Load Shift Potential Analysis Using Various Demand Response Tariff Models on Swiss Service Sector Buildings

E. Birrer, D. Bolliger, R. Kyburz, A. Klapproth, S. Summermatter*

iHomeLab, Lucerne University of Applied Sciences and Arts,
CH-6048 Horw, Switzerland.
****now with BE Netz AG,***
CH-6030 Ebikon, Switzerland

Abstract

With an increasing amount of volatile renewable energy, balancing demand and supply becomes increasingly demanding. To achieve this balance, Demand Response (DR) is one important approach. DR needs a paradigm change from energy savings towards shifting electrical consumption to timeslots with excess energy generation, and from centralized network stabilization efforts to a price driven, decentralized approach. This change empowers consumers to act with load shifting (LS) on price variations, respecting their comfort, process and safety needs. In the residential area, the necessary building automation is not yet widely spread, therefore we use the Swiss service sector buildings (SSSB) as a model.

In this paper iHomeLab reports on investigations on DR and the according LS potential (LSP), focusing on SSSB. We base our LSP calculations on Swiss energy consumption data, broken down to distinct categories of electrical appliances. Further we consider the typical energy usage in different seasons, week- and daytimes. Four time-dependent tariff models are applied in a simulation to the load-curves in order to estimate the peak smoothing by load shifting at tariff peak times.

Our results show that 35% of the total energy consumed in the SSSB can potentially be used for LS. Significant seasonal and intraweek differences are observed. The air condition potential dominates in summer, whereas room heating is the main factor in winter. The summer LSP peak is 45% higher than the winter peak, but available only for 15 to 60 minutes, compared to several hours in winter. Analysing the size structure of SSSB shows that by rolling out DR to only the largest sites (7% of sites), already 65% of the LSP can be tapped.

Introduction

The electricity systems in developed countries worldwide are experiencing a fundamental transformation towards a more decentralized power generation with a growing share of renewable sources with fluctuating production levels as shown in [1]. Given the traditional centralized power generation regime, also grid stability and security of supply are in the responsibility of Transmission System Operators (TSOs) like Swissgrid and the Distribution System Operators (DSOs), which try to cut peaks and minimize balancing energy by using load clipping and Direct Load Control (DLC, i.e. remotely switching off loads during peak demand periods, as in [2], [3], [4], [5], [6], [7]). As the production becomes more decentralized, the decentralized response to the electricity demand – known as Demand-Response (DR) – through non-static energy tariff signals emerges to be a valuable instrument to achieve self-stabilizing energy grids (e.g. [8], [9]).

DR has been investigated in various studies and projects for residential buildings (e.g. [6], [10], [11], [12]) and industrial facilities (e.g. [4], [5], [13], [14]). They have shown that DR needs to be supported by automation to yield sustainable results. However, for residential buildings in Switzerland, penetration with building automation systems and a smart meter infrastructure is still low. In contrast, the majority of SSSB are equipped with building automation as well smart meters already today. The analysis of the LSP in the SSSB can therefore be used to gain experience for the LS in the residential building domain. But there is almost no research available about service sector buildings, e.g. office buildings, schools or shopping centres.

Therefore, the research presented in this paper aims at quantifying the potential of DR in SSSB, both from an energy point of view and from a financial perspective. More detailed, we want to quantify the potential of load shifting for the various load groups, and to know how the potential is distributed during the seasons. Then we apply several different tariff signals to this potential, to find out which tariff signal would maximize load shifting benefits, and if a tariff signal that is realizable with the current metering hardware (without smart meters) could already provide major load shifting.

We use existing data sources to calculate LSPs for 10 usage groups, separately for weekdays, Saturdays and Sundays/nights and for each season (summer, spring/fall, and winter). This data we then use to simulate the load shift effect of four different tariff models, and can therefore show their more or less alleviating effect on demand peaks. Using the size distribution of the consumption sites, we quantify roll-out scenarios (smart meters, DR compliant building automation and new tariff models) and their resulting LSP. This allows us also to calculate the possible financial savings by complete load shifting for the different site sizes.

These findings enable DSOs to develop their DR roll-out strategies in a way to prioritize sites with the best effects for a given investment. Moreover, they also allow TSOs and/or DSOs to evaluate their pricing policies and to develop tariff models that promote DR, and thus help them lowering cost for grid balancing energy. This could not be achieved in past experiments with domestic consumers, where it was found that high investments in building automation and smart meter infrastructure yield only small energy cost savings. Therefore up to now DSOs had only little motivation to change tariff models or pricing strategies.

The paper starts by presenting the data sources and outlines the steps how the total technical LSP can be extracted and calculated. In a second part, the temporal behaviour of the relevant potential groups is deduced, in 15-minute time intervals, for each season and for weekdays, Saturdays and Sundays/nights separately. The paper then presents various tariff models in comparison to the currently used one, and selects four representative models for further analysis. They will be used for simulating the LSP, in order to find out for each time interval how much energy is consumed, how much can be shifted and how the shifted consumption is distributed over time. An analysis of the results concludes the paper.

Data & Methodology

A lot of fundamental energy data is collected in [15]. This study focuses on the impact of a smart meter roll-out in Switzerland. iHomeLab goes further and sharpens the image relevant for SSSB by following the deduction of the technical LSP of [15] with several modifications. Therefore we describe the adapted methodology here in detail and refer to the original publication(s) where indicated.

In a first step, we define the total electricity consumption and divide it into groups of devices with similar consumption characteristics, the *potential groups*. In a second step, we calculate the temporal behaviour of the relevant potential groups. This then allows us to calculate for each interval in a year: first, the energy consumption, and second, which portion of the consumption can be shifted and how the shifted energy consumption distributes over time.

Electrical Energy Consumption and Potential Groups

As data source we used [16], [17], and [18], which cover the overall Swiss electricity consumption of the year 2012 broken down to industry, service and business sector. In this research we focus exclusively on the services sector. [16, p. 43] contains a partition along usage groups for the service sector, as shown in Tab. 1, in which 4 TWh/a for agricultural energy usage are also included in the data.

In the services sector, a remarkable high amount is used for drives and processes (27.5%), which also contains cooling processes such as for freezers and coolers. The other most relevant categories are air conditioning (26.6%) and illumination (23.9%).

From an energy point of view a finer partition makes sense. Further, with the premise that neither comfort nor process security are impaired by DR, the following potential groups are suitable for load shifting:

- Specific industry/service processes
- Process heating
- Air conditioning (cooling)

- Ventilation
- Room heating
- Water heaters
- Process cooling
- ICT
- Compressed air
- Pumps for heating

Tab. 1: Partition of the energy consumption (2012) in the Swiss services sector according to usage groups (from [16, p. 43])

Usage groups	Energy consumption [GWh/a]
Total	**17'300**
Drives, processes	4'750
Process heating	640
Air conditioning	4'610
Room heating	940
Water heaters	220
Illumination	4'140
ICT	1'140
Others	860

It is important to clearly distinguish between energy saving measures and time-flexibilisation of energy demand. The latter means load shifting in time with a potential slight increase of energy (without comfort loss) or energy consumption reduction (with a potential cut-back in comfort). The first comprises measures such as switching off unused devices or dimming illumination according to necessity; and only has indirect influence on DR, because it only influences the amount of the (maybe shiftable) consumption.

Out of many proposed DR methods [19], with the premise of no comfort loss, we focus exclusively on load shifting (and not peak-clipping, load curtailing, etc.). It allows making use of electrical energy when it is available in excess and therefore energy prices are low. From a DSO point of view the energy demand can be stimulated by definition of price levels corresponding to energy availability.

To find the realizable LSP – called *technical potential* –, we use the method according to [15], with modifications.

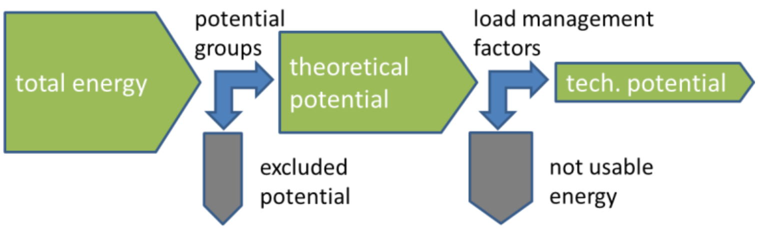


Fig. 1: Method to derive the realizable load shift potential, according to [15]

It applies the following criteria to find groups with load shifting potential:

- The load or consumer has some type of storage. It makes no difference if this storage is a built-in part of the consumer, or if the physical system around the load represents the storage.
- The load or consumer is interruptible or deferrable, and the interruption or deferral only leads to no or only negligible restrictions in the production process.

According to these criteria, we have to detail some of the groups defined by [16], because not all of their applications have the same LSP: “Drives, processes”, “Air conditioning”, and “ICT”. The groups “Illumination” and “Others” have no or a negligible LSP, because lighting is not shiftable without comfort loss. Different to [15], we also omit the LSP for emergency power systems (UPS systems, emergency generators) because we consider them as non-shiftable. In the group “ICT” we can expect a LSP for big data centres, which is not considered by [15]. We then scale the energy consumption data from [15] with the currently available data for 2012 in [16] and assign them to the industry and the services sectors (as defined in [15]). This gives the *theoretical achievable potential* sorted by the different potential groups, shown in the left part of Tab. 2.

Derivation of the Technical Potential

The technical potential is defined as the shiftable part of the total load and the possible shifting duration. The load management factor (LMF) is defined as the percentage of the total load of a potential group that is available as shiftable load. This includes buffering effects and dependencies on business processes (per assumption, we allow no compromises in comfort). Basically, we use the load management factors given in [15], but distinguish between industries and services sector. Main differences are explained as follows:

- A considerable part of process cooling is used to cool food [15, p. 268] and must therefore not be switched off at any time. This leads to a reduction of the LMF from 85% (industries) to 80%.
- The group “Specific industry/service processes” is very heterogeneous. [15] estimates an overall LMF of 10%. We assume that specific processes in the industries are less shiftable than those in the services sector, so we use 5% for industry and 20% for the service sector, respectively.
- Room cooling can be used for DR as long as it is not coupled to some production process (as in a cleanroom or an operating theatre). We assume that for the services sector, a higher percentage is coupled to processes (especially in the medical field) and thus non-shiftable, so we assume 70% instead of 80%.

Tab. 2: Theoretical energy amounts of the potential groups (calculation with modifications from original literature), their LMF and technical potential for industries and services sector (from [15, pp. 270-274], modified).

Potential group	**Theoretical potential [GWh/a]**	**LMF industries [%]**	**LMF services sector [%]**	**Technical potential services sector [GWh/a]**
Total	**11'390**			**6'070**
Drives, processes				
Process cooling	1'300	85	80	1'040
Compressed air	70	20	75	53
Specific service sector processes	4'160	5	20	832
Process heating	**620**	**15**	**15**	**93**
Air Conditioning				
Room cooling	930	80	70	651
Ventilation	1'870	22	75	1'402
Pumps heating	820	100	100	820
Room heating	**940**	**100**	**100**	**940**
Water heaters	**220**	**25**	**25**	**55**
ICT				
Data centres	460	20	40	184

- We add “ICT” as potential group, because a considerable amount of electricity is used in data centres. In the industry sector, data centres and servers have to be available all the time during production hours, which results in a load management factor of 20%. In the services sector however, reducing the power of a data centre is feasible (it would lead to longer computation times e.g. for a search request), so we assume a load management factor of 40% ([20] anticipates energy savings of 40% - 50% by switching off big data centres if they are not used).
- We do consider neither UPS systems nor emergency generators as shiftable loads. On the one hand, the batteries of UPS systems must always be full, so their charging process cannot be shifted. On the other hand, even if emergency generators are operational at any time, they are not loads, but energy supplies.

Tab. 2 lists the LMFs for both industry and services sectors and the technical potential for the services sector for all potential groups.

Temporal Behaviour of the Potential Groups

In a second step, the temporal behaviour of each potential group is characterized. As the services sector works all year round, most of the potential groups are in use 52 weeks per year. Only groups related to heating are reduced to 39 weeks, and cooling to 6 weeks (according to [15, p. 266]).This is important because the LSP of such a potential group is not available for some weeks in the year, but higher in the remaining weeks. The consumption of the potential groups can also be split up among the seasons. We treat spring and fall the same, and as above only potentials related to heating and cooling are distributed asymmetrical during the year, see Tab. 3.

Tab. 3: Yearly usage and season factors of the potential groups (from [15, p. 266], modified)

Potential group	**Usage [week/a]**	**Season factor [%]**		
		summer	**spring/fall**	**winter**
Drives, processes				
Process cooling	52	30	50	20
Compressed air	52	25	50	25
Specific service sector processes	52	25	50	25
Process heating	52	25	50	25
Air Conditioning				
Room cooling	6	100	0	0
Ventilation	52	25	50	25
Pumps heating	39	0	66	34
Room heating	39	0	40	60
Water heaters	52	25	50	25
ICT				
Data centres	52	25	50	25

Other than [15], we consider only the services sector, so we changed some season factors as follows:

- For room heating, [15] uses 10% for summer, 50% for spring/fall, 40% for winter. Given that in rooms of the services sector, generally more people are present than in the industries, no heating is necessary in summer and less in spring/fall. So we use 0%, 40%, 60%, respectively.

The energy consumption of the services sector also depends on the weekday. Different to [15], we distinguish, as stated above, between industry and services sector and between weekdays, Saturdays and Sundays. Our factors (relative to consumption on a weekday) are listed in Tab. 4. The factors include energy saving measures such as switching off some devices during weekends (because then these loads are not available for shifting). We assume that in the services sector, activity on Saturdays is 80% compared to weekdays, on Sundays 20%.

For the most part process cooling is used to cool food [15, p. 268] and must therefore not be switched off during weekends. For process heat this is different: we assume that due to energy savings measures, HVAC (heating, ventilation, air conditioning) is reduced while no personnel is on the premises. Big data centres also are not as busy on weekends as on a weekday. Based on these considerations, we use the numbers in Tab. 4 as weekday factors.

Tab. 4: Day/night factors of the services sector potential groups (from [15, p. 268], adapted)

Potential group	**Day/night factor [%]**		
	Weekday	**Saturday**	**Sunday / night**
Drives, processes			
Process cooling	100	100	100
Compressed air	100	80	20
Specific service sector processes	100	80	20
Process heating	100	80	20
Air Conditioning			
Room cooling	100	80	20
Ventilation	100	86	30
Pumps heating	100	100	20
Room heating	100	95	75
Water heaters	100	80	20
ICT			
Data centres	100	95	75

For a complete temporal load model we need also to distinguish between day and night. As proposed in [15], we divide the 24h-day in two parts, day and night of 12 hours each. During the night, we assume the same factors as for a Sunday. While the 12-hour-day is realistic (or even too short) for shops or leisure facilities, offices usually have shorter hours. By using 12 h nevertheless, we compensate shift-work and unusual work schedules.

Further details about LSP realisation are left open at this point. We assume that DR will replace direct load control used today, in order to get a complete picture. Therefore, we do not introduce a reduction factor for direct load control in contrast to [15, p. 277].

With the time shift model available on the one hand and the load management factors (and thus the technical potential) on the other hand, we still are missing a piece of information to be able to simulate load shift: We need a model about the possible duration of the delay and the necessary pre-announcement time.

This shifting potential vs. time according [15] is shown in Fig. 2. In addition to the pre-announcement interval t_{pre}, the curve contains a „minimal time“ t_{min}, which is the interval during which the load can be shifted without loss of comfort, and a “maximal time” t_{max}, which gives the longest possible shifting interval (i.e. after this time, the load must be supplied with energy again). The case without pre-announcement can be treated the same, with an announcement time t_{pre} of zero. For simplicity we only shift loads to a later point in time, never to an earlier one in our calculations. As we will look at the total SSSB energy sum over the whole year or season, this makes no difference in the compound figures. Therefore in this paper we do not take into account the well-known “rebound effect”.

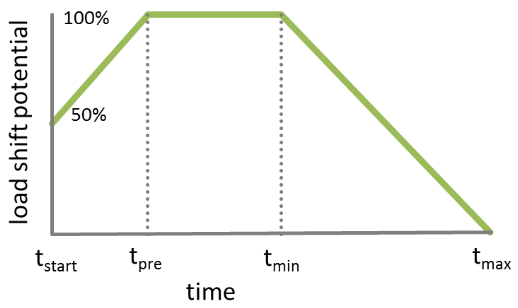


Fig. 2: Model for the potential of the load shift times, with pre-announcement

The pre-announcement times t_{pre} have been evaluated in detail by [15] and are used in this paper with some adjustments:

- No specific reference values can be found for data centres, so we have estimated them using [20]. As shifting the load means only a reduction of computing power, it can be done during a longer period.
- For heating pumps we have reduced the numbers of [15] by 50%, because such pumps need to manage the thermal reservoir partly also when the heating is not used.

The resulting values are listed in Tab. 5.

Tab. 5: Adapted load shift times (after [15, p. 276])

Potential group	**Minimal time [minutes]**	**Maximal time [minutes]**	**Pre-announce-ment time [minutes]**
Drives, processes			
Process cooling	60	240	0
Compressed air	0	30	0
Specific service sector processes	30	180	30
Process heating	30	180	30
Air Conditioning			
Room cooling	15	60	0
Ventilation	15	60	0
Pumps heating	120	240	0
Room heating	240	480	0
Water heaters	60	180	0
ICT			
Data centres	60	120	15

[15] suggests prolonging these intervals during weekends and nights, because reduced personnel on site means less energy consumption (e.g. for ventilation). Therefore we added the following intervals to the minimal time and the maximal time (cumulative):

- plus 30 minutes during the night from Monday to Friday
- plus 30 minutes during the day on Sunday
- plus 30 minutes during the night on Saturday and Sunday

Now we can calculate for each point in time and per potential group: (1) the amount of electrical energy consumption and (2) how much of this can be shifted given a trigger and how the energy is shifted over time. Examples of these calculations are given in the results section.

Applying Tariff Signals

The DR-approach we have chosen for our project is to control one building (or several buildings on one site, if the building control system is set up that way). This basic DR cell makes sense in a way that in the service sector this partitioning is also usually the economic basic cell. The building or site reacts autonomously on a given tariff signal in order to minimize its energy costs. In this paper, we list existing and possible tariff signals, categorize them and then select four representative ones for further investigation.

The various tariff models for DR found in literature (see overview in [1]) can be divided into two main groups: incentive based and price based programs. For our project, we only examined price based ones.

TSO and DSO want to encourage energy consumption when there is plenty of supply (e.g. from renewable sources as wind or solar radiation) and energy savings during times when less energy is produced. This situation is already reflected in the electricity wholesale price, so one of the logical tariff models is to charge the end-customer fluctuating prices reflecting the real cost of electricity in the wholesale market. This is called *real-time pricing (RTP)*. Because the wholesale prices are defined on the day ahead, also the RTP price signal can be announced on a day-ahead or hour-ahead basis. In this regard, it is important to note that RTP is not the same as prices from a real-time energy exchange, where energy prices are negotiated on short notice between the participants of the energy stock exchange. In order to boost the load shifting effect, the tariff signal could be modulated to amplify fluctuations, as described e.g. in [21]. We include a tariff signal with quadratic coupling to the load profile after [22] and call it *RTP+*. Such a signal also reflects higher costs for load peaks due to generating power restrictions

The price signal that is used nowadays in most parts of Switzerland assumes that there is excess energy during the night, so the tariff system depends on the time of day of energy usage, with a lower nightly tariff. Such tariff systems are called *time of use (TOU)*. They could involve more levels (6 have been tested in [23]), different tariffs according to season, weekdays etc. To be able to estimate the effect of DR in the current tariff situation in Switzerland, we include into our simulations a simple TOU model with 2 levels, independent of the season and with same times on Monday to Saturday (Sunday on lower level).

TOU models as the above do not stimulate load-shifting according to a variable energy production, because there is no short-term variability in the tariff. *Critical peak pricing (CPP)* includes such an element. It is based on a flat or TOU tariff model and adds a peak tariff that is valid only for short periods of time (e.g. between 15 min. and 2 hours) and announced on relatively short notice (e.g. the day before). However, the price for the peak tariff and its maximal duration and frequency are fixed and communicated in the contract. Such a tariff model is only moderately complex to implement (most of the existing infrastructure in Switzerland can already handle three price levels), but allow the DSO to give incentives for load-shifting. We include into our simulations a CPP tariff based on a two-level seasonal TOU tariff and call this tariff model CPP+.

The four tariff models we use for simulations represent a good selection from the wide variety of tariff models: 1) TOU, which is a simple and widespread tariff, 2a) and 2b) as two versions of RTP, which are at the opposite end of the complexity scale (one with linear, one with quadratic coupling to the price signal), and 3) a CPP based on a two-level tariff, which represents a compromise between technical simplicity and flexibility for incentives.

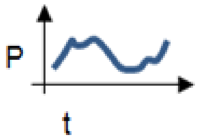
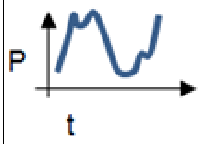
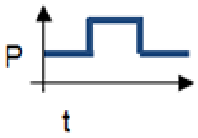
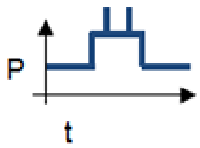
To be able to compare the results, we have designed the detailed prices for each tariff model such that the total energy cost – for end users and DSO – is kept constant compared to the initial situation with no load shifting, using standard load profiles. Additionally, we assumed the following:

- Possible price changes because of changed user behaviour with modified energy demand due to DR are not fed back into the models.
- No differentiation is made between grid cost and energy cost, we use a weighted overall sum.
- An average energy price of 14.41 Rp/kWh is derived from the 2013 Elcom data [24], with mapping the industry and service sector tariff user groups C1-C7 to the total energy consumption of each user category as described in [15, p. 124].

- Energy shifting is considered as free, the cost of additional arising energy storage is neglected.

The resulting tariff models and their detailed parameters can be found in Tab. 6

Tab. 6: Cost neutral price models for DR

RTP[a] 	**Real Time Pricing** • Variable tariff signal with linear coupling • Complexity high • Incentive low	RPT+[b] 	**RTP spread** • Variable tariff signal with quadratic coupling • Complexity high • Incentive medium
TOU[c] 	**Time of Use** • Double tariff with long term stability • Complexity low • Incentive low	CPP+[d] 	**Critical Peak Pricing** • Variable double tariff with two critical peaks • Complexity medium • Incentive high

[a] Load profiles according to [22]
[b] Based on RTP and quadratic coupling
[c] Low tariff (LT) 9.75 Rp/kWh, high tariff (HT) 17,72 Rp/kWh
[d] Peak duration winter 2 h, summer 1.5 h, tariff spread factor: 1.5 x HT
Winter: LT 9.75 Rp/kWh, HT 17.72 Rp/kWh, Peak 26.80 Rp/kWh
Transient: LT 8.84 Rp/kWh, HT 16.08 Rp/kWh, Peak 24.12 Rp/kWh
Summer: LT 7.86 Rp/kWh, HT 14.90 Rp/kWh, Peak 21.44 Rp/kWh

With these four tariff models we have calculated the achievable energy cost savings in the service sector, based on the LSP presented in section “Load Shift Potential”. A promising tariff candidate with moderate communication and infrastructure requirements is the Critical Peak Pricing (CPP) based on a Time Of Use (TOU) double tariff with two critical peaks per day, called CPP+. Price levels usually vary per season. For our initial calculations, we assumed a moderate critical peak price of only 1.5 x the price of the higher TOU tariff level. In literature, spreads up to a factor 10 are reported ([13], [25], [26]), to gain relevant load shift incentives.

Results

Roll-out Scenarios

As a first result, we can use the data of [15] regrouped according to the size of the sites and derive roll-out scenarios. The total electrical energy consumption of the service sector in Switzerland in 2012 is 16 TWh ([16], [17] and [27]) – about the same amount as in the industrial sector. The number of sites within defined ranges of energy consumption can be derived from [12]. The distribution of the cumulated annual energy consumption vs. the cumulated number of service sector sites is shown in Fig. 3. Under the assumption that the LSP is proportional to the energy consumption of a site, this data shows that 50% of the total load shift potential (LSP) can already be realized by addressing only 1.7% of all service sector sites.

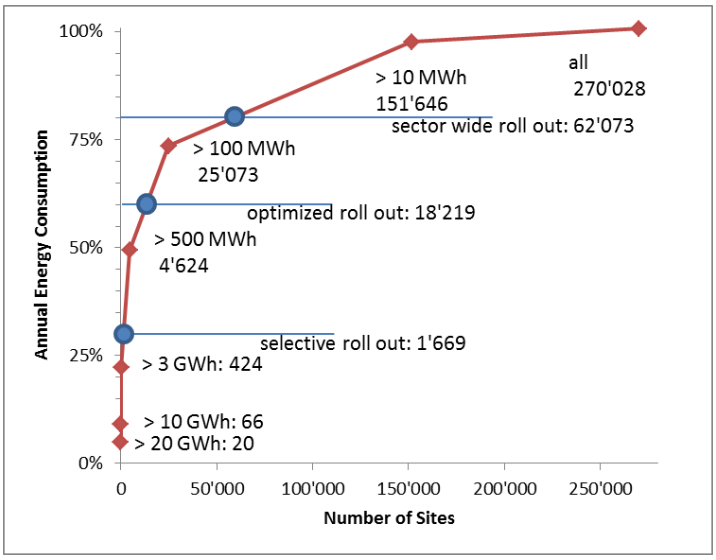


Fig. 3: Cumulated energy consumption vs. consumption size categories

Based on this, we consider three potential roll-out scenarios for DR until 2035. This timespan matches the currently discussed energy perspectives ([28]) of Switzerland. For each roll-out scenario, we propose how many buildings of which electricity consumption level have to be equipped with DR infrastructure. As shown in Tab. 7, the DR LSP could be realized to a remarkable share of 65% if only 7% of all service sector sites are included (scenario "Optimized").

Tab. 7: Roll-out scenarios

	Selective	Optimized	Sector Wide
Realized LSP	1.8 TWh/a 30 %[a]	4.0 TWh/ a 65 %[a]	4.9 TWh/a 80 %[a]
Number of Sites	1’669 0.6 %[b]	18’219 7 %[b]	62’073 23 %[b]

[a] of full LSP of 6.1 TWh/a
[b] of all 270’028 utilities (SSSB)

Load Shift Potential

The simulation of the LSP – according to the methodology described above – for all usage groups, separated for weekdays/Saturdays/Sundays and for each season, leads to the results in Fig. 4. It shows the profiles of the LSP power vs. the possible shift duration, for an average weekday, Saturday and Sunday in each season (the Sunday profiles are also valid for nights).

We observe significant seasonal and intraweek differences of the technical LSP. In summer the technical LSP power peak (dominated by air conditioning), is 45% higher than in winter, but available only for 15 to 60 minutes. Note that cooling is calculated only for 6 weeks in summer, so the LSP of a midsummer day shows a high peak, which is not available for all 13 summer weeks. In winter the LSP is dominated by room heating loads. Therefore a time shift in the range of several hours is feasible, but with a lower power level.

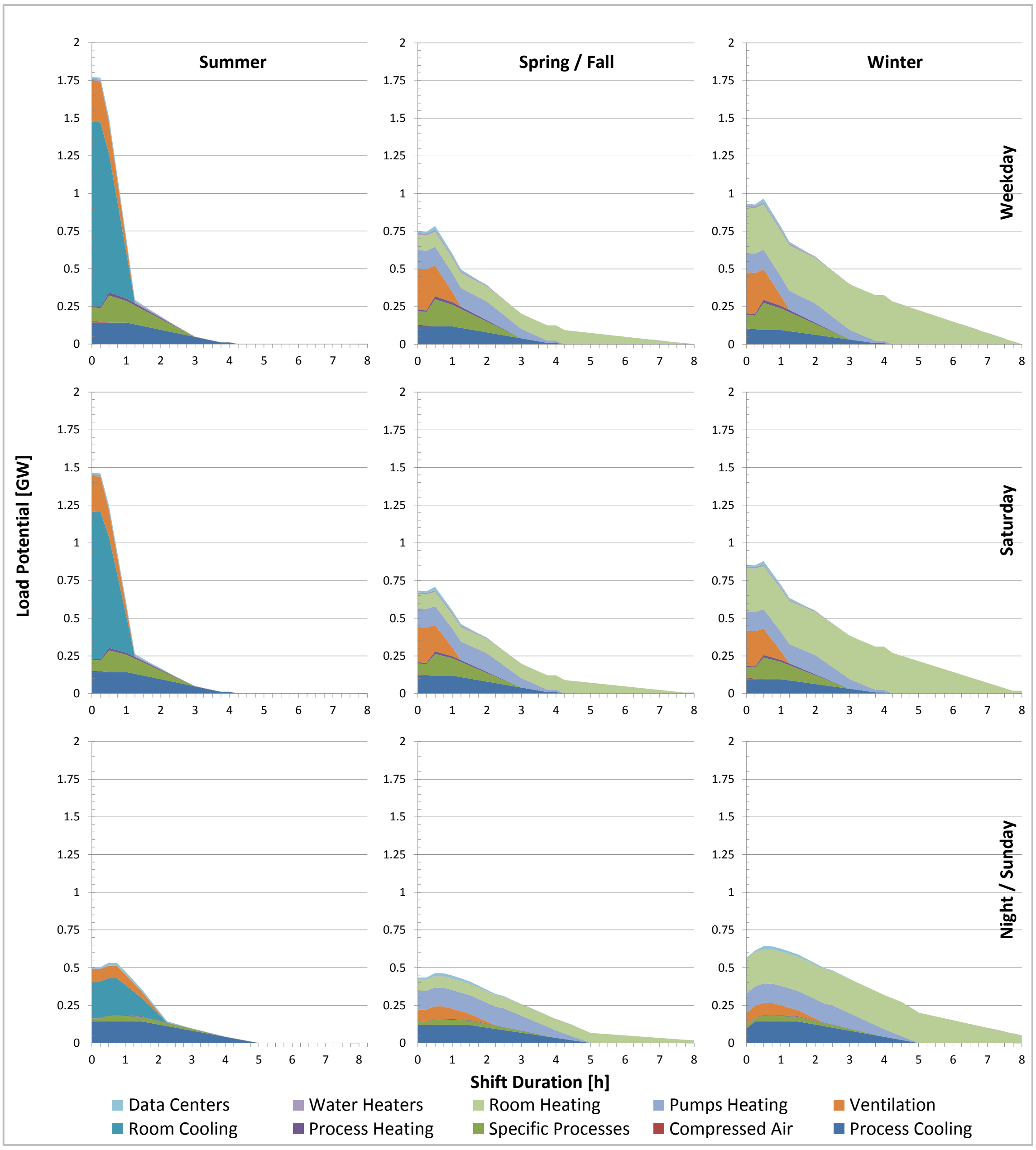


Fig. 4: Achievable load shift potential, split into usage groups, for a typical day of each season and weekday category. Sunday profiles are also valid for nights.

Effect of DR on Peak Consumption

To assess the economic viability of the DR we calculated the user benefit for the four tariff models described in the previous section. First we applied a specific tariff signal to the LSP and calculated the resulting energy cost. Then we shifted the energy consumption within the limitations given by the LSP curves, starting at the beginning of the peak pricing period, and applied the tariff model to the new LSP profile. The cost difference between initial energy cost and load shifted energy cost is defined as load shift profit.

We used the prices as listed in Tab. 6 and its footnotes, and made the following assumptions:

- Total load profiles are taken from [22] for summer and winter season. For spring and fall, no separate data is available, therefore we used the average of summer and winter profiles.
- Time resolution of the data is 15 minutes.

As an example, the peak flattening and broadening effect by using DR driven load shifting is shown in Fig. 5 for a CPP+ tariff model with a price spread of factor 1.5 and the roll-out scenario “Optimized”.

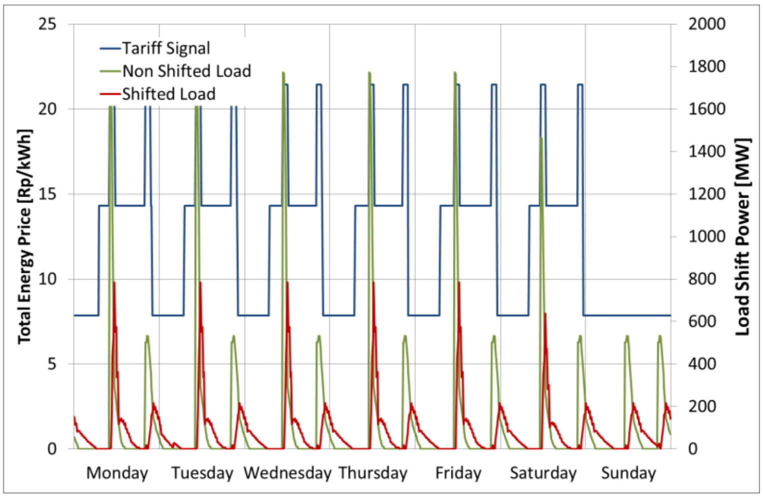


Fig. 5: Sample load, non-shifted and fully off-peak shifted. Responding to CPP+ tariff, for optimized roll-out scenario in summer time

Financial Load Shift Benefit

For the different size categories of utility sites, we calculated the expected financial benefit of load-shifting for each proposed tariff model per site. The results are displayed in Fig. 6 and show that especially sites with high energy consumption can profit from DR substantially, but for all site sizes, CPP+ results in the highest financial load shifting benefit.

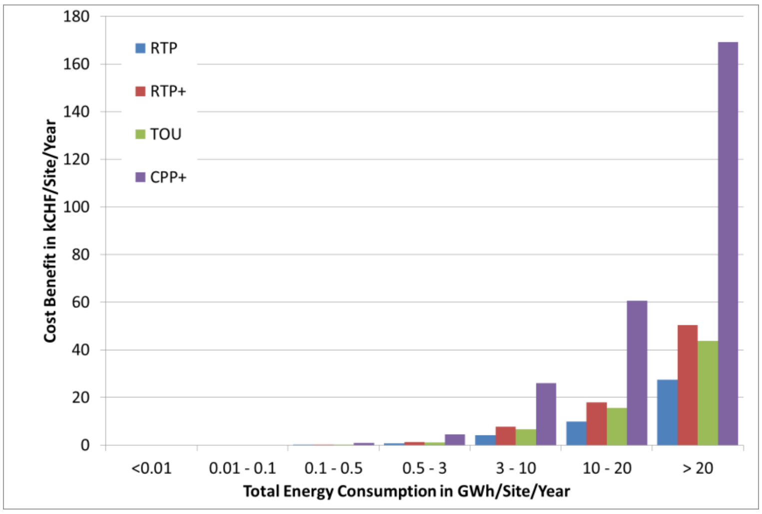


Fig. 6: Cost benefit per site and year for different total annual energy consumption categories per site with the optimized roll-out scenario

Discussion

In this paper iHomeLab has deduced the LSP for SSSB from existing energy consumption data. Our calculations show that the LSP for the service sector is higher than the one for the industry sector, with 20% of the energy consumption compared to 13%, given that the compound annual electrical energy consumption is of the same order for both sectors. The reason can be found in the fact that the services sector has less non-shiftable energy-intensive processes. Further we have shown that the distribution of site sizes and their associated LSP allow a highly cost-effective roll-out scenario. The Pareto principle is valid here too – i.e. targeting the biggest site sizes only, a prominent portion of energy consumption can be shifted already. The fact that most big sites nowadays are already equipped with the necessary building control systems and smart meter infrastructure again increases the financial benefit.

Modelling in more detail the LSP, we derived that it varies significantly per season, weekday and time of day. As expected, thermal loads offer the biggest potential for load shifting. In summer, these are ventilation and air conditioning, while in winter, it is the room-heating. Based on the load-shift characteristics of the relevant supplies, the total shift duration is much longer in winter than in summer. Moreover, smart load shifting distinctly flattens consumption peaks. This leads to more stability in the overall grid, and therefore also less necessity for grid expansion and upgrading. These findings are important for the residential sector too, because there, similar thermal loads are in use, like room and water heating and cooling. Moreover, the method of calculating the LSP for weekdays and seasons can be applied to the residential sector too, once the necessary fine-grained statistical energy usage data is available.

Providers of electricity and electrical energy services currently have a top-down approach to deal with peaks (direct load control or pooling). Our approach is bottom-up, based on sites, with price-induced load-shifting, and thus does not rely on enforcement, but on cost benefits. This will change the energy landscape, but of course, the pricing still lies within the power of the DSO and TSO.

Looking back critically to our research presented in this paper, we have made some assumptions, stated explicitly in the text above. These assumptions on the one hand limit the generality of the results, on the other hand lead to representative quantitative findings and also open the door for succeeding research work. We have used some LMF and arrangements of the potential groups different than those in literature (see “Data & Methodology”) because, to the best of our knowledge, no studies are available yet that target specifically our field of research, the Swiss service sector. To derive data for the services sector for 2012, several statistical sources were combined carefully. With a look at [16], our data is consistent. We have assumed that the mix of potential groups is homogenous among sites of different sizes. Of course, this is true for statements about the total summed electricity consumption in SSSB of Switzerland. If the focus is set to a specific single building, the actual mix of the available potential groups has to be taken into account and applied for LSP calculation. For the calculations we assumed the reduction of the weekday energy consumption to 80% on Saturdays, respectively 20% on Sundays. This has to be proven by additional specific research or studies. For financial benefit calculation we defined several specific tariff models: we parametrized the tariff models such that the total non-shifted energy consumption cost is cost-neutral. Even with this very conservative approach and small tariff spreading, remarkable effects were shown. Sensitivity analysis of tariff parametrization can be carried out in further research. Also, local production and storage has been considered for the total service sector in sum and not for a single building. For increasing directly energy autonomy of a single building, this can be studied separately in further research, as indicated in last phase research of [13] in order to flatten local grid bottlenecks.

In experiments with real-time energy market and real-time energy tariff models, oscillation effects of loads and tariffs have been reported (e.g. [29]). Although our approach uses a pre-defined price signal and does not include such short-time price adaptations, a feedback to the DSO about the expected energy consumption is foreseen. It has to be proven in practice that this coupling effect does neither prevent the proposed DR model from flattening the peaks nor lead merely to a peak shifting.

With the TOU or flat tariffs currently in effect, building control systems optimize costs by minimizing energy consumption, by switching loads “as late as possible” before effective use. With the results of our research, these systems can react to variable tariffs and still optimize costs. This will not minimize energy consumption, but rather shifts the electricity consumption towards times with high availability – without compromising comfort. Thus, it facilitates balancing energy consumption with the production.

DSOs in turn need to develop new tariff models helping them to flatten load peaks and to stabilize the grid effectively. This entails new products for balancing energy. The WARMup project [30], which does research in this field and pools local storage, is still running and might yield interesting results. However, it still uses a top-down approach and targets the currently available products for balancing energy. We consider the current definition (where balancing energy must be available at all times) as too rigid for SSSB and residential buildings with local renewable production and storage. New products must be more flexible in order to stimulate the switch from “production follows consumption” to “consumption follows production” actively. This is also a chance for a new allocation of roles in the energy landscape, by including renewable energies, while conserving the energy producers’ flexibility to guarantee the energy supply stability.

In the SSSB, with few installations a lot of experience can be gained. In the residential sector the market currently is bustling with several big companies boosting home automation (Google Nest, Apple HomeKit, and Samsung SmartHome). Moreover, data communication will be facilitated in near future by the glass fibre network roll-out pushed all over Switzerland also by the DSOs. Our research represents a remarkable contribution to this very active field of “smart homes” and consumer building control systems, and our results and methods presented in this paper can be transferred to the residential sector for the upcoming introduction of DR.

Acknowledgments

Without the expert knowledge and financial support of our partners from BFE, BKW, MeteoSchweiz, Siemens and Swissgrid, this work could not have been realized. These partners represent a complete set of stakeholders in the field of DR and therefore give iHomeLab a unique chance to study the LSP of SSSBs in Switzerland in depth.

References

[1] Y. Domigall, A. Albani and R. Winter, “Effects of Demand Charging and Photovoltaics on the Grid,” in *Proceedings of the IECON 2013-39th Annual Conference of the IEEE*, Vienna, 2013.

[2] S. Koch and M. Wiederkehr, “Lokales Lastmanagement,” 2010. [Online]. Available: http://www.iast.ch/lastmanagement_ch/. [Accessed 10 März 2014].

[3] Landis+Gyr, Dominic Lendi, “Micro Grids und deren Möglichkeiten,” Präsentation am 6. Smart Grid Circle, 2011.

[4] BKW & IBM, «FlexLast - Dynamisches industrielles Lastmanagement,» Bern, 2013.

[5] InfraWatt, “Potential der Schweizer Infrastrukturanlagen zur Lastverschiebung,” Bundesamt für Energie BFE, Bern, 2013.

[6] S. Koch, «Local Load Management and Distributed Generation,» 2010. [Online]. Available: http://www.eeh.ee.ethz.ch/en/no_cache/power/power-systems-laboratory/research/projects/view/detail/project/local-load-management-and-distributed-generation.html. [Zugriff am 17 April 2014].

[7] VSE, «Anbindung von Regelpools an den Schweizer SDL-Markt,» VSE / AES RP/PR – CH, Aarau, 2013.

[8] P. Palensky and D. Dietrich, “Demand Side Management: Demand Response, Intelligent Energy Systems, and Smart Loads,” *IEEE Transactions on Industrial Informatics,* vol. Vol. 7 , no. No. 3, pp. 381-388, August 2011.

[9] BKW FMB AG, Daniel Berner, “Halbzeit beim Projekt iSmart in Ittigen,” *Bulletin ,* no. 9/2011, pp. 18-20, 2011.

[10] BFE, IWÖ-HSG, BEAG, “IMPROSUME - The Impact of Prosumers in a Smart Grid based Energy Market,” BFE, Bern, 2013.

[11] J. Coquoz, Potential contribution of households’ demand response for integration of distributed solar photovoltaic in Switzerland, Zürich: ETH Zürich, 2012.

[12] econcept, “Smart Metering für die Schweiz – Potenziale, Erfolgsfaktoren und Massnahmen für die Steigerung der Energieeffizienz,” Bundesamt für Energie BFE, Bern, 2009.

[13] BFE, SUPSI, BEAG, “Swiss2G – Pilot- and Demonstration Project,” BFE, Bern, 2013.

[14] S. von Roon and T. Gobmaier, “Demand Response in der Industrie - Status und Potenziale in Deutschland,” FFE, München, 2010.

[15] Bits to Energy Lab, Ecoplan AG, Weisskopf Partner GmbH, ENCO AG, “Folgeabschätzung einer Einführung von «Smart Metering» im Zusammenhang mit «Smart Grids» in der Schweiz,” BFE, Bern, 2012.

[16] Prognos AG, Infras AG, TEP Energy GmbH, “Analyse des schweizerischen Energieverbrauchs 2000-2012 nach Verwendungszwecken,” Bundesamt für Energie BFE, Bern, September 2013.

[17] Hebling Beratung + Bauplanung AG, Polyquest AG, Bundesamt für Statistik BFS, “Energieverbrauch in der Industrie und im Dienstleistungssektor, Resultate 2012,” Bundesamt für Energie BFE, Bern, Juli 2013.

[18] Bundesamt für Energie BFE, “Schweizerische Elekrizitätsstatistik 2012,” Bundesamt für Energie BFE, Bern, 2012.

[19] M. Albadi and E. El-Saadany, "Demand Response in Electricity Markets: An Overview," IEEE, 2007.

[20] D. B. Aebischer, “Energy- and Eco-Efficiency of Data Centers,” DIAE / ScanE / Kanton Genf, Genf, 2003.

[21] A. Faruqui and S. George, "Quantifying Customer Response to Dynamic Pricing," *The Electricy Journal,* vol. 18, no. 4, pp. 53-63, 2005.

[22] A. Gunzinger, “Die Speicherfrage,” scs, Zürich, 2013.

[23] “iSMART,” 2014. [Online]. Available: http://inergie.ch/wie-funktioniert-es/ergebnisse-ismart/. [Accessed 13 3 2014].

[24] elcom, “Stromstatistik 2013,” 2014.

[25] S. Kaufmann, K. Künzel and M. Loock, "Customer Value of Smart Metering - Explorative Evidence from a Choice-based Conjoint Study in Switzerland," Energy Policy 53, 2013.

[26] A. Faruqui and S. Sergici, "Household Response to Dynamic Pricing of Electricity — A Survey of the Experimental Evidence," The Brattle Group Inc., 2009.

[27] BFE, «Schweizerische Elekrizitätsstatistik 2012,» Bundesamt für Energie BFE, Bern, 2012.

[28] Prognos, “Die Energieperspektiven für die Schweiz bis 2050,” BFE, Basel, 2012.

[29] “PowerMatching City II,” 2014. [Online]. Available: http://www.dnvkema.com/innovations/smart-grids/powermatching-city/default.aspx. [Accessed 17 März 2014].

[30] Misurio AG, “WARMup Phase 2 - Pilotversuch zur Verwertung der Flexibilität von thermischen Speichern in Gebäuden,” Bundesamt für Energie BFE, Bern, 2013.