Generation Expansion Planning in Switzerland Considering Climate Change Scenarios

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***Abstract*—In this work a formulation of the generation expansion planning problem is applied to the detailed Swiss power system to study the impacts of possible climate-driven changes in hydro inflows on the country's generation portfolio in 2050. To capture the influence of electricity trade on the investment decisions, we include an aggregated representation of the production capacities of the surrounding countries under a net-zero GHG emission scenario and market-based tie line constraints. Our results show that investing in new generators in Switzerland is more economically viable than relying only on imports regardless of the simulated hydrological conditions. Despite the projected annual decrease in hydro inflows during a typical hydrological year impacted by climate change, the total system costs are lower compared to a typical year under current climate conditions. This is due to the fact that in the future we expect wetter winters and thus more water during months when the system load is higher.**

***Index Terms*—Climate change, generation expansion planning, net-zero GHG emissions, RES integration, hydro inflows**

I. Introduction

Hydro power is the backbone of the electricity supply in many European countries and around the world and is expected to play an even greater role in the future as we move towards low-carbon systems abiding by EU-wide or national emission ambitions. As air temperature rises, precipitation, absorption and evaporation of surface water will change and so will the availability of water for hydro power production [1], [2]. In the context of Switzerland, for example, we expect changes in the generation regime of run-of-river power plants, whereby the annual production will slightly decrease, but winter production could increase by 8% [2] by the end of the century. The goal of this work is to investigate the impacts of climate-driven changes in hydro inflows on the electricity supply in Switzerland and to identify under what conditions new capacity investments at the transmission system level could be economically viable.

The authors in [3] present a detailed literature review of the impact of climate change on the electricity sector with a European focus. For example, [4] investigates the effects of climate change and land use on water availability and the operational reliability of one reservoir in Northern Greece. In [5], the focus is on creating detailed synthetic runoff projections for a water basin in Eastern Italy. However, these studies do not comment on how possible changes in hydro production could impact the power system of the region. In Switzerland, [6] goes one step further and provides a link between changes in hydro generation due to climate change and the electricity market by studying potential effects related to future wholesale electricity prices as well as revenues of hydro power producers. While [6] optimizes the operation of all generators with a detailed treatment of hydro units, they do so without considering Generation Expansion Planning (GEP) in their problem formulation. Furthermore, the assumptions on the existing generators in the surrounding countries for the target year 2050 do not reflect recent EU-wide net-zero Green House Gas (GHG) emission scenarios [7]. The contributions of this work are:

- the application of a GEP formulation with high temporal and spatial resolution to the existing detailed Swiss power system to determine the optimal size and location for new generators under different hydrological conditions impacted by climate change.
- the integration of projected capacity developments in the neighboring countries under a net-zero GHG emission scenario and investigation of potential impacts on Switzerland.

The remainder of the paper is structured as follows: Section II details the methodology and the results are discussed in Section III. Section IV draws the main conclusions and provides an outlook of the paper.

II. Methodology

A. Problem Formulation

In this work, we use the Centralized Investments module (CentIv), a core module of the interconnected energy systems modeling platform Nexus-e [8] to run our simulations. The formulation of CentIv is described in previous work [9]. CentIv aims to minimize the sum of the investment and operating costs of all existing and candidate generation and storage technologies over the examined year (i.e. static) from the perspective of a centralized decision maker:

$$\begin{aligned} \min \ & \underbrace{\sum_{(j\in J),t} C^{\text{tot}}_j p_{j,t}}_{\text{(i)}} + \underbrace{\sum_{(b\in B),t} C^{\text{voc}}_b p^{\text{dis}}_{b,t} + \sum_{(s\in S),t} C^{\text{voc}}_s p^{\text{dis}}_{s,t}}_{\text{(ii)}} \\ & + \underbrace{\sum_{(r\in R),t} C^{\text{voc}}_r p_{r,t}}_{\text{(iii)}} + \underbrace{\sum_{(n\in N),t} C^{\text{ls}} ls_{n,t}}_{\text{(iv)}} + \underbrace{\sum_{f\in F} \alpha^{\text{inv}}_f C^{\text{inv}}_f u^{\text{inv}}_f}_{\text{(v)}} \end{aligned} \tag{1}$$

where i) - iii) are the total operating costs of each thermal unit j, storage unit (b for utility-scale battery storage and s for hydro storage) and renewable generator r for each time step t, iv) refers to the load shedding costs at the transmission node n and v) are the annualized investment costs associated with building a candidate unit f. The generation costs are assumed to be linear functions of the power generated by the technology (e.g. $p_{j,t}$, discharge power $p_{b,t}^{dis}$, etc.) and the variable O&M cost C^{voc}. The load shedding cost is C^{ls} and the investment cost (including fixed O&M cost) is C_f^{inv}. For thermal units, C_j^{tot} consists of the fuel cost, CO_2 emissions cost and variable O&M cost. The investment decision variable is u_f^{inv} and the annuity factor is denoted by α_f^{inv}. The objective function in (1) is subject to constraints related to: a) operation, b) reserves, c) grid (i.e. DC power flow constraints) and d) investment. Here, we outline the modifications made to the formulation in [9] that are necessary and relevant for the current study. Instead of using a detailed Unit Commitment (UC) formulation, to speed up the computations, we apply the following operational constraints to candidate thermal units (i.e: $j \in J^F$):

$$0 \leq p_{j,t} \leq P_j^{max} u_j^{inv}, \forall j \in J^F, \forall t \tag{2a}$$

$$p_{j,t-1} - p_{j,t} + (r_{j,t}^{SCR\downarrow} + r_{j,t}^{TCR\downarrow}) \leq R_j^D u_j^{inv}, \forall j \in J^F, \forall t \tag{2b}$$

$$p_{j,t} + (r_{j,t}^{SCR\uparrow} + r_{j,t}^{TCR\uparrow}) - p_{j,t-1} \leq R_j^U u_j^{inv}, \forall j \in J^F, \forall t \tag{2c}$$

$$u_j^{inv} \in \{0, 1\}, \forall j \in J^F \tag{2d}$$

where $p_{j,t}$ is the power generated by the unit, P_j^{max} is the maximum power output, $R_j^{U/D}$ are the ramp-up/ramp-down limits and $r_{j,t}^{SCR\uparrow\downarrow}$, $r_{j,t}^{TCR\uparrow\downarrow}$ are the variables indicating the contribution of each generator towards upward/downward secondary and tertiary reserves. In order to allow the generators to shut down, we assume $P_j^{min} = 0$ in (2a). Ramping limits (2b)-(2c) are included because as shown in [10] ignoring them could be the most distorting simplification of the UC in expansion planning studies. To speed up the solution of the MILP, while keeping chronological accuracy and high temporal resolution, every other day of the year is simulated with hourly resolution and the operation of hydro storages is adjusted using the heuristic outlined in [9]. Since the investment costs are considered over the entire year, the operating costs in (1) are doubled.

B. Test System

The simulated test system consists of a part of the Central European power system, shown in Fig. 1, for the target year 2050. We include a detailed representation of Switzerland (CH) and an aggregated representation of Germany (DE), France (FR), Italy (IT) and Austria (AT). The tie lines connecting the neighboring countries are aggregated to one line using the method described in [11]. The generators and storages in DE, FR, IT and AT are aggregated to a single unit per technology type with capacity values taken from the TYNDP 2020 Global Ambition Scenario [7] for 2040. This scenario presents a vision of how the centralized European power system could evolve to achieve carbon neutrality by 2050. Where data was available, additional estimations of the capacities in 2050 were made [12]. The hourly demand time series for DE, FR, IT and AT are from [7] while solar irradiation and wind time series are from [13]. An important simplification which stems from the scope of the simulated system is fixing the cross-border flows between DE, FR, IT and AT and all surrounding countries which are not modeled to the hourly values in 2018 from [14]. Fuel and CO_2 costs are from [7] and own assumptions to project to 2050.

In CH we model 391 generators, including 290 existing[1] and 54 candidate units as well as solar injections at 47 different system nodes, representing a projected increase in distribution-level rooftop PV[2] amounting to 33.6 TWh [16]. The hourly demand time series for CH are from [17], scaled to match total demand projections from [16]. Wind and solar timeseries are from [18]. We consider all Swiss nuclear power plants to be decommissioned by 2050 [16] and perform the expansion planning by introducing candidate units (only at Swiss nodes) with cost parameters summarized in Table I.

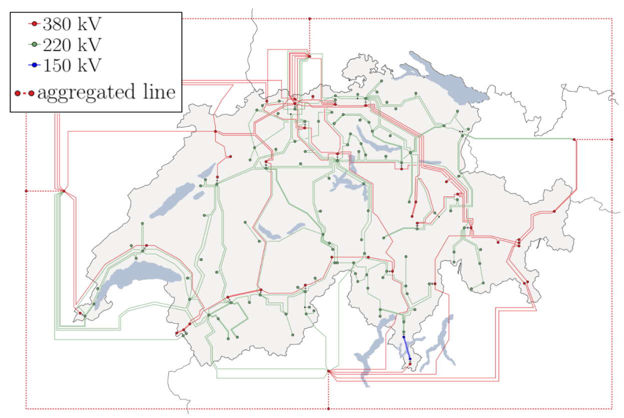

Fig. 1. Overview of the modeled transmission system in 2050.

TABLE I
COST PARAMETERS OF CANDIDATE UNITS IN CH (2050) BASED ON [19]–[21] AND OWN ASSUMPTIONS

Unit type	Inv. Cost + FC [kEUR/MW/a]	Tot. Var. Cost [EUR/MWh]	Capacity [MW]
Gas CC + CCS	103 + 40	121	4'200
Biomass	125 + 0	1	240
Wind	110 + 41	36	1'960
Battery (100MW-4h)	200 + 3.8	0.5	700

FC refers to Fixed Cost. The total variable cost includes fuel and CO_2 costs for gas. Biomass costs are subject to subsidies, while wind costs are not. For Gas CC + CCS we introduce 28 candidates: 14x100MW and 14x200MW and for Biomass: 12x20MW. The hourly ramp rates of all gas and biomass candidates are assumed to equal 40% of the corresponding P^{max} value [22]. The reserve contribution attributes per technology are summarized in Table 1 in [9].

C. Scenarios

Table II defines the five simulated scenarios for the target year 2050. Across scenarios we only vary the CH hydro inflow profiles according to the description provided in Table II. The inflow time series in the surrounding countries remain

[1] Unlike in a greenfield approach, the existing generation and storage units in CH in 2050 are dispatched depending on their technology types and generation costs. A validation of CentIv's operational model is included in [9].

[2] For a TSO-DSO coordinated generation expansion planning the reader is referred to [15].

unchanged. The hydro inflow data used in the climate change scenarios (Average CC, Dry CC and Wet CC) are based on [6]. The authors use run-off projections from several different climate models for two future climate periods (2021–2050 and 2070–2099) to generate Swiss hydro inflows with monthly temporal resolution and high spatial disaggregation. In our work, we use the inflows for the period 2070-2099 and ignore the spatial disaggregation (i.e. all CH hydro power plants of a given type (Run-of-River (RoR), dam storage and pump storage) in the system operate according to the same monthly hydro inflow pattern). The inflow data for the "average" hydrological year is derived from historical data [23], [24]. Similar to [6], 2008 is taken as the representative year. Fig. 2 shows the total monthly RoR inflows for the 4 simulated hydrological scenarios.

TABLE II
SIMULATED SWISS HYDRO INFLOW SCENARIOS (2050)

Scenario Name	Description	Total Inflows [TWh]
Hist. Avg. - No Inv	"average" hydro year + no climate change + no invest.	38.3
Hist. Avg.	"average" hydro year + no climate change	38.3
Average CC	"average" hydro year + climate change	36.7
Dry CC	"dry" hydro year + climate change	28.6
Wet CC	"wet" hydro year + climate change	44.8

Note: In the last three scenarios the abbreviation CC refers to Climate Change.

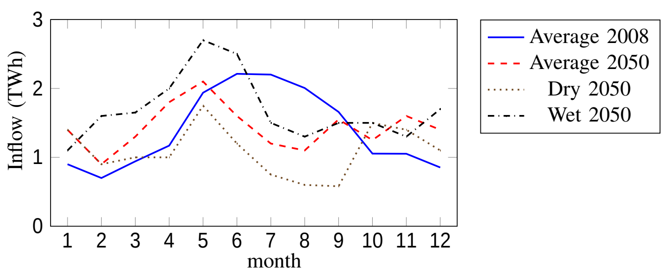

Fig. 2. Total monthly RoR inflows for the four hydrological scenarios.

III. RESULTS

A. Investments and Operation

Table III summarizes the investments made in 2050 under the five scenarios as well as the relative change in the objective function value compared to the scenario with hydrologically average inflow conditions (Hist. Avg.). We see that regardless of the simulated hydrological year or impacts of climate change, investing in new candidate units in 2050 results in an overall lower objective function value, and thus makes economic sense. All biomass candidate capacity gets built due to the overall low investment costs reflecting on-going subsidies which we assume to remain in the future. We also see investments in gas with CCS and wind across all scenarios. The new gas capacity is primarily used during winter months, characterized by higher demand and lower PV production. This can be seen in Fig. 3 which compares the monthly production per technology type in 2050 for the Hist. Avg. scenario with and without (No Inv.) investments in candidate units. In addition to the generation per technology type, we plot the demand and demand plus pumping load (i.e. the total load) as a green and a red (dashed) line. With a dashed pattern, as another "production", the total imports[3] are stacked. The total exports can be read out from the plot and are the difference between the red line and the top of the import bar. In January, for example, the exports are less than the imports (i.e. entire dashed bar) and so, we have a net import position. In the context of Switzerland, it is important to see absolute instead of only net import/export values. As shown, the magnitude of imports relative to the production is very significant. This stems from the fact that Switzerland is a transit country in terms of electricity supply.

TABLE III
NEW INVESTMENTS IN CH (2050)

Scenario Name	Wind [MW]	Gas [MW]	Biomass [MW]	Objective f-n
Hist. Avg.-No Inv.	✗	✗	✗	↑↑
Hist. Avg.	1'727	2'400	240	–
Average CC	1'714	2'000	240	↓
Dry CC	1'865	2'000	240	↑
Wet CC	380	2'200	240	↓↓

The production from newly built gas units is not used solely as an export to offset more expensive generators in the neighboring countries; it is also used during hours with lower PV production as a way to reduce the need for imports to cover the demand. This is shown in Fig. 4 which presents the hourly dispatch during a typical winter week in January.[4]

When comparing a "typical" hydrological year (Hist. Avg.) and the same hydrological year impacted by climate change (Average CC), Table III provides an interesting insight. Despite the slight decrease in the annual hydro inflows (38.3 TWh vs. 36.7 TWh from Table II), the overall objective function is lower in Average CC. This highlights the importance of the distribution of hydro inflows throughout the year. In the future, we expect wetter winters and drier summers as shown by the total monthly RoR inflows in Fig. 2. This means that more water would be available in the months when the system load is higher. Therefore, in Average CC we require less investment in gas compared to Hist. Avg. because the gas units are mainly used in the months that see an increase in RoR inflows.

In addition, the simulated scenarios also facilitate a comparison of the investments and operation during a dry and a wet hydrological year impacted by climate change. The wet year received 16.2 TWh more inflows than the dry year (Table II), which is reflected in the fact that the objective function value in Wet CC is the lowest and that of Dry CC is the second highest of all scenarios. Another important distinction between Wet CC and all other scenarios is the relatively low investments in wind - the higher the inflows, the lower the economic viability

[3]These are actual total imports and not net-imports. This is important because Switzerland sometimes imports and exports at the same time.

[4]Because we only model every second day, the curves for two consecutive days are equal to each other.

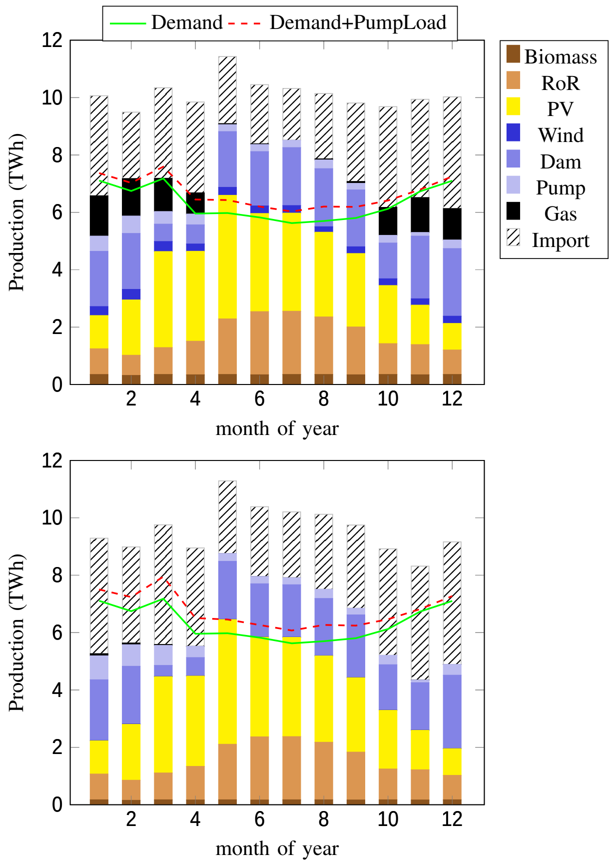

Fig. 3. Monthly production per technology type in 2050. Scenario Hist. Avg. (top) and Hist. Avg.-No Inv. (bottom).

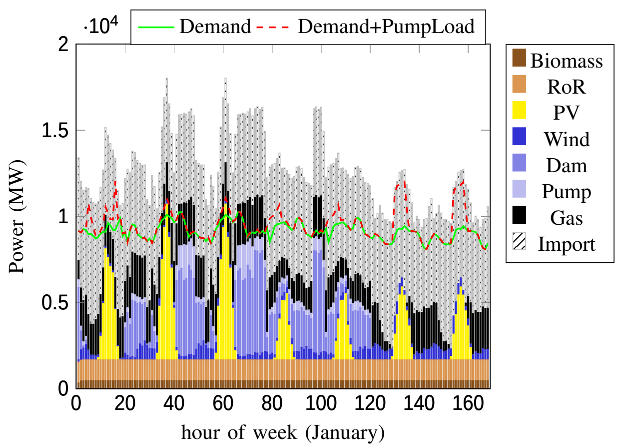

Fig. 4. Hourly dispatch per technology type for a typical winter week in January 2050. Hist. Avg. scenario. The curves for two consecutive days are equal to each other due to modeling every second day.

of new wind investments. Alternatively, in Dry CC, wind is used to compensate partially (total wind production is 3.5 TWh) for the lower inflows throughout the year. Nevertheless, despite the new investments and increased PV production, in Dry CC Switzerland becomes a net importer. The only two scenarios when this is the case are Hist. Avg.-No Inv. for which the annual net imports are 5.63 TWh and Dry CC with 0.14 TWh annual net imports. The higher investments in gas in Wet CC are due to the lower RoR inflows in January (Fig. 2), when the demand in the test system (all five countries) is the highest. To check our reasoning, we increase the January inflows in Wet CC to equal the values in Average/Dry CC and run an additional simulation. As expected, the investments in gas go down to 2’000 MW. As a last step, we compare the weekly operation throughout the year in Wet CC and Dry CC shown in Fig. 5. We observe that in Dry CC gas is consistently used throughout the year. During summer, it is used in hours with low solar production (i.e. early mornings and nights). In Wet CC, instead of gas during summer, we see production by dams and RoR due to higher inflows.

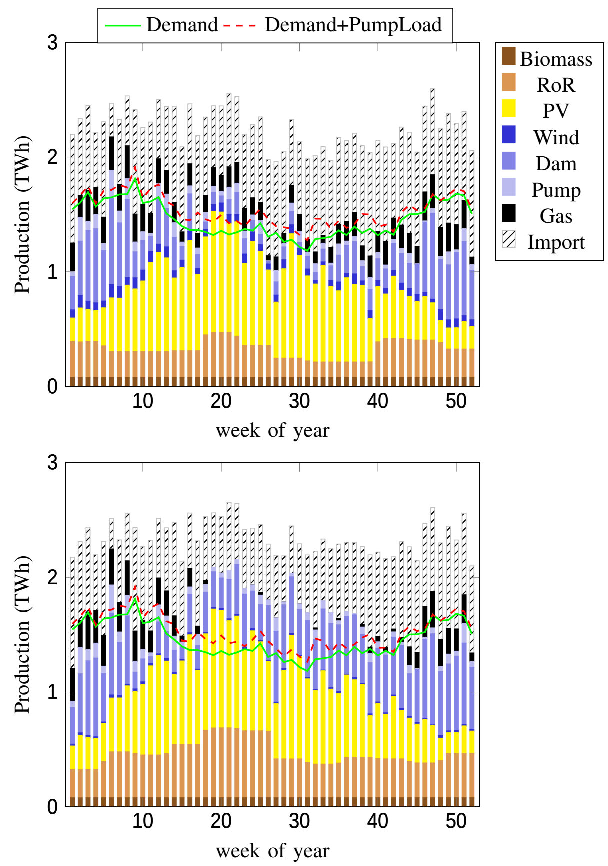

Fig. 5. Weekly production per technology type in 2050. Scenario Dry CC (top) and Wet CC (bottom).

B. *Locations of New Gas Units*

One of the advantages of incorporating the transmission system (albeit through a lossless DC power flow representation) as part of the optimization problem, is the ability to position candidate units at system nodes. Under the same investment cost assumptions and depending on the topology of the grid, there could be optimal locations which, for example, alleviate grid congestions and therefore lead to overall lower objective function values. In this work, we select 7 locations and position 4 gas candidate units at each location. Fig. 6 shows the locations which are always selected across all scenarios (magenta) and those that are never selected (orange). It is important to note that fixing the investment decisions at orange nodes leads to higher objective function values.