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Assessing Local Power Generation Potentials of Photovoltaics, Engine Cogeneration, and Heat Pumps: The Case of a Major Swiss City

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Abstract: In this paper, we investigate the potentials of distributed generation (DG) in a medium-sized Swiss city. We show the role of private households in the sustainable energy transition process induced by Swiss energy policy. For the analysis, we define six scenarios that enable us to study the potentials and impacts of different combinations of DG technologies in terms of costs, CO_2 emissions, and amounts and shares of DG provided by non-industrial end-users (essentially private households and the services sector). Three variants are investigated, one with real electricity costs and CO_2 emissions, one with increased electricity costs (e.g., construction of new power plants), and one with increased CO_2 emissions (e.g., due to the planned nuclear phase-out in Switzerland). We find that non-industrial entities can play an important role as prosumers. They mitigate the need for centralized generation. Within a scenario where the non-industrial energy end-users install water-water heat pumps and photovoltaics, a total reduction of the gas procurement from the grid is possible whereas the electricity demand from the grid increases by 24%. This scenario reveals higher DG electricity costs in comparison to conventional electricity supply, but the total costs of energy supply decrease due to the elimination of gas supply, and the CO_2 emissions can be reduced by 68%.

Keywords: distributed generation; solar; PV; engine CHP; cogeneration; heat pumps; Switzerland

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1. Introduction

For energy system planning at the municipality level, it is of importance to know the technical conditions for satisfying the local energy requirements, ideally with distributed and renewable energy resources [1]. However, the question remains of whether the more distributed energy supply systems of this kind will outperform the traditional centralized supply systems in terms of energy needs, costs, and greenhouse gas (GHG) emissions. This study presents a framework to quantitatively evaluate both decentralized power generation and policy impacts in an urban setting.

As in most European countries, the energy sector in Switzerland is also undergoing a major transformation process. The country's decision to phase-out nuclear energy requires the development of new generation capacity. With the use of decentralized power and heat generation plants, such as solar photovoltaics (PV) systems, cogeneration (CHP) and heat pumps, even residential consumers can become active players in the energy sector (as "producer-consumers", or "prosumers" for short), thus making a contribution to the Swiss sustainable energy transition. As the Swiss Energy Strategy 2050 includes the support and expansion of renewable energies, prosumers too will experience an increase in significance. The share of prosumers, and thus the local energy generation potential of the aforementioned technologies, is calculated in this study by using the example of a major Swiss city. The two research questions of this study are: (1) What is the level of self-supply of a private household's electricity and heat demand by means of distributed energy resources (DER) such as PV systems, CHP and heat pumps in a medium-sized Swiss city? (2) What changes in energy purchase volumes, costs, and CO_2 emissions are associated with the use of the DER mentioned?

In the following, we investigate how the electricity and gas procurement of the various consumer groups in a city changes if the currently prevailing supply from the electric grid and heat generation by using a conventional gas boiler is substituted by distributed generation (DG) technologies, such as solar PV systems, engine-CHP, and heat pumps to meet the private household's own energy needs. In cogeneration systems, high-temperature heat first drives a gas or steam turbine-powered generator. At smaller scales (typically < 1 MW), a gas or diesel engine may be used instead of a turbine. The term "engine cogeneration" or "engine-CHP" is thus often used for characterizing such small-scale CHP plants. We also analyze the investment and operating costs as well as the CO_2 emissions associated with the use of DG technologies.

The aim of the study presented here is to show that (and how) DG power plants can make a major contribution to both reduced electricity procurement from the centralized energy supply system and a reduced environmental burden measured in GHG emissions. The focus of our investigation, which is based on detailed data obtained for a major Swiss city, is on the effects of a consistent and comprehensive use of various DG technologies in the buildings of a city. For simplicity reasons, it is assumed that specific technology combinations are applied in all non-industrial buildings. Irrespective of where in the city the demand for heat and electricity is, and what size the non-industrial building has, the type of technology used for heating, and if applicable, also for electricity generation, is assumed to be the same. It is neither examined in how far different buildings could actually use the DG technologies nor is the option of storing excess electricity or heat considered. Still, this type of analysis seems novel and is attractive for energy planning due to its reduced computational effort. It gives a first idea of the potentials that DG hold, and can thus help local policy-makers and urban planners alike. Previous research on the use of DG technology in Switzerland has often focused on rural (agglomeration) areas only [2], has investigated single villages only [3], has investigated single renewable energy technologies used in an urban environment [4], has analyzed technical DG energy potentials for a specific urban setting only [5], or has taken a wider (typically a Swiss national or cantonal) holistic system planning perspective [6,7].

In order to assess the economic and the environmental potential for a change in electricity and heat production of a city by a widespread adoption of DG technologies, the impacts of the widespread use of these technologies are simulated by comparing six different scenarios of DG use with a reference scenario. The scenarios considered are defined based on different combinations of the investigated technologies (PV systems, engine-CHP, two types of heat pumps). In the reference scenario, the use of a conventional gas-fired condensing boiler for heat generation is the benchmark technology, plus electricity from the grid. The model has an hourly resolution and reflects typical load curves for heat and electricity consumption as well as temperature and solar irradiation in the city investigated, based on historical data available for a marker year.

The parameter values in the scenarios investigated were altered in such a way that different variants of the scenarios can be calculated and analyzed as well. Specifically, this calculation of variants allows an assessment of the effects of a possible increase in CO_2 emissions from electricity purchases (e.g., the simulated phase-out of nuclear energy), or the impact of a possible increase in the gas and electricity purchase prices.

By addressing the uncertainty regarding intermittency, the present paper introduces a comprehensive, yet simplified and complementary model, for localized energy planning purposes. It is aimed at integrating the analysis of technological and economic feasibility with environmental considerations (the effect of a changing power and heat generation mix on greenhouse gas emissions from electricity use). Existing energy system models, such as e.g., TIMES, allow an in-depth analysis of complex energy systems with various constraints along the energy value chain (from primary resources, over electricity production, transport, distribution, conversion into supply) [8]. However, these are often very complex and specific or are not available free of charge (in contrast to e.g., HOMER [9]), and thus often of very limited use to practitioners. A useful review on modeling tools for energy and electricity systems with large shares of (distributed) variable renewable energy sources (VRES) is provided in [10].

The remainder of this paper is structured as follows. Section 2 provides an overview of similar studies and literature related to this work. In Section 3, the Swiss energy sector is described, including the current situation regarding power and heat production and sales in Switzerland, the most important types of power generation, and the future development of the Swiss energy sector in the context of the Swiss Energy Strategy 2050. Section 4 reports on the data used for the calculations, characterizes the technologies considered (solar PV, engine-CHP, heat pumps) in terms of their power generation potential, and presents the scenarios used for the model-based analysis. Section 5 shows the effects of implementing different DG technologies in the considered scenarios. After a presentation of the model, the results are presented separately by variants and set in relation to the research questions. Section 6 concludes and gives an outlook on some possible avenues for future research.

2. Related Literature

Over the years, several studies have focused on the use of distributed generation technologies in Switzerland, using different mode types and having different foci. In the following, a brief overview is provided that aims at contrasting our approach and scope of analysis with those of the others.

Andersson et al. [11] address the future development of the Swiss Energy sector. In their study, different options for a sustainable future design of the Swiss energy system are analyzed. The main objective of their analysis is the compliance with climate policy objectives, the successive phase-out of nuclear energy, and the security of supply in Switzerland. Technological and ecological approaches are both examined. The analysis is carried out under the premises that the climate change targets will be adopted throughout Europe, that a pan-European electricity market with an integrated electricity network will emerge in a foreseeable future, and that dependence on electricity imports will be reduced. In the study, the following findings are obtained: the simultaneous reduction of CO_2 emissions from the energy system (decarbonization) and a phasing out of nuclear energy would be complicated but will help to establish a sustainable future Swiss energy system. In addition, Switzerland, with its numerous hydro reservoirs and pumped storage hydro power plants, is in a favorable position for the expansion of renewable energies, which is necessary to compensate for the intermittent production from variable renewable energy sources (VRES). Due to the increased competitiveness of batteries, the decentralized production and consumption of electricity will be empowered and thus limit the need for the expansion of supply networks. Still, the current levelized costs of electricity (LCOE) is found to increase in the future development. The key message of the study is that the transformation of the energy system is feasible both technologically and economically, but only if all the actors are indeed willing and able to cooperate with each other.

Dyllick-Brenzinger et al. [12] also consider the proposed Energy Strategy 2050 of Switzerland. They summarize the results of a study by the Energy Center of the École Polytechnique Fédérale de Lausanne (EPFL) that dealt with the feasibility of the Swiss Energy Strategy 2050. The focus of their study is on the feasibility of the development of PV power plants in combination with storage power plants, in order to compensate for the future successive phase-out of nuclear energy. Switzerland already has a large energy storage capacity today. In the study, a scenario analysis investigates what proportion from renewable energy production can be stored by the existing hydro storage power plants. In addition, security of supply aspects is considered. The study delivers the following main results: the rapid expansion of solar PV is leading to storage bottlenecks and requires an expansion of storage capacity. This expansion would not be able to compensate for the vanishing nuclear energy, even if the expansion of PV is supplemented by two additional gas-fired power plants. In addition, the expansion of renewable energies and the resulting increasingly fluctuating energy supply will lead to bottlenecks in the Swiss electric grid. In order to ensure a sustainable energy supply in the future, a higher energy efficiency, as well as a stronger co-operation with European countries is thus paramount.

Prognos [13] deals with mechanisms for the integration of CHP technology. The aim of this study is to determine the future potential of CHP plants for the simultaneous production of electricity and heat in Germany. The analysis of the expansion potential of CHP plants is performed by a scenario-based analysis under the premise that no electricity is displaced by renewable energy. The study provides the following key results: Germany holds a large potential for CHP plants if heat storage is used. However, the current situation in Germany hardly allows for a cost-effective operation of large-scale CHP plants. Small-scale CHP plants are only economical if the generated electricity covers the own demand and only above a certain size. Therefore, the study gives the recommendation to improve the framework conditions for CHP in Germany. The introduction of additional measures of support is desirable, and electricity-oriented operation of the CHP is found to be useful in order to take advantage of the CO_2 reduction benefits. In addition, the introduction of binding CO_2 reduction values for buildings in Germany, and/or the introduction of a CO_2 tax, would further supplement this technology.

Wagner et al. [14] show the impact of the increased use of heat pumps (HP) in the heating of buildings in Germany. The impact is shown by comparing HP with other popular heat-producing technologies, in particular its primary energy consumption and the emission discharging behavior, in 2008 and future frameworks. Following this, two scenarios are created—one with and the other without an increase in CO_2 emissions from electricity generation in Germany. The study reveals that the use of HP within the operation of the general German power mix was already leading to primary energy saving benefits of between 25 and 50% in 2008, and that these primary energy saving benefits would further increase with the increased efficiency of the German power plant fleet. Moreover, the environmental performance of the HP improves with the increasing proportion of renewable energies in the electricity mix. According to their study, HP with a seasonal performance factor of 2.0 was already leading to CO_2 savings compared with traditional technologies for meeting the heat demand. The use of HP leads to both a contribution to the global environmental protection as well as to lower local emissions. Note, however, that their study does not differentiate between different types of heat pumps.

Yazdanie et al. [2] present a framework in order to quantitatively evaluate decentralized generation and storage technology (DGST) performance and policy impacts in a rural setting. To this end, a cost optimization modeling approach is used in order to assess the role of DGST in the future energy systems planning of a rural agglomeration in Switzerland. Evidence is found that the self-supply can be strongly increased by using energy storage technologies, such as seasonal heat storage units connected to the DH network, daily heat storage for buildings, and daily battery storage for buildings. By introducing a small hydro power plant serving the community, an increased PV capacity of 27%, compared to the decentralized scenario without storage, is enabled. Moreover, the use of DGST leads to a significant reduction in the electric grid usage, allowing the community to become largely self-sufficient. In the decentralized technology scenario, import reductions of up to 68% can be realized, and adding an efficient storage technology is shown to reduce imports by an astonishing 86% by 2050. Moreover, it is observed that while investment decisions in small hydro (e.g., run of river) are robust against cost variations, heating technology investments are, expectedly, quite sensitive to oil and grid electricity prices. Furthermore, the introduction of carbon pricing is shown to effectively mitigate local fossil fuel emissions.

Orehounig et al. [3] deal with the introduction of decentralized energy systems in a village in Switzerland aiming at energy autarchy. In order to meet this ambitious goal, both remodeling of the current energy system and deep retrofitting of the building stock are necessary. The energy hub concept is applied, which enables the optimization of energy consumption during planning and operation. The decentralized energy technologies covered, which are investigated also with regard to their environmental performance including CO_2 savings, are solar PV, biomass, and small hydro power plants. This study concludes that in order to make use of the entire potential of decentralized renewable energy technology, it is essential to combine it with energy storage technologies. The results show that it would be possible to reduce CO_2 emissions by 86%.

Last but not least, in a recent major study developed on behalf of the Swiss Federal Office of Energy (SFOE), named "Energy Perspectives 2050+ (EP 2050+)" [7], a net-zero emissions scenario (ZERO) has been investigated, in order to show how to develop an energy system that is compatible with the long-term climate goal of net-zero greenhouse gas emissions by 2050. At the same time, the aim is to ensure a secure energy supply. Several variants of this scenario were considered, differing in their combination of technologies and the speed of the renewable energy transition in the electricity sector. The study updates a previous one of 2012 [6].

3. The Swiss Energy Sector and Policy

3.1. Status-Quo: Production and Consumption

The Swiss power generation mix consists mainly of hydropower and nuclear energy, jointly accounting for some 92%. Only 8% of the total electricity production results from cogeneration plants, wood or biogas combustion, solar PV, and wind turbines. In 2019, hydropower had the largest share, with around 56.4%, followed by nuclear power with 35.2%. The remaining 8.4% is composed as follows: conventional thermal power and district heating power stations, with a share of 4.2% (including CHP), furnaces with wood, biogas plants, solar PV plants, and wind turbines, accounting for 4.2% of the total production [15].

Due to the current power generation mix, the electricity generated in Switzerland has a very low CO_2 footprint compared to those of other countries. According to the Swiss Energy Foundation (SES) the power generation mix of the four largest Swiss electricity producers entailed 149 g CO_2 equivalents (CO_2eq) per kWh in 2019 [16] (CO_2eq are a measure for all greenhouse gases including CO_2, methane, nitrous oxide, etc.,). In comparison, the German power generation mix entailed 401 g CO_2 per kWh in 2019 [17]. The emissions of Swiss natural gas amount to 228 g CO_2eq per kWh in 2019 [18].

In 2019, the largest share in total electricity consumption was attributable to transportation (38%), followed by the private household (27%), industry (18%), and the service (16%) sector. The statistical difference also includes the agricultural sector, accounting for 1% of total consumption [15]. Final electricity consumption in the same year amounted to 57,198 Gigawatt hours (GWh), which implies an increase of approximately 12% compared to the 1999 level, but a decrease of approximately 1% if compared to 2018 [15].

The entire Swiss energy industry is in turmoil. After the nuclear accident at the nuclear power plant (NPP) Fukushima Daiichi in Japan in March 2011, the Swiss government decided to phase out nuclear energy [19,20]. If all nuclear power plants in Switzerland are shut down as planned, almost 40% of the generation capacity will be gone, requiring major restructuring of the existing power generation mix. Renewable energies, in particular for DG, are expected to play a major role.

3.2. Power Generation from the Swiss Technology Mix

As already mentioned above, the two main sources in electricity supply are hydropower and nuclear energy (92%). As of 31 December 2019, the Swiss Hydropower Park produced a combined average of 36.6 TWh per year, comprising 674 central power plants with 48.7% hydroelectric run-of-river power plants, 47.0% hydro storage power plants, and 4.3% pumped hydro storage power plants [15]. The Energy Strategy 2050, which includes plans for the future development of the Swiss energy supply (explained in detail in Section 3.3), plans an installed hydropower capacity of 37.4 TWh by 2035 and 38.6 TWh by 2050. Switzerland aims to reach this goal by upgrading existing power plants and by constructing new hydroelectric power plants, while at the same time taking ecological requirements into account. The expansion will be supported by various measures—such as cost-based feed-in renumeration for new hydropower plants, investment grants for the expansion and retrofitting of existing plants, and a general improvement of the framework conditions for hydropower plants. Besides, many operating concessions are about to expire and thus due for renewal. The expansion of generating capacity from hydropower was investigated by the Swiss Federal Office of Energy (SFOE) in 2019. This study reveals a conflict of interest between the usage of hydropower and protection of the ecosphere. Even though it is likely that the hydropower capacity goal of 37.4 TWh will be met by 2035, reaching the goal of 38.6 TWh by 2050 remains unclear. The set goal for 2050 is strongly dependent on the economic framework for hydropower. Rising electricity and CO_2 prices raise the competitiveness of hydropower and thus favor such investments [21,22].

Nuclear energy, as the second-largest component of the Swiss electricity supply, had a share of around 35% of the total Swiss electricity production in 2019 [15]. As previously mentioned, the Swiss federal government decided on the nuclear phase-out as a reaction to the Tsunami-induced nuclear accident at the Fukushima Daiichi nuclear plant. No new nuclear power plants are to be built in Switzerland [22]. At present, in 2021, there are four active nuclear power plants (NPPs): Beznau 1 and 2, Gösgen and Leibstadt. A fifth NPP and one of the oldest in the world, Mühleberg, was shut down in 2019 [23]. In addition, on 12 August 2014, the Swiss National Council decided that the operators of nuclear power plants are required to submit a long-term vision for the further operation, two years before reaching 40 years of operation, to the Swiss Federal Nuclear Safety Inspectorate (ENSI). ENSI may extend their term for another 10 years, and has recently commissioned a study on the flood risk of NPPs in Switzerland in light of the ongoing climate change. According to the long-term operational concept, the remaining four NPPs can be operated for at least 40 years, or for as long as they meet the legal safety requirements [19].

3.3. Future Development: Energy Strategy 2050

The planned phasing out of nuclear power will lead to a major reduction of installed generating capacities from conventional power plants. In order to meet the electricity demand of the future, a reorientation of Switzerland's energy strategy is thus necessary. The Swiss Federal Council therefore formulated a new energy policy, the so-called "Energy Strategy 2050", back in 2013 [24]. The initial package of measures, included in the Energy Strategy 2050 and entered into force in 2016, entails measures for increasing energy efficiency, measures for the development of renewable energies, changes in the law on nuclear energy, and measures related to reinforcing the electric grid [25].

In regard to the measures for the development of renewable energies the following aspects are taken into account: the existing feed-in remuneration scheme for operators of new facilities producing electricity from solar PV, wind, geothermal energy, and biomass will be in use until the end of 2022. Besides, the feed-in renumeration scheme will be structured in a more market-oriented way, so that the electricity produced can also be directly sold on the market. Capital grants for small and large PV systems, as well as for large hydropower plants, and the retrofitting (and often expansion) of existing hydropower plants, will be made until 2030. As the electricity price sometimes falls below the production costs of the majority of Switzerland's hydropower plants, a market premium will be offered to operators of large hydropower plants until the end of 2022. The electricity production from both renewable energies and environmental protection is of national interest and has to be balanced. For further enhancement of renewable energies, the corresponding licensing procedures will be shortened [26].

In 2015, by signing the Paris Agreement on Climate Change, Switzerland committed itself to halving its greenhouse gas emissions by 2030 compared to the level of 1990. The existing Federal CO_2 Act still needs to be revised by the Swiss Federal Council in order to include the time period after 2020. Switzerland aims to reach the set goal of the Paris

Agreement of reducing the risks and impacts of climate change by limiting the temperature increase to 1.5 °C above pre-industrial levels (UNFCCC 2015 [27], Art.2 (1.a)) by a resolution of the Federal Council in 2019. This resolution contains the reduction of net greenhouse gas emissions to zero by 2050 [24].

The ongoing revision of the Federal Electricity Supply Act aims for the full Swiss electricity market liberalization and the adaption of the Federal Energy Act. The latter focuses on measures supporting the market liberalization and supply security through raising the attractiveness of investments into domestic renewable energies [24].

The issue of extending the current energy supply and improving security of supply under the Energy Strategy 2050 is of particularly high importance for the further analysis in our study. It emphasizes the need to analyze the local power generation potential from renewable energy sources and decentralized energy-efficient fossil fuel production such as PV systems, CHP, and heat pumps. By using the example of one major city, we investigate how far the consistent use of decentralized power generation and eco-friendly heat generation technologies can contribute to achieving the CO_2 reduction targets.

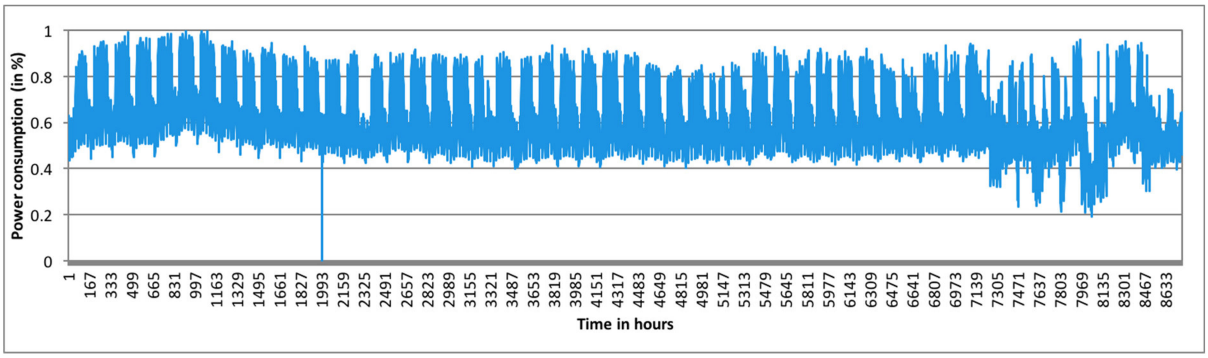
4. Calculation of the Local Power and Heat Generation Potentials of a City

4.1. Data Used

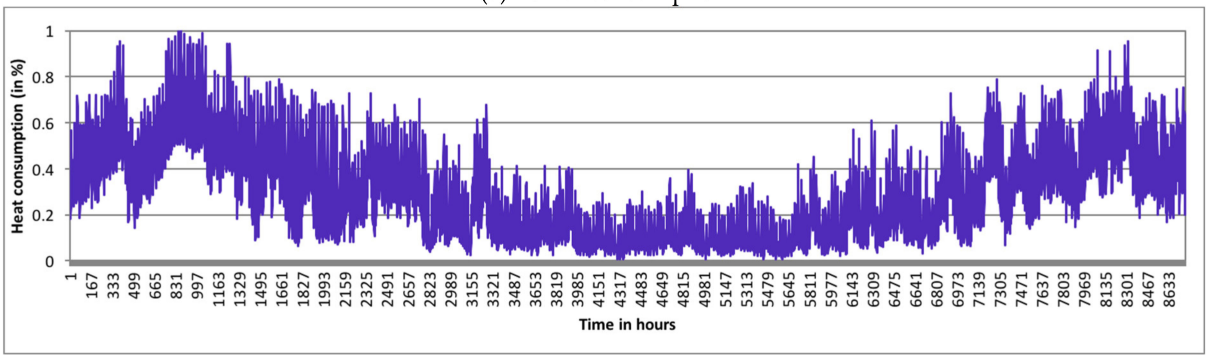
The following calculations of local energy potentials are based on data obtained from Rechenzentrum Wehr GmbH (RZVN). RZVN has engaged in grid calculations for more than 60 years, mainly for municipal companies in Germany and Switzerland, and is therefore endowed with a large data pool [28]. The delivered file of data includes a medium-sized Swiss city (Cfb climate according to Köpper-Geiger) with more than 100,000 inhabitants: electricity and heat demand of all consumers of energy of this city in the year 2012, excluding the industrial sector. The total electricity demand amounts to 761.6 GWh and the total heat demand amounts to 1509.4 GWh (without industry) in this city in 2012. The electricity and heat consumption are summed up per building within the delivered data file. Hence the average electricity and heat energy demand per building can be calculated. In addition, a solar cadaster exists to derive the potential performance of PV systems per building in kilowatts (kW). The buildings in the city are categorized into 35 different consumption classes according to their electricity demand.

The exact load curves of electricity and heat demand per building are not known. However, the entire electricity and gas consumption of the city is accurately measured (as mean values per hour). Therefore, the graph can serve as a load profile for the buildings. The load profiles were standardized for electricity and heat consumption. In addition, the corresponding curves of the solar irradiation and the temperature in the city for each hour of the year 2012 were taken into account within further calculations (see Figure 1a–d). Using these curves, the electricity and heat consumption patterns can be determined for each residential building type per hour. The hourly electricity and heating demand results from the multiplication of the normalized curves with the average electricity and heat power consumption of each building.

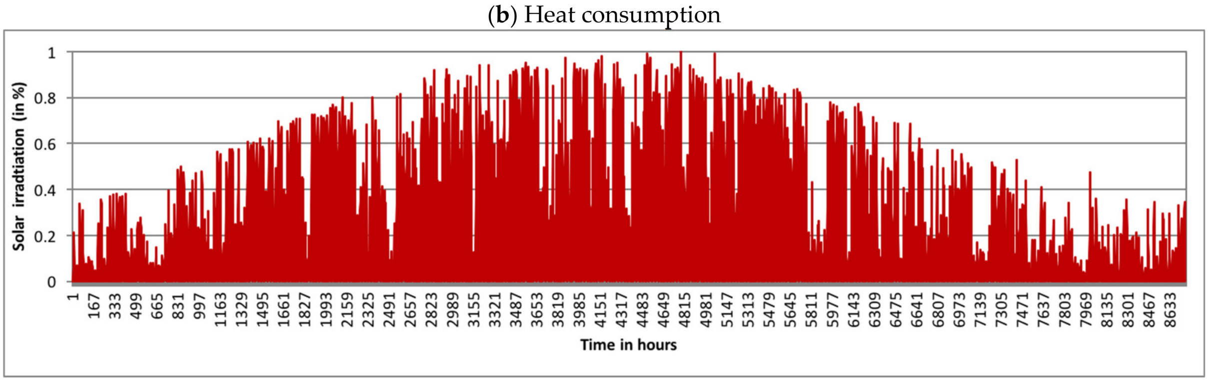
As the data delivered by RZVN is the exact electricity and heat demand data for the year 2012, also the temperature and solar irradiation data are for the year 2012. Other data applied in the conducted calculations, including technology costs, feed-in tariffs for surplus electricity, etc., are for the year 2019, thus enabling an accurate picture of the DG technology mix and the effect of the individual technologies in the energy system.



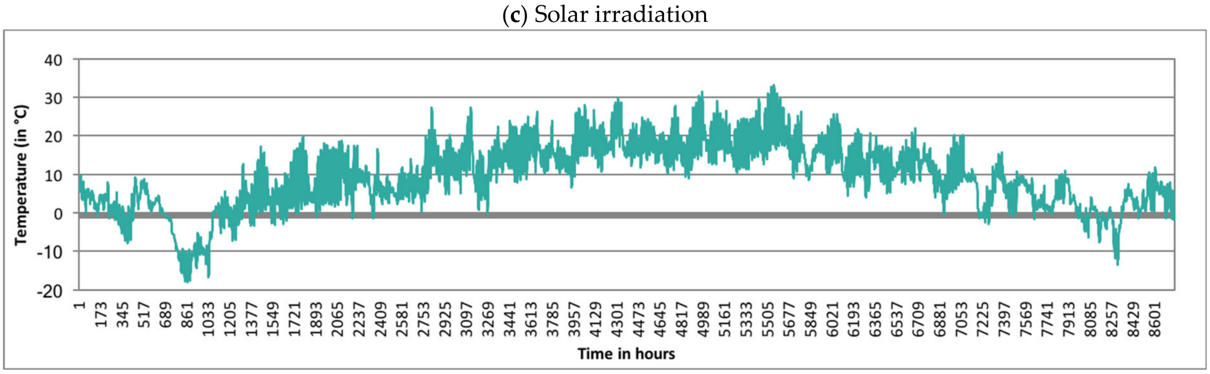
(**a**) Power consumption



(**b**) Heat consumption



(**c**) Solar irradiation



(**d**) Temperature

Figure 1. Hourly power and heat consumption, solar irradiation and temperature of the investigated city, 2012. Source: own illustration, based on data from RZVN (only available for that year). (**a**) Power consumption; (**b**) heat consumption; (**c**) solar irradiation; (**d**) temperature.

4.2. Technologies Considered

The electricity and heat energy requirements in each building can be met by using different technologies. In the present study, the technical and economic potentials of solar PV systems, combined heat and power (CHP), and heat pumps (HP) are analyzed. In particular, the amounts of electricity and heat are determined that can locally be generated within the city limits, as well as the resulting costs and greenhouse gas emissions. The specific technologies used in the simulations, and the support policy measures applied in Switzerland are described in some detail in what follows.

In order to compare the considered local generation technologies for heat and electricity with conventional supply, the reference scenario is set by assuming that the total electricity demand of consumers is covered by an external producer, and that the heat demand is covered by means of a standard gas-fired condensing boiler (GCB). GCBs have the largest market share in the heating sector and are, therefore, used as the reference heating technology [14]. In a GCB, in contrast to low-temperature boilers, the heat of the condensation water vapor from the resulting combustion gases is used as well, increasing the energy efficiency that can be achieved [29]. For the calculations, it is assumed that the investment costs of GCBs equal the average costs calculated for each capacity class based on the information provided by various major heating system manufacturers (such as Viessmann, Buderus and Vaillant). We assume that the installation costs of GCBs correspond to the investment costs. In addition, annual operating costs and maintenance costs are assumed to be 2% of the total investment costs.

Electricity can be generated from solar energy by PV systems. The yield of a PV plant is maximized when the proper alignment and slope is selected for each site. In Switzerland, the average annual solar irradiation amounts to some 1300 kWh/m^2, which is significantly higher than the average solar irradiation in the neighboring country Germany of 1100 kWh/m^2 [30]. The CO_2 emissions during the operation and decommissioning of the PV system are negligible, since they only account for some 5–8% of the total emissions [31]. If, however, the production of solar modules is included, the literature gives values for CO_2 emissions of 50–100 g/kWh [31]. In 2019, the number of installed PV systems in Switzerland was 98,340, resulting in a total installed capacity of 2498.1 MW. These plants generated 2177.7 GWh of electricity in total in 2019 [12]. The diffusion of solar PV in Switzerland is still significantly lower than in its four neighboring countries (Germany, Austria, Italy, and France), especially compared to Germany and Italy [15]. In 2019, for instance, the per capita electricity production from solar PV in Switzerland amounted to 267 kWh, which is less than half of the value in Germany of 572 kWh [32]. In Switzerland, solar PV has been promoted by several policy instruments. Since 2018, PV systems with more than 100 kW$_p$ of installed peak capacity can benefit from a feed-in tariff (FIT) or a capital grant, whereas smaller PV installations can benefit from capital grants only [33]. For the subsequent calculations, it is assumed that the price of a crystalline solar module and its installation is €1500 per kilowatt peak (kW$_p$), based on the average price of PV modules in Germany in 2019 of €1515.56 per kW$_p$ [34]. In addition, annual costs, e.g., assumed for insurance and meter rental, are assumed to amount to 2% of the total annual costs [35].

Cogeneration plants use the technology of combined heat and power (CHP). This allows the generation of electricity and heat as by-products [36]. CHP can be installed in industrial, commercial, and residential buildings [36]. The operation of the CHP depends on the electricity or heat consumption of the consumer. Usually, the heat consumption is used as a reference variable, since the produced excess electricity can be fed into the power grid. In this mode, the electric power of the CHP is determined by the heat demand. In the electric-driven mode, the CHP unit cannot, or only at high costs, make use of the excess heat produced [36]. To ensure a high utilization of the CHP plant, the sizing of the plant should be such that it covers 20% of the nominal heat output, whereas the remainder is covered by a conventional boiler [36]. Advantages of this method are the low energy losses within the generation due to a high utilization level, the low emission output, and the fact that the grids can be relieved by local generation [36]. In addition, CHP could function as a so-called "virtual power plants" to compensate for fluctuation caused by the expansion of renewable energy [36]. The electrical efficiency of a CHP plant depends on its size. Natural-gas-fired CHP plants have an average electrical efficiency of 38% and a thermal efficiency of 49%, resulting in an overall efficiency of 87% [37]. In the following investigation, the electrical efficiencies are calculated as a function of the declared capacity of the CHP, using the functions of the CHP characteristics 2014/15 of the German *Arbeitsgemeinschaft für sparsamen und umweltfreundlichen Energieverbrauch e.V. (ASUE)* [37]. We assume that the thermal efficiency of the CHP can be calculated from the difference between the total and the electrical efficiency. In 2019, 48 CHP plants with a capacity of more than 1000 kW each (mainly used in industry), and a total installed capacity of 401 MW, generated a total amount of 1399 GWh in Switzerland. Furthermore, 856 CHP plants with a capacity of less than 1000 kW each, and a total installed capacity of 137 MW, led to a total electricity production of 532 GWh and a total heat production of 690 GWh in 2019 in Switzerland [15]. The cost of CHP plants assumed in the subsequent investigations are based on the CHP characteristics 2014/15 of ASUE as well, as this source describes the total cost of small-scale CHP plants very accurately. The indicated prices of 2015 have been multiplied with the corresponding prevailing inflation rates in Germany (2016: 0.5%, 2017: 1.5%, 2018: 1.8%, 2019: 1.4% [38]) in order to obtain estimated prices for CHP plants in 2019. More specifically, the costs are calculated as follows: first, the specific module cost in Euros (€) per kilowatt-electric (kW_{el}) are determined by using the functions of the CHP characteristics provided by ASUE by power plant size. By multiplying this result with the nominal plant capacity, the module costs are calculated. In addition to the module costs, there are installation and other costs, which are determined by ASUE as a share of the typical CHP system costs. Likewise, specific maintenance costs per kWh of electricity produced are calculated and made available [37].

Electric heat pumps withdraw ambient heat and take the heat to a higher level for usage in a heating system. 100% of the consumption energy arises from 75% ambient energy and 25% electrical energy [39]. The efficiency of heat pumps can be measured by the coefficient of performance (COP) and the seasonal performance factor (SPF). The correlation between heat output and consumed electric power at a given operating point is described by the COP. However, since this only reflects a particular operating point and does not reflect all operating points in one year, an additional measure for the efficiency of a heat pump is required. Therefore, the SPF is used, which characterizes the relationship between the generated heat energy and electrical energy in a year [39]. The higher the SPF, the more efficient is the heat pump considered. However, since the SPF is determined first by the difference between ambient and heating temperature, and only second by the behavior of the user, a value range is considered. In the following calculations, the production potentials are examined for two different types: air/water heat pumps (AWHP) and water/water heat pumps (WWHP). AWHP use ambient heat from ambient air, whereas WWHP use ambient heat from reservoirs like groundwater or surface water from lakes or rivers [39]. The SPF of AWHP typically ranges between 2.8 and 3.5, whereas WWHP feature a higher value range of 3.8 to 5.0 [39]. In 2008, assuming the German power mix, an SPF of only 2.0 emits less CO_2 compared to heat generation by a gas-fired condensing boiler [11]. In 2019, 327,114 heat pumps with an electric motor were installed in Switzerland. In total, the installed capacity amounted to 4742 MW, had an electricity consumption of 2170 GWh, an ambient heat consumption of 5000 GWh, and a generation of 7170 GWh [15]. In Switzerland, no specific funding scheme for heat pumps is currently in place. To use realistic specifications and costs, average values for each performance class from the information provided by relevant and major technology manufacturers (including Dimplex Glen, Vaillant, and Viessmann) were calculated. For the AWHP, for example, the average calculated investment costs for an installed capacity of 6 kW, excluding VAT, amount to €8529. The largest plants offered by the manufacturers considered can be used for capacities of up 27 kW, and have a calculated average price of €23,692 (excl. VAT). We assume that the costs for the transport and installation of AWHP are in the same order as the costs of the heat pump itself. Therefore, the costs are doubled. In addition, annual operating costs of 2% of the total investment costs are assumed. The system prices of WWHP are lower compared to the investment costs of AWHP. Thus, the calculated average purchase price for a WWHP with a capacity of 8.5 kW amounts to €5791 (excl. VAT). Generally speaking, the cost components of WWHP are higher due to further cost components like development costs, such as the drilling of a conveyor fountain for groundwater [40]. For the calculations that follow, we assume that the costs of a well bore correspond to the acquisition costs of each asset. Moreover, it is assumed that the costs for transport and installation correspond to the costs of purchasing the system concerned. The acquisition costs are thus tripled. The operating costs are assumed at 2% of the total investment as well. For both types of heat pumps, we assume that once the required energy for each building exceeds the maximum average energy, then multiple pumps are installed until the energy demand is fully covered.

The three technologies for electricity and heat generation introduced differ from conventional, centralized production methods in terms of comparatively low CO_2 emissions and low fuel consumption, and can thus help to achieve the climate protection goals of the Swiss energy policy. Here, the technologies are complements in several aspects: the combined use of CHP and PV systems leads to a smoothing of the seasonal generation flows, since CHP units mainly generate electricity in the winter months when there is low solar irradiation, while solar PV units achieve their highest yields during the summertime. Furthermore, CHP as an instantly controllable electricity generation technology is an energy-efficient way to balance the fluctuating PV power generation and thus to stabilize power supply. The installation of CHP units combined with the expansion of heat pumps leads to a relief of the electric grid and helps to provide the additional power required by the HP. In particular, as CHP units have their production peaks on cold days when the electricity demand of heat pumps is highest. In Switzerland, the use of these low-carbon plants is promoted indirectly: fossil fuels are subject to a CO_2 tax, the rate of which depends on the carbon contents of the fuel (amount of emitted CO_2 per ton). Since 2018, the CO_2 tax is CHF 96 per metric ton [41] (or €86.29 per t, using an average exchange rate in 2019 of CHF 1 = €0.8989 [42]).

4.3. Scenarios Considered

In the following, the scenarios for the calculations in Section 5 are described. As shown in Table 1, the scenarios are made up of various combinations. The Reference Scenario (RS) is used in order to enable a benchmarking with a situation where the only distributed generation technology is a condensing boiler for heating.

Table 1. Technologies and combinations considered in the different scenarios investigated.

Technology	Ref.	1	2	3	4	5	6
PV	-	x	x	x	x	x	x
Engine-CHP	-	-	x	-	-	x	-
HP	-	-	-	WWHP	AWHP	-	AWHP
CB	x	x	-	-	-	x	x

CB = condensing boiler; CHP = combined heat & power; PV = solar photovoltaics; WWHP = water/water heat pump; AWHP = air/water heat pump.

The RS, considering a condensing boiler (CB) only, is set up to describe the case of non-industrial energy end-consumers who do not use any special DG technologies for electricity and heat supply. Instead, the required electricity is taken from the power grid, whereas the heat demand is covered by the operation of a natural-gas-fired CB. In this scenario, it is assumed that the CB converts 96% of the natural gas taken from the gas grid into useful heat. The overall investment costs of the CB consist of the costs of the CB itself and its installation. The staggered average unit prices of CB were derived from the prices of Viessmann, Buderus, and Vaillant for a number of different power classes (measured in kW). We assume that the installation costs correspond with the equipment price of the respective class. If the power class is higher than all power classes offered by the considered manufacturers, it is assumed that several CB units are installed.

In Scenario 1 (S1), the heat demand is covered by a conventional gas-fired CB. As an additional technology, a PV system is used to cover the electricity demand. Excess electricity is fed into the power grid, for which the PV system owner receives an FIT. Possible electricity storage units (batteries) are not considered. Therefore, there are three main cost components in this scenario: the costs of the PV system, those of the CB, and the revenues from the FIT (leading to a cost reduction). The cost components of the PV system are described in more detail in Section 4.2. The costs of the CB are the same as in the RS. The FIT per kWh is paid per kWh of the solar electricity fed into the grid.

Scenario 2 (S2) consists of a combination of solar PV and engine-CHP. Here, the CHP is heat-driven. Thus, the heat demand of the consumer is covered and, in addition, electricity is produced. Further, the PV system is used to generate electricity. Excess electricity is fed into the power grid, for which the consumer receives an FIT. If neither the PV system nor the CHP unit produces enough electricity to cover demand, electricity is taken from the grid. In this scenario, the costs consist of the cost components of the PV system and the CHP. These are slightly reduced by the FIT revenues from electricity fed into the grid.

In Scenario 3 (S3), a PV system and a WWHP are combined. The electricity produced by the PV system is used to meet the electricity demand of the consumer and to meet the electricity demand of the WWHP. Excess electricity is fed into the power grid and the operator receives the FIT. This situation typically occurs during the summertime, since this period implies less heat demand compared to the other seasons. Moreover, solar irradiation is particularly intense, leading to increased electricity generation by the PV system. If the produced electricity is insufficient to cover the total needs, the lacking electricity is again taken from the grid. Cost components of this scenario are the costs of the PV system and for operating the WWHP. No gas procurement costs arise in this scenario.

Scenario 4 (S4) is similar to Scenario 3, with the only difference being that an AWHP is used instead of a WWHP. The electricity produced by the PV system is used to cover the electricity demand of the consumer and to meet the electricity demand of the AWHP. If the electricity generated from the solar PV system is insufficient to meet the demand, then electricity is taken from the grid. Excess electricity produced is fed into the power grid and the operator receives the FIT. Accordingly, the cost components are similar to the previous scenario: there are costs for the PV system and the AWHP and also for power procurement. Note that, again, no gas procurement costs appear in this scenario.

In Scenario 5 (S5), a PV system, a CHP unit, and a CB are used in combination. The PV system produces electricity independently of the other technologies. The CHP is heat-operated. It is designed in a way that 20% of the maximum heat demand of the consumer is covered by the operation of the CHP. That mode of operation allows a particularly high utilization of the CHP. The remaining heat demand is covered by the operation of a conventional CB with natural gas. The electricity produced by the PV system and by the CHP unit is used to cover the electricity demand of the final energy consumer. Excess electricity is fed into the power grid and the operator receives the FIT. The cost components of this scenario are the costs of the PV system, the CHP and the CB, the gas procurement costs, and the (cost-reducing) revenues from the FIT.

Scenario 6 (S6), finally, involves a combination of a solar PV system, an AWHP, and a CB. The PV system is used for electricity generation as in the previous scenarios, independently of the other generating technologies. The generated electricity is, on the one hand, used to cover the electricity demand of the final energy consumer and, on the other hand, to meet the demand of the AWHP. One peculiarity of the AWHP is an ambient temperature of no less than -5 °C to operate the HP economically. Outside temperatures below -5 °C would decrease the efficiency of the AWHP, which is comparable to a direct electric heating system. In order to keep the electricity demand low, the CHP is switched on at temperatures below -5 °C in order to meet the heat demand. The AWHP is switched off at these lower temperatures. Excess electricity is fed into the power grid and the operator receives the FIT. In this scenario, the cost components are the costs of the PV system, the AWHP, and the CB taken together. Additional costs for electricity and gas purchases may arise. The costs are reduced by the revenues gained from the feed-in of electricity into the grid at the predetermined, guaranteed FIT.

5. Analysis and Evaluation

5.1. Method

In order to investigate the different scenarios just described, a program was written in visual basic for applications (VBA) which is able to display and simulate the various technologies with their non-linear properties. The program retrieves the data sets from Excel spreadsheets provided by RZVN, performs simulations for each scenario for the 8760 h of a year and stores the results in the Excel sheet. Then, the charts produced are parametrized in VBA (also created in the Excel sheets). In this way, a simple examination of each individual result and the overall results are possible. The approach and procedure adopted are shown in more detail in Figure 2.

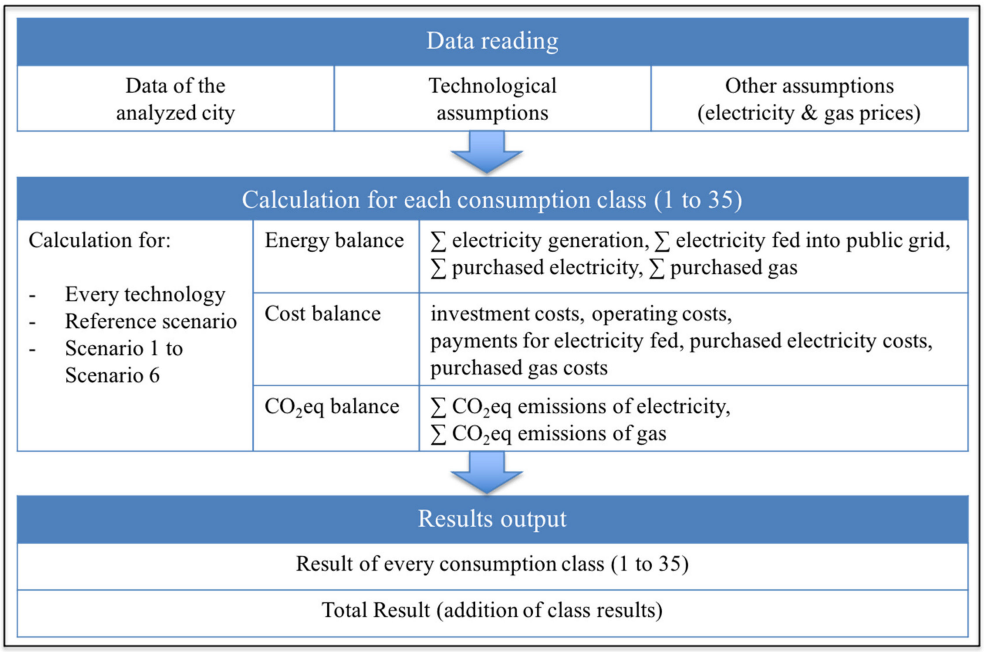


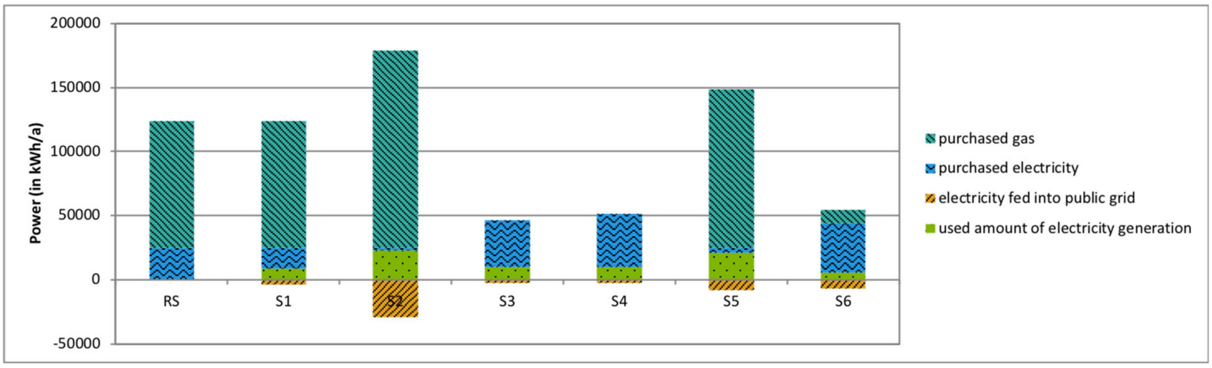
Figure 2. Procedure for the exploitation of the data set.

First, the data for the city analyzed are imported. These include the necessary consumption data of the buildings, the assumed daily load curves in terms of electricity and heat consumption, solar irradiation, and temperature of this city in 2012, the technical assumptions and costs of the technologies, as well as other assumptions (e.g., the prices of electricity and gas, the FITs, and the amount of CO_2eq emissions from the electricity and natural gas purchased).

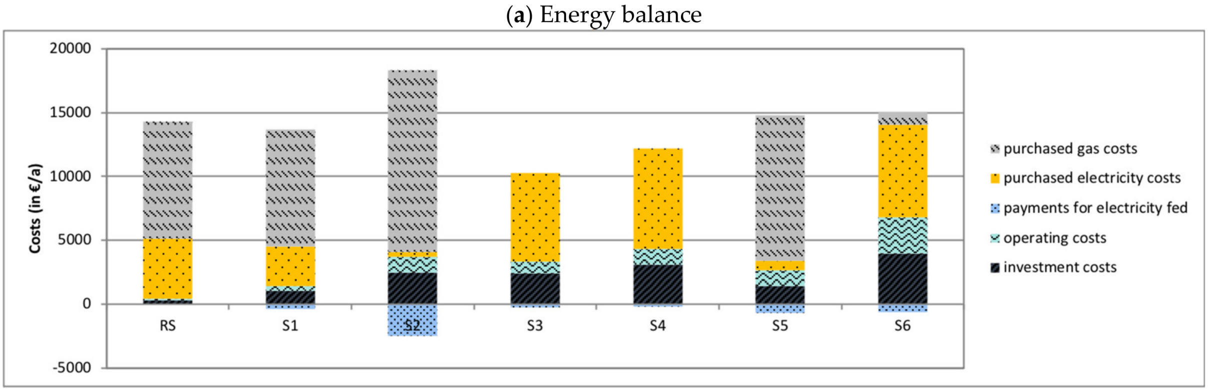
Separate calculation and evaluation are carried out for each of the 35 consumption classes (as already mentioned, 35 distinct final energy consumption classes were scrutinized, based on their electricity demand). The percentage of non-industrial city buildings that can be supplied by the DG technologies considered is assumed to be 100%. The sums of the electricity and heat demand and maximum possible generation of electricity from solar PV are computed. In addition, the maximum heat and electricity demand and the maximum generating capacity of the PV system are determined. Then, the power generation, power supply, the electricity procurement, and the gas procurement are added up for each technology (i.e., for the CB, CB, and PV, CHP, WWHP, and AWHP) and scenarios, respectively. These calculations are collectively referred to as the "energy balance". Furthermore, a cost balance is set up, which includes the capital and operating costs of the technology, as well as the electricity FIT, electricity procurement costs, and gas procurement costs (all in €). The investment costs are divided by an assumed useful lifetime of 20 years, in order to represent the considered costs as the annual costs. GHG (CO_2eq) emissions resulting from the required procurement of electricity and natural gas from the grid per scenario are depicted in the chart "CO_2 balance". Specifically, the related CO_2eq are depicted, which are a measure for all greenhouse gases (see Section 3.1 for further details). Note that CO_2eq emissions for manufacturing and decommissioning of the different technologies are ignored for simplicity reasons.

The results for each class are stored in a separate worksheet per class. For illustrative purposes, three plots for each class, and in aggregate, are produced: (1) an energy balance chart, (2) a cost balance chart, and (3) a GHG emission balance chart. Additionally, three variants are investigated: Variant 1 considers the real electricity and CO_2 costs; Variant 2 reflects increased electricity costs (e.g., due to new power plants); and Variant 3 accounts for increased CO_2 emissions (e.g., induced by the nuclear phase-out).

The energy balance chart shows how much electricity can be generated with DG technologies in each scenario, and consumed in the non-industrial buildings, how much of the decentrally generated electricity is fed into the grid, and how much electricity and gas are procured via the grid. For each scenario, the electricity procurement, the gas procurement, the amount of self-consumed electricity, and the amount of electricity fed into the grid are shown. Figure 3a shows the outcome in terms of the energy balance for the consumption class 5 kW_{el}.

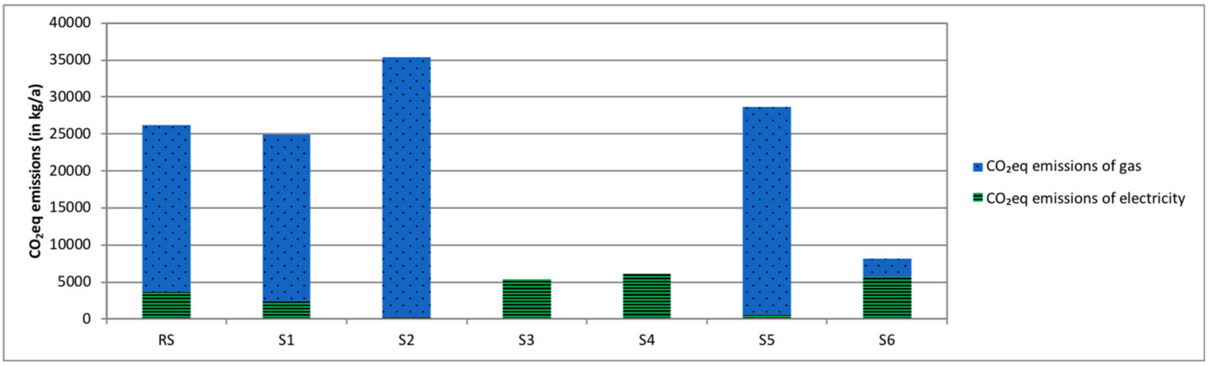


(**a**) Energy balance



(**b**) Cost balance

Figure 3. *Cont.*



(**c**) CO_2eq balance

Figure 3. Energy, cost, and GHG balances for consumer class 5 kW_{el}, by scenario, Variant 1 (real electricity costs and GHG emissions). (**a**) Energy balance; (**b**) Cost balance; (**c**) CO_2eq balance.

In the cost balance chart (plot 3 (b)), the annual costs of installed technologies of each scenario are contrasted with the possible revenues generated by the FIT. The annual costs per scenario are calculated by dividing the sum of the investment costs and the operating and fuel costs per scenario by the assumed useful lifetime of the DG technologies. The cost balance chart contains the following five components: (1) gas procurement costs, (2) electricity procurement costs, (3) operating costs, (4) investment costs, and (5) revenues from feed-in at the prevailing FIT (reducing the cost of operating DG technology). Figure 3b shows the cost balance for the consumption class 5 kW_{el}.

The GHG emission balance diagram (plot 3 (c)) includes a comparison of the emissions generated by the procurement of electricity and natural gas from the grid, depending on the considered scenario and thus the applied technologies (and combinations). It consists of two components: CO_2eq emissions for gas and those for electricity. Figure 3c shows an emission balance chart for the 5 kW_{el} consumption class.

In order to also enable an aggregate assessment of the results obtained for the medium-sized Swiss city analyzed, the results for all 35 different consumption classes is aggregated by the program (multiplying the result per building by the number of buildings in a specific consumption class and summing up).

5.2. Results

5.2.1. Variant 1: Estimated Real Energy Procurement Costs

For calculating this variation, the real average Swiss consumer prices for electricity and gas (incl. taxes) are used for all scenarios considered. It amounts to 19.1 €-ct/kWh for electricity and 9.3 €-ct/kWh for natural gas in 2019 [15]. The electricity FIT is 8.5 €-ct/kWh [43]. In addition, the CO_{2}-eq emissions of the purchased electricity and gas are taken into account, which amount to 149 g/kWh for electricity and to 228 g/kWh for natural gas in Switzerland in 2019 (see Section 3.1, p. 5).

Figure 4 shows the energy balance of the overall results for the entire city (i.e., the sum of all 35 consumption classes per scenario). This illustration corresponds to the above-described energy balance of the individual consumption class concerned (see also Figure 2).

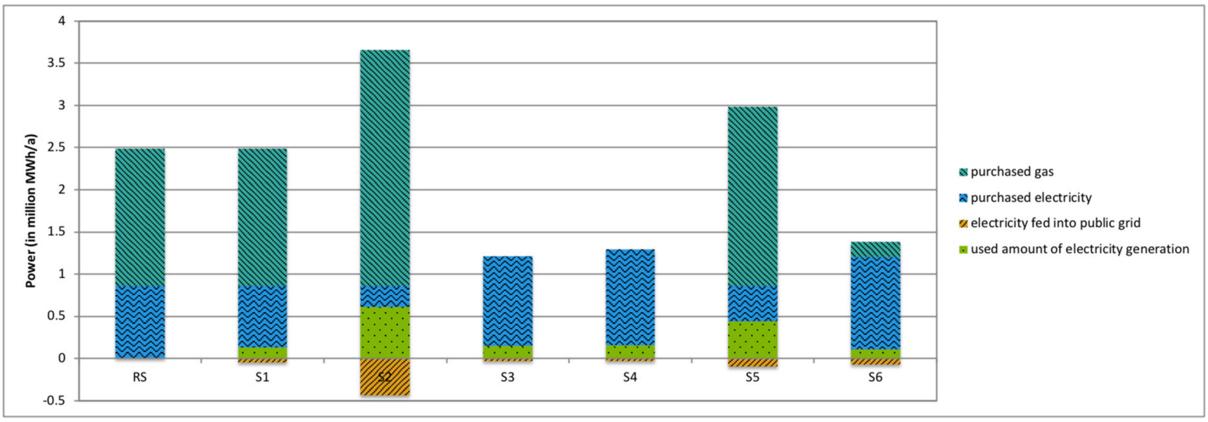
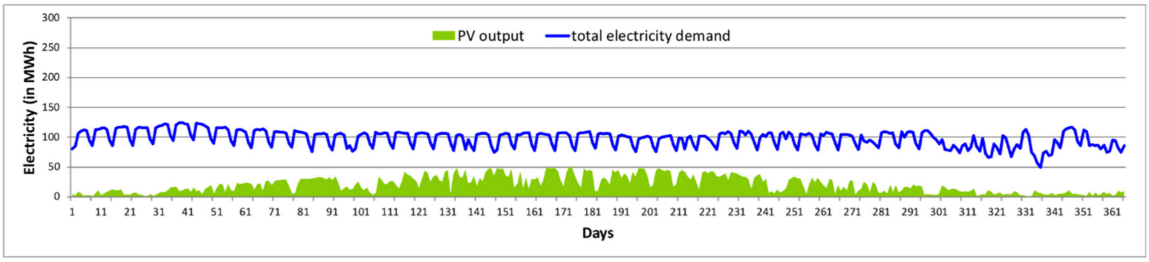


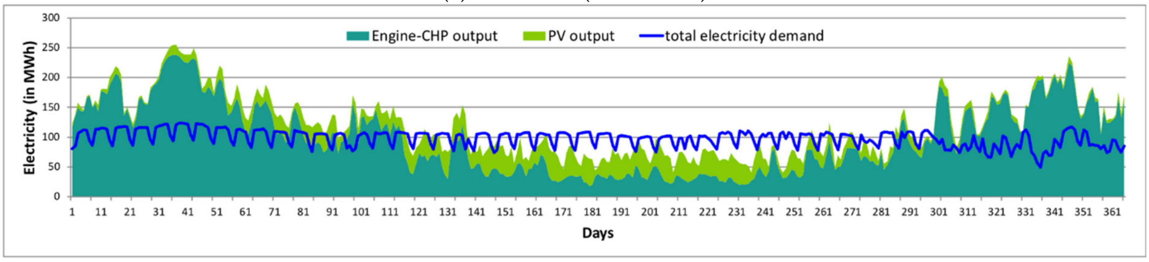
Figure 4. Energy balance of the total result, by scenario, Variant 1 (real electricity costs and GHG emissions).

For the Reference Scenario (RS), a total power demand (electricity and gas) of about 2.5 million MWh/a arises. In each of the Scenarios 1–6, approx. 21% of the total electricity demand of the city can be generated almost CO_2-free by solar PV systems. The total annual power demand (electricity and gas) of Scenario 1 of approx. 2.5 million MWh corresponds to the total annual electricity demand in the RS. In Scenario 1, 74% of the electricity generated from solar PV systems can be used by the prosumers themselves (self-consumption of self-generated electricity), the remaining 26% is fed into the electric grid. Scenario 2 has the greatest total power demand (electricity and gas) of about 3.7 million MWh/a. The combination used in this scenario—solar PV systems and CHP units—involves the greatest potential for decentralized power generation in the considered Swiss city of about 430% of the total demand for electricity. In this scenario, some 58% of the electricity locally generated can be consumed by the prosumers themselves, whereas the remaining 42% is fed into the grid. The Scenarios 3 (PV and WWHP) and 4 (PV and AWHP) have the lowest total electricity demand with approx. 1.2 million MWh/a and 1.3 million MWh/a, respectively. Some 83% (S3) and 84% (S4) of the locally generated electricity can be self-consumed by the prosumers, the remaining 17% (S3) and 16% (S4) are fed into the grid. The total electricity demand of the city in Scenario 5 is the second-highest of the observed scenarios, with approx. 3.0 million MWh/a. In this scenario, however, a share of 129% of the total electricity demand of the city can be generated locally through the combined use of PV and CHP. Some 82% of the electricity generated can be used by the prosumers themselves, and only the remaining 18% is fed into the grid. Finally, Scenario 6 includes the combination of PV, AWHP, and CB. This combination of technologies meets a total annual electricity demand of 1.4 million MWh in the considered city. From the locally generated electricity, 60% can be used by the producers themselves, the remaining 40% is fed into the grid. If natural gas would not release CO_2 emissions, as in the case of synthetic gas generated in power-to-gas (P2G) plants [44], the proportion of CO_2-free power generation in the city could even be 430% and 129% in Scenarios 2 and 5.

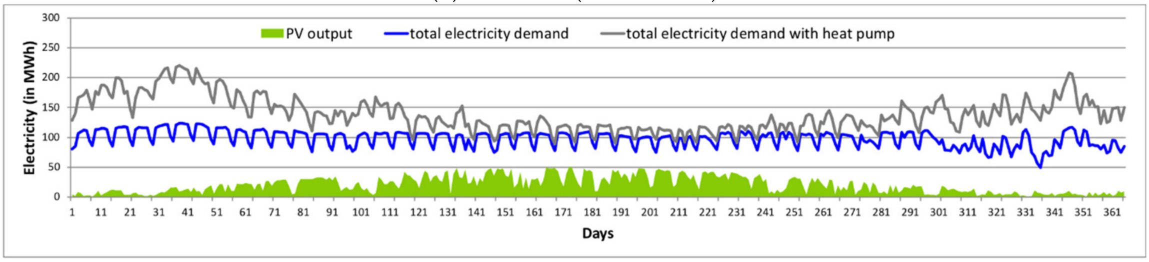
To assess the aggregated impacts of the scenarios, we further need to scrutinize the scenario-specific electricity balances in detail. Figure 5 shows the overall electricity demand (blue) and the electricity from PV (light green) for each of the six alternative scenarios for a year (hourly resolution). Note that if a CHP unit is used in the considered scenario, an additional electricity line is shown (dark green). If heat pumps are used in the scenario, also the resulting electricity demand (gray) is displayed.



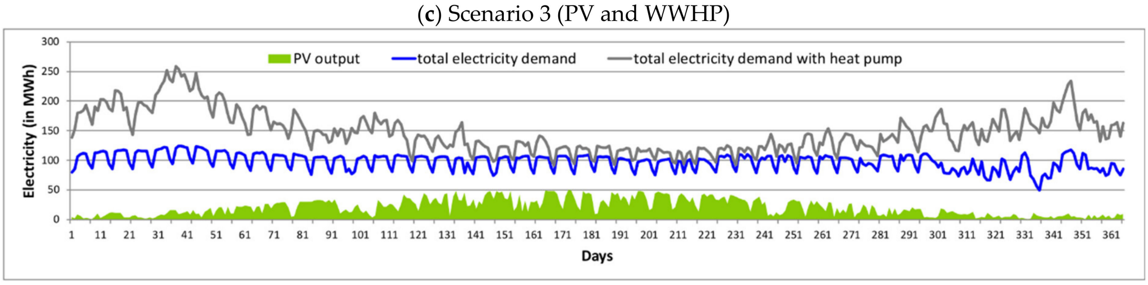
(**a**) Scenario 1 (PV and CB)



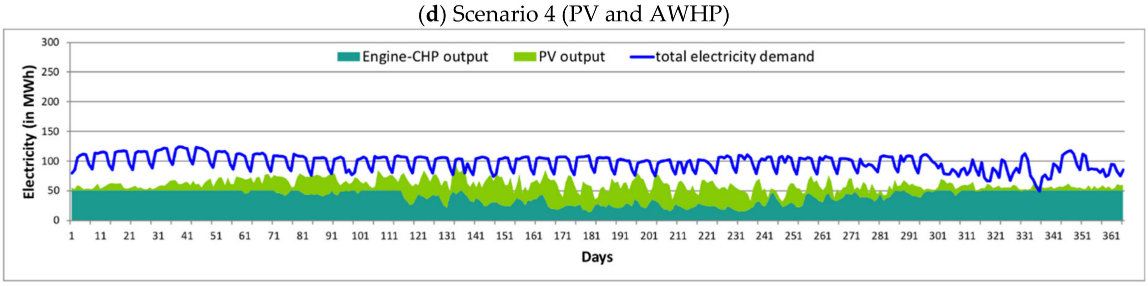
(**b**) Scenario 2 (PV and CHP)



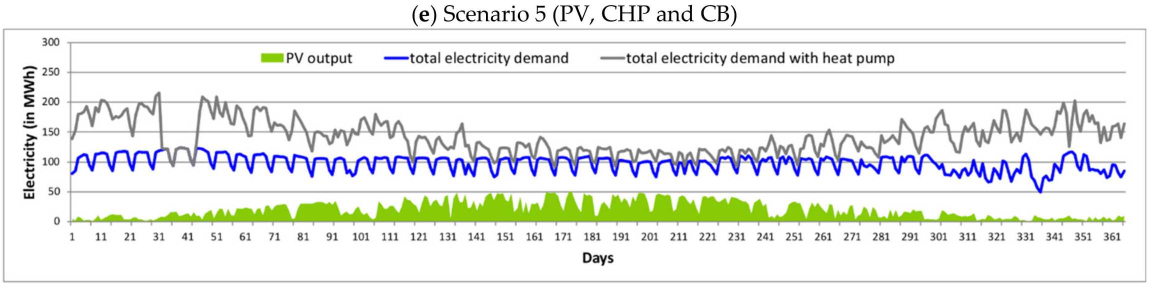
(**c**) Scenario 3 (PV and WWHP)



(**d**) Scenario 4 (PV and AWHP)



(**e**) Scenario 5 (PV, CHP and CB)



(**f**) Scenario 6 (PV, AWHP and CB)

Figure 5. Hourly electricity balances of the six alternative scenarios considered. (**a**) Scenario 1 (PV and CB); (**b**) Scenario 2 (PV and CHP); (**c**) Scenario 3 (PV and WWHP); (**d**) Scenario 4 (PV and AWHP); (**e**) Scenario 5 (PV, CHP, and CB); (**f**) Scenario 6 (PV, AWHP, and CB).

Figure 5a depicts the electricity balance resulting from Scenario 1. It shows the average values of the daily electricity demand and the feed-in from PVs. In summer, the city analyzed can self-generate nearly 50% of its own electricity demand by PV. In winter, less than 1% of its electricity needs can be covered by PV systems on most days. Figure 5b shows the electricity balance for Scenario 2, in which PV systems and CHP plants are used. In this scenario, the CHP production during the winter months can cover a lot more than the total electricity demand of the city. During the summer months, the potential of CHP is lowered due to the reduced (or maybe even zero) heat demand. During these warmer months, the share of PVs increases the amount of self-generated electricity. Accordingly, PV and CHP units complement each other very well in this scenario. Figure 5c shows the resulting electricity balance for Scenario 3 (PV systems combined with WWHP units). While the electricity demand of heat pumps is much higher during the colder months, PV systems produce electricity especially in the warmer months. Thus, these two technologies PV and WWHP do not complement each other well. Figure 5d depicts the electricity balance of Scenario 4, combining PV and AWHP. The electricity balance in S4 is similar to the electricity balance of S3. The only difference is that the electricity demand of AWHP is even higher in the colder months than the demand for electricity of the WWHP units. Figure 5e shows the electricity balance of Scenario 5, the combination of PV, CHP, and CB. In this scenario, the assumption is that a maximum of 20% of the heat demand of consumers is covered by the operation of the CHP unit in order to achieve a particularly high utilization of CHP. In this scenario, more than half of the annual electricity demand can be generated locally from PV and CHP units. Similar to Scenario 2, the two technologies complement each other again very well: in the colder months the increased use of CHP units for generating heat also generates much electricity, in the warmer months the heat generation by the CHP is low and so is the electricity generation. However, a large amount of electricity is generated by the use of PV systems. The annual electricity demand is thus smoothed by the continuous self-generation of electricity. Finally, the electricity balance for Scenario 6, in which PV, AWHP, and CB are combined, is shown in Figure 5f. The special feature of this scenario is that the AWHP is switched off at temperatures below −5 °C and, instead, conventional condensing boilers are used to cover the heat demand. The electricity balance is compared to the electricity balance of Scenario 4 (combination of PV and AWHP). When comparing the total power demand with HP, it is striking that the electricity balance in Scenario 6 is significantly less volatile than in Scenario 4. With the implementation of CB at low temperatures, the spikes that arise from implementing AWHP units can be avoided.

Figure 6 shows the cost balance of the overall results. It includes all results from the Swiss city (i.e., all 35 consumption classes) and corresponds to the presentation of the cost balance of the individual consumption classes.

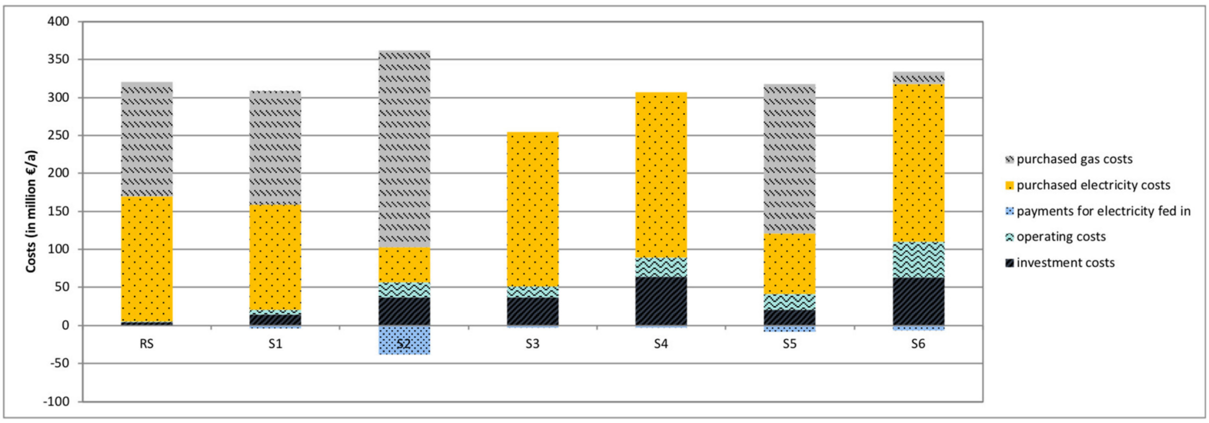


Figure 6. Cost balance in the aggregate, by scenario, Variant 1 (real electricity costs and GHG emissions).

The annual costs in the Reference Scenario amount to approximately €320 million. In the RS, the investment costs of €4.1 million, divided by the useful lifetime, are the lowest compared to all other scenarios. In addition to the investment costs, annual operating costs of €1.6 million arise. These are also the lowest compared with the other scenarios. The electricity procurement costs amount to €164 million and those for gas to €151 million. In Scenario 1 (PV and CB), the total costs amount to approx. €305 million. Investment costs equal €14.6 million and are thus higher than in the RS due to the investment in PV systems. By investing in PV systems, the electricity procurement costs can be reduced to €138 million. In addition, the operators of PV systems will receive an FIT of about €4 million. The gas procurement costs remain unchanged relative to the RS at €151 million. Investing in a PV system and a CB is, therefore, worthwhile in comparison to the investment in a CB only. The total costs in S2 (PV and CHP) amount to approx. €324 million. Thus, this scenario has the second-highest total costs of all considered scenarios, with investment costs of €37 million. The operating costs amount to €19 million. The annual electricity procurement costs can be reduced compared to the RS, amounting to only €47 million. By contrast, the annual gas procurement costs increase by 72% compared with the RS to a level of €259 million. In S2, the operators receive the highest feed-in compensation of €38 million. Scenario 3 (PV and WWHP) incurs total costs of approx. €252 million and is thus the scenario with the lowest total costs. The investment costs of this scenario amount to €37 million, similarly to the investment costs in Scenario 2. Operating expenses amount to €15 million. The electricity procurement costs are approx. €203 million. This large sum can be explained by the high power consumption of WWHP during colder months. There is a total FIT revenue of €2.7 million and no gas procurement costs. In Scenario 4 (PV and AWHP), the total costs amount to €304 million and the investment costs to €64 million. Operating expenses amount to €25 million and the electricity procurement costs to €217 million. With the operation of an AWHP unit, S4 has the highest electricity procurement costs. No gas procurement costs occur. Overall, FIT revenues of €2.5 million in total are paid in this scenario. The total costs in Scenario 5 (PV, CGP and CB) amount to €310 million. The investment costs in S5 amount to €21 million, operating costs to €21 million. In addition, electricity procurement costs are €79 million and gas procurement costs €197 million. In S5, the DG plant operators get FIT revenues of €8.2 million in total. Finally, Scenario 6 (PV, AWHP, and CB) comprises total costs amounting to €328 million, the highest total costs of all scenarios. The investment costs in S6 amount to €63 million, which are the highest investment costs of all scenarios. Scenario 6 also shows the highest total annual operating costs of €46 million. The electricity procurement costs amount to €208 million, whereas those for gas are comparatively low at €17 million. In S6, the DG plant operators receive FIT revenues of €6.2 million overall.

The results obtained under the given conditions show that the combination of electricity procurement and heat generation by a conventional gas-fired condensing boiler with natural gas is not the least-cost alternative. The cheapest way to supply the city with electricity and heat is the situation in Scenario 3 (combination of PV and WWHP). Part of the required electricity is generated by the PV unit, whereas the remaining portion of the required electricity is procured externally via the grid. Scenario 6 (combination of PV, AWHP, and CB) has the highest total costs and is thus the most expensive option to supply the city. However, it also has a great potential to produce more electricity than required by the CHP.

Figure 7 shows the emission balance (CO_2eq balance) of the overall results for the entire city (all 35 consumption classes). The presentation of this CO_2eq balance corresponds to that of the CO_2eq balance of all individual consumption classes. The CO_2eq emissions in Scenarios 3 (PV and HP), 4 (PV and AWHP), and 6 (PV, AWHP and CB), respectively, are significantly lower than those in the RS and Scenarios 1 (PV and CB), 2 (PV and CHP), and 5 (PV, CHP and CB). Accordingly, those scenarios where no natural gas is used and those using only small amounts of gas are more environmentally friendly than the scenarios in which a high level of gas procurement takes place. This is due to the low specific

CO_2eq emissions of the Swiss electricity mix as well as due to the high energy efficiency of heat pumps. Assuming gas would not cause CO_2 emissions, like the production of gas in power-to-gas plants, Scenario 2 (PV and CHP) would be the scenario with the lowest emissions.

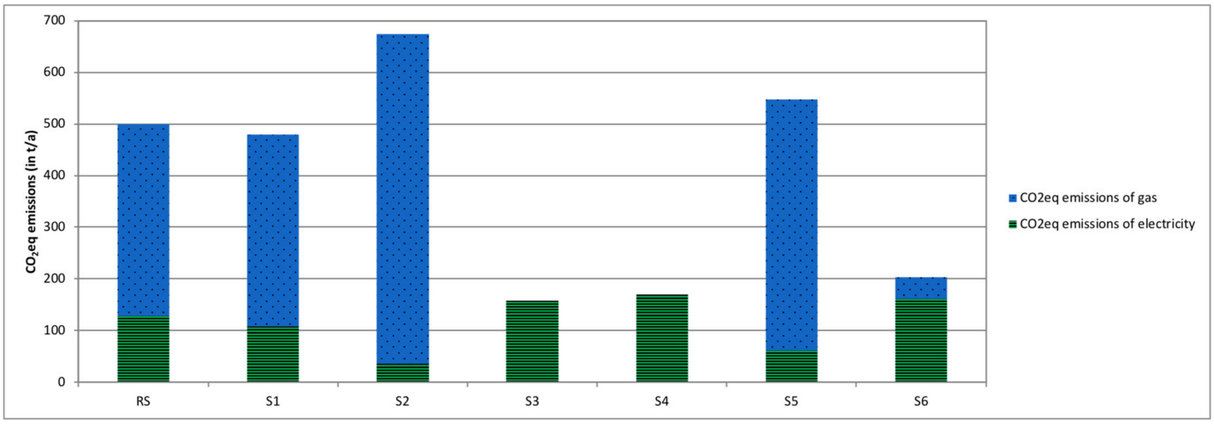


Figure 7. CO_2eq balance in the aggregate, by scenario, Variant 1 (real electricity costs and GHG emissions).

5.2.2. Variant 2: Increased Electricity Procurement Costs

In this variant, the calculations are implemented with increased electricity purchase costs. An increase in the electricity purchase costs could be caused by the construction of new power plants or by a changed regulatory framework. A future increase in electricity production costs in Switzerland can be expected, but its extent is unknown. The study "Energy Future Switzerland" considered the increase in costs in different scenarios ([11], pp. 35–36). Here, the assumption is made that the Swiss price will rise up to 50% compared to the average costs for the year 2019. Consequently, a price of 28.6 €-ct/kWh is assumed for electricity. This price is still below the average electricity price of household customers in Germany, which amounted to 30.46 €-ct/kWh in 2019 [45]. The gas procurement costs of 9.3 €-ct/kWh, and the electricity FIT of 8.5 €-ct/kWh are assumed to remain unchanged to Variant 1. The CO_2eq emissions of Variant 2 correspond to the CO_2eq emissions of Variant 1. Accordingly, the CO_2eq emissions per kWh of electricity amount to 149 g and the CO_2eq emissions per kWh of natural gas amount to 228 g. The energy balance and the emission balance of Variant 2 thus remain the same as in Variant 1. The price increases of electricity lead to changes in the cost balances of the individual results and thus in the cost balance of the overall results. The resulting cost balance of the overall result is shown in Figure 8.

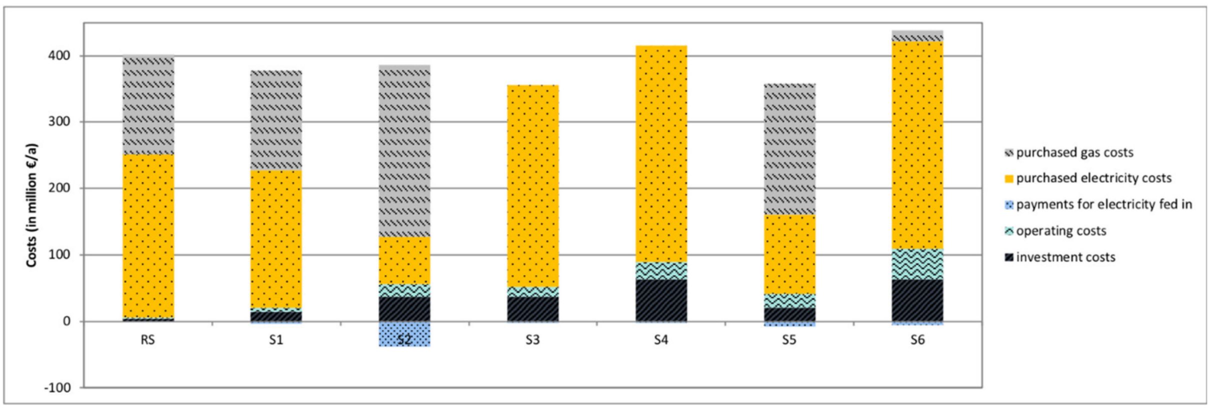


Figure 8. Cost balance in the aggregate, by scenario, Variant 2 (increased electricity procurement costs).

Due to the price increase of electricity by 50%, the total costs in each scenario rise by between 7.2% (S2) and 40.3% (S3). The price increase of electricity causes a change in the preferability of the scenarios. The most expensive scenario remains Scenario 6 (PV, AWHP, and CB), with total costs amounting to €432 million. In contrast, the lowest total costs now occur in Scenario 2 (PV and CHP), with total costs amounting to €347 million. For obvious reasons, the attractiveness of the self-generated electricity rises with this price increase.

5.2.3. Variant 3: Increased CO_2eq Emissions of Electricity

For the calculation of this variant, the average Swiss prices for electricity and gas from 2019 are used, as in Variant 1, amounting to 19.1 €-ct/kWh for electricity and 9.3 €-ct/ kWh for gas. The electricity FIT remains unchanged compared to Variants 1 and 2 (8.5 €-ct/kWh). The characteristic of this variant is the increase in CO_2eq emissions from electricity of 50% compared to Variants 1 and 2. One reason for such an increase in CO_2eq emissions from electricity generation could be a lower contribution from nuclear power plants and thus an induced increased electricity generation by gas-fired power plants (or increased electricity imports, for example, from Germany, involving higher CO_2eq emissions). Consequently, for this variant, CO_2eq emissions of 224 g/kWh for electricity and 228 g/kWh for gas are assumed.

Figure 9 shows the resulting GHG emission balance from Variant 3. By increasing the CO_2eq emissions from electricity by 50%, the total emissions increase as well. Interestingly, the preference ordering of the scenarios in terms of the GHG environmental performance remains unchanged (compared to Variant 1). The increased CO_2eq emissions from electricity, however, increase the overall attractiveness of CO_2-free power generation.

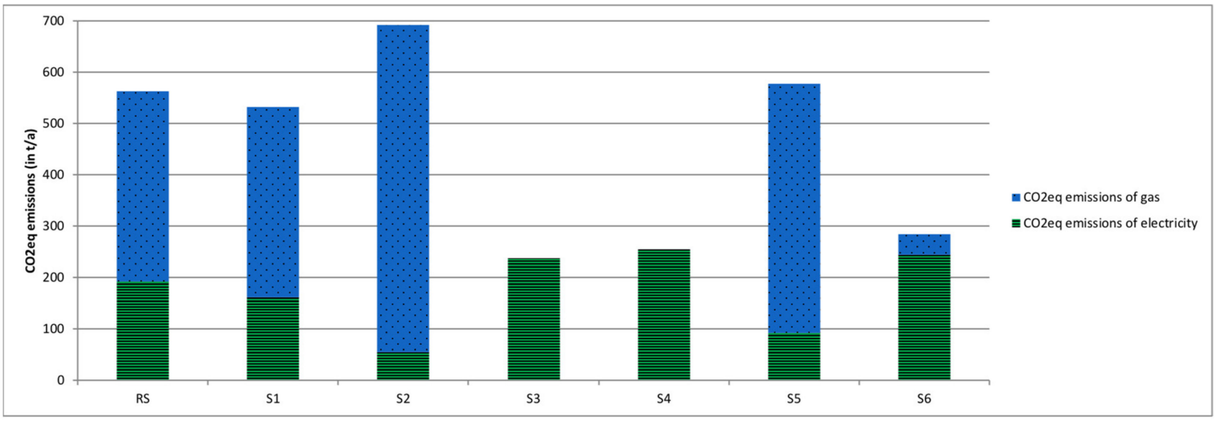


Figure 9. CO_2eq balance of the total result, by scenario, Variant 3 (increased CO_2eq emissions of electricity).

5.3. Discussion of the Study's Limitations

In the calculations, it is assumed that all non-industrial final energy consumers in the medium-sized city investigated use the same combination of technologies, and thus the same electricity and/or heat generation technology in each scenario. This assumption is not realistic. The sequential modernization of today's heating systems depends on the age of the plants. Thus, a more heterogeneous mix of technologies is to be expected with the most cost-efficient technologies, depending on the respective building size, electricity tariff conditions, and promotion scheme available. This is likely to result in higher real terms than in the investigated monovalent use of technologies considered in our analysis.

Furthermore, with the modeling framework adopted, not all factors related to the considered technologies and their impact on the required electricity and gas demand could be analyzed. For example, solar thermal energy on rooftops, possible reductions in the heat demand through better insulation of the buildings, or the potential of smoothing electricity and heat demand peaks through using electricity storage solutions and hot water tanks were ignored. Hence the overall results obtained need to be interpreted with caution.

Within the model, the electricity and heat demand of the investigated city from the year 2012 was used, as this was the most recent and detailed data set that was available to us. Even though all economic factors, such as the investment and operation costs as well as electricity and gas procurement prices and the FIT, relate to the year 2019, it is likely that the results will vary when using a more recent data set of the investigated city once that becomes available, which would make a comparison with our results both interesting and useful.

In addition, the model-based analysis was conducted for a medium-sized Swiss city. For drawing conclusions for other Swiss cities or even Switzerland in general, the analysis should also be performed while using the consumption and solar irradiation data of other Swiss cities. Afterwards the obtained results should be compared in regard to the most preferable technology combinations, the lowest costs, as well as the highest potentials for decentralized electricity generation. When taking different regulatory frameworks into account, it would also be possible to apply our model to other Western European cities outside of Switzerland.

For the cost calculations within our model, the investment costs were simply divided by the presumed lifetime of 20 years for all technologies (i.e., no interest rate was considered for calculating annuities). However, higher technical lifetimes for individual components are likely in the sector of heat generation (e.g., deep drilling for heat pumps or pipeline construction for heating systems). In addition, the annual operating costs of equipment exclude maturity-related overhauls, making the complete retrofitting of a plant redundant. This basis is not sufficient for making any judgement about the efficiency of these scenarios. It lacks a net present value calculation of each scenario for the period of the operating technologies.

Furthermore, the costs of the different scenarios were only analyzed from the perspective of the operator of the technologies used in each case. A relatively expensive scenario, however, such as Scenario 2, where PV and CHP are combined, could still be useful in order to avoid the high electricity transport costs for ensuring the supply security. Our study thus lacks a macro-level evaluation of the total costs of both the power generation and the transmission and distribution costs.

The proposed model calculates the CO_2eq emissions entailed with the operation of the different DG technologies by calculating the CO_2eq emissions entailed with the required electricity and gas procurement from the grid. CO_2eq emissions arising, for example, during the production and decommissioning of the different DG technologies, have not been taken into account. In future research, such an analysis should be added, and the model extended accordingly, in order to achieve a more comprehensive analysis of CO_2eq emissions entailed with the usage of DG technologies. In addition, the CO_2eq emissions have been calculated for today's ("conventional") natural gas. The expected future CO_2-reducing effects of biogas or P2G have been not addressed.

Based on the findings of the analysis conducted, the main research questions raised in this study can be answered as follows. The total energy demand of the examined buildings can be minimized by up to 51% (Scenario 3: PV and WWHP) by means of DG technologies. Through the usage of DG technologies, it is possible to reduce the electricity and gas procurement from the grid of non-industrial buildings by up to 51% (S3) compared to a situation where all electricity is procured from the grid and heat is produced with a conventional GCB (reference scenario). With the use of PV, a considerable share (up to 50%) of the own daily electricity demand of buildings can be covered in the summer months. During the winter months, this contribution is, however, almost zero. The use of heat pumps can significantly reduce the primary energy consumption in order to cover the heating demand (with the use of PV systems in combination with HP in Scenarios 3 and 4). However, the demand for electricity in the cold winter months partly exceeds 100%. But with the combined use of PV systems and CHP (Scenario 2), approx. 430% of the total annual electricity demand of the city can be generated locally. On the one hand, the demand for gas is rising significantly; on the other hand, the power generation, transmission and distribution capacity required for the grid electricity is reduced. According to the present results, the combination of solar PV systems and CHP is particularly suitable throughout the year to generate electricity locally.

6. Conclusions

In this paper, we have introduced a novel approach for analyzing the impact of an intensified use of DG technologies in an urban, industrialized country context, based on matching heat and electricity loads on an hourly resolution with the maximum possible supply from different DG technology combinations (in the absence of storage). As such, the analysis shows the possibilities in the absence of smart grids and new storage options, which feature large but often still largely untapped or not yet realizable potentials. The focus is on the technical potentials, the economic impacts, and environmental implications in terms of energy, cost, and GHG "balances" (i.e., electricity self-generation, feed-in, and electricity and gas grid purchases; changes in investment and operating costs; changes in emissions from electricity generation and gas consumption). Due to the specific focus, and the limitations of the approach proposed and adopted, our approach is complementary to those of other researchers, but yields interesting new insights for the case of Switzerland. Moreover, the application of the model, despite data limitations encountered, seems more practical for urban energy planners and policy-makers, compared to the often very sophisticated and/or only commercially available national or regional energy system models.

The use of the investigated DG technologies leads to both positive and negative impacts on the local primary energy consumption. The investment costs of DG technologies are significantly higher compared to the conventional production methods, though—like heat generation with a GCB and electricity procurement from the grid. However, the sum of the annual costs accrued from depreciation, operation, and energy procurement are on a similar level. With the use of PV, CHP, and HP a high share of the demand can be generated locally in a more environmentally friendly way. The combination of PV and CHP units enables ensuring a large share of the supply by distributed renewable energies. Conclusions from an aggregated perspective can only be drawn if the costs of central production and transport are also included in the cost comparisons. The reduction of CO_2eq emissions with the installation of HP is very effective but requires additional and assured power plant capacity (unless these capacities are compensated by local CHP) that cannot be provided by renewable energy plants alone. In addition, the reduction of CO_2eq emissions with the use of HP is only valid as long as the CO_2eq emissions from the Swiss electricity mix remain low. If we assume increased electricity procurement costs and increased CO_2 emissions caused by the phase-out of nuclear power plants, then the attractiveness of self-generated electricity by natural gas-CHP rises.

The calculations made and results presented can be complemented by further studies, as suggested in the following outlook. A cost analysis using NPV calculations, taking into account the possible depreciation and interest rates for the period of the lifetime of each technology as well as technology-specific expected useful lifetimes, would be more accurate for a comparison of the considered scenarios. In addition, a macro-level cost calculation and optimization, which includes the value of decentralized supply security and costs of energy transmission and distribution, would be of great interest. The overall results could be altered by a differentiation of the best scenarios for each consumption class. The consideration of a heterogeneous local technology mix is likely to lead to a better overall economic solution compared to the observed results in this work with the monovalent use of technologies. An investigation in this direction seems possible with a refined version of the model used in the present study. It should be kept in mind, however, that the scenario analysis presented does not consider possible effects stemming from the reduction of the heat demand by using solar thermal energy, or building insulation, or possible smoothening of electricity and heat demand peaks by the use of batteries, hot water tanks, and smart grid technology. This omission should be included in further analyses. In future research, the CO_2eq emission calculations produced by the model could be expanded in such a way that the CO2eq of the production and the decommissioning of the different DG technologies are also taken into account (life-cycle analysis). Likewise, the effects and the use of CO_2-free gas should be considered. Finally, quarter-hourly energy consumption data would provide more accurate results than the hourly data used here.

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Abbreviations

ASUE	Arbeitsgemeinschaft für sparsamen und umweltfreundlichen Energieverbrauch e.V. (German Association for a Rational and Environmentally Benign Energy Consumption)
CB	Condensing boiler
CHP	Combined heat and power
COP	Coefficient of performance
CO_2eq	Carbon dioxide equivalent
DER	Distributed energy resources
DG	Distributed generation
DGST	Decentralized generation and storage technology
ENT	Electricity network
ENSI	Swiss Federal Nuclear Safety Inspectorate
EPFL	École Polytechnique Fédérale de Lausanne
FIT	Feed-in tariff
GCB	Gas-fired condensing boiler
HP (AWHP, WWHP)	Heat pump (air/water, water/water)
LCOE	Levelized costs of electricity
NPP	Nuclear power plant
PV	Photovoltaics
P2G	Power to gas
RS	Reference scenario
RZVN	Rechenzentrum für Versorgungsnetze Wehr GmbH
SFOE	Swiss Federal Office of Energy
VBA	Visual Basic for Applications
VRES	Variable renewable energy sources

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