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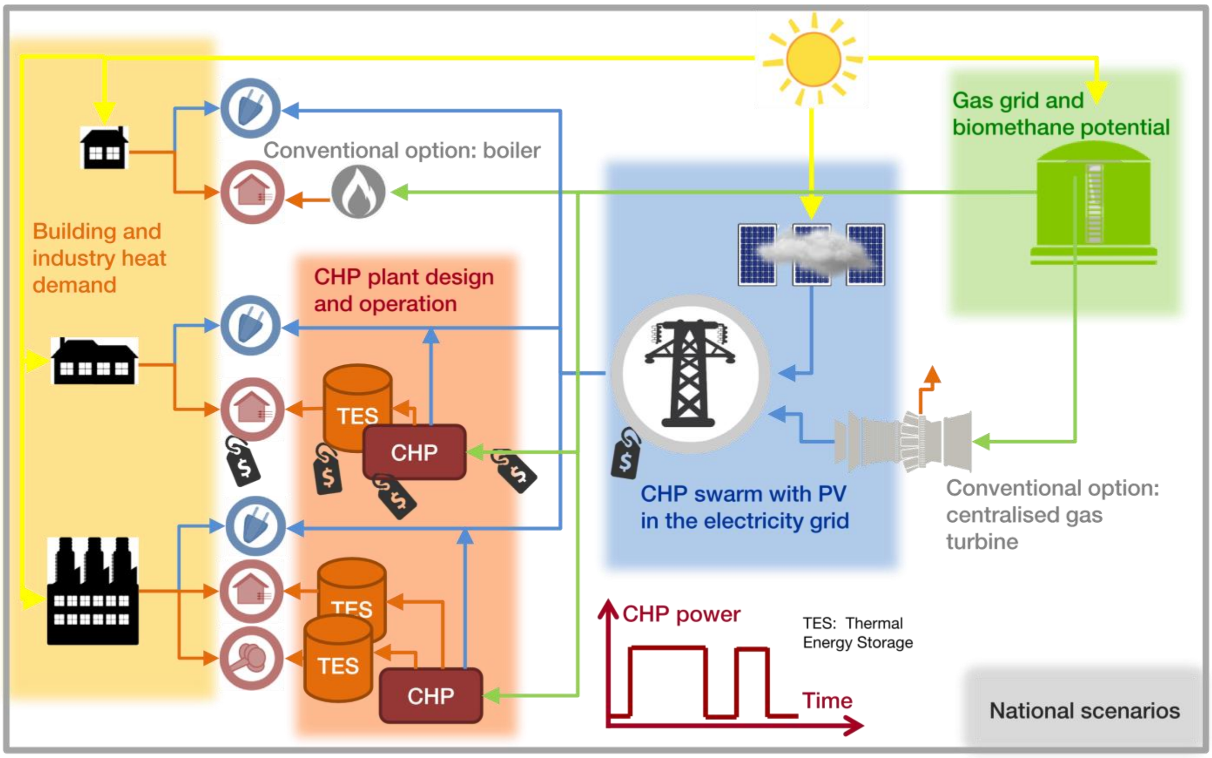
Bundesamt für Energie BFE
Sektion Energieforschung

Final report 29th January 2016

System modelling for assessing the potential of decentralised biomass-CHP plants to stabilise the Swiss electricity network with increased fluctuating renewable generation



Datum: 29th January 2016
Ort: Zurich, Switzerland

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Abstract

Project CHPswarm investigated the role, Combined Heat and Power (CHP) or cogeneration may play in the future Swiss energy system. CHP refers to an energy conversion process, producing both useful heat and electricity (or mechanical work) at the same time. In principle, any energy converter could form the heart of a CHP system. For reasons discussed at a later point in this report, this project only considered gas-fired internal combustion engines. The primary interest were the energy systemic potentials of a whole swarm of distributed, local CHP plants, under the premise that biogenic resources are the only admissible fuel sources (i.e. no natural gas).

To that end, a set of detailed, regional case-studies was combined with energy-economic modelling on the national level. The case-studies investigated the biomethane production potentials within the boundaries of the study region. Then, softly coupled simulations of the swarm, the buildings and industrial processes they provide with heat and the electric grid were run to explore the technical feasibility of installing such a swarm in detailed. Finally, on the national level, the competitiveness with respect to other technologies such as combined cycle gas-turbines (CCGTs) were explored in energy economic scenarios.

On the example of the case-study of Lucerne, it was shown that a swarm consuming all the biogenic resources in the canton can provide on the order of 100 MW of electrical power and around 19 % of the heat-demand of those buildings connected to the gas-grid. Even though the operation units were operated completely agnostically of the state of the electric grid (i.e. local bottlenecks), no capacity constraints in the grid were exceeded at any time. This held true also for larger swarms, consuming more than the estimated biogenic potential. The economic analysis revealed that CHPPs are to play an important role if natural gas prices become high, or climate policies very stringent. Otherwise, they mostly complement other assets in the heat, electricity and grid services markets, with main competitors primarily being other renewables, CCGTs, heat-pumps and hydropower.

Acknowledgements

First and foremost, we, the project group, would like to express our very great appreciation to our two project sponsors:

- Swisselectric research (SER)
- Bundesamt für Energie (BFE)

In particular, we would like to thank the participants of the stakeholder meetings, namely (in alphabetical order) Ms. Carina Alles, Ms. Sandra Hermle, Mr. Martin Kauert, Mr. Michael Moser and Mr. Stephan Renz for their continued support and valuable feedback.

We wish to thank the following energy utilities and institutions, for providing us with technical data regarding the gas and electricity grids in the studied regions:

- Centralschweizerische Kraftwerke (CKW)
- Energie Wasser Luzern (EWL)
- Industrielle Werke Basel (IWB)
- Kanton Thurgau, Abteilung Energie
- Wasserwerke Zug WWZ

We wish to acknowledge the support provided by the following CHP plant manufacturers in our modelling and assessing CHP technology:

- Avesco
- IWK

We also express our appreciation to our colleagues from project “Aladin” and their sponsors, for providing us with measurement data from their CHP test-bench.

Advice given by the following companies has been a great help in our efforts of quantifying biomethane production potentials:

- Axpo Kompogas
- Eisenmann
- I.C.E. AG

We also thank our colleagues from WSL, “Gruppe Waldresourcen: forstliche Produktionssysteme”, for their valuable input concerning synthetic natural gas production potentials (from wood gasification).

We would also express our appreciation to:

- The Lucerne geo-information office for access to their PV potential maps
- BKW for providing electricity pricing data

1. Introduction

1.1. Paradigm shifts: central vs. decentral production

Our current energy system is mostly based on the traditional paradigm of separate production: electricity is generated centrally in large plants, and then distributed to consumers via the electric grid, while heat is produced decentrally using local gas, oil or electric heaters – see Figure 1.

This is primarily due to economies of scale in electrical energy generation: thermal plants, convert a fuel (e.g. natural gas) to heat, which is then converted to electricity. The efficiency of a plant is defined by how much of that heat is turned into electricity. As a fundamental matter of thermodynamics, there is a specific amount of heat that can never be converted. In practice this theoretical minimum cannot be achieved; but designers take all means at their disposal to come as close as possible. Typically this becomes easier (i.e. more affordable) at larger scales. As a result, power generation processes are engineered to the point that further exploitation of the remaining heat is no longer economical. That is why it is dumped to the atmosphere – and why it is referred to as waste-heat.

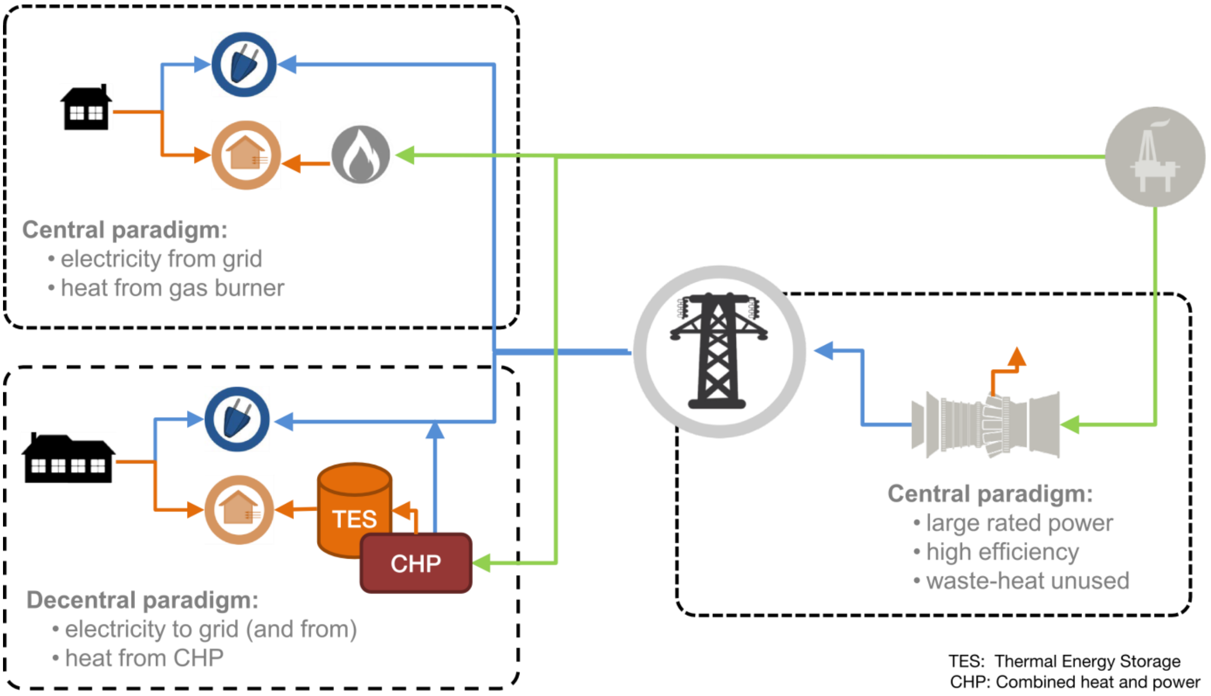


Figure 1: Schematic representation of the differences between a central and decentral (using CHP plants) electricity generation paradigm. Note the supporting role of the gas infrastructure in both cases.

In contrast, in a cogeneration scenario, the would-be waste-heat is harnessed to power a useful purpose, namely space heating or process heat. Contrary to electricity, it is generally not economical to transport heat over large distances resp. distribute it over large areas. Therefore the consumers must be close-by. This limits the amount of marketable heat and with it the plant size and its electrical output. In fact, in absence of district heating networks, this may translate to catering to the heating demand of individual single family houses. The rated electrical power of such plants typically falls into the single-digit kilowatt scale, which attributes them the name “µCHPs”. Just for comparison: the largest CHP plants produce on the order of 20 MW electric.

Production levels akin to central plants will thus require the combined output of a potentially large swarm of many such installations. Naturally, they are scattered in space over many buildings, linked by the same electric grid. This leads to the paradigm of decentralized production, directly at the low-voltage network level (to which consumers are connected).

From a purely demand-driven perspective, this may appear as an odd idea: the achievable overall conversion ratio (from gas to electricity) would fall below those of state-of-the-art combined cycle gas-turbines (CCGT) – so more gas would be required to fulfil the same electricity demand. Similarly, modern gas boilers would be able to produce the same amount of heat with significantly less fuel, since they do not "lose" fuel energy to electricity.

However, virtually 100 % of the fuel energy consumed by the CHP swarm is converted to useful energy – whereas, in a CCGT, only 50-60 % is used (as discussed above). Of course, a gas boiler also achieves an almost 100 % conversion efficiency. However, heat is a much less versatile energy vector than electricity. Indeed the latter is easily converted to practically any usable energy form, including heat. The other way around is not true: converting heat to electricity requires heat-engines, which are always lossy. Thus thermodynamically, burning gas for heat only is squandering its potential to generate electricity.

To illustrate this further, consider the following thought experiment, schematically represented in Figure 2 assume 100 units of gas (=chemical energy) are burned in a CHPP, producing 70 units of heat and 30 units of electricity. This electricity then powers a heat-pump, which uses the 30 units to draw another 60 units from the environment (or a ground source). With this elaborate conversion process the 100 units of fuel become 160 units of heat and not just to the 100 we would get from a direct burner. If the goal is to produce 100 units of heat, then the heat-pump could be made to consume only 10 units of work. In that case, we get the same energy flows as with the boiler (100 fuel in, 100 heat out), plus 20 units of so-to-speak "free" electricity.

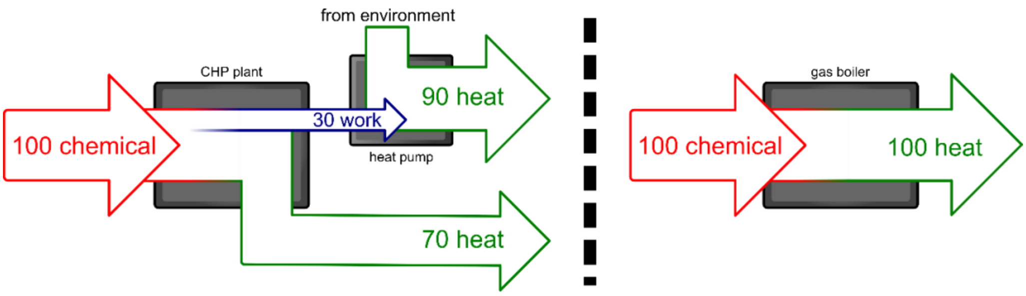


Figure 2: Thought experiment: the conversion to work in a heat engine (CHP plant) enables the operation of a heat-pump. With a hypothetical COP of 3, it generates 90 units of heat from 30 units of work. In total, the more complex system thus generates 160 units of heat from 100 units of fuel. If just burnt in a boiler, the capacity to operate a heat-pump is lost, so that 100 units of fuel become 100 units of heat.

1.2. The particular case of CHP swarm fuelled by biogenic gas

From a thermodynamic perspective, the decentral CHP approach constitutes a much more efficient systemic allocation of the energy resource "gas", compared to burning it purely for gaining heat. This becomes relevant in the context of biogenic fuel resources: depending on the production process, biogas can be virtually carbon-neutral. If augmented to biomethane (by scrapping the remnant CO_2 from fermentation), it can be used as a direct substitute for natural gas. Technically, this could be used to address the sustainability issue of large portions of the space heating and process heat markets – without the need of substituting to new conversion technologies on the consumer-side. Yet as discussed, thermodynamically, this is squandering a potential for carbon-neutral electricity production.

At least under current market conditions in Switzerland, the economy of a CHP swarm may be a challenge. However, this could change in the future, due to another key characteristic of CHPPs: they are uniquely agile, in that they can be switched on and off within seconds (to minutes for the larger plants), multiple times per day. This becomes important if there are high shares of fluctuating renewables in the electricity generation portfolio: while future solar and wind technologies may address overproduction by controlledly disconnecting from the grid, there is no innate means of compensating for an underproduction. A distributed swarm of CHPPs could provide this service. Being installed at the building level, it would directly access the same grid levels as do PV installations, thereby relieving higher grid levels.

1.3. Research questions: realistic assessment of CHP technology

For the reasons discussed in the first section, biogenic CHP is one of few energy technologies, able to sustainably plug the provision gap in a renewable dominated electricity future. However, the actual potentials are difficult to assess, because (a) they depend on regionally specific boundary conditions, and (b) the actual business case may only become feasible in a future energy economy.

This is why project CHPswarm, combining the competences of 4 research groups at ETH Zurich and PSI, produced an integrated simulation and assessment methodology. It is able to address the following core questions:

1. Swarm design: to install a CHP plant in a building, it must be connected to the gas grid and electric grid. The number of such buildings, the totally available biomethane and the local grid capacity are limited. So how large can a CHP swarm become? What are the limiting factors, and how can they be avoided?
2. Swarm operation: How should a given swarm in a given region be operated? How much communication and central planning is required? To which extent does this effectively compensate fluctuations from renewable production?
3. Economic potential: what markets can such swarms play, and what technologies do they compete with? Under what political and economic boundary conditions can they be commercially successful?

2. A methodological overview over the project

2.1. Logical entities and their relationships

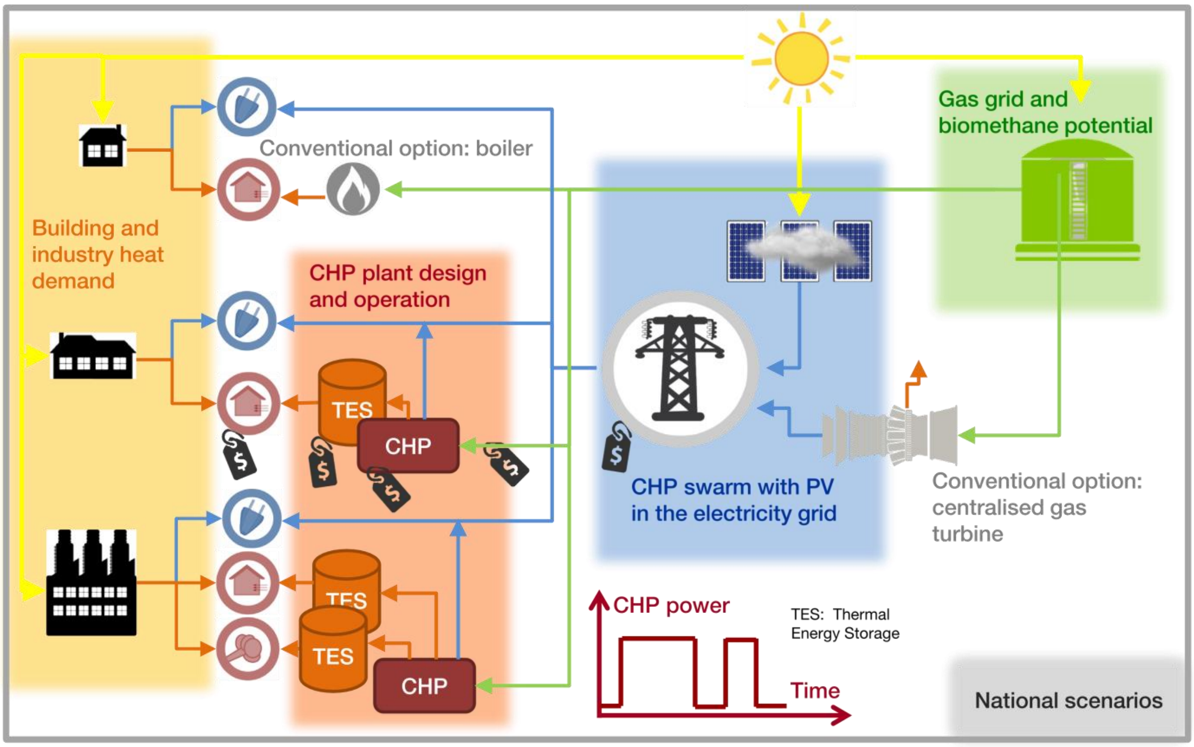


Figure 3: Schema of the system studied within CHPswarm: a building-wise distributed demand for heat and power is to be met by a swarm of CHPPs. To that end, suitable buildings have to be selected, and the CHPP designs adjusted for the specific locations. The production is modulated according to economic considerations. The swarm-size is limited by the biomethane potential. Finally the grid-impact is analysed.

The physical system under consideration resp. the methodology applied in CHPswarm is depicted in Figure 3. It can be split into 5 levels (although only 4 are shown), each involving particular competences of the research partners. The following explanations are meant to provide a first orientation. They do in no way cover the full extent of the generally quite sophisticated methodologies. Some further indications are given in the dedicated sections. For an in-depth discussion, please refer to the technical documentation.

1. Building and industry heat demand (ETHZ-LAV, ETHZ-GIE): the regional analysis departs from assessing the demand for heat and electricity in the given region. To that end, information necessary for energetic modelling is collected from governmental building inventory databases. For each building, this involves data such as its physical dimensions or possible economic / industrial activities. When combined with meteorological data, this enables the calculation of time-resolved profiles of the heat energy demand throughout one calendar year – see chapter 3 (detailed in sections 11.1 and 11.2).

2. Gas grid and biomethane potential (ETHZ-GIE): a second key input is the available amount of biomethane energy. This is estimated in a bottom-up approach, accounting for the spatio-temporal distribution of biomass resources such as manure, bio-waste and wood drawn primarily from governmental data-sources. The final output is one energetic potential (i.e. the amount of energy) under the assumption that only yet unallocated biomass generated within the borders of the study region may be used – see chapter 0 (detailed in chapter 0).

3. CHP plant design and operation (ETHZ-LAV): in this multi-stage process, a CHP swarm is designed based on inputs from points 1 and 2. In essence, for every building

with a gas-grid access, the locally optimal CHPP design is determined according to economic criteria. Then, out of all possible CHPP sites the swarm is chosen as the overall profitable subset, whose annual consumption does not exceed the biomethane potential determined in point 2. Note that the operation strategy of the individual plants impacts their profitability – consequently, a swarm-wide operation strategy not accounting for constraints in the electric grid is an implicit output of this step – see chapter 5 (detailed in sections 11.3 and 11.4).

4. CHP swarm with PV in the electric grid (ETHZ-FEN): superimposing the swarm's electrical output from point 3, flows in the electricity network are determined using an optimal power flow simulation. This is done for several assumed levels of PV penetration, to emulate possible future production scenarios. As most important outcome, this procedure unveils bottlenecks resulting from the grid-agnostic operation strategy assumed in point 3. In the evaluated test-cases, no such situations were encountered. However, if they were, the grid simulation is able to re-dispatch the swarm's production. This would then be looped back to point 3, as it either implies that the swarm is too large or that individual plants are ill-designed – see chapter 6 (detailed in chapter 13).
5. National scenarios (PSI-LEA): all considerations in points 1-4 refer to current-day boundary conditions (with the exception of the variation in PV penetration) and well-defined regions of Switzerland. In this final step, those findings are then fed into the energy economic model STEM-E of the Swiss electricity system, covering Switzerland in its entirety. Various scenarios of the development of the future energy system were the applied, to observe how CHP, as a technology, fares in the different markets – see chapter 8 (and detailed in chapter 14).

2.2. A note on the case-studies and data availability

The case-studies (points 1-4 above) cover the canton of Thurgau, Lucerne and Basel-Stadt. These represent respectively a rural, an urban and a mixed region. Unfortunately, we could only obtain a complete digital representation of the electric grid for the canton of Lucerne; for the other two study regions, only very limited subsets were available. The limitations due to bottlenecks in the grid were therefore only studied for Lucerne.

3. Building and industry heat demand

3.1. Modelling the demand for space heating energy

This was based on the EN ISO norm 13790, accounting for construction properties, building mass, ambient temperature, solar irradiation and certain behavioral patterns of the residents as the main drivers for the heat demand into account. The canton building structure was divided in single and multi-family houses as well as commercial buildings. Further data about footprint area, number of floors and construction period were used to parametrize the model together with standard SIA 380 norm values. Regional weather data was derived from Meteonorm by Meteotest. The model output is an hourly resolved heat demand profile over 8760 h of the year (see also section 11.1).

3.2. Modelling the demand for industrial process heat

The industrial process heat demand was represented directly as constant or piece-wise constant profile (if there is shift working). Facilities within sectors running processes at temperatures up to 400 °C (such as food, laundry, chemical and plastics industry), the demand was assessed on an individual basis, accounting for publically available information on their annual heat demand, process hours, shift operation, share of heat demand above 90 °C and monthly variations. The data served to created individual heat demand profile over 8760 h for all facilities (more in section 11.2).

3.3. Modeling the demand of biogas production plants

Biogas production plants are a particular type of heat sinks. They have to heat the biomass substrate to the fermenter temperature of 55 °C. This is typically done with heat from a local CHP, saving costs by directly using gas from the fermenter without purification. This results in very low fuel-costs (0.11 CHF/kWh). The plants energy demand was assessed based on their annual throughput (more in section 11.2).

3.4. Aggregated results from the heat demand model

As an illustration of the heat-demand modeling step, Figure 4 displays so called load-duration curves. A point on one of those curves can be understood as the number of hours per year a given load is required. It can be seen that especially the rural region of Thurgau differs from the other two.

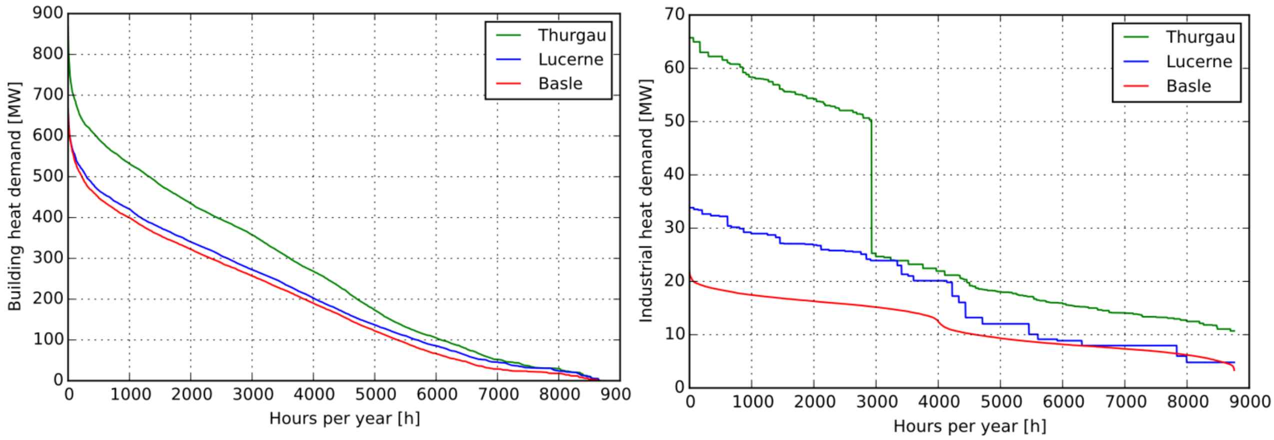


Figure 4: Heat demand load-duration curves from residential (left) and industrial (right) buildings in Thurgau, Lucerne and Basel. The plots are shown in absolute units [MW] to highlight the diverging properties of the three regions. The sudden jump on the right is due to the seasonal operation of one particularly large industrial plant in the canton of Thurgau.

4. Biomethane potentials

The estimates of the biomethane potentials were done separately for so-called wet biomass (such as manure or household waste) and woody biomass. Wet biomass is converted primarily through fermentation; whereas woody biomass is converted through gasification and subsequent catalytic conversion – the resulting product is also referred to as Synthetic Natural Gas (SNG). Note that it is generally economically infeasible to transport wet biomass over large distances.

The biogas potential of wet biomass was estimated with a bottom-up geographic information system (GIS) based model. It distinguishes between agricultural and non-agricultural bio-waste: the latter was estimated on a per-household basis, as it includes mostly bio-waste from households and gastronomy. Agricultural bio-waste on the other hand was estimated via life-stock inventories of individual farms. The result is a set of spatially biomass distribution profiles, as visualized in Figure 5. Details of the biomass model can be found in section 12.1.

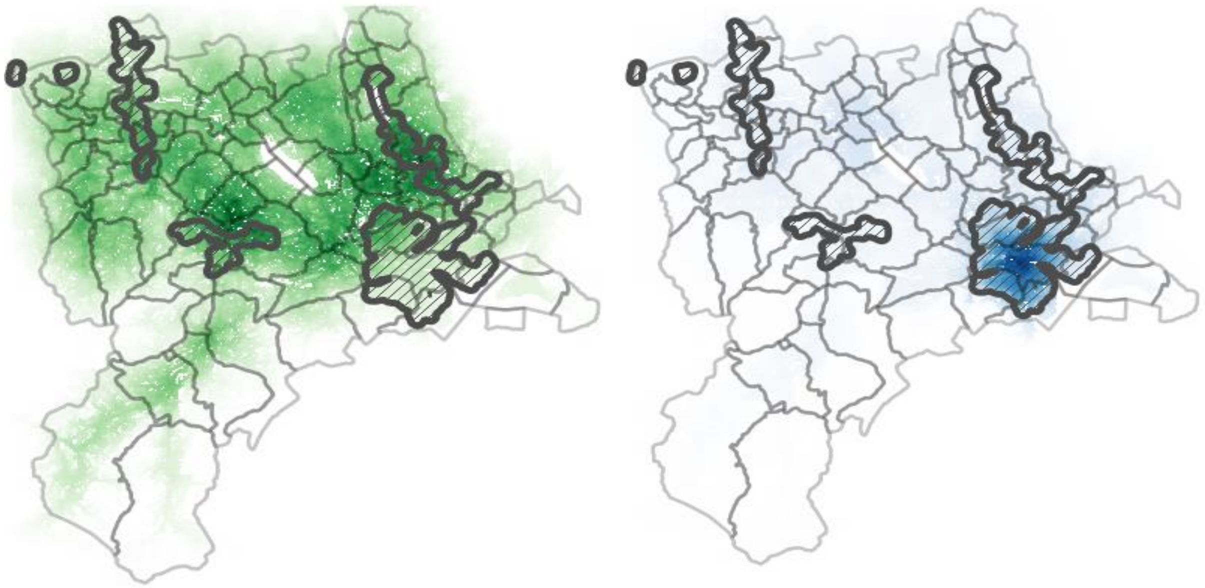


Figure 5: Spatial distribution of agricultural (let) and non-agricultural (right) biomass in the canton Lucerne. The areas surrounded by a thick grey line are those equipped with a public gas grid. Biogas plants cannot be installed outside that region, as they would have nowhere to sell their products to.

The biomethane potential was then obtained by least-cost optimization of a hypothetical, dedicated fleet of biogas plants. Figure 6 displays how extending that fleet one plant at a time increases the available biomethane potential (on the example of Lucerne), but also the specific costs. The optimization accounts for various aspects, including transportation costs, collection fees and the thermo-physical properties of the biomass. Note that only locations with access to the gas grid and sufficient potential output for current upgrading technology were considered (more in section 12.2). For the case study Lucerne, the seasonal feed-in capabilities of the gas grid were reviewed by the grid operator. Towards complete utilization of the biomethane potential, additional gas storage capabilities are required for smaller local distribution grids to store parts of the gas production during summer months.

The biogas potentials from woody biomass were based on a top-town method, using national estimates on sustainable energy wood potentials. The number was chosen so as to represent a theoretical upper bound of wood available for energy production (more in section 12.3). Figure 7 illustrates the final results, i.e. the biogas potentials used in the three case-studies, as break-down of by the different biomass sources.

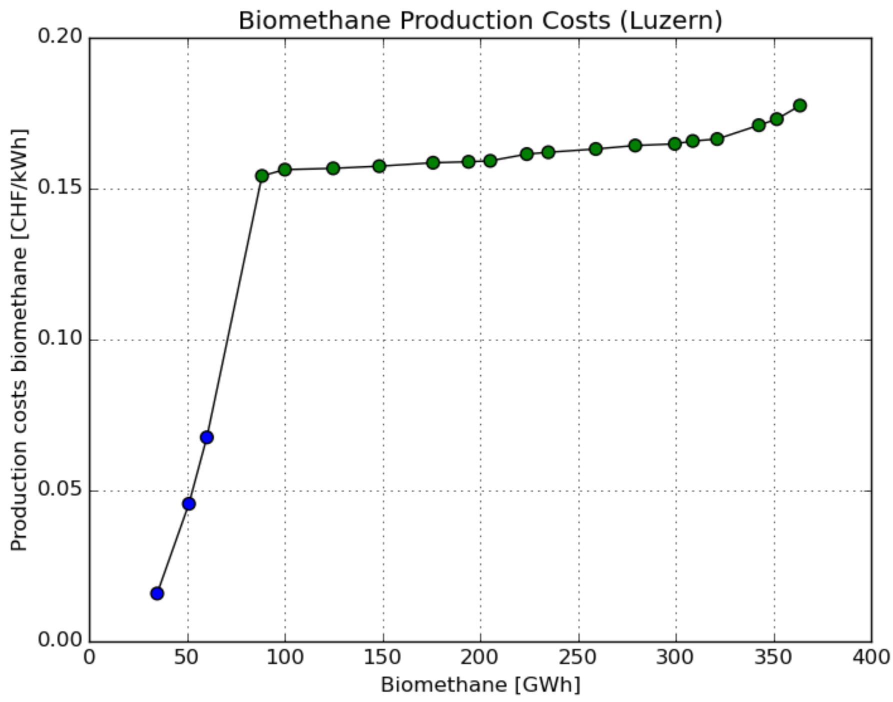


Figure 6: Estimated biogas production costs for Lucerne, extending the biomass processing capacity one plant at a time (=dots). Initially (blue dots) only non-agricultural plants are selected, as their cost-balance benefits from recycling fees. Further increasing the capacity (green dots) adds agricultural plants, but at diminishing returns (mostly due to transport).

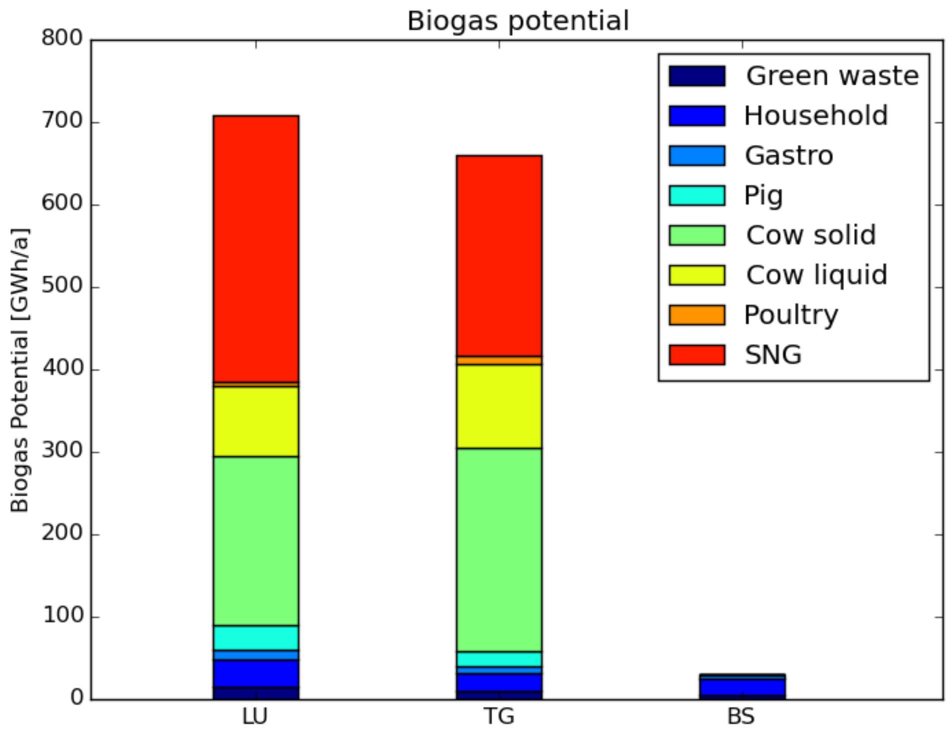


Figure 7: Break-down of the estimated biogas potential in the three case-study regions by biomass source. SNG stands for "Synthetic Natural Gas" and refers to biomass from dry biomass (wood); all other sources are considered wet biomass.

5. Combined Heat and Power plants: design and operation

5.1. Description of the physical system

In general, the technology of combined heat and power generation, also known as cogeneration, is driven by a thermal machine converting chemically bound energy (fuel) to mechanical work and heat. In this project, internal combustion engines with methane as a fuel coupled to an electric generator were chosen for their:

- very high conversion efficiency from methane to electricity
- fast response times (from zero to full load) from seconds to minutes
- covering the power range compatible with decentralized generation on low-voltage grids
- operational flexibility using a thermal energy storage for decoupling heat delivery
- heat availability below 100 °C from the main coolant loop and up to 400 °C from the exhaust

The basic construction and relevant aspects of such a plant are schematized by Figure 8 (details in section 11.4). Note in particular the intermediary thermal energy storage (TES) device between the plant and its associated heat sink. Heat up to 90 °C is typically stored in an insulated water tank; high temperature applications demand for an insulated rock bed through which the exhaust gases pass. The TES provides flexibility (depending on the capacity of the TES) to optimize plant operation with respect to the revenues attainable on the electricity market, and not only the current heat demand of the heat sink (as would be the case in a conventional central heating setting).

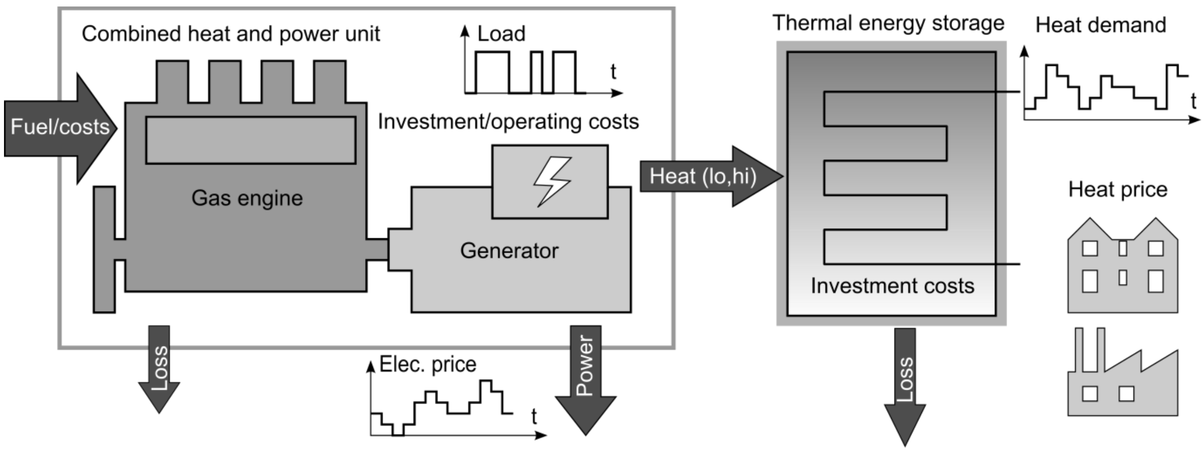


Figure 8: System diagram of a cogeneration plant and its thermal energy storage system. Fuel is converted to mechanical energy by the gas engine, and then to electricity by the generator. Some losses during this conversion process (first arrow on the left) are unavoidable. The heat is then fed to a building by intermediary of a thermal energy storage device (in essence: a water tank) decoupling the electricity and heat production.

5.2. Technical model of a CHP plant

Technically, the plants were modeled as energy converters, using basic thermodynamic principles. As a-priori it was unclear which plant-sizes to expect in the case-studies, the entire range of current-day technology was modeled. Techno-economic input data was gathered in an exhaustive market sweep – see Figure 9 for an example of data on peak electric conversion efficiencies (extended description in section 11.3).

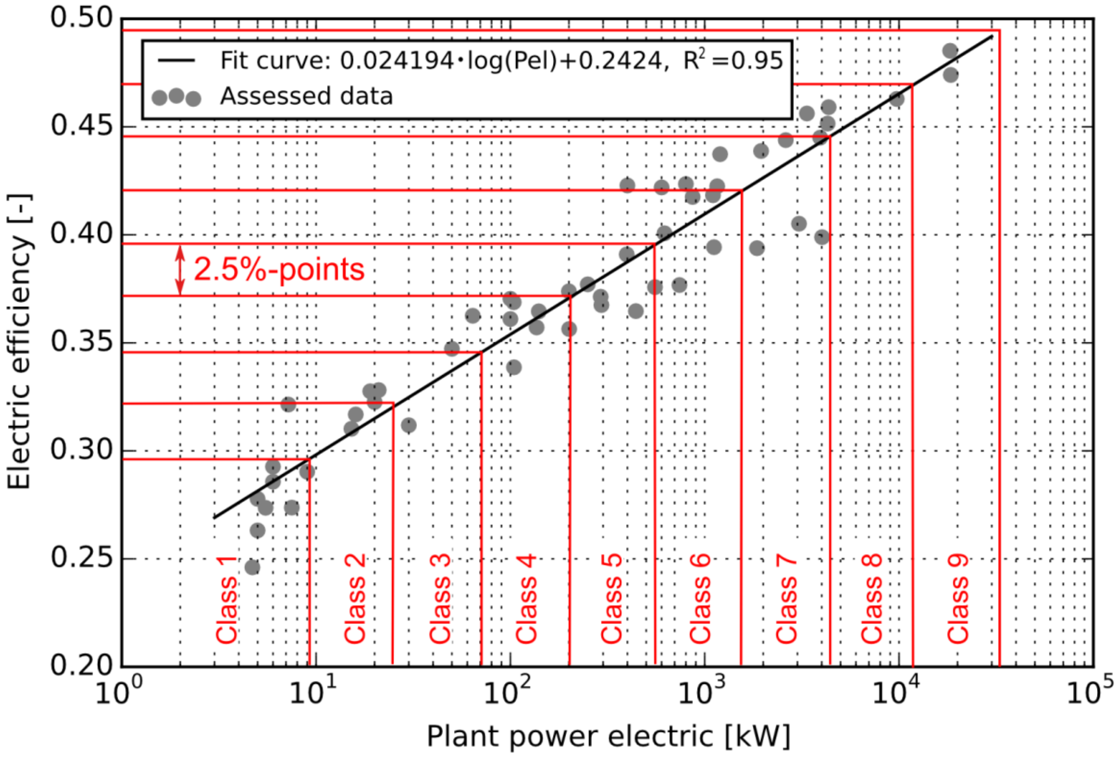


Figure 9: Overview of the thermodynamic conversion efficiencies (gas to electricity) over the whole spectrum of currently, commercially available gas-engine CHP units (in terms of rated electrical output power). There is a very clear tendency ($R^2 = 0.95$) of larger plants being more efficient. To facilitate certain modeling tasks, 9 classes were introduced, in regular intervals of 2.5 % efficiency points.

5.3. Economic model and cost break-down for insulated operation

Economically, the cost-balance for a given plant was split into fixed annualized investment costs and the running production costs/revenues. For consistency reasons, the latter was expressed relatively to the amount of electricity produced (there is other, equivalent possibilities. Since the electric efficiency is constant for a given plant, there is a linear relationship between the annual operation hours and the amounts of consumed gas, resp. produced heat and electricity.). However, it includes all running costs, also the retail price (resp. economic worth) of heat. The latter was presumed equivalent to that of a conventional gas burner, fueled by biomethane and supplying the same heat sink as the CHP plant.

Figure 10 displays the cost break-down when assuming 2000 h of annual operation time. Note that there is no fluctuating market-price behind this plot. In fact figure displays the average market price that is required for break-even.

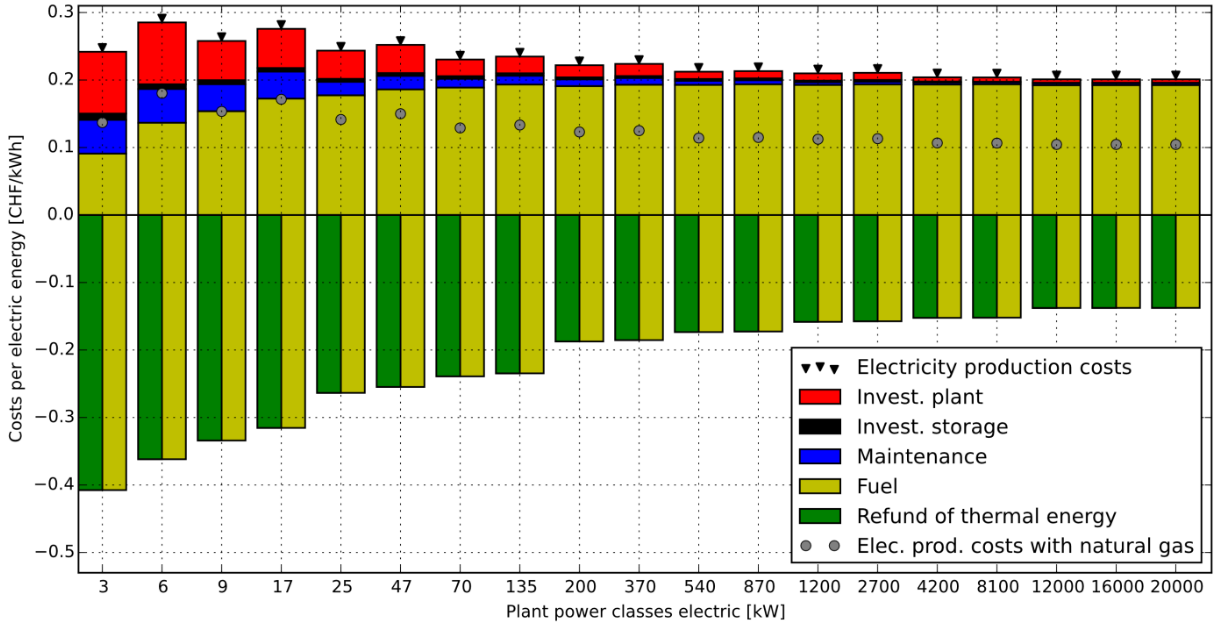


Figure 10: Cost break-down of various sizes of CHP plants, assuming 2000 operation hours, 2 % interest rate, 20 years of life-time and biomethane as fuel. The combined investment, maintenance and fuel costs are shifted downward by the "benefit thermal" (revenues from heat sales). The bars protruding onto the positive half of the y-axis thus present the electricity generation costs. They generally decrease with plant-size, but initially, there is a reversal: the smallest plants are cheaper than their next-largest neighbours, due to the high "benefit thermal" of the equivalent gas boiler.

5.4. Plant design and operation strategies

When a CHPP is paired with a heat sink, the task of "plant design" consists in fixing:

- the engine electric power
- the thermal energy storage capacity
- the operation pattern (which is Boolean vector, describing whether the plant is on or off for each hour of the simulation year)

Obviously, the most economic CHP design for the sink should be used. Note that the optimal design then also implies the optimal operation strategy. Adopting the traditional approach in scientific literature, the problem was reformulated as a linear program. Its objective function was the total-cost function as described in the section above; the thermodynamic model equations (see technical model above) entered as constraints. Since the on/off state is discrete, this led to a so-called Mixed-Integer Linear Program (MILP). It was solved using a commercial solver (details in section 11.4).

During the course of this project, ETHZ-LAV developed a heuristic algorithm capable of solving that same problem much faster. This makes it possible to optimize against the entire swarm – and not individual plants (as with the MILP-based approach).

6. CHP swarm with PV in the electric grid

6.1. Note on data availability

As was mentioned in the introduction, Thurgau and Basel will not be considered in the following, as only for the canton Lucerne full datasets regarding the grid topology were available. Furthermore, there are in fact two utilities covering different regions of the canton. One of them did not provide geographic coordinates of the network nodes, so that individual locations of the CHPPs resp. their housing buildings cannot be associated to grid nodes.

6.2. Methodology: Checking CHP swarm operation profiles for grid violations

The basis of the power flow analysis was an optimal power flow (OPF) simulation. Given a PV injection signal, as well as the disaggregated production signals of individual CHPPs in the swarm, the OPF simulation is used to detect network constraint violations – in particular line overloading and overheating. More concretely, the OPF was configured to overwrite the imposed CHPP injection in case it cannot avoid a constraint violation otherwise. The number of re-dispatched hours of CHPP production thus becomes a direct measure of how "problematic" a given swarm layout is in terms of grid loading (more details in section 13.3).

6.3. Modeling of PV injection

The PV injection signal was derived on the basis of the 2050 scenarios set forth in the BFE/Prognos Energy Scenarios. In their scenarios "low", "medium" and "high", the authors assume an annually and nationally aggregated production of 5.5, 11.0 and 16.5 TWh respectively. These numbers were scaled down to Lucerne, proportionally by its number of inhabitants. Next, diurnal variations were introduced by means of hourly resolved solar irradiance profiles. These were linearly scaled, so that the annual, cumulated production matches the aforementioned, down-scaled Prognos results (see also section 13.2).

6.4. Stabilization of the electric grid

In this sense starting from a generic time series of (scalar) values *x(k)*, one common approach for computing its degree of variability is by evaluating the standard deviation σ of the signal. It expresses variability by considering the degree of oscillation around the average (a constant signal yields $\sigma = 0$). In order to assess the effect of CHP dispatch, the standard deviations of *PV(k)* and *PV(k)+CHP(k)*, i.e. the power generated by the PV units and the PV and CHP units combined, are calculated for all considered combinations and denoted as σ_p and σ_{pc}. Please find further explanations in sections 13.3 and 13.4.

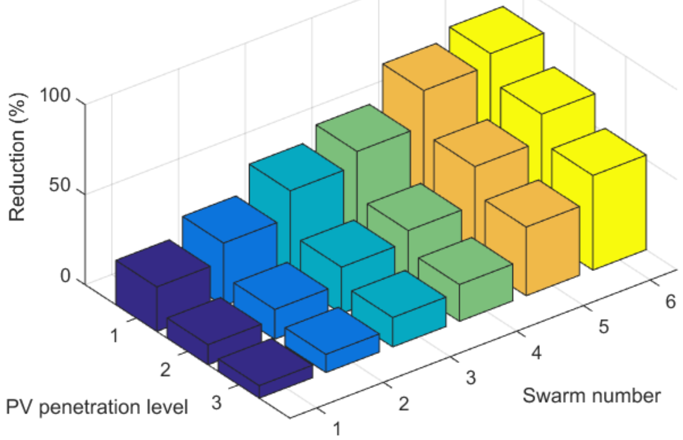


Figure 11: Average yearly percentage reduction between σ_p and σ_{pc} in CKW grid (PV penetration levels 1, 2, 3 correspond to low, intermediate and high scenarios respectively)

7. Combined results from the case-studies

7.1. Swarm design

As the bio methane supply in a given region is limited, it is generally not possible to install a CHP unit in all buildings that are eligible (on account of being connected to the gas and electricity grids). In that case, a great number of individual swarm configurations (in terms of selected installation sites) are possible. An obvious choice is to request the most profitable subset of locations that does not exceed the local biomethane potential. The mathematical formulation of this is a knapsack-type combinatorial optimization problem. For the case-study of Lucerne, where a geographical allocation of CHPPs and grid nodes was possible, it was further constrained by requiring that the totally installed CHPP power at a given node (= transformer substation) never exceeds the median residual load at that node. This ensures a more even distribution of CHPPs among the network.

7.2. Combined potentials

Table 1 displays the numeric results of the swarm design process, applied to the three case-study regions. It is apparent that the structure of the region plays a crucial role in determining the potential for a CHP application, as can be seen in particular in the context of Basel-Stadt (BS). Here, as per the modeling paradigm of all bio-mass having to originate within the boundaries of the study-region, the “all-city” region has a perhaps unfair deficit.

Reference swarm properties	Unit	Thurgau	Lucerne	Basel
Cantonal electricity demand	GWh	1'763	2'713	2'393
Heat demand in gas grid area	GWh	2’588	1’977	1’762
Total biomethane potential	GWh	684	692	30
Bio-CH_4 from wet biomass	GWh	431	370	30
Bio-CH_4 from woody biomass	GWh	253	322	0
Number of possible CHP sites	-	45'687	27'585	20'216
Sites effectively in swarm	-	9'676	6'806	509
Building CHPs in swarm	-	9648 (of 45'641)	6'785 (of 27'550)	508 (of 20'211)
Industrial CHPs in swarm	-	5 (of 23)	1 (of 15)	0 (of 4)
Biogas plant CHPs in swarm	-	23 (of 23)	20 (of 20)	1 (of 1)
Swarm peak power electric	MW	169	101	5.6
Swarm electricity output	GWh	289	256	11
Swarm covered heat demand	GWh	323	359	15
Swarm overall electric efficiency	%	42.2	37.1	38.3
PV scenario “low”	GWh	176	248	130
PV scenario “medium”	GWh	350	497	260
PV scenario “high”	GWh	525	745	390

Table 1: Characteristics of the cost-optimal “reference” swarm: if a swarm is a subset of buildings connected to the gas-grid, then the optimal swarm is the one that maximizes profits without exceeding the regional bio-CH_4 potential (see section 7.1)

Plain to see: in each case, the limiting factor is the biomethane potential – note that the network simulation showed no network constraint violations for the case of Lucerne. To explore this issue further, Figure 12 and Figure 13 extend the scope by varying the available biomethane. The coverable share of the heat demand of buildings connected to the gas grid increases seemingly linearly. For the case of Lucerne (the only one where the grid simulation could be performed) the grid only becomes constraining when more than 5 times the estimated biomethane potential is allocated – which translates to almost 90 % of the heat demand covered.

With regards to electricity (Figure 13), the share of the residual load (demand not covered by PV) supplied by CHPPs similarly increases almost linearly with the invested amount of biomethane.

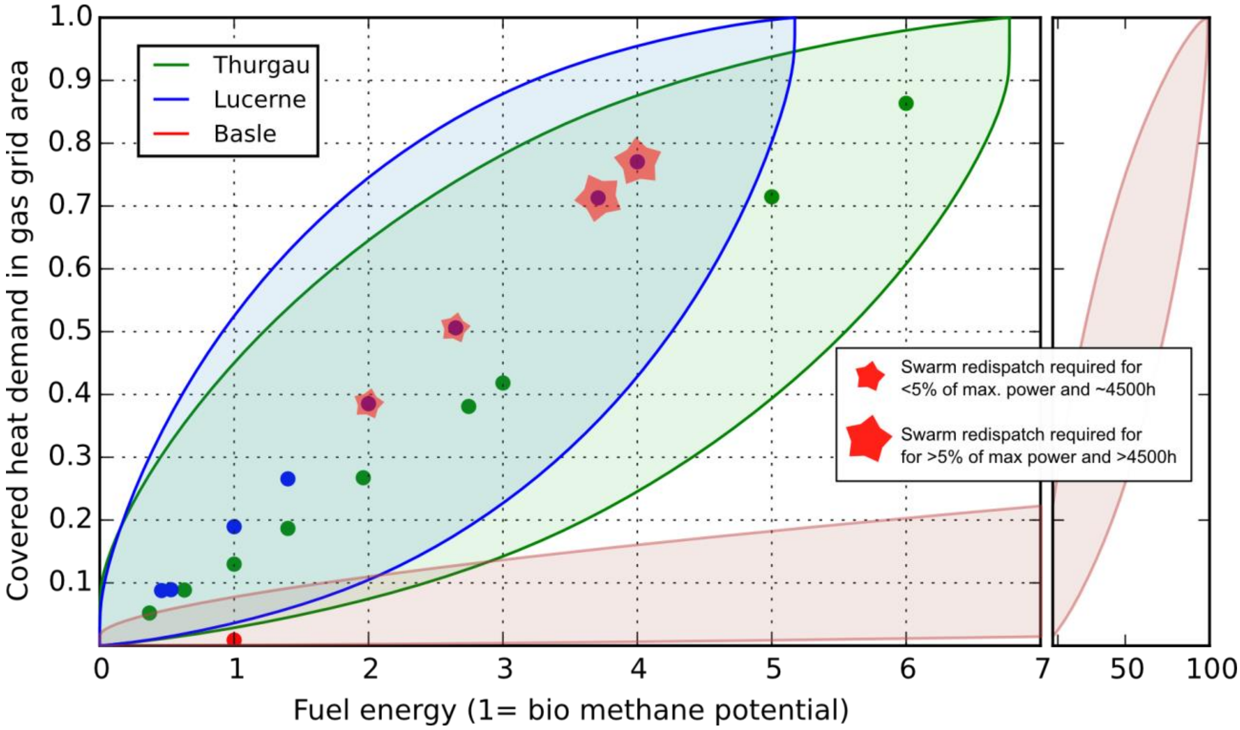


Figure 12: Satisfied share of the heat demand from buildings connected to the gas grid as a function of biomethane invested (into a CHP swarm). The plot shows all constraining factors: the colored areas mark the domain of all possible swarm configurations – the upper point of the "lenses" being the swarm involving all available sites; the x-axis is normalized to the local biomethane potential; dots highlighted by red stars are infeasible due to network constraint violations.

The saturation effect towards the largest swarm is likely due to the constraint on installable power (see section "Swarm design" above): some plants, in particular large CHPPs in industrial sites, may never be selected into the swarm, regardless of how much biomethane is available. This would happen in particular with industries consuming a lot of gas (for heat), but relatively little electricity. A CHPP, able to provide sufficient heat is quite likely going to be too powerful for the grid connection to the site.

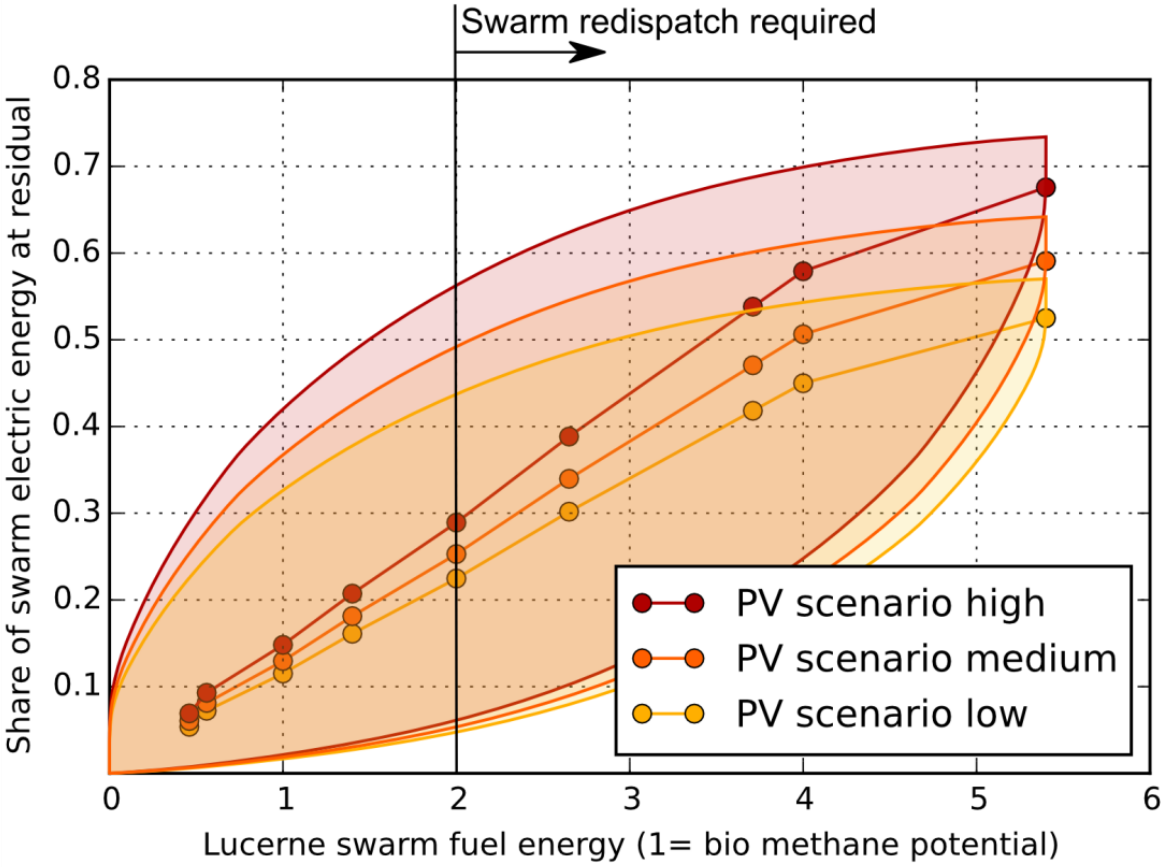


Figure 13: Share of the residual energy (demand not covered PV - or CHPPs) supplied by CHPPs as a function of biomethane invested on the example of the canton Lucerne. Results are shown for the 3 PV penetration scenarios (see section 6.3). By the definition or "residual energy", the CHP-supplied share increases with the PV penetration level. The colored areas mark the domain of all possible swarm configurations.

8. National scenarios

The objective of this final part was to quantify the role of biogenic CHPP and the conditions under which they become competitive applying “what-if” type scenarios – see section 8.3. For the sake of brevity, this report only features main results; see section 14 in the technical report for an in-depth discussion.

8.1. Methodology: the Swiss TIMES electricity and heat model

The Swiss TIMES Electricity and Heat Model (STEM-HE) is a partial equilibrium bottom-up model covering the Swiss electricity and heat systems from resource supply to end use. It determines, with perfect foresight and long-run marginal cost pricing, the least cost combination of technologies and fuel mixes to meet exogenously given electricity and heat demands subject to technical and policy constraints. The model has a long time horizon (2010-2100) with an hourly time resolution, and it is an extension of the Swiss TIMES Electricity Model (STEM-E). The model includes the following features (for a more detail description of the model see section 14.2):

- Biogas/biomethane production and distribution infrastructure
- Detailed representation of the decentralized heat/electricity generation with four levels of electricity transmission and distribution grids
- Assessment of the role of CHPP in electricity and heat supply, together with their flexibility in providing secondary reserve control power for electricity grid balancing services
- Endogenously modeling of primary and secondary reserve control power markets for electricity grid balancing (participation of a power plant in the balancing service markets based on long run marginal costs for electricity production and the revenues from providing grid ancillary services)
- Heat demands from three main end-use sectors, *viz*. industry, services and residential (single- and multi-family houses; existing and new buildings (existing buildings are considered those built until 2000 – 2005; single family houses include both one and two -family houses).

8.2. Integration of case-study results

The main assumptions and insights from the regional case studies have been incorporated into the scenario analysis. These include techno–economic characterization of the biogenic CHPP, wet biomass resources, and potential for the technology to participate in electricity grid balancing services. The main output of the scenario analyses includes, but not limited to, technology and fuel mix in supplying electricity and heat demands, energy system costs, CO_2 emissions, as well as marginal costs of electricity and heat.

8.3. Core energy transition scenarios

Four core scenarios have been defined across two main dimensions regarding the future configuration of the Swiss electricity and heat system: the investment decisions in new centralized gas power plant(s); and climate change mitigation goals (Figure 14). A “*Reference*” scenario consistent with the “*Politische Massnahmen – POM*” scenario of the Swiss Energy Strategy is defined. The energy service demands in the “*Reference*” scenario are derived from the developments and policies of the “*POM*” scenario. In addition, we included zero net imported-electricity constraint at the annual level from 2020 and beyond (we enforce a constraint that the net sum of the internationally imported and exported electricity volumes should be zero, reflecting the historical trends, but the model has the option to import/export electricity at the seasonal and diurnal levels).

The “*No Gas*” scenario includes all the assumptions of the “*Reference*” scenario, but investments in new large scale gas power plants are not allowed. The “*CO2*” scenario aims at a CO_2 emissions reduction target of 70 % in 2050 compared to the 2010 levels, by imposing a cap on total CO_2 emissions across all sectors represented in the model (the imposed CO_2 emissions reduction target is compatible with the recent pledges submitted by Switzerland to UNFCC and with the objectives of the Swiss Energy Strategy). The "*No gas and CO2*" scenario combines the "*CO2*" and "*No Gas*" scenarios. To understand the key drivers influencing the penetration of biogenic CHPP in electricity, grid balancing and heat markets, a set of parametric sensitivity analyses on the main drivers in the "*Reference*" scenario were addressed. These are not part of this summary report. Details about the description of the core scenarios and their variants are given in section 14.3.

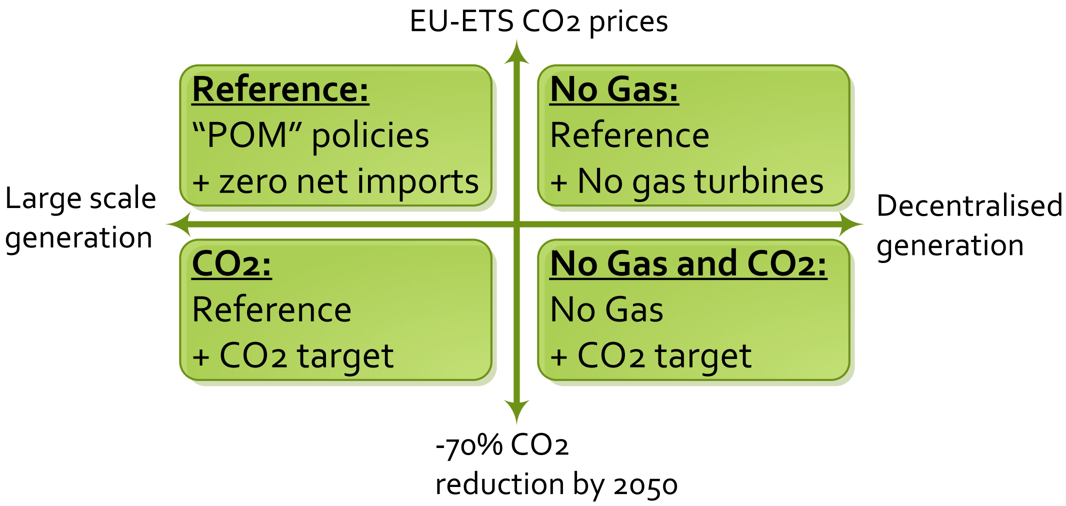


Figure 14: The four core national energy transition scenarios.

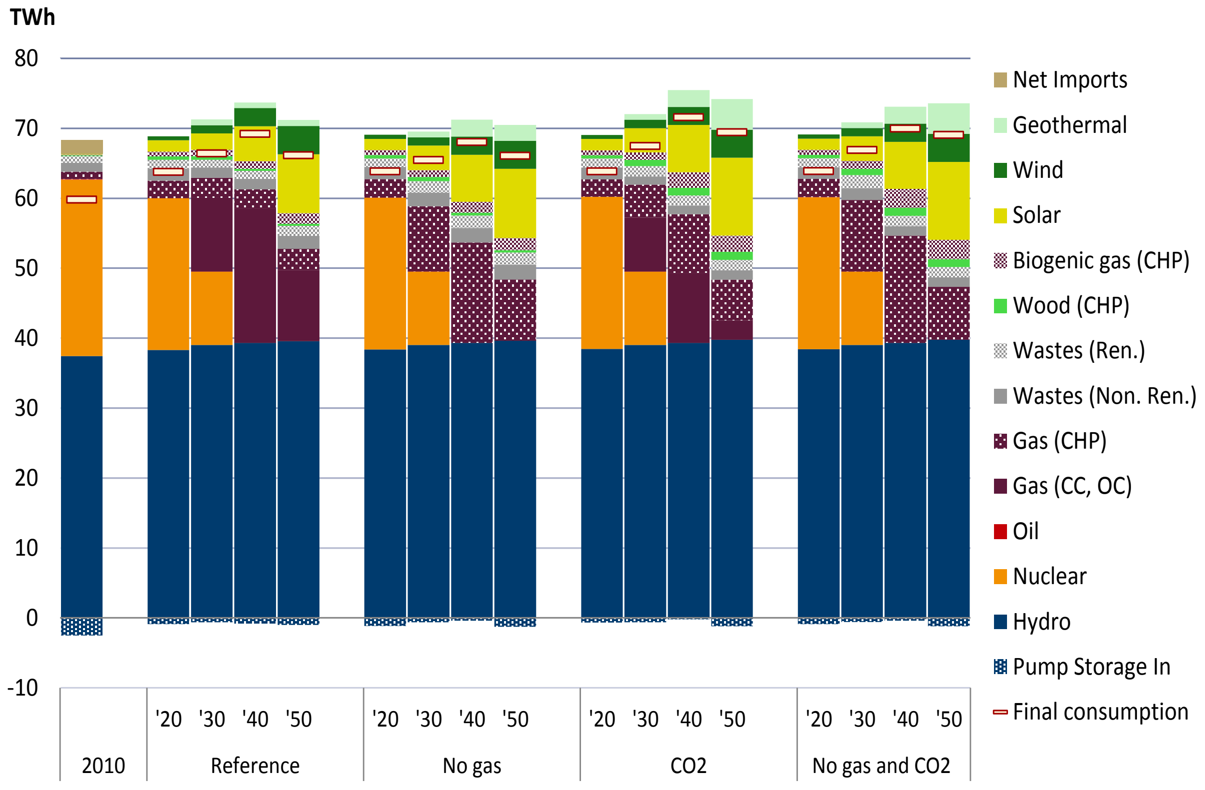
8.4. Results

The main findings from the national electricity and heat core scenarios are discussed below. An in-depth analysis is provided in section 14.4.

8.4.1. Electricity supply and the role of biogenic CHP plants

The electricity supply gap arising from the nuclear phase out (and the assumption of zero net imports of electricity) requires investment in renewable energy, decentralized CHP plants and large gas plants (see Figure 15). There is a trade-off between decentralized and centralized electricity generation, which is driven by the economies of scale and the electricity production costs. Across all scenarios the share of CHP plants in electricity supply increases until 2050. Their penetration depends on the decision of investing in centralised gas plants, the stringency of the climate policy and the competitiveness of renewable energy for electricity production. In fact, the intermittent renewables for electricity production have a two-fold effect in the penetration of biogenic CHP plants: while they increase competition in electricity supply, at the same time they also increase the demand for grid balancing services.

To this end, biogenic gas CHPP can provide 2.1 – 3.8% of the total electricity production by 2050 (or equivalently they produce about 1.5 – 2.8 TWh_e). For a detailed analysis regarding the long-term developments in the electricity sector, its future configuration in the four core scenarios, as well as the role and the prospects of the biogenic CHP plants in the electricity supply market please see section 14.4.1.



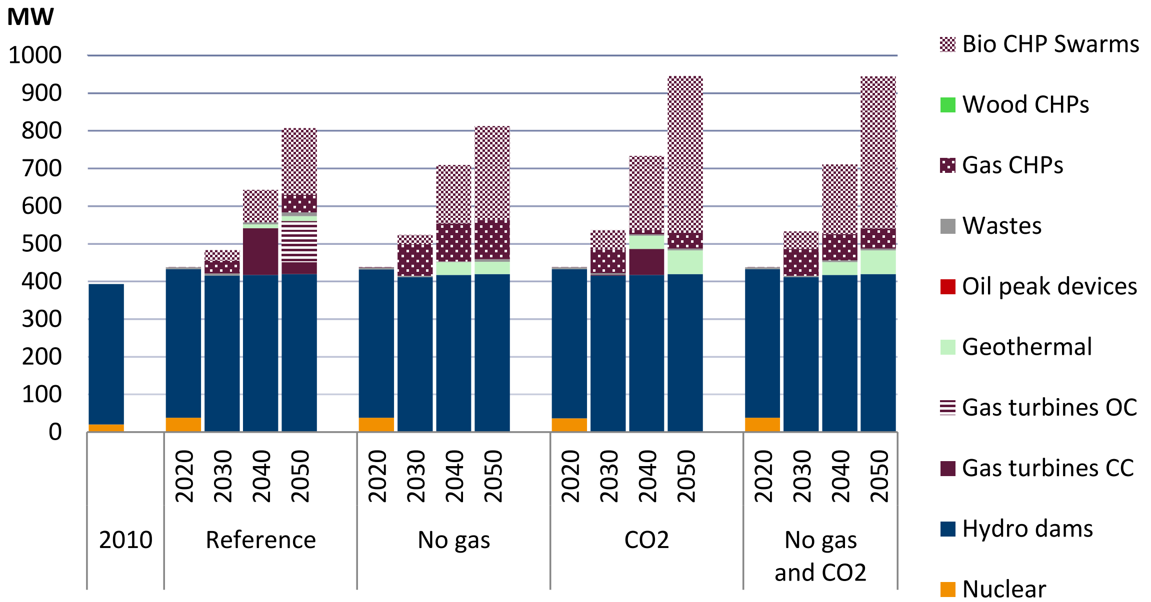
Gas CC=gas turbine combined cycle; Gas OC=gas turbine open cycle; Wastes (Non. Ren.)=non-renewable waste treatment plants (KVA/ARA) ; Wastes (Ren.)=renewable waste treatment plants (KVA/ARA); Wood (CHP) = CHP units using wood on-site (combustion or gasification); Biogenic gas (CHP) = CHP units using biogas or bio-methane from gas grid

Figure 15: Electricity production mix and electricity final consumption in the four core scenarios.

8.4.2. Electricity grid balancing and the role of biogenic CHP plants

The grid ancillary services assessed in the analysis are limited to provision of secondary control power, which depends mostly on the development of the Swiss electricity system and the needs for flexible generation capacity (demand for primary control power mainly depends on the developments of the European electricity system and is defined by ENTSO-E). Today hydropower, and to some extent nuclear power plants, provide about 400 MW of secondary positive control capacity. Because of the higher penetration of intermittent renewable sources in electricity generation by 2050, the requirements of secondary control reserve is doubled from today's levels. The highest demand for reserve occurs in scenarios with increased electricity supply from solar PV (Figure 16). The secondary reserve is lower in the scenarios with restricted centralised gas plants ("*No Gas*" scenario) because the electricity demand itself declines, which eventually lowers the demand for balancing reserve services. Most importantly, the analysis reveals a shift in the peak demand for secondary control power from winter in 2010 to summer in 2050, due to high outputs from solar PV in summer.

The role of biogenic gas CHPs in the grid balancing markets depends on the trade-off between committing the installed capacity for electricity supply versus reserving it for grid balancing. This is driven by the marginal cost of electricity supply and its value against the cost of capacity to cover capital and fixed operating costs. The availability of the biogas resource and its price are also influencing factors for the participation of the biogenic CHPP in the balancing markets, since some units are kept at a stand-by mode to serve for secondary reserve. In the current analysis, about one sixth of the total reserved capacity of biogenic gas CHPP for balancing services is kept online (i.e. 30 – 70 MW). An in-depth analysis of the electricity grid balancing long-term requirements as well as the prospects of the flexible biogenic gas CHPP in providing such ancillary services is given in section 14.4.2.



Gas turbines CC=gas turbine combined cycle; Gas turbines OC=gas turbine open cycle; Wastes=renewable and non-renewable waste treatment plants (KVA/ARA) ; Gas CHPs = natural gas-fired CHPP; Wood CHPs = CHP units using wood on-site (combustion or gasification); Bio CHP Swarms = CHP units fuelled by bio-methane/biogas and operate as swarm

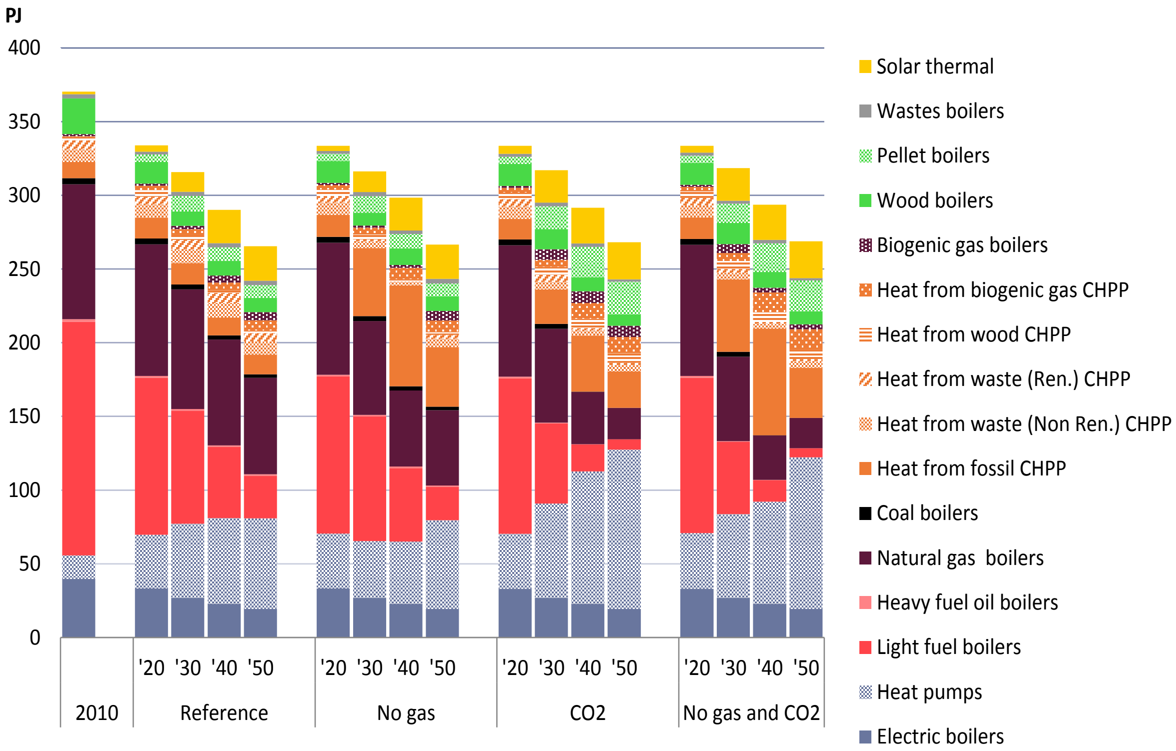
Figure 16: Contribution of different technologies in secondary positive control power.

8.4.3. Heat supply and the role of biogenic CHP plants

Figure 17 presents the penetration of heating technologies, including biogenic CHPP, in total heat supply in all sectors (the heat production from CHP plants includes both heat consumed on-site or fed into district heating networks). In all end-use sectors oil-fired heating systems are phased out and replaced by natural gas boilers, electric heat pumps, and heat from CHP units. In the case of stringent climate policy, wood/pellets-fired boilers play also a substantial role.

Heat pumps can constitute both competitors and complementary technologies to biogenic CHP plants. In the second case they constitute electricity sinks for the electricity produced by CHPP, and this combination increases the efficiency in electricity and heat supply. This synergy is prominent in those markets where the two technologies serve different types of demands (e.g. industry). In other markets, it mainly occurs when there is need for higher efficiency in the electricity and heat supply (e.g. in residential/services sectors when climate policy is in place). This is because of economies of scale, which increase the specific capital costs for small in size combined applications of heat pumps and CHPP.

To this end, the heat produced by biogenic gas CHP plants accounts for 2.6 – 5.1% of the total heat supply in 2050 (or equivalently they produce about 6.9 – 13.6 PJ). More detailed analysis regarding the developments in the end-use sectors and the role of biogenic CHP plants in the heat market are given in sections 14.4.3 and 14.4.4.



Heat from fossil CHPP = heat from natural gas or oil-fired CHPP; Heat from waste (Non. Ren.) CHPP= heat from non-renewable waste treatment CHPP (KVA/ARA); Heat from waste (Ren.) CHPP= heat from renewable waste treatment CHPP (KVA/ARA); Heat from wood CHPP = heat from CHP units that use wood on-site (combustion or gasification); Heat from biogenic gas CHPP = heat from CHPP fuelled by biogas/bio-methane; Biogenic gas boilers = heat from boilers fuelled with biogas/bio-methane; wastes boilers = heat from boilers using non-renewable waste; The heat from CHPP is either used on-site or injected into district heating networks

Figure 17: Heat supply mix (all technologies, all sectors).

8.4.4. Propspective drivers of biogenic CHP plants

The analysis from the core national electricity and heat supply scenarios and their variants identified key competing technologies to biogenic CHPP in three markets, *viz*. electricity, heat and grid balancing services, and a set of synergies and barriers that can potentially drive their deployment (see also section 14.5):

- The natural gas price and its competitiveness with the biogas/bio-methane price is a main factor affecting the uptake of biogenic gas CHP plants. Viewed another way, the biogas production pathways and resource potential also determine their penetration.
- The stringency of climate policy creates a market for low carbon heat and electricity, and enables investments in biogenic CHPP. Despite the increased competition for biomass resource from other technologies as well, biogenic CHPP prove to be an efficient pathway for using biomass in stationary applications.
- The demand for grid balancing services also affects the uptake of biogenic CHPP. If they cannot provide such grid balancing services, then their installed capacity is reduced nearly by half compared to the opposite case.
- Growth in future electricity and heat demands is another factor that influences the prospects of biogenic CHPP, since it affects the size of the electricity, heat and grid balancing markets and consequently the investments in new technologies.
- Key competing technologies in electricity and heat markets are the centralised power plants and the gas CHPP. Intermittent renewables increase competition in electricity supply, but they also create opportunites for biogenic CHPP to participate in balancing services. Heat pumps can constitute competitors, but synergies with CHPP in heat supply also have been identified. In the balancing market, key competing technologies include hydropower and flexible gas plants and indirectly batteries and demand side management measures (that mitigate the need for control reserve capacity).

9. Concluding thoughts

9.1. Conclusions

Referring back to the research questions raised in section 1.3:

1. As to the maximum size of a CHP swarm and the limiting factors behind it: clearly, the case-studies show that the biomethane supply is the most constraining factor. For the case of Lucerne, the grid seems to become limiting if the swarm consumes 200 % or more of the biomethane potential. However, as demonstrated by the national scenarios, the allocation of biogas is finally a market matter. Availability of heat sinks was never really limiting. The reference swarm, consuming all the biomethane in the region, had a peak power output on the order of 100 MW. This is not a negligible contribution – for example it would be more than enough to participate in the Swiss balancing services market.
2. In the case study Lucerne, swarm operations followed a purely greedy economic strategy, trying to maximize profits for each individual plant, regardless of bottlenecks in the grid (only considering spot market electricity prices). Only a swarm consuming more than 200 % of the biomethane potential was big enough to require re-dispatching of the swarm. At that point, 20-30 % (depending on PV penetration) of the residual electric energy (demand covered neither by CHPPs or PV), and about 25 % of the heat demand of gas grid connected buildings are covered by the swarm. A larger swarm would only be possible under direct integration with the dispatch operations within the electric grid, i.e. some form of interaction with the grid operator. From a purely technical perspective, there is thus a quite significant potential for CHP services that do not require advanced communication schemes.
3. With regards to economic potentials, high natural gas prices or stringent climate policy regimes could allow biogenic gas CHP plants to cover up to 4 % of the national electricity demand in 2050 (16 % if including natural gas CHPs, wood-fired CHPs and waste treatment CHP plants). Otherwise, they may end up playing a mostly complementary role to the expected options for electricity production (gas plants, renewables), heat supply (heat pumps) and balancing services (hydropower, flexible gas plants).

On a methodological level, a loosely coupled simulation and analysis framework was developed and successfully implemented in three case-studies and a national scenario analysis. A crucial stepping stone was the formulation of clear, interdisciplinary modeling paradigms – this is what ultimately enabled linking the different problem areas. The experience is available now and can be applied to other problem settings.

9.2. Outlook

At this point of the analysis, several additional roads could be taken:

– Even though the analysis of Lucerne suggests that CHP operation could occur, to a certain extent, in ignorance of grid constraints, a tighter integration may enable further business cases for CHP swarms. On one hand of course, even larger swarms could be constructed. On the other hand, more conscientious planning may create added value, for example if a grid operator can use CHPs to defer an infrastructure investment. This raises the more general question as to who owns and operates such a swarm – or other decentralized assets. If the operator is not allowed to take control of the asset, this probably implies some form of dynamic, nodal pricing scheme. The methodology developed in CHPswarm could easily be adopted to explore possible solutions. A good understanding of this interface issue could be a crucial contribution to the marketability of CHP technology. A first development in this direction consists a control algorithm developed at LAV, able to re-dispatch swarm production to match a desired overall output signal – see Figure 18.

- Another extension that could be constructed rather leanly on top of the current methodology are the inclusion of local and district heating networks. In principle, the tools to perform such an analysis were developed in the project. Yet this adds several degrees of freedom to the design problem, and thus requires well-defined boundary conditions. For one, this involves highly resolved data on existing networks. But it also requires in-depth knowledge of how energy utilities make decision with regards to power generation, network extension and operation. Such a study would ultimately generate technically feasible decarbonization strategies for regional energy systems.
- On the demand side, the bottom-up modeling approach could be extended to include all energy sectors, in particular mobility (which currently, in CHPswarm, is not reflected). The mobility is uniquely flexible in when and where it draws energy from the energy system, as mobility implies some form of on-board storage.

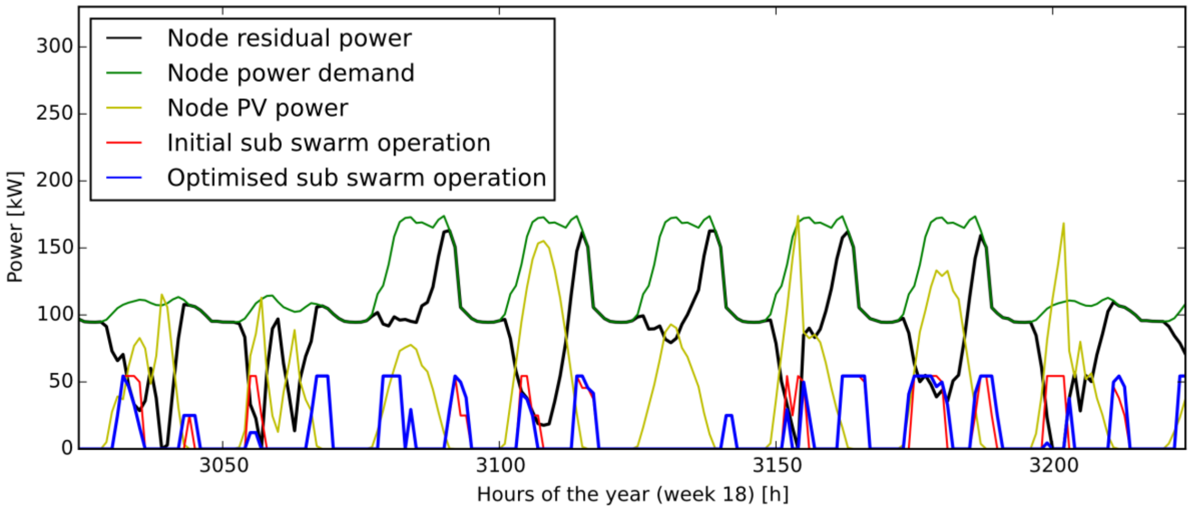


Figure 18: Example of redispatching of 8 units (3.6, 3.9, 4.1, 4.4, 4.4, 4.5, 4.5, 25 kWel) connected to a common grid node in the canton Lucerne. In essence, an additional, supervisory controller rearranges production so that the swarm never produces more power than is locally consumed. This reduces the annual profits over the whole swarm by merely 0.1 ‰.

10. Project methodology (ETHZ-LAV)

Chapters 1-9 were designed to provide an overview over the very complex subject matter, at the expense of methodological detail. Starting with this chapter, we do the opposite: the different methodologies are covered in more detail, but we do no longer explicitly relate every step to the overall goals of the projects.

In this chapter, we open the discussion with a more managerial overview over the workflow, through which we effectively combined the specific competences of the individual research into a consistent, multidisciplinary system analysis.

10.1. Project workflow: weaving individual competences into a coherent, multidisciplinary system perspective

We consider the definition of the workflow resp. the interface definitions between different work units as perhaps the most important achievement of CHPswarm – for certain it was one of the hardest to obtain. While a division of labour parallel to the different focus topics of the research partners was established early on, the precise methodological couplings took almost 3 years to emerge.

As primary cause, we identified the slightly different viewing angles experts from different (albeit generally still more or less engineering-related) fields tend to have on the same system – or, more to the point, the miscommunications that occur when different people consider different things as self-evident. Practically this primarily materialized as simulation models implicitly making assumptions on aspects covered differently in other models. For example, the grid-simulation initially employed operation strategies globally optimal with respect to the grid, plant-design optimized locally, maximizing the economic benefit of each single plant. As trivial as it may sound, the key to overcoming this was the formulation of clear, mutually accepted modelling paradigms (see section 10.2). This was a long, iterative process, generally driven by our progressively uncovering methodological incompatibilities – and introducing new ones in the process.

Based on a common understanding of the nature of the individual group methodologies, we were able to softly couple them in the work and data-flow displayed in Figure 19. It defines primarily the different steps necessary to excute the regional case-studies.

The outcome is a fully qualified CHP swarm, including its operation strategy and the resulting impact on the electric grid. The analysis begins within the greyed area in the middle of Figure 19. This area regroups the gathering and preprocessing of the required input datasets, namely (1) information on energy network topologies (see sections 13.2 and 12.5), (2) inventory data used in the estimation of available biomass (see section 12.1) and (3) building specifications (see section 12.4) and their heat energy demand (see sections 11.1 and 11.2).

In a next step, those datasets are successively combined into (1) a set of buildings suitable for CHP plant installation (see section 12.4.4) allocated to a node of the electric grid, (2) the nominal load to be expected at each node (for swarm design) and (3) the amount of available biomethane energy (see section 12.2).

Then, for each potential installation site, the economically optimal design is computed (see section 11.4). Out of that set, the largest, most profitable subset of plants consuming not more than the previously calculated biomethane potential is selected (see section 11.5). The resulting operation strategy is finally fed into an optimal power flow simulation (see section 13.3) as a starting point. If constraint violations are detected, the swarm-design step is reiterated (e.g. by restricting the installable CHP power for critical network nodes). Otherwise, the procedure is considered succesful at this point, and the results are ready for post-processing.

Figure 19 also details the integration of the national scenario analysis by PSI-EEG (see section 14). At various stages throughout the modeling process, intermediary and final results were fed into the EEG energy-economic models. The indicated loop of repeating the case-studies for future conditions as derived from the EEG scenarios had to be foregone due to time-constraints.

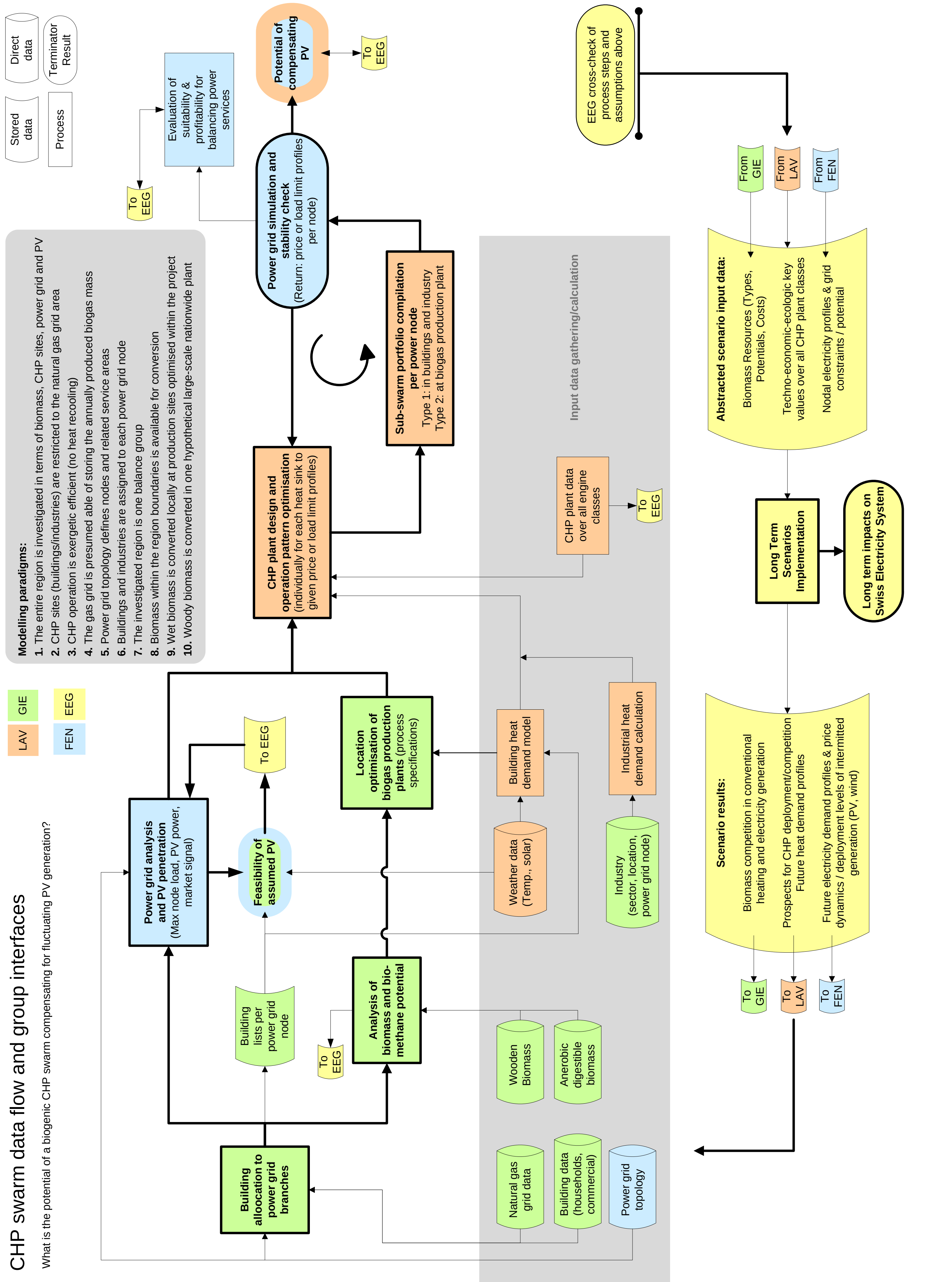


Figure 19: Data flow chart structuring the case study work among the research groups.

10.2. Modelling paradigms

CHPswarm united energy-economic, geo-spatial, thermodynamic and electrical engineering researchers around the problem of decentralized power production. As discussed in section 10.1, these different points of view initially led to misunderstandings. So in the course of building the data flow chart, a set of modelling paradigms were formulated. Mostly, they are but verbalizations of implicit assumptions, interfaces and boundary conditions (including the system boundaries). They facilitate enable by taking out the room for interpretation.

We list those principles here, centrally, as an overarching guide to the following chapters. Note that most of them only apply to the regional case-studies.

1. The studied regions are investigated only with respect to their biomass (resp. biomethane) potential, the availability of suitable CHP plant installation sites, the impact on the power grid and the potential for PV production.
2. A building or industry is considered a feasible CHP plant installation site if and only if it has a natural gas grid connection (resp. one could be established on account of the building being reasonably close to a main gas line).
3. CHP plant design and operation strategies generally follow economic principles. However, plants are not allowed to dump heat to the environment; all heat must be "consumed" by the building/industry for heating purposes.
4. The gas grid dynamics are presumed negligible. The gas grid is presumed able of storing the annually produced biomethane mass.
5. Each residential and industrial site is assigned to a node of the electric grid. In general, these are level 6 transformers.
6. The investigated region is considered as one power balance group – if, as was the case in all regions except Basel – several companies operate in the same region, they are aggregated into one.
7. Only biomass available within the geographical oundaries of the studied region is available for conversion. Already utilized biomass may not be reallocated.
8. Wet biomass is fermented locally at sites optimized within the project; woody biomass is methanized in one hypothetical, large-scale, national plant. In both cases, the output is made available via the gas-grid. In other words, installations consuming all their production locally (and thus inject no gas into the grid) are disregarded.

10.3. Case study region selection

In the assessment of the technical potentials of swarms of CHPPs, a regional approach was preferred to the full-scale national consideration primarily because of the ability to include energy network topologies. This allows detecting bottlenecks in production, but also, at least seemingly reduces the data gathering effort.

A case study region is geographically defined by its cantonal boundaries surrounding spatially resolved data like wet and woody biomass, building and industry structure, power and gas grid topology (Figure 21). In principle, biomass sources and buildings can occur anywhere within the considered territory. As with virtually all infrastructures, the cost of operating power grids and even more so gas grids relatively decreases with population density. Thus sparsely populated areas are not covered. Conversely, if a region has a gas grid, it is thus also reasonable to assume that it has access to a power grid - the opposite is not necessarily ture. Hence, PV penetration can occur anywhere within the service area of the power grid; but residential and industrial CHP plants may only occur within in the gas grid service area. Depending on the biomass transport distance, biogas production plants (and the on-site CHP) can be located either in the whole gas grid area or only where overlapped with biomass.

While regional specificity enables a lot of the aforementioned considerations, it also reduces the potential of generalizing any findings. So, in order to retain representativity, different regions of Switzerland were considered, varying in characteristics such as demography, topography, solar irradiance and the dominant biomass source. Figure 20 shows typical combinations with respect to those indicators for the finally selected cantons of Thurgau, Lucerne and Basel-Stadt. Note that Ticino, although indicated was finally dismissed due to time-constraints.

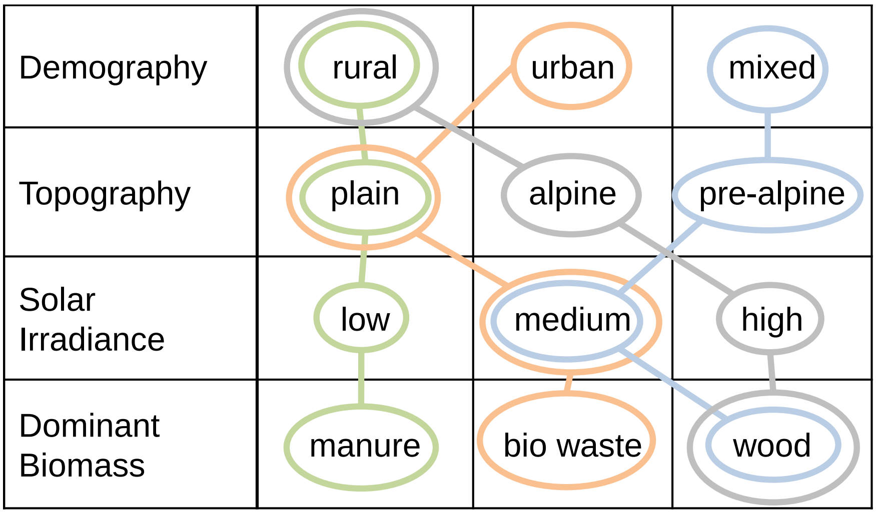


*Figure 20: Typical combinations of region characteristics leading to the selection of three case study regions: cantons of **Thurgau**, **Lucerne** and **Basel-Stadt** (Ticino not selected).*

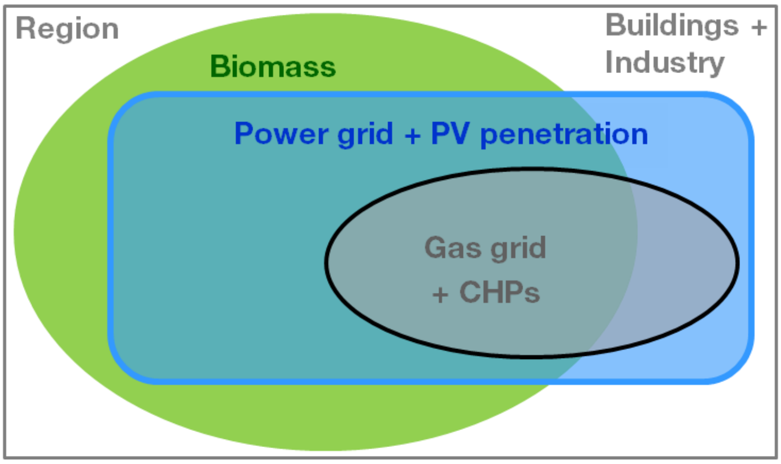


Figure 21: Schematic view on the main data layers of a regional analysis including their overlapping.

10.4. Theoretical potential of biogenic CHP plants in Switzerland

Before going into the individual group contributions, this section tries to display the potential of CHP technology, using the data and modelling approaches discussed so far. Figure 22 shows the replacement of a conventional boiler with a CHP plant. Instead of burning 100 energy units of fuel in a conventional boiler it is used in a CHP which generates only 60 units. 10 units electricity are used to drive a heat pump with an assumed coefficient of performance of 4 resulting in the missing 40 units of heat. Even if natural gas would be used, 25 units of quasi "CO_2-free" electricity can be fed with temporal flexibility to the grid.

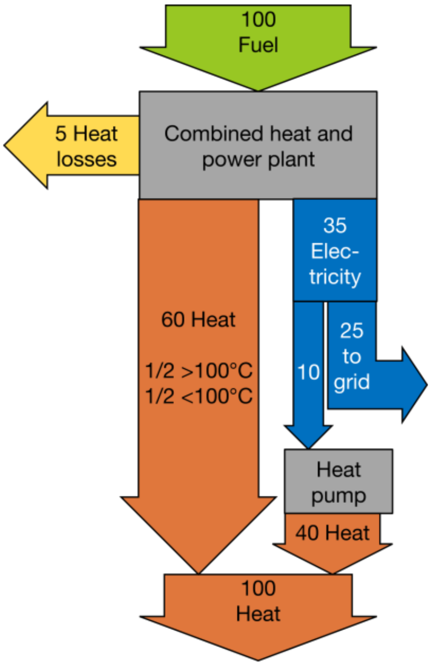


Figure 22: General application of CHP plants for power generation on demand instead a conventional gas boiler heating systems. The same amount of heat is generated with a local or remote heat pump fed via the electricity grid and 25 % of quasi "CO_2-free" electricity is provided.

The theoretical technical potential for a biogenic CHP swarm in Switzerland would benefit from the entire sustainable biomass of 23 TWh per year [1]. Figure 23 shows the biomass conversion to electricity and heat.

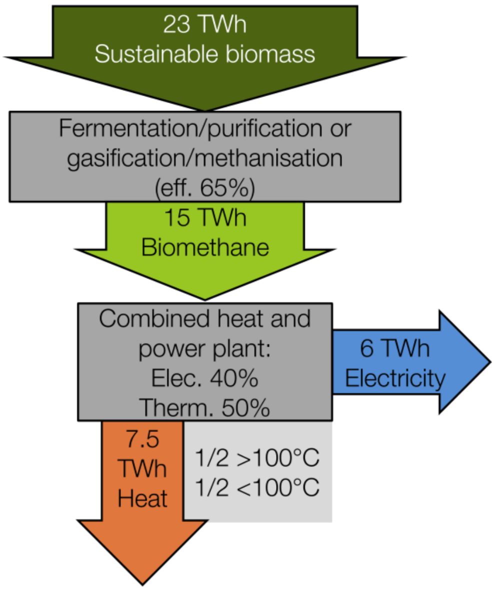


Figure 23: Biogenic CHP conversion chain from biomass to electricity and heat. The electricity produced on-demand could contribute about 10 % to the annual Swiss electricity demand. Assuming 2000 operating hours per year, the power potential of such a biogenic swarm would be 3 GW (about a third of the peak Swiss electricity demand.

11. Technical report LAV (CHP technology and heat sink characterisation)

11.1. Building heat demand model

A building is a complex energy system for its own providing comfortable conditions for the residents in terms of temperature, air quality and warm water. The system is dynamically influenced by the weather and the resident behavior. As a result, there a heat gains such as solar radiation through window panes, internal electric loads and metabolic heat as well as heat losses through the building hull to ambient, heat demand conditioning the ventilation air and domestic hot water (DHW). The building structure behaves like a damping thermal mass given by the heat capacity of the construction materials (Figure 24).

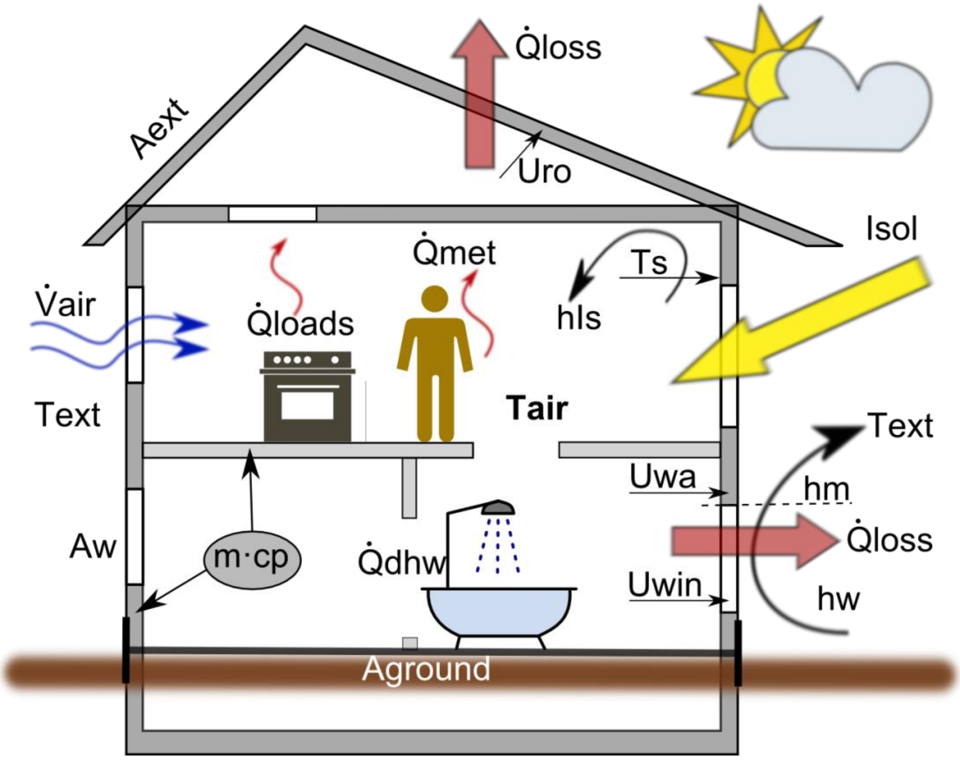


Figure 24: Schematic building model with external and internal influences. The air temperature inside of the building is the set point for the model to calculate the required heat demand. ***Aext****: external surface area,* ***Aground****: footprint area,* ***Aw****: window area,* ***Isol****: solar radiation diffuse/direct,* ***hm****: heat transfer coeff. to building mass,* ***hIs****: internal heat transfer coeff.,* ***hw****: heat transfer coeff. external air to window,* ***m·cp****: building mass heat capacity,* ***Qdhw****: domestic hot water heat demand,* ***Qloads****: internal electric loads,* ***Qmet****: occupants metabolic heat,* ***Tair****: room air temperatur,* ***Text****: external temperature,* ***Ts****: internal surface temperature,* ***Uro****: heat transfer coeff. roof,* ***Uwa****: wall heat transfer coeff.,* ***Uwin****: window heat transfer coeff.,* ***Vair****: ventilation air flow.*

Due to the limited building data (building, foot print area, number of floors, construction period), the time resolution of an hour and the high number of location to be calculated a simplified but effective model is required. The technical norm EN ISO 13790 describes an hourly calculation method based on the electric analogy of a thermal system where a capacity represents the lumped building mass, resistances the heat transfers and voltage the temperatures nodes (see Figure 25 and [2]). The model calculates the required heat flow to hold the air temperature inside of the building at its set point. Typical shares of the heat flows to the nodes are suggested. Further, the numerical computation is very fast using the Crank-Nicholson scheme for the time discretization.

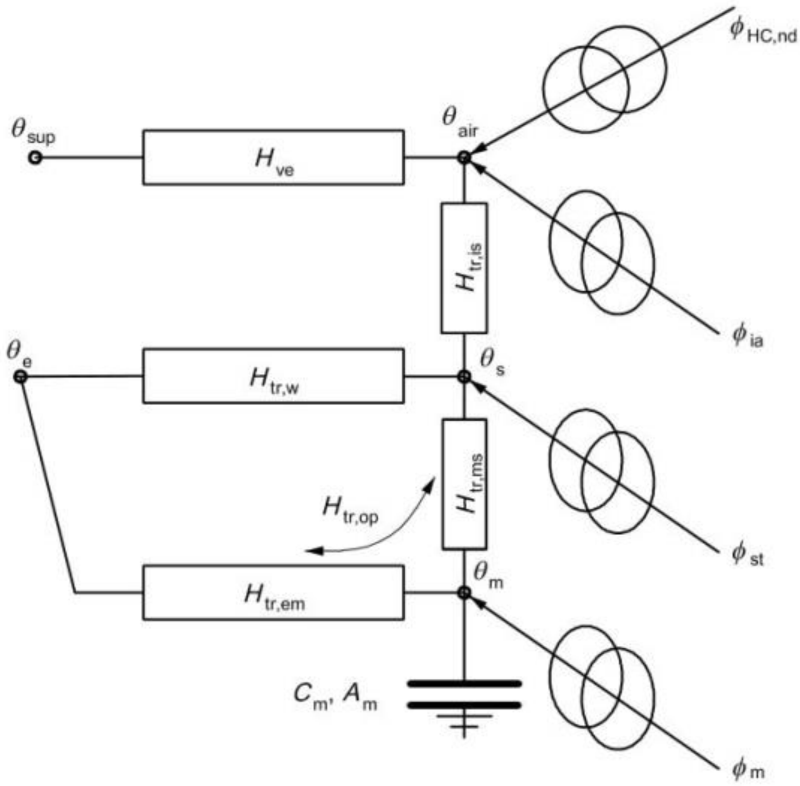


Figure 25: Electric analogy model scheme for the thermal system of a building adopted from EN ISO 13790 [2]. Nomenclature: ***Θ****: temperature,* ***Φ****: heat flow,* ***H****: heat,* ***C****: heat capacity,* ***A****: area. Indices:* ***sup****: air supply,* ***e****: external,* ***air****: inside building,* ***ve****: ventilation,* ***HC,nd****: heating/cooling need,* ***ia****: to internal air,* ***tr,is****: transfer internal wall surface to air,* ***s****: internal wall surface,* ***tr,w****: transfer through windows,* ***tr,ms****: transfer mass to internal surface,* ***st****: to surface,* ***tr,em****: external to mass,* ***tr,op****: trough opaque mass,* ***m****: lumped thermal mass.*

The model described above requires various parameters specifying the building type like single family houses, multi-family houses and commercial buildings (see Table 2).

Model parameter	**Unit**	**Single family house**	**Multifamily house**	**Commercial building MO-SO**	**Commercial building MO-FR**
Floor height	[m]	2.8	2.8	2.8	2.8
Pitched roof min. height	[m]	1	1	1	1
Number of attic floors	[1]	1	0	0	0
Footprint aspect ratio	[-]	1	2	2	2
Ratio footprint to net area	[-]	0.9	0.9	0.9	0.9
Glazing factor	[-]	0.7	0.7	0.7	0.7
Ratio of windows to wall area	[-]	0.1	0.1	0.1	0.1
Window g value	[-]	0.6	0.6	0.6	0.6
Air infiltration through walls	[m^3/m^2h]	0.1	0.1	0.1	0.1

Heat transfer coeff. air to central node	[Wh/m^{2}K]	3.45	3.45	3.45	3.45
Factor for internal walls to floor area	[-]	4.5	4.5	4.5	4.5
Heat transfer coeff. mass to internal wall surface	[Wh/K]	9.1	9.1	9.1	9.1
Ventilation air heat capacity	[Wh/m^{3}K]	0.3333	0.3333	0.3333	0.3333
Heat loss reduction factor for basement	[-]	0.7	0.7	0.7	0.7
Roof max. U value	[W/m^{2}K]	0.4	0.4	0.4	0.4
Heat loss reduc. factor for unconditioned attic and flat roof	[-]	1	1	1	1
Heat loss reduction factor for uninsulated uncond. attic	[-]	1	0.9	0.9	0.9
Heat loss reduction factor for insulated uncond. attic	[-]	1	0.7	0.7	0.7
Area per person	[m^2/Pers]	60	40	20	20
Metabolic heat rate	[W/Pers]	70	70	80	80
Electricity demand	[J/m^2 a]	22222	27778	22222	22222
Domestic hot water demand	[J/m^2 a]	13889	20833	6944	6944
Factor for electric internal loads to heat	[-]	0.7	0.7	0.9	0.9
Ventilation air volume per person	[m^3/hPers]	30	30	30	30
Temperature limit for heating	[°C]	21	21	21	21
Temperature limit for cooling	[°C]	24	24	24	24
Room temperature enabling window shutters	[°C]	23	23	23	23
Shutter factor	[-]	0.5	0.5	0.5	0.5
Building mass starting temperature	[°C]	20	20	20	20
Occupation factor weekends	[-]	1	1	0.1	1
Electricity demand factor weekends	[-]	1	1	0.1	1
Domestic hot water factor weekends	[-]	1.2	1.2	0.1	1
Ventilation reduction weekends	[-]	1	1	0.1	1

Table 2: Building model parameters with respect to building type [2], [3], [4], [5], [6].

Structural building properties such as insulation of walls and windows have changed during the past century. The construction periods in

Table 3 address the most relevant parameters and further assuming renovation of windows at least to the level of 1990.

Construction period	Year	<1945	<1960	<1970	<1980	<1990	<2000	<2010
U value walls	[W/m²K]	2	2	1.056	0.644	0.531	0.428	0.25
U value windows	[W/m²K]	2	2	2	2	2	1.6	1.3
U value roof	[W/m²K]	0.8	0.8	0.8	0.6	0.46	0.32	0.17
Factor for living area to reference mass area	[-]	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Mass heat capacity per living area	[J/m²K]	440000	440000	440000	440000	440000	440000	440000

Table 3: Building structural parameters resolved for construction period including the assumption of a minimal window renovation state from <1990 [7] [3].

Hour	DHW SFH MFH	Electricity demand SFH MFH	Occupation SFH MFH	Ventilation reduction SFH MFH	DHW ComB	Electricity demand ComB	Occupation ComB	Ventilation reduction ComB
1	1	0.2	1	0.5	0	0.3	0	0.5
2	0.5	0.2	1	0.5	0	0.3	0	0.5
3	0	0.2	1	0.5	0	0.3	0	0.5
4	0	0.2	1	0.5	0	0.3	0	0.5
5	0.5	0.2	1	0.5	0	0.3	0	0.5
6	1	0.5	1	0.5	0.2	1	0.2	0.5
7	4	1	0.8	1	0.4	1	0.4	1
8	10	1	0.6	1	0.6	1	0.4	1
9	7.5	0.5	0.4	1	0.8	1	0.6	1
10	6	0.5	0.4	1	1	1	0.8	1
11	4	0.5	0.4	1	1	1	1	1
12	2	1	0.6	1	1	1	0.8	1
13	2	1	0.8	1	1	1	0.8	1
14	2	0.5	0.6	1	1	1	1	1
15	2	0.5	0.4	1	1	1	1	1
16	1	0.5	0.4	1	1	1	0.8	1
17	1.5	1	0.6	1	0.8	1	0.6	1
18	2.5	1	0.8	1	0.6	1	0.4	1
19	4	1	0.8	1	0.4	1	0.2	1
20	4	1	0.8	1	0.2	1	0.2	1
21	3	0.5	0.8	1	0	0.3	0	1
22	3.5	0.5	1	0.5	0	0.3	0	0.5
23	2	0.5	1	0.5	0	0.3	0	0.5
24	2	0.2	1	0.5	0	0.3	0	0.5

Table 4: Hourly resolved profile shaping the total annual energy values for domestic hot water, internal electricity loads as well as occupation and ventilation [3], [8], [9]. Data for commercial buildings (ComB) are assumed.

The preparation of domestic hot water requires a heat input proportional to the demand of the occupants. Instead of constant demand, measured data of a multi-family house during weekdays and weekends were taken from [9] and implemented as shown in

Table 4.

The solar radiation data is relevant for solar heat gains through the building windows and is typically given related to horizontal surfaces. In this case the building wall are vertical and the orientations were assumed to be north, south, east and west. Figure 26 shows the general case of solar radition on a tilted surface. In the solar engineering literature presents incident angle equations for inclined surfaces depending on the hour of the year [10].

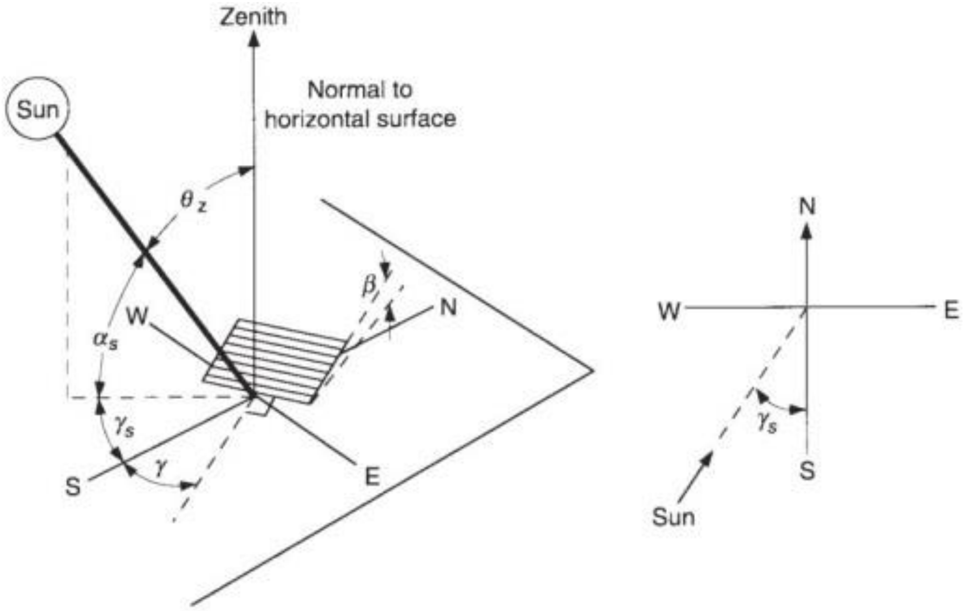


Figure 26: Solar incident angles on inclined surfaces adopted from [10], used to calculate solar radiation on vertical building walls accounting for heat gains through windows.

The buiding model asks for weather data input, namely ambient temperature and diffuse/direct solar radiation which was specified by the typical meteorological year created by the software meteonorm [11]. In case of Thurgau the weather station Guettingen was used as a reference, in Luzern the city itself and in Basle the weather station Bottmingen.

The building strucutre data of the investigated area was prepared by GIE based on the national building inventory [12] followed by the building individual heat demand calculation.

Figure 27 demonstrates the building heat demand model functionality for a selected week and the entire year of a multi-family house with details given in Table 5.

Region		Lucerne
Building type		Multi-family house
Construction period		1950-1960
Ground area	[m^2]	252
Height	[m]	14
Floors	[1]	5
Area all floors	[m^2]	1135
Nominal number of residents	[1]	28
Room heating demand	[kWh/a]	173704
Domestic hot water heat demand	[kWh/a]	26265
Total heat demand	[kWh/a]	199969
Total heat demand per area	[kWh/m^2a]	153

Table 5: Example building used for model demonstration in Figure 27.

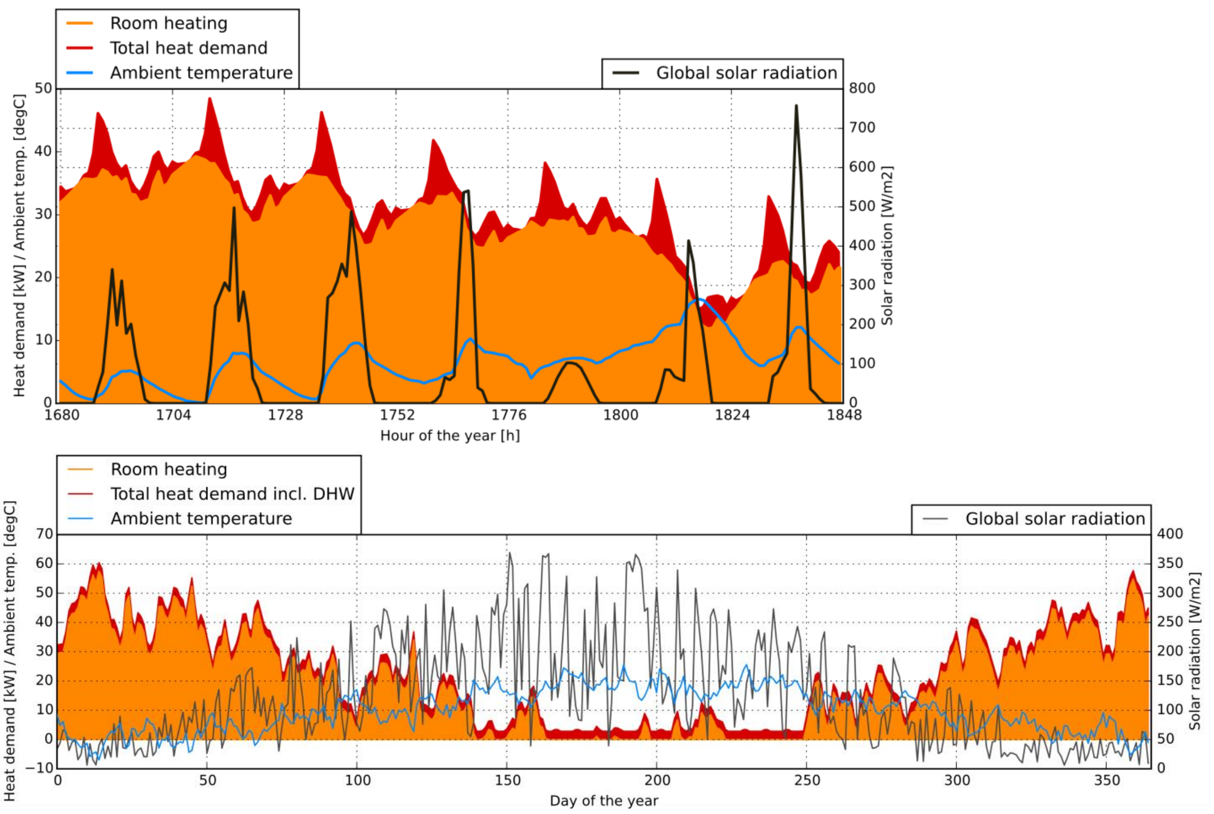


Figure 27: Building heat demand calculation example for an old multi-family house in the study region of Lucerne for the third week of March.

The residential heat price is an important economic boundary condition for operating a CHP plant. In this study it was assumed that a customer would not pay more than a conventional biomethane gas boiler would cost. Such a heating system supplies the heat sink instead with 2000 operating hours and has a typical lifetime of 15 years. Current market prices of gas boilers with thermal power (Pth) served as an input to compute fit curves for investment (annualised with 2 % interest rate) and maintenance costs [13]:

- Gas boiler investment cost $= 2613 \cdot Pth^{-0.546}$ CHF
- Gas boiler maintenance costs $= 0.545 \cdot Pth + 273$ CHF

Figure 4 shows the residential heat demand load duration curves of the case study regions.

11.2. Industrial heat demand

Industrial sites with process heat demand are interesting opportunities to install a CHP plant generating low and. In contrary to the residential heat demand the industrial heat demand is typically constant throughout the year and can make use of the high temperature heat (400 °C) drawn from the engine exhaust gases. Due to lack of any Swiss database describing the industrial heat demand on a company individual basis, a manual assessment of facilities was conducted for all three case study regions. The sectoral classification of industries by the Nomenclature Générale des Activités économiques (NOGA, [14]) was used to select sectors with a heat demand up to 400 °C:

- *10* food and forage production
- *11* beverage production

– *17* paper and cardboard production
– *20* chemical products
– *211* pharmaceutical products
– *222* plastic production
– *353* heat and cooling supply
– *861* hospitals
– *9601* laundry services
– *9604* baths and saunas

Industrial companies were contacted directly regarding the assessment of annual total heat demand, shift operation, seasonal variations. The share of high temperature heat demand above 90 °C with the related process temperature was included as well. About half of all contacted companies were either willingly to share data or estimations from similar industries were possible. Figure 28 summarizes the gathered data respecting the confidentiality of company names and locations.

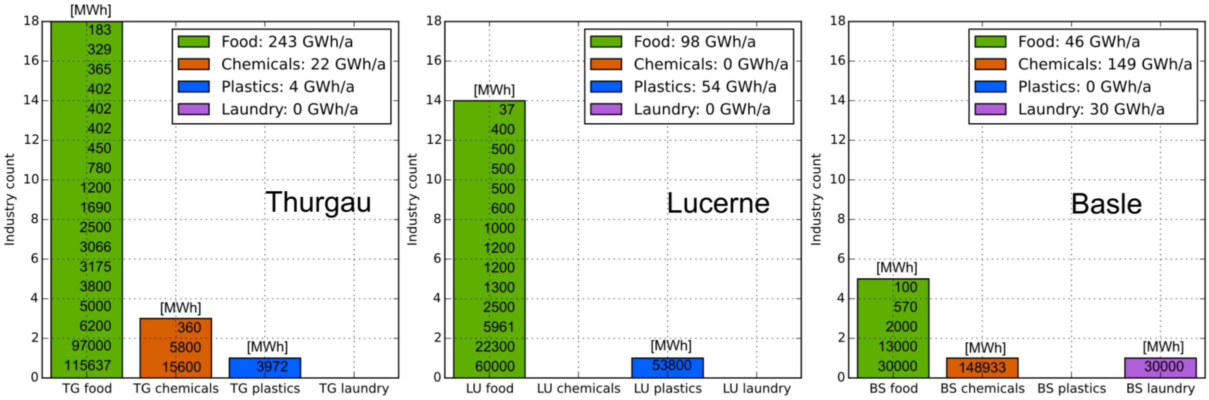


Figure 28: Structure of food, chemicals plastic and laundry industry for case study regions Thurgau, Lucerne and Basle. The bars show the number of facilities and the related listing of the annual process heat demand (see load duration curves in Figure 4).

Figure 4 shows the industrial heat demand load duration curves of the case study regions.

The industrial heat price was estimated based on an equivalent biomethane industrial burner supplying the process instead of the CHP unit with heat. Industrial burner market prices from 50-20000 kW thermal power (Pth) served as an input for investment and maintenance cost fit curves [15].Investment costs were annualized with 2 % interest rate and 15 years of lifetime. The annual burner operating hours were matched with the industrial process hours per year:

– Industrial burner investment costs = $490.7 \cdot Pth^{-0.505}$ CHF
– Industrial burner maintenance costs = $93.6 \cdot Pth^{0.2394}$ CHF

Beside the residential and inidustrial heat demand a third typ heat sink was included in the analysis: Biogas production plants (see also chapter 12). The process of wet biomass fermentation requires heat for increasing the substrate temperature from ambient conditions to the fermenter temperature of ~55 °C. If food waste is processed, it must be sterilized at 130 °C for about 10 min according to current Swiss legislation. The sterilised hot substrate is then blended with the cold bio-waste which also leads to the warm-up process. Given the monthly resolved biomass flow by GIE and the ambient temperature by meteonorm [11], the demand was calculated over 8760 h as a temperature lift of the substrate flow (Figure 29).

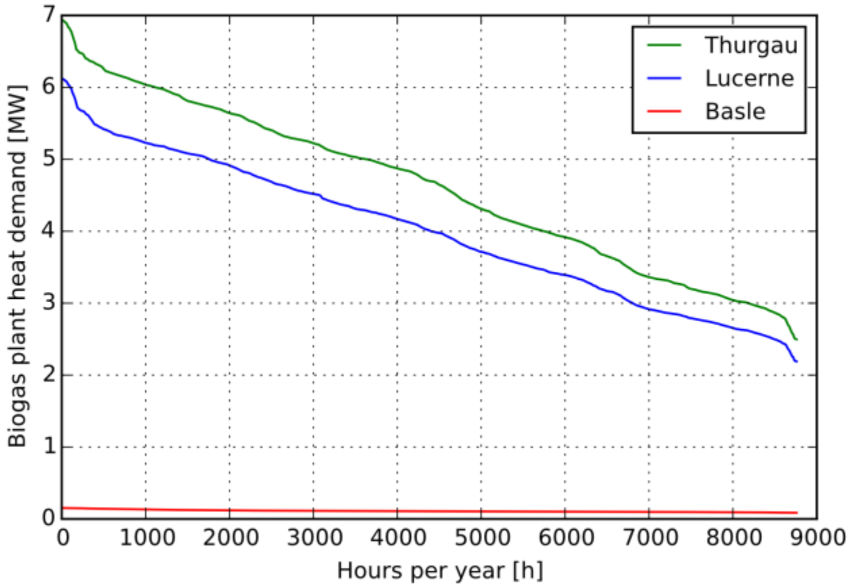


Figure 29: Biogas production plant heat demand duration curves of the case study regions. The heat demand of all biogas plants in a region is summed up.

11.3. CHP plant technology assessment

The technical specifications and techo-economic parameters of CHP plants describe the conversion technology and is used by all research groups to parametrise their models.

The power range of CHP gas engines covers 3-20'000 kW (electric) from small single cylinder engines up to large-scale machines similar to marine propulsion engines. An extensive source was the CHP plant reference values of a German energy association which was paired by an extensive own assessment including manufacturer contact or brochures. With regard to the linear modelling and optimization approach (see section 11.4) constant specifications were required for different engine sizes. Hence, the power spectrum was split into 9 engine classes with piece-wise constant data (see Figure 9).

Table 6 shows engine data and techno-economic values from an own assessement. The low temperature heat storage investment costs were derived from tank manufacturers while for the high temperature storages double the costs were assumed due to lack of market products.

The transient dynamic performance of gas engines from stand-by state to full load range from 10 to 150 seconds as demonstrated in [16] and [17]. The starting procedure creates increased pollutant emissons during the first minutes compared to the steady-state operation. In consideration of the given hourly electricity price data and the simulation framework on an hourly basis over one year, the transient engine dynamics can be neglected.

The following exogenous parameters were set equal for all classes:

- The biomethane fuel price was set to 0.16 CHF/kWh according to current market prices [18] while CHP plants installed on a biogas production site using non-purified fuel benefit from 5 CHF/kWh lower price [19].
- The hourly electricity price profile was taken from the EpexSpot Day-Ahead market of the year 2014 with a mean value of 0.037 CHF/kWh and a standard deviation of 0.013 CHF/kWh [20]. A constant offset of 0.07 CHF/kWh was added to the profile accounting for reduced grid costs due to the plant connection on the lowest grid level [21].
- The annual plant costs were calculated by annualizing the investment costs with an interest rate of 2 % and a plant lifetime of 20 years (resulting annuity factor 0.0612).

Figure 10 explains the resulting electricity production costs.

		Class 1	Class 2	Class 3	Class 4	Class 5	Class 6	Class 7	Class 8	Class 9
Elec. power min	[kW]	3	9	25	70	200	540	1200	4200	12000
Elec. power max	[kW]	9	25	70	200	540	1200	4200	12000	20000
Elec. power med	[kW]	6	17	47.5	135	370	870	2700	8100	16000
Plant with highest eff.	[kW]	7.2	19	64	200	400	1200	3431	9979	18321
Electrical efficiency	[%]	32.1	32.8	36.3	37.4	42.3	43.7	45.6	46.3	48.5
Thermal efficiency	[%]	57.9	57.2	53.7	52.6	47.7	46.3	44.4	43.7	41.5
Thermal exhaust efficiency	[%]	36.1	32.7	29.0	25.9	24.1	21.6	19.5	17.5	16.5
Total efficiency	[%]	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Investment costs	[CHF/kW]	3000	1900	1370	810	590	355	350	210	170
Overhaul costs	[CHF/kW]	600	400	260	210	160	125	90	70	60
Time to overhaul	[h]	20000	20000	40000	40000	40000	40000	40000	40000	40000
Maintenance costs	[CHF/kWh]	0.05	0.04	0.02	0.013	0.01	0.006	0.004	0.003	0.003
TES LT investment costs	[CHF]	445	445	445	445	445	445	445	150660	150660
TES LT volum. inv. costs	[CHF/m^3]	964	964	964	964	964	964	964	113	113
TES LT inv. cost 50/90°C	[CHF/kWh]	21.24	21.24	21.24	21.24	21.24	21.24	21.24	2.49	2.49
TES HT base inv. costs	[CHF]	890	890	890	890	890	890	890	301320	301320
TES HT volum. inv. costs	[CHF/m^3]	1928	1928	1928	1928	1928	1928	1928	226	226
TES HT inv. costs 200/400°C	[CHF/kWh]	26.03	26.03	26.03	26.03	26.03	26.03	26.03	3.05	3.05
Bore	[mm]	78	81	108	128	132	170	190	340	500
Stroke	[mm]	68	95.5	125	166	160	195	225	400	540
Number of cylinders	[1]	1	4	6	6	8	12	20	20	18
Engine speed	[1/min]	3100	1500	1500	1500	1500	1500	1500	750	500
Air-fuel ratio	[-]	1	1	1.4	1.6	1.6	1.6	1.7	2.1	2.1
Exhaust gas temperature	[°C]	680	620	520	520	520	430	430	400	400

Table 6: CHP gas engine data specification for 9 different power classes [17], [22], [23], [24].

The thermal energy storage (TES) is modelled as a sensible heat storage where the heat capacity of a mixed/homogenous media underlies a temperature change. The typical low temperature TES design is an insulated water tank equipped with two heat exchanging apparatus (e.g spiral pipes) for heat loading and drawing. High temperature TES technology is known from solar thermal power plants where an insulated rock bed is used as a sensible heat storage media. Alternatively, latent TES relying on melting salt mixtures are documented from many applications [25]. The TES losses were assumed to be constant over time resulting from a cylindrical volume minimal in surface, the mean temperature and the insulation properties (see Table 7). Water tank cost data in was assessed using manufacturer price lists from Huch [26] and Lorenz [27].

		Low temperature TES	**High temperature TES**	***Comments***
TES temperature empty	[°C]	50	90	*Or defined by industrial process temperature*
TES temperature fully charged	[°C]	90	400	
Media		Water	Ceramic/rock	*Stacked block with channels for exhaust gases and drawing heat exchange pipes*
Media density	[kg/m3]	975	1000	
Media heat capacity	[J/kgK]	4190	2000/1.5	*Assuming reduction for heat exchange channels*
Insulation thickness	[m]	0.15	0.3	
Insulation heat conduction coeff.	[W/mK]	0.04	0.04	*Glas wool* [28]
External heat convection coeff.	[W/m^2K]	5	5	*Assuming natural convection*
Ambient temperature	[°C]	20	20	

Table 7: Thermal energy storage (TES) parametrization.

The transient dynamic performance of gas engines from stand-by state to full load range from 10 to 180 seconds as demonstrated in [16] and [17]. Considering the electricity price data and the annual simulations in this project on an hourly basis, the transient engine dynamics can be neglected. Class 1 values were derived from our ongoing development of a micro CHP plant. The optimized single cylinder gas engine generates 7.1 kW electric power at a conversion efficiency of 32 % via an asynchronous generator. Further, the plant features near-zero pollutant emissions in steady-state operation and warms up after a cold start in less than 10 minutes [16]. Also larger class 5 gas engines reach fuel conversion efficiencies of comparable Diesel engines but going well below strict Swiss city NOx limits [29].

11.4. CHP plant model and optimization

As sketched in Figure 30, the CHP plant plays between the local heat demand and the electricity price. If the heat sink and the electricity price profile is given, the power and storage size as well as the operating remains unknown. An optimisation of the unknown variables is a useful tool to solve the design problem. Three different objectives are thinkable:

1. **Minimized ecological impact:** lowest possible number of starts due to high exhaust gas start emissions (see section 11.3) resulting in the smallest plant and high operating hours per -> rather trivial solution.
2. **Maximized quality of produced energy (exergetic optimization):** maximized electrical output and the plant applied to a high temperature heat sink resulting in the

largest plant due to its highest electrical efficiency operating during highest electricity prices -> rather trivial outcome.

3. **Maximized annual profit of the plant:** trade-off between generating and selling electric during hours with high prices and investment costs for the plant and the heat storage. A larger plant can produce more electric energy but for less number of hours per year due to the fixed heat sink or a large TES offers more operational flexibility -> complex interaction of plant cost structures and the operating pattern over time, **objective 3 selected!**

The CHP plant is basically modelled with linear as an energy converter as the literature suggests [30], [31], [32], [33] with the opportunity for linear optimization (see Figure 30). Load modulation is avoided achieving highest electrical efficiency at nominal design load. Thermal power can be split into low and high temperature heat gathered from the engine cooling circuit (up to 90 °C) and exhaust gases (up to 400 °C) respectively. Without any heat demand above 90 °C the high temperature heat is merged with the low temperature share. In rare cases industrial applications (e.g. bakery) with pure high temperature heat demand the low temperature share was discarded without being refunded. However, far the most of the cases require heat below 90 °C or suitable process engineering with heat recovery prevents from recooling any heat.

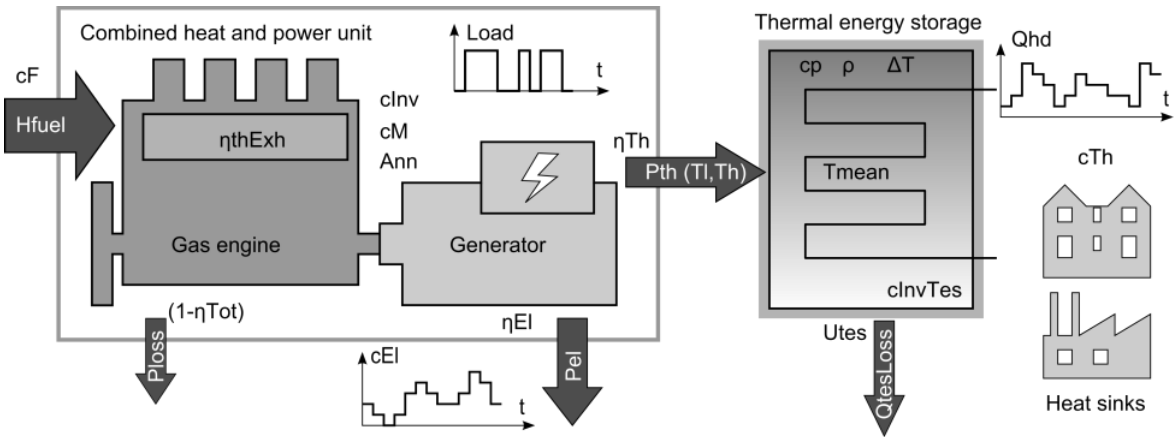


Figure 30: CHP plant model. ***Ann****: annuity,* ***cF****: fuel price,* ***cInv****: plant investment costs,* ***cTh****: thermal energy price,* ***cInvTES****: investment costs thermal energy storage,* ***cM:*** *maintenance costs,* ***cp****: heat capacity of the TES,* ***ηTh****: thermal efficiency,* ***ηThExh****: thermal efficiency of the exhaust gases,* ***ηTot****: total plant efficiency,* ***Hfuel****: fuel enthalpy,* ***Ploss****: heat power loss from plant,* ***ρ****: density of heat storage media,* ***Tmean****: mean TES temperature,* ***Utes****: U-value TES losses,* ***Qhd****: heat demand,* ***QtesLoss****: TES heat losses,* ***Tl/h****: low/high temperature.*

The state of the art method is a problem formulation as mixed-integer linear programming (MILP). In each time step the plant can either be switched on or off resulting in a set of binary decision variables which represents the operating pattern (the mixed integers are 0/1). Due to the fact that the operation variables are multiplied with the plant power, the latter parameter must be constant in order to keep linear equations. Hence, with the fixed power, the operating pattern and the TES capacity remain the degrees of freedom.

MILP computing time shows an exponential dependency on the number of decision variables. Therefore a time mask reduced the number of time steps as function of the heat demand by about a factor of two. Meaning that for high demand winter days up to 24 hourly time steps were set, while for low demand summer days only 2 time steps were set in the problem equations. Introducing the concept of the time mask made the problem solvable on a desktop computer at all.

The objective function includes annualized costs, a fixed refund for the annual heat generation and the time depended benefit from electricity generation. In every time step the heat balance must be fulfilled with respect to the storage capacity:

Objective function (annual cost balance including annualised investment costs):

$$\max O = \left[\sum_{t=1}^{8760} Pel \cdot op(t) \cdot \left(cEl(t) - cM - \frac{cF}{\eta El} \right) \right] + cTh \cdot QhdTot - Ann \cdot (cInv \cdot Pel + cInvTes \cdot QtesCap)$$

Constraints. Energy balance must be fulfilled for all time steps with respect to the storage capacity:

$$QtesCap \geq \left[\sum_{t=1}^{t} \left(\frac{Pel \cdot \eta Th}{\eta El} \cdot op(t) - Qhd(t) \right) - QtesCap \cdot tesLoss \cdot t \right] \geq 0 \text{ , } \forall t \in [1, 8760]$$

Nomenclature:

Pel : Electric power output [kW]

ηEl : Electric efficiency [-]

ηTh : Thermal efficiency [-]

$cInv$: Investment costs CHP per electric power output [EUR/kWEl]

cM : Maintenance costs [EUR/kWhEl]

$cInvTes$: Investment costs thermal energy storage [EUR/kWh]

cTh : Thermal energy costs based on equivalent gas boiler as heat generator [EUR/kWh]

Ann : Annuity factor [-]

cF : Fuel costs [EUR/kWh]

$tesLoss$: Thermal energy storage constant loss factor [1/h]

$Qhd(t)$: Heat demand over 8760 hours [kW]

$QhdTot$: Total annual heat demand [kWh]

cEl : Electricity price profile [EUR/kWh]

To be optimised by mixed-integer linear programming or own heuristic algorithm:

$op(t)$: Operation pattern over 8760 hours

$QtesCap$: Thermal energy storage capacity [kWh]

Figure 31 shows the optimization process executed for all feasible locations in the case study regions. The calculated power cases correspond to the minimal plant covering the peak heat demand, 2000 operating hours per year as well as the minimal, medium and maximal power of the same CHP class and the minimal, medium power of the next higher CHP class. Then, the most beneficial case was selected. All models were implemented with the programming language Python 3.4. The MILP problems were computed using the commercial solver Gurobi version 6.0 via the related Python interface (free academic license) [34].

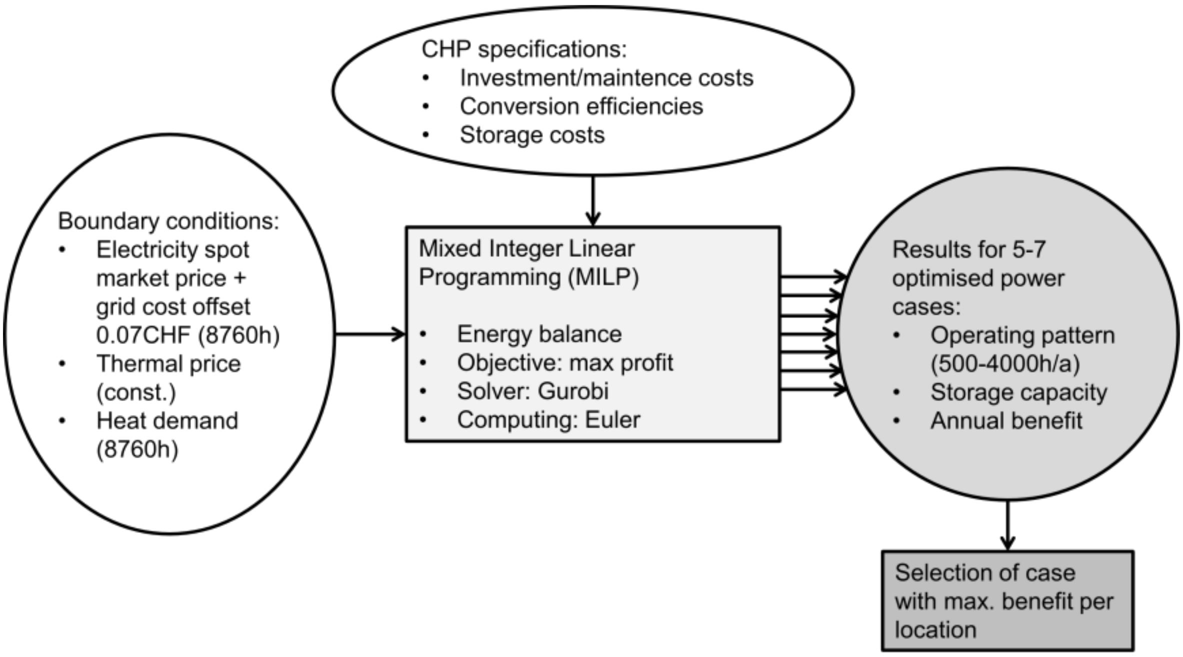


Figure 31: Optimization process executed for all locations (heat sinks) in the case study regions and with gas grid access.

Hourly resolved data of a selected CHP plant illustrate the exemplary optimization results of in Figure 32. The optimization algorithm clearly picked the electricity price peaks for CHP operation while avoiding operation during low price periods and supplying the heat sink from the storage.

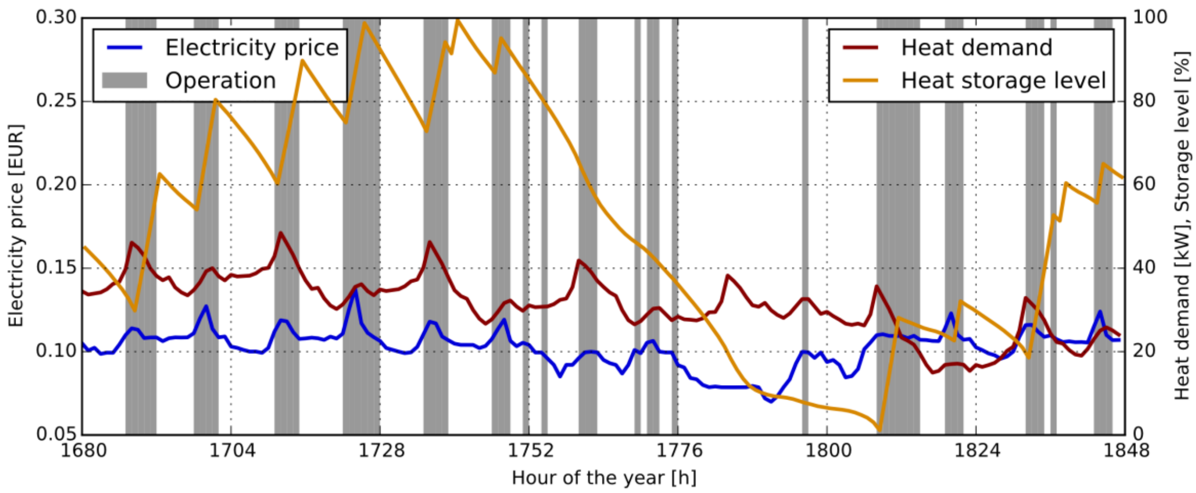


Figure 32: Behaviour of a CHP plant with optimized operating pattern and heat storage capacity aiming for maximized annual profit (see also the building heat demand of the same location described in Table 5).

Region		Lucerne
Building type		Multi-family house
Total heat demand covered	[kWh/a]	199969
CHP electric power	[kW]	70
Operation hours	[h/a]	2578
Storage capacity optimised	[kWh]	943
Storage volume optimised	[m^3]	21
Heat price refunded to CHP	[CHF/kWh]	0.17

Table 8: Selected example CHP plant used for displaying data in Figure 32.

The full year operation pattern of the presented example plant was statistically analyzed for number starts per day and runtime duration (Figure 33) as well as downtime duration (Figure 34).

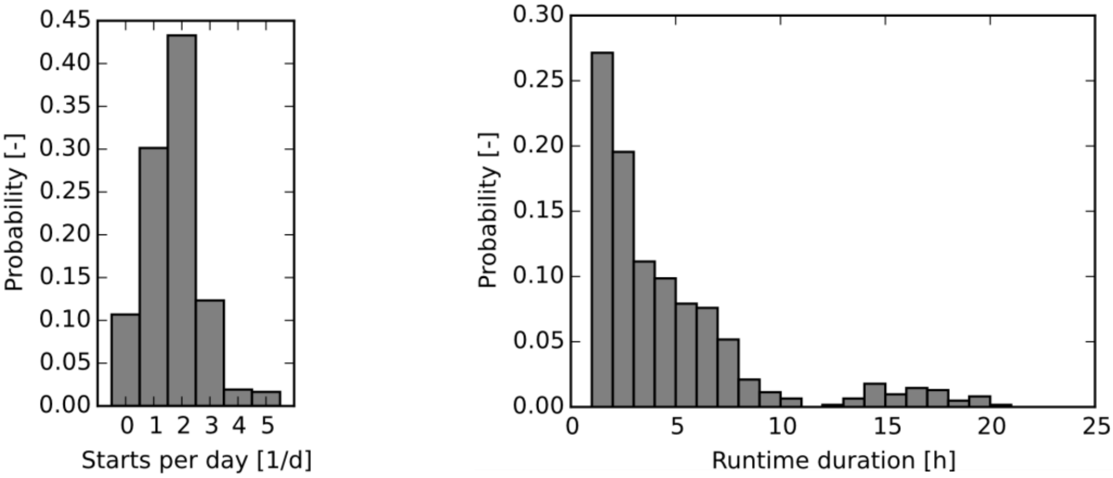


Figure 33: Operation pattern evaluated for number of starts per day and runtime durations.

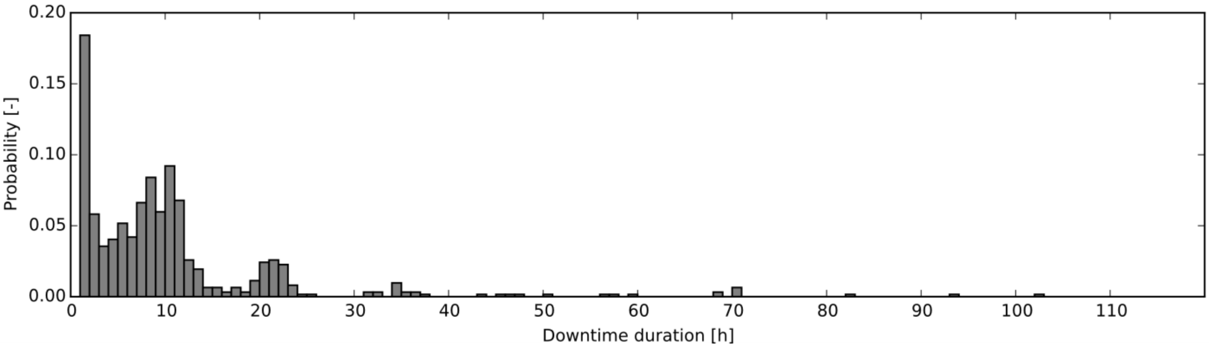


Figure 34: Example CHP plant operation pattern evaluated for downtime duration.

11.5. Swarm plant selection

After calculating optimal CHP plant designs for all buildings and industries within the gas grid area of the case study region, a sub set of plants are selected for the swarm. All case study regions offer an individual finite amount of biomethane per year which limits the fuel burnt by the CHP swarm. Hence, the plants were selected to consume as close as possible the fuel potential but not more while maximizing the sum of annual plant profits (also known as the so called knapsack problem [35]).

$$\mathrm{Max.Objective} = \mathrm{AnnualProfit}_{swarm} - \left(H_{biomethane,\,potential} - H_{biomethane,swarm}\right) \cdot c_{biomethane}$$

In the problem objective function the costs for buying the regional biomethane ($H_{biomethane}$) potential are subtracted from the annual profit of the swarm (selected plants). Costs ($c_{biomethane}$) for unburnt biomethane are included as well (due to generally negative annual plant profits, costs for unburnt biomethane are added). The problem sets a decision variable (choose or not choose) for all available plants and was solved efficiently as a mixed-integer problem (0/1) with Gurobi 6.0 [34]. Figure 35 shows the plant selection for case study regions Thurgau and Basle.

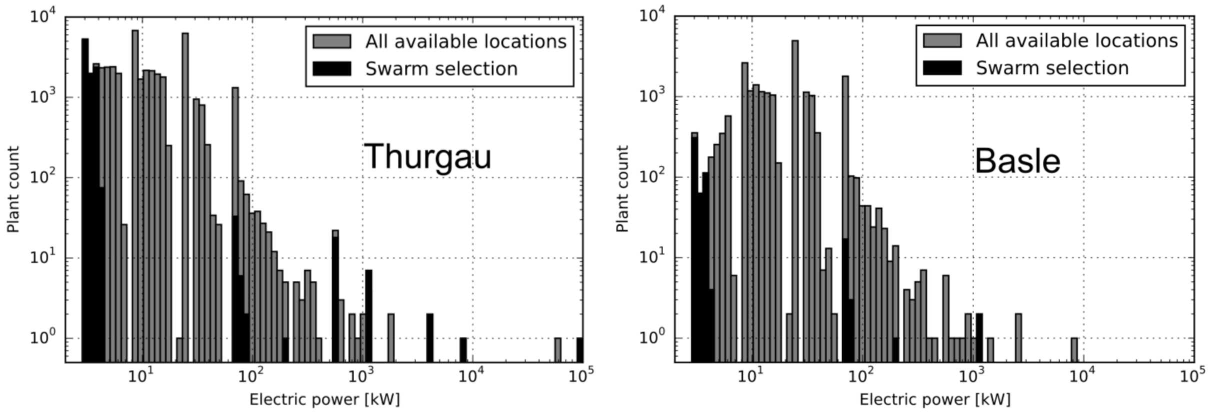


Figure 35: Plant selection for case study regions the Thurgau (684 GWh biomethane) and Basle (30 GWh biomethane).

In the case study region of Lucerne the electricity grid topology is available and used in the swarm selection process (see Figure 36). All plants were grouped and assigned by GIE group to the electricity grid nodes. Then, constraints were built for each node so that the nominal power of selected plants does not exceed the local maximal demand. Without node constraints, too many plants could accidentally be selected by the algorithm violating the node capacity. As a consequence, the largest plants available were not selected despite the higher profitability (industrial sites). It is possible that a company with a natural gas fired process has a relatively low grid connection capacity which would be exceeded with the deployment of CHP plant providing the same heat.

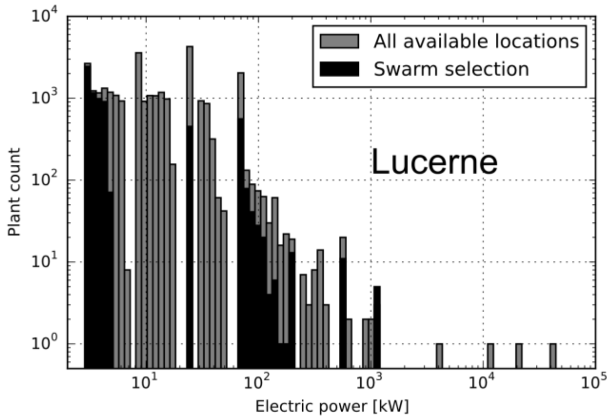


Figure 36: Plant selection for case study region Lucerne (692 GWh biomethane) including grid constraints in the sense that the nominal plant power per node does not exceed the node demand peak.

The set of calculated plants building the cantonal swarms can now be used to derive a correlation between the CHP plant electric power and the found thermal energy storage capacity. As shown in Figure 37, the heat storage has a typical capacity of approximately 10 times the thermal plant power.

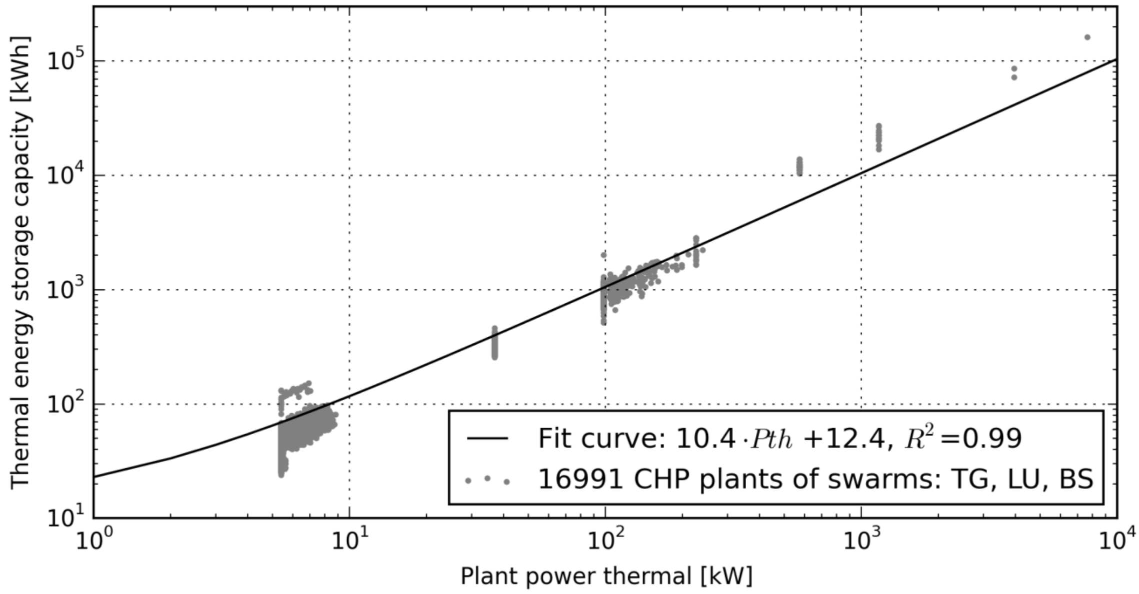


Figure 37: Thermal energy storage capacity correlation to CHP plant electric power output.

11.6. Performance analysis of regional swarms

Figure 38 illustrates the electric performance of the regional swarms including their building, industriy and biogas plant heat coverage. In Thurgau, a large industrial facility operates only a few months per year leading to a drop in the load duration curves. The effect of heat storage systems is clearly shown in Figure 38: electric energy is mostly produced during 4000 h while the heat demand exceeds 8000 h.

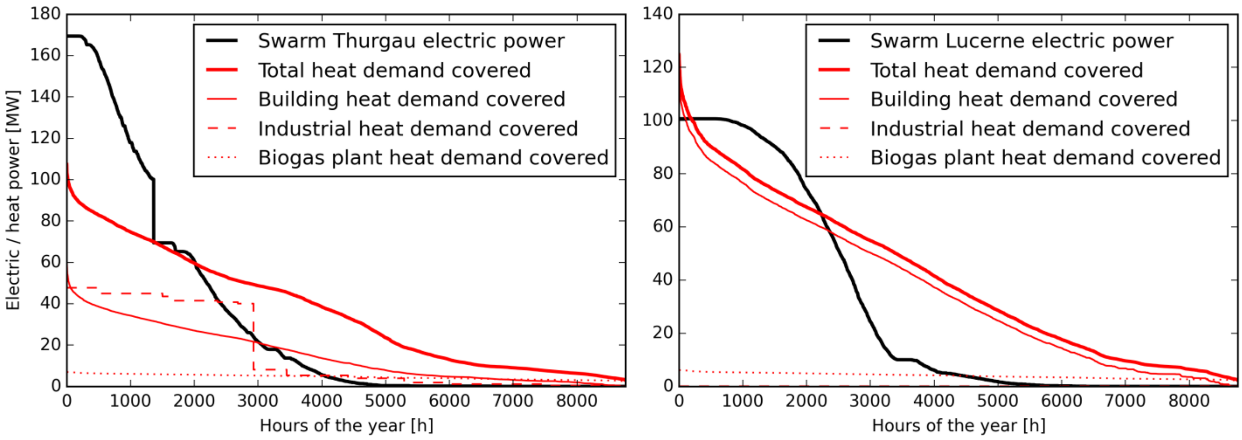


Figure 38: Thurgau and Lucerne swarm electric load duration curves and covered heat demand. Basle shows the same characteristics as Lucerne just with 5 MW peak electric power.

The swarm power modulation throughout the year is illustrated by means of the Lucerne swarm in Figure 39 where rising electricity prices in the morning and evening drive most of the plants to switch on.

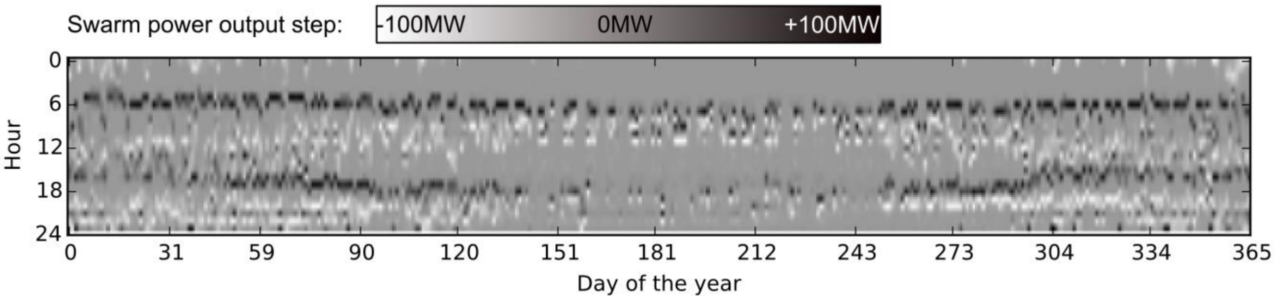


Figure 39: Aggregated power output of all plants of the swarm in Lucerne over 8760 h

11.7. LAV group conclusions

A successful methodological pathway from heat sink modelling, optimisation of single CHP plants and the swarm design was developed including the underlying data. The method was tested in regional case studies. Electricity grid capacity can be taken into accout for the swarm plant selection. Further, in the course of the project a fast heuristic CHP plant optimiser was found which can also be used to operate and coordinate a swarm following exegenous quality signals or electricity prices (see Figure 18).

12. Technical report GIE (Biomass and spatially resolved data)

12.1. Spatial biomass model

A bottom-up GIS based model was established to assess the spatial and temporal distribution of wet biomass. Goal of the model is to estimate for every location the local available amount of biomass and its temporal variability. The model is designed to allow to optimize locations of biogas plants in order to determine the biomass potential from wet biomass inside the case study regions. Figure 40 shows the biomass locations used for the case study Lucerne.

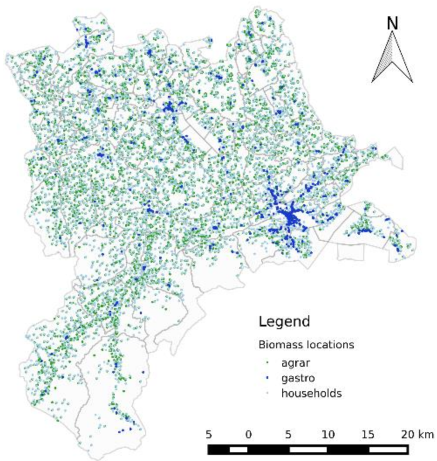


Figure 40: Biomass locations for case study Lucerne

The model distinguishes between agricultural biomass and industrial biomass. Agricultural biomass includes manure from different animals. Industrial biomass includes biogenic household waste, green waste and biogenic waste from the gastronomy.

12.1.1. Green waste

The yearly collected amount of green waste is estimated for each municipality based on the number of inhabitants of the municipality. Monthly data of collected green waste was available from green waste processing plants [36]. The ratios shown in Table 9 are derived by averaging 13 years of data. The amount of green waste was estimated based on the number of inhabitants as shown in Table 10.

Month:	**1**	**2**	**3**	**4**	**5**	**6**
[%]	3.34±0.51	3.14±0.80	6.90±0.58	8.46±0.78	11.19±1.58	11.04±1.10
Month:	**7**	**8**	**9**	**10**	**11**	**12**
[%]	9.70±1.25	10.30±0.98	9.67±0.63	11.58±0.99	11.12±0.52	3.55±0.65

Table 9: Monthly green waste availability

	Inhabitants of municipality			
Amount [kg / Inhabitant]	101-1000	1001-10000	10001-50000	>500001
Green waste	82.7	100.7	71.7	65.3

Table 10: Green waste per inhabitants [37]

12.1.2. Biogenic household waste

The “Erhebung der Kehrichtzusammensetzung” of the Federal Office for the Environment found that 32.2% of Swiss is household waste is biogenic [38]. The amount of household waste is estimated for each municipality based on [37] for each municipality as shows in Table 11.

	Inhabitants of municipality			
Amount [kg / Inhabitant]	101-1000	1001-10000	10001-50000	>500001
Household waste	158.6	192.8	215	242.7

Table 11: Household waste per inhabitant [37]

12.1.3. Biogenic gastro waste

Biogenic waste is modelled by estimating the number of meals for each municipality and month. An average value of 115.0 gram per meal is assumed based on [39]. The number of meals are estimated both for local customers as well as tourists. According to GastroSuisse, Swiss citizens have in average 4 out-of-house meals per week [40]. Meals from tourists are modelled using the number of overnight stays in hotels using the Beherbergungsstatistik HESTA of the Federal Office of Statistics [41]. The statistic includes for each municipality and month the number of overnight stays. For each municipality the monthly average number of overnight stays is calculated based using data from 2006 to 2013. It is assumed that tourists consume 2 meals per day in restaurants. For each municipality, the estimated biomass is then distributed with equal weights over the restaurant and hotels located inside the municipality.

12.1.4. Agricultural biomass

Agricultural biomass is estimated depending on the number of animals of each farm [42]. Table 12 shows the amount of yearly biomass for each animal category.

BFS Category	Type of biomass	t / a
Übrige Rinder	Solid cow manure	6.0
Übrige Kühe	Solid cow manure	3.3
Milchkühe	Solid cow manure	8.9
Kälber und andere Rinder - 1jährig	Solid cow manure	2.0
Übrige Rinder	Liquid cow manure	8.0
Übrige Kühe	Liquid cow manure	4.45
Milchkühe	Liquid cow manure	11.5
Kälber und andere Rinder - 1jährig	Liquid cow manure	2.7
Eber	Pig manure	1.66
Sauen	Pig manure	3.13
Übrige Schweine	Pig manure	0.57
Legehühner und Zuchthühner	Hen manure	0.02
Übrige Hühner	Hen manure	0.01
Mastpoulets	Hen manure	0.01

Table 12: Yearly amounts of biomass depending on animal category [43], [44]

12.2. Biogas plant location optimization

The biomass model allows analysing the spatial and temporal biomass availability. For a biogenic CHP swarm only the producible biogas that can be fed into the gas grid is relevant. The location of biogas plant determines if they can be connected to the gas grid, allowing upgrading of biogas to natural gas quality and feed-in into the gas grid. Neighbouring biogas plants compete for biomass inside shared catchment areas. An optimization model was developed in order to select biogas plant locations with respect to economic aspects. Figure 41 shows an overview of the input parameters of the optimization model. The input parameters include for each biomass location the available amount of biomass. The optimization model takes physical and economic constraints of different biogas plant types, as well as transport costs, different types of biomass as well temporal variability into account.

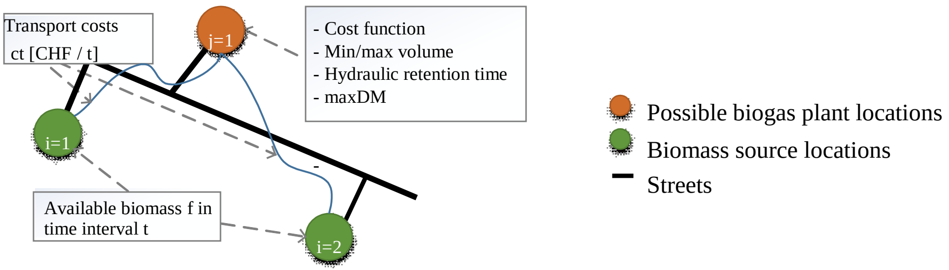


Figure 41: Overview of input parameter used for biogas plant location optimization

The optimization was performed separately for industrial as well as agricultural biogas plants. For agricultural plants, farm locations within 300 meter to the gas grid were chosen as possible plant locations. Industrial biogas plants have higher transport distances. Thus the accuracy of the used locations is less important. For the optimization of industrial plants, virtual plant locations using the centroids of municipalities with access to the gas grid were used as possible plant locations.

The feed-in capacity of local distribution gas grids is depending on technical properties of the grids as well as for residential areas the heat demand. Thus the gas demand can be lower in summer than in winter. In order to utilize the total available biogas potential gas storage facilities can be required.

12.2.1. Biomass transport costs

Transport costs are modelled depending on the type of biomass. Agricultural solid biomass is assumed to be transported with a tractor and a manure trailer. Agricultural wet biomass is transported with a tractor and a trailer. The transport costs are derived from the Agroscope report Maschinenkosten 2012 [45]. Industrial biomass is assumed to be transported with an 18 ton lorry. The transport costs are estimated based on data from the Schweizerischer Nutzfahrzeugverband (ASTAG) [46]. Table 13 shows an overview of the parameters used to estimate the transport costs. Figure 42 shows the transport costs used for the location optimization. To calculate the transportation costs, a salary of 34 CHF/h, 20 min load, respectively unload time as well as 45 km/h respectively 60 km/h average speed for tractors, respectively lorries are assumed. It should be noted that the costs for the transportation of the industrial biomass includes capacity-rated heavy goods traffic tax (LSVA), while the transportation with tractors does not. The shortest paths over the street network are used to estimate the transport distance between each biomass and possible biogas plant location.

Biomass type	Cost distance [CHF/km]	Cost hour [CHF/h]
Agricultural wet biomass	0	144.41
Agricultural solid biomass	0	143.30
Solid biomass	2.11	127.53

Table 13: Transport costs for different types of biomass [45], [38]

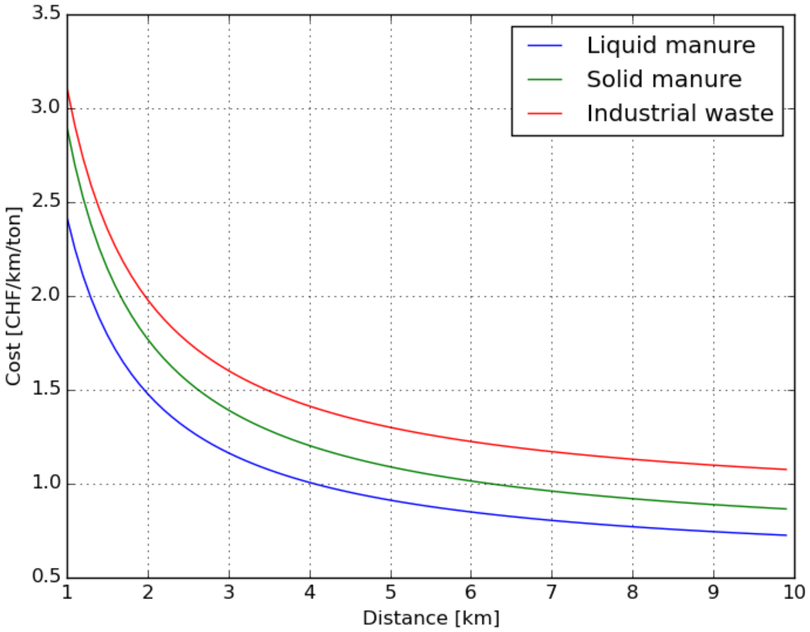


Figure 42: Transport costs per ton and kilometre depending on transportation distance

12.2.2. Biomass characteristics

For each type of biomass the methane potentials, densities and dry matter ratios as shown in Table 14 are assumed.

Biomass type	Methane potential [Nm3/t]	Density [t/m3]	Dry matter ratio [%]
Solid cow manure	52.59	0.83	25
Liquid cow manure	16.72	1.0	10
Pig manure	12.1	1.0	6
Hen manure	82.5	0.8	40
Green waste	43.0	0.6	50
Food waste	131.25	0.63	16
Gastro waste	131.25	0.63	16

Table 14: Methane potential, dry matter ratios and biomass densities [44], [47], [48], [49]

12.2.3. Biogas plant economic model

Figure 43 and Figure 44 show investment costs of recent large biogas plants in Switzerland. The linear fitted cost function is used to estimate investment costs for different sizes of biogas plants. Based on [50] and [51] the annual operating costs are estimated with 20% of the investment costs of a plant. Agricultural plants are assumed to support a dry matter ratio of up to 15% of the biomass, while industrial plants support a higher dry matter ratio.

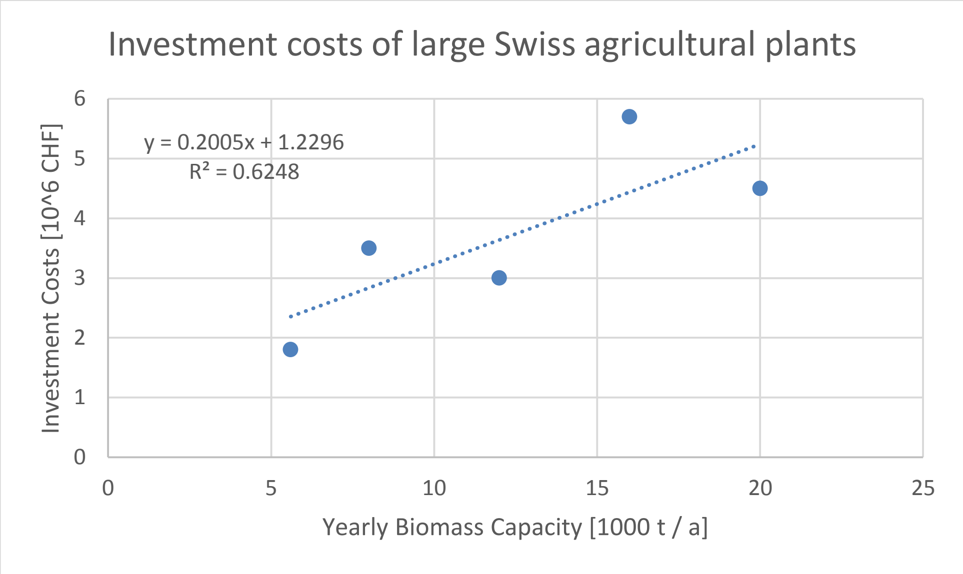


Figure 43: Investment costs of agricultural plants

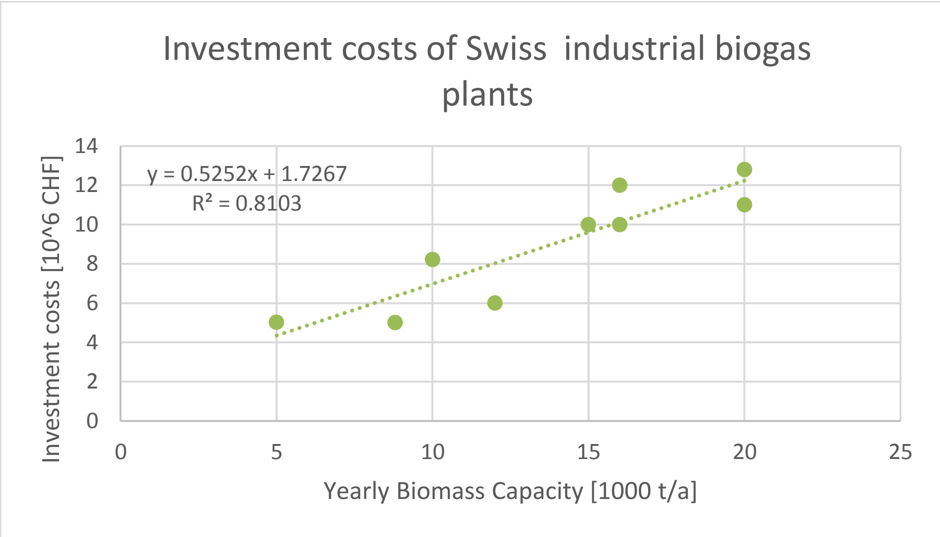


Figure 44: Investment costs for industrial biogas plants

12.2.4. Biogas plant location optimization

The optimization model expects as input a set of biomass sources $i \in I$ and a set of possible biogas plant locations $j \in J$. The model optimizes biomass locations over $t \in T$ time intervals. Each time interval t spans over a number of days d_t $[days]$. d_a $[days]$ stands for the number of days of a year. For each biomass source i the available biomass $b_{i,f,t}$ $\left[\frac{t}{d_t}\right]$ of biomass type $f \in F$ for time interval t is known. $ct_{i,j,f}$ $[\frac{CHF}{t}]$ are the transport costs between biomass source i and plant location j for one ton of biomass f. Each biomass f has a density $\rho_f[\frac{t}{m^3}]$, dry matter ratio DM_f $[\%]$, biomass production cost $cb_f[\frac{CHF}{t}]$ and methane yield $y_f[\frac{Nm^3}{t}]$.
For each biogas plant location, the operating costs are described as a linear cost function $plant\_cost$ depending on the plant volume V $[m^3]$:

$$plant\_cost = ca\,[\frac{CHF}{m^3}] * V + cb\,[CHF]$$

As the cost function is not valid for arbitrary plant capacities, the plant volume is bound by a minimal and a maximal volume:

$vmin\ [m^3] \leq\ V\ \leq\ vmax\ [m^3]$

Each plant has a maximal allowed dry matter content of the biomass mix $maxDM_j$ [%] and a mean hydraulic retention time $HRT_j\ [days]$. The HRT is the average duration the biomass is kept in the plant. For agricultural plants a HRT of 38 days, for industrial plants 18 days was assumed based on [44].

Different decision variables are used: $x_j \in \{0\ ,1\}$ has value 1 if plant j should be built or value 0 if plant j should not be built. $y_{i,j,f,t}\ [t]$ is the amount of biomass f transported from source i to fermenter j in time interval t. The used capacity (volume available for number of days d_t of time interval t) of a plant j in time interval t is $v_{j,t}[m^3 d_t]$. The maximal capacity of a plant (the volume available over a year) of plant j is $v_j[m^3 * d_a]$. $G_{j,t}\ [Nm^3]$ is the maximal producible methane at location j in time interval t. p_{gas} is the assumed gas price.

The aim of this optimization model is to select the best locations maximizing the total profit of all plants. In the model the profit of the plants is defined as the revenue of gas, heat and electricity sales minus biomass production and transportation costs and plant operating costs depending on the capacity of the plants. The model is optimized by limiting the number of plants to build to a fixed number k. The model is then optimized for different k.

$$gasRevenue = \sum_j \sum_t G_{j,t} * p_{gas}$$

$$transportationCosts = \sum_j \sum_i \sum_f \sum_t y_{i,j,f,t}\ * ct_{i,j,f}$$

$$biomassCosts = \sum_j \sum_i \sum_f \sum_t y_{i,j,f,t}\ * cb_{i,f,t}$$

$$plantCosts = \sum_j x_j * cb_j + \frac{v_j}{d_a} * ca_j$$

Thus the objective function is to maximize:

$$maximize\text{:}\quad gasRevenue + \\ - transportationCosts - biomassCosts - plantCosts$$

The objective function should be optimized with respect to the following constraints.
The number of plants to be built is limited to k.

$$\sum_j x_j = k$$

The used capacity $v_{j,t}$ of plant j and time interval t is bound to the used biomass with the following constraint.

$$\forall\ j, \forall\ t\text{:}\ \sum_i \sum_f y_{i,j,f,t} *\ \rho_f * HRT_j = v_{j,t}$$

The maximum plant volume v_j is the maximum of all interval capacities:

$$\forall\, j, \forall\, t:\ v_{j,t} \le v_j * \frac{d_a}{d_t}$$

The volume of a plant j must be inside $vmin_j$ and $vmax_j$. The multiplication with x_j ensures that not building plants cannot consume biomass.

$$\forall\, j:\ v_j \ge vmin_j * d_a * x_j$$

$$\forall\, j:\ v_j \le vmax_j * d_a * x_j$$

For each biomass source i and for each time interval t no more biomass of type f can be used as available:

$$\forall\, i, \forall\, f, \forall\, t:\ 0 \le \sum_j y_{i,j,f,t} \le b_{i,f,t}$$

The gas potential $G_{j,t}$ of a plant j in time interval t is bound to the used biomass and the specific methane yield y_f of the used biomass f.

$$\forall\, j, \forall\, t:\ \sum_i \sum_f y_{i,j,f,t} *\ y_f = G_{j,t}$$

The dry matter ratio of a plant should not exceed the maximal average dry matter ratio supported by the plant:

$$\forall\, j, \forall\, t: \sum_i \sum_f y_{i,j,f,t} *\ DM_f \le maxDM_j * \sum_i \sum_f y_{i,j,f,t}$$

12.3. Synthetic natural gas from wood

Wood can be gasified and converted to synthetic natural gas (SNG). The SNG potential from wood was estimated with a top-down method. In [52] the sustainable forest energy wood potentials for Switzerland were estimated. The potential for each case study region is derived using the ratio of forest area of the case study regions. Harvest losses of 10% are assumed for “Schaftderbholz” and “Astderbholz”, 40% for “Riesig” and “Blätter”. As mentioned in [52] the forest energy wood potentials reflect theoretical potentials and not potentials available on the wood market. Additionally, forest energy wood can be used for different purposes. The available potential for SNG production is thus dependent on the market situation. It was not possible to model the wood market in the scope of this project. Thus the SNG potential should be considered as theoretical “envelope” potential.

12.4. Building database

Modelling building heat demand requires detailed data about buildings. This data includes physical properties of buildings, including the footprint area, the height of the building or the number of floors and the volume. Additionally, the construction period is important to derive the materials a building is built with. No single database is available containing all required data. However different databases and datasets contain relevant building related information. These datasets were integrated into a Swiss wide building database.

12.4.1. Data

12.4.1.1. Register of buildings and dwellings (RBD)

The register of buildings and dwellings of the Swiss Federal Office of Statistics contains many data of buildings [53]. The register exists since 2002. It is based on the "Gebäude- und Wohnungserhebung" of the population census in 2000. The data collection was performed by questionnaires sent to all households. Thus the data was entered by individuals and not experts. Since 2002 the register is updated by the municipalities. The following attributes included in the dataset are used to model building heat demand:

- The construction period of a building
- The construction year
- The renovation period
- The type of the building (single family home, multi family home, office building, mixed usage)
- The footprint area
- Parcel number or "Baurechtsnummer" (LOTNR)
- Building identification number (EGID)
- Building location (x, y coordinate)
- Municipality id (FOSNR)

Not all attributes are mandatory. Only roughly 45% of buildings in Switzerland have the footprint area field set. Due to the collection method the quality of the building areas of the "Gebäude- und Wohnungserhebung" can be considered only as rough estimates [54], [55]. However, for buildings built after 2002 the situation is different as the municipalities derive the data from the planning applications [45]. The register requires only buildings with residential usage to be included. Depending on the municipality, additional buildings are also included. The data model includes a building identification number (EGID) that is unique for each building.

12.4.1.2. Cadastral survey

The cadastral survey datasets include building footprints (Polygons), building entrances (Point coordinates) as well as parcels (Polygons). Parcels and building entrances are only used to match RBD buildings to building footprints. As shown in Figure 45, both the building footprint as well as the building entrances have an EGID attribute in the data model. The geometric quality of cadastral footprints is high due to the data quality requirements of the cadastral survey. Thus they are used to derive the footprint area. However the cadastral survey is not yet completely digitally available [56]. For some regions no data is available. Additionally, available geometries might have incomplete attributes (e.g. missing EGID or parcel id attribute).

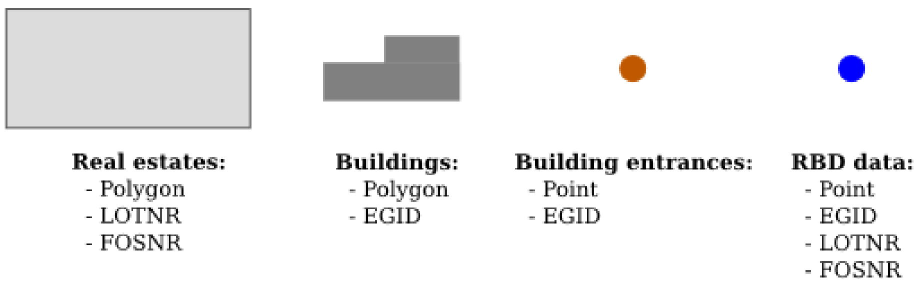


Figure 45: Selection of data model of cadastral and RBD datasets used for matching

12.4.1.3. swissTLM3D building footprints

The swissTLM3D is a large-scale topographical landscape model of Switzerland created by the Federal Office of Topography swisstopo. It is used by swisstopo to create the Swiss national maps. The dataset contains building footprints according to cartographic quality criteria. The goal of the dataset is not to represent building footprints as close to reality as possible but to maintain cartographic quality requirements.

12.4.1.4. Elevation models

The Federal Office of Topography swisstopo provides with SwissALTI3D a digital terrain model (DTM) and DOM a digital surface model (DSM) of Switzerland. The DTM models the surface without vegetation or artificial structurers such as buildings. The DSM models the surface of artificial structures such as buildings. Average building heights were derived for each building footprint using the elevation difference between both datasets. This enabled to have height information for building footprints with no RBD data.

12.4.1.5. SwissBoundaries3D

The SwissBoundaries3D dataset contains the boundaries of Swiss cantons and municipalities as vector data.

12.4.1.6. Historic municipalities BFS

The Federal Office of Statistics provides with the “Historisiertes Gemeindeverzeichnis” a regularly updated datasets of mutations of municipalities in XML format [53].

12.4.1.7. Business and Enterprise Register

The business and enterprise register (BER) of the Federal Office of Statistics contains location as well as the type of business in form the NOGA classification code [57]. The BER is joined with building footprints with a spatial join. The spatial join matches BER data points to the building footprint they are within. The NOGA codes are then used to classify building footprints as commercial or industrial as well as to estimate the heat demand patterns (More details can be found in section 11.2).

12.4.2. Dataset integration

The data integration process of RBD and BUR buildings to building footprints consists of multiple steps from data cleaning and pre-processing to matching based on the available data.

12.4.2.1. Unified building footprint database

The building footprints of the cadastral survey were integrated into one dataset. All cadastral buildings are included in the database. Building footprints of the swissTLM3D dataset were added if they do not touch a cadastral survey building footprint. They are if no building footprint from the cadastral survey is available.

12.4.2.2. Data cleaning

Despite of a unified national data model different abnormalities were observed. Thus the datasets were cleaned before further processing. The cleaning procedure included removing of buildings that overlap to more than 90%. If overlapping buildings were detected, the newer building is kept. Unrealistic large parcels with an area of more than 10 km^2 are ignored. Buildings with an area of 1.1 km^2 are considered as misclassified buildings. Small buildings with a footprint area of less than 20 square meter are assumed to be non-residential buildings such as sheds and are ignored. In some regions parcel ids do not follow the format used in the RBD data. In this regions, the parcel ids were harmonized using heuristics.

12.4.2.3. Harmonization of municipality ids

An important attribute for matching building data is the municipality id. This attribute can be used to partition the data. This reduces the number of buildings that need to be matched at an instance of time. Municipality ids are subject to change as municipalities can split or fusion over time. Thus the municipality ids of all datasets are updated to the municipalities of the swissBOUNDARIES3D dataset with revision March 12th 2014. The swissTLM3D and cadastral survey datasets were matched spatially with the swissBOUNDARIES3D municipalities in order to derive the current municipality id. The municipality ids of the RBD buildings were updated with the mutation information of the “Historisiertes Gemeindeverzeichnis” datasets from the Federal Office of Statistics.

12.4.3. Matching

The simplest possibility to join the RBD dataset with the building footprints with a matching EGID. This method only works if the EGID is available in both datasets. Missing or erroneous data increases the complexity of matching both datasets significantly. Figure 46 shows examples of location inaccuracies of the RBD dataset. These include local errors in the coordinates (left), multiple buildings for the same coordinate (middle) or misplaced coordinates (right). An algorithm was developed to match RBD buildings and building footprints using as much data as possible. The algorithm matches RBD data with footprints by searching possible links between both datasets using the attributes as well as spatial relations. These links are formed with different search strategies.

Figure 46: Inaccurate RBD data points. (left) coordinates outside building footprints, (middle) multiple buildings with same coordinate, (right) RBD building outside of corresponding parcel

Inaccuracies of the datasets can lead to multiple possible matches. Thus a RBD building might match to multiple building footprints or multiple RBD buildings might match to the same building footprint. The algorithm choses the link that uses the most available information.

It is assumed that typographic errors can be present in the RBD data for all attributes including coordinates. Typographic errors are determined by calculating the Damerau-Levenshtein distance. This distance measures the number of operations used to transform one word in another. Allowed operations include adding a letter, removing a letter or swapping two neighbouring letters. A typographic error is considerd as a Damerau-Levenshtein distance of 1 for words longer than 3 letters.

The following sections describe the strategies used to find links between RBD buildings and building footprints.

12.4.3.1. Building Footprint + EGID

In this strategy buildings are matched based on the EGID present in the RBD data as well as the the building footprints. The two left cases shown in Figure 47 are examples of errorneous data. If a RBD point is within a building with the same EGID the match is considered very good. Error cases are if an RBD point is outside a building or inside a building with a different EGID. In the first case, it is detected if a typographic error in the coordinates of the RBD point can explain the wrong position of the RBD point. For the second case, it is detected if the difference of the EGIDS can be explained by a typographic error.

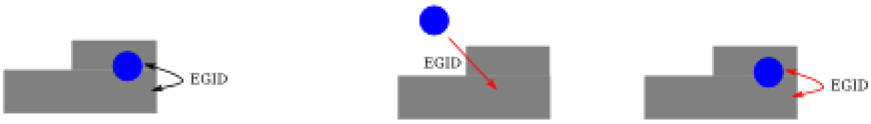


Figure 47: (left) Example of a good match, (right) example of errors preventing good matches

12.4.3.2. Building Entrance + EGID

A match is considred good if a RBD point can be matched to a building entrance with the same EGID and both points are within the same building. The left example of Figure 48 illustrates this case. If a point can not be matched to building entrances in the same building footprint, it is checked if a typographic error can be detected that allows to match a RBD point to a building entrance point in the same building. If a RBD point is outside a building with a building entrance point with the same EGID, it is detected if this error can be explained by a typographic error in the coordinates.

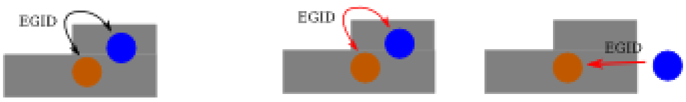


Figure 48: (left) Example of a good match, (right) example of errors preventing good matches

12.4.3.3. Minimum cost matching

This strategy is only applied if a parcel has the same amount of buildings as well as RBD points with the same parcel id as shown in Figure 49. The RBD points are paired with building footprints in oder to minimize the total distance in meters between pairs of RBD footprints buildings. If the total distance is 0 the pairs are considered to be the best possible link.

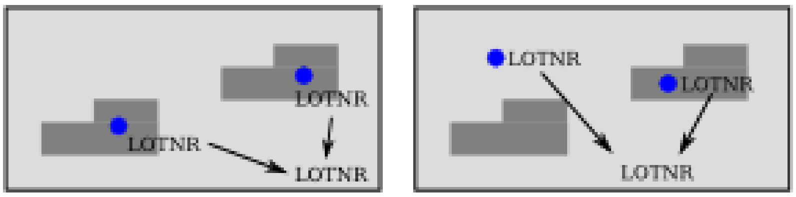


Figure 49: The same number of building footprints and RBD buildings can be matched to the same parcel

12.4.3.4. Typographic error in parcel id

The mincost strategy can not be applied to parcels where the number of building footprints is not equal to the RBD buildings as shown in Figure 50. This strategy applies if the parcel id of a RBD building can be matched to a parcel polygon by the parcel id. It is then detected if a typographic error would move the RBD point within a building within the parcel with the same parcel id.

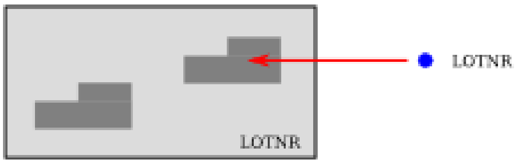


Figure 50: Matching strategy when no EGID can be matched and different number of building footprints and RBD buildings

12.4.3.5. Spatial join

If neither EGIDS nor parcel ids can be used to join the data the spatial properties are expoited. A RBD point is matched if he is either within a building footprint or alternatively if he is not more than 2 meteres away.

12.4.4. Match selection

These strategies were applied for all buildings. For each building the match according to the ranking of the strategies in Table 15 are used. Figure 51 shows an overview of the spatial distribution of the strategies used to match the RBD building to building footprints.

Strategy	Ranking
Minimum cost matching, 0 cost	1
Building entrance + EGID	2
Building footprint + EGID	3
Minimum cost matching, >0 cost	4
Building entrance + EGID + Error detection	5
Building footprint + EGID + Error detection	6
Typographic error in parcel id	7
Spatial join, 0 meter distance	8
Spatial join, <2 meter distance	9

Table 15: Ranking of matching strategies

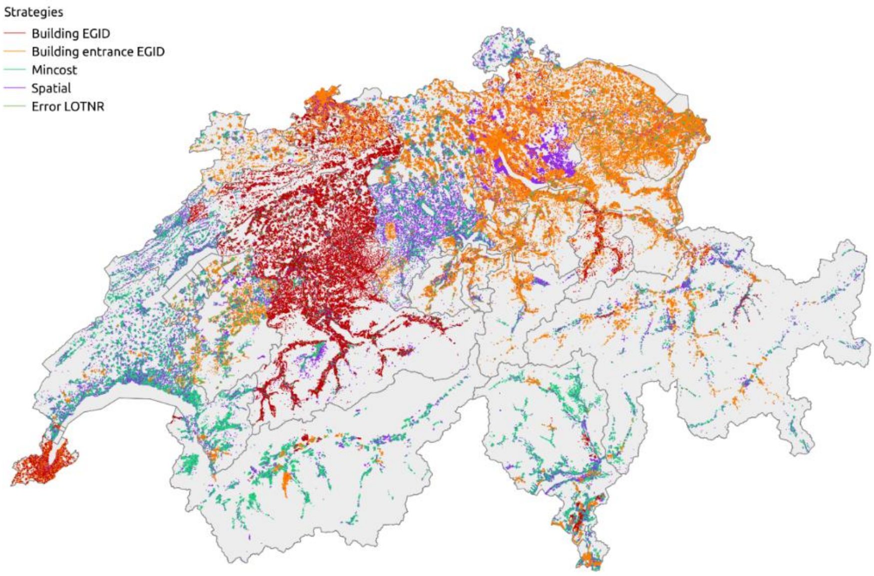


Figure 51: Spatial distribution of chosen matching strategies

12.5. Gas grid reconstruction

Geographic gas grid data was only available for the case study Lucerne. Thus it was necessary to reconstruct the gas grid for the other case study regions. Two data sources were used for the reconstruction. The register of buildings and dwellings [53] contains the heating system type, including gas heater, for each residential building. Additionally the Verband der Schweizerischen Gasindustrie (VSG) maintains online on www.erdgas.ch a list of postal codes with available gas grid [58].

The reconstruction process selects residential buildings with possible gas grid access and creates a buffer area using a buffer distance of 300 meter to define the area with possible access to the gas grid. The assumption is, that multiple buildings in close proximity with access to the gas grid have a gas based heating system. Thus clusters with only a few buildings are considered as outliers. This is achieved by only selecting residential buildings with at least 15 buildings within 100 meters with gas based heating system. For postal codes areas with available gas grid it is unlikely that the whole area has access to the gas grid. Thus only buildings with at least 15 residential buildings within 300 meters are included. The reconstructed gas grid for the case studies Thurgau and Basel is shown in Figure 52.

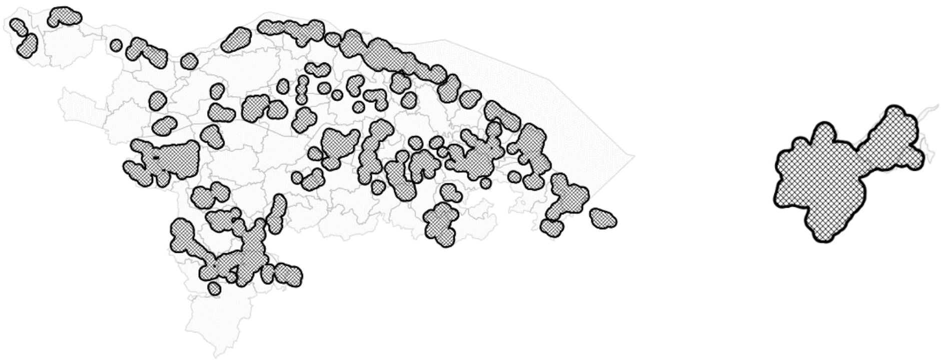


Figure 52: Reconstructed gas grid for case study Thurgau (left) and Basel (right)

12.6. GIE group conclusions

A GIS based spatio-temporal biomass model was developed. It has a high spatial resolution and models the available biomass for each site. Biogas plant locations are determined by optimizing the biogas production chain. This allows to determine the biogas that can be delivered to the gas grid. Thus the biogas that effectively can be used for the CHP swarms is determined.

To model building heat demand a methodology was developed to integrate different heterogenous datasets. The datasets are available on a national level and allow a nation wide bottom-up heat demand modelling.

13. Technical report FEN (Electricity grid simulations and PV injection)

13.1. Introduction

The Research Centre for Energy Networks (FEN, *Forschungsstelle Energienetze*) at ETH Zurich analysed the potential for deployment of small-scale CHP technologies in selected distribution grids in Switzerland. The specific objective of the analysis was to compensate for the fluctuations introduced by local PV production. Grid data for 3 different case studies was acquired from distribution network operators and employed for the analytic investigation, and the location and installed capacity of CHP units was derived based on a numerical assessment performed by IKG and LAV. Uncertainty concerning different photovoltaic (PV) penetration levels were addressed by defining alternative scenarios and by also employing assumptions and objectives taken from the Swiss Energy Strategy 2050. A simple indicator is proposed to assess the degree of compensation that is effectively possible based on the installed CHP/PV capacity and relevant network constraints. Section 13.2 gives an overview of the selected benchmark networks and modelling assumptions while Section 13.3 illustrates the method applied for the featured analysis. Numerical results are presented in Section 13.4 and in Section 13.4 conclusions are briefly drawn.

13.2. Grid data/parameters and modelling assumptions

Three different case studies were considered and analysed throughout the project, namely:

- Canton Lucerne
- An urban district within Basel City
- The municipality of Bürglen in Canton Thurgau (TG)

Designing operation strategies for power systems, especially in the presence of non-dispatchable generation and rising storage capacities, is a challenging task. Intermittent generation can be formally regarded as a disturbance, which might cause imbalances in the power system. The framework presented in [59], [60] aims at providing a platform to model any such elements that will be presumably present in future distribution networks. The generic description therein enables the representation of various energy conversion units within the power network, naturally including biogas/biomass plants and PV panels. The employed framework was integrated with the classical grid equations, in order to allow for the prototyping and validation of sample systems.

13.2.1. Canton Lucerne

Canton Lucerne is served by a number of different utilities and for the purpose of the present work 2 separate grid models were acquired from EWL (Energie Wasser Luzern) and CKW (Centralschweizerische Kraftwerke), respectively (approximately) covering the city of Lucerne and the remaining part of the canton. The EWL grid features about 1000 branches and 850 nodes at 10 kV, whereas the CKW includes some 3800 branches and 3700 busses at 20 kV. For the CKW grid geographical data was available for the grid nodes, so that it was possible to topologically map the foreseeable heating requirements and related CHP capacity directly to the network, based on available cantonal statistics. For EWL no geographic coordinates were available, so that only an aggregate analysis was possible, i.e. for the city of Lucerne CHP and PV capacities were assigned by assuming that a higher electrical load would imply a proportionally higher CHP/PV capacity at the same location. Demand varies throughout the day according to the assumed loading profile, with the peak load amounting to about 300 MW (CKW) and 90 MW (EWL).

For the PV units solar irradiance profiles specifically acquired for canton Lucerne with an hourly resolution for the whole year were employed. The PV injection is then taken to be proportional to the irradiance time series, with summer peak values (i.e. measured at midday) approximately 3 times higher than the corresponding winter values. The proportionality factor is determined by the assumed overall yearly PV power production level, which is in turn derived from the 2050 scenarios set forth in [61] and [62] for Switzerland as a whole and which correspond to low/medium/high generation levels of 5.5, 11.0 and 16.5 TWh respectively. The latter values have been then scaled to the population of Lucerne in order to derive appropriate projections.

13.2.2. Basel City district

For the Basel City district a model of the local electrical grid was delivered by IWB. The network features 85 branches and 88 busses, mostly at 0.4 kV. CHP and PV capacities were assigned by assuming that a higher electrical load would imply a proportionally higher CHP/PV capacity at the same location, since geographic coordinates of the busses were not available. Demand varies throughout the day according to the assumed loading profile, with the peak load amounting to about 0.6 MW. For the PV units yearly solar irradiance profiles specifically acquired for canton Basel City with an hourly resolution were employed, and the PV injection is then taken to be proportional to the irradiance time series. Three different penetration levels (low/medium/high generation levels) were assumed, based on the building surface availability, respectively corresponding to 0.4, 0.8 and 1.2 MWp.

13.2.3. Bürglen (TG)

For Bürglen (TG) a model of the local electrical grid was delivered by the Thurgau cantonal authorities. The network features 274 branches and 266 busses, predominantly at 0.4 kV. Geographic coordinates of the busses were not available, so that no physical mapping between the electrical and heating systems could be performed and the CHP and PV capacities were therefore assigned by assuming that a higher electrical load would imply a proportionally higher CHP/PV capacity at the same location. Demand varies throughout the day according to the assumed loading profile, with the peak load amounting to about 3 MW. For the PV units yearly solar irradiance profiles specifically acquired for canton Thurgau with an hourly resolution were employed, and the PV injection is then taken to be proportional to the irradiance time series. Three different penetration levels (low/medium/high generation levels) were assumed, based on the building surface availability, respectively corresponding to 2.5, 5 and 7.5 MWp.

13.3. Optimal power flow

The introduction of distributed generation in the lower voltage levels of the grid creates new power flow and operation patterns in the overall system, the security of which must nevertheless be ensured. In order to achieve this objective it is necessary to establish which generation units can be dispatched while avoiding system constraint violations, and respecting heating requirements. This can be done by employing an optimal power flow procedure which determines the maximal injection level, i.e. the admissible power generation at each instant and at each node that is compatible with grid constraints.

The resulting layout of distributed capacity units, as described in Section 13.2, was therefore featured in the grid and employed for the purpose of optimal dispatching. The CHP plants are in general freely dispatchable, but they must satisfy a certain operating constraint related to heat storage requirements. Specifically, it is desired that each plant store a certain amount of (heat) energy during the day, which varies depending on the season of the year: for summer an energy value corresponding to 2 hours with full-load operation was selected, whereas for autumn, winter and spring this value was respectively set to 7, 13 and 7 hours. Exactly how and when the CHP plants are operated is then decided upon by the dispatching algorithm, as long as this energy condition is taken into account and fulfilled. It should be noted that the

CHP generation at the nodes is actually representative of a number of underlying units of smaller capacity. Each such unit might feature a capacity of e.g. 5-10 kW, and aggregating the individual capacities one obtains the relevant overall amount for each node.

The dispatch algorithm consists of an optimisation problem of the type that has been historically used for dispatch/scheduling problems in transmission grid operation. It performs the dispatch by minimising a chosen cost function reflecting the selected objective and subject to the system equations and constraints. In the present setting the constraints consist of the CHP capacity limitations and the imposed heat storage constraints, whereas the system equations consist of the network equations for the selected case study.

Concerning the cost function, the choice was made to minimize the variation of the combined CHP and PV power production over the selected prediction horizon. If *k* denotes a generic discrete time instant for a selected sampling interval (i.e. one hour), then the selected cost function can be formalised as

$$J = \sum_{k=1}^{k=N} (PV(k+1) + CHP(k+1) - PV(k) - CHP(k))^2$$

where *N* denotes the number of sampling instants (the horizon length) and *CHP(k)* and *PV(k)* (resp. *CHP(k+1)* and *PV(k+1)*) the overall power produced by the CHP and PV units in the grid at instant *k* (resp. *k+1*).

In other words the dispatch aims at “flattening” the combined CHP and PV generation. The reason for this is that PV generation in itself inherently tends to deliver a production profile that is relatively irregular and in any case subject to external and incontrollable weather conditions, that are furthermore (at least partially) partially unpredictable. Additionally, in certain operating conditions, for example during winter evenings, there might be some pronounced load peaks while PV injections drop sharply exactly there and then. PV injections can therefore cause erratic power flow patterns in the grid, which might produce undesirable side effects.

Through the CHP units it is then possible to compensate for such variations by delivering power whenever there is a dearth in PV production. Since the cost function *J* featured above penalizes the variation of the overall CHP and PV generation, this compensation is effected with the aim of achieving a constant profile over time, since in that case the associated variation would be equal to zero. Other types of compensation are naturally possible, and in principle one could try to steer the joint CHP and PV production to an arbitrary reference, keeping in mind of course that only positive compensation is possible. The choice of trying to achieve a flat output was made for the sake of generality and due to the fact that further input on the side of the grid operators for specific network configurations and requirements was not available. The implemented choice allows at least to quantify the effect of CHP production in an analytical manner for a selected network.

The employed optimal power flow formulation therefore consists in minimising the cost function *J* subject to the grid equations and CHP capacity/heating constraints and branch limits. Notice that the minimisation is furthermore only activated during daylight hours, since during the night there is obviously no PV variation to compensate.

13.4. Numerical results

13.4.1. Canton Lucerne

Different CHP unit configuration levels were considered for the Lucerne case study, depending on the assumed type and availability of biogenic fuel per year, namely:

- Swarm1: 323 GWh/a biomethane fuel from woody biomass potential in Lucerne
- Swarm2: 370 GWh/a biomethane fuel from wet biomass potential in Lucerne
- Swarm3: 692 GWh/a biomethane fuel from total biomass potential in Lucerne

- Swarm4: 968 GWh/a biomethane fuel from total biomass potential in Lucerne times 1.4 (approximated) in order to provide the same heat as with gas boilers
- Swarm5: 1832 GWh/a biomethane fuel equivalent to the natural gas demand in Lucerne
- Swarm6: 2565 GWh/a biomethane fuel equivalent to the natural gas demand in Lucerne times 1.4 (approximated) in order to provide the same heat as with gas boilers

For each of the above cases both CKW and EWL grids were simulated over one full year. The optimal dispatch problem was formulated and solved on a daily basis, i.e. with a prediction horizon of 24 hours, in order to establish the optimal dispatch pattern for each day. All data related to predicted load, forecast PV generation and CHP dispatch was sampled and generated with an hourly resolution.

Figure 53 illustrates a sample plot for the obtained results in terms of PV generation and joint PV/CHP production for the CKW grid for Swarm5 on February 21st. The PV production profile is exogenously determined by weather conditions and, as can be seen for the chosen day, features a certain degree of variability due to meteorological perturbations. The combined PV injection and CHP production on the other hand is effectively constant (during sunlight hours), since the latter tries to compensate for variations in the former in order to yield a constant profile. Conceptually similar plots can naturally be produced for other days of the year, which might then look different depending on daily weather patterns and on the considered season (with which the amount of available CHP heating production varies).

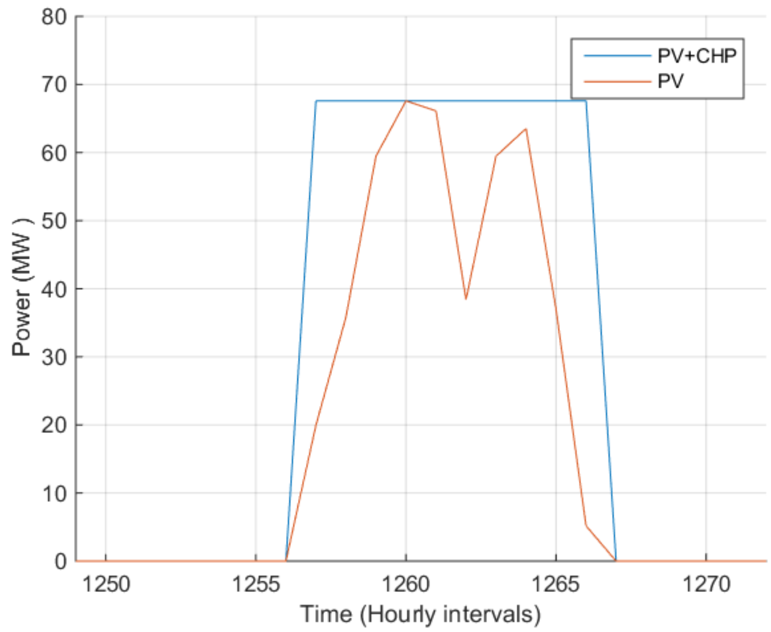


Figure 53: PV and combined PV+CHP generation in CKW grid (Swarm5) with intermediate PV penetration on February 21st

The CHP dispatch is performed subject to the condition that line loading conditions be respected. This is exemplified in Figure 54, which features the power flows in the branches on January 4th scaled to their admissible maximum value for the CKW grid for Swarm4. As can be seen power can flow freely in the lines as long as it remains below its maximum value, but it is actively constrained not to exceed the 100% limit. Again, similar plots can be produced for other combinations and days of the year.

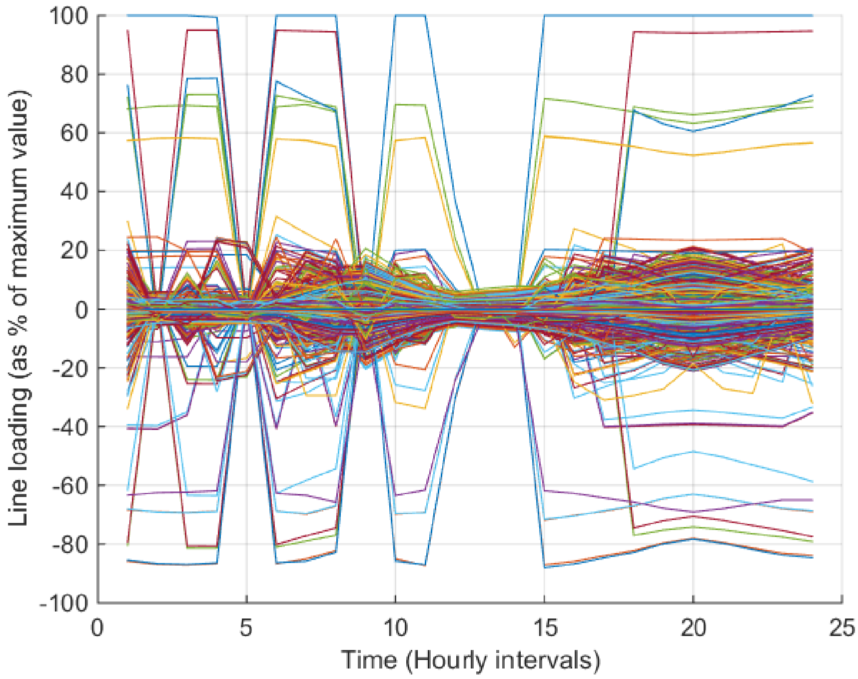


Figure 54: Line loading in the CKW grid (Swarm4) with intermediate PV penetration on January 4th

In order to visualise the effect of the resulting power dispatch on grid voltages, the active power injection for each of the hourly time-samples was considered and modelled in an AC formulation model of the grid, starting from the obtained active power flows and overlaying the latter with appropriate reactive power injections/absorptions, assuming that each CHP and PV generating unit has reactive power control capability with a $cos\phi$ factor of up to 0.95. As can be seen in Figure 55 all voltages can then be effectively maintained sufficiently close to the nominal value 1 per unit, and more specifically between 0.9 and 1.1 per unit if the CHP/PV units are capable of providing reactive power according to the assumed capability. The diagram refers to simulation results for the EWL grid for Swarm2 with high PV penetration on June 10th, and for each bus the associated hourly time series of 24 voltages for the chosen day is plotted. In this regard distributed generation resources featuring reactive power control can contribute in a positive manner to local voltage regulation.

Beyond active/reactive power limits, which must naturally be enforced to ensure secure grid operation, the purpose of deployment of the CHP units is to generate an overall power production profile featuring as little variation as possible during sunlight hours, cf. Figure 53. Since it is not possible to visualize such plots for all 36 cases (CKW and EWL grids simulated with 3 PV penetration levels and 6 CHP swarms) and for all days of the year, a numerical indicator is rather required to synthetically quantify and indicate what the effect of the CHP dispatch is.

In this sense starting from a generic time series of (scalar) values *x(k)*, one common approach for computing its degree of variability is by evaluating the standard deviation, defined as

$$\sigma = \sqrt{\frac{\sum_{k=1}^{k=T}(x(k)-\mu)^2}{T}}$$

where T is the length of the observation interval and μ denotes the average of x, computed as

$$\mu = \frac{\sum_{k=1}^{k=T} x(k)}{T}$$

The standard deviation therefore expresses variability by considering the degree of oscillation around the average. Notice that a constant signal has the property that $x(k)=\mu$, so that $\sigma=0$.

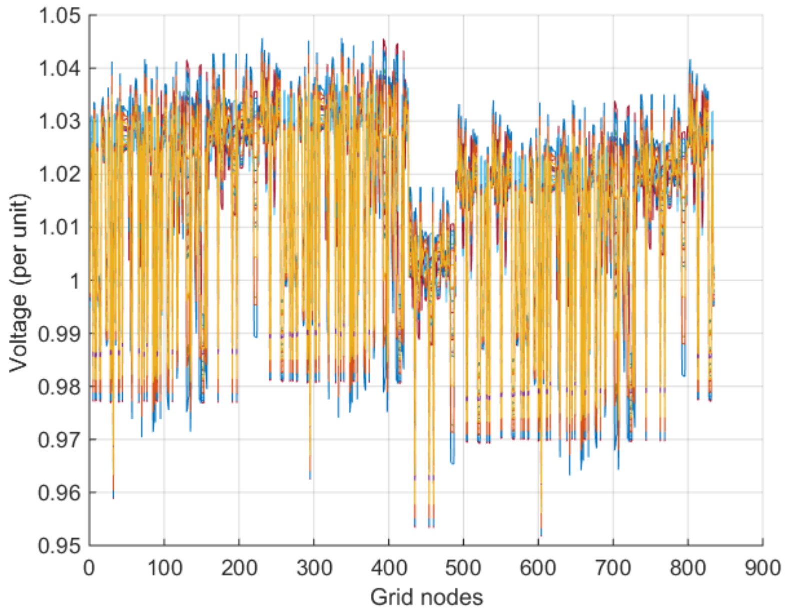


Figure 55: Voltages in the EWL grid (Swarm2) with high PV penetration on June 10th (for each node the hourly time series of 24 associated voltages is featured)

In order to assess the effect of CHP dispatch the standard deviations of *PV(k)* and *PV(k)+CHP(k)*, (i.e. the standard deviations of the power generated solely by the PV units and the combined PV and CHP units), are calculated for all considered combinations and denoted as σ_p and σ_{pc}. Specifically, a distinct value is calculated for each day of the year, that is with T=24, but only values during sunlight hours are retained in the calculation. By way of example, this would yield $\sigma_{pc}=0$ for the joint PV and CHP generation curve displayed in Figure 53, since during the daytime (that is, when PV production is greater than zero) it is completely flat. Figure 56 displays the percentage reduction of the standard deviation, i.e. the percentage reduction between σ_p and σ_{pc} defined as

$$\text{Reduction(\%)} = 100 \times \frac{\sigma_p - \sigma_{pc}}{\sigma_p},$$

for each day of the year for Swarm4 and with intermediate PV penetration (CKW grid). Notice that during the winter, and to a lesser extent in the spring and in the autumn, one relatively often has the case $\sigma_{pc}=0$ so that the relative reduction amounts to 100 %, since PV production is fairly small and there is a comparatively higher availability of CHP generation due to heating specifications. Similar plots naturally can be produced for the other combinations, for which also similar remarks hold. The related results are summarized in Figure 57 and 58, respectively for CKW and EWL, where the average reduction computed throughout the whole year is given. During winter (summer) the average reduction value would naturally be higher (lower). The compensating potential of the CHP swarms increases with their own size and decreases with PV penetration, as intuitively consistent.

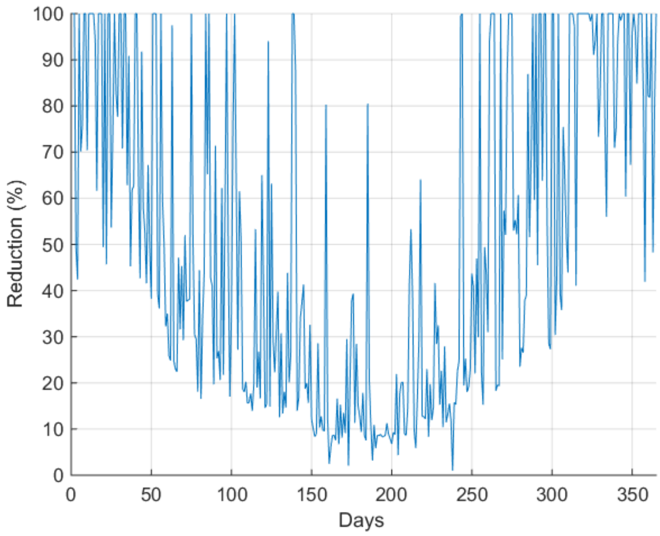


Figure 56: Percentage reduction between σ_p and σ_{pc} for Swarm4 with intermediate PV penetration (CKW grid), values calculated on a daily basis

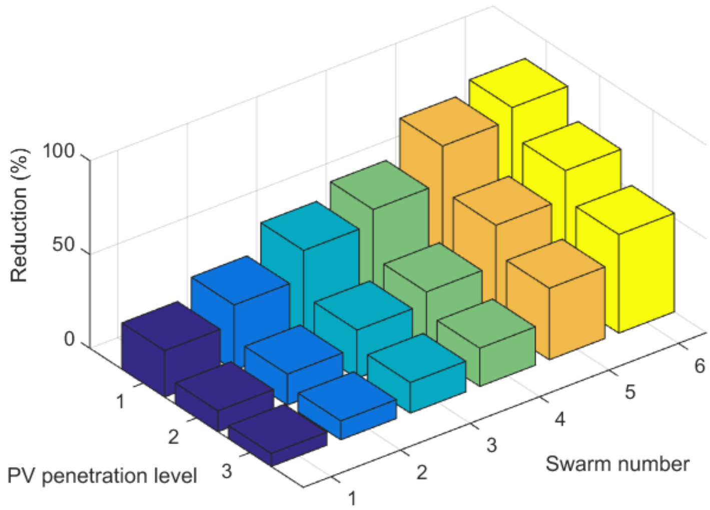


Figure 57: Average yearly percentage reduction between σ_p and σ_{pc} in CKW grid (PV penetration levels 1, 2, 3 correspond to low, intermediate and high scenarios respectively)

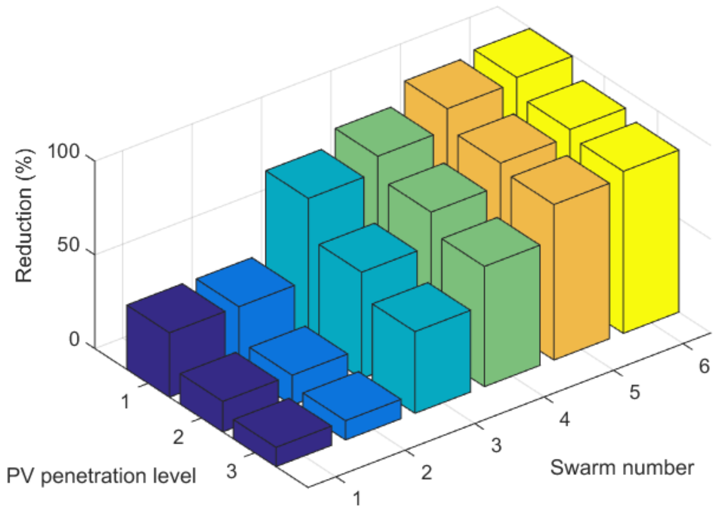


Figure 58: Average yearly percentage reduction between σ_p and σ_{pc} in EWL grid (PV penetration levels 1, 2, 3 correspond to low, intermediate and high scenarios respectively)

13.4.2. Basel City district

For the given configuration (i.e. installed PV+CHP capacity assumed to be proportional to local load, see also Section 13.4.1) the system was simulated over one full year. The optimal dispatch problem was formulated and solved on a daily basis, i.e. with a prediction horizon of 24 hours, in order to establish the optimal dispatch pattern for each day. All data related to predicted load, forecast PV generation and CHP dispatch was sampled and generated with an hourly resolution. Since the dispatch is performed inclusive of system constraints, overloading limits and voltage bounds are inherently respected at all times.

Figure 59 illustrates a sample plot for the obtained results in terms of PV generation and joint PV/CHP production on July 25th. As can be seen the combined PV and CHP injection tends to be flatter than the PV production alone (during sunlight hours) since the CHP units are dispatched with the aim of compensating for the former's fluctuations.

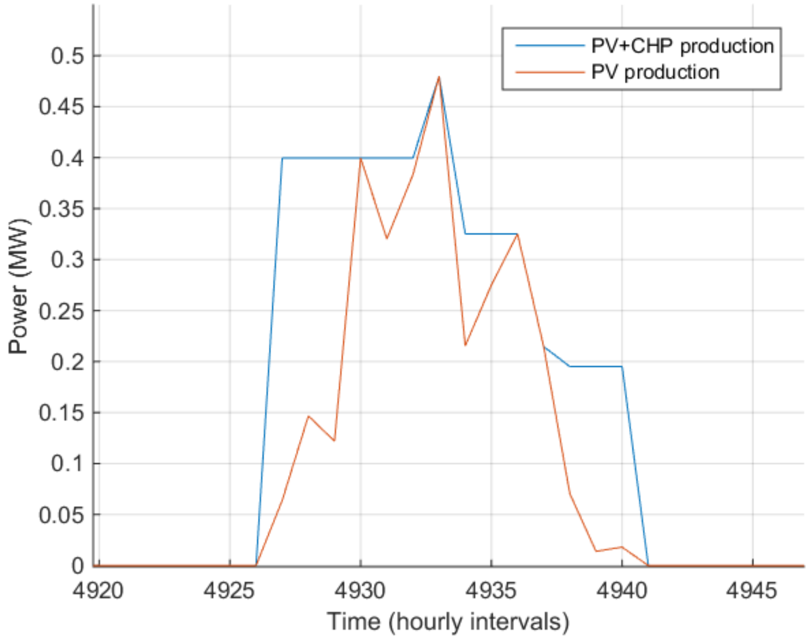


Figure 59: PV and combined PV+CHP generation for Basel City district grid with intermediate PV penetration on July 25th

In other words, if one were to compute the standard deviation σ_{pc} of the PV+CHP production, this would be smaller than the corresponding value σ_p computed considered only the PV generation (see Section13.4.1), since it features fewer localised fluctuations. By assessing the percentage reduction between σ_p and σ_{pc}, for each day of the year, one can therefore measure the "flattening" effect of the CHP production on overall daily injections. Visualizing the percentage reduction (cf. Section 13.4.1) throughout the year for the 3 different PV penetration levels yields Figure 60-62, where it can be intuitively seen that the compensating effect of the CHP plants decreases with increasing PV production. Computing average reduction values for seasonal periods furthermore confirms this, since more reduction is possible whenever CHP and PV production are respectively relatively high and low, as would be the case during the heating season, see Figure 63.

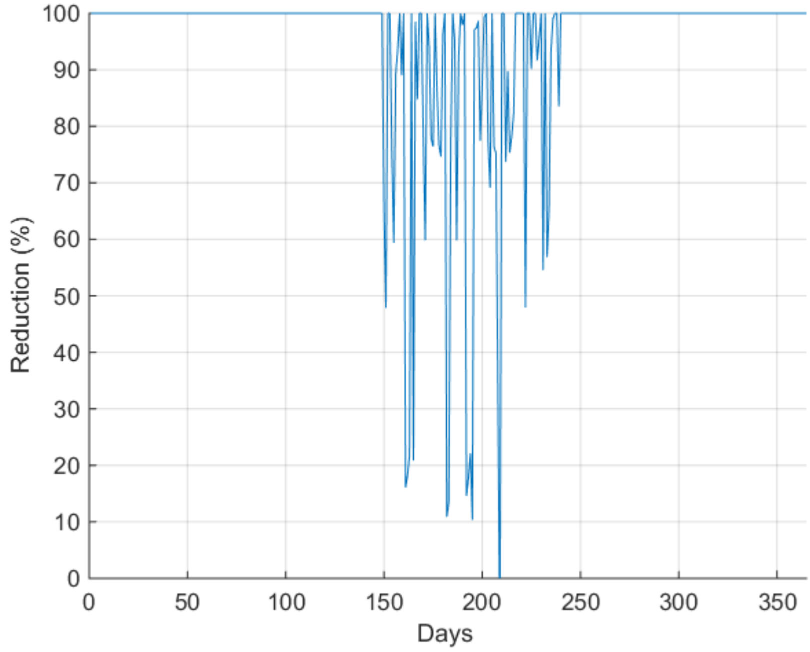


Figure 60: Percentage reduction between σ_p and σ_{pc} for Basel City district grid with low PV penetration, values calculated on a daily basis

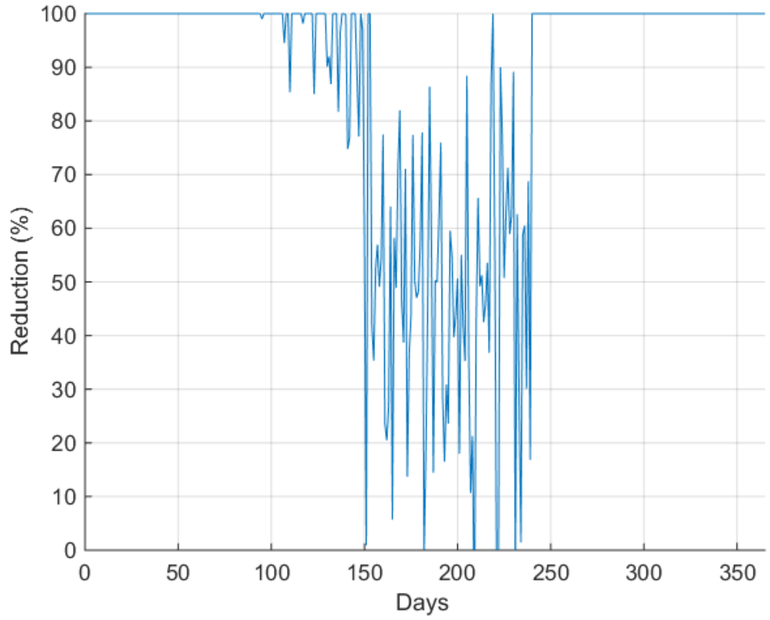


Figure 61: Percentage reduction between σ_p and σ_{pc} for Basel City district grid with intermediate PV penetration, values calculated on a daily basis

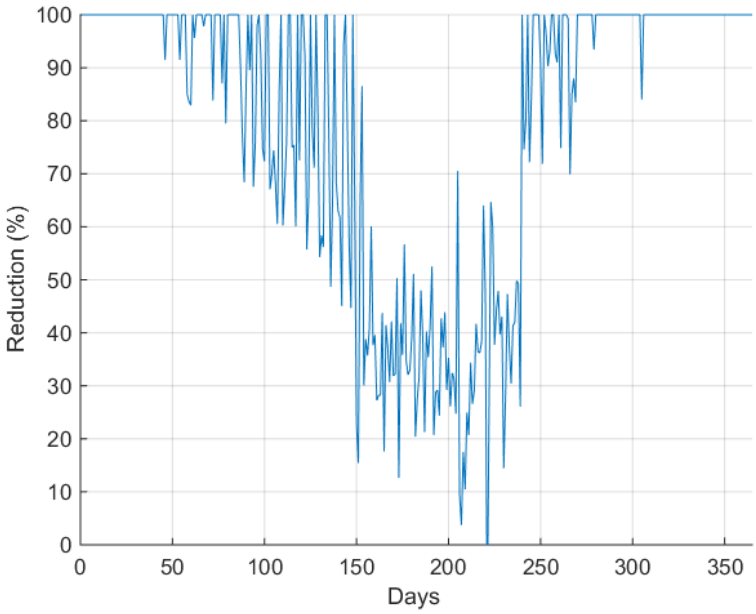


Figure 62: Percentage reduction between σ_p and σ_{pc} for Basel City district grid with high PV penetration, values calculated on a daily basis

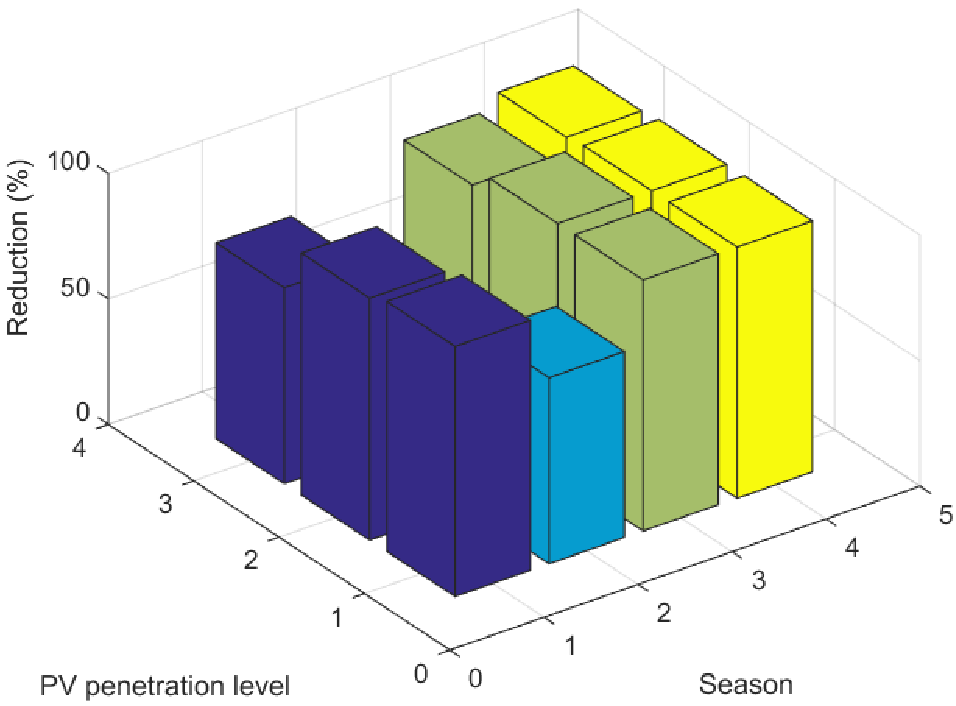


Figure 63: Average seasonal percentage reduction between σ_p and σ_{pc} for Basel City district grid (PV penetration levels 1, 2, 3 correspond to low, intermediate and high PV scenarios, seasons 1, 2, 3, 4 correspond to spring, summer, autumn and winter)

13.4.3. Bürglen (TG)

Also for the case study Bürglen (TG) the system was simulated over one full year, where the installed PV+CHP capacity was assumed to be proportional to the local node demand (see also Section 13.4.1). The optimal dispatch problem was formulated and solved inclusive of system constraints on a daily basis, i.e. with a prediction horizon of 24 hours and with an hourly sampling interval.

Figure 80 exemplifies the obtained results in terms of PV generation and joint PV/CHP production on July 7th where it can be seen that the CHP injection tries to compensate for local variations in the PV production. The standard deviation σ_{pc} of the daily PV+CHP production, would therefore be smaller than the corresponding value σ_p computed considered only the PV generation (see Section 13.4.1), since local fluctuations are somewhat reduced and flattened.

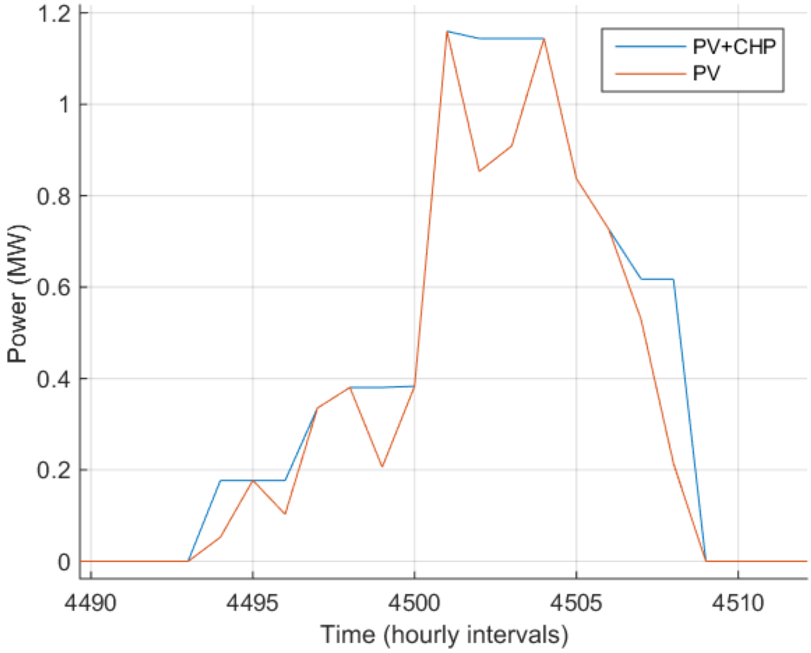


Figure 64: PV and combined PV+CHP generation for Bürglen (TG) grid with low PV penetration on July 7th

By assessing the percentage reduction between σ_p and σ_{pc}, for each day of the year, one can therefore measure this “flattening” effect of the CHP production on overall daily injections. Visualizing the percentage reduction (cf. Section 13.4.1) throughout the year for the 3 different PV penetration levels yields Figure 65-67 which illustrate that the compensating effect of the CHP plants decreases with increasing PV production. Computing average reduction values for seasonal periods furthermore confirms this, since more reduction is possible whenever CHP and PV production are respectively comparatively high and low (i.e. in the heating season during winter), see Figure 68.

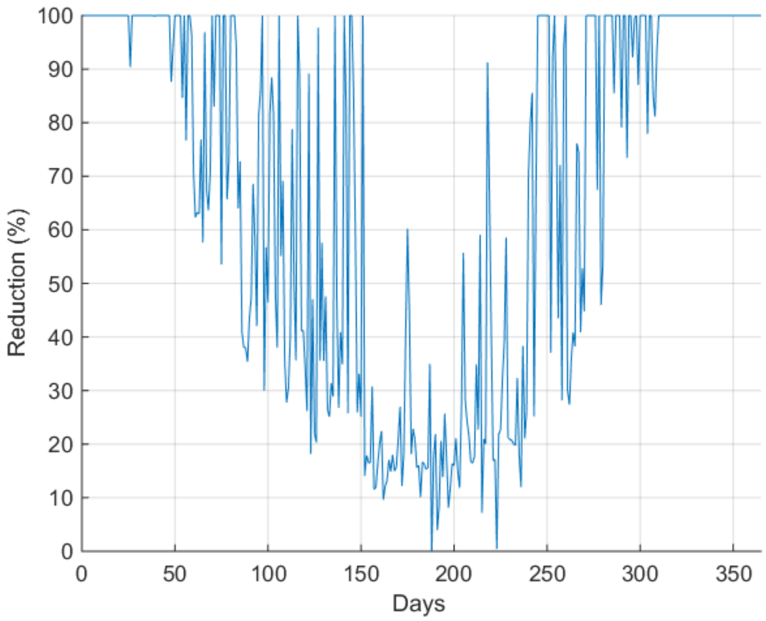


Figure 65: Percentage reduction between σ_p and σ_{pc} for Bürglen (TG) grid with low PV penetration, values calculated on a daily basis

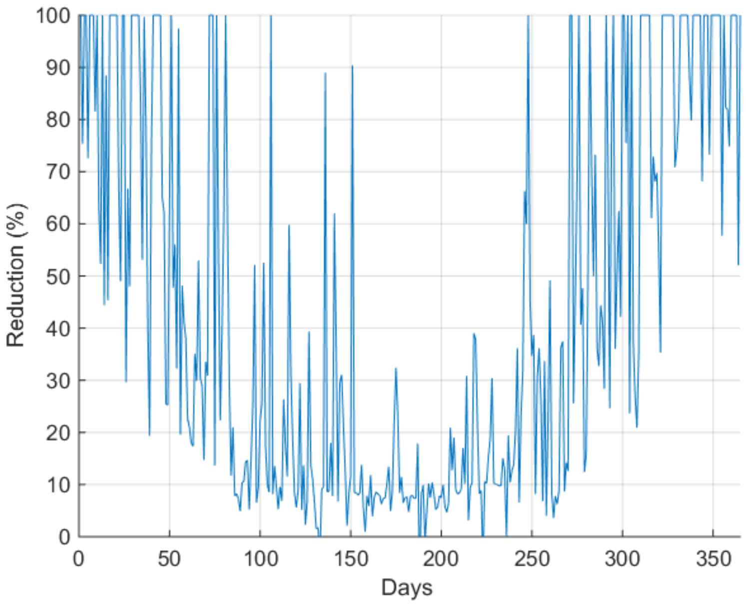


Figure 66: Percentage reduction between σ_p and σ_{pc} for Bürglen (TG) grid with intermediate PV penetration, values calculated on a daily basis

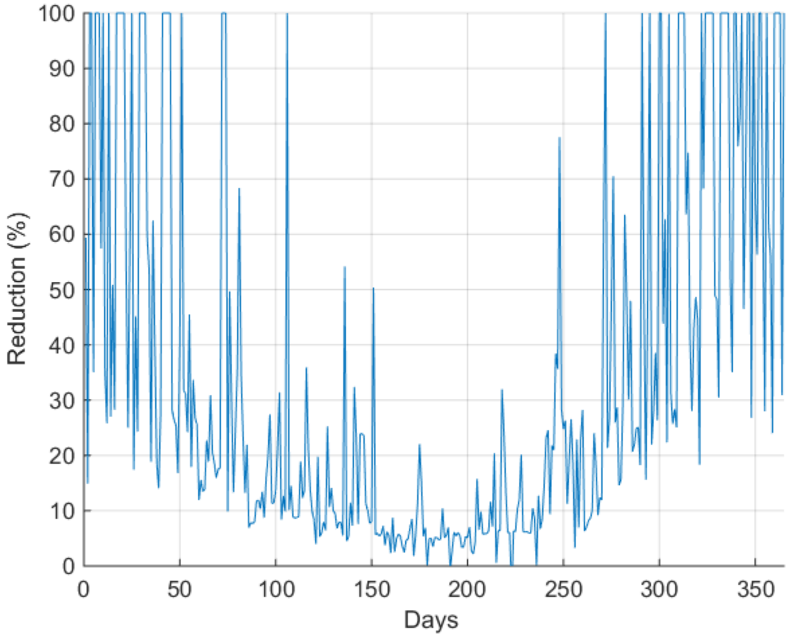


Figure 67: Percentage reduction between σ_p and σ_{pc} for Bürglen (TG) grid with high PV penetration, values calculated on a daily basis

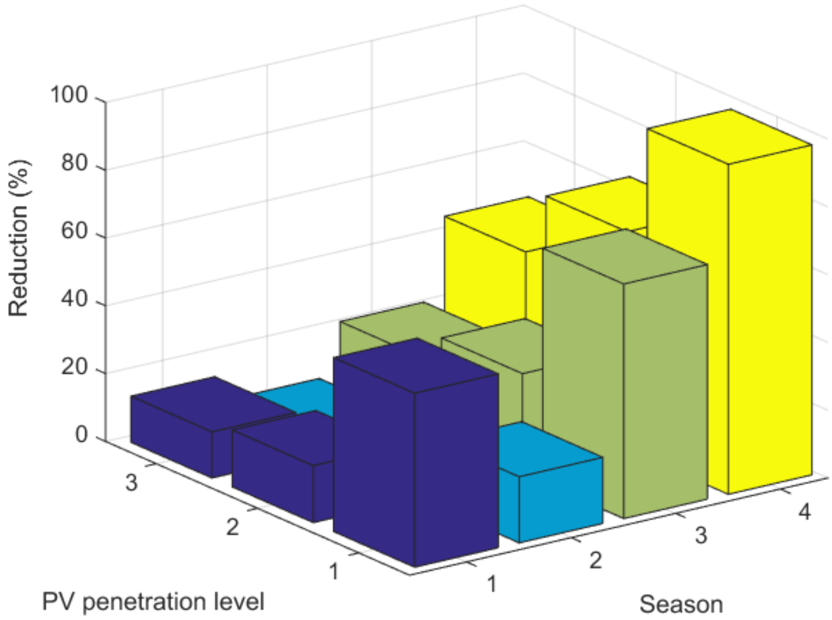


Figure 68: Average seasonal percentage reduction between σ_p and σ_{pc} for Bürglen (TG) grid (PV penetration levels 1, 2, 3 correspond to low, intermediate and high PV scenarios, seasons 1, 2, 3, 4 correspond to spring, summer, autumn and winter)

13.5. FEN group conclusions

The provided analysis assesses the effect that CHP generation can have on local PV production by trying to provide (positive) compensation for fluctuations in the latter. Given the grid topology and installed generation capacity, appropriate methods exist for the coordinated dispatch of the units including satisfaction of the network constraints. The compensation capability depends on the size of the installed swarm and on the assumed level of PV penetration, as well as seasonal factors related to heating requirements.

14. Technical report EEG (Long-term national electricty and heat supply scenarios)

14.1. Introduction

The Energy Economics Group (EEG) at the Paul Scherrer Institute (PSI) analysed the potential for deployment of biogenic gas CHP technologies[1] in Swiss electricity and heat system over a long term at a national level. The objective of the analysis was to quantify the role of biogenic gas CHP plants (CHPP) and the conditions under which they become competitive in the electricity, heat, as well as grid balancing markets.

A technology rich, cost-optimisation modelling framework of the Swiss electricity and heat sectors has been used for the quantification of four core “what-if”-type scenarios, defined across the objectives of the Swiss Energy Strategy [61]. The quantification of the scenarios generated insights about the long term prospects of biogenic gas CHPP and it also considered competing energy pathways from primary energy resource to end use demands through energy carrier conversions.

Uncertainties surrounding the future electricity and heat demands, climate change mitigation objectives, technological breakthroughs and other external factors, such as international energy prices, were assessed through parametric sensitivity analyses. A set of metrics have been used as indicators in assessing the synergies and barriers of biogenic gas CHP plants in electricity, heat and grid balancing services.

14.2. Methodology: The Swiss TIMES Electricity and Heat model

The Swiss TIMES Electricity and Heat Model (STEM-HE) is a partial equilibrium bottom-up single-region model covering the Swiss electricity and heat systems from primary energy resource supply to end use demands. The model determines, with perfect foresight and long-run marginal cost pricing[2], the least cost combination of technologies and fuel mixes to meet exogenously given electricity and heat demands subject to technical and policy constraints. The model has a long time horizon (2010-2100) and each modelling time period is divided into 288 typical hours, i.e. in each period four seasons are modelled, each of which is delineated into three typical days (working days, Saturdays and Sundays) with a 24-hour resolution. The STEM-HE model is an extension to the Swiss TIMES Electricity Model (STEM-E) [63] and tailored to assess the role of CHP plants in electricity and heat supply markets, together with their flexibility in providing grid balancing services.

The model has a detailed representation of large and small scale decentralised electricity generation technologies in four electricity transmission and distribution grid levels (*viz*. very high voltage, high voltage, medium voltage and low voltage) by considering economic rather than physical flows[3]. It also includes a range of biogas and bio-methane production technologies together with distribution infrastructure. The STEM-HE model has heat demands from three end use sectors, *viz.* industry, services and residential. Particularly, four categories of residential buildings are included (single- and multi- family houses; existing and

[1] In the text the term “biogenic CHP plant” refers to CHP units fuelled with food waste, industrial bio-waste, municipal bio-waste, gastro-waste, biogas, bio-methane, syngas and wood. The term “biogenic gas CHP plants” refers to CHP units fuelled with biogas and bio-methane from the natural gas grid, i.e. it excludes CHP plants fuelled by wood that is used in on-site combustion or gasification and hence the produced syngas is not injected into the gas grid.

[2] The long-run marginal cost is the incremental cost when all production inputs are variable. These include variable costs, fuel and tax payments, CO_2 prices, capacity expansion and maintenance costs, and capacity scarcity rents. Fuel subsidies are entering with a negative sign in the calculation.

[3] The model does not include a spatial representation of the electricity grid, therefore it cannot account for physical transmission and distribution lines. To this extent, grid constraints related to the resistances and reactances of the lines are not accounted. However, the model takes into account aggregated grid capacity, and aggregated transmission and distribution losses for each grid level. It also includes average typical values for grid extension and maintenance costs in each level, which are reported in the literature and have been adapted for Switzerland by using consumer network tariffs [38].

new buildings[4]), due to the sheer share of the buildings sector in heat demands. It also models primary and secondary reserve control power markets for electricity grid balancing (ancillary services markets)[5], with their needs being determined endogenously depending on forecast errors in electricity demand, wind and solar PV electricity supply[6]. The trade-off between committing capacity to the electricity (and heat if CHPP) market versus grid balancing is based on the marginal cost of electricity production (in order to cover generation costs) and revenue from reserve market (in order to cover fixed operating and investment costs). Figure 69 presents an overview of the structure of the STEM-HE model, while a more detailed description is given in section 15.1.

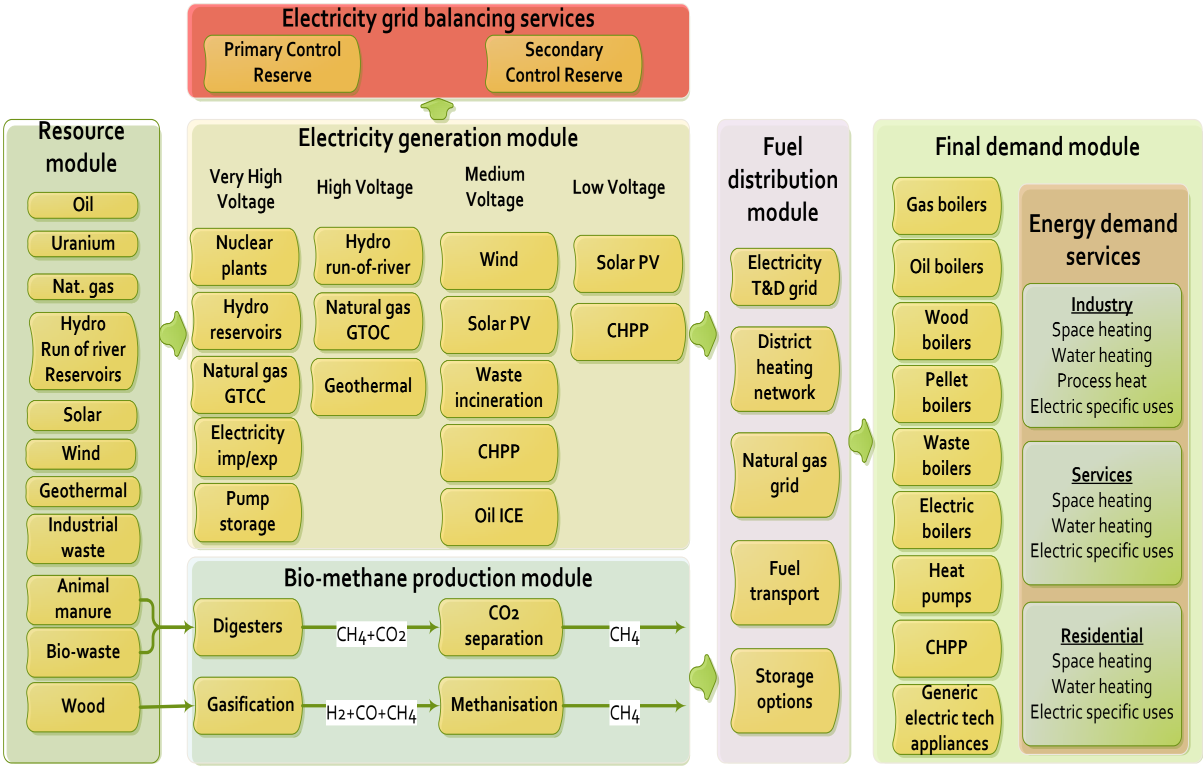


Figure 69: Overview of the structure of the STEM-HE model.

The main assumptions and insights from the regional case studies of Thurgau, Basel and Lucerne have been incorporated into the scenario analysis. These include the techno–economic characterisation of biogenic gas CHPP, wet biomass resources, and potential for the technology to participate in electricity grid balancing. Then the scenario analyses produced insights on the technology and fuel mixes in supplying electricity and heat demands, on the provision of electricity grid balancing services, on electricity and heat system costs and marginal production costs, on CO_2 emissions, etc.. These insights were used to quantify the role of biogenic gas CHPP in the Swiss electricity and heat system.

However, it is worthy to note some important limitations of the modelling framework, which should be kept in mind when interpreting the results of the current analysis: a) there is no spatial representation in the model, and this affects the cost of electricity, heat and gas infrastructure, together with its possibility for further expansion; b) demand-side efficiency measures are given exogenously and their costs are not accounted in the total system costs

[4] Existing buildings are considered to be those built until 2005; single family houses include both one and two - family houses.

[5] This feature on grid ancillary services is partly developed for another project, the ISCHESS project [39]. The model considers only the provision (i.e. available capacity required) and not the activation of the grid ancillary services.

[6] Different forecast errors are used for primary and secondary control reserve, obtained from literature [40] and historical data for Switzerland [47]. Then we apply three standard deviations on the joint probability distribution of the forecast errors, by assuming independency, in order to calculate the demand for primary and secondary control reserve.

of the analysis; c) the electricity and heat energy service demands are given exogenously and are inelastic with respect to the energy cost; d) the model does not include the concept of the individual plant or boiler, and this can lead to underestimation of the investment costs and overestimation of the technology performance; and e) electricity grid and gas grid technical characteristics are not accounted, which implies increased dispatchability compared to the reality. Therefore the reader shall keep these limitations in mind, notwithstanding the additional modelling that has been undertaken in order to mitigate their effects on the results obtained.

14.3. Definition of the national energy transition scenarios

Four core scenarios have been defined across two main axes regarding the future configuration of the Swiss electricity and heat system: the investment decisions in new centralised gas power plant(s); and climate change mitigation goals (Figure 70).

The exogenous energy service demands for electricity and heat were derived from the developments and policies of the "*Politische Massnahmen – POM*" scenario of the Swiss Energy Strategy [61]. These demands are the same in all core scenarios and variants, except those variants with explicitly stated different demand assumptions.

In this context, the "*Reference*" scenario could be considered consistent with "*POM*". We additionally include to all scenarios a zero-net imported-electricity constraint at annual level from 2020 and beyond[7]. The "*No Gas*" scenario includes all the assumptions of the "*Reference*" scenario, but new investments in large scale combined cycle or open cycle gas turbines plants are disabled. The "*CO2*" scenario aims at a CO_2 emissions reduction target of 70% in 2050 compared to the 2010 levels[8], by imposing a cap on total CO_2 emissions across all sectors represented in the model. The "*No gas and CO2*" scenario combines the assumptions of the "*CO2*" and "*No Gas*" scenarios. More details regarding the assumptions of the four core scenarios, including the energy service demands, are given in section 15.2.

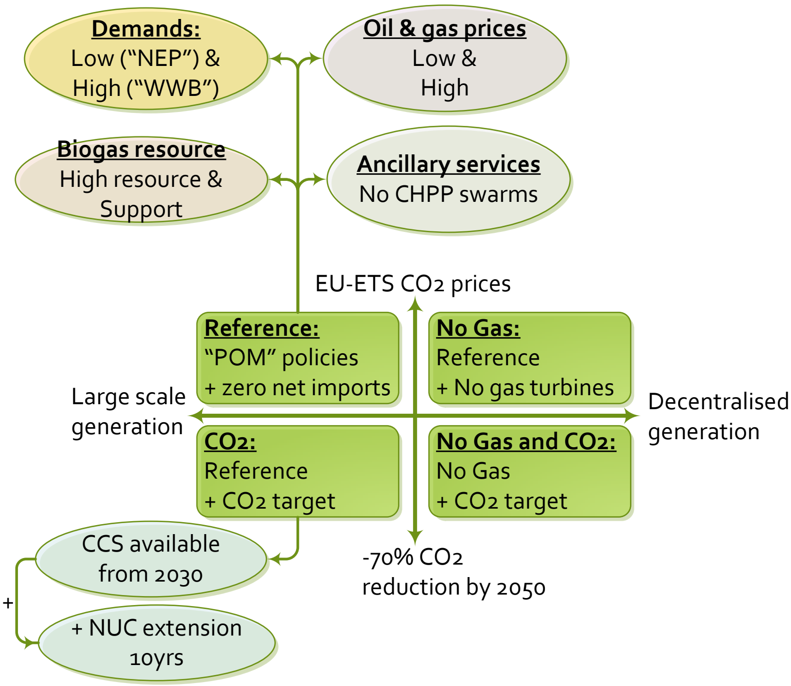


Figure 70: Summary of the four core scenarios and their variants.

To understand the key drivers influencing the penetration of biogenic gas CHPP in electricity/heat supply and grid balancing, a set of parametric sensitivity analyses on the main

[7] We enforce a constraint that the net sum of the internationally imported and exported electricity volumes should be zero at annual level, reflecting historical trends. The model has, however, the option to import/export electricity at seasonal and diurnal levels.

[8] The imposed CO_2 emissions reduction target is compatible with the recent pledges submitted by Switzerland to UNFCC [42], and with the "*Neue Energiepolitik - NEP*" scenario of the Swiss Energy Strategy [35].

drivers in the “*Reference*” scenario were analysed. Table 16 shows the parametric variants with their descriptions, while more details on their assumptions are given in section 15.2.

Variant name	Based on	Sensitivity on
Electricity and heat demands		
Low demand	Reference	Low electricity and heat demands based on the "*NEP*" scenario [61]
High demand	Reference	High electricity and heat demands based on the "*WWB*" scenario [61]
International oil and gas prices		
Low prices	Reference	Low prices based on the "*2D*" scenario of IEA [64]
High prices	Reference	High prices based on the "*6D*" scenario of IEA [64]
Support mechanism for biogenic CHP		
High biogas resource	Reference	Forced exploitation of all sources for biogas production
Bio-electricity support	Reference	Continuation of existing supporting mechanisms for electricity from biogas
Alternative low-carbon options		
CO2 with CCS	CO2	Availability of natural gas combined cycle with CCS after 2030
CO2 with CCS and NUC	CO2 with CCS	Extension of operation of the current nuclear power plants by 10 years
Ancillary services		
No swarms in ancillary services	Reference	Biogenic gas CHPP cannot operate as swarms to balance the electricity grid

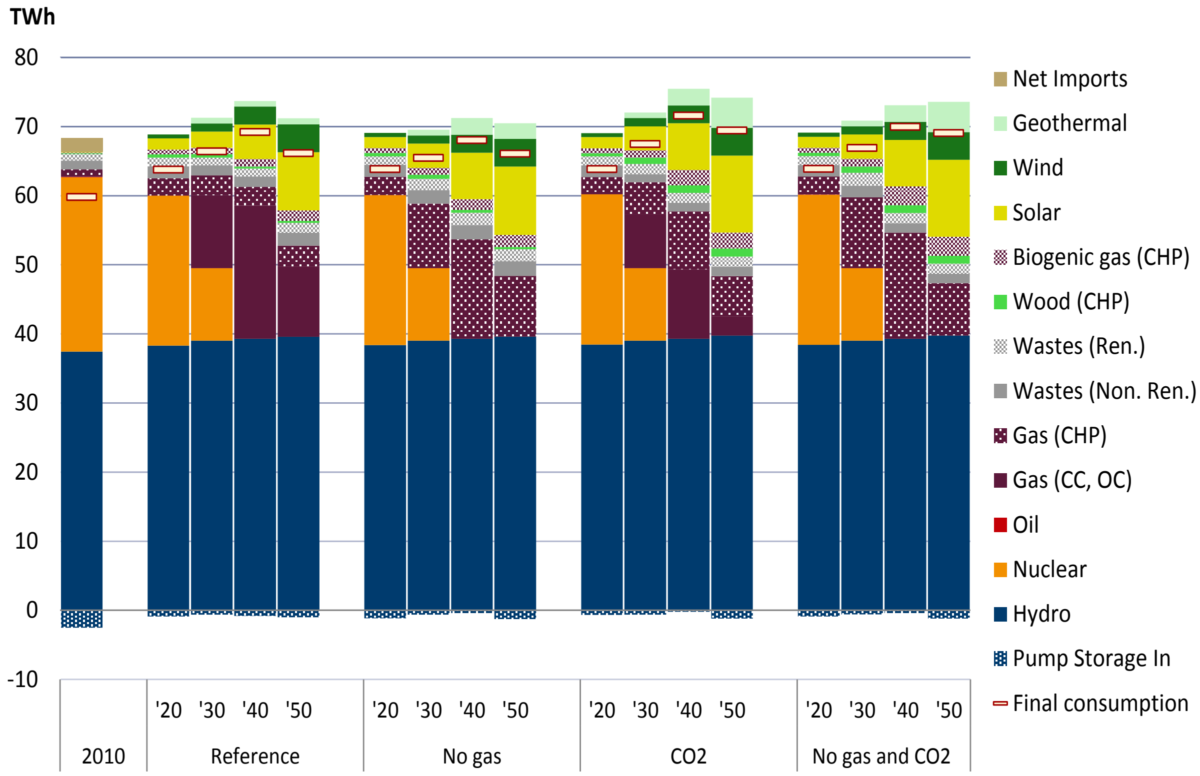
Table 16: Description of the parametric variants.

14.4. Results from the core scenarios

14.4.1. Electricity supply

Figure 71 presents the electricity supply mix in all four core scenarios. The total electricity production increases from 5 % (in the “*No Gas*” scenario) to 11 % (in the “*CO2*” scenario) in 2050 compared to 2010. The “*No Gas*” scenario displays the smallest increase due to the higher electricity production costs arising from lack of economies of scale in electricity production. On the other hand, the “*CO2*” scenario displays the largest increase among all scenarios due to the higher electrification of demand, mainly through electric heat pumps that contribute to efficiency gains in final energy consumption and hence to a reduction of the CO_2 emissions in the end use sectors (see also section 14.4.4).

In the “*Reference*” scenario, gas turbine combined cycle plants (GTCC) replace existing nuclear electricity production until 2040. Around 2.7 GW of GTCC plants are installed by 2040, accounting for about 25 % in the total electricity supply. However, the share of electricity production from GTCC declines towards 2050, because of cost effectiveness of the new renewables in electricity supply, especially solar PV, which is attributable to their capital cost reduction and to higher gas and CO_2 emission prices.



Gas CC=gas turbine combined cycle; Gas OC=gas turbine open cycle; Wastes (Non. Ren.)=non-renewable waste treatment plants (KVA/ARA) ; Wastes (Ren.)=renewable waste treatment plants (KVA/ARA); Wood (CHP) = CHP units using wood on-site (combustion or gasification); Biogenic gas (CHP) = CHP units using biogas or bio-methane from gas grid

Figure 71: Electricity final consumption and production mix by technology.

When the investments in large gas plants are restricted ("*No Gas*" scenario) there is a higher contribution from decentralised electricity generation from CHPP after 2030 (compared to the "*Reference*" scenario). In this context, the gas-fired CHP plants account for 21% in the total electricity supply by 2040, in a way equivalent to the large gas power plants in the "*Reference*" scenario. However, their share in electricity production is reduced by 2050, when new renewable technologies become more cost-competitive – a trend similar to the centralised gas plants facing in the "*Reference*" scenario. As already stated above, the lack of economies of scale in electricity generation results in high electricity production costs up to 2040, until new renewables increase their share in electricity supply by 2050 (Figure 100 in section 14.4.6 presents the marginal costs of the electricity generation in the different scenarios). As a consequence the electricity demand in this scenario is 3 % lower than in "*Reference*" in 2040, but afterwards it bounces back to the levels seen in the "*Reference*" scenario. It is worthy to note that in the "*No Gas*" scenario much of the base load electricity is produced by geothermal power plants, in the absence of gas turbines combined cycle units. It turns out that the geothermal capacity in this scenario is more than 320 MW (twice the capacity installed in "*Reference*"), while the geothermal production reaches 2.3 TWh in 2050.

In the "*CO2*" scenario, carbon free options supply about 88% of the total electricity in 2050, with the rest being produced by gas plants and non-renewable wastes. Hydro contributes to close to 54.5 % in total electricity supply (39.8 TWh), new renewables (wind, solar and geothermal) account for about 26.7 % (19.5 TWh), while biogenic CHP plants (incl. renewable waste treatment plants, i.e. KVA/ARA) have a share of 6.8 % (5.0 TWh). The electricity demand is about 5% higher than in "*Reference*" in 2050, driven by a higher uptake of heat pumps (see section 14.4.4).

Finally, the developments in the "*No gas and CO2*" scenario are similar to the "*CO2*" scenario, but with a higher uptake of biomass based CHP plants due to restriction of centralised natural gas fired units. Thus, in this scenario the wood-fired and biogenic gas CHP plants produce about 3.9 TWh (or 5.4 % of the total electricity supply), while the renewable waste treatment plants contribute additionally 1.5 TWh (or 2.1 % of the total electricity supply). Thus, the overall contribution of biogenic CHPP to electricity production is close to 7.5 % in 2050.

Across all scenarios, the share of electricity supply from all CHP plants increases until 2050 (Figure 72). Their penetration depends on the decision of investing in centralised gas plants, the stringency of the climate policy and the competitiveness of renewable energy for electricity production. Thus, due to the increased share of renewables in electricity supply beyond 2040, the electricity production from CHPP peaks in 2040 and then it declines. This occurs in all scenarios except "*Reference*", where the deployment of renewables is the lowest among the core scenarios.

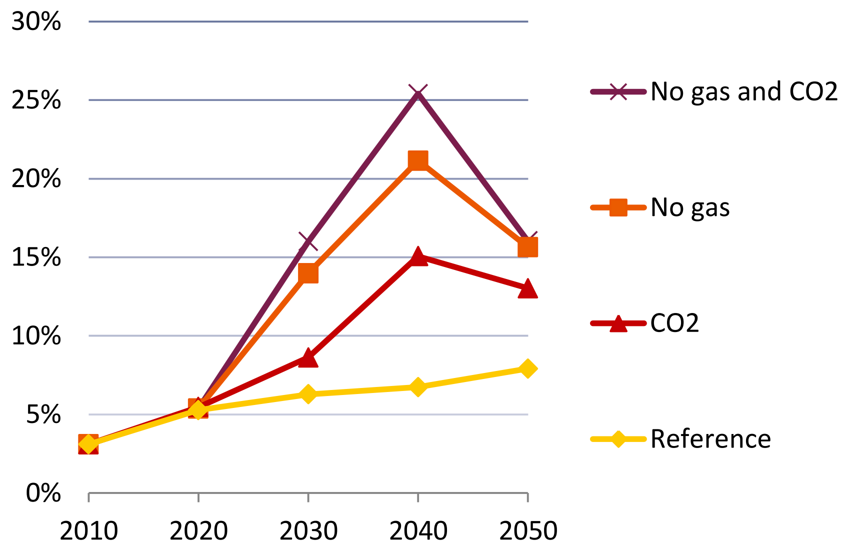


Figure 72: Share of CHP plants in total electricity production.

14.4.1.1. Role of biogenic gas CHP plants in electricity supply

The installed capacity and electricity production from biogenic gas CHP plants, together with their share in total electricity supply in the four core scenarios are presented in Figure 73. In the "*Reference*" scenario, biogenic gas CHP plants produce about 1.5 TWh of electricity, which is close to the realisable potential of electricity from biogas reported by the Swiss Federal Office of Energy [62]. Their penetration increases when a stringent climate policy is applied, with their electricity production reaching 2.3 TWh in the "*CO2*" scenario and 2.8 TWh in the "*No gas and CO2*" scenario by 2050.

Key rival technologies in electricity supply are the natural gas fired technologies (including gas-fired CHPP). This implies that the biogas/bio-methane price and its competitiveness with the natural gas price is an important factor influencing the uptake of biogenic gas CHPP. When a stringent climate change mitigation policy is in place, there is increased competition for accessing the (limited) domestic biomass resource potential. In this context, other biogenic technologies, such as wood-fired CHP plants, and renewable waste incinerators can be competitors to biogenic gas CHPP plants as well.

The intermittent renewables for electricity production have a two-fold effect in the penetration of biogenic gas CHPP: while they introduce additional competition in electricity supply, their penetration increases also the demand for grid balancing services. Thus, they create opportunities for biogenic gas CHPP to participate in the balancing market as swarms (see also section 14.4.2). This can be observed in Figure 73, where the installed capacity of biogenic gas CHPP continues to increase, despite the slowdown in their electricity production arising from the increased supply from new renewables.

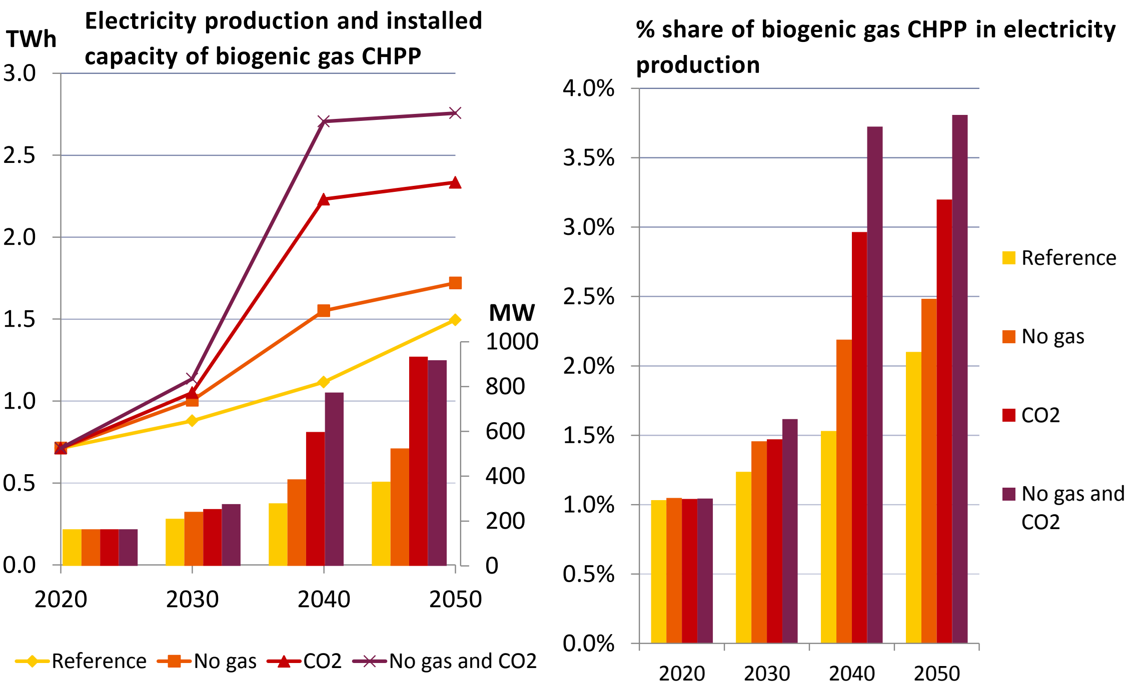


Figure 73: On the left: electricity production (right axis) and installed capacity (left axis) of biogenic gas CHP plants; on the right: share of biogenic gas CHP plants in total electricity supply.

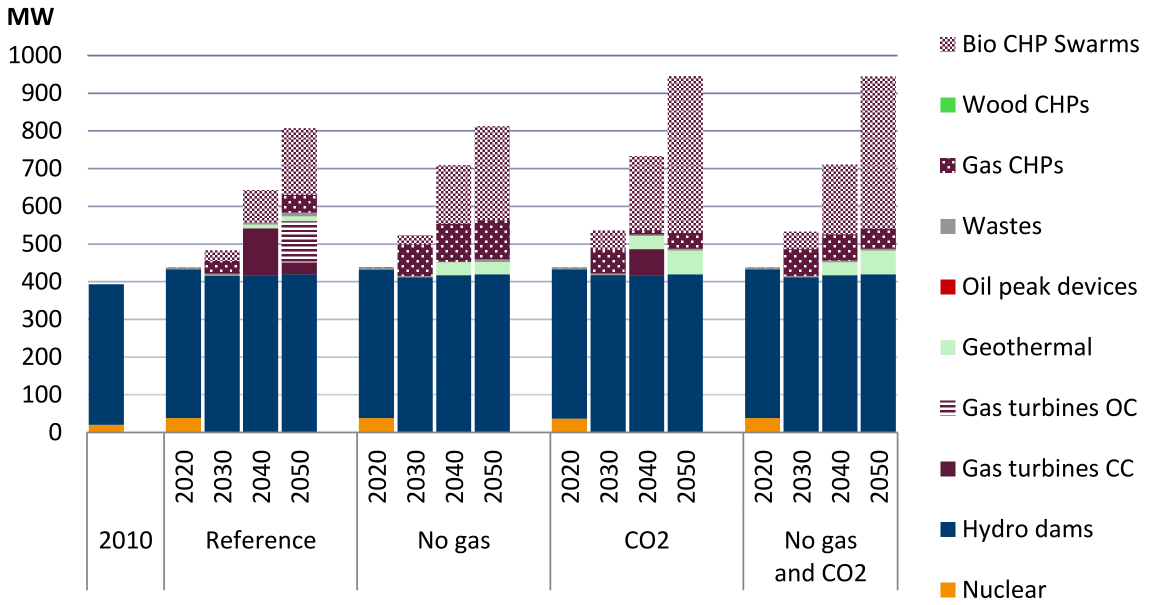
14.4.2. Electricity grid balancing

The model considers the provision of both primary and secondary control reserve, negative and positive. The primary control reserve required for Switzerland is adjusted annually by the ENTSO-E, and it mainly depends on the developments in the European electricity system. On the other hand, the requirements in secondary control reserve depend mostly on the developments in the Swiss electricity system [65].

The primary reserve demand in Switzerland is approximately ±70 MW in 2014. In our analysis it is estimated to double by 2050, because of increasing intermittent electricity supply at the European level. The required secondary control reserve for Switzerland amounts to ±400 MW in 2014, and it also doubles by 2050 because of increased deployment of domestic intermittent renewables and increased electricity demand. Since the objective of the project is to analyse the role of flexible biogenic gas CHPP in the Swiss grid balancing area, the discussion in this section focuses on the provision of secondary positive control reserve, which is influenced by the developments in the domestic electricity supply and demand.

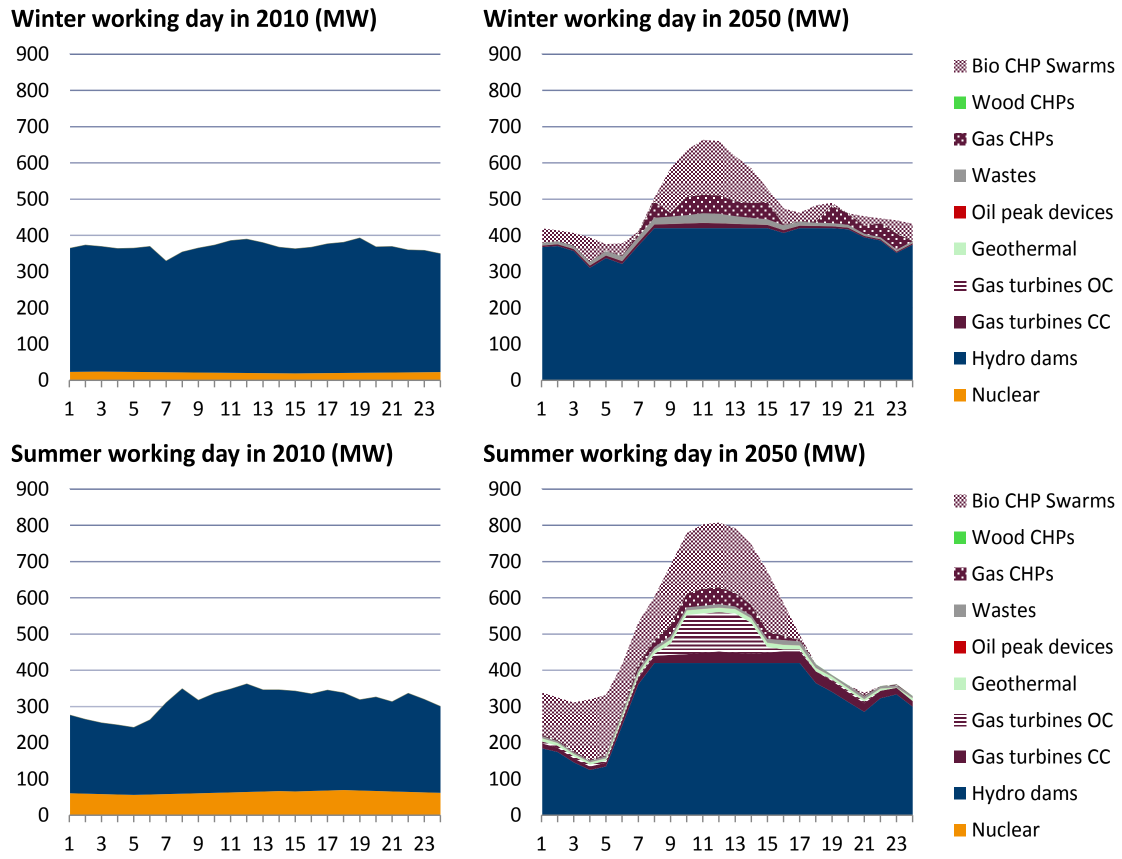
Figure 74 presents the demand for secondary positive control capacity, and its provision by power plant type over the period of 2010 – 2050. The demand for secondary reserve is high when the electricity demand or the share of intermittent renewables in electricity supply is high[9]. In this context, the demand for secondary reserve is about 810 MW in "*Reference*" and "*No Gas*" scenarios in 2050, and it increases to about 945 MW in "*CO2*" and "*No gas and CO2*" scenarios for the same period. Most importantly, the analysis reveals a shift in the peak demand for secondary control power from winter to summer between 2010 and 2050 (Figure 75). This is attributable to the high levels of electricity supply from solar PV in summer.

[9] This is because the demand for balancing services is straightforwardly calculated by applying three standard deviations on the joint probability distribution of the forecast errors of the peak electricity demand and the peak wind and solar electricity production (see also 15).



Gas turbines CC=gas turbine combined cycle; Gas turbines OC=gas turbine open cycle; Wastes=renewable and non-renewable waste treatment plants (KVA/ARA) ; Gas CHPs = natural gas-fired CHPP; Wood CHPs = CHP units using wood on-site (combustion or gasification); Bio CHP Swarms = CHP units fuelled by bio-methane/biogas and operate as swarm

Figure 74: Contribution of different technologies to secondary positive control reserve.



Gas turbines CC=gas turbine combined cycle; Gas turbines OC=gas turbine open cycle; Wastes=renewable and non-renewable waste treatment plants (KVA/ARA) ; Gas CHPs = natural gas-fired CHPP; Wood CHPs = CHP units using wood on-site (combustion or gasification); Bio CHP Swarms = CHP units fuelled by bio-methane/biogas and operate as swarm

Figure 75: Provision of secondary positive reserve in the "Reference" scenario in a typical day (24h).

Today, the secondary positive control power is mainly provided by hydro dams and to some extent by nuclear power plants. The contribution of hydropower plants only slightly increases over time in all scenarios (from 370 MW in 2010 to 420 MW in 2050), because of their increased participation in the electricity market, resulted by the nuclear phase out, and because of the limited potential for further expansion due to climate change corrections for future river flows[10]. Therefore, the gap in power capacity for grid balancing is fulfilled by additional investments in flexible gas plants, CHP plants and to some extent by geothermal power plants[11,12].

There is a clear difference in the four core scenarios regarding the participation of the gas turbine (combined cycle or open cycle) plants in the secondary positive control reserve market. In the "*Reference*" scenario GTCC plants provide ancillary services up to 2040, but afterwards the need for additional flexibility, due to the integration of large amounts of intermittent electricity, enables investments in gas turbine open cycle plants (CTOC). The average utilisation rate of the GTOC plants is only 5 % in 2050, which indicates their primary role as reserve providers. However, in the other three core scenarios there are no contributions from GTCC or GTOC units in the secondary positive control reserve market, either because of restrictions in their investments ("*No Gas*" and "*No gas and CO2*" scenarios) or because of a stringent climate change mitigation policy in place ("*CO2*" scenario).

Thus, in these scenarios the flexible CHP units increase their participation in the secondary positive control reserve market. The flexible CHPP account for about 44 % of the total secondary positive control capacity in the "*No Gas*" scenario and 49 % in the "*CO2*" and "*No gas and CO2*" scenarios by 2050. Geothermal power has also a minor contribution to secondary positive control reserve with a share of 2 – 7 %; the high shares of geothermal power plants occur when a stringent climate policy is in place.

It should be noted that in order to realise this level of participation from decentralised units in balancing markets appropriate legislation frameworks should be in place that would regulate a number of issues such as ownership of swarms etc.. Steps towards this direction have been already made by Swissgrid with the concept of the "virtual generating unit" [66], which enable the participation of CHP and heat pumps units that operate at medium and low voltage grid levels.

14.4.2.1. Role of biogenic gas CHP plants in balancing the electricity grid

The biogenic gas CHP plants, in the form of swarms, account for 22 – 44 % in the total secondary positive control reserve capacity, which translates to 178 – 417 MW. Their contribution is higher when there is a restriction in investments in gas power plants or a stringent climate policy in place. On average about 45 % of the installed capacity of biogenic gas CHPP operates as swarm to balance the electricity grid. About one sixth of this capacity, i.e. 30 – 70 MW, is provided by units in a stand-by mode.

Key direct competitors to biogenic gas CHPP in the ancillary services market are the flexible gas power plants (large scale gas turbines and CHPP). Hydropower, though it has a large share in grid balancing, is location-dependent. Batteries and demand side management measures constitute indirect competitors, because they mitigate the needs for grid balancing and shrink the size of the market. In contrast, the higher integration of intermittent renewables enables investments in flexible generation, and thus favours the penetration of biogenic gas CHPP.

In general, the concept of swarm (which is similar to the concept of the "virtual generating unit" introduced by Swissgrid [66]) turns to be particularly attractive for the participation of small-to-medium size CHPP in balancing the electricity grid, which wouldn't be able to

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[10] In our analysis it has been taken into account the effect of climate change in water availability, and hence to the potential of electricity generation from hydropower according to [38].

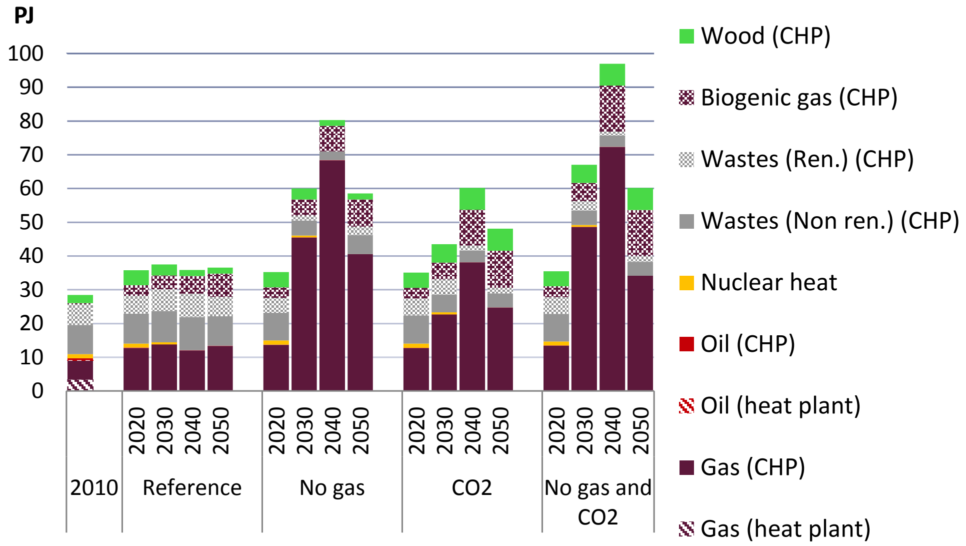
[11] The geothermal power plants have the technical flexibility to provide not only base load but grid balancing services as well [46].

[12] In the STEM-HE model, batteries and demand side management measures mitigate the need for positive control reserve; in this sense, they participate indirectly into the balancing services market.

participate as individual units due to size and flexibility restrictions. In fact, in all scenarios more than 70 % of the total capacity of both CHP plants (biogenic or gas-fired) and waste incineration units that contribute to secondary positive control reserve, is provided by biogenic gas CHP plants that participate in the market through swarms.

14.4.3. Heat supply from CHPP and heat plants

Figure 76 shows the total heat supply by fuel from CHPP (including CHP waste treatment plants) and heat plants. In general, the trends in the heat supply from CHPP reflect the trends in electricity generation discussed in section 14.4.1. This means that the heat generation from CHPP is high in those scenarios with favourable conditions for CHPP in electricity production. At the same time it also implies that the reduction in heat from CHPP towards 2050 is mainly attributable to the increased penetration of renewables in electricity supply.



Wastes (Non. ren.)=non-renewable waste treatment plants (KVA/ARA); Wastes (Ren.)=renewable waste treatment plants (KVA/ARA); Wood (CHP) = CHP units using wood on-site (combustion or gasification); Biogenic gas (CHP) = CHP units using biogas or bio-methane from gas grid

Figure 76: Heat production from CHPP and heat plants.

In the "*Reference*" scenario natural gas and wastes are the main sources for heat, with equal shares each, reflecting current trends and practices. However, in the other scenarios there is a significant increase of natural gas at the expense of wastes. This is driven by the need for efficient pathways for electricity production, either due to restrictions in large gas power plants that increase the electricity production costs ("*No Gas*" and "*No gas and CO2*" scenarios), or by a stringent climate change mitigation policy that increases the electrification of the demand ("*CO2*" scenario). Thus, in these scenarios wastes are directed to incinerators with low heat-to-power ratios, or they converted to biogas for use in CHPP (about 5% of the bio-waste is converted to biogas in the "*No Gas*" scenario and 33 % in the "*CO2*" scenario by 2050). In addition, the use of non-renewable waste in the "*CO2*" and "*No gas and CO2*" scenarios is reduced compared to "*Reference*" and "*No Gas*" scenarios respectively, due to the accounting of CO_2 emissions[13]. This implies that alternative to incineration waste treatment processes, such as recycling, should be explored.

The increased contribution of natural gas in heat from CHPP even when climate change mitigation policy is in place, is driven by efficiency gains in electricity and heat supply from the combined application of efficient gas-fired CHPP and heat pumps (as electricity sinks).

[13] The CO2 emission factor of non-renewable waste assumed in our analysis is 103.4 ktCO2/PJ, approximately two times emission factor of natural gas [48]

Thus, given the limited quantities of domestic biomass available, this pathway can contribute to a further reduction of the overall CO_2 emissions despite the use of fossil fuel for electricity generation (see also section 14.4.5 which discusses the CO_2 emissions).

The role of district heating in heat supply declines in all four scenarios (Figure 77). This is because the expansion of the district heating infrastructure is less cost effective in the long term, due to the reduction in heat demand by 29 % between 2010 and 2050 (see also section 14.4.4) that hampers the recovery of capital costs. By contrast, the on-site consumption of heat from CHP units proves to be more economically attractive to serve the new demand after 2040, by the time when a significant part of the current district heating infrastructure is decommissioned due to the end of its technical lifetime.

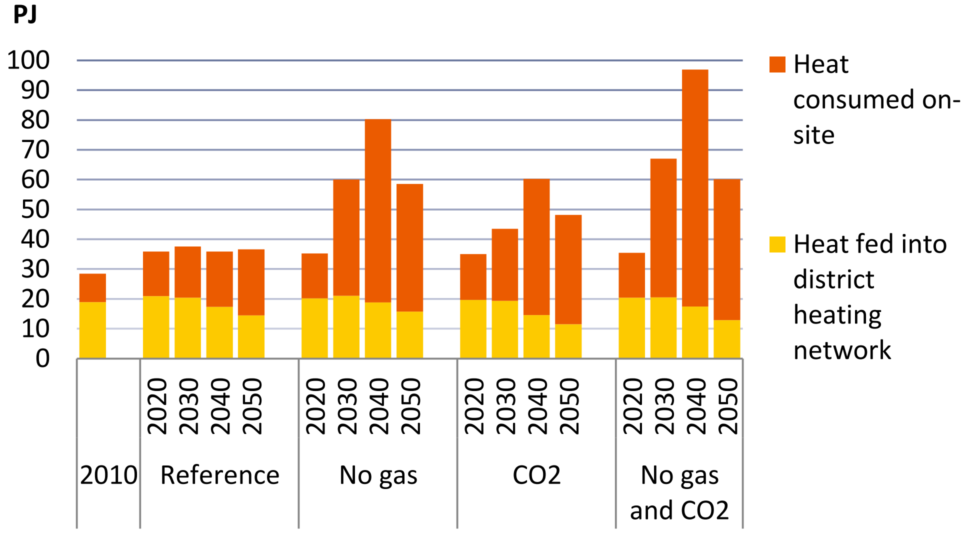


Figure 77: Split of the heat produced by CHPP and heat plants between heat consumed on-site and heat fed into district heating networks.

14.4.3.1. Role of biogenic gas CHP plants in total heat supply (all technologies, all sectors)

Figure 10 presents the total heat production from biogenic gas CHP plants and their share in total heat supply from all technologies – i.e. including all CHP plants, waste incinerators, heat plants, boilers, heat pumps, solar thermal, etc. – and in all sectors. In general their uptake resembles their trends in electricity generation. In the long run, penetration of biogenic gas CHPP increases across all scenarios, with the highest share observed when climate policy is applied. The biogenic gas CHP plants account for 2.6 – 5.1 % in the total heat supply in 2050, which translates to 6.9 – 13.6 PJ of heat.

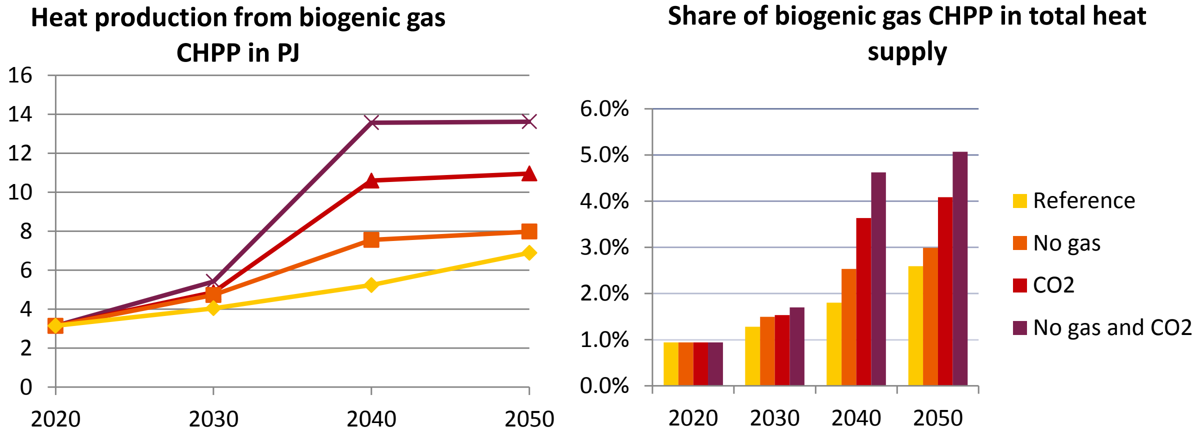


Figure 78: Heat production from biogenic gas CHP plants and their share in total heat supply (all technologies, all sectors).

14.4.4. Final energy consumption in end-use sectors

14.4.4.1. Industry

The industrial final energy consumption decreases between 24 % (in the "*Reference*" scenario) and 31 % (in the "*CO2*" and "*No gas and CO2*" scenarios) in 2050 compared to 2010. This is attributable to the assumed demand side efficiency measures[14] (e.g. waste heat recovery, building codes and standards) and induced technology change and fuel switching (Figure 79). It turns out that the final energy consumption is reduced by 17 % due to demand side measures in all scenarios, with the rest is driven by technology change. The climate policy accelerates technology change and results in higher efficiency gains in the sector.

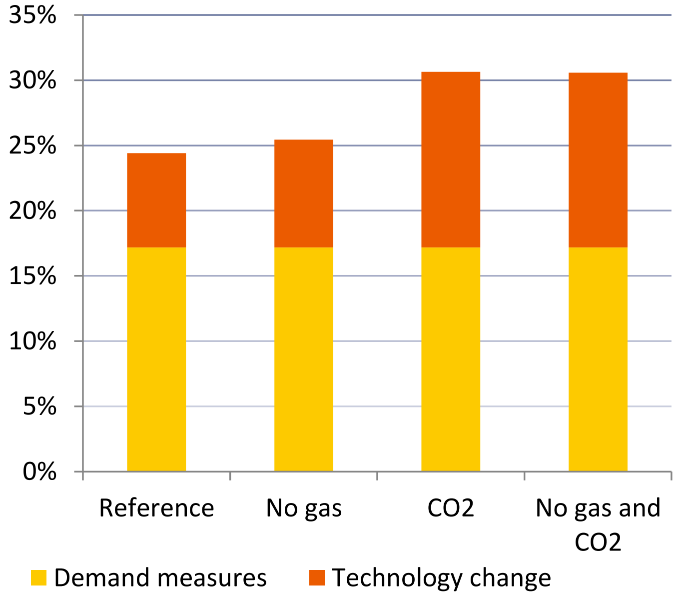


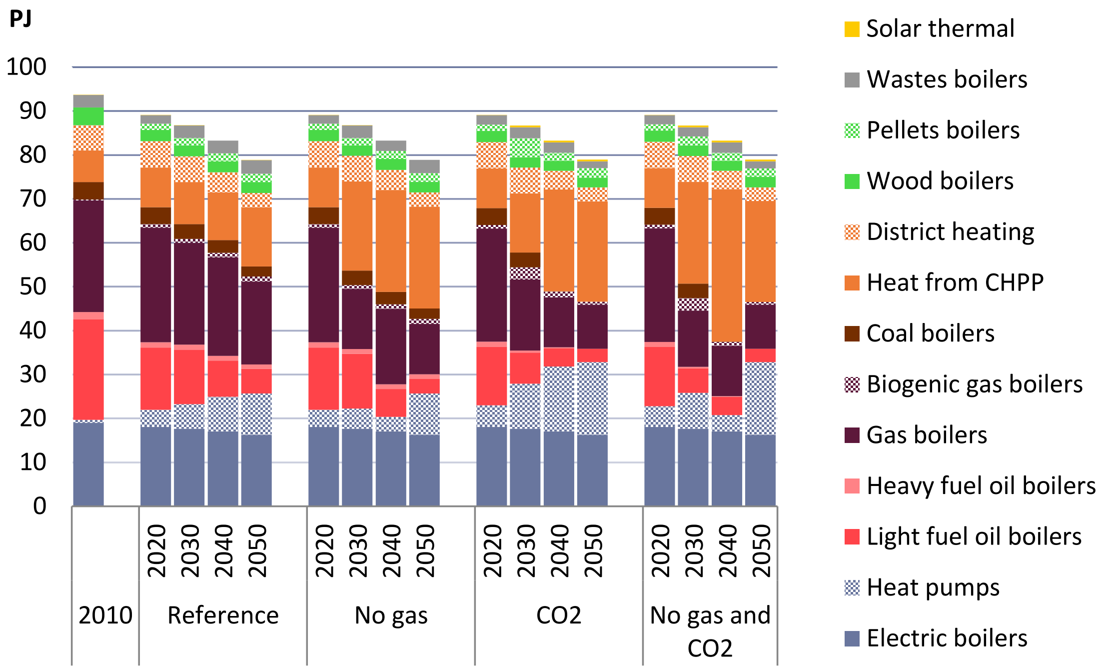
Figure 79: Efficiency gains in final energy consumption due to demand measures and due to technology change in industrial sectors in 2050 with respect to 2010.

Figure 80 presents the penetration of the different technologies in supplying the industrial heat demand. Oil based heating systems are replaced mainly by natural gas until the mid-term (2030) and by CHP plants and heat pumps in the long-term in all scenarios. At the same time waste boilers remain as sources of heat supply until 2050, while pellets replace about half of the wood boilers of today in all scenarios. When climate change mitigation policy is applied, heat pumps (if it is technically feasible[15]) and CHP plants increase their contribution in industrial heat supply.

Heat pumps constitute electricity sinks for CHP plants in the industrial sector, and this considerably increases the net efficiency of their combined application for electricity and heat production. This synergy is facilitated also by the different types of heat demands that are served by the two technologies in the industrial sectors: for example heat pumps supply low temperature heat, while CHPP supply heat at medium-to-high temperatures. In this context, the share of heat pumps increases from 1 % in 2010 to 12 % in "*Reference*" and 21 % in "*CO2*" scenarios in 2050. However, their penetration depends not only on the stringency of climate policy, but also on the electricity production costs. Thus, in the "*No Gas*" scenario the high electricity production costs attained in 2040 hinder investments in heat pumps in industry. Nevertheless, they regain their market share in 2050, by when renewable-based electricity becomes cost-effective.

[14] Demand efficiency measures are not explicitly modelled; instead by using the "*POM*" scenario of the Swiss Energy Strategy [35] as the basis for all the core scenarios and their variants, we implicitly take into account its set of policy measures.

[15] Based on the literature [49] with the introduction of high temperature heat pumps that provide heat up to 140°C, about 25 – 30% of the heat demand in industry can be potentially supplied by heat pumps.



Heat from CHPP = total heat supplied by on-site CHP plants; Biogenic gas boilers = heat from boilers using biogas or bio-methane from gas grid

Figure 80: Supply of space, hot-water and process heat in industry by technology.

The penetration of CHP plants in the industrial sectors is affected by the availability of centralised electricity generation ("*No Gas*" scenario) and the stringency of the climate policy ("*CO2*" scenario). As already mentioned, after 2040 the increased uptake of renewables in electricity supply slows down the overall uptake of CHP plants in industry. Notwithstanding this slowdown, the share of on-site industrial CHP plants in total industrial heat increases from 17 % in "*Reference*" to about 29 % in the "*No Gas*" and "*CO2*" scenarios in 2050; for comparison, in 2010 the share of heat from industrial CHPP in total industrial heat demand is slightly less than 8 %.

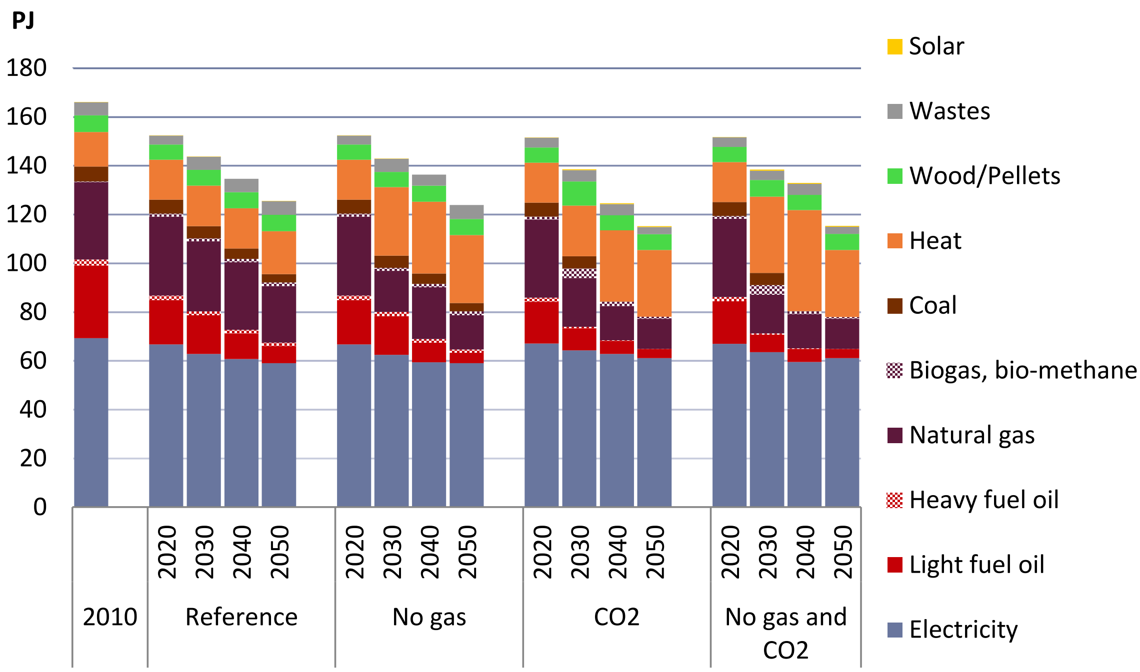


Figure 81: Final energy consumption in industry (excluding consumption in on-site CHPP).

The higher penetration of both CHPP and heat pumps in industry contributes to efficiency gains in final energy consumption in all scenarios, on top of the exogenously assumed demand reduction measures. Figure 81 presents the final energy consumption in industry by fuel. The electricity and heat in this figure include quantities either produced on-site or bought from grid. To avoid double counting the final energy consumption in Figure 81 does not include fuel consumed in on-site industrial CHP plants. This is reported separately in Figure 82.

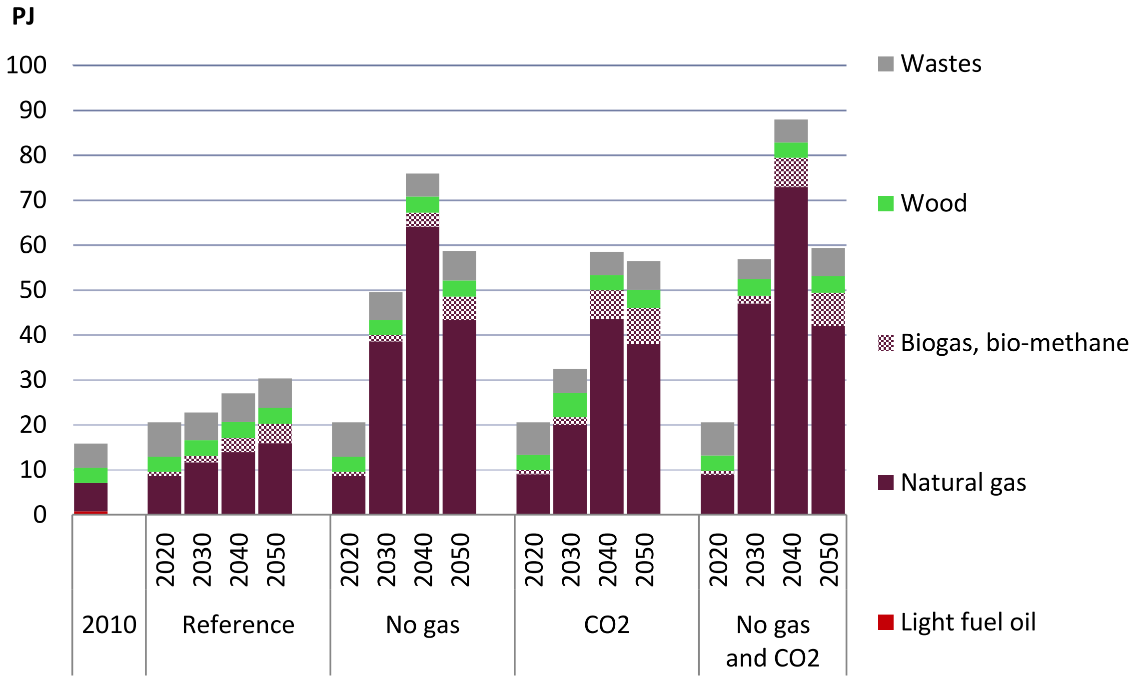


Figure 82: Fuel consumption in on-site CHP plants in industry.

<u>Role of biogenic gas CHP plants in industry</u>

The installed capacity of on-site biogenic gas CHP plants in the industrial sectors ranges from 137 MW to 319 MW and they produce about 1.9 – 3.5 PJ of electricity (or 520 – 960 GWh_e) and 2.0 – 3.7 PJ of heat (or 550 – 1020 GW_{th}) by 2050 (Figure 83). This corresponds to shares of 3.2 – 5.7 % in total electricity consumption of the sector and 2.5 – 4.7 % in total heat demand of the sector. The above imply an average heat-to-power ratio of 1.06 and a capacity factor of 28 % - 43 % (or 2450-3770 operating hours per year) in 2050.

Additionally to the analysed in the previous sections factors that affect the penetration of biogenic gas CHPP, an important driver for the industrial sector is the competition from the rest of the end use sectors in accessing the biogas resource. In fact, the flexibility of the industrial sectors to increase efficiency gains (and hence reduce CO_2 emissions) by combined applications of efficient natural gas CHP plants and heat pumps, allows for shifting biogas quantities to those end use sectors where such synergies are weaker, because of cost and technical constraints, in order also to be able to reduce also their CO_2 emissions as well (e.g. in the residential sector).

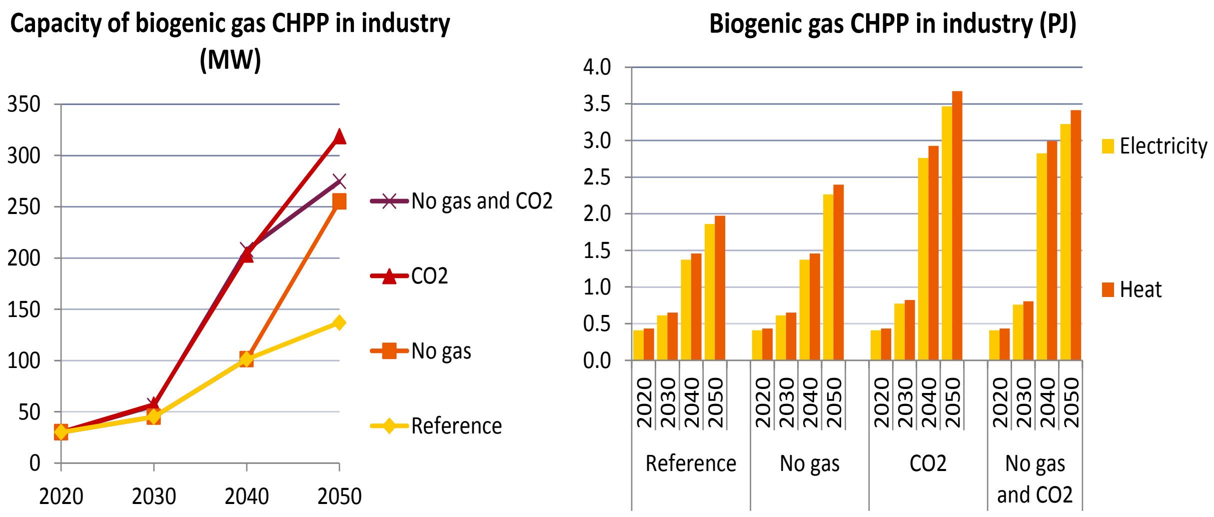


Figure 83: Installed capacity and production from biogenic gas CHP plants in industry.

14.4.4.2. Services (including agriculture)

In services sector, the assumed demand measures (e.g. building codes and renovation rates) and the induced technology change result in a reduction in the final energy consumption between 22 % (in the “*Reference*” scenario) and 29 % (in the scenarios with stringent climate policy) over the period of 2010 – 2050. The contribution of the demand side efficiency measures in the reduction of the final energy consumption in the sector is 10 %, while the rest is attributable to technology change and fuel switching (Figure 84). It turns out that when climate policy is in place, additional efficiency gains of about six to seven percentage points are achieved through the use of more efficient technology (mainly heat pumps) in services sectors.

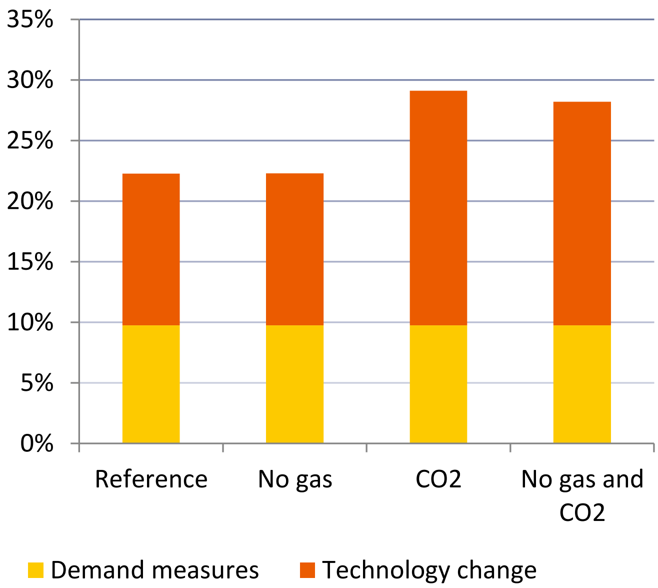
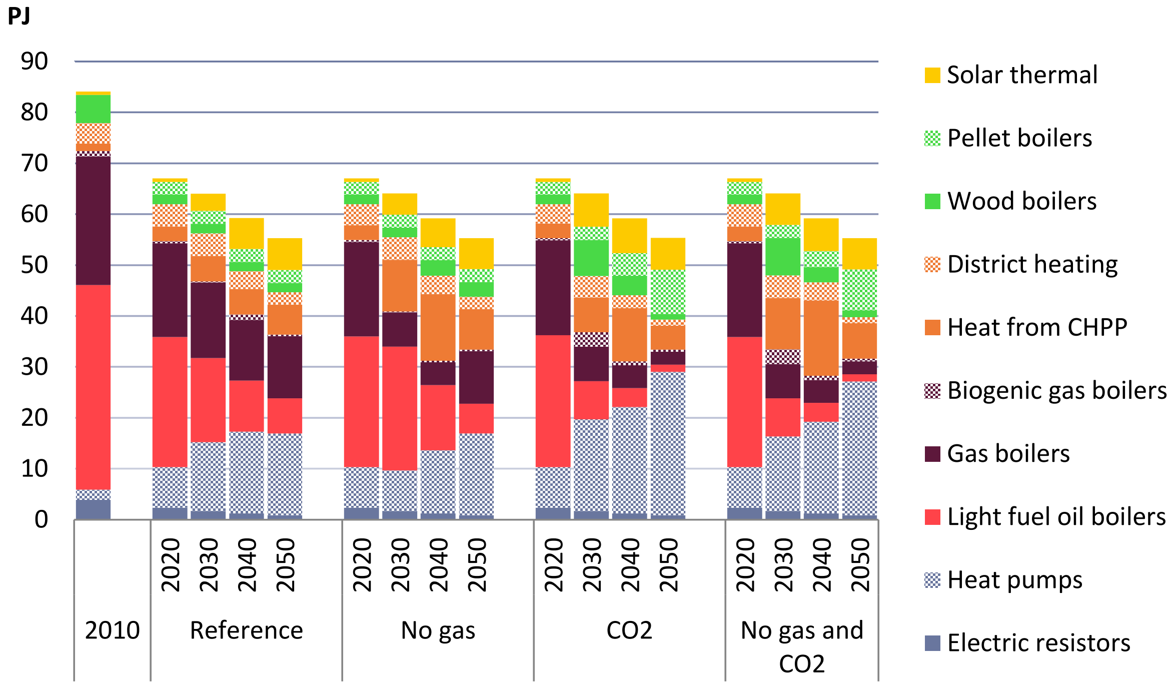


Figure 84: Efficiency gains in final energy consumption due to demand measures and due to technology change in services sectors in 2050 with respect to 2010.

Figure 85 presents the technology mix in total heat supply in services. Oil based heating systems are replaced mainly by heat pumps and natural gas boilers. When there are additional restrictions in large scale gas power plants, on-site CHPP also increase their contribution to heat supply at the expense of oil and natural gas boilers, as they fill the gap in the electricity production. In those scenarios with climate policy, pellets increase significantly their contribution by substituting remaining oil-fired generation.



Heat from CHPP = total heat supplied by on-site CHP plants; Biogenic gas boilers = heat from boilers using biogas or bio-methane from gas grid

Figure 85: Supply of space, hot-water and process heat in services by technology.

In services there is also a synergy between heat pumps and CHP plants, though weaker than in industry because of economies of scale (smaller units that result in increased specific investment costs) and because of serving heat demands of the same temperature ranges. Heat pumps increase their share in total heat supply in services from 2 % in 2010 to 29 % in "*Reference*" and 51 % in "*CO2*" scenarios in 2050. Their uptake slows down when there are no investments in large scale gas power plants ("*No Gas*" vs "*Reference*"), due to increased electricity production costs, but this slowdown is much milder than in industry. This is attributable to the smaller increase in electricity cost to services compared to industry, because of the larger weight of the grid costs in end-user costs[16] [67] that smoothens the increase in marginal electricity production costs. This, in combination with the higher gas prices in services compared to industry, retains the cost-effectiveness of heat pumps in providing low temperature heat in the sector.

As already mentioned in the previous sections, the uptake of CHP plants is positively influenced by both the stringency of the climate policy and the decision of not investing in large gas plants, while it slows down when renewables increase their penetration in electricity supply. The share of on-site CHPP in total heat supply in the sector is 9 – 14 % in 2050, from 2 % in 2010. However, their maximum share in heat supply is attained in 2040 (9 – 25 % of the total).

The increased penetration of heat pumps and CHPP, together with improvements in the efficiencies of gas and wood/pellet-fired boilers, result in efficiency gains which reduce the final energy consumption of the sector (on top of the exogenously assumed demand efficiency measures). Figure 86 presents the final energy consumption in services. The reported electricity and heat in Figure 86 include both quantities produced on-site or bought from grid. To avoid double counting the fuel consumption in on-site CHP plants is reported separately in Figure 87.

[16] The electricity network costs account for more than 60% of the total marginal cost when in industry their share is less than 40% (see also the electricity tariffs reported by [41]).

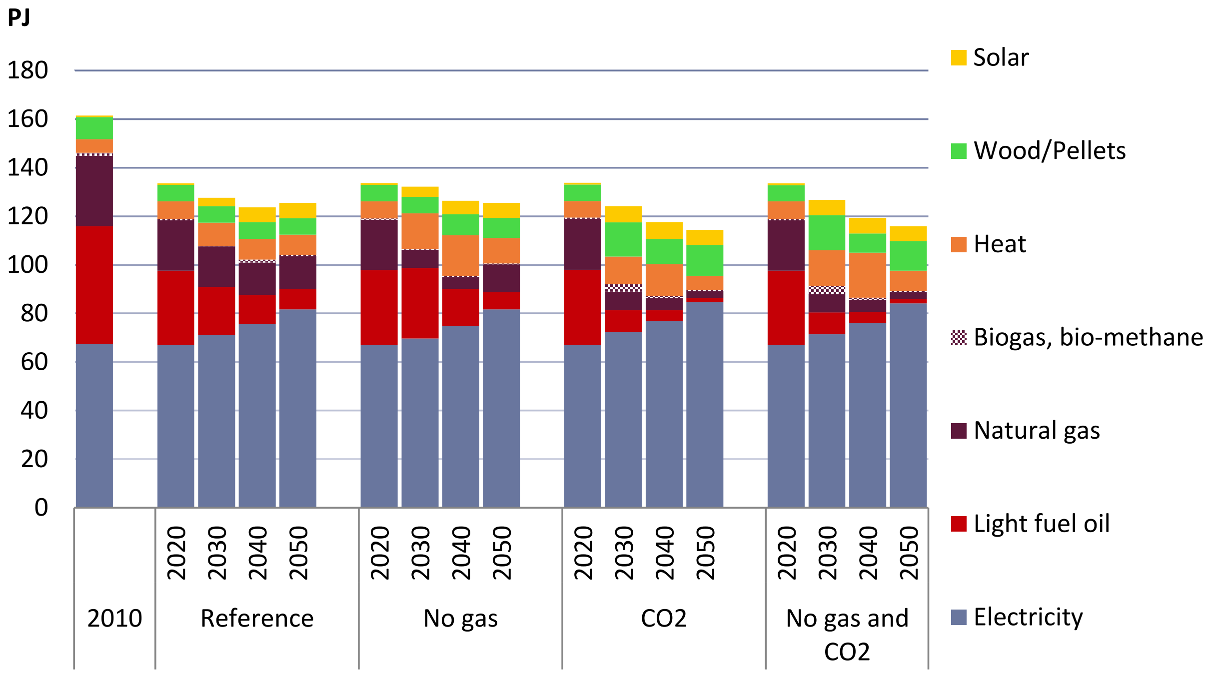


Figure 86: Final energy consumption in services (excluding consumption in on-site CHPP).

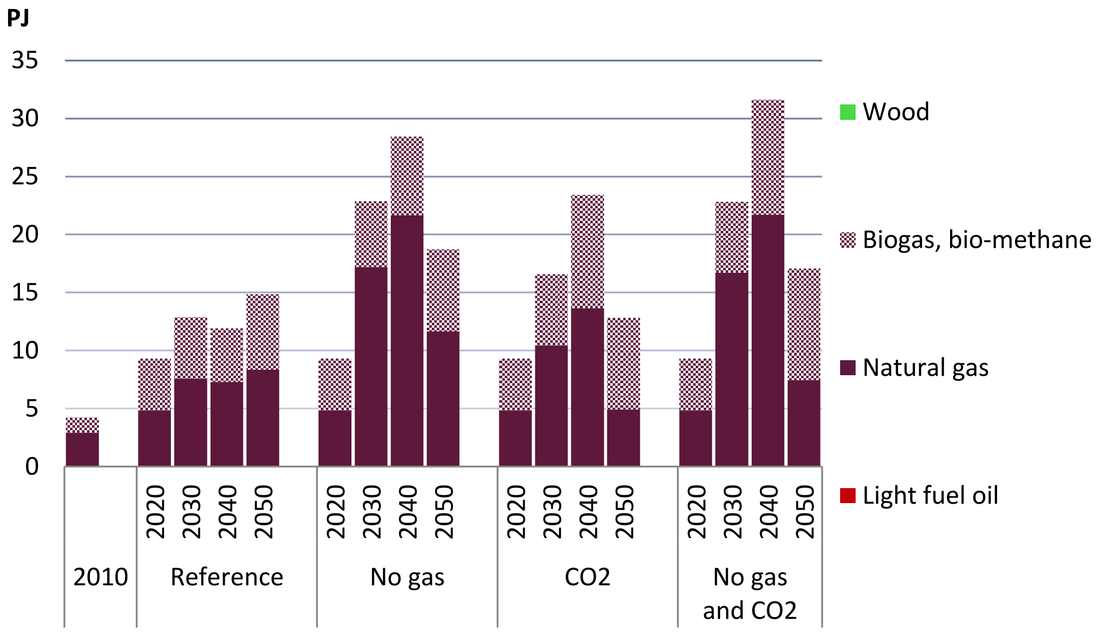


Figure 87: Fuel consumption in on-site CHP plants in services.

<u>*Role of biogenic gas CHP plants in services (and agriculture)*</u>

The on-site biogenic gas CHP plants supply about 1.2 - 2.5 % of the electricity consumed in the sector and about 2.6 – 5.6 % of the total heat demand in 2050 (Figure 88). This translates to about 1.0 – 2.1 PJ of electricity (or 268 – 584 GWh_e) and 1.4 – 3.1 PJ of heat (or 397 – 864 GWh_{th}). It turns out that the average heat-to-power ratio of biogenic gas CHPP in the services sector is about 1.48. Their installed capacity is between 72 MW (in “Reference”) and 216 MW (in “CO2”) in 2050. The above imply an average annual utilisation rate of between 21 % and 43 % (or 1840 – 3770 operating hours) in 2050. The penetration rate of biogenic gas CHP plants in the services sector depends on the same factors already analysed in the previous sections.

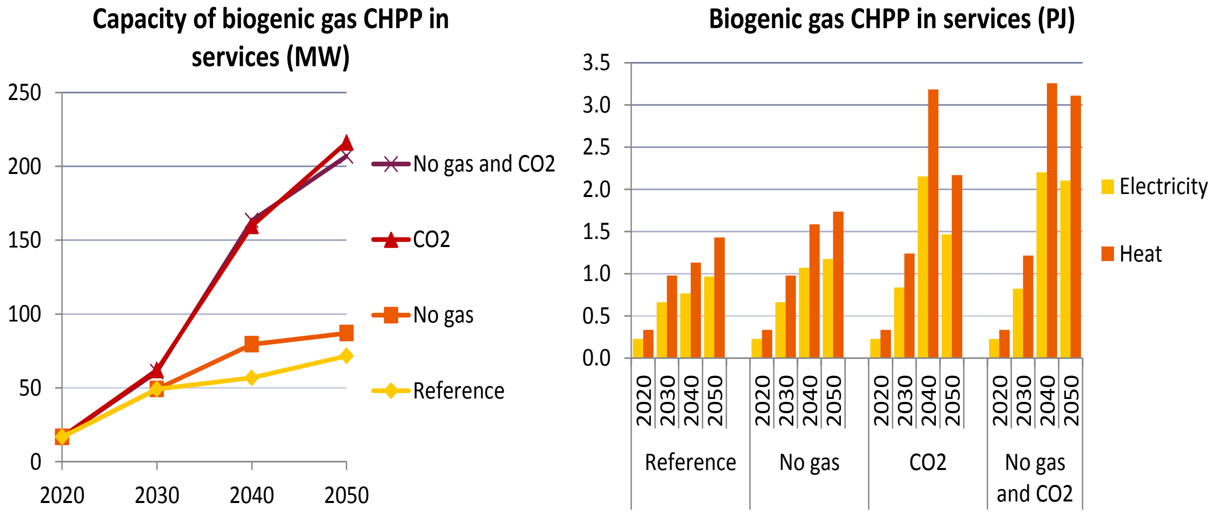


Figure 88: Installed capacity and production from biogenic gas CHP plants in services.

14.4.4.3. Residential sector

In the residential sector the final energy consumption declines by 41 – 50 % over the period of 2010 – 2050. The assumed building renovation and demolition rates, as well as additional efficiency measures in form of codes and standards, contribute about 27 % to the reduction in final energy consumption in residential. The rest is attributable to technology change and fuel switching. The induced technology change also helps in offsetting final energy consumption due to increase demand in new houses (Figure 89).

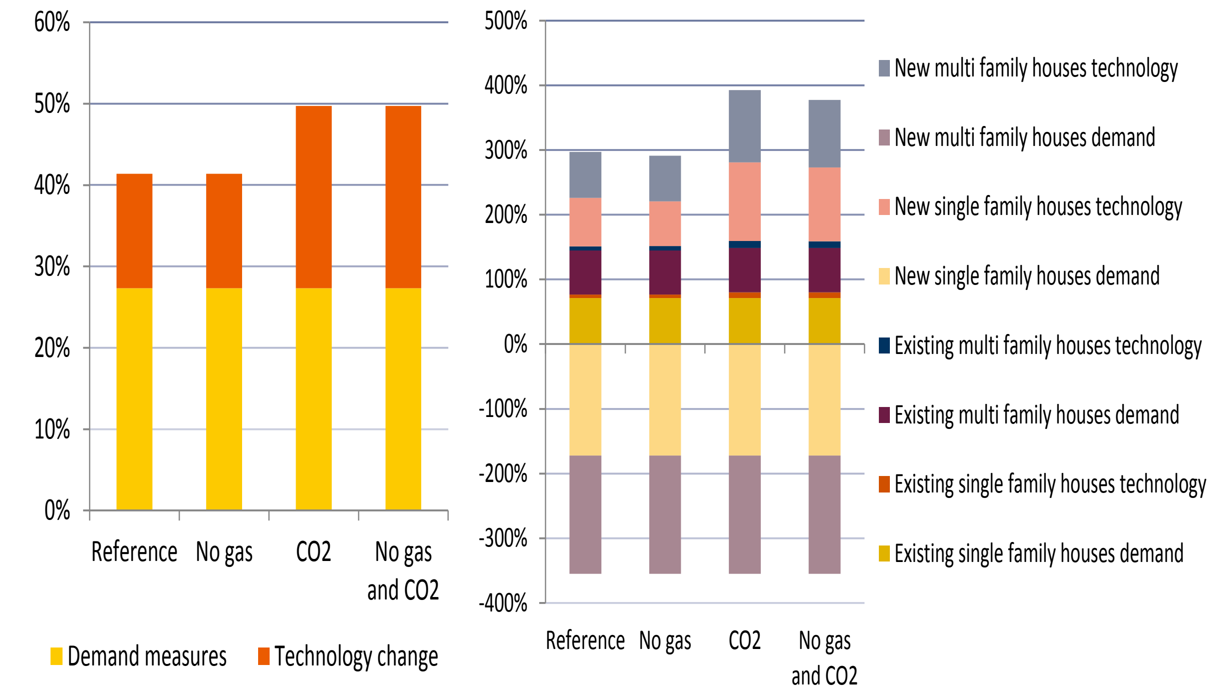
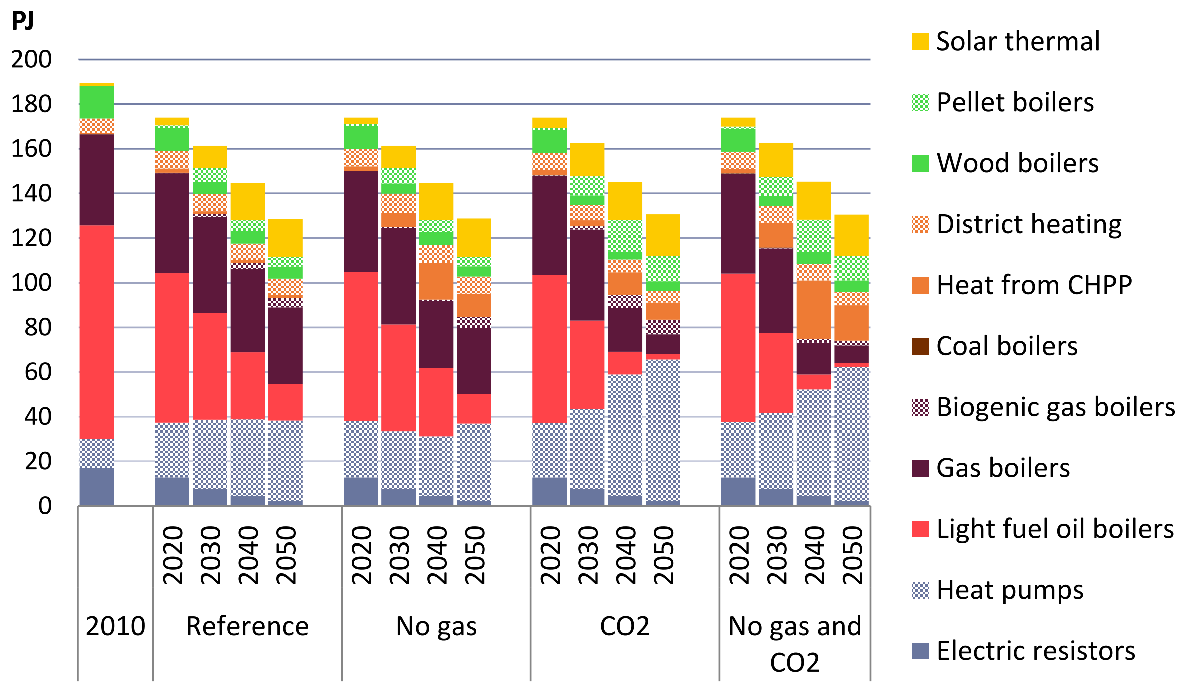


Figure 89: Efficiency gains in final energy consumption due to demand measures and to technology change in the residential sector (left) and in its sub-sectors (right) in 2050 with respect to 2010.

Figure 90 presents the technology mix in residential space and water heating supply. In all scenarios there is a decrease in heat from oil-fired boilers, in accordance to the trends seen in industry and services sectors. The results also show a synergy between heat pumps and CHP units in all scenarios, similar to the one seen in the services sector.



Heat from CHPP = total heat supplied by on-site CHP plants; Biogenic gas boilers = heat from boilers using biogas or bio-methane from gas grid

Figure 90: Supply of space and hot-water heat in residential by technology.

More specifically, in the "*Reference*" scenario natural gas boilers and heat pumps replace oil-fired boilers over the period of 2010-2050. In the period after 2030, solar thermal (mainly for water heating) and pellets (that also replace existing wood boilers) also gain substantial share in total heat supply. District heating retains its today's shares in residential. On the other hand, the deployment of CHP units is quite limited in the "*Reference*" scenario compared to the developments seen in the other end-use sectors, which is attributable to the economies of scale (i.e. higher specific investment costs per kW).

Investments in CHP plants increase mainly in the "*No Gas*" scenario, at the expense of natural gas boilers, driven by the increased need for distributed electricity production. Similar to the trends in the services sector, the penetration of heat pumps in the "*No Gas*" scenario slows down compared to "*Reference*" due to the higher electricity production costs. They regain market share in 2050, by when the increased electricity production from renewables lowers the marginal costs of electricity generation.

In the scenarios with effective climate policy ("*CO2*" and "*No gas and CO2*") heat pumps account for 46 – 48 % of the total heat supply by 2050, which is 20 percentage points higher than in the "*Reference*" scenario. This high penetration of heat pumps is driven by the increased need for efficiency gains in order to meet the stringent CO_2 emission reduction targets. In addition, the share of pellet boilers and CHP also increases in the climate policy scenarios. However, the penetration of the CHP units slows down after 2040, because of increased competition from renewable electricity and heat supply.

It is worth mentioning that in our analysis, where the energy service demands are inelastic to the cost of energy[17], there are technical challenges that need to be overcome in order to meet stringent CO_2 emission reductions targets. These challenges apply mostly to the case of heat pumps, pellets and CHP units. Though heat pumps are considered as cost effective technology option under climate policy, their market penetration can be hampered due to non-cost drivers, such as technological barriers (e.g. geological conditions and seasonal variations in ground temperature) and market barriers (such as space constraints in urban

[17] The inelastic energy service demands in our analysis imply that no demand reductions, other than exogenously assumed, occur due to a stringent climate policy that increases the energy costs. This is not the case in the "*NEP*" scenario of the Swiss Energy Strategy [35], in which a large part of the reduction in the CO_2 emissions is achieved through additional reductions in energy service electricity and heat demands.

areas and environmental regulations that restrict re-injection of ground water). Similarly, the installation of pellet boilers may have space constraints, since they occupy more space than an equivalent oil-fired boiler[18], which could hinder their market penetration in those sites where space is an issue. On the other hand, CHP units are more flexible in terms of technical and market constraints, but they need access to natural gas grid. These non-cost drivers are not explicitly considered in the current analysis[19]. Nevertheless, we assessed variants of the "*CO2*" scenario with restricted-penetration of heat pumps and pellet technologies to understand their trade-off in meeting the CO_2 emission reduction targets. When heat pumps are restricted, pellet boilers increase in zero-carbon heat supply. On the other hand, when pellet boilers are restricted, heat pumps increase, but also wood-fired boilers begin to enter the market.

Figure 91: Share of technologies in space heating in different houses types.

Figure 91 provides insights regarding the technology choice for space heating supply in the different categories of residential buildings considered in the analysis. In existing houses, the low capital stock turnover hampers technology change, especially in the absence of additional incentives. On the other hand, the implementation of voluntary standards in space heating in new buildings (such as the "Minergie" standard) provides a basis for increased penetration of efficient and low-carbon technologies, such as heat pumps and CHPP.

The results also show that there are better market prospects for CHP plants in multi-family houses than in single-family houses, because of economies of scale that lead to lower specific investment costs and to higher electric and heat efficiencies. However, the collective nature of the decision for changing the heating equipment in multi-family houses may impose obstacles that do not exist in single-family houses, and these constraints are not fully captured by the cost-optimisation framework used in this study.

[18] A pellet boiler needs more than twice the space needed by an oil boiler, according to the most optimistic calculations.

[19] This would have required an increased spatial resolution in the model; we tried to partially capture these non-cost barriers through additional modelling incl. constraints and cost-supply curves. The latter were derived from the developments in the scenarios of the Swiss Energy Strategy [35].

In addition, the analysis shows that in those existing buildings where non-cost technical and market barriers hinder the installation of heat pumps, pellet boilers can constitute a carbon-free alternative option for heat supply. This substitution effect does not occur in the case of new buildings, where heat pumps dominate. This is because technical and market barriers of heat pumps can be overcome more easily when they are installed in a "green field".

The substitution of oil boilers with more efficient alternatives, such as heat pumps, results in efficiency gains in the residential sector that reduce its overall final energy consumption. Figure 92 presents the final energy consumption in the residential sector by fuel, which reflects the developments in the technology choices described previously. The reported electricity and heat include both quantities produced on-site or bought from grid. To avoid double counting the fuel consumption in Figure 92 does not include fuel in on-site CHP plants. Instead, this is reported in Figure 93.

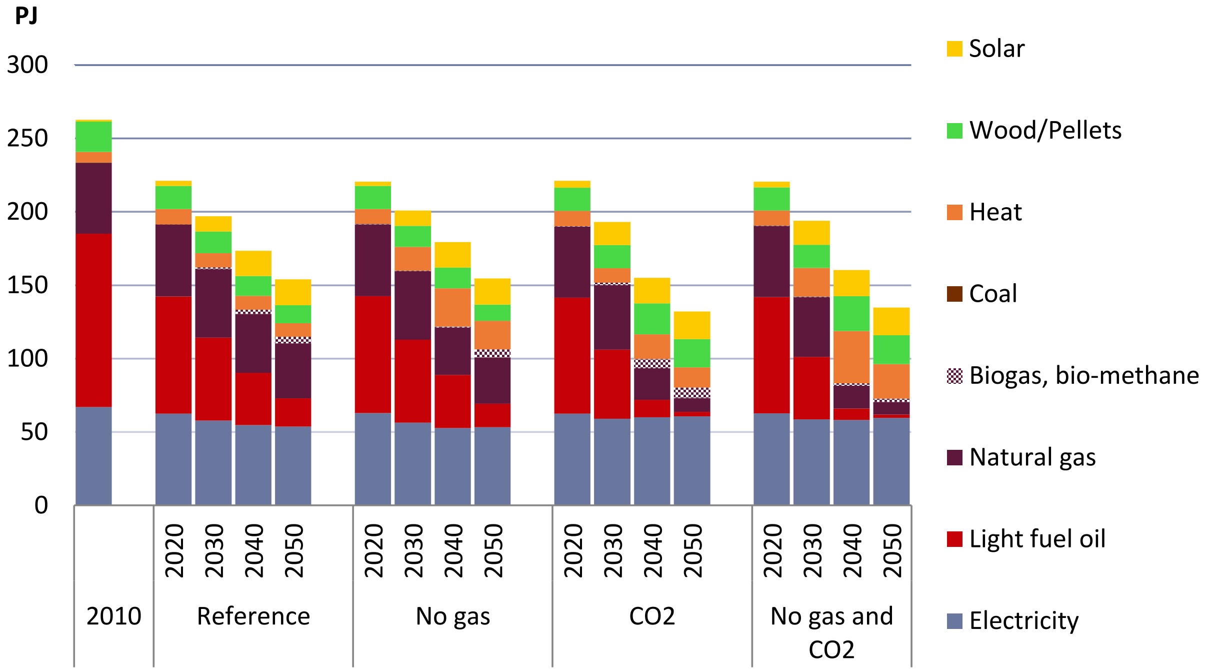


Figure 92: Final energy consumption in residential (excluding consumption in on-site CHPP).

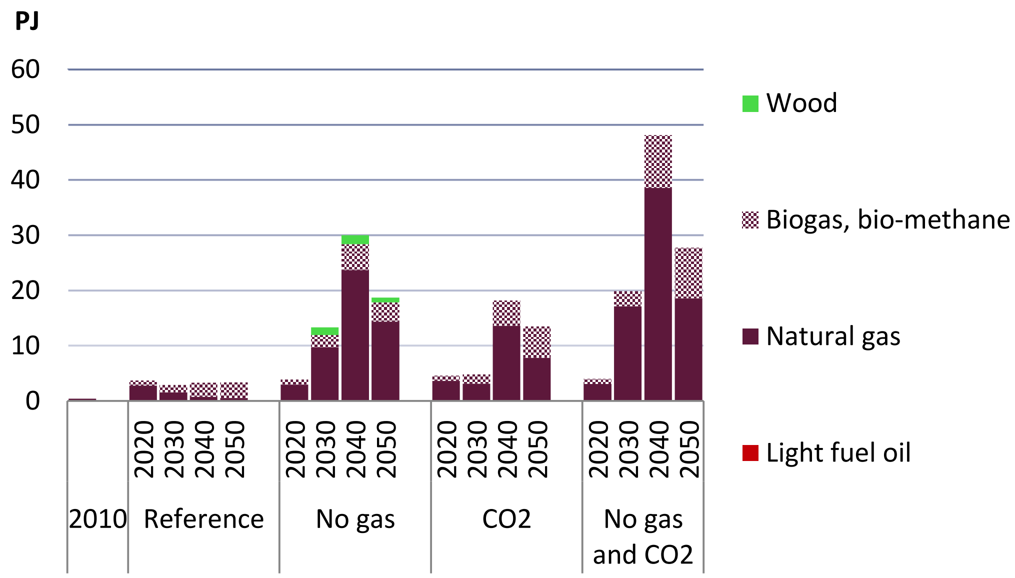


Figure 93: Fuel consumption in on-site CHP plants in residential.

Figure 94 presents the final energy consumption in the different residential sub-sectors and energy uses considered in the model. Due to the assumed demolition and renovation rates of existing buildings, there is a shift in the final energy consumption to new houses over the period of 2010 - 2050. It turns out that the existing houses account for less than 40 % in the total residential energy consumption in all scenarios in 2050 (from 85 % in 2010). On the other hand, the share of new residential buildings increases to more than 60 % in all scenarios in 2050.

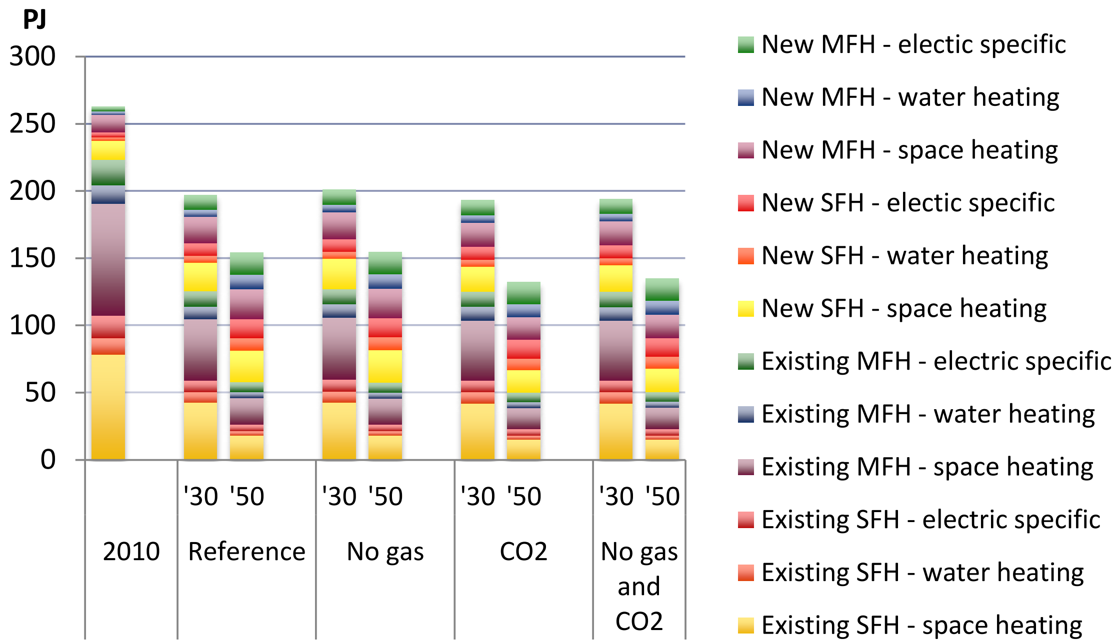


Figure 94: Final energy consumption per house type and use in the residential sector.

<u>*Role of biogenic gas CHP plants in residential*</u>

The on-site biogenic gas CHP plants, supply about 0.9 – 3.0 PJ of electricity (or 258 – 825 GWh_e) in 2050, which account for about 1.7 - 5.0 % of the total electricity consumption of the sector (Figure 95). In addition, they produce about 1.6 - 5.3 PJ of heat (or 458 – 1462 GWh_{th}), which translates to a share of 1.3 – 4.0% in total residential heat demand in 2050. It turns out that the average heat to power ratio is about 1.77. The installed capacity of biogenic CHP plants is between 68 MW (in "*Reference*") and 337 MW (in "*No gas and CO2*") in 2050, with an average annual utilisation rate of 20 – 43 % (or 1750 – 3770 operating hours in a year). The underlying drivers in penetration of biogenic gas CHP plants in the residential are similar to the ones analysed in the previous sections. As already stated above biogenic CHPP have good market prospects in multi-family houses, due to economies of scale.

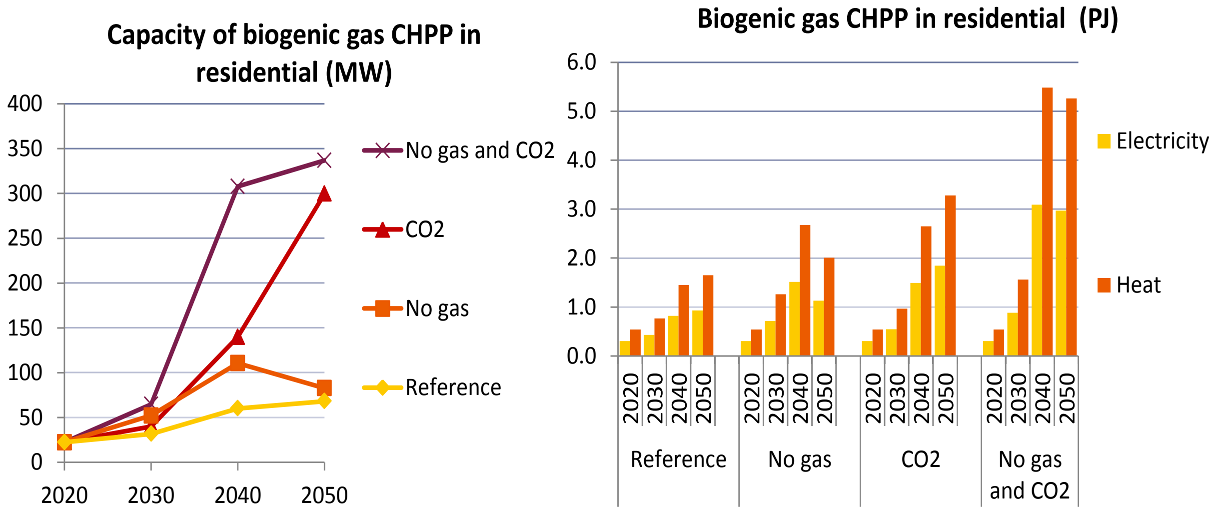


Figure 95: Installed capacity and production from biogenic gas CHP plants in residential.

14.4.5. CO_2 emissions

Figure 96 presents the CO_2 emissions in the four core scenarios from the electricity and heat sectors (i.e. excluding transport). The "*Reference*" scenario achieves a reduction in CO_2 emissions of about 40 % in 2050 compared to 2010 levels. When investments in large scale gas plants are disabled ("*No Gas*" scenario), there is a further reduction in CO_2 emissions due to the increased penetration of CHP plants and renewables. Thus, the "*No Gas*" scenario achieves a total emission reduction of 48 % in 2050 compared to 2010 levels. In the climate policy scenarios ("*CO2*" and "*No gas and CO2*" scenarios), the emission reduction trajectory follows the imposed constraint: that is 35 % in 2030, 48 % in 2040 and 70 % in 2050 compared to 2010 levels.

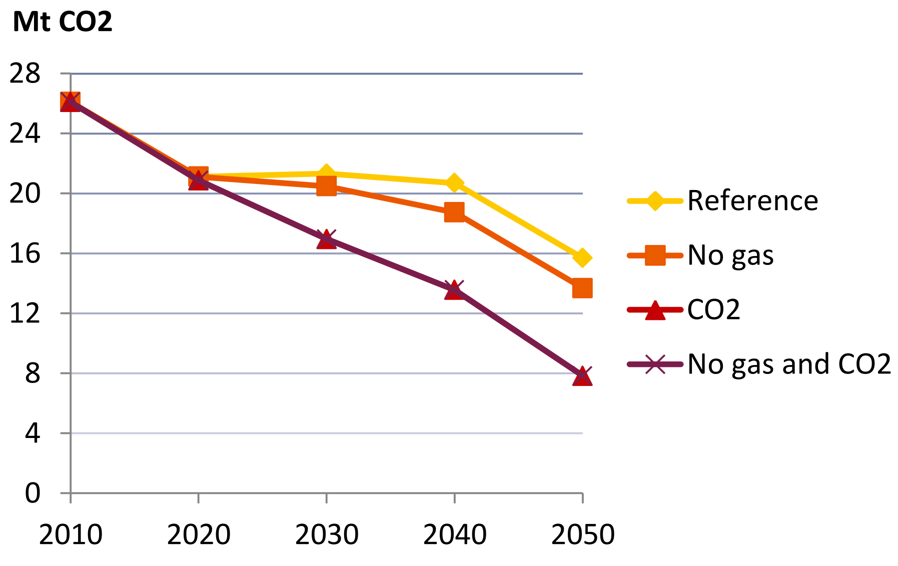


Figure 96: CO_2 emissions from electricity and heat sectors.

Figure 97 presents a decomposition of the CO_2 emissions reduction in the four core scenarios by distinguish the amount of the emissions that is avoided: a) due to the long-term decrease in end-use demand; and b) due to the induced technology change and fuel switching in the heating sectors. The same figure also shows the CO_2 emissions emitted from large scale gas power plants in the electricity sector. The reduction in end use demands, which is exogenously given in the model, contributes to a decrease in CO_2 emissions on the order of 4 Mt over the period of 2010 – 2050 in all scenarios. The technology change and fuel switching in heating sectors, results in a decrease between

8.6 Mt CO_2 and 17.0 Mt CO_2. On the other hand the large scale gas power plants additionally produce about 3.2 Mt CO_2 in "*Reference*" and 2.7 Mt CO_2 in "*CO2*" scenarios in 2050.

The above results show that the contribution of technology change in lowering the CO_2 emissions is substantial in all scenarios. A determinant factor for the size of this contribution is the decision in investing in large scale gas power plants or not. When these investments are allowed, then more than 90 % of the CO_2 emissions reduction is attributable to technology change in end use sectors, in order to offset increased emissions from large scale electricity generation ("*Reference*" and "*CO2*" scenarios). On the other hand, when investments in large gas power plants are disabled, then the contribution of the technology change in end use sectors is about 70 %, since there is no need to offset emissions from the large scale electricity generation sector ("*No Gas*" and "*No gas and CO2*" scenarios). This implies that the end use sectors bear a higher burden in reducing emissions when investments in large scale gas power plants are allowed, which is ultimately translated to increased emission mitigation costs compared to the opposite case (see section 14.4.6).

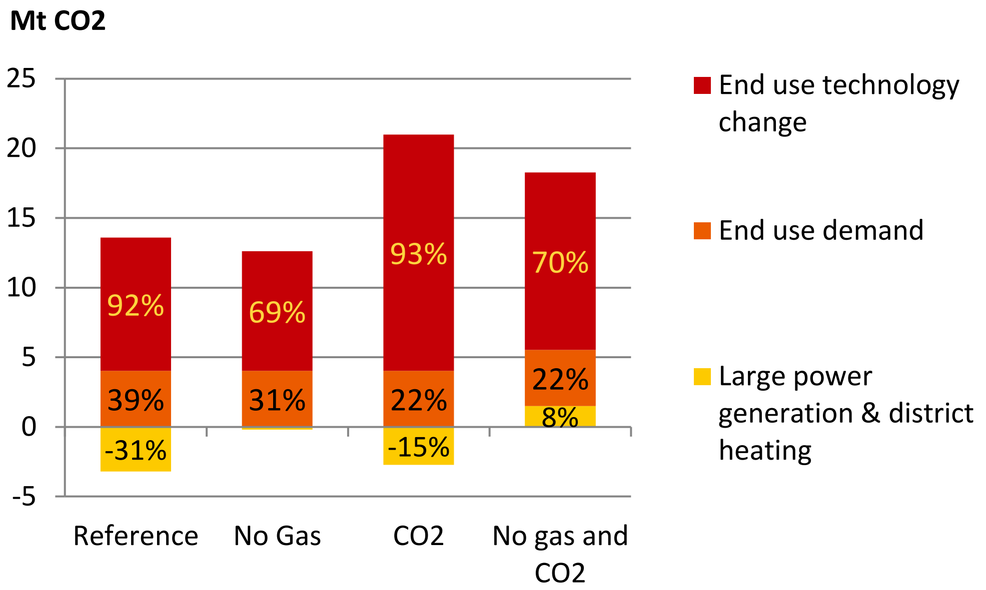


Figure 97: CO_2 emission reductions (positive values) due to demand reduction, technology change in end use sectors, and due to fossil-based large scale electricity and heat generation in 2050 with respect to 2010 levels.

Figure 98 presents the decomposition of CO_2 emissions by sector in all scenarios. In the "*Reference*" scenario, the emissions from large gas power plants account for 30 % of the total in 2040 and 20 % in 2050. When a climate policy is in place ("*CO2*" scenario), the CO_2 emissions from the gas plants have a share of 24 % in 2040 and 12 % in 2050.

If we apply the sectoral approach in calculating the CO_2 emissions, i.e. emissions from CHP plants are accounted to the sector of application, the decision in investing in large scale gas plants clearly influences the emission trajectories in the end-use sectors. While in the "*Reference*" scenario the end-use sectors achieve a reduction in CO_2 emissions of the order of 58 % in 2050 from the 2010 levels, in the "*No Gas*" scenario they reduce their emissions by 54 % over the same period. This translates to 1.0 Mt CO_2 more emissions from the end use sectors in the "*No Gas*" scenario than in "*Reference*", due to the deployment of natural gas based CHP plants. Much of this increase occurs in the industrial sector (about 0.8 Mt out of 1.0 Mt CO_2), with the rest mainly in residential. Thus, the CO_2 emissions reduction in industry is only 17 % in the "*No Gas*" scenario, compared to 30% in "*Reference*" between 2010 and 2050. The residential and services sector achieve a reduction of 68 % and 66 % respectively by 2050, which is a similar to the levels attained in the "*Reference*" scenario over the same period (69 % and 66 % respectively).

When climate policy is in place ("*CO2*" scenario) the CO_2 emissions from the end-use sectors decrease by 75 % in 2050 compared to 2010 levels (and 71 % in the "*No gas and CO2*" scenario). The residential and services sectors are almost decarbonised between 2050 and

2010. On the other hand, the reduction of CO_2 emissions in industry in the "*CO2*" scenario is more modest, because on-site gas fired CHP plants continue to contribute in electricity and heat supply in the sector. Thus, under climate policy, industry reduces its CO_2 emissions by 35 % over the period 2010 – 2050: this is only 5 percentage points more than the decrease attained in the "*Reference*" scenario. This is translated to only 0.4 Mt CO_2 less emissions in "*CO2*" scenario compared to "*Reference*" in industry in 2050.

Finally, the CO_2 emissions from non-renewable waste remain constant in the "*Reference*" and "*No Gas*" scenarios over the period of 2010 – 2050. However, when a climate policy is in place the emissions from non-renewable waste reduce by 50 % in 2050 compared to 2010 levels, due to a decrease in their use in incineration. In this case, alternative options for non-renewable waste treatment may have to be explored (e.g. recycling).

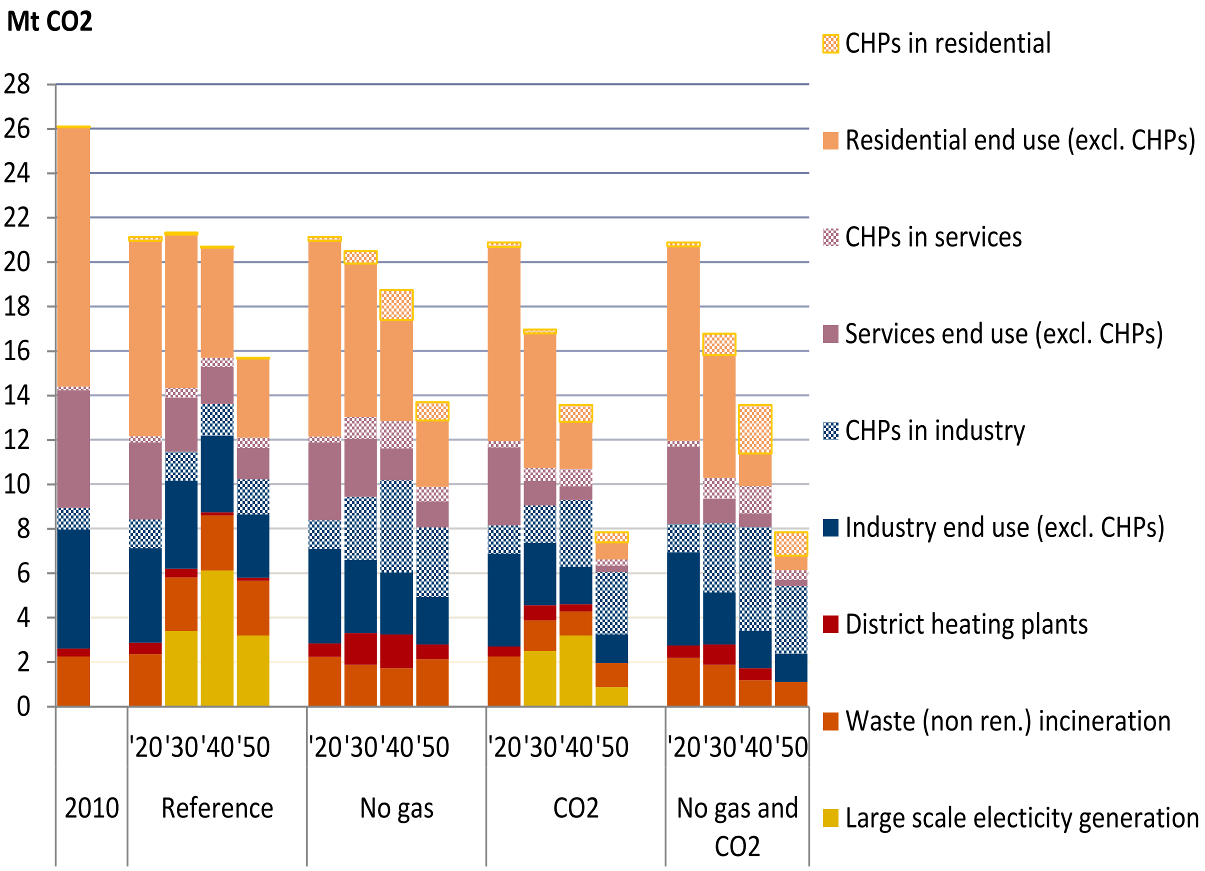


Figure 98: Breakdown of the CO_2 emissions by sector.

The shadow (marginal) prices of the CO_2 emissions in the four core scenarios are given in Table 17. It should be noted that the prices for "*Reference*" and "*No Gas*" scenarios are based on the exogenously assumed EU-ETS prices of Swiss Energy Strategy [61]. On the other hand, the CO_2 prices in "*CO2*" and "*No gas and CO2*" scenarios correspond to the dual of the imposed constraint on the total CO_2 emissions.

CO_2 prices (CHF/t)	**2010**	**2030**	**2040**	**2050**
Reference	36	48	55	58
No gas	36	48	55	58
CO2	36	233	480	932
No gas and CO2	36	233	621	855

Table 17: Shadow prices of CO_2 emissions in real Swiss francs of 2010.

The high CO_2 emission prices under stringent climate change mitigation policy are due to the lack of flexibility because of the inelastic energy service demands[20] and because of the exclusion of some low-carbon options other than hydro and renewables (e.g. nuclear power, CCS and imported electricity). In this context, the induced technology change in demand sectors, which in fact enables the reduction in the emissions, cannot take place without such high CO_2 emissions shadow prices.

14.4.6. Electricity and heat system costs

The annual system cost of the electricity and heat sectors in our analysis is calculated in accordance with the practices followed by the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency (IEA)[21]. However, the estimated system cost shall be seen as a lower bound because some aspects of the energy system transition are not fully captured (see section 14.2 regarding the limitations in the modelling framework). The system cost, includes all the costs associated with the electricity and heat production, distribution and use:

$$SystemCost_t = cr_t \cdot InvCost_t + FixCost_t + VarCost_t + Subsidies_t - Taxes_t$$

cr_t is the capital recovery factor in year t; $InvCost_t$ is the investment cost in year t; $FixCost_t$ is the fixed operating and maintenance cost in year t; $Subsidies_t$ are the subsidies and feed-in tariffs payments in year t; $Taxes_t$ are the fuel taxes in year t.

Figure 99 presents the annual electricity and heat system cost in the four core scenarios. In all scenarios the annual system cost is almost the same by 2020, driven by lock-in effects from investments in the short-term, which today are in advanced planning stage or their construction has already been started: for example the "Strategic grid 2025" project [68] and the pump storage project in Limmern [69]. The cost evolution in the later periods is driven by the underlying energy and climate change policies.

In the "*Reference*" scenario the system cost declines in 2030 from its 2020 levels, mainly due to efficiency gains from technology switching that offsets moderate increases in imported fuel prices. In 2040 the system cost increases, driven by investments in large gas plants and in decentralised electricity and heat supply, in order to cope with the phase out of the largest (and last) nuclear power plant. The system cost declines again in 2050, because of savings in fuel expenditure due to electricity and heat supply from renewable energy sources.

In the "*No Gas*" scenario, the lack of economies of scale in electricity production results in increased investment in smaller (and more expensive) CHP units. This capital intensive pathway leads to a higher undiscounted annual system cost on the order of CHF 3 – 4 billion compared to "*Reference*" during the period of 2030 – 2050. The cumulative undiscounted system cost is about CHF 71 billion higher (or 7 %) than the cumulative system cost in the "*Reference*" scenario over the period of 2010 – 2050.

In the "*CO2*" scenario the imposed CO_2 emission targets accelerate investments to capital intensive, but low-carbon and more efficient, technologies. The difference in the annual system cost between this scenario and "*Reference*" is higher from 2030 onwards, when the last nuclear power plant is phased out and the CO_2 emissions reduction targets become more stringent. As a result, the undiscounted annual system cost is about CHF 10 billion higher than in "*Reference*" scenario beyond 2030. At the same time, the cumulative undiscounted system cost is CHF 220 billion more than in "*Reference*" over the period 2010 – 2050 (this corresponds to an increase of 22 % from "*Reference*").

[20] In contrast, in the "*NEP*" scenario with the stringent climate policy of the Swiss Energy Strategy the energy service demand declines by 14% compared to "*POM*" in 2050, which results in lower CO_2 emission prices than the ones obtained from our analysis with inelastic demand.

[21] Subsidies are included in the system cost, because they constitute payments of the electricity TSOs to producers. Fuel taxes are subtracted from the fuel prices during the calculation of the system cost, because taxes induce investments to more efficient (and expensive) technologies and therefore by including them in the system cost their effect is double counted.

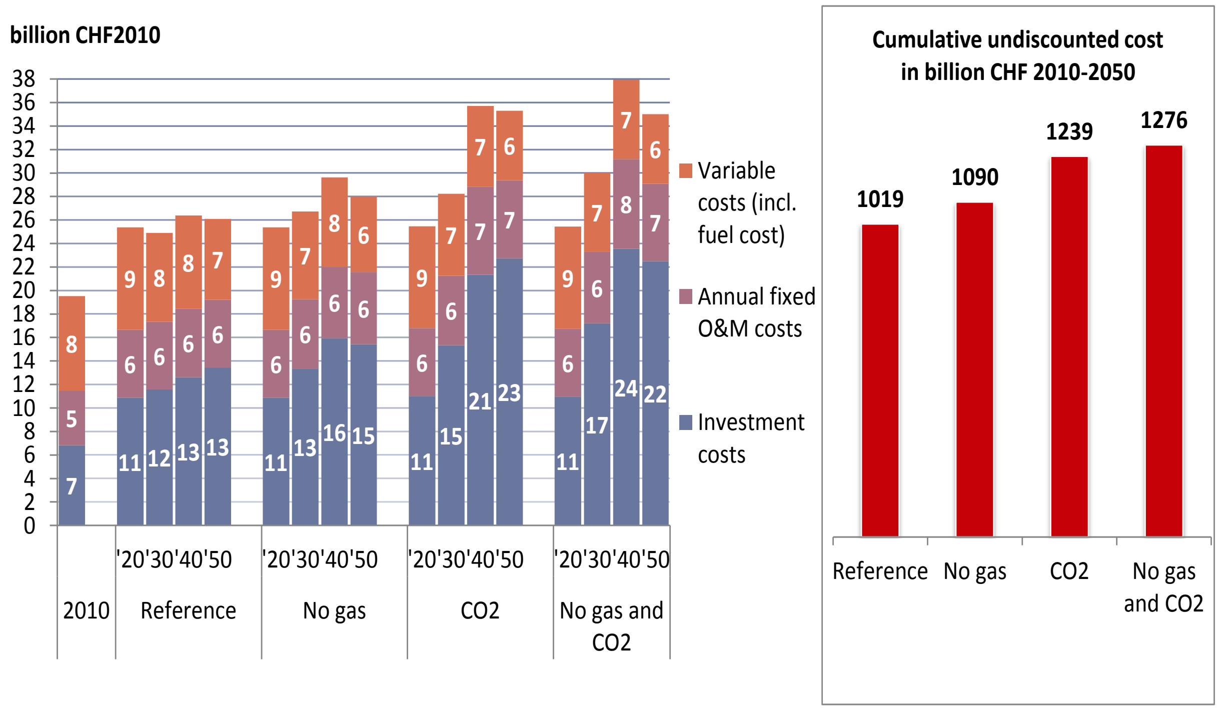


Figure 99: Electricity and heat system cost in real Swiss francs of 2010.

Finally, the "*No gas and CO2*" scenario is the most expensive, because of the combined factors of "*No Gas*" and "*CO2*" scenarios. However, if it is to compare this scenario with the "*No Gas*" scenario it turns out that the cumulative policy cost is CHF 187 billion. Comparing it with the policy cost when investments in large gas power plants are allowed (CHF 220 billion), it turns out that it is about 15 % less. This lower policy cost is attributable to the further reduction in CO_2 emissions achieved in the "*No Gas*" scenario compared to "*Reference*".

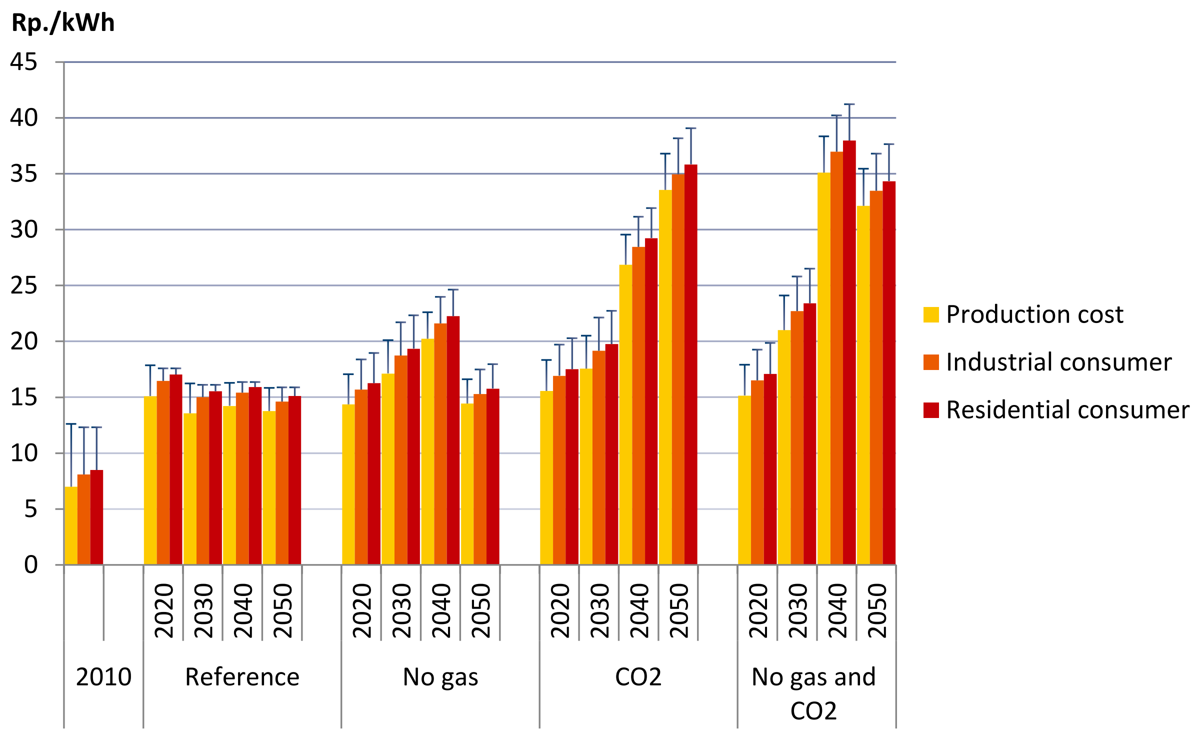


Figure 100: Volume-weighted electricity marginal cost in real Swiss francs of 2010 (the error bars correspond to the upper 5 % quantile).

Figure 100 presents the volume-weighted long run marginal cost of electricity, which follows the trends of the total system cost described above. Thus, in the “*Reference*” scenario the long-run marginal cost of electricity increases on average from around 7 Rp./kWh in 2010 to 14 Rp./kWh in 2050 (however, much from this difference occurs because many existing assets in electricity production have been already amortised). In the “*No Gas*” scenario the marginal cost of electricity is also 14 Rp./kWh in 2050, although in 2040 it reaches the level of 20 Rp./kWh. In the “*CO2*” scenario the marginal electricity production costs is on average on the order of 34 Rp./kWh in 2050.

14.5. Prospective drivers of biogenic gas CHP plants

In order to obtain more insights on potential drivers, which influence the deployment of biogenic gas CHP plants, a set of sensitivity analyses has been assessed (see Table 16 for a definition of the variants and section 15.2 for more details regarding their underlying assumptions). Table 18 presents a set of indicators on biogenic gas CHPP in the four scenarios and their variants in the electricity, heat and grid balancing markets. Figure 101 presents an overview of the sectoral penetration of biogenic gas CHPP in terms of installed capacity.

Across all scenarios and variants, the total installed capacity of biogenic gas CHP plants ranges between 186 MW and 1003 MW in 2050, depending on the demand levels, the climate policy and the international oil and gas prices. They supply about 0.8 – 3.9 TWh_e of electricity and about 1.0 – 5.2 TWh_{th} of heat over the same period. At the same time, about 38.2 – 47.6 % of the total installed capacity of biogenic gas CHPP operates as swarms and provide about 18.2 – 49.7 % of the total secondary positive control power demand by 2050. The wet and woody biomass required for producing biogas that is used in CHP plants (either as raw biogas or injected to gas grid bio-methane) amounts from 7.1 PJ to 41.5 PJ in 2050. This corresponds to 11.6 – 44.0 % of the total biomass used for electricity and heat stationary applications or 6.7 – 39.4 % of the assumed total biomass potential in this year.

Apart from the developments in the large scale gas electricity generation and the stringency of the climate change mitigation policy, which have been already identified as drivers affecting the uptake of biogenic CHPP, the level of the electricity and heat demand is also among the factors influencing the penetration of biogenic gas CHPP. When the energy service demands are high (+22 % in “*High demand*” variant compared to “*Reference*”) the installed capacity of biogenic CHPP is about 14 MW (or +4 %) higher than in “*Reference*”. When the demand is low (-14 % in “*Low demand*” variant compared to “Reference”) the installed capacity is about 87 MW (or -23 %) less than “*Reference*”. Importantly, in the low and high demand variants big changes are seen in the investment in large scale gas turbine combined cycle plants (GTCC). In “*Low demand*”, their total installed capacity is 1.6 GW in 2040, compared to 2.7 GW in “*Reference*”. In the “*High demand*” variant, investments in GTCC increase by 1 GW compared to “*Reference*” (i.e. they reach 3.7 GW), which hamper the penetration of the CHP plants in electricity and heat markets. In this scenario, however, the increased requirements in grid balancing enable investments in biogenic gas CHPP capacity for ancillary services. Thus, despite that the electricity and heat production of biogenic gas CHPP in this scenario is of the same order as in “*Reference*”, their installed capacity is much higher. Viewed another way, this also implies that when the electricity demand is low there is also lesser need for grid flexibility, which further contributes with a negative sign to the uptake of biogenic gas CHPP.

	Scenario and Variant Name		Installed capacity	Electricity Production		Heat Production		Secondary positive control power		Required wet and woody biomass for biogas to CHPPs		
			MWe	TWh	% of total production	PJ	% of total production	MW	% of total required capacity	PJ	% of total biomass used	% of total biomass potential
Core scenarios	Reference		376	1.5	2.1%	6.9	2.6%	178	22.0%	14.2	18.5%	13.5%
	No gas	↑	524	1.7	2.5%	8.0	3.0%	250	30.7%	16.5	21.1%	15.6%
	CO2	↑↑	933	2.3	3.2%	11.0	4.1%	417	44.1%	22.6	21.4%	21.4%
	No gas and CO2	↑	917	2.8	3.8%	13.6	5.1%	404	42.8%	27.5	26.1%	26.1%
Variants	High demand	↑	390	1.5	1.9%	6.8	2.0%	185	21.3%	14.0	15.8%	13.3%
	Low demand	↓	289	1.2	1.8%	5.3	2.4%	136	18.2%	11.0	17.3%	10.4%
	High biogas resource	↑	693	2.7	3.8%	12.6	4.7%	322	39.4%	28.3	31.9%	26.8%
	High prices	↑	462	1.8	2.5%	8.2	3.1%	217	24.2%	17.0	18.8%	16.1%
	Low prices	↓↓	186	0.8	1.1%	3.4	1.3%	78	13.4%	7.1	12.2%	6.7%
	Bio-electricity support	↑↑	1003	3.9	5.5%	18.7	7.0%	436	49.7%	41.5	44.0%	39.4%
	CO2 with CCS	↓	607	2.1	2.9%	9.8	3.7%	287	31.6%	20.3	19.4%	19.2%
	CO2 with CCS and NUC	↓	642	2.2	3.0%	10.2	3.9%	245	31.7%	21.1	20.0%	20.0%
	No swarms in ancillary services	↓↓	208	0.8	1.2%	4.1	1.5%	0	0.0%	8.2	11.6%	7.8%
	minimum		***186***	***0.8***	***1.1%***	***3.4***	***1.3%***	***0***	***0.0%***	***7.1***	***11.6%***	***6.7%***
	maximum		***1003***	***3.9***	***5.5%***	***18.7***	***7.0%***	***436***	***49.7%***	***41.5***	***44.0%***	***39.4%***

Table 18: Overview of the performance of biogenic gas CHPP in all scenarios and variants.

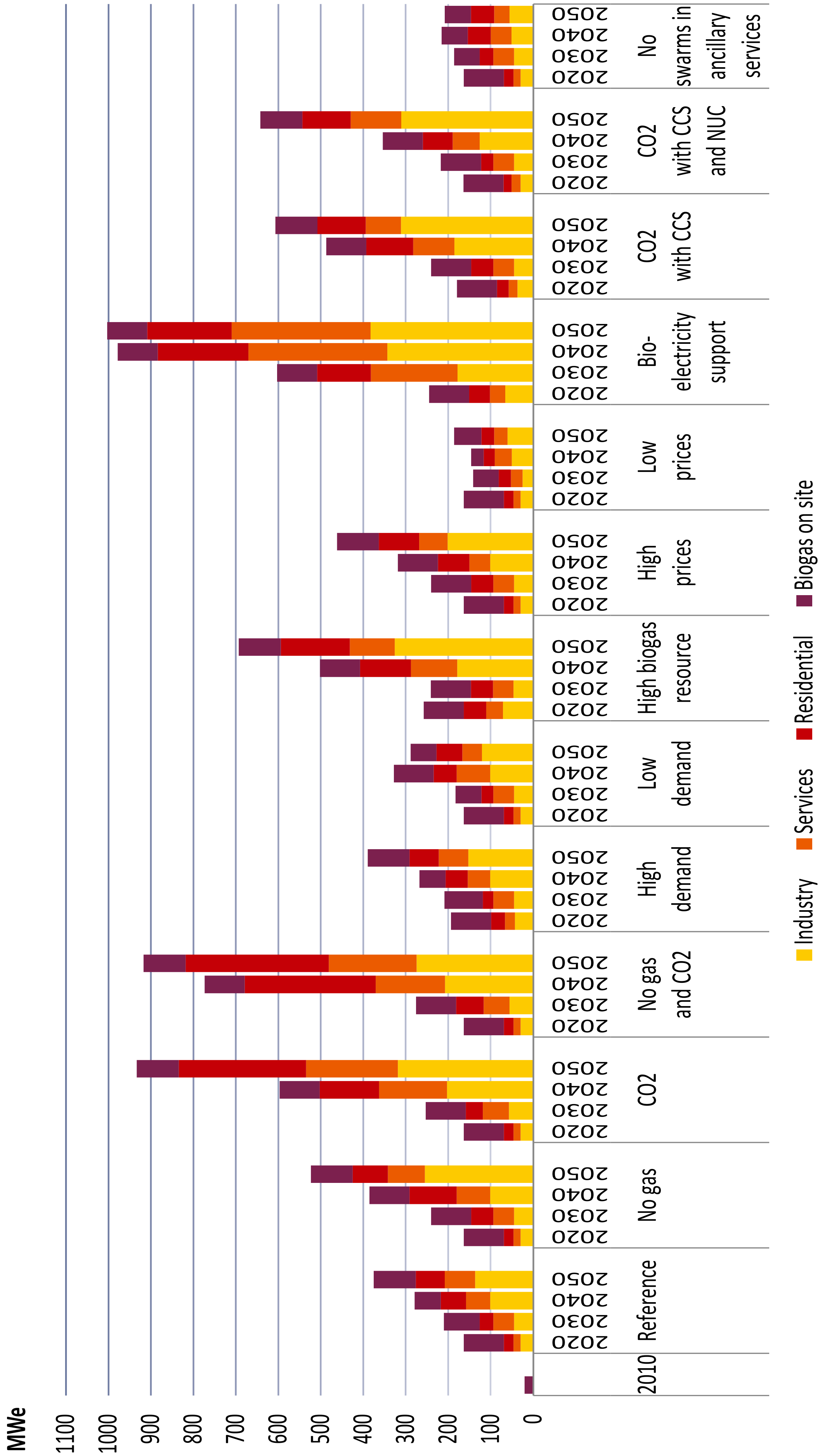


Figure 101: Installed capacity of biogenic gas CHP in each sector.

The level of the natural gas price, and its competitiveness with the biogas production costs, is also an important factor affecting the uptake of biogenic gas CHPP. In the "*High prices*" variant, in which the natural gas price is assumed to be about 15 % higher than in "*Reference*" in 2050 (see section 15.2), the installed capacity of biogenic gas CHP plants is by 87 MW (+23 %) higher from "*Reference*" in the same year. On the other hand, the lowest installed capacity of biogenic gas CHPP across all scenarios in 2050 is obtained in the "*Low prices*" variant (50 % less compared to "*Reference*"), where the prices are about 40 % lower than in "*Reference*" in 2050. The above imply an almost one-to-one relationship between the change in natural gas price and the change in the penetration of biogenic gas CHPP.

When current supporting policies for electricity production from biomass[22] are assumed to continue until 2050 ("*Bio-electricity support*" variant), the penetration of biogenic gas CHP plants increases slightly above 1 GW by 2050 – the highest capacity across all scenarios/variants. It follows that the total electricity production from biogenic gas CHP is about 3.9 TWh.

On the other hand, in the case where all the available domestic wet and woody biomass resources are forced to be used for biogas production ("*High biogas resource*" variant), about 2.7 TWh of electricity are produced from biogenic gas CHP plants, which consume around 20.9 PJ of bio-methane and 3.8 PJ of biogas. The rest quantities of biogas and bio-methane (1.0 PJ and 14.8 PJ respectively) are used in boilers. Thus, it can be inferred that additional financial supporting mechanisms are needed in order to enable the use of remaining biogas in CHPP. This threshold of 2.7 TWh_e of our analysis is close to the economic potential for electricity production from biogas estimated by BFE (2.3 TWh_e) in [62].

When gas combined cycle plants with CCS are assumed to be available from 2030 ("*CO2 with CCS*" variant) and/or the operating lifetime of nuclear power plants is extended ("*CO2 with CCS and NUC*" variant), the uptake of biogenic gas CHPP slows down and their capacity declines by 31 – 35 % compared to the "*CO2*" scenario in 2050. This is attributable to the increased competition from low-carbon large scale electricity generation. It is worthy to note that the "*CO2 with CCS and NUC*" variant leads to slightly higher capacity of biogenic gas CHPP than in "*CO2 with CCS*" by 2050, because the extension of nuclear by 10 years delays investments in large scale generation with CCS and hence reduces competition from centralised sources in 2050.

Finally, the provision of grid balancing services from biogenic gas CHPP is a key driver for their uptake. The variant "*No swarms in ancillary services*" affirms the economic benefits for the CHP swarms operators by participating in ancillary services markets: when the balancing services from biogenic gas CHPP are disabled then their installed capacity declines by 50 % compared to "*Reference*" in 2050.

In terms of sectoral penetration (Figure 101) the biogenic gas CHP plants are first introduced on-site with biogas production facilities, driven by existing trends and practices, and by the low natural gas prices that hamper the expansion of the bio-methane upgrade and distribution infrastructure since gas is very competitive. Their uptake in industry, services and residential sectors increases after 2020, because of: a) the limited potential for further investments in on-site biogas-fired CHP plants due to local constraints; b) the increased natural gas and CO_2 emission prices that enable investments in alternative technologies and in their associated infrastructure; and c) the phase-out of the nuclear capacity that increases the need for low-carbon electricity generation in view of CO_2 emission reduction pledges.

Among the end-use sectors, industry displays the largest share in the total biogenic gas CHPP capacity in all scenarios by 2050, driven by economies of scale. However, under a stringent climate change mitigation policy, there is competition for biogas resource from services and residential sectors as well, which results in shifting biogas from industry to the other end-use sectors. In this case, the share of biogenic gas CHPP in the residential and services sectors increases. However, when the electricity sector has additional flexibility in reducing its CO_2 emissions (e.g. CCS or extension of the operating lifetime of nuclear power plants), then the bulk of the use of biogas/bio-methane remains at the industrial sectors.

[22] See section 15.2 for the feed-in tariff assumed for the production of electricity from wet and woody biomass.

14.6. Biogas and bio-methane production pathways

The biogas and bio-methane production pathways in the four core scenarios are presented in Figure 102 and Figure 103. In all scenarios biogas is produced from additional to existing uses quantities of biomass and especially from animal manure. Animal manure is exclusively used for biogas production since there are no other energy uses for the resource. On the other hand, there are competing pathways regarding bio-waste and wood for electricity and heat production. Therefore, the use of bio-waste for biogas production occurs mainly when there is a stringent climate policy in place, at the expense of alternative waste treatment processes (e.g. incineration). However, large scale wood gasification for producing syngas that is injected into the natural gas grid appears as a cost-effective option only when there is support (in form of subsidies or feed-in tariffs) for bio-electricity (see Figure 104). In all other scenarios, syngas from wood gasification is mainly used on-site in wood-fired CHP units, and it is not injected as bio-methane. This implies that large scale wood gasification is cost-effective when demand is high enough to allow for recovering infrastructure costs (large gasification plant, pipelines).

In the "*Reference*" scenario about 90 % of the potential animal manure is converted to biogas. The resource potential of 24.5 PJ is fully exploited in the rest of the core scenarios due to the higher uptake of biogenic gas CHP units. Under a climate policy ("*CO2*" and "*No gas and CO2*" scenarios) about 32 % of the bio-waste (8.2 PJ) is converted to biogas and injected into the natural grid as bio-methane. When there is support for biogenic electricity, then 15.2 PJ of wood are used to produce 10.8 PJ of syngas that is injected into the natural gas grid as bio-methane. The maximum quantity of bio-methane that is injected in the natural gas grid in our analysis is about 37.4 PJ in 2050 (Figure 104).

It is worthy to note that the conversion efficiency of biomass to electricity and heat, by taking into account all pathways, increases in all scenarios in 2050 compared to the 2010 levels. Hence, in the "*Reference*" and "*No Gas*" scenarios the average conversion efficiency of biomass is 67 % in 2050 from 59 % in 2010. In the "*CO2*" and "*No gas and* CO2" scenarios it increases to 72 % in 2050. When support mechanisms to biogenic electricity are in place, the average conversion efficiency is 74 %, which is the highest across all scenarios and variants. This implies that biogenic gas CHP plants constitute an efficient pathway in converting woody and wet biomass into electricity and heat, and especially compared to the current practices of using the biomass resource in stationary applications.

Figure 105 presents the consumption of natural gas and bio-methane from the natural gas network. In terms of share in total gas consumption, bio-methane accounts from 3 % (in the "*Low prices*" variant) to 23 % (in the "*CO2*" scenario). In terms of absolute values, the bio-methane consumption from the natural gas grid network ranges from 7.8 PJ (in the "*Low prices*" variant) to 37.1 PJ (in the "*Bio-electricity support*" variant). The above indicate that the competitiveness of biogas production costs with the natural gas prices is a determinant factor for the consumption levels of bio-methane attained in Switzerland.

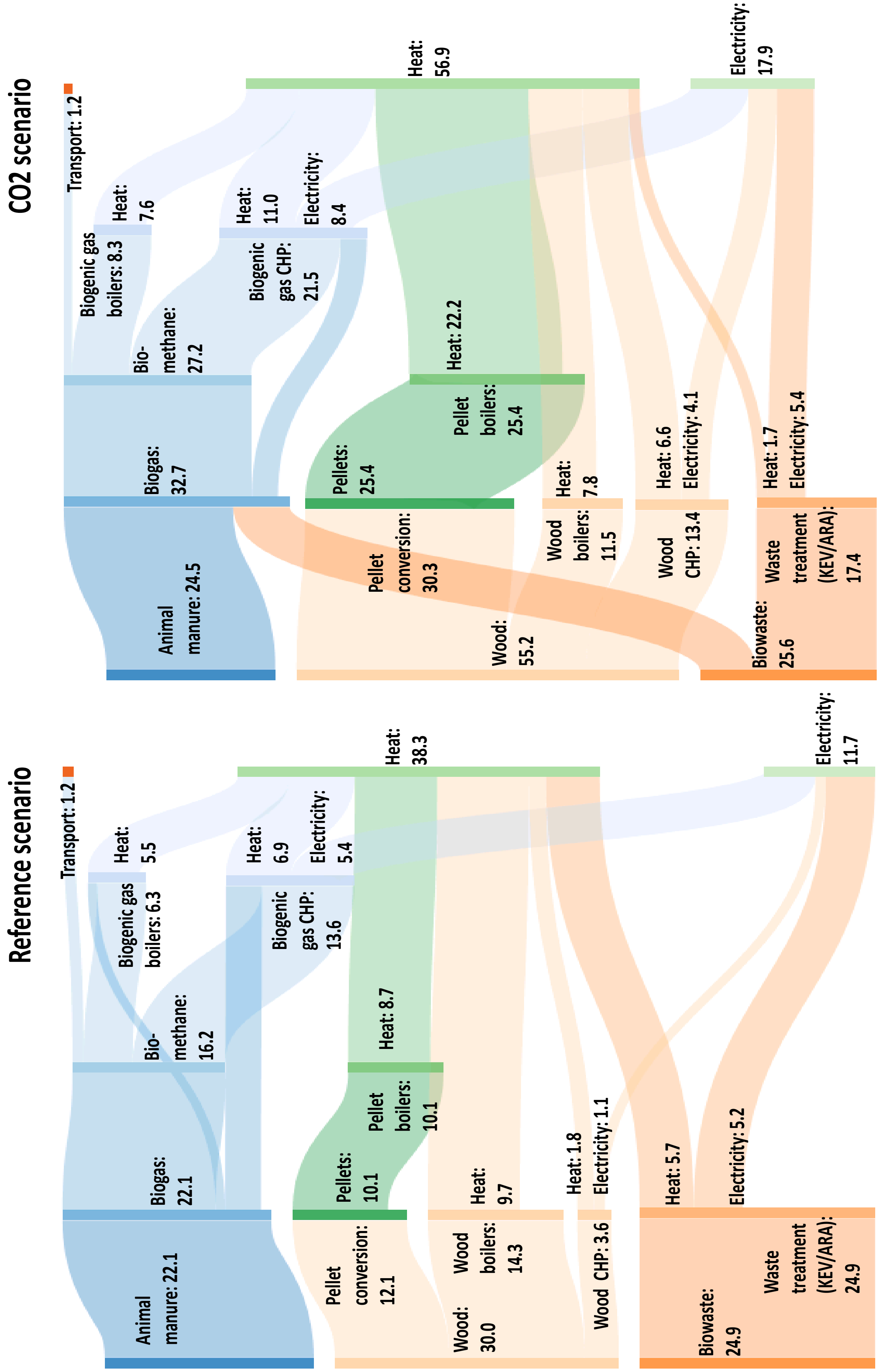


Figure 102: Biogas production and use pathways in “Reference” and “CO2” scenarios in PJ, 2050 (note: values on the left of the vertical bars denote input, values on the right of the vertical bars denote output).

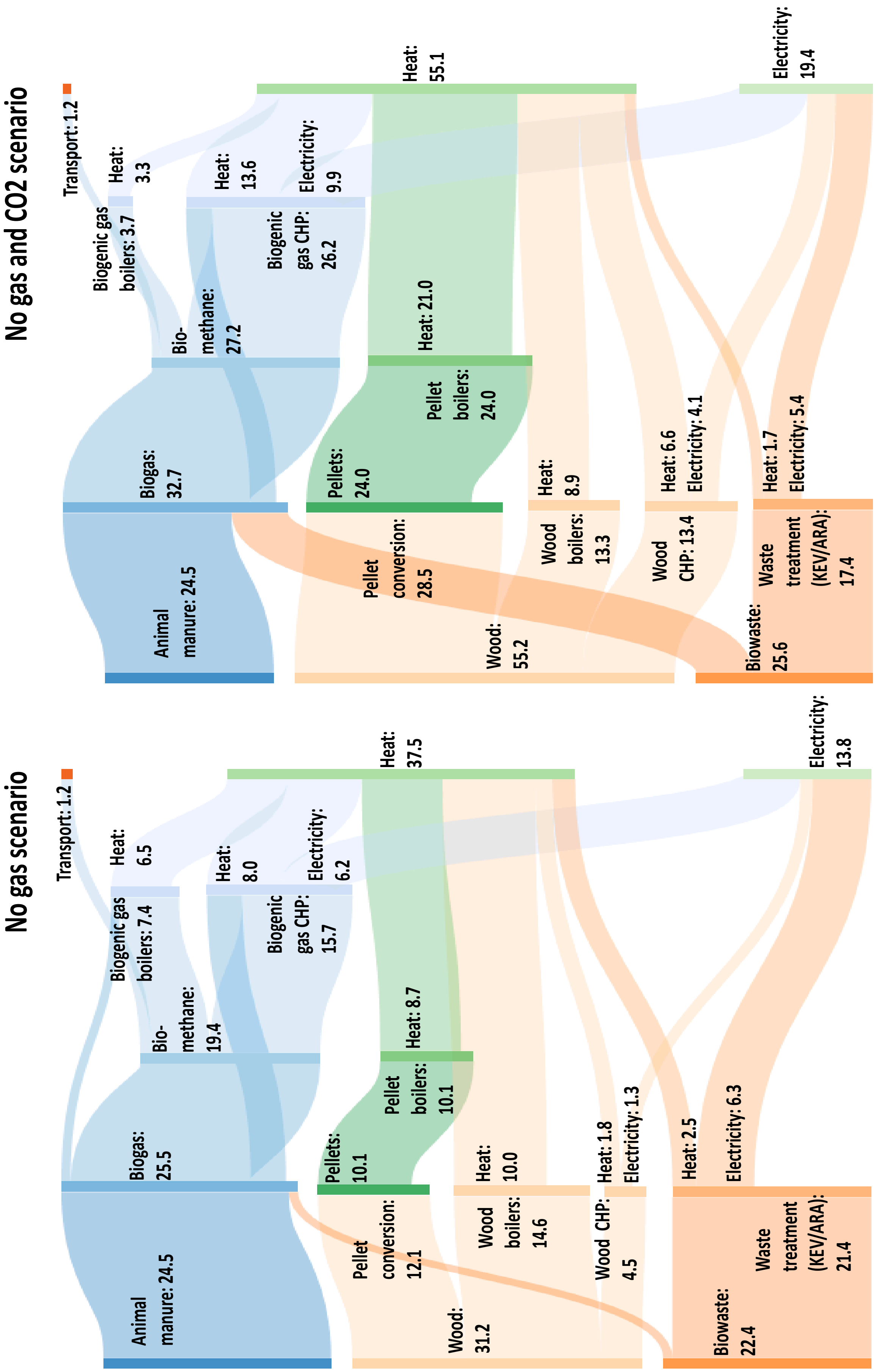


Figure 103: Biogas production and use pathways in "No Gas" and "No gas and CO2" scenarios in PJ, 2050 (note: values on the left of the vertical bars denote input, values on the right of the vertical bars denote output).

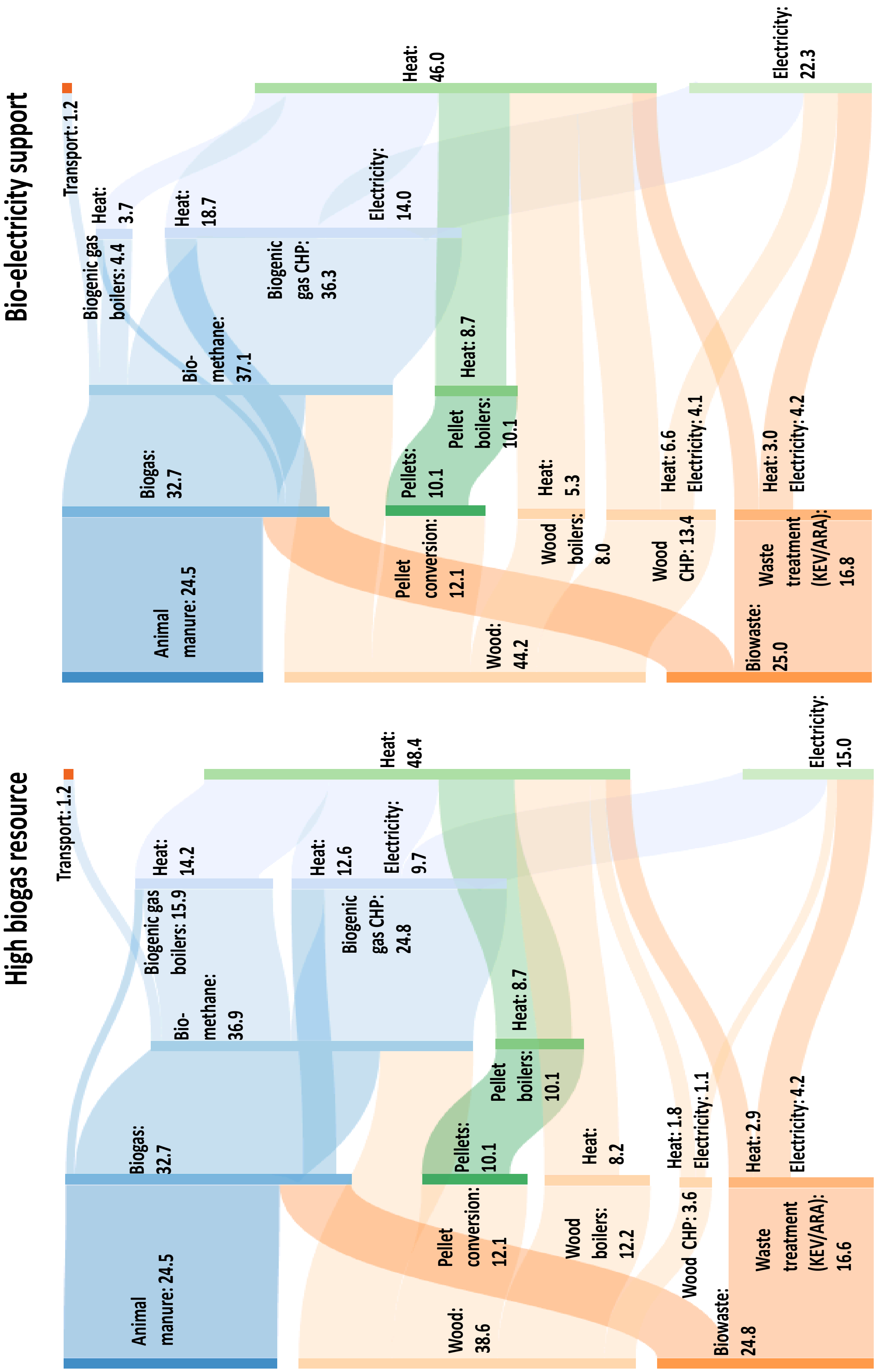


Figure 104: Biogas production and use pathways in “High biogas resource” and “Bio-electricity support” variants in PJ, 2050 (note: values on the left of the vertical bars denote input, values on the right of the vertical bars denote output).

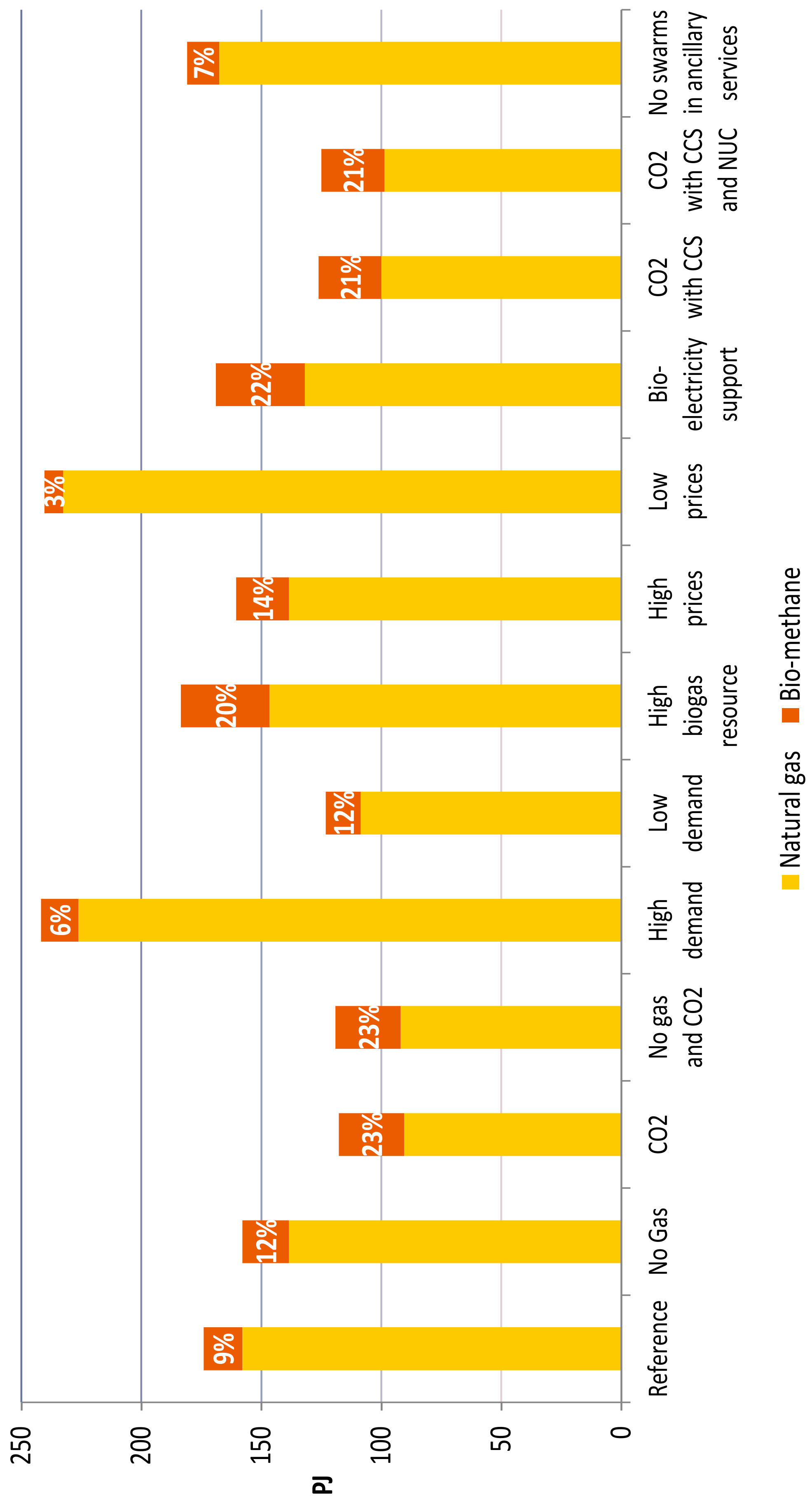


Figure 105: Bio-methane and natural gas consumption from the natural gas grid network (in PJ and as % of total), 2050.

14.7. EEG group conclusions

The aim of the analysis was to assess the long term role of biogenic gas CHP plants, which are defined to be fuelled with biogas or bio-methane from natural gas grid, in the Swiss electricity and heat supply from a national prospective. For the analysis, we developed and applied the Swiss TIMES Electricity and Heat Model (STEM-HE), which is a technology rich, cost optimization model, suitable for capturing the multi-dimensional role of CHP plants in electricity, heat and grid balancing markets.

A set of four core scenarios were assessed, which take into account two main policy decisions regarding the Swiss electricity system in the long term. Uncertainties surrounding the evolution of future electricity and heat demands as well as the development of future import oil and gas prices were addressed through parametric sensitivity analyses. Across all the core scenarios, biogenic gas CHPP can potentially supply about 1.5 – 2.8 TWh_e of electricity and 1.0 – 5.2 TWh_{th} of heat by 2050, which are about 2.1 – 3.8 % and 2.6 – 5.1 % of total electricity and heat supply respectively. Of the installed capacity of 376 – 933 MW_e of biogenic gas CHP plants in 2050, about 178 – 417 MW_e can provide grid balancing services by forming swarms, accounting for 22 – 44 % of the total secondary control reserve capacity in the long run.

The analysis identified key competing technologies to biogenic gas CHP plants in three markets, *viz.* electricity, heat and grid balancing services, and a set of synergies and barriers that can potentially drive their deployment:

- The **natural gas price** and its competitiveness with the biogas/bio-methane price is a main factor affecting the uptake of biogenic gas CHP plants. Biogas directly competes with natural gas in electricity and heat markets, and a high natural gas price induces investment in biogenic gas CHPP. Viewed another way, the **biogas production pathways** also determine the penetration of biogenic gas CHPP. To this extent, biogas is primarily produced from animal manure using anaerobic digestion, since there are no other competing energy uses for manure. The second most cost effective source is biogas from bio-waste. The injection of synthetic gas from wood gasification into the natural gas grid is a third option, which is cost-effective when demand for biogas is high enough to recover infrastructure costs (gasification plant(s) and pipelines).
- The **limited domestic biomass resource** is also a determinant factor for the uptake of biogenic gas CHPP, because other biomass-based electricity and heat generation options (e.g. wood-fired CHPP, wood-fired boilers and pellets) compete for it.
- The **stringency of climate policy**, which creates a market for low carbon heat and electricity, also enables investments in biogenic gas CHPP. Although such a policy increases competition for accessing the limited domestic biomass resource from other options as well, e.g. wood-fired boilers and CHPP, it turns out that biogenic gas CHPP constitute an efficient pathway for stationary applications of biomass.
- Due to the ability of biogenic gas CHP plants to provide grid balancing services, the **demand for grid balancing services** is also a key driver affecting their future uptake. If they cannot provide such grid balancing services, then their installed capacity is reduced nearly by half compared to the opposite case.
- Growth in **future electricity and heat demands** is another determinant factor that can influence the prospects of biogenic gas CHPP. In the case of high demands, the installed capacity of biogenic gas CHPP is also high because of: a) the increased size of the electricity and heat markets that enables investments in new technologies; and b) the higher demand for grid balancing services both due to increased electricity loads and intermittent renewable electricity supply. On the other hand, when demands are low, the role of biogenic gas CHP plants declines because: a) heat and electricity markets are smaller in size and their demands can be relatively easily met with conventional technologies (given the generally slow capital stock turnover in the end use sectors); and b) the demand for balancing services is also low.
- Key competing technologies in the **electricity market** are the **centralised power plants and the gas CHPP**. In the absence of centralised large scale power plants,

the penetration of biogenic CHPP can increase because they now compete with conventional decentralised CHPP. The uptake of **intermittent renewables** in the electricity sector (and especially solar PV systems) increases the competition in electricity supply, but at the same time it also increases the demand for grid balancing services. However, in case that biogenic gas CHPP are restricted from providing balancing services, then the intermittent renewables constitute direct competitors to them in the electricity market.

- In the **heat market** direct competitors are the **natural gas fired CHP plants**, as it is the case in the electricity market. **Heat pumps** can constitute both competitors and complementary technologies to biogenic gas CHP plants. In the second case they can operate as electricity sinks for the electricity produced from CHPP. This is prominent in some sectors (e.g. industry), while in other sectors this synergy is weaker. Nevertheless, the combined application of heat pumps and CHPP can lead to substantial efficiency gains in overall electricity and heat supply, and therefore it needs further investigation in future analysis.
- Finally, in the **balancing market**, key competing technologies include hydropower and the **flexible gas turbines open cycle plants** and indirectly **batteries** and **demand side management measures** (that mitigate the need for control reserve capacity).

To summarise, the biogenic gas CHP plants cannot be seen as game changers in the three markets, partly due to the limited domestic biomass resource potential. Their role is mostly complementary to other options for electricity production (gas plants, renewables), heat supply (heat pumps) and balancing services (hydropower, flexible gas plants) depending on the boundary conditions. However, the transformation of the wet and woody biomass into bio-methane for use in biogenic gas CHP plants is proved to be an efficient pathway for converting biomass to electricity and heat.

14.8. EEG outlook

The model described in this report provides a framework for assessing the role of both centralised and decentralised options in the Swiss energy system. The energy system modelling advances made in the context of this project, *viz.* the biomass conversion pathways, the increased detail in electricity grid, the heat profiles in the different sectors and the modelling of the grid balancing services are going to be transferred to the STEM model (Swiss TIMES Energy Model) [70], which is the main model that is used for the assessment of long-term Swiss energy system transition pathways by the Energy Economics Group of the Laboratory for Energy Systems Analysis in PSI.

During the analysis of the electricity and heat supply scenarios for Switzerland a number of structural extensions and data refinements have been identified, which will help in overcoming the key limitations in the methodology described in section 14.2. These include:

- Increase of the spatial resolution of the modelling framework and introduction of elastic demands for electricity and heat supply. In fact the spatial extension of the model can better integrate insights from regional case studies, leading to richer insights and more in-depth analysis at sub-national levels.
- Improvement of the representation of electricity, heat and gas infrastructure in order to account for non-cost technical and environmental limitations in delivering energy to end-use consumers.
- Improvement of the dispatchability features of the framework, accounting for example for minimum online and offline operation times of the power plants, part-load efficiency and start-up and shut-down costs (currently only ramping and minimum stable operation constraints are considered in the model).
- Improved electricity and load profiles in end-sectors; improved data regarding the ability of power plants to provide balancing services and also improvement of the estimation of the currently used forecasted errors regarding the electricity demand and supply.

The performed analysis regarding the role and potential of biogenic CHP plants in the Swiss energy system, identified areas that require further investigation and further scenario analyses such as:

- Further investigation of the synergies between heat pumps and CHPP in all end-use sectors.
- Further investigation of the role of CHPP in deferring investments in both electricity and district heating networks, which raises also the question of the ownership of the decentralised assets.
- Additional scenarios that allow electricity imports and include also demand side management measures.
- Scenarios with imports of biomass.
- Analyses regarding the availability of capital and future costs of technologies.
- Analyses regarding the interaction with the transport sector (which currently has been excluded) and the additional competition from this sector arising from the use of bio-methane in vehicles.
- Analyses regarding the application of the model at cantonal scales, which among others will enable the assessment of different cantonal energy policies under the objectives of the Swiss Energy Strategy. To this end, by applying the methodology and databased developed by the four participating research groups in the context of this study, a new modelling tool can be constructed suitable for assessing regional energy policies.

15. EEG Appendices

15.1. Appendix I: Technical description of the STEM-HE model

The Swiss Times Electricity and Heat model (STEM-HE) is an extension of the Swiss Times Electricity Model (STEM-E) developed in PSI [63], which represents in detail the electricity and heat supply and demand in Switzerland. It is used to assess the impact of energy policies on the future configuration of the electricity and heat system in Switzerland. The model computes an intertemporal partial equilibrium across the electricity and heat markets under policy and technical constraints by minimising the total electricity and heat system cost. Equilibrium is established at every stage of the electricity and heat system: that is, for primary energy and secondary energy commodities and services. The model considers international interconnectors for electricity imports and exports between Switzerland and neighbouring countries, a range of technologies for electricity and heat supply, renewable resources potentials, electricity and heat storage options, and domestic biomass production and use pathways.

A key feature is the combination of long-term horizon with high intra-annual resolution. Its horizon is 2010 – 2100 with a time step of 10 years. Each modelling time period is divided into four seasons (winter, spring, summer and autumn), with three typical days in each season (working days, Saturdays and Sunday) and 24 hours in each day. This results to a total of 288 representative (typical) hours in each modelling period.

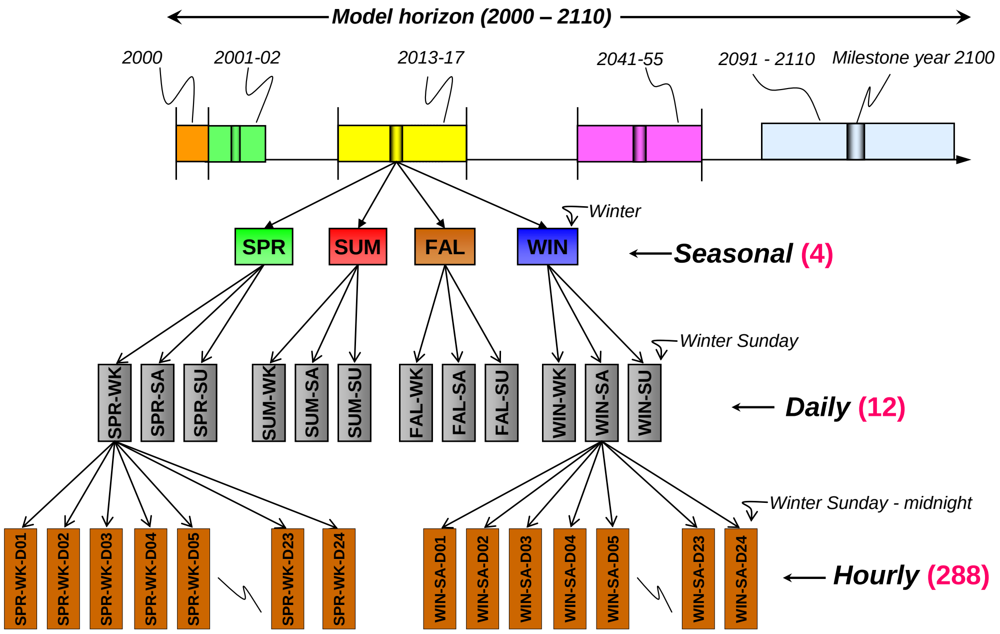


Figure 106: Time resolution in STEM-HE model [63].

The model has been tailored to capture the multi-dimensional role of the decentralised CHP units in the Swiss energy system. To this extent it includes a detailed representation of the electricity sector, in which it identifies four different grid levels from extra high voltage to low voltage. In each grid level a set of power plants can be potentially installed as shown in Figure 107.

STEM-HE does not include a spatial representation of the electricity grid. This implies that it accounts only for economic flows and not for physical electricity flows. In each grid level, there is a limit of the amount of electricity that can be transferred, which corresponds to an aggregated thermal capacity of the underlying transmission and distribution lines. The model accounts for losses in the transmission and distribution of electricity between the different grid levels, and considers also costs for the expansion of the grid. The technical-economic data for the different power plants and the grid expansion are given in Table 22, Table 23 and Table 25. Among the key technical-economic characteristics for describing a power plant are: construction time, overnight investment cost, decommissioning cost, fixed and variable

O&M costs, technical availability, efficiency for electricity and heat, heat-to-power ratios, minimum stable operation level, ramp up/down rates, etc.

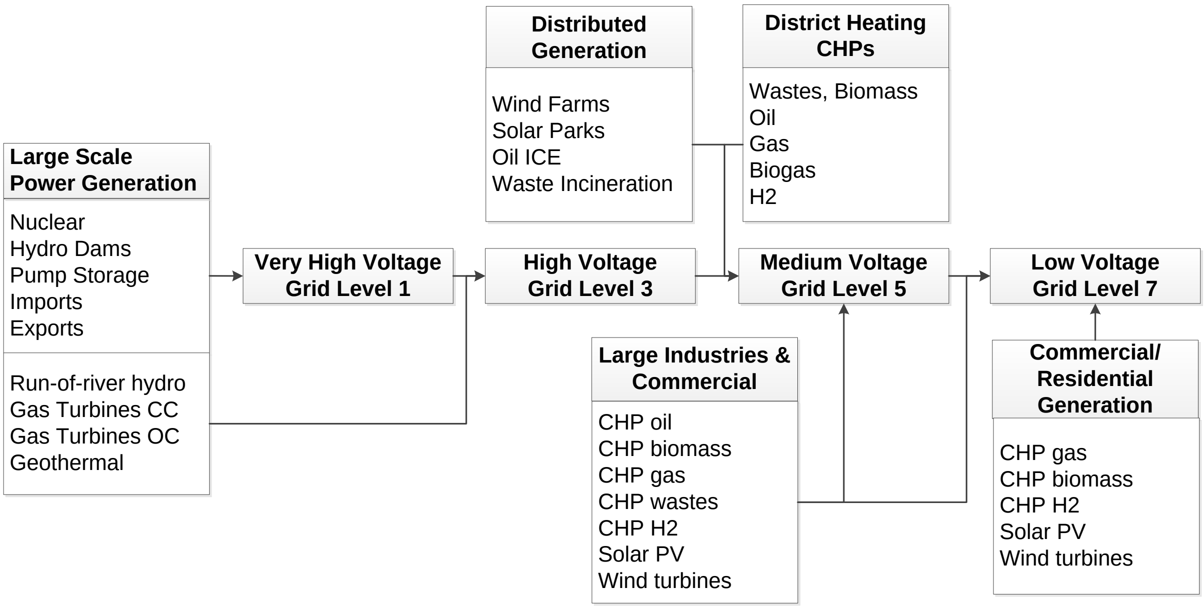


Figure 107: Overview of the electricity supply sector in STEM-HE.

The model includes also different options for biogas production, as well as bio-methane upgrade facilities and distribution infrastructure. The biogas can be produced from animal manure, bio-waste (which includes food waste, organic waste, industrial renewable waste and sewage sludge) and from wood through gasification. Then it can be either used on-site, or upgraded to bio-methane and injected into the natural gas grid. In the latter case it becomes available to boilers, CHP plants and large scale gas plants (Figure 108). The technical-economic data of the biogas production and distribution technologies are given in Table 24.

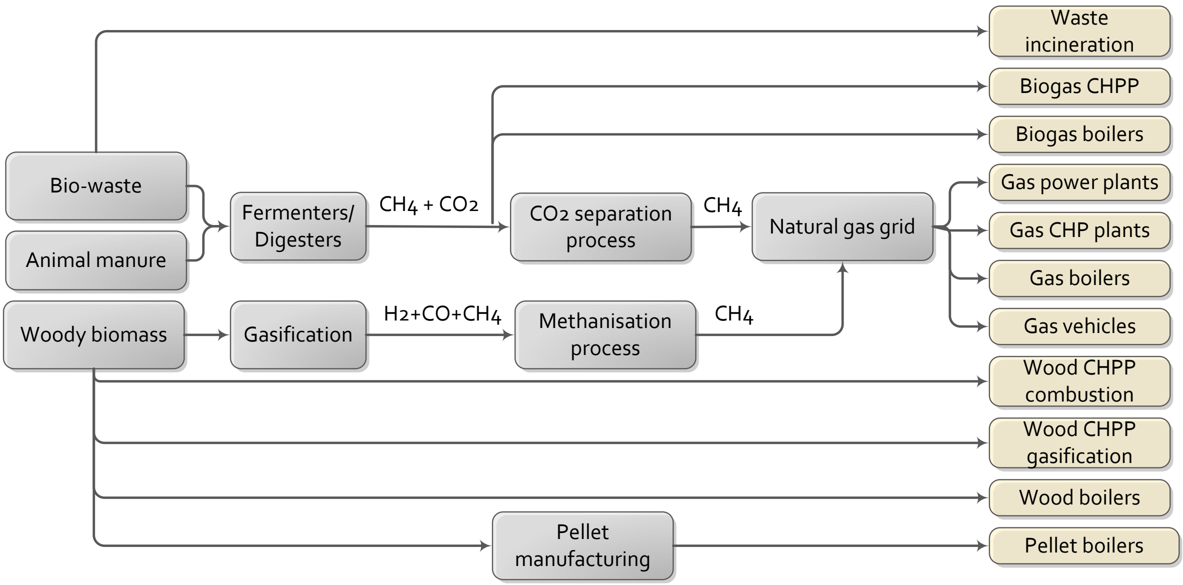


Figure 108: Biogas production and use pathways.

The end-use sectors represented in the model include industry, services and agriculture, and residential. The residential sector is modelled with higher detail than the other two, because of its large share in the final electricity and heat consumption. The electricity consumption in the end-use sectors is divided into substitutable electricity and non-substitutable electricity (i.e. electricity specific uses). The substitutable electricity consumption includes consumption in uses in which electricity can be replaced by other fuels (e.g. heating uses), whereas the non-substitutable electricity includes consumption in uses in which electricity cannot be replaced by other fuels (e.g. electrical appliances, lighting). For each sector the non-substitutable electricity is represented as a separate demand category. The heat demand in industry and services sectors includes as a single category the space heating, water heating and process heating uses. However, in the residential sector the space heating is delineated into space heating in existing single family buildings, in existing multi-family buildings, in new single family buildings and in new multi-family buildings. The water heating is represented as a separate category, aggregated for all types of houses. Each demand can be supplied by a number of technologies, including boilers, heat pumps, storage devices and CHP units (Figure 109).

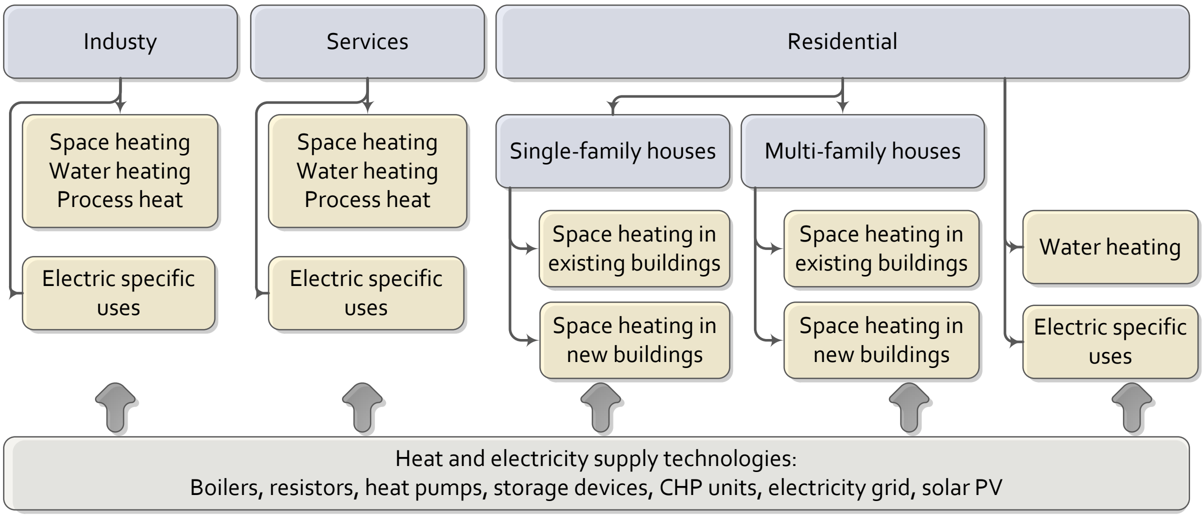


Figure 109: The end-use sectors represented in the STEM-HE model.

The model also includes power-to-gas pathways via the conversion of electricity into hydrogen, which then can be accommodated in the gas grid, utilised directly in industry and transport sector or converted into methane (Figure 110). The model includes representative technologies for electrolysis (alkaline systems until the mid-term, PEM systems afterwards), the hydrogen storage (only gaseous hydrogen is considered distributed via pipelines to urban areas and trucks in remote areas) and for hydrogen methanation.

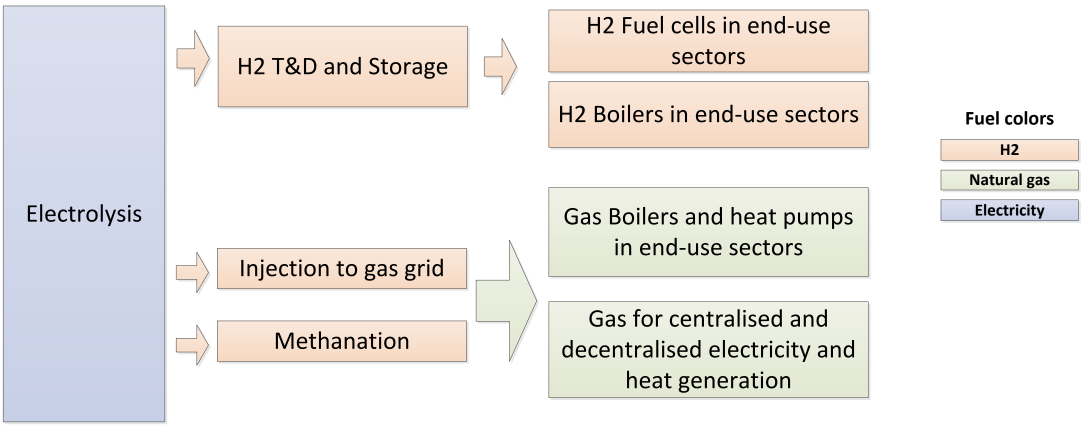


Figure 110: Power-to-gas pathways in STEM-HE model.

15.1.1. Heat and electricity demand load curves

The hourly heat demand profiles for space and process heat in the end-use sectors, are estimated on the basis of daily heat demand patterns derived from statistical analysis of gas consumption patterns for heating and consumer behaviour in Germany [71] , adapted by using the heating degree days and ambient temperatures of Switzerland. The residential hot water demand profiles were based on statistical estimation of consumer behaviour from surveys conducted mainly in Switzerland and Germany [72].

To ensure consistency over a longer historical period (2006-2010), the derived heating demand profiles were also implemented into a quadratic minimisation model. This optimisation model estimates adjusted demand profiles that minimise the deviation between the actual annual heat demand[23] and the calculated demand (by applying the derived profiles) over the 5 year period for each sector and type of use. However, larger weights were given to meet the annual demands of the calibration year (2010) and smaller weights for the distant past years.

The hourly electricity consumption profiles were obtained from Swissgrid [73], which publishes data in 15 minute intervals. The model distinguishes two main uses of electricity: specific uses, in which the electricity cannot be substituted by other fuels, and non-specific uses, in which substitution is possible. The first use considers electricity in lighting, motors, electric appliances, cooling etc. The second use considers electricity in supplying space heat, water heat and process heat demand. The national electricity consumption by use is obtained from [74].

We assume that the electricity load curve for non-specific uses follows the load curve of heat in each sector. Then the load curve for electricity specific uses is calculated as the residual between the national electricity load curve and the load curve of electricity used in heat. An illustration of the obtained heat profile by sector is given in Figure 111 for space, water and process heat by sector for a typical working day in winter. An illustration of the electricity profile for specific uses by sector for the same typical working day in winter is given in Figure 112.

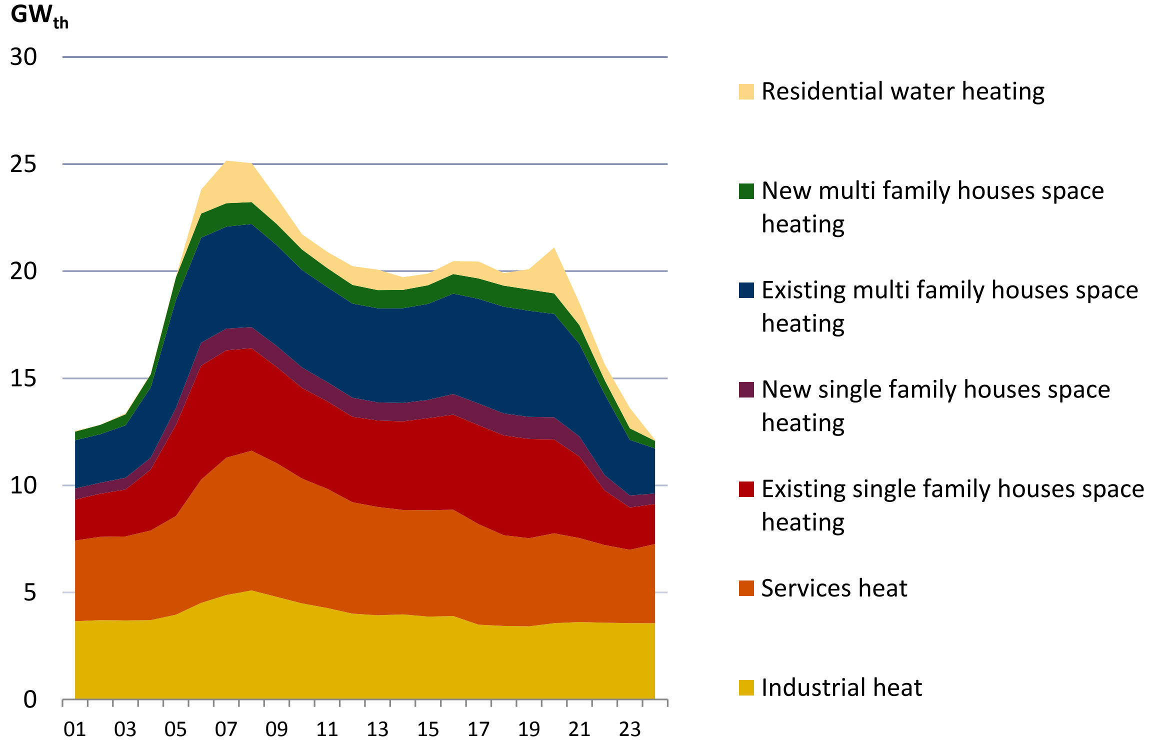


Figure 111: Load profiles for heat for a typical working day in winter, 2010.

[23] The statistics report the final energy consumption for heating uses and not the energy service demand that is the main input to STEM-HE. The STEM-HE coefficients of performance were applied to translate the fuel energy consumption to the energy service.

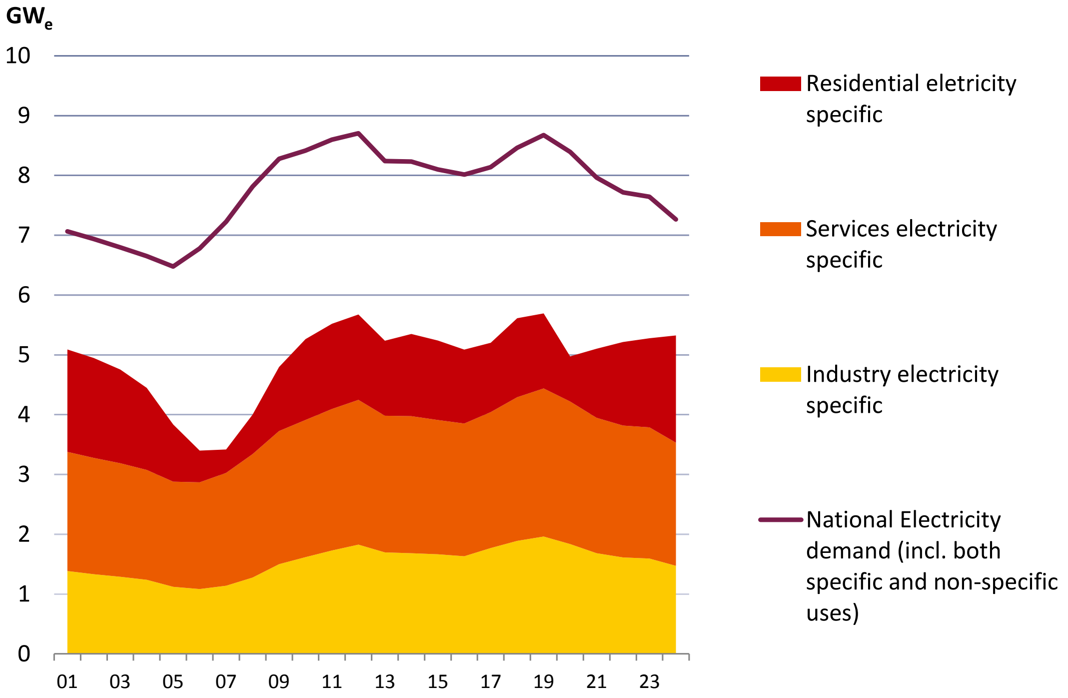


Figure 112: Electricity specific load curve for a typical working day in winter and the national electricity load curve (incl. both specific and non-specific uses) for the same day, 2010.

15.1.2. Electricity grid balancing services

Variable renewable energy sources such as wind and solar are often thought to increase the capacity reserve requirement significantly, due to deviates from forecasted generation that have to be balanced by the power system. Most commonly, three types of operating reserves can be distinguished [65]: a) primary reserve that provides grid stability services and it is locally automated reacting to deviations to the nominal system frequency within 30 seconds; b) secondary reserve that is automated centrally and serves to release the primary reserve for future operation by maintaining a balance between generation and demand within the balancing area from 1 to 15 minutes; and c) tertiary reserve that it is activated manually and only after secondary reserves have been used for a certain duration, with an activation time of up to 1h. Reserve services may be also provided by demand response measures facilitated through smart grids and load shedding, as well as batteries. Ancillary markets for the trading of reserve services may help to ensure that all options compete against each other to provide reserve at the lowest cost.

The provision of the primary and secondary reserve is modelled endogenously, by introducing new demands (or markets) in a similar way to the energy demands (or markets) included already in the model. In Figure 113 a power plant is logically divided into two parts: the part p participates into the electricity supply market, while the part pp participates in the ancillary services markets. A capacity transfer equation can be used to ensure that the total capacity of the power plant is determined by the maximum sum of the capacity p used for electricity production and the capacity pp participating into the ancillary services market(s).

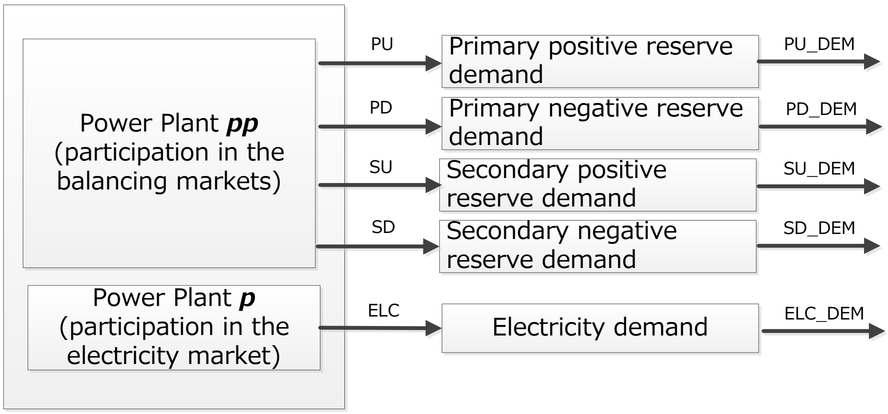


Figure 113: Introducing markets for ancillary services in the TIMES modelling framework.

The reserve requirements for short-term balancing can be derived by using the standard deviation of the distribution of the forecast error of the random variables that cause unpredictable variations of supply and demand, such as electricity load forecast errors, wind and solar electricity production forecast errors, forced plant outages, etc. By assuming statistical independence between these random variables, then the total standard deviation of their joint distribution is $\sigma = \sqrt{\sigma_D^2 \cdot D^2 + \sigma_S^2 \cdot S^2}$, where D is the demand, S is the supply from intermittent sources and σ_D, σ_S the standard deviations of the load and supply error distributions respectively (Figure 114).

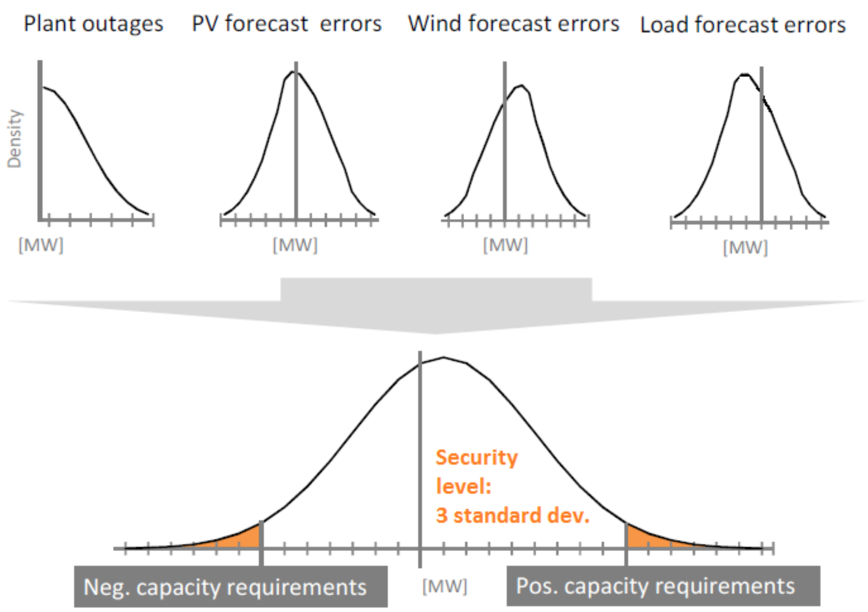


Figure 114: Probabilistic approach for ex-ante determination of requiring positive and negative control capacity [75].

Often we apply $\pm 3 \cdot \sigma$ in order to cover 99.7 % of all possible system states[24] [75]. Extensions to this formula include the loss of the largest unit (n-1), or more sophisticated probabilistic approaches [76]. The forecast errors of the different reserve types, primary, secondary and tertiary, are different due to the different time horizons considered for the activation of each reserve type. Based on historical data of the provision of ancillary services in the Swiss control area we use for primary control reserve as forecast errors for demand, wind and solar 0.25 %, 1.4 % and 0.4 % respectively. For secondary control power, we apply 1.31 % demand

[24] The formula for calculating the standard deviation, and hence the demand for control reserve, needs linearization if it is to be applied in linear programming modelling frameworks.

forecast error, 6.0 % wind electricity production forecast error and 5.9 % solar electricity production error.

The competitiveness of each power plant in both electricity and reserve markets is determined by investment and operating costs as well as ramping rates and minimum stable operation levels. In addition, maximum reserve capacity contribution of a technology to positive and negative primary and secondary reserve can be introduced to mimic real working operations. Based on [77] a technology can be classified into one of the following three categories with respect to the provision of primary and secondary reserve:

- The first category includes flexible units with high ramping rates, which can provide positive reserve up to their total available capacity. In addition there is no constraint for providing negative reserve since these technologies can ramp up and down fast enough. In this case no more capacity is required to be online other than what is needed for electricity generation.
- The second category includes non-flexible units that cannot be ramped down to zero output or back up to their operating level within the reserve timeframe. This means that these units have to operate above their minimum stable operation level and in between their operating range in order to provide reserve. The negative reserve is then limited by the difference between the current electricity generation level and the minimum stable operation, while the positive reserve is constrained by the ramping characteristics of the online capacity. Therefore, the online capacity should be enough to provide power output plus positive reserve services.
- Finally, the third category includes technologies that cannot provide fast enough primary reserve but are suitable for secondary reserve. This implies a combination of the above two categories: the provision of primary reserve requires electricity generation below the online capacity in order to be able to ramp-up if needed and it is constrained by the ramping characteristics of the online capacity, while the secondary reserve is independent of the online capacity and it is limited by the ramping characteristics of the total available capacity of the technology.

15.1.3. Limitations of the STEM-HE model

The STEM-HE model has some limitations, which should be kept in mind when interpreting its results. These include:

- Exogenously defined inelastic energy service demands: the electricity and heat energy service demands in the model are derived from the assumptions of a coherent storyline and given as an input to the model. This implies that there are inelastic with respect to the energy cost. This limitation reduces the model flexibility to cope with stringent climate change mitigation policies and hence it can lead to high shadow prices for CO_2 emissions.
- Lack of spatial representation: the electricity and heat infrastructure, including both supply and distribution technologies, are represented at an aggregated level. Thus, electricity grid related constraints (such as thermal limits of the lines, topology, line reactance and resistance) are not explicitly accounted in the model. Similarly, the topology of district heating and gas networks is not represented in the model. In addition, many heat supply options (such as heat pumps, gas boilers and CHPP) are site-dependent and their installation costs (and performance) can vary significantly between different locations, or it can be also the case that they cannot be installed at a specific location due to non-cost technical/environmental barriers. Finally, the availability of energy resources in the model also does not consider any topological limitations, and it is assumed that all the resources are available to all locations (subject to aggregated transportation costs where applicable). All the above imply, that both infrastructure costs and expansion rates reported in our analysis are subject to the limitation of the lack of spatial representation in the model.
- Lack of individual technology representation: the model does not include the concept of the individual plant or individual boiler. Rather it represents technologies in aggregated manner. For example 2 GW of GTCC can be either 2 units of 1 GW or 5

units of 400 MW and so on. This implies that the technical-economic characterisation of a technology uses “representative” or “typical” values for a given application. This limitation, however, could lead to underestimation of the technology costs and overestimation of the technology performance.

15.2. Appendix II: Scenario definitions and detailed assumptions

This section provides a more detailed description of the assumptions underlying the four core scenarios and the variants quantified by the Swiss TIMES Electricity and Heat model.

15.2.1. “*Reference*” scenario

The “*Reference*” serves as a benchmark upon which the other scenarios will be compared. It is based on the “*POlitische Massnahmen (POM)*” scenario of the Swiss Energy Strategy [61]. The “*Reference*” scenario” is not aiming at reproducing the results of the “*POM*” scenario, as the Prognos model and the STEM-HE model are different in their philosophy and some important assumptions are also different (e.g. international prices). In summary, the key assumptions of the “*Reference*” scenario are:

- Energy Service Demands for electricity and heat in line with the developments of the key macro-economic drivers in the “POM” scenario (GDP, population, floor area, conservation and efficiency measures, etc.) (Table 20).
- A social discount rate of 2.5 %; a specific discount rate of 2.5 % for energy supply and energy infrastructure technologies and 5.5 % for end use technologies.
- Global energy prices from the recently published OECD/IEA Energy Technology Perspectives “*4D-Scenario*” [64] (Table 19).
- CO_2 price same as the EU-ETS price assumed in the “*POM*” scenario; however, as the model is not currently distinguishing between emission trading and non-trading sectors this CO_2 price is applied to all sectors uniformly (Table 19).
- Electricity levy of 0.9 Rp/KWh for all end-use sectors; however, no recycling of the levy is included.
- Continuation of existing excise taxes on energy carriers in end uses (obtained by the IEA/OECD databases for energy prices and taxes [78]).
- Self-sufficiency in electricity production. This implies zero (or close to zero) net annual imports of electricity, in line with the historical trends; however, imports/exports of electricity can occur at different hours on a cost-effective basis
- Nuclear-phase out, which is to be completed by 2034.
- No CCS in electricity generation.
- Exclusion of coal from power generation and from the residential/commercial sectors.
- Large-scale centralised gas power plants available from 2025.
- Natural gas and biomass based centralised and distributed CHP generation available.
- Small expansion of exploitable hydro potential (Table 21).
- Geothermal energy available for electricity generation and space heating via heat pumps; geothermal cost-supply curves based on [79] (Table 19).
- Solar thermal collectors for space heating applications available.
- Options for electricity and heat storage, including pumped-hydro, power-to-gas, gas-to-power, batteries, night storage heaters, water heat storage and thermochemical heat storage.

Import prices in CHF per GJ excl. taxes	**2010**	**2020**	**2030**	**2040**	**2050**
Natural Gas	7.9	11.8	12.2	13.2	13.8
Light Fuel Oil	16.4	21.1	22.5	24.8	25.9

Carbon price (CHF per t CO_2)	**2010**	**2020**	**2030**	**2040**	**2050**
Applicable to all sectors	36.0	40.0	48.0	55.0	58.0

Resource cost: CHF/GJ	**2010**	**2020**	**2030**	**2040**	**2050**
Wet biomass	6.3	7.7	8.1	8.8	9.1
Industrial non.ren waste	3.1	3.4	3.5	3.6	3.6
Wood step 1 (current use)	14.4	16.9	17.7	18.9	19.5
Wood step 2 (50% of additional use)	15.8	18.3	19.1	20.3	20.9
Wood step 3 (50% of additional use)	19.2	21.6	22.4	23.6	24.2
Geothermal step 1 (about 3.2 PJ)	0.0	0.0	0.0	0.0	0.0
Geothermal step 2 (about 4.3 PJ)	3.5	3.5	3.5	3.5	3.5
Geothermal step 3 (about 21.2 PJ)	4.0	4.0	4.0	4.0	4.0
Electricity imports from Austria (average)	16.5	30.3	44.0	43.5	43.0
Electricity imports from France (average)	17.8	30.0	42.2	41.7	41.2
Electricity imports from Germany (average)	16.9	30.1	43.3	42.8	42.3
Electricity imports from Italy (average)	20.9	40.6	60.2	59.5	58.8
Electricity exports to Austria (average)	16.7	22.4	28.0	22.1	16.2
Electricity exports to France (average)	16.8	22.6	28.4	28.1	27.8
Electricity exports to Germany (average)	16.7	22.3	27.9	27.6	27.2
Electricity exports to Italy (average)	16.5	22.2	27.8	27.5	27.2

Table 19: Assumptions of the fuel and CO_2 prices in the "Reference" scenario (real CHF 2010).

In the above table the resource costs were obtained: for wet biomass from GIE in the context of CHPSwarm project, for wood from [80], for geothermal from [79], for electricity imports/exports from the CROSSTEM model of PSI energy economics group [81].

15.2.1.1. Energy Service Demands

Table 20 presents the evolution of the energy service demands for electricity and heat in the end-use sectors represented in the model. These demands are common to all scenarios assessed in the current analysis, unless if it is stated otherwise. The energy service demands are given exogenously to the model, based on macroeconomic and demographic developments, building renovation rates and policies regarding efficiency measures, codes and standards of the "*POM*" scenario of the Swiss Energy Strategy [61]. The main developments in energy service demands can be summarised as follows:

- In industrial sector, the energy service demands for electricity and heat declines by 0.5 % p.a. during the period 2010 – 2050, as a result of the efficiency measures in buildings and the implementation of waste heat recovery options.
- In services sector, the space and water heating energy service demand is reduced by 1 % p.a. because of increased renovation rates and the implementation of efficiency standards in buildings. On the other hand, the electric specific uses increase by 0.5 % p.a. driven by the increased use of electric appliances and lighting that arise from the increased economic activity of the sector.
- Finally, in the residential sector the space heating energy service demand in existing buildings decreases by around 3 % p.a. between 2010 and 2050, while the space heating demand in new buildings increases by around 2 % p.a. over the same period.

The above developments reduce the overall space heating demand in residential buildings by 1.2 % p.a. in the period 2010 - 2050. On the other hand, the demand for water heating increases by 0.19 % p.a. , reflecting the trade-off between population increase and efficiency, while the electricity in specific uses remains almost stable throughout the period because of saturation effects in appliances markets and efficiency gains in lighting.

	2010	2020	2030	2040	2050	% CAGR 2010-50
Industry electric specific	46.5	44.1	40.2	38.3	37.2	-0.6%
Industry space and water heating	30.9	28.5	24.5	22.5	20.4	-1.0%
Industry process heat	62.8	60.7	62.3	60.8	58.5	-0.2%
Services electric specific	62.5	62.2	65.7	70.3	77.0	0.5%
Services space and water heating	84.1	67.1	64.0	59.1	55.3	-1.0%
Residential electric specific uses	42.7	40.8	40.6	40.9	42.3	0.0%
Existing single family houses space heat	65.9	49.8	40.2	28.3	18.7	-3.1%
Existing multi family houses space heat	71.6	54.0	43.3	31.5	20.5	-3.1%
New single family houses space heat	14.6	24.1	27.5	30.1	32.3	2.0%
New multi family houses space heat	14.4	22.0	25.8	28.3	30.3	1.9%
Residential water heating	22.9	24.0	24.4	24.6	24.7	0.2%
Transport electric	11.4	14.4	20.2	27.2	31.5	2.6%

Table 20: Evolution of energy service demands per sector for electricity and heat common to all scenarios and variants in PJ.

15.2.1.2. Renewable Energy Potentials

The renewable energy potentials for electricity and heat production, for all scenarios are presented in Table 21. The renewable potentials for electricity generation are based on studies from BFE [62], from the scenarios of Swiss Energy Strategy [61] and from studies from PSI [82]. The animal manure potential is based on bottom-up analysis performed by ETH/GIE in the context of the current project. The wood potential is based on the existing uses of wood [83] augmented with the remaining forest wood, landscape wood and waste wood potential reported in [1].

	2012	2035	2050
Electricity (TWh):	**38.4**	**46.2**	**59.3**
Hydro dams	20.1	20.9	21.1
Hydro run of river	17.8	18.3	18.7
Wind	0.1	1.5	4.0
Solar	0.3	4.4	11.1
Geothermal	0.0	1.1	4.4
Biomass and wastes (PJ)	**100.1**	**139.3**	**142.6**
Wood	40.0	55.2	55.2
Wastes	56.3	59.6	62.9
Renewable waste (bio-waste)	23.0	24.4	25.7
Non-renewable waste	33.3	35.2	37.2
Animal manure	3.8	24.5	24.5

Table 21: Renewable technical potential for electricity production, biomass and wastes.

A similar approach is followed also for the renewable waste potential, which is based on the existing use [83] augmented with the remaining food waste, bio-waste and sewage sludge potential from [1]. Finally the non-renewable waste is estimated from the current uses [83], the historical trend of industrial waste generation and industrial output in Switzerland [84], and the projection of the industrial output in the Swiss Energy Strategy scenarios [61].

For the production of biogas we assume that all the animal manure potential can be used in anaerobic digestion. On the other hand, we follow a more conservative approach for the other pathways of biogas and synthetic gas production. Thus, only wet bio-waste (i.e. food waste, industrial bio-waste and sewage sludge) as it is reported in [1] can be fermented into biogas that then is upgraded to bio-methane and injected into the natural gas grid. Similarly, only the remaining potential of wood from [1] can be used in large scale gasification plants that produce syngas which then is also injected into the natural gas grid. Therefore, in total we assume that about 47.9 PJ of biomass can be converted to biogas/syngas that is then injected as bio-methane into the natural gas grid: 24.5 PJ of animal manure, 15.2 PJ of wood and 8.2 PJ of wet renewable waste.

15.2.1.3. Technical-economic characterisation of supply and demand technologies

The technical – economic characterisation of electricity and heat supply technologies, as well as biogas production technologies, are shown in Table 22 - Table 26.

These are based on a compilation from a number of sources, including: The STEM-HE model database [63] ; The JRC EU-TIMES model database [85] ; The IEA/ETSAP technology database [86] ; The IEA World Energy Outlook power generation technologies database [87] ; The EIA/DOE technico-economic database for the NEMS model [88]; Price lists for boilers, heat pumps, solar PV and CHP units from Viessman [89]; Data from ETH/LAV for CHP technologies provided in the context of the CHPSwarm project ; Technico-economic data for electricity and heat technologies from the Swiss Energy Strategy study [61] ; Technical-economic analysis of electricity and heat storage technologies in Switzerland [90] ; Technical-economic analysis for storage and power-to-gas pathways [91]; Data from companies specialised in biogas production and biomethane upgrade from [92] and [93] ; PSI studies regarding decentralised electricity and heat systems [94]; Technical-economic analysis of biogas production facilities in Switzerland [95] ; Analysis of energy production costs from anaerobic digestion systems in US [96] ; Kompogaz bio-waste fermentation facilities in Switzerland [97] ; METSO gasification projects described in [98] and in [99]; Technical-economic characterisation of GoBiGas biomass gasification project ([100] and [101]); Technical-economic analyses of wood pellet production ([102] and [103]) ; Electricity and network usage tariffs in Switzerland [67].

However, the cost of capital for different actors (municipalities, large industries, private consumers, etc.) is not known. We used discount rates in the model similar to the Swiss Energy Strategy study [61]: 2.5 % for investments in large scale electricity power plants and infrastructure; and 5.5 % for the investments in electricity and heat supply technologies in the end use sectors.

Biomass fired CHPs	**Investment cost CHF/kW$_e$**		**Fixed O&M cost CHF/kW$_e$**		**Variable O&M cost CHF/GJ**		**eff elc %**		**eff heat %**		**Lifetime yrs**
	2010	**2050**	**2010**	**2050**	**2010**	**2050**	**2010**	**2050**	**2010**	**2050**	
District heating CHP											
Gas/Biogas/Biomethane	900	800	0	0	1.1	1.1	23 %	31 %	54 %	51 %	20
Wood-fired	2500	1800	160	160	14.6	14.6	26 %	31 %	49 %	50 %	20
Waste incinerator	7700	7700	365	365	8.1	8.1	4 %	7 %	42 %	43 %	20
Industrial CHP											
Gas/Biogas/Bio-methane	1300	1200	0	0	2.9	2.9	34 %	44 %	44 %	47 %	15
Wood-fired	3500	2600	420	130	14.6	14.6	6 %	31 %	57 %	50 %	15
Services CHP											
Gas/Biogas/Bio-methane	2400	2400	0	0	8.3	8.3	35 %	36 %	51 %	53 %	15
Wood-fired	5000	3800	300	230	14.6	14.6	22 %	26 %	55 %	55 %	15
Residential CHP											
Gas/Biogas/Bio-methane	3300-5100	3300-5100	0	0	11.1-16.7	11.1-16.7	32-33 %	32-33 %	57-58 %	57-58 %	15
Wood-fired	6900-10700	6600-10200	350-490	350-490	16-29	16-29	15-17 %	18-20 %	65-66 %	64-66 %	15

Table 22: Technical-economic characterisation of CHP plants (real CHF of 2010).

	Investment cost CHF/kWe		Fixed O&M cost CHF/kWe		Variable O&M cost CHF/GJ		Efficiency for electricity		Lifetime
Electricity production technologies	**2010**	**2050**	**2010**	**2050**	**2010**	**2050**	**2010**	**2050**	
Gas turbine combined cycle	1200	1000	7.8	7.8	6.7	6.7	58%	65%	25
Gas turbine open cycle	800	700	5.1	5.1	6.7	6.7	38%	43%	25
Gas with CCS	2000	1700	15.6	15.6	13.4	13.4	56%	61%	25
Geothermal	13800	6700	133.5	110.3	12.4	29.0	-	-	30
Wind turbines	2200	2000	43.8	33.8	13.9	13.9	-	-	20
Solar PV (different sizes)	2300 - 6500	1400 - 2000	4 - 5	4 - 5	1.0	1.0	-	-	20

Table 23: Technical-economic characterisation of electricity production technologies (real CHF of 2010).

	INVCOST		FIXOM		VAROM		Efficiency		
	CHF/kW$_{th}$		CHF/kW$_{th}$		CHF/GJ		%		Lifetime
	2020	2050	2010	2050	2010	2050	2010	2050	
Animal manure digester	900	900	13.0	13.0	1.0	1.0	100%	100%	20
Bio-waste fermenter	1200	1200	15.0	15.0	1.0	1.0	100%	100%	20
Biogas upgrade facility	2300	2300	40.0	40.0	2.2	2.2	91%	95%	20
Wood gasification facility (gasifier+methanisation)	3500	3500	40.0	40.0	3.7	3.7	55%	71%	20
Pellet manufacturing	1000	1000	50	50	0.5	0.5	80%	84%	20

Table 24: Technical-economic characterisation of biogas, syngas and pellet production plants (real CHF of 2010).

	Investment cost CHF/kWe		Fixed O&M cost CHF/kWe		Variable O&M cost CHF/GJ		Efficiency for electricity		Lifetime
Electricity transmission and distrib.	**2010**	**2050**	**2010**	**2050**	**2010**	**2050**	**2010**	**2050**	
Extra high voltage (220/380 kV)	800	800	38	38	4.1	4.1	100%	100%	60
High voltage (50/150 kV)	1400	1400	66	66	5.5	4.1	97%	97%	60
Medium voltage (10/35 kV)	1500	1500	73	73	5.5	4.1	96%	96%	60
Low voltage (230/400 kV)	2600	2600	163	163	5.5	4.1	100%	100%	60
Gas and heat networks									
Natural gas pipelines	2500 - 4700	2500 - 4700	60 - 120	60 - 120	1-2	1-2	99%	99%	60
District heating pipelines	4000 - 5000	4000 - 5000	70 - 130	70 - 130	1-3	1-3	91%	92%	60

Table 25: Technical-economic characterisation of gas, district heating and electricity network (real CHF of 2010).

	Investment cost CHF/kWth		Fixed O&M cost CHF/kWth		Efficiency for heat		Lifetime
Industrial heat supply technologies	**2010**	**2050**	**2010**	**2050**	**2010**	**2050**	
Oil boilers	33	33	0.3	0.3	77%	80%	15
Gas/biogas/bio-methane boilers	44	44	0.4	0.4	80%	82%	15
Heat pumps (reference values)	363	363	3.1	3.1	296%	345%	15
Electric boilers	30	30	0.3	0.3	84%	85%	15
Solar thermal	2750	2750	0.2	0.2	-	-	15
Pellet boilers	75	75	0.6	0.6	74%	75%	15
Wood boilers	73	73	0.6	0.6	59%	60%	15
Coal boilers	58	58	0.5	0.5	66%	68%	15
Wastes boilers	58	58	0.5	0.5	66%	68%	15
Heavy fuel oil	30	30	0.3	0.3	66%	72%	15
Services heat supply technologies							
Oil boilers	109	109	0.6	0.6	83%	86%	15
Gas/biogas/bio-methane boilers	140	140	0.8	0.8	87%	95%	15
Heat pumps (reference values)	630	630	0.7	0.7	305%	420%	15
Electric boilers	60	60	0.4	0.4	90%	95%	15
Solar thermal	2750	2750	0.2	0.2	-	-	15
Pellet boilers	230	230	1.4	1.4	90%	90%	15
Wood boilers	170	170	0.9	0.9	72%	72%	15
Residential heat supply technologies							
Oil boilers	410 - 1350	410 - 1350	0.5 - 1.6	0.5 - 1.6	83%	86%	15
Gas/biogas/bio-methane boilers	430 - 1460	430 - 1460	1.5 - 1.7	1.5 - 1.7	87%	95%	15
Heat pumps (reference values)	1360 - 3140	1360 - 3140	1.4 - 1.5	1.4 - 1.5	305%	420%	15
Electric boilers	190 - 640	190 - 640	0.6 - 0.7	0.6 - 0.7	90%	95%	15
Solar thermal	3760 - 4370	3760 - 4370	0.3 - 0.4	0.3 - 0.4	-	-	15
Pellet boilers	630 - 2360	630 - 2360	1.9 - 7.1	1.9 - 7.1	90%	90%	15
Wood boilers	500 - 1610	500 - 1610	0.6 - 1.9	0.6 - 1.9	72%	72%	15

Table 26: Technical-economic characterisation of heat supply technologies in end-use sectors (real CHF of 2010).

15.2.1.4. Feed-in tariffs for renewable generation

The feed-in tariffs and subsidies for electricity production are presented in Table 12 and they are based on the most recent legislation “*Energieverordnung 730.01*” [104]. Table 27 presents the feed-in tariffs used in the model, which are based on the following assumptions:

- Solar PV: for single family houses we assume a reference system of 7 kW and that the investor choses the investment support scheme; for multi-family houses we assume a reference system between 10 kW and 30 kW and that the investor choses the feed-in tariff scheme; in services we apply the feed-in tariff that corresponds to capacities in the range of 30 – 100 kW; finally for industry and large solar PV parks we apply the feed-in tariff that corresponds to systems in the range of 100 – 1000 kW.
- Small hydro: we use the feed-in tariff that applies to units of less than 10 MW.
- For biomass (wood and manure): we take the average feed-in tariff that applies to sizes from less than 50 kW to more than 5 MW.
- For wastes: we consider the feed-in tariff only for the renewable part and we distinguish according to the heat efficiency (CHP and non-CHP waste incinerators).
- For wind: we apply directly the feed-in tariff for wind turbines as it is in the legislation
- For geothermal: we apply the average feed-in tariff for geothermal power plants of sizes in the range of less than 5 MW to more than 20 MW.

We assume a gradual phase out of the supporting schemes until 2030.

Technology	Applies as	Unit	2015
Solar PV in single family houses	One time in investment	CHF/Kw	806
Solar PV in multi family houses	Feed in tariff	Rp./kWh	19.0
Solar PV in services	Feed in tariff	Rp./kWh	16.4
Solar PV in industry	Feed in tariff	Rp./kWh	16.3
Solar parks	Feed in tariff	Rp./kWh	16.3
Wind turbines	Feed in tariff	Rp./kWh	20.0
Small hydro	Feed in tariff	Rp./kWh	6.4
Geothermal	Feed in tariff	Rp./kWh	29.4
Wood for electricity production	Feed in tariff	Rp./kWh	25.9
Biogas for electricity production	Feed in tariff	Rp./kWh	30.2
Renewable waste for electricity only	Feed in tariff	Rp./kWh	10.6
Renewable waste for CHP	Feed in tariff	Rp./kWh	13.2

Table 27: Feed-in tariffs and subsidies for electricity production (real CHF of 2010).

15.2.2. "*No Gas*" scenario

The scenario performs a "what-if" analysis in the case that no large scale centralised gas power plants are allowed. It can be considered as a scenario potentially favouring decentralised generation. The main assumptions of this scenario are:

- All the assumptions of the "*Reference*" scenario, plus
- No large-scale natural gas electricity generation.

15.2.3. "*CO2*" scenario

The scenario focuses on a stringent climate policy action to target 1-1.5 t-CO_2 per capita by 2050 and evaluates the response of the energy system under high CO_2 emission prices. The assumptions of the scenario include:

- All the assumptions from the "*Reference*" scenario, plus
- A reduction in the CO_2 emissions from the electricity supply sector, the heat supply sector (CHPs and district heating) and the industrial, services and residential sectors by 70 % in 2050 compared to 2010 levels (Table 28).

This cap is compatible with the INDC commitments submitted by Switzerland to UNFCCC on 27th February 2015 [105] and with the "C&E" variant of the "*NEP*" scenario of the Swiss Energy Strategy [61].

	2020	2030	2040	2050
Electricity and heat sectors	-20 %	-35 %	-48 %	-70 %

Table 28: CO_2 emissions reduction trajectory assumed in the "CO2" scenario from 2010 levels.

15.2.4. "*No gas and CO2*" scenario

This scenario is the combination of "*No Gas*" and "*CO2*" scenarios. Therefore it includes the union of the assumptions considered in both scenarios.

15.2.5. "*High prices*" variant

This is a "variant" of the "*Reference*" scenario, which assesses the response of the electricity and heat sectors to higher oil and gas prices. The main assumptions of this scenario are:

- All the assumptions of the "*Reference* Scenario", plus

- High international oil and gas import prices (Table 29).

The prices trajectories of this scenario have been obtained from the International Energy Agency Energy Technology Perspectives "*6D Scenario*" [64].

"***High prices***" **variant**	**2010**	**2020**	**2030**	**2040**	**2050**
Natural Gas	7.9	12.3	14.0	14.8	15.9
Light Fuel Oil	16.4	22.4	25.3	28.3	30.3

Table 29: Import prices in real CHF 2010 per GJ, without taxes, in the "High prices" variant.

15.2.6. "*Low prices*" variant

This is a "variant" of the "*Reference*" scenario, which assesses the response of the electricity and heat sectors to lower oil and gas prices. The main assumptions of this scenario are:

- All the assumptions of the "*Reference*" scenario, plus
- Low international oil and gas import prices (Table 30).

The prices trajectories of this scenario have been obtained from the International Energy Agency Energy Technology Perspectives "*2D Scenario*" [64].

"***Low prices***" **variant**	**2010**	**2020**	**2030**	**2040**	**2050**
Natural Gas	7.9	11.3	9.9	8.9	8.5
Light Fuel Oil	16.4	20.5	19.4	18.1	17.1

Table 30: Import prices in real CHF 2010 per GJ, without taxes, in the "Low prices" variant.

15.2.7. "*High demand*" variant

This is a "variant" of the "*Reference*" scenario, which assesses the Swiss electricity and heat supply and demand fuel mixes and costs when the energy service demands are higher than the ones assumed in the "*Reference*" scenario. The main assumptions of this scenario are:

- All the assumptions of the "*Reference*" scenario, plus
- Energy service demands compatible with the "*Weiter wie bisher - WWB*" scenario of the Swiss Energy Strategy [61].

	2010	**2020**	**2030**	**2040**	**2050**	**% CAGR 2010-50**
Industry electric specific	46.5	48.0	47.3	47.1	47.0	0.0%
Industry space and water heating	30.9	28.6	24.6	22.6	20.4	-1.0%
Industry process heat	62.8	62.4	65.6	65.1	63.6	0.0%
Services electric specific	62.5	66.2	73.5	80.5	89.0	0.9%
Services space and water heating	84.1	67.6	67.0	65.7	64.4	-0.7%
Residential electric specific uses	42.7	41.1	42.3	43.8	46.3	0.2%
Existing single family houses space heat	65.9	59.1	51.4	41.3	33.2	-1.7%
Existing multi-family houses space heat	71.6	63.6	54.7	45.3	35.9	-1.7%
New single family houses space heat	14.6	27.2	35.3	42.5	49.3	3.1%
New multi-family houses space heat	14.4	28.0	35.2	41.5	47.6	3.0%
Residential water heating	22.9	24.1	24.6	24.8	24.6	0.2%
Transport electric	11.4	13.8	17.1	21.1	23.7	1.8%

Table 31: Energy service demands in the "High demand" variant in PJ.

15.2.8. "*Low demand*" variant

This is a “variant” of the “*Reference*” scenario, which assesses the Swiss electricity and heat supply and demand fuel mixes and costs when the energy service demands are lower than the ones assumed in the “*Reference*” scenario. The main assumptions of this scenario are:

- All the assumptions of the “*Reference*” scenario, plus
- Energy service demands compatible with the “*Neue Energiepolitik- NEP*” scenario of the Swiss Energy Strategy [61].
-

	2010	2020	2030	2040	2050	% CAGR 2010-50
Industry electric specific	46.5	46.2	39.5	34.2	36.6	-0.6%
Industry space and water heating	30.9	26.4	21.3	18.6	16.2	-1.6%
Industry process heat	62.8	56.7	54.2	50.4	46.9	-0.7%
Services electric specific	62.5	58.3	56.7	54.6	53.5	-0.4%
Services space and water heating	84.1	65.8	60.9	55.4	51.1	-1.2%
Residential electric specific uses	42.7	40.2	39.1	38.7	39.4	-0.2%
Existing single family houses space heat	65.9	57.1	42.1	26.5	16.3	-3.4%
Existing multi-family houses space heat	71.6	60.6	43.4	27.4	16.1	-3.7%
New single family houses space heat	14.6	25.6	26.1	24.7	22.8	1.1%
New multi-family houses space heat	14.4	26.4	26.9	25.5	23.5	1.2%
Residential water heating	22.9	24.0	24.6	24.2	23.9	0.1%
Transport electric	11.4	16.5	24.6	34.6	41.0	3.3%

Table 32: Energy service demands in the “Low demand” variant in PJ.

15.2.9. “*Bio-electricity support*” variant

This is a “variant” of the “*Reference*” scenario, in which it is assumed that there is a continuation of the current policies for producing electricity from biogas, syngas and bio-methane. The main assumptions of this variant are:

- All the assumptions of the “*Reference*” scenario, plus
- Feed-in tariff for biogas and wood based electricity generation until 2050, which is set at the levels of 2015.

15.2.10. “*High biogas resource*” variant

This is a “variant” of the “*Reference*” scenario, in which it is assumed that all the technical potential for biogas production in Switzerland is exploited by 2050. This variant aims at assessing the role of the resource (biogas) in the penetration of biogenic CHP plants. The main assumptions of this variant are:

- All the assumptions of the “*Reference*” scenario, plus
- Exploitation (forced) of all technical potential in Switzerland for biogas production by 2050.

15.2.11. “*CO2 with CCS*” variant

This is a “variant” of the “*CO2*” scenario in which it is assumed that CO_2 capture and sequestration is commercially available and socially acceptable for the gas turbines combined cycle power plants in the electricity sector. The main assumptions of this scenario are:

- All the assumptions of the “*CO2*” scenario, plus
- CCS is assumed to be available after 2030 for gas turbines combined cycle plant, but not coal power plants with CCS are allowed.

15.2.12. "*CO2 with CCS and NUC*" variant

This is a "variant" of the "*CO2 with CCS*" scenario in which it is assumed that the current nuclear power plants get a 10-year extension in their operational lifetime. Therefore, the last nuclear power station (Leibstadt) is decommissioned by 2044. The assumptions of this scenario are:

- All the assumptions of the "*CO2 with CCS*" scenario, plus
- 10-year extension in the lifetime of current nuclear power stations, but no new nuclear power stations are allowed to be built.

15.2.13. "*No swarms in ancillary services*" variant

This is a "variant" of the "*Reference*" scenario, in which there is no participation of biogenic CHP swarms in grid ancillary services. The objective of this variant is to assess the effect of the possibility of biogenic CHP plants to form swarms and participate in control reserve capacity on their uptake. Put another way, this variant assesses their competitiveness only in the electricity and heat supply markets.

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