Renewable Energy Systems: Project

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By Frederik Giessing Nielsen (201608565)

AARHUS UNIVERSITET

Photo: SwissWinds

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Introduction

The following assignment describes the procedure and results of modelling the energy system of a European country. In line with the earlier assignments, the country of choice is Switzerland. The model is coded using Python and the energy modelling framework PyPSA [1] is utilized. A full description of the linear optimization formulation can be found in [2]. The model will be carried out using the *green field* approach, which seek to determine the optimal energy system composition, given no earlier installments are present. The used data and code can be found at the following github repository https://github.com/Rahca2308/RES_Project_FGN.

A. Calculate optimal capacities for generators

This section will solely concern the optimal solution to an isolated swiss electric grid, in the year 2015. The Pypsa *Network* object is created, and the swiss electricity bus is added. All generator data is taken from [2]. Open cycle gas turbine (OCGT) is added as the only non-renewable generator option. The bus load/electricity demand, offshore wind and solar capacity factors are added as hourly resolution data from the project description. Solar are assumed to be utility scale installations.

From the same data source, the water inflow for Switzerland can be found with a daily resolution. This data is not present for 2015, so instead a mean of the present values between 2003 and 2012 will be used through the model. The data is up sampled to an equally distributed hourly resolution, so the sum of 24h will result in the original mean daily value. The water inflow will now be divided into two different types of hydropower sources, Run-of-River (RoR) and Hydro Reservoir (hydrores). The model will assume that these technologies are fully amortized, and the inflow will be split evenly between the two, given that they produce the same amount of electricity, in the currently swiss grid [3]. Run-of-River (RoR) will be modelled as a generator, which always dispatches the inflow power through time. Hydro Reservoir will be modelled as a storage unit, which receives the hourly inflow values, but is free to dispatch the optimal amount, given the constraint of maximum power output of 8224 MW [3] and a maximum energy capacity of 8.8 TWh [4].

The optimization is carried out, with the following results:

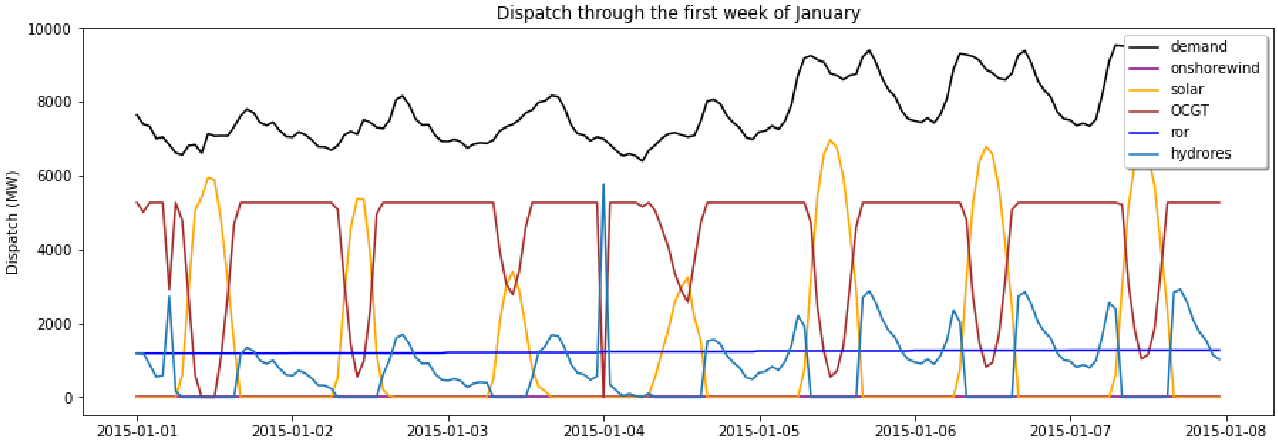
Table 1: System costs of the no CO2 constrain optimization

Total cost of the system	1413.69 mio. €
Total cost of system pr. MWh	22.78 €

Table 2: Optimal generator capacities with no CO2 constraint

Generator	Optimal capacity [MW]
Onshore wind	0.0
Solar	11549
OCGT	5268.7

Interestingly, as seen from Table 2, the optimal solutions does not contain any wind energy at all. To visualize the electricity system a plot of dispatch timeseries in the first week of January and July is presented in Figure 1:



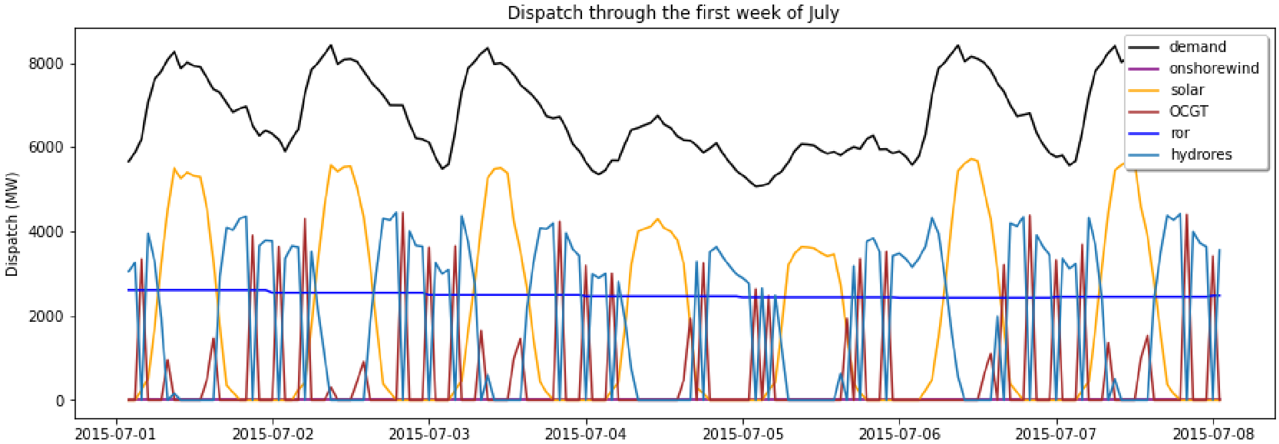


Figure 1: Dispatch of the no CO2 constraint system through January and July

The figures show that RoR serves as relatively constant dispatch on the weekly scale. Solar is, especially during July, the primary electricity source during the day. OCGT is used as the primary source when the sun is not shining, but during the summer the hydro reservoirs will largely take over this role. This is of course because the reservoirs have been filled with melting water through the spring which can also be seen from the state-of-charge of hydrores, Figure 2. This can now be dispatched when RoR capacity drops.

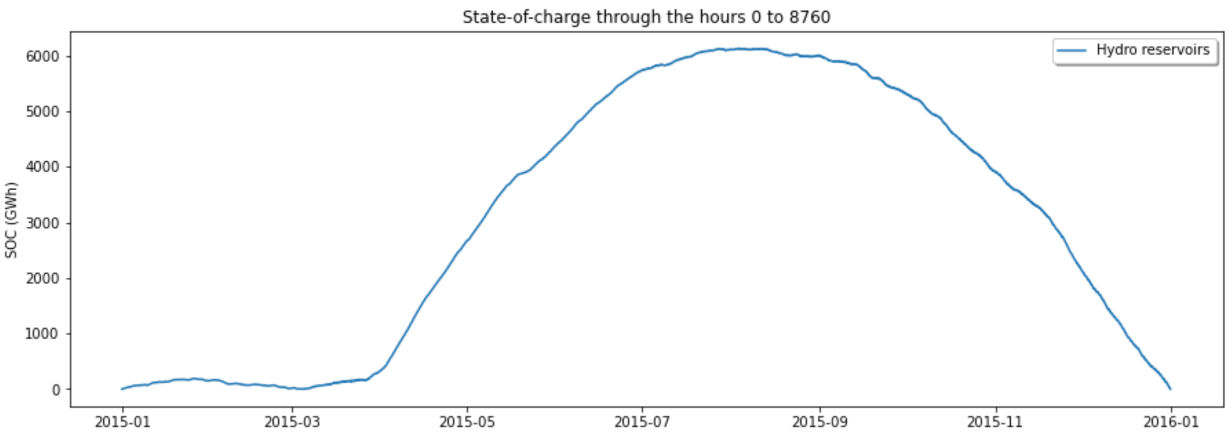


Figure 2: SOC of hydro reservoir in the non-constrained system

To get an overview of electricity mixture through the year, one can make a pie plot, see Figure 3.

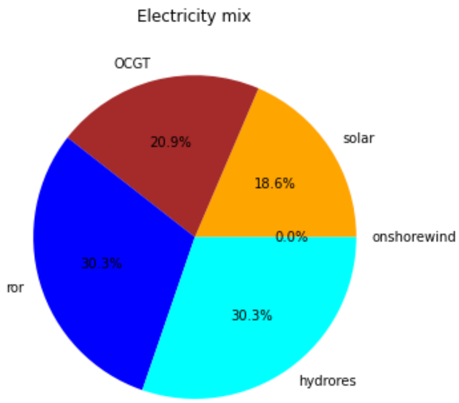


Figure 3: Electricity mix in the unconstrained system

Here the collective hydro power is seen to be 60.6% of the total electricity usage. This is in line with real present value of 57% [3]. To inspect how the conditions are for the renewable generators we can plot the capacity factors. In the following figure CF's is up sampled to days, and inflow CF is just normalized inflow.

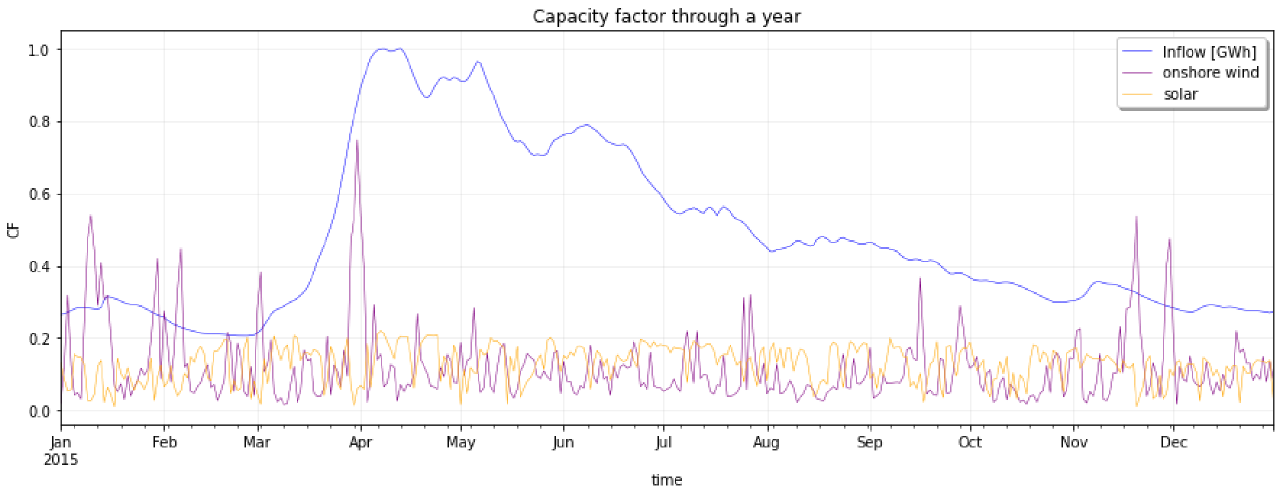


Figure 4: Capacity factors of the reneable generators

The figure essentially shows quite low onshore wind capacities, and that is why this option is not very feasible. All mean values, by monthly basis, is below 0.2 CF. In comparison Denmark has a mean annual CF of 0.468 [5]. Few synoptic spike patterns exist though, as shown by the plot. For solar energy there is some seasonal dependance, but it is not that significant. Monthly mean values are between 0.15 in the winter to 0.18 in peak summer.

B. Constrain the CO2

The following section will investigate how the optimal capacity changes with varying CO2 constraints on the system. A loop is done through constraints from 4 Mton to 250 kton CO2. The following table presents the results of the strictest constraints.

Table 3: Optimal installed capacities and TCOS of varying CO2-constraints

Optimal capacities, with different CO2-contraints				
CO2 constraint [ton/CO2]	Onshore wind [MW]	Solar [MW]	OCGT [MW]	TCOS [mio. €]
250,000	40909	18442.8	4533.5	4089.7
500,000	25115.5	16671.8	4714.6	2908.6
750,000	16234.9	14851.9	4844.9	2246.9
1,000,000	10235.1	14030.8	4941.1	1839.2
1,250,000	5960	14054.1	5077.9	1595.9

Interestingly the table shows that wind energy now becomes vital to the system and the TCOS have increased by a factor of 3 (4090 mio. €) compared to the unconstrained scenario (1413.7 mio. €).

To visualize the results the follow figure will show optimal installed capacity as a function of the CO2-contraint. The vertical lines represent the historical CO2-emissions of swiss electricity generation[6].

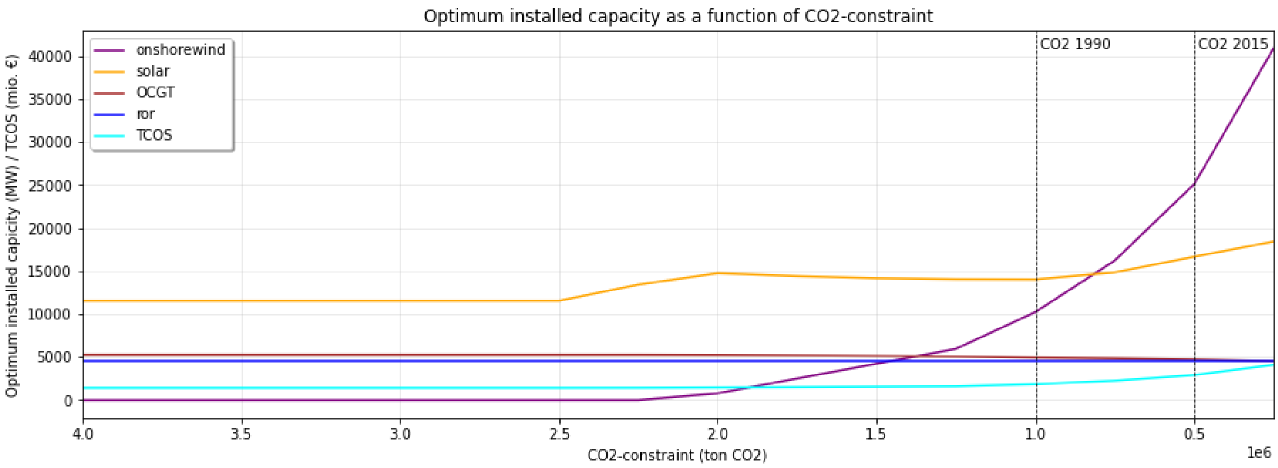


Figure 5: Optimal installed capacity as a function of CO2-constraint

What is seen on the figure is that up to the point of 2.5 Mton, the solution is independent of CO2-constraint, i.e., the constraint is inactive. From this point the installation of solar will increase and wind power capacity will sharply increase. Interestingly the optimal capacity of OCGT remains relatively unchanged, which emphasize its need as a backup supply when the renewables are unavailable. It has been chosen not to extend the CO2-constaint further, because this simply will sharply increase the need of onshore wind, which we have learned is a suboptimal solution for the swiss electricity grid, greatly increasing the TCOS. One can study the electricity mix through Figure 6, which plots % of annual electricity mix as a function of the CO2-constaint.

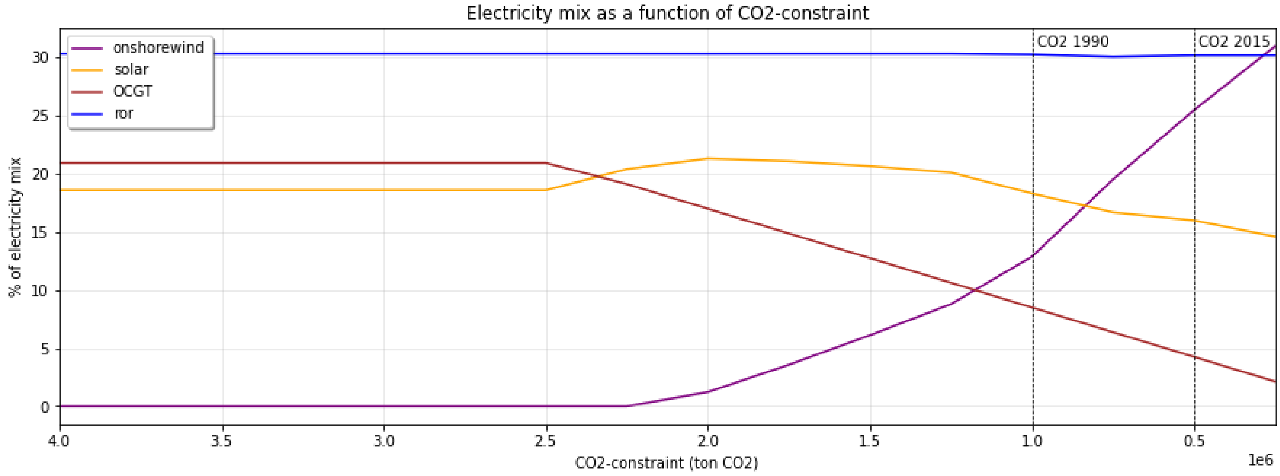


Figure 6: Electricity mix as a function of CO2-constraint

This figure shows some interesting insights about the system. Even though it was seen that the capacity of the OCGT generator remained the same, the following plots shows how the generator contribution decreases linearly, to the point where it only produces around 2.5% of the total annual electricity, as the constraint hits 250 kton. Furthermore, it's also noteworthy that even though the installed solar capacity increases, the produced electricity fraction decreases as onshore wind becomes the dominant power annual power source.

C. Investigate interannual variability

Given that the model so far only has been for the year 2015, it's interesting to look into how this year compares to other years with different weather. To investigate this, a script has been constructed to loop through years between 1991 and 2015, and determine the optimal installed capacities. The script will incorporate CF data from the given year, but the demand and inflow will be assumed constant.

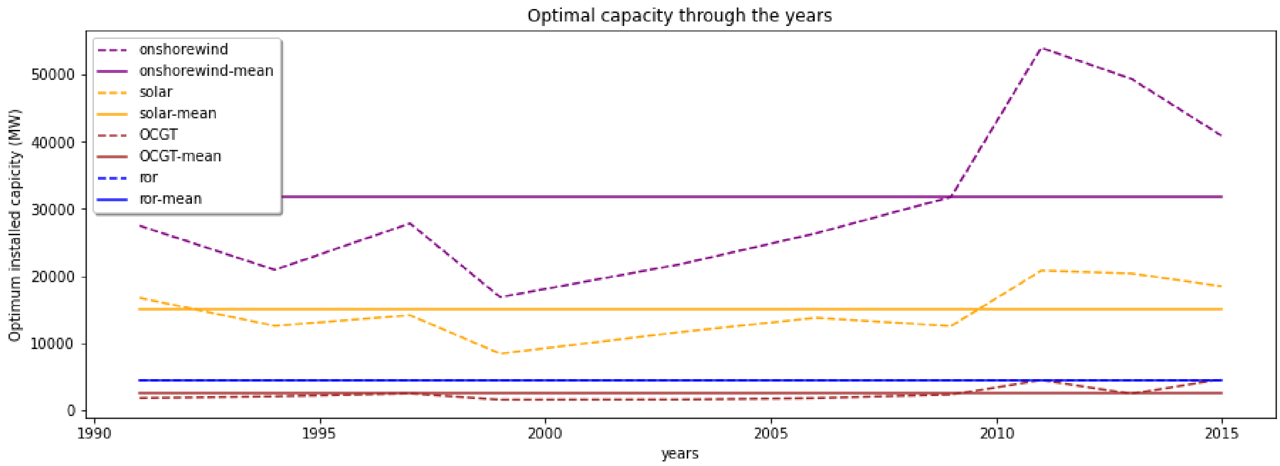


Figure 7: Optimal capacity through the years 1991-2015

What is interesting to note is that large variations occur through the years. The year modeled so far, 2015, has more challenging weather for the renewables compared to the mean, but 2011 is even worse and require substantially higher capacities for all generators. A table of optimal capacities can be found in Appendix I – Overview of optimal capacities through the years. With this concern in mind, the model will continue to use 2015 for consistency.

D. Add storage technologies

The following section will investigate how adding storage technologies will influence the model, utilizing the PyPSA, *storage_unit*, *store* and *links* components. Pumped Hydro Storage (PHS) will be added as a fully amortized technology with power capacity 1380 MW, and 369 GWh energy capacity [7]. Electric batteries with inverters for both charging and discharging, as well as hydrogen with fuel cells and electrolyzes is added. These will be optimized for both energy storage and power capacity.

Optimizing the network shows a substantial reduction in the TCOS of ~900 mio. €

Table 4: TCOS for the system with added storage

Total cost of the system	3209.84 mio. €
Total cost of system pr. MWh	51.72 €

The following table will show the optimal capacities of generators and storage.

Table 5: Optimal capacities of generators and storage

Generator	**Optimal capacity [MW]**
Onshore wind	23645.4
Solar	23538.7
OCGT	4736.2
Storage/Links	**Optimal capacity**
Battery/Inverters	0 [MWh]/ 0 [MW]
Hydrogen storage	47047.4 [MWh]
Fuel cell	1275.6 [MW]
Electrolyzers	4065.1 [MW]

We see that onshore wind generator has been reduced to roughly half of the scenario without storage available, OCGT is roughly the same and solar has gained a small increase. The optimal solution does surprisingly not contain any electric battery storage, but hydrogen with substantial electrolyzes capacity of 4 GW, and storage of 47 GWh. This is possibly because of the already available hydro storage, and because the model is without any ramp times or startup cost. The actual storage of hydrogen pr. kWh electricity is also very much cheaper than batteries with 8.4 compared to 144.6. The storage balance can be studied through the following figures:

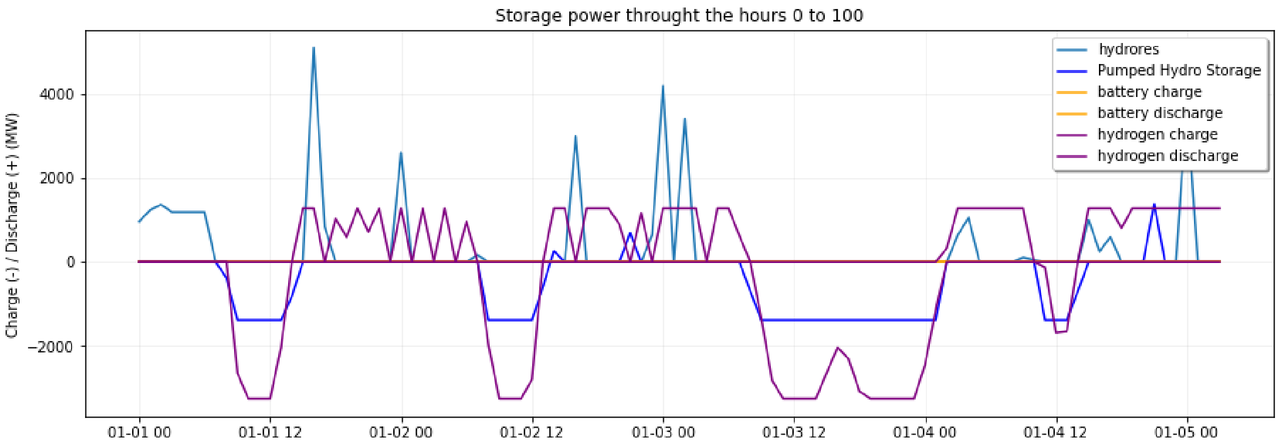


Figure 8: Storage power dispatch through the first 100 hours of 2015

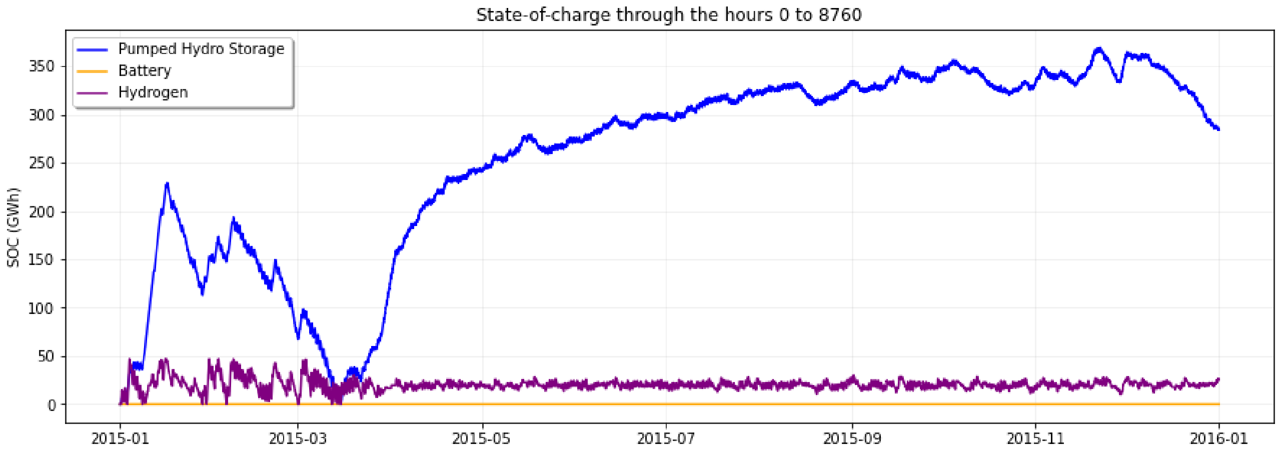


Figure 9: Storage SOC through the 2015

E. How does the system balance different timescales

It was seen in the first section how hydro reservoirs was used as the primary seasonal balancer, and PHS does to some extend act in the same way. The plot of storage power, Figure 8, does show how all present technologies possess diurnal patterns, with PHS and hydrogen charging during the day, with solar present. These diurnal pattern for highly renenable systems were also seen by [2]. Hydrores and hydrogen act as the main discharger when the sun sets in January. The SOC shows how both hydrogen and PHS act at a synoptic balancing in the winter months but beginning in the fall PHS seem to overtake this role.

F. Select decarbonization level, and investigate results

In line with the previous work the selected CO2-level target will be 250k ton. This is 50% reduction compared to 2015 and 75% compared to 1990 levels. We check the CO2-shadow price by looking at the lagrangian multiplier.

Table 6: CO2 contraint and shadow price

CO2 constraint	250,000. ton/CO2
CO2 shadow price	2866.7 €/ton

This is an extremely high tax. As of 2018, Switzerland has a CO2 levy of 89,14 €/ton for fossils fuels for heating [8]. What does need to be taken into account, is that the relatively small emissions of the swiss electricity generation today, is not because of renewables like solar and wind, but because Switzerland relies heavily on nuclear generation. Furthermore, these results show another key insight about the swiss electricity grid. Decarbonizing a the isolated swiss electricity grid is quite costly, so therefore a major component of this transition will be for the swiss to enhance the reliance on interconnectivity with its neighboring countries, and the rest of the European electricity grid.

G. Connect to neighboring electricity grids

Two investigate how the system changes when adding interconnections, the French and German electricity grid will now be added as two new busses. They will have the same generators and storage possibilities, but without any hydro power. This is deemed less vital in these grids and keeps the system at a manageable complexity to analyze connectivity. The electricity busses will be connected via the *links* functionality, which will represent HVDC lines and converters. Capital cost will here be proportional to the length of lines, given as the mean distance between the two countries represented on Google Maps. The links are assumed to be 100% efficient. The applied CO2 constraint will be 5% of 1990 emissions for the three countries.

The actual optimal solution will of course depend a lot on the size of the CO2 constraint enforced, but nevertheless there are some prevalent continues patterns when the 3-country system is optimized.

- The generators of Switzerland have completely changed. In all scenarios where we connect Switzerland, onshore wind is eliminated as a generator. Only solar is now installed with capacities around 20GW.
- Both electric batteries and hydrogen has a place in the optimal solution in the 5% CO2 scenario, but with a less restrictive constraint the storage become less important. As the constraint becomes more restrictive, hydrogen becomes the storage option of choice for Switzerland.
- Switzerland relies heavily on power import in the hours without sun. Storage and export are done midday.

In the 5% scenario, France will be the dominating generator with the highest amount of solar and wind capacity installed. The link capacities will be 1,8 GW for CHE-DEU and 6,2 GW for CHE-FRA. It is seen that the link DEU-FRA is generally in the order of 10 times the size of the swiss links. Annual imports from France is 9.3 TWh and exports to Germany is 6.3 TWh, for the swiss electricity bus. In comparison the annual swiss electricity consumption is 62 TWh.

The CO2 shadow price for this system is now 272 €/ton, which is still high, but much closer to realistic numbers than what was seen with the isolated swiss system. Information on all optimal capacities can be found in Appendix II – Optimal capacities of interconnected system.

H. Connect the with heating sector and co-optimize

To investigate how the system behaves when heating also becomes part of the model, a new heating bus is added. To keep the system manageable and find key insights the connection with Germany and France is removed. Initially the model will include urban centralized heating, i.e. district heating. Given that 85% of the swiss population lives in metropolitan areas [9]. The demand will be modeled as 85% of the total heat demand. To the heat bus a gas boiler *generator*, resistive heater and heat pump *links* are added, with centralized heating costs. The heat pumps are assumed to have a COP of 3. A gas CHP powerplant will be added on its own bus. From here the powerplant will be assumed to produce equal amounts of heat and electricity at an induvial efficiency of 0,4. The CO2 constraint is maintained at 250k ton CO2. The system is optimized, and the results is inspected. Figure 10 shows heat demand and dispatch.

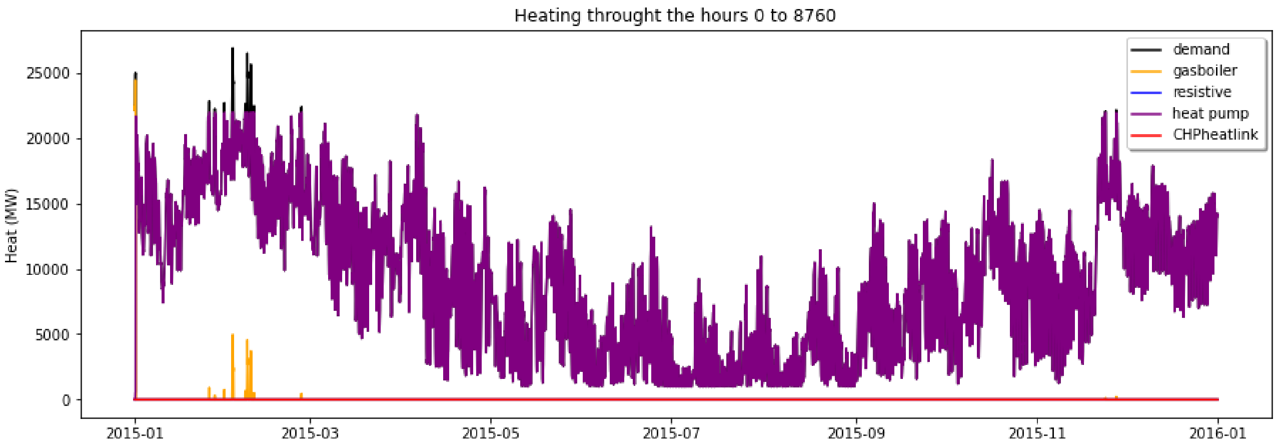


Figure 10: Heating dispatch through the year 2015

It is seen that heat pumps will supply the demand through most of the year, with the gas boiler to supply peak demands during the winter. Resistive heating and CHP are found not to be a part of the optimal solution. An interesting observation is that the gas boiler capacity is capped in the start of the year, when the different storage options are assumed empty. The total system cost has now increased significantly to 7974.4 mio. €, and the onshore wind capacity doubles, solar triples to supply the heat pumps with the needed electricity. Hydrogen remains storage of choice with similar capacities.

H2. Rural heating and heating storage

The model will now include rural heating, i.e. heating which cannot feasibly be done as district heating. The demand will be 15% of the total heating demand, and the bus will not include CHP, but all other generators are present, with cost assumptions related to smaller installations included in [2].

As for electricity it is also possible to add storage to the heating buses. Centralized and Individual heating thermal storage will be added to the given buses, and the system is optimized with following results:

Table 7: Optimal capacities of heat generators and storage

Generator	**Optimal capacity [MW]**
Heat pump (centralized)	12355
Resistive (centralized)	8061.8
Heat pump (Individual)	1032.2
Gas boiler (individual)	651.3
Storage	**Optimal capacity [MWh]**
ITES	6445.7 MWh
CTES	3,479,257 MWh

Furthermore, it's seen that the need for hydrogen storage now has vanished from the optimal solution. The peak solar demands will primarily be mitigated to the heat buses by heat pumps and resistive heaters. Centralized gas boilers are existent in the optimal solution, but inspections of dispatch show that the sole purpose of these is to supply in the first hours where the heat storage is assumed empty. Only for the individual/rural bus does the gas boiler provide dispatch during peak demands, which in the optimal solution, is only 3 days in the year. To study the thermal storage one can plot the SOC through the year. The two storage options give quite different dispatch patterns. On the synoptic timescale CTES will charge, only to distribute large amounts during very short time intervals. The role of ITES seems to be centered much more around diurnal storage with large amounts of the capacity being stored and discharges daily. Full overview of all optimal capacities can be found in Appendix III – Optimal capacities heating.

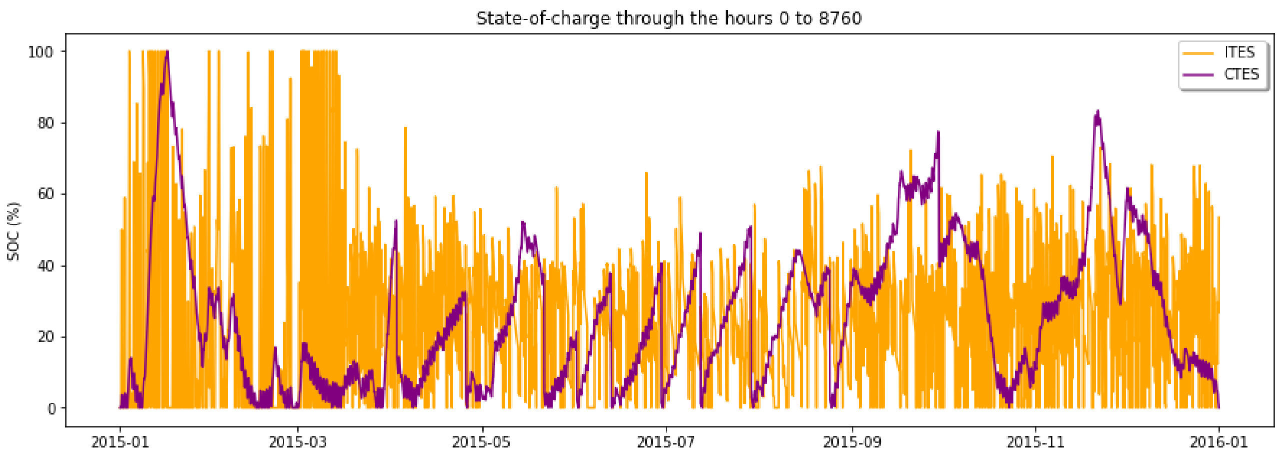


Figure 11: Heating storage SOC through the year 2015

I. Nuclear lifetime extension

As of this time Switzerland has 4 operating nuclear reactors, supplying 32% of the swiss electricity mix. It has been decided by the swiss government in 2017 to phase out the use of Nuclear power. The reactors Beznau 1&2, are the oldest but have been approved for operation until 2030 [10]. What now seems to be an interesting question is weather it would be feasible to carry out a lifetime extension, also called "long term operation" of the current nuclear power generators, despite of the political decisions made. To test out this hypothesis it's assumed that the nuclear power plants in question is fully paid off. A new generator is added to the electricity bus which has the financials of extending the lifetime. An estimated capital cost of 700 mio. USD/GWh, annual O&M cost of 170k USD/MW and marginal price of 8 €/MWh [11]. The extension is modelled to have 10 years of operation.

Optimizing the system, the optimal capacity of the nuclear generator is found to be 11,216 MW completely removing the need of solar, OCGT, and onshore wind. This is of course not possible given the current capacity is far lower than this, but if the maximum installed capacity is set to be that of Beznau 1&2, the cap is still hit. This indicates that from a purely economic point of view the lifetime extension of nuclear is viable and cost competitive option. Looking at the TCOS it is seen to increase by 425 mio. €, without nuclear power compared to the system with lifetime extension in capacity to that of Beznau 1&2 (730 MW). In the actual case of Beznau 1&2, it would be interesting to make an assessment such as this, at their actual end of lifetime, given that the financials of renewable generators likely will have changed by then. For instance, given the assumption that capital cost of solar will be half of today, the model shows solar to be cost competitive with even unlimited amounts of nuclear life extension capacity.

In the discussion of whether to retire nuclear reactors or not, one also must take the cost of decommissioning into account. In December 2019 the 47-year-old Muhleberg plant was shot off, and is to be decommissioned in a 15 year project, with end target 2034 [12]. The total price of dismantling the plant, as well as managing radioactive waste is estimated to cost 1.4 billion USD [13]. To postpone this expenditure could be economically advantageous.

Conclusion

The work of the project has, even with the relatively simple model, given some key insight in the behavior of a future renewable based swiss energy system. In line what was concluded by the IEA[14], the transition to a sustainable future energy system with less nuclear, the swiss must strengthen the interconnection infrastructure and legislation to a greater extend become part of the European energy market. The model showed how an isolated Switzerland is heavily dependent on onshore wind to meet demands, while the interconnected system is relying on solar as the renewable energy generator of choice. Hydrogen is found to be the most preferable electric storage option, and hydro reservoirs and PHS secure large power dispatches when they have had to time to achieve substantial storage levels.

The analysis of incorporation of the heat sector showed heat pumps to be the dominant generator, with gas boilers to be the main peak demand source for individual heating and resistive heaters for centralized heating. CTES becomes a large part of the general system storage, reducing hydrogens presence in the optimal solution. Lastly the research into the viability of nuclear power plant lifetime extension, showed the refurbishment to be very cost competitive with the rest of the system operators.

Further investigations into the system behavior, besides the most crucial points presented in this report, can be made by running the supplied code and utilizing the build framework for visualization and system complexity extension.

Literature

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Appendix I – Overview of optimal capacities through the years

Overview of optimal capacities through different years

	onshorewind	solar	OCGT	ror
1991	27478.9	16704.7	1776.07	4465.34
1994	20885.3	12527.3	2012.17	4465.34
1997	27815.8	14119.6	2430.26	4465.34
1999	16807.1	8382.68	1535.8	4465.34
2003	21729.7	11610.9	1559.02	4465.34
2006	26333	13725.8	1766.74	4465.34
2009	31762.9	12495.7	2281.13	4465.34
2011	54013.5	20770.8	4404.43	4465.34
2013	49388.3	20345	2423.01	4465.34
2015	40909	18442.8	4533.48	4465.34
Mean	31712.3	14912.5	2472.2	

Appendix II – Optimal capacities of interconnected system

```
onshorewind             0.000000
solar               20339.952901
OCGT                 1758.610818
ror                  4465.341667
onshorewind FRA    345604.831441
solar FRA          163850.465968
OCGT FRA            34626.222281
onshorewind DEU     95314.494324
solar DEU           43167.194354
OCGT DEU            40220.140576
Name: p_nom_opt, dtype: float64
hydrores    8224.0
PHS         1380.0
Name: p_nom_opt, dtype: float64
Optimal electric battery capacity is 10176.255629101008 MWh
Optimal hydrogen capacity is 5129.186994467688 MWh
batterylink1          5088.127815
batterylink2          1703.903777
hydrogenlink1          149.930081
hydrogenlink2          246.595529
CHE-DEU               1807.658763
CHE-FRA               6248.841867
DEU-FRA              43998.856230
batterylink1 FRA      1981.389401
batterylink2 FRA       650.702595
hydrogenlink1 FRA    77970.701681
hydrogenlink2 FRA    65420.731554
batterylink1 DEU      3776.515330
batterylink2 DEU      1387.835692
hydrogenlink1 DEU     6654.608792
hydrogenlink2 DEU     5792.418620
Name: p_nom_opt, dtype: float64
```

Appendix III – Optimal capacities heating

```
onshorewind    48487.160287
solar          47546.860120
OCGT            5421.653051
ror             4465.341667
gasboiler      20204.940721
CHP                0.000000
gasboiler I      651.349776
Name: p_nom_opt, dtype: float64
hydrores    8224.0
PHS         1380.0
Name: p_nom_opt, dtype: float64
Optimal electric battery capacity is 0.0 MWh
Optimal hydrogen capacity is 0.0 MWh
Optimal ITES capacity is 6445.681665049792 MWh
Optimal CTES capacity is 3479257.075353949 MWh
batterylink1     0.000000e+00
batterylink2     0.000000e+00
hydrogenlink1    0.000000e+00
hydrogenlink2    0.000000e+00
resistive        8.061818e+03
heat pump        1.235537e+04
CHPheatlink      0.000000e+00
resistive I      0.000000e+00
heat pump I      1.032040e+03
ITESlink1        3.196118e+03
ITESlink2        2.948099e+03
CTESlink1        8.776904e+06
CTESlink2        7.896515e+06
Name: p_nom_opt, dtype: float64
```

```
CO2 constraint: 0.25 mio. ton
Total cost of system is 7454.10 mio. €
Total cost of system pr. MWh is 51.53 €
CO2 shadow price is: 2505.260609960979 €/ton
```