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sweet swiss energy research for the energy transition

Summary

Switzerland's pathways to net-zero over the coming decades feature a shared cornerstone: a massive expansion of intermittent renewable electricity generation. Against this backdrop, an active debate persists regarding the appropriate portfolio of flexibility options required to integrate these resources into the Swiss power system.

We model each of the 2148 Swiss municipalities existing in 2022 individually, following the *Energieperspektiven 2050+* (EP2050+) scenario ZERO Basis[1], which specifies 33.6 TWh/a of PV generation and 4.3 TWh/a of wind generation (with other production technologies only playing a marginal role). Building on year-long, 15-minute-resolution municipality-specific time series for decentralized electricity generation technologies and consumption categories under this net-zero scenario[2], we develop a decentralized techno-economic optimization that yields cost-optimal energy-shifting portfolios for each municipality. The model explicitly represents short-term battery storage, power-to-X-to-power (PtX; electrolysis, hydrogen storage, and re-electrification), PV overbuilding with curtailment, and demand-side flexibility, while accounting for each municipality's grid import/export capacity constraints.

In our net-zero starting point before optimizing energy shifting, the Switzerland-wide aggregation of municipalities' power profiles exhibits large power fluctuations with accentuated power peaks due to PV most of the year and consumption peaks in winter (generation peak: 18.6 GW, load peak: 11 GW). After the optimization, power peaks are drastically reduced to levels compatible with the existing centralized hydropower capacities (generation peak: 3.7 GW, load peak: 6.9 GW). Seasonally, the system is structurally energy-deficient in winter, while summer is characterized by robust surpluses driven by hydropower and PV. Transition seasons are broadly balanced but sensitive to weather variability.

Using literature data to find a reasonable consensus in technology costs, different scenarios for varying combinations of technology cost projections are created. Across all cost scenarios, PV overbuilding combined with curtailment is, in a vast majority of municipalities, more cost-effective than seasonal storage using PtX. Even when PtX is parameterized at the lower end of cost projections, it does not emerge as a substantial seasonal electricity-storage option (77-112 GWh energy storage capacity across scenarios). While curtailment increases the cost per unit of PV energy, PV's low underlying cost base in combination with abundant short-term battery storage means that, system-wide, the strategy remains economically attractive. The optimization suggests PV overbuilding of 9.4–24.9 TWh per year (depending on the cost projection) and large-scale deployment of short-term battery storage (60–117 GWh, 1C rate), with significant implications for Switzerland's future energy system. Short-term power balancing, even with high shares of intermittent generation, becomes less challenging once these short-term batteries are in place. The residual concern shifts to net energy balancing over multi-week to monthly horizons rather than intra-day or single-day mismatches. PV and hydropower produce substantial surplus energy in late spring, summer, and early autumn. Due to the high flexibility of batteries, this energy can be reprofiled into virtually any required power shape. For instance, battery-buffered electrolysis increases its full-load hours, making it more economically feasible. While this strategy emerges in our model under specific circumstances, the effect is still insufficient for PtX to become broadly cost-effective. In this new energy system, cost-effective energy delivery in winter - irrespective of detailed generation profile - will be useful if Switzerland wants to reduce electricity imports.

As a comparison of scale, combining the overbuilt PV with the baseline expansion yields 43–58.5 TWh/a of PV generation, depending on the scenario. This range is comparable to (but in parts exceeds) the Swiss targets of 45 TWh/a from new renewables until 2050 (this addition to the energy law entered into force on 01.01.2025[3]), of which ~40 TWh/a is estimated to originate from PV. In particular, the lower bound (43 TWh/a) modestly exceeds the indicative PV component, while the upper bound (58.5 TWh/a) surpasses strongly even the aggregate target for new renewables. Overbuilding of PV in conjunction

[1] Swiss Federal Office of Energy (SFOE), Energieperspektiven 2050+, https://www.bfe.admin.ch/bfe/de/home/politik/energieperspektiven-2050-plus.html

[2] This is the third report in a series and it builds on the work for the first two reports: "Need for energy balancing by region for renewable energy system scenarios of Switzerland" (https://www.aramis.admin.ch/Dokument.aspx?DocumentID=72338), "Techno-economic realization of energy balancing with batteries, power-to-x, and demand-side management" (https://www.aramis.admin.ch/Dokument.aspx?DocumentID=73517).

[3] Energiegesetz EnG Art. 2, https://www.fedlex.admin.ch/eli/cc/2017/762/de

with high levels of curtailment emerges as an economically rational trade-off – a comparatively inexpensive way to avoid over-investment in long-term storage or grid expansion.

The winter energy challenge is, on the decentralized level, primarily addressed through PV overbuilding (with associated curtailment). Winter PV peaks can, to a large degree, be absorbed by batteries and redistributed over several days. On the centralized level, hydropower remains a critical pillar in winter, and its contribution can be enhanced by adapting reservoir management once additional PV generation frees today's reliance on hydropower reserves in October, March and April. International imports play a supporting role in the modelled winter system but remain below 5 TWh when the freed hydropower energy is accounted for. Achieving complete self-sufficiency would be very costly with new renewables, unless wind energy can be developed at substantially larger scale. With its elevated winter generation profile, wind would be extremely cost-effective in our optimization model. Complementary measures include heat storage and winter-oriented biomass dispatch, both of which can and should contribute to seasonal adequacy.

Demand-side flexibility, particularly from electric vehicles, further improves the system's capacity to integrate intermittent renewables. Policymaking and market design should therefore prioritize unlocking this comparatively low-cost resource through appliance-readiness, control enablement, and dynamic retail and network tariffs.

A predictable consequence of the PV-overbuilding strategy is a substantial volume of curtailed generation in summer, driven by favourable solar conditions and comparatively lower seasonal demand. Space cooling could therefore be run with surplus electricity, benefitting from its demand profile exhibiting high simultaneity with PV output, even easing demand integration. We expect the pronounced seasonal differences in electricity availability to be reflected in price dynamics, creating incentives for electricity-intensive technologies or business models whose costs are dominated by electricity inputs.

The analysis highlights pronounced differences across municipalities. Integrating PV and even overbuilding it in load centers such as cities is, in most cases, relatively straightforward due to the existing excess in consumption. In contrast, rural and alpine municipalities, with their high agrivoltaics and alpine PV potentials, face more complex integration challenges that can result in high curtailment shares. PtX is deployed mainly where the local PV potential is exhausted, removing the usually cheaper alternative of PV overbuilding with curtailment to cover the characteristic winter deficit. Since at the same time, a consistent summer surplus production is needed for the local PtX use case, PtX concentrates in medium-sized urban municipalities that can generate summer surpluses yet still face large winter deficits, whereas large cities rarely reach such surpluses even when fully utilizing local PV potentials.

Under the modelled boundary conditions, we find that a fully decarbonized Swiss electricity supply based on 100 % renewable energy is feasible with net electricity imports below 5 TWh during winter. Imports could be avoided altogether but at substantially higher cost or by expanding wind energy more than in our underlying EP2050+ scenario. Our results underscore that decentralized cost-optimal, net-zero-aligned portfolios of energy shifting technologies are inherently local, yet follow a coherent national logic: prioritize PV overbuilding with managed curtailment, deploy substantial short-term storage, leverage demand-side flexibility, refine hydropower operations, and support winter adequacy efforts with imports, seasonal thermal storage, winter-led biomass, and wind development. PtX does not emerge as a cost-effective option for seasonal storage of electricity in our results, but direct hydrogen usage in difficult-to-electrify applications could be viable.

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[4] More details to be found in section 6 “Collaboration within EDGE Consortium”

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Nomenclature

Acronyms

CAPEX	Capital Expenditure
EDGE	Enabling Decentralized Generation of Energy
EP2050+	Energieperspektiven 2050+
EV	Electric Vehicle
GDP	Gross Domestic Product
GL	General Load
HP	Heat Pump
LCOE	Levelized Cost of Electricity
OPEX	Operational Expenditure
PEM	Proton-Exchange Membrane
PtX	Power-to-X
PV	Photovoltaics
STS	Short-Term Storage

Variables

P	Power
C	Capacity
G	Grid Connection Capacity
B	Boundary Value
E	(Stored) Energy
μ	Constant Multiplier
η	Efficiency

Subscripts

ch	Charging
dc	Discharging
BAT	Battery
IMP	Import
EXP	Export
CUR	Curtailment
FLEX	Flexibility

Superscripts

0	Initial (immutable) Timeseries
T	Last Value

1 Introduction

The work described in this report builds on the methodology and data presented in deliverable reports D1.2 (“Need for energy balancing by region for renewable energy scenarios of Switzerland”, [1]) and D2.4 (“Techno-economic realization of energy balancing with batteries, power-to-x, and demand-side management”, [2]). The contents of these reports are thus briefly summarized.

The work presented in Report D1.2 lays the foundation by providing high-resolution electricity production and consumption timeseries projection data for every Swiss municipality, differentiated by production and consumption categories based on estimates derived from the *Energieperspektiven 2050+* [3]. The process consisted of two main steps: (1) The CH-wide scenario value was spatially disaggregated to obtain yearly-aggregate numbers for each municipality, for each category of decentralized production and consumption, and (2) finding the appropriate timeseries for the temporal variation. In such a way, the total decentralized production and demand are modelled for each Swiss municipality.

Report D2.4 details a methodology to obtain a minimal necessary storage size for full municipal autarky given the production and consumption estimates provided. Together with two other options, namely increasing the permitted power flow over a municipal boundary (greater than zero) and overbuilding/curtailing PV, a methodology is presented which finds necessary storage sizes for all combinations thereof. It is of special note here that the presented methodology differs substantially from the one presented in this report, as the use of a commercial optimizer (gurobi) proved to be more flexible for cost optimization [4]. In report D2.4, a significant number of improvements to the data basis are presented, notably a methodology to discriminate between centralized and decentralized production, as well as a host of other improvements.

This third report finally attaches monetary attributes to this analysis by estimating costs for overbuilding and curtailment, and notably different implementations of storage or generally energy-shifting technologies (which specifically include demand-side management). It also attaches a cost function to import and export on a municipal level, such that grid electricity cost is tied to the CH-wide production/demand. This allows to find a cost-optimal combination of PV overbuilding/curtailment, battery/PtX deployment and grid usage, such that the electricity demand is met at all times.

The methodology used to arrive at the conclusions presented in this report differ from most other established models insofar as the spatial distribution and the deployment of decentralized electricity generation is considered as a given boundary condition. It is assumed that this technology proliferation does not necessarily follow a cost-optimal route but is rather guided by practical considerations. The presented analysis presents an answer to the question of how to deal with this situation in an optimal way.

This report is structured as follows: Section 2 details the cost data used under different scenario assumptions, as well as the methodology used to set constraints used in the convex optimization procedure. The mathematical formulation of the optimization problem for each municipality is discussed, and its integration into the overarching, iterative optimization framework explained. Section 3 presents the obtained results, with three main avenues of investigation: first, results on a CH-wide aggregated basis are shown, which summarize the key findings. Second, the spatial distribution of the solution components is presented, showcasing the regional differences in how a large share of new renewables can be integrated into the energy system. Third, exemplary timeseries results are used to illustrate a number of interesting effects, such as the role of Power-to-X and in what specific circumstances it is applied. Finally in section 4, the main findings are discussed and summarized.

2 Cost Data and Optimization Methodology

This chapter documents the methodology developed for the techno-economic analysis. After documenting our cost estimations, the mathematical optimization problem of single municipalities and the interaction of individual municipalities' solution on the country level is presented. After introducing the scenario definition and general modelling choices in section 2.1, section 2.2 details the technology cost estimates and their adaptations for specific scenarios, section 2.3 describes the import/export cost model, while section 2.4 describes the methodology used to find a cost-optimal solution for each municipality.

2.1 General Remarks

To find cost-optimal solutions, the costs in a target year need to be estimated. Costs for the following categories are estimated:

- Short-term battery storage (Li-Ion batteries)
- Long-term energy storage (Power-to-X)
- Demand flexibility (cost and amount of flexibility)
- Ground-mounted photovoltaic systems (agrivoltaics setup)

Importantly, an increase in grid connection capacity as a solution to the local mismatch of power generation and consumption could be envisioned, but an estimate of the cost of this measure in a general sense is exceedingly difficult to obtain, if not to say impossible as general values (cost are extremely case specific). In addition, grid expansion does not solve the balancing challenge but moves it from a municipality to a higher grid level. Grid expansion is therefore assumed to be a measure of last resort, as permitting, planning and building periods are usually very long. In order not to impede the rapid transition towards a fully decarbonized Swiss electricity system, the aim is to find a cost-optimal solution that does not impose additional strain on the electricity grid. Two measures are thus taken: 1) No grid expansion is allowed at all, the upper limits of import and export are fixed at the estimated maxima of today, 2) An overarching electricity price function based on the aggregated CH-wide deficit/overproduction is constructed, which keeps the overall Swiss power demand on the grid within reasonable boundaries set by the already existing centralized power plants and pumped hydro storage capacity.

To allow for studying the effects of different cost projections, four scenarios are constructed. The main scenario *Reference* uses the cost projections deemed to be the most probable outcome. The three other scenarios deviate from this *Reference* scenario in the following way:

- *PV & Battery Low-Cost* (*PVBat*)

  The costs for short-term battery storage (currently estimated to be Li-Ion batteries) and PV systems are assumed to decline significantly. The installed base of battery systems is assumed to be double the amount of the *Reference* scenario.

- *PtX Low-Cost* (*PtX*)

  The costs for long-term energy storage in form of power-to-x are assumed to decrease significantly. This includes the main technologies electrolysis, (above-ground) storage, and fuel cells.

- *Optimistic* (*Opt*)

  The costs for short-term storage (Li-Ion batteries) and PV systems are assumed to decline significantly. The install base of battery systems is assumed to be double the amount of the *Reference* scenario. The costs for long-term energy storage in form of power-to-x is assumed to decrease moderately on a level between the scenarios *Reference* and *PtX Low-Cost*. This includes the main technologies electrolysis, (above-ground) storage, and fuel cells. Furthermore, this scenario assumes a high degree of demand-side flexibility within the energy system. This includes a higher degree of controllability of the power demand modelled individually for electric

vehicles, heat pumps, and general load than in all other scenarios. Vehicle-to-grid is not considered in our simulation.

The four scenarios are summarized in Table 1.

Table 1. Scenario characteristics overview. The entries in this table represent the chosen high-level developments for each respective technology. The exact values are discussed in section 2.2.

	Reference (Ref)	**PV & Battery Low-Cost (PVBat)**	**PtX Low-Cost (PtX)**	**Optimistic (Opt)**
Cost of short-term battery storage	Baseline	Favorable trend	Baseline	Favorable trend
Pre-installed short-term battery storage	1 kWh per 1 kW installed PV capacity	Doubling of *Reference* (2 kWh per 1 kW)	1 kWh per 1 kW installed PV capacity	Doubling of *Reference* (2 kWh per 1 kW)
Cost of photovoltaics (PV)	Baseline	Favorable trend	Baseline	Favorable trend
Cost of long-term storage (Power-to-X)	Baseline	Baseline	Favorable trend	Between baseline and favorable trend
Amount of demand flexibility[5]	Baseline	Baseline	Baseline	Favorable trend
Remarks	Reference scenario: current assessment of expected situation when net-zero is reached	Focus on short-term batteries (expectation: Li-Ion) and PV: the prospective cost development favors these technologies	Focus on Power-to-X: the prospective cost developments suggest a significant reduction of investment costs for electrolysis, storage and fuel cell technologies	Positive development across all technologies. Power-to-X follows a cost trajectory between the baseline and the favorable one

2.2 Technology Cost Estimates

All costs are estimated with a target year of 2030, however using 2024 Swiss franc value as a base[6]. Lifetime (n) refers to the technical lifetime of the installation, after which it is expected to fail and be fully depreciated. The costs are annualized using an interest rate (i), of 3%. As there is never just a single "correct" cost projection for a given technology, multiple sources are used for each. The final values used within this report are a best-guess pick where a clear consensus between multiple sources could be found. In other instances, there is enough evidence from industry reports that costs lower than the

[5] Demand flexibility encompasses the use of electric vehicles electricity storage, the controllability of heat pumps and the general capability of the energy system to adjust production to varying electricity demand.

[6] An exchange rate of 0.8 Swiss franc per US$ is applied

estimates found in scientific literature respectively at the lower end of those estimates are used. The annuity method is used to spread the capital expenditure costs (CAPEX) evenly over the lifetime of each system. The annuity factor ($a_{n,i}$), is calculated for each technology according to eqn. (1). Since the operational expenditures (OPEX) presented within this report already depict future costs, no further adjustment is needed to be done.

$$a_{n,i} = \frac{(1+i)^n * i}{(1+i)^n - 1} \quad (1)$$

The total annualized costs for each technology are calculated by summarizing the OPEX and annualized CAPEX.

$$A_{Technology} = OPEX_{Technology} + a_{n,i} * CAPEX_{Technology} \quad (2)$$

2.2.1 Short-term Battery Storage

It is assumed that the cheapest form and thus dominating technology for short-term battery storage is a form of lithium-ion battery in the coming decade. On the cell level, the costs nowadays and most certainly in the future are very uniform, as cells have become a fungible commodity. On the system level, the size of the installation as well as other factors such as location and capabilities (such as the ability to provide grid ancillary services) can influence the cost significantly. As the specific kind of installation employed by the optimization is deliberately left unspecified, the cost assumed is a middle-ground between cost estimates found for different kinds of Li-Ion battery storage systems. It is further assumed that for a given Li-Ion battery, storage capacity and charge/discharge power are intrinsically linked, with a ratio of 1:1 (1C) being used. Thus, cost values can be used per kW or kWh interchangeably.

In addition to the storage optimized in the simulation, a fixed amount of already installed Li-ion batteries was assumed due to the expansion of home PV systems that include a battery[7]. The ratio was set as 1 kWh of battery capacity for every kWp of PV.

The OPEX for each cost trajectory are chosen to be at 4% of the CAPEX (derived from table ES.1 in [5]). The battery cells account for approximately 65-70% of the total Li-ion battery pack (P. 61 [6]). Li-ion battery pack prices have dropped rapidly in recent years and are expected to drop further [7]. For the cost trajectory baseline a reduction of the cell costs to around 65 $/kWh are assumed. For the cost trajectory favorable trend, a more aggressive reduction in the prices of Li-ion batteries is deliberately chosen. Drawing on reasoning about learning curves based on observed lithium-ion battery manufacturing capacities, a decrease of 75% is assumed [8].

Li-Ion batteries are exposed to degradation. The lifetime of the systems is influenced by various factors such as temperature, number of charge cycles or overcharging. A reasonable lifetime, consistent with the order of magnitude typically found in scientific publications, was chosen for the illustrated cost trajectories [9], [10], [11], [12].

[7] Of PV-systems built in 2024, 47 % were equipped with home storage in single-family homes according to Swissolar (https://www.swissolar.ch/de/news/detail/wachstum-bestaetigt-solarstrom-fuer-2-millionen-haushalte-74307).

Table 2. Technical lifetime, yearly OPEX, and total CAPEX estimates for short-term battery storage (i.e. **Li-Ion battery systems)** in 2030, using 2024 CHF as basis. The cost trajectory baseline represents a consensus for a realistic outcome, with the favourable trend trajectory assuming a more positive cost development.

Cost trajectory	Lifetime [years]	OPEX [CHF/kW]	CAPEX [CHF/kWh]	Total annualized cost [CHF/MWh]
Baseline	10	3.20	80	12'578
Favorable trend	15	1.6	40	4'951

2.2.2 Long-term Storage (Power-to-X)

Long-term storage in this context is achieved by a combination of water electrolysis, hydrogen storage, and fuel cells. Importantly, these components can be sized relatively independently from each other, as their use is decoupled. Costs for each of those components are thus specified.

For water electrolysis, different technologies are in development (e.g. Solid Oxide, Proton Exchange Membrane, Alkaline), which promise to serve specific use cases. No exact technology is selected here, with the cost estimate being the average of the cost estimates found in literature, regardless of the technology. It is further assumed that electrolyzer and fuel cell are two separate devices – although devices exist that demonstrate this reversible operation, such technology is still in a very early stage. For fuel cells, the most suitable technology was deemed PEM (Proton-Exchange Membrane), with the cost estimate again being bounded by literature estimates. Since cost curves for electrolyzers and fuel cells within the literature differ significantly, values in the range of the upper end is used for the baseline cost trajectory, whereas values from the lower end are used to define the cost trajectory favorable trend [13], [14], [15], [16], [17]. A moderate trend cost trajectory, between the baseline and favorable trend, suggesting a less positive development of the costs of these technologies is further proposed and implemented. The OPEX are assumed to be identical in all our cost trajectories and are based on more recent values [13]. Other sources suggest a fixed 5% of the CAPEX, which, compared to other literature, were deemed to be too pessimistic for any of the proposed cost trajectory cases [15]. The lifetime for fuel cells is assumed to be shorter than the lifetime for electrolyzer systems in accordance with literature findings [15], [18], [19]. For the cost trajectories favorable and moderate trend, the lifetimes of these technologies are hypothesized to be higher. For hydrogen storage, cost estimates for high-pressure aboveground storage systems were used, while alternative storage concepts such as metal hydrides or underground storage (not employable in a decentralized fashion) were not considered. For the cost trajectory favorable trend CAPEX targets for the year 2030 as suggested by the Hydrogen Europe Research are adapted[8] [16]. The OPEX are fixed at 5% of the CAPEX [15]. The lifetime for all cost trajectories is chosen to be 20 years [15].

Table 3. Lifetime, OPEX, and CAPEX estimates for PEM **fuel cell** systems in 2030, using 2024 CHF as basis. The baseline cost trajectory represents a consensus for a likely outcome, with the other trajectories assuming a better-than-predicted cost evolution.

Cost trajectory	Lifetime [years]	OPEX [CHF/kW]	CAPEX [CHF/kW]	Total annualized cost [CHF/MW]
Baseline	13	13.4	765	82'634
Favorable trend	20	13.4	320	32'229
Moderate trend	16.5	13.4	560	54'246

[8] Hydrogen energy density at 20°C and 700 bar

Table 4. Lifetime, OPEX, and CAPEX estimates for water **electrolyser** systems in 2030, using 2024 CHF as basis. The baseline cost trajectory represents a consensus for a likely outcome, with the other trajectories assuming a better-than-predicted cost evolution.

Cost trajectory	Lifetime [years]	OPEX [CHF/kW]	CAPEX [CHF/kW]	Total annualized cost [CHF/MW]
Baseline	20	11.6	534	47'466
Favorable trend	30	11.6	302	26'987
Moderate trend	25	11.6	418	32'582

Table 5. Lifetime, OPEX, and CAPEX estimates for **hydrogen pressure storage** systems in 2030, using 2024 CHF as basis. The baseline cost trajectory represents a consensus for a likely outcome, with the other trajectories assuming a better-than-predicted cost evolution.

Cost trajectory	Lifetime [years]	OPEX [CHF/kWh]	CAPEX [CHF/kWh]	Total annualized cost [CHF/MWh]
Baseline	20	0.40	8.0	938
Favorable trend	20	0.32	6.4	750
Moderate trend	20	0.36	7.1	834

2.2.3 Photovoltaics (PV)

Electricity generation using photovoltaics is the main source of energy production in the energy system under consideration. There is a huge untapped potential of electricity produced by ground-mounted agrivoltaic plants in Switzerland [20]. Such plants can already today be realized at lower costs than photovoltaic systems on (existing) infrastructure such as rooftops [21]. The favorable trend cost trajectory is chosen to illustrate a more positive development in the CAPEX of ground-mounted photovoltaic systems. The authors consider these cost trajectories to represent realistic scenarios for future developments, based on consultations with experts and their own experience of the current and past market situation. The OPEX are based on current costs and considered at a slightly higher level than documented by the International Renewable Energy Agency (IRENA) [22]. The lifetime for the baseline cost trajectory is based on commonly used values from the literature [23]. For the favorable trend cost trajectory, a more advantageous durability is considered in accordance with warranties that are already granted for certain modules.

Table 6. Technical lifetime, yearly OPEX, and total CAPEX estimates for **PV systems** in 2030, using 2024 CHF as basis. The base cost trajectory represents a consensus for the most likely outcome, with the other trajectories assuming a better-than-predicted cost evolution.

Cost trajectory	Lifetime [years]	OPEX [CHF/kW]	CAPEX [CHF/kW]	Total annualized cost [CHF/MW]
Baseline	25	11.5	800	57'442
Favorable trend	30	11.5	450	34'459

2.2.4 Demand-Side Flexibility

The increased implementation of decentralized electricity production, the further installation of heat pump systems and the expansion of the fully electric vehicle fleet lead to an increased network load. In practice, this often leads to a physical expansion of the grid capacity. The costs of such modifications

of infrastructure are highly project-specific and vary locally; therefore, it is not purposeful to standardize them within the scope of this project. The necessity for extension of grid capacity can be reduced through flexible demand-side management. The energy system's capacity for flexibility is represented in the optimization problem by introducing a (pseudo-)cost parameter. The load flexibility is determined by three mechanisms: heat pump operation control, load management of electric vehicles and the demand management of the general consumption (aggregation of the remaining types of electricity consumption). A cost factor is assigned to each of these mechanisms. These costs do not reflect reality, as they are not resolved spatially and temporally. They represent numerical values solely for the purpose of capturing technical flexibility in the model. The monetary significance for the cost function is of subordinate importance for the optimization problem. The favorable trend cost trajectory assumes that energy load control incurs no costs, allowing to investigate a maximally flexible energy system.

Table 7. Pseudo-costs associated with the shift of energy consumption of electric vehicles, heat pumps and an unspecified general load within the energy systems. These costs do not represent actual values that would occur for such energy shifts. They are a means to an end, used to implement flexibility in the optimization problem. The flexibility is constrained according to the models and parameters presented in 2.4.3.

Cost trajectory	Electric vehicles [CHF/MWh]	Heat pumps [CHF/MWh]	General load [CHF/MWh]
Baseline	0.1	0.1	0.5
Favorable trend	0.0	0.0	0.0

2.2.5 PV Overbuilding and Curtailment

Overbuilding and curtailment refers to the practice of installing surplus intermittent generation, which is curtailed during times of overproduction to obtain a more predictable and controllable generation profile and increase yield in times of suboptimal weather. In the case of PV, this is mostly relevant during the early and late hours of the day, days with bad weather, or winter. Overbuilding and curtailment specifically can effectively help to remedy the seasonal fluctuation present in the Swiss energy system. In this regard, it can be very well complimentary with storage solutions.

2.3 Import/Export Cost Curve

In order to correctly pose the optimization problem for each municipality, the interaction with the overarching grid must necessarily be defined as a boundary condition. While the main focus of the presented analysis is the determination of storage and curtailment extents, grid interaction is still a desirable occurrence, if only for the simple reason that no municipality strictly balances local production and consumption on a yearly basis. Within the presented framework, the only remedy for this shortfall or overproduction is provided by the grid. Further, it is not hard to argue that a connected system is more efficient up to a certain point, as production and consumption peaks will be smoothed. For the optimization system, grid interaction needs to be tied to costs, namely if additional transmission capacity is needed, and via the price of (locally) imported and exported energy. Quantifying the cost of installing additional grid connection capacity is an exceedingly difficult undertaking, as it is highly dependent on local circumstances and specifics of the project at hand. At the same time, the argument is made that the energy transition is progressing faster than infrastructure can be adapted. For those reasons it is assumed that no increase in grid connection capacity is allowed – thus also no costs are associated therewith. Each municipality is strictly limited to its current grid connection capacity, which is derived by scaling the respective timeseries with current values, instead of scenario values. The maximum absolute power flow is then used, which might differ from the physically installed capacity. It is however assumed that all associated safety factors and spare capacity is kept constant.

With regard to the price of energy, it is necessary to construct a function that relates the total aggregated decentralized production/consumption with a price. This should reliably reproduce market dynamics such as self-cannibalizing of PV generation on very sunny days. Three key properties are desired: 1)

The price is directly tied to the balance of production and consumption, 2) As soon as aggregate production reaches the capacity of all installed pumped hydro storage, the price goes to zero, 3) As soon as aggregate consumption approaches the maximum observed power of all Swiss centralized hydro power, the price increases exponentially. The total installed capacity of all Swiss pumped hydro storage plants is 5'607 MW, if the planned projects of Lago Bianco (1000 MW) and Grimsel 3 (660 MW) are included. The average maximum observed power output of all centralized Swiss hydro (storage + running) over the past 10 years was 11'133 MW, it is assumed that the price starts increasing rapidly after 90% of this value is reached (10'020 MW).

The usage of such a cost-curve implies a dynamic simulation, since there is an obvious feedback-loop between optimal solution and energy cost. It is challenging insofar as the optimization is conducted on a municipal level, with the price timeseries being an immutable boundary condition – which is only known after completing the optimization for all municipalities. This issue is addressed by running simulations iteratively until an equilibrium is reached. Starting from an initial guess for the price, a cost-optimal solution is found for each municipality, with associated (local) import and export timeseries, from which a new price timeseries is calculated. This new timeseries is then used as a boundary condition for the next simulation iteration on a municipal level.

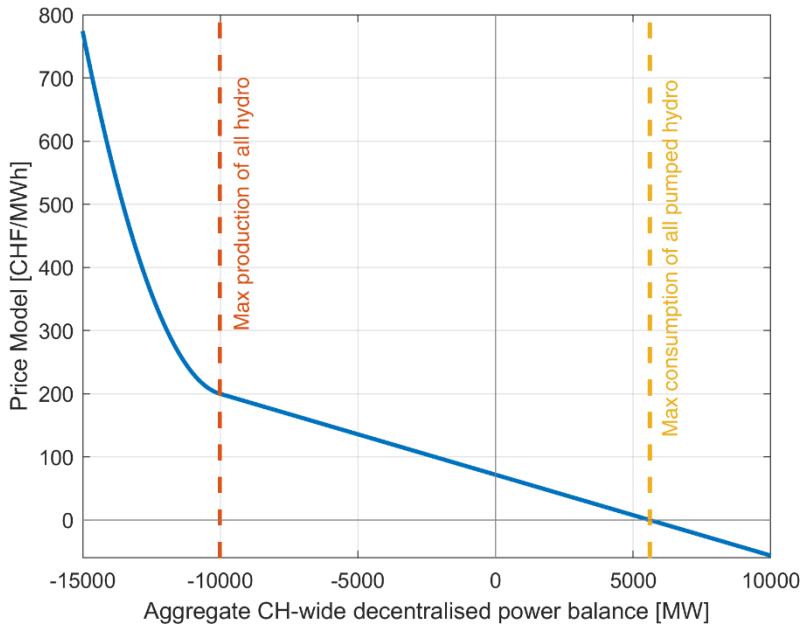


Figure 1. Modelled energy price curve (CHF/MWh) dependent on CH-wide aggregated decentralised power balance. Prices become negative if more is fed into the grid than what all pumped hydropower can accommodate and rise exponentially if more is demanded than all existing hydro (storage + running) can realistically produce.

2.4 Optimization Methodology

2.4.1 Overview

The methodology to arrive at a cost-optimal solution to integrate the proposed levels of decentralized renewable generation and new/changed consumption patterns into the existing system involves multiple steps. The entire modelling and simulation framework is schematically shown in Figure 2. At the core of the analysis sits an optimization algorithm, able to process a given decentralized production and consumption timeseries, costs and constraints for various energy shifting technologies, as well as a price timeseries for centralized electricity, to arrive at a cost-optimal solution. The main outputs are the required amounts of storage (and which kind), flexibility (and when to use it), PV overbuilding and curtailment levels, and residual grid usage. Each municipal simulation receives as an input its respective decentralized production and consumption timeseries (15-minute timesteps), as described in detail in the

prior reports (deliverable reports D1.2 and D2.4). These remain constant for all subsequently described scenarios and iterations, however are downsampled to 1-hour timesteps to reduce the computational load to an acceptable level. As a second input, each simulation receives the scenario data for costs and constraints of different energy shifting options (e.g. batteries). Multiple scenarios are defined which aim to reproduce different possible cost trajectories of the relevant technologies. These scenarios are described in section 2.2. Within each cost scenario, every municipality is subject to the exact same costs, which are further constant during the subsequent iterations. Finally, each simulation receives a timeseries for grid electricity prices, which are identical for every municipality. Subject to these inputs a solution is found, whereby some residual grid interaction is in most all cases still cost-effective. Since this exhibits a feed-back reaction with the grid electricity prices, the problem is solved iteratively, by updating the price timeseries after each iteration according to the methodology described in section 2.3. Given sufficient amounts of numerical damping, convergence is usually reached after 10 – 20 iterations. In the following, the mathematical formulation of the optimization problem (i.e. the core simulation) is given.

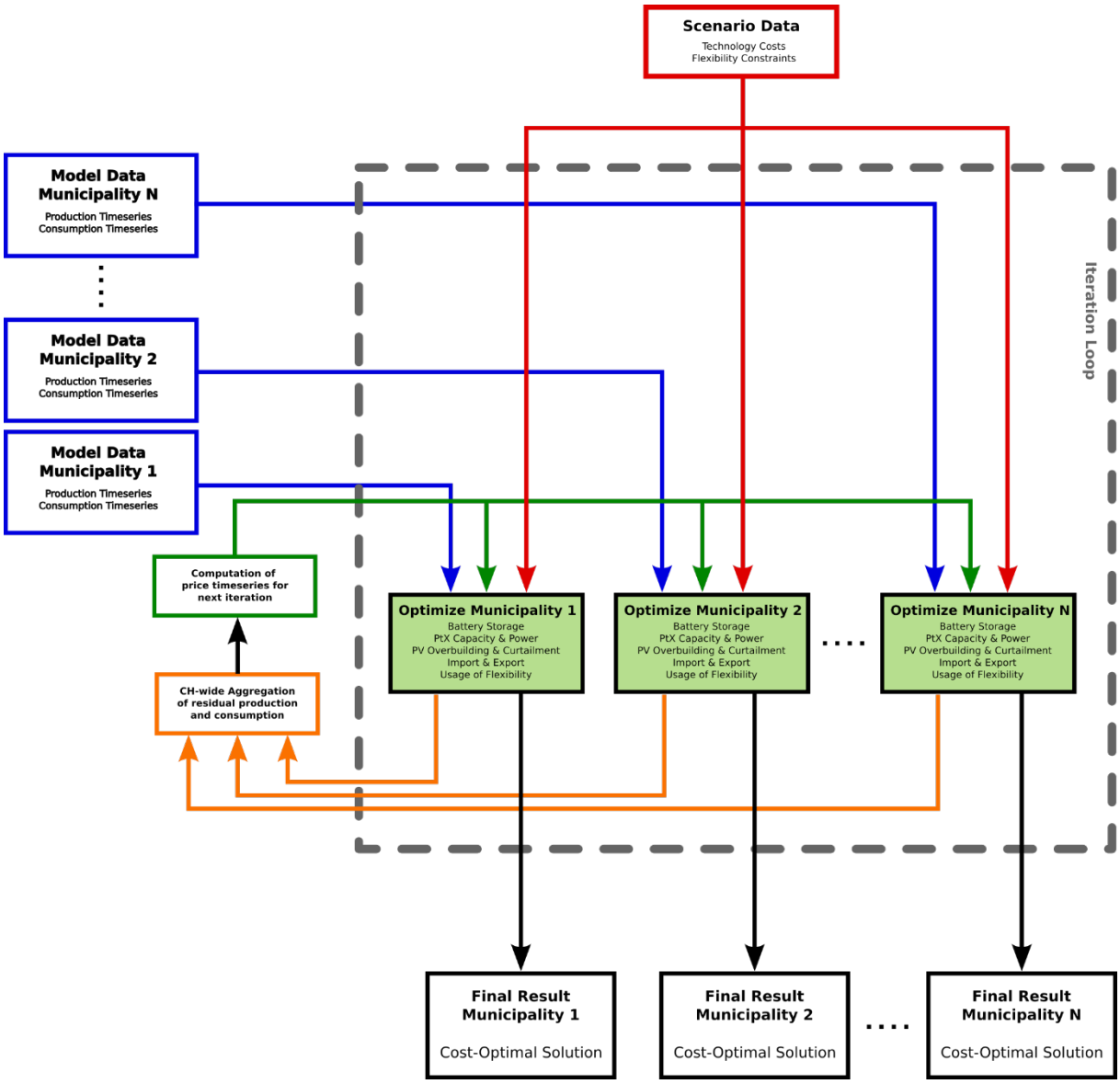


Figure 2. Graphical overview of simulation methodology. Each municipal optimisation (green background) needs three individual inputs: 1) Model data describing decentralized production and consumption timeseries (blue), 2) Scenario data specifying the costs of various technologies and boundary conditions for flexibilities (red), 3) A grid energy cost timeseries (green). The results of each municipal simulation consist of two parts, namely the cost-optimal solution (i.e. to what extent the different measures are deployed) and the residual grid interaction. The latter is summed for all municipalities to obtain the aggregated grid utilization, resulting in an updated grid cost timeseries. The process is repeated until convergence is reached. It is important to note that the results are cost-optimal after each iteration, however for the respective grid electricity price timeseries.

2.4.2 Immutable inputs

As shown in Figure 2, each municipality receives a set of input timeseries, which remain unchanged during the optimization. These are the decentralized production timeseries P^0_{PROD}, the separate consumption timeseries for general load (P^0_{GL}), electric vehicle charging (P^0_{EV}), as well as heat pumps (P^0_{HP}). Further, any PV overbuilding is scaled with the municipality-specific production profile for façade PV, which most closely resembles the envisioned overbuilding as vertical agri-PV installations. Each municipality additionally receives its specific agri-PV potential, which is set as an upper limit to the amount of possible PV overbuilding.

2.4.3 Flexibilities and Constraints

The optimizer can choose to adapt the consumption of heat pumps and electric vehicles as well as general uncategorized consumption within certain bounds. In general, both an upper and lower limit are specified in order to limit the consumption to within a reasonable range. Further, constraints are set that require each kind of consumption to be cumulatively met within a certain timeframe (i.e. consumption is deferred or moved forward, not eliminated or created).

In the special case of **EV's,** upper and lower consumption limits were made available through the study "Modeling Charging Demand and Quantifying Flexibility Bounds for Large-Scale BEV Fleets" [25]. The EV charging consumption (P_{EV}) must conform to those specified lower and upper boundaries as

$$B_{low} \leq P_{EV} \leq B_{high} \tag{3}$$

At the same time, the deviations from the original timeseries must even out over any given week:

$$\sum_{t} (P_{EV} - P_{EV}^{0}) = 0 \quad \forall \text{ weeks} \tag{4}$$

In the case of **heat pumps,** the maximum consumption was set as a simple multiple of the maximal original timeseries through

$$P_{HP} \leq \mu_{HP} \cdot \max(P_{HP}^{0}) \tag{5}$$

while the absolute minimum consumption was set to zero. Further, the shifted timeseries could not deviate from the original one by more than a certain fraction, ensured by the following condition:

$$\mu_{HP}^{-} \leq \frac{P_{HP}}{P_{HP}^{0}} \leq \mu_{HP}^{+} \tag{6}$$

Similar to EV consumption, changes are constrained to be equivalized in any given day:

$$\sum_{t} (P_{HP} - P_{HP}^{0}) = 0 \quad \forall \text{ days} \tag{7}$$

In the case of **general load,** the maximum consumption was set as a simple multiple of the maximal original timeseries through

$$P_{GL} \leq \mu_{GL} \cdot \max(P_{GL}^{0}) \tag{8}$$

Further, the shifted timeseries could not deviate from the original one by more than a certain fraction, ensured by the following condition:

$$\mu_{GL}^{-} \leq \frac{P_{GL}}{P_{GL}^{0}} \leq \mu_{GL}^{+} \tag{9}$$

Finally, changes are constrained to be equalized within any given 72h-window:

$$\sum_{t} (P_{GL} - P_{GL}^{0}) = 0 \quad \forall (72\text{h} - \text{windows}) \tag{10}$$

2.4.4 Storage and Constraints

For both battery storage and PtX/Hydrogen storage, charging and discharging efficiencies are applied such that the charge state at any time is defined by

$$E_{BAT} = E_{BAT}^{0} + \sum_{0}^{t} \left(\eta_{BAT}^{ch} \cdot P_{BAT}^{ch} - \frac{1}{\eta_{BAT}^{dc}} \cdot P_{BAT}^{dc} \right) \tag{11}$$

$$E_{PtX} = E_{PtX}^{0} + \sum_{0}^{t} \left(\eta_{PtX}^{ch} \cdot P_{PtX}^{ch} - \frac{1}{\eta_{PtX}^{dc}} \cdot P_{PtX}^{dc} \right) \tag{12}$$

It was mandated that both storages return to their initial fill level after a full year, thus no energy is being introduced into the system by accident:

$$E_{BAT}^{0} = E_{BAT}^{T}, \quad E_{PtX}^{0} = E_{PtX}^{T} \tag{13}$$

Numerical constraints are introduced to limit the fill levels:

$$0 \leq E_{BAT} \leq C_{BAT}, \quad 0 \leq E_{PtX} \leq C_{PtX} \tag{14}$$

While the charging speed of the PtX-Storage is a decision variable ($\max(P_{PtX})$), the charging/discharging rate of the battery storage was limited to 1C, i.e.

$$\max(P_{BAT}) \leq \frac{C_{BAT}}{hr} \tag{15}$$

In the case of lithium batteries, it is assumed that a certain amount of storage is pre-installed due to PV installations. As this is not explicitly described in the fundamental data set (EP2050+), varying amounts are added depending on the chosen scenario. The total amount of installed batteries is thus defined as $C_{BAT} = C_{BAT}^{0} + C_{BAT}^{+}$.

2.4.5 Grid, PV and Curtailment

Each municipality can import and export electricity via the grid, which has a fixed (symmetric) interchange capacity *G*.

$$P_{EXP} \leq G, \quad P_{IMP} \leq G \tag{16}$$

The grid interchange capacity *G* in each municipality is found by applying current decentralized production and consumption values to the relative temporal distributions for each municipality, instead of the EP2050+ scenario values, in order to approximate the current grid interaction. The grid interchange capacity is assumed to remain unchanged from today, such that the maximum current import/export observed is set as the capacity. It is assumed that safety factors, future-proofing etc. remain constant, such that any (unknown) current spare capacity is not considered. Further it is assumed that grid capacity is perfectly symmetric, i.e. the same restrictions apply both for local import and local export.

The optimizer can choose to add additional PV generation capacity C_{PV}^{+} to the generation mix, which is scaled to the municipality-specific time-resolved production profile for vertical façade PV, in order to represent vertical Agri-PV installations, which has been modelled as producing 1050 kWh/kWp annually. Further, it can choose to dynamically curtail parts of the PV generation, consisting of the combined baseline PV and additional PV generation:

$$0 \leq P_{CUR} \leq P_{PV} = P_{PV}^{base} + P_{PV}^{+} \tag{17}$$

2.4.6 Power Balance

The final technical constraint consists of a power balance, which ensures that no energy is created or lost in the system at all times:

$$P_{PROD}^{0} + P_{PV}^{+} - P_{CUR} + P_{IMP} - P_{EXP} - P_{BAT}^{ch} + P_{BAT}^{dc} - P_{PtX}^{ch} + P_{PtX}^{dc} - P_{EV} - P_{HP} - P_{GL} = 0 \tag{18}$$

2.4.7 Costs and Optimization Function

In general, all costs are calculated on an annualized basis, utilizing their relative lifetimes and taking into account discount factors. These calculations are detailed in section 2.2.

Investment costs consist of the costs for battery capacity, PtX capacity, PtX charging/discharging power capacities as well as additional PV:

$$c_{CAPEX} = c_{BAT}^{cap} \cdot C_{BAT}^{+} + c_{PtX}^{cap} \cdot C_{PtX} + c_{PtX}^{dc,cap} \cdot \max(P_{PtX}^{dc}) + c_{PtX}^{ch,cap} \cdot \max(P_{PtX}^{ch}) + c_{PV} \cdot C_{PV}^{+} \tag{19}$$

Note that only the cost for additional battery capacity are included (see section 2.4.4).

Operational costs are dependent on the actual usage of the installed storage capacities:

$$c_{OPEX} = c_{BAT}^{op} \cdot \sum (P_{BAT}^{ch} + P_{BAT}^{dc}) + c_{PtX}^{ch,op} \cdot \sum P_{PtX}^{ch} + c_{PtX}^{dc,op} \cdot \sum P_{PtX}^{dc} \quad (20)$$

Grid costs consist of energy costs for import and export (see section 2.3), as well as grid usage costs, which are modelled in such a way that higher grid utilization is disincentivized (representing faster aging of components etc.):

$$c_{GRID} = c_{GRID}^{en} \cdot \sum (P_{IMP} - P_{EXP}) + c_{GRID}^{cap} \cdot \sum \frac{P_{IMP}^2 + P_{EXP}^2}{G} \quad (21)$$

Flexibility costs are assumed to be symmetric, i.e. a demand deferral is priced equally as a moving it forward:

$$c_{FLEX} = c_{EV} \cdot \sum |P_{EV} - P_{EV}^0| + c_{HP} \cdot \sum |P_{HP} - P_{HP}^0| + c_{GL} \cdot \sum |P_{GL} - P_{GL}^0| \quad (22)$$

The total costs associated with a given set of chosen decision variables is then

$$c_{TOTAL} = c_{CAPEX} + c_{OPEX} + c_{GRID} + c_{FLEX} \quad (23)$$

which represents the objective function to minimize. Table 8 summarizes all decision variables which are determined for every municipality.

Table 8. Optimization decision variables and timeseries.

Variables	Description
$P_{BAT}^{ch}, P_{BAT}^{dc}, P_{PtX}^{ch}, P_{PtX}^{dc}$	Charging and discharging timeseries for battery and PtX.
$C_{BAT}^{+}, C_{PtX}, C_{PtX}^{ch}, C_{PtX}^{dc}$	(Additional) storage capacities of battery and PtX, charging and discharging power capacity of PtX.
P_{GL}, P_{HP}, P_{EV}	Demand-shifted consumption timeseries for general load, heat pumps, and electric vehicles.
C_{PV}^{+}	Added PV capacity.
P_{IMP}, P_{EXP}	Import and export timeseries.
P_{CUR}	Curtailment timeseries.

3 Results

The analysis of the optimization output is split into three main parts. First, CH-wide or region-aggregated results are compared between the different scenarios (see section 2.1 for the scenario definitions). This includes insights into total costs, different penetration levels of technologies and residual grid utilization. Second, regional differences in cost-optimal solutions are being highlighted by comparing various outputs spatially. Third, the usage of several technologies on a temporal base is investigated by showcasing the optimized production and consumption timeseries for selected and representative municipalities. The categorization of municipalities into regions follows the methodology defined within the EDGE project consortium [24].

3.1 Aggregated Results

3.1.1 Installed Storage Capacity

Figure 3 shows the cumulative installed storage capacity in all Swiss municipalities, segmented into battery storage and hydrogen storage. In the *Ref* scenario, a total of 61 GWh of short-term battery storage is installed, whereas a total of 102 GWh of long-term, hydrogen storage is deployed. At a population of roughly 9.1 Mio[9], this amounts to 6.7 kWh/cap of battery storage and 11.2 kWh/cap of hydrogen storage. Part of the short-term storage is assumed to be already installed irrespective of the optimization, as homeowners and businesses often consider storage when installing PV.

The *PtX* scenario does not produce significantly different values in installed storage capacity, with short-term storage being virtually equivalent to the base scenario *Ref*, and long-term storage capacity only marginally higher. Both *Opt* and *PVBat* produce significant deviations, with the deployment of short-term storage much higher, up to 117 GWh CH-wide installed capacity. Conversely, the hydrogen storage capacity deployed is significantly lower, with a roughly 24% decrease compared to Ref. Two effects are thus visible: Lower costs for hydrogen storage capacity do not significantly increase the cost-effective total installed storage capacity, at least at the levels investigated within this report. At the same time, lower costs for short-term storage show a very direct impact, with installed capacities responding strongly.

Irrespective of the assumed cost scenarios, the analysis shows a combination of both short-term and long-term storage to be cost-optimal. In all scenarios, a minimum of 60 GWh of short-term (Li-Ion) storage is being projected, and a minimum of 77 GWh of hydrogen storage. This clearly hints towards the respective strengths and weaknesses of both.

[9] https://www.bfs.admin.ch/bfs/de/home/statistiken/bevoelkerung/stand-entwicklung.html

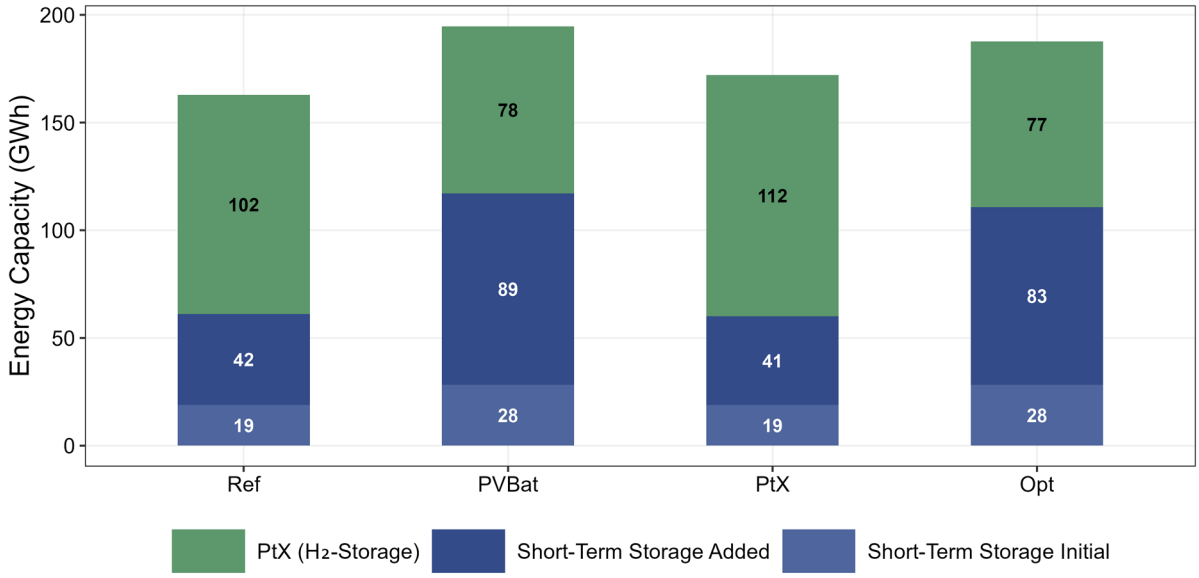


Figure 3. Cumulative (CH-wide) installed energy storage capacity, segmented into short-term (Li-Ion) and long-term (hydrogen) storage, for all four discussed cost/flexibility scenarios. Short-term storage is further segmented into initial storage, assumed to be co-installed with PV, and additional storage determined by the optimizer (see section 2.4.4 for details).

3.1.2 Installed Storage Power

Aside from the storage capacity, the rated power of both charging and discharging the respective storages was a decision variable in the optimization, with scenario-specific costs attached to each. Note that for short-term (Li-Ion) storage, this rated power was fixed at 1C, such that the optimization is only concerned with the power capacity of PtX charging (via electrolysis) and discharging (via PEM fuel cell). Figure 3 shows the cumulative (CH-wide) installed PtX charging and discharging capacities for all four scenarios. In the base scenario *Ref*, the total rated electrolysis power was found to be 130 MW, while the total rated fuel cell power was found to be 70 MW. Given the hydrogen storage capacity of 102 GWh in the *Ref* scenario, this corresponds to 1'120 h of storage production-side, assuming an electrolysis efficiency of 70 %, or 728 h of storage consumption-side, assuming a fuel cell efficiency of 50 %. This clearly points to the use-case of seasonal storage. Note also the clear difference in magnitude between 130 MW / 70 MW and the rated power of short-term storage in the *Ref* scenario, 61 GW (symmetric, both charging and discharging).

In the scenarios where short-term battery storage is cheaper (*PVBat* and *Opt*), the installed rated power of electrolysis and fuel cells becomes significantly smaller – 40 MW bidirectionally for both cases. For charging, this amounts to 2'785 h of storage, for discharging to 975 h.The more interesting case is the scenario with low costs for *PtX*, namely also the electrolysis and fuel cell aspects of the complete system. In contrast to the installed storage capacity, which remains largely unchanged with respect to the base scenario, the installed rated powers are increased substantially, with an electrolysis installed power of 370 MW (corresponding to 432 h of storage) and a fuel cell capacity of 110 MW (corresponding to 509 h of storage). The higher ratio of conversion capacity to storage capacity suggests a mix between seasonal and shorter-duration storage, although it is still very far from intra-day storage.

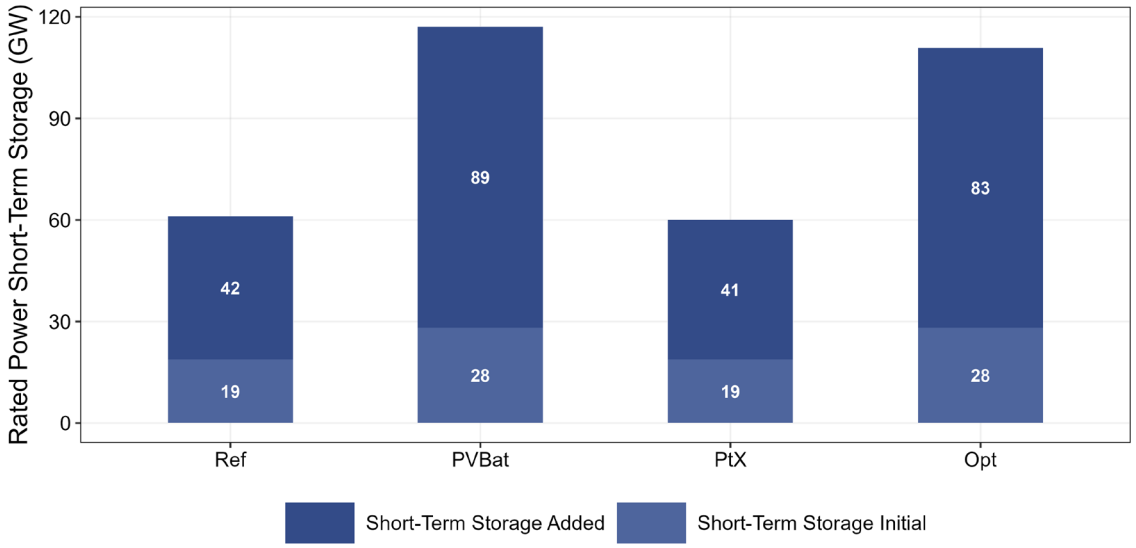


Figure 4. Cumulative (CH-wide) installed short-term storage (batteries) in the four cost/flexibility scenarios. Indicated are the "pre-installed" home battery storages (Short-Term Storage Initial), where the assumption is made that a certain amount of batteries will be installed alongside residential and commerical PV (see section 2.1 and Table 1).

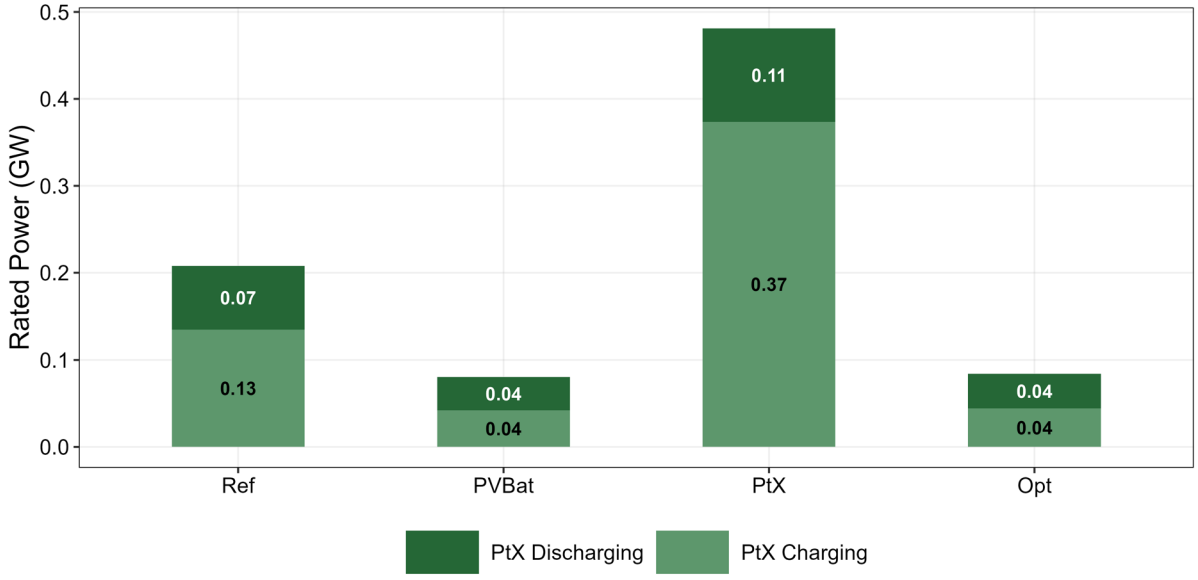


Figure 5. CH-wide aggregated rated power of PtX charging (electrolysis) and discharging (fuel cell) for all four scenarios.

Figure 6 shows an interesting aspect of the interplay between the two storage options, namely buffer charging – where electrolysis is being fed by the local battery, as opposed to either grid or locally produced electricity. The short-term battery acts as a buffer to absorb (mostly) short-lived PV peaks, which allows to use a smaller electrolysis setup with higher utilization. In the base scenario *Ref*, 16.6 % of all energy stored as hydrogen has been buffered in this way. In the scenarios with lower costs for short-term storage (*PVBat* and *Opt*), this number increases to 46.9 % and 44.5 %, respectively. The lower costs for batteries thus have a direct impact on the feasibility of PtX as a technology, as they allow cheaper buffer storage and therefore facilitate higher utilization of the electrolysis equipement. In the case where Power-to-X-related costs are assumed lower (scenario *PtX*), buffer-charging is reduced substantially to only 2.6 %, with the bulk of municipalities not relying on this mechanism at all. The higher

installed capacity of electrolysis (370 MW vs 130 MW in the *Ref* scenario) means that more energy can be stored directly without first being buffered.

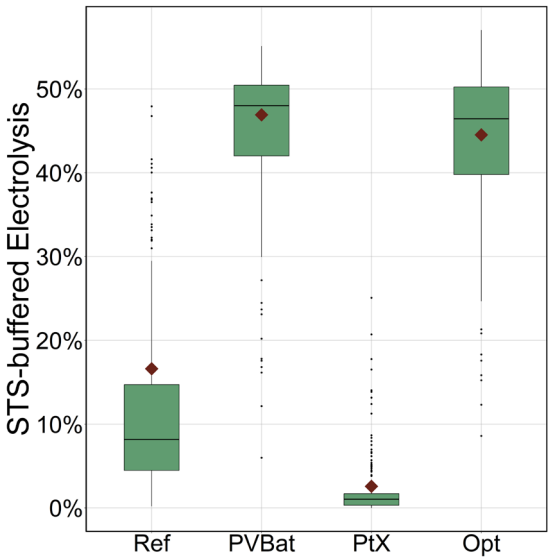


Figure 6. Municipal distribution and overall (indicated red) fractions of PtX charging (electrolysis use) with concurrent short-term battery discharge (so-called STS-buffered electrolysis). Lower values do not necessarily correspond to less buffered charging overall, but a higher fraction of direct charging.

3.1.3 Storage Dynamics

Across all scenarios and with little dependence on the large variations in battery capacity additions, the charge and discharge utilization rates of short-term battery storage is in the range of around 165 times per year (see Figure 7). The results show that these batteries are normally used daily. Power-to-X on the other hand only features a utilization rate of 1.25 in the scenarios *PVBat* and *Opt*, thus serving the role of seasonal storage. In scenarios with a cost ratio more advantageous for power-to-X compared to short-term battery storage, power-to-X is observed to have a utilization rate of up to 3.7, thus competing stronger with batteries for the role of short-term or medium-term storage (scenarios *Ref* and especially *PtX*). This finding is surprising because the expected competition would be power-to-X vs. PV overbuilding and curtailment for winter energy provisioning, yet we do not see a drastic increase in energy discharge by power-to-X (fuel cells) in winter.

It is evident that short-term battery storage runs through many cycles each month with charging and discharging rates being equal in each month. This is clear evidence that energy is shifted by hours to days. More activity is observed in spring and summer due to an increase in PV generation. Energy shifting by months is observed by power-to-X with electrolysis (charging) happening predominantly in spring and summer when there is energy surplus and reconversion to electricity with fuel cells (discharging) occurring mostly in autumn and winter months.

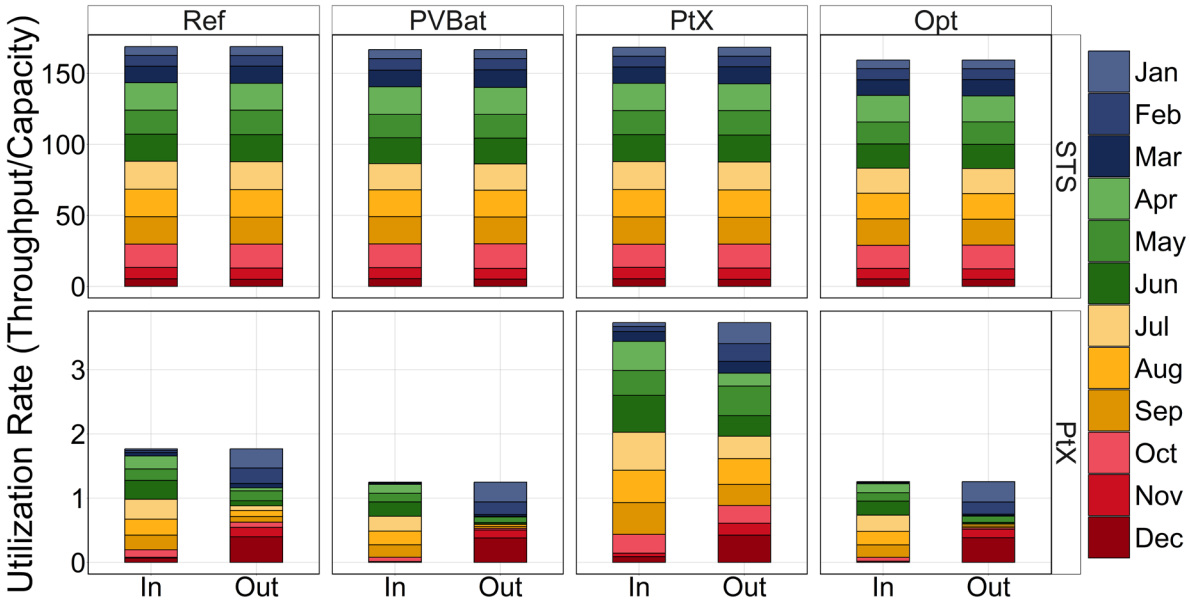


Figure 7. Dynamics of short-term (STS) and long-term (PtX) charging and discharging throughput under all four scenarios. Shown are the charging (In) and discharging (Out) amounts per month, i.e. the ratio between total energy stored and capacity. With short-term storage, an average of 165 cycles happen annually, with the majority occurring during the summer months. Further, input and output cycles are distributed roughly evenly. With long-term storage, naturally far fewer cycles occur, with the majority of input occurring in the summer months, and output in the winter months.

3.1.4 Flexibility Use

In all three consumption categories (general load, electric vehicles, and heat pumps), demand-side flexibility was added within clearly specified bounds. The overarching constraints for all categories are described in section 2.4.3, with the costs associated with flexibilities dependent on the specific scenario (described in section 2.2.4). Note that for both the *PVBat* and *PtX* scenarios, the costs for flexibility are kept constant, whereas for the *Opt* scenario, zero costs are associated with flexibility. Figure 8 shows the cumulative flexibility use for the three consumption categories, for all four investigated scenarios (aggregated CH-wide values).

In the *Ref* scenario, a total of 6.4 TWh of demand were shifted, with the main contributor being electric vehicles (3.5 TWh). Note that this analysis does not specify over what timeframe the demands were shifted, nor at what time of year/day. Demand-side-management of general load and heat pumps were smaller in comparison, with a combined demand-side shift of 2.9 TWh. In the two scenarios where costs associated with flexibilities were unchanged with regards to the base scenario, the cost-effective solution is virtually unchanged. If the costs are removed (*Opt* scenario), demand-shifting becomes much more prevalent. A total of 20.5 TWh of consumption are shifted, with the relative distribution between the three categories remaining roughly unchanged. Electric vehicles, accounting for the largest category, amount to a total CH-wide demand-shift of 13.1 TWh. As a comparison, this is a factor of 118 larger than the installed short-term battery capacity in this specific scenario, showing that low-cost demand-shifting can be an important piece of the solution.

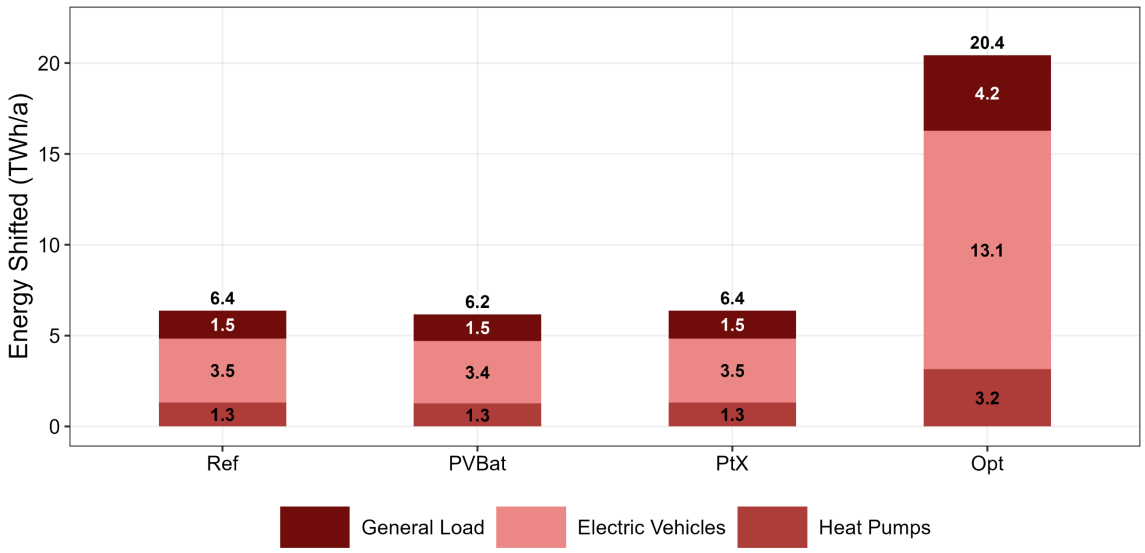


Figure 8. Flexibility use of general load, electric vehicles, and heat pumps for all four investigated cost/flexibility scenarios (aggregated CH-wide values).

3.1.5 PV overbuilding & Curtailment

PV overbuilding and curtailment are technically independent measures but together achieve two major goals: Adding or removing energy to or from the system and altering the PV production profile. Depending on the specific situation, this can drastically reduce the need for imports (by increasing the amount of locally generated electricity) or the need for storage (by flattening the PV production profile). Figure 9 shows the yearly production of all Swiss PV, both pre-installed (according to Energieperspektiven 2050+) and additional PV as found by the optimization algorithm, for all four discussed cost/flexibility scenarios. Further shown is the total yearly amount of PV energy that is curtailed under the respective assumptions. Note that curtailment is not associated with any cost, for all scenarios.

In the scenario *Ref*, 9.6 TWh of additional PV is added – this corresponds to an increase by 28.5 % compared with the original production estimate. In scenario *PVBat*, which assumes identical costs for PV installations, slightly (but not significantly) less PV is being overbuilt (9.4 TWh), which is most likely owed to the fact that additional Power-to-X capacity is not well-suited to profit off PV peaks, as the ratio of rated power to storage capacity is very low. In the other scenarios, *PVBat* and *Opt*, additional PV is assumed to cost less (40% less on an annualized basis), which results in a significantly larger amount of additional PV being considered cost-effective. In both scenarios, vertical PV to the extent of close to 25 TWh is added.

Curtailment in all scenarios is similar on a relative basis, with 16.5 – 17.8 % of all produced PV electricity being curtailed. The absolute amounts of curtailed PV electricity vary from 7.1 TWh in the *PtX* scenario to 10.4 TWh in the *PVBat* scenario. An argument can be made that increased flexibility in demand can significantly reduce the need for curtailment, the results however suggest a much weaker if not non-existent connection. Comparing the total amount of demand-shifted energy in both the *PVBat* and *Opt* scenarios, where the *Opt* scenario assumes no costs for flexibility, curtailment remains virtually unchanged. This is due to the fundamentally different timescales involved: flexibility operates at most on a weekly timescale, while curtailment is mostly seasonal, i.e. happens mostly in summer. Since demand is not shifted from winter into summer, it cannot reasonably help to reduce (the still cost-effective) curtailment.

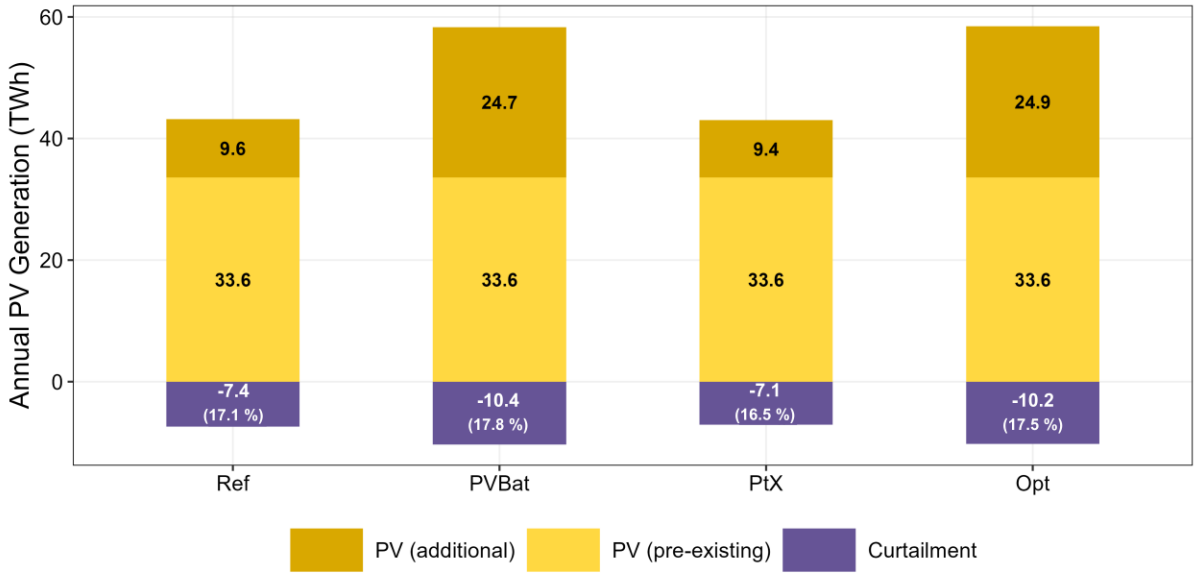


Figure 9. Absolute CH-wide cumulative values for pre-installed PV and additional PV yearly production, as well as cumulative curtailment, both in absolute values and as a percentage of total annual PV production.

3.1.6 Costs

The total costs for all measures, given the per-technology costs in section 2.2, are presented here. It is important to reiterate two points: First, the costs are annualized according to their estimated lifetime. Second, the shown values represent the costs associated with the integration of all projected additional decentralized generation and consumption, without significant additional strain on the electricity grid. Note also that costs shown here are not to be understood as being without profit counterpart – but for lack of a sophisticated market model, an estimate is difficult. Additional PV, for example, will still feed into the grid at a certain price, while storage can be used for arbitrage. The shown costs are not reflective of this fact.

Figure 10 shows the cumulative annualized costs for integration of the projected increase in decentralized electricity generation and consumption, for all four cost/flexibility scenarios. It is further segmented into the three main investigated mitigation measures (short-term storage, long-term storage, PV overbuilding & Curtailment). Note that the residual grid utilization cost function is constant for all scenarios, such that it is mainly driven by the attractiveness of alternative options. It is for this reason that an optimistic scenario, with solely cheaper technology costs, results in a higher total system cost than the base scenario. In this optimistic scenario, a larger portion of the local fluctuations are dealt with locally, as opposed to using centralized production/consumption for balancing.

In the base scenario, decentralized system costs for all Swiss municipalities are estimated to be 1’168 Mio. CHF/a. Given a current GDP of approximately 854 billion CHF[10], this represents roughly 0.137 % of GDP, annually. The two main components of this total cost are the installed short-term batteries (532 Mio. CHF/a) and the additional PV for overbuilding & curtailment (523 Mio. CHF/a). Costs for PtX-systems are comparatively low, with 95 Mio. CHF/a.

In the *PtX* scenario, costs stay relatively similar to the base scenario *Ref*, with slightly lower overall cost (1’135 Mio. CHF/a). The higher installed rated power of both electrolysis and fuel cell system components causes the overall system to be more efficient, thus also lowering the necessary amounts of short-term storage and PV overbuilding & curtailment, albeit to a very small degree. A more significant shift can be seen with the *PVBat* and *Opt* scenarios, where decentralized system costs are higher than in the base scenario, for the reasons mentioned before. Despite significantly higher amounts of short-term

[10] https://www.bfs.admin.ch/bfs/de/home/statistiken/volkswirtschaft/volkswirtschaftliche-gesamtrechnung/bruttoinlandprodukt.html

battery storage deployed, the costs associated therewith are lower (440 Mio. CHF/a and 409 Mio CHF/a, respectively). This is however offset by a large increase in the annualized cost for additional PV (811 Mio. CHF/a and 816 Mio. CHF/a, respectively). The PtX-related costs remain comparatively low in these scenarios. With decentralized system costs of 1'134 Mio. CHF/a and 1'296 Mio. CHF/a, respectively, those two scenarios show the highest values.

Figure 10 further shows an extension of the discussed numbers, with grid import costs and export revenues included. Note that this does not represent international import/export per se, but rather electricity provided by centralized power plants, and electricity consumed by pumped hydro storage. The costs are dependent on the aggregated CH-wide grid use, which is explained in section 2.3. It is clearly visible that grid use is, under all scenarios, still a predominantly important part of balancing decentralized production and consumption. The result is reflective of the core assumption made for the cost curve: grid usage only becomes prohibitively expensive when centralized capacities are exceeded (i.e. there would be a need for international import/export). It is important to stress that the relative differences in costs between scenarios are more illustrative of certain effects than the absolute numbers themselves, since they are heavily reliant on the artificial cost curve. The residual grid usage is investigated in more detail in section 3.1.7.

Total system costs under the base cost/flexibility scenario *Ref* are 4'996 Mio. CHF/a, of which 3'828 Mio. CHF/a are grid energy costs (minus surplus revenue) and grid usage costs (see also section 2.4.7). If PtX-related costs are assumed to be lower (scenario *PtX*), the total system costs do not respond significantly (total annual system costs of 4'970 Mio CHF/a). In contrast, the scenario with lower costs for PV and batteries (scenario *PVBat*) shows a substantially lower system cost of 4'016 Mio. CHF/a, of which 2'680 Mio. CHF/a are grid energy and usage costs. Similarily, in the optimistic scenario (*Opt*), the total system costs are estimated to be 3'905 Mio. CHF/a, with grid-related costs being 2'609 Mio. CHF/a. This points to a fundamental shift, where reliance on the grid is reduced substantially. While the total costs for decentralized measures (local energy shifting) increase, the total system costs are reduced overproportionally.

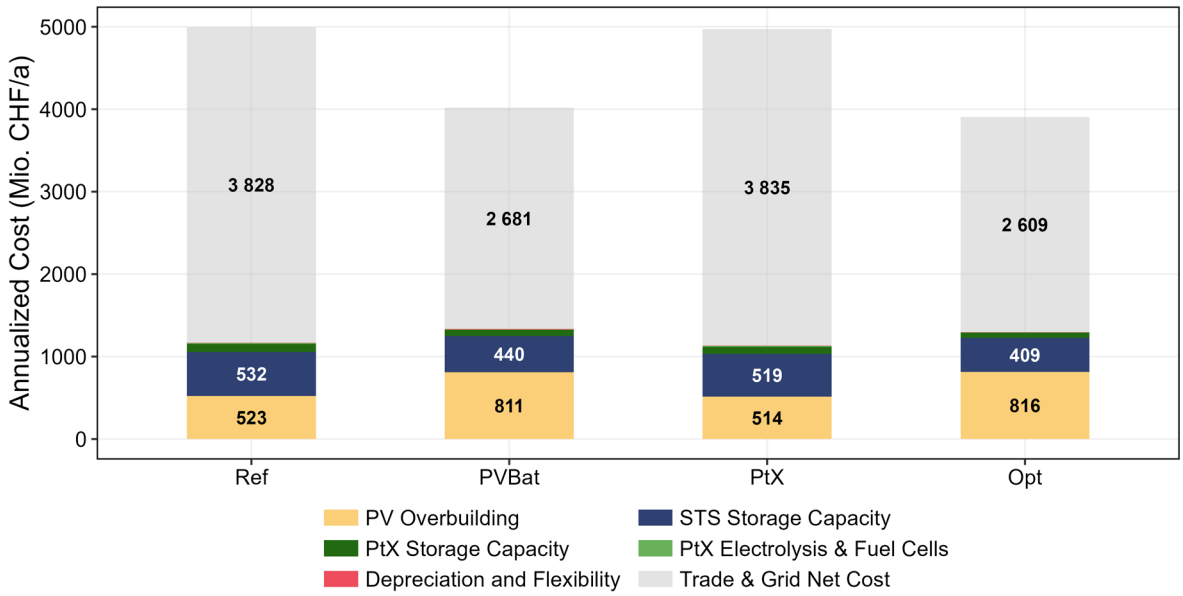


Figure 10. Cumulative annualized costs (in Mio. CHF/a) and revenues for integration of the projected increase in decentralized electricity generation and consumption, segmented into the three main investigated mitigation measures (short- and long-term storage, PV overbuilding & curtailment), under all four cost and flexibility scenarios, with the aggregated import costs and export revenues included (grey area). Note that these specifically are not representing international import/export, but import/export with the national grid.

Figure 11 shows the same data segmented per EDGE-region. In the *Ref* scenario, a large share of the costs (3'784 Mio. CHF/a) occur in the cities, while only a very small fraction occurs in the alps (243 Mio. CHF/a). Comparing different scenarios, the main differences are to be found in the grid usage – with cheaper batteries and storage (both in the *PVBat* and *Opt* scenarios), local PV overbuilding and curtailment as well as short-term battery storage are increased. While this raises local costs, the overall system costs (including grid energy and usage costs) decline.

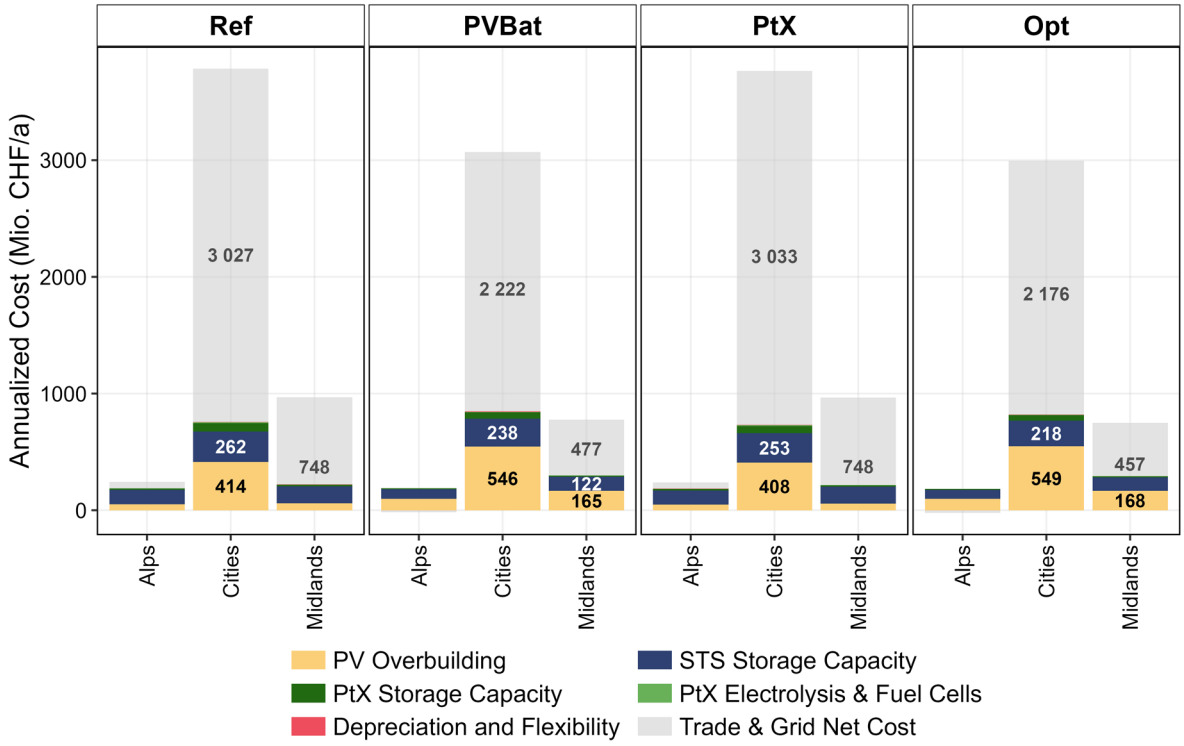


Figure 11. Cumulative annualized costs (in Mio. CHF/a) and revenues for integration of the projected increase in decentralized electricity generation and consumption, per EDGE-region and cost/flexibility scenario.

Figure 12 shows the annualized costs per capita under the different scenarios, segmented into EDGE-regions. In the *Ref* scenario, an interesting effect can be seen where the difference in grid reliance is very apparent. While the per capita costs for local installations (PV and storage) are largest in the *Alps*, the total system costs are lowest (215 CHF/a/cap), the costs for local installations are lower in the *Cities*, but with much larger total system costs (692 CHF/a/cap). The per capita costs for local installations are lowest in the *Midlands* (107 CHF/a/cap), with total system costs of 468 CHF/a/cap (including grid usage). Scenarios with lower technology costs naturally lower the total system costs, however have no significant influence on the overall distribution, with the exception of alpine municipalities in scenarios with lower costs for PV and batteries (*PVBat* and *Opt*), in which their grid interaction results in a net revenue.

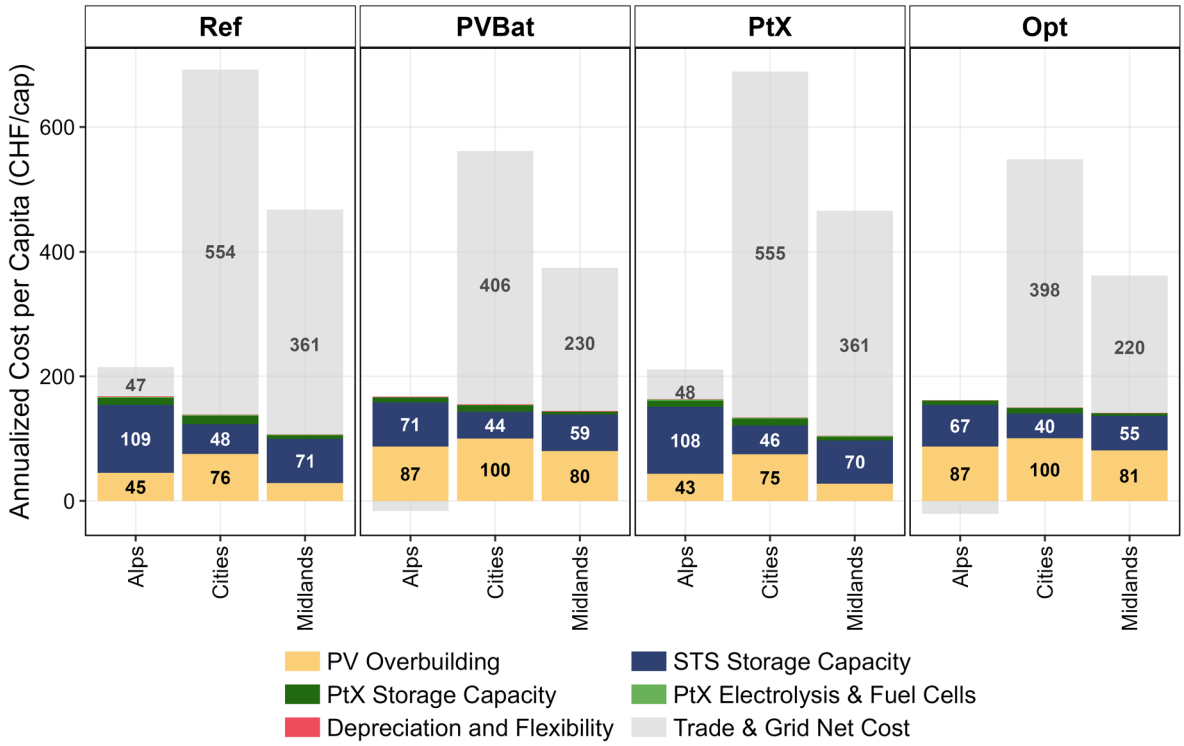


Figure 12. Annualized costs per capita for all investigated measures to integrate the projected increase in decentralized electricity production and consumption, segmented into cost/flexibility scenarios, EDGE-regions and technologies.

3.1.7 Residual Grid Usage

Within each scenario, utilizing the grid to balance decentralized production and consumption is allowed, to a certain degree. Grid usage is constrained by a custom cost function, which aims to represent the limits of centralized production and consumption, and disincentivizes excessive grid usage. This cost function, described in detail in section 2.3, is identical for all scenarios. It follows that different levels of grid interaction are caused by differences in attractiveness of alternative measures of production/consumption balancing. Figure 13 shows the CH-wide aggregated residual grid utilization as a timeseries over the model year, with the curves shown for all four scenarios as well as the base case without any mitigation measures in place. Note that this base case does not include any local storage as part of the included PV expansion, which is conversely included in the scenario-dependent optimized configurations. In the base case, municipal surpluses of up to 18.6 GW are observed during the summer months, which correspond to very sunny days. During winter, cumulative net consumption can reach values of close to 11 GW. Owing to the limits set in the cost function, the optimized configurations keep within significantly tighter boundaries, conforming to both the available capacity of pumped hydro storages for centralized consumption and hydropower in general for centralized production. Figure 14 shows the residual grid utilization for all four scenarios separately, with the *Reference* scenario indicated below the other three. It is very notable that the scenario *PtX* with lower power-to-X-related costs (and thus also higher penetration of this measure) does not significantly affect the fluctuations passed onto the overarching electricity grid. In contrast the scenarios with lower costs for PV, batteries and flexibility show a clear reduction of fluctuations, on top of generally lower consumption in winter and higher grid export in summer.

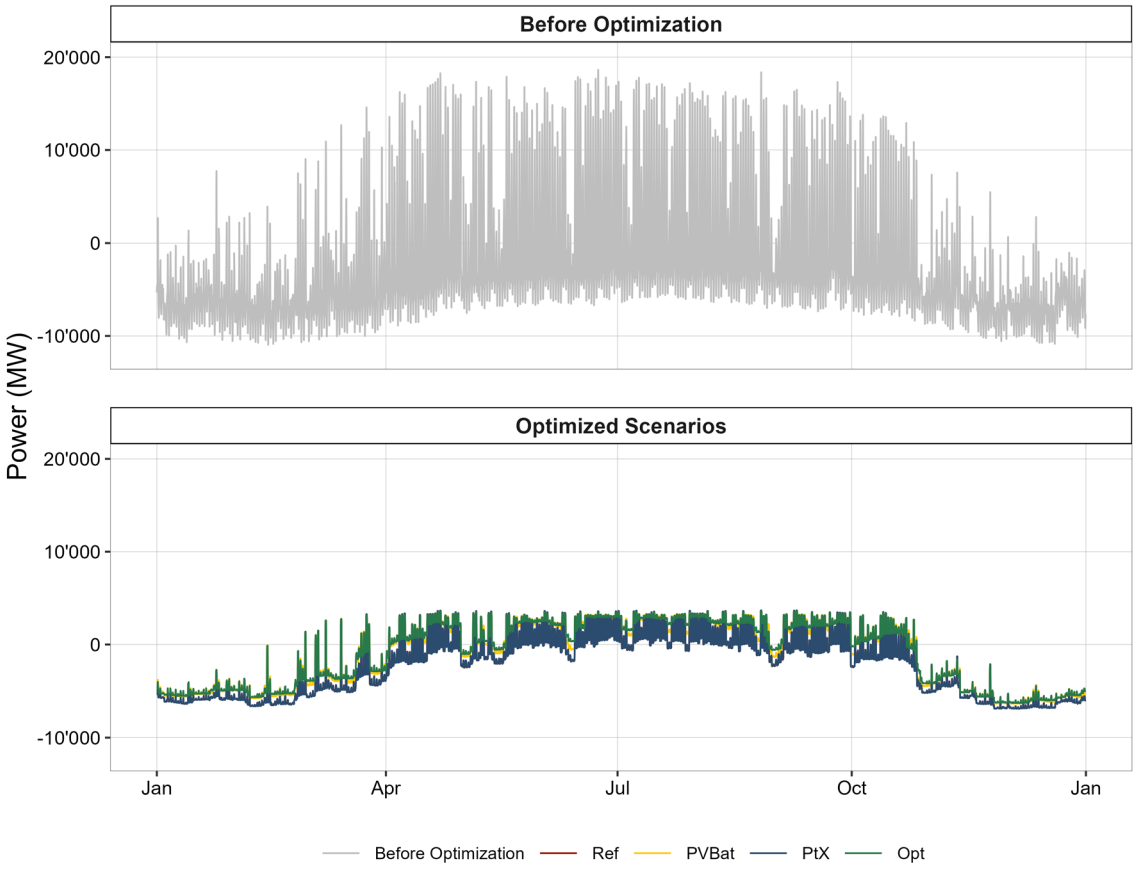


Figure 13. CH-wide aggregated residual grid utilization over the model year, for all four cost/flexibility scenarios (bottom) as well as the baseline case without any additional local energy shifting measures (top).

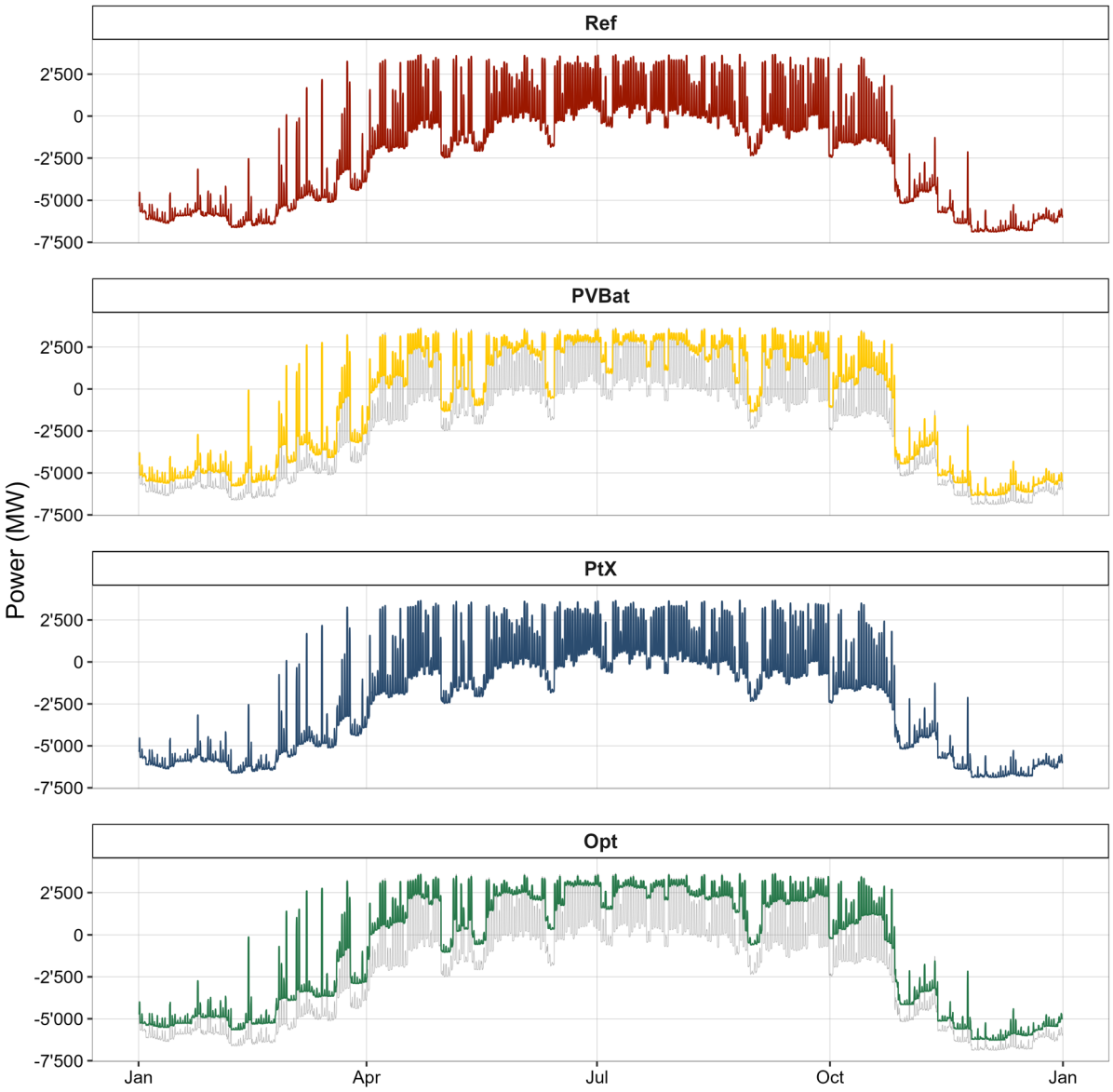


Figure 14. CH-wide aggregated residual grid utilization over the model year, for all four cost/flexibility scenarios separately. The base case (*Ref*) is indicated in light gray as a comparison in the other three scenarios. It is well visible that lower PtX costs do not significantly affect grid usage, whereas lower battery/PV costs reduce grid consumption in winter and increase production in summer. Notably, the widespread deployment of batteries clearly reduces fluctuations passed into the grid.

Figure 15 shows the same residual grid usage data, with cumulative net surpluses/deficits in each month, for every scenario. In the *PVBat* and *Opt* scenarios, PV overbuilding and curtailment is used to a substantially higher extent than in the other scenarios, which explains the closer adherence to the (soft) upper export limit during summer. During winter, less of this additional PV is being curtailed, therefore the net deficit is lower during those months. What is clearly visible from both Figure 14 and Figure 15 is that while the net import/export over a longer period (i.e. each month) is not significantly reduced by local energy shifting measures, the fluctuations passed into the grid are substantially reduced. While in the scenarios *PVBat* and *Opt*, net imports during each winter month are reduced by around 20% (mostly owed to PV overbuilding & curtailment), it is mainly the strong reduction of import/export peaks on the municipality and aggregated level that contribute to lowering total system costs.

Figure 15 shows the small impact of power-to-X on the aggregated system level in terms of monthly net energy. Comparing the scenario Ref to PtX reveals no improvements even though the cost associated with power-to-x are substantially lower. In contrast, lower cost for short-term battery storage and PV lead to a noticeable reduction of the winter deficit and to more surplus energy in all other seasons.

The months of March, April, and October are likely to change from months with net deficits to months that are decentrally already at least balanced in terms of aggregated net energy, thus freeing centralized hydropower resources that are nowadays reserved for these months (see Figure 16). In the future, January, February, November, and December will be the critical winter months, where more energy is needed.

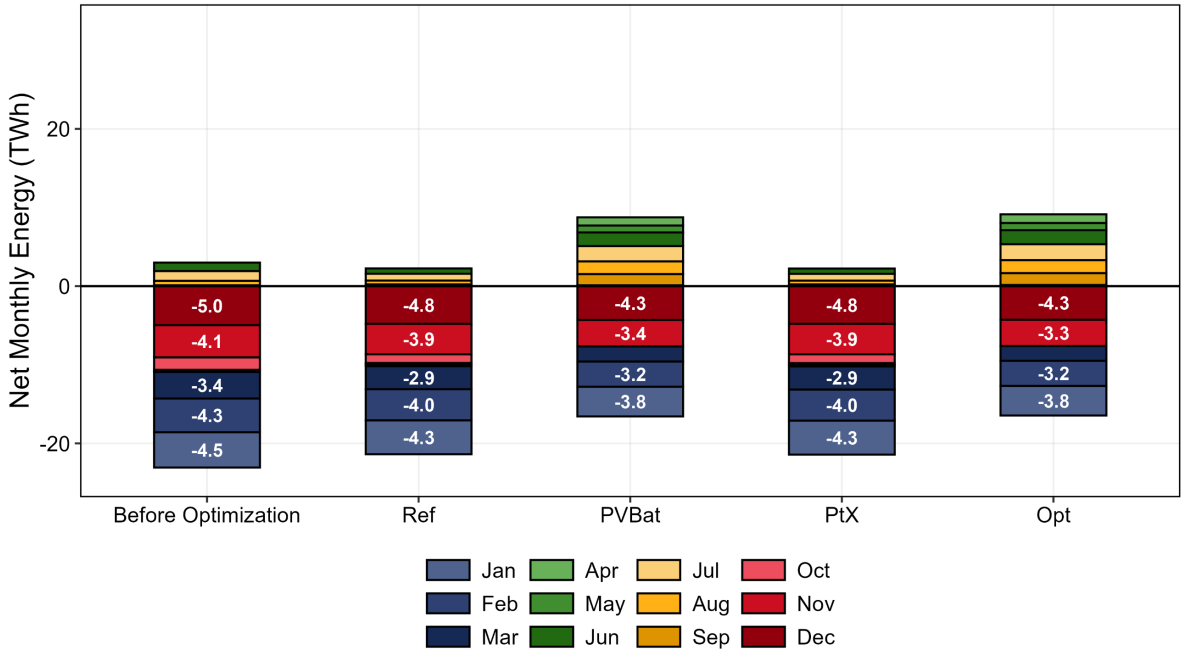


Figure 15. CH-wide aggregated residual grid utilization, cumulative net surplus/deficit per month, for all four cost/flexibility scenarios as well as the base case without any additional measures.

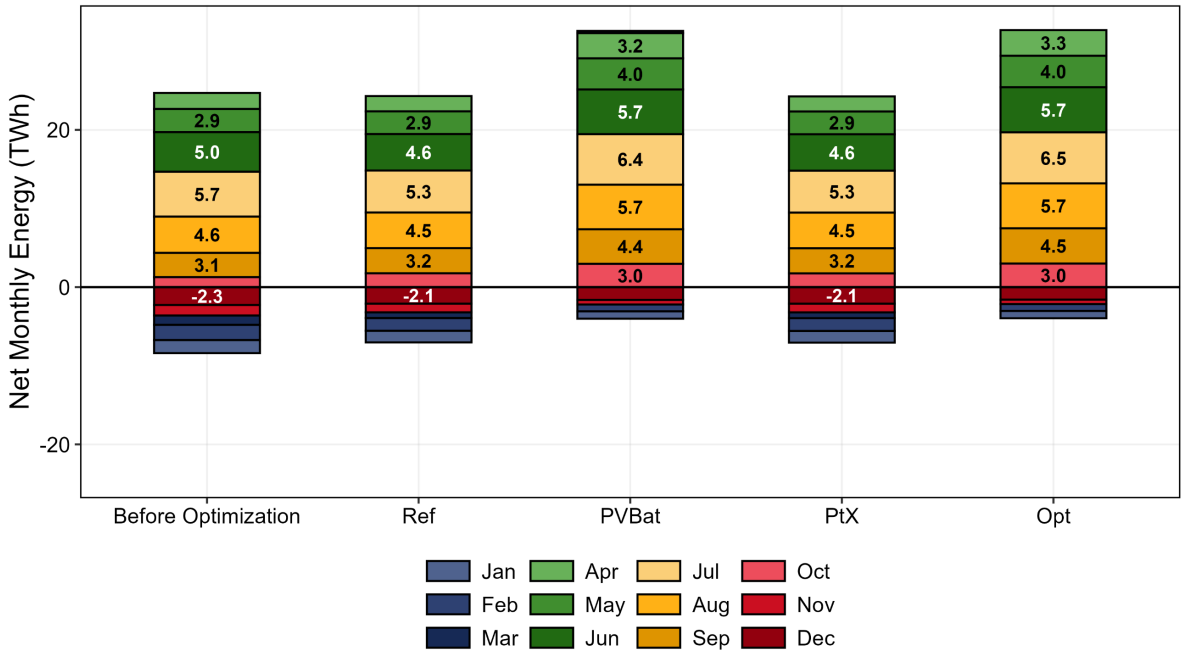


Figure 16. CH-wide aggregated residual grid utilization, cumulative net surplus/deficit per month, for all four cost/flexibility scenarios as well as the base case without any additional measures, including the average Swiss hydropower generation during those months (calculated as the monthly average of the years 2018-2024 [25]).

3.2 Regional Results

While the analysis of CH-wide aggregated values helps to provide the necessary scale of the measures needed to integrate a large share of decentralized producers and new consumers into the existing energy system, analyzing the regional distribution and differences in cost-optimal solutions can show where certain measures are most cost-effective to deploy. Where not specified otherwise, the presented numbers and graphics are related to the *Reference* scenario, which was deemed the most realistic.

3.2.1 Short-term Battery Storage

Figure 17 shows the total installed short-term battery storage capacity under the *Ref* scenario cost and flexibility assumptions. It is obvious that in absolute terms, large cities employ the largest amount of short-term storage, with the largest ones being Zürich (711.2 MWh), Bern (695.1 MWh) and Lucerne (548.7 MWh). Categorized into EDGE-regions, most battery storage is being deployed in the *Cities* (29.16 GWh), followed by the *Midlands* (17.89 GWh) and finally the *Alps* (14.04 GWh). Table 9 summarizes the battery installations by region.

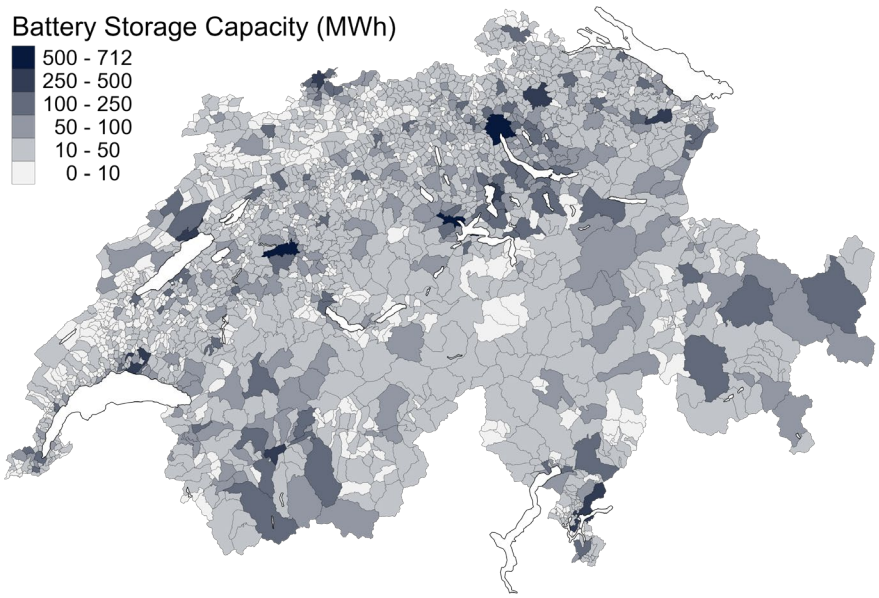


Figure 17. Total short-term battery storage capacity installed in the scenario *Ref*. Well visible are the large capacities in cities, with the maximum being Zürich (711.2 MWh). Conversely, a large number of municipalities remain below 50 MWh (1'855 of 2'148 total) or even 10 MWh (663).

Table 9. Short-term battery storage capacity installed in the scenario *Ref*, reported separately for the three EDGE regions (*Cities* – *Midlands* – *Alps*). While in absolute terms, most battery storage is being built in the cities, alpine regions installed significantly more per inhabitant.

EDGE Region	Battery Storage Total (GWh)	Battery Storage Relative (kWh/cap)
Cities	29.16	5.33
Midlands	17.89	8.64
Alps	14.04	12.41

Figure 18 shows the spatial distribution of relative installed battery capacities, normalized by municipal population. A clear trend is visible whereby comparatively large amounts of storage are deployed in the *Alps*. In contrast, large *Cities* tend to show very small battery deployments in relative terms – the aforementioned examples of largest absolute numbers register very low on the list: Zürich (1.69 kWh/cap), Bern (5.16 kWh/cap) and Lucerne (6.64 kWh/cap). Note that current typical home battery storage systems are in the capacity range of 10-15 kWh, while typical EV batteries can reach values of 50 – 100 kWh. Figure 19 shows the annual full battery cycles (calculated as the ratio between total stored energy and storage capacity), with a clear trend of higher utilization visible in the alpine regions. Notably, all deployed battery energy storage is cycled at least 150 times every year, which points to the high overall utilization of short-term storage. At the upper end, storages are cycled up to 360 times/year. Interestingly, lower utilization does not necessarily indicate unfavorable economics of batteries in a specific location, but rather that the alternatives are worse (i.e. batteries are cost-effective even though they are not used very much).

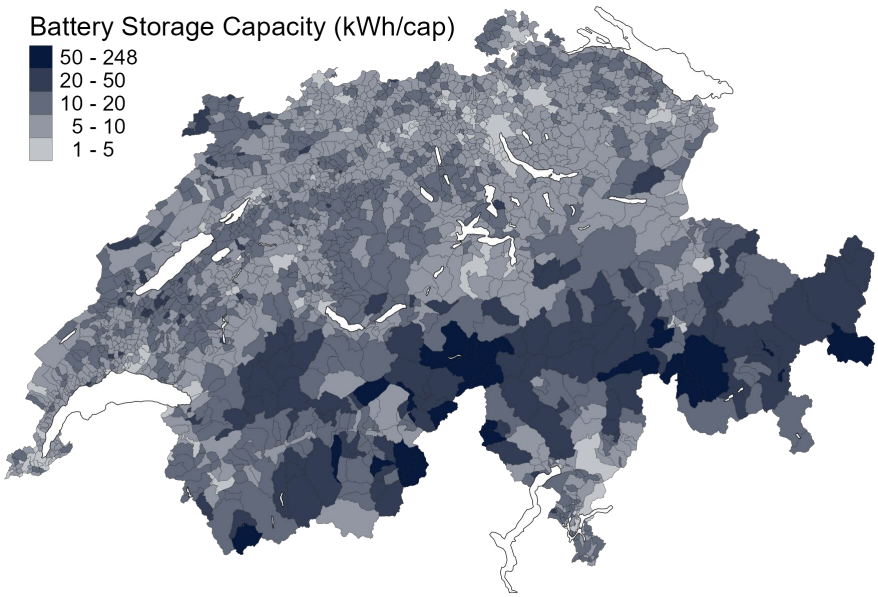


Figure 18. Relative distribution of installed short-term battery storage capacities in the *Ref* scenario, normalized by population. A clear trend towards battery deployment in the alpine regions is visible, mainly driven by frequent production peaks.

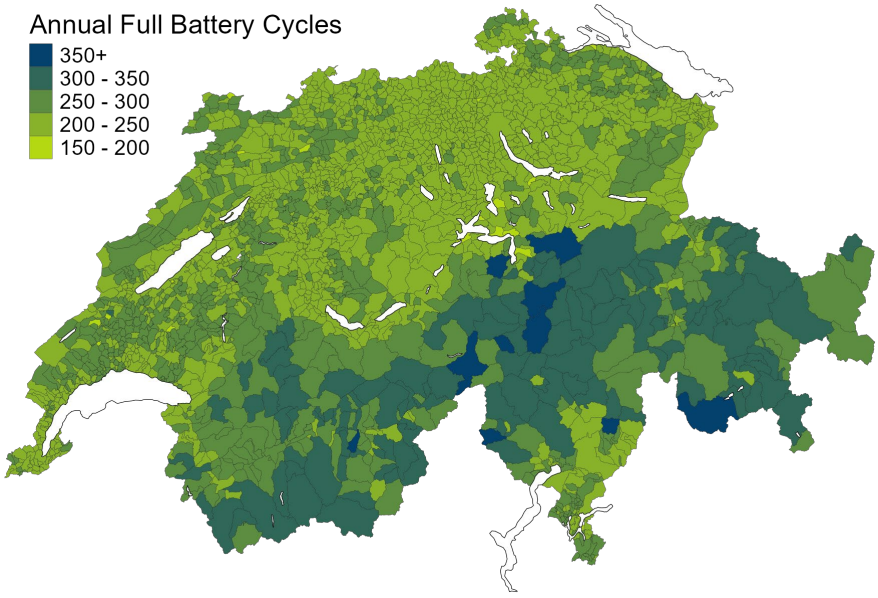


Figure 19. Annual full battery cycles in each municipality in the *Ref* scenario, whereby the total annual stored energy is divided by the local storage capacity. Well visible is the higher utilization in the alps, with most alpine municipalities reaching 250+ yearly cycles.

3.2.2 Long-term Hydrogen Storage

In the scenario *Ref*, only a small fraction of municipalities (260 of 2'148 total) employs long-term hydrogen storage at all. Note that due to the utilized methodology, hydrogen storage and the necessary energy conversion installations – electrolysis and fuel cells – are always co-located. This is not necessarily realistic, as transportation of hydrogen can easily be envisioned. Costs are heavily concentrated in the storage (88.5% of total cost), such that the analysis is heavily biased towards storage, as opposed to installed conversion capacity.

The largest absolute deployed hydrogen storages are projected to be in Neuchâtel (14.56 GWh), Horw (10.84 GWh), and St. Moritz (6.55 GWh). Notably, under these scenario conditions, no hydrogen storage is built in the cantons of Zürich, Bern, and Geneva. Categorized into EDGE-regions, the majority of projected hydrogen storage is being built in *Cities* (75.11 GWh), with *Midlands* (13.28 GWh) and *Alps* (13.37 GWh) roughly similar, albeit significantly smaller in scale.

In general, hydrogen storage (and the related Power-to-X-components) are only built at significant scales where there is large enough summer surplus generation, and a large enough winter demand. This mainly happens in municipalities that fully utilize their available PV potential, such that massive overbuilding and curtailment (which often is the more cost-effective option) is not possible. In municipalities with very small additional PV potential, not enough overbuilding is possible to achieve significant summer surplus generation, whereby the necessary boundary conditions for Power-to-X deployment are not given.

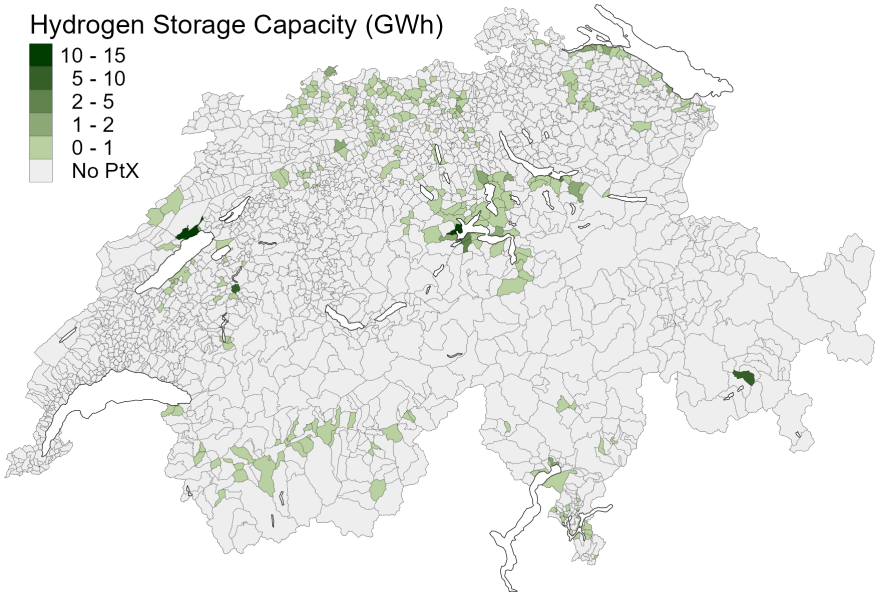


Figure 20. Total long-term hydrogen storage capacity installed in the scenario *Ref*. While a large proportion of municipalities do not employ any long-term storage at all (1'888 of 2'148 total), the remaining municipalities amount to a total of 101.76 GWh.

In the Power-to-X storage system, the energy conversion steps (electrolysis and fuel cells) could be sized independently of the deployed storage. Since no hydrogen transfer between municipalities was foreseen, these conversion units are only deployed where hydrogen storage is envisioned. Figure 21 shows the regional distribution of electrolysis capacity, with the patterns closely following deployed storage. The largest electrolysis units are projected to be installed in Zug (9.59 MW), followed by Neuchâtel (9.39 MW) and Horw (7.40 MW). In total, there are only 34 municipalities with a projected electrolysis capacity exceeding 1 MW. Since costs are modelled as scaling perfectly linear with capacity, very small installations are at times cost-effective. Fuel cell capacities are distributed very similarly, with the largest installations envisioned in Neuchâtel (6.43 MW), Horw (3.67 MW) and St. Moritz (3.16 MW). As discussed in section 3.1.2, electrolyser rated power is in general quite a bit higher than the co-located fuel cell rated power. One clear reason for this can be found in the inefficiency associated with converting electricity and hydrogen. The difference can be mainly found in the way in which conversion is sized – while electrolysis is generation-driven, fuel cells are consumption-driven. Figure 22 shows the annual full load cycles of hydrogen storage, defined as the ratio between yearly stored energy and storage capacity. A minimum of 1 storage cycle is by definition reached wherever Power-to-X is deployed. Low values correspond to a seasonal storage use case, whereas higher values indicate storage on a shorter timescale, such as bridging periods of low generation due to weather.

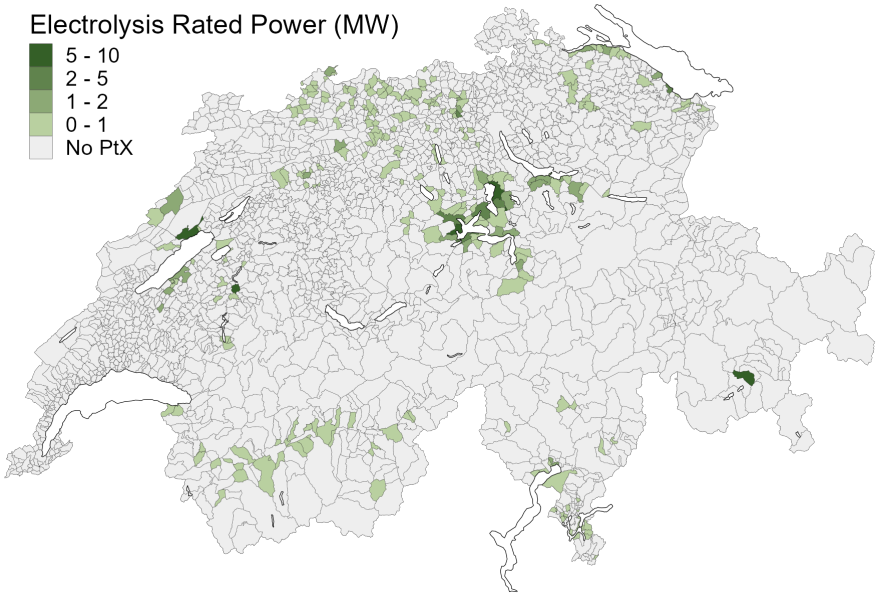


Figure 21. Regional distribution of electrolysis installations under the base scenario cost/flexibility assumptions. Since conversion is always co-located with storage within the presented modelling framework, no conversion is envisioned in municipalities without local hydrogen storage.

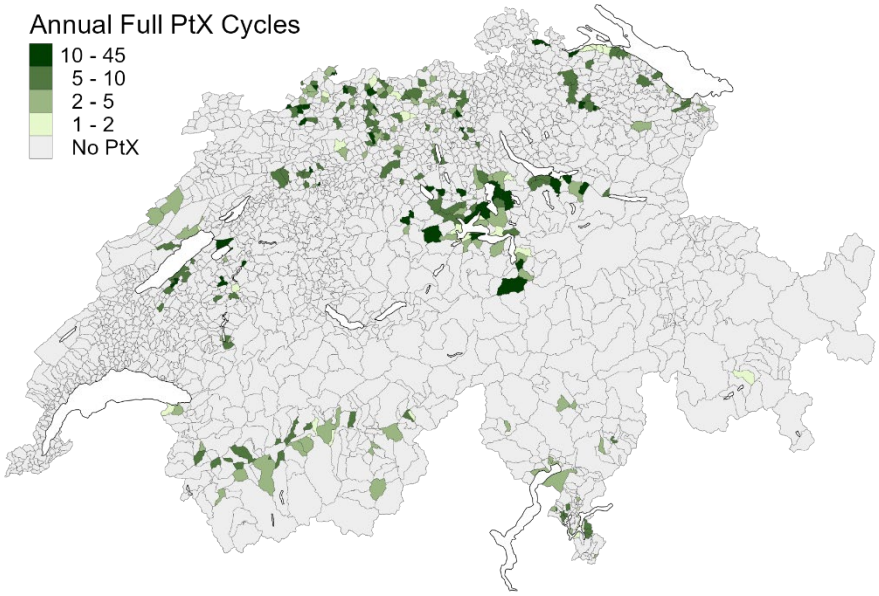


Figure 22. Annual full PtX cycles per municiaplity in Switzerland under the base scenario cost/flexibility assumptions, defined as the ratio between total stored energy and storage capacity. Note that full load cycles lower than one are not present in the results, as that would indicate unused storage capacity and thus cost inefficiencies. All municipalities with any amount of hydrogen storage complete at minimum one full load cycle annually.

3.2.3 Power-to-X Expansion

The analysis and comparison of Figure 23 and Figure 24 reveal the main reason why power-to-X is expanded in certain municipalities but not in others. A large majority of municipalities with substantial PtX deployment have exhausted their agrivoltaics potential (larger violet bubbles in Figure 23). In these

cases, PtX is used primarily for seasonal storage of electricity when PV overbuilding and curtailment as the usually more cost-efficient alternative is not possible once local PV siting opportunities are fully utilised. Seasonal storage, however, is only possible in municipalities with a structural energy surplus in summer. These conditions are met mainly by urban municipalities of medium size. Big cities exhaust their local PV potential but even when doing so, do not have structural surplus energy in summer due to their large consumption. Medium sized, urban municipalities that are locally limited to an amount of PV that produces structural surpluses in summer but leaves large deficits in winter are predestined for PtX additions.

Also, there is a clear trend indicating correlation between PV overbuilding and short-term battery storage, as anticipated from system-integration principles: municipalities that overbuild PV typically deploy more short-term storage to integrate and firm the surplus energy profile. Notable exception groups to this observation underscore the heterogeneity of local conditions. There exists a group of municipalities in the *Alps* and in parts of the *Midlands* that add large quantities of short-term battery storage per capita yet do not overbuild PV (see Figure 24). These municipalities already experience strong surplus PV energy under standard net-zero PV additions and thus encounter integration constraints that make further PV expansion locally impractical. Here, batteries are added to integrate the existing surpluses rather than to support additional PV. Conversely, a group of municipalities in the *Cities* region displays high PV overbuilding with comparatively low additions of short-term battery storage. Here, high consumption and structurally low local generation (even after the PV additions associated with net-zero pathways) mean that additional PV primarily reduces existing deficits rather than creating surplus profiles that would necessitate sizable short-term storage.

Taken together, these findings support a locationally differentiated strategy. Where PV potential is exhausted, PtX can play a seasonal storage role, but it mainly emerges because the cost-effective alternative (PV overbuild with curtailment) is unavailable, not because PtX is intrinsically superior. Where PV overbuilding is feasible, co-deployment with short-term storage remains the expected pattern. Deviations are explained by pre-existing surplus conditions (some municipalities in Alps/Midlands) or structural demand dominance (some municipalities in the Cities region).

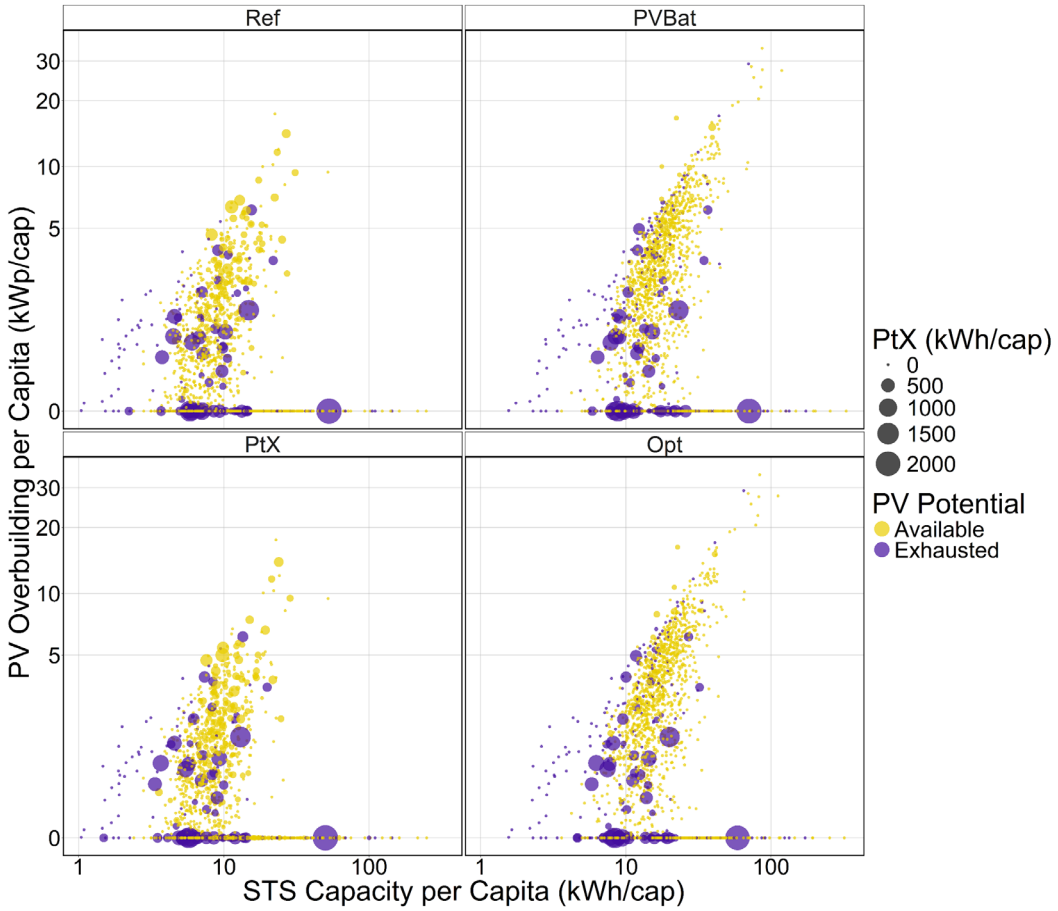


Figure 23. Scenario intercomparison of per capita short-term battery storage vs. PV overbuilding with bubble sizes according to power-to-X energy storage capacity per capita. Each bubble represents one municipality and is colored according to whether its available PV potential is exhausted by PV overbuilding. Y-axis uses a log1p scale, $y = \log(1 + x)$, which preserves zeros and compresses high values.

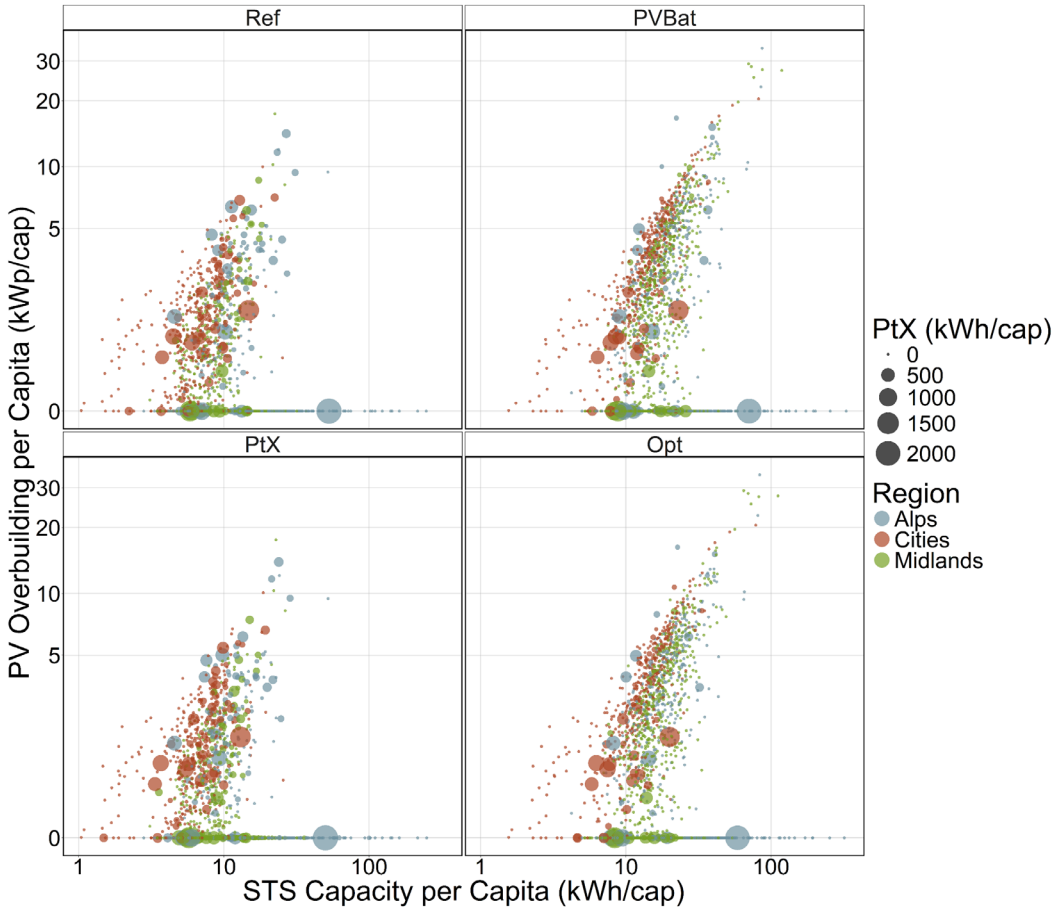


Figure 24. Scenario intercomparison of per capita short-term battery storage vs. PV overbuilding with bubble sizes according to power-to-X energy storage capacity per capita. Each bubble represents one municipality and is colored according to its EDGE-region classification. Y-axis uses a log1p scale, $y = \log(1 + x)$, which preserves zeros and compresses high values.

3.2.4 PV & Curtailment

Figure 25 shows the municipal distribution of additional PV generation (PV overbuilding) deemed to be cost-effective under the Ref scenario cost/flexibility assumptions. This generation is on top of the already planned installed capacity necessary to reach the goals specified in the EP2050+ (see also reports D1.2 and D2.4). It is not surprising that large cities dominate the map in absolute terms, with Bern (391.6 MWp), Zürich (267.7 MWp) and Winterthur (214.8 MWp) finding the highest amounts of additional PV beneficial. Notably, other large cities such as Basel (27.7 MWp) and Geneva (1.0 MWp) are found much lower. This is not because additional PV generation would not be cost-effective, but rather that all their total available potential is utilized. Even though the urban structure and density in the mentioned cities proper is very comparable, the municipal boundaries are fundamentally different. Cities such as Zürich encompass a significant amount of suburban area and associated farmland, which was the deciding factor for potential estimation. Contrary, cities such as Geneva and Basel only encompass the actual city center, with the suburbs remaining their own, separate municipality. It is therefore very beneficial to investigate the added PV generation capacity on a per capita basis, which is shown in Figure 26. With few exceptions, additionally installed PV generation capacity per capita is below 10 kWp/cap, the highest being in Sisseln (17.46 kWp/cap). In only 32 municipalities, more than 5 kWp/cap are envisioned. Table 10 summarizes the values in absolute and relative terms, categorized into EDGE-regions. While cities are projected to install the most additional PV in absolute terms (7.2 GWp), the difference is much smaller when normalized with population. In *Cities,* an additional 1.67 kWp/cap is projected, while in the *Midlands* (0.49 kWp/cap) and A*lps* (0.78 kWp/cap), this number is significantly lower.

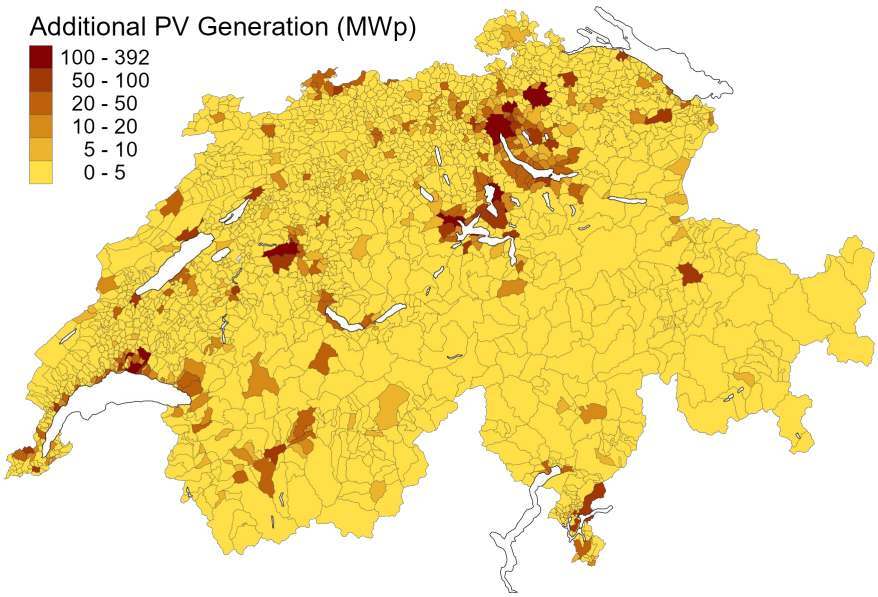


Figure 25. Absolute additional PV generation capacity installed per municipality under the *Reference* scenario.

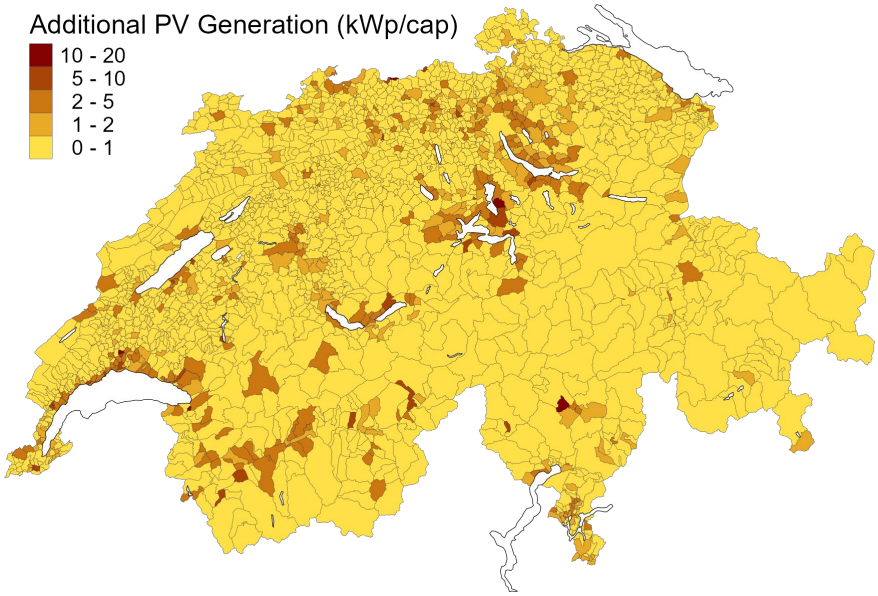


Figure 26. Additional PV generation capacity installed per municipality, normalized by municipal population, assuming the base cost/flexibility values.

Table 10. Additional PV generation capacity installed in the base cost/flexibility scenario, reported separately for the three EDGE regions (*Cities* – *Midlands* – *Alps*). Cities are the predominant deployment location by a large margin, which is relativized to a certain degree when normalizing by population. In all three regions, surprisingly low amounts of additional PV are envisioned.

EDGE Region	Additional PV Capacity (MWp)	Additional PV Capacity (kWp/cap)
Cities	7'201	1.32
Midlands	1'031	0.49
Alps	883	0.78

Aside from adding energy into the system, PV overbuilding and curtailment is very effective at smoothing the PV production profile, both on a daily and on a seasonal basis. The yearly municipal distribution of curtailed energy is shown in Figure 27**Fehler! Ungültiger Eigenverweis auf Textmarke.**. Note that curtailment is dynamic, as opposed to a fixed power-based curtailment method, such as undersizing of the inverter. While a total of 7.4 TWh of PV energy is curtailed, the largest share occurs in the alps (3.4 TWh). This corresponds to 31.4 % of all PV energy produced in the alps. In cities, only 1.67 TWh are curtailed, which corresponds to 8% of the total produced PV energy. If only winter curtailment is investigated (October – March), it becomes clear that curtailment was primarily optimized to reduce the need for expensive seasonal storage. The municipal distribution of curtailment in winter is shown in Figure 28, with the results summarized in Table 11. While in the alps, a still-high percentage of 16.9 % of all produced PV energy is curtailed, this drops to only 2.5 % in the cities.

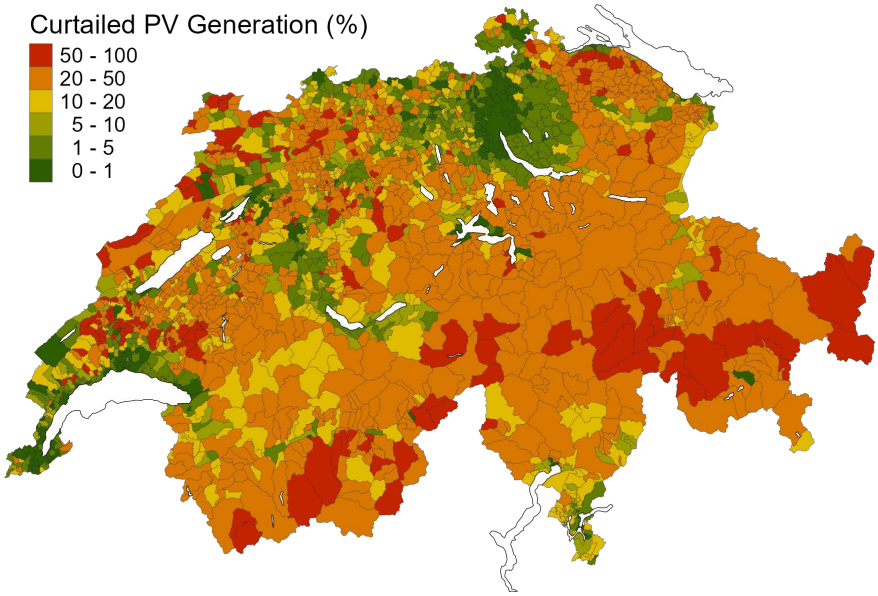


Figure 27. Percentage of annual PV production that is curtailed under the *Reference* scenario.

Table 11. Curtailment of PV generation, categorized by the three EDGE Regions. On an annual basis, a total of 7.4 TWh of PV energy is curtailed, of which 3.4 TWh is culled in the alps. This corresponds to 31 % of all PV energy produced in the alps. If only winter time is considered (October – March), curtailment drops significantly, owed to both decreased PV production and increased consumption.

EDGE Region	Annual PV Curtailment (GWh)	Winter PV Curtailment (GWh)	Annual relative PV Curtailment (%)	Winter relative PV Curtailment (%)
Cities	1'674	145	7.99	2.47
Midlands	2'339	355	20.48	12.11
Alps	3'388	583	31.35	16.89

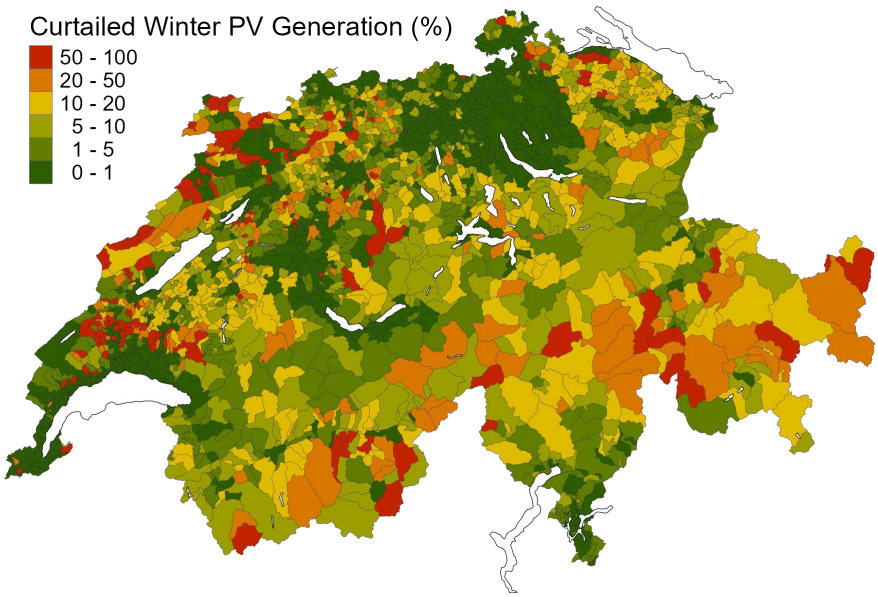


Figure 28. Percentage of winter PV production that is curtailed. Note that the color scale is identical to Figure 27, which shows the annual curtailment percentage.

3.2.5 Net Self-Sufficiency

Figure 29 shows net self-sufficiency, which describes the ratio between annual local production and consumption, whereby a value of 100% represents full net self-sufficiency. Values above 100% indicate that the municipality is a net producer of electricity, a value below that indicates that it is a net consumer. Note that net self-sufficiency does not indicate self-sufficiency at all the time throughout the year. Of the *Cities*, 72 out of 476 reach an annual net self-sufficiency (15 %), in the *Midlands* this rises to 609 out of 1100 (55 %), while in the *Alps* 389 out of 572 municipalities reach an annual net self-sufficiency (68 %).

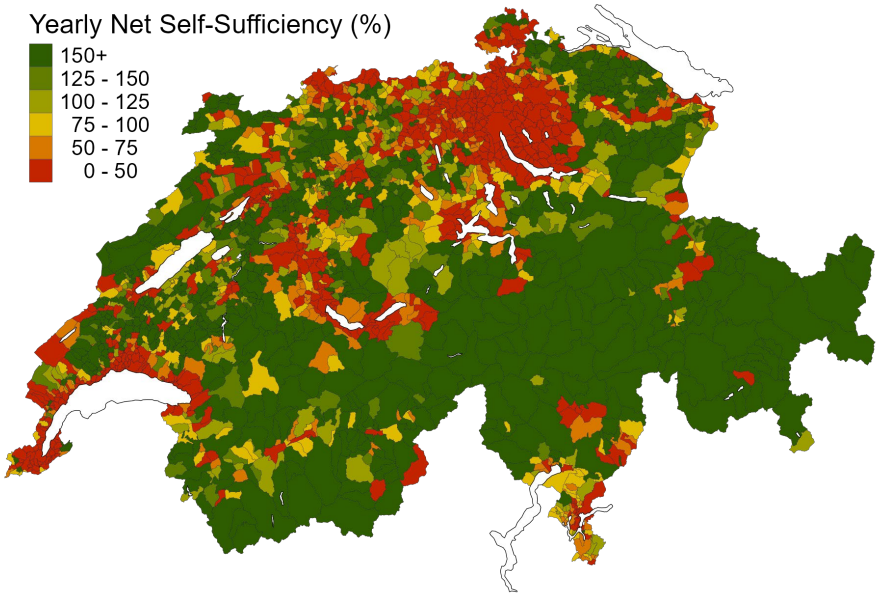


Figure 29. Net self-sufficiency on an annual basis, defined as the ratio between locally produced and consumed electricity.

If only winter is considered (October – March), net self-sufficiency is (expectedly) reduced. The municipal distribution of winter net self-sufficiency is shown in Figure 30. In the *Cities*, the number of net self-sufficient municipalities drops to 14 out of 476 (2.9 %), in the *Midlands* to 275 out of 1100 (25.0 %),

while in the *Alps* it drops to 225 out of 572 (39.3 %). Note that it is specifically not an objective of the optimization to necessarily achieve self-sufficiency, but rather to not put additional strain on the overarching electricity grid.

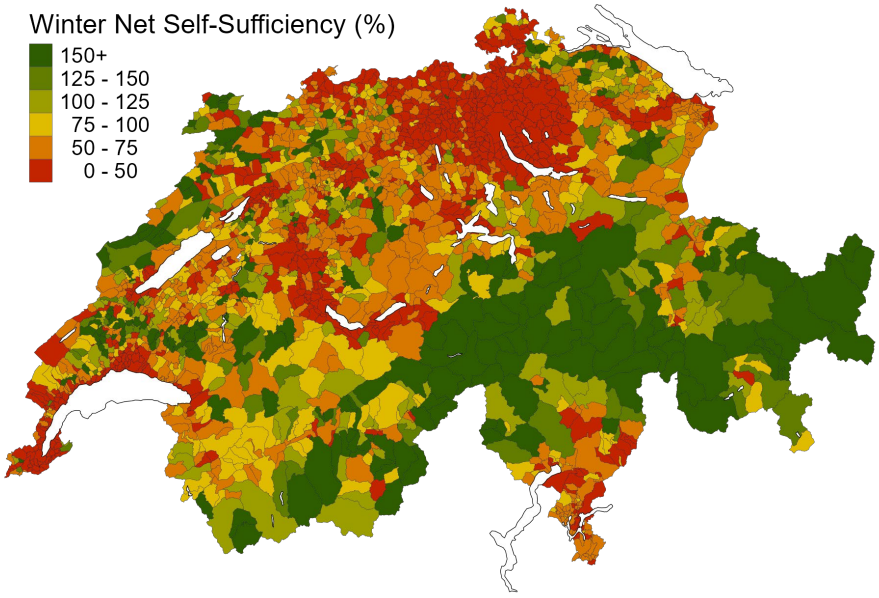


Figure 30. Net self-sufficiency in winter (October – March), defined as the ratio between locally produced and consumed electricity.

3.3 Time-dependent Effects

In this section, a selection of time-resolved municipal results are presented to illustrate a number of interesting effects.

3.3.1 PtX Buffer-Charging

Figure 31 shows two weeks during the summer in the municipality of Horw (LU), which is one of the few in Switzerland to deploy PtX at scale in all investigated scenarios. In the *Ref* scenario, strong PV generation during the day is complimented by STS discharging during the night, whereby both batteries and PtX are charging during the high PV peaks hours. The electrolysis is only utilized during the day. This mechanism remains unchanged in the *PtX* scenario, with the main difference being the increased rated power of the electrolysis. In contrast, in both the *PVBat* and *Opt* scenarios, the electrolysis is used constantly during periods of sustained high PV generation, with short-term battery storage being used to charge PtX during the night. This is mainly made possible by the better economics of cheaper batteries, which enable a smaller-sized electrolysis unit to charge the same total amount of energy over a certain time period, compared to a larger-sized unit that is not utilized fully. At the same time, it is well visible that this mechanism does not extend over multiple overcast days.

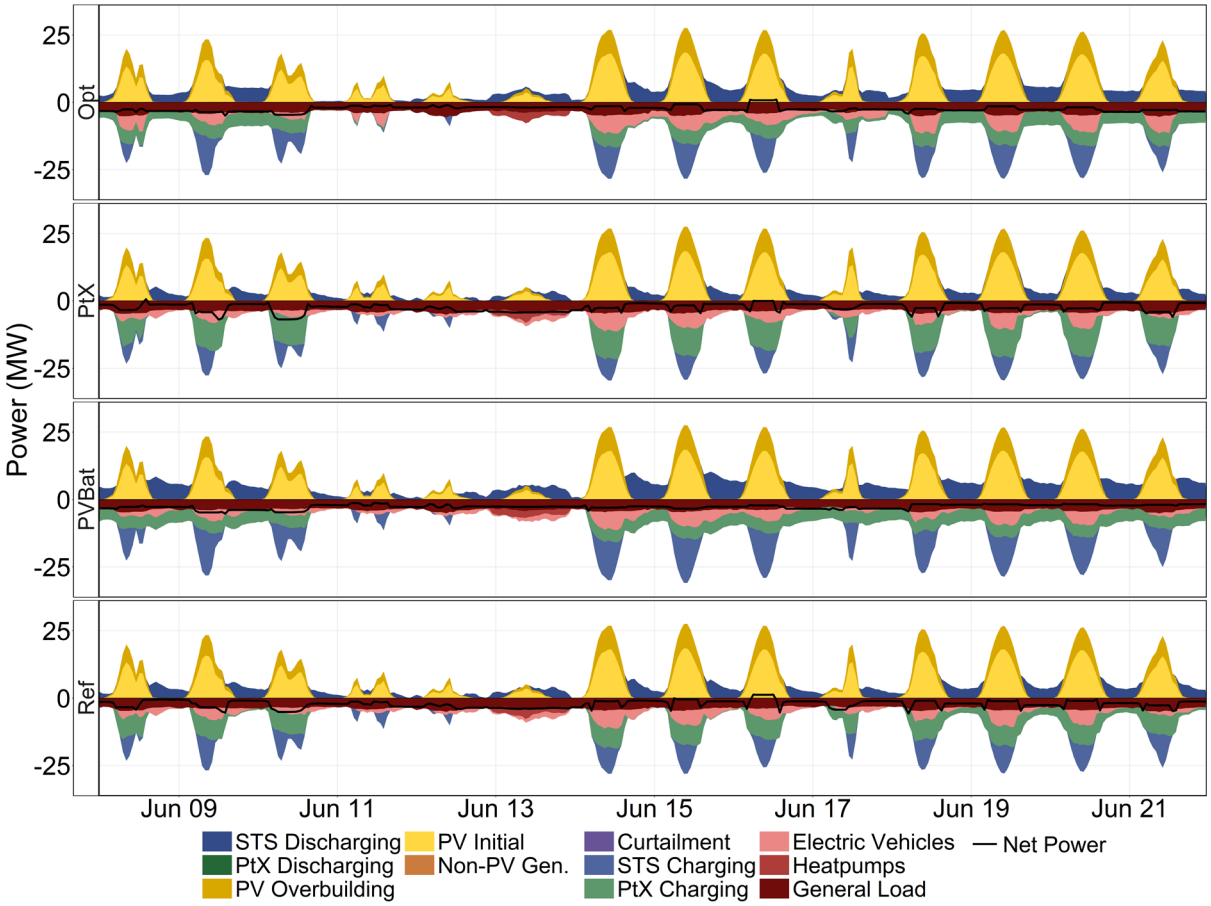


Figure 31. Decentralized generation and consumption in Horw (LU) during two sunny summer weeks, shown for each scenario separately. Horw is one of the few Swiss municipalities where the optimization foresees the deployment of PtX at scale. The better utilization of PtX during sustained periods of high PV generation seen in the *PVBat* and *Opt* scenarios showcases the interesting interplay between cheap batteries and PtX, by which PV energy generated during the day is buffered in batteries, in order to be converted to hydrogen during the night.

3.3.2 Fuel Cell Usage

Again, using the municipality of Horw as an example of PtX usage, the utilization of fuel cells is illustrated. Figure 32 shows the generation and consumption timeseries for two very overcast weeks in late November, with very low PV generation. Note that Horw does not have any significant decentralized production capacity other than PV. In times of variable weather (first week), intermittent PV energy is buffered by the short-term storage, to be released at night. In times of exceptionally low PV generation (second week), hydrogen is converted in the fuel cell to the exact extent such that the grid import limit is not violated. Rather than showcasing the economics of PtX, this mechanism demonstrates the strongly diminishing returns of short-term battery storage: Absent the option of increased import, the cheapest option is expensive seasonal storage, due to the fact that additional battery storage, installed specifically to cover this event, would remain severely underutilized during the rest of the year. The general behaviour is very similar under all four cost scenarios, with the *Opt* scenario showing the smallest fuel cell utilization during this time – mainly due to increased demand flexibility negating some of the need for time-constrained production.

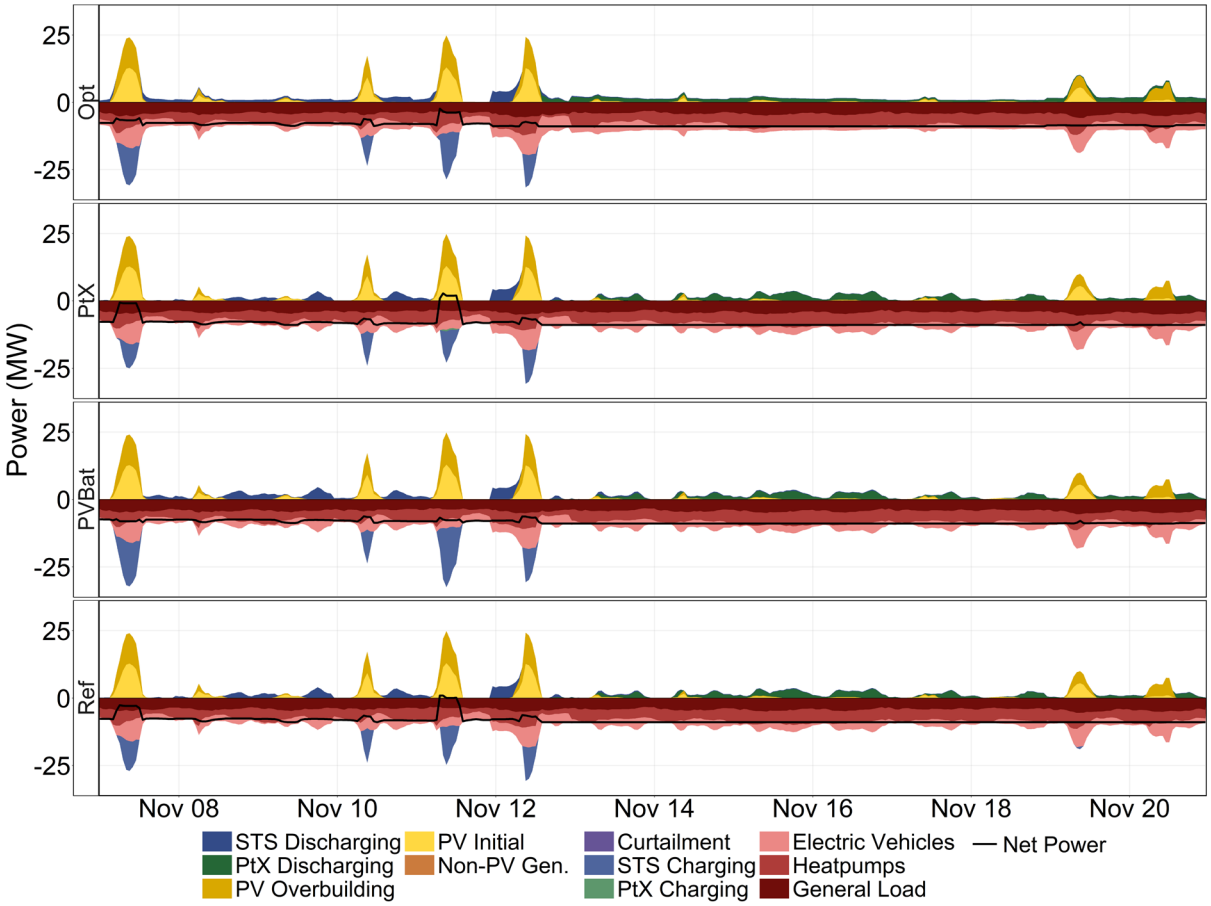


Figure 32. Decentralized generation and consumption in Horw (LU) during two mainly overcast late autumn weeks, shown for each scenario separately. Horw is one of the few Swiss municipalities where the optimization foresees the deployment of PtX at scale. It can be seen in all scenarios that PtX discharging is mainly used in sustained periods of very low PV generation, while at other times, battery-buffered PV energy is utilized to remain within the grid capacity limits.

3.3.3 *Optimistic* Summer

Figure 33 shows the decentralized generation and consumption during two sunny summer weeks, for three exemplary municipalities (one per EDGE region: Vals – *Alps*, Zug – *Cities*, Avenches – *Midlands*), optimized according to the *Opt* (optimistic) scenario constraints. In Vals, it is very notable that PV generation is very high despite virtually no PV had been added by the optimization. This is mainly due to the high potential for alpine PV. During the two weeks, the bulk of the production is curtailed with the short gaps during the night being filled by battery storage discharging. The available grid capacity is used to export at an almost constant, maximal rate. In Zug, a significant amount of PV has been added by the optimization, such that one day of full production is sufficient to store enough battery power such that a constant grid export can be sustained during multiple days of comparatively bad weather. A very similar mechanism can be seen in Avenches.

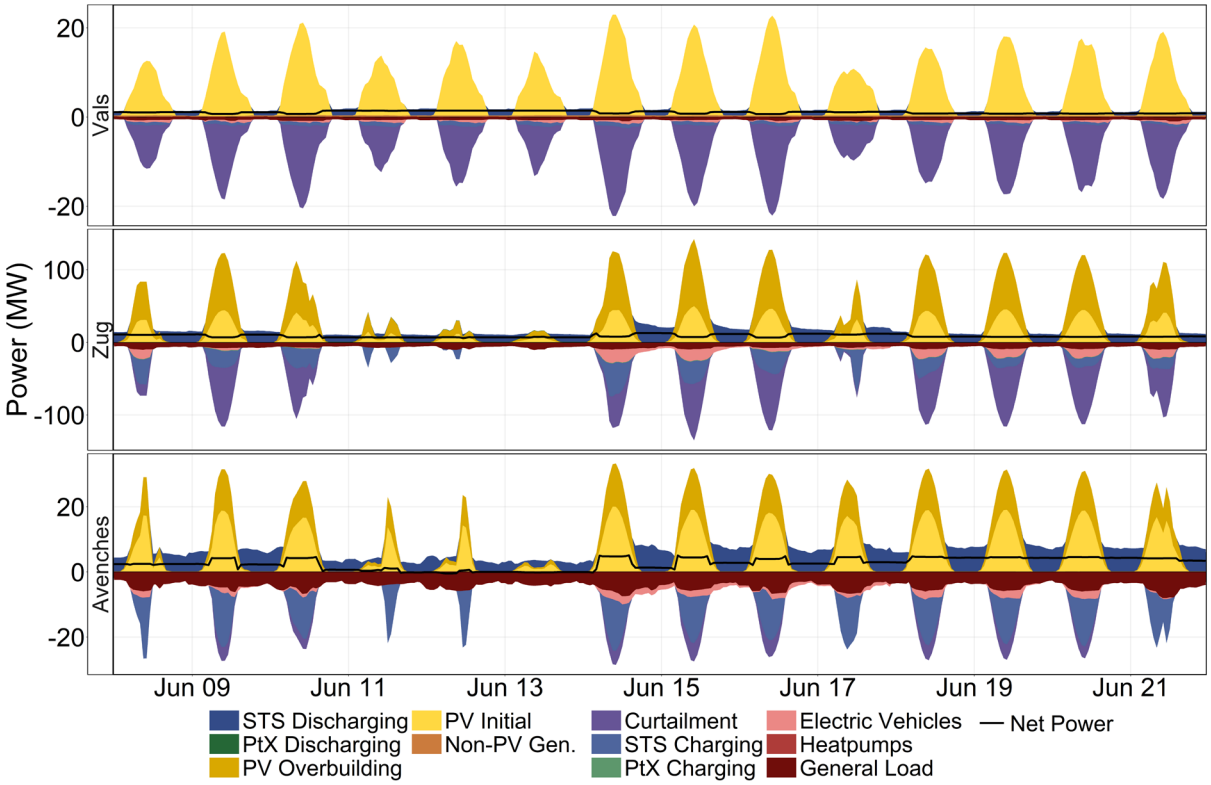


Figure 33. Decentralized generation and consumption dynamics of two weeks in summer of exemplary municipalities (Vals: *Alps*, Zug: *Cities*, Avenches: *Midlands*) of the *Optimistic* scenario.

3.3.4 Scenario *Optimistic* - Winter

Figure 34 shows the decentralized generation and consumption during two very overcast late autumn weeks, for three same exemplary municipalities (one per EDGE region: Vals – *Alps*, Zug – *Cities*, Avenches – *Midlands*), optimized according to the *Opt* (optimistic) scenario constraints. In Vals, the a priori very high deployment of PV and very favorable alpine location lead to sustained PV generation even at times of bad weather at lower elevations. In combination with the installed battery storage, Vals is able to sustain a constant grid export even during winter, during the day as well as during the night. In Zug, the large amount of PV overbuilding contributes to lowered grid imports, as the scarce days of high PV generation are sufficient to charge the battery storage, with only the highest peaks still being curtailed. The important role of mostly EV charging flexibility is apparent in this scenario, with large fractions of the demand shifted towards sunny days. In Avenchens, EV charging represents a smaller fraction of the overall demand, resulting in less flexibility as general load and heat pumps are not able to shift over longer timespans. This results in a sustained grid import, even at times of high PV generation. In this situation, battery storage is charged by grid electricity in order to discharge at times where additional grid import would not be possible due to the set constraints.

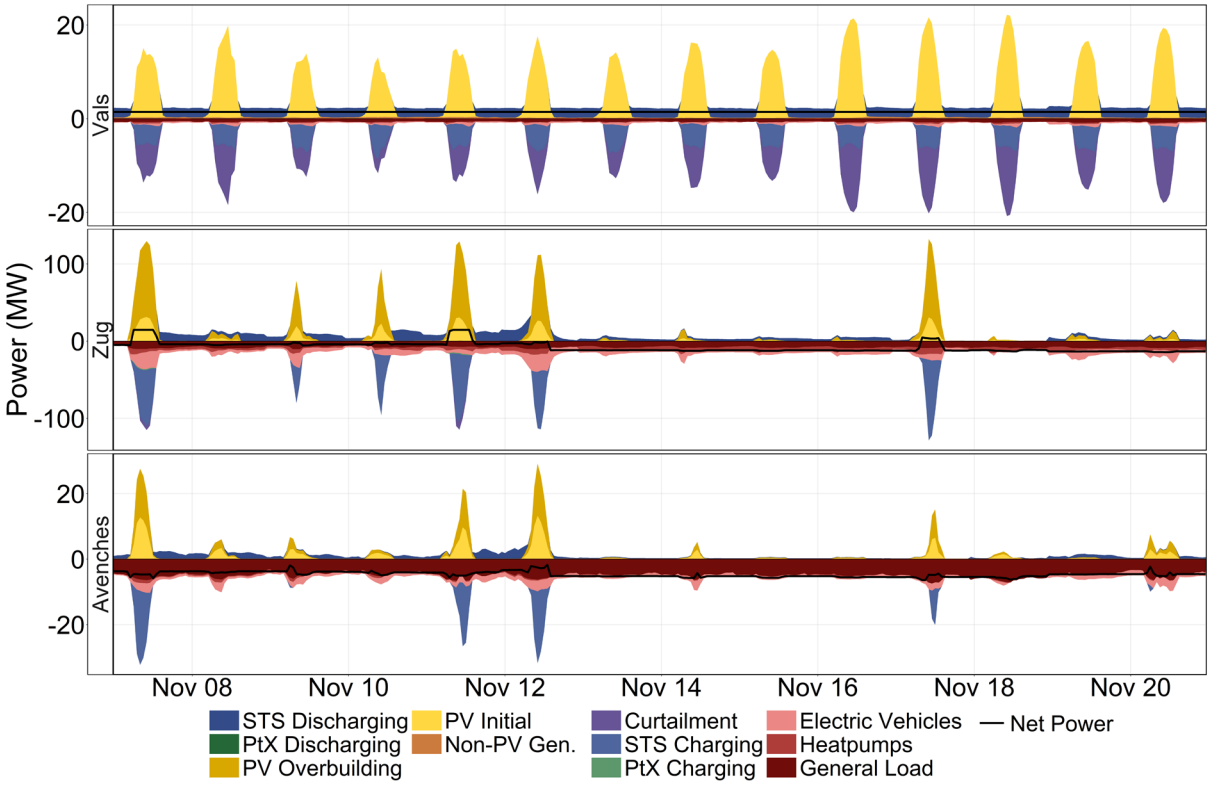


Figure 34. Decentralized generation and consumption dynamics of two weeks in early winter of exemplary municipalities (Vals: *Alps*, Zug: *Cities*, Avenches: *Midlands*) of the *Optimistic* scenario.

4 Discussion

4.1 Key Findings

Independent of the scenario utilized, certain patterns emerge consistently. Given the range of assumptions behind these scenarios, the findings can be considered to be quite robust.

4.1.1 PV Overbuilding and Curtailment

In all scenarios, a significant amount of PV is being overbuilt, on top of the already modelled large PV expansion of 33.6 TWh according to the *Energieperspektiven 2050+* ZERO Basis scenario [3]. The Switzerland-wide aggregation of PV overbuilding ranges from 9 TWh/a under the *Reference* scenario, to up to 24 TWh/a in the *Optimistic* scenario. The main driver behind this effect is a combination of the structural energy deficit during winter and the low costs of both PV and short-term battery storage, which makes it possible to combine them in such a way that the impact of the intermittency of PV generation is strongly reduced. Large amounts of both PV overbuilding as well as curtailment do not necessarily increase the amount of electricity generated over the whole year but increase the share of generated electricity during the winter months, thus alleviating these deficits. To put those numbers into context, combining the overbuilt PV with the baseline expansion yields 43–58.5 TWh/a of PV generation. The latest addition to the energy law, entering force on 01.01.2025[11], specifies Swiss targets of 35 TWh/a until 2035 and 45 TWh/a until 2050 of new renewables. According to the EP2050+ PV will deliver up to 88 % of new renewables, which would result in close to 40 TWh/a of PV energy as part of the Swiss official goals until 2050. The PV expansion, according to our optimization model, is higher than the official Swiss renewable electricity goals, suggesting that those goals should be increased to achieve a cost-effective energy transition.

At the urban scale, there is effectively no economic upper bound on additional local production; practical limits arise first from available siting potential. This is because the demand is at almost all times much higher, such that locally produced electricity can also be consumed locally. This effect is more differentiated in other regions, where large amounts of overbuilding can significantly increase the amount of necessary curtailment, such as not to exceed the available grid capacity or necessitate additional, cost-intensive storage. There is therefore an upper limit to the reasonable amount of PV overbuilding in the EDGE-regions *Midlands* and *Alps*. In some cases, this limit is beyond the calculated local siting potential for additional PV, in which case full utilization of the PV potential is beneficial.

4.1.2 The Role of Power-to-X

Power-to-X is discussed as a key technology for seasonal storage [26]. In the presented optimization, it is indeed emerging as a solution, however to a very limited degree. In the *Reference* scenario, a combined winter half-year (October – March) local deficit on the order of 20 TWh occurs, while at the same time a hydrogen storage of 102 GWh is found to be cost-effective, compared to other options. The reasons for this limited deployment are twofold: First, the alternative of adding winter energy by simply installing more PV is practically always cheaper. Second, a municipality needs to fulfill a very narrow range of conditions for PtX to be financially viable: To begin with, the potential for additional PV installations must be fully utilized, such that adding more PV (i.e. the more cost-effective strategy in most cases) is not an option in the first place. There does however need to be a sufficiently large generation surplus in the summer, such that cheap electricity is available to charge the storage. Since the round-trip efficiency (35 %) is very low in comparison to short-term storage, it is in almost all cases necessary to rely on electricity that would otherwise have been curtailed.

In the presented analysis, it becomes clear that the deployment of PtX is limited to a very specific and narrow set of circumstances. Due to the inherent uncertainties and forward-looking nature of our assumptions, it is fair to say that while the exact selection of municipalities and their specific PtX capacities

[11] Energiegesetz EnG Art. 2, https://www.fedlex.admin.ch/eli/cc/2017/762/de

are probably random to a certain degree, the type of municipalities and its specific characteristics are not.

Consistent with seasonal availability, electrolysis (charging) concentrates in spring/summer during surplus periods, while re-electrification via fuel cells (discharging) occurs primarily in autumn/winter. Across scenarios *PVBat* and *Opt* (that feature low battery cost trajectories), the power-to-X-to-power chain also exhibits a low utilization factor (~1.25), consistent with a predominantly seasonal-storage role. When relative costs shift in favor of PtX (scenarios *Ref* and especially *PtX*), the utilization factor rises to up to 3.7, indicating substantially more short- to medium-term cycling and thus stronger competition with short-term battery storage. Notably, even under *PtX* cost reductions, we do not observe a substantial absolute increase in winter electricity discharge from fuel cells. Contrary to an initial expectation of a tradeoff between PtX and PV overbuilding to secure winter supply, lower-cost PtX mainly competes with batteries for short- and medium-term storage, needing fewer full-load hours to remain competitive.

4.1.3 Short-term Battery Storage

In all investigated scenarios, a certain amount of short-term battery storage was assumed to be pre-installed with residential and commercial PV installations (1-2 kWh per kWp of PV installation, depending on the scenario), because the deployment of home storage alongside rooftop PV is today already in full swing[12]. In all scenarios, large volumes of additional storage were deemed to be cost-effective. The low cost allows batteries to become a major backbone of the electricity system, mainly by negating the drawback of intermittent PV generation. In the *Reference* scenario, a total of 61 GWh of battery storage is proposed, consisting of 19 GWh of pre-installed storage and 42 GWh of additional storage. Depending on the cost projections, this number increases to a total of up to 117 GWh of total battery storage. These large amounts of short-term storage are still used very effectively, by being fully cycled up to 360 times a year. In scenarios with low battery costs, these systems are even cost-effective as a means to buffer electricity during the day for use in PtX during the night to increase the capacity factor of PtX needed for economic deployment. A special characteristic of short-term battery storage like Li-Ion-Batteries is their high C-rate (power to capacity ratio), which in turn shapes their impact on the energy system. In comparison to today's main dispatchable generation in Switzerland, hydro and pumped hydro storage, the storage capacity is lower by around two orders of magnitude. At the same time, the high discharge rate of short-term batteries allows for significantly more instantaneous power.

While the charging flexibility of EVs is explicitly modelled in the presented optimization, vehicle-to-grid is not part of the model. A large share of the positive contributions of EVs is accounted for with the modelled flexible charging, but with a comprehensive rollout of vehicle-to-grid, the associated decentralized power and energy capacities could reach similar orders of magnitude as for short-term batteries reported above. For perspective, the current Swiss stock of around 5 Mio. road vehicles[13] would contribute around 200 GWh of battery storage if fully electrified, assuming an average battery capacity of 80 kWh and an average of 50 % availability as short-term storage.

4.1.4 Demand-Side Flexibility Matters

In the presented methodology, three different categories of demand-side flexibility were employed, namely heat pumps, electric vehicles, and general load. Each category is associated with its own set of restrictions, being limited in the fraction of demand that can be shifted (power) and the timeframe in which demand can be shifted (energy over time). Naturally, less flexibility is available in certain applications than in others. It is evident that "free" flexibility is extensively used, whereby "free" flexibility can be envisioned as either technical optimization that is not associated with any consumer detriment, or policy-mandated flexibility. Especially in winter, flexibility is often used to shift demand to times with high PV generation. In this case it is highly advantageous to have flexibility with long timescales of multiple days,

[12] Of PV-systems built in 2024, 47 % were equipped with home storage in single-family homes according to Swissolar (https://www.swissolar.ch/de/news/detail/wachstum-bestaetigt-solarstrom-fuer-2-millionen-haushalte-74307).

[13] In 2025, 4.83 Mio. passenger vehicles and 0.5 Mio. goods vehicles were registered in Switzerland (https://www.bfs.admin.ch/bfs/en/home/statistics/mobility-transport/transport-infrastructure-vehicles/vehicles.html)

as this allows to bridge several bad-weather days. The results indicate that achieving cost efficiency requires prioritizing demand-side flexibility. An impressive amount of 6.4-13.1 TWh of demand was shifted in time, with the exact value depending on scenario settings. It must be highlighted that a lot of the shifted demand is shifted within the day, with the maximum length being one week. Demand flexibility is thus useful for integration of intermittent renewables and short-term balancing, but does not provide any monthly to seasonal contribution. If such flexibility is not mobilized, batteries will provide these short-term balancing services but at higher system cost.

4.1.5 Interaction Effects

The relationship between PV overbuilding and short-term battery storage generally follows system-integration logic: municipalities that overbuild PV generally add more short-term storage to firm surplus profiles. Two notable groups of municipalities that do not follow this rule exist. First, several municipalities of the EDGE-regions *Alps* and *Midlands* add large amounts of short-term battery storage per capita while not overbuilding PV. Basic net-zero PV additions already create strong local surpluses in these municipalities, so batteries are only deployed to absorb existing surpluses rather than to enable incremental PV. Second, a set of municipalities in the *Cities* region shows high PV overbuilding with comparatively modest battery additions. In these demand-dense systems, additional PV, even during peak generation times, mainly reduces pre-existing deficits instead of creating surplus profiles that would warrant substantial short-term storage.

PtX is mainly deployed in mid-sized urban municipalities that have a limited potential for PV expansion. The detailed reasons for this interaction are explained in section 4.1.2. Operationally, the optimization yields battery-buffered PtX: electrolysis operated in a baseload fashion during summer, made possible by overnight short-term battery discharging. This interaction enables storage of large PV surpluses without the need for costly overexpansion of electrolysis capacity. It increases electrolyzer full-load hours and maximises seasonal energy stored per unit of installed electrolysis capacity, while making use of short-term battery storage capacity that is present anyways.

4.2 Model Applicability and Limitations

It is important at this stage to address the robustness of the findings and certain limitations of the modelling and optimization methodology in general.

4.2.1 Data Basis

Although this point is discussed at length in both previous reports ([1], [2]), it is reiterated here. The optimization methodology is fed by a model of the decentralized production and consumption in each of the 2148 Swiss municipality of the year 2022, assuming a fully decarbonised Swiss electricity system in accordance with the scenario values given in the EP2050+. While in some categories, modelling of the future generation and consumption could be made with a high degree of certainty, others are less robust. Top-down scenario and potential values are generally more reliable than exact attributions to single municipalities. What follows for the results presented here is that general results (e.g. that PV overbuilding is very cost-effective in cities) are much more dependable than municipality-specific results (e.g. that a large hydrogen storage is cost-effective in Horw).

The data basis is defined for one exemplary year of 15-minutes data with the optimization model running with 1-hour resolution. The weather has an impact on most aspects of our data, with the strongest component being solar irradiation at each location. As the results are directly impacted, the usage of a different exemplary year certainly would lead to differences in the results, however mostly on a muncipal level. Confidence in the general findings about the roles of battery storage, power-to-X-to-power, PV overbuilding and curtailment, and energy shifting is high.

4.2.2 Perfect-Foresight Optimization

The optimization sizes all components perfectly cost-optimal to the required needs. Compared to real-world dimensioning of solutions, it has the unfair advantage of perfect foresight over the whole year,

which negates the need for safety factors or probabilistic approaches. As an example, the amount of storage necessary in a specific municipality is often directly dictated by the longest continuous deficit during winter, during which time additional grid import is not possible. Since the data is sourced from a single model year, it is highly likely that over the lifetime of the storage, a longer period of storage will be necessary at some point. In reality, these systems would be dimensioned with this in mind, i.e. by considering the probabilities of extreme weather events. Two important points mitigate this limitation to a certain extent: First, this limitation applies to all municipalities roughly equally, such that general results and findings are not necessarily impacted significantly, and second, the grid capacity limitations imposed in the optimization are conservative as they take todays power peaks as capacity. They therefore do not include any already safety factors in place, existing futureproofing, nor strategic future capacity expansions. This means that additional grid import/export could be possible in extreme situations.

4.2.3 Lack of Comprehensive Market Model

As described in section 2.3, grid electricity prices were modelled in a simplified way, whereby the price is directly determined by the CH-wide aggregated demand or production surplus. It is soft limited by imposing either negative prices at times of large surpluses or steeply rising prices when the aggregated demand exceeds Switzerland's centralized production capacity. Due to the nature of trying to simulate future behaviour, influenced by a host of most likely unforeseeable effects, reliably modelling electricity prices and its dynamic reaction is out of scope for this analysis and would be extremely challenging even with dedicated models. To illustrate this point: Generally unforeseeable events such as the war in Ukraine or other possible external disruptions can have an outsized influence on how the market behaves, while being impossible to predict. The choice of using a relatively simple model to create price time series is thus also a conscious choice, as it allows to more clearly understand the mechanisms that determine the presented results. The modelled price only serves the purpose of linking the optimizations of each individual municipality by suppressing unrealistically high maxima and minima in the aggregated power time series of all municipalities.

4.2.4 Literature Context

Compared with other recent techno-economic studies of the future Swiss electricity sector, our results feature substantially higher PV generation and relative to many scenarios/models lower contributions from wind and renewable bioenergy-based electricity ([27], [28]). An important source for differences is the use of divergent modelling approaches. In our framework, the aggregate capacities of renewable technologies consistent with Switzerland's net-zero goal are taken exogenously from EP2050+ (ZERO Basis). With these values as base expansion, we optimize decentralized integration with different means for energy shifting. By contrast, the compared techno-economic optimization models typically endogenize most investment and operational decisions within an optimization problem that minimizes total system cost (or maximizes welfare) subject to constraints. Our analysis emphasizes high temporal and spatial resolution to clarify the role of decentralized energy shifting approaches. With our approach we also inherently account for current political and legislative conditions and social preferences in that large-scale wind energy expansion is challenging in Switzerland and the potential for sustainable biomass is already largely utilized [29].

5 Conclusion

Under the modelled boundary conditions, a fully decarbonized Swiss electricity supply based on 100 % renewable energy was found to be feasible with net winter electricity imports below 5 TWh. The integration of a large share of decentralized renewable electricity generation as well as a profound shift in demand caused by the widespread adoption of electric mobility and heat pumps is technically and economically possible with decentralized energy shifting measures and todays centralized hydro power plants.

As the major backbone of this new energy system, a massive expansion of PV capacity, coupled with dynamic curtailment and short-term energy storage, emerges as the cost-effective way forward. In such a way, local production can be consumed locally, not putting further stress on the overarching electricity grid. Barring unforeseen drastic cost reductions in PtX technologies, hydrogen (at least as a local seasonal electricity storage solution) will only contribute marginally to this system. If market conditions were accurately reflecting real costs, this lowest-cost system would be reached naturally. To some extent, this would necessitate measures with strong social and technical implications, such as dynamic energy and grid usage costs, which would enable the necessary large amounts of demand-side flexibility by providing the appropriate economic incentives.

This new paradigm of decentralized electricity generation and consumption will bring about fundamental changes in the availability of electricity, which will eventually be reflected in dynamic electricity costs. The combination of large-scale PV adoption and higher winter demand causes electricity to become extremely cheap during the summer months. Further added generation capacity can thus only expect to produce economically during winter (mainly November to February), causing effective LCOE to increase significantly, depending on the production profile. With baseload generation such as nuclear, the economics sharply worsen, whereas especially wind energy (producing roughly two thirds of its yearly production in winter) is excellently suited to these conditions. The same effect also benefits alpine PV (as opposed to other PV applications), and systems where feedstock can be stored.

Low to zero prices for electricity during summer will also have an impact on demand, where industries dominated by energy costs can profit immensely. It fosters the creation of new applications, where low fixed costs and high flexibility are necessary. As an important demand category, building cooling naturally emerges as a clear benefactor of this price development, its demand profile more or less coinciding with PV generation. While especially residential building cooling is not commonplace in Switzerland currently, it is projected to account for at least 3-5 TWh/a, while an upper value of 17.5 TWh/a is found under extreme climate projections [30]. With a minimum amount of 7.1 TWh/a of curtailed energy found in the simulations, this matches very well.

While electricity costs are projected to be extremely low during summer, higher costs will generally be experienced in winter. In turn, this causes energy savings in winter to be especially valuable. Applications that predominantly use electricity during winter are economically incentivized to increase their efficiency – the main example being heating. In the context of heating, the development and deployment of low-cost seasonal thermal energy storage fits very well into this energy system.

6 Collaboration within EDGE Consortium

The present report (D3.9) as well as the previous reports in this series (D1.2 and D2.4) were enabled and facilitated by close collaboration within the SWEET EDGE project consortium. This includes both the sharing of data and results as well as discussions and informal feedback regarding the employed methodology. The most notable collaborations are listed in the following, consolidated for all three reports (D1.2, D2.4, D3.9). The names listed are limited to the authors' direct contacts, though further contributors from the mentioned institutions may have been involved. In addition, there was an active exchange of ideas with other research groups working on techno-economic modelling in the EDGE consortium (UNIGE - Renewable Energy Systems, ETHZ - Risk and Reliability Engineering, EPFL - Laboratory of Cryospheric Sciences, ZHAW - Center for Energy and the Environment).

HSLU – CC Thermal Energy Storage (Philipp Schütz, Manuel Meyer, Sarah Schneeberger, Ueli Schilt): Regular contact to coordinate work between the recommender tool (lead HSLU) and these reports (lead ZHAW). Special collaboration within the areas of heating energy requirements, spatial disaggregation of general electrical load, and distinction on centralized and decentralized power plants.

ETHZ – Power Systems Laboratory (María Parajeles Herrera): Sharing (and explaining) of data regarding EV charging with its spatial and temporal dimensions. Discussions about modelling decisions for EV flexibility.

ETHZ – Energy Science Center (Marius Schwarz): Data provisioning and discussions about spatial allocations and Switzerland-wide potentials of alpine PV and wind energy.

WSL – Sustainable Forestry Group (Gillianne Bowman): Data provisioning and discussions about spatial allocations and Switzerland-wide potentials of different categories of biomass-based power generation technologies.

EPFL – Laboratory of Cryospheric Sciences (Jérôme Dujardin): Data provisioning and discussions about spatial allocation of wind energy potential in Switzerland.

BFH – Laboratory for Photovoltaic Systems (Christof Bucher): Explanations of datasets of rooftop and façade PV timeseries for individual Swiss municipalities.

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