The Value of Flexibility in a Carbon Neutral Power System

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Abstract—In this paper, we use a formulation of the generation expansion planning problem with hourly temporal resolution, to investigate the impact of the availability of different sources of flexibility on a carbon-neutral central European power system (with a focus on Switzerland) for the year 2040. We assess the role of flexible generation, load shifting and imports on the investment and operation of existing and newly built units. Our results show that including load shifting as part of the optimization could reduce the need for investments in both RES and conventional technologies. The combination of newly built flexible generators (gas turbines) and load shifting increases the flexibility of the simulated power system and results in the overall lowest system costs. The reduction of cross-border transmission capacity between Switzerland and its neighbors has a significant impact on the domestic operation and investments but could also affect the surrounding countries.

Index Terms—cross border congestion management, flexible generation, generation expansion planning, load shifting, RES integration

I. INTRODUCTION

The integration of large shares of intermittent Renewable Energy System (RES) technologies driven by net-zero Green House Gas (GHG) emissions targets and policies related to phase out of conventional thermal and nuclear generation provides many opportunities, but also challenges. One of the main challenges is related to maintaining reliable operation of the future electric power system, which will be characterized by an increased need for flexibility to balance the fluctuations of weather-dependent generation. The main objective of this work is to integrate different sources of flexibility in a Generation Expansion Planning (GEP) formulation and study their impact on the investment and operation of existing and newly built generation and storage capacities in a carbon neutral power system. The sources of flexibility that we focus on are 1) dispatchable generation (conventional, hydro and battery storage technologies), 2) load shifting and 3) imports/exports.

In [1], [2] the authors investigate the operational aspect of flexibility in expansion planning, focusing on detailed operation of conventional generators using Unit Commitment (UC) constraints in the formulation of the optimization problem. These studies, however, do not include other technologies which could provide flexibility such as hydro power and Battery Energy Storage Systems (BESS). Furthermore, they do not assess the role of flexible loads on the investments and operation of the units. On the other hand, in [3], [4] the authors include a detailed Demand Response (DR) representation within the capacity expansion planning but omit UC constraints and the latter does not model ramp limits. While modeling very large test systems ( [3] has a European scope and [4] models Germany), both [3] and [4] do so by aggregating generators. In addition, the transmission lines are also aggregated and power flows between different zones are constrained using a transport model. In [4], the authors treat the aggregated German power system as an island and do not model the interconnections with the surrounding countries.

To bridge the gap between the aforementioned studies, the present work proposes a GEP formulation which includes a variety of technologies providing flexibility such as conventional thermal units, for which we include ramp limits, hydro power as well as BESS. In addition, flexible loads are modeled as part of the optimization. The GEP formulation is static (i.e. spans a single target year) and deterministic, however, we model the target year with hourly resolution in one shot to capture short-term fluctuations of intermittent RES but also the seasonal operation of hydro storages. The expansion planning includes DC power flow constraints and is conducted for a real-size power system (i.e. the Swiss power system), considering also the cross-border connections with the neighbouring countries as well as an aggregated representation of their projected generation portfolio under a carbon-neutral scenario for the year 2040. This allows to capture the impact of imports and exports on the investment and operational decisions in Switzerland.

The remainder of the paper is organized as follows: the problem formulation is detailed in Section II. Section III presents the test system and corresponding input data used. Section IV describes the simulated scenarios and presents the results and Section V concludes the paper.

II. PROBLEM FORMULATION

We use the Centralized Investments module (CentTv), a core module of the interconnected energy systems modeling platform Nexus-e [5] to perform the simulations. The goal of CentTv, which is based on previous work [6], is to co-optimize the capacity investment and operational decisions of units at the transmission system level. This includes large-scale thermal generators (nuclear, gas, biomass, etc.), hydro power plants (run-of-river (RoR), dam and pump storages), large-scale RES (wind, PV) and grid-scale batteries. Mathematically,
CentIv minimizes the sum of the annualized investment costs and the operating costs of all existing and candidate generation and storage technologies over the planning horizon \( T \) (one year):

\[
\min \sum_{d \in D} \alpha_d C_d u_d^{\text{inv}} + \sum_{j \in J} \sum_{t \in T} (C_j^{\text{inv}} + C_j^{\text{fuel}} + C_j^{\text{em}}) p_{j,t} + \sum_{k \in K} \sum_{r \in R} C_{k,r}^{\text{dis}} p_{k,t} + \sum_{n \in N} \sum_{t \in T} C_{n,t}^{\text{ls}} l_{n,t} \tag{1}
\]

where (i) are the investment costs of building candidate generators or storages \( d \), (ii-iv) are the total operating costs of each thermal unit \( j \), energy storage unit \( r \), and renewable generator \( k \) for each time step \( t \) and (v) indicates the load shedding cost at transmission node \( n \). To derive the operational costs, we multiply a constant variable operating cost, \( C_j^{\text{fuel}} \), by the power produced by each thermal unit \( p_{j,t} \), each hydro or battery storage device \( p_{k,t}^{\text{dis}} \), and each renewable generator \( p_{r,t} \). For thermal generators, the fuel cost \( C_j^{\text{fuel}} \) and CO2 emissions cost \( C_j^{\text{em}} \) are also accounted for. The load shedding cost is \( C_j^{\text{ls}} \). The investment cost (including fixed O&M cost) for unit \( d \) from the candidate units \( D \) is \( C_d^{\text{inv}} \). The investment decision variable is \( u_d^{\text{inv}} \) and the annuity factor, which annualizes the total investment cost for the simulated year, is \( \alpha_d^{\text{inv}} \). The optimization objective (1) is subject to four sets of constraints related to: a) investments, b) operation, c) reserve provision, and d) the transmission system (i.e. DC power flow). Next, we briefly describe the changes that were made for the current formulation compared to the previous work in [6].

1) Investment and Operation Constraints: In this work we simulate each hour of the target year. First, this allows us to capture short-term fluctuations of intermittent RES and demand but also battery storage and pumps. Furthermore, by simulating the full year in one shot, it’s possible to better represent the seasonal operation of dams. To speed up CentIv and be able to perform simulations with such high temporal resolution, all investment decisions are linearized, i.e., \( u_d^{\text{inv}} \) is a continuous variable with decisions for investment in thermal units as given by (2d). The formulation for candidate thermal generators (i.e., \( j \in J^D \)) is simplified by removing the Unit Commitment (UC) and investment constraints from the previous formulation (i.e., (2)-(9) and (19) in [6]). Instead, the generated power in each time step is limited by each generator’s rated capacity \( u_j^{\text{max}} \) and ramping constraints allow for the incorporation of reserve provision \( u_j^{\text{UP/Down}} \) and ramping constraints allow for the incorporation of reserve provision \( u_j^{\text{UP/Down}} \) and ramping constraints allow for the incorporation of reserve provision \( u_j^{\text{UP/Down}} \):

\[
0 \leq p_{j,t} \leq P_j^{\text{max}} u_j^{\text{UP/Down}}, \forall j \in J^D, \forall t \tag{2a}
\]

\[
p_{j,t-1} - p_{j,t} + (r_{j,t}^{\text{SCR}} + r_{j,t}^{\text{TCR}}) \leq P_j^{\text{up}} u_j^{\text{UP/Down}}, \forall j \in J^D, \forall t \tag{2b}
\]

\[
p_{j,t} + (r_{j,t}^{\text{SCR}} + r_{j,t}^{\text{TCR}}) - p_{j,t-1} \leq P_j^{\text{down}} u_j^{\text{UP/Down}}, \forall j \in J^D, \forall t \tag{2c}
\]

where \( P_j^{\text{max}} \) is the maximum power output, \( R_j^{\text{up/dn}} \) are the ramp-up/ramp-down limits and \( r_{j,t}^{\text{SCR/TCR}} \) are the variables for the unit’s contribution towards upward/downward secondary (SCR) and tertiary (TCR) reserves. Ramping constraints are included since [8] shows that their omission could be the most distorting simplification of the UC in GEP studies. The existing thermal units are also constrained by the equations in (2) but with the investment variable \( u_d^{\text{inv}} \) set to 1. The constraints for candidate battery storages are identical to (10)-(16) and (20) in [6]. Similar to the thermal generators, the binary investment variable for candidate storages (i.e: \( k \in K^D \)) is relaxed:

\[
0 \leq u_k^{\text{inv}} \leq 1, \forall k \in K^D \tag{3}
\]

The constraints for candidate RES technologies are identical to (21) in [6]. Additionally, in the case of a required RES production target \( B^{\text{RES}} \), the following constraint is added:

\[
r_{k,t}^{\text{dis}} + \sum_{j \in J^{\text{RES}}} p_{j,t} \geq B^{\text{RES}} \tag{4}
\]

2) Transmission System Constraints: The transmission system constraints [5] begin with the active power balance at each bus node \( n \in N \) where \( P_{n,t}^{D} \) is the nodal hourly demand, \( l_{n,t} \) refers to the load shedding variable, and the remaining terms correspond to the power output of each generator and storage system. The nodal active power \( p_{n,t} \) is the sum of the active power flows of all lines \( l \in L \) connected to \( n \) as shown by (5a). The active power flow \( p_{l} \) of a single line is constrained by (5b) and (5d) where \( B_l \) is the admittance, \( \delta_n \), \( \delta_l \) are the voltage angles at the start and end nodes and \( P_{l,\text{max}} \) is the line limit. Load shedding is allowed at each bus with an associated demand and constrained by (5c) which does not allow load shedding to be more than the nodal hourly load:

\[
\begin{align*}
    p_{n,t} &= P_{n,t}^{D} - l_{n,t} + \sum_{k \in K_n} s_k p_{k,t} - \sum_{j \in J_n} p_{j,t} - \sum_{k \in K_n} \sum_{r \in R_n} p_{r,t} - \sum_{n' \in N_n} \sum_{t \in T} p_{n',t} \quad \forall n, \forall t \tag{5a} \\
    p_{n,t} &= \sum_{l \in \pi_t} (p_{l,t} - \sum_{i \in \pi_t} B_l \delta_{n,i}) \quad \forall n, \forall t \tag{5b} \\
    p_{n,t} &= \sum_{l \in \pi_t} B_l (\delta_{n,t} - \delta_{n,i}) \quad \forall n, \forall t \tag{5c} \\
    l_{n,t} &= \max(0, P_{n,t}^{D} - P_{n,t}^{\text{max}}) \quad \forall n, \forall t \tag{5d} \\
\end{align*}
\]

In this work, we represent the hourly nodal electricity demand profile \( P_{n,t}^{D} \), as the combination of several different profiles, namely heat pump demand \( P_{n,t}^{\text{HP}} \), electric mobility demand \( P_{n,t}^{\text{EM}} \), hydrogen demand \( P_{n,t}^{H2} \) and the base demand \( P_{n,t}^{\text{base}} \), i.e.:

\[
P_{n,t}^{D} = P_{n,t}^{\text{HP}} + P_{n,t}^{\text{EM}} + P_{n,t}^{H2} + P_{n,t}^{\text{base}} \quad \forall n, \forall t \tag{6}
\]

To facilitate load shifting in CentIv we introduce four new variables. The first two of these, \( u_{n,t}^{\text{up/down}} \), enable the hourly
upward/downward shifting of the electric mobility load. The other two variables, \( l_{n,t}^{up/down} \), allow for upward/downward shifting of the combination of all other loads (i.e., HPs, \( H_2 \), and the base demand). For both of these up/down load shift variables, two constraints are used to limit the maximum hourly power shift and two more to limit the maximum daily energy shift. In each hour, the upward and downward shifting is constrained as shown in \((7a)\)–\((7b)\) and \((7c)\) where \( E_{hr,max} \) is the maximum hourly power shift allowed for shifting the electric mobility load and \( L_{hr,max} \) is the maximum hourly power shift allowed for shifting of the other loads. Similarly, \( E_{hr,max} \) is the maximum hourly power shift allowed for shifting the combination of all other loads (i.e., HPs, \( H_2 \), and the base demand). For both of these up/down load shift variables, two constraints are used to limit the maximum hourly energy shift. In each hour, the upward and downward shifting of the combination of all other loads (i.e., HPs, \( H_2 \), and the base demand) are the daily energy shifting limits. Equations \((7d)\) and \((7g)\) ensure that over each day, the up and down shifts are balanced:

\[
\begin{align*}
0 &\leq e_{n,t}^{up} \leq E_{hr,max}, \forall n, \forall t \quad (7a) \\
0 &\leq e_{n,t}^{down} \leq \min(E_{hr,max}, P_{n,t}^{EM}), \forall n, \forall t \quad (7b) \\
\sum_{t=t_0}^{t_0+24} (e_{n,t}^{up} + e_{n,t}^{down}) &\leq E_{day,max} \quad (7c) \\
\sum_{t=t_0}^{t_0+24} (e_{n,t}^{up} - e_{n,t}^{down}) &\leq 0 \quad (7d) \\
0 &\leq l_{n,t}^{up/down} \leq L_{hr,max}, \forall n, \forall t \quad (7e) \\
\sum_{t=t_0}^{t_0+24} (l_{n,t}^{up} + l_{n,t}^{down}) &\leq L_{day,max} \quad (7f) \\
\sum_{t=t_0}^{t_0+24} (l_{n,t}^{up} - l_{n,t}^{down}) &\leq 0 \quad (7g)
\end{align*}
\]

It is important to note that the linear formulation in \((7)\) allows for simultaneous up and down shifting in each hour. Once the four newly introduced and constrained variables are included in \((5a)\), the nodal balance equation becomes:

\[
p_{n,t} = P_{n,t}^D + e_{n,t}^{up} + \sum_{k \in K_{n,t}} p_{k,t}^{ch} - e_{n,t}^{down} - l_{n,t}^{up} + \sum_{k \in K_{n,t}} p_{k,t}^{dis} - \sum_{r \in R_{n,t}} p_{r,t}^T, \forall n, \forall t
\]

### III. Input Data

The updated problem formulation of CentTv is applied to a representation of the central European electricity market, which is shown in Fig. 1 and described in this section. This system consists of a detailed representation of Switzerland (CH) and an aggregated representation of Germany (DE), France (FR), Italy (IT) and Austria (AT) for the year 2040. Much of the input data used were taken from current or future projections of the regions modeled; however some data were also utilized from projections created by the Euro-Calliope modeling framework \[9\]. Section III-A details the input data related to the surrounding countries, while Section III-B describes the input data used for CH.

#### A. Aggregated surrounding countries (DE, FR, IT, AT)

The tie lines connecting DE, FR, IT and AT, along with the lines connecting these four countries to the CH border are an aggregated representation of the transmission grid of the four neighboring countries. The line parameters are set by a network reduction process \[10\] that is applied to the physical European grid data from \[11\], \[12\]. The line limits are set to reflect the market-based transfer capacities using data from \[13\], \[14\]. The generators and storages in DE, FR, IT and AT are aggregated to a single unit per technology type with capacity values summarized in Table I and taken from Euro-Calliope model results that represent the year 2040 where the European continent has reached a nearly carbon-neutral energy system \[15\]. The solar and wind production time series for the surrounding countries are also taken from the Euro-Calliope results \[15\]. Additionally, to account for imports and exports from these four countries to their other neighbors, which are not included in this work, we utilize the cross border flow results of the Euro-Calliope analysis \[15\]. To represent the variable operating costs of all EU generators, we use data from \[16\]. Note that, several VOM costs were adjusted as part of a calibration process performed for a separate study. This calibration process aimed to adjust generator costs and network reactances to achieve a dispatch that is more consistent with the historical 2018 conditions. Parameters that were focused on include the annual generation by generator type for all non-CH countries, the monthly generation by generator type for CH, the annual cross border flows, the annual average wholesale prices, and the monthly behavior of Swiss hydro storage units. The fuel prices for all EU generators were taken from \[17\]. Since all gas units in the neighboring countries are assumed to consume carbon-neutral synthetic natural gas, priced based on \[18\], no other \( CO_2 \) price is necessary. As mentioned earlier, the hourly demand profile in this work is a combination of four profiles, namely 1) e-mobility demand, 2) heat pump demand, 3) hydrogen demand and 4) base demand. The annual values for each demand type for the surrounding countries are summarized in Table I. The hourly profiles for each of these demands are also from Euro-Calliope \[15\].

The limits on the maximum daily energy shift for the e-mobility demand for each country are set using the assumption that the total annual shiftable energy can be at most 10% of the total annual e-mobility demand. Assuming each day of the year shifts the same maximum amount allowed, this 10% assumption translates directly into a daily maximum quantity (i.e., each day is given the same shifting allowance). Once

3 To impose mutual exclusivity, it is necessary to introduce additional binary variables \[7\], resulting in a MILP formulation characterized by a significant increase in solver run-time.

4 As shown in Fig. 1 all CH cross-border lines are included but they all connect to a common border node that then connects to each neighboring country.

5 The results in \[15\] are different from the ones used in the present work due to the 2040 baseline for the rest of Europe and the higher resolution of Switzerland and the transmission constraints applied.
TABLE I: Installed Capacities (2040) in DE, FR, IT, AT from Euro-Calliope

| Gen type          | DE | FR | IT | AT | CH |
|-------------------|----|----|----|----|----|
| Wind [GW]         | 42.6 | 172.0 | 50.4 | 52.6 | 30.4 |
| PV [GW]           | 267.5 | 180.2 | 289 | < 0.1 | 1.4 |
| Biomass [GW]      | 6.4 | 2.9 | 2.0 | 0.6 | 1.4 |
| Hydro Dam [GW]    | 0.2 | 9.5 | 5.5 | 5.2 | 1.4 |
| Hydro Pump [GW]   | 6.4 | 5.1 | 7.9 | 3.6 | 1.4 |
| Hydro RoR [GW]    | 3.5 | 6.3 | 5.9 | 4.5 | 1.4 |
| GasCC [GW]        | 0.3 | 7.0 | 14.7 | 0 | CH |
| Batt [GW]         | 0.1 | 0.4 | 12.3 | < 0.1 | 1.4 |

TABLE II: Demand (2040) from Euro-Calliope

| Demand type | DE | FR | IT | AT | CH |
|-------------|----|----|----|----|----|
| E-mobility [TWh] | 339.7 | 288.3 | 199.7 | 41.6 | 30.4 |
| Heat Pump [TWh]  | 0.2 | 57.0 | 87.7 | < 0.1 | 1.4 |
| Hydrogen [TWh]   | 0.1 | 0.4 | 11.2 | < 0.1 | 0.3 |
| Base [TWh]       | 457.7 | 349.8 | 290.1 | 55.9 | 49.2 |

These daily energy limits are determined, the maximum hourly power up/down shift is calculated such that the daily energy shift could be spread over 10 hours for each upward and downward shifting. The calculation of these limits is based on the e-mobility profile for each country from Euro-Calliope. Finally, the limits on the maximum hourly power up/down shift for the other loads in each country are set equal to the DSM capacities defined for 2040 in [17]. Once these power limits are applied, the maximum daily energy shift is calculated based on the maximum up/down power shift being allowed in up to 3 hours per day each (i.e., three times the DSM capacities equals the maximum energy that can be shifted down or up within any one day).

B. Detailed CH

While the neighboring countries are represented with aggregated transmission network elements, the Swiss network is modeled in full detail using data from [19] and shown in Fig. 1. For existing Swiss generator capacities and locations, we use data from [20–25] and previous studies [24]. The generating capacities represent those existing in 2020, of which we assume all hydro, biomass, wind, and PV to also remain in place until 2040. However, the phase out of nuclear is assumed to occur prior to 2040 along with removal of all conventional gas and oil units in Switzerland. In addition to the existing hydro units, twenty-eight new hydro units are included that represent a mixture of pump, dam, and RoR generators with a total additional capacity of 2.6 GW. Of these additions, 1.8 GW represent three new hydro pump units that are planned to be operational between 2029 and 2037 [25]. The rest are based on projects that have been previously or are now in planning stages [26]. To represent the variable operating costs and fuel costs of all Swiss generators (existing and new) we use data from [27], [28]. The costs of biomass reflect current waste incineration subsidies, which we expect to continue in the future. The VOM cost for each technology type is assumed to stay the same until 2040; however, the fuel and CO$_2$ portions of the total variable operating cost will change based on the assumed trajectories for the prices of each fuel and the price of CO$_2$ in future years. Since some of the candidate gas units (i.e., those with CCS) will still emit a limited amount of CO$_2$, a price based on [17] is also included. All non-CCS gas units are assumed to consume a carbon-neutral synthetic methane (similar to what is assumed for the neighboring countries); however, the fuel price for the Swiss units of this type is set based on the average value provided for gas-to-methane from the recent Swiss study on Power-to-X [29]. In total, in CH we model 303 existing and 82 candidate units with cost parameters summarized in Table III. The production time series for existing wind generators are gathered from [31]. Rooftop PV is modeled by using cantonal irradiation profiles from [32] and by applying a price based on [17] is also included. All non-CCS gas units (i.e., those with CCS) will still emit a limited amount of CO$_2$, a price based on [17] is also included. All non-CCS gas units are assumed to consume a carbon-neutral synthetic methane (similar to what is assumed for the neighboring countries); however, the fuel price for the Swiss units of this type is set based on the average value provided for gas-to-methane from the recent Swiss study on Power-to-X [29]. In total, in CH we model 303 existing and 82 candidate units with cost parameters summarized in Table III. The production time series for existing wind generators are gathered from [31]. Rooftop PV is modeled by using cantonal irradiation profiles from [32] and by applying a very low variable cost since most of this generation will not be seen by the transmission system but will instead be used to satisfy household demands.

Similar to the neighboring countries, the hourly demand profile for Switzerland is a combination of e-mobility demand, heat pump demand, hydrogen demand and base demand. The annual totals for each demand type in CH are summarized in Table IV. The hourly profiles for each of these demands are again from Euro-Calliope [15].

IV. RESULTS

Table IV defines the four simulated scenarios for the target year 2040. The optimization problem is implemented in Pyomo [35] and solved with Gurobi [36]. Section IV-A discusses the impact of load shifting and building new flexible generators

\*For a TSO-DSO coordinated generation expansion planning investigation, the reader is referred to [30].

\*This ensures that the PV generation is in the same range as the projections from [31].
Investment costs include fixed costs. The total variable cost includes fuel and CO₂ costs for gas. Biomass costs are subject to subsidies, while wind costs are not. For GasCC (CCS) we introduce 11 candidates: 11x500MW, for GasCC (Syn): 11x500MW, 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 [34].

Note: the abbreviations in the second column are used throughout the text.

### Table III: Cost parameters of candidate units in CH (2040)

| Unit type | Inv. Cost | Tot. Var. Cost | Capacity |
|-----------|-----------|----------------|----------|
| Biomass   | 125       | 1              | 240      |
| Wind      | 151       | 36.4           | 1'960    |
| PV        | 71        | 1              | 50'000   |
| Battery (100MW-4h) | 204 | 0.5 | 1'100 |
| Gas CC (CCS) | 135 | 159.5 | 5'500 |
| Gas CC (Syn) | 76.5 | 308.8 | 5'500 |

Investments required to satisfy the RES target (2040) based on [27], [28], [33] and own assumptions.

### Table IV: Simulated Scenarios (2040)

| Scenario Name | Abbr. | Description |
|---------------|-------|-------------|
| "No Gas No Shift" | "NGNS" | No gas candidate units + no load shifting allowed |
| "No Gas With Shift" | "WGNS" | No gas candidate units + load shifting allowed |
| "With Gas No Shift" | "NGWS" | Gas candidate units + no load shifting allowed |
| "With Gas With Shift" | "WGWS" | Gas candidate units + load shifting allowed |

Note: the abbreviations in the second column are used throughout the text.

Table [IV-B] shows the results for the same four scenarios but impose a 70% reduction of the cross-border limits between Switzerland and the surrounding countries. This reduction stems from the European Union’s (EU) decision to reserve 70% of the capacity of the grid elements of its member states for “internal trade”. Last but not least, Section [IV-C] includes a sensitivity analysis to show the impact of rising gas prices on investment decisions for one of the previously simulated scenarios and Section [IV-D] lists the main limitations of the present work.

### A. Load Shifting and Gas

Table [V] summarizes the investments made per technology type in 2040 under the first four scenarios, the relative change in the objective function value of each scenario compared to the baseline scenario ("NGNS") as well as the total annual load shedding in (CH) and outside (non-CH) Switzerland. In all scenarios the entire biomass candidate capacity is built due to the overall low investment costs reflecting on-going subsidies assumed to remain in the future. In terms of the RES target, the overall low investment costs reflecting on-going subsidies scenarios the entire biomass candidate capacity is built due to load shedding (pink) in both scenarios. However, due to the dispatch of gas this load shedding is lower in the "WGWS" scenario. Furthermore, load shifting is correctly employed to further reduce the need for load shedding or building more gas capacity by increasing the downward shifting in the hours following peak demand.

In addition to the electricity generation per technology type, we include the imports, downward load shifting as well as load shedding as "production". In addition to the demand and pump load, the consumption stack includes upward load shifting and exports. The total height of each weekly bar in the consumption and generation plots in a given scenario must be equal (i.e. supply equals demand).

### Table V: New investments in CH (2040)

| Scenario Name | Investment | Obj. f-n | f-n | Load Shed |
|---------------|------------|---------|-----|-----------|
| "NGNS" Biomass: 125 | 240 | - | Non-CH: 0 | CH: 14.8 |
| "WGNS" Biomass: 240 | 255 | 1%↓ | Non-CH: 0 | CH: 5.6 |
| "NGWS" Biomass: 240 | 255 | 1%↓ | Non-CH: 0 | CH: 7.2 |
| "WGWS" Biomass: 240 | 255 | 1%↓ | Non-CH: 0 | CH: 2.6 |

Note: The objective function value spans the cost of operation and investments in Switzerland as well as operation in the surrounding countries. The percent change in the objective function value in the third column is calculated using the total objective function value.
with peak demand and increasing the upward shifting during the rest of the day to satisfy the requirement for equal upward and downward daily shifted energy. An interesting observation that can be made is the lack of production from hydro dams in the off-peak hours in the "NGNS" case. This is due to the lower dam storage levels at the end of September in the "NGNS" scenario as seen in Figure 4 which plots the end-of-month storage levels in the Swiss dams over the year for all four scenarios. The difference in dam operation whereby more water is stored in the period May-October in the two scenarios with shifting is due to the inherently higher flexibility of the system.

B. Reduced Cross-border Transmission Capacity

As shown in Figure 2 and Figure 3, the electricity imports and exports relative to the domestic generation and demand are considerable, highlighting the unique position of Switzerland as a transit country in terms of electricity supply. Furthermore, the ability to export and import due to a reliable grid connectivity is considered as a key source of flexibility in a given power system [37]. The goal of this section is to investigate the impact of reducing the amount of flexibility stemming from imports/exports on the generation portfolio in the country.

Similar to Table V, Table VI summarizes the investments in the case of reduced (by 70%) cross-border transfer limits, denoted by (R) and compares them to the baseline scenario ("NGNS") from Section IV-A. All four new simulated scenarios show an increase in the objective function. In the runs without gas candidate units, in addition to all wind candidate capacity being built, the amount of PV installations increases by 79% ("NGNS (R)") and 82% ("NGWS (R)"). While before the driver for the PV installations was the RES target, here the driver is the lack of available import capacity. Despite the higher RES production, the amount of load shedding both in and outside Switzerland is higher. This means that the reduction in transfer capacity also has a negative impact on the neighbouring countries. Load shifting is beneficial for the reduction of the investments in both gas turbines and battery storages. In the scenarios with gas candidate capacities we...
observe similar amounts of PV installations as in Table VI. However, the investment in gas turbines has increased and the operation of these units has changed.

Figure 5 compares the weekly generation and consumption per technology type for the "NGWS (R)" and "WGWS (R)" scenarios. In both scenarios we see lower volumes of imports and exports (compared to Figure 2) driven by the reduction of the cross-border capacity limits. In "WGWS (R)" the gas turbines with CCS are operated continuously during winter (Jan-Mar and Nov-Dec). These units have higher investment costs, but their total variable costs are significantly lower compared to the syngas turbines which are used as peaker power plants. In the "NGWS (R)" scenario we see increased electricity production from PV in winter due to the very high installed capacity and also wind generation. It is interesting to note that while wind is being dispatched in the winter months, there is very little production during summer. In summer, wind is curtailed due to the oversupply of PV which has a lower total variable cost than wind. In fact the driving factor for investments in both technologies is the reduction in cross-border capacity in winter. The large PV generation in summer results in a net export position of Switzerland in this period.

Looking at the generation and consumption of pumped hydro, we see a similar trend in both scenarios - Swiss pumps are partially used to shift water to weeks in the periods of Jan-Feb and Nov-Dec. In both "WGWS (R)" and "NGWS (R)" there is enough available low-cost electricity in summer which is stored in the reservoirs and used during hours with lower available generation and import capacity. While such operation is rather untypical for pumped hydro, it shows that the pumped storage capacity (2.2 TWh) can be used in a variety of ways.

Figure 6 plots the hourly production and consumption during the same day in October as in Section IV-A but now for the "NGWS (R)" and "WGWS (R)" scenarios. Due to the higher investments in PV, there is more PV production in "NGWS (R)" than in Figure 3. Similarly, due to the higher installed capacity in "WGWS (R)", there is more production from gas. The shifting pattern and the amount of energy shifted are similar. In both scenarios, Switzerland is only importing electricity without simultaneously exporting in the majority of the hours during the day, a direct consequence of the reduced cross-border capacities.

C. Sensitivity Analysis: Rising Gas Prices

Since many of the model inputs are subject to great uncertainty, in this section we briefly discuss the impact of rising gas prices on the investment decisions in the "WGWS (R)" scenario. Table VII summarizes the previously used metrics (i.e. change in objective function value, load shedding and invested capacity per technology type) in case of a 25%, 50%, 75% and 100% increase in the projected price of gas in 2040. The first important conclusion is that even in case of a 100% increase in gas prices, the objective function value is still

| Scenario Name       | Investment [MW] | Obj. f-n [%] | Load Shed [GWh/a] |
|---------------------|-----------------|--------------|-------------------|
| "NGNS"              | Biomass: 240    | –            | Non-CH: 0         |
|                     | PV: 19'172      |              | CH: 14.8          |
|                     | Batt: 200       |              |                   |
| "NGNS (R)"          | Biomass: 240    | 21.7% ↑      | Non-CH: 73.3      |
|                     | PV: 34'111      |              | CH: 17.9          |
|                     | Wind: 1'960     |              |                   |
|                     | Batt: 1’100     |              |                   |
| "WGWS (R)"          | Biomass: 240    | 18.3% ↑      | Non-CH: 48.1      |
|                     | PV: 18'882      |              | CH: 5.9           |
|                     | Wind: 103       |              |                   |
|                     | Batt: 200       |              |                   |
|                     | Gas (Syn): 1’465|              |                   |
|                     | Gas (CCS): 1’685|              |                   |
| "NGWS (R)"          | Biomass: 240    | 16.7% ↑      | Non-CH: 2.7       |
|                     | PV: 32’956      |              | CH: 9.4           |
|                     | Wind: 1’960     |              |                   |
|                     | Batt: 200       |              |                   |
| "WGWS (R)"          | Biomass: 240    | 14.6% ↑      | Non-CH: 2.7       |
|                     | PV: 17’282      |              | CH: 3.4           |
|                     | Wind: 103       |              |                   |
|                     | Batt: 100       |              |                   |
|                     | Gas (Syn): 565  |              |                   |
|                     | Gas (CCS): 1’665|              |                   |

Note: The designation (R) pertains to the scenarios with reduced cross-border transmission capacity.
of intermittent RES generation in the system increases, the minimum up/downtime constraints may become binding. This means that the investments in newly built gas units in the present analysis might be under estimated. Nevertheless, the current formulation is sufficient to show mutual influences between different sources of flexibility and how they could potentially change investment and operational decisions. As already shown in the previous section, the scenario results can differ significantly depending on the input assumptions, therefore we stress the importance of performing sensitivity analyses. Last but not least, in the context of the simulated Swiss power system, we do not model hydro cascades in detail which, in particular, could lead to different operation of hydro pumps.

V. CONCLUSION

In this work a reformulated version of CentIv, the transmission-level generation expansion planning module of the Nexus-e modeling platform, is used to investigate the value of flexibility in a carbon-neutral central European power system in 2040. The power system consists of a detailed representation of Switzerland, for which we establish operational and capacity investment decisions, and an aggregated representation of the four neighboring countries, for which we model the operation only and take the capacities as an input from Euro-Calliope. We simulate two sets of scenarios in order to understand the impact of flexible generation, load shifting and imports on the investment and operation of existing and newly built units.

Our results show that modeling load shifting within a generation expansion planning model could reduce the need for investments in both renewable and conventional technologies. In the context of Switzerland, this means that while increasing the number of electric vehicles, parallel efforts should be made to plan the efficient control of these loads. The combination of gas turbines (either running on synthetic gas or with CCS) and load shifting increases the flexibility of the system and results in the overall lowest system costs. While this could be one possible transition path towards carbon-neutrality for Switzerland, it is associated with certain risks such as increasing gas prices which could lead to an almost tenfold reduction in newly built units as presented in the sensitivity analysis. Nevertheless, our results show that there is an inherent need for flexibility in the simulated power system largely dominated by intermittent RES. The reduction of cross-border transmission capacity between Switzerland and the surrounding countries has a profound impact on the domestic operation and investments but could also have an impact on the surrounding countries as witnessed by the increased amount of load shedding. Future work will focus on implementing a discomfort cost associated with load shifting as part of the objective function in order to reduce the amount of simultaneous up and down shifting in the current formulation.

D. Limitations

An important limitation of this work is the removal of the UC constraints in the problem formulation. As the amount

| Metric               | 25%  | 50%  | 75%  | 100% |
|----------------------|------|------|------|------|
| Obj. F-n [%]         | 15.2↑| 15.6↑| 15.8↑| 15.9↑|
| Biomass [MW]         | 240  | 240  | 240  | 240  |
| PV [MW]              | 28'244| 30'900| 32'044| 33'012|
| Wind [MW]            | 1037 | 1960 | 1960 | 1960 |
| Battery [MW]         | 100  | 69   | 31   | 100  |
| Gas (Syn) [MW]       | 345  | 510  | 570  | 685  |
| Gas (CCS) [MW]       | 1'105| 590  | 500  | 165  |
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