = \sum_{t,i} p_t^{DA} G_{t,i}^{DA} + \sum_{t,i} p_t^{ID} G_{t,i}^{ID} + \sum_{r} S_{T,r}\, wv_{T,r}$$

All other equations and constraints remain similar as in the basic model. However, since in the intraday market 15-minutes products are traded, the model resolution when taking into account intraday markets is 15 minutes instead of one hour.

3.1.3 Technical plant characteristics

In the basic model, technical plant characteristics are simplified. One major limitation of the basic model is that it ignores the three-dimensional relationship between power produced, water discharge and head of the reservoir (i.e., head effects). However, taking into account head effects can have an impact on the optimal generation schedule (Conejo et al., 2002). Therefore, we extend the basic model by taking into account head effects. In literature, head effects are considered in several ways, e.g., by nonlinear programming (see, e.g., Pérez-Díaz et al., 2010). In this paper, we follow the approach of Conejo et al. (2002) who uses mixed integer programming (MIP) to approximate the head effects. Figure 2 illustrates the approach.

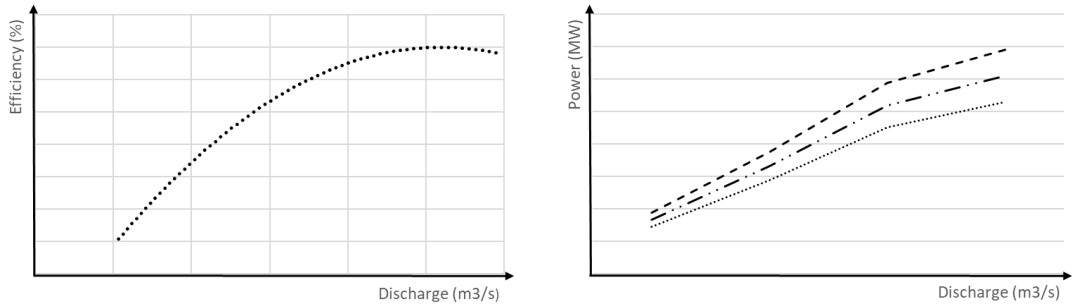


Figure 2: Efficiency curve and power-discharge relationship for different heads.

The left hand side of Figure 2 shows the turbine efficiency in relation to the water discharged for one head level. This nonlinear relationship is approximated by piecewise linear power-discharge curves (right hand side of Figure 2). For each head level, a power-discharge curve is defined while a small number of curves is already enough to accurately model head variations (Conejo et al., 2002). As illustrated in Figure 2, turbine efficiency is highest at discharge levels lower than the maximum discharge and a decrease in head level reduces power output. The detailed model is shown in the appendix (A1.1).

3.1.4 Uncertainty in day-ahead market prices

Another limitation of our basic model is that it assumes perfect foresight. Thus, no uncertainties regarding electricity prices or inflows are considered. However, taking into account such uncertainties can have an impact on the scheduling decision of the hydropower plant operator (see, e.g., Ladurantaye et al., 2009). To analyze the impact of uncertainty on the opportunity costs, we extend our basic model to a stochastic model in which day-ahead prices are represented by a scenario tree. Uncertainty in inflows are not considered. The scenario tree used in this paper to represent uncertainty in the day-ahead market prices is illustrated in Figure 3.

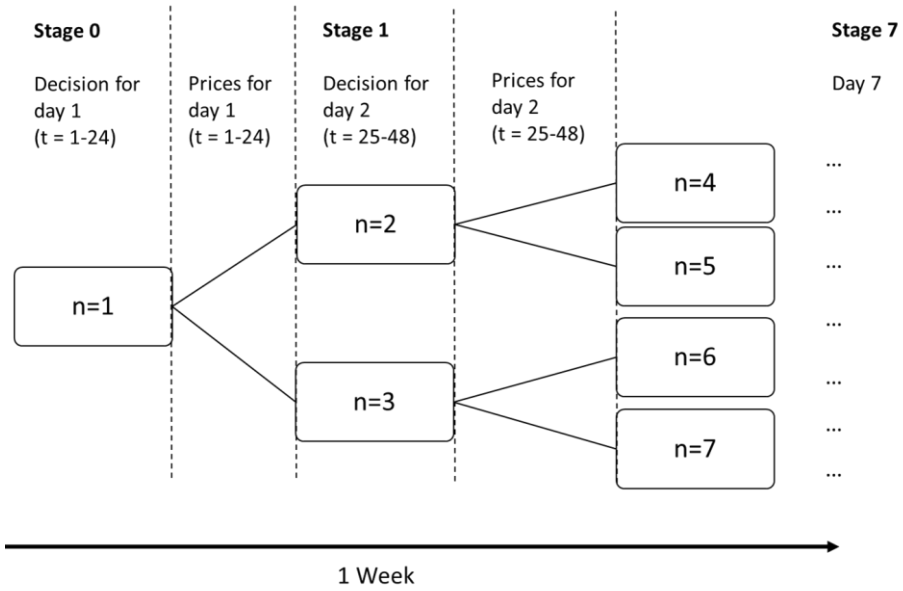


Figure 3: Weekly scenario tree for uncertainty in day-ahead market prices.

The scenario three corresponds to a time horizon of one week while a week is divided in seven stages, each corresponding to a day of the week. At each stage (excluding the last stage) the hydropower operator has to make a production decision for a day without knowing the exact market prices of that day. With a certain probability, the market prices can be high or low. Depending on the realized prices a specific node is reached at the next stage (Ladurantaye et al., 2009). The tree illustrated in Figure 4 is integrated into our basic model. The detailed weekly stochastic model is shown in the appendix (A1.2). To take into account price uncertainty also in the water values, a yearly stochastic model is used to derive the future water values. Due to the time intensive solution process when taking into account price uncertainty, the yearly stochastic model considers price uncertainty only on a monthly basis. Thus, the yearly stochastic model is based on a scenario tree with 12 stages while each stage belongs to a month of the year. With a certain probability (see chapter 3.2.1) prices in a month can be high or low.

3.2 Input data

3.2.1 Market data

The Swiss balancing market is split into three products which are primary, secondary and tertiary reserve. The products differ in the time when they are activated after an imbalance between demand and supply occurred (Abrell, 2016). In this paper, we only have a look at the secondary reserve (SRL) market. The Swiss SRL market has the following characteristics[1] (Abrell, 2016; Swissgrid AG, 2017):

- Demand: approx. 400MW
- Product type: symmetric
- Contract length: 1 week
- Weekly tenders
- Minimum bid: 5 MW
- Capacity payment: Pay-as-bid
- Energy payment: Day-ahead price +- 20%

SRL prices are published by the Swiss TSO (Swissgrid AG, 2019). Since these data include all prices per week which were accepted in the pay-as-bid procedure, we use the average of the accepted SRL prices per week in our analysis. In this paper, SRL prices are only used as benchmark for our simulated opportunity costs but are not required in the model. Prices which are required in the model are day-ahead and intraday prices. Swiss day-ahead market prices are based on EPEXSPOT (2019) while the years 2013 to 2015 are taken into account. Intraday market prices are also based on EPEXSPOT (2019). However, due to data issues German instead of Swiss intraday prices are used. In addition, intraday markets are just considered for the years 2014 and 2015. Since the German intraday market is continuous, no single price per time step is available. Because of this, intraday prices used in this paper represent weighted average values. The prices used in this paper are summarized in Figure 4 by its monthly average values. SRL prices are shown on the right axis, day-ahead and intraday prices on the left one.

[1] The market design of the Swiss SRL market changed in June 2018. In this paper, we consider the market design which was in place before June 2018.

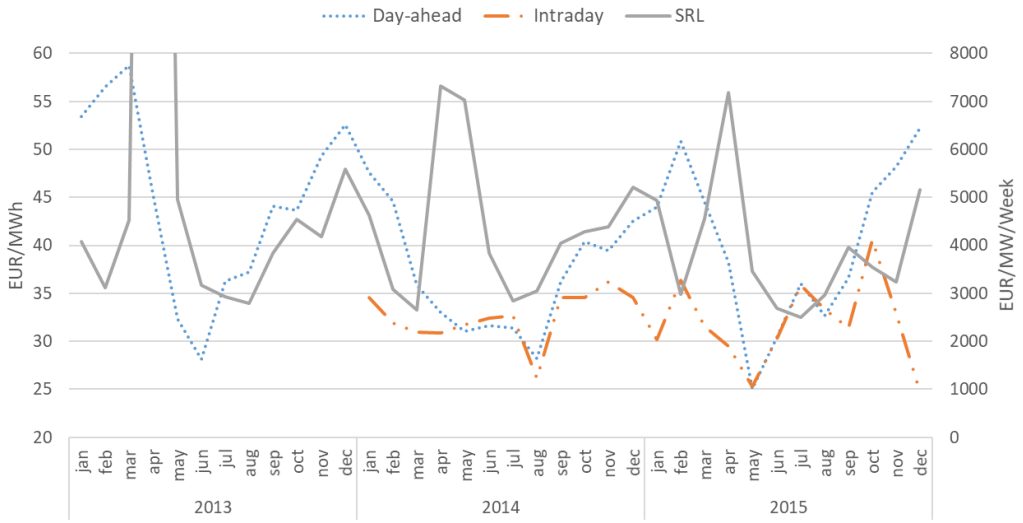


Figure 4: Monthly average day-ahead and intraday prices (left axis); monthly average SRL prices (right axis). Data based on EPEXSPOT (2019) and Swissgrid AG (2019).

Beside the price data, information on the day-ahead price uncertainty are required for the stochastic model used in this paper. To estimate the uncertainty in the day-ahead prices, we calculate the deviations of the future prices from the day-ahead market prices. While positive and negative deviations of the future prices from the day-ahead market prices should be similar in the long term, we only have a look at the positive deviations here. For the yearly stochastic model, which is used to derive the water values for the weekly stochastic model, we use the average monthly deviation of the Phelix DE/AT Base Year Future (EEX, 2019) relative to the yearly base price of the day-ahead market. To derive the weekly uncertainty for the weekly stochastic model, we compare the Phelix DE/AT Base Week Future (EEX, 2019) with the weekly base price of the day-ahead market. Figure 5 illustrates the deviations.

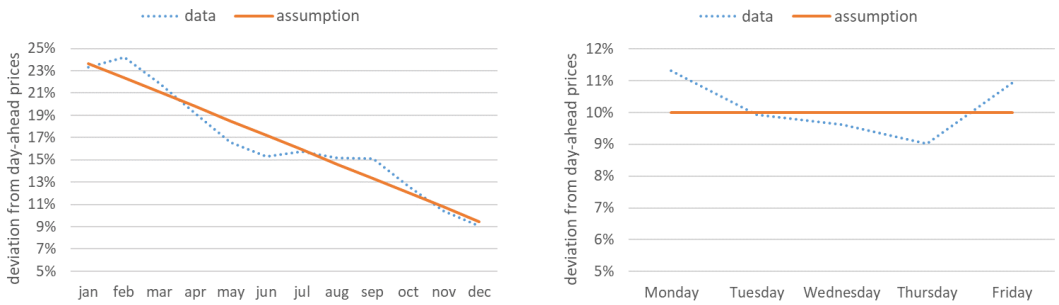


Figure 5: Deviation of yearly (left) and weekly (right) future prices from day-ahead prices. Data based on EEX (2019) and EPEXSPOT (2019).

For the year (left figure), the deviations between the future prices and the day-ahead market prices show a clear downward trend. Uncertainty is decreasing with time since we get closer to the actual day-ahead market from one month to the other. In the yearly stochastic model, we use a linear estimate of the observed downward trend as our assumption on price uncertainty (orange line). For a week (right figure), deviation is much more fluctuating. While there seems to be a downward trend in the deviation between future and day-ahead prices until Thursday, deviation increases again at the end of the week. However, deviation is

around 10% all over the week which is why we assume a constant price uncertainty of 10% in the weekly stochastic model.

3.2.2 Hydropower data

In analysing the opportunity cost of hydropower for providing balancing power we have chosen a set of Swiss hydropower cascades. We focus on cascades which include storage hydropower plants. While some of the cascade also include run-of-river plants, cascades with pump-storage plants are not considered here. The chosen cascades differ ,i.a., in their topology, capacity and storage volume. Table 1 summarizes the main characteristics of the chosen cascades.

Table 1: Data of hydropower cascades. Based on Balmer (2006), Garrison et al. (2018), Schlecht and Weigt (2014) and SFOE (2018).

Cascade Nr.	Capacity (MW)	Avg. Production (GWh)	Storage (Mio. m3)	Number Plants/ Reservoirs	Ratio Storage to Dis-charge*	Ratio Inflow to Storage*
1	54	72	50	1/1	434	3
2	56	214	20	2/2	556	7
3	60	119	40	1/1	553	4
4	104	318	6	3/2	199	17
5	109	227	86	2/1	462	5
6	201	702	62	5/3	998	3
7	397	1’036	204	4/2	1’643	1
8	439	925	111	3/3	1’489	2

***** Based on largest reservoir of the cascade.

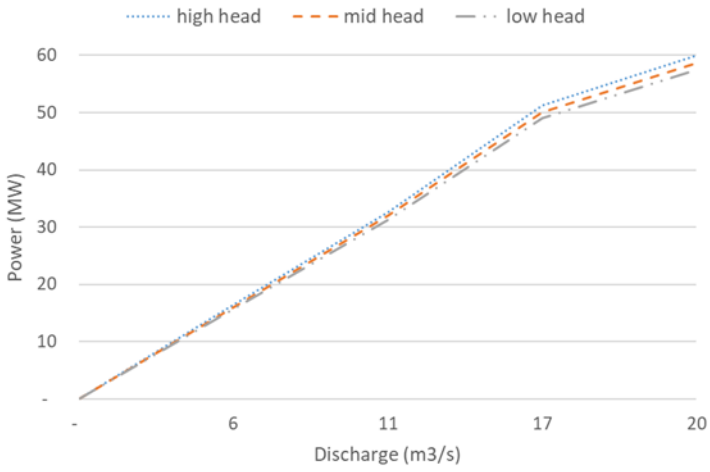
Some of the hydropower plants considered here are simple storage hydropower plants with a single reservoir and a single plant (i.e., cascade nr. 1 and 3). Other cascades are more complex including up to five plants and three reservoirs (i.e., cascade nr. 6). The cascades chosen in this paper should be representative for the whole population of Swiss storage hydropower plants. Approximately 15% of the Swiss storage hydropower plants are single-site plants while the remaining 85% belong to hydro cascades. Regarding turbine capacity, around 60% of Swiss storage hydropower plants have a capacity below 100MW, 30% a capacity between 100MW and 300MW and 10% a capacity above 300MW (Balmer, 2006; Garrison et al., 2018; Schlecht and Weigt, 2014; SFOE, 2018).

In order to consider head effects, additional technical data are required. Since such data are plant specific and rarely available at high degree of detail, we base our assumption on head data on a case study in Ticino, for which detailed data were provided within the NRP70 project “The Future of Swiss Hydropower”[2], and abstract this details to other plants

[2] https://fonew.unibas.ch/de/projects/ongoing-projects/nfp70-futurehydro/

considered in this paper. Data for one of the cascades (i.e., cascade nr. 3) is illustrated in Table 2. Data for all other cascades for which head effects are considered can be found in the appendix (A2).

Table 2: Head data for cascade nr. 3. Data based on Balmer (2006), Garrison et al. (2018), Schlecht and Weigt (2014) and SFOE (2018).



	High Head	Mid Head	Low Head
Head (m)	372	364	356
Power Block 1 (MW)	16	16	16
Power Block 2 (MW)	33	32	31
Power Block 3 (MW)	51	50	49
Power Block 4 (MW)	60	59	57

How relevant the head effects are is plant specific. We do not consider head effects for all plants in the sample. In case of a cascade, head effects are only considered for bigger storage plants. For smaller or low head plants we assume a constant head.

4 Results

The results section is structured as the model section. First, the results of the basic model are illustrated. Afterwards, the results for short-term trading options, head effects and price uncertainty are shown. In the results section, only the year 2015 is illustrated, the results for 2013 and 2014 can be found in the appendix (A3).

4.1 Basic model

In the Swiss SRL market, minimum bid size is 5MW. However, beyond that minimum size, bids can be increased by 1MW (Swissgrid AG, 2017). We consider different bid sizes for each cascade, starting with the minimum bid up to a bid size which is equal to half of the turbine capacity of the plant which is responsible for reserving the water in its reservoir. Figure 6 shows the range of opportunity cost for SRL over all cascades and bid sizes resulting from the basic model in comparison to the average SRL prices for 2015.

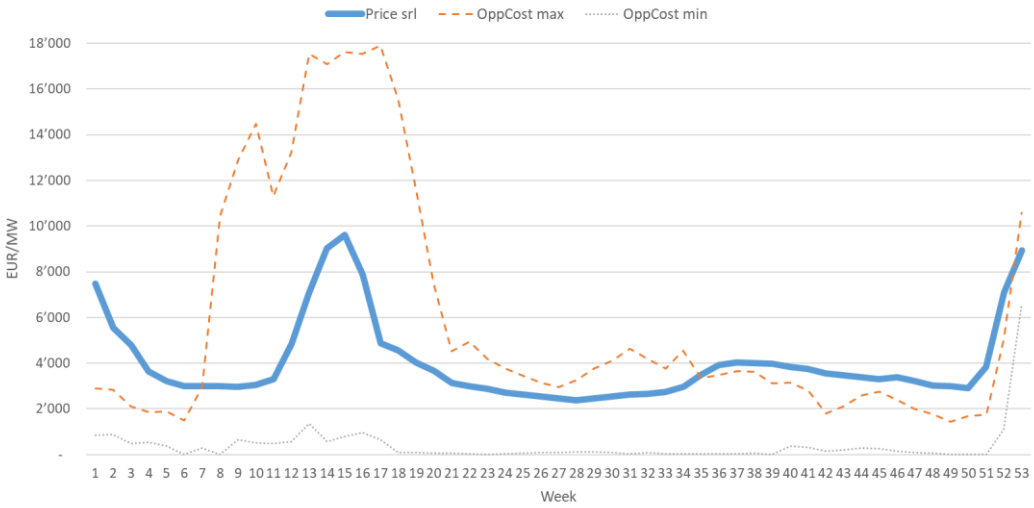


Figure 6: Srl price and maximum/ minimum opportunity cost of sample for 2015.

As illustrated in Figure 6, Swiss SRL prices (blue line) are driven by hydrological conditions. The most pronounced peak in the SRL prices occurs in spring when the reservoirs are empty and the snow melt has not started yet.[3] As illustrated by the maximum opportunity cost (orange line), reserving water in the reservoir for SRL in spring comes at a high cost due to the low flexibility of hydropower at that time. For some cascades in the sample, the spring peak in the opportunity costs already occurs earlier, depending on the local inflow conditions and the consequent reservoir levels. Overall, the maximum opportunity costs reveal that the SRL prices seem to be driven by the opportunity costs of spot trades. However, the difference between the maximum and the minimum (grey line) opportunity costs shows a high cost variance. Depending on the specific hydropower cascade characteristics as well as the respective size of the SRL bid opportunity costs can range from levels close to zero to levels which are significantly above the SRL price level. In some weeks of the year, even maximum opportunity costs are lower than the observed market prices. This could result from the limited set of hydropower plants considered in this paper or from opportunity cost drivers, which have not been considered in the simplified basic model. While we cannot address the first point in this paper, we have a closer look at the individual drivers of the opportunity costs in the remainder of the paper. All further results are only illustrated for two of the cascades considered in this paper, a “single-site” plant (i.e., cascade

[3] See also other years in the appendix (A3). In 2013, the SRL price peak in spring was especially high due to a prolonged winter and a consequent earlier reduction the in reservoir levels (ElCom (2014).

nr. 3) and a "multi-site" cascade (i.e., cascade nr. 7). Results for the other plants and cascades can be found in the appendix (A3.2).

First, we want to have a look at the impact of the size of the SRL bid on the opportunity costs for providing SRL. Figure 7 illustrates this effect.

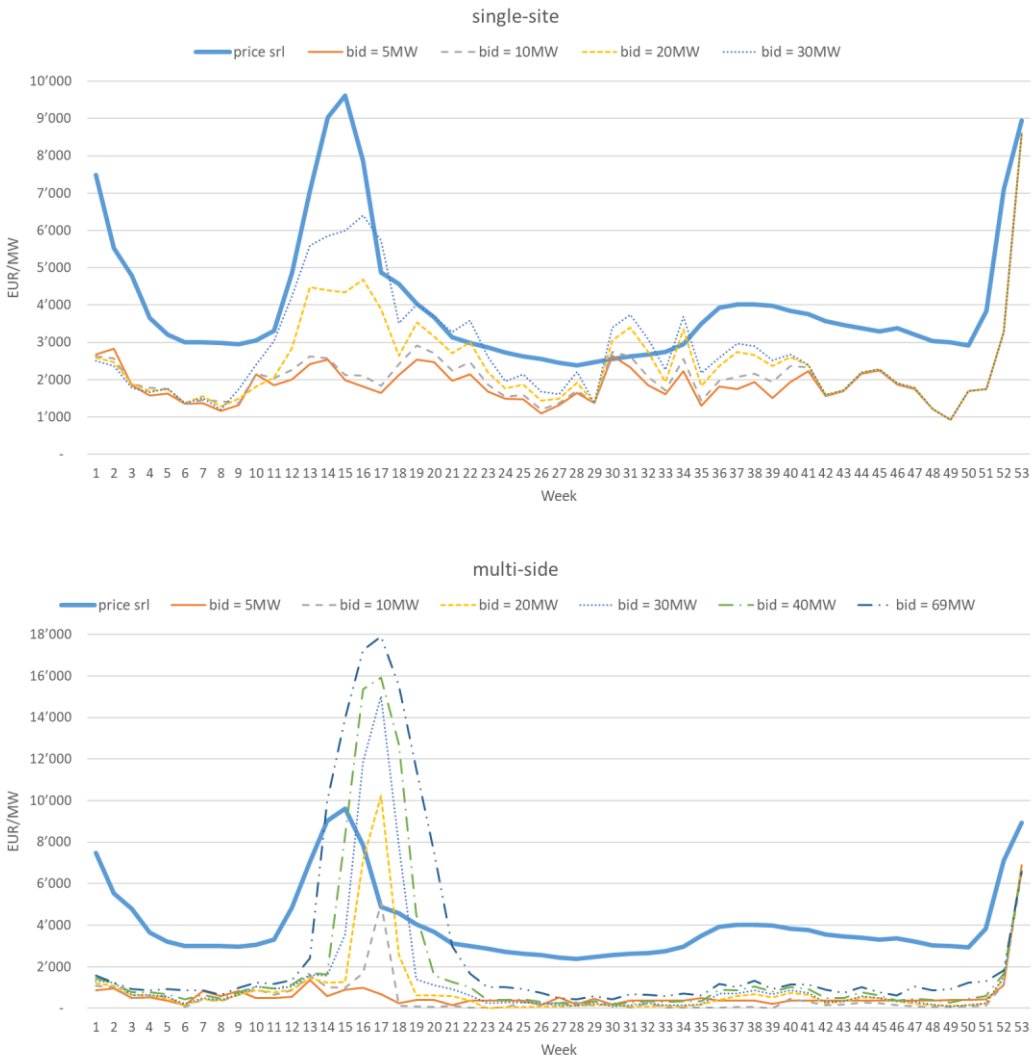


Figure 7: Srl price and opportunity cost of single-site (top) and multi-site (bottom) by size of srl bid for 2015.

Figure 7 shows a significant dependence on the opportunity costs on the size of the SRL bid. The higher the size of the SRL bid, the higher the opportunity cost for 1MW of SRL since a higher amount of water has to be reserved in the reservoir in order to be able to fulfill the reserve obligations. Especially in spring the SRL prices seems to be significantly influenced by the bid size. While for a minimum bid size of 5MW, almost no spring peak in the opportunity costs can be observed, opportunity costs start to peak at higher bid sizes. Due to low reservoir levels in spring, providing higher amounts of SRL at that time leads to significant shifts in the hydropower operation schedule. Having a look at the different cascade characteristics, the multi-site (bottom figure) has much higher opportunity cost in spring as compared to the single-site (top figure). Apart from spring, however, the single-site has higher opportunity costs as the multi-site. In general, our results confirm that larger

cascades can provide SRL at lower opportunity costs (apart from spring). Since it is possible to bid a portfolio of plants into the SRL market, larger cascades can optimally split their reserve obligations among the plants of the cascade based on the respective costs of each plant. Some of the larger cascades also include run-of-river (RoR) plants. In times the inflows are high enough and RoR plants are running at full load anyway, they are able to provide the negative part of the SRL product at low costs. In spring when the inflows are low, RoR plants cannot contribute that much to the SRL obligations. At the same time, the reservoirs of the storage plants of the cascade are empty. This combination leads to high opportunity costs at higher bid sizes for larger cascades at that time.

4.2 Short-term trading options

In reality, hydropower plants are not just traded on the day-ahead market but also on more short-term markets (i.e., intraday markets) in order to value their flexibility (see, e.g., Fodstad et al., 2018). Thus, intraday markets are considered in addition to day-ahead markets. Figure 8 illustrates the impact of intraday markets on the opportunity cost for providing SRL for single- and multi-site plants for a bid size of 20MW. Figures on other bid sizes can be found in the appendix (A3.2).

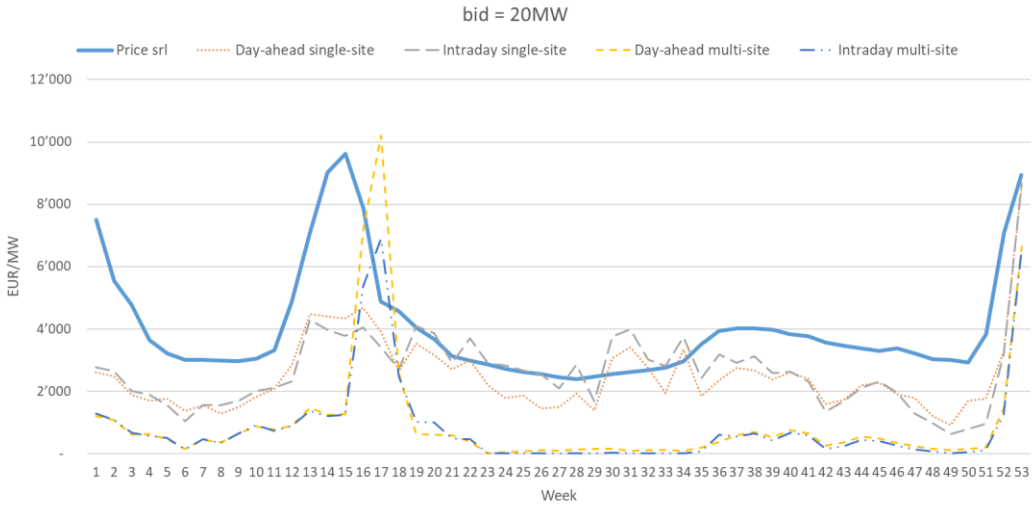


Figure 8: Srl price and opportunity cost of single- and multi-site for a bid of 20MW by market for 2015.

Comparing the opportunity cost for SRL with and without taking into account intraday trade shows that intraday markets have only a minor impact on the opportunity cost level. For single-site plants, generation schedules and corresponding opportunity cost for SRL are slightly changed. In most of the weeks, opportunity costs are slightly increased if the hydropower plant is traded on the day-ahead and intraday market compared to pure day-ahead market trade. For the multi-side cascade, intraday markets seem to have no significant impact on the opportunity costs for SRL beside a reduction in the spring peak. As shown in the previous chapter, the spring peak in opportunity cost is more defined by storage plants along a cascade. For them, intraday markets have an impact on the generation schedule. However, the overall opportunity cost level is also defined by inflexible plants of the cascade. For such plants, generation is mostly driven by hydrology and not by

spot prices leaving their generation schedules unchanged even with changes in prices or trading options.

4.3 Technical plant characteristics

Since the basic model simplifies technical characteristics which have an impact on the generation schedule of storage plants, a mixed-inter model formulation is used to approximate the impact of head effects on the opportunity costs. Figure 9 compares the opportunity cost for SRL of the basic model with the results of the mixed-integer model and the SRL prices. Single- and multi-site opportunity cost for a bid size of 20MW for the year 2015 are illustrated.[4]

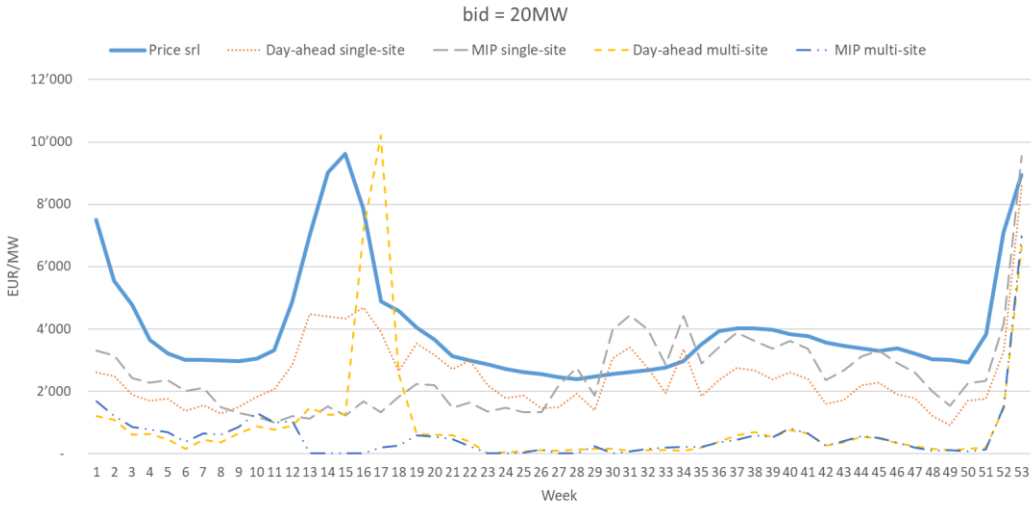


Figure 9: Srl price and opportunity cost of single- and multi-site for a bid of 20MW with and without head effects for 2015.

Having a look at Figure 9, the first thing that stands out is that the spring peak in the opportunity costs does not occur when taking into account head effects. If head effects are considered in the model, the plant operator has an incentive to operate the plant such that the head and correspondingly the turbine efficiency are maximized. Because of that, the storage reservoir is not fully emptied in spring as illustrated for the single-site in Figure 10 (see appendix A3.2 for multi-site).

[4] Since the mixed-integer model is computationally demanding, only a limited number of cascades for a limited amount of bid sizes and years are calculated.

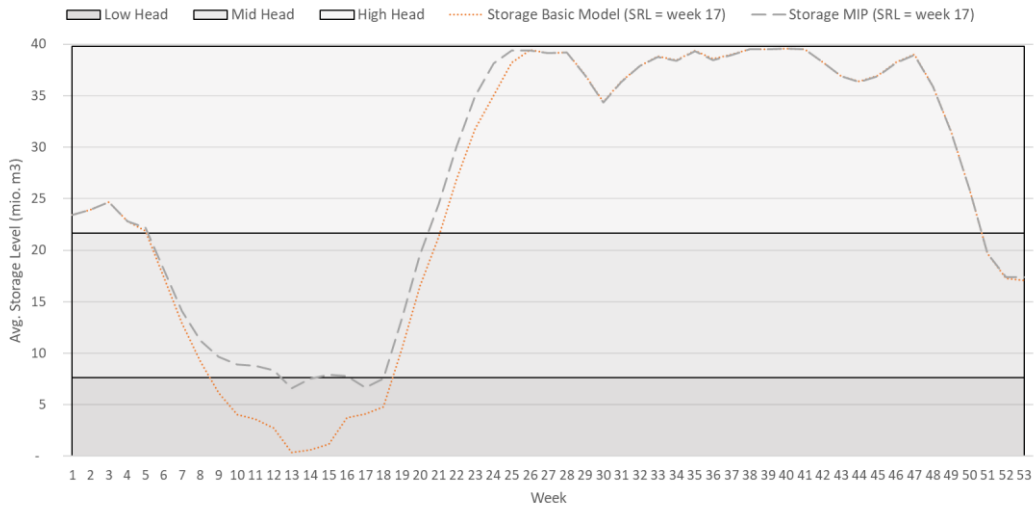


Figure 10: Storage Level of single-site for basic model and MIP. In week 17 of the year, 20MW of SRL are provided.

If the storage reservoir is emptied less, flexibility is higher during that time. This could reduce the opportunity cost in spring but the complete disappearance of the spring peak in our case seems to be a model artifact resulting from our inaccurate data on the head effects of the individual plants. Apart from the spring peak, the overall opportunity costs are increased when taking into account head effects (see Figure 9). While this effect is especially visible for the single-site plant, it can only be observed in the first quarter of the year for the multi-site cascade. Since multi-site cascades include also small storage plants as well as RoR plants for which head effects are not considered in our model, the impact of head effects on the opportunity cost of multi-site cascades is rather small.

4.4 Uncertainty in day-ahead market prices

In the basic model we neglect any uncertainties. However, in reality generation planning is made under uncertainty, e.g., price uncertainty. To analyze the impact of uncertainty in the day-ahead market prices on the opportunity cost for SRL, the basic model was extended to a stochastic model. Figure 10 illustrates the opportunity costs for a SRL bid of 20MW with and without day-ahead price uncertainty for a single- and multi-site plant compared to the SRL price for 2015. Results on additional years, cascades and bid sizes can be found in the appendix (A3.2).

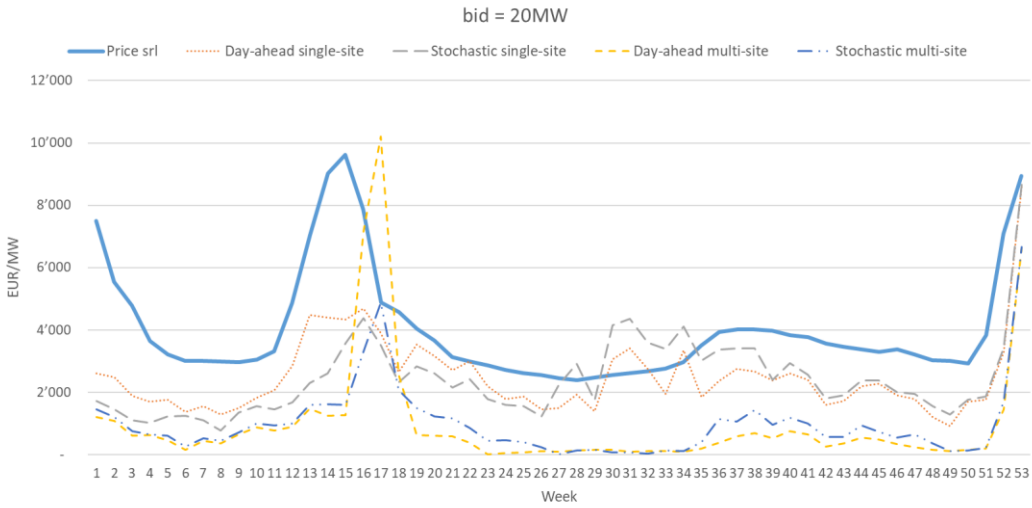


Figure 11: Srl price and opportunity cost of single and multi-site plants for a bid of 20MW with and without day-ahead price uncertainty for 2015.

As shown in Figure 11, uncertainty in the day-ahead market prices changes the opportunity costs for SRL for both, single- and multi-site plants. While the opportunity costs for SRL of the single-site plant are increased in the second half of the year under price uncertainty, opportunity costs under uncertainty are lower in the first quarter of the year. The spring peak in the opportunity costs of the single-site plant is similar with and without price uncertainty. As illustrated for the single-site in Figure 12, the hydropower plant is operated differently if price uncertainty is taken into account (see appendix A3.2 for multi-site).

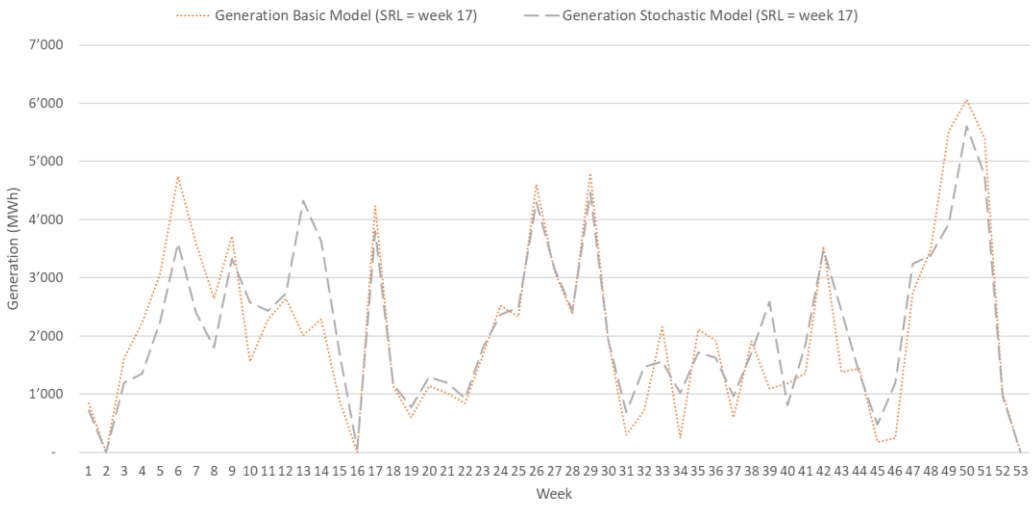


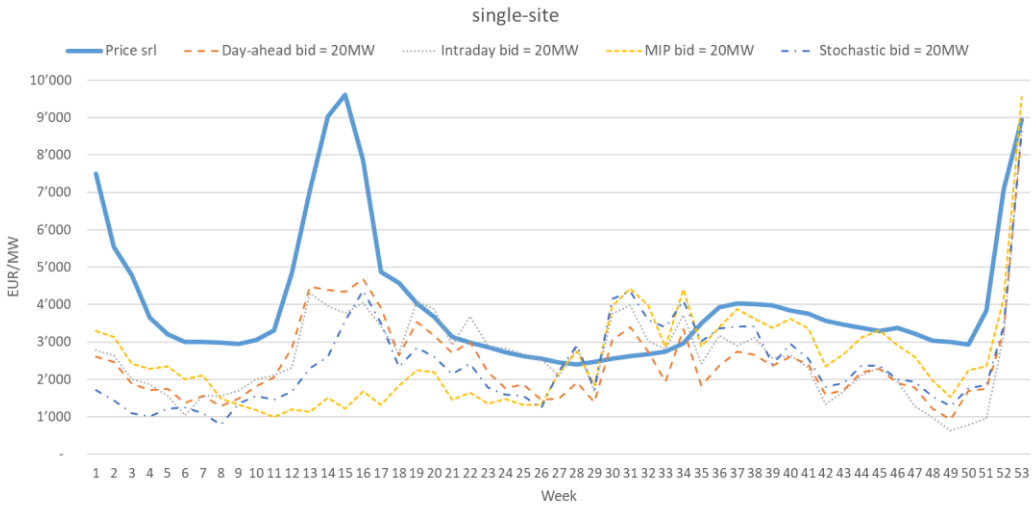
Figure 12: Generation single-site for basic and stochastic model. In week 17 of the year, 20MW of SRL are provided.

With changes in the generation schedule when taking into account price uncertainty, also the opportunity costs change. For the multi-site plant, opportunity costs for SRL are slightly higher under price uncertainty almost all weeks of the year (see Figure 11). However, as for the single-site plant opportunity costs of the multi-site plant significantly change in the second half of the year due to uncertainty in the day-ahead market prices. Compared to the single-site plant, the spring peak in the opportunity costs of the multi-site plant is significantly lower than the deterministic spring peak.

5 Discussion

In this paper, we derived a competitive benchmark for the Swiss SRL prices by analysing the opportunity cost of hydropower for providing SRL. Our results indicate that the historic Swiss SRL prices can be justified by the opportunity costs of hydropower. As in the Norwegian case (Gebrekiros et al., 2013), we could show for Switzerland that providing balancing power could significantly alter optimal generation schedules of hydropower and that the resulting losses in profits are reflected in the balancing prices. While, e.g., Heim and Goetz (2013) or Ocker and Ehrhart (2017) found balancing prices which deviate from the competitive level for the German SRL market, we cannot confirm this findings for the Swiss SRL market based on our method and data. This may results from the differences between the German and Swiss SRL markets regarding their market design, market structure or generation mix. Since the Swiss SRL demand is quite low but the number of hydropower firms which could satisfy demand quite high, there should be enough competition in the Swiss SRL market. In addition, while the German SRL market is dominated by conventional technologies, the Swiss SRL market is dominated by hydropower which makes Swiss SRL prices dependent on hydrological conditions. In spring when the inflows are low and the storage reservoirs empty, opportunity costs for SRL are highest. This peak is especially pronounced for higher bid sizes. According to our results, single- as well as multi-sites have an impact of the opportunity costs for SRL. While single-site plants or smaller cascades seem to have a bigger impact on the overall SRL price level (apart from spring), larger cascades significantly influence the spring peak. However, in this paper, we only have a look at a limited number of Swiss hydropower cascades. Since each hydropower plant is unique, drawing conclusions about Swiss hydropower as a whole could be misleading.

Regarding the opportunity cost drivers, our results have shown that the opportunity costs of hydropower for providing SRL are influenced by a variety of drivers. Figure 13 summarizes these findings.



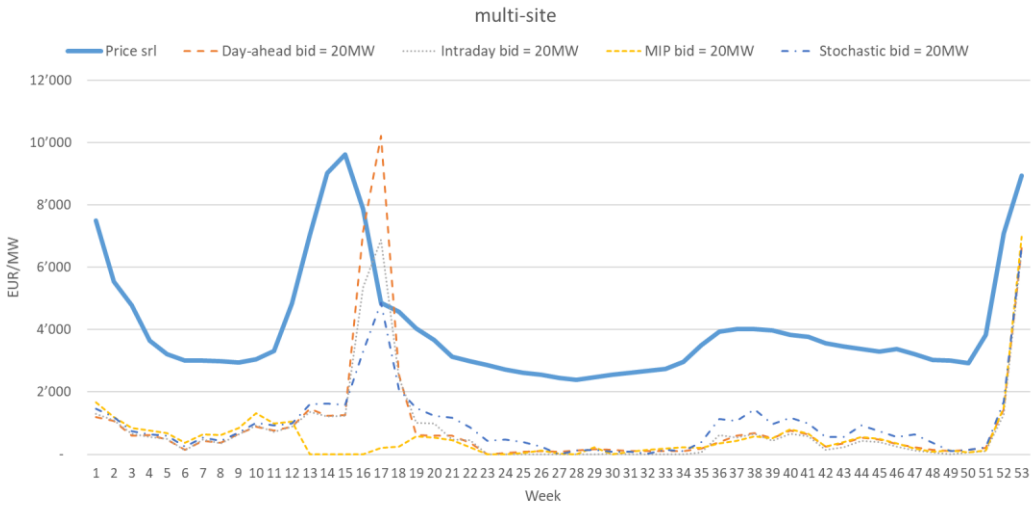


Figure 13: Srl price and opportunity cost of single-site (top) and multi-site (bottom) by model for a bid of 20MW for 2015.

As illustrated in Figure 13, short-term trading options, head effects and price uncertainty all can have an impact on the opportunity costs and should thus be considered in analysing the opportunity costs and the corresponding SRL prices of a hydro-dominated electricity system. Our results indicate that apart from spring, single-site plants (top figure) are more influenced by these drivers than multi-site cascades (bottom figure) since multi-site cascades can split their reserve obligation among various plants and reservoirs. While our results indicate that all three drivers can influence the opportunity costs for providing SRL, we cannot clearly quantify the magnitude of this influence. Since the impact of these drivers on the opportunity costs can be site-specific, drawing any overall conclusion on the magnitude could be misleading. In addition, due to limited data availability, e.g., on site-specific head effects, our results may under- or overestimate the impact of a specific driver. While we only have a look at the individual effects of these drivers on the opportunity costs, the combined effects could be much larger. However, there is a trade-off between analysing the combined effect of drivers on the opportunity costs for balancing power and considering a time horizon which is sufficiently long to capture market characteristics and hydrological conditions.

6 Conclusions

In this paper, we had a look at the balancing market prices of a hydro-dominated electricity system using Switzerland as a case study. By using a short-term hydropower operation model and a set of Swiss hydropower plants, we were able to identify a competitive benchmark for Swiss balancing market prices defined by the opportunity costs of hydropower for providing balancing power. Our results indicate that Swiss SRL market prices are not influenced by any market imperfections (e.g., market power) but can be justified by the opportunity cost of Swiss hydropower. Opportunity cost of Swiss hydropower are influenced by hydrological conditions and vary for different cascade structures. In addition,

short-term trading options, head effects and price uncertainty have an influence the opportunity cost level. However, due to limitations of this paper, we are not able to exactly quantify the magnitude of the influence of these drivers. This may be addresses in future research with more detailed data.

Balancing markets differ in their design across countries (see e.g., Ocker et al., 2016). Because of this, the European Commission introduced a guideline for the harmonization of balancing markets (European Commission, 2017) in the course of the ongoing energy transition. The Swiss balancing market will thus be adjusted in their design within the next years (see e.g., Swissgrid AG, 2018). Changes in the balancing market design may also change the opportunity cost of hydropower for providing balancing services and consequently the balancing market prices. The impact of a change in the Swiss balancing market design should be addresses in future research.

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Appendix

A1 Model Supplement

A1.1 Technical plant characteristics

The mixed-integer approach used in this paper for the approximation of head effects is based on Conejo et al. (2002). For plants and reservoirs along the cascade for which head effects are neglected ($i = nh$ or $r = nh$), the model is the same as the basic model. For plants and reservoirs along the cascade for which head effects are considered ($i = h$ or $r = h$), the basic model is adjusted.

The objective of the plant operator is to maximize its weekly revenue in the day-ahead market taking into account the future value of water. The water values are derived from a yearly model. However, due to the time intensive solution process when taking into account head effects, the yearly model assumes a constant head.

$$\max R_{DA} = \sum_{t,i} p_t G_{t,i} + \sum_{r} S_{t^{end},r}\, wv_{t^{end},r}$$

The generation of each turbine is defined by the water to energy conversion factor η and the water which is discharged through the turbine $D_{t,i}$. If no head effects are considered Eta is assumed to be constant.

$$G_{t,i} = \eta_i D_{t,i} \qquad \forall t, i = nh$$

If head effects are considered, Eta and the corresponding generation depends on the discharge and the head level. For each head level and for each discharge block ($D_{t,i,b}$) an Eta ($\eta_{i,b,1,2,3}$) is defined. The binary variables $d_{r,t,1,2}$ are used to define the head level at which the plant is operating at a specific point in time. Compared to Conejo et al. (2002) we do not take into account a minimum generation level at which the plant has to be operated if it is running due to a lack of data.

$$G_{t,i} - \sum_{b} D_{t,i,b}\, \eta_{i,b,1} - g_i^{max} \left(\sum_{map_{i,r}} (d_{r,t,1} + d_{r,t,2}) \right) \leq 0 \qquad \forall t, i = h$$

$$G_{t,i} - \sum_{b} D_{t,i,b}\, \eta_{i,b,1} + g_i^{max} \left(\sum_{map_{i,r}} (d_{r,t,1} + d_{r,t,2}) \right) \geq 0 \qquad \forall t, i = h$$

$$G_{t,i} - \sum_{b} D_{t,i,b}\, \eta_{i,b,2} - g_i^{max} \left(\sum_{map_{i,r}} (1 - d_{r,t,1} + d_{r,t,2}) \right) \leq 0 \qquad \forall t, i = h$$

$$G_{t,i} - \sum_{b} D_{t,i,b}\, \eta_{i,b,2} + g_i^{max} \left(\sum_{map_{i,r}} (1 - d_{r,t,1} + d_{r,t,2}) \right) \geq 0 \qquad \forall t, i = h$$

$$G_{t,i} - \sum_{b} D_{t,i,b}\,\eta_{i,b,3} - g_i^{max}\left(\sum_{map_{\underline{i},r}} (2 - d_{r,t,1} - d_{r,t,2})\right) \leq 0 \qquad \forall t, i = h$$

$$G_{t,i} - \sum_{b} D_{t,i,b}\,\eta_{i,b,3} + g_i^{max}\left(\sum_{map_{\underline{i},r}} (2 - d_{r,t,1} - d_{r,t,2})\right) \geq 0 \qquad \forall t, i = h$$

The total discharge ($D_{t,i}$) is defined by the discharge over all discharge blocks. A minimum discharge level is not considered in this paper.

$$D_{t,i} = \sum_{b} D_{t,i,b} \qquad \forall t, i = h$$

To define at which discharge level the plant is operating, the maximum discharge by block ($d_{i,b}^{max}$) and the binary variable ($W_{t,i,b}$), which is equal to 1 if the discharge exceeds the maximum discharge of a specific discharge block, are considered.

$$D_{t,i,b=1} \leq d_{i,b=1}^{max} \qquad \forall t, i = h$$

$$D_{t,i,b=1} \geq d_{i,b=1}^{max} W_{t,i,b=1} \qquad \forall t, i = h$$

$$D_{t,i,b} \leq d_{i,b}^{max} W_{t,i,b-1} \qquad \forall t, i = h, b$$

$$D_{t,i,b} \geq d_{i,b}^{max} W_{t,i,b} \qquad \forall t, i = h, b$$

The storage level in each hour for each reservoir is defined as in the basic model.

$$S_{t,r} = S_{t-1,r} + i_{t,r} - \sum_{map_{\underline{i},r}} D_{t,\underline{i}} - \sum_{map_{\underline{i},r}} Spill_{t,\underline{i}} + \sum_{map_{\overline{i},r}} D_{t,\overline{i}} + \sum_{map_{\overline{i},r}} Spill_{t,\overline{i}} \qquad \forall t, r$$

Following Conejo et al. (2002) the head level is approximated by the storage level. Thus, different storage intervals belong to specific head levels. The following three equations define at which head level the plant is operating at a specific point in time based on the lower (s_r^{low}) and upper (s_r^{up}) storage bound and the binary variable $d_{r,t,1,2}$. If both $d_{r,t,1}$ and $d_{r,t,2}$ are equal to zero, the storage level is between the minimum storage level and the lower bound. This range belongs to a low head. If $d_{r,t,1}$ is equal to one and $d_{r,t,2}$ equal to zero, the plant is operating at the intermediate head level. If both binary variables are equal to one, the storage level belongs to a high head.

$$S_{t,r} \geq s_r^{low}\left(d_{r,t,1} - d_{r,t,2}\right) + s_r^{up}\, d_{r,t,2} \qquad \forall t, r = h$$

$$S_{t,r} \leq s_r^{max} d_{r,t,2} + s_r^{low}\left(1 - d_{r,t,1}\right) + s_r^{up}(d_{r,t,1} - d_{r,t,2}) \qquad \forall t, r = h$$

$$d_{r,t,1} \geq d_{r,t,2} \qquad \forall t, r = h$$

For plants for which no head effects are considered, the generation capacity is constrained by the minimum and maximum generation. For plants for which head effects are considered, this constraint is already included in previous equations.

$$g_i^{min} \leq G_{t,i} \leq g_i^{max} \qquad \forall t, i = nh$$

As in the basic model, the generation is constrained by the SRL bid if the plant is active on the SRL market. The minimum generation level has to be increased by the SRL bid while the maximum generation level is decreased by the SRL bid. While we assume a minimum generation level of zero, the maximum generation for plants for which head effects are considered depends on the respective head level. At different head levels different amounts of energy can be produced. Thus, the maximum generation of a plant for which head effects are considered ($g_{i=h}^{max}$) is adjusted by the difference in the maximum generation between consecutive head levels ($g_{i=h,1,2}^{\max diff}$). For plants for which head effects are neglected, this can be ignored.

$$\begin{aligned} g^{min} + bid^{srl} &\leq G_t \\ &\leq \sum_i (g_{i=nh}^{max} + g_{i=h}^{max} + g_{i=h,1}^{\max diff} \sum_{map_{\underline{i=h},r=h}} (d_{r=h,t,1} - 1) \\ &\quad + g_{i=h,2}^{\max diff} \sum_{map_{\underline{i=h},r=h}} (d_{r=h,t,2} - 1)\,) - bid^{srl} \qquad \forall t \end{aligned}$$

In order to be able to deliver what was bid into the balancing market in terms of energy, water has to be reserved in the reservoir. While these constraints are almost equivalent to the basic model formulation, the amount of water which has to be reserved in the reservoir is defined by the average conversion factor at low head ($\eta_{i,avg,1}$). This ensures that independent of the head level, enough water is stored in the reservoir to be able to deliver the SRL bid in terms of energy.

$$S_{t^{end},rr} \geq \left(\frac{2\ bid}{\eta_{i,avg,1}}^{srl}\right) t^{end} - i_{rr}^{future} \qquad \forall rr = h$$

$$S_{t,rr} \geq \frac{bid}{\eta_{i,avg,1}}^{srl} \left(t^{end} - t\right) - i_{rr}^{future} \qquad \forall t, rr = h$$

In addition to the storage constraints resulting from balancing market participation, the storage is constrained by its minimum and maximum storage level. While the maximum storage level for plants for which head effects are considered is already defined by previous equations, it needs to be considered for plants for which head effects are neglected. In addition, the storage level has to be greater or equal the minimum storage level. In our case, the minimum storage level is assumed to be zero.

$$S_{t,r} \geq s_r^{min} \qquad \forall t, r$$

$$S_{t,r} \leq s_r^{max} \qquad \forall t, r = nh$$

The storage level in the first hour is given either by historic data, if it is the first week of the year or in any other week of the year, by the storage end level of the previous week.

$$S_{t=1,r} = s_r^{start} \qquad \forall t = 1, r$$

For additional details on the mixed-integer model formulation see Conejo et al. (2002).

A1.2 Uncertainty in day-ahead market prices

To take into account uncertainty in the day-ahead market prices, a stochastic model is formulated. Details on stochastic modeling can be found, e.g., in Conejo et al. (2010) or Ladurantaye et al. (2009). The stochastic model applied in this paper is similar than the basic model formulation but defined on nodal basis. As described in section 3.1.4, each node belongs to a day of the week while each day has 24 hours. The objective of the plant operator is to maximize its weekly revenue in the day-ahead market taking into account the future value of water. With probability π_n a node belongs to a high or low price realization. To take into account the future value of water the storage level $S_{n=leaf,r}$ and the water value $wv_{n=leaf,r}$ for each reservoir r at the end of the week ($n = leaf$) are taken into account. The water values are derived from a stochastic yearly model. However, due to the time intensive solution process when taking into account price uncertainty, the yearly model considers price uncertainty only on a monthly basis (see chapter 3.1.4).

$$\max R_{DA} = \sum_{n,i} \pi_n \sum_{map_{n,t}} G_{n,t,i} p_{n,t} + \sum_{r} \pi_{n=leaf} S_{n=leaf,r}\, wv_{n=leaf,r}$$

The generation of each turbine, node and hour is defined by the water to energy conversion factor η and the water which is discharged through the turbine $D_{n,t,i}$. Each hour is mapped to the respective nodes by $map_{n,t}$. As in the basic model, no head effects are considered.

$$G_{n,t,i} = \eta_i D_{n,t,i} \qquad \forall t, i, n \; if \; map_{n,t}$$

The storage level at each node for each reservoir is defined by the storage level at the parent node ($S_{n=parent,r}$), the natural water inflows into the reservoir $i_{t,r}$, the water which is going out of the reservoir either by discharging $D_{n,t,\underline{i}}$ or spilling $Spill_{n,t,\underline{i}}$ it via the turbine below the reservoir $\underline{i}$ and the water which is ending up in the reservoir by discharge or spill from a turbine above the reservoir $\overline{i}$. Compared to the basic model, the storage level is defined on daily basis (i.e., each node belongs to a day of the week) instead of hourly basis.

$$S_{n,r} = \sum_{map_{n,parent}} S_{n=parent,r} + \sum_{map_{n,t}} \Big(i_{t,r} - \sum_{map_{\underline{i},r}} D_{n,t,\underline{i}} - \sum_{map_{\underline{i},r}} Spill_{n,t,\underline{i}} + \sum_{map_{\overline{i},r}} D_{n,t,\overline{i}} + \sum_{map_{\overline{i},r}} Spill_{n,t,\overline{i}} \Big) \qquad \forall r, n$$

The generation of each turbine, node and hour is constrained by the turbine capacity g_i^{max} as well as the minimum generation level g_i^{min}. As in the basic model, the minimum generation is assumed to be zero.

$$g_i^{min} \leq G_{n,t,i} \leq g_i^{max} \qquad \forall t, i, n \; if \; map_{n,t}$$

If a hydropower plant bids capacity into the weekly symmetric SRL market its minimum and maximum capacity is constrained by the SRL bid. As in the basic model, the constrained is related to the total cascade generation and not the generation of the individual plants of the cascade.

$$g^{min} + bid^{srl} \leq G_{n,t} \leq g^{max} - bid^{srl} \qquad \forall t, n \; if \; map_{n,t}$$

In order to be able to deliver what was bid into the balancing market in terms of energy, water has to be reserved in the reservoir in the weeks before the week for which capacity was bid into the SRL market as well as in the contracted week.

$$S_{n,rr} \geq \left(\frac{2\, bid^{srl}}{\eta_i}\right) t^{end} - i_{rr}^{future} \qquad \forall rr, n \; if \; map_{n,t=end}$$

$$S_{n,rr} \geq \frac{bid^{srl}}{\eta_i} \left(t^{end} - t\right) - i_{rr}^{future} \qquad \forall n, rr \; if \; map_{n,t}$$

In addition, the storage is constrained by its minimum and maximum storage level and the storage at the beginning of the week is defined by the storage start value.

$$s^{min} \leq S_{n,r} \leq s^{max} \qquad \forall r, n$$

$$S_{n,r} = s^{start} \qquad \forall n, r \; if \; map_{n,t=start}$$

For additional details on the stochastic model formulation see, e.g., Conejo et al. (2010) or Ladurantaye et al. (2009).

A2 Data Supplement

Table A 1: Head data for cascades for which head effects are considered. Data based on Balmer (2006), Garrison et al. (2018), Schlecht and Weigt (2014) and SFOE (2018).

Cascade Nr.	**1**	**3**	**6**	**7**
Power high head block 1 (MW)	15	16	17	38
Power high head block 2 (MW)	29	33	34	75
Power high head block 3 (MW)	46	51	54	118
Power high head block 4 (MW)	54	60	63	138
Power mid head block 1 (MW)	14	16	16	33
Power mid head block 2 (MW)	28	32	33	66
Power mid head block 3 (MW)	43	50	51	104
Power mid head block 4 (MW)	51	59	60	122
Power low head block 1 (MW)	13	16	16	29
Power low head block 2 (MW)	26	31	31	58
Power low head block 3 (MW)	41	49	49	90
Power low head block 4 (MW)	48	57	57	106
Discharge Block 1 (m3/s)	10	6	5	10
Discharge Block 2 (m3/s)	18	11	9	20
Discharge Block 3(m3/s)	28	17	14	30
Discharge Block 4 (m3/s)	32	20	17	35
High Head (m)	190	372	480	489
Mid Head (m)	179	364	460	432
Low Head (m)	167	356	439	375

A3 Results Supplement

A3.1 Model Structure Comparison

While using a weekly model with water values instead of a yearly model with predefined storage values at the beginning and end of the year, some differences, e.g., regarding the storage levels or the revenues, already occur from changes in the model structure. Figure A 1 compares the storage level from the yearly and the weekly model and shows the differences for the single site (i.e., cascade nr. 3). In addition, differences in the weekly revenues are illustrated.

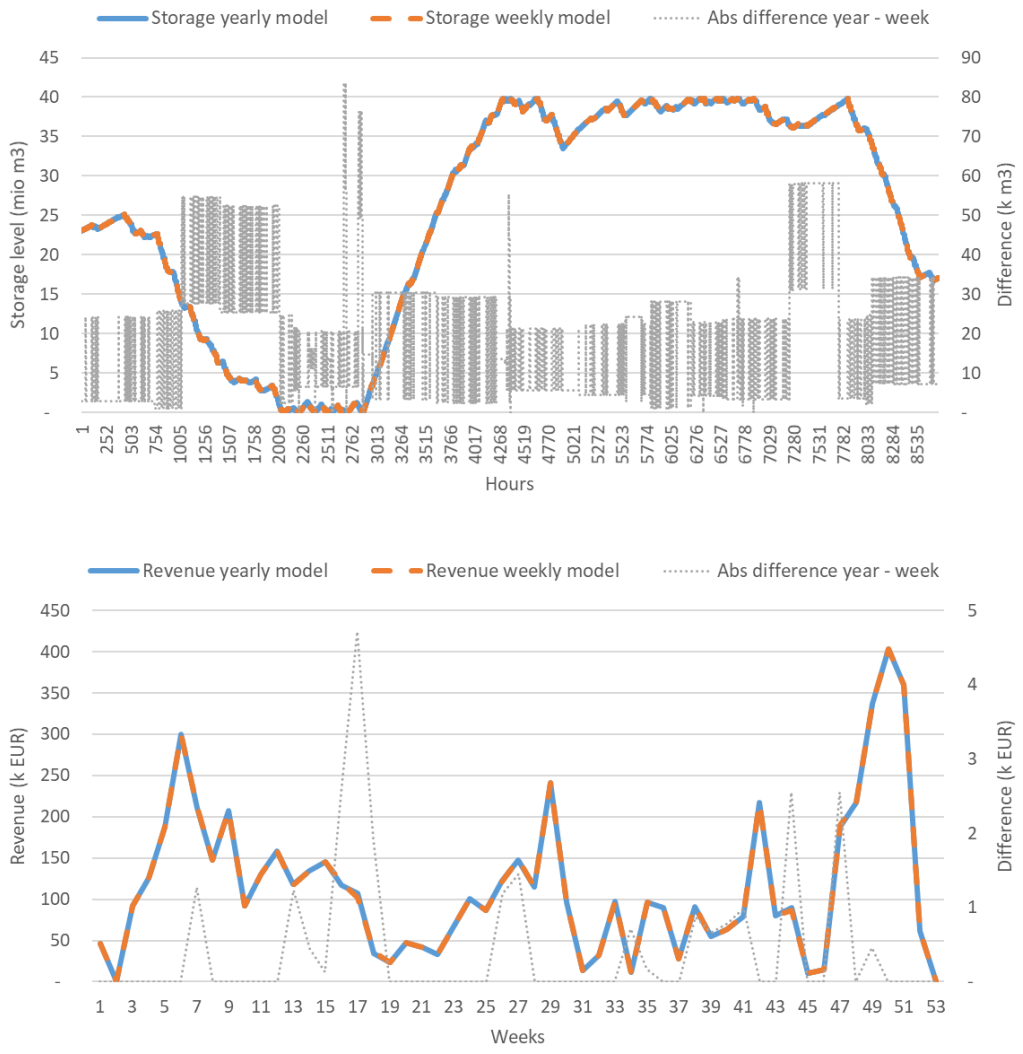

Figure A 1: Comparison of storage level and weekly revenue for yearly and weekly model structures.

A3.2 Additional Results

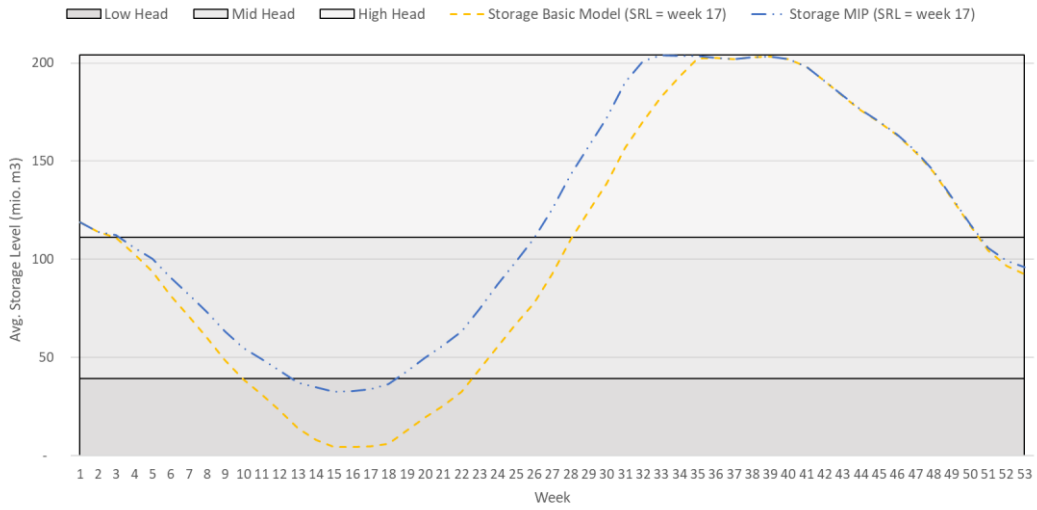

Figure A 2: Storage Level of biggest reservoir of multi-site for basic model and MIP. In week 17 of the year, 20MW of SRL are provided.

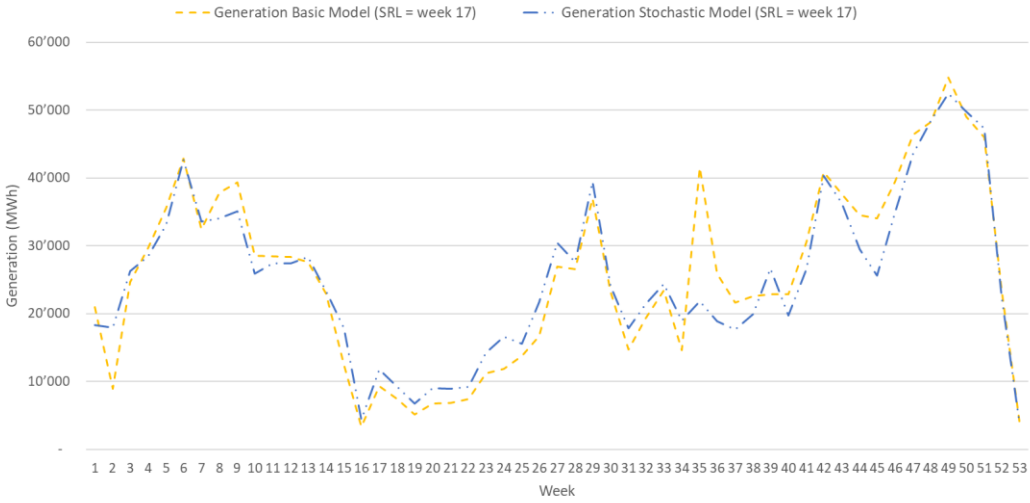

Figure A 3: Generation multi-site for basic and stochastic model. In week 17 of the year, 20MW of SRL are provided.

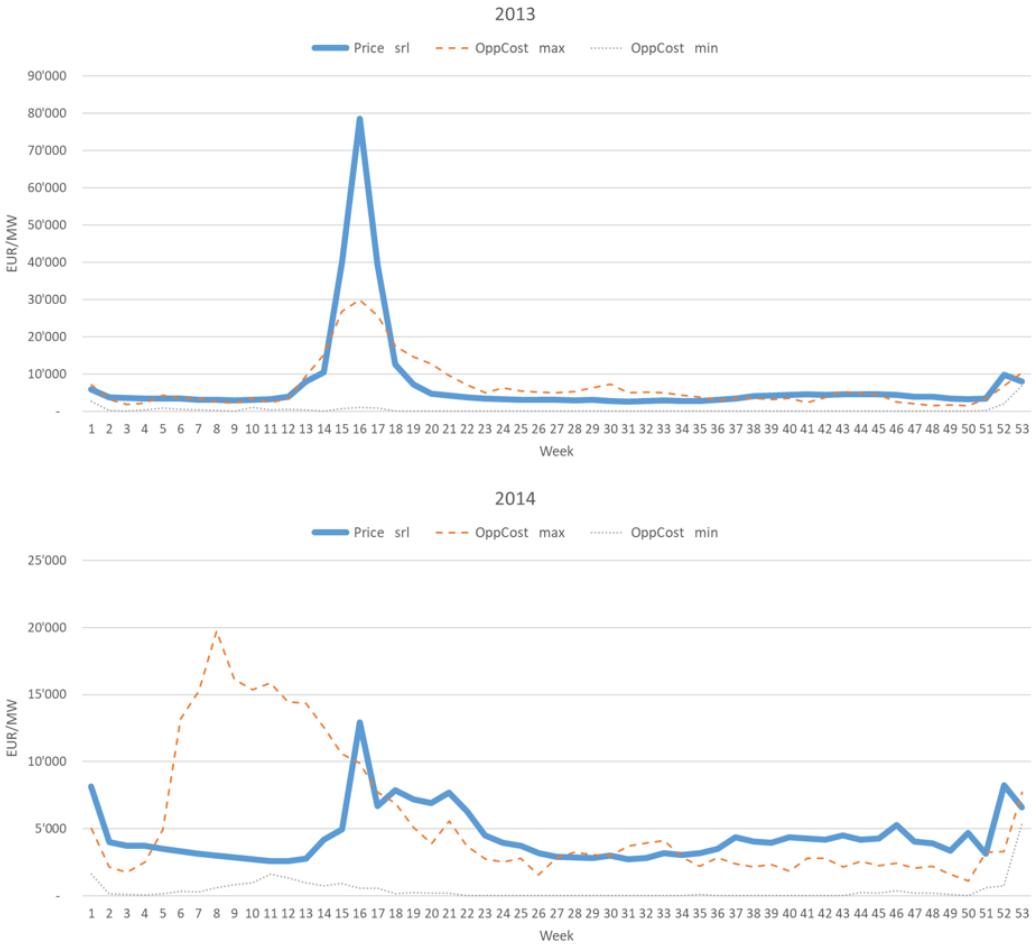

Figure A 4: Srl price and maximum/ minimum opportunity cost of sample for 2013 (top) and 2014 (bottom).

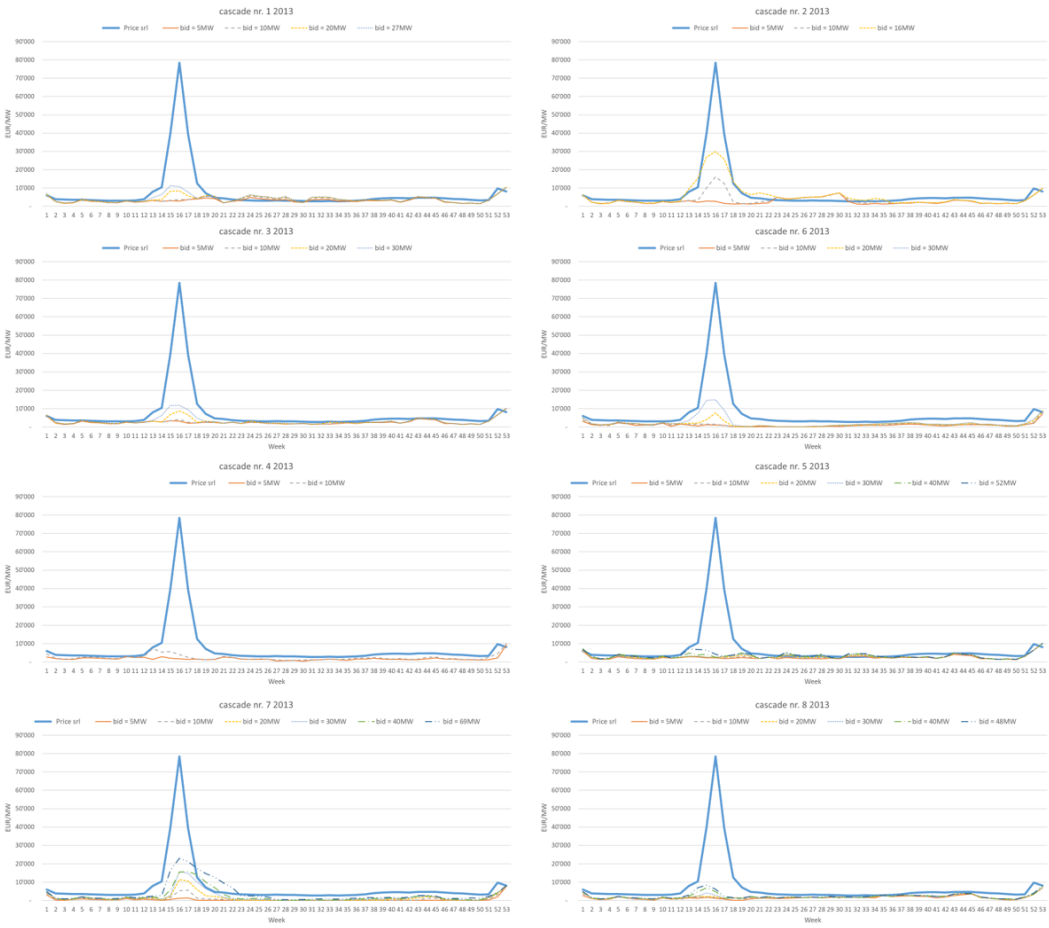

Figure A 5: Srl price and opportunity cost by size of srl bid for 2013.

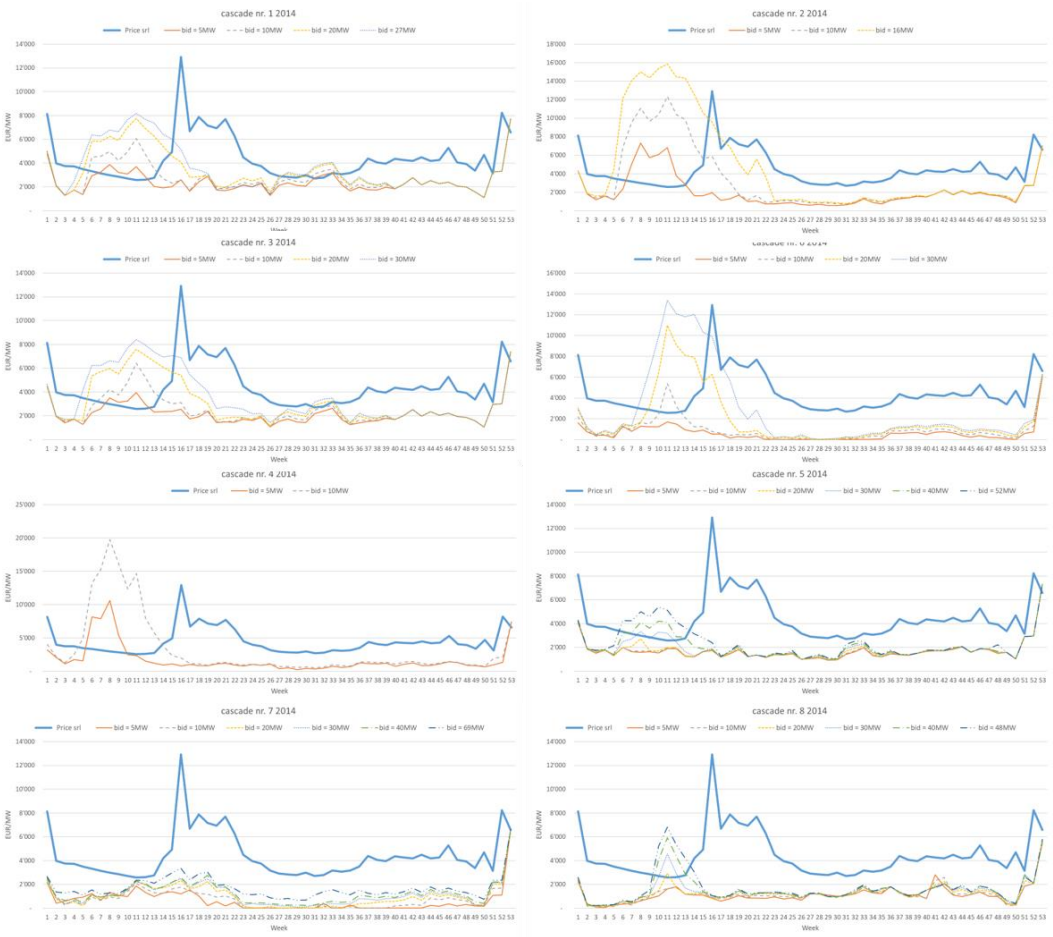

Figure A 6: Srl price and opportunity cost by size of srl bid for 2014.

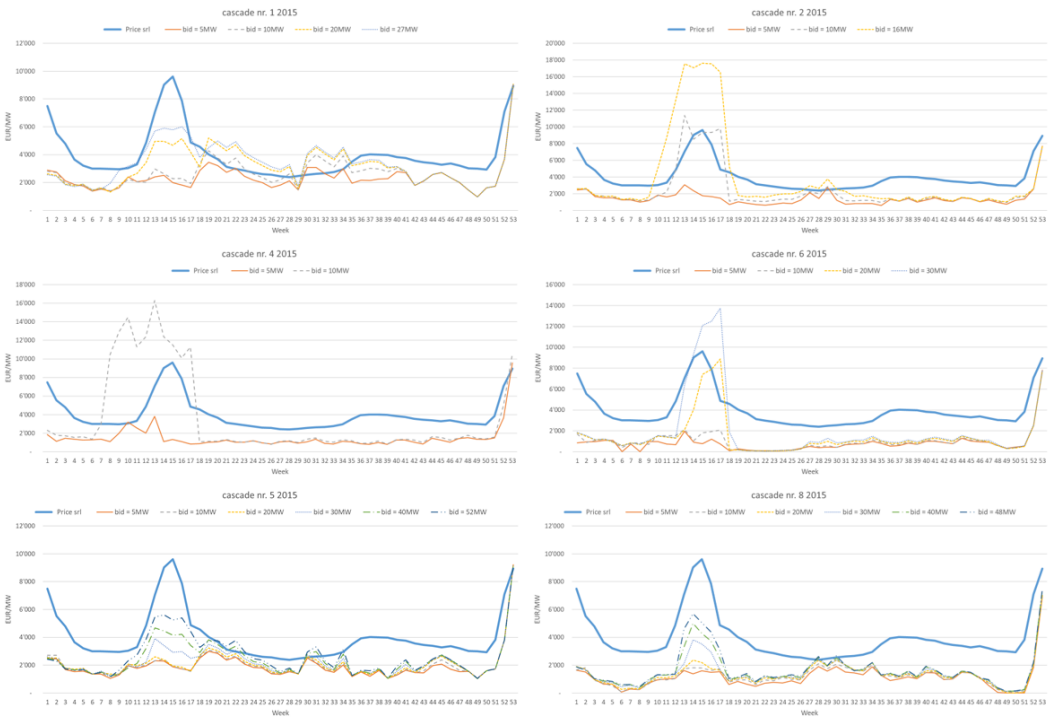

Figure A 7: Srl price and opportunity cost by size of srl bid for 2015.

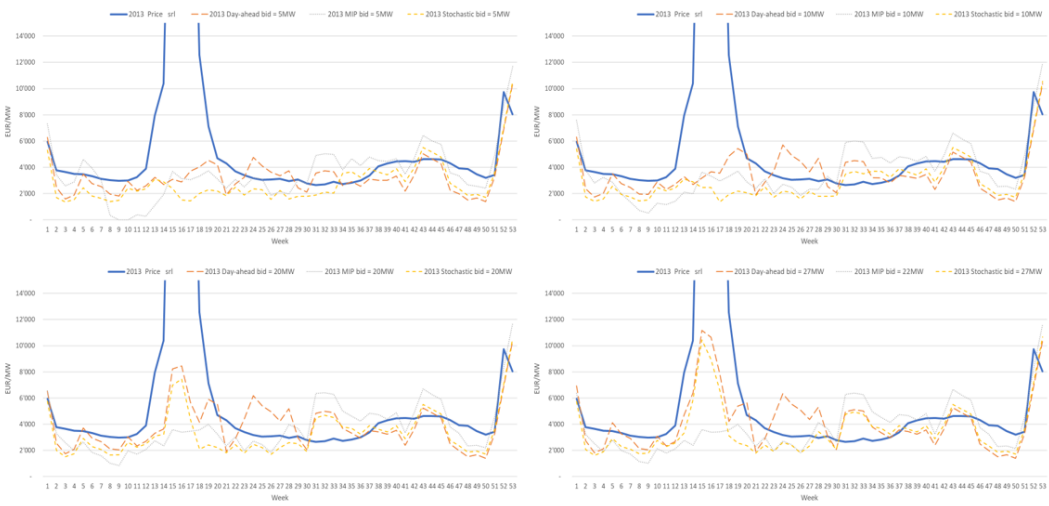

Figure A 8: Srl price and opportunity cost by model and bid size for cascade 1 for 2013.

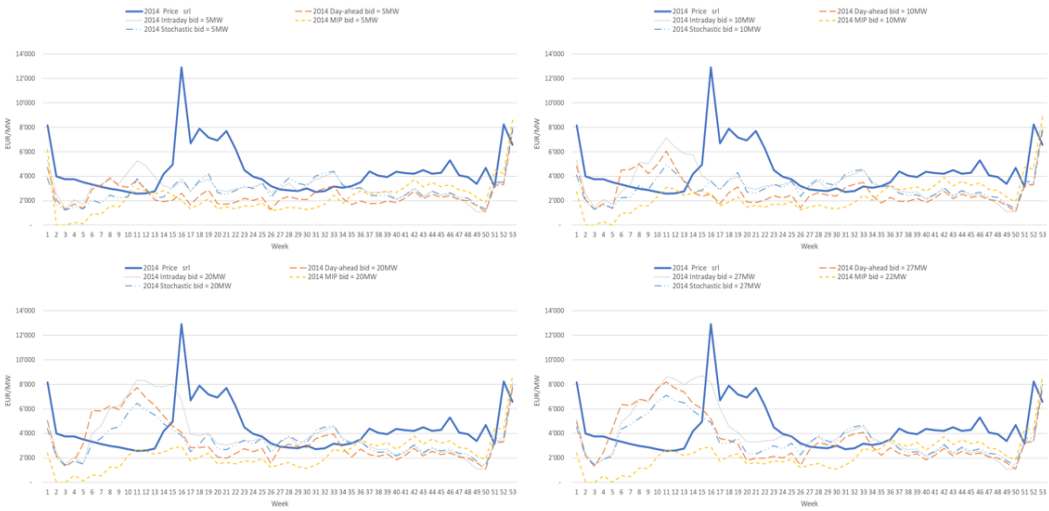

Figure A 9: Srl price and opportunity cost by model and bid size for cascade 1 for 2014.

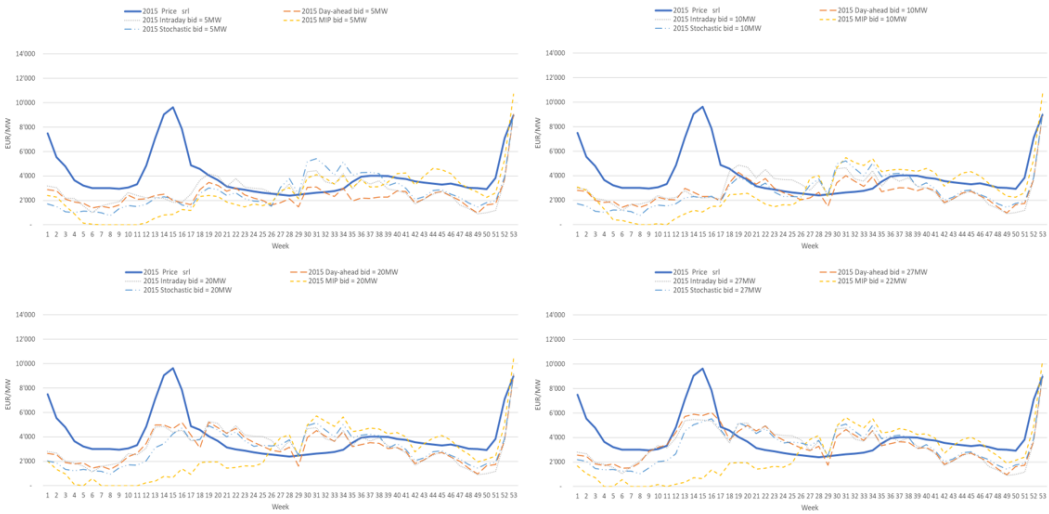

Figure A 10: Srl price and opportunity cost by model and bid size for cascade 1 for 2015.

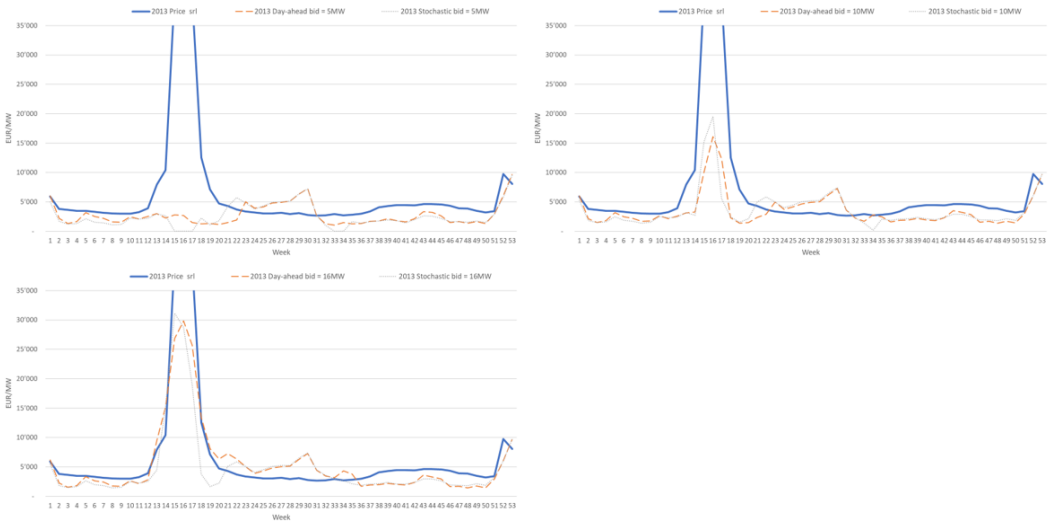

Figure A 11: Srl price and opportunity cost by model and bid size for cascade 2 for 2013.

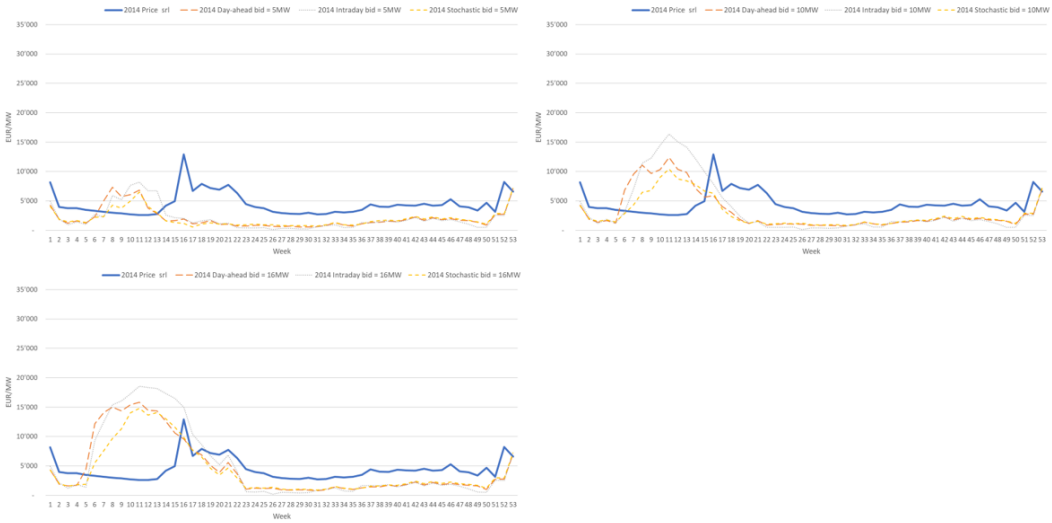

Figure A 12: Srl price and opportunity cost by model and bid size for cascade 2 for 2014.

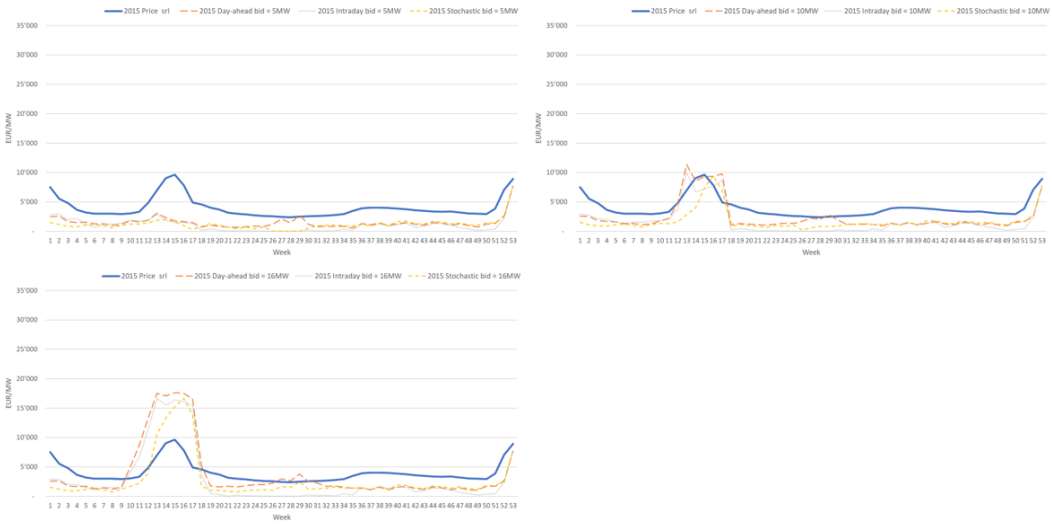

Figure A 13: Srl price and opportunity cost by model and bid size for cascade 2 for 2015.

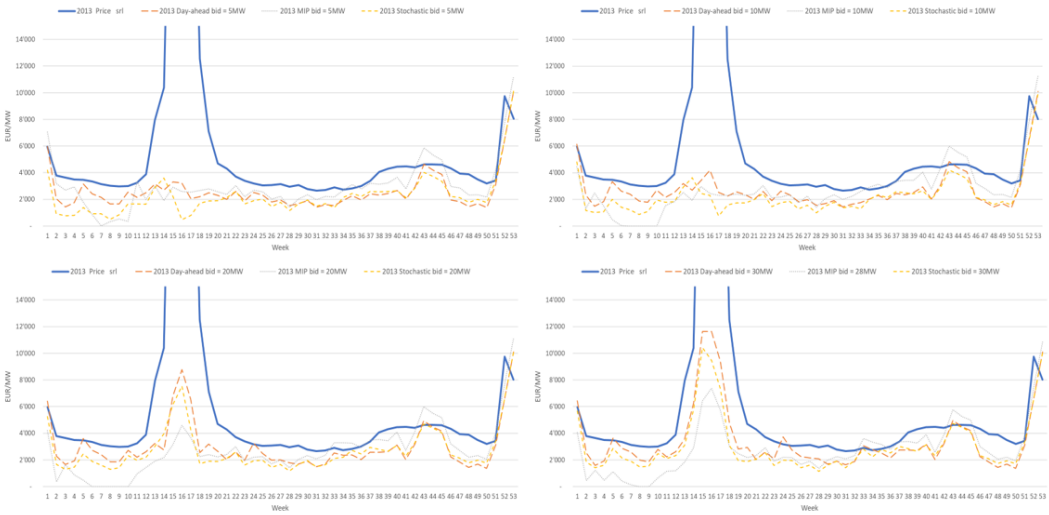

Figure A 14: Srl price and opportunity cost by model and bid size for cascade 3 for 2013.

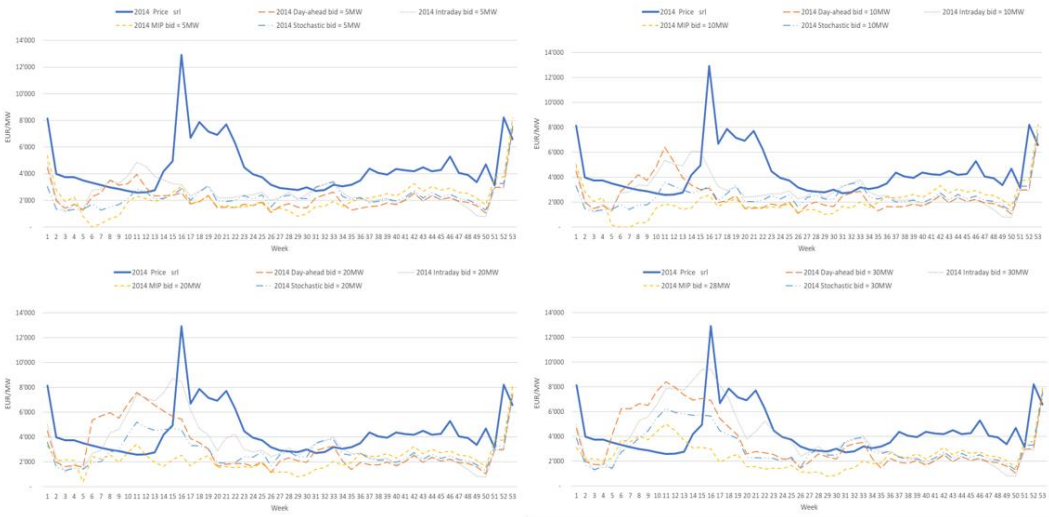

Figure A 15: Srl price and opportunity cost by model and bid size for cascade 3 for 2014.

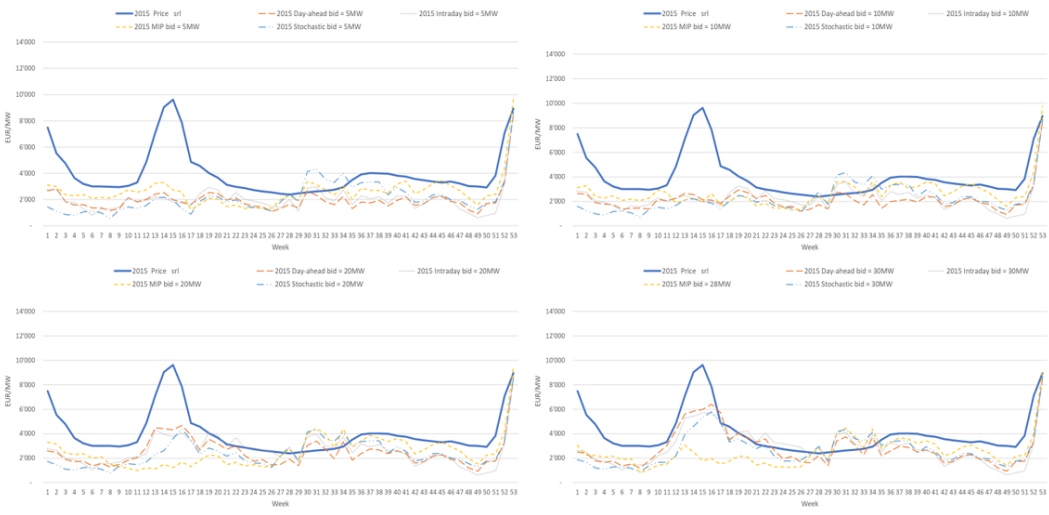

Figure A 16: Srl price and opportunity cost by model and bid size for cascade 3 for 2015.

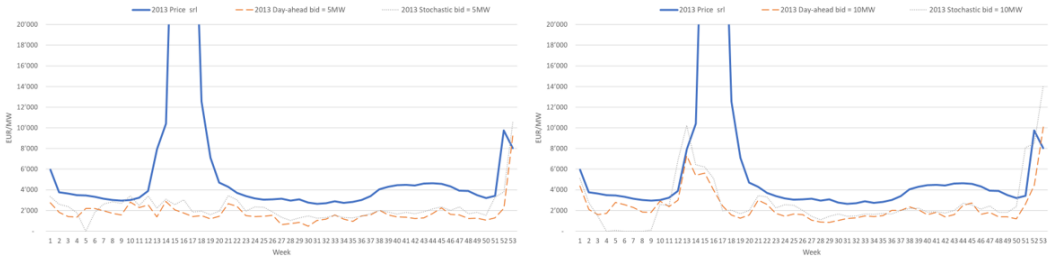

Figure A 17: Srl price and opportunity cost by model and bid size for cascade 4 for 2013.

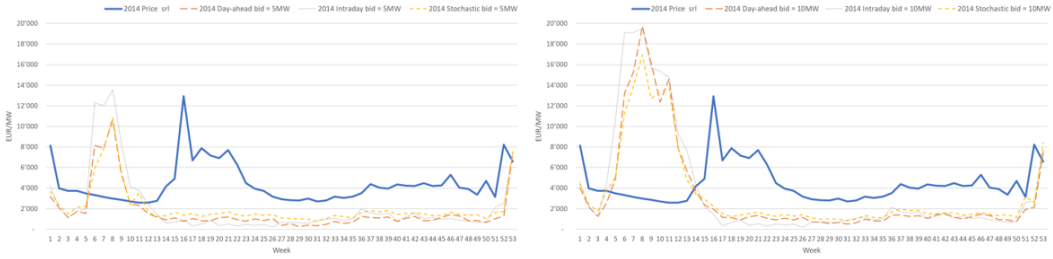

Figure A 18: Srl price and opportunity cost by model and bid size for cascade 4 for 2014.

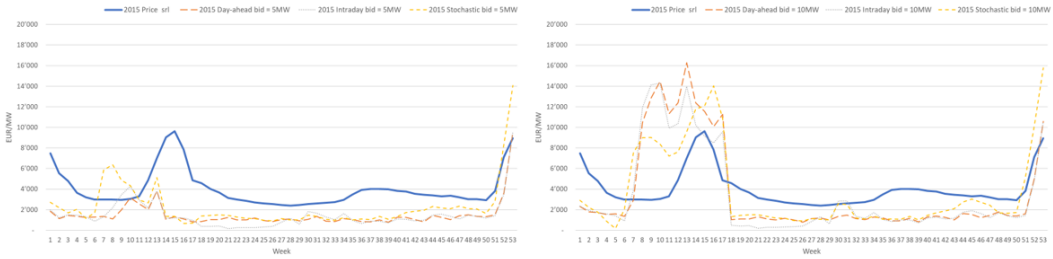

Figure A 19: Srl price and opportunity cost by model and bid size for cascade 4 for 2015.

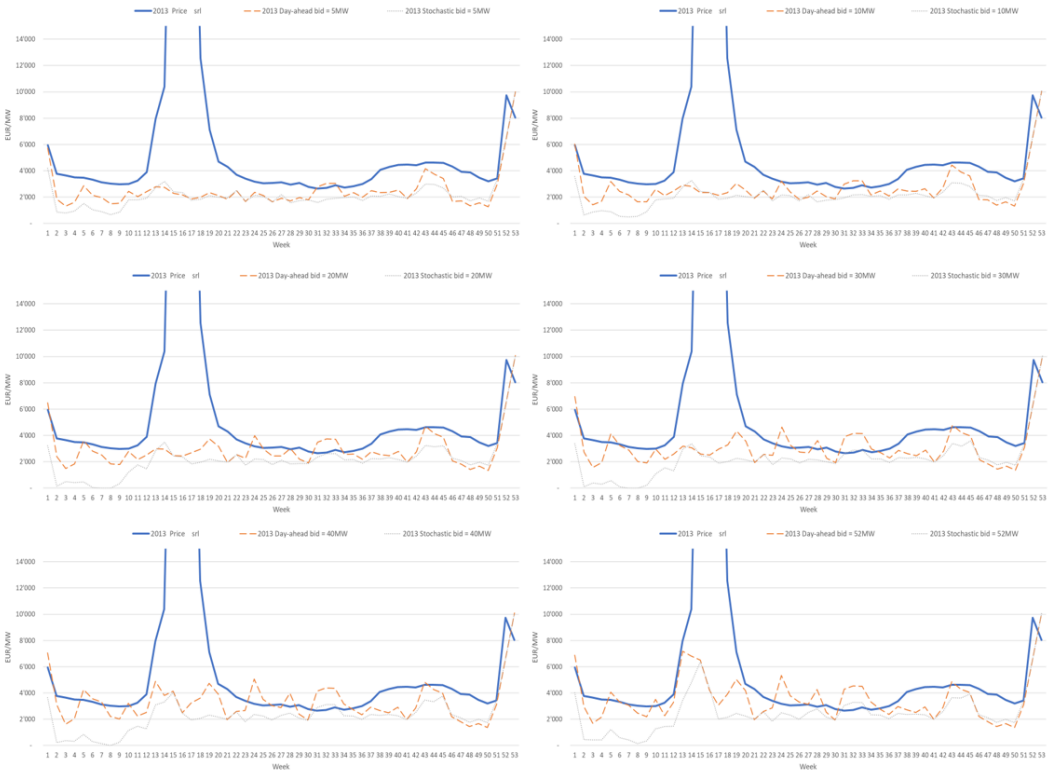

Figure A 20: Srl price and opportunity cost by model and bid size for cascade 5 for 2013.

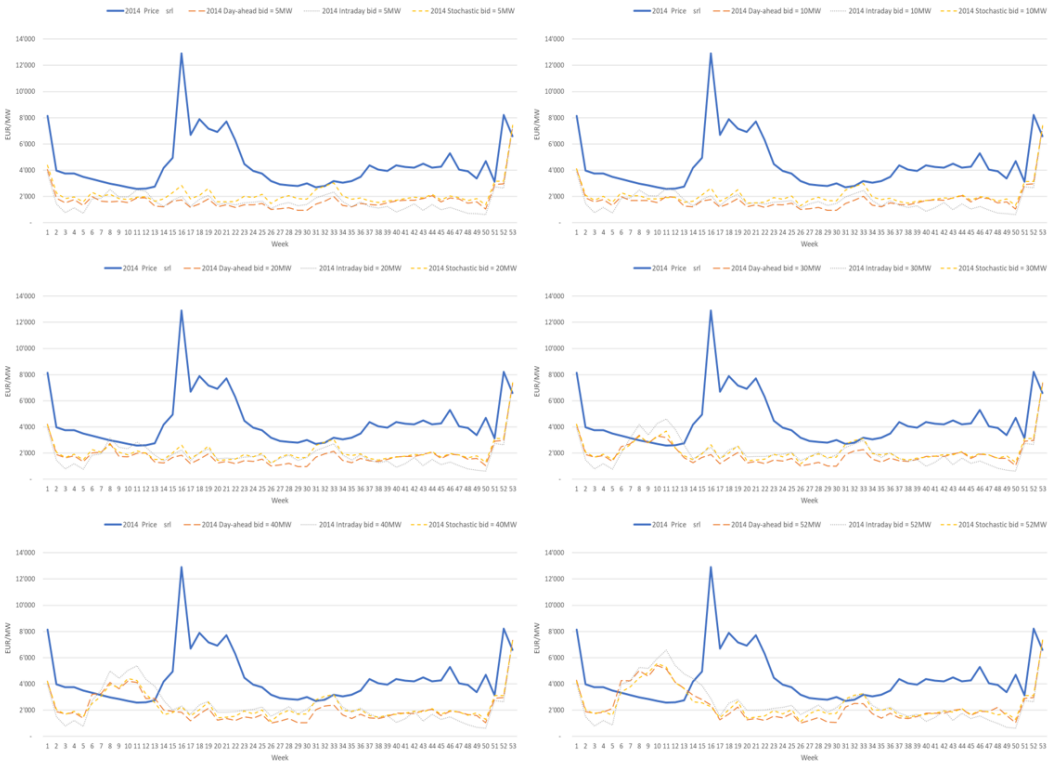

Figure A 21: Srl price and opportunity cost by model and bid size for cascade 5 for 2014.

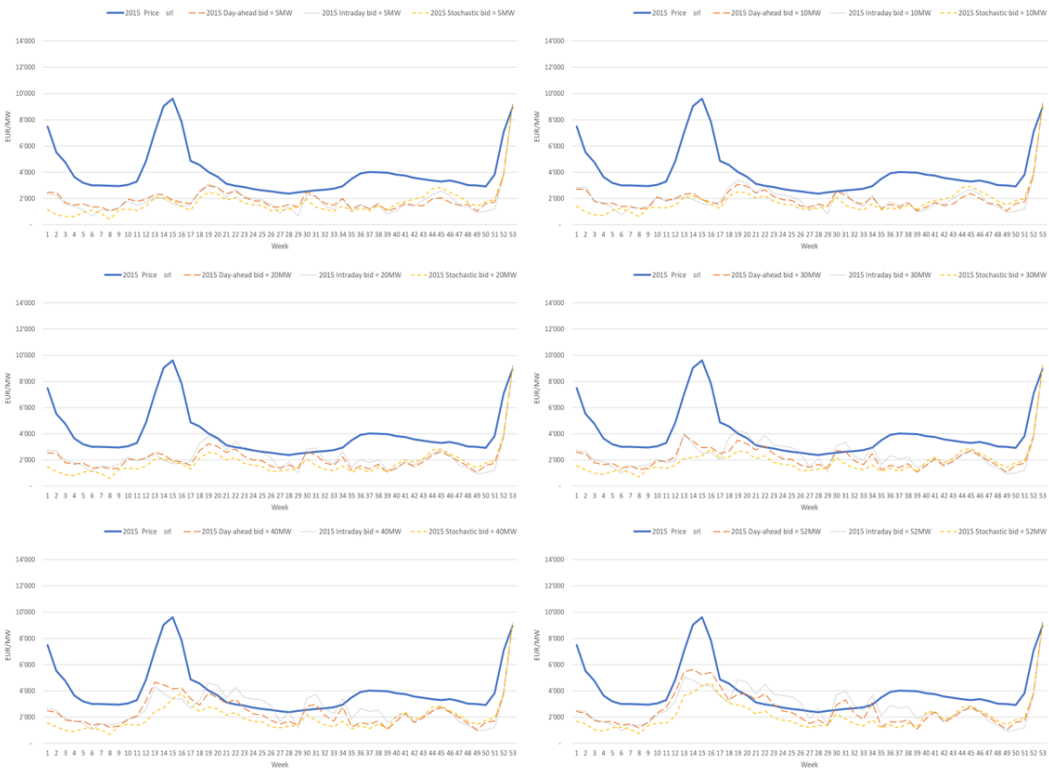

Figure A 22: Srl price and opportunity cost by model and bid size for cascade 5 for 2015.

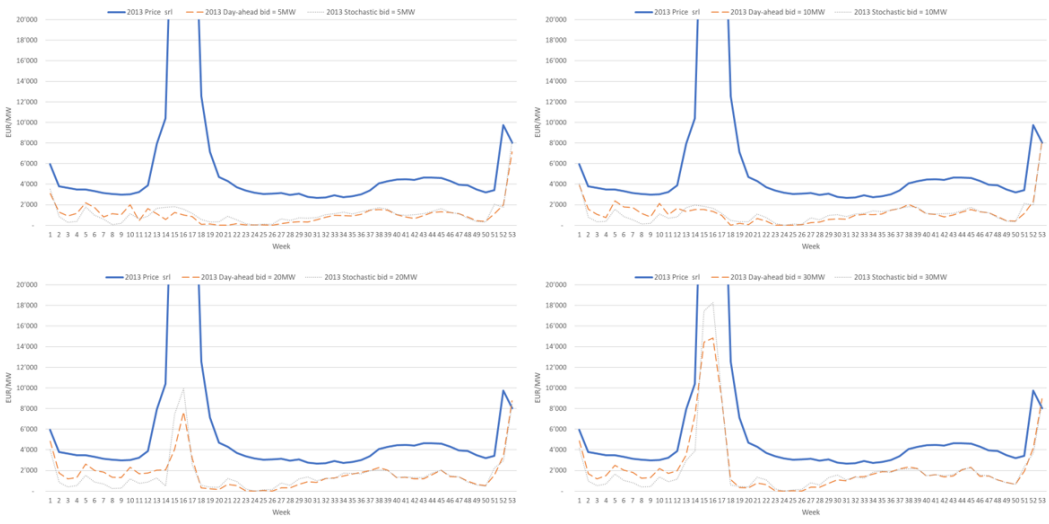

Figure A 23: Srl price and opportunity cost by model and bid size for cascade 6 for 2013.

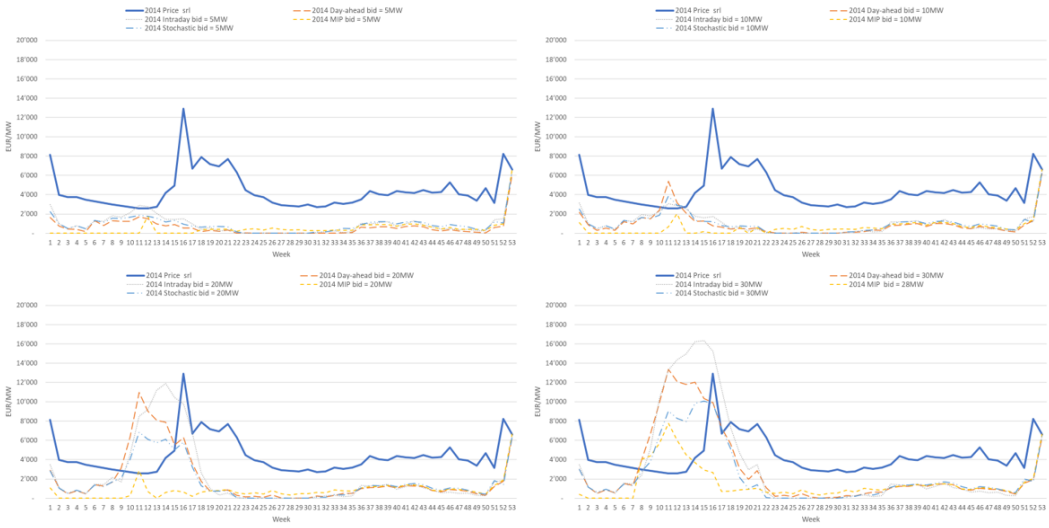

Figure A 24: Srl price and opportunity cost by model and bid size for cascade 6 for 2014.

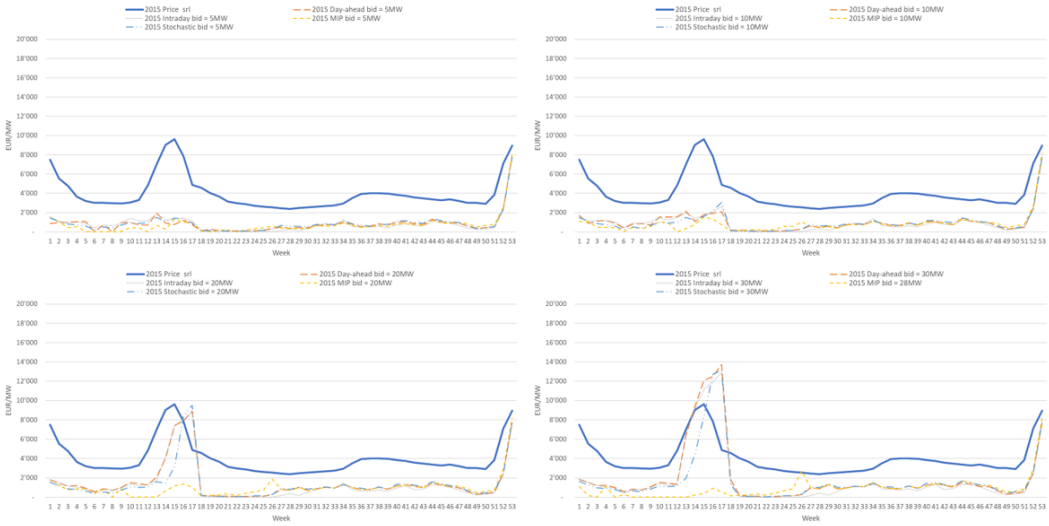

Figure A 25: Srl price and opportunity cost by model and bid size for cascade 6 for 2015.

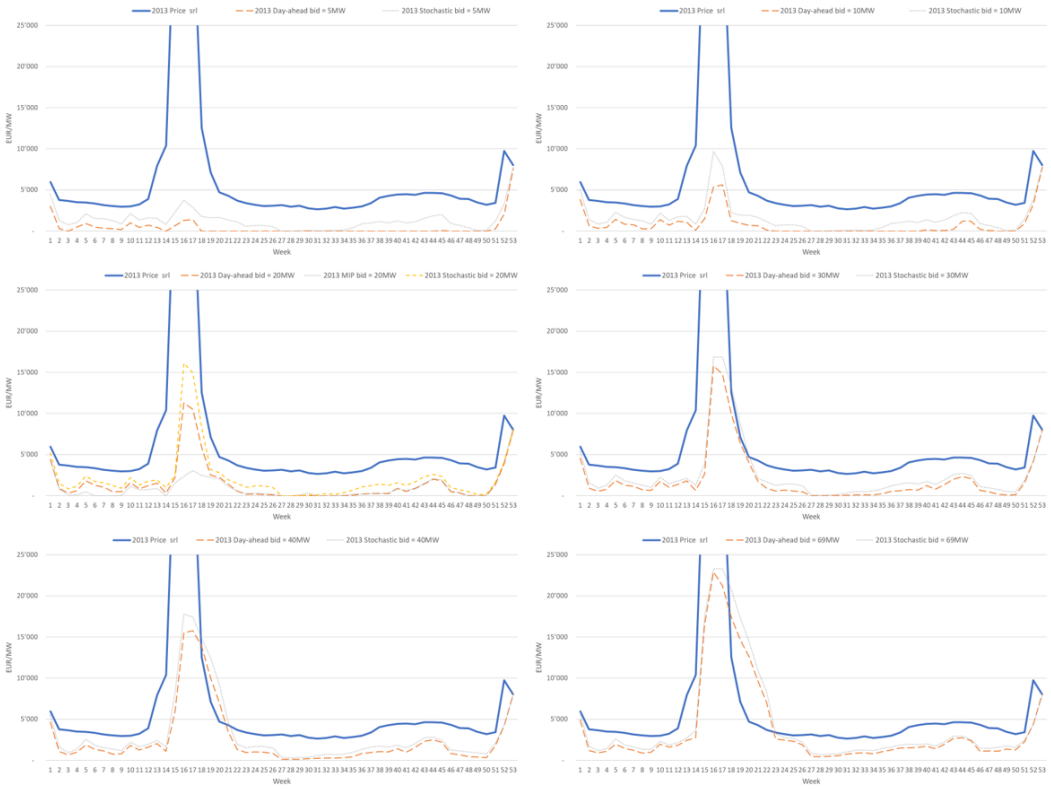

Figure A 26: Srl price and opportunity cost by model and bid size for cascade 7 for 2013.

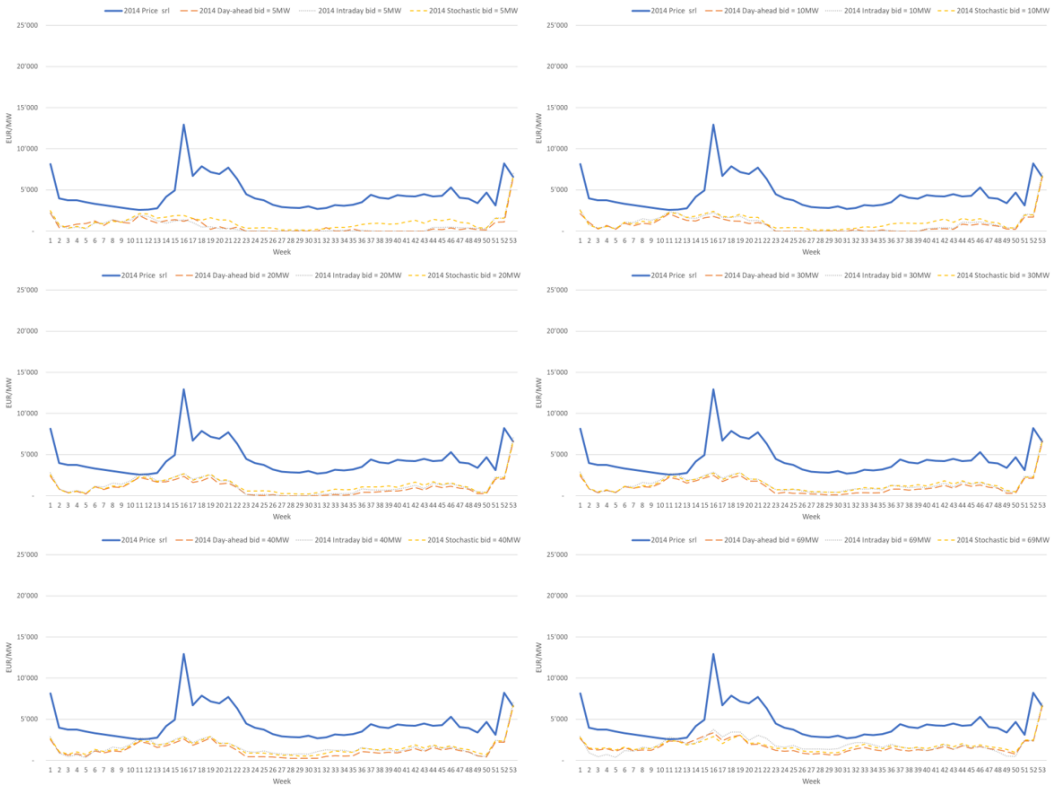

Figure A 27: Srl price and opportunity cost by model and bid size for cascade 7 for 2014.

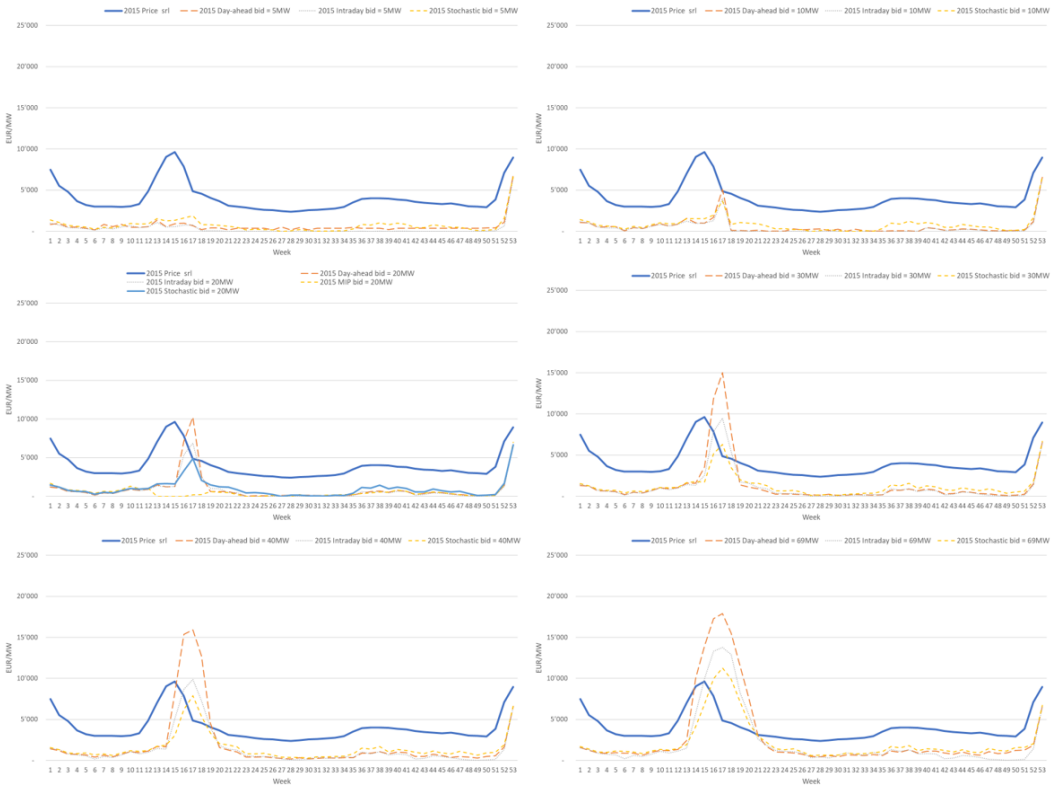

Figure A 28: Srl price and opportunity cost by model and bid size for cascade 7 for 2015.

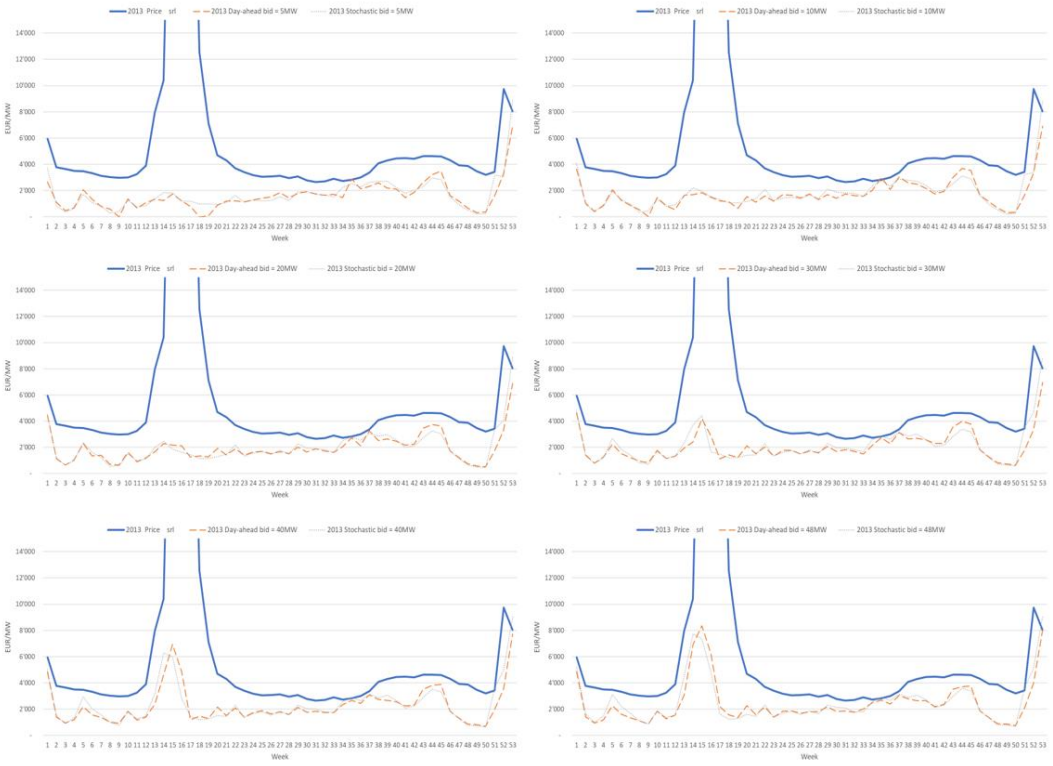

Figure A 29: Srl price and opportunity cost by model and bid size for cascade 8 for 2013.

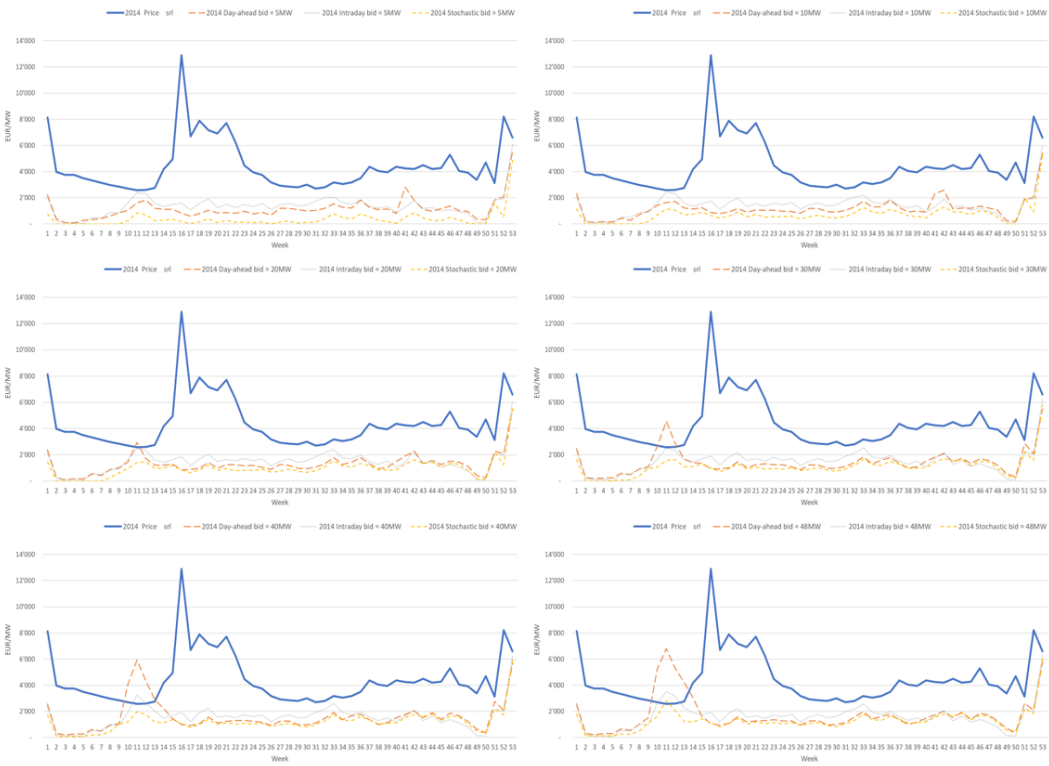

Figure A 30: Srl price and opportunity cost by model and bid size for cascade 8 for 2014.

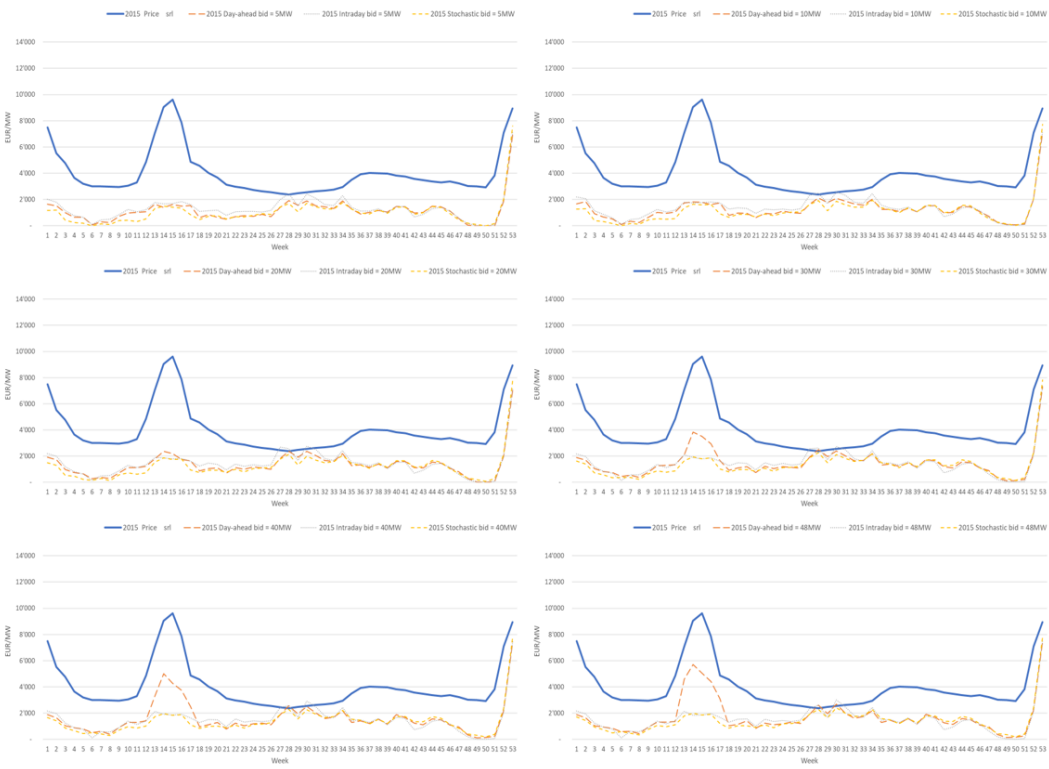

Figure A 31: Srl price and opportunity cost by model and bid size for cascade 8 for 2015.