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Wien, 8.11.2021

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Benjamin Karanitsch

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Glossary

aFRR – Automatic Frequency Restauration Reserve

b_T – Binary variable generating

b_P – Binary variable pumping

BFE – Bundesamt für Energie

C_b – Battery capacity

c_{char} – Charging rate

c_{dis} – Discharging rate

CHF – Swiss Francs

DoD – Depth of Discharge

EAG – Erneuerbare Ausbau Gesetz

EEX – European Energy Exchange

EnG – Energie Gesetz

FC – Frequency Converter

g – Gravity constant

GA – Genetic Algorithm

h – Net head

i – Hours

KWO – Kraftwerke Oberhasli AG

LP – Linear Problem

n – years

NLP – Non-linear Problem

P_b – Battery power

P_c – Charging power

P_d – Discharging power

P_T – Turbine power

P_P – Pump power

$P_{aFRR,eff}$ – Effective aFRR power

p_{base} – Market base price

$p_{service}$ – Service price

p_{work} – Work price

PSPP – Pumped Storage Power Plant

PV – Photovoltaic

$P_{pv,I}$ – Photovoltaic hourly power

$P_{cap,n}$ – Photovoltaic power capacity of a certain year

$P_{cap2019}$ – Photovoltaic power capacity 2019

q – aFRR power utilisation data

Q_{nat} – Natural Inflow

Q_T – Flow rate (turbine)

Q_P – Flow rate (pump)

Q_{aFRR} – Flow rate secondary control

RES – Renewable Energy Systems

Rp – Rappen

SOC – State of charge

V – Storage Volume

V_0 – Current Storage Volume

w – Weighting factor

wC – Water rate

σ – Evaporation

μ – Self-discharge

η_T – Efficiency rating (turbine)

η_P – Efficiency rating (pump)

ρ – Water density

Δt – Time conversion seconds to hours

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Abstract

Nowadays pumped storage power plants (PSPP) play an even more significant role than before, as the increase renewable energy sources, such as wind and solar, increases the volatile energy which can cause regulatory problems for the power grid. With their ability to store and generate energy quickly, PSPP are therefore a possibility to counter these effects. Although these power plants are important for the stability of the grids nowadays, due to the current electricity market prices their ability to run a profit has been diminished and therefore they are not operated as much. In the example of the KWO (Kraftwerke Oberhasli AG) power plant Grimsel 2, there will be an attempt to implement an economic optimisation of the power plant. Built upon this it will be reviewed if an installation of a battery pack in combination with a pumped storage power plant, with other words creating a hybrid pumped storage power plant, could make a difference in the running of the plant. As the dimensions of such a battery for regulatory or quick start purposes would have large dimensions, it will only be looked at from a technical and not economical aspect. Furthermore, it will be looked at how PSPP will perform with the increase of wind and solar power over the years to come.

As the technical aspects are looked at to improve the cost effectiveness of the power plants, a change of politics will determine the future of these plants. Therefore, it will be further investigated what the Swiss government has planned, and a comparison is drawn to Austria.

Kurzfassung

In Vergleich zu früher spielen Pumpspeicherkraftwerke eine viel wichtigere Rolle, da mit der Zunahme von Solar-(PV) und Windenergie die volatile Energie im elektrischen Netz steigt und dies einen erhöhten Regelbedarf mit sich bringt. Pumpspeicherkraftwerke besitzen die Möglichkeit große Energiemengen zu speichern und rasch freizugeben oder einzuspeisen, um den Energiehaushalt im Netz zu balancieren. Trotz ihrer wichtigen Rolle für das Netz, nimmt aufgrund der niedrigen Strompreise die ökonomische Wirtschaftlichkeit ab und somit werden diese Kraftwerke nicht so häufig eingesetzt, wie es eigentlich möglich wäre. Mithilfe des Referenzbeispiels Grimsel 2 der KWO (Kraftwerke Oberhasli AG) in der Schweiz wird versucht eine Optimierung des Betriebs zu finden welche auch die steigende Anzahl an PV und Windkraftanlagen in den kommenden Jahren berücksichtigen wird. Zusätzlich wird untersucht, ob eine Hybridisierung, also eine Kombination mit einem Batteriespeicher, dem Pumpspeicherkraftwerk Vorteile bringen würde. Allerdings wird hier nur ein Augenmerk auf die technische Umsetzung und nicht die Wirtschaftlichkeit gelegt. Weiters wird recherchiert welche politischen Änderungen es in der Schweiz geben wird, um diese Kraftwerke wieder wirtschaftlich betreiben zu können und ein Vergleich mit den Ansätzen in Österreich angestellt.

1. Introduction

Hydro pumped storage power plants (PSPP) play today an even more significant role than before. With the signing and ratification of the Paris Climate Agreement, Switzerland has the goal to become carbon neutral by 2050. As nuclear powerplants are phased out through their safety evaluation, the power loss must be compensated, as well as the loss created by the termination of fossil fuelled power plants. Therefore, plans are made to increase the installed amount of photovoltaics (PV) and wind power, as they currently only constitute a small percentage of the electricity production. However, this creates a well-known problem of a high amount of volatile energy in the grid, as wind and solar power is not constantly available. Here, PSPPs act as valuable assets to the grid, as with their storage and great balancing ability they can regulate the volatility by either pumping when PV or wind production is high, or generating electric power, if needed. Although these power plants are important for the stability of the grids nowadays, their profitability compared to other technologies has decreased over the last years. To run a PSPP effectively is therefore crucial. In this thesis, I will explore this problem and try to optimise a PSPP through an analytical algorithm, for instance with the Simplex algorithm.

In cooperation with the Swiss power plant operator KWO (Kraftwerke Oberhasli AG), which gave access to the data of their pumped storage power plant Grimsel 2, an optimisation of the run time schedule based upon the market price will be developed so that the plant may achieve a better economic and technical performance.

Based on this it will be reviewed if an installation of a utility scaled battery pack could make a difference in the plant's operation, with other words create a hybrid pumped storage power plant. This is already implemented in some on run of river power plants, as this solution should bring these plants the benefit of a better regulation and limit the wear of the mechanical components. As PSPP do not have an issue with changing water flow through the change of seasons and the dimensions of such a battery for regulatory or quick start purposes would have large dimensions, other possible implementations will be investigated, and the most promising combinations are evaluated.

Because the technical and economic evaluation of PSPP might not be enough to permit them to operate with profitability, possible political measures will be discussed, which might have a positive effect on operating PSPPs in the future. This could be achieved by a higher price per kWh for these types of power plants, or a lowering of the price for the subsidised power plants i.e., wind and solar. Furthermore, this will be also researched on the neighbouring country Austria to create a comparison between these two countries and their policies.

2. Current and future Swiss electricity mix

The current Swiss power mix without imports from abroad (as of 2019) is displayed in the pie chart in Figure 1 below.

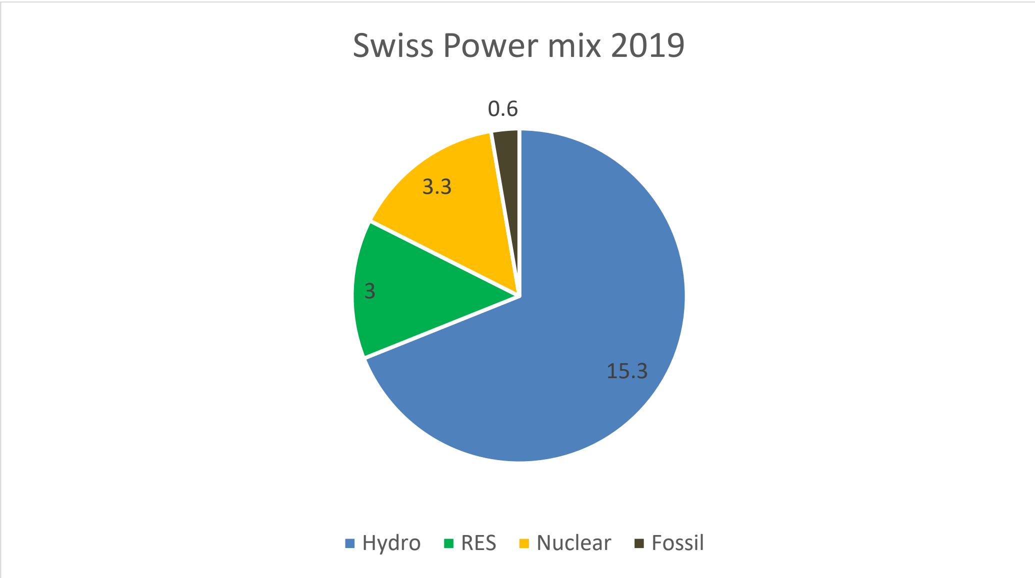

Figure 1: Swiss power mix in GW (2019) [1]

As one can observe, hydropower (including storage and pumped storage) is by far the greatest energy source of Switzerland with 15.3 GW. Solar, wind, and biomass only make up three GW of the energy mix, though this is to change in the future, as Switzerland will phase out of its nuclear energy production and this loss must be covered. In 2020, 430-460 MW [2] of PV were installed with an average cost for solar energy for new plants in 2021 based at around 12 Rp/kWh [3]. In comparison, the price for the electricity production using hydropower is currently at six Rp/kWh [1]. The nuclear power facilities are phased out regarding their safety status; if the safety of the plant cannot be guaranteed, they are taken off the grid. Currently, there are four nuclear power plants active [4] in Switzerland. It is projected that until 2050 all nuclear power plants will be taken off from the grid. The "Kernenergiegesetz" – nuclear energy law states that after their phasing out they are not allowed to be replaced, though there will be no technology ban and so nuclear research can still be done within the 2050 energy strategy.

Switzerland, like other countries in Europe strive for a net-zero electricity production by 2050. To achieve this goal, the renewable energy sources (RES) technologies like wind and solar power will receive a substantial increase within the next years. Especially solar power, as it will be next to hydro the main source for the electricity production. It should generate 40% [5] of the yearly demand and should cover 32% [5] in the winter months. To reach the net zero goal, Switzerland would have to install 37.5 GW of PV until 2050 [5], therefore it would require a PV instalment of roughly 1000 MW [2] per year. This instalment rate will later be used to analyse the future power deployment planning of PSPPs. It is to be mentioned that 70% [1] of the installed PV energy will be coupled with battery storages in 2050, which should dampen the increase of volatile energy in the grid.

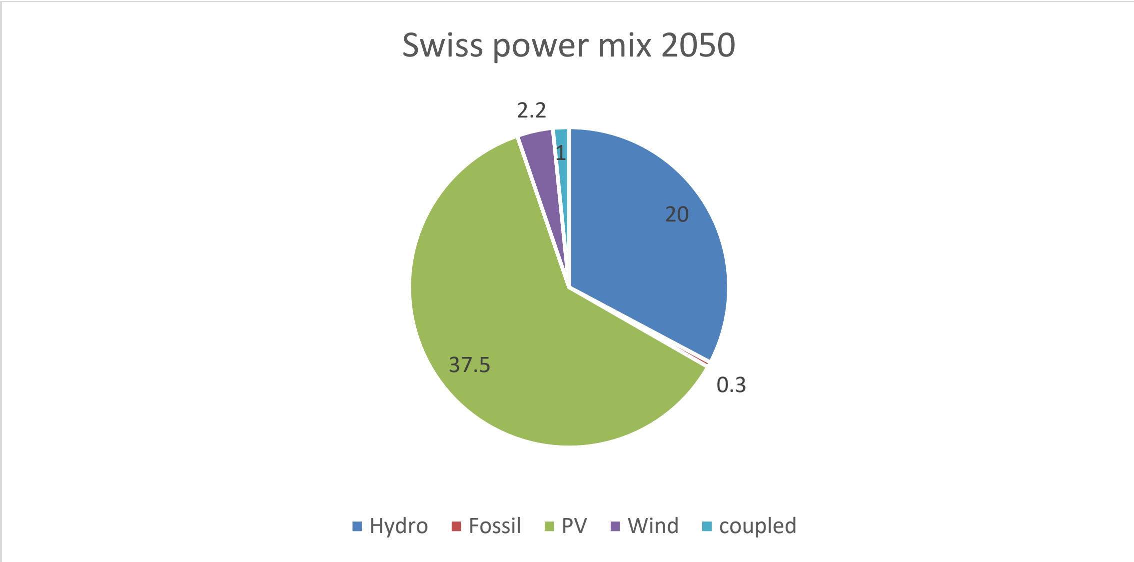

Figure 2: Swiss power mix in GW per technology Zero Basis scenario [1]

The Swiss power mix following the goal of the 2050+ strategy is displayed in Figure 2, for the Zero Basis scenario.

The coupled energy production represents different combinations of renewable energies. It is to be noted that there are several studies of how the energy sector will develop until 2050 depending on the chosen path. These different scenarios are listed below:

- Zero Basis: uses trends of today and develops these further
- Variant A: higher electrification rate of the energy system
- Variant B: Biogas and electricity-based gases play a greater role as energy source next to electricity
- Variant C: Heat networks and biogenic or electrical based fluids play an important role as energy sources next to electricity

For the following assessments the Zero Basis scenario was chosen, as it is based on current available technology.

The available PSPP winter electricity should be expanded to about two TWh until 2040 [6] so that the self-sufficiency would be available for 22 days [6]. Suitable projects should receive an investment contribution of 0.2 Rp/kWh [6]. However, after the current feed-in tariff system, new hydro power plants from 2023 will not be added into the system. The most affected through the current law are small hydro power plants, as they do not receive any investment contributions and are only taken into the feed-in tariff system with a power rating from one MW [7] onwards. Furthermore, it is estimated by the Bundesministerium für Energie (BFE) that until small hydro power plants will fall away as they cannot run economically without this support. The outlook for large hydro projects is more positive, because of the price increase (from four Rp/kWh to six Rp/kWh) [7] at the market for hydro power and the available investment contributions until 2030 for the extension of hydro power plants in the height of 700 million CHF [7].

Another change for PSPP will be how they will operate with the increase of RES, as their old scheme of supplying energy during peak load times during the day will be covered by RES, especially PV, and therefore will not be profitable anymore. PSPP must, as mentioned, operate with a higher flexibility and in times where there is no or reduced PV input, for instance on cloudy or winter days. Of course, the pricing for the PSPP produced energy must be competitive, such that running these plants is attractive from an operator's point of view. Then there is a possibility of adding a battery pack to the facility that could increase the flexibility even more and lower the costs of running a PSPP. The cost lowering can be achieved, when the battery is able to take over for a period to reduce the cycling of pumping and generating. The idea to combine a run of river hydro power station with a battery is already implemented with the expectation to reduce the wear and tear of the hydromechanical equipment and to increase the regulation range of these plants.

Another promising approach is the offering secondary control energy in addition to the base load. The market prices for secondary control energy are higher than the ones for base load. This however obligates the power plant to reserve a contracted amount of power for the event that the secondary control is requested by the grid operator, thus limiting the available power for the base load generation.

3. Methodology of optimisation

In this chapter the general workflow of an optimisation process is explained and how the problems at hand will be solved using different methods. The first section gives a general overview of the optimisation process, while the second section discusses the differences between different solvers.

3.1 General optimisation process

There are different tools one can utilise to optimise a power plant in general. Which tool one chooses to use often depends on the problem at hand. The optimisation of a power plant can be organised into long, short, and momentary optimisation periods. The different periods and grids are displayed in Table 1.

Optimization steps	Period	Resolution
Long time	1 month – 2 years	1 day – 1 month
Short time	1 day – 1 week	¼ hrs – 2 hrs
momentary	2 hrs – 6 hrs	5 min – 15min

Table 1: Definition of time intervals of different optimisation steps [8]

As for a PSPP they would fall under the momentary optimisation, as their operation depends on the current need of the grid operators. Though to optimise the PSPP over the period of a year, one must go through the process of starting with the long-time optimisation at first and work oneself down the periods until the momentary optimisation.

One can classify the optimisation process into non-linear (NLP) and linear problems (LP) as well as analytical or a search procedure.

Non-linear problems can be solved using iterative methods, like the Newton method, though in this case the derivatives must be calculated, which can be difficult and increase the calculation time. Search procedures on the other hand converge step-by-step to a solution and so do not need the derivatives, which makes them simpler to use.

Today, Genetic Algorithm's (GA) are mostly used, which are a replication of the biological evolution process. With this method, multi-path, derivative free searches with adaptive learning can be accomplished. This has the positive effect of not being stuck in a local optimum. An example for such an algorithm would be the Sintflut Algorithm.

For the optimisation at hand, the Simplex Algorithm will be used. It was chosen for the following reasons:

- Easy to implement
- Computation time is reasonable, depending on the number of variables

- Broadly used for optimisation problems
- Iterative procedure

The Simplex Algorithm is composed of two phases. In the first phase a permissible starting solution is decided, depending on how well this starting solution is determined the computation time can be decreased in this step. Phase two constantly improves an existing solution until it is not able to define a better solution for the target function, or the unlimited nature of the problem is determined.

The first step to utilise this algorithm is to define inequalities into an equation. For this purpose, slack variables are introduced, which are not allowed to be negative and show how far one is from the boarder of a given constraint. With constraints, it is possible to separate the result into feasible and infeasible. Constraints can be defined as linear or as non-linear equations. Hereby one can separate constraints into boundary, equality, and inequality. The boundary constraints define the range in which the optimisation solution can be found and therefore limit the computational time. Equality constraints define a function which equals a scalar. As an example:

$$\boldsymbol{a_1 + b_1 = c} \tag{3-1}$$

Inequality constraints functions must be greater/smaller than equal to a scalar constant. As an example:

$$\boldsymbol{f(x) \geq c} \tag{3-2}$$

Depending on the optimisation problem at hand, to maximize or minimize the target function, the permissible starting solution can then be solved with the introduced constraints as these define the problem.

The Simplex algorithm follows the optimal path to the solution; the shape, which is defined by the constraints, is called a polytope, as seen in Figure 3.

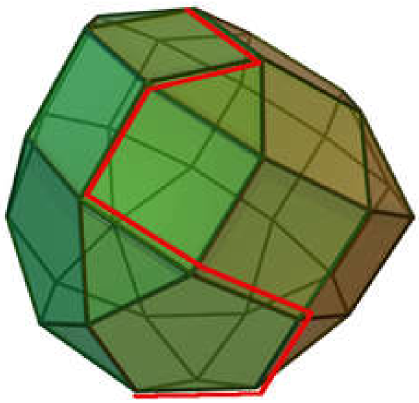

Figure 3: Graphical illustration of the Simplex Algorithm in 3d [9]

To use this algorithm in Matlab, solvers from 3rd party developers have to be installed, which are capable of running the algorithm. YALMIP is a free toolbox developed for the use in Matlab, which models SDPs (Semi Definite Programming) and solves these by using external solvers like Gurobi or Mosek.

Below in Table 2 some important parameters, which have been used to optimise the reference power plant in Switzerland for an interval of one year are displayed. All simulations are done in reference to 2019, as in 2020 the energy production dropped significantly, as the pandemic hindered the industry to produce at full capacity.

Parameters for the optimisation process
Hydraulic machine data
Hydraulic power plant data
Storage volume
Market price
Secondary control price
Production costs
Power plant reserves

Table 2: Important parameters for optimisation

At first, a simulation of the changes in the energy mix, based on the data given from the BFE until the year 2050 is performed. Within this simulation it is looked upon how PSPP can be operated under the growing RES installations. Further on, the reference pumped storage power plant is optimised with the current base price (2019), it will be investigated how it might perform when additionally supplying energy for the secondary control market. The next task is the implementation of the hybrid pumped storage power scheme where there could evolve operational benefits:

- Heightened response time to frequency shifts
- Limited wear and tear on hydro-mechanical equipment

To model the change of the energy mix in Switzerland, a different approach is chosen to optimise the outcome, when compared to the other models. As one now has different power plants with different properties such as efficiency rating, operational costs and load profiles for PV and wind. Here, the emissions and marginal costs (MC) are calculated, as these are the most important parameters for the target function. The target function in this case is not the revenue, as with the other models, but the sum of the total costs of the power plants. Depending on the costs, the operation of each plant type is determined by the solver. Here, different results are achieved regarding the graphical illustration depending on the solver, as displayed in Figure 4 and Figure 5, however the results of the target function are the same for both solvers, only differing in the calculational speed.

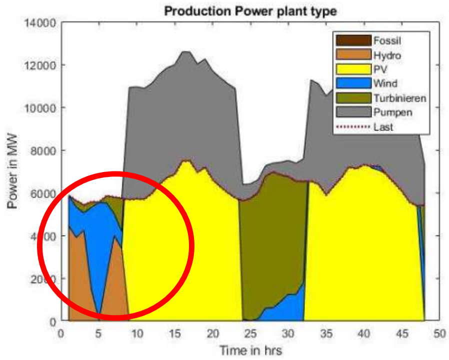

Figure 4: Mosek solver result

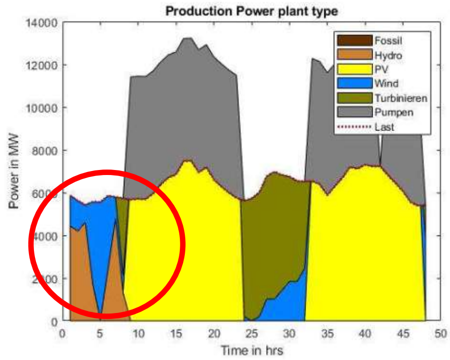

Figure 5: Gurobi solver result

These small changes can be explained hereby that the marginal costs for PV and wind are zero and therefore the optimisers can change their operation without changing the result, as these energy sources do not have an impact on the target function. This is also the reason for the difference in between 25-30 hours. So, to achieve the same result with either solver graphically, one would have to add operational costs for these power sources. This is not done in this simulation, as it is assumed that once PV and wind power is installed, they do not have any costs until they reach their end of life.

The increase of PV power is calculated from existing data from 2019, which were published by the ENTSO-E Transparency site [10]. With this, the hourly PV data and with the given scenario plan that included the reachable installation capacity for the given years, one can calculate the changing PV rates. This is achieved according to the following formula:

$$P_{pv,i,n} = P_{pv2019,i} \cdot \left(\frac{P_{cap,n}}{P_{cap2019}}\right) \qquad \textbf{3-3}$$

Here $P_{pv,i,}$ is the power for a certain hour (i) for a given year (n). $P_{pv2019,i}$ is the measured power for a given hour (i) from the ENTSO-E data sheet in the year 2019. This is then multiplied by the ratio consisting of $P_{cap,n}$ which is the reachable installation capacity for a certain year (n) divided by the installation capacity of the reference data $P_{cap2019}$ for 2019. This way the existing PV profile can be scaled up to account for the future change in installed capacity.

This method is also used for calculating the wind profiles for the future years. However, as the PV profile over a year span has a rather stable profile when compared to the wind data, the yearly production data for wind is randomised, as there are stronger or weaker wind years.

Next, the optimisation of the power plant with its operation coupled to the base price is investigated. Though this is not as realistic, since the operation of the power plant solely depends on the base price and does not include other factors, such as operating in combination with other power plants, it gives an insight when the best time would be to run a pumped storage power plant during the year. The optimisation in this case is based on maximising the revenue.

The optimisation is adapted to include the tender for secondary control energy. Here, the problem is more complex on how to include the secondary control into the already given solution, as one now must calculate the probability of the secondary control activation. During the whole time period it must be guaranteed, that a certain amount of power is reserved, so that it is available upon request of the TSO. Another aspect which has to be included is the pricing, as secondary control energy is built up by two prices, the working price and the service price. The service price is paid regardless of if an activation is called upon or not and is a constant price. The working price on the other hand is only added to the revenue when an activation occurs and is like the base price a dynamic entity. Further on, to witness the influence of the power plant operating now with the possibility of offering automatic frequency regulation reserve (aFRR), one must integrate the (aFRR) power into the storage equation. As it is not possible to work with the power directly with the storage equation, as established constraints hinder each other, the aFRR is integrated by expressing that service power as a flowrate. This is possible as flowrate and power are linked together. The results and the approach are explained in detail in section 6.3.

To consider the effect of secondary control on the revenue, these prices are added to the already existing revenue function. Again, here the optimisation tries to achieve the maximum revenue.

At last, the model of the PSPP in combination with a battery pack will be addressed. The idea is as already mentioned to see if there could be any benefits achieved by a hybridisation. The battery pack in this case should reduce the wear and tear of the electro-hydraulic equipment by limiting the cycles of pumping and generating or by limiting the units power output. The size of the battery pack of 30 MW and 68 MWh is determined by the research of current battery storage projects that are being built or planned [11]. Although the economical aspect of such a battery size is not considered, it is seen upon that the dimensions of the battery pack are reasonable. For a quick calculation of the area dimension, a reference from Tesla is used. As shown in [12] 2.4 MWh need 24 utility power packs with one power pack covering an area of 1.27 m². Therefore, to reach 68 MWh one needs about 672 utility power packs which then would occupy 856.7 m², which would be 12% the area of a football field. A standard football field has an area size of 7140 m² [13].

The implementation of the optimisation of the power plant in combination with the battery pack is done over the power at first and then over the revenue to offer a comparison to the other models. This approach is chosen, as the technical aspect should be evaluated and not the economical. Therefore, an assumed load curve is created with a 24-hour period and the power plants power output optimised to fit the load curve in conjunction with the battery pack. The results of this experiment can be viewed in chapter 7. The revenue evaluation is done to display the operation with the battery pack under normal conditions.

3.2 Mosek/Gurobi solver differences

This section discusses the differences between the two already mentioned solvers, Mosek and Gurobi. The Mosek solver, like Gurobi, can solve LP, quadratic problems, and mixed integer problems. It has its strengths in its powerful interior point optimiser, which is an algorithm that enables the solver to converge faster and find a solution in a fair amount of time. The Gurobi solver is a state-of-the-art solver, which was designed to utilise modern computing architectures and multi-core processors to find a solution for a problem very fast. Mosek and Gurobi solvers cannot solve non-linear SDP (Semi-Definite-

Problems). Both solvers are tested when simulating the PV increase in Switzerland based on the Zero-Basis scenario. The goal of using different solvers is to investigate if they might achieve slight differences in the results or the computational speed. As mentioned above, the two solvers show similar results, with only minor differences caused by the assumed operational costs of zero for the PV and wind plants. Regarding the computational speed for the tasks at hand the Gurobi solver shows better performance and is more efficient. Thus, the Gurobi solver is utilised to find solutions. Another positive aspect of the Gurobi solver is that it is constantly evolving in making the algorithms perform better, as it is used by many.

4. Policies

As countries plan to diminish their climate footprint by installing more renewable energy sources (RES) and gradually shutting down their fossil fuelled power plants, this could aid with making hydro power in general more attractive again. In the following sections the policies of Switzerland and Austria are investigated regarding their stance on hydro power. It is to be noted that these policies might change slightly, as the policies are not passed through parliament at the time. However, their context is used for this thesis.

4.1 Change in Policies - Switzerland

As mentioned before, there are changes in policies to promote the attractivity of hydropower. These policies will be elaborated in this section.

With the acceptance of the 2050 strategy the framework towards positive changes were made regarding hydro power, as it includes the development of new and expansion projects. The new "Energie Gesetz" (EnG) – energy law includes that the Cantons must include spatial planning of certain waterways for hydropower in their master plan. This should make the coordination of hydropower projects more effective. There have also been changes in the ecological framework of the EnG, in which protection and usage have been newly weighed. Hydro power plants with a certain yearly production or storage amount are now of national interest, which should make it easier to realise projects. However, it is not allowed to build new plants in biotopes, water and migratory birds reserves of national importance. As mentioned before the hydropower sector struggled during 2009-2016 [7] as the price dropped to four Rp/kWh [7]. In 2019 the price climbed back to six Rp/kWh [7] so that the operators can run the plants economically. The Swiss government adjusted their advancement policies for hydropower with 100 mil. CHF [7] market bonus per year for existing large hydro power plants until 2022 and 50 mil. CHF [7] per year for the expansion of new plants by means of investment grants until 2030. New large hydropower projects can receive an investment grant of a maximum of 35% [7] of the investment volume, which should increase the incentives for new projects. Small hydropower on the other hand can only apply for the advancement until the end of 2022 [7], though the renewal and expansion of already existing plants will still be granted the investment advancement until 2030 [7]. The investment grant hereby lies at maximum 60% [7], though it is hard to see the future for small hydro, as a study [7] shows that some will not be able to run economically without an advancement.

The BFE sees the current state for Swiss hydropower relatively positive with the advancements and higher market price. They assume that the market price will even rise in the future, as throughout the EU and in Switzerland, conventional power plants are taken off the grid. With this, there will hardly be an overabundance of electricity, which should drive the market price up. The building of new projects is not easy, as the very strict ecological laws to protect the environment present various difficulties and therefor postpone planned projects. Though, what is widely accepted, as it does not have a great impact in the environment, are expansion and renewal projects. As climate change drives the melting of glaciers onwards, it creates new potential for storage plants. There are currently seven [7] potential project sites which meet the economical, ecological, and social demands that have a combined potential of 1,076 GWh/a [7] in Switzerland.

Another aspect, which will affect hydro power plants in general in Switzerland, is the water rate, which must be paid per average power generation in kW per year. The average power generation is calculated from the usable water quantity and the usable head. Therefore, the gross output is smaller than the installed power. In 2019 [7] it was decided that the price of the water rate should not exceed 110 CHF/kW [7] until 2024. Furthermore, in the years to come a lot of hydro power plants will have to renew their concessions to use the water. Figure 6 below displays the expiry date of the water concessions.

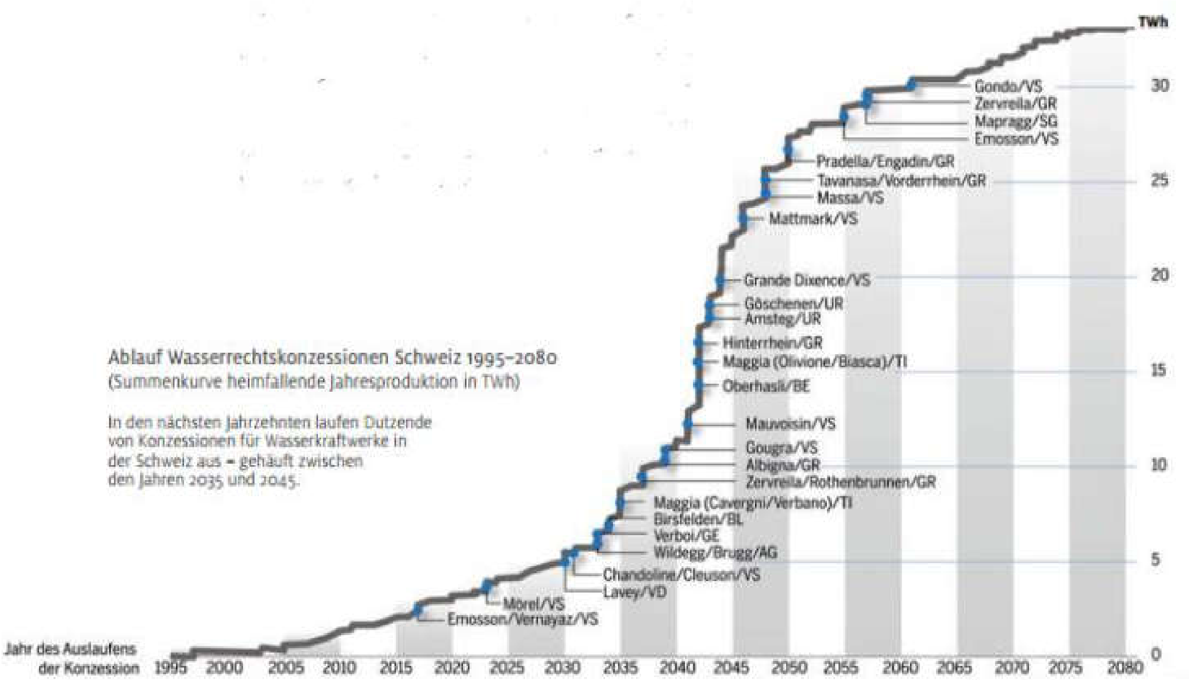

Figure 6: Expiry date of water concessions from 1995-2080 [14]

Regarding PV there are changes made as well within the new EnG. This should uniform the compensation and tariffs in Switzerland for PV produced electricity, as at current, depending in which Canton the site location is, the price varies from 5-25 Rp/kWh [15]. With this broad spacing, the average price of PV lies around at nine Rp/kWh [15]. The newly decided advancement policy for PV rests on a one-time investment grant for large and small systems, a one-time remuneration with direct marketing (EVS). The height of the investment grant is 30% [15] of the investment volume, respectively. From 2020 onwards, large PV operators with a power rating greater than 100 kW [15] must sell their produced electricity independently.

The electricity prices in summer 2021 recently have been extensively high, keeping within a range of between 80-150 CHF/MWh [16]. Switzerland and the EU broke off the seven years pending framework agreement, which might have an impact on the current electricity pricing. Within this it is not given any more that Switzerland can participate on the EU electricity market, and this may even result in an isolation. With this, Switzerland will not be included in future grid projects of the EU and not be included in the European coordination processes, which could result in unplanned load shifts and could potentially destabilise the Swiss grid. This will restructure the energy system in Switzerland in 2022 drastically, as if there is no partial agreement reached, it could mean that Switzerland must take care of its grid stability on its own. The grid operator Swissgrid estimated that until 2025 the challenges for the grid security would grow. Time will show if there will be an agreement reached for the electricity market, as Switzerland and the EU both need each other.

4.2 Change in Policies – Austria

With the introduction of the "Erneuerbaren-Ausbau-Gesetz" (EAG), the renewable expansion law, which should be ratified in 2021, Austria has the goal to receive its electricity 100% [17] from RES and hydro power until 2030 and to reach climate neutrality until 2040 [17]. I will only focus on the energy production aspects regarding RES and hydropower of the EAG. It is to be remarked that the EAG may still change in a few aspects.

To advance the expansion of RES a new advancement system will be introduced, as without advancements, no new RES or hydro power plants will be built and so the EAG goals could not be reached.

The first measure, which this law introduces to make RES and hydropower more lucrative is the introduction of a market bonus. This advancement aims to guarantee the production of renewable electricity, including hydropower, market competitiveness. The market bonus should function as a business promotion, as it is a grant onto the grid feed-in, which should cover the high prime costs of the electricity production. The first 25 MW [18] of a new or revitalised hydro power plant with a 20 MW [18] bottleneck performance can apply for the advancement. New hydro power plants, or expansions, which are in ecologically valuable locations cannot apply. Another change is that the market bonus remuneration period is set for 20 years. [18]

The second measure is aimed at the erection, modernisation and expansion of RES and hydro power plants with investment grants. This should stimulate the private plant operators to make investments for erecting and even renewing and/or expanding their power plants. These investment grants are awarded within a temporary time window, in which the investors can make their funding application. The investment grant is eligible for newly erected hydro power plants with a bottleneck performance to one MW [18], which is again only applicable if the plant is not located in an ecologically valuable region. The same applies to revitalisation projects. The amount of the investment grant is limited to 30% [18] of the new or revitalized plant investment volume.

The renewable subsidy is not available for pumped storage power plants. Pumped storage power plants which started operating after 1st January 2019 [18] do not have to pay grid usage and grid loss charges prescribed for the purchase of electrical energy for 15 years [18]. This is a positive aspect of the to be law, but unfortunately it does not cover PSPP's which were built years ago and represent the majority of pumped storage power plants in Austria. With that addressed, the new law draft makes it even harder to build or expand existing power plants, due to the additional ecological criteria to the already existing ones, which only delays the expansion of hydropower.

Following, in comparison the renewable subsidies for PV in the law draft will be explored. Here the subsidies can be applied for plants in a power range of 5-200 kW_{peak} [19].

New PV systems or expansion of existing ones with a bottleneck performance of up to 20 kW_{Peak} [18] can apply for the subsidy, if it is installed on:

- a building or on a structural system which serves another purpose than the use of solar energy
- a railway system or landfill
- an open space, except an agricultural area or a green area which is not specifically reserved for PV usage

The investment grant for PV can be applied to new, or expansion projects with a bottleneck performance of up to 500 kW_{peak} [12] if the above listed installation procurements are met. The investment grant changes, if a storage unit i.e., battery pack is included in the PV installation with a minimum bottleneck performance of 0.5 kWh [12] per kW_{Peak} until a maximum installed storage capacity of 50 kWh [12] per PV system can be additionally funded. Here, as with the hydropower funding the maximum investment grant is capped with 30% [12] of the investment volume. Another subsidy for PV is a heightened feed-in tariff of 7.06 Cent/kWh with a run time of 13 years.

4.3 Comparison of the policies

In comparison, both policies try to achieve a higher build-up of renewable energy sources with the help of subsidies. Here, both countries offer a maximum investment grant of 30% to bolster the development of hydropower projects. Unfortunately, in both countries small hydro power plants seem not to benefit from these policies. Although both countries offer better conditions for hydropower in general, the stricter environmental laws hinder the building or expansion of existing plants in a reasonable time. Regarding PV, Austria, offers additionally to an investment grant a feed-in subsidy with a run time of 13 years with a cap of max. 200 kW_{peak} on size of the PV installation. Here, Switzerland has a better solution with having larger PV parks (power rating greater than 100 kW_{peak}) selling their produced electricity to current market prices, as all other electricity producers, thus giving all market players the same rules.

Regarding pumped storage power plants, Switzerland unlike Austria does not differentiate between different hydropower types, therefore their policies are also meant for them. In Austria however PSPP's cannot apply for the subsidies and with the policy of not having to pay for the grid usage only addressing PSPP's which only started operation in 2019, basically all current pumped storage plants in Austria cannot benefit from this.

5. Increase of PV affection on PSPP performance

With the introduction of the goal of the future energy mix and the future policies the performance of PSPP will be evaluated in the following simulation.

5.1 Future energy mix based on Zero Basis Scenario

Here, it will be inspected how the steady increase of PV in Switzerland will affect the operation of different power plants throughout a year. The results of the various simulations can be found in 5.2. This analysis will be built upon the Zero Basis scenario from the 2050+ energy perspective plan, which steadily increases the build-up of PV per year until the goal of 37.5 GW are met. The implementation is built upon the PV production of Switzerland in 2019 with data from the ENTSO-E Transparency site [10].The data from the ENTSO-E Transparency may differ from the data which the grid operator has. To not mix different data providers the data solely from the ENTSO-E Transparency is used. Import and Export of power are not part of the construction of the merit Order. The PV production output for the year 2019 is displayed in Figure 7 below.

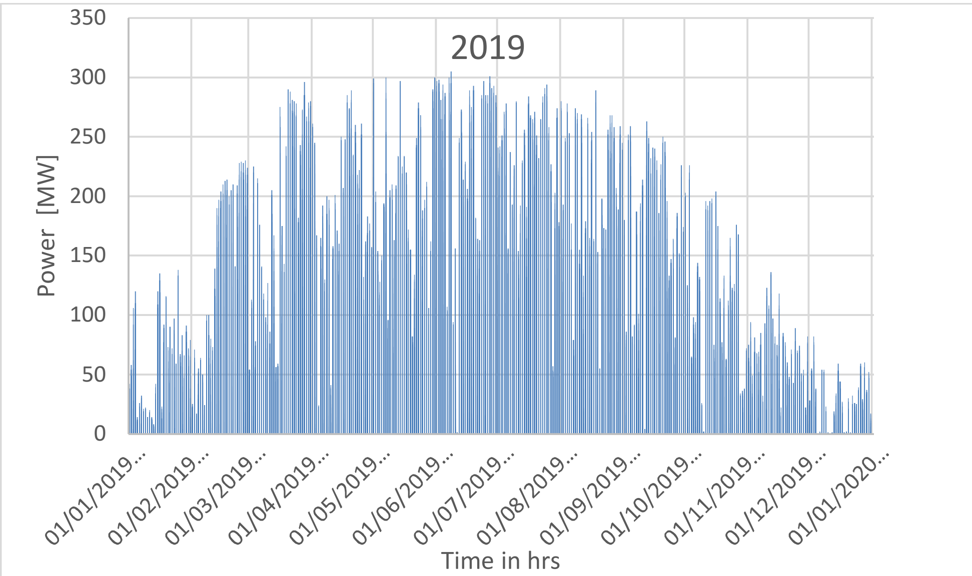

Figure 7: ENTSO-E Transparency data of PV production of 2019

It is assumed that the profile for PV will only change in aspect of the production with the increase of PV per year. Therefore, the data of 2019 is multiplied with the relationship of the PV production value of 2019 to 2025 to receive the profile for 2025. This is done for the coming years until 2050. What must be mentioned is, that the 15.3 GW hydro includes storage, run of river and pumped storage plants. The generation capacities of this are calculated with the 2019 Swiss hydro statistic from the BFE valid from 1.1.2020 [20], though the run of river power plant values for the years 2035 until 2050 must be adjusted some more to get results. The hydro statistic does not include power plants that are smaller than 300 kW [20] of generation capacity. The following values for hydropower in 2019 are taken from the statistic:

- Run of river: 5100 MW
- PSPP
  - Generation: 4598.19 MW
  - Pumping: 3642.99 MW
  - Storage cap: 8500 GWh

The total storage capacity of Switzerland is used with the data originating from the BFE [21]. As with the other capacities which increase over the years, the storage capacities are increased as well until 2050.

In Table 3 below the data for the 2050+ zero basis scheme is displayed which is used for the further calculations.

Plants	2019	2025	2030	2035	2040	2050
Hydro	15.3	16.7	17.1	18	19.3	20
Nuclear	3.3	3.3	2.2	1.2	0	0
Wind	0.1	0.2	0.3	0.6	1.2	2.2
PV	2.5	4.8	9.8	16.2	24.1	37.5
Fossil	0.5	0.6	0.6	0.5	0.4	0.3

Table 3: Zero Basis Scenario in GW [1]

Further on the load data of Switzerland and its wind generation in the year 2019 is acquired through the ENTSO-E Transparency site. Upon this data and with estimates of the operational costs of the fossil and nuclear power plants as well as their efficiency rating, a merit-order for the year 2019 is constructed. As the CO_2 pricing influences the operational costs for fossil fuelled power plants it is also introduced into the merit-order analysis. The estimates of the operational costs and efficiency ratings are displayed in the Table 4 The increase of the CO_2 price is based upon the tendency to increase the price so that fossil fuelled power plants become more unattractive and are sooner retired.

Plant	Efficiency rating	Operational costs [€/MWh]
Nuclear	0.4	16
Fossil	0.46	25
Hydro	0.9	80
PV	1	0
Wind	1	0

Table 4: Estimates for the calculation of the Merit-Order [22] [23]

Table 4 shows the efficiency ratings which are assumed for the simulation and the rough operational costs of the different power plant types. The high costs for hydro are placed to simulate the difficulties that hydropower currently has in the market. The operational costs for PV and wind power are set to zero, as once installed, there are no running costs when compared to other power plant types.

	2019	2025	2030	2035	2040	2050
CO_2 Price[€/tCO_2]	15	25	45	60	85	100

Table 5: CO2 Price estimates

The model is built up in Matlab using the YALMIP and Mosek/Gurobi solver tools for the optimisation of the power plant deployment scheme.

The estimate emission factor ζ for fossil plants of 0.35 is chosen as in this example different fossil fuelled power plants are put into the same category, so the emissions factor is averaged over these power plants.

In general, the emissions factor for coal fired power plants for instance is based upon the grade of coal and over the weighted yearly average emissions of such a plant.

The marginal costs (MC) must be calculated through the operational costs (oc), emissions factor (ζ), CO_2 price (c_{CO2}) and the plant efficiencies (η) as these are important to evaluate what the cheapest power plant is for a certain hour to cover the demand.

$$\boldsymbol{MC} = \frac{oc + \zeta * c_{CO_2}}{\eta} \qquad \textbf{5-1}$$

With the marginal costs calculated, the total costs p_{total} can be calculated with the sum over the power plants power output (PP) multiplied with their MC's.

$$p_{total} = \sum_i PP_i \cdot MC_i \qquad \textbf{5-2}$$

Further, constraints must be set for the optimisation which for one keep the plants power ratings in check and the storage capacity for the PSPP's.

The storage constraints make sure that for one the start storage value is not empty, and that generation is not possible if the storage is empty.

To see the effect of the increase of RES a period of 48 hours in January and July are chosen for the power plant operation calculation. These two months are chosen, as in winter, the PV output is not very high and in summer due to higher radiation, the PV production increases. Wind power on the other hand with its highly volatile nature, does not really have a pattern and therefore its power delivery is randomised. In the appendix, there are the graphics of the suggested power plant operations displayed for a whole year (2019, 2025,2030,2035,2040, and 2050). For the simulation the Gurobi solver is used as the time of the optimisation process with this solver was quicker.

In the appendix the results for the same days solved with the Mosek solver are also depicted.

5.2 2019-Results

Figure 8: 2019 January 12th and 13th power plant operation

As displayed in Figure 8, the base load is covered by nuclear, fossil fuelled and run of river power plants. The load peaks are covered by the pumped storages and in between a small amount of wind power. The PV output in January is low during the hours of solar radiation. In comparison below the graphic for July 2019 is shown. In Figure 9, the PV output starts to come through during the 12:00 and 15:00 hours, where the solar radiation reaches its peak. There is though still a fair amount of pumped storage utilisation for the peak load, especially at times with no solar power. During summer there is also more dynamic in the load profile when compared to the January profile.

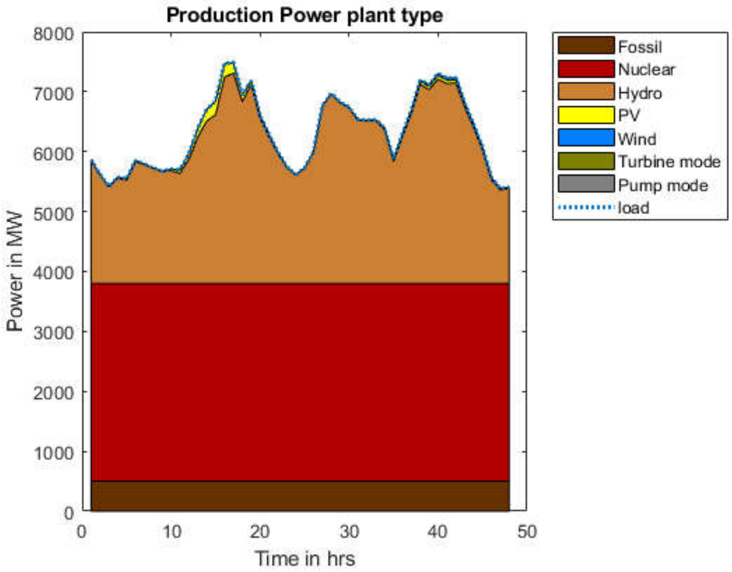

Figure 9: 2019 July 27th and 28th power plant operation

5.3 2025-Results

In 2025, there are increases of hydro, whereas here the most increase is in storage power plants and pumped storage. PV is nearly doubled, and Wind power is doubled. Again, below in Figure 10 is shown the power plant operation for January 2025 for the same days. When compared with the 2019 graph, only subtle changes can be seen, wind power and PV use is increased. The power plant operation for the two days in July 2025, displayed in Figure 11, has not changed significantly either.

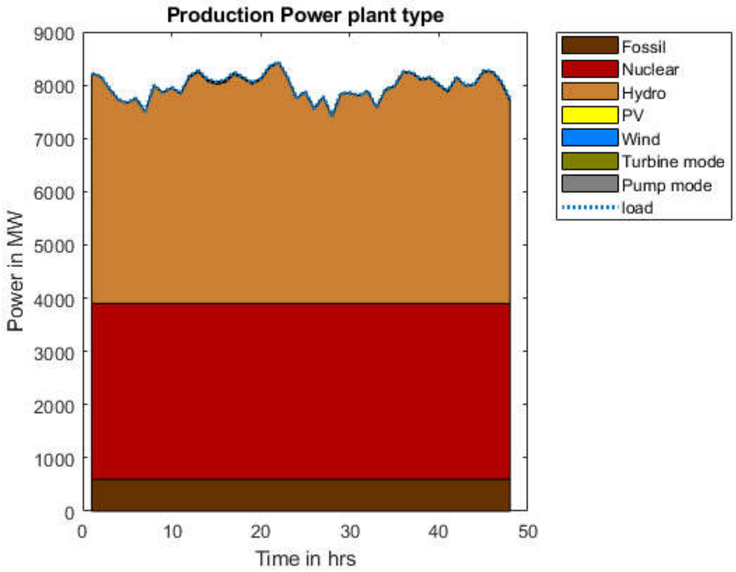

Figure 10: 2025 January 12th and 13th power plant operation

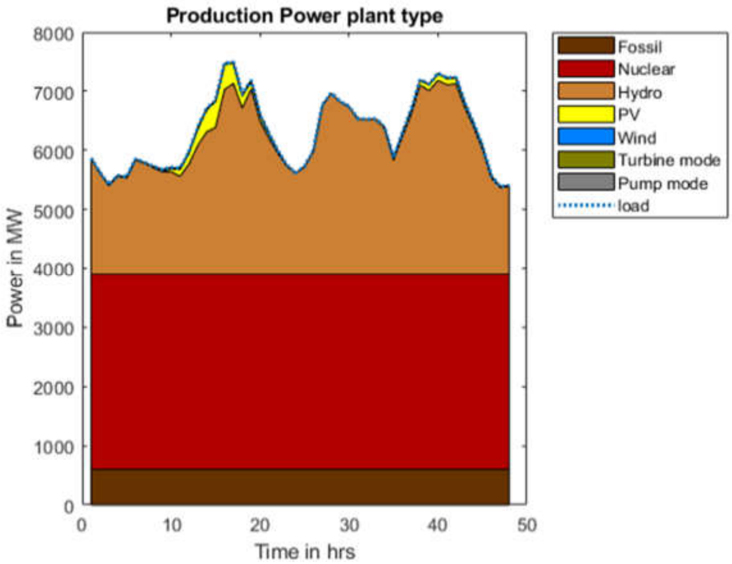

Figure 11: 2025 July 27th and 28th power plant operation

5.4 2030- Results

The increase of renewable energy sources and the increase of the emission costs (45 €/tCO_2) start taking effect. As seen in Figure 12, there is substantially more wind power, due to the growing capacity. The higher CO_2 price has the effect, that fossil-fuelled plants are not operated at the used capacity, as they are too expensive. Furthermore, the shutdown of a nuclear power plant increases the need for hydropower to cover the loss. The peak loads are covered with the pumped storage's power output. However, when compared to the figures before a subtle volatility has entered the base load.

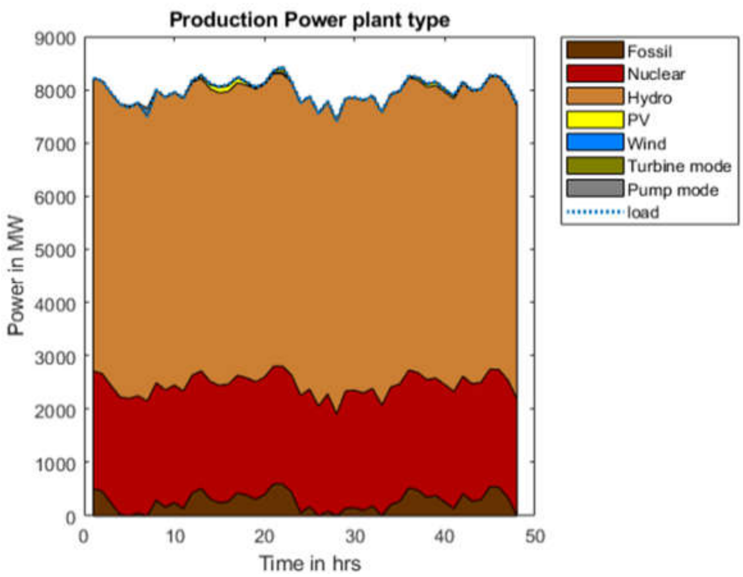

Figure 12: 2030 January 12th and 13th power plant operation

The two days in July 2030 show (Figure 13) that fossil power plants are not needed for this period and even the nuclear power plants cannot run constantly, which would not be possible, as they are designed to deliver their power constantly. At this point, one has to question the result and the weight of its meaning. The increase of PV has the effect, that during peak hours 12:00 to 15:00, the PSPP can utilise the overabundance and therefore cheap price to fill the storages, though after that they must cover the peak load as solar power diminishes further in the day. Pumped storage power plants in this scenario operate more than in the scenarios before.

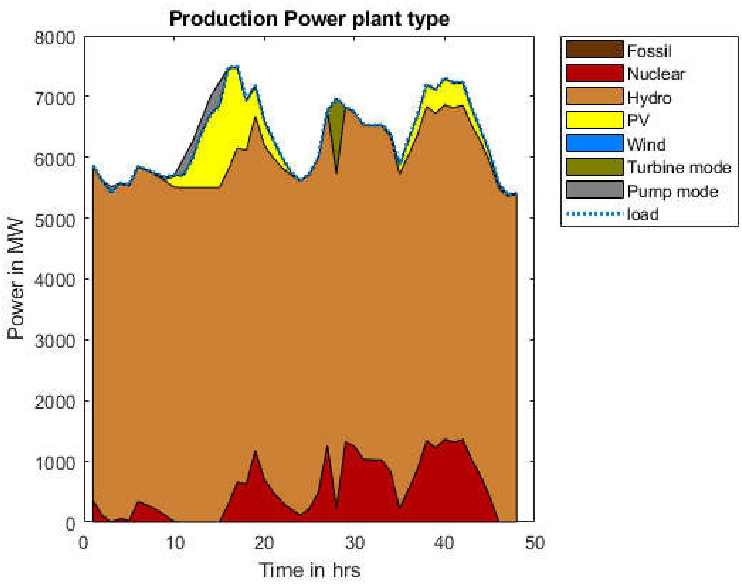

Figure 13: 2030 July 27th and 28th power plant operation

5.5 2035-Results

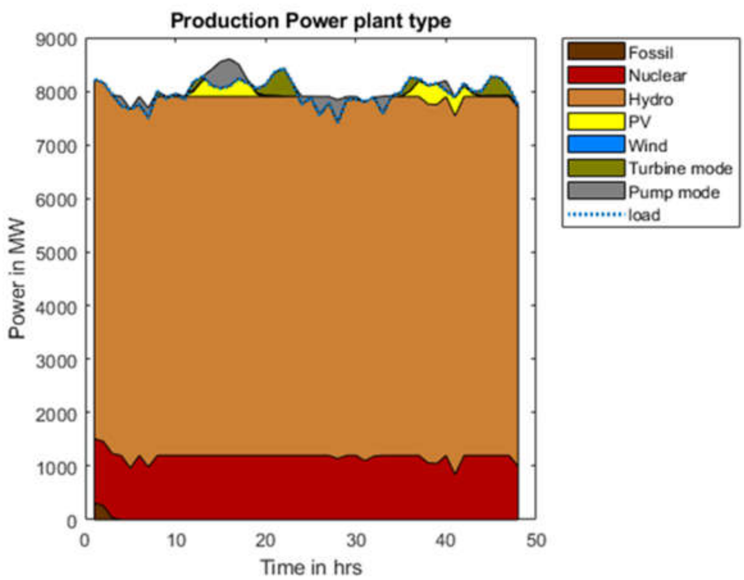

Figure 14: 2035 January 12th and 13th power plant operation

As a result of the high CO_2 pricing, fossil-fuelled power plants are not part of the energy mix anymore (see Figure 14), although there are still capacities installed functioning rather as stand-by power plants. Run of river power plants cover most of the base load. At this time, there is only one nuclear power plant in operation in the year 2035, all others have reached their maximum life expectancy. Another interesting aspect is when comparing the nuclear power production from winter 2035 and 2030. In the year 2035, the profile is constant when comparing it to 2030. This is achieved by PSPP and solar operation which perform at peak load times, with PSPPs regulating the load dynamics. What one can observe during the peak hours of PV generation, the PSPP's are in pumping mode, and in the off-peak hours they must compensate the missing PV generation. The pumped storage power plants are beginning to operate with a heightened flexibility. The summer production as seen in Figure 15 below becomes far more dynamic than the years before. Here, already due to the high production rate of PV, the run of river plants have to operate with a higher dynamic when the PV production reaches its maximum at the peak of the day, until the point that they are taken off the grid. The PSPP provide off peak coverage again, but also during peak hours, if there is not enough generation from wind and solar. Interestingly however, the nuclear energy production is not necessary during the summer anymore.

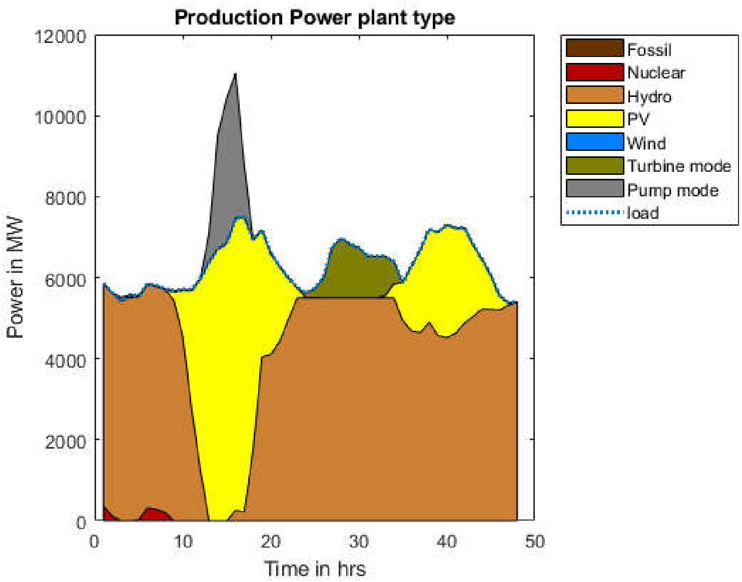

Figure 15: 2035- July 27th and 28th power plant operation

5.6 2040- Results

The results for the simulation of the power mix in the year 2040 experiences some interesting results. For the first time wind power seems to have the capacity to achieve a significant impact, as displayed in Figure 16. As a reminder, the total capacity in this scenario for wind power reached 1.2 GW. During the simulated winter days, solar power again covers most of the energy demand during mid-day. The pumped storage power plants cover the load when PV is not effective anymore and pump during hours of high PV production.

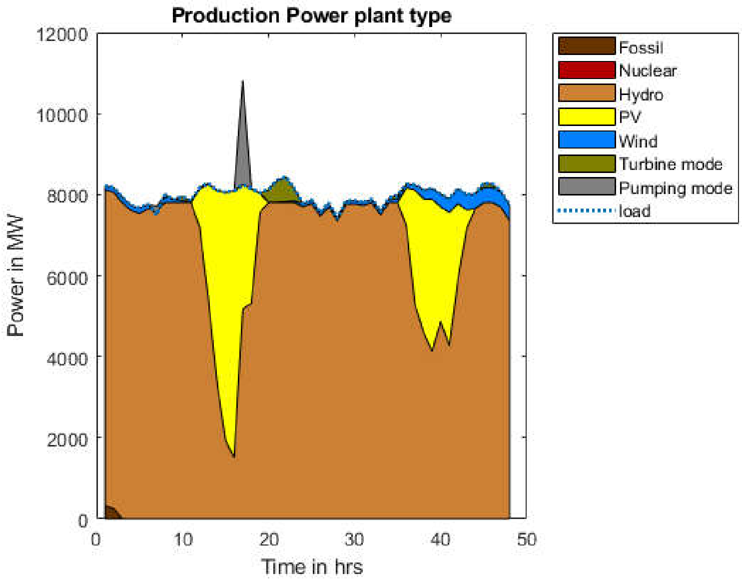

Figure 16:2040 January 12th and 13th power plant operation

In the summer period, displayed in Figure 17, solar power can cover the energy demand between 10:00 and 20:00 hours. The PSPPs pump again pump when the solar production is high and generate to cover the energy demand in the hours where PV is not available. Wind production can cover the peak load with its risen installation capacity. Run of river power plants are in the period of intense PV production switched off, which would not happen. In this case there would be a lot of energy in the system, that cannot be stored with the PSPP anymore and so a lot of utility scaled batteries would be needed to support.

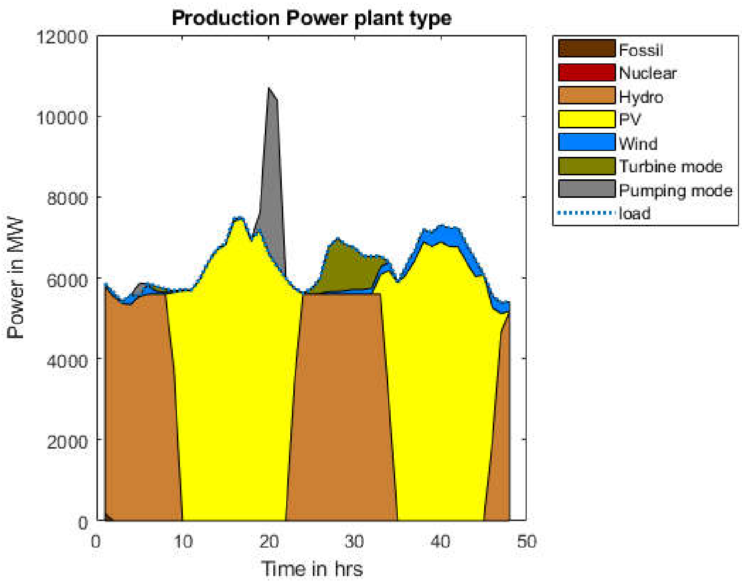

Figure 17:2040- July 27th and 28th power plant operation

5.7 2050- Results

For 2050 with the now installed 37.5 GW of PV and 2.2 GW of installed wind power the results are shown in Figure 18. A lot more PSPPs power is deployed to cover the missing load, as seen in Figure 18 and Figure 19. As explained before, this comes from the fact that the solvers could control how they wanted to deploy PV and wind as the marginal costs of these energy forms is set to zero.

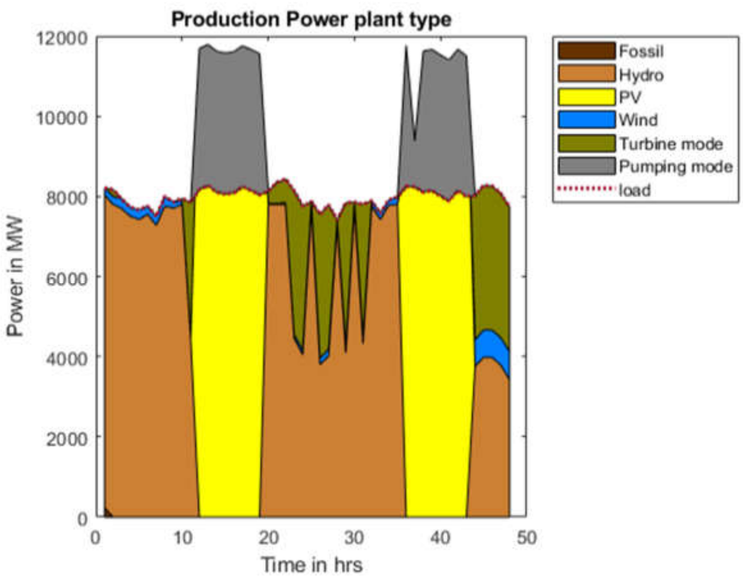

Figure 18: 2050- January 12th and 13th power plant operation

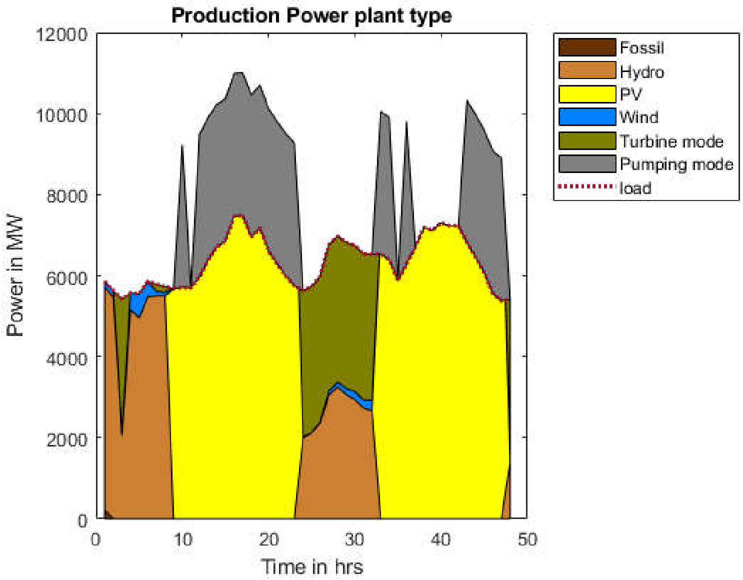

Figure 19: 2050- July 27th and 28th power plant operation

As notable, both images July and January 2050 are similar, with PV covering the total need of load needed for a certain period, PSPP filling in the gaps of off-peak generation and pumping in the peak hours to use the excess PV energy. It is also noticeable in the scenario that the pumped storage power plants are now at constant use, switching between pumping and generation mode. Also due to the high amount of PV during their peak hours, the run of river plants also cannot generate, resulting in the fact that there is no true base load anymore and only a dynamic electricity production. This though creates a problem, as one would not turn off run of river power plants, except if the electricity prices are negative for a certain period. It shows that with the increase of PV one has to find different storage solutions next to PSPP so that the overabundance of energy can be stored. This 2050+ zero base scenario shows that PSPP's and storage power plants will become very important and that the power stability of the grid will rely even more on their flexibility. However, the market prices in the end dictate the overall operation of power plants. For 2050 one could say that PV and wind are well established in the energy mix and have no incentives on pricing. This combined with the volatile nature of these energy forms can have the effect that the electricity market prices rise, as if their production is low, something must fill the created energy hole. This creates a high demand when such scenarios arise and therefore the prices would rise, benefitting PSPP's for example. The results of the solver are in some respects highly doubtable, as it assumes of shutting down run- of river plants and operating nuclear power plants flexible. With the provided data and in general the constant changes in politics and their goals, the results of these simulations are to a degree highly speculative. Hence, the displayed simulations only offer the interpretation of a trend regarding PSPPS in the aspect that the build-up of more storage capacities is of interest when RES are drastically increased.

6. Reference project Grimsel 2

For this thesis the Grimsel 2 pumped storage power plant, which is located in Switzerland and operated by the KWO is used as a reference for the simulation of the following optimisations.

6.1 Grimsel 2

This section gives a brief overview of the KWO and Grimsel 2. The history of the KWO reaches back until 1908, when pioneers travelling the Grimsel area noticed the great hydropower potential of it. In 1925, the KWO was founded and the beginning of the construction of the first hydropower plant Handeck 1 began and lasted until 1932. The unique geographical features of the area provide excellent water catchment for hydropower. The area represents 1% of Switzerland's total area, 450 km² [7] on which 980 mil. m³ [7] of water fall yearly, of which 700 mil m³ is used to produce electricity. The KWO operates 13 hydropower plants in this region, with a total installed output of 1370 MW [7] and a yearly production of 2400 GWh [7]. The eight storage lakes combined hold 195 mil. m³ [7] of water. Figure 20 illustrates the water catchment area and the placement of all hydropower plants of the KWO.

Figure 20: Overview of KWO power plant locations [22]

The red boxes on the map display the current 13 power plants in the area and the yellow boxes the planned future projects. The following schematics, in Figure 21, displays how the power stations are interconnected with each other and how the planned projects would be tied into the current system.

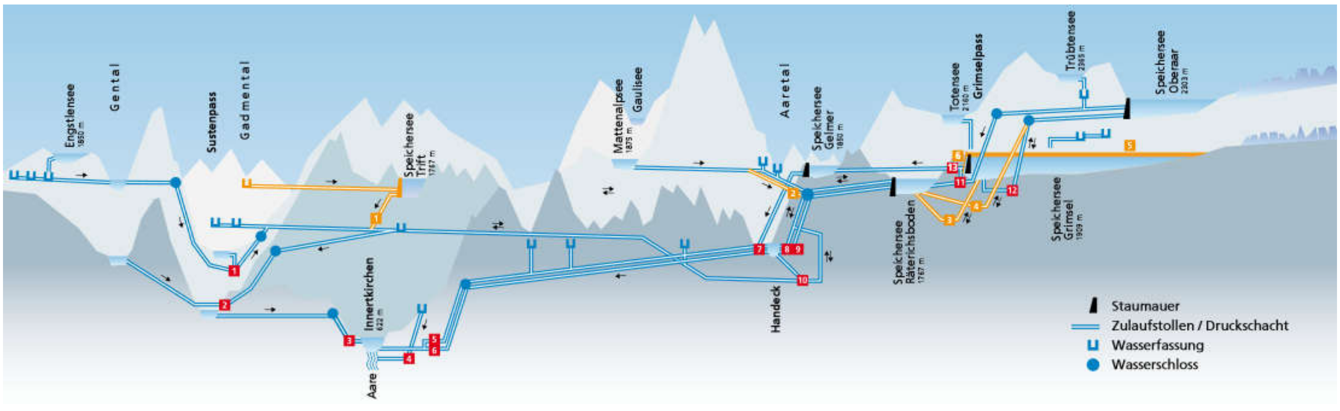

Figure 21: Connection of power plants [22]

The Grimsel 2 pumped storage power plant location can be seen in Figure 20 with the number 12 as reference.

Grimsel 2 was built from 1973 until 1980 and modernized from 2012 to 2016. The following Table 6 and Table 7 display the technical data of the power plant as a whole and per unit.

Technical Data	
Units	4 turbines and pumps
Turbine type	Francis
Total installed turbine power [MW]	372
Total installed pump power [MW]	372
Head [m]	430
Total turbine flow rate [m³/s]	100
Total pump flow rate [m³/s]	77

Table 6: Technical Data Grimsel 2 [17]

Technical Data of one Unit	
Turbine output [MW]	90
Pump output [MW]	94
Speed [rpm]	750

Table 7: Technical Data of one unit [18]

This power plant consists of four units with each unit being set together by a turbine and pump configuration on the same shaft. The modernisation process of 2012 included the instalment of the world's most powerful frequency converter, which is connected to unit one. This was achieved through a collaboration of ABB and KWO, respectively. The frequency converter with its 100 MW is there to operate the power plant more efficiently and flexible when in pumping mode. The 94 MW of the pump are distributed over the frequency converter through two grid- and two machine- side transformers. This allows a frequency regulation of the pump between 40 Hz and 51 Hz [23], which corresponds to a speed variation between 600 rpm to 756 rpm [23].Units 2-4 are operated without the ability of variable speed.

6.2 Optimisation

The optimisation process, if not using an optimisation tool, would divide into many steps, starting with splitting a year up into winter and summer months, for instance. The six months chosen for winter range from October-March and for summer therefore from April-September. Additionally, these months would be further optimised to weekdays and weekends, as here the base price for the produced power changes significantly. When using a solver tool, it makes it easier as one does not have to worry about the months and different price ranges, as the solver will search for the optimal result, when the correct constraints are implied. It is therefore crucial to define the correct constraints to get a valid and quick result.

This is done with the Gurobi solver, therefore one can directly input the data for a year. The data of the Grimsel 2 was kindly given by the KWO to make the following calculations realistic. The optimisation strives to maximise the revenue of the PSPP. The next step after setting up the data is to determine the functions to simulate the plant.

The storage function (V) is established, as the target equation and consists of the current storage level (V_0), the natural inflow (Q_{nat}), the evaporation rate (σ) and the turbine (Q_T) - and pump (Q_P) flow rates. Δt is the conversion time for the flowrates, which are given in m³/s and transformed into m³/hrs to reach the correct dimension. The same equation can be used for the lower reservoir with a change only in the flow direction of the pump flow and turbine flow.

$$\boldsymbol{V = V_0 + Q_{nat} - \sigma - \Delta t \cdot (Q_T + Q_P)} \qquad \textbf{6-1}$$

The evaporation is calculated through the area of the reservoirs and multiplied with the average hourly evaporation rate. The area of the reservoir was supplied by the KWO. For the evaporation rate, the average yearly evaporation rate of the Swiss Alpes of 464 mm/a [24] is used and transformed into hourly values.

The power equations for pumping and turbine mode can be defined as:

$$\boldsymbol{P_T = Q_T \cdot \eta_T \cdot h \cdot \rho \cdot g} \qquad \textbf{6-2}$$

$$\boldsymbol{P_P = -Q_P \cdot \eta_P \cdot h \cdot \rho \cdot g} \qquad \textbf{6-3}$$

The parameters of the equations listed are:

V_0 current storage level

Q_{nat} natural inflow

σ evaporation rate

Δt conversion time

Q_T flow rate (turbine)

Q_P flow rate (pump)

η_T efficiency rating (turbine)

η_P efficiency rating (pump)

h net head

ρ water density

g gravity constant

The flow rate through the turbine and the pump are not constant and in theory, the efficiency rating is not constant, as it is dependent on the flow rate and head. Although the efficiency rating is a non-linear function, as depicted in Figure 22 for a Francis turbine, for the purpose of the optimisation it is set as a constant.

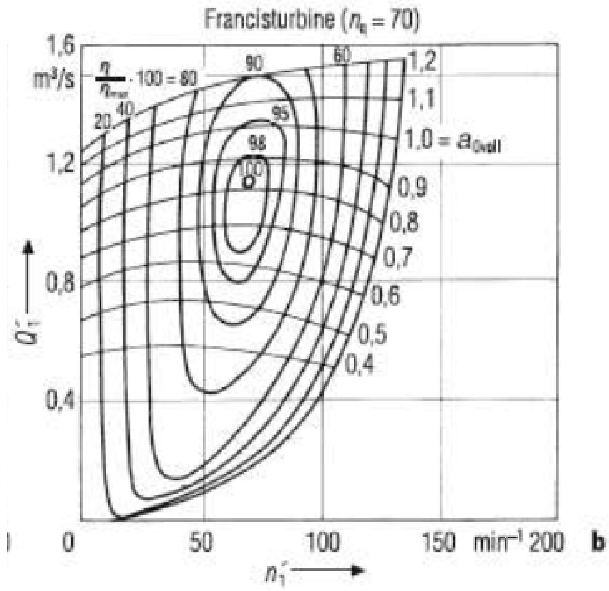

Figure 22: Diagram of the efficiency rating of a Francis turbine [25]

Another aspect which is considered is the change of the hydraulic efficiency depending on the storage level. Two points of interest are added at 3/4th storage level and at minimum storage level. These are added as the pump has a different efficiency rating depending on the storage level. This is because the pump is designed for a specific current range that passes through the pump while in use. Due to the rise or drop of volume the current through the pump changes, causing it to not reach its designed efficiency rating. For Francis turbines the optimal efficiency point can be adjusted via the turbine governor, resulting in a small deviation of the efficiency rating at different storage levels. With a FC in play, the efficiency can always be adjusted to the designed rating.

Further on, the FC of unit one is considered in the simulation for pumping and generation mode with the definition of the power constraints for this unit, as there is a minimum and maximum power range to not damage the FC.

$$\boldsymbol{P_{min} \leq P_i \leq P_{max}} \qquad \textbf{6-4}$$

The next important equation for which the actual optimisation is regarded is the revenue. For this the energy provided or obtained in either turbine or pumping mode in MWh and the spot price (p_{base}) in €/MWh are needed. Energy and power for a given hour (i) cohere through:

$$\boldsymbol{E_i = P_i \cdot t} \qquad \textbf{6-5}$$

Therefore, the standard revenue R function would be:

$$\boldsymbol{R = \sum_i p_{base,i} \cdot E_{T,i}} \qquad \textbf{6-6}$$

From this equation one must subtract the operating costs, which for one consist of the water usage costs (wC) and the costs when operating in pumping mode. The total cost equation then results to:

$$R = \sum_i (P_{T,i} - P_{P,i}) \cdot p_{base,i} - \frac{wC}{8760} \qquad \text{6-7}$$

The wC/8760 is a constant representing the water usage costs which would have to be paid per hour. The water usage costs are calculated through:

$$wC = P \cdot c \qquad \text{6-8}$$

Here, the power P is calculated using the net head of the plant and the average flow rate and c are the costs per year which are set to 80 CHF/kW, circa 73 €/kW. This price level represents roughly the current price level.

After the definition of the main functions, which are used to optimise the problem, the decision variables must be defined. These variables are manipulated through the solver to reach an optimal result, in this case, maximise the revenue.

For the simulations the following decision variables are introduced:

- Storage level
- Turbine flow rate
- Pump flow rate

The next step is to define the constraints, for all relevant quantities, which help the solver to keep within certain limits. These boundary constraints are:

$$V_{min} \leq V_i \leq V_{max} \qquad \text{6-9}$$

$$0 \geq Q_{P,i} \geq -Q_{Pmax} \qquad \text{6-10}$$

$$0 \leq Q_{T,i} \leq Q_{Tmax} \qquad \text{6-11}$$

$$P_{Tmin} \leq P_{T,i} \leq P_{Tmax} \qquad \text{6-12}$$

$$-P_{Pmin} \geq P_{P,i} \geq -P_{Pmax} \qquad \text{6-13}$$

Whereas the storage constraints are implemented on the upper and lower reservoir. As unit one can utilise the FC in turbine and pumping mode, it has separate constraints to keep the maximum and minimum power within the designed operational range of the FC. The regular units have as minimum power the value zero, as they are not able to operate dynamically like unit 1.

The base spot prices for the year 2019 from the EEX (European Energy Exchange) were also kindly provided by KWO.

To guarantee that one unit operates in turbine mode and does not at the same time operate in pumping mode, binary variables are introduced.

Now each unit's power is multiplied with such a variable for either pumping or turbine power. With the following constraint for the binary variables themselves, it is assured that one unit is operated in one mode at a time. The binary variable $b_{T,i}$ is chosen to represent the turbine mode and $b_{P,i}$ to represent the pump mode. The unit's constraints with the introduction of the binary variables are listed below with the binary variable constraint. $P_{T,max}$ is the maximum power rating that a specific unit can achieve while turbining and $P_{P,max}$ the equivalent when pumping.

$$\boldsymbol{P_T * b_{T,i} \leq P_{T,max}} \qquad \textbf{6-14}$$

$$\boldsymbol{P_P * b_{P,i} \leq P_{P,max}} \qquad \textbf{6-15}$$

$$\boldsymbol{b_{P,i} + b_{T,i} \leq 1} \qquad \textbf{6-16}$$

The result of the optimisation can be seen in Figure 24 and Figure 25 for a 200-hour interval, once for a period in winter, and once for summer. The optimisation is done for 200 hours, as with an increase of hours the time to optimise increases exponentially. Below in Figure 23 is the table of the run time analysis of MATLAB. It took 46.246 seconds in total for the optimisation.

Function Name	Calls	Total Time (s)	Self Time* (s)	Total Time Plot (dark band = self time)
linearOptimization	1	48.116	1.120	
sdpvar.subsasgn	603	30.193	29.831	
optimize	1	9.681	0.008	
solvesdp	1	9.673	0.036	
callmosek	1	8.257	0.003	
callmosek>call_mosek_lpqpsocpsdp	1	8.251	0.009	
call_mosek_primal	1	8.242	0.006	
mosekopt (MEX-file)	7	8.241	8.241	
lmi.horzcat	5021	1.911	0.281	

Figure 23: Run time analysis MATLAB

As displayed in Figure 23, most of the time is used to determine the best values of the decision variables and to solve the problem the problem itself with the Gurobi solver. This can be explained hereby that with more decision variables the solver has got the ability to follow more nodes to find an optimal solution. Therefore, shorter time periods in different seasons are chosen to make a simulation possible in a reasonable amount of time.

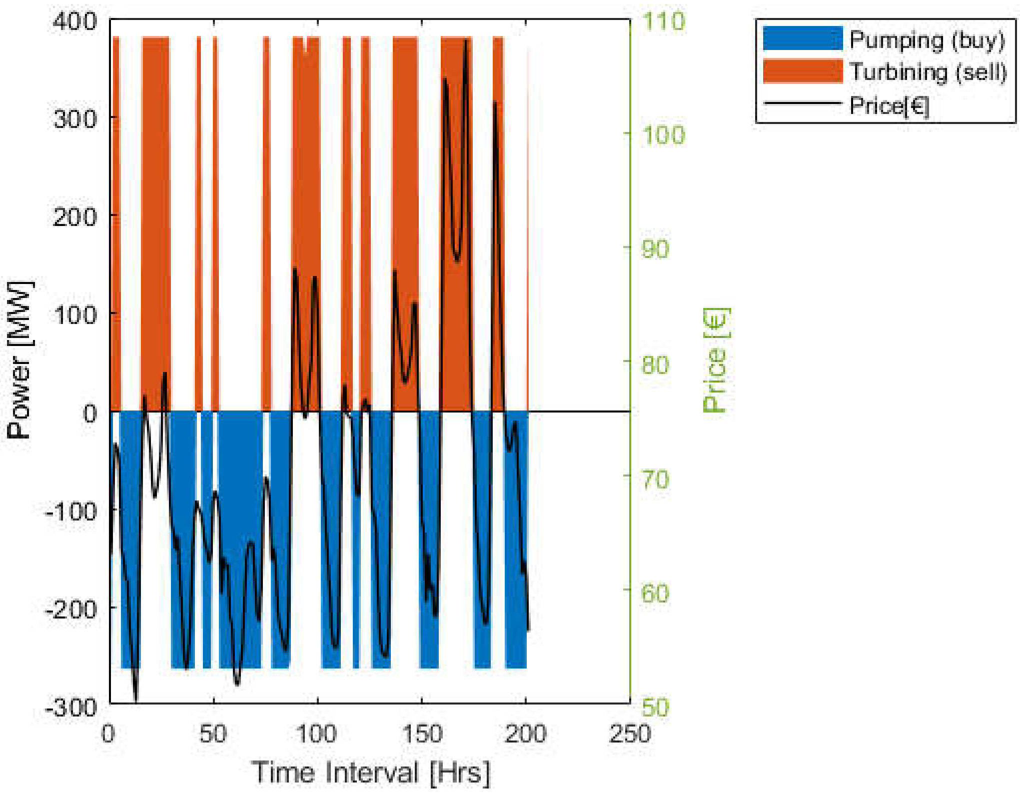

Figure 24: plant operation 17.1.2019-25.1.2019

The optimised run scheme of the plant based on the base price is seen in Figure 24 above. The revenue results for this period, with deducting the water rate adds up to 146,968 €. The operation is not constrained by an operation timetable and so the result displayed is how it would look like if one would operate the power plant after the current market price. Though one would at first glance at Figure 24 suggest that the result of the revenue is too high, as there are a lot of pumping cycles in between which would sink the revenue. However, as one also can see the hourly price has got great fluctuations in between, where there is a significant difference from the price range. The optimiser uses these strong fluctuations to still achieve a good result, as the prices when generating are mostly significantly higher than when pumping. Also, the power plant when generating power utilises all its capacity, while in pumping only 66% of its rated power is used. The utilised pumping power combined with the low price therefore cannot lower the revenue in this case as much as one could have expected.

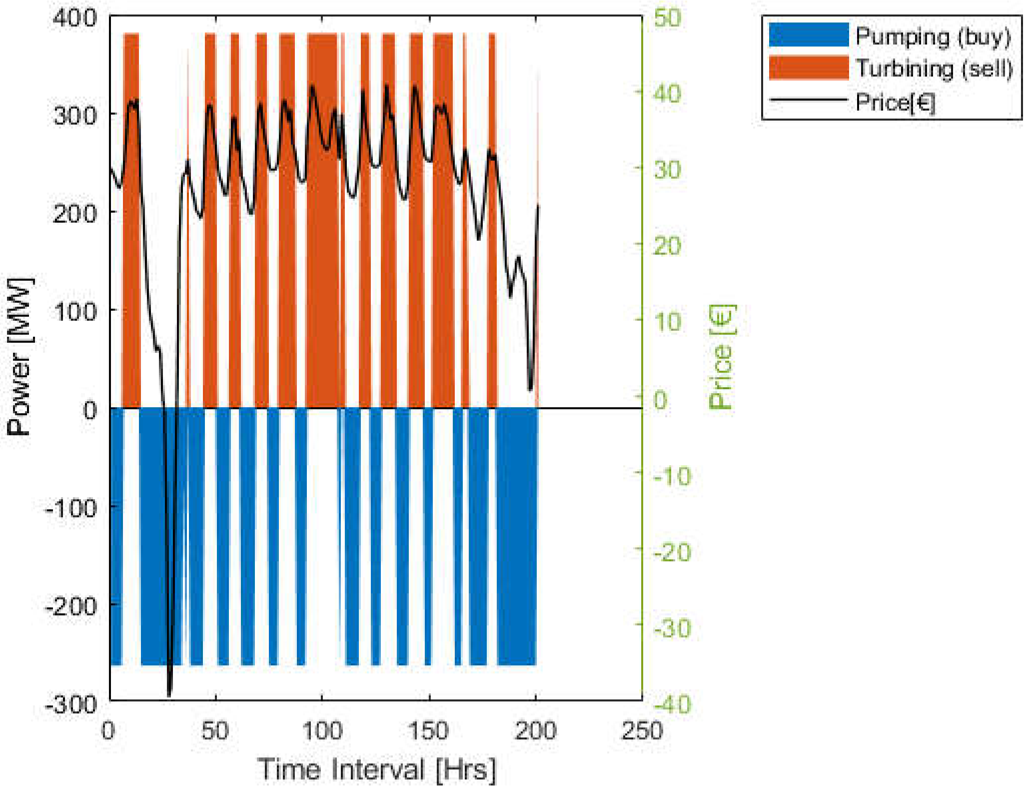

Figure 25: plant operation 29.6.2019-7.7.2019

The revenue during the summertime accumulates to -143,361 €. The revenue for this period is negative, as the prices are low and as displayed in Figure 25, there is a slightly higher pumping operation, which as well decreases the revenue, as electricity has to be bought. The price fluctuations in Figure 25 compared to Figure 24 are low, therefore resulting in not gaining revenue in this period. Therefore, one could debate if an operation in the summertime is necessary, as one would lose money instead of earning money. This would result in an operational shift to rather utilise the power plant in the winter months and fill the storages in summer with the cheaper energy prices.

The constant pumping can be explained hereby that a constraint is set, which makes sure that the end value of the reservoir is the same as at the beginning of the optimisation. This is to guarantee that the reservoir is not depleted or filled thus distorting the simulation results.

The following section presents what would change for the power plant when offering secondary control energy to the market.

6.3 Secondary control market

After the optimisation of the power plant using the base price to operate, it is analysed if the power plant operation, when offering secondary control power for the market could be significantly more profitable. This is because the aFRR prices would be added to the existing revenue.

The aFRR is activated to restore frequency and relieve the primary control, as the primary control only regulates proportionally and therefore is inept of restoring the frequency to 50 Hz on its own.

The maximum energy size per offering for secondary control (in Switzerland) is 100 MW [26], whereas the minimum offer is ± five MW [26] and further power can be offered in one MW steps at different pricing. The energy for secondary control is tendered on a weekly basis from Monday 0:00 until Sunday 24:00 hours. The tender with the lowest price wins the contract, if there are more offerings to the same price; the one, which reached in the bid first succeeds.

For the simulations it is assumed that the contracted supplied energy for secondary control is 50 MW, since it represents a reasonable amount regarding the dimensions of the power plant. This means, that the power plant must constantly reserve this power in case it needs to deploy for an aFRR call. It is to be mentioned that it is assumed that when aFRR is needed, the power plant receives the offer with 100% probability. With this a new constraint must be added, which keeps the total power in check. The implementation of the regulation over the unit power is accomplished with adding an aFRR flowrate (Q_{aFRRT}/Q_{aFRRP}) as power and flow rate are coupled together. With this, the flow is determined depending on the effective called aFRR power and then, if necessary, spread across all units. Therefore, the storage equation is updated, now including the secondary control flow rates.

$$V = V_0 + Q_{nat} - \sigma - Q_T - Q_{aFRRT} + Q_P + Q_{aFRRP} \qquad \text{6-17}$$

Q_{aFRRT} and Q_{aFRRP} are calculated identical with the effective aFRR utilised power.

This effective secondary power P_{aFFR_eff} is calculated by multiplying the reserved aFRR with the weighting factor, which displays the retrieval probability.

$$P_{aFRR,eff,i} = P_{aFRR,i} \cdot w_i \qquad \text{6-18}$$

The weighting factor can be calculated with the hourly utilised aFRR power from the Swissgrid data (q_i) and dividing these values by the maximum aFRR ($aFRR_{max}$) work that is activated in the data series.

$$w_i = \frac{q_i}{aFRR_{max}} \qquad \text{6-19}$$

This results in an activation probability from 0.9% to 100%. Depending on how high the percentage of w (6-19) is, the effective secondary control power can increase or decrease, as well as the work price, which is a product of the activation probability multiplied by the activated aFRR and the aFRR price (negative or positive aFRR prices, depending on the example).

$$p_{work,i} = P_{aFRR,eff,i} \cdot p_{aFRR,i} \qquad \text{6-20}$$

The service price is calculated with the tariff from the year 2020, which is around 28,800 CHF/MW [27], which is roughly 26,438 €/MW (exchange rate 1 € = 1.089 CHF), by multiplying the given tariff with the reserved secondary control power. As the tariff is the sum of the payment of one year, one must divide through the hours of a year to get the service price which would be paid in equivalent per hour to reach the yearly tariff (c_{tariff}).

$$p_{service,i} = P_{aFRR,i} * c_{tariff,i} \qquad \text{6-21}$$

This is a gain in the operator revenue, as $p_{service}$ is received in any case, although aFRR may not be needed, the price is paid for the reserved power.
The work price and service price are then added to the revenue equation, respectively.

$$R = \sum_i \left(P_{T,i} - P_{P,i}\right) \cdot p_{base,i} + p_{service,i} + p_{work,i} - wC/8760 \qquad \text{6-22}$$

At first the power plants operation is optimised for the case of only offering negative secondary control energy as an additional service. Therefore, the turbine and pump flow rates (Q_{aFRRT}/Q_{aFRRP}) are calculated using the pumping hydraulic efficiency for both cases, as the Q_{aFRRT} rate is not to be understood as a flow rate, but as a value which constraints the turbine power due to aFRR activation.

Therefore, constraints have to be adjusted with the addition of the aFRR power to the already existing power constraints.

$$Q_T + Q_{aFRRT,i} \leq Q_T \qquad \text{6-23}$$

The working point is displayed in Figure 26, this represents the power which would normally be available without the aFRR offering. As displayed the nominal power is reduced, as the activated aFRR must be covered.

The same 200 hours are chosen as before to simulate the plant operation. The result with offering negative secondary control energy can be seen below in Figure 26 and Figure 27 for the winter and summer period. The pricing for the negative control energy is lower as the base price but creates an extra income.

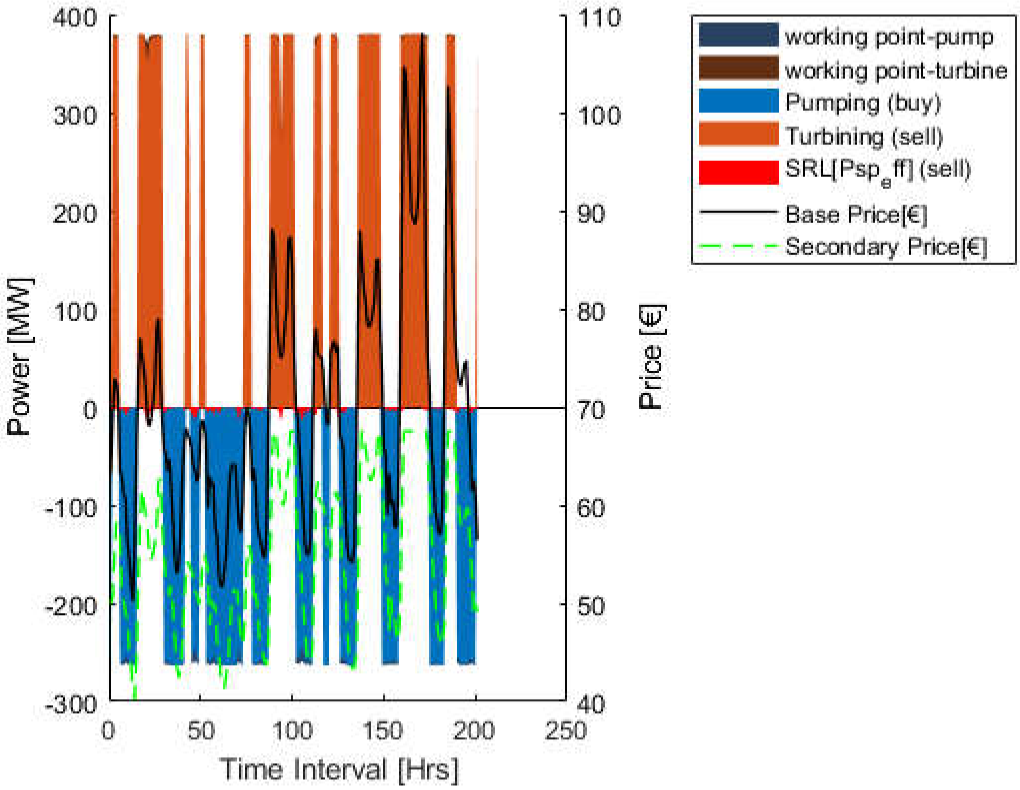

Figure 26: Plant operation with negative aFRR -17.1.2019-25.1.2019

The revenue increases with the offering of negative secondary control to 163,468 €. Here, the utilisation of the secondary control caps in the hours where the plant would generate on full capacity some power for the pumping mode to obey the contracted amount of aFRR. Displayed here in this scenario the secondary pricing is lower than the base price. Pumping therefore for negative secondary control energy is cheaper than under the base pricing, in this case however the plant also creates revenue with pumping, thus minimising the pumping expenses. The results for the summer period are displayed in Figure 27 below.

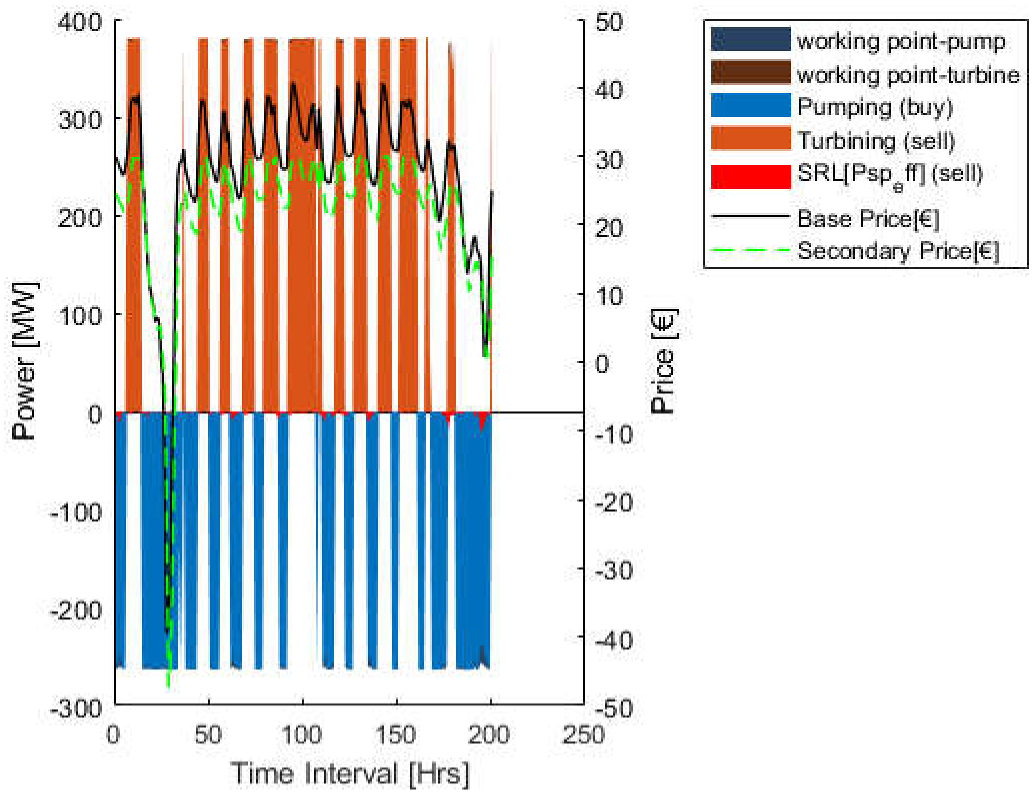

Figure 27:plant operation with negative aFRR -29.6.2019-7.7.2019

As can be observed from the Figure 27 above, the turbine working point is set to the maximum output of the power plant, 388 MW, but due to the negative secondary power it cannot deploy that much. The pumps however are used until roughly 265 MW, which in that case is the working point for the pumps. Here as comparison the revenue reached -130,075 €. Though still negative, it at least caused a gain of 13,286 € when compared to the operation without aFRR, as again, pumping for aFRR control creates an additional revenue to the fixed service price, which counters the pumping expenses in normal operation.

After looking at the effects of offering negative aFRR, now with the same calculations positive secondary control energy is offered. In Figure 28 the results during the chosen winter period are displayed.

As can be observed here, the positive aFRR, now being on the generating side of the power plant, the turbine power working point is again set at a little less than 400 MW. Further on, the price for offering this service is higher than the base price creating a higher revenue of 195,301 €. Noticeable is that the service price has the biggest impact on the revenue.

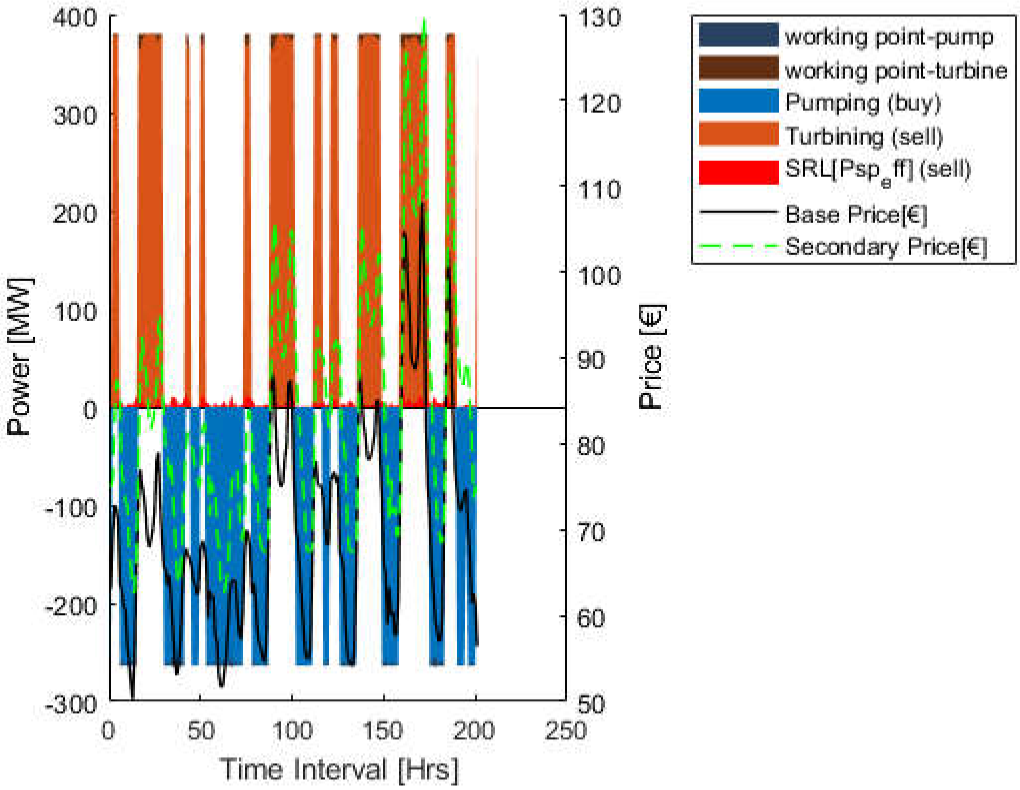

Figure 28:plant operation with positive aFRR- 17.1.2019-25.1.2019

As displayed in Figure 29 below, the positive control energy price is far higher than the base price and does not achieve a negative price in the summer period. The revenue is therefore, -98,075 € which is 32,000 € higher when compared to the negative control energy offering of the same period. Again, the optimiser here searches the best prices with the widest range adding the service and work prices to the already existing revenue, creating a better outcome.

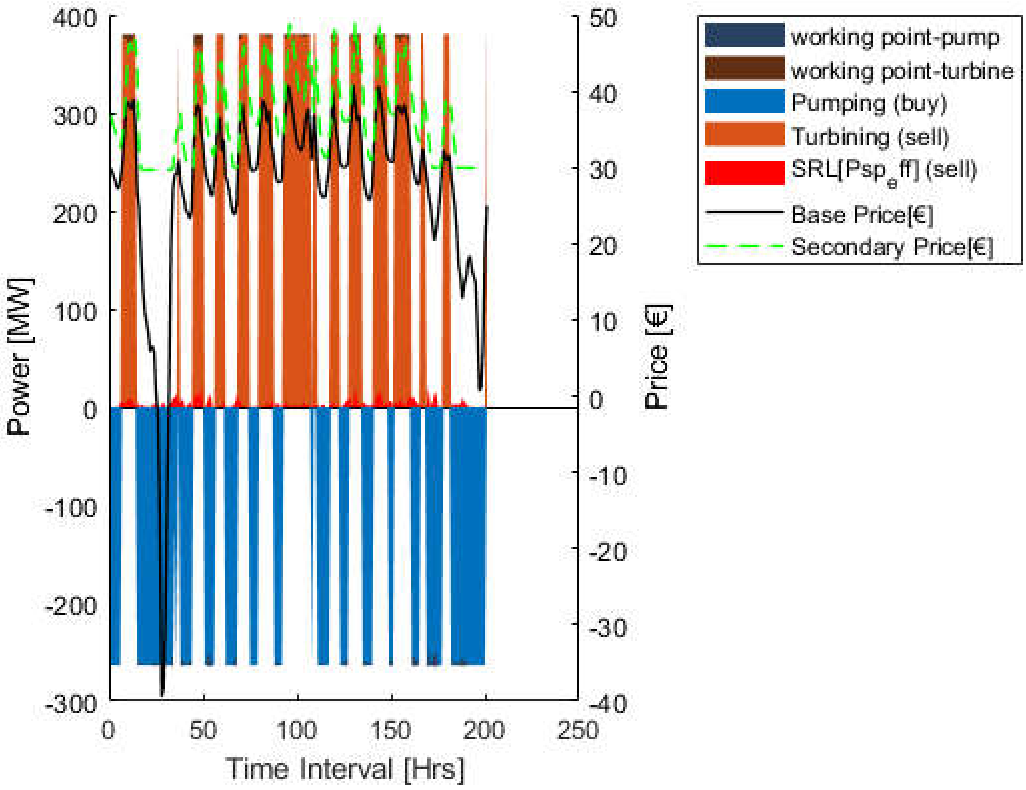

Figure 29: plant operation with positive aFRR- 29.6.2019-7.7.2019

When comparing now all three operation styles it is observable that offering aFRR displays an increase in revenue especially when offering positive control energy. Although the revenue increases, when looking at the 200 hours' time frames, it displays that during the summer periods with a low base price the power plant does not make any profit and so it would be better not to operate during the summer periods.

It is to be noted that the material stress in these scenarios is high due to the nearly constant mode changes, could result in a shortening of the life expectancy of the power plant. The question, which will not be addressed in this thesis is, if the achieved revenue would cover the costs of an earlier refurbishment and still cause a gain.

7. Introduction of Hybrid PSPP

In this chapter it is analysed if adding a 30 MW battery pack is beneficial to the PSPP at hand. The many different existing systems utilising battery packs to enhance the performance of run of river hydro power plants, or store not used energy from PV and wind parks build the motivation for the following investigations. It is to be noted, that while there are several implementations with run of river hydro power plants, there is no existing combination of a battery storage and a PSPP. For the model build, Lithium battery technology is chosen. These batteries have some positive and negative attributes, which will be listed below.

The positive aspects of Lithium-Ion batteries include [28]:

- Fast charging
- High energy density
- Great discharge depths

The high energy density is one of the great aspects of Lithium-Ion batteries, this giving the batteries the possibility to store high amounts of energy within a smaller mass than other batteries. Therefore, their weight when compared to other batteries is low. The discharge depth is also higher than other battery types, meaning that these batteries can utilise more of their capacity than other batteries.

To note as well are the disadvantages [29]:

- High Cost
- Safety
- Ageing
- Optimal working temperature of -20°C ~ 60°C [28]

Lithium-Ion batteries are more expensive than other battery types, as for instance nickel-cadmium batteries, here in comparison Lithium-Ion batteries may be 40% [30] more expensive as the latter.

The safety aspect refers to the further protection equipment needed to make sure that the Li-Ion batteries are not overcharged or discharged completely, as an overcharge can result in an unstable battery condition and can result in an overheating and lead to a fire, which is difficult to contain. Complete discharges on the other hand can reduce the batteries life extensively.

Ageing is another disadvantage of Lithium batteries, as every time they are used their cells degrade, therefore not only ageing due to time but also through usage.

There are different types of storage technologies on the market, depending on how long the storage should hold or how quick the response time should be.

Figure 30 displays in comparison different storage technologies and their technical abilities.

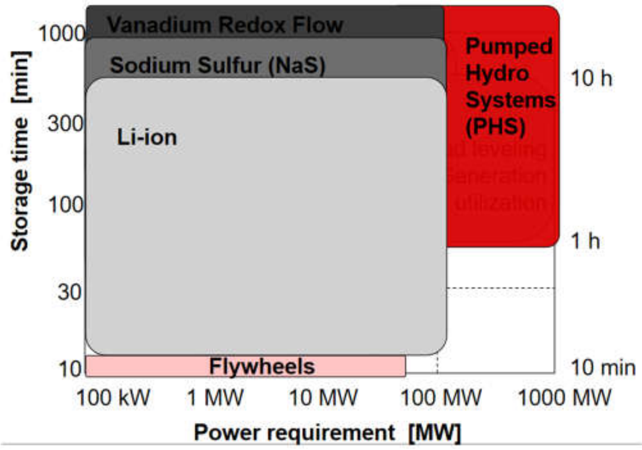

Figure 30: Different storage technologies [31]

Although fly wheels have a very fast response time, which would make them great for rapid changes in the grid, their capacity is very limited and therefore also their storage time. Lithium-Ion batteries are used in many battery storage systems and as mentioned have some advantages over normal batteries, which is why they are chosen to be implemented with the PSPP.

7.1 Optimisation

Before the optimisation of the power plant starts one has to ask the question, what should be optimised so that it may have a positive outcome to consider such an installation. It therefore is decided to optimise the power plant's power operation given an assumed load curve, where there may be a benefit of reducing the operation time of the electro-, mechanical equipment and so possibly extending the lifetime. The load curve data was self-established and not based on a real load curve. The purpose of this was to generate a scenario where the battery- PSPP combination could be analysed best.

In this model a battery with nominal power/a power rating of 30 MW and a capacity of 68 MWh is considered. The ambient temperature is assumed as a constant value and therefore has no effect on the battery. As already mentioned before, temperature has a great effect on the life span of Lithium-Ion batteries, therefore it is of best interest to keep their temperature range as small as possible. However, what is considered is the self-discharge rate. The self-discharge rate of Lithium batteries is very low, about 1%-2% [32] a month and is set to

$$\boldsymbol{\mu = 8 * 10^{-5}\, 1/h} \qquad \textbf{7-1}$$

The height of the self-discharge rate depends again on the temperature, if the temperature increases the self-discharge rate increases as well, therefore assuming the temperature as a constant, enables the self-discharge rate to be a constant factor as well.

The next step is to model the charging and discharging of the batteries. Lithium batteries are charged using the CCCV (Constant Current Constant Voltage) charging method. Here, the battery is charged firstly through a constant current until it reaches a specific voltage level and then shifts to the constant voltage charging to charge it up to 100%. The typical discharge curve for one Lithium cell is displayed in Figure 31 below.

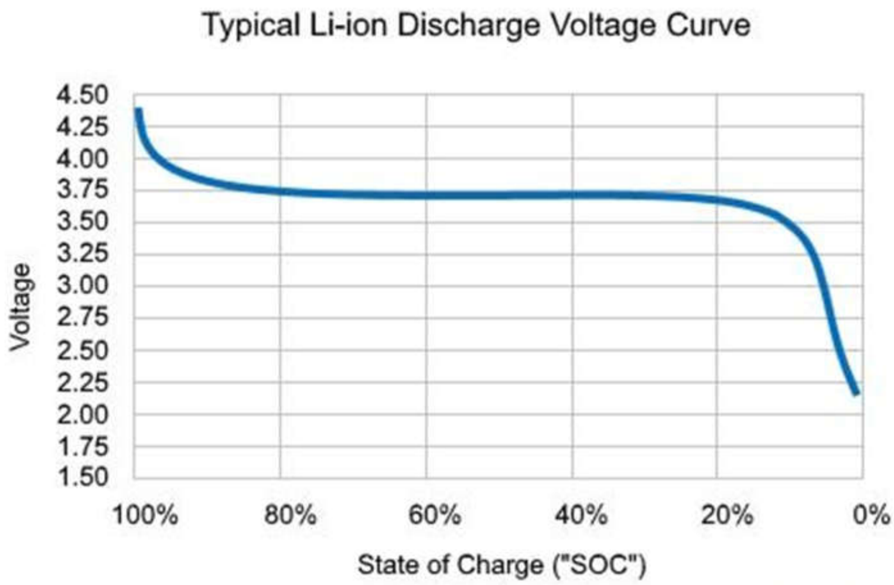

Figure 31: characteristic discharge of Li-Ion battery [33]

As displayed here in Figure 31, Li-Ion batteries have a very high depth of discharge (DoD).

To limit the ageing, one can limit the amount of charge/discharge cycles for a day and set the maximum discharge and charge voltage between 20%-80% of the state of charge (SOC). As the charging process of such batteries is a complex procedure a simplification is made, as between 20%-80% the curve is linear, therefore the SOC (V) equation is implemented as followed:

$$\boldsymbol{V(i) = V(i-1) + (c_{char}(i-1) - c_{dis}(i-1)) * (1-\mu)} \qquad \textbf{7-2}$$

The letter "i" represents the hours of the period of operation, c_{char} the charging variable, c_{dis} the discharging variable. It is also assumed that the battery SOC is fully charged (80% of its capacity).

In the next step the battery is added to the power equation of the pumped storage power plant.

$$\boldsymbol{P = P_T - P_P + P_b} \qquad \textbf{7-3}$$

The battery power P_b is set together by a charging (c) and discharging (d) variable.

$$\boldsymbol{P_b = P_d - P_c} \qquad \textbf{7-4}$$

Due to the simplifications the model resembles the PSPP model with the difference of a smaller capacity and a self-discharge rate. With the battery discharge resembling generation and charging pumping operation of the power plant.

Again, so that the solver can find a solution for the problem at hand, constraints have to be introduced, defining the operating range of the battery. One constraint for the SOC is that it does not go over its boundaries of 68 MWh and for the charging and discharging rates to stay within the 20%-80% range.

The SOC constraint featuring the battery discharge can be viewed below in equation 7-5. The charging constraint has the same formulation.

$$\mathbf{0.2 * C_b \leq c_{dis,i} \leq 0.8 * C_b} \qquad \textbf{7-5}$$

Here, C_b represents the battery capacity and $c_{dis,i}$ the current battery discharge capacity.

With the battery pack and PSPP storage constraints defined, the equation 7-3 was optimised around the power. The result of this is displayed in Figure 32 below.

7.2 Results

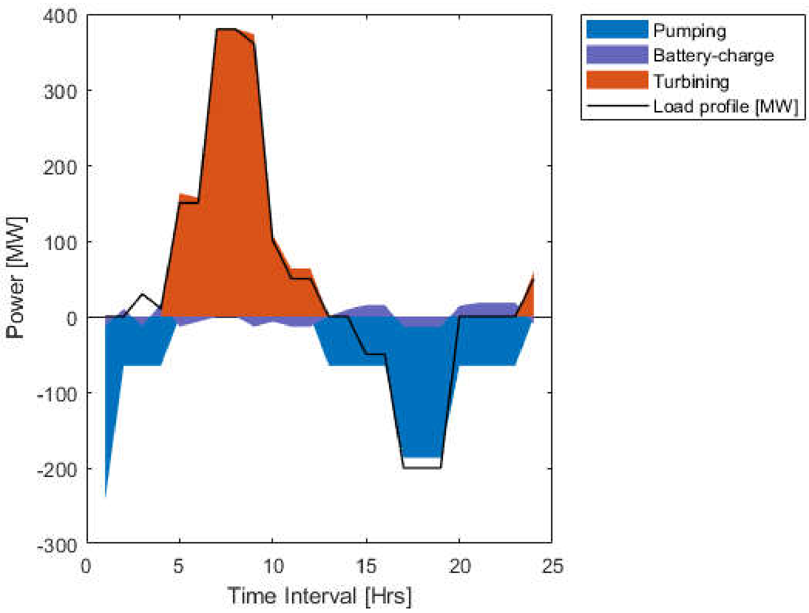

Figure 32: PSPP in combination with battery pack

The load profile is to some extent followed, as the load constraint did not define to be equal in every value.

As seen in Figure 32 the battery pack supports the power plant when generating and therefore relieving the units of not having to drive at maximum power. It is displayed in the graphic as negative, as the battery is discharging, the positive battery curves are when it is being charged. Although the capacity of the battery pack only lasts for 2.26 hrs, when not discharging at full capacity, it can then support the units, though minimal for a longer duration. Ideally the battery pack would have such dimensions, that it could take over the power generation for a short period of time. But this would mean increasing the capacity to a least the power rating of one unit. During the pumping operation the battery pack is also active and thus can support the pump process in the way, that for a period electricity must not be fed in from the grid to operate the pumps but can come from the battery pack.

Table 8: PSPP-generating with Battery below shows the requested power per unit for generating and the batteries cycling. For the first hours all units are zero as in these periods the optimiser does not seem to find it suitable to generate.

Hour [hrs]	Unit 1 [MW]	Unit 2 [MW]	Unit 3 [MW]	Unit 4 [MW]	Battery [MW]
1	0	0	0	0	-13.2
2	0	0	0	0	10.44
3	0	0	0	0	-13.2
4	0	0	0	0	-7
5	66.2	0	97	0	-0.54
6	60	0	97	0	-0.54
7	89.54	97	97	97	-13.2
8	89.54	97	97	97	-7
9	82.2	97	97	97	-0.54
10	60	47.13	0	0	-0.54
11	60	3.2	0	0	-13.2
12	60	3.2	0	0	-7.13

Table 8: PSPP-generating with Battery

Although the battery pack does in some cases reduce the power of some units, it would in the long run not make that much of a difference, regarding the size of the power plant. To create a better comparison and overview of the capabilities of the hybrid power plant to the already treated scenarios, an optimisation over the revenue formula is done. The revenue equation R is adjusted to:

$$R = \sum_{i} \left(P_{T,i} - P_{P,i} + P_{b} \right) \cdot p_{base,i} - \frac{wC}{8760} \qquad \textbf{7-6}$$

Here, the only difference to the revenue function from before is the addition of the battery power P_b.

As before, the plants operation during the winter period is optimised as seen in Figure 33.

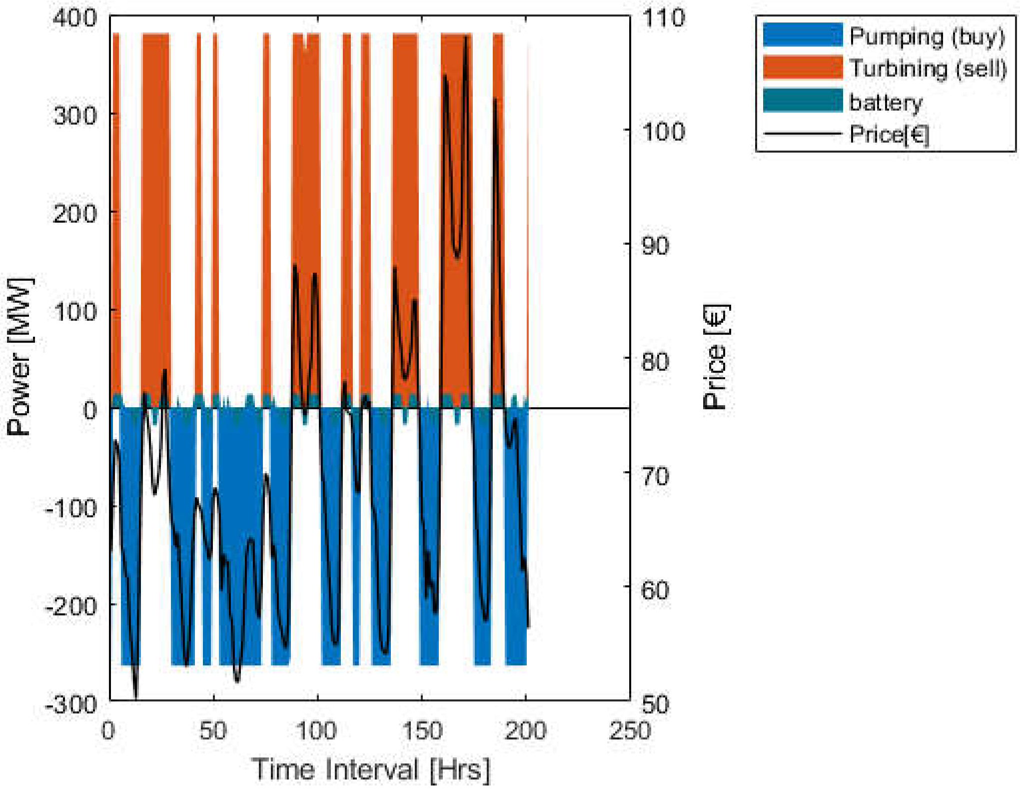

Figure 33: Hybrid 17.1.2019-25.1.2019

When the battery is employed at small price peaks which are of a short duration it can add to the total revenue, which now is 168,834 €. In comparison the revenue without the battery for this period lied at 146,968 €. In this case the power plant runs the battery and itself on full capacity, creating at times they run together a higher power output. It also creates the opportunity to while pumping still generate revenue on small price peaks with the battery. On the other hand, one could in this case view the result and say that one unit of the power plant can run at less capacity for the time in which the battery can cover it. Below the summer result is displayed in Figure 34.

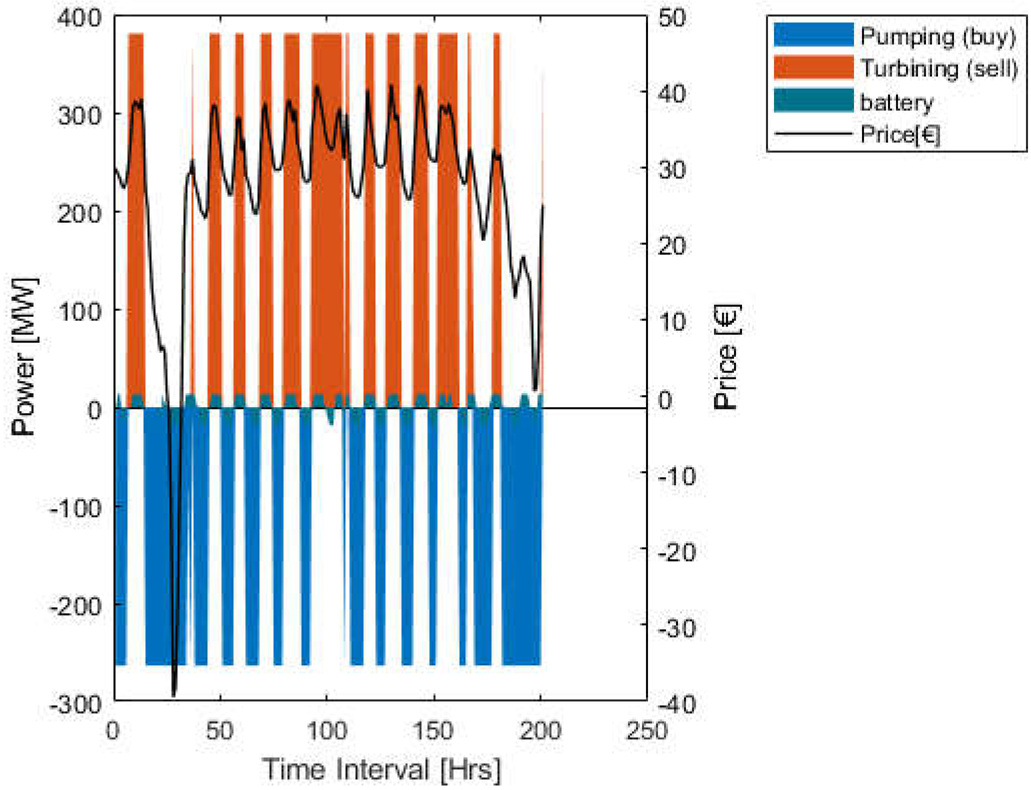

Figure 34: Hybrid 29.6.2019-7.7.2019

Here the battery is rather on par with the pumped storage power plant, adding to the fully deployed capacity of the PSPP and resulting in a decrease of loss to -129;141 €; in comparison -143,361 € without the battery pack. Through the high cycling of the Lithium-Ion battery pack will reach is end of life faster, as they only last a few thousand cycles. The result, as in the optimisation process without a battery, displays again that an operation of the PSPP is best in the winter months.

8. Conclusion

Starting off with the future policies the problem with the low electricity prices is addressed but expected to rise by itself due to missing energy capacities when fossil fuelled power plants are retired, creating therefore a higher demand, and increasing the prices. Another aspect which has changed as one notices that the transformation of the energy systems to 100% renewable will need some form of stable energy, here hydropower comes into play. Policy wise a lot is planned to help with making the realisation of projects shorter and to financially support them with incentives. Although there are some interesting aspects in the policy regarding pumped storage power plants in Austria, where grid usage fees would fall for PSPP which started their operation after the first of January 2019. Most of Austria's PSPP are in operation before that date, which excludes them from the benefit. It would be interesting to know if this includes revitalised power plants into the scheme or only newly built ones. Coming now to the optimisation of PSPP's in regard to the reference project. The optimisation results for the plant without the participation into the control energy market, suggest that the power plant would operate best in the winter times, as here the market price is high, and a good amount of revenue can be achieved. In summer however with the low prices, the power plant operates with losses. When the power plant model is adapted so that it can take part in the secondary control market, especially when offering positive secondary control energy, it could achieve a higher revenue and in summer the losses are dampened in comparison. Although it might be profitable, the constant regulating of the machines to cover the aFRR energy demand would add additional stress to these that could result in an earlier than planned maintenance. The introduction of a hybrid PSPP does in the end not fare as well as assumed when using a reasonable sized battery pack. The battery is used when there are short periods of higher prices and can be deployed while the power plant is pumping, and therefore minimising the loss. Also, it increases the power plants power for a short period of time, though when optimising the power plant for a fixed load it does not significantly support the units. It could also be used, as in the optimisation of the power plant with secondary control, for offering primary control, as this control mechanism needs faster response when called upon and the time it is active should be manageable for a battery. Though here again, if it is called upon multiple times a day, within short intervals the battery pack in the model may not ably compete. Although it fared well in deploying for short peak periods in the price, the amount of battery cycling would with precautions of not driving the battery to its limit, lessen the life expectancy. Though for small pumped storage power plants it could work better, as here the capacity they hold is far less and therefore the battery to integrate with the plant could have the size of the unit. In this case it may fare well with a small power plant as the battery could support the small unit better and thus enhancing the life expectancy.

The scenario analysis displays very well that pumped storage power plants will become very important in the future with the increase of RES. As one can see with the rise of especially PV, the pumped storage power plants worked to store the overabundant energy. Also, as can be seen there, if PV and or wind power are short of their production, pumped storage power plants must make up for the loss. For those periods that this might occur, the electricity prices could rise, as the demand rises creating a lucrative opportunity for pumped storage power plants.

In conclusion one can say that although at the moment it sometimes does not seem economical to operate a pumped storage power plant throughout the whole year, it might become better with the expected future development of higher electricity prices and the correct policies in use.

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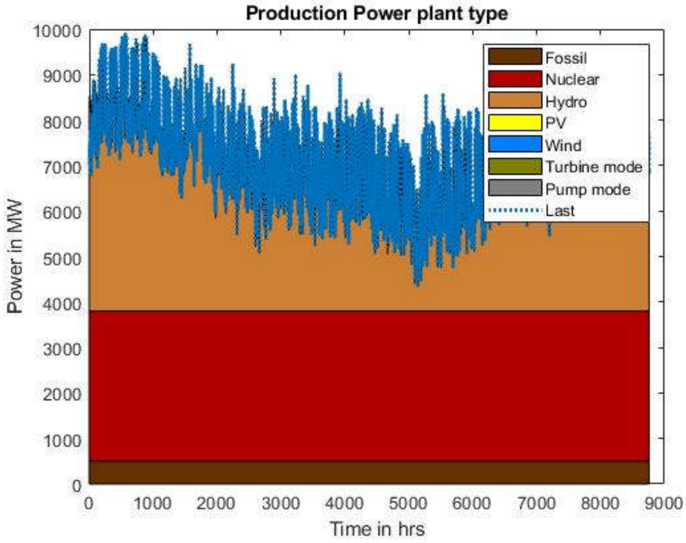
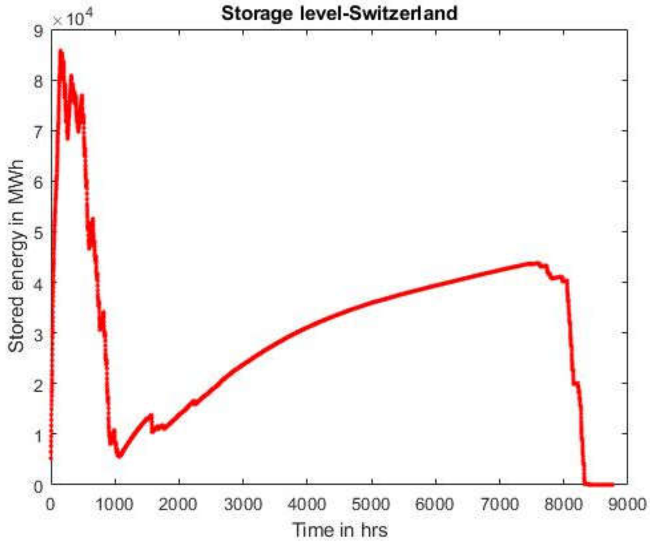
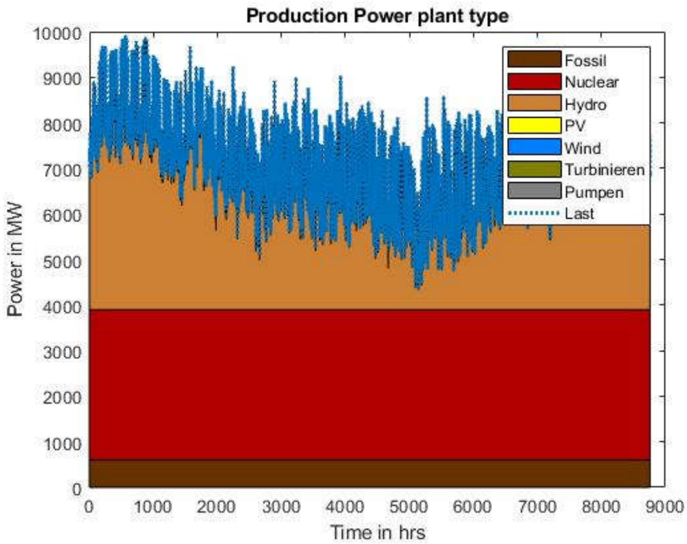
10. Appendix

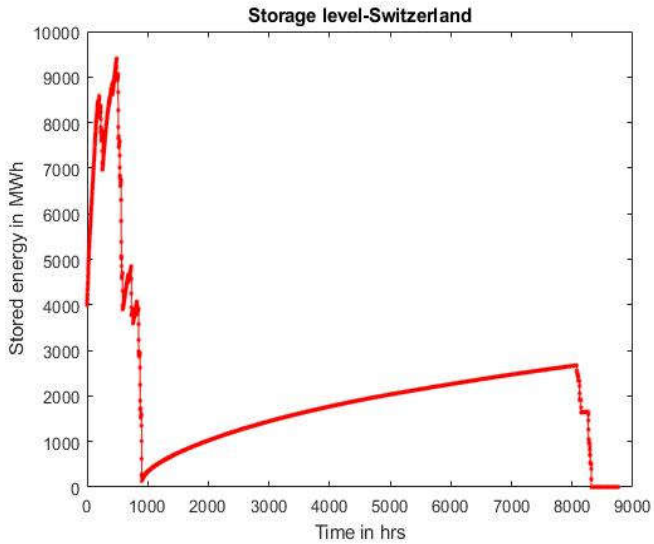
10.1 Power plant operation 2019 and storage utilisation



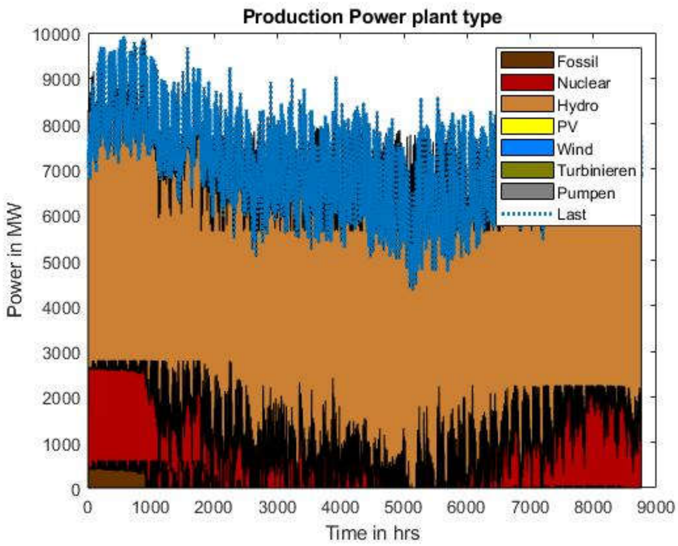


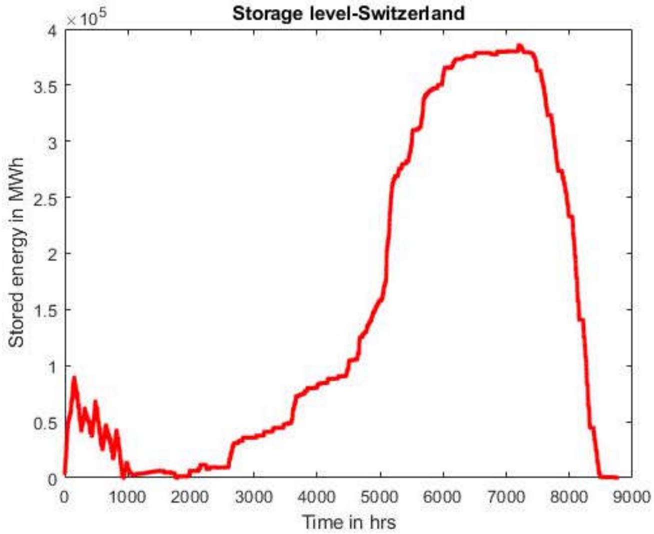
10.2 Power plant operation 2025 and storage utilisation



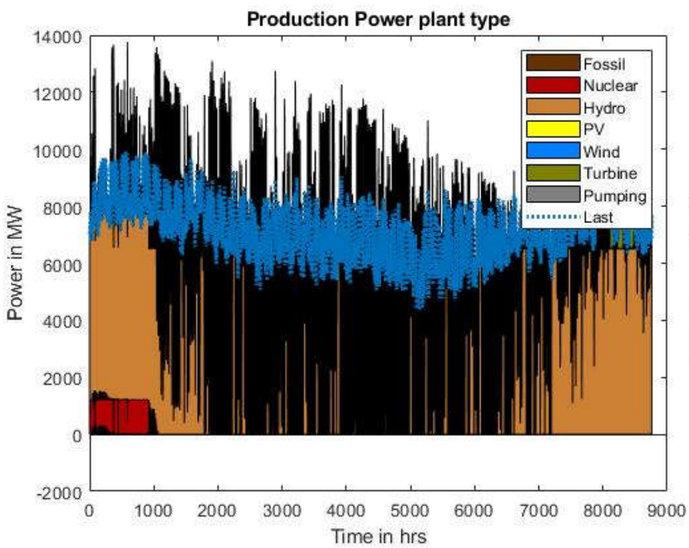


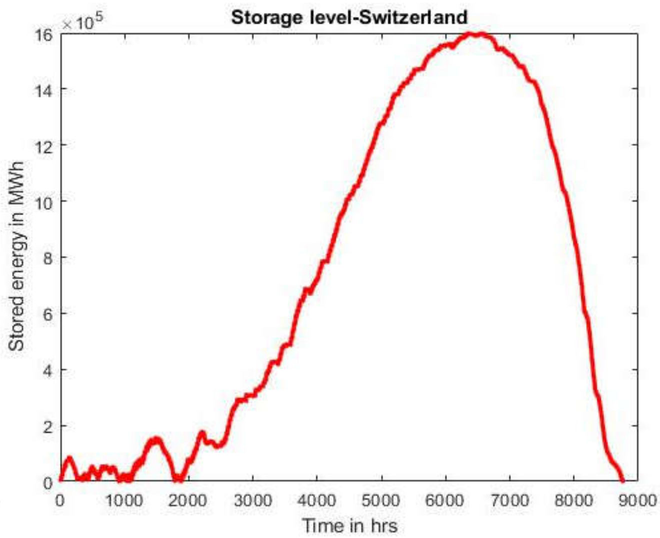
10.3 Power plant operation 2030 and storage utilisation



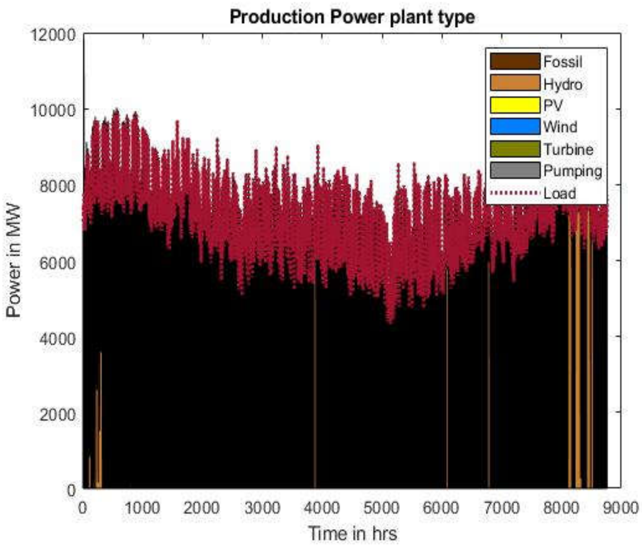


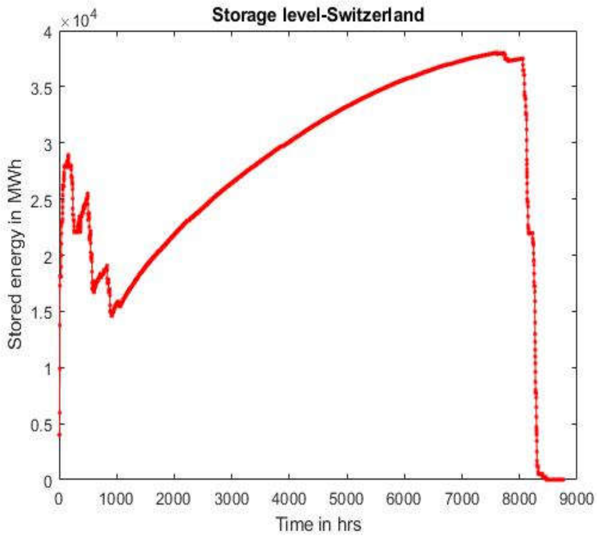
10.4 plant operation 2035 and storage utilisation



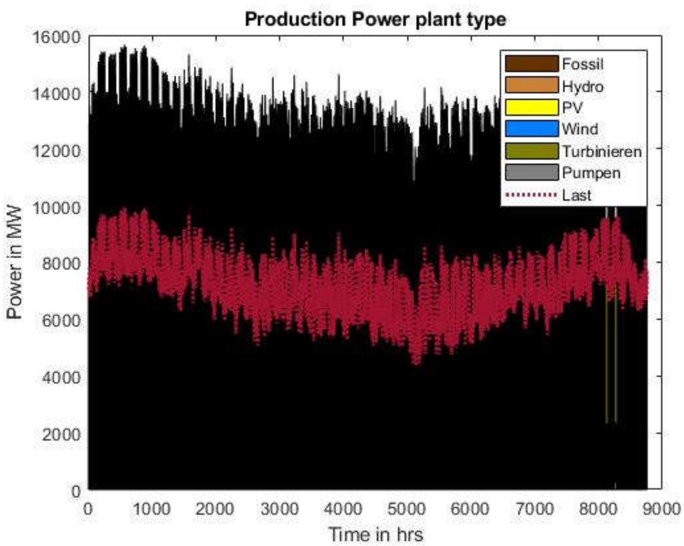


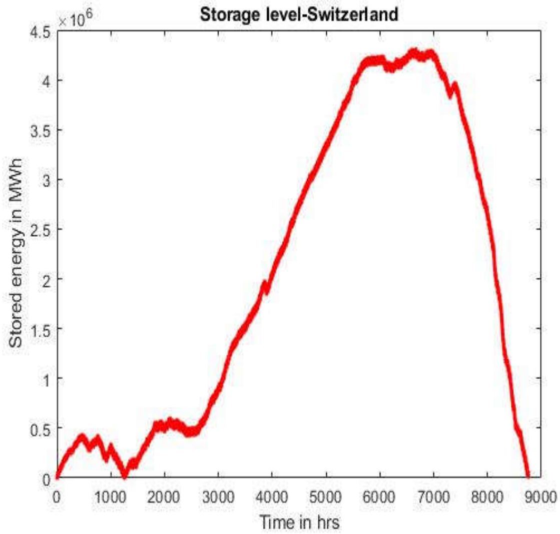
10.5 plant operation 2040 and storage utilisation





10.6 plant operation 2050 and storage utilisation





10.7 Mosek Results

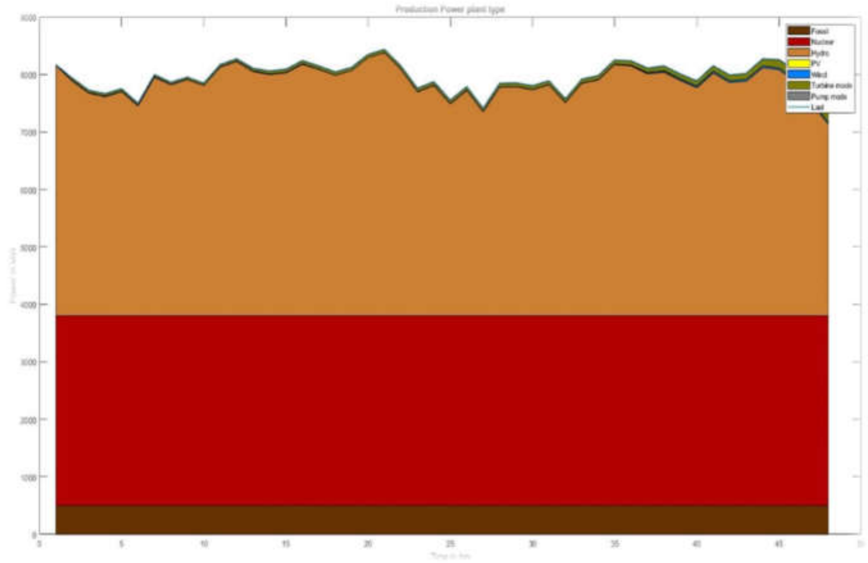


Figure 35: 2019 January 12th and 13th power plant operation

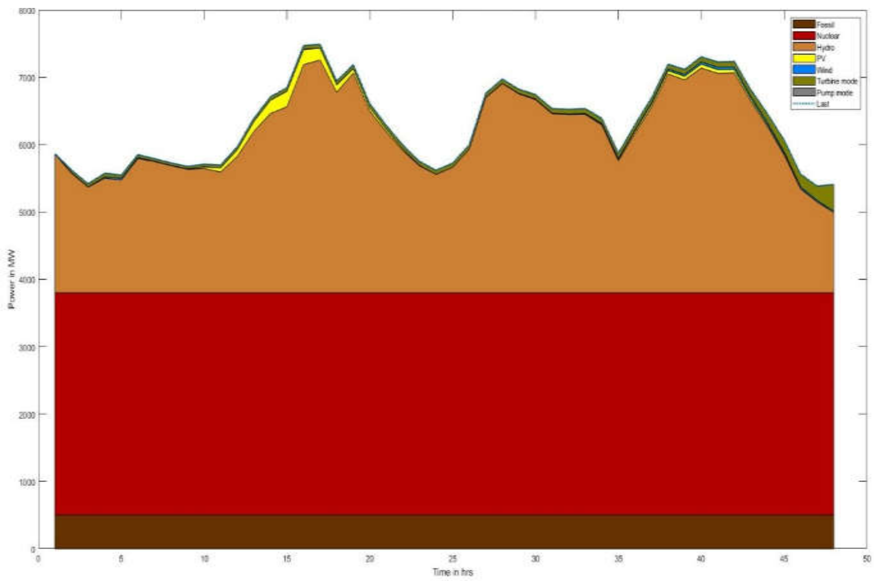


Figure 36: 2019 July 27th and 28th power plant operation

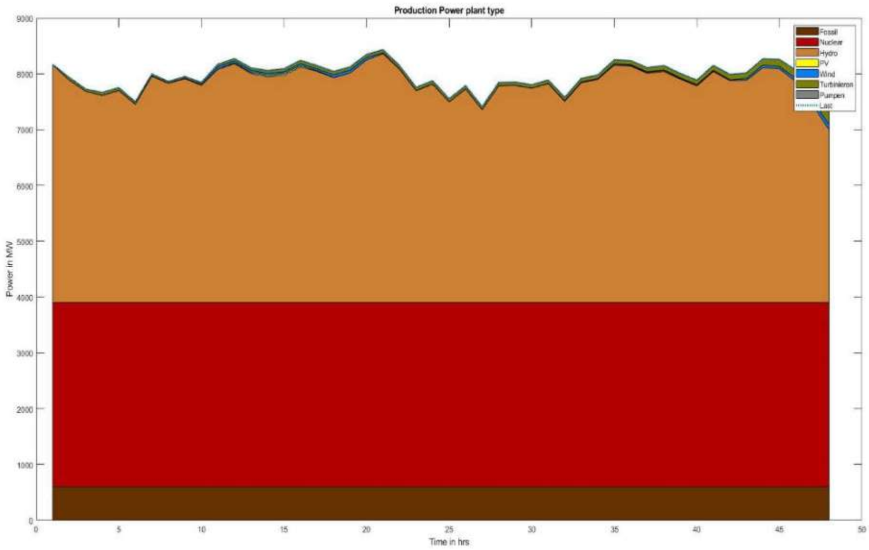


Figure 37: 2025 January 12th and 13th power plant operation

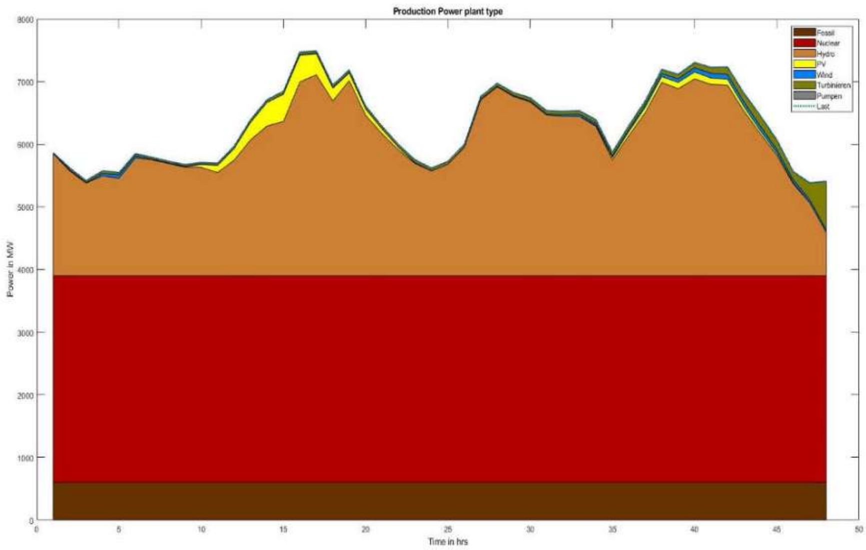


Figure 38: 2025 July 27th and 28th power plant operation

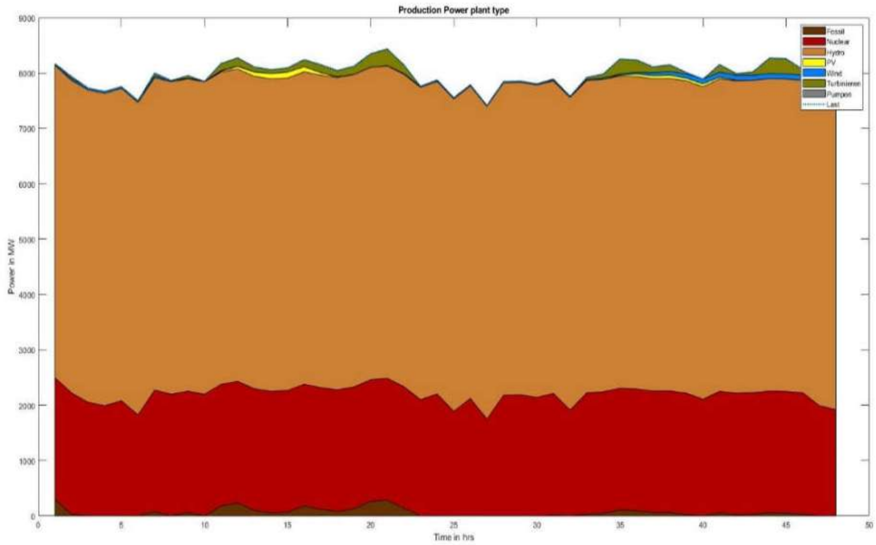


Figure 39: 2030 January 12th and 13th power plant operation

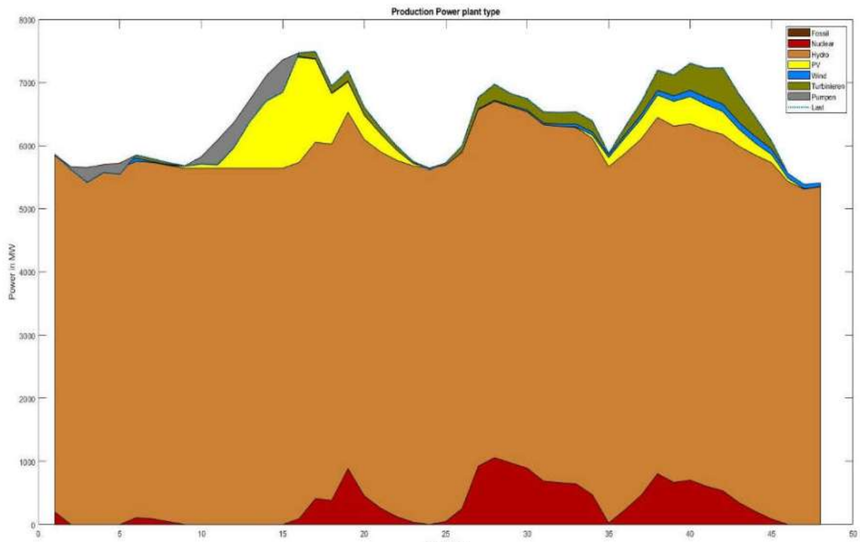


Figure 40: 2030 July 27th and 28th power plant operation

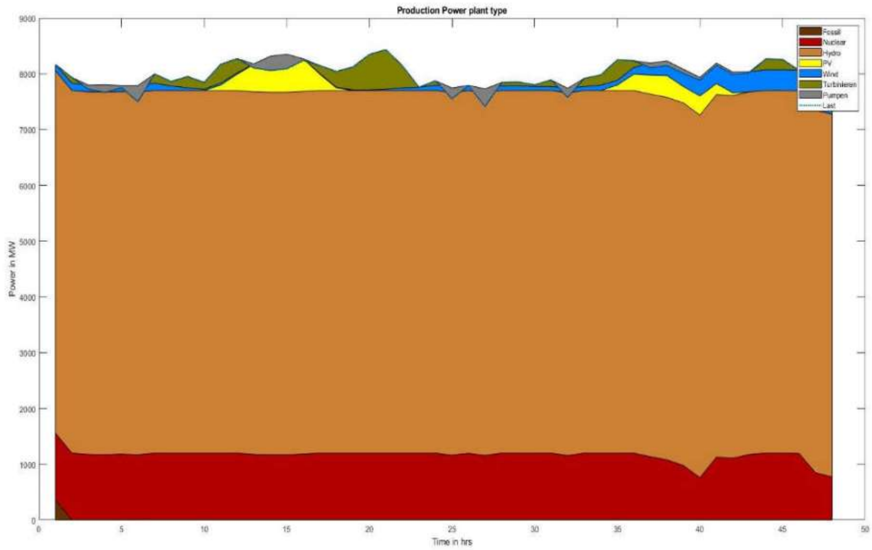


Figure 41: 2035 January 12th and 13th power plant operation

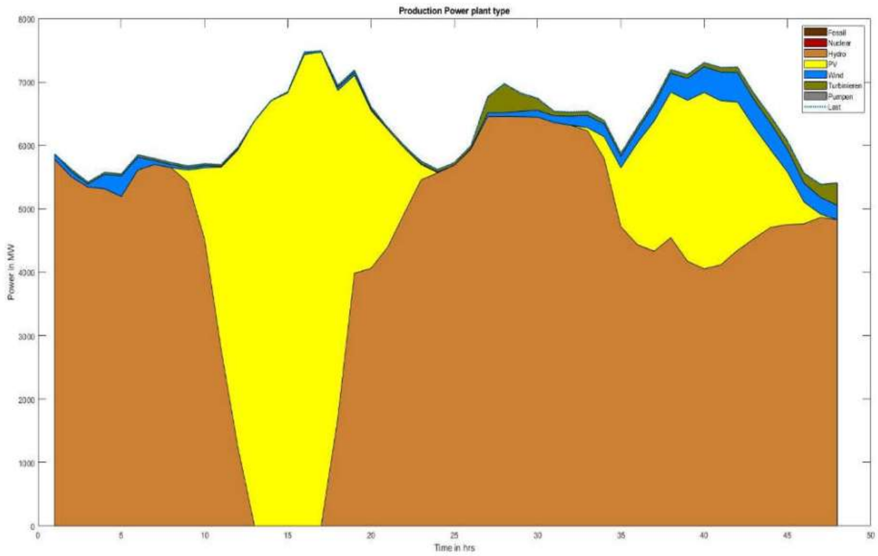


Figure 42: 2035- July 27th and 28th power plant operation

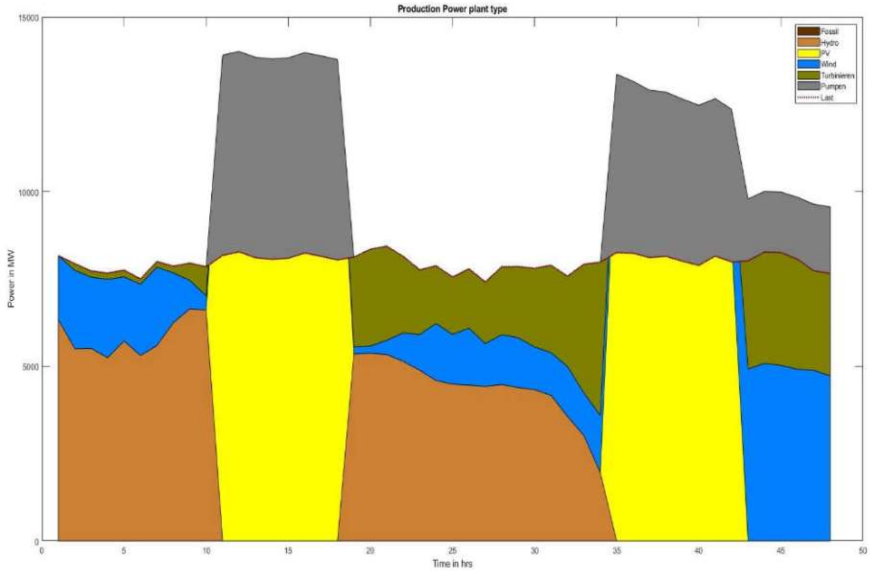


Figure 43: 2050- January 12th and 13th power plant operation

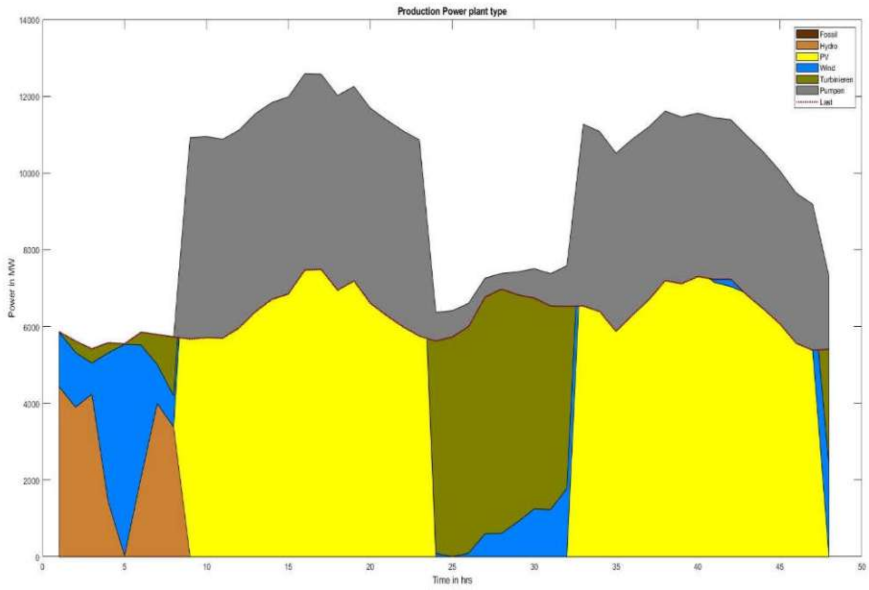


Figure 44: 2050- July 27th and 28th power plant operation