Exploratory analysis of Direct Load Control Policies for Heat Pumps in the Future Swiss Electricity System

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***Abstract*—New flexible electrical loads such as heat pumps present major demand-side flexibility opportunities thanks to their load shifting potential. In this study, we analyze to what extent the direct load control (DLC) of heat pumps within realistic bounds facilitates their integration in the Swiss energy system as it decarbonizes, by coupling a bottom-up building stock model and a high-resolution electricity system model. We rely on recently offered DLC contracts by Swiss distribution system operators to set these bounds and study the impact of different DLC settings. We find that contract parameters such as allowing preheating and prolonging shifting windows significantly impact how much DLC is performed. However, even high levels of DLC lead to small impacts on the electricity system's cost and renewables' integration in Switzerland, possibly only having a significant effect on peak electricity prices.**

***Index Terms*—heat pumps, flexibility, energy policy modeling, direct load control, demand-side management**

I. Introduction

Variable renewable energy (VRE) sources have fluctuating production patterns, which need to be balanced in the energy system to keep the power grid stable [1]. This is reinforced by an evolving demand-side of electricity with additional sector coupling bringing new loads in the power grid, such as heat pumps (HPs) or electric vehicles [2]. This creates additional needs for *flexibility* in the electricity system to manage (expected or unexpected) electricity supply and demand variability at different time scales [3]–[5]. In particular, additional flexibility is not only needed for fully decarbonized energy systems circa 2050 but already in the near future, with estimates that European flexibility needs will double by 2030 if the European Union meets its Green Deal goals [6], [7].

By being able to shift in time when they demand electricity, flexible loads can contribute to these flexibility needs, although significant barriers currently prevent this [8]–[10], calling, among others, for an evolution of policies and regulations regarding demand-side flexibility. In particular, the interplay between regulations, price signals to the end consumer and social acceptance remains a challenge [9]. Direct load control (DLC) contracts, whereby the end consumer is remunerated for allowing an entity to control their device's load within certain predefined bounds, are a promising way of addressing this challenge, facing lower social acceptance barriers than other price signals [11]–[13] and possibly circumventing the need for local flexibility markets.

With the increasing electrification of residential heating, heat pumps in buildings are becoming relevant sources of demand-side flexibility [2], [14], [15]. In particular, well-insulated buildings can provide significant thermal inertia to buildings, enabling the shifting of heat pump load over several hours [14]. As heat pumps are likely to represent significant shares of load in decarbonized energy systems [16], [17], their flexible operation may not just be a co-benefit of their deployment but a necessary requirement for their integration in the power system [2], [18]. This may be particularly true in countries with limited winter electricity supply such as Switzerland or Austria [19], [20]. In this regard, Switzerland has been proactive, and several distribution system operators (DSOs) offer DLC contracts for heat pumps, as detailed in Appendix D.

However, so far, research analyzing the impact of heat pump flexibility has been scarce. European effects have been studied in [2] and [5], and national effects in [15]. However, the focus of these works has mostly been on technical potentials rather than on studying the policy and regulatory dimensions. On the other hand, literature looking at the policy side has remained qualitative [10], [21]. Leveraging recent demand-side flexibility regulatory frameworks [22] and assuming different policy targets for the penetration of heat pumps and the renovation of buildings, our research thus aims to bridge this gap. By coupling a model of the Swiss building stock's energy demand and implementing a novel modeling approach of heat pump flexibility in a high-resolution electricity system model, we analyze the impact of direct load control (DLC) policies for heat pumps for different scenarios of diffusion of heat pumps and thermal renovations. In particular, we explore the impact of different configurations of DLC on the power system, namely VRE integration, system costs and electricity prices, based on real-life DLC contract parameters and evidenced-based thermal inertia of buildings.

II. METHODS

The analysis couples a model of the Swiss building stock utilizing demand.ninja [23] with the high resolution energy system model of Switzerland Nexus-e [24]. This section briefly describes the modeling of the building stock and the modifications made to Nexus-e to incorporate DLC, with more details provided in appendices B and C, as well as the scenarios and DLC configurations analyzed in the study.

A. Modeling of the heating demand of Swiss buildings

We create a bottom-up model of the Swiss building stock's heating demand up until 2050 utilizing demand.ninja [23]. As input data, we make use of public datasets provided by the Federal Register of Buildings and Dwellings of Switzerland (GWR) [25] and the Swiss SIA norms [26] for building characteristics and thermal comfort levels, as well as renewables.ninja for weather data [27], [28].

Four factors influencing the building stock are considered: demolition rates, new building construction, thermal renovations and heating system replacements. We fix demolition and construction rates based on historical data (see Appendix B for details). For thermal renovations and heating system replacements, we create two possible pathways for each, resulting in four scenarios, as displayed in Table I.

"Low" renovation rates are in line with renovations in Switzerland in the past decade [29], while "high" rates correspond to a more ambitious policy framework, similar to the EU's Renovation Wave, including the goal of doubling renovation rates by 2030 [30]. Resulting renovation rates are shown in Table VI in Appendix A.

Similarly, "low" and "high" heat pump penetration levels are based on Switzerland's energy strategy EP2050+ [31]: (i) low diffusion of heat pumps reaching 50% of residential buildings using heat pumps for space heating (scenario WWB of EP2050+) and (ii) high heat pump diffusion reaching 84% by 2050 (scenario ZERO A of EP2050+). Resulting penetration levels are shown in Table VII in Appendix A.

TABLE I
FOUR MAIN SCENARIOS CONSIDERED FOR THE STUDY, FOLLOWING DIFFERENT THERMAL RENOVATION RATES AND HEAT PUMP PENETRATION LEVELS IN SWITZERLAND.

	Low renovation	**High renovation**
Low HP diffusion	BAU	REN
High HP diffusion	HEAT	STRONG

For each scenario, the demand.ninja model outputs a heat demand profile per building, which we convert to a power load using coefficient of performance (COP) values from table VII, in line with the current average COP of heat pumps in Switzerland and the assumptions of Switzerland's energy strategy [32]. Finally, we allocate the load of each building to the nearest node of the Nexus-e power grid, using the Euclidean distance.

B. Electricity system modeling

Nexus-e is an interconnected energy systems modeling platform [24]. It details the Swiss power transmission grid, cross-border connections, power production and consumption. It optimizes the costs of the energy system, including the cost of electricity production and new capacity investments, as well as the operation of the transmission grid. Heat pumps are represented as loads with hourly resolution for each of the scenario years.

The Nexus-e Centralized Investments Module (CentIv) [33] and Distributed Investments Module (DistIv) [34] are used in a loop (CentIv - DistIv - CentIv) per scenario optimization year (i.e., 2020, 2030, 2040, 2050). CentIv is a grid-constrained generation expansion planning and operations module considering system flexibility. DistIv is a consumer-perspective generation expansion planning and operations module, handling investments in distributed energy resources such as solar panels and battery systems. We refer to the Nexus-e documentation and subsequent publications for details on how CentIv and DistIv work.

C. Direct load control modeling

Following [14], [15] and currently offered heat pump DLC contracts offered in Switzerland (see Appendix D), important parameters for DLC are the maximum share of heat pump load that can be shifted up/down at a given time based on thermal comfort of building occupants, the duration of this shift, the thermal comfort recovery time, whether preheating in anticipation of future load reductions is allowed, the remuneration of heat pump owners for load shifting, and how many load shifts are allowed per day. We thus introduce a novel approach for heat pump load shifting to Nexus-e to better reflect these shifting characteristics.

Specifically, we allow Nexus-e to perform heat pump DLC at any time t_0 of the day, but enforce that any downward shifting must be compensated with upward shifting afterward to maintain thermal comfort, within a recovery time denoted $t^{sh,max}$. We also make possible the preheating of the building, in which case the recovery time period is extended to $t_0 - t^{sh,max}$ and upward shifting can occur in anticipation of future downward shifts. We constrain maximum downward shifting of heat pump load to a relative share of the load $l^{sh,max}$ to ensure that the thermal comfort of occupants is not violated. Specifically, we fix this share at 71% following [14], which found using empirical data that within two hours of recovery time, 71% of heat pump load could be reduced without Swiss buildings initially heated at 20°C dropping below 19°C, even on cold days (outdoor temperatures of -7°C). Finally, we add constraints to limit the number of DLC load interruptions per day and add a cost parameter to load shifting, which we add to Nexus-e's objective function. Mathematical details of these constraints are explained in Appendix C and graphically shown in Fig. 1.

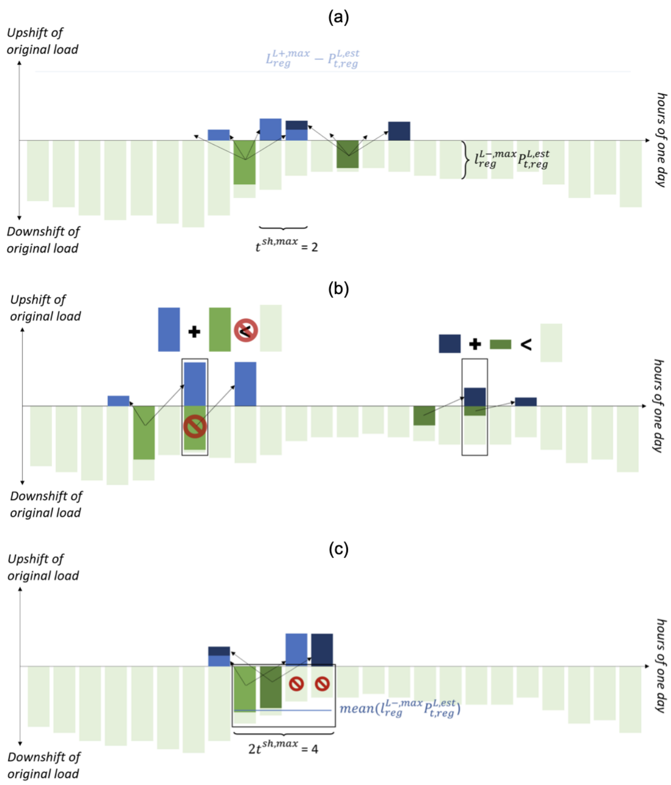

Fig. 1. On top (a), graphical representation of maximum heat pump load shifting within allowed hourly limits around the selected shifting time. In the middle (b), graphical representation of constraint (7), limiting simultaneous downward and upward load shifting. At the bottom (c), graphical representation of constraint (9): in the selected time window, heat pump is shifted downwards in hours 1 and 2, and as a result heat pump load must be shifted upwards in hours 0, 3 and 4 to maintain thermal comfort. Corresponding optimization variables and constraints are detailed in Appendix C.

Based on the variety of heat pump DLC contracts offered in Switzerland and so as to study their impact on the power system, we test for each of the four scenarios different configurations of the above-mentioned parameters in our modeling framework. We display these parameters in Table II.

III. Results

A. Uptake of DLC by the electricity system model

The modeling approach of DLC leads to a significant uptake of heat pump load shifting in the scenarios studied, as shown in Fig. 2. Over all hours of the year, more than 15% of the load is displaced on average in all scenarios. As a result of our assumptions, the relative load shift at every hour is capped at 71%, with several hours reaching this cap. Differences across scenarios are minor, despite significantly different heat pump loads over the year (see Fig. 7 in Appendix E).

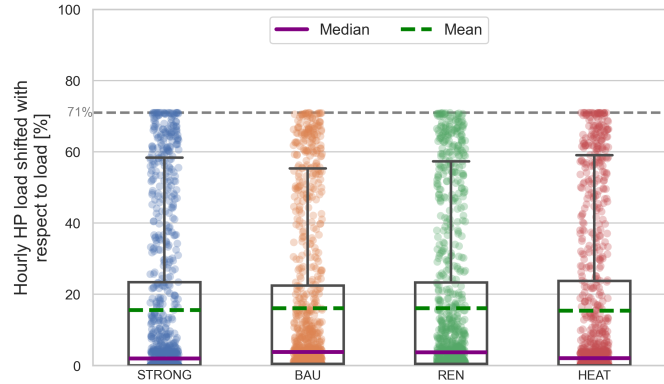

Fig. 2. Distribution of hourly heat pump load shift in the four scenarios for the year 2050. The dotted line represents 71%, the maximum allowed share of load than can be shifted at a given hour.

The load shifting behavior is as expected from the constraints implemented, as evidenced in Fig. 3. Wholesale electricity price drops correspond to increases in heat pump load, and vice versa. Downward shifts are limited to two hours, as $t^{sh,max} = 2$ was fixed in the basic configuration, and either preceded and followed by an upward shift for temperature recovery.

While differences across scenarios in Fig. 2 are minor, large variations of HP load shifting can be observed in Fig.

TABLE II
Summary of DLC parameters tested in our modeling framework, for each of the four main scenarios. Values in bold represent the default value when multiple values are tested. Variables are detailed in Appendix C.

Parameter	Variable	Unit	Value(s)
Max. shift down	$l_{reg}^{L-,max}$	%	71
Max. shift duration	$t^{sh,max}$	hours	{**2**, 3}
Max. hours of load reductions per day	$n^{sh,max}$	hours / day	{4, 6, **24**}
Preheating possible	-	binary	{**yes**, no}
Remuneration	$c_{sh,hp}$	CHF / MWh$_{\text{shift}}$	{0.1, **5**, 25, 50}

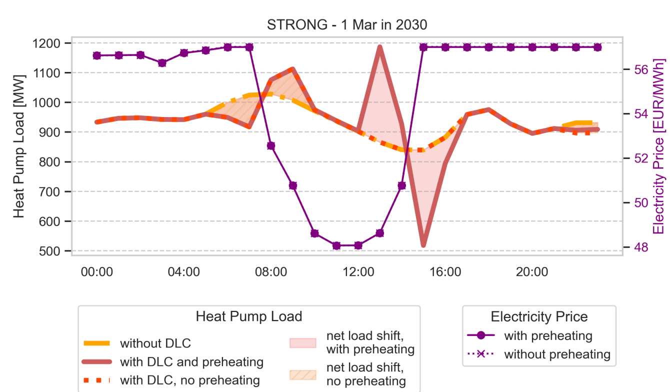

Fig. 3. Load shifting behavior when allowing DLC of heat pumps in the STRONG scenario for a given day in 2030. Allowing preheating enables an extra load shifting opportunity at 14:00–16:00 by preheating the building over the 12:00–14:00 period.

4 across DLC parameters. As can be expected, less DLC is performed as remuneration costs increase, with the average relative load shift falling below 10% above 25€/MWh of remuneration. Similarly, removing preheating and limiting the maximum number of hours of load interruption reduces load shifting compared to the initial setting. Conversely, increasing the shifting window to $t^{sh,max} = 3$ hours enables more DLC.

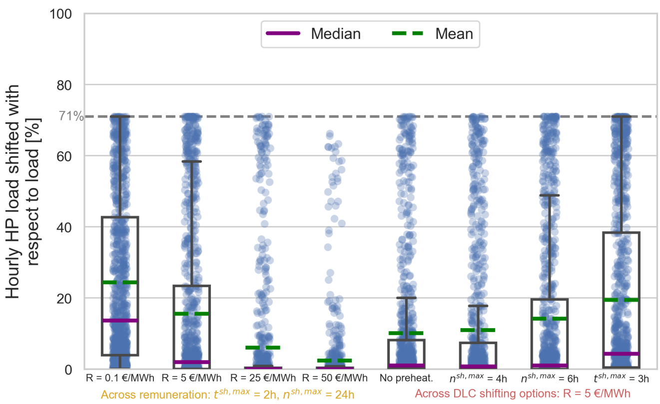

Fig. 4. Distribution of hourly heat pump load shift given different DLC parameters, for the scenario STRONG in the year 2050. The dotted line represents 71%, the maximum allowed share of load than can be shifted at a given hour.

B. *Impacts of DLC on the electricity system*

We look at the impacts of DLC of heat pumps on the electricity system's capacity expansion and generation through three lenses: first through VRE integration, then looking at system costs, and finally by analyzing electricity prices.

1) Impact on variable renewable energy integration: Although the different DLC parameters tested yielded largely different heat pump load shifting patterns, the impact of DLC on VRE integration is minimal in any case. Fig. 5 displays side-by-side the resulting heat pump load profiles given different DLC settings and the corresponding residual load curves. We focus on the STRONG scenario as it is in theory the scenario with the largest DLC potential (high renovation rates and heat pump penetration). While large differences exist across the heat pump load profiles, with smaller load variations as less DLC is performed, ordering the residual loads over time shows that this does not result in any differences. As such, the impact of DLC on curtailment and VRE integration is negligible. On the other hand, the same figure plotted across scenarios shows larger differences (see Fig. 8 in Appendix E), suggesting that total heat pump load matters more for VRE integration than its flexibility in the Swiss case.

2) Impact on system costs: We show the impact of the DLC of heat pumps on system costs over time in Table III across scenarios, and Table V and IV across DLC parameters and remuneration costs. We here consider the system costs of the entire model region (Switzerland and its neighboring countries). In Nexus-e, the neighboring countries' capacity investments are fixed according to ENTSO-E scenarios [24], only their dispatch is optimized. As a result, any change in objective function value must be a result of the impact of DLC in Switzerland.

Three main findings emerge from these results. First, system costs are only reduced when allowing DLC compared to not allowing it, as should be expected from a central planner optimization which only chooses to perform DLC if it reduces the objective functions' value. Second, across scenarios, DLC parameters and remuneration costs, the value of DLC of heat pumps in the system typically increases over time, becoming more relevant in 2050 than in 2030. Third, overall impacts on system costs remain small, ranging from 0% to 0.14% decreases in the most optimal configuration. However, it should be kept in mind that the objective function's value in Nexus-e reflects Switzerland and its neighbors, with Switzerland being far smaller than Germany, France and Italy in particular. Taking this into account, these cost variations are actually roughly in line with [15], which studied similar cases for Austria.

3) Impact on electricity prices: Fig. 9 in Appendix E shows the impact of DLC on average and peak electricity prices for each scenario in the different optimization years. While DLC has no significant effect on average electricity prices, peak electricity prices are reduced by around 40% in the STRONG and HEAT scenarios in the year 2050, i.e. when heat pump load is the largest (see Fig. 7). However, the price duration curve in Fig. 6 clearly shows that this effect only concerns a few hours per year. In addition, varying DLC parameters has little impact on both peak and average electricity prices, as evidenced in Fig. 10 in Appendix E. Overall, results suggest that DLC from heat pump may not bring as much value to the system as other flexibility sources (hydropower, batteries or electricity trading) on a daily basis, despite possibly high utilization, but that its use in peak load hours in scenarios with high heat pump penetration may strongly impact peak electricity prices. In those few peak load hours, DLC appears to be worth it even with high remuneration levels of the end consumer.

IV. Discussion and Conclusions

Our results reveal contrasting findings regarding the relevance of DLC of heat pumps in decarbonized energy systems. This is in line with the scarce existing literature on the topic which also finds ambivalent results [15].

On the one hand, we find negligible impacts of DLC on system costs, VRE integration and average electricity prices despite a large utilization of DLC. On the other hand, we also

TABLE III
Relative change in system costs across scenarios, in percentage points, when allowing the DLC of heat pumps in the optimization.

	STRONG	BAU	REN	HEAT
2030	-0.01	-0.01	-0.02	-0.02
2040	-0.07	-0.03	-0.04	-0.08
2050	-0.09	-0.07	-0.04	-0.09

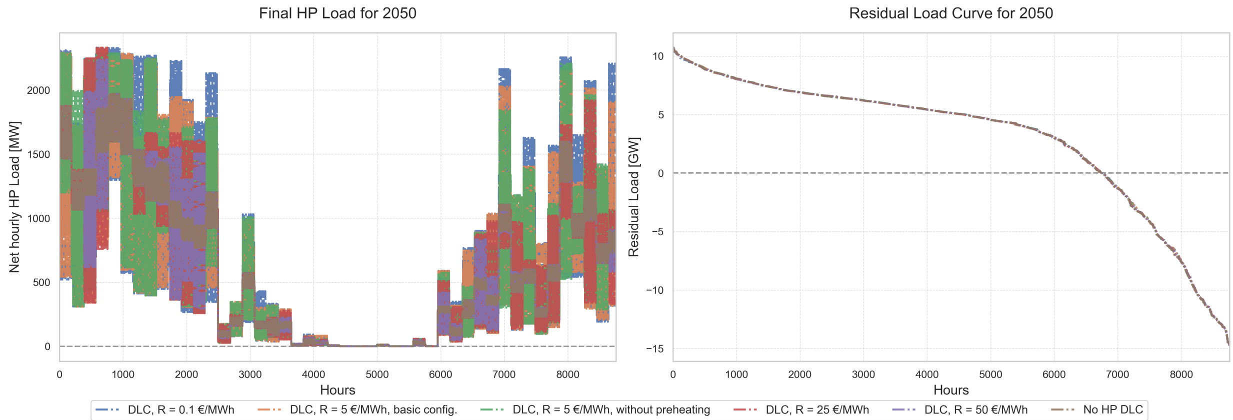

Fig. 5. Heat pump load profiles over the year 2050 in different DLC configurations for the STRONG scenario (left) and corresponding residual load curves (right). While heat pump load profiles vary significantly across DLC parameters, differences in resulting residual load curves are negligible.

TABLE IV
RELATIVE CHANGE IN SYSTEM COSTS ACROSS DLC REMUNERATION LEVELS FOR THE STRONG SCENARIO, IN PERCENTAGE POINTS, RELATIVE TO THE SAME SCENARIO WITHOUT THE DLC OF HEAT PUMPS.

	0.1 €/MWh	**5 €/MWh**	**25 €/MWh**	**50 €/MWh**
2030	-0.03	-0.01	-0.0	0.0
2040	-0.1	-0.07	-0.03	-0.01
2050	-0.11	-0.09	-0.04	-0.02

find that peak electricity prices could be reduced by around 40% with DLC of heat pumps in scenarios of high levels of heat pump loads and under severe grid stress conditions. Furthermore, the relevance of DLC appears to largely depend on the penetration level of heat pumps in the energy system. As such, in scenarios in which heat pump penetration was low or before the year 2050, the DLC of heat pumps yielded little to no impact on the energy system. However, it should be noted that Switzerland is a country with high levels of hydropower, leading to high seasonal flexibility needs but possibly lower daily to weekly needs [19], [35], which could affect the relevance of heat pump DLC compared to other countries.

TABLE V
RELATIVE CHANGE IN SYSTEM COSTS ACROSS DLC SHIFTING PARAMETERS FOR THE STRONG SCENARIO, IN PERCENTAGE POINTS, RELATIVE TO THE SAME SCENARIO WITHOUT THE DLC OF HEAT PUMPS.

	No preheat.	$n^{sh,max}$=4h	$n^{sh,max}$=6h	$t^{sh,max}$=3h
2030	0.0	-0.01	-0.01	-0.02
2040	-0.05	-0.06	-0.07	-0.11
2050	-0.03	-0.07	-0.08	-0.14

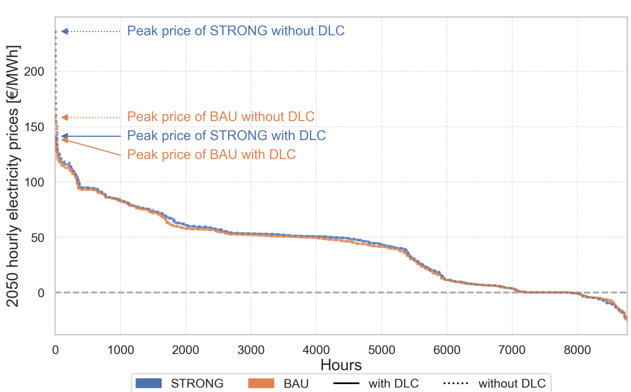

Fig. 6. Electricity price duration curves for the scenarios STRONG and BAU in 2050, with and without DLC.

Finally, as regards the relevance of our analysis for the evolution of regulatory and policy landscapes [22], we find that different DLC contract parameters have a significant impact on how much DLC is performed. In particular, removing the possibility of preheating a building in anticipation of future downward load shifts or higher remuneration levels largely reduced the amount of DLC performed. In contrast, extending shifting windows from 2 to 3 hours instead increased the levels of DLC and the reduction of system costs. However, changing these parameters had negligible impacts on VRE integration or electricity prices, and although system cost changes were large across parameters, they all remained small in absolute value.

Our modeling framework and implementation of DLC can serve as a stepping stone for future research on demand-side flexibility. In particular, case studies on countries with less alternative flexibility sources may find more relevant roles for heat pumps in flexibility provision. In addition, future work should look into integrating the distribution system level and modeling finer time resolutions to fully capture the potential of heat pumps in providing flexibility services.

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APPENDIX

A. Further details on scenario parameters

TABLE VI
ASSUMED ANNUAL RATES OF THERMAL RENOVATIONS IN DIFFERENT POLICY SCENARIOS. SFH = SINGLE-FAMILY HOUSEHOLD, MFH = MULTI-FAMILY HOUSEHOLD.

Scenario	Building Type	2024-2029	2030-2039	2040-2049	2050-2059
Low	SFH (< 1981)	1.0%	1.0%	1.0%	1.0%
	MFH (< 1981)	1.3%	1.3%	1.3%	1.3%
	SFH (> 1981)	0%	1.0%	1.0%	1.0%
	MFH (> 1981)	0%	1.3%	1.3%	1.3%
High	SFH (< 1981)	1.5%	2.0%	2.0%	2.0%
	MFH (< 1981)	2.0%	2.6%	2.6%	2.6%
	SFH (> 1981)	0.75%	1.5%	2.0%	2.0%
	MFH (> 1981)	1.0%	2.0%	2.6%	2.6%

TABLE VII
ASSUMED AVERAGE COP FOR HEAT PUMPS AND HEAT PUMP DIFFUSION RATES IN THE SCENARIO YEARS. THE CURRENT COP WAS COMPUTED WITH NUMBERS FROM THE TOTAL ENERGY STATISTIC OF SWITZERLAND IN 2022 [36], FUTURE NUMBERS BEING ASSUMPTIONS TO SLIGHTLY OVERSHOOT THE CURRENT AVERAGE COP OF NEWLY INSTALLED HEAT PUMPS (4.26) AS OLDER HEAT PUMPS ARE REPLACED OVER TIME. THE DIFFUSION RATES ARE BASED ON THE SCENARIOS WWB AND ZERO A OF [29]. FOR THE HIGH SCENARIO, ALL SUITED BUILDINGS ARE EQUIPPED WITH HEAT PUMPS.

	2023	2030	2040	2050
Mean COP	3.4	3.7	4.0	4.3
Low HP diffusion	-	35%	42.5%	50%
High HP diffusion	-	45%	65%	max = 84%

B. Further details on the modeling of buildings' heat demand

1) Input data from GWR:

TABLE VIII
USED VARIABLES OF THE GWR DATASET [25], [37].

Label	Name	Use
GSTAT	Building status	Filter for 1004 (existing)
GKAT	Building category	Filter for 1020 or 1030 (mainly residential use)
GKLAS	Building class	Identify single-family houses or multi-family houses
GBAUP	Construction period	Classification into old and newer buildings
GKODE	East coordinate (LV95)	Identify nearest transmission grid node
GKODN	North coordinate (LV95)	Identify nearest transmission grid node
GASTW	Number of floors	Compute heated area
GAREA	Building footprint area	Compute heated area
GEBF	Heated area	Heat demand computation for a small share of data points)
GWAERZH1	Primary heat gen. (e.g., heat pump)	Current heat pump load computation
GENH1	Primary heat source (e.g., oil)	Current heat pump load computation

2) Calibration of data for demand.ninja:

Constant rates of demolition and new building construction are assumed across scenarios based on the Energy Perspectives 2050+ [29]. The first parameter that varies across scenarios is the rate of renovations, more precisely, the improvement of buildings' thermal insulation. Additionally, buildings built after 1980 are renovated from the present in the high renovation scenario, 10 years earlier than in the low renovation scenario. Like demolitions, renovations are performed randomly on all existing buildings in the building stock dataset. Both buildings constructed in the future, as well as all renovated buildings, are assigned the target value for p_{heat} (see Table IX and Table X for further details on the chosen input parameters for demand.ninja). Unrenovated and existing buildings keep their assigned p_{heat}.

TABLE IX
CALIBRATED VALUES FOR HEATING POWER (p_{heat}) FOR BUILDINGS OF DIFFERENT TYPES, USED AS AN INPUT TO DEMAND.NINJA AND DERIVED FROM SIA 2024 [26]. SFH = SINGLE-FAMILY HOUSES, MFH = MULTI-FAMILY HOUSES.

Building type	SIA name	p_{heat} [W / °C / m^2]
SFH (before 1981)	stock	2.304
MFH (before 1981)	stock	1.764
SFH (from 1981 to present)	standard	0.622
MFH (from 1981 to present)	standard	0.507
SFH (future)	target	0.439
MFH (future)	target	0.380

For both scenarios, the selection of buildings to be equipped follows the same pattern. First, all new buildings are always equipped with a heat pump. Second, all renovated buildings with a fossil (oil or natural gas) or electric heating source always get equipped with a heat pump[1]. Third, of all existing and non-renovated buildings, enough buildings to reach the target deployment share are chosen randomly among those with a fossil or electric heating source. This implies that buildings currently using no heating or another source, most commonly wood or district heating, are never equipped with heat pumps in the model. This also leads to a maximum deployment share of heat pumps which is at 84% in the dataset.

TABLE X
ASSIGNED VALUES FOR THE DEMAND.NINJA MODEL [23], USED IN THE BUILDINGS MODEL. EXCEPT FOR THE HEATING POWER, THE SUGGESTED STANDARD VALUES ARE USED. COOLING IS IGNORED.

Parameter	Variable	Unit	Value
Smoothing	smoothing	1 / days	0.5
Solar gains	solar	°C / (W/m^2)	0.012
Wind chill	wind	°C / (W/s^2)	-0.2
Humidity discomfort	humidity	°C / (g/kg)	0.05
Heating threshold	T_{heat}	°C	14
Baseline power	P_{base}	kW	0
Heating power	P_{heat}	kW / °C	variable

[1]More precisely, also buildings with no information on the heating source are considered valid candidates. We decided to include electric resistance heating systems because they are specifically targeted by Swiss policies, for instance in the Climate Protection and Innovation Act.

C. Modeling of direct load control in Nexus-e

Nexus-e allows the system operator to shift loads like heat pumps and e-mobility charging. As specified in the CentIv module documentation [33], the initial load of these consumers in region reg is $P^{L,est,npv}_{t,reg}$ and their final scheduled load profile is given by (1).

$$P^{L,sch,npv}_{t,reg} = P^{L,est,npv}_{t,reg} + r^{L+,npv}_{t,reg} - r^{L-,npv}_{t,reg} \tag{1}$$

where $r^{L+,npv}_{t,reg}$ and $r^{L-,npv}_{t,reg}$ denote the positive and negative load shift in time step t and region reg, respectively. To account for the specificity of heat pump DLC, the following characteristics are incorporated into Nexus-e:

1) The downward shifts and the recovery time have strict time boundaries but can happen independently from the time of the day. Preheating can be allowed, that is, shifting loads to an earlier point in time in anticipation of future load reductions.
2) The maximum power shift per hour should be defined relative to the predicted load in this hour and potentially vary with temperature.

Accordingly, new variables for the performed shift are introduced, inspired by the methodology for load shifting optimization proposed by [38]. The implementation of this approach is graphically depicted in Fig. 1.

The variable $r^{sh}_{t\rightarrow i,reg}$ denotes the shifted load from time step t to time step i and exists $\forall t, \forall reg, \forall i \in \{t-t^{sh,max}, t-t^{sh,max}+1, \dots, t-1, t+1, \dots, t+t^{sh,max}\}$, where $t^{sh,max}$ is set to the maximum duration of a shift. $t^{sh,max} = 2h$ is set in the base case for heat pumps. The new variables are constrained with

$$0 \leq r^{sh}_{t\rightarrow i,reg} \tag{2}$$

$$\sum_{i=t-t^{sh,max}}^{t-1} r^{sh}_{t\rightarrow i,reg} + \sum_{i=t+1}^{t+t^{sh,max}} r^{sh}_{t\rightarrow i,reg} = r^{L-}_{t,reg} \tag{3}$$

$$\sum_{i=t-t^{sh,max}}^{t-1} r^{sh}_{i\rightarrow t,reg} + \sum_{i=t+1}^{t+t^{sh,max}} r^{sh}_{i\rightarrow t,reg} = r^{L+}_{t,reg} \tag{4}$$

Constraint (3) controls the load that is shifted down in a given time step while (4) controls the load shifted in a given time step. The power allowed to be shifted in each hour is constrained relatively to the original nodal demand for the downward shift and represents a maximum total load for the upward shift in (5) and (6), with $l^{L-,max}_{reg} \in [0,1]$ and $L^{L+,max}_{reg}$ being the maximum heat pump load observed in the load profile of the year and node in question.

$$0 \leq r^{L-}_{t,reg} \leq l^{L-,max}_{reg} P^{L,est}_{t,reg} \tag{5}$$

$$0 \leq r^{L+}_{t,reg} \leq L^{L+,max}_{reg} - P^{L,est}_{t,reg} \tag{6}$$

With this setup, the optimizer is allowed to shift strongly up and down simultaneously, which is not realistic in practice. Therefore, an additional constraint is introduced $\forall reg, t$ to limit the simultaneous up and downshifting:

$$r^{L-}_{t,reg} + r^{L+}_{t,reg} \leq max(l^{L-,max}_{reg} P^{L,est}_{t,reg}, L^{L+,max}_{reg} - P^{L,est}_{t,reg}) \tag{7}$$

This constraint is shown graphically in Fig. 1. It requires the sum of up and down shifting within the same hour to be smaller than the less restricting hourly bound of constraints (5) and (6).

Furthermore, the constraint for the maximum energy shifted per day is expressed in terms of hours of full reduction, denoted as $n^{sh,max} \in \mathcal{N}$. It can be set to $n^{sh,max} = 24$ if the number of load interruptions per day is not limited. To compute the daily energy allowed to be shifted, the mean load within the day is used, which results in the daily constraint (8).

$$\sum_{t=t_0}^{t_0+23} r^{L-}_{t,reg} \leq n^{sh,max} l^{L-,max}_{reg} \frac{\sum_{t=t_0}^{t_0+23} P^{L,est}_{i,reg}}{24} \tag{8}$$

To ensure enough recovery time for the interrupted loads, the following constraint is introduced hourly ($\forall reg, t$) to provide as much recovery time as interruption time:

$$\sum_{i=t}^{t+2t^{sh,max}} r^{L-}_{i,reg} \leq t^{sh,max} l^{L-,max}_{reg} P^{L,est}_{i,reg} \tag{9}$$

Finally, preventing preheating removes all variables $r^{sh}_{t\rightarrow i,reg}$ that shift backward in time and change the sum boundaries (equations (3) and (4)) as follows:

$$\sum_{i=t+1}^{t+t^{sh,max}} r^{sh}_{t\rightarrow i,reg} = r^{L-}_{t,reg} \tag{10}$$

$$\sum_{i=t-t^{sh,max}}^{t-1} r^{sh}_{i\rightarrow t,reg} = r^{L+}_{t,reg} \tag{11}$$

D. Swiss retail contracts for flexibility from heat pumps

With the proposed Swiss regulation in the new Electricity Act, buildings' flexibility can be unlocked by contract (by the local DSO or other parties), by the owner to optimize self-supply of PV production, or by emergency (by the local DSO). Due to the non-liberalized electricity market in Switzerland, no free choice of tariff models is possible, which limits the possibilities of dynamic tariffs in addition to the regulations carried out by the Swiss Electricity Commission ElCom.

Table XI summarizes what the largest DSOs of Switzerland offer in terms of reduced tariffs applicable for heat pumps and/or other flexible loads like electric vehicles (EV), electric hot water boilers (EB) and electric heating systems (EH). Most of the large DSOs do or did offer special tariffs for flexible heat pump operation, usually as an optional tariff scheme with a decreased grid tariff under the condition that the load can be interrupted during some time of the day. Common conditions are a maximum consecutive interruption of two hours, followed by a recovery time of at least the same duration, with a maximum daily interruption of four to six hours.

The remuneration is currently provided through a reduction on the grid tariff for **all** the electricity delivered to the flexible load. Therefore, a price range from 0.6 to 6.2 Rp/kWh or 6 to 62 CHF/MWh is observed during high tariff periods. This coincides with the observed average grid tariff reduction for load control in Germany of 3.85 ct/kWh [39]. Assuming a linear relationship between the volume of load that is shifted and the remuneration that customers require, the price per MWh *shifted* can be approximated by assuming that the share of shifted load is equal to the share of hours per day in which the load can be interrupted (so, usually 4 or 6 hours out of 24). The remuneration r_{appr} is then given by

$$r_{appr} = \frac{r_{obs} * 24}{n_{h,interrupted}} \tag{12}$$

where r_{obs} is the observed reduction on the high tariff and $n_{h,interrupted}$ is the allowed number of hours per day to interrupt the load. Among the reviewed optional tariffs still available, the lowest remuneration is offered by CKW in the canton of Luzern at 26.4 CHF / $\text{MWh}_{\text{shifted}}$, and the highest remuneration is offered by IWB in the city of Basel at 248 CHF / $\text{MWh}_{\text{shifted}}$. This seems high compared to the historical electricity prices within the European market. However, it is unknown how high the participation in these tariff schemes is and to what degree the remuneration actually reflects cost benefits for the DSO.

TABLE XI

IDENTIFIED OPTIONAL TARIFFS FOR END USERS ALLOWING FOR TARGETED LOAD INTERRUPTIONS, OFFERED BY SOME OF THE LARGEST DSOS IN SWITZERLAND. ALL INFORMATION HAS BEEN TAKEN FROM THE WEBSITES OF THE RESPECTIVE DSOS IN NOVEMBER 2023. THE REMUNERATION IS USUALLY PROVIDED BY A LUMP-SUM REDUCTION PER YEAR OR BY A REDUCTION ON THE TARIFF FOR **ALL** THE ELECTRICITY DELIVERED TO THE DEVICE (HT = HIGH TARIFF, NT = LOW TARIFF FOR TIME-OF-USE (TOU) TARIFFS). HP = HEAT PUMPS, EV = ELECTRIC VEHICLES (OR E-MOBILITY IN GENERAL), EH = ELECTRIC HEATING, EB = ELECTRIC BOILER. *=TARIFF NO MORE AVAILABLE.

DSO	Tariff name	Load spec.	Max. int./day	Max. int. cons.	Recovery time	Reduction monthly	Reduction (HT)	Reduction (NT)
IWB	Wahltarif Elektromobilität	EV, others	6h	2h	2h	min. 10 CHF	6.2 Rp/kWh	-
IWB	Wahltarif Wärmepumpe	HP	6h	2h	2h	min. 10 CHF	6.2 Rp/kWh	-
SIG	Tarif pompe à chaleur*	HP	3h	2h	-	0	0.75 Rp/kWh	0.8 Rp/kWh
CKW	Doppeltarif sperrbar DS	HP & others	6h	-	-	0	0.66 Rp/kWh	2.2 Rp/kWh
Groupe-e	Doppelt unterbrechbarer Tarif	HP, EH, others	2h (yearly avg)	-	-	0	0.6 Rp/kWh	0
Groupe-e	Bonus	HP, EH, (EV)	2h	-	-	4.166 CHF	0	0
Repower	Vergütung Flexibilitätsnutzung	EB, HP, others	4h	2h	-	7.5 CHF	3 Rp/kWh	-
ewz	Netzdienliche Leistungsbegrenzung	others	6h	2h	like interr.	0	2 Rp/kWh	0.6 Rp/kWh
EKZ	Netz 400F	others	-	-	-	0	0.54 Rp/kWh	0.54 Rp/kWh
EKZ	Netz 400WP	HP, EH	4h	2h	like interr.	0	1.08 Rp/kWh	1.08 Rp/kWh
BKW	NS UR*	others	4h	2h	-	0	1.73 Rp/kWh	0

E. Additional results

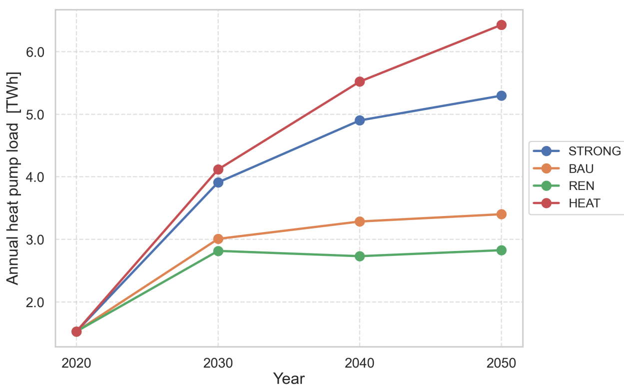

Fig. 7. Total annual Swiss heat pump load resulting from the bottom-up model used, per scenario year.

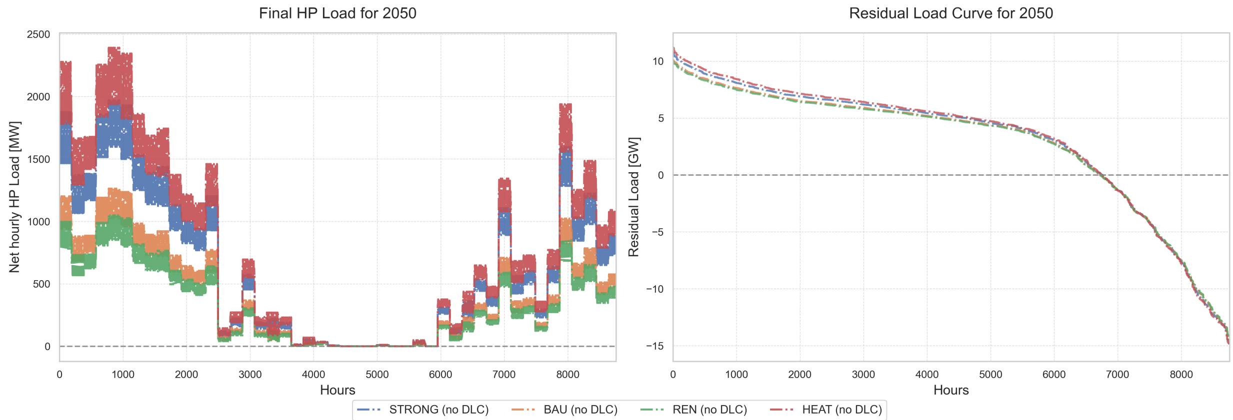

Fig. 8. Heat pump load profiles over the year 2050 in the different scenarios, without DLC (left) and corresponding residual load curves (right).

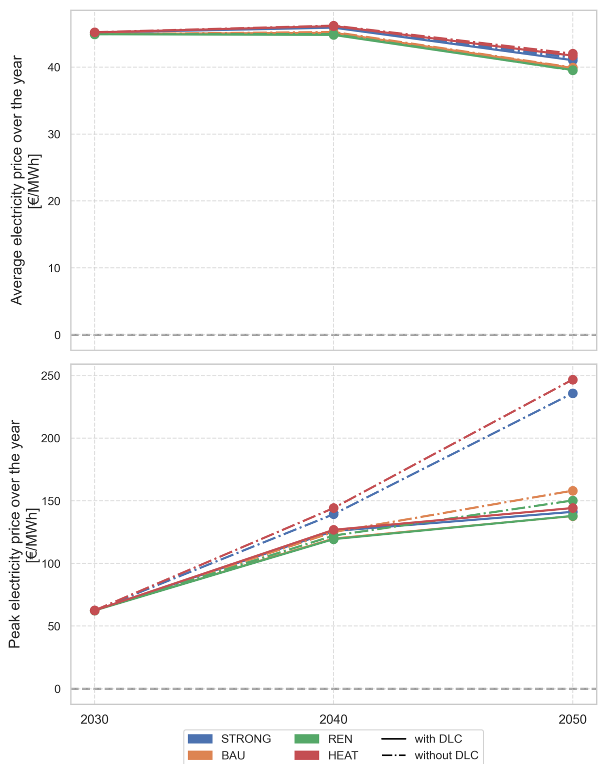

Fig. 9. Average and peak wholesale electricity prices over each optimization year for the four scenarios considered, with and without DLC of heat pumps allowed.

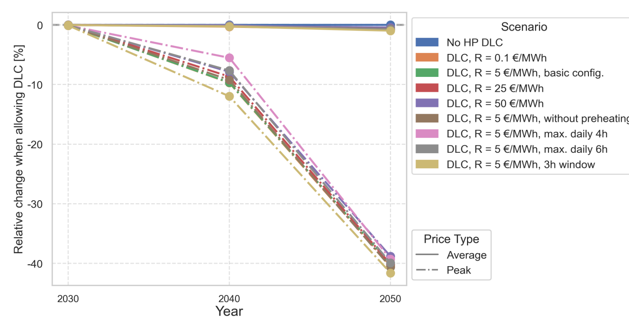

Fig. 10. Average and peak wholesale electricity prices over each optimization year for the scenario STRONG in different DLC configurations, relatively to the scenario without DLC allowed. While allowing DLC has a roughly 40% impact on peak electricity price, variations across DLC parameters are small.