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Impact of different market designs in the CWE market area on electricity prices and on the competitiveness of Swiss hydropower
(PowerDesign)

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Summary

This study examines the effects of market design changes in neighbouring countries on the Swiss electricity market and in particular on the profitability of Swiss hydropower. In a first step, an econometric model based on a multiple linear regression is developed to determine the impact of exogenous drivers on the Swiss wholesale electricity prices. The results indicate that the French load and the Swiss wholesale electricity price interact strongly during peak load periods due to the electricity market coupling and large electricity exchange capacities. In addition, strong correlations are observed between wholesale electricity prices in Germany, France and Switzerland in spring and summer. Furthermore, German wind power and photovoltaic electricity generation have a negative impact on Swiss wholesale electricity prices in spring and summer, but this impact decreases during autumn and winter. In these periods, Swiss wholesale electricity prices mainly follow Italian and French wholesale prices.

Furthermore, an agent-based simulation model (PowerACE) is used to investigate different energy scenarios with regard to the development of the electricity market. In the first scenario, all present market designs (implemented capacity remuneration mechanisms) are represented according to the legislation at the time of this study. As a second scenario, a so-called energy-only market (EOM) is assumed in all surrounding countries of Switzerland (Germany, France, Italy and Austria). In both scenarios, the development of wholesale electricity prices and power plant capacity is examined. The results of the agent-based model also show that wholesale electricity prices are highly dependent on developments in neighbouring countries, independently of the scenario chosen. This dependency is even expected to increase as a result of the expansion of trading capacities. With regard to power plant capacities, there are only minor differences in the scenarios examined. In the scenario with capacity remuneration mechanisms in neighbouring countries, for instance, less flexible power capacity is built in Switzerland. This can be explained by the higher capacity in neighbouring countries and the possibility of importing electricity. The installed flexible power plant capacity, together with the use of hydropower capacities in Switzerland, enables a high level of generation adequacy. Regardless of the scenario, rising prices are expected on the wholesale market due to the assumption of rising CO_2 certificate and fuel prices with at least constant or rising demand.

In addition, the wholesale market prices of the scenarios simulated with the agent-based model are used to examine the support schemes for renewable energies (in particular the fixed feed-in tariffs and direct marketing combined with the market premium model). Due to rising wholesale electricity prices, a decline in the funding volume can be observed in the medium term, as an increasing share of investment expenditures can be refinanced by revenues on the electricity market. However, an increase in the total subsidy volume is again to be expected as a result of the over-proportional increase in the number of photovoltaic systems assumed from 2030 onwards (without assuming a degression of the feed-in tariffs). The declining specific investments should therefore be countered with a reduction of the feed-in tariffs in order to benefit from the declining price developments for renewable energy installations in the overall system.

The simulated wholesale prices in the two scenarios are also the basis for investigating the operational revenues of Swiss hydropower (storage and pumped storage) using an optimal stochastic control model. The results show that the expected electricity prices on the wholesale market are likely to lead to higher revenues for storage and pumped storage power. For seasonal storage power plants, which have a significant natural water inflow, a significant increase in market revenues can be expected in both scenarios as early as 2030, as the average price level strongly increases. For pure pumped storage power plants with short filling cycles, the increase in market revenues is smaller in the mid-term, as this type of power plant is dependent on price fluctuations that increase only slightly until 2030. In the long term, however, pumped storage facilities are able to benefit from the sharp increase in price volatility in both scenarios. In the EOM scenario, in particular, large price fluctuations occur leading to optimal, high-

frequency pump-turbinization cycles. However, this could have a negative impact on the technical feasibility of the plant if all these price fluctuations are exploited. By the year 2050, the general price level will again rise strongly relative to 2030, so that storage power plants without (or with relatively low pumping capacity) will also be able to further increase revenues.

The analysis of the secondary control reserve in the scenarios for 2030 and 2050 refers primarily to the relationship between wholesale electricity prices and control reserve prices. It turns out that a lower limit for the minimum expected secondary control reserve price is determined solely by the fluctuations of the wholesale electricity price, so that secondary control reserve prices should also rise proportionally in the future.

The analyses lead to the conclusion that, due to price dependencies, the Swiss authorities should monitor the development of wholesale prices for electricity, capacity and generation adequacy in neighbouring countries in order to be able to react appropriately to significant changes, in particular when the level of generation adequacy is at risk. However, the results also show that the current market design changes in the neighbouring countries do not have a negative impact on generation adequacy in Switzerland and that therefore the introduction of a capacity remuneration mechanism in Switzerland is not necessarily required. With regard to the strong increase in revenues for hydropower (in both scenarios), Swiss hydropower could, under the assumptions and under the given regulation, play the role of a profitable source of income in the medium term.

Zusammenfassung

In dieser Studie werden die Effekte der Marktdesignänderungen der Nachbarländer auf den Schweizer Strommarkt und insbesondere auf die Wirtschaftlichkeit der Schweizer Wasserkraft untersucht. Hierfür wird in einem ersten Schritt ein ökonometrisches Modell basierend auf einer multiplen linearen Regression erstellt, um die Treiber der Schweizer Strompreise am Elektrizitätsgroßhandelsmarkt zu bestimmen. Die Ergebnisse deuten darauf hin, dass die französische Last und der Schweizer Großhandelsstrompreis in Spitzenlastzeiten aufgrund der Strommarktkopplung stark zusammenwirken. Darüber hinaus werden starke Korrelationen zwischen den Großhandelsstrompreisen in Deutschland, Frankreich und der Schweiz im Frühjahr und Sommer beobachtet. Außerdem haben die deutsche Windkraft- und die Photovoltaik-Stromerzeugung im Frühjahr und im Sommer einen negativen Einfluss auf die Schweizer Großhandelsstrompreise, der jedoch im Laufe des Herbsts und Winters abnimmt. Im Winter folgen die Schweizer Großhandelsstrompreise vor allem den italienischen und den französischen Großhandelspreisen.

Ferner werden mit einem agentenbasierten Simulationsmodel (PowerACE) energiewirtschaftliche Szenarien bezüglich der Entwicklung des Strommarktes untersucht. Im ersten Szenario werden alle Marktdesigns (implementierte Kapazitätsmechanismen) so gewählt, wie sie zum Zeitpunkt der Erstellung der Studie den politischen Gegebenheiten entsprachen. Als zweites Szenario wird in allen umliegenden Ländern der Schweiz (Deutschland, Frankreich, Italien sowie Österreich) ein sogenannter Energy-only-Markt angenommen. In beiden Szenarien werden insbesondere die Entwicklung der Großhandelsstrompreise und der Kraftwerkskapazität untersucht. Auch die Ergebnisse des agentenbasierten Modells verdeutlichen, dass eine starke Abhängigkeit der Großhandelsstrompreise von den Entwicklungen in den Nachbarländern, unabhängig vom gewählten Szenario, besteht oder sogar durch den Ausbau der Handelskapazitäten noch zunimmt. Hinsichtlich der Kraftwerkskapazitäten ergeben sich nur geringe Unterschiede in den untersuchten Szenarien. So werden im Szenario mit Kapazitätsmechanismen in den Nachbarländern weniger flexible Kraftwerke in der Schweiz zugebaut. Dies ist durch die höhere Kapazität in den Nachbarländern und die Möglichkeit des Imports von Elektrizität zu erklären. Die zugebaute flexible Kraftwerkskapazität ermöglicht zusammen mit dem Einsatz der Wasserkraftkapazitäten in der Schweiz ein hohes Niveau an Erzeugungssicherheit. Unabhängig vom Szenario werden steigende Preise am Großhandelsmarkt erwartet, bedingt durch die Annahme steigender CO_2-Zertifikats- und Brennstoffpreise bei mindestens gleichbleibender oder steigender Nachfrage.

Darüber hinaus werden die Großhandelsmarktpreise der Szenarien, die mithilfe des agentenbasierten Modells simuliert wurden, für die Untersuchung der Fördermaßnahmen für erneuerbaren Energien herangezogen (insbesondere die fixe Einspeisevergütung und Direktvermarktung kombiniert mit dem Marktprämienmodell). Durch die steigenden Großhandelsstrompreise ist mittelfristig ein Rückgang des Fördervolumens zu beobachten, da sich ein immer größerer Anteil der Investitionsausgaben durch Erlöse am Strommarkt erwirtschaften lassen. Allerdings ist durch den ab 2030 angenommenen überproportionalen Zubau von Photovoltaikanlagen wieder mit einem Anstieg des Gesamtfördervolumens zu rechnen (ohne Unterstellung einer Degression der Einspeisevergütung). Deshalb sollte den sinkenden spezifischen Investitionen auch mit einem Rückgang der Einspeisevergütungen begegnet werden, um auch im Gesamtsystem entsprechend von den günstigen Preisentwicklungen der erneuerbaren Energien profitieren zu können.

Die simulierten Großhandelspreise in den beiden Szenarien sind auch die Basis für die Untersuchung der operativen Erlöse der Schweizer Wasserkraft (Speicher- und Pumpspeicher) mit einem optimalen stochastischen Steuerungsmodell. Die Resultate zeigen, dass durch die erwarteten Strompreise am Großhandelsmarkt mit höheren Erlösen der Speicher- und Pumpspeicherkraft zu rechnen ist. Für saisonale Speicherkraftwerke, die einen wesentlichen, natürlichen Wasserzufluss haben, kann bereits im Jahr 2030 in beiden Szenarien mit einer signifikanten Erhöhung der Markterlöse gerechnet werden, da

hierfür das mittlere Preisniveau ausschlaggebend ist, welches in beiden Szenarien stark ansteigt. Für reine Pump-Speicherkraftwerke mit kurzen Füllzyklen ist der Anstieg der Markterlöse mittelfristig bis 2030 kleiner, da dieser Kraftwerkstyp auf signifikante Preisschwankungen angewiesen ist, die sich im Jahr 2030 zwar schon leicht vergrößern, aber dennoch schwächer ansteigen als das mittlere Preisniveau. Langfristig können bis 2050 dann die Pumpspeicher in beiden Szenarien umso mehr vom starken Anstieg der Preisvariabilität profitieren. Vor allem im Energy-only-Markt Szenario kommt es zu großen Preisausschlägen, was zu optimalen, hochfrequenten Pump-Turbinierungs-Umschalt-Zyklen führt, die sich jedoch negativ auf die technische Machbarkeit der Ausnutzung dieser Preisausschläge auswirken könnten. Bis zum Jahr 2050 steigt nochmals das allgemeine Preisniveau relativ zu 2030 stark an, sodass auch Speicherkraftwerke ohne (oder mit relativ geringer) Pumpkapazität die Erlöse nochmals steigern können.

Die Untersuchung von sekundärer Regeldienstleistung in den Szenarien für 2030 und 2050 bezieht sich vor allem auf den Zusammenhang zwischen Großhandelsstrompreisen und Regeldienstleistungspreisen. Es stellt sich heraus, dass eine Untergrenze für den minimal zu erwartenden sekundären Regeldienstleistungspreis durch die Schwankungen des Großhandelsstrompreises bestimmt ist, sodass auch sekundäre Regeldienstleistungspreise in der Zukunft proportional dazu ansteigen sollten.

Die Analysen führen zu dem Schluss, dass aufgrund der Preisabhängigkeiten die Schweizer Behörden die Entwicklung der Großhandelspreise für Strom, der Kapazität und der Erzeugungssicherheit in den Nachbarländern beobachten sollten, um bei wesentlichen Änderungen angemessen reagieren zu können, insbesondere wenn das Niveau der Erzeugungssicherheit in Gefahr ist. Die Ergebnisse verdeutlichen aber auch, dass die aktuellen Marktdesignänderungen keinen negativen Einfluss auf die Erzeugungssicherheit in der Schweiz haben und dass daher die Einführung eines Kapazitätsmechanismus in der Schweiz nicht zwangsläufig benötigt wird. Hinsichtlich des starken Anstiegs der Markterlöse für Speicherwasserkraft in beiden Szenarien bereits im Jahr 2030 könnte der Schweizer Wasserkraft unter den Annahmen und unter dem gegebenen Regulierungsrahmen wieder mittelfristig die Rolle einer ertragreichen Einnahmequelle zugewiesen werden.

Résumée

Cette étude examine les effets des changements de conception du marché dans les pays voisins sur le marché suisse de l'électricité et en particulier sur la rentabilité de l'énergie hydraulique suisse. Dans un premier temps, un modèle économétrique basé sur une régression linéaire multiple sera développé afin d'identifier et de quantifier les variables qui influencent les prix de l'électricité en Suisse sur le marché de gros. Les résultats indiquent que la charge française et le prix de gros de l'électricité en Suisse interagissent fortement pendant les périodes de pointe en raison du couplage du marché de l'électricité. De fortes corrélations sont observées entre les prix de gros de l'électricité en Allemagne, en France et en Suisse au printemps et en été. De plus, la production d'énergie éolienne et photovoltaïque allemande au printemps et en été a un impact négatif sur les prix de gros de l'électricité en Suisse, bien que cet effet diminue au cours de l'automne et de l'hiver. En hiver, les prix de gros de l'électricité en Suisse suivent principalement les cours du prix de gros de l’électricité en Italie et en France.

Un modèle de simulation basé sur des agents (PowerACE) est utilisé pour étudier les scénarios de l'industrie énergétique relatifs au développement du marché de l'électricité. Dans le premier scénario, tous les modèles de marché (mécanismes de capacité mis en œuvre) ont été choisis car ils correspondaient à la situation politique au moment de l'étude. Le deuxième scénario était basé sur l’hypothèse d’un marché dit de l'énergie uniquement dans tous les pays limitrophes de la Suisse (Allemagne, France, Italie et Autriche). Dans les deux scénarios, l'évolution des prix de gros de l'électricité et de la capacité des centrales électriques est examinée en particulier. Les résultats du modèle basé sur les agents montrent que les prix de gros de l'électricité dépendent fortement de l'évolution dans les pays voisins, quel que soit le scénario choisi et que les prix de gros ont tendance À augmenter en raison de l'expansion des capacités commerciales. En ce qui concerne les capacités des centrales électriques, il n'y a que des différences mineures dans les scénarios examinés. Dans le scénario avec des mécanismes de capacité dans les pays voisins, par exemple, des centrales moins flexibles sont construites en Suisse. Cela peut s'expliquer par la capacité plus élevée dans les pays voisins et la possibilité d'importer de l'électricité. La capacité de production flexible des centrales électriques ainsi que l'utilisation des capacités hydroélectriques en Suisse permettent d'assurer un haut niveau de sécurité de production. Quel que soit le scénario, on s'attend à une hausse des prix sur le marché de gros en raison de l'hypothèse d'une hausse des prix des certificats de CO2 et des prix des carburants avec une demande au moins constante ou croissante.

Les prix de gros des scénarios simulés à l'aide du modèle d’agents sont utilisés pour examiner les mesures de soutien aux énergies renouvelables (en particulier le tarif de rachat fixe et le marketing direct combinés avec le modèle de prime de marché). En raison de la hausse des prix de gros de l'électricité, une baisse du volume des subventions peut être observée à moyen terme, étant donné qu'une part toujours plus importante des dépenses d'investissement peut être générée par les recettes sur le marché de l'électricité. Toutefois, on peut à nouveau s'attendre à une augmentation du volume total des subventions en raison de l'augmentation supérieure à la moyenne du nombre d'installations photovoltaïques prévues à partir de 2030 (sans supposer une dégressivité du tarif de rachat). Pour cette raison, la baisse des investissements spécifiques devrait également être compensée par une baisse des tarifs de rachat afin de pouvoir bénéficier également de l'évolution favorable des prix des énergies renouvelables dans l'ensemble du système.

Les prix de gros simulés dans les deux scénarios servent également de base à l'analyse des recettes d'exploitation de l'énergie hydraulique suisse (stockage et pompage-turbinage) au moyen d'un modèle de régulation stochastique optimal. Les résultats montrent que les prix de l'électricité attendus sur le

marché de gros seront susceptibles d'entraîner une hausse des recettes provenant du stockage et de l'accumulation par pompage. Pour les centrales à accumulation saisonnière, dont l'apport d'eau est important et naturel, on peut s'attendre à une augmentation significative des recettes du marché dès 2030 dans les deux scénarios, le facteur décisif étant le niveau moyen des prix, qui augmente fortement dans les deux scénarios. Pour les centrales de pompage-turbinage pures à cycle de remplissage court, l'augmentation des recettes du marché est plus faible à moyen terme jusqu'en 2030, car ce type de centrales est tributaire d'importantes fluctuations de prix qui, si elles augmentent légèrement en 2030, augmentent néanmoins moins que le niveau moyen des prix. A long terme, d'ici 2050, les centrales de pompage-turbinage pourront encore mieux profiter de la forte augmentation de la variabilité des prix dans les deux scénarios. Dans le scénario du marché de l'énergie uniquement, en particulier, de fortes fluctuations de prix se produisent, ce qui conduit à des cycles de basculement pompe-turbinisation haute fréquence optimaux, qui ont toutefois un impact négatif sur la faisabilité technique de l'exploitation de ce potentiel.

Contents

List of abbreviations

ABM	Agent-based modelling
CRM	Capacity remuneration mechanism
EOM	Energy-only market
FCM	French capacity market
FiT	Feed-in tariff
KEV	Kostendeckende Einspeisevergütung
MAD	Mean absolute deviation from the median
NPV	Net present value
RES	Renewable energy sources
SR	Strategic reserve
TSO	Transmission System Operator

1 Introduction

The market design of European electricity markets has undergone rapid changes in the recent years. The integration of renewable energy sources (RES) amplifies worries that energy-only markets (EOM) cannot sufficiently remunerate conventional capacities. One reason for this is the so-called merit order effect of RES, which displaces power plants in the merit order by variable costs of RES of almost zero (particularly wind and solar power) and thus reduces the wholesale market prices. This reduction in market prices also lowers the contribution margins of the remaining power plants. Due to the lower contribution margins, it is more challenging to cover fixed costs of the power plants, which makes economic operation more difficult overall. However, for a high generation adequacy, conventional power plants will continue to be needed in the foreseeable future or investments in storage are necessary to absorb fluctuations in the production of wind and solar (e.g. longer wind lull in winter). Against this backdrop, European countries consider revising the market design of their electricity markets. Different countries already took action and implemented capacity remuneration mechanisms (CRMs) in order to remunerate available capacities (e.g. France, UK) or reserves (e.g. Germany) to maintain or increase generation adequacy. However, the European Commission (2015) raised concerns that the remuneration of power plants in a certain country could favour companies over competitors or only one technology type. Therefore, in order not to disturb the internal electricity market, the remuneration mechanisms must comply with the EU state aid rules.

Due to the interconnection of the Swiss electricity market with the surrounded markets, changes in market designs through the introduction of CRMs in France, Germany and Italy (Bublitz et al. 2018) will influence the Swiss wholesale market prices (Dehler et al. 2016). CRMs could lead to dropping spot prices in the market area, because electricity suppliers offer the energy produced to their variable costs while fixed costs are covered by payments through the CRM (Keles et al. 2016a). Even if Switzerland does not plan to introduce a CRM, the introduction in the surrounding countries may result in price changes in Switzerland, as a consequence of the market coupling. Therefore, an investigation by applying an econometric analysis to identify the main drivers of the Swiss electricity prices (and the ones of the neighbouring countries) is conducted in Section 2.

After examining the historical interrelations of the prices between Switzerland and its neighbouring countries (Section 2), an agent-based simulation model is used to investigate the electricity wholesale market to transfer the interrelations to the future. The model captures the price effects of changes in the market designs in the countries around Switzerland. Different market design scenarios have been developed and implemented into the agent-based simulation model (ABM) by taking into account the Energy Strategy 2050 scenarios (Prognos AG 2012) for Switzerland and the EU-Reference Scenario 2016 (European Commission 2016) for the EU countries as input data. The scenarios lead to a differentiated, quantitative view on the market design options and in recommendations for favourable market design change in Switzerland. In addition, the revenues of hydropower plants under these different market designs are examined. The scope of the ABM is the wholesale electricity markets of Central-Western Europe plus Switzerland and Italy (Figure 1). All CRMs in the investigated countries are modelled in order to analyse short-term (e.g. wholesale market prices) as well as long-term effects (investment decisions in flexible power plants) in these markets. Further, it will be discussed whether a change of the Swiss market design is necessary for guaranteeing generation adequacy. Generation adequacy is the ability that the generation capacity and aggregated demand meet at all times (Spisto et al. 2016).

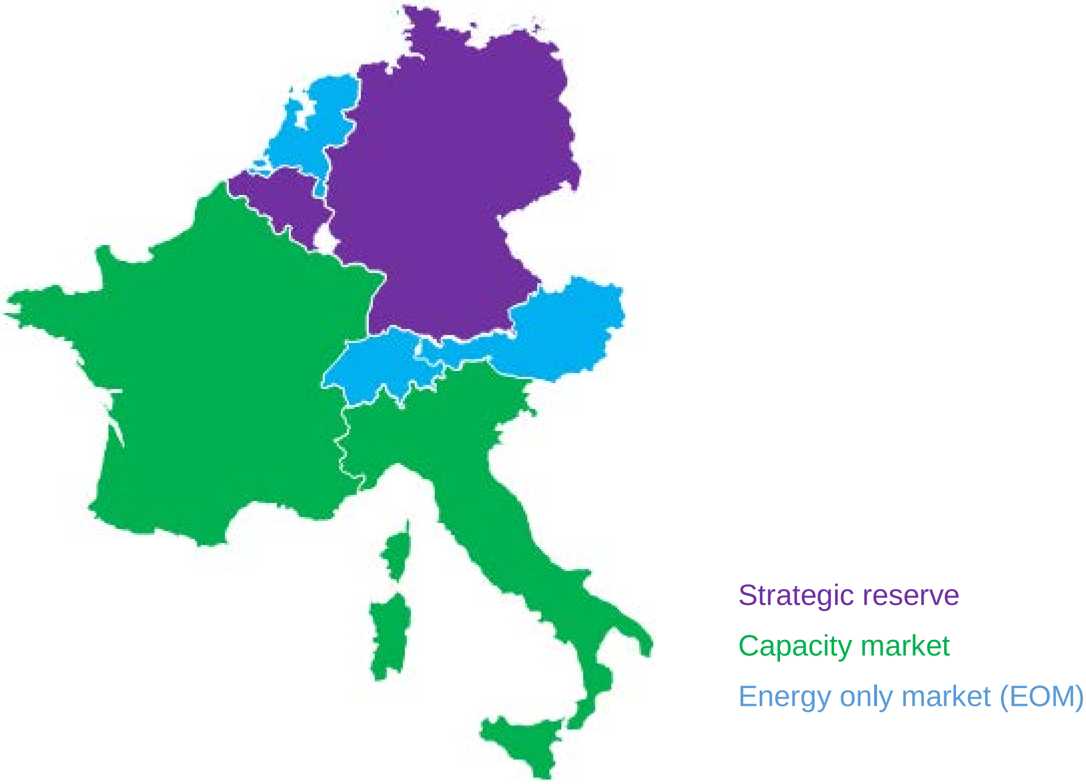

Figure 1: CRM overview according to Bublitz et al. (2018).

The wholesale prices of electricity influence the costs of support for fluctuant RES (e.g. wind, solar power). The development on foreign markets will influence wholesale prices in Switzerland. In case of lower wholesale prices, the feed-in premium will increase due to the current support scheme and higher subsidies/support volumes would be needed. As the current system ("kostendeckende Einspeisevergütung" – KEV) is revised (Der Schweizerische Bundesrat 2017), the costs of KEV system and a support system with direct marketing for RES is thoroughly analysed in Section 3.3. For this investigation, the simulated electricity prices for the different market design assumptions (scenarios) provided by the application of the ABM in Section 3.2 are used to analyse the required RES subsidies due to the new support scheme.

Major shares of Swiss power production is hydro-based, and hydropower will stay the complementary production option apart of new RES according to the Energy Strategy 2050 (Prognos AG 2012) and related studies. Especially stored-hydropower allows flexible generation, and pumped-storage hydropower is additionally capable to store excess or low-cost power with relatively high efficiency. In Section 4, the competitiveness in terms of changes in market revenues of the existing Swiss hydropower sector with its storage capability is evaluated considering the different market design options and related wholesale electricity prices in the considered future scenarios. The operational profit (market revenues) is analysed with a stochastic optimal control model. We examine several typologies of plant types, including for example a two-reservoir system, and also Swiss plants in aggregate. The wholesale prices development as simulated by the agent-based market model will be used as input for the novel stochastic control model.

2 Econometric analysis of Swiss electricity prices

Due to its location in the centre of Europe, the Swiss electricity grid is interconnected to the grids of Germany, Austria, France and Italy. The existing transmission services to neighbouring countries are auctioned in implicit and explicit auctions. In this way, the load and generation of neighbouring countries as well as national price drivers, such as the electricity demand, influence the Swiss market prices. Price differences between market areas with cross-border electricity trade are caused by the limited capacity of cross-border interconnectors. International trade reduces price differences between market areas.

The following analysis is originally based on the paper Dehler et al. 2016, but has been enhanced by new data and was published in the preprint of Keles et al. (2019). (Furthermore, Keles et al. (2019) analyses the impact on Swiss prices by key influence factors also using PSI's game-theoretic market model of Switzerland and surrounding countries). Table 1 shows the exchange of electricity across Switzerland's borders in the years from 2011 to 2017. The absolute figures show a slightly declining trend in the exchange flows from Switzerland to Italy.

Table 1: Exchange of electricity between Switzerland and its neighbours in TWh (Swissgrid 2018b).

Energy flows [TWh]	2011	2012	2013	2014	2015	2016	2017
DE→CH	14.00	12.71	11.68	11.47	16.06	17.02	19.28
CH→DE	2.76	3.13	3.72	4.59	3.02	2.44	1.56
IT→CH	0.43	0.63	1.09	0,82	0.83	1.32	1.26
CH→IT	25.62	25.30	23.35	24.44	26.21	21.00	21.62
FR→CH	12.28	9.55	9.31	10.00	9.61	8.26	8.44
CH→FR	1.83	3.29	3.39	2.89	4.34	5.26	6.36
AT→CH	7.62	8.09	7.31	5.84	7.04	6.91	7.05
CH→AT	0.10	0.13	0.25	0.55	0.26	0.39	0.46
Import	34.34	30.99	29.40	28.12	33.53	33,50	36.04
Export	30.31	31.84	30.71	32.46	33.83	29.09	30.00
Transit	27.59	25.70	24.88	25.03	27,75	23.89	25.04

To analyse the role of international trade for Swiss electricity prices and impact of cross-border price drivers, a multi-linear regression model, that explains causal influences on the Swiss electricity price, has been developed. Before presenting the regression model and its results, a detailed statistical analysis of the Swiss electricity prices and their drivers is presented in the following. Afterwards, the focus is set on the analysis of the influence of fundamental factors resulting from neighbouring countries (e.g. RES feed-in in Germany or system load in France). The model results indicate significant price drivers for different seasons of the year, which are explained in the last part of this section.

2.1 Data and statistical analysis

The data basis for the following analyses is from the period from 1st January 2011 to 31th December 2017. The data originates from various databases that are open accessible. Demand data for all countries besides Switzerland comes from the transparency platform of ENTSO-E (2018b). For Switzerland, the load data provided by the national TSO Swissgrid (2015) is used. In particular, the published gross load excluding pump and own consumption of the power plants is applied to all following analyses and models. The day-ahead forecast for solar and wind power feed-in derived from the ENTSO-E (2018b). Fuel prices for coal and gas are provided by EPEX Spot (2018) in daily resolution. The data for weekends and holidays when fuels are not traded are set to the price of the previous workday. With the exception of the northern Italian price, price data come from EPEX Spot (2018), the operator of the energy stock exchanges in France, Germany and Switzerland. In the regarded period, Germany and Austria form a common market area without transmission bottlenecks at the common border. The German prices thus also represent the Austrian prices. The northern Italian prices originates from GME (2015).

The different electricity prices in France, Italy, Germany and Switzerland are influenced by various factors. Both environmental factors and the prices of primary energy carrier play an important role. For the German electricity market, for example, the installed capacities of volatile RES, such as wind and solar power, have significantly increased over the last decade and contributed by 38.2 % to the total electricity production in 2017 (Fraunhofer-Institut für Solare Energiesysteme ISE 2018). German electricity production depends also on lignite (24.3 %), hard coal (14.8 %), nuclear energy (13.1 %) and natural gas (8.9 %). Because of this composition of the German power production, fuel prices are an important factor in the emergence of electricity prices. France, however, covers a large part of its electricity demand from nuclear energy and hydropower (2017: nuclear 71.6 %, hydropower 10.1 % (Réseau de Transport d'Electricité 2018)). Due to the high number of electric heaters, demand in France is very temperature-dependent (Réseau de Transport d'Electricité 2014; Gerhardt et al. 2017).

Italy's relatively high production of electricity from gas (2016: 69 % of thermal electricity generation) explains the high price level, at which imports from neighbouring countries are particularly profitable and have a price dampening effect (IEA 2017). Imports accounted for 11.1 % of demand cover in 2016. In addition, the share of RES in the supply of electricity is increasing, especially from solar energy (Terna 2017).

The characteristics of the market areas are reflected in the respective price curves. If there is a high feed-in of wind or solar energy in Germany, and at the same time a low load, prices can fall significantly.

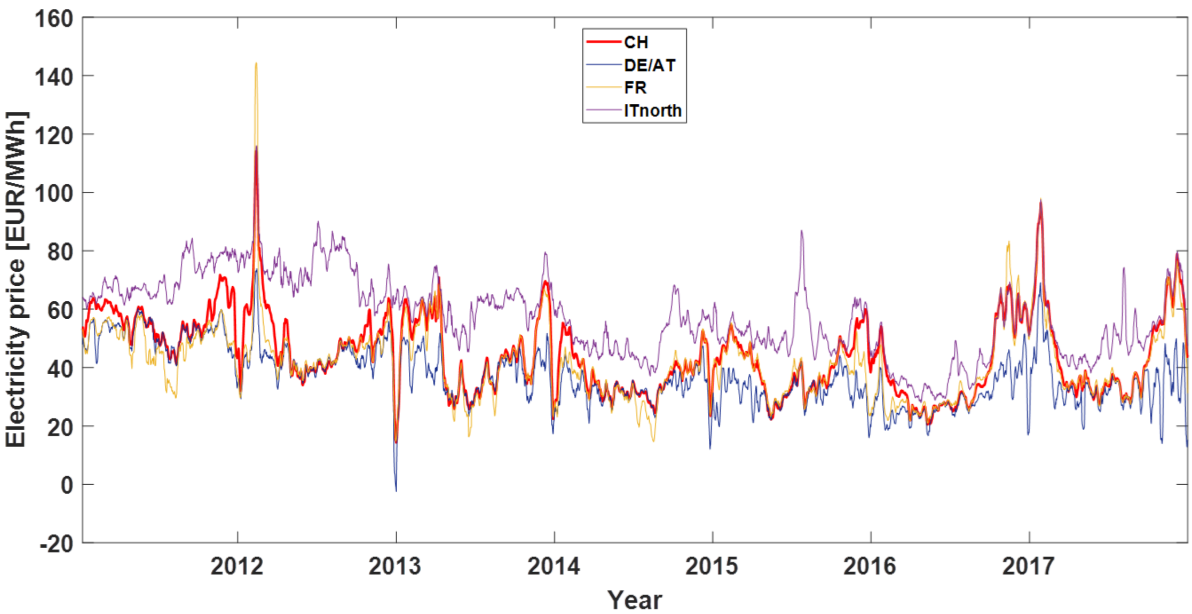

Figure 2: Moving 168-hours average of electricity prices in Switzerland and its neighbouring countries. (EPEX Spot 2018; GME 2015)

The coupling of the electricity markets and the size of Switzerland's cross-border transmission capacities lead to a convergence of electricity prices with Germany or France. Figure 2 shows the moving average of the last 168 prices (equivalent to one week) in Switzerland and its neighbouring countries. While the day ahead prices in France, Germany and Switzerland (data from EPEX Spot 2018) converge strongly in the summer, French and Swiss prices converge towards Italian (data from GME 2015) prices in the winter. The German price remains at a lower level; only in situations with extreme fluctuations, the German price curve approaches to the Swiss and French curves (see Figure 3). This effect is in particular around Christmas visible when the German, French and Swiss price curve decline. This leads to the hypothesis that load and other factors from neighbouring countries have different seasonal impact. The restrictive effect of the Italian electricity price on the Swiss price is also reflected in Figure 4. Apart from a few outliers, the Swiss price is limited upwards by the Italian price (green dotted line).

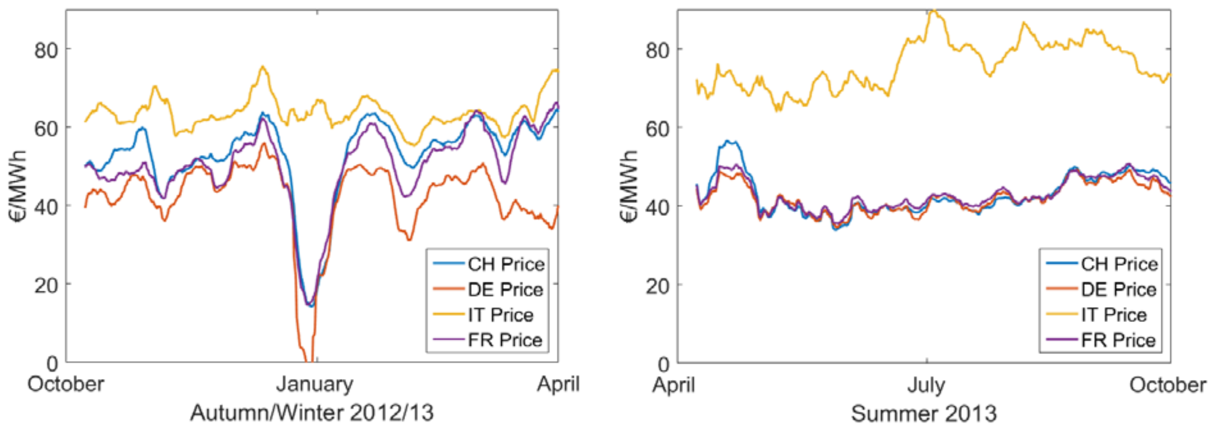

Figure 3: Moving 7-day average of electricity prices in Switzerland and its neighbouring countries for Autumn/Winter 2012-2013 and Spring/Summer 2013. (EPEX Spot 2018; GME 2015)

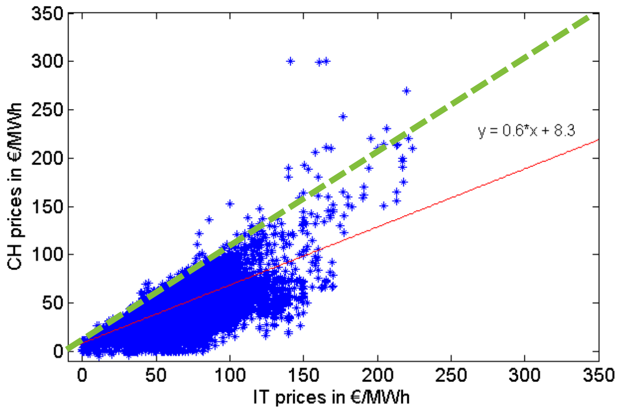

Figure 4: Scatter diagram of the Italian prices and the Swiss electricity prices.

All prices have a falling trend until 2016 and a falling standard deviation until 2015 with the exception of the year 2015 in Switzerland, France and Italy. After that, the trend reversed and prices have risen significantly again until today. This evolution of the prices can be attributed to various causes. In Germany, various studies have identified falling demand and falling carbon certificate- and fuel prices as the driving factors behind price declines (Kallabis et al. 2016; Bublitz et al. 2017), in addition to the increasing expansion of RES (Sensfuß et al. 2008). The different tendencies and interrelations in the seasons will be examined later with the means of regression analysis.

Table 2: Descriptive statistics of day ahead electricity prices of Switzerland and selected neighbouring price zones. (EEX 2018, GME 2018)

[EUR/MWh]	CH		DE/AT		IT-North		FR	
	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.	Mean	St. Dev.
2011	56.18	13.65	51.12	13.60	70.18	15.67	48.89	16.15
2012	49.52	21.19	42.60	18.69	74.05	21.53	46.94	37.29
2013	44.73	18.83	37.78	16.46	61.58	17.38	43.24	20.34
2014	36.79	12.82	32.76	12.78	50.35	14.97	34.63	13.91
2015	40.30	13.15	31.63	12.66	52.71	14.12	38.47	12.95
2016	37.88	16,78	28.98	12.48	42.67	15.03	36.75	24.44
2017	46.00	19.60	34.19	17.66	54.41	18.44	44.96	20.23

The analysis of the correlation of electricity prices in neighbouring countries with the Swiss price confirms the previous observations: While a high correlation to prices in France and Germany can be observed especially in the spring and summer months, the linear relationship to the Italian market is smaller (0.70). In winter, the correlations change: the Pearson correlation of Swiss prices to France and Germany decreases, the correlation with the Italian price increases compared to the summer.

Table 3: Correlation between Swiss electricity prices and electricity prices in neighbouring countries (EEX 2018, GME 2018).

Price correlation	**CH (Pearson correlation)**			**CH (Spearman correlation)**		
Season	TOTAL	SPRING/ SUMMER	FALL/ WINTER	TOTAL	SPRING/ SUMMER	FALL/ WINTER
FR	0.83	0.91	0.80	0.93	0.94	0.90
DE/AT	0.81	0.94	0.75	0.78	0.93	0.73
IT north	0.73	0.70	0.76	0.72	0.69	0.75

However, the figures for France change when the Spearman rank correlation is considered instead: While the coefficient for Germany and Italy remains at the same level, the Spearman correlation coefficient between France and Switzerland is significantly higher in autumn and winter (0.80 and 0.90 respectively). This indicates a strong monotonous, non-linear correlation. Consequently, it can be deduced that the French electricity price has also a strong influence on the Swiss price in the winter.

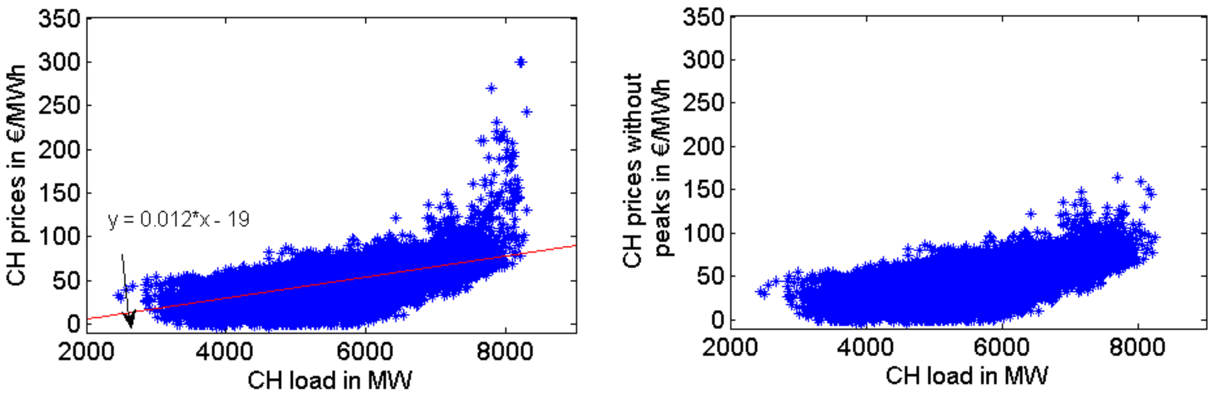

Figure 5: Scatter diagram of the Swiss electricity price and the Swiss load as well as scatter diagram without prices at the same hour with French load greater than 89 GW.

A deeper insight into this effect is provided by the analysis of the correlation of the influencing factors on the electricity prices of the different countries. The electricity load in France correlates strongly with the Swiss load (Pearson 0.89) and the Swiss electricity price (Pearson 0.67). Particularly, high demand in France is accompanied by high prices on the Swiss electricity exchange. Figure 5 shows the Swiss load and electricity prices as a scatter diagram. The figure on the right shows the same values, adjusted by excluding all hours in which the French load is higher than 89 GW. It is noticeable that, with the addition of this condition, prices above 150 EUR are omitted. The average price in hours with a load of over 89 GW in France is 120 EUR. A closer analysis shows that both French peak loads and high Swiss prices occurred around 29 February 2012, while temperatures in France were unusually low (Réseau de Transport d'Electricité 2013). Therefore, it could be confirmed that French demand can have a major impact on prices in Switzerland, especially in hours with very high loads.

2.2 Modelling cross-border effects

The aim of the model design and the selection of variables is to examine significant influencing factors of neighbouring countries and Switzerland in a multiple linear regression. We implicitly obtain simple models for the prices in the different countries, which influence the Swiss electricity price. When selecting the analysed variables, attention must be paid on the one hand to how the predictors behave in relation to the declared variable. It should be possible to establish a linear relationship that is both measurable, theoretically justifiable and there should be no causal repercussions from the declared variable to the explanatory variable. Thus, the use of cross-border trade as explanatory variables can be regarded as problematic. On the other hand, it must be ensured that the predictors are not collinear with each other. Collinearity leads to instability of the model and the interpretation of the regression coefficients becomes impossible, the estimator could then no longer compute meaningful weights of the collinear variables, since these are in linear dependence. The analysis of the collinearity of the predictors is therefore indispensable. The analysis is performed using the Belsley Conditionality Index (Belsley 1991) and the Variance Inflation Factor (VIF). The results lead to the decision to consider trend adjusted and differentiated (time lag of one week) time series. The repeated test with the adjusted time series shows that the trend correction and differentiation efficiently reduce multicollinearity.

Several test runs are carried out to select the variables, in which various factors prove to be insignificant. Among other things, the hard coal prices (mainly relevant for Germany) and the Italian PV feed-in are excluded from the considerations. This is surprising as significant influences of both parameters were expected in advance to this study.

The final selection of predictors results in the following 24 regression models for each hour of the day:

$$\Delta^{7d}price_{h,t}^{CH} = c + b_1 * \Delta^{7d}PV_{h,t}^{DE} + b_2 * \Delta^{7d}wind_{h,t}^{DE} + b_3 * \Delta^{7d}load_{h,t}^{DE\&AT} + b_4 * \Delta^{7d}gas_t + b_5 * \Delta^{7d}load_{h,t}^{IT} + b_6 * \Delta^{7d}load_{h,t}^{FR} + b_7 * \Delta^{7d}load_{h,t}^{CH} + b_8 * price_{h,t-1}^{CH} + b_9 * price_{h,t-7}^{CH}$$

Equation 1: Models for a regression of the wholesale electricity price for each hour of the day.

Besides the general models for the whole period, we divide the data into two seasons (meteorological spring/summer and fall/winter) to identify seasonal differences in the influence of fundamental price drivers on the Swiss electricity price. In addition, each model is tested without including the autocorrelation components to identify further price drivers that may already be explained by the autocorrelation terms. Finally, the time series with the load of all Swiss neighbouring countries are removed to quantify the adjusted influence of the Swiss load on the domestic electricity price.

$1 \le h \le 24$ is the hour of the day and $1 \le t \le n$ the day between January 1, 2011 and the 31st of December 2017. b_i for $1 \le i \le 9$ are the regression coefficients, calculated using the usual least squares method. Δ^{7d} Describes the seven-day seasonal differentiation operator. The German PV feed-in $\Delta^{7d}PV_{h,t}^{DE}$ only enters the models in the hours between 9 a.m. and 6 p.m., the influence before and after is negligible.

The selection of the predictors is based on various determining factors in the different countries. While the analysis of the German energy system showed that fossil fuels and RES have a high share in electricity generation, the Italian influence is mainly represented by the load and gas prices, corresponding to the high gas share in the electricity supply (Terna 2017). The load is included in the analysis as the most important fundamental national electricity price driver. The existence of autocorrelation results from the analysis of residuals. In order to counteract this, various approaches are pursued. On the one hand, a trend adjustment of the data around the long-term linear trend takes place. Furthermore, two auto regression terms $price_{h,t-\nabla t}^{CH}$ are included in the regression. These measures considerably reduce the autocorrelation of the residual. Furthermore, we use Newey-West standard errors (Whitney K. Newey and Kenneth D. West 1987) in order not to overestimate the significance of the predictors, since the usual least squares estimator is less efficient by autocorrelation and the standard errors are distorted.

A t-test with Newey-West standard error justifies the accuracy of the regression models rejecting the null hypothesis H_0 ="the true coefficient is zero" for (almost) all hours with at least 95 % confidence. Figure 6 shows an exemplary in-sample model run and the error estimation by the mean absolute error (MAE). The accuracy of the regression is high, especially in spring and summer. In autumn and winter, the ratios are worse, indicating possible nonlinear correlations in winter or missing explanatory variables.

Figure 6: Exemplary in-sample model run for the months April to October 2011-2014 average absolute error of 24 models over one day.

In order to reduce dependencies (i.e. covariance between the load variables of different countries) within the input set, another set of regression models is developed using principal component analysis. With the above used variables (trend-adjusted and differentiated) excluding the auto regression components, the principal component analysis is executed. Since the first three components explain more than 90 % of the variance in every hourly model, and more than 95 % in almost all hours, we decide to take these three principal components as predictors for the regression models. Thus, the principal component regression models are:

$$\Delta^{7d}price_{h,t}^{CH} = b_1 * \Delta^{7d}component1_{h,t} + b_2 * \Delta^{7d}component2_{h,t} + b_3 * \Delta^{7d}component3_{h,t}$$

Equation 2: Principal component regression model for the Swiss electricity wholesale price for each hour of the day.

In order to be able to determine the influence of the fundamental input data from the regression models, a retransformation of the main components is necessary. Since the dependencies of the individual components are not taken into account here, the significance bounds are not calculated, in contrast to the regression described above.

Since only the in-sample performance is evaluated, the principal component regression models, which reduce the information of the input space, have a slightly higher MAE than the before tested models with the same input variables. Nevertheless, it is expected that the results of the principal component regression are more general and possibly provide smoother results that allow better understandable insights.

2.3 Drivers

The developed models serve to analyse the influence of different predictors over the course of the day. The model run presented below describes the influence of the different variables in spring/summer and autumn/winter. As already explained, the similarities to the electricity prices of neighbouring countries are different in the different seasons. The comparison of the coefficients in the different periods thus allows conclusions to be drawn from the factors that explain the differences between summer and winter.

Differences between the seasons become clear when we consider the seasonal mean values of the regression coefficients. While a change in the gas price of one EUR/MWh in summer results in an average change in the Swiss electricity price of 0.95 EUR/MWh, the change in winter is significantly higher: the electricity price in the regression model changes by 1.36 EUR/MWh on average. Similarly, the Italian load proves to be more influential in winter, with a mean change in the electricity price of 0.70 EUR/MWh per additional GW demanded, while the influence in summer is 0.24 EUR/MWh on average (see Figure 7).

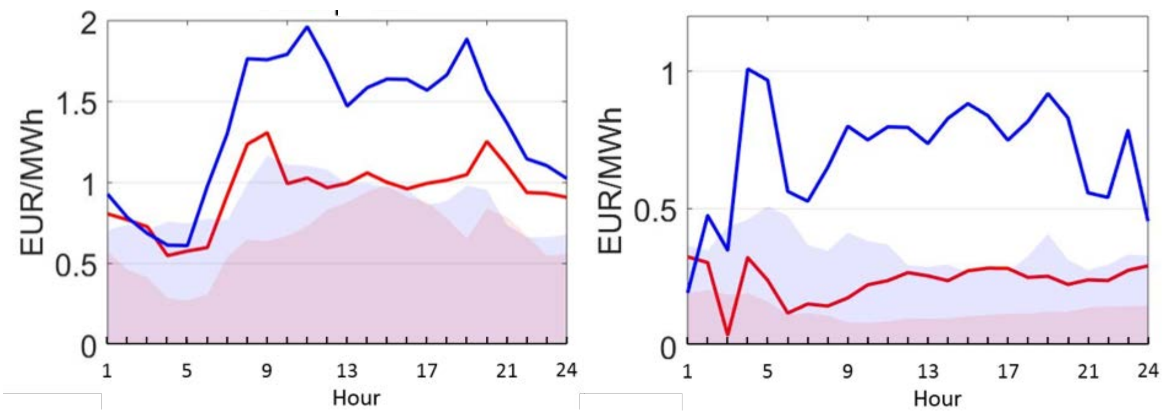

Figure 7: Influence of the gas price (left) and the Italian load (right) on Swiss electricity prices [EUR/MWh per EUR price difference or per additional GW Italian load] in summer (red line) and winter (blue line). The shaded areas indicate the corresponding p-value.

Both trends coincide with the earlier observation that prices approach Italian prices in winter. Gas prices and the load of the Italian electricity system are to be understood in the model as the representatives of the Italian electricity price. However, since gas power plants are not only operated in Italy, this effect cannot solely be attributed to the Italian influence.

The effect of the gas prices shows a further interesting characteristic: In the morning and evening hours in which the electricity demand is usually the highest, the influence is particularly strong. This is in line with the theory of merit order pricing, according to which power plants with higher marginal costs are used primarily at times when there is a high price or demand.

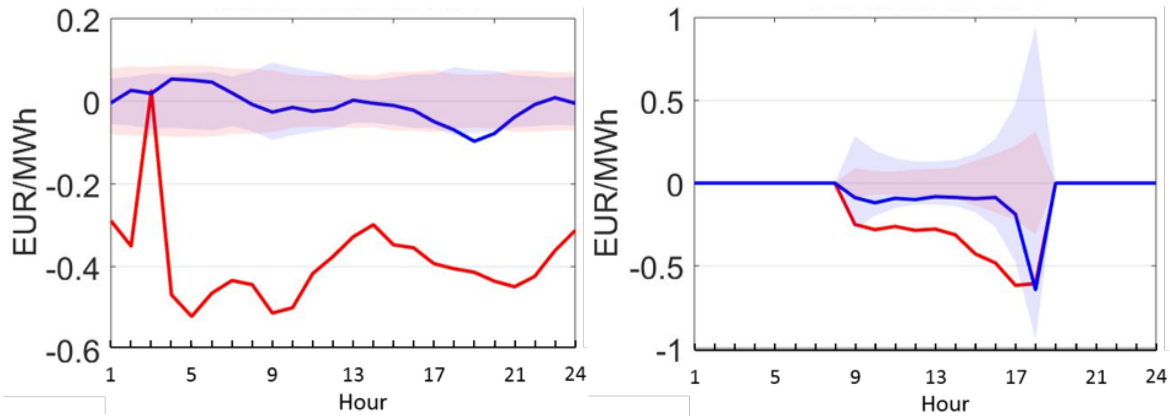

Figure 8: Influence of the German wind power (left) and PV feed-in (right) on Swiss electricity prices [EUR/MWh per EUR price difference or per additional GW feed-in] in summer (red line) and winter (blue line). The shaded areas indicate the corresponding p-value.

For the German wind and solar power feed-in, Figure 8 reveals a high influence in the summer, whereas in winter no significant influence on Swiss electricity prices can be identified. This is also in line with previous observations that the Swiss electricity price follows the German electricity price much more closely in the summer. Consequently, feed in of power from fluctuating RES in Germany in the summer has a greater effect in Switzerland as well.

The negative impact of both wind and solar feed-in can be explained by the way in which electricity from RES is marketed. Due to the negligibly low marginal costs and the support of RES, they often come into the market at any price and thus lower the price (merit-order-effect (Sensfuß et al. 2008)). Although the coefficients show the expected behaviour, caution is required when interpreting them. Since the solar feed-in follows the same pattern in all countries, it is conceivable that the coefficients not only indicate the influence of the German feed-in, but also make use of the overall influence of the PV feed-in. Further methodological developments, e.g. towards partial regression, are necessary if the influences are to be delimited sharply by country.

Regarding the influence of the load, different results could be derived. While the German load has significant impact in the summer, but not in winter, the influence of the French load is reversed: It is hardly significant in the summer, but has a strong effect in the winter. This might come from the higher French electricity demand for heating in the winter (Réseau de Transport d'Electricité 2014; Gerhardt et al. 2017), because the share of demand from electric heaters is higher, if compared to Germany. Both load factors show a similar pattern over the day, with small or even insignificant influence in the night hours with a low electricity demand and the highest influence in the late afternoon, when also the electricity demand peaks (see Figure 9).

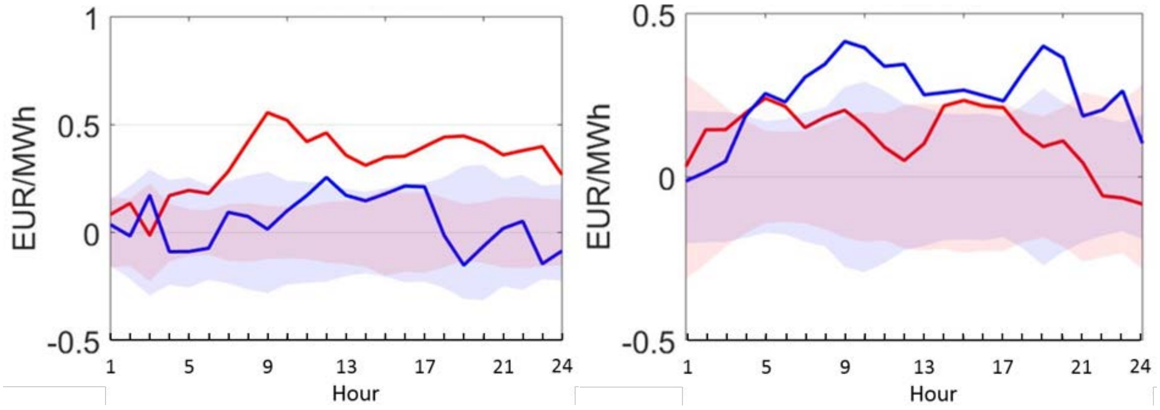

Figure 9: Influence of the German (left) and French load (right) on Swiss electricity prices [EUR/MWh per additional GW] load in summer (red line) and winter (blue line). The shaded areas indicate the corresponding p-value.

Surprisingly, the model reveals no significant influence of the Swiss electricity demand (see Figure 10). A reason for this result can be the two auto regressive predictors, which are both significant for the whole day independent on the season. Hereby, the day before has a positive impact on the Swiss price prediction, the price of the week before a smaller negative impact. If the regression is executed without the autoregressive part, the influence of the Swiss load becomes more visible, but stays insignificant for the given confidence level of 95 %. The weights of the other predictors only change slightly compared to the model with the autoregressive input.

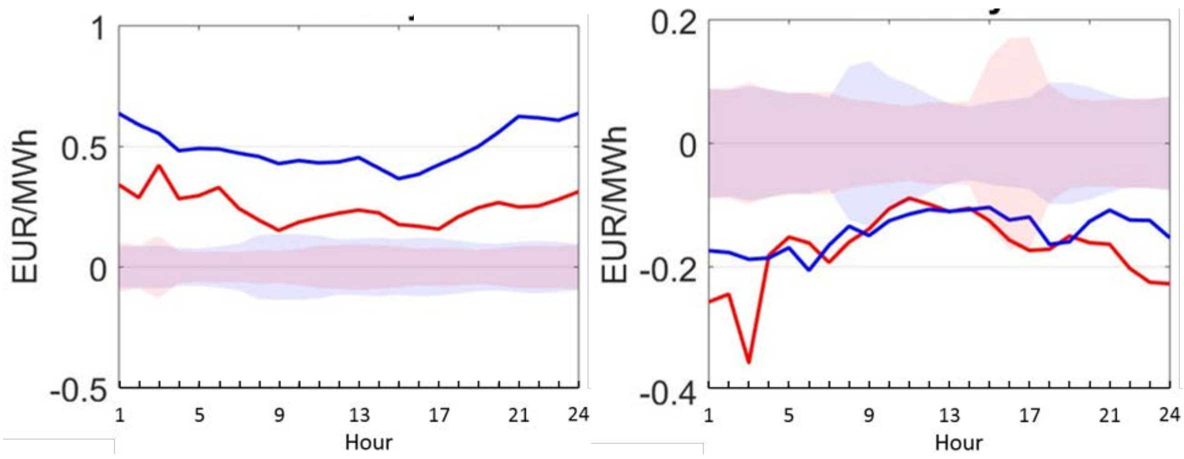

Figure 10: Influence of the day-before price (left) and the week-before price (right) on Swiss electricity prices [EUR/MWh per EUR/MWh price difference] load in summer (red line) and winter (blue line). The shaded areas indicate the corresponding p-value.

Another explanatory approach would be that the influence of the Swiss load is already included in the information on the load of neighbouring countries. This thesis is at least partly supported by the correlation analysis carried out above. Indeed, if the foreign electricity demand is removed from the model, the large influence of the Swiss load becomes visible (see Figure 11 on the right). While in summer the influence is 5.16 EUR/MWh per additional GW load on average, it is even higher in the winter, reaching 9.83 EUR/MWh on average. Additionally, the German wind power also becomes significant for the peak demand hours in winter.

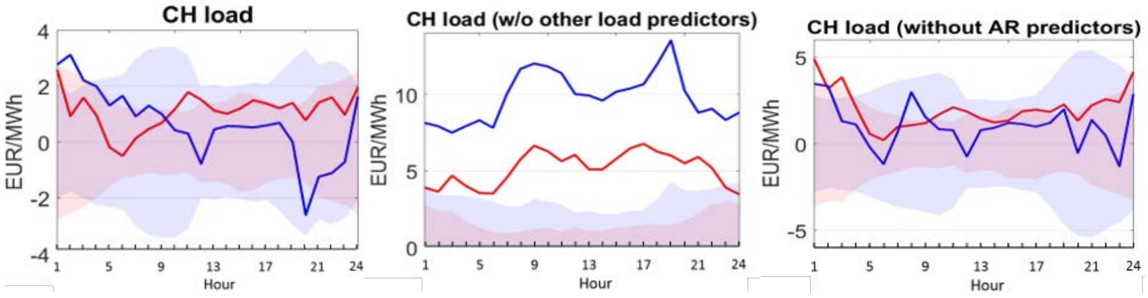

Figure 11: Influence of the Swiss load on Swiss electricity prices [EUR/MWh per additional GW load] in summer (red) and winter (blue), with all predictors (left), without autoregressive predictors (right) and without autoregressive and foreign load predictors (middle). The shaded areas indicate the corresponding p-value.

The interdependency between the different load predictors can be interpreted as collinearity, although initial tests excluded such a relationship. To avoid such interdependencies between predictors, a principal component analysis is additionally carried out. The first step of the interpretation of the principal component regression model is the analysis of the weights of the fundamental factors within the principal components that explain most of the overall input variance. The first component is dominated by the German wind power feed-in for all 24 hours. Additionally, the foreign loads and the PV power feed-in have a small influence on the component. The second component is predominantly modelled by the foreign loads (all with identical signs). Contrary to the first component, the weights of the models are different for the 24 hourly models. The third component that turns out to be insignificant in the regression model consists of almost all fundamental inputs with large differences between the 24 models. In contrast to the third component, the other two main components are significant, the second component (0.7 EUR/MWh) more than the first component (-0.3 EUR/MWh). The influence is hardly dependent on the season, but is larger for hours with high electricity demand (cf. Figure 12).

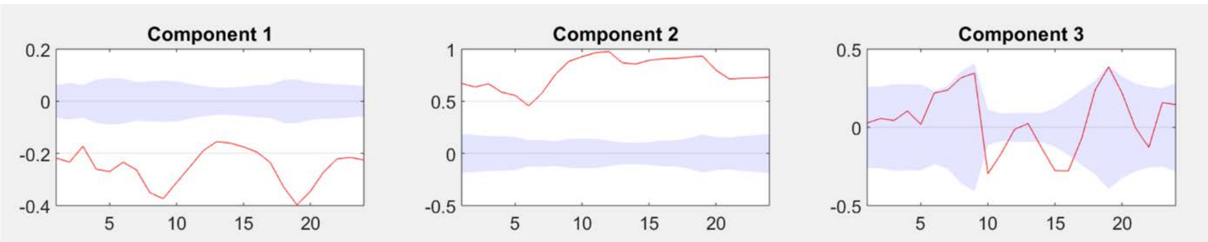

Figure 12: Influence of the principal components 1-3 on Swiss electricity prices [EUR/MWh]. The shaded areas indicate the corresponding p-value.

The analysis of the influence of the fundamental inputs after the retransformation essentially confirms the above findings of the regression model. However, due to the methodology no statement can be made on the significance of the fundamental inputs. In almost all hours, the influence of the load of all countries is higher in the winter and higher in the morning and late afternoon. In contrast to the basic model, this is also true for the German load. The same pattern can be identified for the gas price. As expected, the influence of the PV and wind power feed-in is stronger in the summer. Compared to the basic model, the MAE of the principal component regression model is only slightly higher (5.9 EUR/MWh compared to 5.8 EUR/MWh). On the other hand, the variance of the deviations is smaller. This indicates that the principal component regression model can provide a stable prediction without significant loss of information (Dunteman 1989). It can be assumed that the model would outperform the basic model in an out-of-sample test, because of its higher regularization.

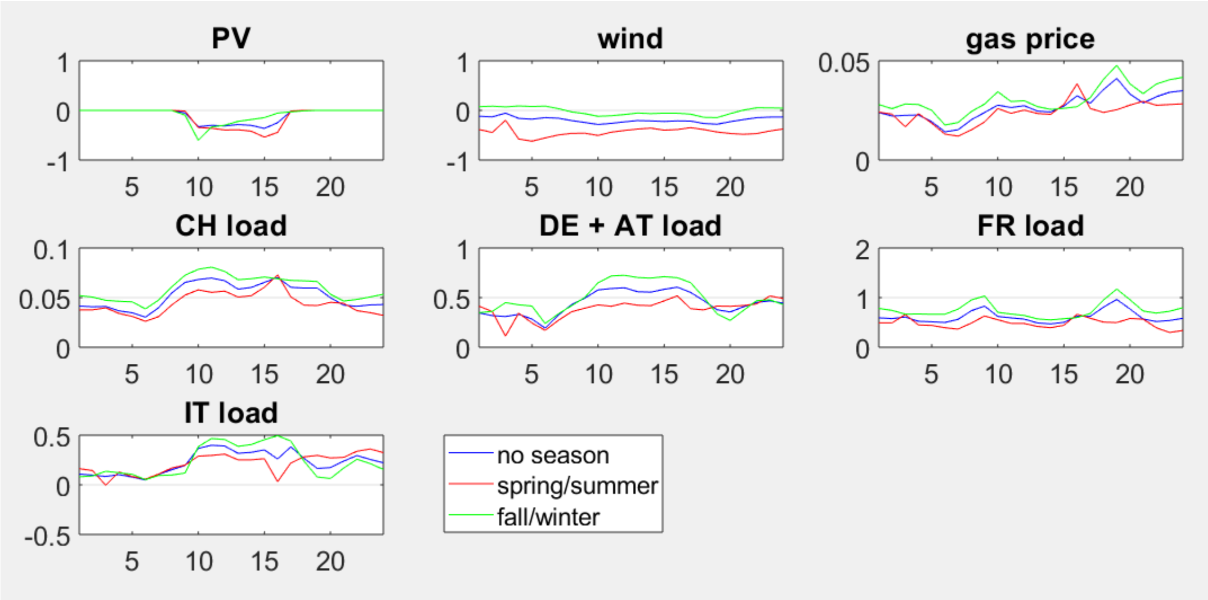

Figure 13: Influence of the fundamental price drivers on Swiss electricity prices [EUR/MWh] per GW (for gas price per EUR/MWh) as result of the retransformation of the principal components.

2.4 Intermediate conclusions

This investigation analyses the hypothesis that factors affecting the electricity prices of neighbouring countries also influence the development of the Swiss electricity price. The coupling of markets and the large cross-border transmission capacities play a decisive role here. Various interrelationships could be demonstrated: On the one hand, it turned out that the French load interacts strongly with the Swiss electricity price, in particular at very high peaks. Furthermore, it was compared how the prices behave in relation to each other in the different seasons. In spring and summer, there was a strong correlation between the German, French and Swiss electricity prices, while the Swiss electricity price in winter is limited by the Italian electricity price. The analysis of the regression coefficients showed that influencing factors of the Italian price gain more influence in winter, while the predictors of the German price tend to decrease.

The autoregressive variables also contribute significantly to the electricity price forecast. Contrary, the Swiss load does not significantly influence the prices, because the information is mainly covered by the neighbouring load values. However, if these variables are removed from the model, the strong influence between the Swiss load and Swiss prices becomes visible. The executed principal component regression confirms the results of the regression models. In principal, it can be stated that the developed regression models are suitable for analysing the complex relationships between the Swiss electricity market and its neighbours.

3 Impact of market design changes in the neighbouring countries on the Swiss electricity market

In this section, the overall methodology for the analysis of the Swiss electricity market is presented. At first, the agent-based simulation model PowerACE is introduced, including the model extensions that were implemented in the context of this project. Then, cross-border effects on Swiss electricity market are analysed, followed by an investigation on the RES share in Switzerland and the development of the possible funding volume under the current support scheme. Finally, we draw conclusions based on results of this section. This section is originally based on the preprint of Zimmermann et al. (2019).

3.1 Agent-based modelling of the Swiss and neighbouring electricity markets

For this research project, an agent-based modelling (ABM) approach was selected. The main reason for ABM is the integration of the market actors'/investors' perspectives into the trading and investment decisions in the model. The main advantage is that no perfect-foresight is applied regarding endogenous power plant investments or de-investments. This means that investment decisions are based on expected future cash flows that do not always have to be sufficient to cover the total investment expenses in the retro-perspective. This also means that demand may not be met by supply capacity (compared to a demand serving constraint in optimization models), because agents can invest less than required capacity in case of an estimated negative net present value (NPV) for new investments in a specific year. Furthermore, it is possible to analyse ex-post the profitability of an investment in a power plant type. Besides, it is also possible for power plant operators to submit strategic bids (in particular in the day-ahead market) in this approach, even above the variable costs. However, the main reason for the application of this approach is the possibility to analyse the interactions between imperfect market segments, which can be integrated on a modular basis. This study is conducted extending and applying the agent-based simulation model PowerACE (Genoese 2010; Keles et al. 2016a; Keles et al. 2016b; Ringler 2017).

PowerACE is an agent-based, bottom-up simulation model for wholesale electricity markets. Individual agents are major national and international actors representing the main generation companies/market players (4 players in Switzerland) in the modelled system. Agents decide based on their preferences without considering any overall objective. The model integrates the short-term dispatching of generation units with an hourly time resolution and the long-term capacity planning with regard to conventional power plants. The model can be applied to single market areas as well as to an interconnected system using a NTC-based market coupling approach, which is as well used by the European Power Exchange (EPEX) coupling some of the European countries. The simulation model can be also used to analyse in detail the formation of clearing prices on spot markets. One or more different design options r of the electricity market can be applied for single market areas or the entire coupled market area. Basically, PowerACE has an hourly resolution combined with a comparably low computing time. It will be the main methodological tool used in this project and provides input data for the analysis in Section 3.3 and 4.

Main structure

With respect to the market structure, major generation companies are represented by individual agents in the model. Other agents are modelled to send bids for electricity demand, for generation from RES, to exchange electricity with neighbouring countries, and to operate markets. Concerning the short-term markets, the focus is on the day-ahead market, which is cleared on an hourly basis. Following economic theory, power plant operators offer their generation capacity based on marginal generation costs in a competitive environment. These costs include inter alia fuel, carbon prices and start-up costs. In scarcity situations, it is possible to include a strategic mark-up that depends on the market scarcity to recover also the long-term fixed costs of a power plant.

Basically, the model is used to simulate the future development of the electricity system in this project. The model helps to analyse the impact of different market design options (EOM, CRMs) and policy measures on electricity prices, investments in new flexible power plants and their contribution to the security of supply in the respective market areas. For that purpose, major aspects of the Swiss electricity system as well as interactions with other market areas are adequately considered in the model (Section 3.1). Outputs of the model are the electricity spot market prices of the modelled market areas, investments and their underlying decisions into flexible power plants, carbon dioxide emissions, exchange flows, hours with not served demand, and cash flows to the power plants including their profitability. In Figure 14, a schematic overview of the PowerACE model is illustrated.

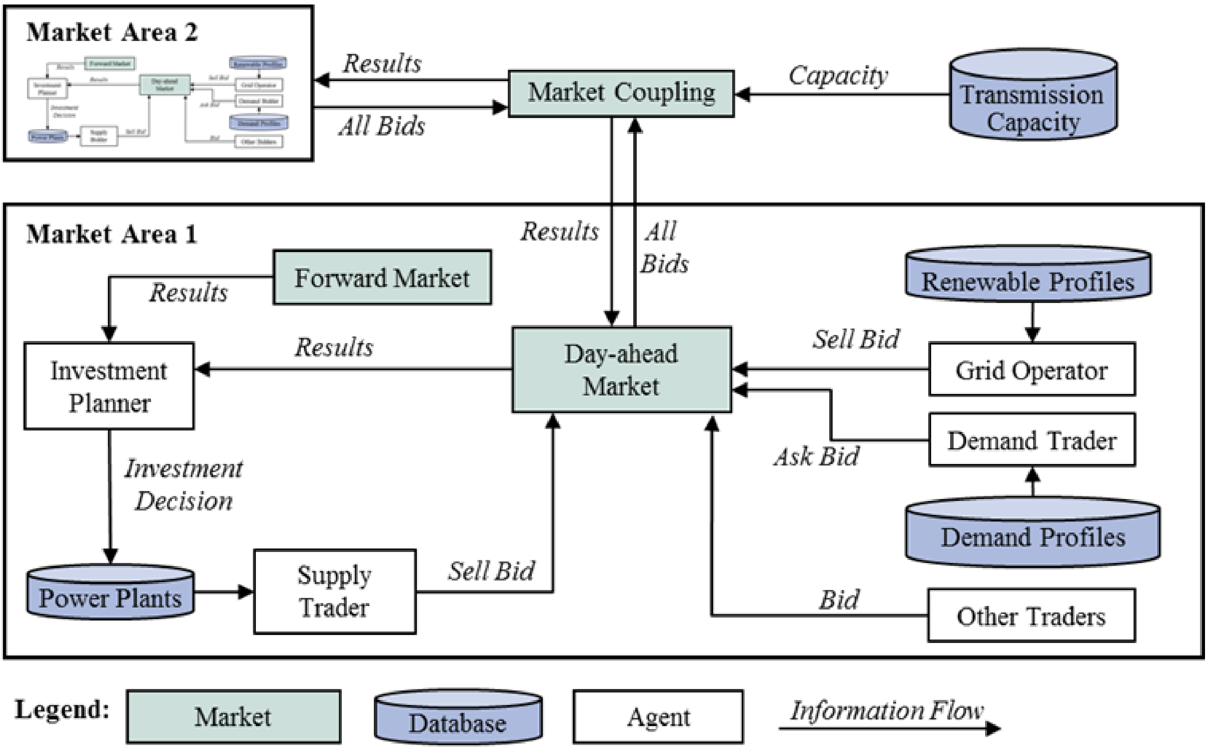

Figure 14: Schematic overview of the PowerACE model. (Ringler 2017)

Spot market

Regarding the geographical scope, different market areas are coupled using a day-ahead market coupling algorithm based on trading capacities between the market areas. As mentioned by Ringler (2017), the objective of the underlying linear optimization algorithm is to maximize social welfare for the coupled system, subject to the demand coverage in the market area, balanced local energy flows, and limited exchange trading capacities. The demand coverage is guaranteed using a dummy power plant, so that the model is always feasible. If the dummy power plant is the one that sets the price, it is equivalent to a not cleared market. Figure 15 shows the generic procedure. All demand and supply bids are transmitted from the agents to the market operators. The operators send the bids to the market coupling operator. It optimizes the welfare and sends the results (i.e. spot market prices) back to the market operators.

Through the market coupling, prices in the market areas implicitly depend on the demand and supply situation in all other markets and eventually converge, if sufficient interconnection capacity is available.

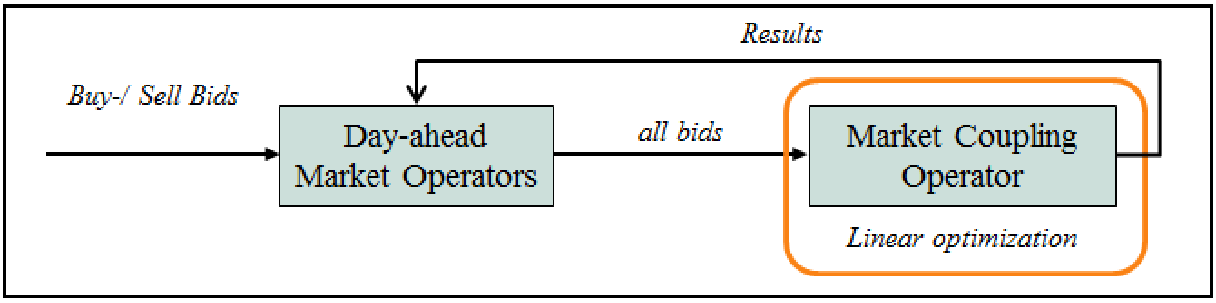

Figure 15: Schematic illustration of the market coupling process in PowerACE. (Ringler 2017)

Investment decisions

The model contains an investment-planning module, which is executed once a year within the chosen time horizon (2050). Thereby, different investment options of flexible power plants are compared according to a certain economic criteria, e.g. the net present value. Potential revenues for power plants can be generated from selling electricity in energy spot markets as well as from participating in different CRMs (e.g. central capacity market, strategic reserve (SR)) depending on the respective market area configuration.

Investment agents in all market areas evaluate different power plant options. Data and assumptions on which the prediction is based are future electricity demand, fuel and emission price developments in the following years. Based on these data, a price forecast is firstly made for future prices in the respective market areas. Each agent *a* uses the price forecast p^{prog} to calculate the Net Present Value (NPV) for each available investment option *j* according to Equation 3.

$$NPV_{j,a} = -I_{0,j} + \sum_{t=1}^{n_j} \frac{-c_{t,j}^{fix} + \sum_{h=1}^{8760} \max\{p_{h,t,a}^{prog} - c_{h,t,j}^{var}, 0\}}{(1+i)^t}, \qquad \forall a, j$$

Equation 3: Calculation of the NPV for an investment option *j*, based on the investment payment I_0, the economic lifetime *n*, interest rate *i*, fixed costs c^{fix} price forecast p^{prog} and variable costs c^{var}.

Investment options are predetermined exogenously based on the scenario (Table 4 in Section 3.2.1) and represent a specific flexible power plant type, such as a gas turbine. The options include all economic (such as investment I_0 or investment horizon *n*) and technological parameters (such as efficiency) that vary over the simulation period. In addition, future technological developments such as carbon capture systems are taken into account in various investment options.

For the calculation of the annual cash flows, an hourly price forecast (p^{prog}) is used for electricity prices to determine the expected revenues via the spot market. The price forecast for the NPV calculations works analogously to the determination of the spot market price by applying a welfare maximizing market coupling. The variable costs (c^{var}) for each hour *h* of the year *t* are deducted from this. Since a power plant only produces if at least the variable costs are covered, all negative cash flows are excluded (neglecting must-run conditions, start-up costs or minimum downtimes). For the calculation of the variable costs, fuel prices and carbon certificate prices are assumed to be the same in all market areas. The rationale behind this is that the Swiss emission trading system (ETS) will be coupled to the EU ETS scheme and produces the same price results. The gas price difference for different European virtual trading points differ marginally on European energy exchanges, so that this price is also kept constant assuming that network charges are neglictable.

A list with the NPV values of all power plant options is created for all agents *A* (from all market areas). From this, the option *j** is selected that reaches the highest positive *NPV** (according to Equation 4).

$$j^* = \max\{NPV_{j,a}\}, \forall j \in \{j|NPV_j > 0\}, \qquad \forall a \in A$$

Equation 4: Selecting the investment option with the highest NPV of all agents.

Each investment increases the totally installed capacity and thus influences prices. Consequently, no investor would make an investment with an initial positive NPV, if it affects prices to such an extent that the own new investment becomes unprofitable. Therefore, a new price forecast is calculated after each investment decision for option *j**. Subsequently *j** is re-evaluated with the new price forecast. If the *NPV** of *j** is still positive, the agent invests in option *j**. If not, a new price forecast is calculated with the option with the second highest NPV (and so on) until an investment is done. If no investment with a positive NPV is available, the algorithm terminates and no further investments are made in the simulation year. Finally, it is important to mention that the investment process is repeated every year of the model horizon.

Output

One of the main outputs of the model within this project are the hourly spot electricity prices for each market area. These electricity prices reflect both the national situation (market design, demand, generation mix etc.) as well as developments in interconnected markets. Therefore, determining the profitability of existing and new generation units is also a result in this study. Consequently, these results are used in order to analyse effects on the support volumes for fluctuant RES and the effects on profitability of hydropower in Switzerland.

Given the possibility to vary model parameters (e.g. with certain CRM activated) and input data (e.g. fuel and carbon prices varied), PowerACE is suitable to analyse a range of different scenarios. Therefore, in the past several investigations of the authors were already successfully conducted (e.g. Keles et al. 2016b) using the PowerACE modelling approach.

Within this project, the PowerACE model has been improved with regard to the methodology and the spatial resolution. The methodological extensions are inter alia the implementation of the French capacity market as well as the hydropower dispatch module, in particular for Austria and Switzerland. Furthermore, the long-term price forecast, which is used in particular in the investment planning module, as well as the investment planning module itself have been improved regarding the consideration of market coupling effects. Geographical extensions include the market areas of Switzerland, Italy and Austria, while before the project the model was limited to the Central-Western-European (CWE) market area.

3.1.1 Modelling hydropower

Analyses of the Swiss electricity market require an adequate representation of hydropower plants in the electricity market model. In Switzerland, approximately 17.1 GW of hydropower generation capacity and a total storage capacity of 8.8 TWh are available. The hydropower generation capacity (including power plants under construction) is divided into 4.7 GW of run-of-river, 3.6 GW of pumped storage plants and 8.7 GW of seasonal hydro storage plants. (Swiss Federal Office of Energy 2018g)

The run-of-river power plants are integrated into the model based on historical generation profiles (Swiss Federal Office of Energy (2017b) data used from year 2015) due to the regular patterns over the years. The pumped storage plants are modelled according to the approach described by (Fraunholz et al. 2017) assuming 10 % of the total volume of all hydro storage volume is available for pumping (acc. to Swiss Federal Office of Energy 2018f).

Different modelling approaches are tested and evaluated for this project, and finally, due to the transparency of the methodology, a linear regression approach is chosen to model the seasonal hydropower, as it is the generation technology with the highest installed capacity in Switzerland. For this purpose, the hourly historical production time series of seasonal hydro storage power plants from ENTSO-E (2018b) for the years 2015 to 2017 are used for the regression analysis.

$$\begin{aligned} hydroGen_t = & \beta_s^0 + \sum_m \left(\beta_{m,s}^{load} load_{m,t} + \beta_{m,s}^{RES} RES_{m,t}\right) \\ & + \sum_{m \neq CH} \beta_{m,s}^{NE} netExchange_{CH \rightarrow m,t} \\ & + \sum_{i=1}^{23} \beta_s^i hour_t \qquad\qquad \forall t \\ & + \beta_{CH,s}^{Storage} V \\ & + \epsilon_t \end{aligned}$$

Where:

t	= Hour of the year
m∊M	= Market areas of Switzerland's neighbouring countries (Austria, France, Germany, Italy)
β	= Estimated values
RES	= RES production
V	= Storage volume
day	= Weekday or weekend
hour	= Hour of the day

Equation 5: Regression model to estimate the hourly operation of seasonal storage hydropower plants.

The following influencing factors are examined with the assessment of the regression: Demand, RES feed-in, dummies for weekday or weekend days, exchange flows with neighbouring market areas, storage level and hour of the day. Inflows are implicitly included in the storage level and the fit to the historical production. Coefficients for these factors are individually estimated for each season. To account for the increasing capacity of RES, normalized values (normalized to the total annual production) are used for the variable RES feed-in. Equation 5 describes the regression model. Appendix 8.1 documents the individual regression coefficients for each season.

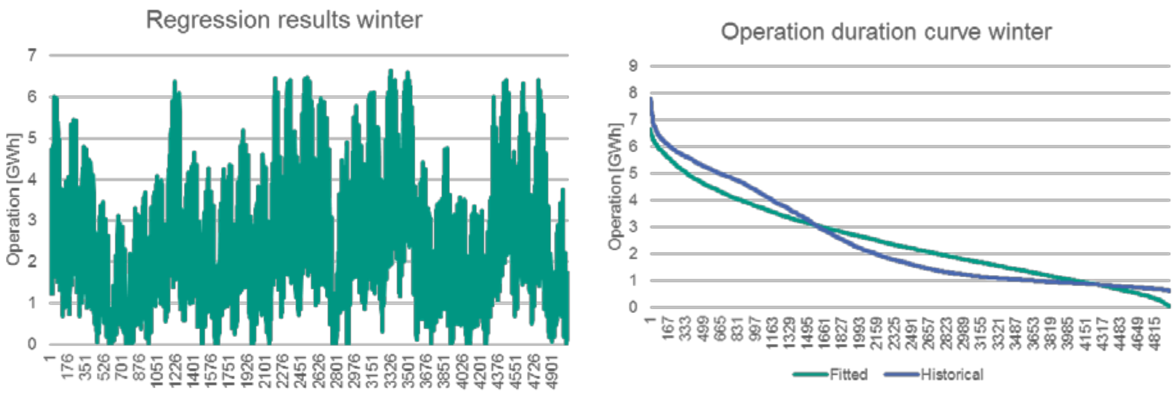

Figure 16: Left: Time series of the fitted operation for seasonal hydro storage power plants in winter. Right: Operation duration curve historical and fitted of the seasonal hydro storage power plants.

The developed regression model and its coefficients are integrated into PowerACE. Based on the regression model, the hourly operation of the seasonal hydropower plants according to Equation 5 is calculated. In addition, the storage levels are tracked at any time and in the event of overflow or underrun, the operation is adjusted accordingly. Taken from the PowerACE model results, Figure 16 left shows the hourly operation in winter[1] simulated with the regression in PowerACE. Figure 16 right visualizes the sorted operation (duration) curve for the winter compared with the real operation. Figure 17 illustrates the historical storage level and the storage level of the simulation in PowerACE for the year 2016.

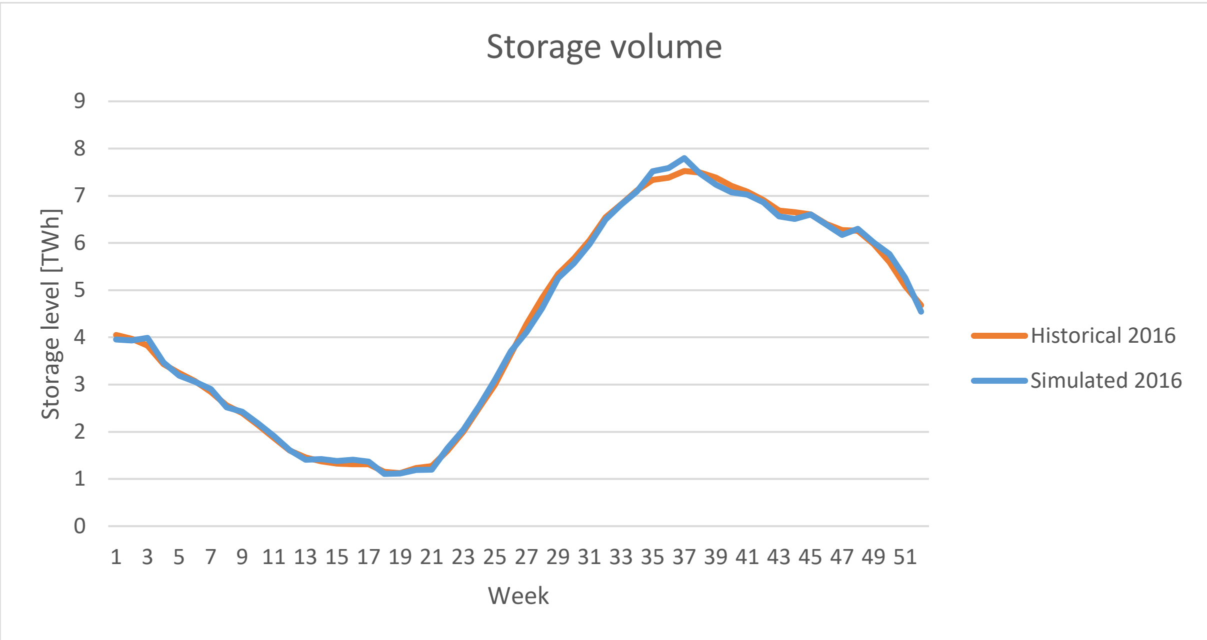

Figure 17: Storage volume of the seasonal hydropower plants for the year 2016 historical (Swiss Federal Office of Energy 2016) and simulated.

[1] The seasons in the regression are divided according to meteorological definitions.

3.1.2 Modelling capacity remuneration mechanisms

A complete description of how the CRMs are implemented in PowerACE can be found in (Keles et al. 2016a). For this study, adjustments and new developments regarding CRMs in PowerACE are conducted. The different market design options deployed in the market areas are briefly described in the following.

Strategic reserve

Recently, Belgium and Germany implemented a Strategic Reserve (SR) (Bublitz et al. 2018). Therefore, the SR is modelled in PowerACE as follows. Every year, the network operator organizes a unit price auction, in order to allocate the power plants for the SR. Existing reserve power plants are initially transferred to the SR (e.g. in Germany), and therefore, the capacity demand quantity of the auction is reduced in the height of the existing reserve capacity. In order to participate in the SR, a power plant must be available within a certain time, this means after a cold start time of less than 10 hours. During the auction, the selection of the power plants is based solely on the capacity price bid without considering variable costs.

Generation companies offer existing power plants for the SR based on their individual annual fixed and opportunity costs. The opportunity costs arise from the ban on power plants from participating in other markets outside the SR, once they are part of the SR, and correspond to the lost profits from the other markets. This ban remains even after the end of the contract period ("no-way-back rule"). The maximum price in the SR auction equals to the cost of new entry (CONE)[2], because for this price a new power plant could be built explicitly for the SR.

If a power plant is part of the SR, the operational control is carried out by the grid operator. The SR is only used in extreme situations, when no balance between supply and demand on the spot market is expected. In this case, the network operators offer the reserve in the day-ahead market at the maximum price. The power plants are activated in the order of their variable costs: First the power plant with the lowest variable costs is used, then the more expensive ones. In case of being dispatched, the SR power plant operators receive a recompensation for the costs additionally incurred during the operation time (e.g. fuel costs).

Central capacity market/central buyer

The central capacity market with capacity options, e.g. applied in Italy, is based on the Forward Capacity Market, which is currently implemented in the market area of the US system operator ISO New England (2014), and is adjusted to the Italian market area.

In the model with a lead time of four years, the regulator agent determines the conventional capacity requirement which is calculated based on the forecasted peak load in the respective year of execution minus the contribution of RES and which ensures the generation adequacy (on the basis of predefined capacity credits).The regulator takes also into account imports from other countries that are available in scarcity times. The generation adequacy level is controlled by specifying a certain reserve margin. The regulator buys as the central agent the whole capacity in the model including all reserve margins. An auction is used as trading platform to ensure that the capacity requirement is purchased at lowest prices.

[2] The CONE can be regarded as the annuity of the investment payments for the cheapest, newly built conventional power plant.

The auction is designed as a descending clock auction whose floor and starting price depend on the CONE. To conduct the auction, all incoming bids are at first randomly mixed and then sorted in ascending order according to their capacity price. The price is reduced by a defined increment, which leads to plant operators and investment planners "leaving" the auction when their bid is undercut, until the specified conventional capacity requirement is reached. This procedure results in the final capacity price. The remaining bids comply with the cost-efficient provision of the required capacity. The successful bidders receive this price for four years in case of new plant investments and for one year in case of existing plants.

A call-option-like mechanism is implemented to ensure that no supplier withholds power plant capacity in scarcity situations. All participants in the CRM agree to a strike price for the electricity to be sold in the spot market. The strike price can be equal to the short-term marginal cost of a reference gas turbine (which has comparatively high variable costs and is used mainly in peak load situations). As soon as the price on the spot market rises above the strike price, the power plant operator receives the strike price as maximum. The (positive) difference between the market price and the strike price is used to cover the capacity payments resulting from the capacity auction. It is therefore unattractive for the power plant operator to withhold capacity, as it cannot generate any higher revenues for the other capacity in the market. Since capacity payments are based on the fixed costs of a reference gas turbine, these power plants can also operate profitably.

French capacity market

The implementation of the French capacity market in PowerACE, which was particularly developed for this project, is addressed in the following. Firstly, the reference capacity demand including exogenously determined security factor is calculated prior to each auction. The reference capacity value is based on the future annual peak demand. The security factor also includes capacities from foreign countries, which lower the need for domestic capacity during peak load times if neighbouring countries could provide electricity. Depending on the reference capacity, the capacity obligations of the obligated parties (supply companies and large consumers) are determined depending on their share in total peak demand, so that each obligated party needs to prove capacity obligations (in the form of certificates) covering the amount of its own demand (Zimmermann et al. 2017, Kraft 2017).

For the certificate price bids of the generation capacities in the market, the expected income on the electricity market is estimated for each generation unit on a yearly basis. This determines the difference costs that will form the price of the capacity bid. The difference costs are defined as the gap between the yearly income on the energy market and the required income to break even a generation unit's profitability. This means, if a plant cannot cover all costs by contribution margins earned on the electricity market, it needs additional payments in the amount of its difference costs. However, it has to be considered that not the entire installed capacity of a power plant is granted with capacity certificates, but only the share of available capacity. That means: The volume of the granted certificates equals to the installed net capacity multiplied with a technology-specific capacity factor to respect availability constraints (RTE 2017).

The created certificates are then ordered by the offer price. The certificates for RES capacities, considering respective capacity credits for each technology, are added to the list of capacity certificates with a bid price of zero (see RTE (2017)). The demand side is considered to be price taking and asks for certificates in the amount of the reference capacity (is defined by the regulatory authority to meet the security of supply target) for the respective year. For each simulation year, supply and demand curve are intersected to record the capacity auction results in the form of price and volume. Based on the results, the certificate prices are payed to the selected power plants.

At the end of each simulation year, the investments are planned in the model. That requires the endogenously modelled spot price forecast to estimate the difference costs and the resulting capacity certificates prices, taking into account all limitations defined by RTE (2017) (the future installed capacity and investments as well as the reference capacity development). For new investments, the first forecast year is crucial since the initial contract lasts seven years and accounts for the main share of capacity revenues considered in the investment appraisal.

3.2 Analysis of cross-border effects on the Swiss electricity market

3.2.1 Scenarios and data

In this section, a scenario framework is defined in accordance with the modelling approach (Section 3.1). Therefore, assumptions are made for the development of electricity demand, fuel and carbon certificate prices, and costs of production technologies.

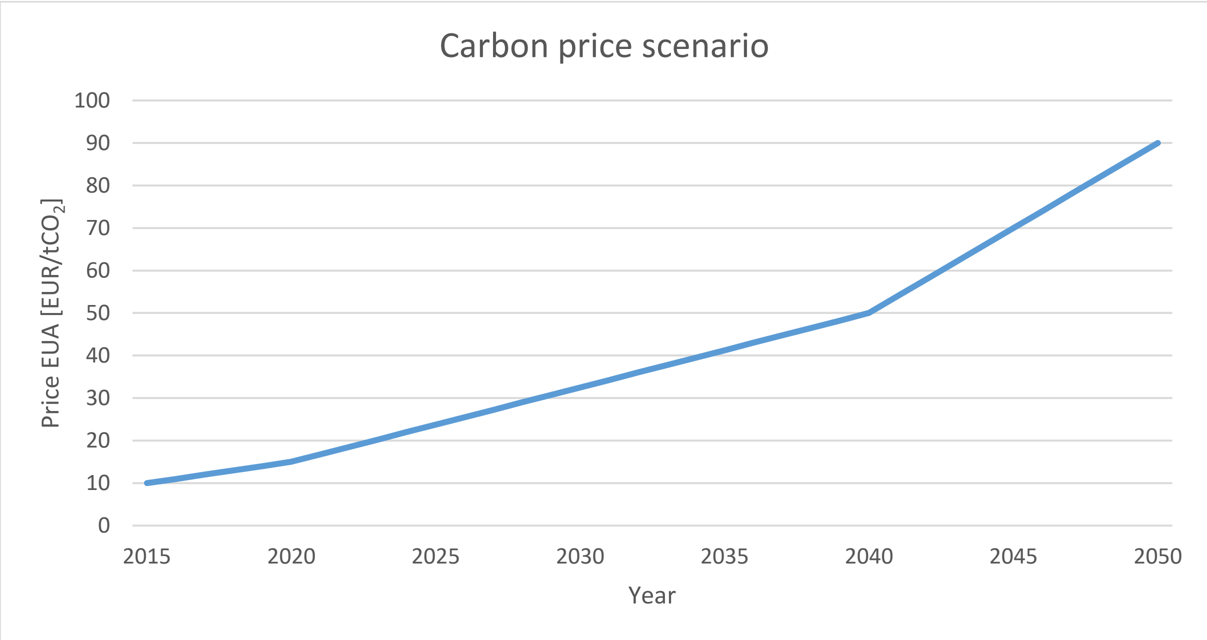

Figure 18: Development of the European Emission Allowances (EUA) in [EUR/tCO_2] (European Commission 2016).

In this context, the presented results are based on several input data sources, which requires selection and processing large amounts of data in order to use them in the scenario runs. First of all, the EU Reference Scenario (European Commission 2016) was used to derive fuel- (Figure 19) and carbon-prices (Figure 18) for all market areas. All flexible fossil fuelled power plants in the modelled areas are based on S&P Global Platts (2016) power plant database. Regarding the market coupling, the transmission capacities between the market areas are derived from Rippel et al. (2018) and ENTSO-E (2018a). Investments in new flexible power plants as well as assumptions for fixed and additional variable costs (in addition to the costs of fuel and carbon certificates) of power plants are used from Schröder et al. (2013).

Due to the high temporal resolution of the model, hourly feed-in and demand profiles (year 2015) are used as initial data taken from ENTSO-E (2018b) as well as from Swissgrid (2015), depending on the market area. The yearly development of the demand is taken from European Commission (2016) for the EU countries and from Prognos AG (2012) (Variant C&E) for Switzerland. All profiles are scaled according to the underlying development in the modelled years.

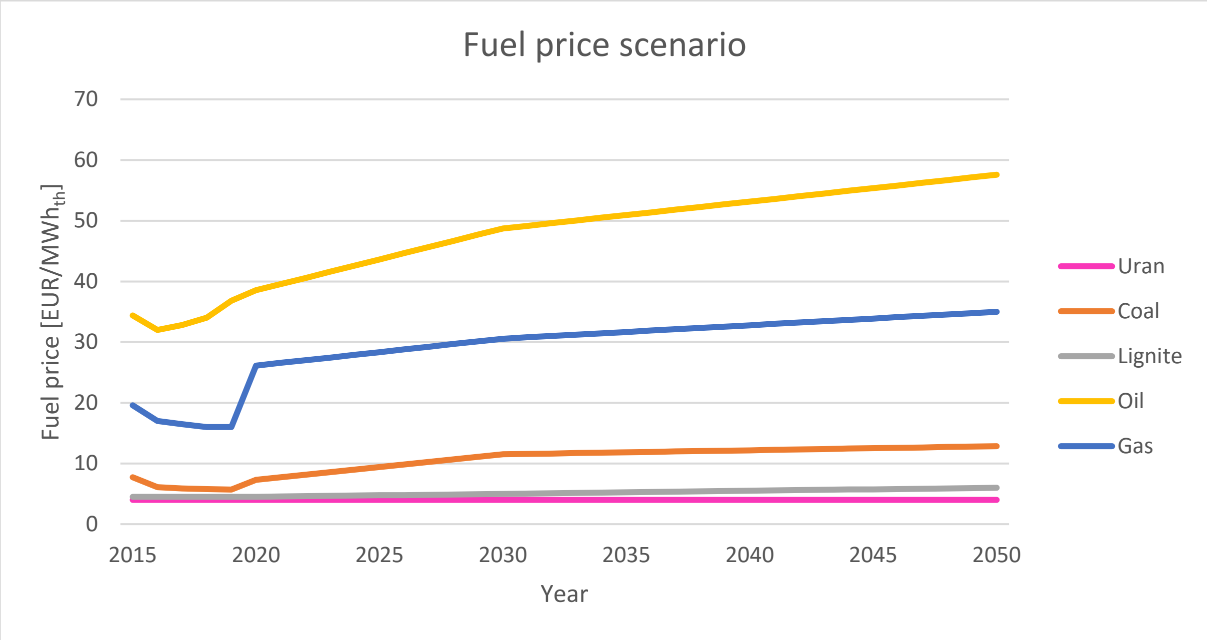

Figure 19: Development of the fuel prices in [EUR/MWh$_{th}$] (European Commission 2016).

The RES feed-in volume, containing all relevant development until 2050 and considering the countries' individual RES support schemes, is taken from European Commission (2016) for the European Union countries and for Switzerland from Prognos AG (2012) (Variant C&E). Hydropower plants play a crucial role in the Swiss electricity market. The aggregated capacities for hydro river, seasonal hydro storage and pumped storage power plants are taken from the Swiss Federal Office of Energy (2018g).

Table 4: Assumptions for Investments in conventional power plants according to Schröder et al. (2013) regarding to the block size, electrical efficiency, maximum lifetime, investment payment as well as fixed and variable operations and maintenance (o&m) costs.

Investment option	Block size [MW]	Electrical efficiency [%]	Lifetime [Years]	Investment [EUR/kW]	Fixed o&m costs [EUR/MW]	Variable o&m costs [EUR/MWh]
Nuclear	1600	0.33-0.34	50	6,000	42,000	12
Coal Combined Cycle	600	0.48-0.52	45	1,800	60,000	6
Coal	600	0.46	45	1,300	25,000	6
Lignite	800	0.43-0.46	45	1,500	30,000	7
Gas Combined Cycle	400	0.60-0.61	40	800	20,000	4
Gas Steam Turbine	400	0.41	40	400	15,000	3
Oil Steam Turbine	400	0.41	40	400	15,000	3

For the model, the storage capacity has to be divided for each generation type (i.e. seasonal hydro storage and pumped storage) because methodically no joint management of the storage types is possible. Therefore the total storage capacity is divided by the expected production of each type according to Swiss Federal Office of Energy (2018f). For a complete overview of input data and sources, see Table 5.

Table 5: Input data types and source overview.

Input data type	Resolution	EU-countries	Switzerland
Conventional power plants	Plant/unit level, various techno-economic characteristics	Research completed with S&P Global Platts 2016 and with own assumptions	
Demand and feed-in from RES	Hourly, aggregated for each market area	European Commission 2016, ENTSO-E 2018b	Prognos AG 2012, ENTSO-E 2018b, Swissgrid 2015
Fuel and carbon spot market prices	yearly	European Commission 2016	
Investment options		Schröder et al. 2013	
Transmission capacity	yearly	ENTSO-E 2018a/Rippel et al. 2018	

In order to examine the effects of the CRMs in detail, various scenarios are calculated using the agent-based wholesale electricity market simulation model for a time horizon from 2015 to 2050. These are shown in Table 6.

Different scenarios or sensitivities are modelled for the analysis and evaluation of the individual market designs for the simulated market areas. The CRM Policies scenario represents the currently implemented and planned market designs in the modelled market areas/countries. This represents a close to reality representation of the circumstances prevailing at the time the project was being processed. The EOM scenario is an historic scenario when power plants in all market areas have to cover all costs on the energy only market, i.e. on a market that only allows the refinancing of fixed costs of flexible power plants in hours with peak load prices (peak-load-pricing theory) (Boiteux 1960).

For the study of CRM market designs, availability factors of 6 % for wind and 1 % for PV are assumed in all hours. In Italy, conventional power plants are considered with 90 % availability in the CRM and for the capacity market auction, an additional reserve of 3 % of the peak load is implemented. For France, a security factor of 1.03 as well as capacity credits for wind (20 %) and solar (5 %) (defined by RTE (2017)) are applied. For Germany, the SR ('Kapazitätsreserve') allocates 5 GW power plant capacity to a reserve. In all market areas, demand response (interruptible load) capacities are assumed in the height of 2 % of the maximal peak load and are dispatched for a price of 700 EUR/MWh.

The EOM scenario is characterized by the fact that only EOMs are implemented in all modelled markets. This means that all income from flexible power plants is generated by the sale of electrical energy on the wholesale electricity market. Therefore, no additional payments are made for these power plants via capacity markets or SRs. Consequently, all incentives to invest in new power plants are also only resulting from expected revenues in this market.

Table 6: Applied market designs for the different scenarios used in this research project. EOM = Energy-only market, SR = Strategic reserve, FCM = French capacity market, CB = Central buyer

Market Areas	EOM	CRM Policies
CH	EOM	EOM
DE	EOM	SR
FR	EOM	FCM
IT	EOM	CB
BE	EOM	SR
NL	EOM	EOM
AT	EOM	EOM

In order to cover the costs of generating electricity, at least the short-term marginal costs (variable costs of generation) must be covered, otherwise production is economically not feasible. However, in order to operate a power plant economically, the long-term marginal costs must also be covered, which include both variable costs and the coverage of investment-dependent expenditures. If prices are continuously realised below the long-term marginal cost, the operator will not be able to cover all the costs incurred by the power plant. In the case of a static demand, prices are based on the long-term marginal costs of power plants. However, since electricity demand is subject to stochastic fluctuations, a distinction is made in theory between a peak-load phase and a low-load phase. In the low-load phase, the capacity of the power plant is not fully utilised; in the high-load phase, on the other hand, the capacity is fully utilised. In the low-load phase, it is possible to work economically at a price at least equal to the variable costs. However, during the high-load phase, prices must be achieved that exceed the variable costs, i.e. variable costs plus the total specific investments for the power plant. (Boiteux 1960)

An essential aspect of the EOM is to cover the remaining expenses and costs of conventional power plants through scarcity prices, i.e. comparatively high prices in high-load phases. The extent to which high prices are accepted in the markets is rather a political discussion (these are summarised Bublitz et al. (2018)).

The results, based on the above framework parameters are also used in the calculations of the RES funding volumes in Section 3.3 and of hydropower profitability in Section 4. This includes the hourly resolved development of wholesale market prices over the whole simulation period. In all scenarios, an implicit coal phase-out is presumed. Therefore, no new investments in coal- or lignite-fired power plants are possible in the investigated market areas.

3.2.2 Capacity development in the EOM scenario

Since CRMs are already established in some markets at the time of the preparation of this study, the EOM scenario serves more as a benchmark scenario.

In the EOM scenario, the total installed conventional capacity across all countries decreases, with the exception of Austria. This can be explained by overcapacities, especially in Germany, and by better counterbalancing effects across the various market areas. For instance, market coupling and expansion of trading capacities allow larger volumes of energy exchanges across countries. However, there is a short-term increase in capacity in 2030 and 2035 in the model runs. This can essentially be explained by the closure of large nuclear capacities in France, so that with a (purely hypothetical) assumption of the maximum operating life of nuclear power plants of 50 years, starting in 2027, their total capacity shrinks from over 60 GW to less than 10 GW within 15 years (excluding new investments) (Zimmermann et al. 2017). This leads to raised prices in the forecast module in consecutive years and in some cases to anticipated investments in new power plants. However, after 2035, capacity is falling back below the level of before 2030, both in France and in all countries considered. After 2035, the reason for the reduction of the installed conventional capacities is due to the growth of RES in all countries.

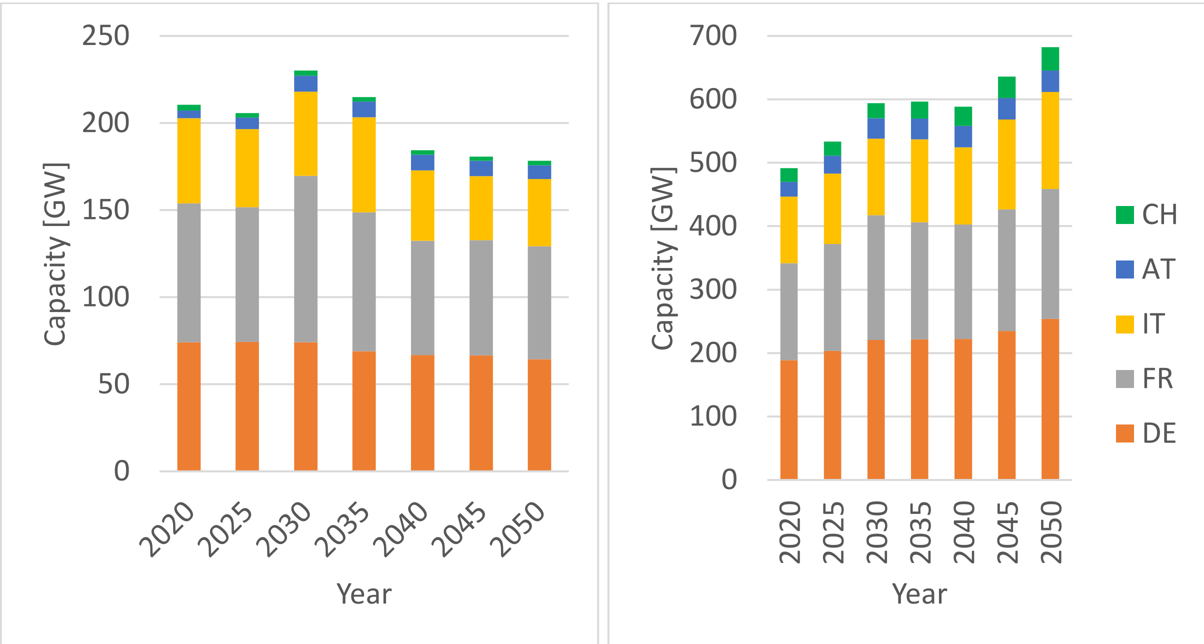

Figure 20: Cumulated conventional capacity development (left) and total installed capacity (right) in the EOM scenario in Switzerland and its neighbouring countries from the PowerACE simulation.

However, Austria is an exception, because of the newly introduced market splitting between Austria and Germany (since October 2018) and the merely static exchange with Czech Republic, Hungary and Slovenia without price effects. The latter issue could distort prices to such an extent that investments in Austria appear profitable in the model because of high price forecasts due to low installed capacity. For better illustration, Figure 20 shows the conventional capacity development without RES (left) and with the dedicated RES development (right), which can be found in European Commission (2016).

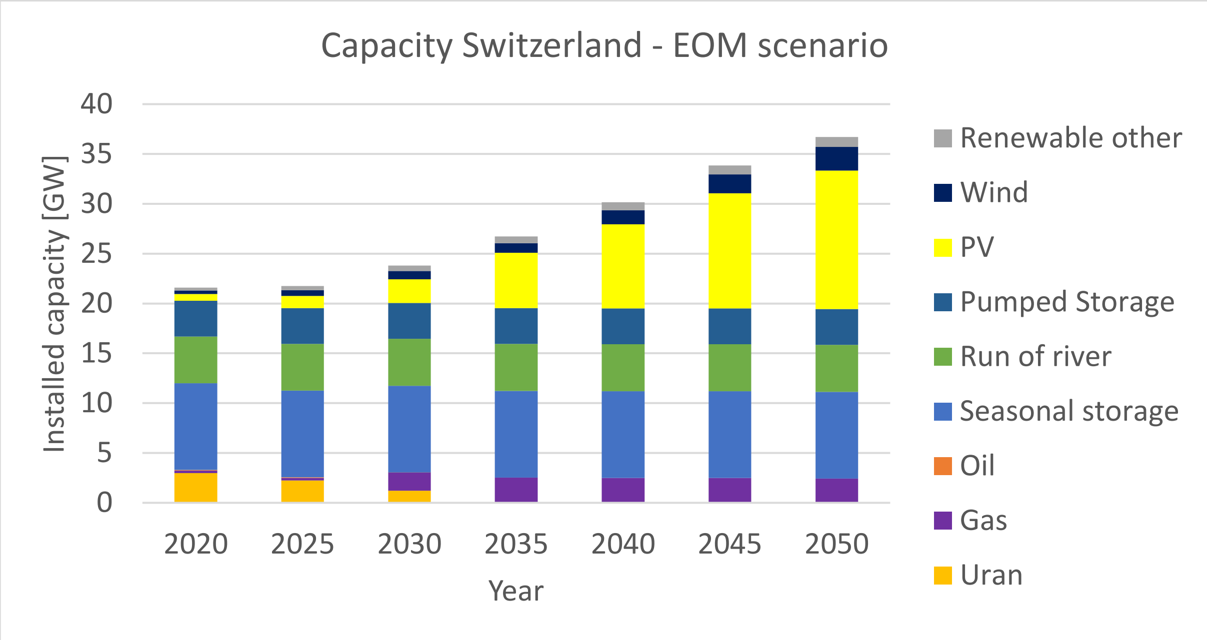

Figure 21: Capacity development in the EOM scenario in Switzerland including the RES and the conventional generation.

Figure 21 shows the capacity development in Switzerland, including all RES capacities, broken down by the respective generation technology. While the nuclear power plants will be completely phased out by 2035 due to the assumed maximum lifetime of 50 years, the capacity will be replaced by new investments in Gas Combined Cycle (Table 7) up to a total capacity of 2.4 GW. However, if the nuclear power plants are operated for a longer period, this picture may change.

Table 7: Investments into new flexible power plants in Switzerland in the EOM scenario.

Year	Gas Combined Cycle [MW]	Open Cycle Gas Turbine [MW]
2027	800	-
2028	400	-
2030	400	-
2032	400	-
2035	400	-

Full load hours for wind (1,800 hours), solar (800 hours) and all other technologies (8,760 hours) were assumed for the calculation of RES capacities, as the corresponding scenario (Prognos AG 2012, Variant C&E) only defines generated RES energy quantities. Under the assumptions regarding full load hours, the installed wind capacity increases from 367 MW in 2020 to 2,367 MW in 2050 and for solar from 650 MW in 2020 to 13,900 MW in 2050.

Due to the current high total capacity of hydropower (compared to wind and sun) this capacity is kept constant at 16.6 GW in the scenarios based on the publication of SFOE (Swiss Federal Office of Energy 2017d). With regard to the age of the Prognos AG (2012) study, a constant capacity of 13.7 GW is assumed there.

The general increase in installed RES capacity in Switzerland is mainly caused by the growth in solar power plants. As a result, the total generation capacity rises from over 21 GW (in 2020) to over 36 GW in 2050 in the EOM scenario.

3.2.3 Capacity development in the CRM Policies scenario

In the CRM Policies scenario, all model results are generated considering already implemented or proposed CRMs. Therefore, the introduction of the capacity markets in France and Italy lead to significantly higher capacities and to a more constant conventional capacity development in these countries compared to the EOM scenario (see Figure 19). In the scenario with CRMs, the demand for flexible generation capacity is driven by the peak demand plus potentially security margins (e.g. defined by the regulatory authority) and not as in the EOM by peak prices (Boiteux 1960). Hence, the demand for conventional capacity also rises in the countries with other CRM implementations. These increases are caused by the increase (compared to 2020) in electricity demand in France and Italy assumed by the scenario (European Commission 2016) because the CRMs must ensure in contrast to the EOM that, depending on their design, national demand can be met, especially during peak load hours.

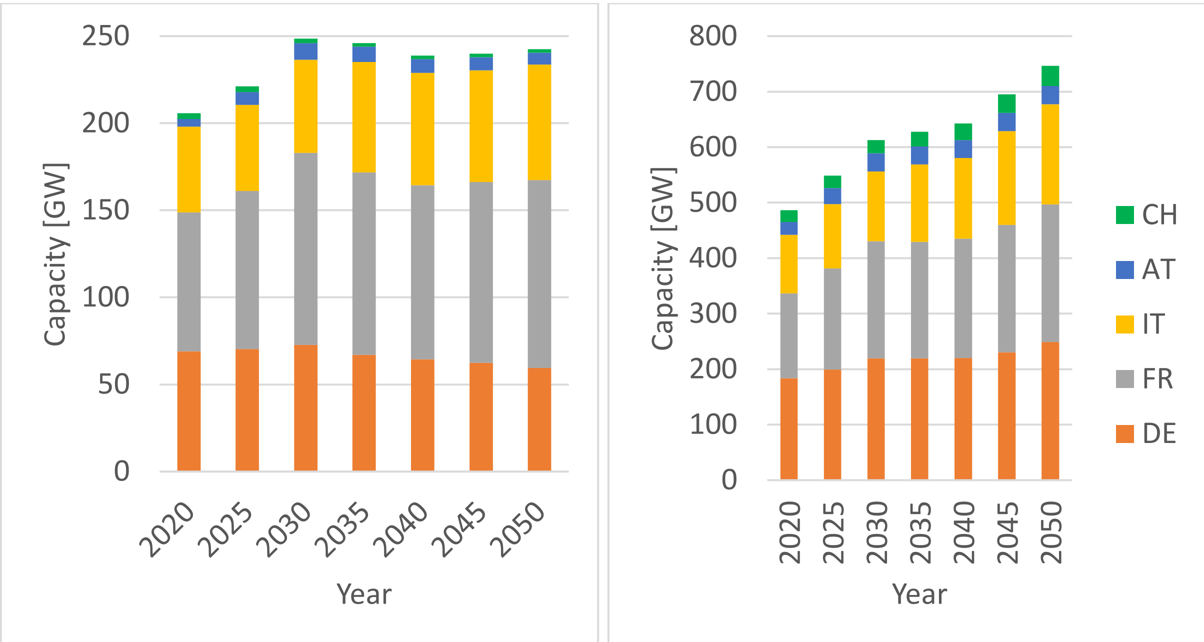

Figure 22: Cumulated conventional capacity development (left) and the total installed capacity (right) in the CRM Policies scenario in Switzerland and its neighbouring countries.

RES can have a mitigating effect on the rise of the conventional capacity demand caused by the CRMs. However, due to the fluctuating behaviour of RESs, they may only participate to a certain extent in the capacity market (or by reducing peak residual demand). This also depends on the respective design or parameterization of the CRMs. The assumptions regarding capacity credits can be found in Section 3.2.1. However, as a result of the capacity credits, the sum of required and installed conventional capacity corresponds to almost peak demand in the overall market area due to the CRM configuration.

Table 8: Investments in Switzerland in new flexible power plants in the CRM Policies scenario.

Year	Gas Combined Cycle [MW]	Open Cycle Gas Turbine [MW]
2022	-	800
2030	400	-
2033	800	-

For illustration, Figure 22 shows the capacity development in Switzerland and the neighboured countries left and together with the RES capacities (right). The RES development can be found in European Commission (2016). In Table 8, the investments in new power plants are listed. Investments are made purely in gas-fired power plants in the height of 2 GW. However, investments not only in combined cycle gas turbines (CCGTs), but also in open cycle gas turbines (OCGTs) are part of the results. The OCGTs outperform CCGTs in terms of capital costs. Therefore, the agents choose the OCGTs if the power plant is mainly build to provide reserve or if the power plant is dispatched only to a small number of hours in the spot market with low average market prices.

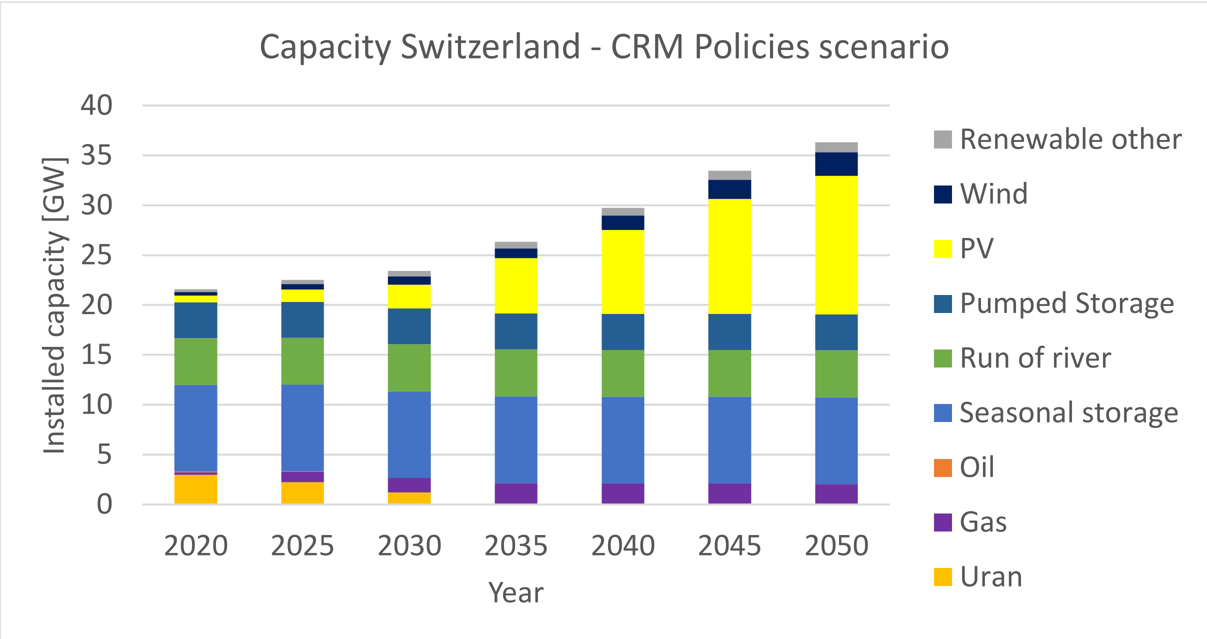

Figure 23: Capacity development in the CRM Policies scenario in Switzerland including the RES and the conventional generation.

Figure 23 shows the total development of Swiss capacities, i.e. including RES. The development of the RES is analogous to the EOM scenario. The general increase in installed capacity in Switzerland is therefore due to the growth in solar power plants. As a result, total capacity will rise from over 21 GW (in 2020) to almost 36 GW in 2050.

Figure 24 shows the flexible capacities in Switzerland in the two scenarios. Due to the slightly lower market prices and the higher flexible capacities (stimulated by CRM) in the neighbouring countries France and Italy, the flexible and therefore the total installed capacity in Switzerland is lower (by 400 MW from 2030) in the CRM Policies scenario. However, this does not increase the number of hours, in which the market cannot be cleared, or the hours when demand response is needed to clear successfully the market, as more capacities from the neighbouring market areas are available also for the Swiss market.

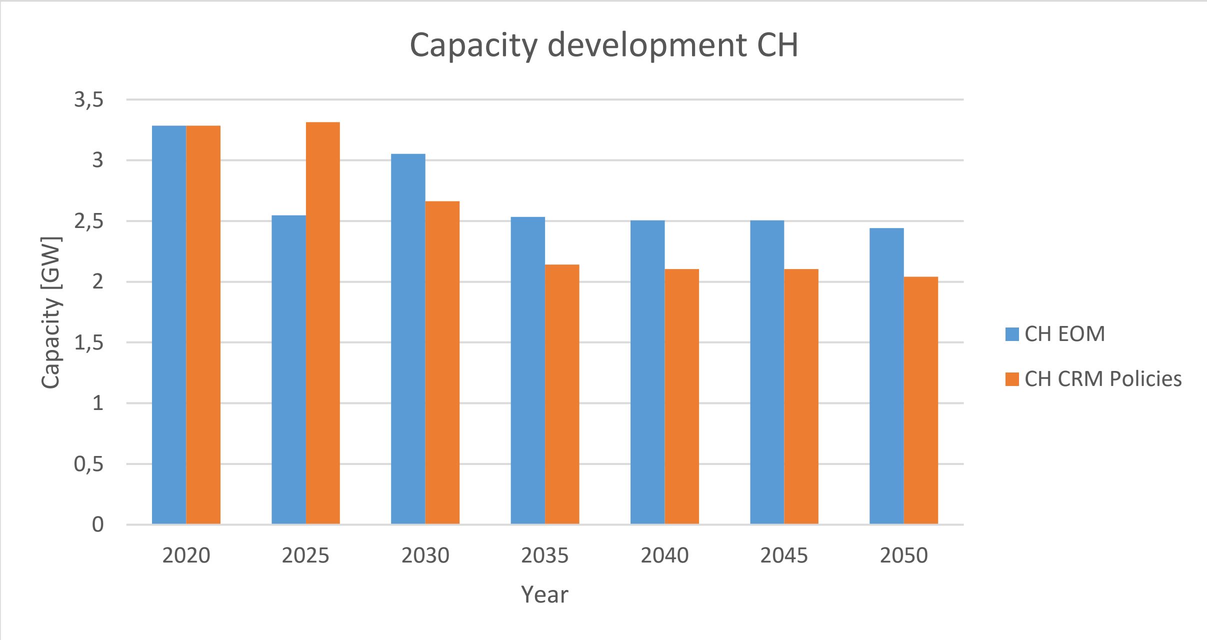

Figure 24: Capacity development of the flexible conventional power plants in Switzerland for the different scenarios.

3.2.4 Generation adequacy in the scenarios

The generation adequacy is illustrated here in the form of hours and expected volumes where the spot market cannot be cleared normally. The development of the number of hours with missing market clearing in the different scenarios is listed in Table 41, Table 42, Table 43 and Table 44 in the Appendix 8.9. Table 9 summarizes and aggregates the number of hours in which the spot market in the model cannot generate a feasible market result with usual generation capacities. So either immediately switchable capacity is necessary for market clearing (demand side management (DSM)) or the market cannot be cleared due to insufficient supply ("No market clearing, therefore price is 3,000 EUR/MWh (EPEX Spot 2018)). However, this does not necessarily indicate black- or brownouts, because there is, for instance, still the available balancing capacity, which also may not be sufficient to cover demand and avoid outages. The availability of DSM potential is assumed as 2 % of the peak demand in all market areas. Table 9 indicates the cumulated number of hours with the use of demand response or with no market clearing for both scenarios. Furthermore, the expected energy not covered in case of a non-feasible market result in the spot market is specified in the same table.

Table 9: Cumulated hours with the use of demand response or no market clearing in the simulated time horizon from 2020-2050 in the EOM scenario.

	CH	DE	FR	IT	AT
EOM scenario					
DSM usage [h]	846	988	982	725	834
No market clearing [h]	0	492	541	308	2
Expected load not served [MW]	0	5,337	5,470	3,992	1,127
CRM Policies scenario					
DSM usage [h]	14	165	0	0	88
No market clearing [h]	0	42	0	0	17
Expected load not served [MW]	0	1,936[3]	0	0	1,042

In Switzerland, the lower installed generation capacity in the CRM Policies scenario does not increase the number of hours in which the market cannot be cleared or the hours when DSM is needed to successfully clear the market successfully. On the contrary, the number of hours with DSM dispatch even falls due to higher flexible capacity in the neighbouring countries compared to the EOM scenario. In the EOM scenario, the market can be cleared in all hours, which is caused by the use of demand response and the high hydropower capacity. In the CRM Policies scenario, only Austria has many hours in which the market cannot be cleared.

3.2.5 Comparison of electricity prices

Validation

In order to be able to interpret and verify the results, a short validation based on historical prices is carried out in advance. Table 10 shows the comparison of real prices, of the years 2015 and 2016 (cp. EPEX Spot (2018)), and the prices that are calculated in the PowerACE simulation. In some cases, there are larger deviations, which are explained in the following.

Concerning the German price deviation, it has to be mentioned that several market areas around Germany (e.g. Denmark, Poland) are not yet explicitly modelled in PowerACE. Although the exchange flows with these markets are modelled in PowerACE via static exchange, only the hourly volume effects, but not price effects of these flows are taken into account. Calculations with all neighbouring market areas of Germany in PowerACE show that the mean value of deviations is below 2 EUR/MWh for Germany and Austria in the years 2015 and 2016. Furthermore, the carbon certificates prices in this study are derived by the EU Reference Scenario (European Commission 2016), but in reality the carbon prices were lower in these years, which also explains some of the higher electricity prices in the simulation. The error between simulated and historical series is quite small for the Swiss and French electricity price. In general, the price validation delivers sufficiently good results except for Italy.

[3] In Germany this would be coverd by the strategic reserve

The main reason for the deviation in Italy is that there is no internal splitting of Italy into different price zones in the model as it is the case in reality. Therefore, no network restrictions in Italy are taken into account that would shorten the market in the different zones and lead to higher prices in the model. Higher prices in the different zones in Italy lead to a higher average than in the case of considering Italy as an unique market zone.

Table 10: Price validation of the PowerACE model: Comparing real (EPEX Spot 2018) vs. simulated prices. Simulated price are similar in both Scenarios for 2015 and 2016.

[EUR/MWh]	2015		2016	
	real	simulation	real	simulation
CH	40.30	43.41	37.88	38.29
DE/AT	31.63	43.51	28.98	38.48
FR	38.48	39.07	36.75	34.17
IT*	52.71	42.64	42.67	38.01
*PUN 2015=52.31, 2016=42.78				

Price development in the scenarios

Looking at the simulated wholesale prices in the EOM (Figure 25) and in the CRM Policies scenario (Figure 26), it is immediately visible that the prices in France are clearly below the prices for all other market areas until approx. 2035. The reason for this is the high proportion of nuclear power plants in France, which are not affected from rising carbon certificate prices and set the prices at a lower level in France due to their low marginal costs. Due to the limited trading capacities between the countries, the other market areas can only party profit from these low prices. Moreover, the price increasing effects of exchange trades with Spain and Great Britain (which are connected to the French grid and tend to have a higher price level) are missing. This leads to large deviations between French and other prices until trading capacities between the modelled countries are substantially increased. In addition, few new nuclear power plants are being built in France during the time horizon of the analysis (only towards the end of the simulation period), but rather gas-fired power plants, which align to the price with the other market areas. This can be observed in both scenarios. Therefore, from 2035 onwards, prices in the EOM scenario rise significantly due to scarcity prices in several hours caused by less installed capacity and increasing carbon certificate prices. The average prices in the model in the years 2041 and 2043 are thus over 120 EUR/MWh in the EOM scenario. In the following years, however, the average price is falling again, because these prices again incentivize new investments.

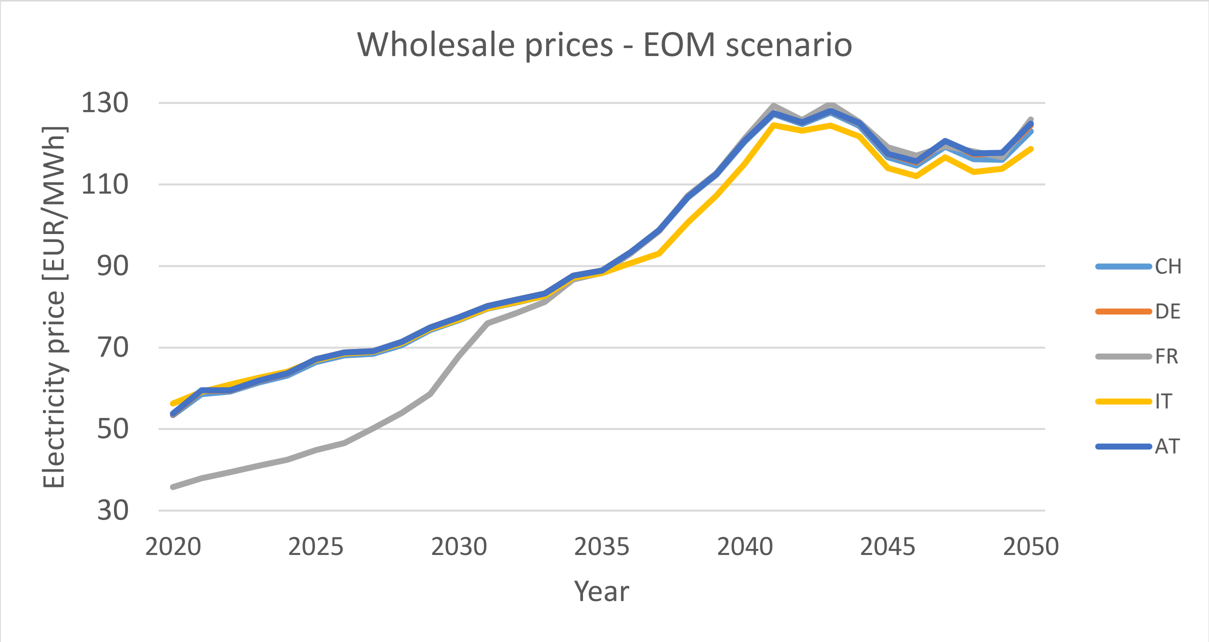

Figure 25: Development of the simulated market clearing wholesale prices for the EOM scenario.

In all modelled market areas, prices are developing in a similar way, only Italy has average prices slightly below the other areas considered from 2035 onwards. These differences are due to the still limited exchange capacities to neighbouring countries together with still available production capacity in Italy (e.g. RES), so that it is no longer possible export more electricity in the corresponding hours. E.g. in the year 2043, Italy generates in average 39 GW from RES in the hours with fully used export capacities.

From 2035, the picture is similar for the CRM Policies scenario as in the EOM scenario, with the difference that the average prices are significantly lower. The absolute price deviation of the wholesale market prices of the different scenarios are at the beginning (until 2023) only caused by the introduction of the SR in Germany because the power plants will be taken out of the market. Until 2035, the prices of both scenarios are almost the same, the EOM average prices are even slightly below the average prices of the CRM Policies scenarios. From 2035 onwards, however, prices deviate significantly due to the occurrence of scarcity caused by an insufficient supply in various market areas in the EOM scenario. The prices remain lower (see Figure 23) due to sufficient capacities in the CRM Policies scenario.

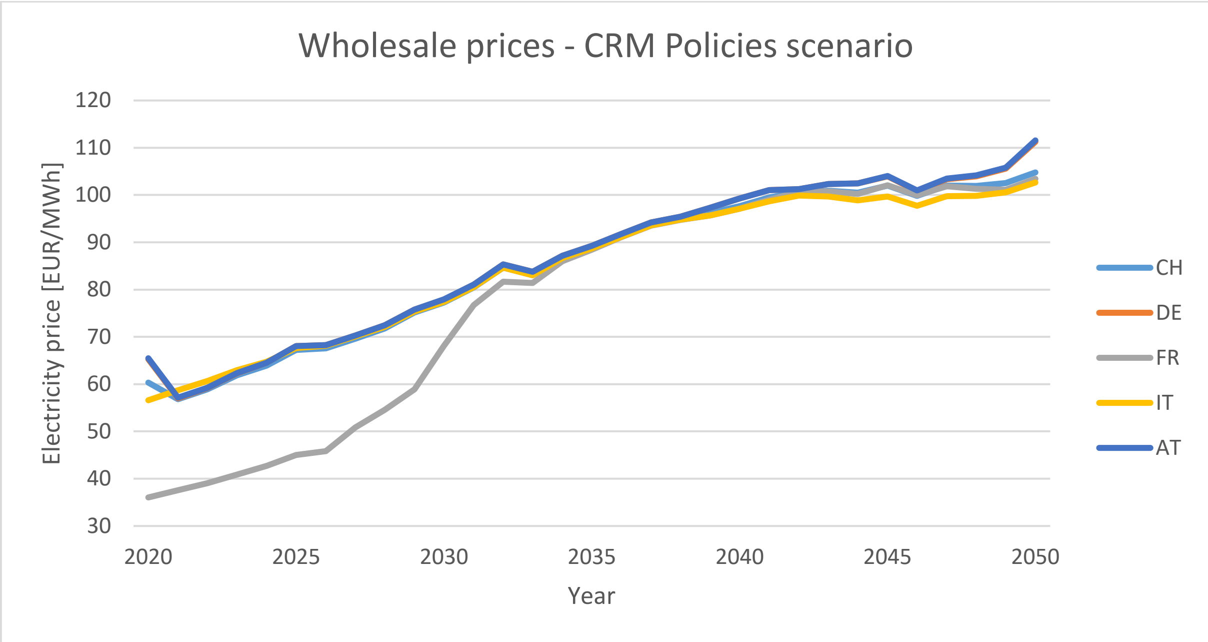

Figure 26: Development of the simulated market clearing wholesale prices for the CRM Policies scenario.

For Switzerland, this deviation of the average prices is shown in Figure 27. The maximum difference between the yearly average prices of the EOM scenario and the CRM Policies scenario is more than 20 EUR/MWh in some years after 2035. This high price difference is, of course, due to the significantly higher flexible capacities in France and Italy, which are available at any time. The neighbouring countries also profit from the high installed capacity that is signalled by significantly fewer hours in which the market cannot be cleared (Table 9).

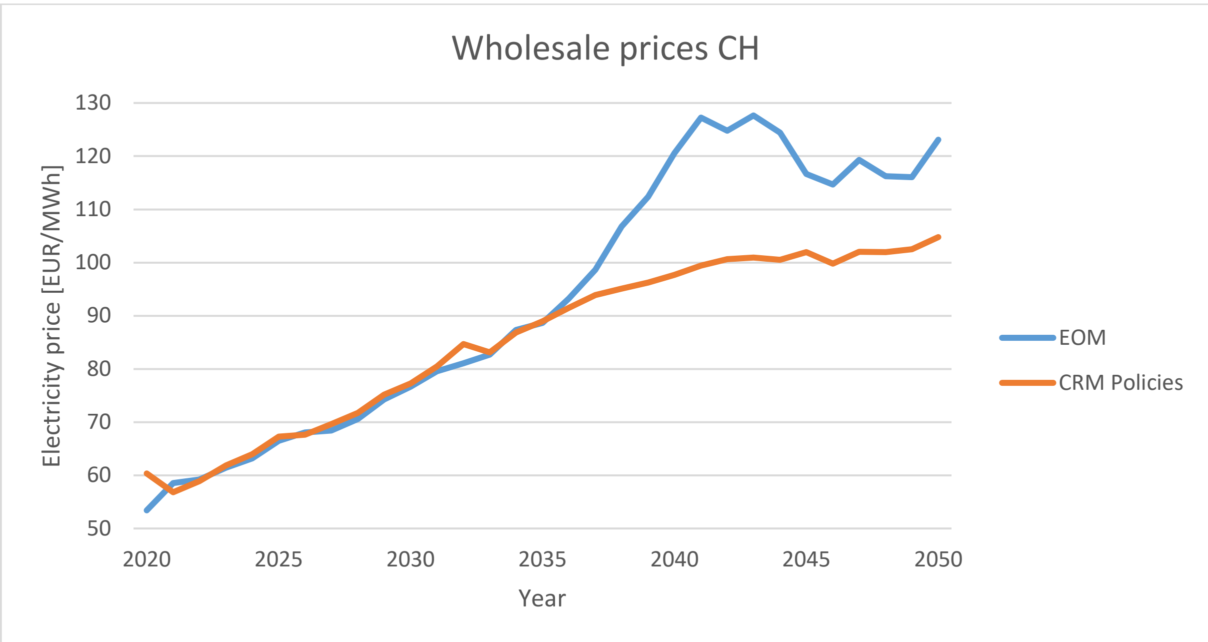

Figure 27: Comparison of the development of the simulated wholesale market clearing prices in Switzerland for the EOM and the CRM Policies scenario.

Regarding the prices and the capacity development, the picture is ambivalent for Switzerland. On the one hand, less will be invested in the CRM Policies scenario, prices are lower than in the EOM scenario, and Swiss hydropower offers enough capacity in all hours to ensure that the wholesale market can always be cleared. However, on the other hand, compared to the neighbouring countries, the EOM scenario does not have many hours in which the market does not provide sufficient supply, but at significantly higher prices. However, CRMs also causes costs (and could lead to inefficient investments), but this is not relevant for Switzerland because this costs for CRMs are normally allocated within the countries.

3.3 Market value of the Swiss' renewables and analysis of impacts on RES subsidies

The costs of RES electricity may partially be higher than those generated by existing conventional technologies. However, the expansion of RES is advantageous for various reasons, particularly from an environmental perspective.

In Switzerland, as in many other countries, electricity generation through RES is supported by the government (e.g. Der Schweizerische Bundesrat 2017). Since the introduction of the support scheme, Switzerland's RES investors receive either a one-time (direct) capital support (as a contribution to the investment expenses) or fixed cost-oriented feed-in remuneration rates (feed-in tariff (FiT)) for a certain amount of years. Normally, only one of the two options can be applied for one project. However, the possible instrument depends on the RES technology and the size of the planned installation capacity. The FiTs are differentiated for the various RES generation technologies. Switzerland's support scheme comprises solar photovoltaics, small hydropower, biomass, wind, and geothermal power plants. Basically, support schemes are introduced to accelerate the expansion of RES technologies by private investors.

In the past, decreasing wholesale prices were observable on the wholesale electricity market due to the merit-order effect (Sensfuß et al. 2008) or declining carbon prices and coal prices (Bublitz et al. 2017). This lead to higher surcharges for RES funding (in case of support by FiTs), since grid system operators are forced to sell RES on the wholesale market and to collect the remaining funding volume to producers from end consumers.

In January 2018, Switzerland decided to reform the support regime and to integrate innovations into the existing Energy Promotion Regulation (Energieförderungsverordnung, Der Schweizerische Bundesrat 2017). Among other things, the law was extended to include FiT with the obligation to direct marketing (German: "Direktvermarktung") for the installed RES capacity above a certain capacity threshold. In future, RES electricity will be no longer exclusively remunerated by a FiT, but the producer will receive a combination of the wholesale market price and the so-called feed-in premium via a levy.

3.3.1 Methodology

This new feed-in legislation will be examined more closely in the following. For this purpose, the reference market price (or in the other literature the so-called market value) is to be calculated for different period lengths. First, the payments for elapsed periods are analysed based on the current change in the law. Then, for the two scenarios CRM Policies and EOM, the feed-in premium are calculated for selected years and periods therein in the future. Therefore, the simulated wholesale market prices of the specific years are used from the PowerACE simulation for Switzerland.

The feed-in premium is the difference between the FiT and the reference market price within a certain period (see Figure 28). The guaranteed FiT ensures that the investor's cash flows remain stable. However, the generator can receive higher revenues if feed-in takes place in hours with high market prices (above the FiT). Direct marketing with feed-in premiums should help to achieve the aim of a further expansion of RES while at the same time increasing market integration. Therefore, improvements regarding a higher forecast quality and a feed-in in line with the market are intended as well.

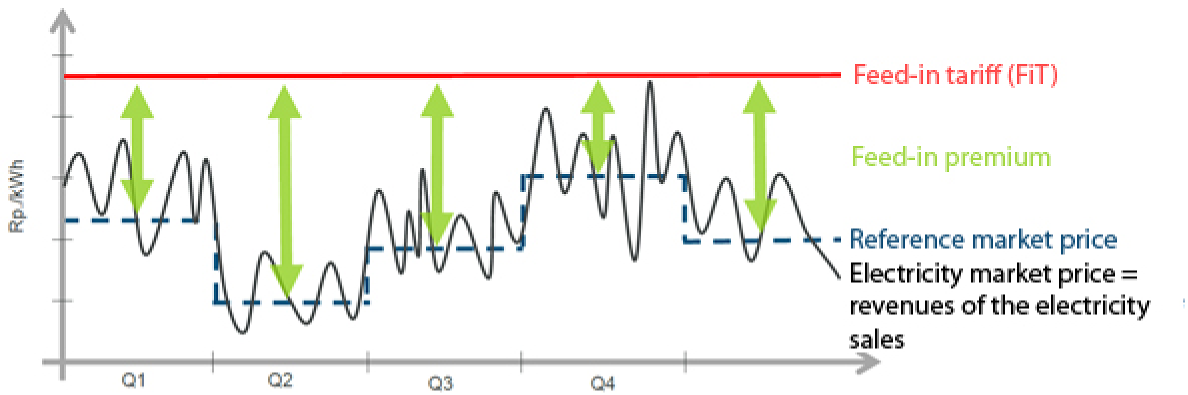

Figure 28: Schematic illustration for the calculation of the feed-in premium. (Swiss Federal Office of Energy 2017a)

Calculation of reference price and market value

The development of the reference price for RES electricity is calculated according to Equation 6. Time resolution is the observation period, such as one month or one quarter, for which the reference price is calculated. The wholesale market prices of EPEX Spot 2018 or the simulated wholesale market prices of the different scenarios from PowerACE are used as input for the reference price calculations. The hourly prices are multiplied by exogenous (from EPEX Spot 2018) or endogenous (from PowerACE) production (feed-in) of the different RES types. The reference price multiplied with the production results forms the market value for the specific RES-type.

$$Reference\ price_{RES}\,(Period) = \frac{\sum_{h \in Period} Prices(h) \cdot Production_{RES}(h)}{\sum_{h \in Period} Production_{RES}(h)}$$

Equation 6: Market value of RES for a specific period e.g. one quarter.

In Switzerland, there are two different methods of calculating the reference market price, depending on the legal situation:

1. According to the revised regulation Swiss Federal Office of Energy (2018d): “Relevant for determining the feed-in premium for generation plants with FiT: The reference market price for photovoltaic systems corresponds to the average of the prices set on the electricity exchange (SWISSIX) for the following day (day-ahead) over a quarter of a year, weighted according to the actual quarter-hourly generation of the systems measured according to the load curve.

For the other technologies, the reference market price corresponds to the quarterly averaged prices on the electricity exchange for the following day.”

2. According to the revised regulation Swiss Federal Office of Energy (2018c): “Relevant for determining the uncovered costs of electricity from generation plants with FiT: Volume-weighted average of prices according to SWISSIX Base with hourly generation to the balance group for renewable energies (BG-EE) taking into account the exchange rate. “

Based on the analysed years (2016 and 2017) as well as the not in detail available data, Equation 6 is applied with the hourly generation of the total RES for the investigation (related to the method 2).

Feed-in premium (Einspeiseprämie)

The (positive) difference between the FiT and the reference price is the feed-in premium (Figure 28). The feed-in premium is paid for the specified period (i.e. quarter, analogously to the reference price) to the owner of the RES power plant.

Results for required support volumes

The reference price of RES, based on data from EPEX Spot (2018), is calculated according to Equation 6. Since the data of the generation for the KEV subsidised RES cannot be disaggregated with publicly available sources, the historical values are taken based on the volume-weighted average of the prices according to SWISSIX-Base and the total hourly traded volume contracts. The officially values are announced in the SFOE-columns according to Swiss Federal Office of Energy (2018c). Deviations are due to the static exchange rates and the limited data availability. In order to obtain a consistent comparison, the reference prices calculated in Table 11 are used as the basis for further analyses of the market values and feed-in premiums.

For the simulated prices, the volume-weighted average of the prices and the summed generation of solar, wind, geothermal and biomass from PowerACE runs is used. Table 11 provides the results of the calculated reference price.

For instance, based on the current tenders for wind energy in Germany (Bundesnetzagentur 2018) with results between 61.25 and 73.08 CHF/MWh (52.80 and 63.00 EUR/MWh, exchange rate Table 36), the rising market prices alone would be able to cover costs according to Table 11 (already in 2020), making the requirement of subsidisation very unlikely in the foreseeable future.

Table 11: Calculated reference market prices according to different scenarios. SFOE means by the SFOE (Swiss Federal Office of Energy 2018d) published value.

Period [CHF/MWh]	2016	2016 SFOE	2017	2017 SFOE	2020 EOM	2020 CRM Policies	2030 EOM	2030 CRM Policies	2050 EOM	2050 CRM Policies
January	51.63	-	85.77	-	65.86	121.65	90.92	91.35	261.00	132.10
February	37.69	-	61.56	-	70.15	73.96	94.19	94.44	186.51	139.31
March	32.11	-	40.07	-	60.55	61.49	87.28	87.44	109.82	108.80
1st Quarter	40.40	39.48	62.22	56.43	65.48	84.72	90.68	90.95	179.44	125.05
April	27.50	-	37.63	-	54.15	54.54	77.11	78.00	87.60	86.62
May	25.99	-	38.39	-	49.65	49.91	72.40	73.22	76.97	77.07
June	30.24	-	35.19	-	51.81	52.30	76.74	77.90	84.76	84.36
2nd Quarter	28.10	28.05	37.17	35.57	51.75	52.13	75.42	76.39	83.08	82.66
July	31.30	--	39.01	-	49.51	49.61	79.40	80.50	84.47	83.99
August	32.39	-	35.80	-	54.81	55.29	78.09	79.08	84.37	83.17
September	39.44	-	41.22	-	58.92	59.50	83.50	83.54	102.94	102.13
3rd Quarter	34.07	33.48	38.52	38.97	53.79	54.14	80.06	80.84	89.52	88.71
October	62.04	-	59.29	-	67.53	69.41	90.52	90.49	128.28	127.30
November	67.42	-	73.46	-	62.73	78.28	86.14	87.03	121.00	109.23
December	63.32	-	70.87	-	56.23	62.15	81.80	82.10	105.83	104.80
4th Quarter	64.03	62.94	67.31	69.58	62.47	70.63	86.30	86.71	118.80	114.01
Year	41.07	38.67	50.60	47.46	56.68	61.69	81.67	82.35	107.56	97.64

3.3.2 Analysing support volumes under existing KEV scheme for 2017

In the list of all KEV-receiver ("Liste aller KEV-Bezüger" Swiss Federal Office of Energy 2017c, 2018b) all projects supported by the KEV are listed. This list contains information about the generation technology, installed capacity, generated electricity and paid subsidy in the considered year. In order to analyse the changes of the support scheme in Switzerland due to the new legislation, an ex-post assessment is applied to the existing projects.

At first, clusters are formed based on the list for each generation technology. The clusters are based on Switzerland's rules on direct market participation. The conditions for participating on the markets and receiving subsidy from 2018 onwards apply for "operators of plants with an output of 500 kW or more that already receive a KEV, as well as operators of plants with an output of 100 kW or more that are newly included in the subsidy system. These operators must directly sell their electricity at the wholesale market by 1 January 2020 at the latest and onwards." (Swiss Federal Office of Energy 2017a)

It should be noted that there are no geothermal power plants among the KEV-receivers so far. For biomass and geothermal (in the scenarios) power plants, a constant and equally distributed production output is assumed. Therefore, no difference in the production volume between the disaggregated periods is visible. Inline with the new rules, the feed-in premium volumes are analysed ex-post (for the year 2017 and 2016 in the Appendix 8.7) for plants with a capacity >500 kW, because new and remaining plants >500 kW must always offer the generation directly at the market and get feed-in premium instead of FiT as support payments.

In 2017, the maximum wholesale price was 199.71 CHF/MWh (acc. to EPEX Spot (2018), 179.92 EUR/MWh, exchange according to Table 36), the technology with the lowest FiT was for photovoltaics with 117 CHF/MWh (0.117 CHF/kWh). The prices on the wholesale market were higher than 117 CHF/MWh in more than 100 hours. The FiT of the other technologies are even higher than the one of solar power. Therefore, it can be stated that in case of direct marketing the difference between FiT and reference price is positive the technologies need feed-in premium in almost all hours of the year.

Production and funding volumes (according to Swiss Federal Office of Energy (2018b)) as well as the market values and feed-in premiums are calculated based on the presented methodology. Table 11 lists disaggregated reference prices for different periods and Table 12 shows funding values for a yearly time frame.

Table 12: 2017 funding volumes for RES power plants with a capacity >500 MW. Production and subsidy from Swiss Federal Office of Energy (2018b). Ex-post market value is based on EPEX Spot (2018) and feed-in premium is based on a yearly average price according to Table 11.

Technology	Production [GWh]	Total FiT payments [CHF millions]	Resulting average FiT [CHF/MWh]	Market value [CHF millions]	Calculated feed-in premium [CHF millions]
Solar	363	97.0	267.36	18.3	78.7
Small hydro	1,289	184.8	143.35	65.2	119.6
Wind	81	15.4	188.86	4.1	11.3
Biomass	1,015	181.3	178.62	51.3	129.9
Sum	**2,749**	**478.5**		**138.9**	**339.5**

Table 12 shows the complete funding volume of CHF 478.5 million total funding volume (i.e. total FiT payments according to Swiss Federal Office of Energy (2018b)), CHF 138.9 million would be covered via the market based on an annual reference price. The difference between total FiT payments and market value makes up CHF 339.5 million and has to be covered via the feed-in premium in the respective support scheme. If the time resolution of the calculation methodology is changed to the volume-weighted reference price and quarterly RES production (see second methodology above), different results are obtained. For instance, the total funding volume increases to CHF 345 million based on quarterly reference prices, compared with CHF 339.5 million on an annual basis. The funding volume on a monthly basis increases further to CHF 346.2 million. Analogously to the year 2017, there is an analysis for the year 2016 in the Appendix 8.7.

In order to see inner-year development of the funding volume, quarterly and a monthly production, market value and feed-in premium are calculated and listed in Table 13 (quarterly) and Table 35 (monthly).

Table 13: 2017 funding volumes for RES power plants with a capacity >500 MW. Feed-in premium is based on a quarterly average price according to Table 11 and the FiTs of Table 14.[4]

		Solar	**Small hydro**	**Wind**	**Biomass**	**Total**
Q1	Production [GWh]	27	198	15	253	495
Q1	Market Value [CHF millions]	1.6	12.3	0.9	15.7	30.5
Q1	Feed-in premium [CHF millions]	5.5	16.1	1.9	29.5	53.0
Q2	Production [GWh]	122	405	20	253	802
Q2	Market Value [CHF millions]	4.5	15.0	0.7	9.4	29.6
Q2	Feed-in premium [CHF millions]	28.2	43.0	3.1	35.8	110.1
Q3	Production [GWh]	155	437	18	253	865
Q3	Market Value [CHF millions]	5.9	16.8	0.7	9.7	33.1
Q3	Feed-in premium [CHF millions]	35.5	45.8	2.7	35.5	119.5
Q4	Production [GWh]	58	248	27	253	586
Q4	Market Value [CHF millions]	3.9	16.6	1.8	17.0	39.3
Q4	Feed-in premium [CHF millions]	11.6	18.8	3.2	28.2	61.8
	Total market value in 2017 [CHF millions]	**16.1**	**60.9**	**4.2**	**52.0**	**133.2**
	Total feed-in premium in 2017 [CHF millions]	**80.9**	**123.8**	**11.1**	**129.2**	**345.0**

[4] Due to rounding inaccuracies, the total values do not correspond exactly to the disaggregated quarterly values.

3.3.3 Support volumes for the analysed scenarios and selected future years

In order to estimate roughly the development of RES funding, current FiTs are set as an upper limit. It can be assumed that the FiT will continue to fall in the near future, but this would require further assumptions, hence the FiT have been frozen at the current level shown in Table 14. The aim is to estimate the amount of funding based on the existing situation in order to point out possible future developments. The different technology-dependent FiTs are shown in Table 14. Thus, the price development from the different scenarios of Section 3.2 are used. The reference prices are taken again from Table 11.

The following analyses are based on the current FiTs and serve as an estimation of an upper limit for the funding volumes, since no cost degression is assumed.

Table 14: Minimal FiT from 2018 onwards according to Der Schweizerische Bundesrat (2017).

[CHF/MWh]	FiT per technology
Biomass	175
Geothermal	227
Small hydro	66
Solar	110
Wind	230

As a first step, the support volume was calculated if all technologies were only supported by guaranteed FiT. Therefore, Table 15 shows the maximum funding volume that would be achieved without direct marketing. This can be seen as the upper limit for the supporting volume if it is assumed that no negative prices will occur.

Table 15: Funding volumes if only the FiT (according to the rates of Table 14) will be paid to all considered technologies.

[CHF millions]	2020	2030
Biomass	185.5	437.4
Geothermal	45.3	177.0
Hydro	692.3	704.0
Solar	57.1	210.1
Wind	151.8	335.7
Sum	**1,132.0**	**1,864.2**

To isolate the technologies that benefit most from direct marketing, the reference market prices in Table 11 give a first indication. As soon as the reference price rises above the FiT, it would be advantageous to sell the electricity directly at the wholesale market. In the Appendix (Section 8.3 and 8.4), the different calculated values for feed-in premiums can be found. Positive values indicate that the feed-in premium continues to be the preferable option. Negative values indicate that direct marketing is more advantageous and no feed-in premium is required for these technologies. Derived from the current level of FiTs in Switzerland, a guaranteed FiT or the feed-in premium scheme is still advantageous for the majority of technologies in future, apart from a few exceptions, such as hydropower plants.

Table 16 shows the market values for the EOM scenario using the PowerACE spot market price for the years 2020, 2030 and 2050. Table 17 show the market values for the CRM Policies scenario. Comparing the two scenarios, the market value rises simultaneously with the market prices. This indicates that in 2020 and 2030 the EOM scenario implies a lower market value because the wholesale electricity prices are lower. However in later years (e.g. 2050), the CRM Policies have a lower market values for the RESs due to the lower average wholesale electricity price.

Table 16: Yearly market values for the EOM scenario.

[CHF millions]			**Market values EOM**		
Year	**Biomass**	**Geothermal**	**Small hydro**	**Solar**	**Wind**
2020	62.2	11.7	595.0	27.2	36.5
2030	210.9	65.8	881.6	137.5	118.4
2050	381.7	594.3	1,367.4	803.3	470.1

In contrast to biomass, geothermal, solar and wind power, it is generally attractive for hydropower plants to offer the generated volume of electricity directly at the market. Only in the scenarios for 2020, the hydropower plants receive feed-in premiums additionally (see Appendix 8.3 und 8.4).

Table 17: Yearly market values for the CRM Policies scenario for the different years.

[CHF millions]			**Market values CRM Policies**		
Year	**Biomass**	**Geothermal**	**Small hydro**	**Solar**	**Wind**
2020	70.3	13.2	646.9	27.8	39.2
2030	212.4	66.2	889.4	138.3	119.4
2050	325.0	506.0	1,218.1	791.9	442.1

The total funding volume in Table 18 was calculated based on the scenarios and the respective spot market prices originating from PowerACE based on the current FiT for the years from 2018 onwards (Table 11). For this purpose, the wholesale electricity price was multiplied for the respective hourly production quantities. The difference between the FiT and the reference price (Table 11) was then calculated to determine any feed-in premium. For determining the funding volume per MWh, the total funding volume was divided by the total volume fed into the system by the respective RES. The values with an annual or monthly evaluation with regard to Table 18 are in the Appendix 8.8.

Table 18: Feed-in premium funding volumes for both scenarios under a quarterly reference price.

	2020 EOM	2020 CRM Policies	2030 EOM	2030 CRM Policies	2050 EOM	2050 CRM Policies
Funding volume [CHF millions]	499.5	477.3	613.2	608.9	1,334.8	1,497.3
Specific funding volume [CHF/MWh]	38.64	36.92	35.41	35.17	39.70	44.53

The total funding volume increases in both scenarios caused by the strong expansion of RES. Contrary to this development, the funding volume per MWh decreases firstly in 2030 (compared to 2020), but increases until 2050. The initial decrease from the years 2020 to 2030 is due to the rising prices on the wholesale market and thus also to rising reference prices, which have a negative effect on the funding volume. Although the feed-in volumes rise during this period and thus, the amount of electricity that has to be funded, the effect of reduced feed-in premiums due to reference price increase is stronger. Between 2030 and 2050 (Figure 29), there is a strong increase in the RES expansion, especially of solar power.

The increase in the funding volume per MWh in Switzerland is also a result of a disproportionate increase in the feed-in volume from 2030 to 2050, while the price is not rising to the same extent. The disproportionality leads to an increase of the funding volume per MWh.

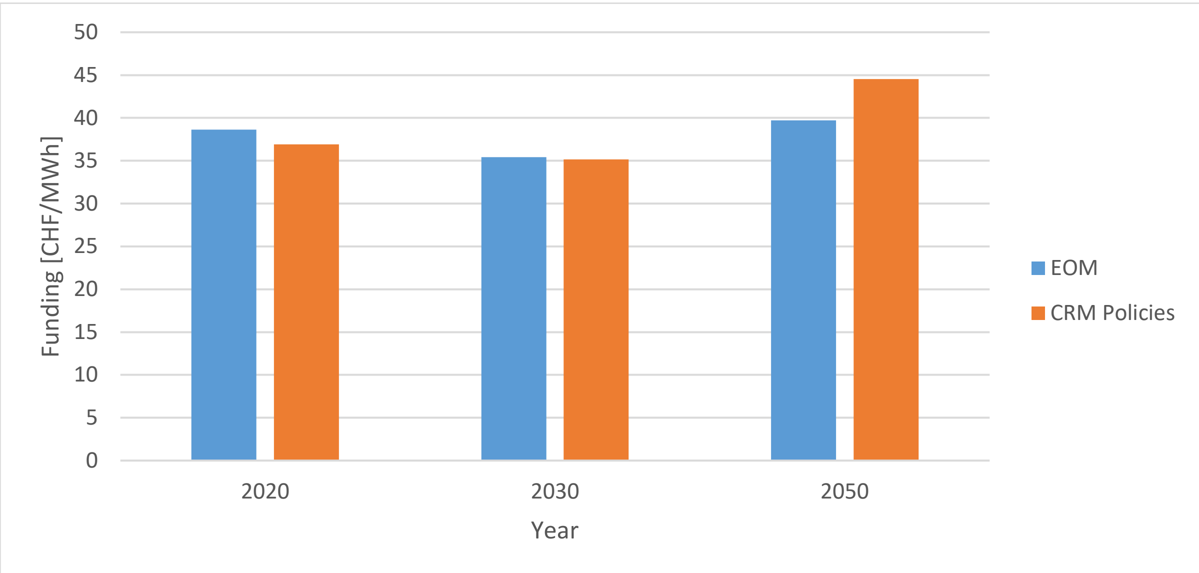

Figure 29: Development of the funding volume per MWh with a quarterly reference price and the FiT of Table 14 in the different scenarios.

3.4 Critical reflection

The assumptions and input data assumed for the modelling are subject to major uncertainties. Especially the development of demand, the prices for carbon certificates and fuel prices for gas and coal remain subject to uncertainty. No reliable (market) data are available for a time horizon up to 2050. Technological developments and trends in power plant technologies (both conventional and RES) can only be taken into account to a limited extent and are assumed rather conservatively.

The development of the demand response potentials with regard to the immediately switchable load depends on future economic and technological developments as well as on the attractiveness of providing the technologies on the markets.

In addition, simplifications are necessary in every model so that the complexity of the reality depicted remains manageable with available computing power. Simplifications in the models used are among others:

- consideration of one weather year,
- no intraday market,
- no hedging transactions and
- no emergency power capacity.

PowerACE incorporates simplified combined heat and power plants so that only the heat decoupling in the form of a lower efficiency has been taken into account.

Further simplifications have been made with regard to the electrical grid. The domestic grid is currently not modelled, neither at the transmission nor at the distribution grid level, only the interconnector capacities are considered by using NTC values. This means that no grid congestions within a country or other disturbances in the grid are taken into account, but they may play an important role in reality. Thus, the high feed-in period of RES energies combined with grid bottlenecks could lead to redispatch measures, so that other power plants have to generate contrary to the market results (e.g. with higher variable costs). Redispatch measures are not in the focus of this study.

In the modelled CRM modules, some own assumptions had to be made, since not all design details are available for all market areas at the time of the preparation of this study. For example, PowerACE does not differentiate in the French capacity market between the obligated parties regarding to different sector or consumer demand curve patterns. Furthermore, the participation of foreign power plants in CRMs is neglected. However, in the French mechanism energy served from neighbouring markets is included in the security margin.

Uncertainties also persist with regard to the weather data. The influence of the weather on the supply and consumption of electricity is considerably high. For instance, wind power, hydropower or photovoltaics are directly dependent on the weather and even conventional power plants can be affected by the weather. Regulations with regard to river levels or maximum water temperature may also be directly depending on the weather. Conventional power plants can be forced to reduce their output or to shut down due to excessive production of RES.

Temperature-sensitive demand for electricity, especially in the winter, is considered only by the weather profile of 2015. For instance, households (apartments and houses are heated by electric heating systems or heat pumps), industry and services show increased demand patterns in cold winters (RTE 2017). This means there is a strong negative correlation between demand and weather in France and to a minor extent in other modelled market areas. In general, the load profiles and the expansion of RES were set exogenously based on the year 2015.

In some scenarios of future development, data can be found only in steps of several years. The intermediate years are therefore linearly interpolated. In principle, the agents in PowerACE can only invest in conventional power plants; RES are taken exogenously from the scenarios. For this purpose, the agents rely on reference technologies (gas turbines, combined cycle power plants, hard coal or lignite-fired power plants).

For this analysis, storage expansion, especially in battery storage, has not been considered. Moreover, in Switzerland, Prognos AG (2012) does not envisage any expansion of hydro storage facilities. Furthermore, in the regression model for determining the seasonal storage operation, possible non-linear effects are neglected.

These simplifications lead to uncertainties in the simulation results. Therefore, the results are not direct projections for reality. Neither in the models nor in the selection of scenarios can take into account all uncertainties. Even the scenario data are subject to further assumptions and uncertainties. The aim is rather to compare different scenario developments with different assumptions in order to be able to evaluate options for action (Voß 1982).

3.5 Intermediate conclusions

In this section, changes in the market design of Switzerland's neighbouring countries and, in particular, their effects on the Swiss electricity market are investigated in two scenarios. The focus is on the impact on installed capacity and the wholesale electricity market prices. Furthermore, the effects of the two scenarios on the promotion volume of RES are examined.

As shown in the scenarios, the electricity prices of the wholesale market depend on neighbouring countries. This leads to different investment activities in both scenarios. The overall amount of flexible capacities is lower in the CRM Policies scenario, as the Swiss market can rely on higher imports from the neighbouring countries. This means that Switzerland remains dependent on neighbouring countries, although it cannot influence market design decisions there. However, it also turned out that the Swiss wholesale market, in contrast to the surrounding countries, can be cleared in all scenarios (with and without CRM) in each time step. This means that although there is an influence on prices, the generation adequacy is not affected by market design changes in neighbouring countries.

The operational profitability of Swiss power plants mainly depends on price development and is therefore more feasible in the EOM scenario than in the CRM Policies scenario, as the EOM scenario produces higher wholesale prices. However, with marginal costs of hydropower at almost 0 EUR/MWh and an increase in electricity wholesale prices to more than 100 EUR/MWh in 2040 and beyond in both scenarios, it is very likely that future investments and retrofit measures are profitable independently from the CRM policies in the neighbouring countries. For this reason and the fact that generation adequacy is ensured in the investigated scenarios, a change of the Swiss market design is currently not required.

Taking into account the support scheme of FiTs for RES and the increasing market prices, a decline in the support volume can be observed in the mid-term. However, in the long-term an increase in the total subsidy volume can be expected due to the strong increase of RES capacities, in particular of solar power.

A possible reduction of feed-in premiums could be achieved by falling FiT, due to falling installation costs. Therefore, the FiT for new installations could be linked to the decreasing costs. Alternatively, the introduction of RES auctions, as already realised in Germany in order to obtain more competition on the requested feed-in premium based on installation costs of RES plants. These changes would possibly limit the overall RES-funding volume. Finally, it can be observed that the funding volume is remarkably lower in the EOM scenario due to the higher market prices in the EOM scenario compared to the CRM Policies scenario.

4 Profitability of hydropower in different scenarios

4.1 Overview and scope of profitability assessment

Complementary to the agent-based modelling approach in Section 3, the profitability of Swiss hydropower is evaluated with an additional modelling approach by using the electricity price output from the agent-based modelling. The scope of the profitability analysis is as follows:

- **Evaluation of competitiveness of existing Swiss hydropower sector with its storage capability under the different market regimes.** Hence, we investigate the CRM Policies and the EOM scenarios as defined in Section 3. The target years for the profitability analysis are the years 2030 and 2050 to be in line with the analysis of the previous section.
- **Modelling of dispatch decision under different inflow regimes and under stochastic prices.** We apply an experimental, innovative modelling approach, based on stochastic control theory. Indeed, this modelling approach allows for an explicit solution of dispatch thresholds, for production and for pumping. Stochastics of inflows are covered by a sensitivity analysis.
- **Investigation of several power plant configurations.** Ranges of operational profitability (market revenue) in the CRM Policies and the EOM scenario in the years 2030 and 2050 are evaluated for different types of hydropower configurations.
- **Valuation of existing plants (or pool of plants), up to a year; single pumped-storage plant or several interconnected reservoir (i.e. small set of typical hydropower plant configurations); possibility of re-parametrization for different plant configurations.** We evaluate the following configurations:
    - Aggregated dam-hydropower Switzerland (with inflow), i.e. pool of all Swiss plants
    - Pumped-storage plant, Typology “Muttsee” (short-term operation)
    - Aggregated pumped-storage Switzerland (short-term operation)
    - Pumped-storage plant, Typology “Wägitalersee” (yearly variations)
    - System of reservoirs: Wägitalersee (pumped-storage) + Rempen (storage)

  The range of configuration corresponds in the modelling results to a range of market revenues in the scenarios for the future years 2030 and 2050, which allows identifying the influence of key factors for the change in operational profit; such factors include the levels and variability of the electricity price in the scenarios (provided as input from Section 3).
- **Secondary ancillary service (control reserve power); estimating the alternative earnings**. While the agent-based analysis tool (Section 3) can provide (energy-only) electricity prices, it does not cover ancillary market prices, or the volume of such markets. Generally, ancillary market prices for reserve power are determined by the opportunity cost by not being able to produce fully for the energy-only market and to lock-in into the service for the TSO. In this project, we evaluate this relation, and we provide a lower bound for the service price. In addition, in the case of a system of reservoirs we provide also an estimate on additional expected earnings increase (taking into account the reduction on the energy-only market) in dependence of differ-

ent reimbursements for the service. Note that secondary ancillary prices are not yet fully analysed in the research community as of today, such that long-term scenarios results have a high degree of uncertainty.

The scope of the project does not encompass the following issues.

- The size of the future ancillary market cannot be evaluated due to the limited scope of the agent-based model. The size determines the scarcity values (peak prices) of ancillary service in seasons where aggregated hydropower availability is low. Hence, such peaks, especially in future long-term scenarios cannot be evaluated exactly (but they may be interfered from today's peaks proportionally).
- The purpose of the hydropower-focussed analysis is to investigate market dynamics and interdependencies in revenues of hydropower plant typologies under possible future market conditions. The model applied therefore incorporates the main features of hydropower. However, actual hydropower plant configurations might deviate with implications on real world economics and profitability. For instance, water flow due to environmental constraints are excluded. Generally, the research model is not intended to compete with commercial day-ahead dispatch software. Hence, all presented results are indicative and subject to model limitations; no absolute numbers of real-world profitability of real-world power plants shall be derived from the results, and the main focus of the analysis is primarily on the dynamics in terms of relative changes of market revenues over time and over scenarios.

4.2 Statistics of Swiss stored hydropower

Reliable publically available data of the operation of stored hydropower in Switzerland is mainly the monthly statistics from the yearly Swiss Electricity Statistics of the SFOE. The historical production pattern of stored hydropower in Switzerland is shown in Figure 30.

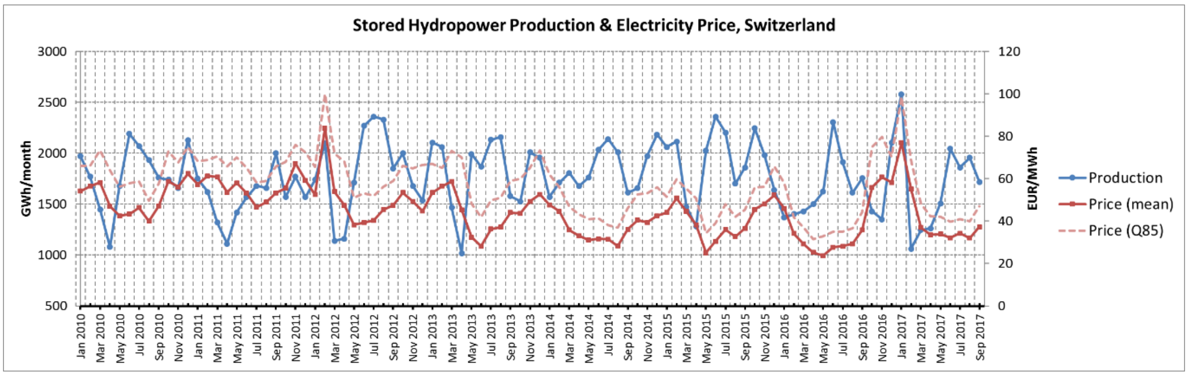

Figure 30: Historical monthly production of stored hydropower in Switzerland. (Net) Production = Gross production with pumps subtracted. Day-ahead Swiss electricity price of EPEX Exchange, averaged over months. 85 %-quantile of monthly electricity price. Source: Swiss Electricity Statistics, 2010–2017, Swiss Federal Office of Energy; EPEX historical market data feed

Figure 30 shows also the monthly mean of the hourly Swiss electricity price and the mean of the 85 %-percentile of the price over the months (EPEX Spot, 2018). In a market environment, the dispatch of stored hydropower is mainly triggered by high hourly prices, that is, prices in high percentiles. According to Figure 30, such price peaks correlate with averaged (mean) prices, such that the mean price is sufficient to be considered. The inter-annual production patterns change over the years; this is due to several reasons, for example changing inflow and reservoir filling patterns, changing market prices, and changes in electricity supply domestically or abroad (e.g. prolonged nuclear plant outages), which have again an impact on prices. A distinctive pattern over the years is when the natural inflow caused by snow melt increases in spring relatively drastically (March & April), and therefore the availability of hydropower increases (domestically and abroad): Within this time window, the electricity price is usually always decreasing. Stored hydropower production is usually high in summer and winter, whereas early spring and autumn have slightly lower production (Table 19). The monthly load factor of the turbine capacity is low: It never surpasses 33 % in each season or annually averaged over the years (Table 19). Table 19 shows also that the inflow variability can be high in each season, but the per-annum variability is relatively low. Hence, the variability of the water inflow consists mainly of a shift over the seasons. Hence, this shift can be tamed by stored hydropower, which has indeed also a slightly lower variation of the load factor annually than monthly.

Table 19: Mean and standard deviation of load factor of stored hydropower gross production (production without subtracting pump demand) and of natural water inflow per season and per year (2010-2016 data). Capacity assumption for load factor = 9.35 GW. Pumping efficiency for the natural inflow calculation: 0.775.

Season	Load factor, Variations	Natural inflow [TWh], Variations
Jan+Feb+Mar	33 % ± 18 %	1.02 ± 47 %
Apr+May+Jun	22 % ± 10 %	7.43 ± 18 %
Jul+Aug+Sep	29 % ± 9 %	8.43 ± 9 %
Oct+Nov+Dec	26 % ± 8 %	2.40 ± 16 %
Annual	26 % ± 6 %	19.27 ± 6 %

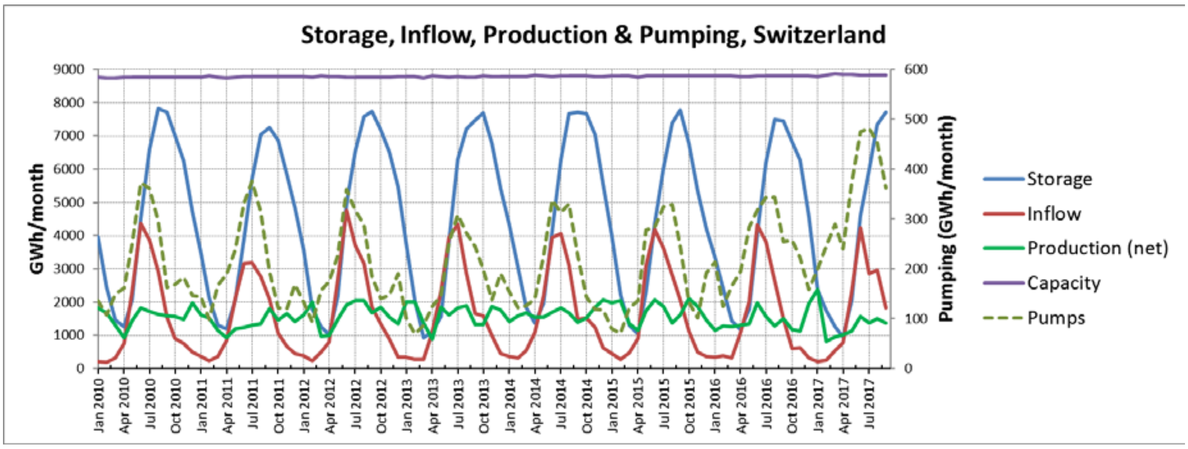

Figure 31: Historical monthly storage, net production and pumping of stored hydropower in Switzerland. Net production = (Gross) production with pumping demand subtracted. Capacity = gross storage capacity. (Swiss Electricity Statistics, 2010–2017, SFOE)

The historical storage, production and pumping patterns are summarized in Figure 31. The minimal and maximal filling rates over the years 2010–2017 are in the range of 11–16 % for the minimal and 83–89 % for the maximal filling rate, respectively. These rates correspond to a net-storage volume of 69–77 % of gross storage, where the gross storage is approximately 8.8 TWh. For comparison, annual Swiss electricity demand in 2017 is 62.9 TWh, and the annual inflow is roughly more than twice the storage volume (Table 19). Figure 31 shows also the relatively high pumping in summer; in recent years, significantly more pumping capacity was installed (e.g. Veytaux (Forces Motrices Hongrin-Léman SA) in 2016, and Muttsee (Axpo AG) in 2017/18, Nant de Drance in 2019), but not all of this capacity is yet operational in 2018.

4.3 Stochastic model

The purpose of the model within this project is to estimate the operational profit (market revenue) of Swiss stored hydropower under the CRM Policies and the EOM scenarios. The valuation of hydropower enhances the project's main analysis tool (the large-scale agent-based model, which includes all power production technologies). Input to the model is output from the agent-based model, which consists in our case of the hourly electricity price series of the different scenarios (ancillary service prices or volumes are not provided by the agent-based model).

The hydropower model is a stochastic optimal control model. The model type uses linear optimal control theory to find explicit profit-maximizing solutions of "bang-bang" type, that is, thresholds for turbining (i.e. production) and for pumping. These thresholds can change over time due to time-varying natural water inflows and time-varying electricity price distributions. Figure 32 shows the example of a single-period model with pumping, and a lower bound on the water level; the actually applied model is a multi-period extension and uses also upper bounds on the water level.

Single-period (steady-state) pumped-storage plant model

- Constraint on water-level in expectation
- $S \in L^1_+$ electricity spot price (EUR/MWh), continuous df
- $u^{\pm}: \mathbb{R}_+ \to \mathbb{R}_+$ ctrl-funct, $u^{\pm}(S)$: turbined/pumped water (MWh)
- Max. capacity, initial, minimal water level: $u^{+}_{\max} > l_0 - l_{\min} > 0$
- $c \in (0,1)$ efficiency of pumping

$$\max_{u^{\pm}} \mathbb{E}\left[S u^{+}(S) - \frac{1}{c} S u^{-}(S) \right]$$

$$\text{s.t.} \begin{cases} l_0 - \mathbb{E}\left[u^{+}(S) - u^{-}(S)\right] \geq l_{\min} \\ 0 \leq u^{\pm}(S) \leq u^{\pm}_{\max} \end{cases}$$

Optimal solution:

$$\hat{u}^{+}(S) = u^{+}_{\max} 1_{\{S \geq \hat{q}\}}, \quad \hat{u}^{-}(S) = u^{-}_{\max} 1_{\{S \leq c\hat{q}\}}, \quad \hat{q} \text{ given by}$$

$$u^{+}_{\max} \mathbb{P}[S \geq \hat{q}] - u^{-}_{\max} \mathbb{P}[S \leq c\hat{q}] = l_0 - l_{\min}$$

Figure 32: Example of single period stochastic optimal control model. Orange colour: Terms for pumping.

To allow for explicit solutions, some assumptions have to be in place. The most important is that the water level enters the model as an expected value, such that stochastic inflow variations over several years are not taken into account endogenously (i.e. the inflow is deterministic within a year). Changes of inflow patterns can be analysed by a sensitivity analysis (as executed further below). As shown in Figure 32, the electricity spot price, *S,* is assumed to be a non-negative random variable and to have a finite expectation (mean value); this is expressed in that the spot price is an integrable, non-negative random variable, denoted by L^1_+. We assume also that the spot price has a continuous distribution function; for distribution functions with steps, the bang-bang behaviour of the solution is more complicated, but still retrievable in principle (see Densing (2019b) for details). The control function for production, u^+, and pumping, u^-, depends on the spot price. The model has capacity bounds for pumping and production. The example of Figure 32 has only a lower bound on the water level; it is possible to consider also an upper bound, which is—as mentioned—the case in the numerical profitability analysis for this project. The efficiency of pumping is denoted by *c*. The controls u^+ and u^- have formally units MW (i.e. power), whereas the hourly electricity price has unit EUR/MWh (i.e. energy); hence, raw model output is post-processed (i.e., the optimal value of the maximization problem is multiplied by the number of hours per time step).

The optimization problem maximizes the objective function, which is the sum of expected profit of production and of the loss from pumping, under the constraints on water level, and under the capacity constraints of production and pumping. The optimal solution can be proven to be of bang-bang type (see Densing 2019a), which is notationally expressed in Figure 32 through an indicator function, denoted by 1_A: The function equals 1 if event *A* is realized and 0 otherwise. The event for (full) production is that the spot price is at least *q* (EUR/MWh), where *q* is the Lagrange multiplier in the optimum solution of the maximization problem. The event for full pumping is the opposite event, but additionally lowered by the efficiency of pumping (Figure 32). The optimal Lagrange multiplier (which can be commonly referred to as a “water value” of the modelling) is given by an equation involving the quantiles of the spot price distribution. Quantiles are expressed by the probability distribution of the spot price, *P[S<=c*q],* and by the complementary event *P[S>=q]*, where *P[A]* is the probability of event *A*, and *q* is the optimal Lagrange multiplier. Note that *P[S=q]*=0 because we assume that the spot price distribution has no steps, which facilitates (as already mentioned) the closed form of the optimal solution considerably. Note also that no assumption about the distribution of the spot price is in place.

The multi-period extension of the example in Figure 32 is rather straightforward. For multiple periods, the sum of the single-period expected profit and loss over time is maximized, and the water level constraints hold in every time period separately. The full mathematical formulations are in a forthcoming scientific publication (Densing 2019a), and the multi-period case of only lower bounds on reservoir level is presented in Densing (2013a, 2013b).

Table 20 summarizes some of the differences between the optimal control approach and the (more traditional) multi-stage stochastic programming approach. The main reason why we use stochastic control instead of multistage stochastic programming is that stochastic control provides the explicit form of the optimal solution in terms of bang-bang control thresholds, which are governed by the relation between the shadow price of the constraint on water and the spot price. Hence, the approach is more accessible and allows for a better interpretation of the optimal solution and the optimal value, whereas with stochastic dynamic or multistage programming the numerical (“black-box”) solution can be analysed merely by numerical sensitivity analysis. The optimal control formulation assumes that the constraints on water level have to be fulfilled in expectation (i.e., on average). Such an averaging can be interpreted as a valid assumption for medium- and long-term dispatch optimization, where a (distant future) violation of the bounds of reservoir level is acceptable because there is enough time to correct the dispatch in some specific scenarios where this may happen, whereas for short-run operations the bounds have to be respected strictly in every (short-term) scenario. The new model of this research project is thus not intended to substitute existing commercial (day-ahead) optimization software, where constraints are strict, but the model may be applicable as a benchmark model (with suitable extensions).

Table 20: Comparison between stochastic optimal linear control and multi-stage stochastic programming.

Topic	Stochastic optimal control	Multi-stage stochastic programming
Relevance	• Development of an accessible tool to evaluate profit dispatch optimization under uncertainty • Can be used to check profitability for a large variety of plants • Possibility to "plug-in" into other models to improve their dispatch heuristic	• Proven large scale numerical model approach; no significant scientific advancement expected • Scenario tree needed of price and of inflow scenarios
Numerically allowed time steps	• Arbitrarily many time steps possible: For example up to 1000(!) steps were tested • Numerical solutions are obtained by minimizing a real-valued function of pumping- and production-thresholds	"Curse of dimensionality": The scenario tree grows exponentially by the number of time steps. At least 2 branches per node are needed; multiplication by 2 per stage
Detail of modelling	• The constraints on water level are formulated in expectation over different scenarios, which is a relaxation. • Possibility to evaluate lower bounds for secondary reserve ancillary service (in a simplified setting; see Densing (2019b)).	• More reservoirs → more variables → numerical problems (because of scenario tree) • More types of constraints are possible, e.g., a constraint on financial risk. But: Bound on financial risk is dependent on idiosyncratic risk profile of each company → not useful if the entire Swiss perspective is considered
Extensions	Possibility to write an online web application (e.g. with sliders for change of input parameters, and similar types of results as in this work package)	Must use of commercial large-scale optimization software (e.g. CPLEX)

The optimal control problem is numerically solved in the software Mathematica for the twelve-step hydropower models (monthly steps over a year) and with the software GAMS/CONOPT for the 168-step pumped hydropower plant modelling (hourly steps over a week).

As a technical remark, we do not solve the so-called "primal" problem, which is the maximization of operational profit as outlined above, but the corresponding "dual" problem, which yields the same objective value. Generally, in microeconomics, the primal problem is a cost-minimization problem (cost := – profit) representing a least-cost resource *allocation*, whereas the dual is a resource *valuation* problem, such that value of the resources are maximized. In this project, we focus on the operational profitability, such that dual valuation is appropriate. It can be shown (Densing 2019a; 2019b), that in the dual formulation the resources are *additive* in the objective function, where the resources are: production capacity; pumping capacity; initial water level with the water inflow per reservoir (i.e. available energy); available headroom per reservoir; and an optional resource term for secondary ancillary service.

The main probabilistic parameters of the spot price are the mean and the standard deviation over the time steps. In this project, we assume a Gaussian distribution, which is determined by its mean and standard deviation. Gaussian distributions allow calculating the quantiles by a compact formula via the well-known error function. As stated earlier, the chosen approach of optimal stochastic control is in principle not limited by distributional assumptions.

An implicit assumption of the model approach is that the dispatcher knows the probability distribution of the spot price over the time horizon. This implies that the dispatch is according to a stochastic price forecast over the time horizon and the associated step size that is reliable. In contrast, commercial dispatch models are run in succession over time to incorporate updated market and inflow information as quickly as possible. Such real-world iterative model update is difficult to replicate by single modelling, because in addition to use the comprehensive model itself, the model would have to be run in a successive simulation mode by taking into account forecast errors and updates. A first step in this direction is the work of Kämpfer and Winnington (2012).

4.4 Results on profitability of hydropower plants

4.4.1 Typology “Swiss stored hydropower” (aggregated plants)

Stored hydropower plants in Switzerland can be of part interconnected reservoir systems involving several turbine stations and reservoirs. It is still an open (and difficult) research question whether a disaggregation can represent an interconnected system in terms of its optimal operation with a sufficiently high degree of accuracy. According to the Statistics of Hydropower Plants in Switzerland of 2018, there are 100 plants in service or under renovation of type “storage” or “pump”. Obtained results with our modelling approach indicate that an aggregated view can indeed replicate historical storage patterns. Moreover, in a separate numerical experiment, the aggregated Swiss storage capacity, the production capacity, and also the natural inflow were randomly partitioned into several plants. The shares of storage, production capacity, and of natural inflow were chosen differently (non-proportional). The result of the experiment was that even by a split into only five “sub-plants”, the back-aggregation exhibited minor differences to the single-plant aggregation. The experiment does not prove generally that aggregation leads to a satisfying representation of Swiss stored hydropower (and the gain of flexibility by aggregation to be minor), but at least this behaviour holds for the considered optimization modelling within this project.

Aggregation is more an issue for pumped storage, because the five largest pumping plants (Linth-Limmern, Nant de Drance, Grimsel, FMHL+, Maggia) cover already approximately 75 % of Swiss pumping capacity. These dedicated pump-storage plants are usually not used for seasonal storage, but exploit price differences between weekends and weekdays, and between night and day during the week (also according to the private communications available; exact data is company owned). Hence, storage volumes must accommodate (in an extreme case) almost 2 days of continuous pumping over the weekends, and then, subsequently, a combination of turbining at day and pumping in the nights and at workdays. Because the large pumped-storage plant storage volume are sized such they can accommodate such a short-term profit-exploiting schedule, the pumping and production capacity (Swiss Federal Office of Energy 2018g) can be considered as the main limiting factor for market revenues. In 2017, approximately 4 GW pumps and 4.5 GW turbines were installed in pumped-storage plants (this differs from the older figures used in the previous agent-based modelling).

Motivated by the foregoing discussion, in the following, for the typology of aggregated plants in Switzerland, we model aggregated stored hydropower (without pumps) separately from pumped-storage plants, by repeating on of the main reasons: Stored hydropower is mainly used for seasonal storage, whereas pumped-storage plant profit mainly from weekly or even daily cycles.

For the seasonal storage, we are interested in the yearly operational profit (market revenue) by an optimal dispatch decision. Studying aggregated stored hydropower makes it also possible to compare with publically available monthly statistics of Swiss hydropower production, which is generally not available on a monthly or shorter time scale for single plants.

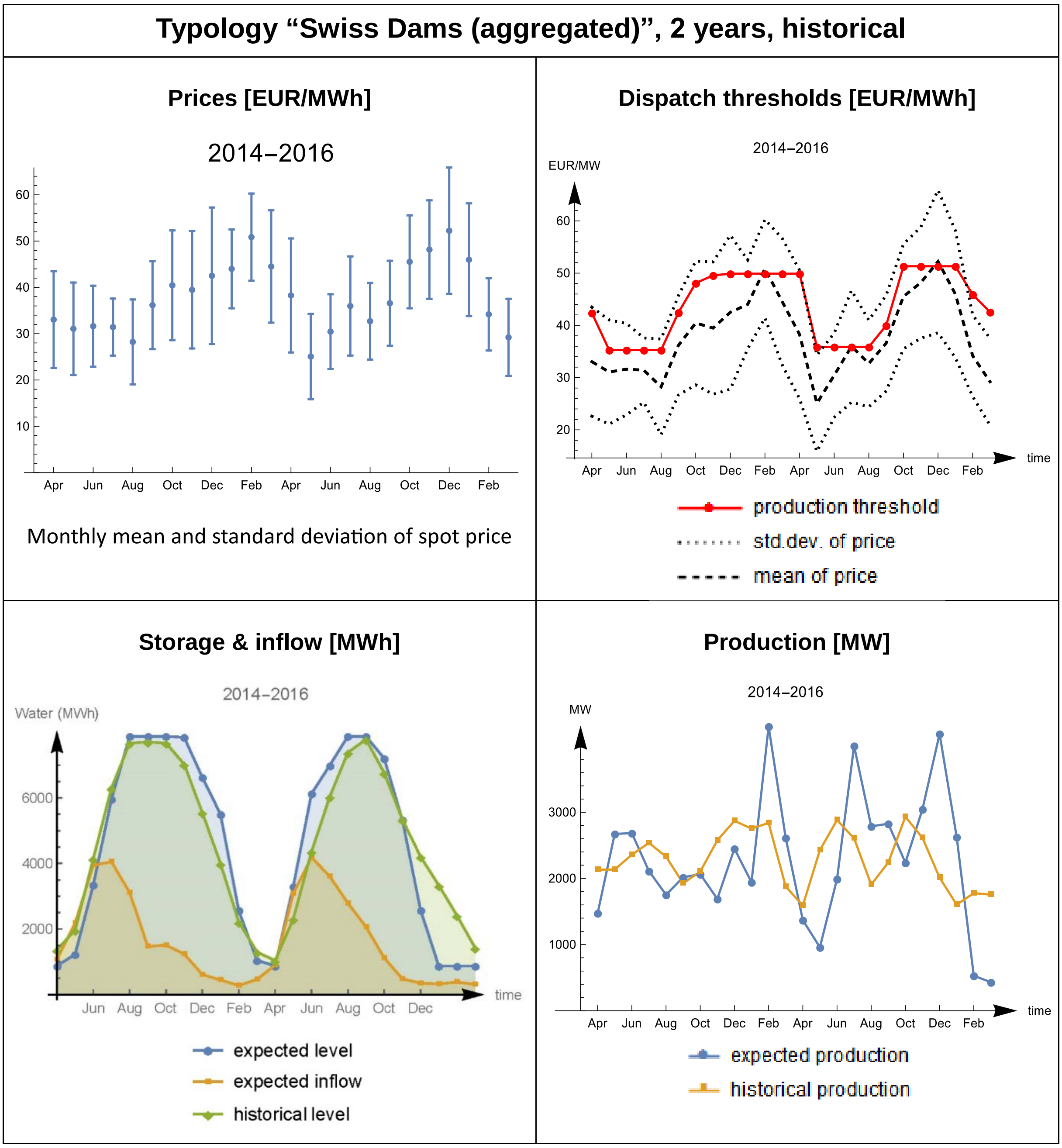

Figure 33: Stochastic control model result over two years of historical price distribution and inflow of 2014 (April) – 2016 (March). Storage and production capacity of Switzerland aggregated. Usable storage = 8750 GWh·* 75 %. Minimally allowed storage = 10 %.

For the aggregated Swiss dams, the optimization against historical price distributions and historical inflows over two years is shown in Figure 33. In particular, the price distribution, which is a model input, is shown in the upper-left subfigure of Figure 33; it is the monthly spot price distribution from the year 2014 (April) until year 2016 (March).

The chosen step size is adapted to model-use. For example, to replicate yearly storage patterns, a monthly step size was found to be appropriate. Indeed, the model with weekly step size (and with historical inflow and prices) over a year resulted in a dispatch that was adapting to each historical, idiosyncratic week, which can be interpreted as overfitting. On the other hand, in the following case of pumped-storage plants, with their typical daily or weekly cycling, an hourly time-step was found to be appropriate.

In Figure 33, the mean of the spot price is shown together with the monthly up- and downward standard deviation. The usable storage is assumed 75 % of gross storage, and the storage is assumed to be able to be emptied down to 10 %. Spot prices are higher during winter, hence the model tries to dispatch more during winter. In fact, as shown in the upper-right subfigure, the dispatch threshold for production ("water value" of the modelling) is increasing during winter, yet the threshold moves from higher quantiles more to the mean of the price, resulting in more production in winter. Such variations of the thresholds are difficult to predict without an optimization model. Note that the vertical axis has unit (EUR/MW), which is equivalent to (EUR/MWh) because the electricity price is hourly. The lower left subfigure of Figure 33 shows the historical water inflow (labelled "expected inflow"), which is a model input. The historical storage level and the storage level calculated by the model are shown.

Note that no other additional constraint is applied to (over-)fit the model to historical patterns; the optimization tries to spend the water more quickly towards the end of the second year than the historical pattern. A reason for that could be an end-of-horizon effect. The production pattern (lower right subfigure in Figure 33) is more volatile than the historical pattern. This is expected because the real-world operation of stored hydropower may be constrained by other, non-price factors. In an extended analysis, lower capacity factors could be imposed for the turbining (we use 85 % of the relatively large 9.35 GW production capacity). For our analysis in this research-oriented project, we abstain from such constraints because we do not want to influence results by ad-hoc constraints.

Table 21 summarizes the main result of the Swiss stored hydropower, that is, the operational profit (market revenues) of aggregated stored hydropower of Switzerland in various settings. The operational profit is the revenue from selling the electricity, whereas the net profit is obtainable for hydropower by subtracting fixed O&M and capital costs (variable O&M costs are relatively low), which are normally evaluated at utility level with different accounting rules. In the modelling, all electricity is assumed to be sold at the electricity market. For the rows with historical entries, the average market revenues of stored hydropower is taken from the recent profitability survey of Swiss Federal Office of Energy (2018e).

Table 21: Yearly market revenues of (aggregated) Swiss stored hydropower production under the modelled assumptions. Historical values: Sources: Swiss Electricity Statistics 2013–2016; Historical profits: (Swiss Federal Office of Energy 2018e).

Model / Historical	Scenario	Year	Price and inflow data	Available Storage [% gross volume]	Yearly Profit [mio. CHF (historical)] [mio. EUR (model)]	Volume [GWh]	Gross Volume [GWh]	Gross Generation [GWh]	Operational Profit [Rp./kWh (Historical)] [cent/kWh (Model)]
Historical	-	2013–2014 (Oct/Sep)	-	72 %	1,194	6,300	8,750	21,715	5.5
Historical	-	2014–2015 (Oct/Sep)	-	77 %	1,143	6,738	8,750	22,858	5.0
Historical	-	2015–2016 (Oct/Sep)	-	72 %	995	6,300	8,750	20,725	4.8
Model	-	2015–2016 (Apr/Mar)	historical (monthly)	70 %	1,008	6,125	8,750	19,664	5.1
Model	-	2015–2016 (Apr/Mar)	historical (monthly)	75 %	1,014	6,653	8,750	19,664	5.2
Model	-	2015–2016 (Apr/Mar)	historical (monthly)	80 %	1,021	7,000	8,750	19,664	5.2
Model	-	2015–2016 (Apr/Mar)	historical (monthly)	153 %	1,060	13,360	8,750	19,664	5.4
Model	EOM	2030	EOM; inflow: avg. 2010–16	75 %	1,986	6,563	8,750	19,540	10.2
Model	EOM	2050	EOM; inflow: avg. 2010–16	75 %	6,251	6,563	8,750	19,540	32.0
Model	CRM Policies	2030	CRM; inflow: avg. 2010–16	75 %	2,036	6,563	8,750	19,540	10.4
Model	CRM Policies	2050	CRM; inflow: avg. 2010–16	75 %	3,201	6,563	8,750	19,540	16.4

In Table 21, the operational profit of the model results is calculated by dividing yearly profit by the generated energy. Table 21 shows in the first rows the historical results with the historically declining profit over the years 2013–2016. Then the model result for a recent year is shown repeatedly with varying storage volume. As already mentioned, the effect of changed storage volume within certain bounds (70–153 %) on the operational profit of stored hydropower is surprisingly small. Comparison with the historical values shows also that the optimal operational profit obtained by the model is comparable with the survey results (Swiss Federal Office of Energy 2018e); for example, the reported historical profit in 15/16 was 4.8 Rp./kWh, whereas the corresponding year in the model yields 5.2 Cents/kWh. The model result is an optimistic result, where no further restrictions than the pure market optimization is taken into account. The remaining rows in Table 21 show also the scenario results in the years 2030 and 2050 for the EOM and CRM Policies scenarios, which exhibit significantly higher market revenues because of the increased price levels.

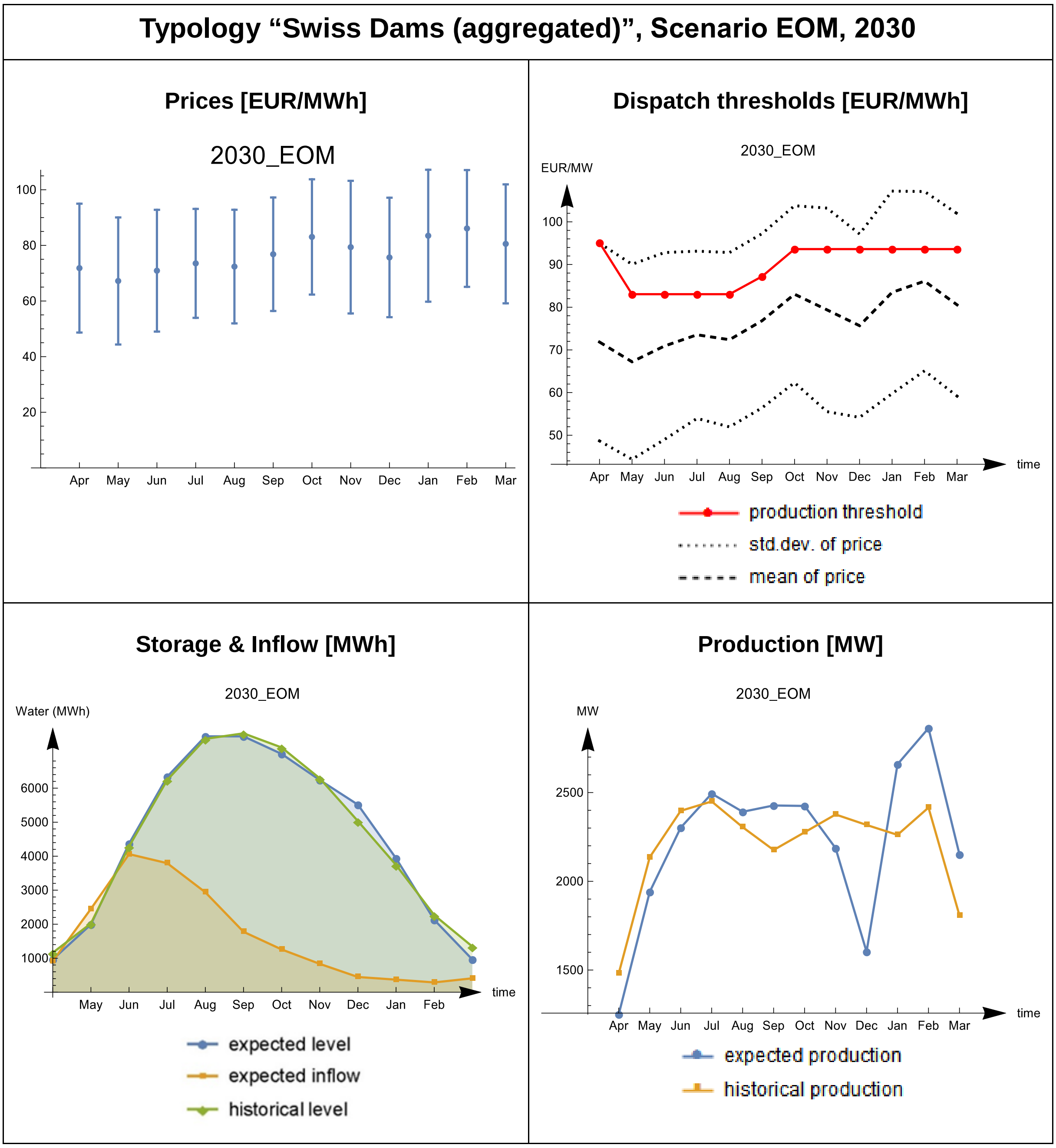

Figure 34: Model result with the price distribution of 2030 EOM scenario. Storage and production capacity of Switzerland aggregated. Inflow, historical storage values, and historical prices: Average historical years 2012–2016.

Figure 34 and Figure 35 show the EOM and the CRM Policies scenario in the year 2030. In this relatively early target year, the scenarios exhibit very similar dispatch results, which is reflected also in a similar operational profit (Table 21), which is approximately twice of today's profit. As a peculiar coincidence, the storage pattern in the EOM and CRM Policies scenarios matches the historical averaged storage volumes very closely over the monthly time steps.

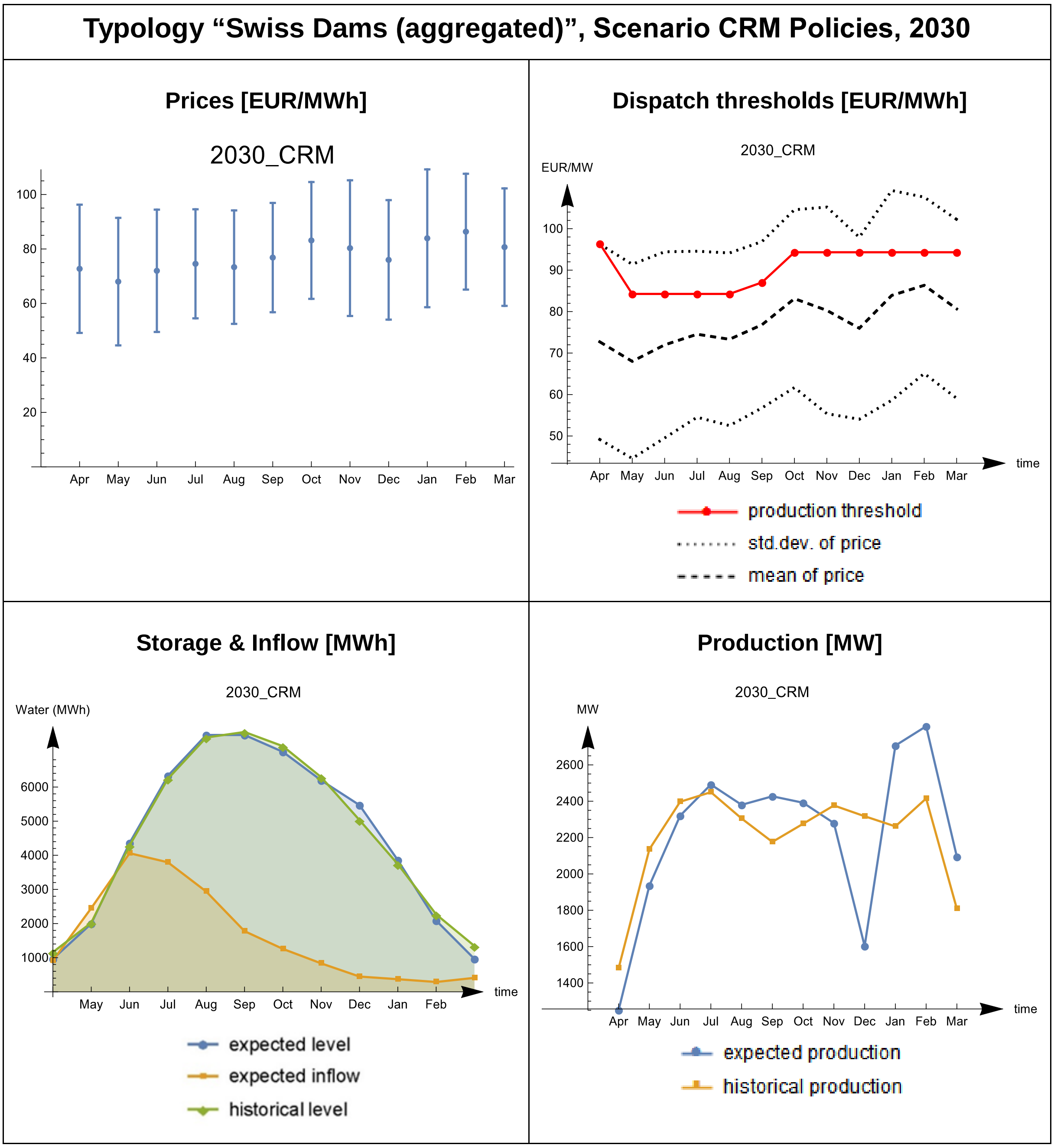

Figure 35: Model result with price distribution of 2030 CRM Policies scenario. Storage and production capacity of Switzerland aggregated. Inflow, historical storage values, and historical production: Average historical years 2012–2016.

Figure 36 and Figure 37 show the EOM and CRM Policies scenarios in the target year 2050. In this late year, the scenarios exhibit high prices; the EOM scenario hits for example several times the cap of 3,000 EUR/MWh. In the EOM 2050 scenario, the hydropower makes full use of the very high price peaks during January, such that the production in other months, for example December, is very low (approx. 500 GWh) according to our model results; historically, production can also fall to low values (e.g. 815 GWh in February 2017). Note that the stochastic control and the associated analysis is purely price driven, whereas in a hypothetic "real" scenario in 2050 various system effects may drive also the December prices upwards. Indeed, the modelled price dip in December is entirely determined by the assumption of the agent-based modelling, where are key factor is for example the load, which is assumed to be lower in December than in other, neighbouring months over all years (up to 2050).

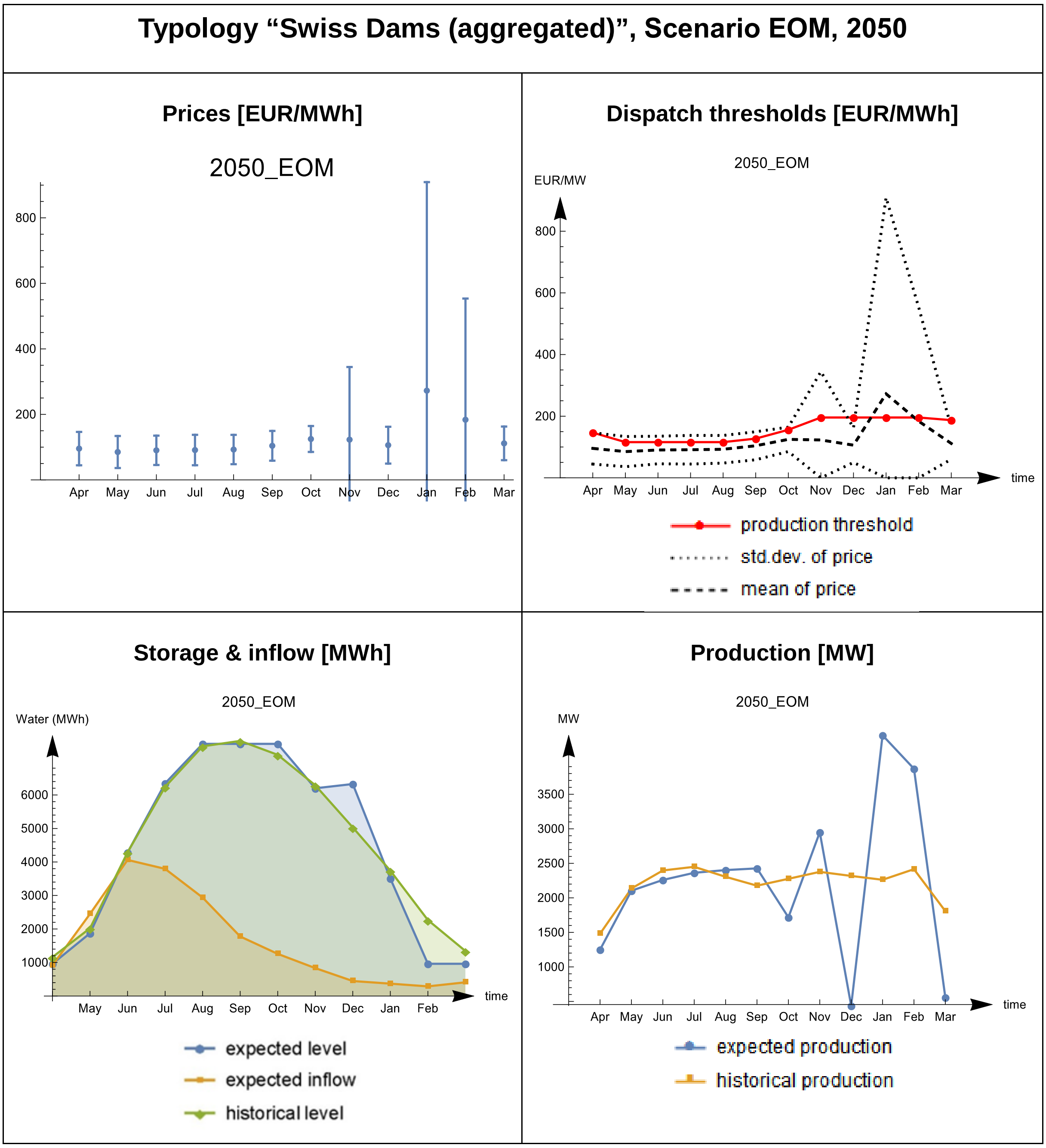

Figure 36: Model result with price distribution of 2050 EOM scenario. Storage and production capacity of Switzerland aggregated. Inflow, historical storage values, and historical production: Average historical of years 2012–2016.

The CRM Policies scenario is less extreme than the EOM scenario in terms of prices, and operational profit only triples compared with today’s modelled profit.

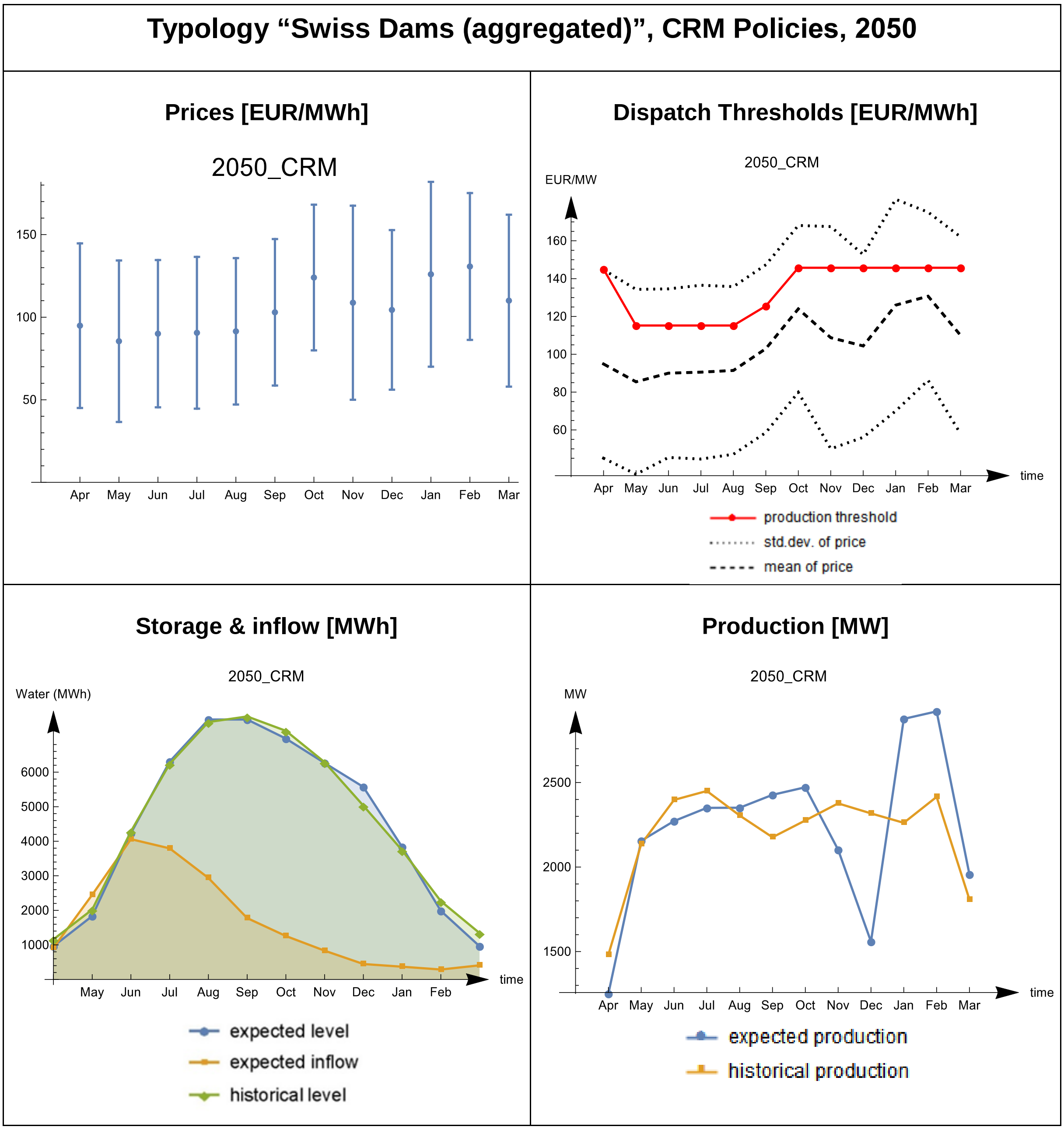

Figure 37: Model result with price distribution of 2050 CRM Policies scenario. Storage and production capacity of Switzerland aggregated. Inflow, historical storage levels, and historical production: Average historical years 2012–2016.

Sensitivity with respect to water inflow

Water inflow into hydro storage dams in Switzerland varies over the years (see Figure 31). To test the influence of water inflow on scenario results, we consider the years 2011/12 and 2012/13, which have relatively very distinctive monthly inflow patterns (Figure 31). The production (which corresponds approximately to the inflow) in 2011/12 (Apr-Mar) was 17.4 TWh, whereas in 2012/13 it was higher: 20.4 TWh. The corresponding impact on profits is shown in Table 22: The profits vary by 14 % and 12 % for the CRM Policies scenarios in 2030 and 2050, respectively. The operational profit per produced energy varies considerably less because most of the profit change is caused by the change of the annual inflow volume, and to a considerably lesser extend by the relatively moderate shifting of inflow over the months between the considered years. In fact, the profit per energy diminishes slightly with more inflow, which indicates the additional inflow is not exploitable in high price ranges.

Table 22: Sensitivity analysis with respect to different inflow years for the CRM Policies scenario.

Timespan / Year	Inflow data	Operational profit (market revenue) [mio. EUR]	Gross Generation [GWh]	Operational profit (market revenue) [Cent/kWh]
2030	2011/12	1.85	17,286	10.6
2030	2010–16 averaged	2.04	19,540	10.4
2030	2012/13	2.11	20,423	10.3
2050	2011/12	2.93	17,286	16.9
2050	2010–16 averaged	3.20	19,540	16.4
2050	2012/13	3.29	20,423	16.1

4.4.2 Pumped storage plants

We consider three typologies of pumped storage plants, whereas in the subsequent section on the ancillary service we will present in addition the case of two interconnected reservoirs.

4.4.2.1. Typology “Muttsee” (short-term pumped-storage)

We consider a typological example of a pumped-storage plant that has similarities with the plant of Muttsee, which is part of the Linth-Limmern power plant system. In the example, we consider one week of operation, with 1 GW production and pumping capacity. The historical data of electricity prices is the hourly Swiss day-ahead price of the EPEX Spot Exchange of years 2015–2016. The mean and standard deviation is calculated for each hour separately for the subset of Saturdays of the years 2015–2016. In the same way, the mean and standard deviation is calculated for Sundays and for the workdays. The resulting hourly price distribution is shown in Figure 38: Saturday and Sunday have lower prices than workdays; for simplicity, the same distribution of workdays is repeated five times. The storage is assumed empty in the first hour of Saturday, and we assume that the storage volume can be fully used. The storage volume is assumed to be 24 GWh; hence, it is possible to pump or produce fully during a single day (Muttsee: approx. 40 h). The lower reservoir is assumed to be sufficiently large (or not to be restrictive for the pumping), and the upper reservoir has no natural inflow. This is similar setting as Muttsee, where the lower Limmernsee is relatively much larger; zero inflow is a valid assumption in this case of a high-altitude lake with limited catchment area and short-term operation according to a personal communication from the corresponding power plant utility). Moreover, we consider a relatively short-time horizon of a week, because the profit-oriented cycling is short, such that inflows can be neglected. Pumping efficiency is assumed to be 75 %. The optimized operational profit of one week (and up-scaled annually) is shown in Table 23.

Figure 38 shows the corresponding optimal dispatch: Pumps operate during the weekends and as well during the nights of the workdays. The water value of production differs from the water value of pumping by the factor of pumping efficiency. A peculiarity of the modelled water values in this example is that they stay constant over the time horizon, which holds also for the future scenario results further below. Note that the upper bound of storage is not hit, which is in line with observation that the pumping capacity is most relevant and the storage volume is usually appropriately selected to accommodate this capacity.

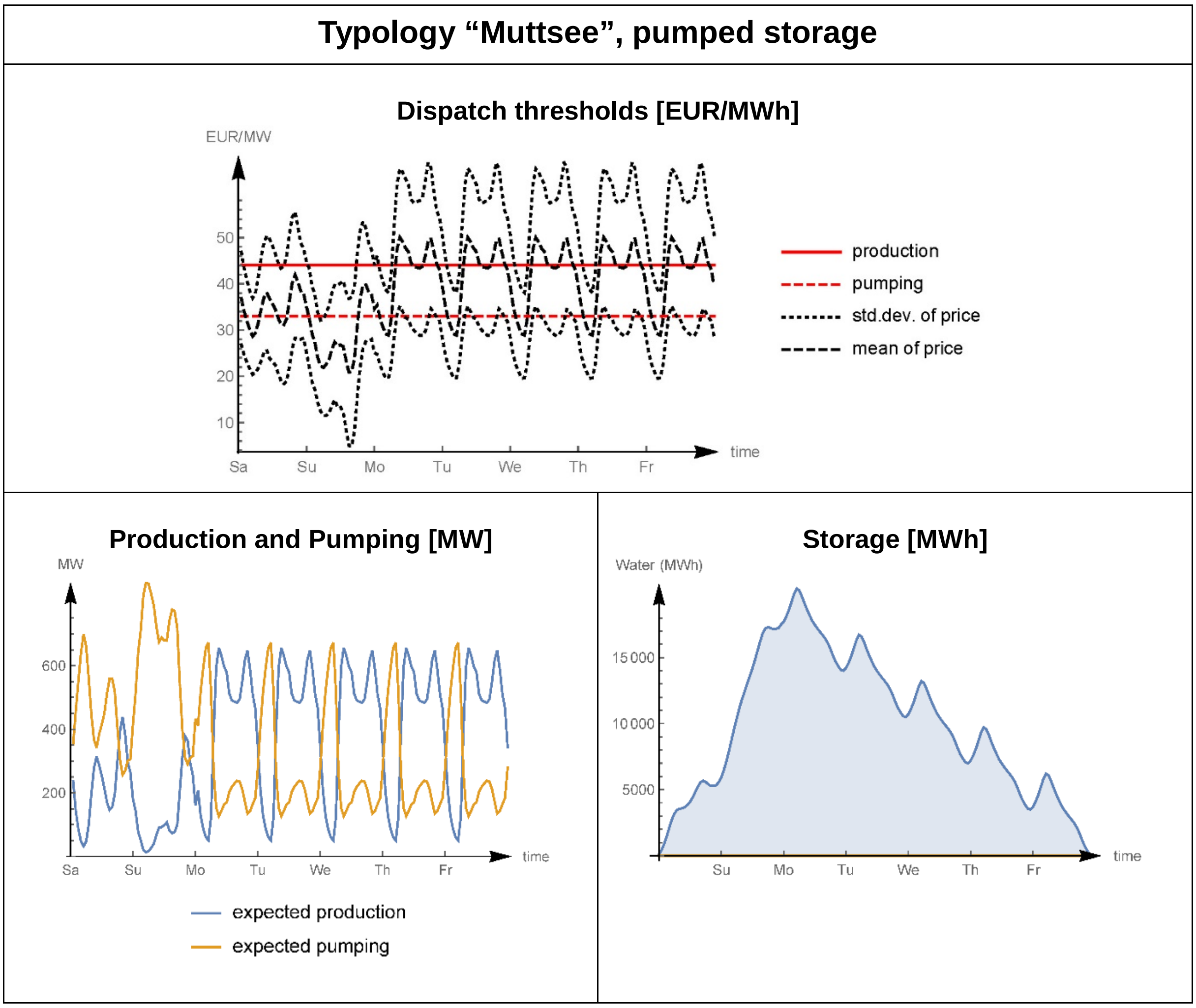

Figure 38: Optimal control of pumped-storage plant over a week with historical price distributions, typology “Muttsee”. Price distribution of years 2015–2016.

The dispatch patterns for the scenarios are shown in the appendix; the patterns show higher gradients of production and pumping compared with today’s optimal pattern in Figure 38. The high gradients lead to increased turbine wear-down and increased maintenance cost if the dispatch should follow such an extreme optimal schedule.

The operational profit of the pumped-storage plant is as follows (Table 23). In contrast to the (pure) stored hydropower (Table 21), the operational profit in year 2030 is not yet increased significantly compared with today’s profit, because the variability of the prices is not significantly higher than today; the EOM and the CRM Policies scenarios have 22 and 23 EUR/MWh yearly standard deviation in 2030, respectively (standard deviation is 13, 17, and 20 EUR/MWh for the Swiss EPEX day-ahead price in years 2015, 2016 and 2017, respectively). On the other hand, in the year 2050, the operational profits increase more drastically to very high levels (standard deviation of prices is 231 and 51 EUR/MWh for EOM and CRM Policies, respectively).

Table 23: Optimal stochastic control of a stylized pumped-storage hydropower plant, typology “Muttsee”.

Timespan	Scenario	Yearly operational profit (market revenue) [mio. EUR]	Average weekly operational profit (market revenue) [mio. EUR]
2015 – 2016	-	74	1.4
2030	EOM	85	1.6
2050	EOM	385	7.4
2030	CRM Policies	87	1.7
2050	CRM Policies	258	5.0

Corresponding to the dispatch patterns above, an example of the modelling result of a pumping and production schedule for the CRM Policies scenario in year 2030 is shown in Figure 39 (additional figures are provided in Appendix 8.11). The figures show that the switches between –1, 0, and +1 GW power output are more frequent in the scenarios than today; for example, the CRM 2050 scenario in the considered example has 45 switches of 1 GW, whereas the historical pattern has only 25 switches. The extreme operation patterns with many switches may lead to an increased turbine wear-down if today’s turbine technology is still applied.

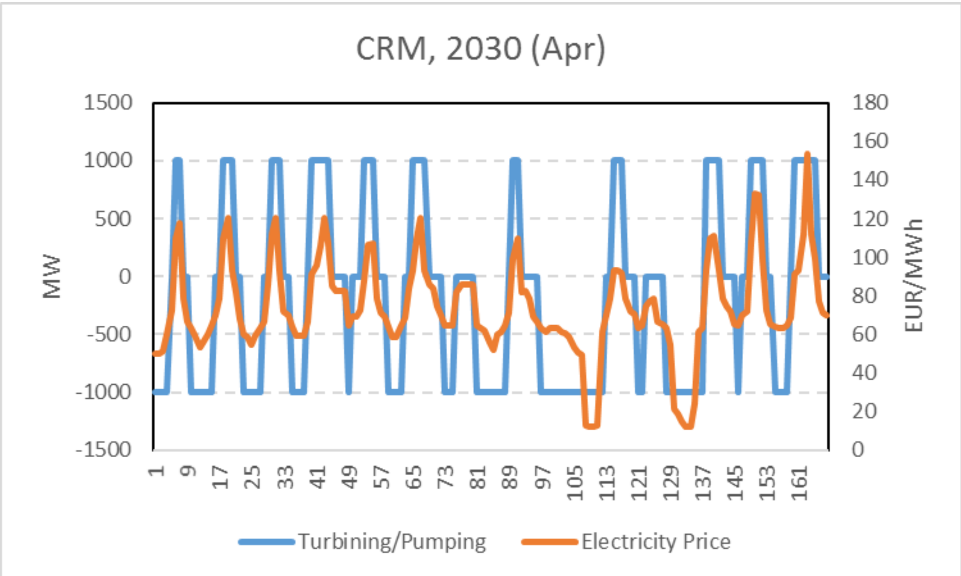

Figure 39: Example of dispatch schedule (bang-bang control) computed by the stochastic control model over a week (169 hours). Weekend is the 4th and 5th day.

4.4.2.2. Typology “Wägitalersee” (Seasonal storage with small pumps)

In this typological example, we consider a pumped-storage reservoir that is used for seasonal (long-term) storage. We choose the typological example of the Wägitalersee, which is a relatively large reservoir, and where the turbining capacity of 60 MW and the (lower) pumping capacity 16 MW are relatively small compared to the reservoir size. In the chosen example, a relatively moderate volume of the lake is usable because of assumed environmental concerns of this relatively highly-used recreational lake, and we introduce a security margin of 10’000 MWh such that the reservoir is ensured not be emptied in some extreme scenarios; hence, we assume approximately 50 mio. cubic meters, which is below the 75 mio. fully usable volume of the Wägitalersee as of today. The historical inflow data is based on Densing (2007). The Wägitalersee is located at low altitude, such that the inflow is not concentrated with the snowmelt in spring. In the chosen typology, we assume that the operation of the relatively small pump capacity is not restricted by a limiting lower reservoir.

A resulting operation pattern of the stochastic control model as of today is shown in Figure 40, and corresponding operational profits (market revenues) are in Table 24. The operational pattern depends on the electricity price. In today’s pattern, operation is relatively low in spring after the snow melt and with generally abundant hydropower production domestically and abroad, which contributes to low prices, such that for example more pumping happens early in the first half of the year (by contrast, the prices in the CRM Policies scenarios in 2050 are more balanced over year span).

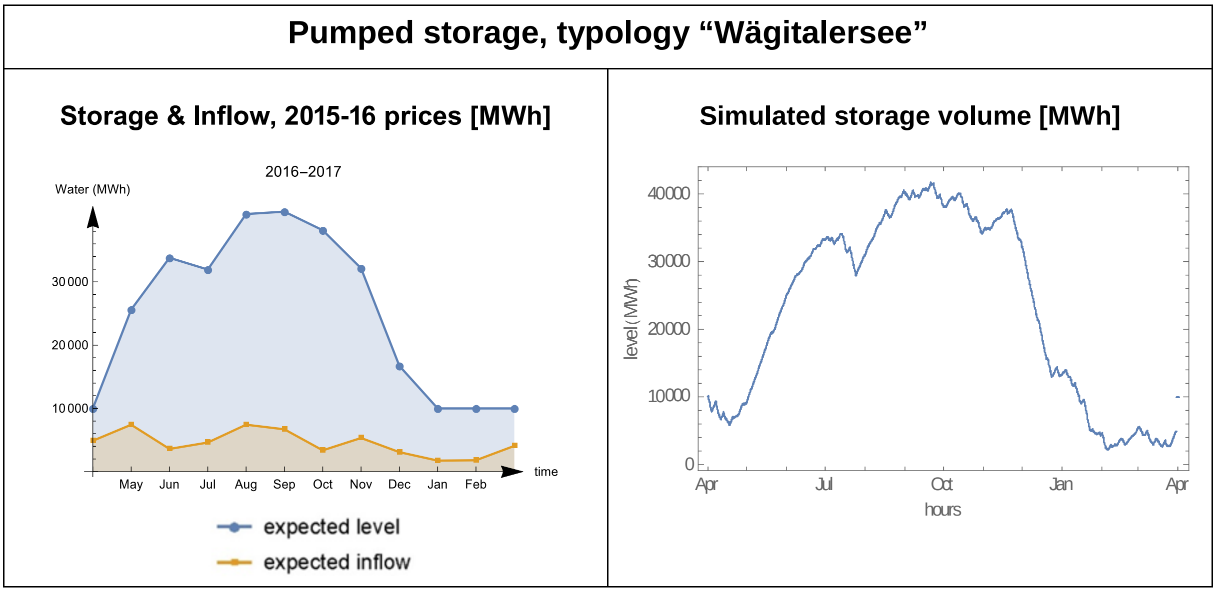

Figure 40: **Left:** Optimal stochastic control of pumped-storage plant, typology “Wägitalersee”. Monthly price distributions of 2016/17; historical inflow pattern. **Right:** Example of an hourly simulation of storage level using the obtained thresholds from the optimal control optimization problem (identical price and inflow data).

Figure 40 shows on the right an example of an hourly dispatch pattern applied to historical year 2016/17 prices; inflow is constant during the hours of a month: It can be seen that the security margin of 10 GWh ensures feasible water levels. Note again that the primary aim of the modelling is to yield a dispatch for the “average” (uncertain) future development of price distributions for each scenario, whereas real-world dispatch optimization software updates each day anew with new information; hence, a constraint violation of an upfront optimization over a long-time horizon (here even over a whole year) can be considered as tolerable to some extent.

Table 24 shows also that the relatively large reservoir with yearly cycles can profit from high price levels already in the year 2030, and is not fully dependent on high price variations, which are the key income factor mostly in the late year 2050 for short-cycle “pure” pumped-storage plants (and not yet in 2030). On the other hand, the increase in profit relative to today is higher in year 2050 for short-cycled pumped-storage plants because of the very high variability in year 2050.

Table 24: Operational profit (market revenue) by optimal stochastic control of a pumped-storage hydropower plant, typology “Wägitalersee”. Historical inflow pattern.

Time	Price data / Scenario	Yearly operational profit [mio. EUR]	Yearly operational profit with zero pumping [mio. EUR]
Today	2016/17 prices	4.1	3.3
2030	EOM	7.7	6.3
2050	EOM	19.9	13.8
2030	CRM Policies	7.9	6.3
2050	CRM Policies	15.3	10.5

Table 24 shows also the benefit of the pumps. The operational profit increase of the pump is in the year 2030 in both scenarios and as well as of today in the quite substantial range of 23 – 24 %, whereas in 2050 the operational profit increase is relatively higher, 44 – 45 % in the scenarios. This corresponds to the already mentioned observation that the large profit increase of pumped storage happens only in the long-term; in other words, the relative increase in advantage of pumped storage versus pure storage realized only later.

Table 25: Relative increase in operational profit (market revenue) in the scenarios in 2030 and 2050 relative to today’s modelling results.

Scenario	Time span for relative price difference	Typology	
		Muttsee	Wägitalersee
CRM Policies	2030 – today	18 %	92 %
EOM	2030 – today	15 %	89 %
CRM Policies	2050 – 2030	198 %	94 %
EOM	2050 – 2030	355 %	157 %

Table 25 compares the relative increase in operational profit of the typologies “Wägitalersee” and “Muttsee”. In the intermediate year 2030, the relative increase in market revenue is smaller for “Muttsee” than for “Wägitalersee”, because “Muttsee” is a fully dedicated pumped-storage plant without a significant natural inflow, and price variations are in 2030 still comparable to today’s variations in both scenarios. By contrast, the typology “Wägitalersee” has a significant natural inflow, such that it can already profit until 2030 from increased price levels. In the period 2030 – 2050, the pattern is reversed: “Muttsee” can profit more from the increased variability, whereas “Wägitalersee” has a lower pump than turbining capacity, such that higher price differences can be exploited less.

4.4.2.3. Swiss pumped-storage plants (aggregated)

The third group of pumped-storage plants is the aggregate of all pumped-storage plants of Switzerland. The installed pumping capacity at the end of year 2017 in Switzerland is 3'896 MW, and the corresponding turbine capacity of these plants is slightly higher at 4'674 MW. The aggregated reservoir storage volume is assumed to be 379 GWh, which is the pumping-capacity-averaged reservoir size of the currently five capacity-largest plants in Switzerland (Muttsee, Nant de Drance, KWO (Grimsel), FMHL+, Maggia (Naret+Cavagnoli)); the minimum of the size of the upper and of the lower reservoir is used (Swiss Federal Office of Energy 2017d). The number is comparable with the 369 GWh estimated by Eurelectric, which does not include the recently newly built plants (Eurelectric 2011).

Table 26: Optimal stochastic control of Swiss pumped storage (aggregated).

Year	Price data / Scenario	Yearly market revenue [EUR millions]	Weekly market revenue [EUR millions]	Pumping [GWh/year]
Today	2016+17 EPEX prices; full capacity of Nant de Drance + Muttsee is available	312	6.0	13,127
2030	CRM Policies	372	7.2	11,006
2030	EOM	363	7.0	11,033
2050	CRM Policies	1,088	21.0	13,111
2050	EOM	1,642	31.6	13,835

The capacity of the new pumped-storage plants in Switzerland (Nant de Drance, Muttsee) is taken into account in the modelling; as of year 2018, these new plants are not yet fully operational. The addition will approximately double the existing Swiss pumping capacity, and the new plants are built such that short-cycling is technically possible.

Table 26 shows again high price increases in the long-term scenarios in the year 2050, and the increase is higher than for (pure) stored hydro, whereas the shorter-term increase in the year 2030 is relatively lower. Hence, we have again the results that for pumped-storage plants the price variability is a determining factor for profitability, and this variability is very high only long-term in 2050.

The pumping capacity in the results of Table 26 includes the new plants (rescaled back to the capacity of 2016, the results are comparable to today's pumping amount; e.g. 4.2 TWh in 2017). On the other hand, there are several reasons for higher modelled values: (i) The model assumes that the switch from pumping to production can be instantaneous, and there is no wear-down to consider by very fast switching ; (ii) the model optimizes only and fully against the day-ahead market and takes other criteria, e.g. environmental concerns, not into account ("Dotationsturbinierung"); (iii) the assumed storage volume is a capacity-weighted average, which may be too large; (iv) the real-word dispatch of the pumps may not be optimal.

4.4.3 Ancillary services for control reserve

Currently in Switzerland and also in many European markets, there are three types of ancillary service for active control reserve: Primary, secondary and tertiary, which are categorized by different time horizons for ramping-up requirements (Swissgrid, 2018). The markets for these services are managed separately from the energy-only markets. This separation is by no means fully driven by technical power system requirements, but by mutual agreements between countries and practical suitability within the European markets; for example, market areas in the United States (e.g. PJM) or New Zealand use different schemes, which are more integrated and can be considered to be more efficient. Therefore, also by the recent change of the energy-only market structure by allowing more short-term (intraday, up to 15 minutes notice period) trading possibilities, and by the change of the generation structure towards more renewables, and as well by the introduction of capacity markets to ensure system stability in a complementary way, the rules for providing ancillary services are likely to change in the future also in Switzerland. Changed rules and different supply patterns will have an impact on the prices for the ancillary services. Future prices on control reserve markets are hypothetical. In this project, we try to extrapolate today's prices for ancillary service for the long-term years 2030 and 2050 in the CRM Policies and EOM scenario.

In our analysis, we consider secondary reserve. We focus on secondary reserve also for the following reasons. Stored hydropower is under the current market rules very suitable to provide secondary reserve for the following reasons: (i) Secondary service provision in Switzerland is not (yet) coupled to non-domestic ancillary markets, such that there is only domestic competition. (ii) Secondary service must be currently provided in symmetric bands of capacity, that is, up- as-well-as downward regulation must be provided in terms of power. Downward regulation penalizes plants that cannot store the fuel (also indirect "fuel", e.g. water) for later use, for example, wind power or photovoltaics. (iii) The lower limits for offers to the Swiss TSO in terms of capacity are relatively large (>> 1 MW) and must be valid for a whole week, such that mid- to large-sized hydropower plants are suitable to participate. (iv) If a hydropower plant offers secondary service, it can also provide primary service, because the water turbines and generators are able to react within seconds to frequency changes, such that the primary service is automatically covered by online capacity (Reichlet, Köppel 2013).

Note that the electricity prices of the agent-based model are the input for the profitability analysis of hydropower. By contrast, the agent-based model does not provide any non-energy market prices, for example for ancillary services. We provide in this project rough limits for such possible future prices, which depend on the energy-only prices of the agent-based modelling. Note also that currently the auction for ancillary services are pay-as-bid in Switzerland, such that there is no single (market-clearing) price.

4.4.3.1. Secondary ancillary service

Because market rules for secondary service are likely to change, the analysis is kept general; still, some results can be verified empirically.

$$\max_{u(\cdot),u_a} \mathbb{E}\big[S(u(S)+u_a)\big] + p_a u_a$$
$$\mathbb{E}[u(S)+u_a] \leq l,$$
$$u(S)+2u_a \leq u^+_{\max},$$
$$u(S), u_a \geq 0,$$

Figure 41: Example of stochastic optimization problem of secondary reserve over a single period.

The stochastic optimization problem for a plant over a single period is shown in Figure 41. In this single-period model, we assume that we decide (e.g. for the next week as currently in Switzerland) to allocate some of our turbine capacity to secondary ancillary service with symmetric up- and downward regulation. The amount of turbine capacity that is attributed to ancillary service is the variable u_a, which is called the set-point, and the amount of turbine capacity that produces still in dependence of a sufficiently high electricity price for the usual energy-only (day-ahead) market is the variable *u(S)*, which depends on the actual hourly spot price *S,* which is modelled as a random variable. Upper and lower turbine capacity limits have to be fulfilled; because the service is symmetric, the set-point u_a of constant operation during the time period has to be deducted twice from the total available capacity. In the modelling, there is also a lower bound on water; in fact, the main hurdle for providing the service over a prolonged period of time is that enough water (fuel) is present. By providing ancillary service, the plant must operate at the set-point, and a (possibly) remaining capacity used for the free market reduces also the water level. We assume that the lower bound on the water level has to be fulfilled in expectation; hence the model may be interpreted to be used for medium- to long-term planning (by contrast, in reality, the short-term hourly dispatch is usually iteratively adapted daily with commercial dispatch-software, which we cannot capture in this research project). The profit of the plant is from the free production and from the reimbursement from the lock-in into ancillary service; in other words, the plant sells u_a over a week at the market, and this amount cannot be changed (lock-in). The operational profit includes also the reimbursement of the ancillary service, denoted by p_a, which includes in our case also payments for delivered energy. In fact, the net-energy payments in the case of Switzerland as of today are at least an order of magnitude lower than the volume-weighted capacity price, such that we can focus on the reimbursement price for the capacity. Moreover, the reimbursement for delivered energy depends also on the amount of call-ups by the TSO during the time period, which depends in turn on the stability of the supply network, which is not in scope to be evaluated in this project for the future scenarios. Generally, further details of the modelling are presented in Densing (2019a).

It can be shown that a necessary condition for the secondary ancillary service to be profitable for the power producer is that the reimbursement p_a must be higher than the mean absolute deviation of the median of the spot price (MAD); see Densing (2019a). Indeed, the validity of this condition can be empirically verified in Figure 42. As by the figure, the yearly MAD is an appropriate lower bound. It can be also seen that when the water is abundant in late spring and summer, then the volume-averaged price approaches the lower bound of MAD. Note that the yearly MAD is usually higher than the weekly MAD because each weekly MAD has its own (weekly) median of spot price, which is better adapted to each weekly variations. Figure 42 shows also that the average price of the secondary reserve seems to be sometimes correlated with the weekly MAD, but based on the finite sample and changing/improved bidding-behaviour of real-world utilities over the years, we cannot make a conclusive statement.

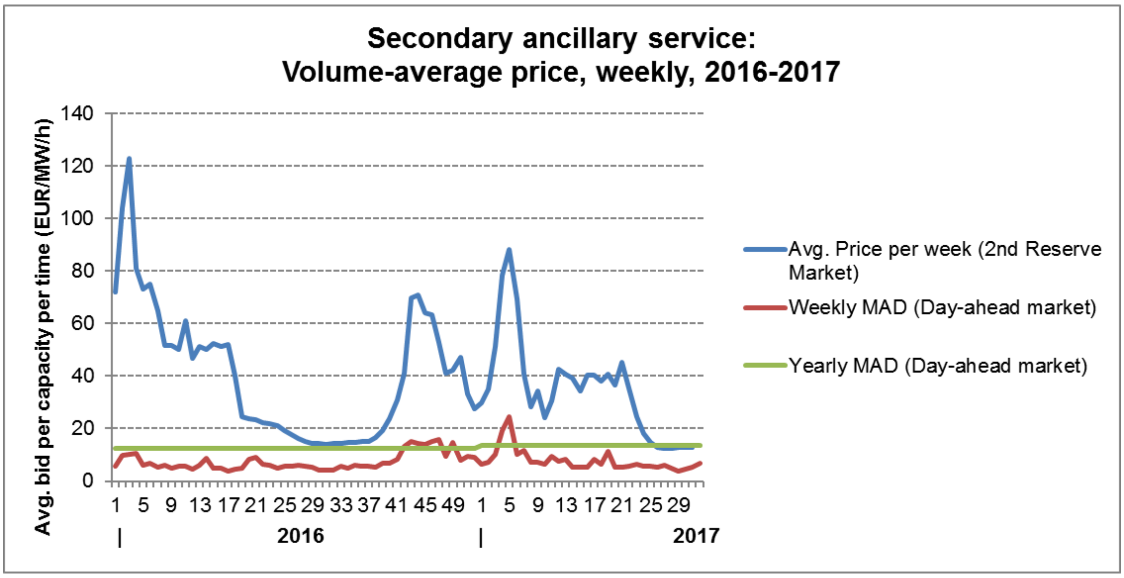

Figure 42: **Blue:** Volume-weighted weekly prices of secondary reserve service in Switzerland (scaled to 1 hour of service) (Swissgrid 2018a). **Green/Red:** Mean absolute deviation of the median of the day-ahead Swiss spot electricity price. (EPEX Spot 2018)

4.4.3.2. Secondary ancillary service prices for the 2030 and 2050 scenarios

Based on the foregoing discussion and its caveats, we provide an estimate of secondary ancillary service prices for the EOM and the CRM Policies scenarios in the future years 2030 and 2050. Note again that the electricity prices of the EOM and CRM Policies scenario as provided by the agent-based modelling are energy-only prices (and do not cover any ancillary services).

Figure 43 shows on horizontal axis at “2016/17” three values: (i) Today’s lower bound, that is, the MAD of the electricity price (12 EUR/MW/h); (ii) today’s averaged service price (39 EUR/MW/h; volume and time averaged over the historical period); and (iii) the maximum service price achieved (123 CHF/MW/h, over the historical period of 2016/17 as of Figure 42). In the columns for the years 2030 and 2050, the corresponding Min-value correspond to the MAD of the scenarios EOM and CRM Policies, and the average value and the Max-value are scaled proportionally from today’s value to the corresponding MAD. As a result, because price variations increases in both scenarios and therefore the MAD, the ancillary service average prices are expected to rise by 37 % and 137 % in the CRM scenario in 2030 and 2050, respectively, and in the EOM scenario by 173 % and 319 % in 2030 and 2050, respectively.

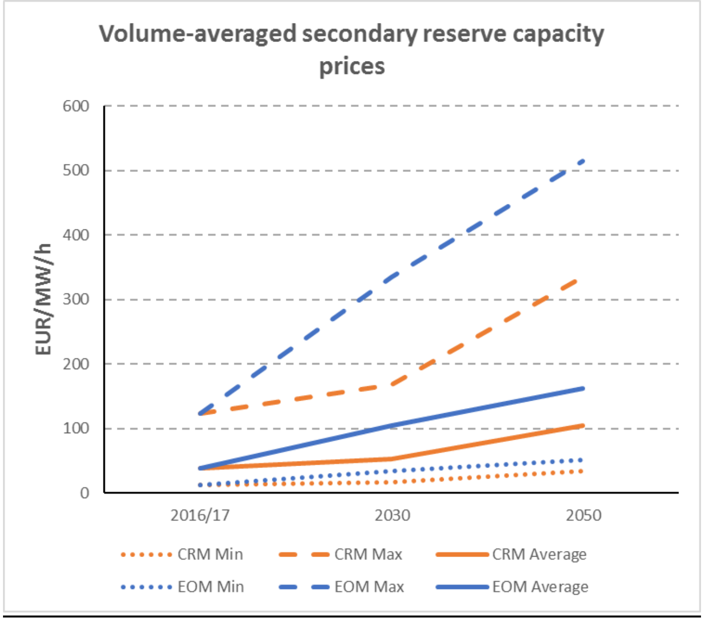

Figure 43: Volume-weighted prices of secondary reserve service (scaled to 1 h of service) for the EOM and CRM Policies scenarios in 2030 and 2050. Values in column “2016/17” correspond to the historical sample of Figure 42.

4.4.4 Several reservoirs with option of secondary ancillary service

As a last example of hydropower plant typologies, we consider a system of reservoirs similar to the whole Wägitalersee-Kraftwerke (see Figure 44), which consists of two reservoirs (Wägitalersee and Rempen) and two power plants: Rempen has 60 MW turbines and 16 MW pumps, and Siebnen at the bottom has 48 MW turbines. Usable water volume are assumed to be 44 mio. and 0.278 mio. cubic meters for the upper and lower reservoir, respectively. As already mentioned, the Wägitalersee-Kraftwerke have relatively low altitude in Switzerland compared to alpine plants, such that inflow is not highly correlated with snowmelt. The reservoirs Wägitalersee and Rempen have comparable water catchment areas in terms of size, whereas the inflow for the lower Rempen is even less affect by snowmelt peaks. Monthly inflows from a historical year were made available from a former operator of the plant. A typical operation profile is shown in the appendix.

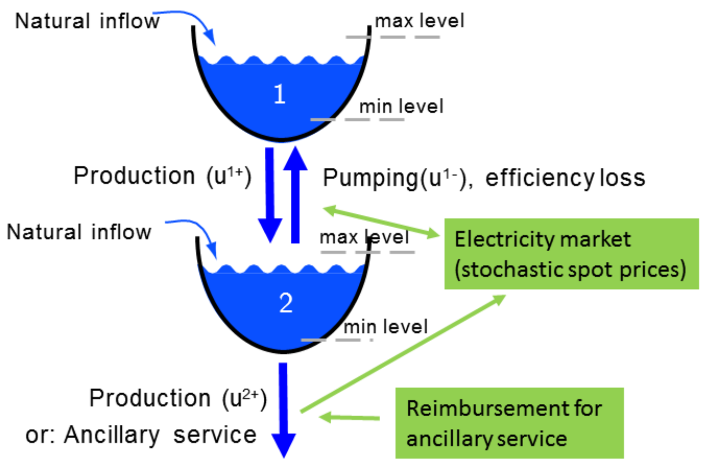

Figure 44: Two reservoirs, full system of "Wägitalersee-Kraftwerke", with the possibility to enter secondary ancillary service.

As an extension, we allow the switch to ancillary services at the lower reservoir; lower reservoirs are usually elected for ancillary service because both the inflow from upper lakes and the direct inflow of the catchment area of the lower reservoir can be used, such that relatively more water is available in the lower reservoirs for providing the constant operation for the service over a prolonged period. For the stochastic control modelling, we use the optimization problem of Figure 41 in the dual form, but now applied to the multi-period setting. Indeed, as mentioned earlier, the dual problem is additively separable in the different resources, both in case for ancillary service (Densing 2019a) and in case for several reservoirs (Densing 2019b). The optimization model is solved over year with monthly time steps of price distributions and water levels.

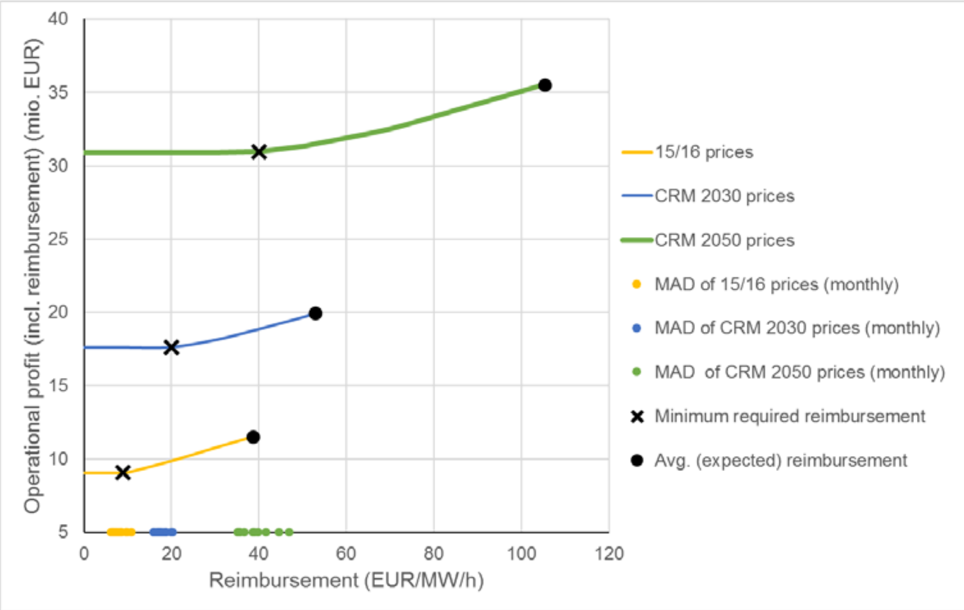

Figure 45: Operational profit (market revenue) in the CRM scenarios and as of today, in dependence of the reimbursement for the ancillary service. The operational profit consists of the sum between energy-only market profit and ancillary service reimbursement. Typology "Two reservoirs". **Black Crosses:** Minimum reimbursement for the service per scenario where it becomes profitable to enter the service. **Black Dots:** Average expected reimbursements and the corresponding increased total operational profit; the value on the horizontal axis in each scenario is the average value as in Figure 43. **Dots on horizontal axis:** MAD of day-ahead electricity prices as of today and in the CRM scenario.

The model results for the operational profitability are shown in Figure 45 with today's price assumption and with the prices of the CRM scenario. If the reimbursement for the ancillary service is zero, then the plant operates obviously in the energy-only mode, and the operational profitability is again similar to the previous typologies: The market revenues increase in the years 2030 and 2050 because of the increased prices and variability of prices in the scenario. As mentioned earlier, the ancillary service becomes only profitable when its price surpasses the MAD (mean absolute deviation from median) of the electricity price. In Figure 45, the monthly MADs are indicated at the bottom (for today's prices, and CRM 2030/50 prices). In case the ancillary service becomes profitable, the total operational profit of the plant rises, too. Note that the operational profit from free (i.e. non-ancillary service) operation is reduced and taken into account, too. The slope of the increase in profit is similar over the scenarios and as of today, because the slope depends on the increase in the reimbursement, which is also on the same scale. Hence, in the future, the operational advantage to enter ancillary service is qualitatively not different under the (strong) assumption that current rules for the service stay the same.

5 Conclusions and policy recommendations

In this study, first an econometric analysis regarding the driving factors of the Swiss electricity price has been conducted. Afterwards, with the agent-based simulation model (PowerACE) two scenarios, one with energy-only-markets (EOMs) and one with implemented capacity remuneration mechanisms (CRMs) in the neighbouring countries of Switzerland, have been examined. The focus of the analyses lies on the future development of wholesale market prices and installed capacity in Switzerland, but investigations are also carried out on the support volumes of renewable energy sources (RES). Eventually, the simulated wholesale market prices are analysed with an experimental model for stored hydropower, which uses the stochastic optimal control theory. Using this novel approach, operational electricity market revenues of stored hydropower are analysed by considering several typological examples.

In order to analyse the significant factors influencing Swiss electricity prices, a multiple linear regression model has been developed. Analysing the correlations shows that factors affecting the electricity prices of neighbouring countries also influence the development of the Swiss electricity price. Market coupling and the large trading capacities between the markets play a crucial role in this regard. Results indicate that in times with very high load peaks the French load and the Swiss electricity price strongly interact. Furthermore, strong correlations in spring and summer between electricity prices in Germany, France and Switzerland are observable. It is also pointed out in the results that the German electricity generation from wind power and solar is a significant driver for the Swiss prices, while its role decreases in the autumn and winter months. In winter, the Swiss electricity prices follow the Italian and French electricity price. In addition, the Italian price curve serves as kind of upper threshold for the Swiss prices. Because of these price dependencies, it is important that Swiss authorities monitor the development of the wholesale electricity prices, the capacity and the generation adequacy in the neighbouring countries to be able to react adequately when the markets significantly change and the generation adequacy level in Switzerland is at risk.

The agent-based simulation model PowerACE also required methodological improvements. In particular, capacity expansion planning for flexible power plants, which can also take into account price effects from market coupling, has been enhanced. For this purpose, a price forecast based on linear optimization has been integrated into the model. With regard to Switzerland, the model has been extended to include seasonal storage hydropower and pumped storage power plants. The operation of seasonal storage hydropower plants has been included using a linear regression model based on various factors. Pumped storage power plants use a heuristic approach based on expected market prices. In addition, scenarios have been developed and, in particular, the needed data has been identified and prepared.

The PowerACE results also show the strong dependency of Switzerland's electricity wholesale prices on neighbouring countries' prices. Regarding the investments, the activity in Switzerland differs slightly between both scenarios. In the CRM Policies scenario, there are less investments in Switzerland, as it is possible to rely on imports due to the larger CRM incentivized generation capacity in the neighbouring countries. Independently from the new installed capacity in Switzerland, the Swiss hydropower provides sufficient energy in times of scarcity and can even supply electricity to other countries in many hours. This leads to a successful market clearing in Switzerland in all simulated hours due to the usage of demand-side management. Consequently, the successful market clearing together with the high installed capacity of hydropower plants is a strong indication generation adequacy can be secured, even without a capacity remuneration mechanism.

For the modelling of stored hydropower a complementary model approach using the stochastic control theory was newly developed. The novel approach allows for a transparent model formulation of the objective function and constraints, and uses the distributional information of the spot price in each time step to derive the optimal operation of an energy storage device. The obtained results must be viewed under the limitation and assumptions of the applied modelling approach.

In the CRM Policies and EOM scenario, the average price levels are rising up to the year 2030 and further up to 2050 (due to rising carbon certificate prices, fuel prices, and increasing demand among other factors). The results show that increasing price levels lead to an expected increase of market revenues of stored hydropower plants. For seasonal storage plants that have a significant, natural water inflow, the results show already for the mid-term year 2030 a considerable increase of market revenue, because the average price levels are the central factor for market revenue, and those levels are rising already mid-term in both scenarios. In fact, the EOM and CRM Policies scenario have still similar price distributions until 2030.

Compared to dam storage power plants, the increase in market revenue is smaller until the year 2030 for dedicated pumped storage plants (having short-cycles), because the profit of these plants depends on the variability of electricity prices, which increases in the scenarios until the year 2030 only slightly and less than average price levels. In the long-term (past 2030), the pumped storage plants can profit strongly from the long-term increased variability of electricity prices. Especially the EOM scenario exhibits in the year 2050 extreme price peaks. From the profitability optimization perspective, the increased variability leads to more pump-turbine cycles during a week, which may lead to challenges in implementing such heavy-cycling operation (turbine wear down etc.). From the year 2030 until 2050, the electricity prices further increase considerably in both scenarios, such that stored hydropower (with zero or relatively small pumping capacity) can increase market revenues, too, but to a lesser extent than pure pumped-hydropower. Generally, market revenues are higher in the scenario where Switzerland is neighboured by EOMs than in the CRM Policies scenario due to the higher price levels and variability. This is the case especially in the long-term (i.e. 2050) for which results of the EOM scenario indicate that no sufficient capacity markets are available to mitigate extreme price peaks.

Results of the profitability analysis can be summarized for example by evaluating the relative increase in market revenue in the scenarios over the considered typologies (see the summary Table 45 in Appendix 8.12). For example, for stored hydropower (with relatively low pumping capacity), the operational profit approximately doubles compared with today's profit until the mid-term year 2030, and the profits approximately at least double again up to year 2050.

The hydropower-focused analysis also provides an indication on revenues and prices for secondary control reserve, which are estimated for the scenarios for the years 2030 and 2050. The investigation of the secondary ancillary market during the project showed that the required reimbursement for the service (i.e. the capacity price the plant owner should bid on the pay-as-bid ancillary service auction) depends on the variations of the energy-only-market electricity prices. In other words, the opportunity cost of not being able to bid on the energy-only market but to be locked-in into the service is the relevant key mechanism (also in the future). Hence, no qualitative changes in ancillary price patterns are to be expected under the assumption that not significantly more capacity will be demanded by the TSO (which can be questioned in view that short-term energy-only intraday markets can substitute some of the ancillary service markets).

Concerning the chosen modelling approach for stored hydropower, the experimental stochastic optimal control framework is able to replicate historical patterns (up to a certain degree) and yields reasonable ranges of market revenues. It is also suitable for other purposes (e.g. teaching), because the dispatch thresholds can be evaluated explicitly, which is commonly not the case with other modelling approaches.

In summary, with an average electricity price increase to more than 100 EUR/MWh in 2040 and beyond in both scenarios, it is likely that hydropower plants are profitable independently from the CRM policies in the neighbouring countries under the studies' scenario and modelling assumptions. For this reason and due to the fact that generation adequacy is ensured in the investigated scenarios, a major adaption of the Swiss market design is, according to our results, currently not required.

Regarding the RES-support, a decline in the amount is observed in the mid-term because of increasing wholesale prices. In the long-term, however, an increase in the total subsidy can be expected caused by the targets for installed RES capacities in the future energy market, in particular due to a disproportionate growth of solar power (under the assumption of no degression of the feed-in tariffs).

As a recommendation, a reduction of the RES feed-in tariffs can be pronounced from a certain point in time in order to take into account of the falling total installation costs (Wirth 2018; Sussams and Leaton 2017) or a direct marketing mechanism with auctions can be used as an alternative, since so far positive experiences have been made in other countries (e.g. Germany) (Bundesnetzagentur 2018). Thus, a market integration (based on the development of installation costs) into the system is possible. Renewable energy auctions can be an effective method to limit the increase in RES-funding volume.

A critical reflection of the study, particularly on future hydropower plants' profitability, concerns uncertainties that cannot always be fully integrated neither in the scenarios nor in the models. This means that scenario results rather illustrate the dynamics of possible future developments and systemic interdependencies than actual expected future system configurations (and profitabilities). Trends can be derived from the scenarios that will occur with a high probability under the given framework conditions, or comparisons can be made between different scenario developments with different assumptions in order to evaluate, for instance, different policy or market design options.

6 Publications [within the project]

Bublitz, Andreas; Fraunholz, Christoph; Zimmermann, Florian; Keles, Dogan (2016). *Capacity remuneration mechanisms in Europe*. REFLEX - Policy Brief.

Dehler, Joris; Zimmermann, Florian; Keles, Dogan; Fichtner, Wolf (2016). *Der Einfluss der Nachbarländer auf den Schweizer Strommarkt. Proceedings des 14. Symposium Energieinnovationen, 10.02. - 12.02.2016, Graz, Österreich*.

Bublitz, Andreas; Keles, Dogan; Fichtner, Wolf *(2017). An analysis of the decline of electricity spot prices in Europe : Who is to blame?. Energy policy*, 107, 323-336.

Fraunholz, Christoph; Zimmermann, Florian; Keles, Dogan; Fichtner, Wolf (2017). *Price-based versus load-smoothing pumped storage operation: Long-term impacts on generation adequacy. 14th International Conference on the European Energy Market (EEM), 6-9 June 2017, Dresden, Germany*.

Ringer, Philipp (2017). *Erzeugungssicherheit und Wohlfahrt in gekoppelten Elektrizitätsmärkten*. Dissertation. Karlsruhe

Zimmermann, Florian; Keles, Dogan; Fichtner, Wolf (2017). *Agentenbasierte Analyse der Auswirkungen des französischen Kapazitätsmarkts. 10. Internationale Energiewirtschaftstagung (IEWT), Wien, AT, 15.-17.02.2017*.

Bublitz, Andreas; Keles, Dogan; Zimmermann, Florian; Fraunholz, Christoph; Fichtner, Wolf (2018). *A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanism.* Working Paper Series in Production and Energy: 27, Karlsruhe.

Densing, Martin (2018). *Explicit solutions of stochastic energy storage problems*. 29th European Conference on Operational Research (EURO2018), Valencia, ES, 8.-11. 07.2018.

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Annual reports:

Zimmermann, Florian; Dehler, Joris; Densing Martin (2017). *Annual report 2016.* https://www.aramis.admin.ch/Default.aspx?DocumentID=35354&Load=true

Zimmermann, Florian; Dehler, Joris; Densing Martin (2018). *Annual report 2017.* https://www.aramis.admin.ch/Default.aspx?DocumentID=46177&Load=true

Work in progress:

Zimmermann, Florian; Bublitz, Andreas; Keles, Dogan; Fichtner, Wolf (2019). *Cross-border effects for Switzerland*
(to be submitted in Energy Policy)

Keles, Dogan; Dehler, Joris; Densing, Martin; Panos, Evangelos; Hack, Felix (2019). *Drivers of Swiss electricity prices and interdependencies with neighboring markets*
(PSI/KIT joint publication, to be submitted to Energy Economics)

Densing, Martin (2019a). *The value of flexibility: Lock-in of power generation with storage into ancillary* services
(under revision at European Journal for Operational Research)

Densing, Martin (2019b). *Extensions of optimal storage-dispatch solutions,* working paper.

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8 Appendix

8.1 Appendix 1: Regression values of the operation of stored hydropower plants

Table 27: Regression values for the seasonal hydropower plant modelling.

	Spring		Summer		Autumn		Winter	
	Estimate	**pValue**	**Estimate**	**pValue**	**Estimate**	**pValue**	**Estimate**	**pValue**
'(Intercept)'	-3055.30	0.00	-2590.32	0.00	-5492.26	0.00	-4413.64	0.00
'Storage_CH'	0.09	0.12	0.00	0.81	0.20	0.00	0.14	0.00
'LoadDENormal-ized'	-167.40	0.52	804.49	0.02	-1277.39	0.00	1214.66	0.00
'LoadITNormal-ized'	1790.62	0.00	1008.49	0.00	4910.04	0.00	3698.31	0.00
'LoadATNormal-ized'	-50.24	0.87	1524.15	0.00	-911.18	0.00	-1883.26	0.00
'LoadFRNormal-ized'	286.56	0.18	2646.13	0.00	3116.91	0.00	2425.81	0.00
'LoadCHNormal-ized'	4499.44	0.00	1991.39	0.00	2291.99	0.00	2667.61	0.00
'ResDENormal-ized'	-116.84	0.00	-1021.53	0.00	-247.18	0.00	62.77	0.05
'ResITNormal-ized'	404.13	0.00	97.66	0.09	112.59	0.03	-94.74	0.19
'ResATNormal-ized'	-115.73	0.10	16.22	0.79	-359.64	0.00	-402.61	0.00
'ResFRNormal-ized'	-647.59	0.00	1083.81	0.00	-348.66	0.00	-396.45	0.00
'ResCHNormal-ized'	165.33	0.10	-1275.55	0.00	416.83	0.00	-636.80	0.02
'Weekday'	-138.07	0.00	-168.58	0.00	-132.65	0.00	-32.66	0.40
'HourOfDay_1'	-3.81	0.96	95.52	0.23	90.69	0.24	-48.47	0.58
'HourOfDay_2'	-34.62	0.64	70.11	0.39	145.66	0.06	-6.35	0.94
'HourOfDay_3'	-74.37	0.32	-65.74	0.43	57.47	0.46	-0.50	1.00
'HourOfDay_4'	-177.28	0.02	-360.92	0.00	-291.58	0.00	-152.46	0.09
'HourOfDay_5'	-229.52	0.01	-442.28	0.00	-502.69	0.00	-529.90	0.00
'HourOfDay_6'	-7.06	0.94	168.08	0.12	-404.29	0.00	-617.49	0.00
'HourOfDay_7'	-10.04	0.92	496.31	0.00	-284.82	0.00	-488.87	0.00
'HourOfDay_8'	-226.43	0.03	301.86	0.01	-367.98	0.00	-442.42	0.00
'HourOfDay_9'	-545.62	0.00	-19.01	0.88	-506.21	0.00	-433.35	0.00

'HourOfDay_10'	-679.40	0.00	-105.21	0.39	-466.28	0.00	-623.01	0.00
'HourOfDay_11'	-744.33	0.00	-260.98	0.03	-500.32	0.00	-618.75	0.00
'HourOfDay_12'	-870.76	0.00	-432.90	0.00	-715.45	0.00	-783.78	0.00
'HourOfDay_13'	-898.47	0.00	-521.07	0.00	-791.37	0.00	-876.77	0.00
'HourOfDay_14'	-885.22	0.00	-646.32	0.00	-848.68	0.00	-711.47	0.00
'HourOfDay_15'	-821.78	0.00	-762.39	0.00	-862.33	0.00	-666.76	0.00
'HourOfDay_16'	-669.07	0.00	-632.03	0.00	-992.57	0.00	-794.42	0.00
'HourOfDay_17'	-466.30	0.00	-137.89	0.18	-684.73	0.00	-607.35	0.00
'HourOfDay_18'	-31.46	0.73	398.74	0.00	-60.35	0.55	-382.03	0.00
'HourOfDay_19'	201.34	0.02	416.56	0.00	-23.18	0.80	-303.17	0.00
'HourOfDay_20'	102.08	0.21	179.67	0.05	-370.24	0.00	-490.31	0.00
'HourOfDay_21'	-26.70	0.73	225.86	0.01	-338.67	0.00	-495.46	0.00
'HourOfDay_22'	-10.79	0.89	-50.66	0.54	-243.20	0.00	-367.96	0.00
'HourOfDay_23'	-2.43	0.97	16.93	0.83	-98.09	0.20	-196.59	0.03
'SWIGER'	-0.32	0.00	-0.11	0.00	-0.37	0.00	-0.32	0.00
'SWIAPG'	-0.52	0.00	-0.05	0.23	-0.70	0.00	-0.26	0.00
'SWIRTE'	-0.30	0.00	-0.14	0.00	-0.27	0.00	-0.44	0.00
'SWIYIT'	-0.24	0.00	-0.09	0.00	-0.38	0.00	-0.28	0.00

8.2 Appendix 2: Historical distribution of the Swiss wind and solar generation

Table 28: Distribution of CH's Wind and PV generation. According to ENTSO-E 2018b generation profile of 2015 and Swiss Federal Office of Energy 2017b, 2018a run-of-river production for hydro.

Period	Wind 2015	Solar 2015	Hydro run of river 2015	Hydro run of river 2016	Hydro run of river 2017
Q1	0.19	0.07	0.17	0.17	0.15
Q2	0.25	0.34	0.34	0.33	0.31
Q3	0.22	0.43	0.32	0.35	0.34
Q4	0.33	0.16	0.16	0.15	0.19
Jan	0.07	0.01	0.06	0.05	0.04
Feb	0.04	0.02	0.05	0.06	0.04
Mar	0.08	0.05	0.06	0.06	0.07
Apr	0.09	0.11	0.09	0.09	0.07
May	0.10	0.10	0.12	0.11	0.10
Jun	0.06	0.13	0.13	0.13	0.13
Jul	0.08	0.17	0.13	0.14	0.12
Aug	0.06	0.15	0.11	0.12	0.12
Sep	0.09	0.11	0.08	0.09	0.09
Oct	0.08	0.07	0.06	0.05	0.07
Nov	0.13	0.05	0.05	0.06	0.06
Dec	0.12	0.04	0.05	0.04	0.06

8.3 Appendix 3: Feed-in premium development in the EOM scenario

Table 29: Feed-in premium subsidy per MWh in EOM scenario for the year 2020 for different RES power plants based on the average price according to Table 11 and the FiTs of Table 14.

[CHF/MWh]			2020		
Resolution	**Biomass**	**Geothermal**	**Small hydro**	**Solar**	**Wind**
Yearly	118.32	170.32	9.32	53.32	173.32
Q1	109.52	161.52	0.52	44.52	164.52
Q2	123.25	175.25	14.25	58.25	178.25
Q3	121.21	173.21	12.21	56.21	176.21
Q4	112.53	164.53	3.53	47.53	167.53
January	109.14	161.14	0.14	44.14	164.14
February	104.85	156.85	-4.15	39.85	159.85
March	114.45	166.45	5.45	49.45	169.45
April	120.85	172.85	11.85	55.85	175.85
May	125.35	177.35	16.35	60.35	180.35
June	123.19	175.19	14.19	58.19	178.19
July	125.49	177.49	16.49	60.49	180.49
August	120.19	172.19	11.19	55.19	175.19
September	116.08	168.08	7.08	51.08	171.08
October	107.47	159.47	-1.53	42.47	162.47
November	112.27	164.27	3.27	47.27	167.27
December	118.77	170.77	9.77	53.77	173.77

Table 30: Feed-in premium subsidy per MWh in EOM scenario for the year 2030 for different RES power plants based on the average price according to Table 11 and the FiTs of Table 14.

[CHF/MWh]			2030		
Resolution	**Biomass**	**Geothermal**	**Small hydro**	**Solar**	**Wind**
Yearly	93.33	145.33	-15.67	28.33	148.33
Q1	84.32	136.32	-24.68	19.32	139.32
Q2	99.58	151.58	-9.42	34.58	154.58
Q3	94.94	146.94	-14.06	29.94	149.94
Q4	88.70	140.70	-20.30	23.70	143.70
January	84.08	136.08	-24.92	19.08	139.08
February	80.81	132.81	-28.19	15.81	135.81
March	87.72	139.72	-21.28	22.72	142.72
April	97.89	149.89	-11.11	32.89	152.89
May	102.60	154.60	-6.40	37.60	157.60
June	98.26	150.26	-10.74	33.26	153.26
July	95.60	147.60	-13.40	30.60	150.60
August	96.91	148.91	-12.09	31.91	151.91
September	91.50	143.50	-17.50	26.50	146.50
October	84.48	136.48	-24.52	19.48	139.48
November	88.86	140.86	-20.14	23.86	143.86
December	93.20	145.20	-15.80	28.20	148.20

Table 31: Feed-in premium subsidy per MWh in EOM scenario for the year 2050 for different RES power plants based on the average price according to Table 11 and the FiTs of Table 14.

[CHF/MWh]			2050		
Resolution	**Biomass**	**Geothermal**	**Small hydro**	**Solar**	**Wind**
Yearly	67.44	119.44	-41.56	2.44	122.44
Q1	-4.44	47.56	-113.44	-69.44	50.56
Q2	91.92	143.92	-17.08	26.92	146.92
Q3	85.48	137.48	-23.52	20.48	140.48
Q4	56.20	108.20	-52.80	-8.80	111.20
January	-86.00	-34.00	-195.00	-151.00	-31.00
February	-11.51	40.49	-120.51	-76.51	43.49
March	65.18	117.18	-43.82	0.18	120.18
April	87.40	139.40	-21.60	22.40	142.40
May	98.03	150.03	-10.97	33.03	153.03
June	90.24	142.24	-18.76	25.24	145.24
July	90.53	142.53	-18.47	25.53	145.53
August	90.63	142.63	-18.37	25.63	145.63
September	72.06	124.06	-36.94	7.06	127.06
October	46.72	98.72	-62.28	-18.28	101.72
November	54.00	106.00	-55.00	-11.00	109.00
December	69.17	121.17	-39.83	4.17	124.17

8.4 Appendix 4: Feed-in premium development in the CRM Policies scenario

Table 32: Feed-in premium subsidy per MWh in CRM Policies for the year 2020 for different RES power plants based on the average price according to Table 11 and the FiTs of Table 14.

[CHF/MWh]	2020				
Resolution	**Biomass**	**Geothermal**	**Small hydro**	**Solar**	**Wind**
Yearly	113.31	165.31	4.31	48.31	168.31
Q1	109.52	161.52	0.52	44.52	164.52
Q2	122.87	174.87	13.87	57.87	177.87
Q3	120.86	172.86	11.86	55.86	175.86
Q4	104.37	156.37	-4.63	39.37	159.37
January	53.35	105.35	-55.65	-11.65	108.35
February	101.04	153.04	-7.96	36.04	156.04
March	113.51	165.51	4.51	48.51	168.51
April	120.46	172.46	11.46	55.46	175.46
May	125.09	177.09	16.09	60.09	180.09
June	122.70	174.70	13.70	57.70	177.70
July	125.39	177.39	16.39	60.39	180.39
August	119.71	171.71	10.71	54.71	174.71
September	115.50	167.50	6.50	50.50	170.50
October	105.59	157.59	-3.41	40.59	160.59
November	96.72	148.72	-12.28	31.72	151.72
December	112.85	164.85	3.85	47.85	167.85

Table 33: Feed-in premium subsidy per MWh in CRM Policies for the year 2030 for different RES power plants based on the average price according to Table 11 and the FiTs of Table 14.

[CHF/MWh]	2030				
Resolution	**Biomass**	**Geothermal**	**Small hydro**	**Solar**	**Wind**
Yearly	92.65	144.65	-16.35	27.65	147.65
Q1	84.05	136.05	-24.95	19.05	139.05
Q2	98.61	150.61	-10.39	33.61	153.61
Q3	94.16	146.16	-14.84	29.16	149.16
Q4	88.29	140.29	-20.71	23.29	143.29
January	83.65	135.65	-25.35	18.65	138.65
February	80.56	132.56	-28.44	15.56	135.56
March	87.56	139.56	-21.44	22.56	142.56
April	97.00	149.00	-12.00	32.00	152.00
May	101.78	153.78	-7.22	36.78	156.78
June	97.10	149.10	-11.90	32.10	152.10
July	94.50	146.50	-14.50	29.50	149.50
August	95.92	147.92	-13.08	30.92	150.92
September	91.46	143.46	-17.54	26.46	146.46
October	84.51	136.51	-24.49	19.51	139.51
November	87.97	139.97	-21.03	22.97	142.97
December	92.90	144.90	-16.10	27.90	147.90

Table 34: Feed-in premium subsidy per MWh in CRM Policies for the year 2050 for different RES power plants based on the average price according to Table 11 and the FiTs of Table 14.

[CHF/MWh]			2050		
Resolution	**Biomass**	**Geothermal**	**Small hydro**	**Solar**	**Wind**
Yearly	77.36	129.36	-31.64	12.36	132.36
Q1	49.95	101.95	-59.05	-15.05	104.95
Q2	92.34	144.34	-16.66	27.34	147.34
Q3	86.29	138.29	-22.71	21.29	141.29
Q4	60.99	112.99	-48.01	-4.01	115.99
January	42.90	94.90	-66.10	-22.10	97.90
February	35.69	87.69	-73.31	-29.31	90.69
March	66.20	118.20	-42.80	1.20	121.20
April	88.38	140.38	-20.62	23.38	143.38
May	97.93	149.93	-11.07	32.93	152.93
June	90.64	142.64	-18.36	25.64	145.64
July	91.01	143.01	-17.99	26.01	146.01
August	91.83	143.83	-17.17	26.83	146.83
September	72.87	124.87	-36.13	7.87	127.87
October	47.70	99.70	-61.30	-17.30	102.70
November	65.77	117.77	-43.23	0.77	120.77
December	70.20	122.20	-38.80	5.20	125.20

8.5 Appendix 5: Monthly market values and feed-in premiums

Table 35: 2017 funding for RES power plants with a capacity >500 MW. Feed-in premium is based on a monthly average price according to Table 11.[5]

		Solar	Small hydro	Wind	Biomass	Total
Jan	Production [MWh]	4,854	50,703	5,884	84,588	146,029
Jan	Market Value [CHF millions]	0.4	4.3	0.5	7.2	12.4
Jan	Feed-in premium [CHF millions]	0.8	2.9	0.6	7.8	12.1
Feb	Production [MWh]	5,823	54,099	3,184	84,588	147,695
Feb	Market Value [CHF millions]	0.3	3.3	0.2	5.2	9.0
Feb	Feed-in premium [CHF millions]	1.1	4.4	0.4	9.9	15.8
Mar	Production [MWh]	16,452	93,643	6,687	84,588	201,370
Mar	Market Value [CHF millions]	0.6	3.7	0.2	3.3	7.8
Mar	Feed-in premium [CHF millions]	3.7	9.6	0.9	11.7	25.9
Apr	Production [MWh]	38,137	87,578	7,623	84,588	217,926
Apr	Market Value [CHF millions]	1.4	3.2	0.2	3.1	7.9
Apr	Feed-in premium [CHF millions]	8.7	9.2	1.1	11.9	30.9
May	Production [MWh]	37,569	140,788	7,947	84,588	270,892
Mayi	Market Value [CHF millions]	1.4	5.4	0.3	3.2	10.3
May	Feed-in premium [CHF millions]	8.6	14.7	1.1	11.8	36.2
Jun	Production [MWh]	46,868	176,935	5,159	84,588	313,551
Jun	Market Value [CHF millions]	1.6	6.2	0.1	2.9	10.8
Jun	Feed-in premium [CHF millions]	10.8	19.1	0.7	12.1	42.7
Jul	Production [MWh]	61,837	160,196	6,342	84,588	312,963
Jul	Market Value [CHF millions]	2.4	6.2	0.2	3.3	12.1

[5] Due to rounding inaccuracies, the total values do not correspond exactly to the disaggregated monthly values.

Jul	Feed-in premium [CHF millions]	14.1	16.7	0.9	11.8	43.5
Aug	Production [MWh]	54,107	160,357	4,894	84,588	303,947
Aug	Market Value [CHF millions]	1.9	5.7	0.1	3.0	10.7
Aug	Feed-in premium [CHF millions]	12.5	17.2	0.7	12.0	42.4
Sep	Production [MWh]	39,370	117,175	7,113	84,588	248,246
Sep	Market Value [CHF millions]	1.6	4.8	0.2	3.4	10.0
Sep	Feed-in premium [CHF millions]	8.9	11.9	1.0	11.6	33.4
Oct	Production [MWh]	23,795	89,761	6,784	84,588	204,929
Oct	Market Value [CHF millions]	1.4	5.3	0.4	5.0	12.1
Oct	Feed-in premium [CHF millions]	4.9	7.5	0.8	10.0	23.2
Nov	Production [MWh]	18,141	77,631	10,696	84,588	191,057
Nov	Market Value [CHF millions]	1.3	5.7	0.7	6.2	13.9
Nov	Feed-in premium [CHF millions]	3.5	5.4	1.2	8.8	18.9
Dec	Production [MWh]	16,124	80,624	9,573	84,588	190,908
Dec	Market Value [CHF millions]	1.1	5.7	0.6	5.9	13.3
Dec	Feed-in premium [CHF millions]	3.1	5.8	1.1	9.1	19.1
	Total market value monthly [CHF millions]	15.8	59.9	4.3	52.2	132.2
	Total feed-in premium monthly [CHF millions]	81.2	124.9	11.1	129.0	346.2

8.6 Appendix 6: Annual average exchange rates for CHF/EUR

Table 36: Annual average exchange from Eidgenössische Steuerverwaltung 2018 and own assumptions.

Year	Rate CHF/EUR
2016	1.09
2017	1.11
2018	1.16
2020 and following years	1.10

8.7 Appendix 7: Analysing the KEV and the direct marketing of RES for 2016

According to the new rules, for 2016 and 2017 the subsidies are analysed for plants with a capacity >500 kW, since new and remaining plants >500 kW must always offer the generation directly at the market.

Table 37: 2016 funding for RES power plants with a capacity >500 MW. Feed-in premium is based on a yearly average price of 41.07 CHF/MWh from Table 11.

Technology	Production [GWh]	Subsidy [CHF millions]	Average FiT [CHF/MWh]	Market value [CHF millions]	Feed-in premium [CHF millions]
Solar	287	81.2	283.20	11.7	69.5
Small hydro	1,124	166.1	147.73	46.1	119.9
Wind	73	13.8	187.32	3.0	10.8
Biomass	917	158.4	172.70	37.6	120.7
Sum	2,403	419.5		98.4	320.9

Table 38: 2016 funding for RES power plants with a capacity >500 MW. Feed-in premium is based on a quarterly average price according to Table 11.[6]

		Solar	Small hydro	Wind	Biomass	Total
Q1	Production [MWh]	21,448	190,459	14,213	229,422	455,542
Q1	Market Value [CHF millions]	0.8	7.6	0.5	9.2	18.1
Q1	Feed-in premium [CHF millions]	5.2	20.4	2.0	20.9	48.5
Q2	Production [MWh]	96,909	369,315	18,700	229,422	714,346
Q2	Market Value [CHF millions]	2.7	10.3	0.5	6.4	19.9
Q2	Feed-in premium [CHF millions]	24.7	44.1	2.9	23.7	95.4
Q3	Production [MWh]	122,794	390,891	16,553	229,422	759,661
Q3	Market Value [CHF millions]	4.1	13.3	0.5	7.8	25.7
Q3	Feed-in premium [CHF millions]	30.5	44.4	2.5	22.3	99.7
Q4	Production [MWh]	45,903	173,903	24,406	229,422	473,634
Q4	Market Value [CHF millions]	2.9	11.1	1.5	14.6	30.1
Q4	Feed-in premium [CHF millions]	10.0	14.5	3.0	15.5	43.0
	Total market value quarterly [CHF millions]	10.7	42.5	3.2	38.2	94.6
	Total feed-in premium quarterly [CHF millions]	70.5	123.6	10.6	120.2	324.9

Since in 2016 the maximum wholesale price would be 131.78 CHF/MWh (acc. to EPEX Spot 2018, 120.90 EUR/MWh, Exchange rate according to Table 36), a direct marketing would not have been advantageous and this high price only occurred in one hour.

The sum of total market values is lower on a quarterly basis (Table 38) than on an annual basis (Table 37) and is lower again on a monthly basis (Table 39) than on a quarterly basis. The feed-in premium increases accordingly. This is due to the calculation of the weighted market clearing price.

[6] Due to rounding inaccuracies, the total values do not correspond exactly to the disaggregated quarterly values.

Table 39: 2016 funding for RES power plants with a capacity >500 MW. Feed-in premium is based on a monthly average price according to Table 11.[7]

		Solar	Small hydro	Wind	Biomass	Total
Jan	Production [MWh]	3,837	58,963	5,309	76,474	**144,583**
Jan	Market Value [CHF millions]	0.2	3.0	0.2	3.9	**7.3**
Jan	Feed-in premium [CHF millions]	0.8	5.6	0.7	9.2	**16.3**
Feb	Production [MWh]	4,604	67,987	2,872	76,474	**151,937**
Feb	Market Value [CHF millions]	0.1	2.5	0.1	2.8	**5.5**
Feb	Feed-in premium [CHF millions]	1.1	7.4	0.4	10.3	**19.2**
Mar	Production [MWh]	13,007	63,509	6,032	76,474	**159,022**
Mar	Market Value [CHF millions]	0.4	2.0	0.2	2.4	**5.0**
Mar	Feed-in premium [CHF millions]	3.2	7.3	0.9	10.7	**22.1**
Apr	Production [MWh]	30,152	97,502	6,877	76,474	**211,005**
Apr	Market Value [CHF millions]	0.8	2.6	0.2	2.1	**5.7**
Apr	Feed-in premium [CHF millions]	7.7	11.7	1.1	11.1	**31.6**
May	Production [MWh]	29,703	120,097	7,169	76,474	**233,442**
May	Market Value [CHF millions]	0.7	3.1	0.2	2.0	**6.0**
May	Feed-in premium [CHF millions]	7.6	14.6	1.1	11.2	**34.5**
Jun	Production [MWh]	37,055	151,716	4,654	76,474	**269,899**
Jun	Market Value [CHF millions]	1.1	4.5	0.1	2.3	**8.0**
Jun	Feed-in premium [CHF millions]	9.3	17.8	0.7	10.8	**38.6**
Jul	Production [MWh]	48,889	157,686	5,722	76,474	**288,771**
Jul	Market Value [CHF millions]	1.5	4.9	0.1	2.3	**8.8**
Jul	Feed-in premium [CHF millions]	12.3	18.3	0.8	10.8	**42.2**
Aug	Production [MWh]	42,778	135,363	4,415	76,474	**259,030**
Aug	Market Value [CHF millions]	1.3	4.3	0.1	2.4	**8.1**
Aug	Feed-in premium [CHF millions]	10.7	15.6	0.6	10.7	**37.6**
Sep	Production [MWh]	31,127	97,842	6,417	76,474	**211,859**
Sep	Market Value [CHF millions]	1.2	3.8	0.2	3.0	**8.2**

[7] Due to rounding inaccuracies, the total values do not correspond exactly to the disaggregated monthly values.

Sep	Feed-in premium [CHF millions]	7.5	10.5	0.9	10.1	**29.0**
Oct	Production [MWh]	18,812	59,913	6,120	76,474	**161,319**
Oct	Market Value [CHF millions]	1.1	3.7	0.3	4.7	**9.8**
Oct	Feed-in premium [CHF millions]	4.1	5.1	0.7	8.4	**18.3**
Nov	Production [MWh]	14,343	66,698	9,649	76,474	**167,164**
Nov	Market Value [CHF millions]	0.9	4.4	0.6	5.1	**11.0**
Nov	Feed-in premium [CHF millions]	3.0	5.3	1.1	8.0	**17.4**
Dec	Production [MWh]	12,748	47,292	8,636	76,474	**145,150**
Dec	Market Value [CHF millions]	0.8	2.9	0.5	4.8	**9.0**
Dec	Feed-in premium [CHF millions]	2.8	3.9	1.0	8.3	**16.0**
	Total market value monthly [CHF millions]	**10.5**	**42.4**	**3.2**	**38.3**	**94.4**
	Total feed-in premium monthly [CHF millions]	**70.6**	**123.7**	**10.5**	**120.1**	**324.9**

8.8 Appendix 8: Scenario based feed-in premiums

Table 40: Feed-in premium based on the scenarios considering yearly, the FiTs of Table 14 and the monthly reference prices.

	2020	2020	2030	2030	2050	2050
Funding volume [CHF millions]	**EOM**	**CRM Policies**	**EOM**	**CRM Policies**	**EOM**	**CRM Policies**
yearly	497.1	379.8	617.3	612.8	1,263.1	1,487.3
monthly	506.4	475.6	613.7	609.5	1,366.9	1,500.9
Funding volume per MWh [CHF/MWh]						
yearly	38.45	29.38	35.65	35.39	37.56	44.23
monthly	39.17	36.79	35.44	35.20	40.65	44.64

8.9 Appendix 9: Evolution of the number of hours with the use of demand response or with not market clearing

Table 41: Hours with the use of demand response in the simulated time horizon from 2020-2050 in the EOM scenario.

Year [h]	CH	DE	FR	IT	AT
			DSM		
2020	0	1	0	0	1
2021	2	20	0	0	14
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0
2030	0	0	0	0	0
2031	0	0	0	0	0
2032	0	0	0	0	0
2033	0	0	0	0	0
2034	0	0	0	0	0
2035	0	1	0	0	0
2036	11	14	9	0	6
2037	18	25	24	0	17
2038	41	52	50	22	36
2039	63	73	67	41	60
2040	77	84	83	57	74
2041	83	99	105	73	81
2042	78	89	90	73	75
2043	79	92	99	74	76
2044	73	81	78	74	73
2045	55	62	65	52	54
2046	50	57	63	51	48
2047	61	68	63	62	60
2048	45	52	56	44	46
2049	52	56	57	48	53
2050	58	62	73	54	60

Table 42: Hours with no market clearing in the simulated time horizon from 2020-2050 in the EOM scenario.

Year [h]	CH	DE	FR	IT	AT
		No market clearing			
2020	0	0	0	0	0
2021	0	0	0	0	1
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0
2030	0	0	0	0	0
2031	0	0	0	0	0
2032	0	0	0	0	0
2033	0	0	0	0	0
2034	0	0	0	0	0
2035	0	0	0	0	0
2036	0	4	2	0	0
2037	0	12	5	0	0
2038	0	24	20	0	0
2039	0	33	26	3	0
2040	0	51	47	10	0
2041	0	57	66	27	0
2042	0	53	55	35	0
2043	0	55	62	33	0
2044	0	51	46	38	0
2045	0	22	37	25	0
2046	0	16	35	24	0
2047	0	35	32	33	1
2048	0	22	30	23	0
2049	0	24	27	26	0
2050	0	33	51	31	0

Table 43: Hours with the use of demand response in the simulated time horizon from 2020-2050 in the CRM Policies scenarios.

Year [h]	CH	DE	FR	IT	AT
			DSM		
2020	14	58	0	0	45
2021	0	4	0	0	3
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0
2030	0	0	0	0	0
2031	0	0	0	0	0
2032	0	0	0	0	0
2033	0	0	0	0	0
2034	0	0	0	0	0
2035	0	0	0	0	0
2036	0	2	0	0	0
2037	0	3	0	0	0
2038	0	2	0	0	0
2039	0	8	0	0	3
2040	0	15	0	0	3
2041	0	12	0	0	3
2042	0	2	0	0	0
2043	0	6	0	0	2
2044	0	10	0	0	4
2045	0	8	0	0	4
2046	0	1	0	0	0
2047	0	1	0	0	1
2048	0	3	0	0	1
2049	0	8	0	0	4
2050	0	22	0	0	15

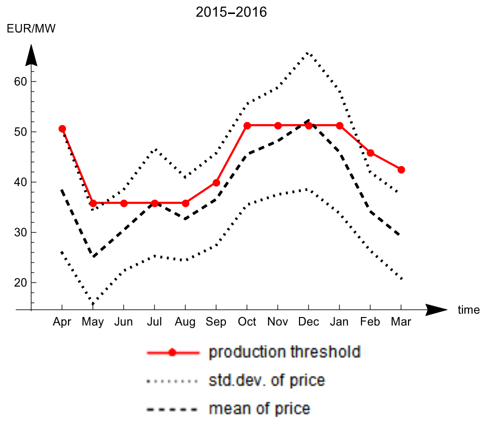
Table 44: Hours with no market clearing in the simulated time horizon from 2020-2050 in the CRM Policies scenario.

Year [h]	CH	DE	FR	IT	AT
No market clearing					
2020	0	17	0	0	13
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0
2030	0	0	0	0	0
2031	0	0	0	0	0
2032	0	0	0	0	0
2033	0	0	0	0	0
2034	0	0	0	0	0
2035	0	0	0	0	0
2036	0	0	0	0	0
2037	0	0	0	0	0
2038	0	0	0	0	0
2039	0	1	0	0	0
2040	0	2	0	0	0
2041	0	2	0	0	0
2042	0	0	0	0	0
2043	0	2	0	0	0
2044	0	2	0	0	0
2045	0	2	0	0	0
2046	0	0	0	0	0
2047	0	0	0	0	0
2048	0	0	0	0	1
2049	0	2	0	0	1
2050	0	12	0	0	2

8.10 Appendix 10: Aggregated Swiss dams: Case of unlimited storage volume

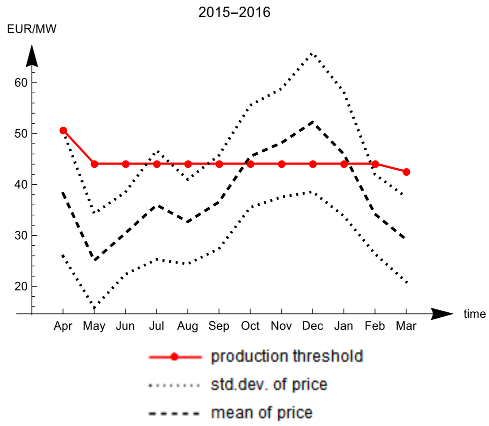
<table>
<tr><th>75 % of (gross) storage available</th><th>153 % of (gross) storage available</th></tr>
<tr><td>

Dispatch thresholds [EUR/MWh]



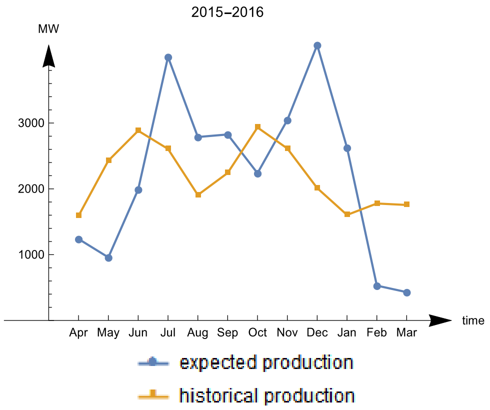
</td><td>

Dispatch thresholds [EUR/MWh]



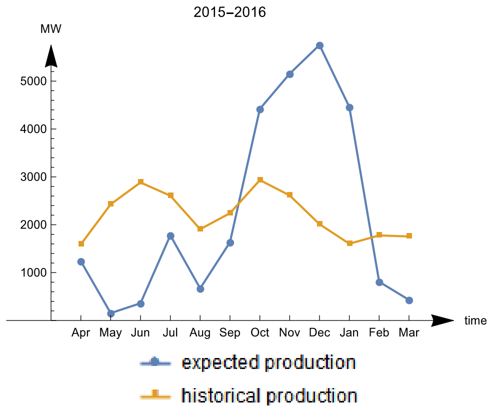
</td></tr>
<tr><td>

Production [MW]



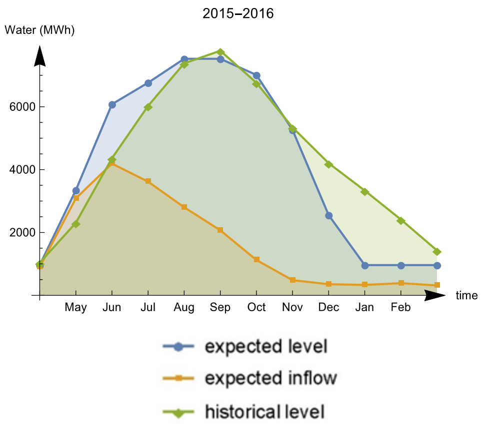
</td><td>

Production [MW]



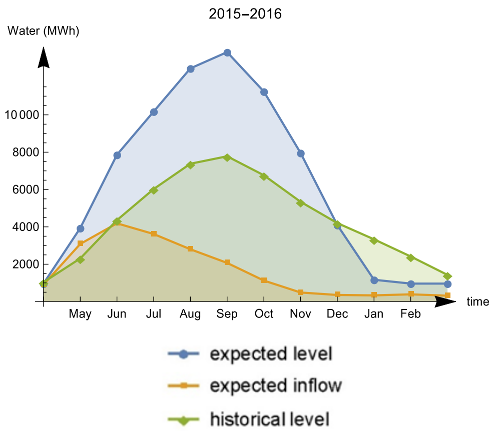
</td></tr>
<tr><td>

Storage & inflow [MWh]



</td><td>

Storage & inflow [MWh]



</td></tr>
</table>

Figure 46: Results of the stochastic control model with historical price distribution and inflows (2015 April – 2016 March). Monthly price distributions. **Left:** Usable storage volume = 8750 GWh * 80 %. **Right**: Usable storage volume = 13'360 GWh = 8750 GWh * 153 %.

Figure 46 shows again the optimization of the typology “Swiss dams (aggregated)” for the historical year 2015/16. The subfigures in the left column show the result with limited storage volume, and the right column results with an (assumed) unlimited storage volume. Hence, if the optimization of the stored hydropower in Switzerland could use an unlimited storage volume, then 153 % of current Swiss storage would be used. Clearly, with unlimited storage, dispatch happens more when prices are highest, that is, during winter. Interestingly, the storage constraints force the modelled water value to follow more closely the time-varying price distribution, whereas in case of unlimited storage the water value stays constant over time. In contrast to the relatively large storage volume that is used in the unlimited case, the corresponding additional operational profit is relatively small (Table 21). This can be interpreted that today's aggregated storage volume has an appropriate size in relation to today's installed aggregated production capacity.

8.11 Appendix 11: Typology “Muttsee”, scenarios EOM and CRM Policies

Figure 47 and Figure 48 show the storage and generation/pumping patterns of the typology «Muttsee» for the scenarios EOM and CRM Policies.

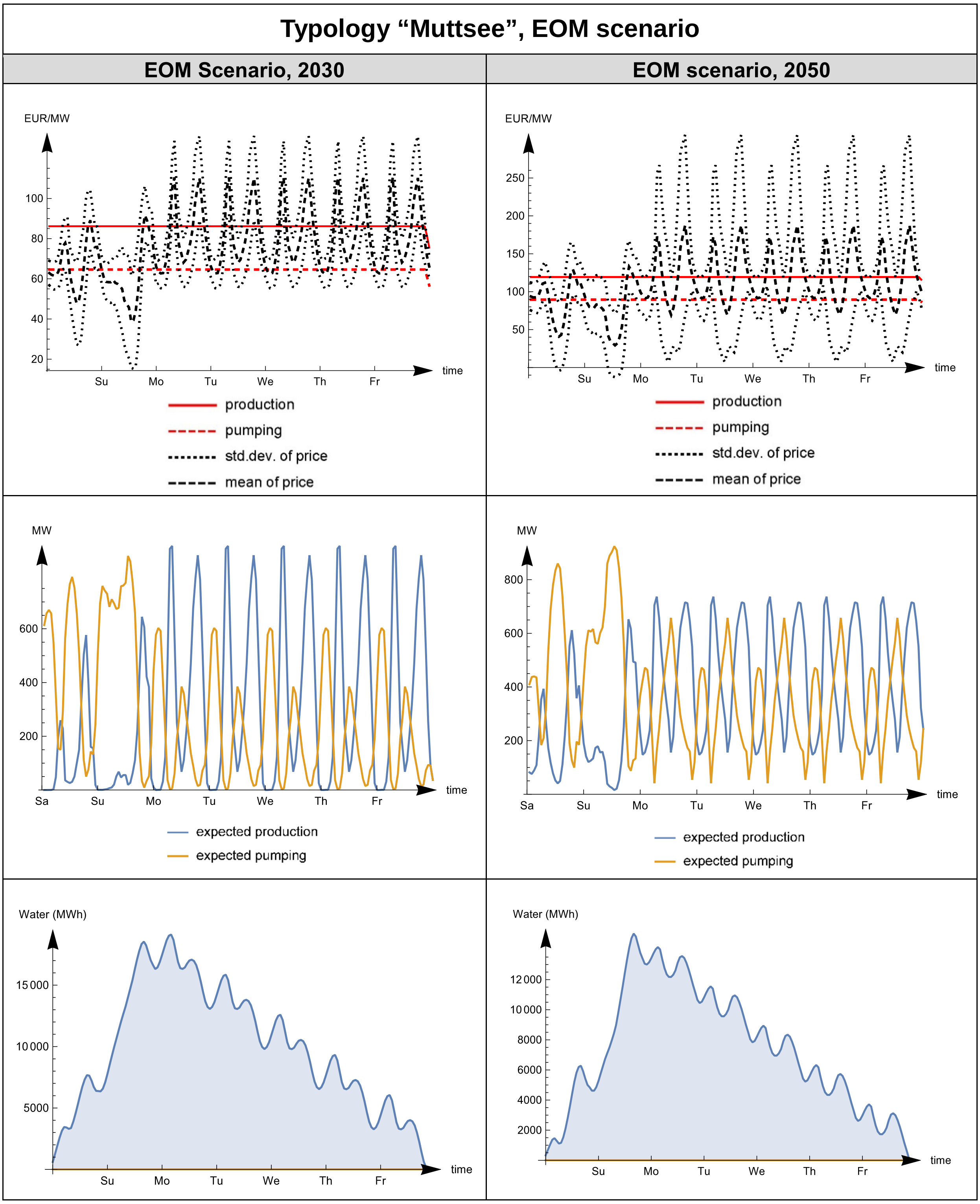


Figure 47: Results of stochastic control model of pumped-storage plant over a week with EOM scenario price distributions. Typology “Muttsee”.

Typology “Muttsee”, CRM Policies scenario

CRM Policies, 2030	CRM Policies, 2050

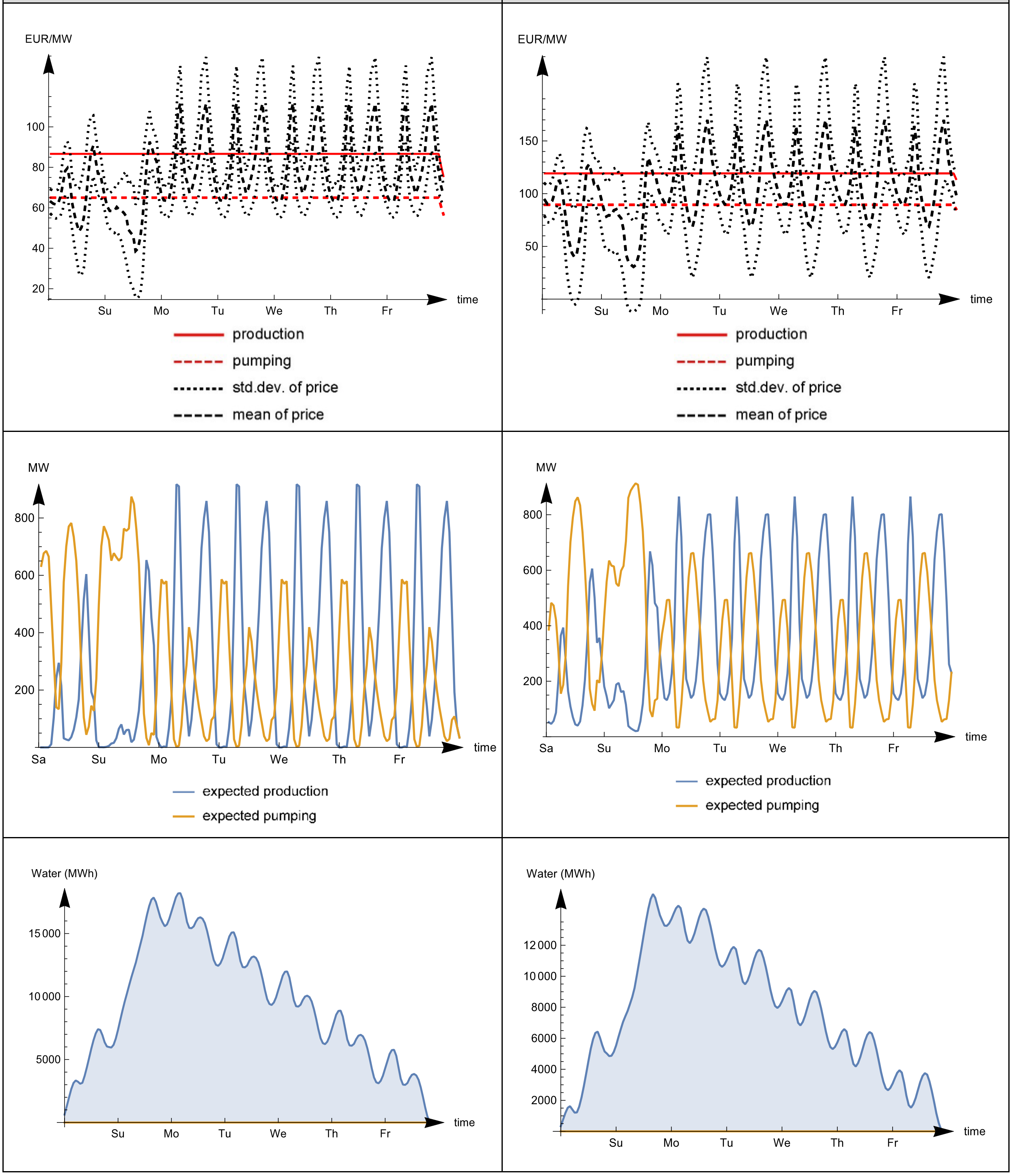


Figure 48: Results of stochastic control model of pumped-storage plant over a week with CROM scenario price distributions. Typology “Muttsee”.

Additional examples of weekly dispatch patterns are shown in Figure 49. The optimal control is of the form of a *bang-bang* control with three states: Either to pump with maximal capacity, to produce with maximal capacity, or to wait.

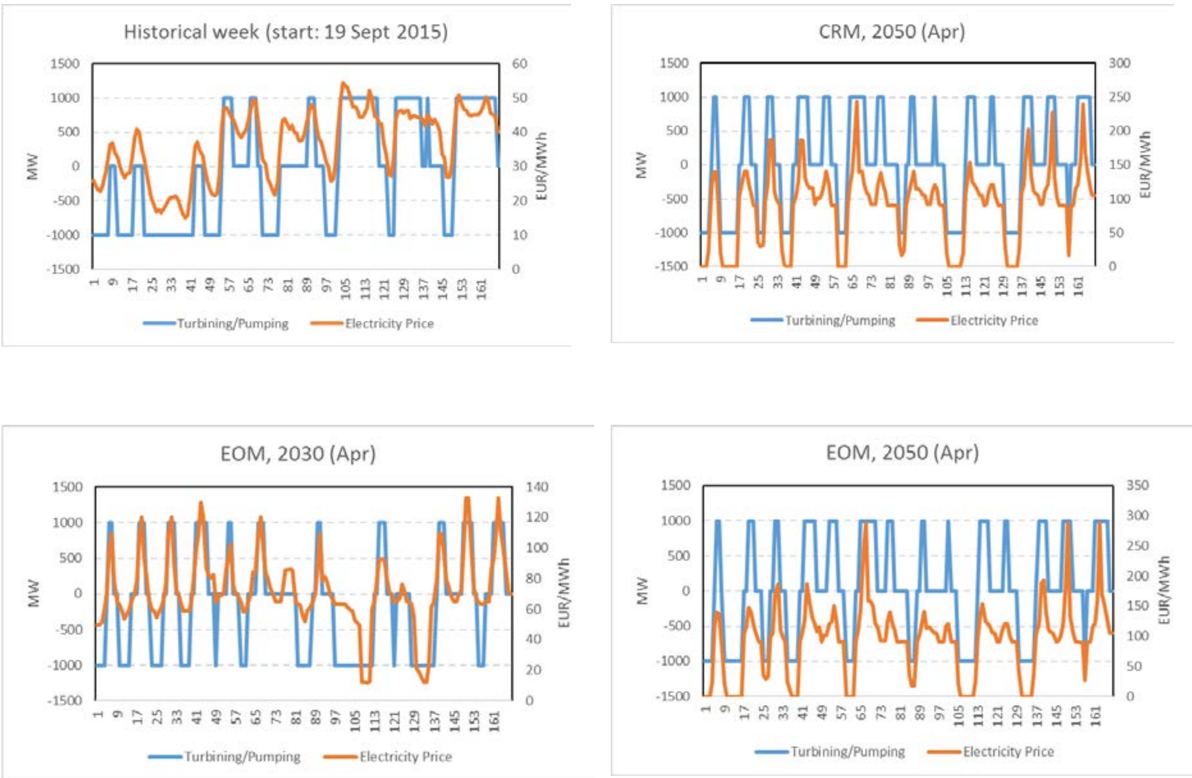


Figure 49: Examples of weekly dispatch profiles of pumped-storage plant. Typology “Muttsee”.

8.12 Appendix 12: Typology “two reservoirs” and summary table

Figure 50 shows an example of the thresholds for the two-reservoirs system “Wägitalersee-Kraftwerke”. As already mentioned, the natural inflow in the small lower reservoir is relatively large, and driven by rainfall in late fall in the sample year. The lower reservoir must also process the turbined water from the upper reservoir, such that the turbining thresholds for the lower reservoir are more flat than for the upper reservoir.

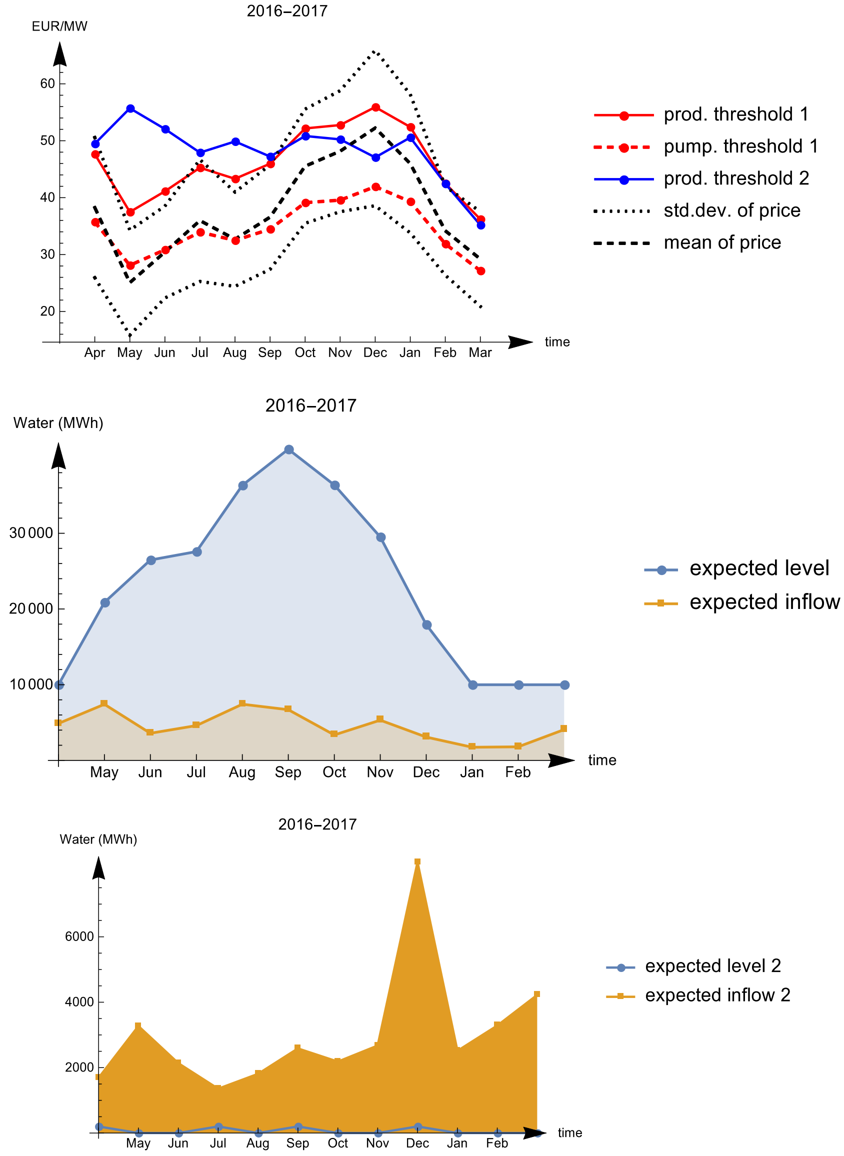


Figure 50: Results of the stochastic control model for two reservoirs: Typology: “Wägitaler Kraftwerke”.

Table 45: Relative increase of market revenue (operational profitability) per scenario/year and plant type, relative to today's values (year 2015/16 or 2016/17).

Plant Typology	CRM Policies		EOM	
	2030	2050	2030	2050
Swiss dams (aggregated), Wägitaler-see (standalone), Wägitaler-see+Rempen	92 – 101 %	216 – 274 %	89 – 96 %	387 – 387 %
Muttsee, Swiss pumped-storage (ag-gregated)	18 – 19 %	249 – 251 %	15 – 16 %	423 – 426 %