Sector Coupling

SGEN Project

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Executive summary

This study aimed at making a step in quantitatively analysing the future energy system as a whole, i.e. considering all demand sectors and all potential energy carriers. Objective of the performed analysis has been to identify the potential individual role of each of the various energy carriers, as well as the way that they might complement each other towards an economic and efficient CO2-free energy system.

The problem has been addressed by formulating and solving an optimisation problem which explicitly models each of the considered energy carriers and the various generation, storage, energy carrier conversion and demand technologies. The problem, which models an entire year in hourly resolution (i.e. it considers, in a sequential manner, 8760 time steps), is optimising the "operation" of the entire energy system, i.e. it dispatches for every hour all the dispatchable technologies (and curtails excess available generation), subject to the cross-country network constraints and the technology technical limits, with objective to satisfy the final demand for energy carriers (demand curtailment is possible, but it is avoided except if otherwise the problem is not feasible) at the minimum total cost.

The performed analysis concluded into the following findings:

1. Huge investments in electricity generation technologies are needed in order to maintain energy adequacy (measured annually) if a pathway is followed where fossil fuels are eliminated from the heating and transport sectors.
2. Even with extremely high wind and solar penetration levels, reliably satisfying the final demand requires the presence of very high levels of installed peak power generation capacity and/or very aggressive demand-side flexibility schemes
3. Energy storage has a high value in the future energy system, at all time-scales (from diurnal to seasonal). Hydrogen storage, in specific, is a great enabler for higher utilisation of wind and solar.
4. It is questionable whether satisfaction of the end demand by means of hydrogen (instead of electrifying) brings value from the overall energy system perspective.
5. Switzerland just relying on the rest-of-Europe acting as a buffer (via electricity imports and exports) entails risks, because the moments when Switzerland will have an energy supply deficit (due to no solar availability) highly correlate with when the rest of Europe faces the same challenge.

Contents

1 Introduction

1.1 Background and motivation

The energy strategy of Switzerland aims at progressively reducing CO2 emissions until reaching, in 2050, an energy system with zero net emissions. This requires the complete removal of oil products and natural gas from the Swiss energy mix. According to the Global Energy Statistic for Switzerland [1], these energy carriers covered 59% of the Swiss energy demand in 2020 (440'690 TJ / 122.4 TWh out of a total of 747'400 TJ / 207.6 TWh). In parallel, another target of the Swiss energy strategy is the progressive decommissioning of all nuclear power plants. In 2020, nuclear power plants produced 32.9 % of the total Swiss electricity generation (23 TWh out of a total of 70 TWh) [1]. In short, three major sources of energy in Switzerland today are to be removed from the energy mix. The resulting potential energy deficit is planned to be covered by solar power (plus relatively small amounts of wind, biomass and other renewable sources), by ambient heat sources (explored by means of heat pumps) and by reduction of the final demand for energy.

Clearly, decarbonisation calls for a paradigm shift from the (fossil) fuels that dominate today the heating and transport sectors. Both sectors are already being electrified and this trend is expected to continue at increasing speed, especially in the sectors of space (low temperature) heating and passenger and light-duty transport. However, first, it might be difficult to electrify process (high temperature) heating and long-distance / heavy-duty transport [2], while, second, a full (or very high) electrification of space heating and passenger and light-duty transport will result into a large increase in the total electricity demand (see, for instance, the Energy Perspectives 2050+ [3], as well as the remainder of this report). The available electricity supply might not be enough to meet the new electricity demand all-year-long on a continuous basis.

In this context, the future role of fuels, such as hydrogen or synthetic methane, which can be produced by consumption of electricity (a process often generically referred to as power-to-X, P2X, independent of which is the end fuel X), is a topic of high interest [4]. These fuels can (at least partially) replace natural gas and oil. For instance, according to [4], promising P2X options in the Swiss context are the use of hydrogen in fuel cell vehicles and the generation of synthetic methane replacing natural gas as heating and transport fuel. A potential practical advantage of including these fuels into the Swiss energy mix is that today's gas infrastructure can be used for their transport and storage[1].

Since the production of these fuels requires consumption of energy, in order for them to contribute to the net-zero CO2 targets this energy shall come from renewable primary sources. As a matter of fact, several suggested pathways propose that so-called "green" hydrogen or "green" synthetic methane shall make up a significant part of the future energy system, with their production happening at moments of excessive availability of wind and solar energy [6][2], [7, 8, 9]. In the remainder of this document, we will refer to such "green" hydrogen or synthetic methane as "renewable fuels".

Several studies [2, 6, 9, 10] have concluded that the integration of renewable fuels into the energy mix in a manner that simultaneously considers all energy vectors at the planning and operation stage ("sector coupling") will facilitate the stable and efficient integration of high shares of intermittent renewables (wind and solar), as sector coupling provides increased flexibility to cope with fluctuations (at various time-scales) of renewable energy supply.

[1] For hydrogen, modifications will be required, but their cost is claimed to be much lower than building new infrastructure [5].

[2] Statements from the executive summary: i. "A broad mix of energy carriers enables more cost-effective and robust transformation paths." ii. "Synthetic renewable energy carriers complement energy efficiency and the expansion of renewable energies."

As a matter of fact, based on the results of a study [9] performed by Navigant under the order of the Gas for Climate consortium [3], the latter expresses its full conviction that "coupling the sectors electricity, gas and heat - by linking their markets and their respective infrastructures in a better coordinated and integrated way - provides the greatest overall benefits for the European energy system" [9].

Clearly, electrification (full or partial) of demand sectors and domination of wind and solar (in Switzerland mostly the latter) in the energy supply mix are the two main pillars of the (planned / expected) future energy system. An important question which still remains open is the role of renewable fuels in the future; i.e. the extent of their penetration and the way that they shall be used. In this context, several studies, such as [7, 8], have outlined three potential pathways for the future evolution of the energy system. All three pathways assume that the energy supply sector will be dominated by intermittent renewables, while they differ from each other as follows.

1. A **full electrification pathway**, *where the various demand sectors become fully electrified and the supply-demand mismatch, at different time-scales, is bridged by means of dispatchable biomass or biogas power plants, demand flexibility and electrochemical storage (batteries).*

2. *A* **full electrification pathway with storage in intermediate energy carriers***, where, in addition to the solutions in pathway 1, energy is also stored in the form of renewable fuels. This allows for seasonal energy shifting and for generation dispatchability, as the renewable fuels are converted back to electricity by means of gas turbines or fuel cells.*

3. *A* **mixed pathway***, where part of the end demand is not electrified, but it is rather served by renewable fuels (e.g. fuel cell vehicles, or hydrogen boilers). Storage of renewable fuels and re-conversion of the latter to electricity may also be part of such a pathway.*

Obviously, in all three pathways, fossil fuels or nuclear power could also be part of the mix. This is expected to be the case, as we progressively move towards the energy system of 2050.

It is interesting to note that, while biogas and synthetic methane can directly utilise the existing gas transportation and storage infrastructure (mixed with natural gas or not), when it comes to hydrogen a planning of the transition to this fuel is required. Small quantities (up to 10-20% of the total mix) of hydrogen can be blended with methane gas in the existing infrastructure. However, as the hydrogen penetration in the energy mix increases, infrastructure will be required to be dedicated exclusively to hydrogen (as opposed to a hydrogen-methane blend) due to technical constraints. It is logical to expect that (part of) the existing natural gas infrastructure will be converted such that it can be utilised to transport and store hydrogen [5]. In fact, a European hydrogen transport backbone is already discussed and proposed, at least by the stakeholders of the European gas industry [11, 12]. Figure 1 illustrates a potential future backbone hydrogen transmission network as envisioned by those studies.

As a matter of fact, the European Commission set up in July 2020 the European Clean Hydrogen Alliance[4], in support of the EU Hydrogen Strategy[5], with the objective to stimulate the roll-out of clean hydrogen production and use in Europe. The members of the Alliance are currently or will be implementing a total of 750 hydrogen projects on a large scale from all parts of the value chain, including

- hydrogen production,
- transmission and distribution, and

[3] "Gas for Climate: a path to 2050" is a group of ten leading European gas transport companies (Enagás, Energinet, Fluxys, Gasunie, GRTgaz, ONTRAS, Open Grid Europe, Snam, Swedegas, and Teréga) and two renewable gas industry associations (Consorzio Italiano Biogas and European Biogas Association). See website: https://gasforclimate2050.eu/

[4] https://ec.europa.eu/growth/industry/strategy/industrial-alliances/european-clean-hydrogen-alliance_en

[5] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020DC0301

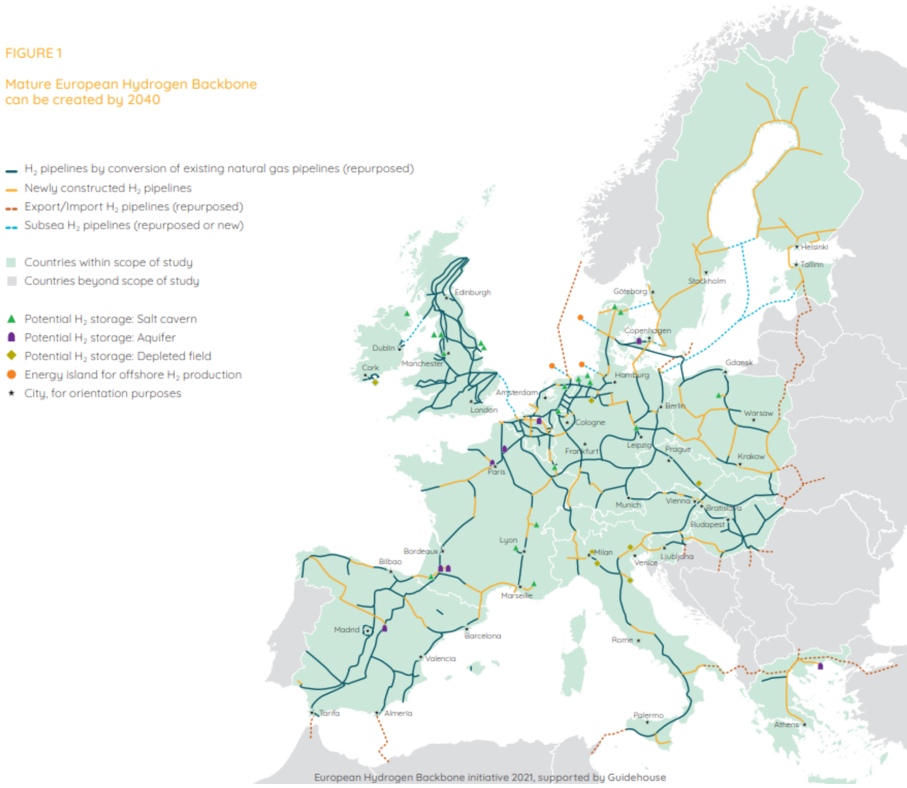


Figure 1: A potential future backbone hydrogen transmission network according to [12]

- application in industry, transport, energy systems and buildings.

Clearly, there is an increasing interest in understanding what is the potential of hydrogen in the future energy system, raising questions such as:

- In which parts of the value chain shall hydrogen be more prominent?
- What infrastructure investments and/or upgrades will be required and when shall they take place?

As acknowledged by the European Commission [13], "... driving hydrogen development past the tipping point needs critical mass in investment, an enabling regulatory framework, new lead markets, sustained research and innovation into breakthrough technologies and for bringing new solutions to the market, a large-scale infrastructure network...". Obviously, a strategy for Switzerland in this regard shall be harmonised with the developments in the rest of Europe.

Valuable as it is foreseen to be, development of hydrogen as an energy carrier has the following drawback compared to the development of electricity: Whilst electricity transmission and distribution networks exist already, immediately usable (and expandable whenever required) by new generation or demand, investments in hydrogen infrastructure face a "chicken and egg" problem, as hydrogen demand is dependent on the existence of a (today non-existent) hydrogen delivery network, while investments for building the latter face the risk of an expected demand eventually not appearing. This is explained by ETHZ Professor Anthony Patt in a recent post[6].

The above problem makes the need of a coordinated planning on the entire future energy infrastructure, considering all demand sectors and energy carriers, even more pronounced.

[6]https://ethz.ch/en/news-and-events/eth-news/news/2021/11/hydrogen-for-ground-transportation-and-heating-is-a-bad-idea.html

1.2 Objective and scope of this study

This study aims at making a step in *quantitatively analysing the future energy system as a whole*, i.e. considering all demand sectors and all potential energy carriers. Objective of the performed analysis is to identify the potential individual role of each of the various energy carriers, as well as the way that they might complement each other towards an economic and efficient CO2-free energy system.

The focus of the analysis is on country level. That is, *the various energy sectors are represented for the entire Switzerland in an aggregated manner*. The emphasis is to identify which energy carrier is better suited for which energy sector, as well as what is the value of investing into coupling technologies (such as electrolysers and heat pumps) and operating the overall coupled system in a coordinated manner. The study does not consider the current topology of the Swiss energy network infrastructure. However, *the interconnection capacities of the Swiss electricity and gas networks are modelled and considered*.

This modelling is combined with aggregated representation of the energy generation, storage and demand in the rest of Europe. This is an important aspect of this study, which *does not treat Switzerland as a bubble but rather as integrated into the European energy system*, allowing to account for the correlations in intermittent energy generation (wind and solar all over Europe) and in energy demand (e.g. heating in winter), as well as a coordinated utilisation of the gas storage all across Europe.

1.3 Questions of this study

Within the above-described context, the main question addressed by this study is:

- Which of the three pathways outlined in Section 1.1 is preferable?

Other addressed questions include:

- What is the value of cross-country exchanges of energy carriers?
- To what extent the optimal design of Switzerland's future energy system depends on the developments in the rest of Europe? Which of those developments are the most critical for Switzerland?
- What is the best way to bridge the higher energy demand in winter with the expected energy surplus in summer?
- What is the future importance of gas networks? Shall new investments in gas infrastructure be made?
- Shall today's gas infrastructure be progressively converted such that it becomes suitable for hydrogen or shall (a part of) it continue transport methane (renewable synthetic or biogas) until 2050?
- Which energy carrier shall be used per demand sector/application?
  - Let us note that, in this study, this question is addressed from the overall system optimality viewpoint, rather than from the end-customer viewpoint. Hence, answering this question will provide insight on whether it makes sense for a policy-maker to provide incentives for proliferation of specific end-demand technologies.
  - Precisely, an hypothesis tested in this study, is whether it would be desirable that parts of the end-demand for heating or transport are not electrified, in order to avoid overly increasing the stress to the electricity generation and transmission system, but rather served by means of a renewable fuel. (This corresponds to the third pathway outlined in Section 1.1.)

1.4 Outside the scope of this study

Finally, we itemise below what is not part of this analysis:

- Estimation of the future end demand for energy (i.e. the end-user need for heating, transport etc.) is not part of this study. Here the focus is on the technologies used to serve a given end energy demand. Obviously, the amount of this demand is a very influential factor in this analysis. As explained in Section 2, the end demand is derived from other studies and is an exogenous input to this study.
- Estimation of the future power generation installed capacities is also not part of this study. As explained in Section 2, future generation installed capacities are derived from other studies. They correspond to "scenarios" of this study.
- The regulatory framework is not addressed. This study performs a total cost minimisation. It identifies what investments make sense from the viewpoint of total social welfare, but it does not address the question of who shall pay for those investments and which regulatory measures might be required in order for the most meaningful investments to take place. Obviously, no subsidies are considered in this study.
- The electricity and gas transmission and distribution networks in Switzerland are not modelled in this study. Only the interconnection capacities with Germany, France, Italy and Austria are considered (for both electricity and gas). In other words, constraints resulting from network congestions within Switzerland (or other European countries) are neglected.
- In fact, the distribution of the energy carriers to the end customers is beyond the focus of this study. The reader who is interested in sector coupling at the level of distribution is encouraged to check the recently completed study "The Role of Gas and the Gas Infrastructure within the Future Energy System - a Techno-Economic Assessment" [14], which analyses the coupled electricity, gas and heat distribution systems of a Swiss utility (hydrogen is analysed only if blended with natural gas, not as a standalone energy carrier) and to follow the development of WP2 in the PATHFNDR project[7], funded by the SWEET program of the Swiss Federal Office of Energy, which (WP2) analyses future pathways at district level, considering all energy sectors and carriers in a coupled manner.
- In our analysis, production to hydrogen is assumed to be taking place only within Europe. Importing hydrogen from an external system (i.e. outside Europe) was not considered. However, it is worth noting that according to a couple of studies this might be a more economic option [15, 16], i.e. trading hydrogen in a global market.

1.5 Snapshots from other studies

A study [10] by Ecofys, a Navigant company, explored the role of gas in a fully decarbonised energy system by 2050. It concluded that it is possible by 2050 to scale up renewable gas (biomethane and renewable hydrogen) production in the EU to a quantity of 122 billion cubic metres per year. It also concluded that using this gas with existing gas infrastructure, smartly combined with renewable electricity in sectors where it adds most value, can lead to 138 billion societal cost savings annually compared to decarbonisation without a role for renewable gas.

The study starts from the perspective that all gas consumption in Europe must, by 2050, be net zero

[7] https://sweet-pathfndr.ch/

carbon, i.e. that it is produced from renewable sources and that any remaining natural gas consumption will be combined with carbon capture and storage or capture and permanent utilisation. Ecofys analysed how much renewable gas Europe can produce and what the societal value is of using this gas in existing gas infrastructure in various sectors of the economy. Based on conservative assumptions, the authors concluded that it is possible to greatly increase the production and use of renewable gas in the EU. Keeping the existing gas infrastructure in place to enable the transport, storage and distribution of this renewable gas significantly lowers the total EU energy system costs.

As a result, according to the study, gas can play a significant role in a fully decarbonised energy system. This is possible through the large-scale implementation of sustainable biomethane production produced from a range of agricultural and woody biomass types. The study estimates that it is possible to produce at least 98 billion cubic metres (bcm) of biomethane within the EU, i.e. 1'072 TWh of energy annually, by 2050. In addition, the study sees a potential to produce 24 bcm of renewable hydrogen (assumed to be used by industry in the vicinity of the production site) by converting low cost wind and solar electricity into hydrogen.

Study [9], also ordered by the Gas for Climate consortium (two years after [10]) concludes that hydrogen shall play an even larger role in Europe, with the total annual hydrogen production in 2050 corresponding to 1'710 TWh of energy. In addition, the study identifies a total annual energy potential of 1'170 TWh from biomethane (mostly) and power-to-methane. As shown in Fig. 2 (copied from [9]), these fuels are to be used in the buildings sector (for heating), the industry, transport and for power generation.

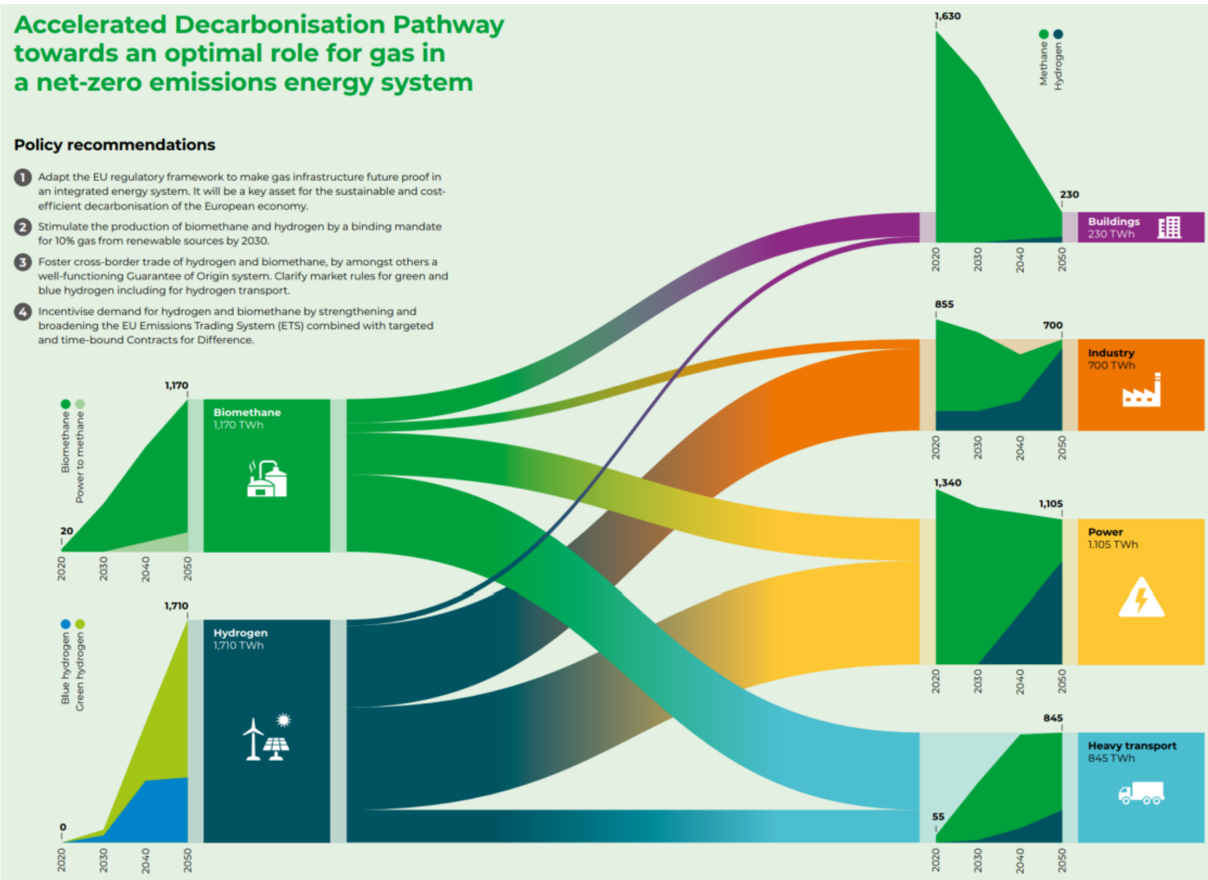


Figure 2: Production and utilisation of renewable methane and hydrogen in Europe according to [9].

2 Approach and methodology

2.1 Overview of the approach

The core of the followed approach consists in solving an optimisation problem which explicitly models each of the considered energy carriers and the various generation, storage, energy carrier conversion and demand technologies. The problem, which models an entire year in hourly resolution (i.e. it considers, in a sequential manner, 8760 time steps), is optimising the "operation" of the entire energy system, i.e. it dispatches for every hour all the dispatchable technologies (and curtails excess available generation), subject to the cross-country network constraints and the technology technical limits, with objective to satisfy the final demand for energy carriers (demand curtailment is possible, but it is avoided except if otherwise the problem is not feasible) at the minimum total cost.

The optimisation problem, presented in detail in Section 2.3, is solved for exogenously provided (i) infrastructure (cross-country transfer capacities, energy conversion and storage technologies), (ii) end demand and (iii) availability of primary energy supply. That is, the optimiser does not identify which are the optimal infrastructure investments, but, for these investments given as an "input scenario", it optimally utilises them identifying the most cost efficient manner to satisfy the end demand. This "operation cost" corresponding to the input scenario is, hence, an output of the optimisation.

Solving the annual energy system optimisation for different input scenarios allows to estimate the operating cost corresponding to each scenario. In addition, each solution of the optimisation problem provides valuable information regarding the way that the various technologies and energy carriers are utilised in a coordinated manner, as presented in the Results section (Section 4).

Figure 3 provides an illustration of the relationships modelled in a "node". The flows of energy carriers from generation and storage to demand, storage or conversion to other energy carriers are decided by the optimiser subject to the installed capacities of the various technologies. Within a node, no network

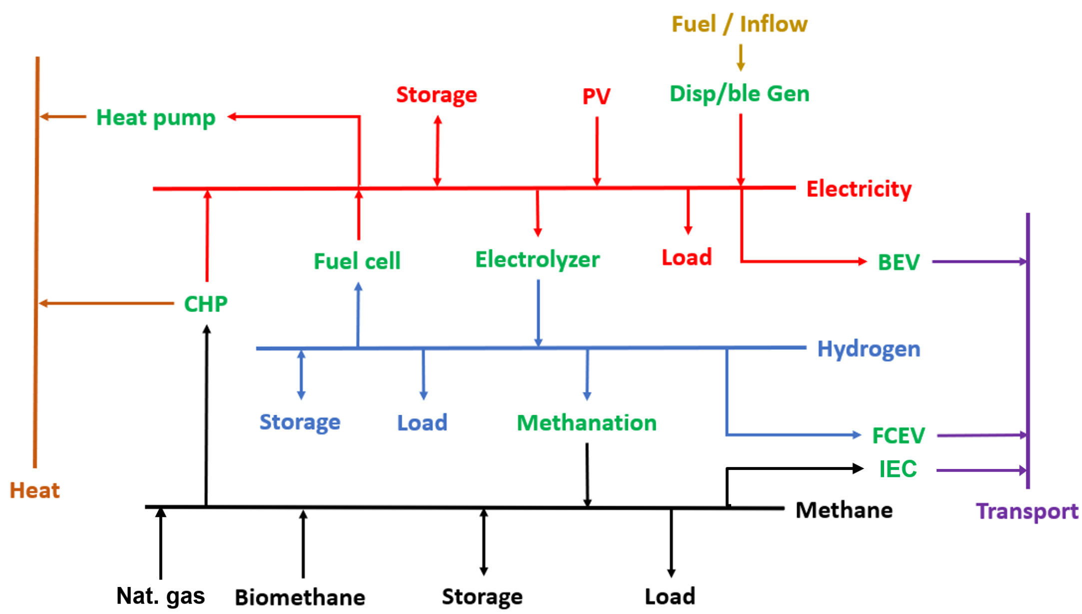


Figure 3: A "node" in the annual operation optimisation problem. The solver dispatches all technologies in a coordinated manner such that the end demand is satisfied in the most cost-effective manner. There is no network modelling with a node.

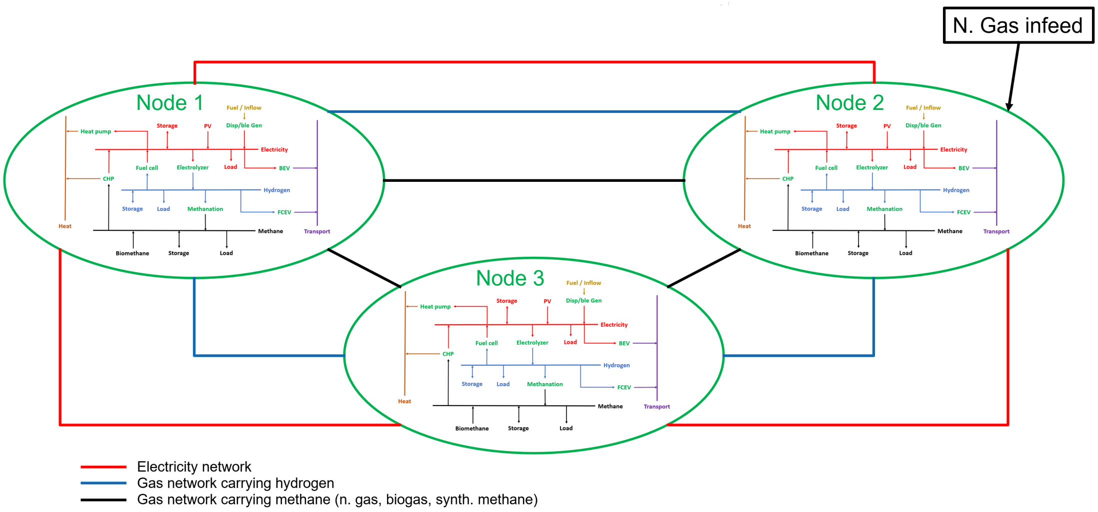


Figure 4: A "entire system" in the annual operation optimisation problem, consisting of a set of interconnected "nodes". The interconnections are per energy carrier. The available transfer capacity between each pair of nodes, for each energy carrier, is an input parameter to the optimisation problem. The solver dispatches all technologies within the nodes, such as the energy carriers flow between the nodes, without violating the corresponding transfer capacities, to achieve a cost optimal result.

constraints are considered. In this study, Switzerland is modelled as such a node.

Let us note that, when performing this study, thermal energy storage was not considered in the model, which has in the meanwhile been expanded accordingly. New results (including thermal energy storage) will be made available in a follow-up report. Similarly, production of hydrogen be methane (by means of steam methane reformers and/or pyrolysis) was not considered in this study, but the model has in the meanwhile upgraded accordingly and associated results will by made available in a follow-up report.

Figure 4 illustrates how several such nodes are interconnected to form the overall modelled energy system. In this study, the various considered nodes correspond either to individual European countries (e.g. Switzerland, Italy), or to aggregation of such countries (e.g. rest-of-Europe). The network transfer capacities of the various energy carriers (namely: electricity, methane and hydrogen) between each pair of nodes need to be provided as an input to the optimisation, which is solved subject to the constraints imposed by them. Note that heat cannot be transferred across nodes, it is "locally" produced and consumed, within a node.

The above-outlined "core" annual optimisation is part of an overall workflow, which starts from the identification of the boundary conditions and input scenarios and ends with the derivation of conclusions. The main steps of this workflow are as follows:

1. Identify the end demand, per demand sector (electricity, heating, transport) and node.
2. Identify scenarios regarding the utilised generation, storage, transmission and demand technologies, per node.
3. Optional step (not performed in this study): Per scenario, assign a corresponding total investment cost, representing the investments that need to be made in order for the scenario to be materialised.
4. Per scenario, solve the yearly operation optimisation.
5. Derive conclusions and recommendations.

2.2 Considered sectors and technologies

In this section, we summarise all the demand sectors and energy technologies that are considered in this study.

2.2.1 Demand sectors

In this section, we cluster the energy sectors based on the type of service (e.g. heating). Another typical alternative is to cluster based on the type of energy consumer (such as residential, commercial, industrial etc.). Since the emphasis of this study is on the selection and appropriate combination of energy carriers, the second way of clustering (i.e. by type of consumer) is not explicitly considered in this study. For example, per node, the electricity demand of households, of commercial buildings etc. is aggregated to make up a total electricity demand for the node.

The following demand sectors have been considered:

1. **Electricity**: It includes all demand for electricity from end demand needs that cannot (or are extremely unlikely to) be served by another energy carrier, such as lighting, cooking, devices, processes, IT, air-conditioning etc. Note that, in addition to this "base" electricity demand, the total electricity demand of a node will also include the electricity demand that might result if the end demand of other demand sectors is (fully or partially) met by technologies which use electricity as the input energy carrier (such as heat pumps to satisfy the demand for heating).

2. **Space & warm water heating**: It includes all demand for low temperature heating, aggregating all type of consumers. For simplicity reasons, in this study we have assumed that each customer used the same technology to meet its demand for space heating and its demand for warm water. We believe that this simplification, which will not completely hold in reality, does not change the validity of the performed analysis.

3. **Process heating**: It includes all high temperature heating, practically coming exclusively from the industrial sector. In this study, we differentiate low from high temperature heating because we, typically, assign different technologies to these sectors, as explained in Section 3.

4. **Passenger transport**: It is split into two demand sectors as follows. The summation of the passenger-km performed in the two sectors shall equal the total passenger-km of a node, which is an exogenous input (see Section 3).

    - *Passenger cars*: It corresponds to the movement of people, measured in passenger-km, by private or shared cars. Depending on the technology (e.g. electric vehicle) and the use (e.g. charging at home), it will correspond to a demand time-series for a given energy carrier.

    - *Public transport*: It corresponds to passenger transport (again in passenger-km) by means of buses, trams and trains. In this study, we have assumed that public transport is progressively fully electrified, contributing to the nodal electricity demand.

5. **Freight transport**: It corresponds to the movement of goods, measured in tonne-km. It is split into three demand sectors as follows:

    - *Light trucks*: Typically used for the final delivery of goods. They are lighter and are used for short-distance transport.

    - *Heavy trucks*: Typically used for long-distance transport of goods.

- *Freight rail*: Also used for longer-distance transport of goods. In our study, we assume that freight rail is electric, contributing to the nodal electricity demand.

Let us close this section by ensuring that two terms, used in this study, are properly clarified. The both refer to the energy demand.

- **End demand**: This term refers to the energy content of the actual user need. For example, the end demand for space heating refers to the amount of heat energy that should by delivered in a room, while the end demand for passenger transport refers to the energy content of transporting a certain amount of customers by a certain distance. End demand is an objective energy metric of the customer need, independent of the technology utilised to satisfy the need.
- **Final demand**: This term refers to the amount of energy that is consumed by a technology in order to satisfy the need (i.e. to satisfy end demand). For a given need, the final demand will depend on the technology characteristics. In this study, all technologies are represented as efficiencies (constant or time-varying).

2.2.2 Technologies serving the end demand

In this study, the nodal "base electricity demand" corresponding to the Electricity sector presented in Section 2.2.1 is represented by an hourly resolution time-series. This time-series stems from the aggregation of various types of demand (as listed in Section 2.2.1), which are not considered independent from each other.

On the contrary, part of the analysis performed in this study consists in identifying advantages and disadvantages (from the overall energy system viewpoint) from utilising different technologies in order to meet the end demand for heating and the end demand for transport.

All technologies are modelled as efficiencies. Thus, the use of a technology to cover (a part of) the *end demand* of a specific sector results in a certain *final demand* for the energy carrier utilised by the technology.

The technologies considered in this study are listed below.

- **Technologies for heating**
  - *Heat pump (HP)*. Only used for space & warm water heating.
    - air-sourced, water-sourced, ground-sourced
  - *Boiler*. Can be used for both heating sectors in the model, used only for process heating in this report.
    - methane-fueled, hydrogen-fueled
- **Technologies for transport**
  - *Battery electric vehicle (BEV)*. Used by passenger cars and light trucks.
    - Passenger cars are differentiated according to their charging profile: "at home", "at work" and "fast charging". The reason is that different charging profiles result into different resulting electricity demand time-series.
  - *Fuel-cell-electric vehicle (FCEV)*. Can be used by passenger cars, light trucks and heavy trucks in the model, used only for heavy trucks in this report.

    * hydrogen-fueled

  - *Internal combustion engine (ICE)*. Used by heavy trucks.
    * methane-fueled

  - *Direct electric (or BEV whose charging profile is not explicitly modelled)*. For the sake of simplicity, transport by rail, tram or bus is assumed to be electric and its end demand is directly translated to electricity demand time-series.

2.2.3 Power generation technologies

The following power generation technologies are considered in this study.

- Solar PV
- Wind
- Reservoir hydro
- Run-of-river hydro
- Nuclear
- Methane-fired
- Hydrogen-fired

Solar, *wind* and *run-of-river* are non-dispatchable technologies, modelled by means of hourly resolution time-series of available generation. For each hour when the available energy from these sources is higher than the electricity demand, the optimiser selects a combination between either (partially) curtailing the excess energy or "consuming" it by means of storage and/or energy carrier conversion (e.g. hydrogen production), such that the overall annual cost is minimised.

Nuclear power plants are dispatchable. In this study, it is assumed that there is always enough uranium available. Hence, these units are dispatched by the optimiser up to their maximum capacity such that the overall operation cost is minimised and the end demand is satisfied. It shall be noted that, in this study, no flexibility constraints are assumed for the nuclear. This assumption overestimates their potential contribution in providing flexibility to the system[8].

Reservoir-hydro plants are dispatched by the optimiser for the sake of total annual cost minimisation subject to the availability of water in the reservoir. The water inflows are modelled as time-series. The optimiser regulates the utilisation of the reservoir storage capacity such that the total annual operation cost is minimised.

Finally, *hydrogen-fired* and *methane-fired* plants which are also dispatchable, draw their fuel from the hydrogen or, respectively, methane network. Contrary to the case of uranium, infinite fuel availability is not assumed in the case of hydrogen and methane.

Hydrogen is an *internal variable* of the optimisation; no external source of hydrogen (i.e. imported in one of more of the nodes) is assumed. As a result, the optimiser dispatches the production and storage of hydrogen over the simulated year such as there is enough availability during the moments when hydrogen-fired power plants need to operate (which is typically when there is a deficit of wind and solar).

[8]On the other hand, one should also note that in this study the model considers the total generation capacity per node, not each individual power plant. Hence, one can argue that flexibility from nuclear can be achieved by appropriately scheduling the individual generators.

The total methane flowing during each hour in the network is a blend of three types: i. natural gas, which is imported to Europe from Russia or Africa, ii. biogas which is produced locally in Europe (see Section 3) and iii. synthetic methane which is produced from hydrogen by means of methanation. The amount of natural gas and biogas which can be fed each hour into the network is limited to a predefined maximum value (an input parameter to the optimisation problem). During hours of limited demand for methane, the optimiser might still import (natural gas) or produce (biogas) and store it (see Section 2.2.5 for later use. On the contrary, there is no predefined amount of available synthetic methane. Similarly to hydrogen, it is an *internal variable* of the optimisation which the optimiser might select to produce at hours of excess hydrogen (and probably electricity) availability.

2.2.4 Energy-carrier conversion technologies

Conversion of energy from one energy carrier to another takes place by utilisation of the corresponding technology. In the context of the optimisation-based approach followed in this study, the energy conversion technologies are dispatched by the optimiser such that conversion takes places at the moments when it is most beneficial from the total cost minimisation viewpoint. Below, we list the energy conversion technologies considered in this study which pull an input energy carrier from a network (i.e. the "consume" this energy carrier) and push another energy carrier into a network (i.e. they "produce" this other energy carrier).

- *Hydrogen-fired power plant*, converting hydrogen to electricity.
- *Methane-fired power plant*, converting methane to electricity.
- *Electrolyser*, converting electricity to hydrogen.
- *Methane reformer*, converting hydrogen to methane.

Clearly, these technologies allow for a *coupled operation* of the various energy sectors.

Let us note that, while the use of methane reformers was considered in this study, cases where such methanation takes place are not presented in the results section. The reason for this is that adding a methanation step turns out to be too inefficient from the overall system optimisation viewpoint, as it entails non-negligible energy losses. As a result, conversion of hydrogen to methane did not make up, in the context of the analysis performed in this study, a economically justified operation.

Let us also note that the possibility of combined heat and power (CHP) production, which can be modelled in the utilised optimisation framework, was not considered in this study. The reason for this is that delivery of heat via a heat network was not modelled in this study. A follow-up study shall also consider this possibility, as it is expected to increase the overall efficiency of a coupled energy system planning and operation.

2.2.5 Energy storage options

The following energy storage options are considered in this study.

- Pumped hydro storage
- Methane storage
- Hydrogen storage
- Battery storage

The existing pumped hydro storage capacity in Switzerland and the rest of Europe is considered. No new capacity buildup is assumed.

Reservoir hydro is not listed among the "storage technologies" because in this study it is not operated in a bi-directional manner (it does not pump water up into the reservoir). However, it is worth iterating that it also has a certain energy storage capacity. This is considered by the optimiser as available generation flexibility.

The existing and planned natural gas storage installations (in formations such as salt caverns, aquifers and depleted gas fields) all across Europe[9] are utilised for methane and for hydrogen storage. It is assumed that a part of this installations, presently used exclusively for storage of natural gas, are converted to accommodate storage of hydrogen while another part stays as is, accommodating methane (consisting in a mix of natural gas, biogas and synthetic methane). The only buildup of new capacity assumed in this study is what is already planned.

Table 9 presents the amount of hydro and gas storage capacities assumed in this study for Switzerland and for the rest of Europe. Let us draw the reader's attention to the fact that the storage volume is presented in TWh, while the storage charging and generating capacity is presented in GW. The term "charging capacity" refers to the rate at which the energy carrier can be drawn from the network and stored, while the term "generating capacity" refers to the rate at which the stored energy carrier can be fed to the corresponding network.

One can clearly observe that the existing gas storage capacity (either kept as methane storage or converted to hydrogen storage) can accommodate a much larger amount of energy compared to hydro storage. This storage capacity could potentially be utilised for seasonal storage, while pumped hydro storage suits better for short-term regulation. Finally, let us comment that, although not able to directly absorb excess wind and solar power, reservoir hydro offers a considerable amount of storage, making it a potentially valuable balance regulation technology.

Table 1: Hydro and gas storage capacities

Node	**Storage type**	**Storage volume TWh**	**Charging capacity GW**	**Generating capacity GW**
	Reservoir hydro	8.62	0	9.9
CH	Pumped hydro	0.02	3.85	3.85
	Natural gas	0	0	0
	Reservoir hydro	171.3	0	79.9
EU	Pumped hydro	10.6	48	48
	Natural gas	1'440	1'056	652

In this study, we consider batteries that are installed as part of PV+BESS[10] systems for diurnal regulation. We assume that a building-owner with rooftop PV would install a battery system with power capacity equal to 30% of the PV maximum capacity and c-rate equal to one (i.e. a x kW battery has a storage capacity of x kWh). No large-scale batteries are considered in this study. Scenarios are differentiated in terms of the installed battery capacity by modifying the percentage of PV systems that are complemented by a BESS. The optimiser utilises the installed BESS power and energy capacity for the sake of the total system cost minimisation.

[9]Values taken from the Storage Map 2018, published by the Gas Infrastructure Europe. https://www.gie.eu/download/maps/2018/GIE_STOR_2018_A0_1189x841_FULL_FINAL.pdf

[10]BESS: battery energy storage system

Let us note that BEV[11] also have a certain energy storage capacity. This technology is not listed among the storage technologies because, in this study, BEV are not operated in a bi-directional manner; in this study EVs are only consumers of electricity, never producers.

2.2.6 Total operation cost: Cost of fuels

For the sake of simplicity, the only operation cost that is considered in this study is the cost of fuel and of CO2 emissions. As a result, technologies such as wind, solar and hydro are assumed to have zero operation cost. Their input energy is delivered to them "for free". Nuclear, natural gas and biogas are the only fuels to which a purchase cost is assigned as shown in Table. Natural is also assigned a CO2-emissions cost.

Table 2: Variable cost of power generation (/MWh)

Type of plant	**Fuel Cost** (/ MWh of input fuel)	**CO2 emissions** (kg Co2 / MWh of input fuel)	**CO2 cost** (/ tonne CO2)	**Total cost** (/ MWh of input fuel)
Nuclear	20	-	-	20
Natural gas	40	400	150	100
Biogas	57	-	-	57

The fuel cost for biogas is taken from [9], while the costs of uranium and natural gas are taken from the data used in the System Adequacy study for Switzerland performed by the ETHZ-FEN[12] team [17]

2.2.7 Summary of considered technologies

Table 3 summarises the various technologies considered in this study. In most cases, a technology is modelled as an efficiency value, according to which energy is converted from one form to another (e.g. input fuel to electricity). In the case of heat pumps, the efficiency (i.e. the heat pump average COP) is time- and region-dependent. Finally, some technologies are modelled as timeseries of generation (wind, solar, run-of-river) or demand (EV charging).

Table 3: Summary of considered technologies

Type	**Technology**	**Input energy form**	**Output energy form**	**Efficiency** (round-trip for storage)
Demand	HP (air-sourced)	electricity	heat	1.78 - 4.06
	HP (ground-sourced)	electricity	heat	3.56 - 6.32
	Boiler	methane	heat	0.90
	Boiler	hydrogen	heat	0.90
	BEV	electricity	transport	0.85
	FCEV	hydrogen	transport	0.45
	ICE	methane	transport	0.40
Generation	Nuclear	uranium	electricity	0.33
	Methane-fired	methane	electricity	0.50
	Hydrogen-fired	hydrogen	electricity	0.50
	Reservoir-hydro	water	electricity	0.90
	Electrolyser	electricity	hydrogen	0.80
Storage	Pumped-hydro	electricity	electricity	0.71
	Battery	electricity	electricity	0.85
	Methane	methane	methane	1.00
	Hydrogen	hydrogen	methane	1.00

[11] BEV: battery electric vehicle
[12] FEN: Forschungsstelle Energienetze (Research Center for Energy Networks). http://www.fen.ethz.ch

2.3 Formulation of the optimisation problem

This section is to be filled in and be made available at a second draft of this report.

3 Input data and considered scenarios

In this section, we present the input data and scenarios utilised in this study. This information corresponds to steps 1 and 2 of the workflow described in Section 2.1. As explained, the optimisation problem is solved per considered scenario to identify the corresponding optimal utilisation of the technologies. Each scenario corresponds to a potential future evolution of the energy system by, approximately, 2040-2050.

3.1 Regions

An important aspect of this study is to analyse Switzerland's future energy system while considering the rest of Europe, so that the cross-border energy flows (into and out of Switzerland) are modelled in a relatively more realistic way (as opposed to modelling Europe as being able to provide energy any time Switzerland has a deficit and to consume / absorb any Swiss excess energy).

By following an approach where the rest of Europe is explicitly modelled in the optimisation problem, a two-fold objective is achieved:

1. The approach accounts for the correlations among wind and solar power availability and of the energy demand patterns across Europe.
2. The approach accounts for the fact that the flexibility provided by certain resources (namely energy storage and dispatchable generation) can be shared among the various European countries.

In order to avoid making the study overly elaborated, Europe has been modelled as a system consisting of three nodes: Switzerland, Italy and rest-of-Europe, allowing to put the emphasis on Switzerland, while explicitly considering the North-South gas and electricity corridors make use of the Swiss energy transmission infrastructure. In the remaining of this document, we will refer to the three considered nodes using the acronyms cH, IT and EU (note that the "EU" node does not include Italy, while it includes Norway).

3.2 Energy demand

As explained in Section 1.2, the estimation of the end energy demand is an input to this study. The annual energy demand per considered sector (see Section 2.2.1) is taken from a few selected sources, listed below:

- Energy Perspectives for Switzerland 2050+ [3], Zero Basis scenario for 2050, Swiss Federal Office of Energy.
- Transport Outlook 2040 - Development of passenger and freight transport in Switzerland [18], Reference scenario for 2040, Swiss Federal Office for Spatial Development.
- EU Reference Scenario 2016 - Energy, transport and GHG emission Trends to 2050 [19], European Commission Directorate-General for Energy, Directorate-General for Climate Action and Directorate-General for Mobility and Transport.

- European Commission's EUCO3232.5 scenario [20], which is part of a group of EUCO scenarios used in EU energy and climate policy development that have been derived from the EU Reference 2016 scenario. Since the scenario projections are made until 2030, in our study we extrapolated the 2030 values to come up with an assumption about 2050.
- Heat Roadmap Europe [21], funded by the European Unions Horizon 2020 research and innovation programme addressing the topic Removing market barriers to the uptake of efficient heating and cooling solutions of the Energy-efficiency Call.

Table 4 shows which of the above-listed references was used per node and demand sector.

Let us note that since the EU scenarios in[19], [20] and [21] do not include Norway (which is however important to model in our study due to its high hydro resources), for the sake of simplicity we have added today's electricity demand of Norway to the "Electricity" demand sector of the rest-of-Europe. Since heating in Norway is already electric and hence part of the added electricity demand, the Norwegian demand for space and water heating is not included in the "Space & warm water heating" sector which, for the other countries, is explicitly modelled in this study.

Table 4: Sources of end energy demand per node and sector

Demand sector	**CH**	**IT**	**EU**
Electricity	[3]	[19]	[19] + Norway's total electricity demand
Space & warm water heating	[3]	[21]	[21] (does not include Norway)
Process heating	[3]	[21]	[21] (does not include Norway)
Passenger transport	[18, 3]	[20] (extrapolation)	[20] (extrapolation, without Norway)
Freight transport	[18, 3]	[20] (extrapolation)	[20] (extrapolation, without Norway)

Table 5 shows the annual end energy demand per node and demand sector. With the exception of the "Electricity" demand sector, which is always consuming electricity, the end demand of the other demand sectors is converted to final demand for one or more energy carriers, as explained in Section 2.2.1 using the technology efficiencies presented in Table 3.

The analysis presented in this report is performed only for the end demand values presented in Table 5. Different scenarios are considered by assuming different combinations of technologies utilised to satisfy the demands for heating and transport, as presented in Section 3.5.

Table 5: End demand per sector (TWh)

Demand type	**CH**	**IT**	**EU**	**Total**
Electric appliances	32.20	359.42	3013.97	3405.60
Space water heating	56.10	343.00	2016.00	2415.10
Process heating	18.60	143.00	1319.00	1480.60
Passenger transport	22.20	185.12	1164.45	1371.76
of which Passenger cars	20.18	171.05	1069.28	1260.50
of which Public transport	2.02	14.07	95.17	111.26
Freight transport	4.80	44.79	495.45	545.05
of which Light trucks	0.59	7.21	70.95	78.75
of which Heavy trucks	2.79	33.95	334.04	370.77
of which Freight rail	1.42	3.64	90.47	95.53

3.3 Energy supply and storage infrastructure

3.3.1 Power generation and available energy

As a basis for the analysis, a "reference" future evolution of the power generation and storage installed capacities has been assumed for each of the three considered nodes.

Table 6 presents the installed capacities, per node, of the considered power generation technologies. These capacities were derived as follows:

- **CH**: Energy Perspectives for Switzerland 2050+ [3], Zero Basis scenario for 2050, Swiss Federal Office of Energy.
- **IT** and **EU**: European Commission's EUCO3232.5 scenario [20], which is part of a group of EUCO scenarios used in EU energy and climate policy development that have been derived from the EU Reference 2016 scenario. It should be noted that:
  1. Since the EUCO3232.5 scenario projections are made until 2030, the following assumptions are made in order to crate the "reference" scenario of this study:
     - Nuclear power capacity: the 2030 values are used (which are every similar to 2020 values).
     - Methane-fired power capacity: it is assumed that the gas-fired capacity of 2030 remains available, while the solids-fired capacity of 2030 is converted to methane-fired.
     - Hydro power capacity: the 2030 values are used (which are every similar to 2020 values). Since in EUCO3232.5 the total hydro capacity is provided, in our study this capacity is split among reservoir, run-of-river and pumped hydro using today's values.
     - Wind power capacity: it is assumed that the increase in total installed capacity from 2030 to 2040 happens 10% faster than the increase from 2020 to 2030 (which is part of the EUCO3232.5 scenario). Following, it is assumed that the increase from 2040 to 2050 happens 10% than the previously computed increase from 2030 to 2040. The resulting 2050 is used in our study.
     - Solar power capacity: the same process is used as described above for the case of wind capacity.
  2. For Norway, today's reservoir hydro capacity has been considered.
- **Hydrogen-fired capacity** is taken from the "Gas Decarbonization Pathways 2020-2050" [9], a study ordered by the Gas for Climate consortium.

Let us point the reader's attention to the fact that, for the sake of simplicity and compactness, sources of electric power, such as biomass-waste-fired or geothermal, have been omitted from this study. The expected installed capacity of the latter is too little to play a role in the big picture, while, regarding biomass, it has been assumed that all available biomass is converted to biogas and injected to the gas network (from where it can be utilised by methane-fired power plants or by gas boilers). Also, carbon and oil is assumed to be completely removed from the energy mix, so no such power plants are considered.

Table 7 shows the amount of electric energy that can be produced annually by the installed capacities of Table 6. For nuclear and methane-fired it is computed assuming that operation at full capacity during the entire year is feasible. In addition, for methane-fired plants, the availability of input fuel (natural gas or biogas) is also taken into account (for nuclear, let us recall here that the supply of uranium is assumed to be unconstrained). This availability is presented in Section 3.3.2, where Table 8 shows the maximum amount of methane (expressed in energy units) which is available per year. With the assumptions made in this study (see Section 3.3.2) there is not enough methane to allow all methane-fired plants to operate at full capacity during the entire year[13]. For reservoir hydro, run-of-river, wind and solar, the annual energy is depended on the input time-series of water, wind and solar irradiation. The hourly resolution time-series of a reference year (1 October 2013 - 30 September 2014) are used in this study, taken from the System Adequacy study for Switzerland performed by FEN [17].

One can observe in Table 7 that, in the European system considered in this study, the "reference" power generation scenario corresponds to a maximum of 10'000 TWh of electric energy which can be injected into the electricity network over the year. Pumped-hydro and hydrogen-fired power generation is omitted in this table, because it does not constitute a net new electric energy injection. In both cases, electric energy has been originally consumed (to pump water or for electrolysis).

Table 6: Power generation capacities (GW)

Technology	CH	IT	EU	Total
Nuclear	0.00	0.00	110.00	110.00
Methane-fired	0.00	45.00	242.00	282.00
Hydrogen-fired	0.00	70.00	420.00	470.00
Reservoir-hydro	9.90	4.18	75.70	89.77
Pumped-hydro	3.85	7.79	39.96	51.60
Run-of-river	6.26	6.93	32.28	45.47
Wind	2.20	57.91	1'071.95	1'132.05
Solar	37.50	256.52	2'118.65	2'412.70

Table 7: Available electric energy (TWh)

Technology	CH	IT	EU	Total
Nuclear	0.00	0.00	963.60	963.60
Methane-fired	0.00	394.20	2'062.69	2'062.69
Sum fuel-based	0.00	394.20	3'026.29	3'026.29
Reservoir-hydro	25.72	19.66	354.06	399.44
Run-of-river	16.98	31.18	141.77	189.93
Wind	4.82	101.45	3'286.59	3'392.86
Solar	42.55	307.91	2'654.79	3'005.25
Sum inflows	90.07	460.20	6'437.21	6'987.48
Sum all	90.07	854.40	9'463.50	10'013.77

3.3.2 Available energy in form of methane

Two sources of methane are considered in this study; natural gas and biogas.

The annual biogas potential of each node is taken from the "Energy Perspectives 2050+" [3] for CH and from the "Gas Decarbonization Pathways 2020-2050" [9] for IT and EU.

Natural gas has been assumed to be entirely imported from Russia and Africa, i.e. local European production and potential LNG imports are omitted. These assumptions do not influence the conclusions of this study since, first, the omitted natural gas sources are very small compared to the considered

[13] Note that the "Total" column does not equal to the sum of maximum production in CH, IT and EU. The reason for this is that each node individually is constrained by the local installed capacity of methane-fired generation and the *total* available methane (since methane can flow between nodes). Obviously, the "Total" power production is also constrained by the total available methane.

ones and, second, the use of natural gas in this study is anyway as minimal as possible, acting only as a "slack" fuel when absolutely needed, due to its CO2 footprint. The considered natural gas imports (from Russia to node EU and from Africa to nodes EU and IT) are constraint by today's transmission capacities of the corresponding gas pipelines (see Section 3.4). No other natural gas delivery constraints were considered in this study.

Table 8 summarises the amount of methane that can be injected to each node per year.

Table 8: Available energy in form of methane (TWh)

Type	CH	IT	EU	Total
Biogas	6.00	125.30	884.70	1'016.00
Natural gas	0.00	580.39	2'528.98	3'109.36
Sum	6.00	705.69	3'413.68	4'125.37

A follow-up report will also consider the potential import of natural gas in the form of LNG and import of hydrogen and synthetic methane from outside Europe (let us recall that in this report we assume that all hydrogen is produced within Europe and that synthetic methane is not used).

3.3.3 Energy storage

It is assumed that the existing pumped-hydro and natural gas storage infrastructure is also available in the reference year which is simulated in this study (see Section 3.2). Table 9 presents the corresponding *storage volume* (in *TWh*), as well as the *storage charging and generating capacities* (in *GW*)[14], per storage type and node. The values for pumped hydro are the same as those used in the System Adequacy Study [17], while the values for gas storage are taken from the Storage Map 2018 of the "Gas Infrastructure Europe"[15]. They cover all the existing or planned natural gas storage locations in Europe.

Clearly, the amount of energy that can be stored in pumped hydro units (10 TWh for the entire Europe) is too little for this technology to be able to serve as a longer-term energy storage option (see in Table 5 that the demand consists of a few thousand TWh). On the other hand, it seems that the existing (or already planned) gas storage (>1400 TWh) could potentially play such a role.

In this study, it is assumed that in the future base scenario, part of the gas storage infrastructure is utilised for storage of methane (i.e. as is today the case), while another part is converted to hydrogen storage.

Table 9: Energy storage capacities

Storage type	Metric	CH	IT	EU	Total
Pumped hydro	Storage volume (TWh)	0.018	0.406	10.183	10.606
	Charging capacity (GW)	3.849	7.787	39.959	51.596
	Generating capacity (GW)	3.849	7.787	39.959	51.596
Gas storage	Storage volume (TWh)	0.000	254.630	1185.240	1439.870
	Charging capacity (GW)	0.000	148.435	907.393	1055.828
	Generating capacity (GW)	0.000	92.460	562.045	654.504

[14] The term "charging capacity" denotes the maximum rate at which electricity or gas can be withdrawn from the corresponding network in order to be stored in the storage technology, while the term "generating capacity" denotes the maximum rate at which electricity or gas can be injected back to the network (when the storage is discharged).

[15] Link: https://www.gie.eu/publications/maps/gie-storage-map

3.4 Energy transmission infrastructure

As explained in 2.1, the hourly flows of the energy carriers (electricity, methane, hydrogen) between the nodes are constrained by the transmission capacity of the network infrastructure. Table 10 shows the values that have been used in this analysis. The electricity network capacities are taken from the System Adequacy study [17] [16], while the capacities of the gas network are taken from ENTSO-G. Note that maximum hourly import capacities of natural gas from Russia and Africa are considered, again based on ENTSO-G.

Table 10: Cross-node network capacities (GW)

Node 1	Node 2	Electricity	Natural Gas
CH	EU	40.77	28.14
CH	IT	15.08	26.48
EU	IT	13.79	36.16
RU	EU	-	258.21
AF	EU	-	30.49
AF	IT	-	66.25

An important question investigated in this study is the potential value that could result from converting a part of today's gas network infrastructure to be utilised from transmission of hydrogen (instead of methane gas). Section 4 presents results of such an analysis. For the purposes of this study, the vision expressed in the "Hydrogen Pathway Europe" [22], a report representing the view of the gas industry developed with input from 17 companies and organisations[17], is adopted in this study. The resulting split of today's gas network into network for methane and network for hydrogen is presented in Table 11.

Table 11: Cross-node network capacities (GW); gas network split according to the vision of Hydrogen Pathway Europe

Node 1	Node 2	Electricity	Gas - Methane	Gas - Hydrogen
CH	EU	40.77	12.23	15.91
CH	IT	15.08	-	26.48
EU	IT	13.79	12.23	23.93
RU	EU	-	258.21	-
AF	EU	-	30.49	-
AF	IT	-	66.25	-

It is assumed that today's natural gas pipelines, if repurposed, will be able to transfer the same amount of energy per hour in form of hydrogen as they do today for natural gas. Even though this a topic of further ongoing research, this assumption is justified as following. "At standard conditions, methane has three times the calorific heating value per cubic meter of hydrogen. Assuming the same operating pressure and the same pressure drop along the pipeline, hydrogen will flow at three times the velocity due to its low density. Hence, a gas pipeline can transport about three times as many cubic meters of hydrogen during a given period and thus deliver roughly the same amount of energy." [23]

[16] Note that the physical cross-border electricity transmission network capacities have been used in this study, implicitly assuming a perfect utilisation (by means of power flow control) of the transmission network. In practice the transfer capacities (ATC) that are made available to the electricity market are significantly lower: ś10 GW between Switzerland and its neighbouring countries. A follow-up report will illustrate results using various ATC values.

[17] Air Liquide S.A., BMW Group, Deutscher Wasserstoff- und Brennstoffzellenverband, Enagás, Engie, Equinor ASA, N.V. Nederlandse Gasunie, Hydrogenics, ITM Power, Michelin, NEL Hydrogen, Plastic Omnium, Salzgitter AG, Solid Power, Total SA, Toyota Motor Europe, and Verbund

3.5 Considered scenarios

The scenario analysis presented in this report focuses on the impact and/or value to the overall energy system that result from the utilisation of different technologies in order to satisfy the end energy demand (see Section 2.2.7 for a comprehensive list of the considered technologies). Three "boundary" scenarios are considered, selected such that the effect of choosing specific end demand technologies is clearly illustrated. They are as follows:

1. **Scenario 1: "Electrification scenario without hydrogen"**
   - All energy demand is electrified, except process heating.
   - Process heating is served by methane boilers.
   - There is no hydrogen infrastructure (electrolysers, hydrogen storage, hydrogen network).
2. **Scenario 2: "Electrification scenario with moderate hydrogen penetration"**
   - All energy demand is electrified, except process heating.
   - Process heating is served by hydrogen boilers.
   - Two thirds of the methane infrastructure (i.e. gas storage and gas network) is appropriately converted to be used for hydrogen instead of methane.
   - A total of 490 GW electrolyser capacity, as well as a total of 490 GW hydrogen-fired power plant capacity are installed in Europe [9]. There are no electrolysers in Switzerland, which imports hydrogen to meet its hydrogen demand for process heating.
3. **Scenario 3: "Electrification scenario with considerable hydrogen penetration"**
   - Same as scenario 2, with the addition that the entire fleet of heavy trucks is made up of hydrogen FCEV (instead of being electrified, as in scenarios 1 and 2).

In addition, for each scenario, sensitivity analysis is performed by defining sub-scenarios as follows. The purpose of doing so is to gain insight in which options are better suited in helping satisfying the end demand in the most economic manner.

- **"Higher RES proliferation"**: Increase the wind and solar proliferation. Precisely, the installed capacity of Wind and Solar power is doubled.
- **"More energy storage"**: Increase the amount of and/or the diversification of energy storage. This is achieved in two ways:
  1. Battery energy storage system are assumed to be installed by various costumers.
  2. The methane storage capacity is fully converted to hydrogen storage.
- **"Flexible demand"**: Consider various options of demand flexibility (to be further explained in the sequel).
- **"More dispatchable generation"**: Increase the amount of methane- and hydrogen-fired generation capacity.

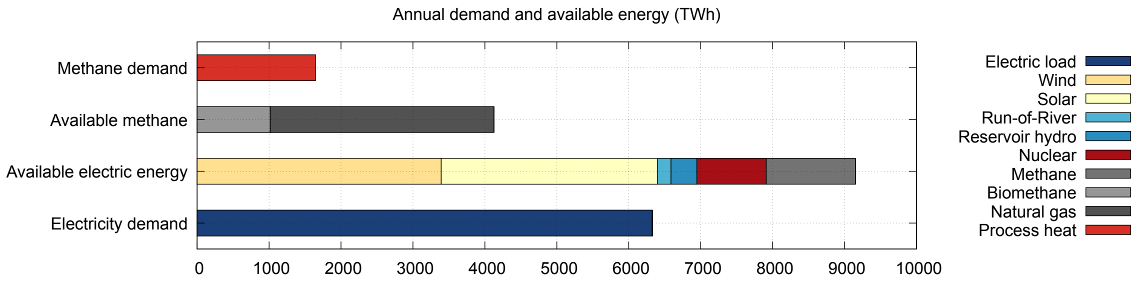
4 Results and Discussion

4.1 Final demand for energy carriers

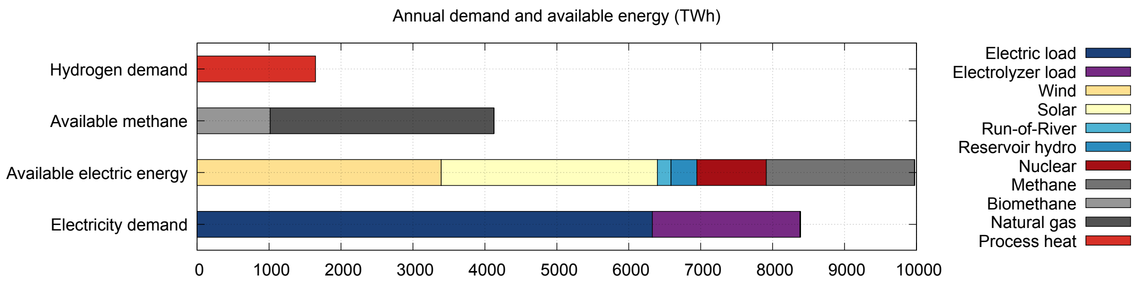
In this Section, we quantify the final demand for energy carriers that results from the technology options in each of the scenarios. Per scenario, the final demand for electricity, methane (only in scenario 1) and hydrogen (only in scenarios 2 and 3) are computed by multiplying the end demand with the efficiency of the technology which is utilised to serve it (see Table 3).

Following, we compare the resulting final demand with the available energy supply stemming from the "reference" future evolution scenario (presented in Sections 3.3.1 and 3.3.2). This allows to obtain, per scenario, a "feeling"[18] of whether there is an adequate amount of supply to satisfy the demand at all moments.

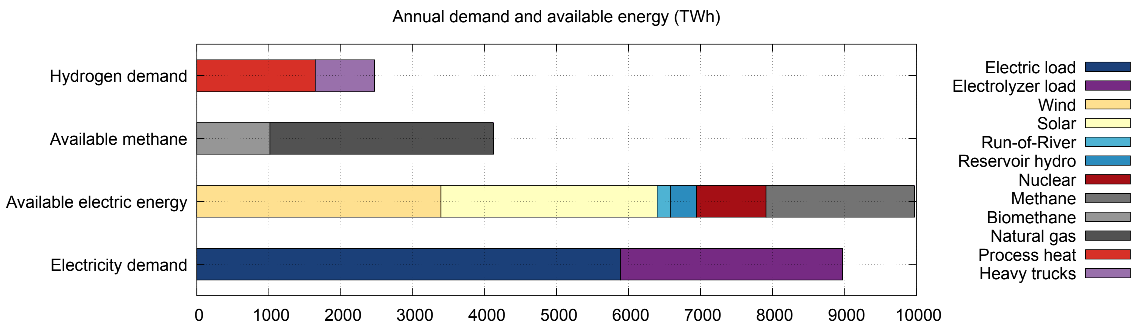
[18] We call it a "feeling" because even if there is enough energy supply on an annual basis, there might still be hour slots during which there is not enough generation adequacy to satisfy the demand.



(a) Scenario 1

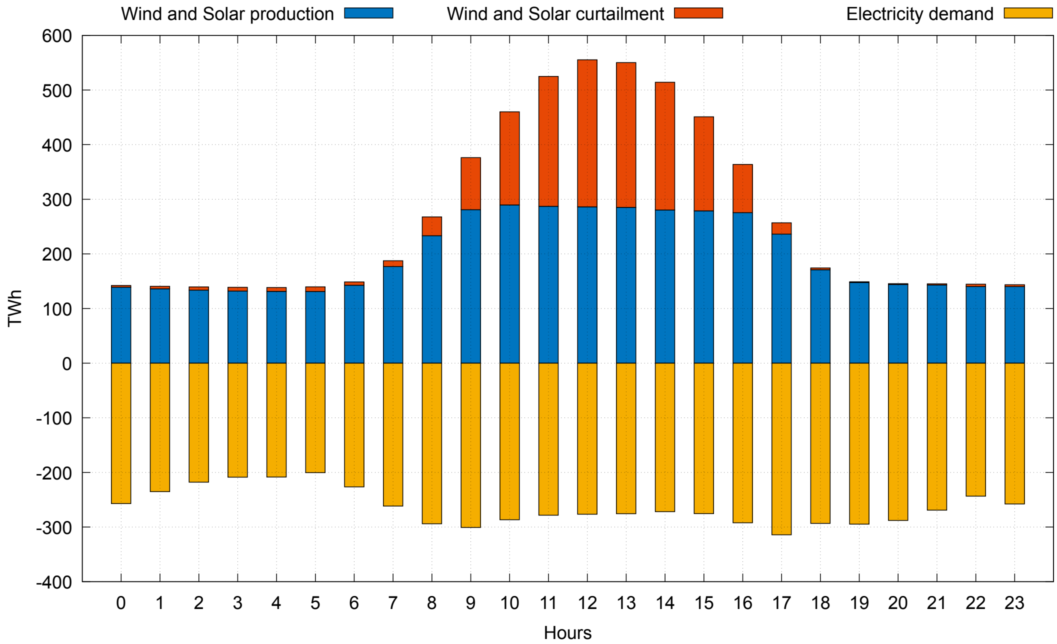


(b) Scenario 2

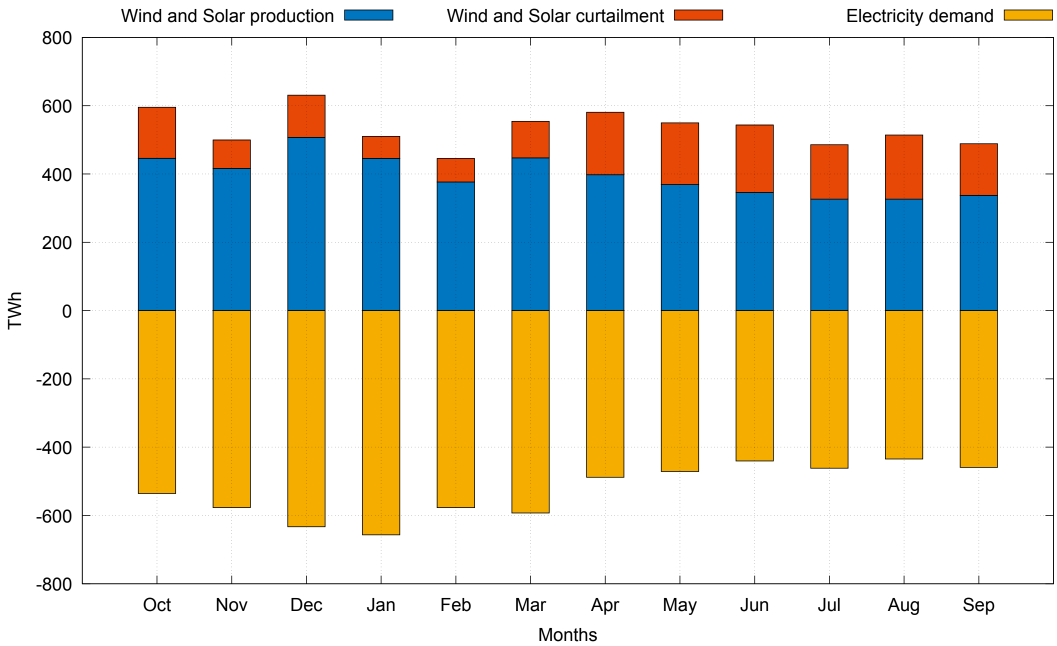


(c) Scenario 3

Figure 5: Annual final demand for energy carriers and available supply of energy carriers



(a) Energy per hour

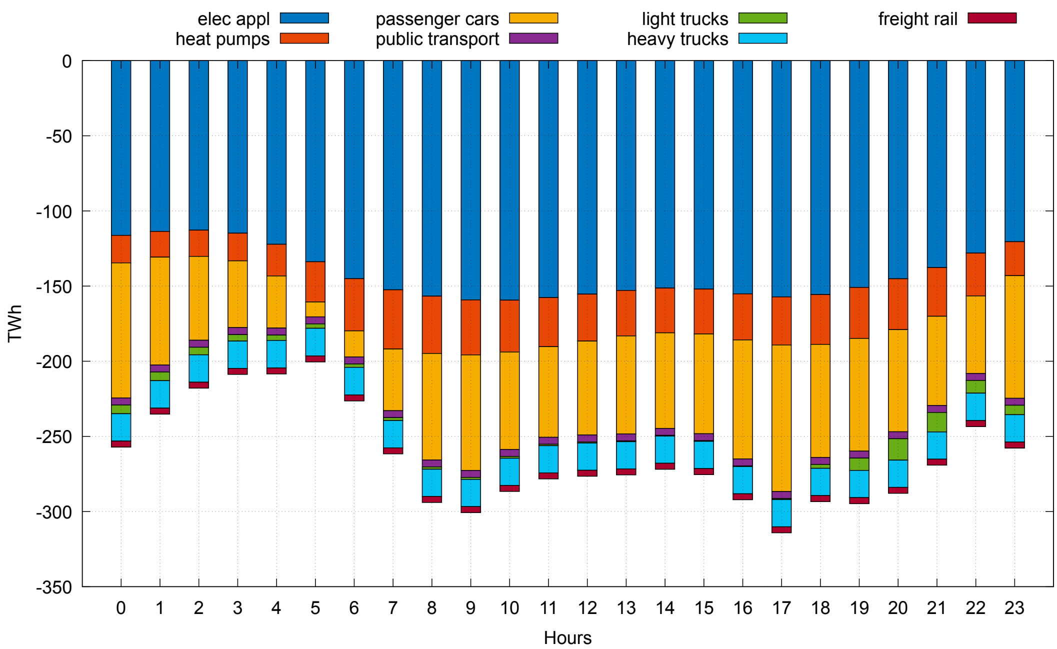


(b) Energy per month

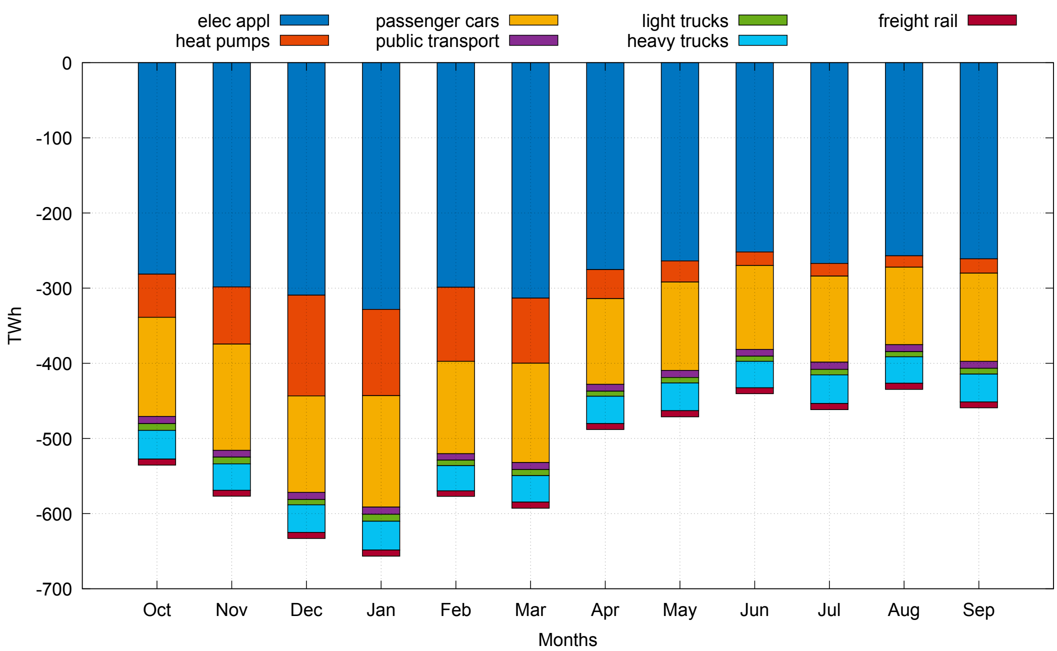
Figure 6: Scenario 1: Wind & solar surplus or deficit

Figures 5 show the total annual final demand per energy carrier, as well as the annual available supply per energy carrier. Note that there is no supply of hydrogen, since it is an intermediate energy carrier, produced by consuming electricity. In the scenarios where there is demand for hydrogen, this also appears as additional electricity demand (computed by dividing the demand for hydrogen by the electrolyser efficiency).

In scenario 1, part of the available methane is used to satisfy the demand for methane (stemming from process heating). The remaining is available to be utilised for electricity production. In scenarios 2 and



(a) Aggregated per hour



(b) Aggregated per month

Figure 7: Scenario 1: Total electricity demand

3, where there is no primary demand for methane, all available methane can be utilised for electricity generation.

One can observe that the available energy from the installed wind and solar capacities is barely enough to cover the electricity demand resulting from a full electrification of all demand sectors except process heating. Using hydrogen as a fuel eventually results in a significant additional demand for electricity, which, for the "reference" scenario used in this study, can be covered only by resorting to nuclear and natural gas (available biogas is not enough as will be discussed in the following sections).

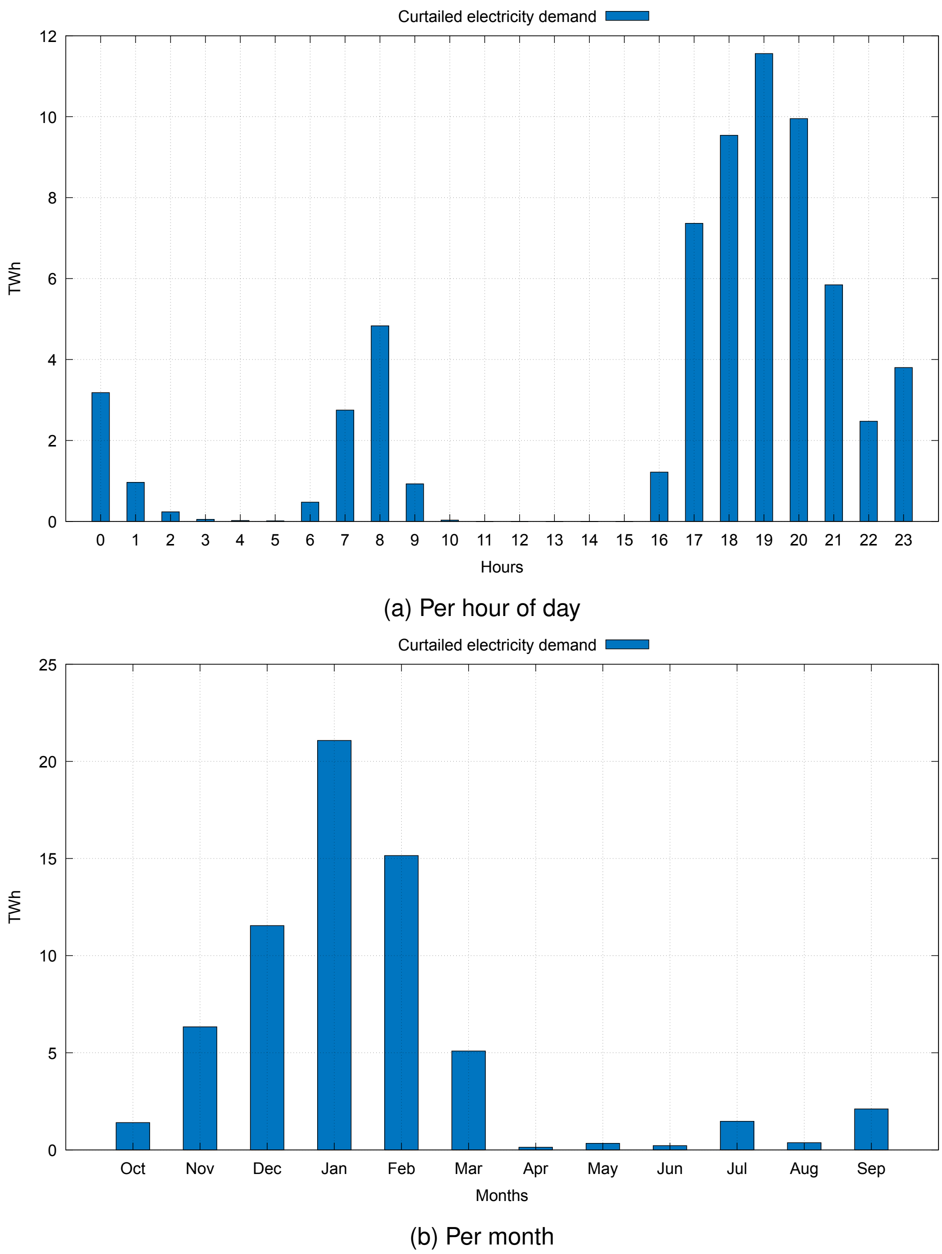


Figure 8: Scenario 1: Total electricity demand curtailment

In practice, even in scenario 1, it is not possible to satisfy the final demand solely by means of wind, solar and hydro power due to the temporal mismatch between wind and solar availability and electricity demand. As shown in Figure 6a, there is systematic excess of renewable energy around midday and systematic deficit during the evening, night and early morning. On a monthly basis (see 6b), the deficit is somewhat more exacerbated in winter (when there are months during which the total available wind and solar is less than the monthly demand), but even in summer wind and solar cannot cover the total electricity demand because of the aforementioned diurnal mismatch. Figure 7 shows how the various demand sectors contribute to the total electricity demand, per hour and per month, in scenario 1.

Clearly, more dispatchable generation capacity than the one available by the hydro units is required in order to satisfy the final electricity demand at all moments. In the "reference" scenario considered in this study, this is provided by nuclear and gas-fired plants. In addition, excess wind and solar energy can be stored in form of hydrogen and converted back to electricity when needed by means of hydrogen-fired plants (in scenarios 2 and 3, as well in selected sub-scenarios of scenario 1 as explained in the sequel).

4.2 Scenario 1: Lack of dispatchable generation capacity

Solving the optimisation problem for scenario 1 allows to identify that the energy supply of the "reference" scenario cannot satisfy the final electricity demand at all moments. A total of 65.2 TWh needs to be curtailed (i.e. ~1% of the annual final electricity demand of scenario 1, which equals 6'328 TWh). Figure 8 shows the total electricity demand curtailment per month and hour of day. As expected, it takes place during hours with no solar, mostly in the winter months. During the worst hour (which happens to be the 24 January at 18:00) a 497 GW of electricity demand is curtailed. Let us note that the maximum and minimum demand, in scenario 1, are 1'155 GW and 323 GW, respectively.

Figure 9 illustrates the reason of the demand curtailment. In this figure, a duration plot of the net supply of wind and solar (i.e. available power from wind and solar minus electricity demand for each hour, which is the opposite of what is often referred to as "residual load") is presented. The curve contains data for all 8'760 hour slots, but instead of them be shown in chronological order, they are sorted. For example, one can observe in the plot that there are 5'000 hours during which the summation of wind and solar power is less than the electricity demand of that hour. In addition to the duration curve, Figure 9 presents the total available dispatchable power capacity (from nuclear, hydro and methane-fired plants) in the entire modelled system. These are the power sources which "kick in" when wind and solar power is not enough to cover the demand. One can observe that **there are 608 hour slots during which the available dispatchable power generation is not enough to satisfy the electricity demand.**

Figure 10 shows how the dispatchable power generation technologies are utilised according to the mismatch between available renewable power and electricity demand. Pumped-hydro is charged at full capacity during hours with renewable surplus. Since the energy in reservoir hydro and the stored energy in pumped hydro is not enough to cover the total missing energy during moments with renewable deficit, nuclear is utilised as a base unit during these hours. It should be noted that this requires a somewhat flexible operation of the nuclear fleet. Finally, methane-fired power generation, as the most expensive option, is utilised when all other options have been exhausted. Let us note however that, despite the desperately missing peak power capacity, most of the time methane-fired power plants are barely used. Precisely:

- They all operate at their maximum during a total of 548 hours.
- They stay switched off for almost 3000 hours.
- They operate at <16% of their total capacity for another 3200 hours.

Table 12 presents the amount of energy produced by each of the dispatchable sources, as well as the total amount of wind and solar available energy which is curtailed, during the year, because of lack of demand to consume it. Interestingly, the amount of curtailed wind and solar is higher than the amount of energy produced by dispatchable units.

Clearly, the "reference" scenario for the evolution of energy supply and storage infrastructure in Europe struggles to accommodate an aggressive electrification of demand for heating and transport (as assumed in scenario 1). Let us recall from Section 3.3.1 that the here-considered "reference" scenario practically keeps the same available power generation capacity as today (except that coal-fired plants are converted to methane-fired), while it assumes a massive increase of wind and solar installed capacities

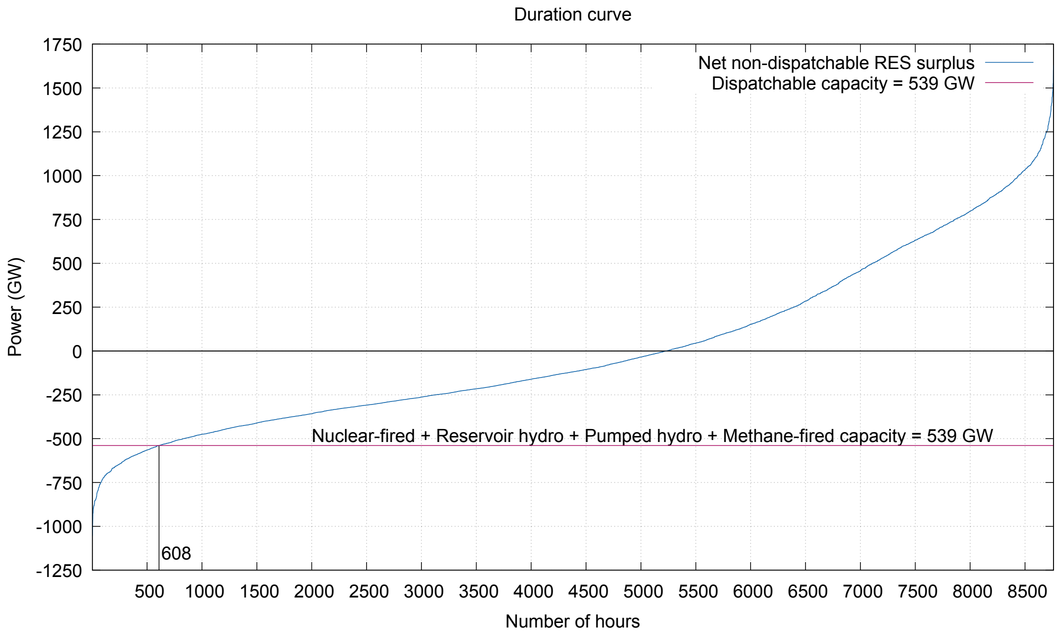


Figure 9: Scenario 1: Duration curve of net supply (wind + solar - electricity demand)

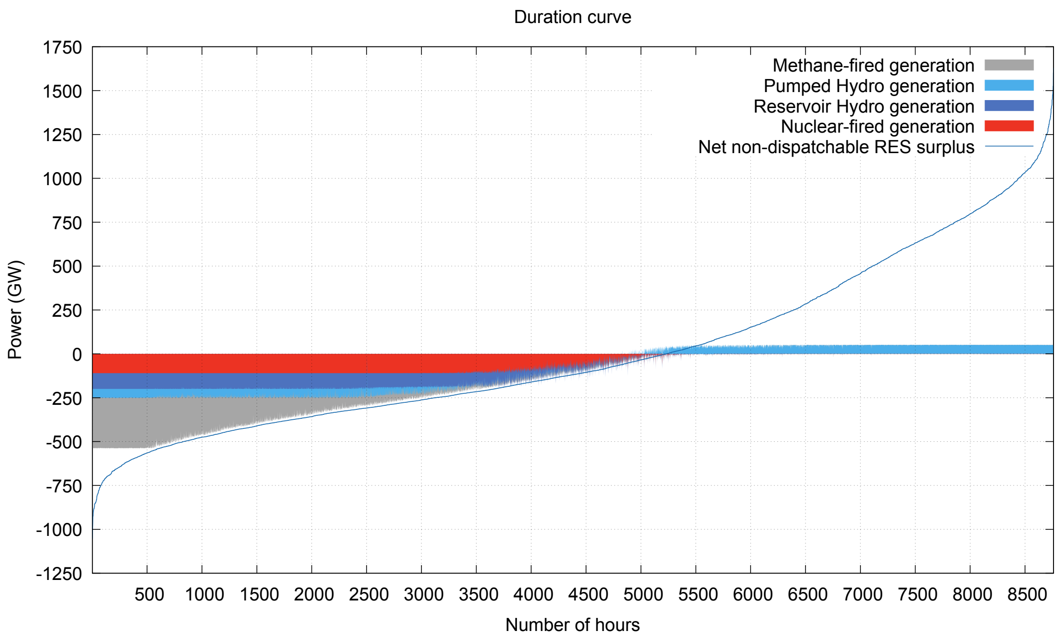


Figure 10: Scenario 1: Duration curve of net supply (wind + solar - electricity demand) and dispatch of nuclear, hydro and methane-fired generation.

(more that 5-fold and, respectively, 18-fold compared to the installed capacities in 2020). Even though there is enough electric energy available on an annual basis to satisfy the electricity demand, this cannot be achieved due the existence of hours with a deficit of availability of electric energy. **The assumed full electrification of low temperature heating and of transport requires a significant degree of flexibility, to enable bridging the temporal gap between energy need and energy availability.**

Table 12: Annual production and curtailment (TWh)

Power plant type	Annual electricity production (TWh)	Annual curtailment (TWh)
Nuclear	489	-
Reservoir Hydro	360	-
Methane-fired	542	-
SUM dispatchable	1391	-
Wind and Solar	4742	1656

In Section 4.5, the four options outlined in Section 3.5 are investigated in form of sensitivity analysis, namely:

1. increasing the amount of dispatchable generation,
2. increasing the installed wind and solar capacity,
3. using demand flexibility, and
4. adding or diversifying the energy storage capacity.

Prior to this analysis, in the following two sections we provide more insight into the results of the base-case (i.e. the one presented in this subsection), precisely:

- in Section 4.3 insights concerning the utilisation and potential additional need of energy storage, and
- in Section 4.4, results concerning Switzerland in specific.

4.3 Scenario 1: Utilisation and potential need of energy storage

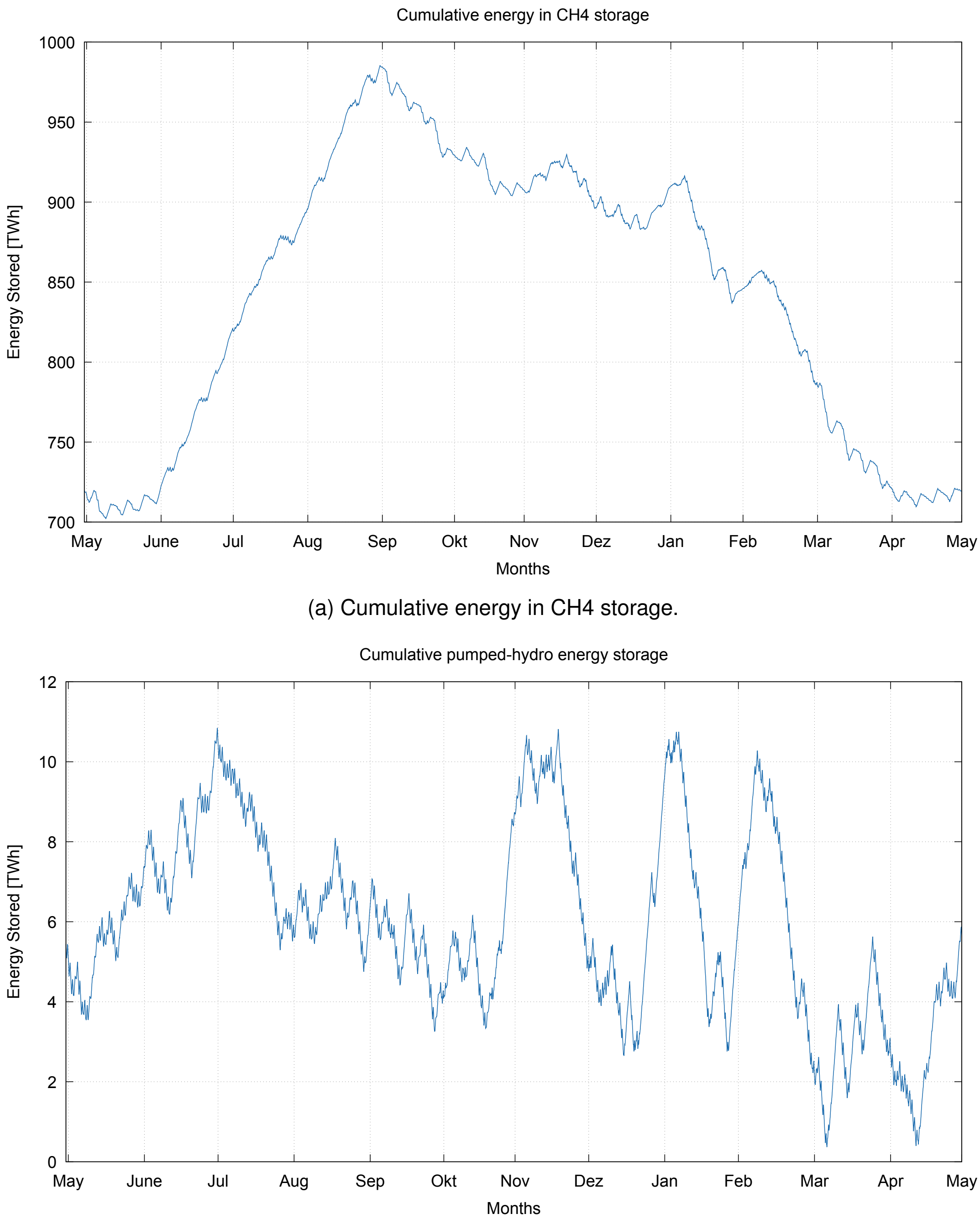
Figure 11 shows the amount of energy that is stored in the gas (CH4) and pumped-hydro storage units as resulted by the optimisation (where storage is optimally used for the overall cost minimisation).

It can be observed that methane is stored in a seasonal manner, accumulating during the summer period and then progressively being utilised during the rest of the year. This is mostly driven by the need to consume methane for electricity generation during the period when the renewable deficit is the higher (see Figure 6b). In addition to this seasonal trend, one can observe that small amounts of methane are extracted from or injected to the storage on a diurnal basis. This is driven by the diurnal solar pattern.

On the other hand, the available pumped-hydro storage is too little to be used on a seasonal basis. It is used to compensate weekly and diurnal variability.

An interesting metric towards designing a fully renewables-based energy system is to identify how much total energy storage would be required in order to be able to fully meet the electricity demand solely by utilising the available intermittent renewable sources (wind, solar and run-of-river). Figure 12 provides some related insights. Starting from the month of April, it shows the cumulative hourly difference between available renewable non-dispatchable electricity and electricity demand. One can see that excess renewable energy could accumulate (if stored) during the summer months and then be used during the winter months when there is a renewable energy deficit. **A seasonal shift of ~400 TWh of electricity would be required to achieve such a "sufficiency" on a European scale.**

Note that the total "non-dispatchable renewable energy deficit" equals to ~1'450 TWh of electricity (computed as the sum of dispatchable generation, i.e. 1'391 TWh as shown in Table 12, and the amount



(a) Cumulative energy in CH4 storage.

(b) Cumulative energy in pumped-hydro storage.

Figure 11: Scenario 1: Cumulative energy in CH4 and pumped-hydro storage.

of electricity demand that needed to be curtailed, i.e. 65.2 TWh). From Figure 12, one can derive the maximum amount of energy that needs to be stored (i.e. 409 TWh), not the total amount of energy shift (i.e. 1'450 TWh). These two differ, since an existing storage can be used to smoothen short-term fluctuations (shown as "riffles" in Figure 12) while in parallel being filled up for a long-term shift.

One can observe (see Figure 12) that in the "reference" scenario considered in this study, there is a surplus of ~500 TWh of electricity from wind, solar and run-of-river which can be accumulated from May until October. Assuming that the excess electricity is stored in form of hydrogen (by converting part of the

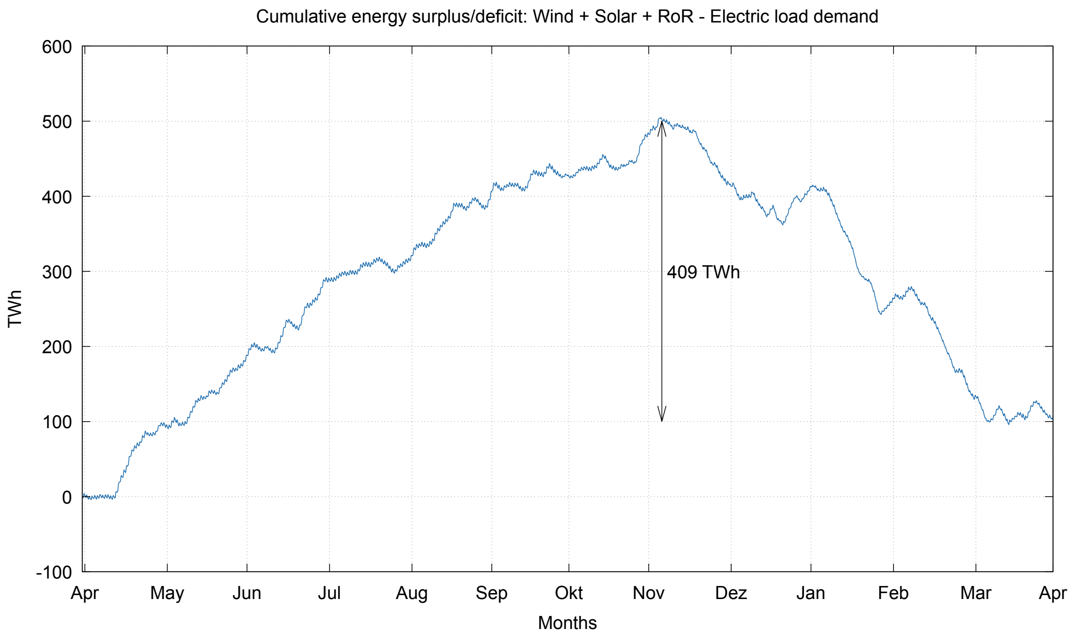


Figure 12: Scenario 1: Cumulative net supply of non-dispatchable renewables. Note that there is ~400 TWh of electric energy deficit from November to March. This amount of energy can be accumulated from May to October, provided enough storage is available.

existing natural gas storage locations to hydrogen - see Table 9), and utilising the efficiencies provided in Table 3 [19], one can compute that an input of 500 TWh can, eventually, generate back ~200 TWh [20], which is half of the "missing" 400 TWh. On the other hand, an additional ~360 TWh of electricity are available from reservoir-hydro (see Tables 7 and 3).

The above reasoning is obviously coarse. But, it provides evidence that a pathway where:

- part of the existing natural gas storage reservoirs are used for hydrogen storage, and
- enough capacity of electrolysers and hydrogen-fired power plants (or fuel cells) is added,

might allow for a massive electrification of the heating and transport sectors and satisfaction of the corresponding demand by massively increasing the installed wind and solar power generation capacities.

4.4 Scenario 1: Focus on Switzerland

While in the previous sections the presented results were aggregated over the entire considered European energy system, this section focuses specifically on Switzerland.

A total of 476.2 GWh of the final electricity demand needs to be curtailed. This corresponds to the 0.6 % of the total annual demand for electricity in Switzerland, which equals 80.7 TWh in scenario 1. Table 13 shows the contribution of the various sectors in the final demand for electricity. Similarly to the entire Europe (presented in Section 4.2), the deficit occurs in hours when there is no solar power, more often in winter months.

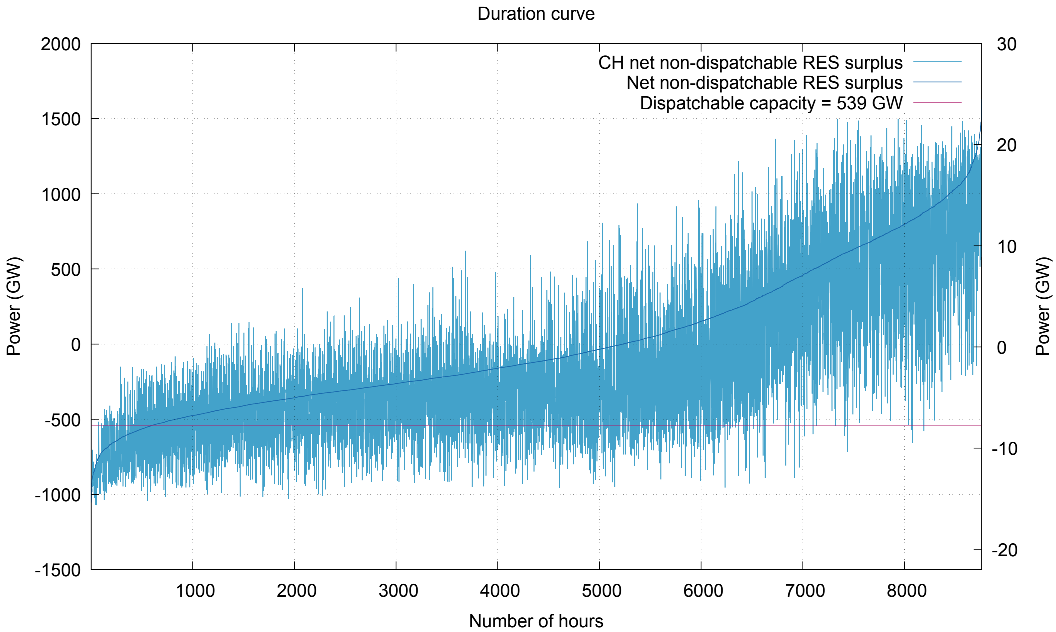
A discussion point that is often raised is whether and to what extent **could Switzerland rely on electricity imports to cover its electricity deficit**. Figure 13 provides relevant insight. Precisely, Figure 13a

[19] Electrolyser efficiency: 0.80. Hydrogen-fired power plant efficiency: 0.50.
[20] 0.50 x 0.80 x 500 = 200

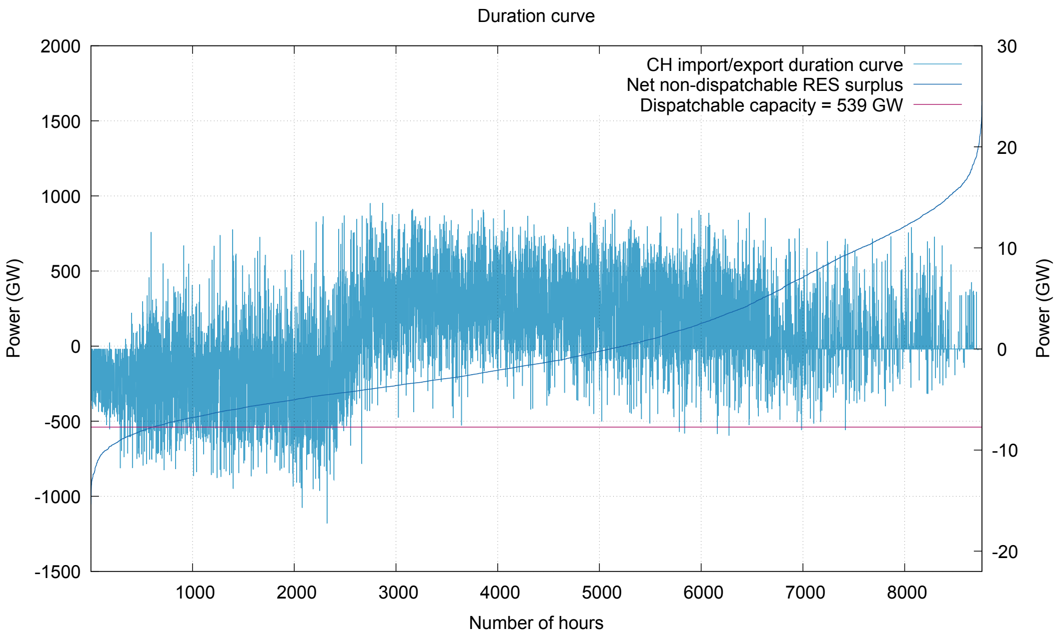
Table 13: Scenario 1: Annual final electricity demand per demand sector in CH (TWh)

Electric appliances	**Space & warm water heating**	**Passenger transport**	**Freight transport**	**Total**
32.20	17.37	25.76	5.40	80.73

shows the non-dispatchable renewable energy surplus/deficit for each hour, while Figure 13b shows the electricity exports/imports to/from Switzerland for each hour. In both cases the hour slots in the x-axis



(a) Scenario 1: CH duration curve, with x-axis according to EU duration curve



(b) Scenario 1: CH electricity exports, with x-axis according to EU duration curve

Figure 13: Scenario 1: Switzerland new non-dispatchable renewable surplus/deficit and electricity exports/imports

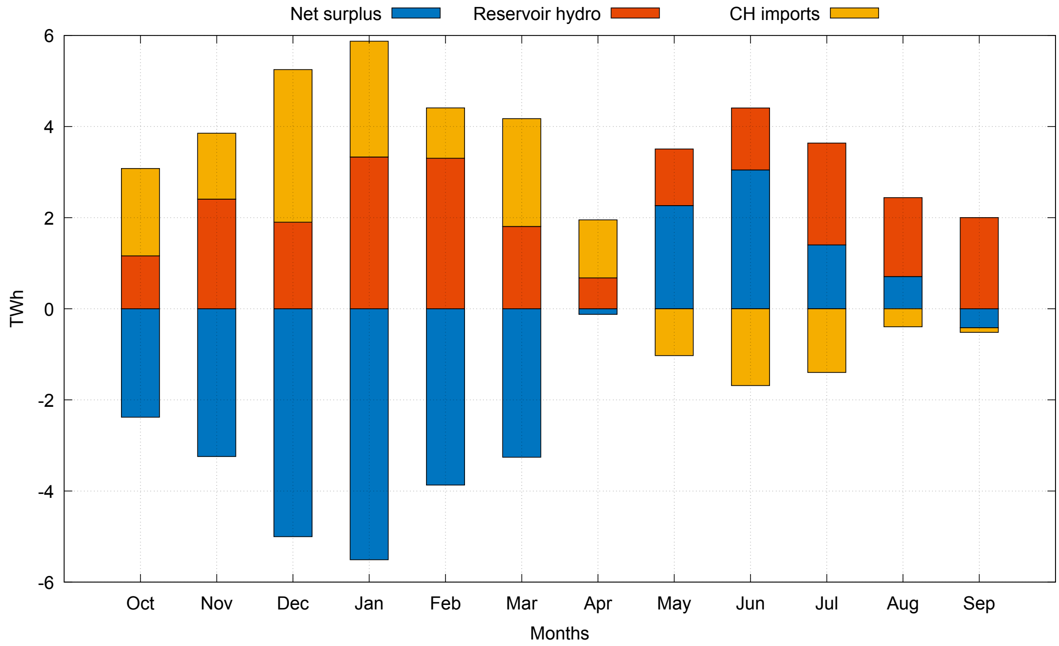


Figure 14: Scenario 1: Monthly surplus/deficit of variable renewables, electricity imports and reservoir-hydro utilisation (TWh)

are ordered as in the duration curve of the entire Europe, presented in Figure 9 and copied in 13 for the reader's convenience. Like this, one can directly compare the moment when there is a renewable power surplus or deficit at a pan-European scale with what is happening in Switzerland in specific.

It can be clearly observed in Figure 13a that, as a general rule, Switzerland experiences surplus and deficit at the same moments when the rest of Europe also experiences a surplus or, respectively, deficit.

Arguably, the ideal for Switzerland would be to be able to export its excess renewable energy to Europe at moments of surplus and be able to import electricity from Europe at moments of deficit. However, in a scenario where the European energy system develops similarly to the Swiss one in a setup where (i) energy is mostly provided by non-dispatchable renewables and (ii) the heating and transport sectors are electrified, this might be challenging to achieve, as illustrated in Figure 13b. One can observe that high Swiss renewable surplus cannot be exported to Europe (as it happens in moments when Europe does not need it), while an increased renewable deficit cannot be covered by Europe either, because it typically happens in moments when there is electricity scarcity in Europe as well. Clearly, **policy-makers and analysts should not assume Europe to be an "infinite buffer" of electric energy when they perform studies concerning the Swiss future energy system**.

Finally, Figure 15 shows the cumulative net supply of non-dispatchable renewables (wind + solar + run-of-river - electricity demand) for Switzerland (i.e. the same information as shows in Figure 12 for the entire Europe). One can observe that, contrary to Europe, in the considered "reference" generation capacity scenario and scenario 1 the available wind, solar and run-of-river energy is ~16.4 TWh lower than the total final electricity demand (note that, in addition to non-dispatchable renewables, ~23 TWh of electricity can be produced by reservoir-hydro annually).

Noteworthy is that even though there is enough electric energy in the considered scenario to satisfy the final electricity demand, this in practice cannot be achieved due to lack of available power generation capacity. In the worst hour, there is a deficit of 15.6 GW of non-dispatchable renewables (see Figure

16), while the dispatchable hydro installed capacity equals 13.7 GW (Table 6, including pumped-hydro capacity). As a matter of fact, **there are 69 hours in the year during which there is not enough power generation capacity in Switzerland to satisfy the electricity demand**. All these instances happen in the period from end of November until end of February.

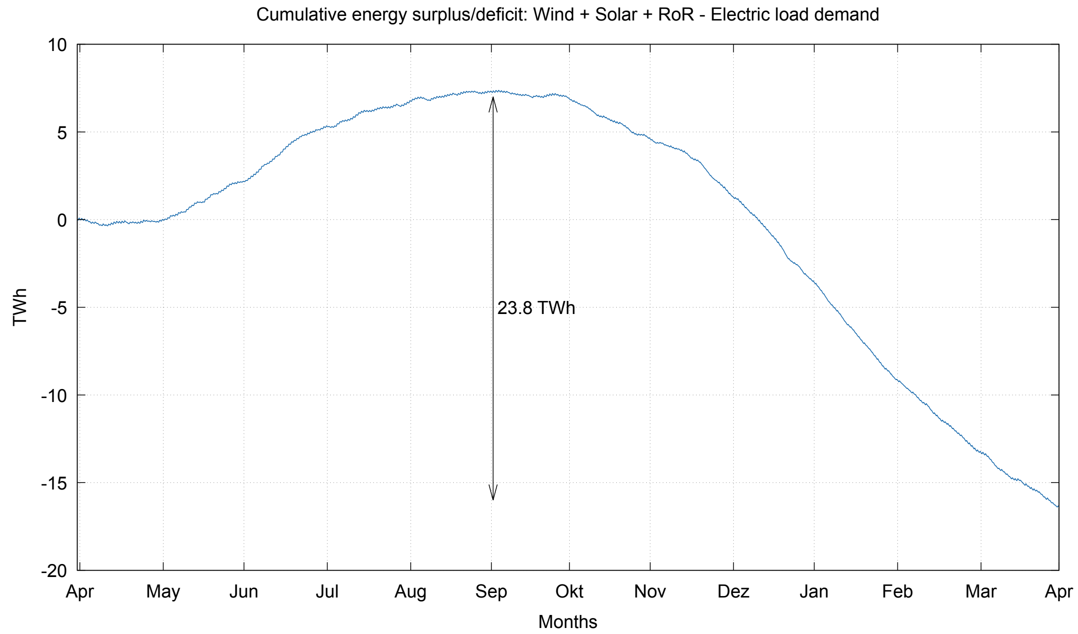


Figure 15: Scenario 1: Cumulative surplus of variable renewables (TWh)

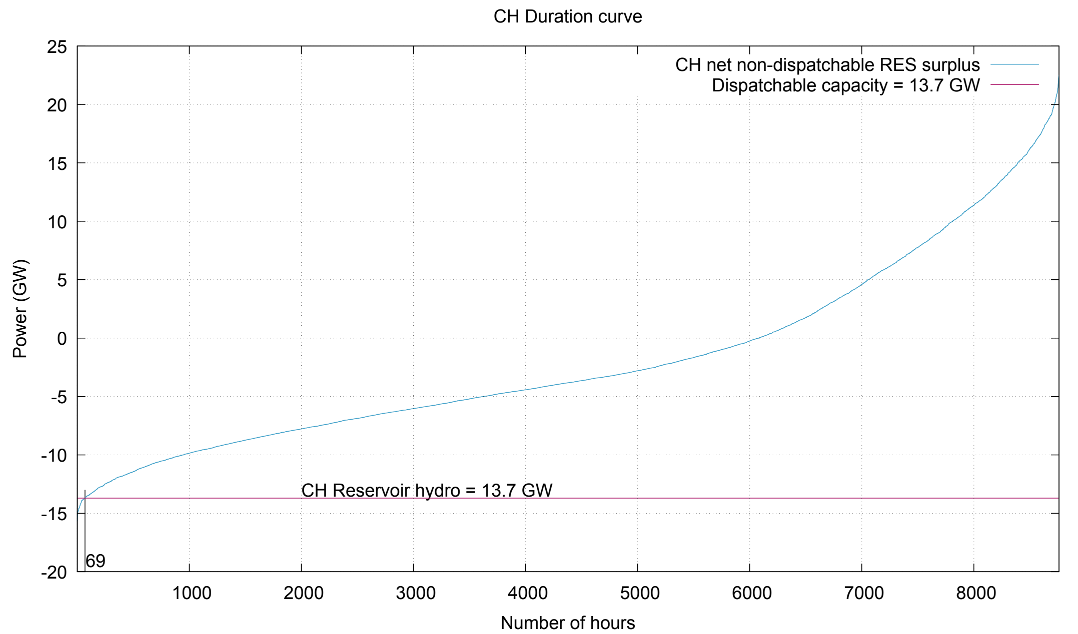


Figure 16: Scenario 1: Duration curve of net supply (wind + solar - electricity demand) for Switzerland

4.5 Scenario 1: Sensitivity analysis of various potential solutions

As illustrated in Section 4.2, the installed energy supply infrastructure of the "reference" scenario considered in this study (see Section 3.3) cannot satisfy the final demand that would result from an aggressive electrification of the low temperature heating and transport sectors. In this section we present, by means of sensitivity analysis, the potential of the various options presented in Section 4.2 and copied below:

1. increasing the amount of dispatchable generation,
2. increasing the installed wind and solar capacity,
3. using demand flexibility, and
4. adding or diversifying the energy storage capacity.

Precisely, the following "sub-scenarios" are considered. From now on we will refer as "Baseline" to denote the original scenario. Each sub-scenario is identical to the baseline, except of the modifications described below.

1. **"Gas plants +"**: The total methane-fired power plant capacity is increased to 400GW. In specific, EU capacity is increased to 337 GW, IT capacity to 63 GW, while CH capacity remains zero. This corresponds to an additional 118 GW of dispatchable methane-fired capacity compared to the baseline scenario (see Table 6). Clearly, such an increase is still not enough to provide to cover the peak of missing dispatchable power identified in Section 4.2 (which equals 497 GW), but it allows to quantify the potential of adding more dispatchable power capacity to the European energy system.
2. **"2x Wind & Solar"**: The total wind and solar power capacity is doubled for each of the considered nodes (see Table 6). This results on a total wind installed capacity equal to 2'264 GW and a total installed solar capacity equal to 4'825 GW. As a result, 12'796 TWh of electric energy are available annually from wind and solar in this sub-scenario[21]. Clearly, this amount of energy is greatly higher than the annual final electricity demand. However, there might still be time periods (hours, days, weeks) of energy deficit due to the the resource variability. This sub-scenario aims at quantifying the impact of massively increasing the installed non-dispatchable renewable capacity as a means to achieve higher penetration of those resources.
3. **"Flex demand 2h / 16h / 24h"**: In this set of three sub-scenarios, electricity demand flexibility is step-wise introduced; the demand for space & warm water heating as well as the charging of electric vehicles can be shifted by up to 2, 16 and, respectively, 24 hours (earlier or later) to enable the optimisation solver to obtain a better temporal match between available electricity supply and final electricity demand. Clearly, allowing the demand to be shifted for the sake of overall cost optimality corresponds to the implicit assumption that a proper demand flexibility market is in place. The design of such a market is beyond the scope of this study.
4. **"Hydrogen 2/3 of gas infra"**: Two thirds of the natural gas (i.e. methane) power generation and storage infrastructure is converted to be used for hydrogen (e.g. by replacing the compressors). In addition, a significant amount of the gas transmission network is converted to be used for hydrogen, according to the vision described in the "Hydrogen Roadmap Europe" [22]. It is assumed that enough electrolyser capacity is installed.The differences of this sub-scenario compared to the baseline can be seen in Table 14 and by comparing Tables 15 with 9 (where gas storage is exclusively used for methane) and Tables 11 with 10.

[21] For the sake of simplicity, we assumed that the capacity factor does not change as more capacity gets installed.

5. **"Hydrogen + 2x Wind & Solar"**: A combination of sub-scenario "2x Wind & Solar" with sub-scenario "Hydrogen 2/3 of gas infra".
6. **"PV+BESS 50%"**: Half of the total installed PV capacity corresponds to PV+BESS (battery energy storage system) systems. For each such system, it is assumed that the battery's power capacity equals 30 % of the PV capacity and that it has a C-rate equal to 1. That is, for example, a 10 kW PV is accompanied by a 3 kW - 3 kWh battery. The battery utilisation (i.e. when it charges and when it discharges) is performed by the solver for the sake of the overall system cost minimisation, i.e. similarly to the demand flexibility case, it is assumed that a functioning market is in place. The batteries are assumed to have a round-trip efficiency of 0.85. The resulting aggregated additional storage is shown in Table 16. One can observe that while a non-negligible dispatchable power capacity is added, the amount of energy storage capacity is very low (almost 100 times less that pumped-hydro energy storage capacity).

Table 14: Comparison of methane and hydrogen installed power capacities (GW), between the "Baseline" and the "Hydrogen 2/3 of gas infra" sub-scenarios

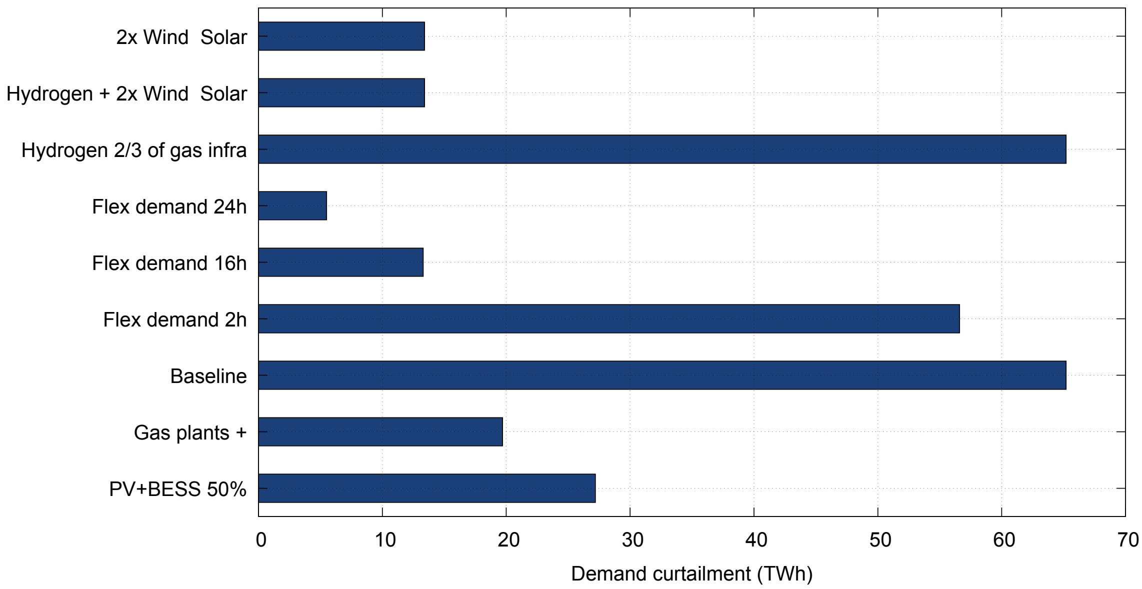
Sub-scenario	Technology	CH	IT	EU	Total
Baseline	Methane-fired power plants	0.00	45.00	242.00	287.00
	Hydrogen-fired power plants	0.00	0.00	0.00	0.00
	Electrolysers	0.00	0.00	0.00	0.00
Hydrogen 2/3 of gas infra	Methane-fired power plants	0.00	15.00	80.67	95.67
	Hydrogen-fired power plants	0.00	30.00	161.33	191.33
	Electrolysers	0.00	100.00	600.00	700.00

Table 15: Split of natural gas storage into storage for methane and storage for hydrogen in the sub-scenario "Hydrogen 2/3 of gas infra"

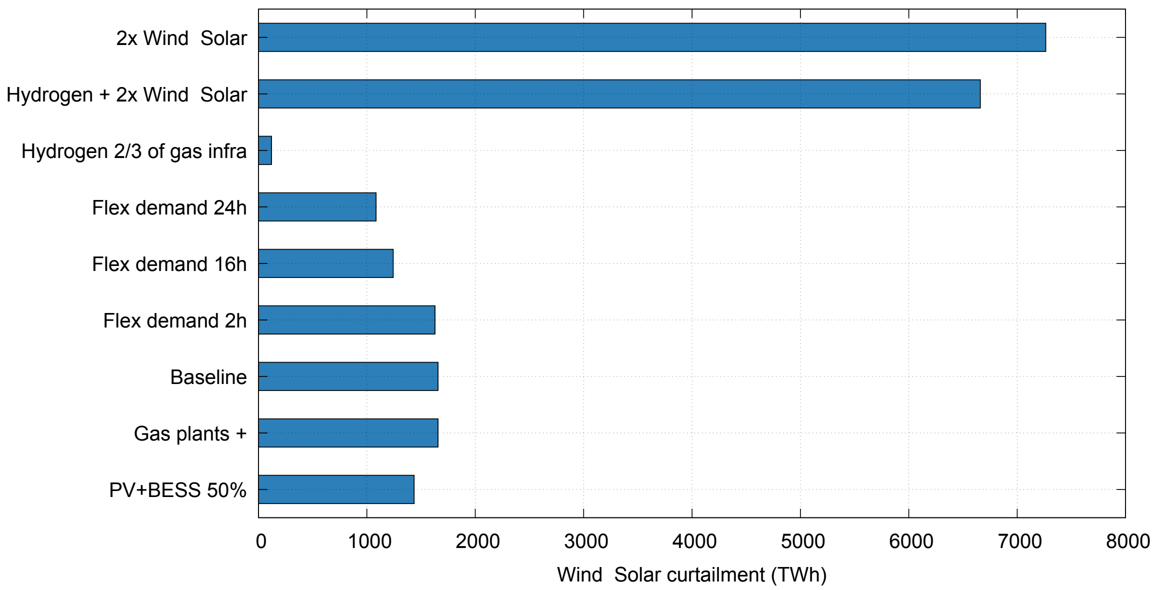
Storage type	Metric	CH	IT	EU	Total
Methane Storage	Storage volume (TWh)	0	84.88	395.08	479.96
	Charging capacity (GW)	0	49.48	302.46	351.94
	Generating capacity (GW)	0	30.82	187.35	218.17
Hydrogen Storage	Storage volume (TWh)	0	169.75	790.16	959.91
	Charging capacity (GW)	0	98.96	604.93	703.89
	Generating capacity (GW)	0	61.64	374.7	436.34

Table 16: Battery storage in the sub-scenario "PV+BESS 50%"

Storage type	Metric	CH	IT	EU	Total
Battery Storage	Storage volume (TWh)	0.009	0.064	0.530	0.60
	Charging capacity (GW)	5.63	38.48	317.80	361.90
	Generating capacity (GW)	5.63	38.48	317.80	361.90



(a) Scenario 1: Demand Curtailment



(b) Scenario 1: Wind and Solar curtailment

Figure 17: Scenario 1: Sensitivity analysis

The results from solving the various above-described sub-scenarios for scenario 1 are presented in Figures 17, 18 and 19, where "baseline" refers to the original scenario 1 (the one presented in Sections 4.2, 4.3 and 4.4).

Figure 17 shows the resulting need for demand curtailment (Fig. 17a) and wind & solar curtailment (Fig. 17b) for each of the considered sub-scenarios. Figure 18 shows the amount of electric energy generated by each of the dispatchable power generation technologies, while Figure 19 shows the resulting power generation fuel cost (Fig. 19a) and CO2 emissions (Fig. 19b).

One can observe that, with the exception of utilising the gas infrastructure for hydrogen, all other options reduce the curtailment of demand.

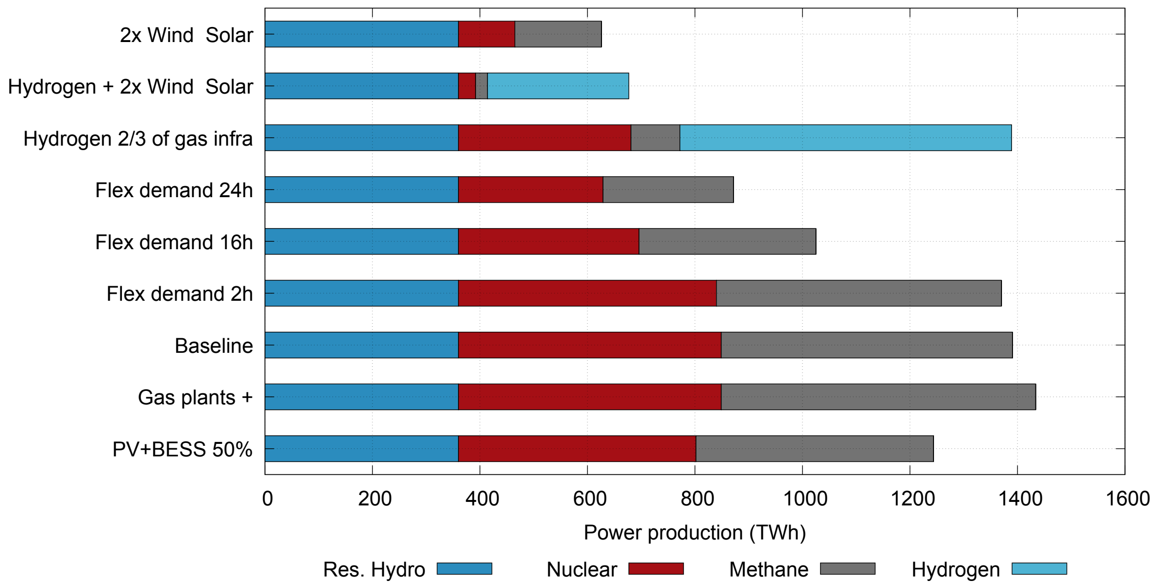
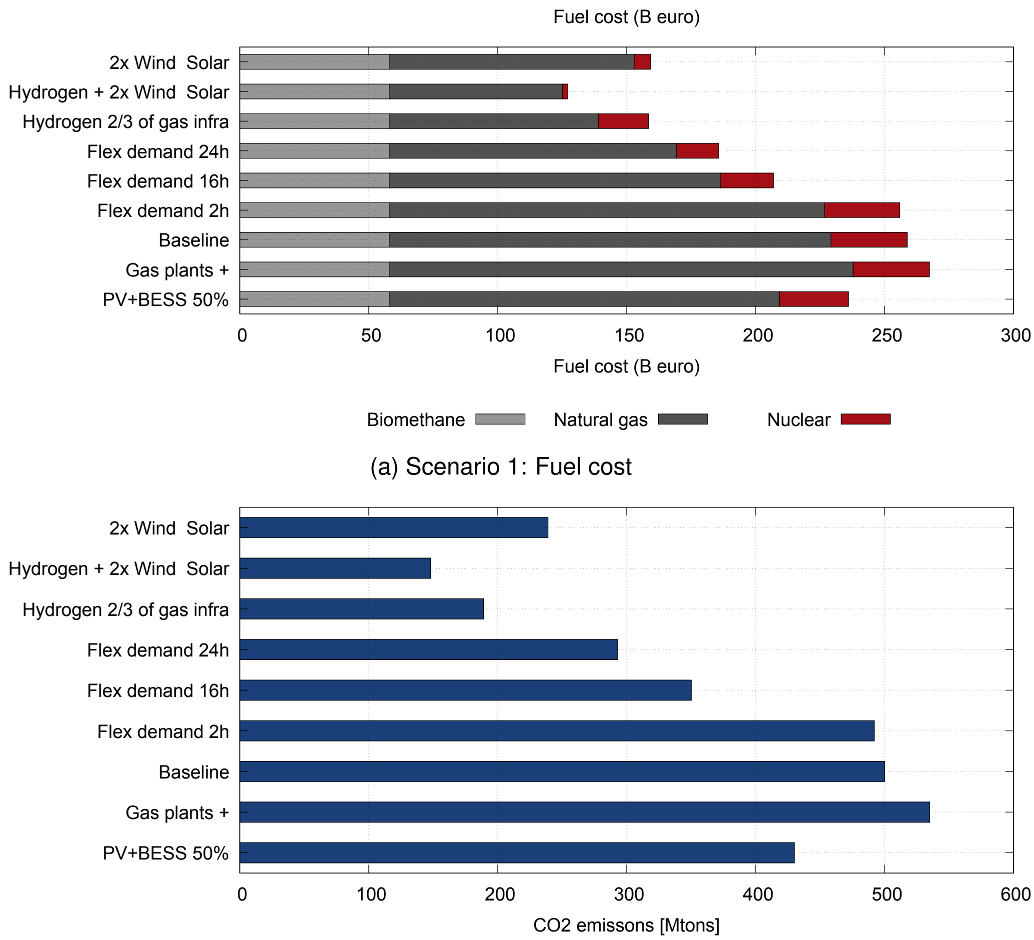


Figure 18: Scenario 1: Power production

- Sub-scenario "Gas plants +" achieves so by directly improving the lack of dispatchable power generation capacity discussed in Section 4.2 and illustrated in Figure 10. As expected, the extra ~200 GW of dispatchable power generation is not enough to satisfy the final electricity demand during all hour slots. As shown in Section 4.2, almost 500 GW of dispatchable generation are missing in order to achieve this. As a matter of fact, by performing additional simulations, we observed that even adding 500 GW of new gas power plants would not fully satisfy the final demand. The reason is that it is not feasible to draw so much gas from the network during one hour without upgrading the gas storage facilities. One can observe in Table 9 that at most 654 GW of gas can be injected from the storage location to the gas network. Adding (see Table 10 the 355 GW of natural gas which can flow from Russia and Africa during a given hour results in a maximum of 1'000 GW of gas which can be fed to the natural gas fleet, which, in turn, corresponds to a maximum ~of hourly electricity generation. One can however observe, in Figure 4.2, that ~750 GW would be required. Clearly, trying to rely exclusively on new dispatchable power generation capacity to obtain 100% adequacy is a path that would require very large investments in new power plants and the ability to extract stored methane at a high power rate.
- The family of "Flex demand" reduce the demand curtailment by shifting the excess electricity demand to hours when there is more energy available from wind and/or solar (see Figure 17b). One can observe, however, that for an allowed shift of up to 2 hours the benefit is relatively small (of course, still worth achieving). Even 24 hours of demand flexibility are not enough to completely eliminate the demand curtailment. Demand flexibility has clearly significant value (as will be discussed in the sequel, with reference to Figures 18 and 19), but it cannot realistically be the only option.
- In sub-scenario "PV+BESS 50%", reduction in demand curtailment is achieved thanks to the fact that the batteries make up a total of 362 GW of additional dispatchable power generation capacity (see Table 16). Clearly, this capacity cannot be fully utilised because of the limited energy storage capacity (observe that the sub-scenario "Gas plants +" achieved a larger reduction in demand curtailment by adding less power generation capacity to the system), but it is still noteworthy to



(a) Scenario 1: Fuel cost

(b) Scenario 1: CO2 emissions

Figure 19: Scenario 1: Sensitivity analysis

observe that most of the reduction can be achieved without the need for mid-term energy storage/shifting.

- Finally, it is not a surprise that adding more wind and solar capacity (in the "2x Wind & Solar" sub-scenario) allows to reduce the demand curtailment. On the other hand, one can clearly observe that there is clearly a saturation; solely adding more and more wind and solar is not the solution towards achieving a reliable future energy system.

Expectedly, converting (part of) the methane-fired power capacity to hydrogen-fired, as in sub-scenario "Hydrogen 2/3 of gas infra", makes no difference in the amount of demand curtailment. The reason is that there in no new source of dispatchability (or flexibility) added to this sub-scenario, but rather a change of input fuel. The benefit of replacing methane (hence, natural gas) with hydrogen can be seen in Figures 17b and 18: less natural gas and nuclear is used, while the available wind and solar energy is almost perfectly exploited. In other words, introducing hydrogen as an intermediate energy carrier (let us recall that, in scenario 1, there is no final demand for hydrogen) is an efficient facilitator towards a zero-CO2 (and even zero-nuclear) energy system.

Finally, it is important to point out that, beyond a certain penetration level, wind and solar energy cannot be easily accommodated by the system. The available energy stemming from the additional capacity is to a large extent wasted. For instance, while 6’398 TWh of available wind and solar energy are added

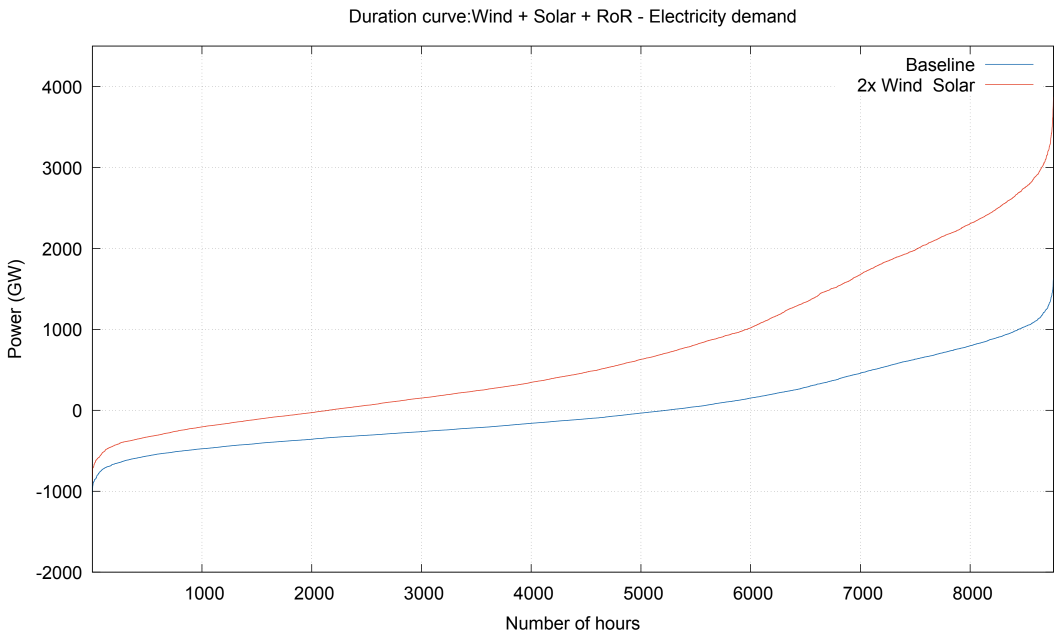


Figure 20: Scenario 1: Duration curve with double Wind and Solar installed capacity

in the "2x Wind & Solar" sub-scenario, 5'608 TWh of this additional energy is curtailed. That is, the utilisation factor of the additional 2'264 GW of Wind and 4'825 GW of Solar is only 12.35 %.

Again, one can observe (in sub-scenario "Hydrogen + 2x Wind & Solar") that using hydrogen as an intermediate carrier allows to increase the utilisation factor of the additionally installed wind and solar capacity (to 21.8 % of available energy), while practically eliminating the need for nuclear and natural gas as sources of energy.

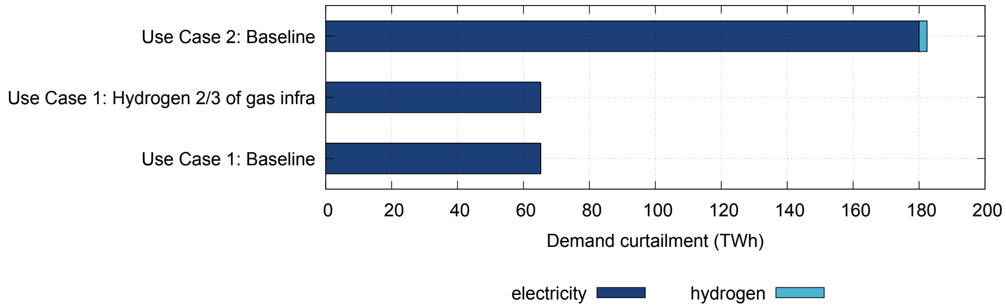
In the remainder of this section, two new scenarios are analysed. In these cases, part of the end energy demand is satisfied by technologies that utilise hydrogen as an input fuel. The objective of this analysis is to quantify the value (if any) of not only using hydrogen as an intermediate energy carrier (which is eventually converted back to electricity) but as an energy carrier which is delivered to the end demand.

4.6 Scenario 2: Replacing methane demand with hydrogen demand

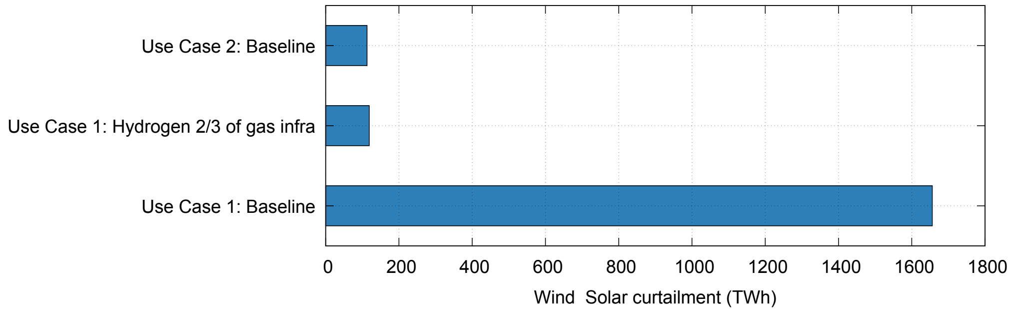
In scenario 2 (outlined in Section 3.5) it is assumed that process heating is satisfied by means of hydrogen boilers (instead of methane boilers, assumed in scenario 1). As a result, in scenario 2 there is *a final demand for hydrogen*, equal to 1'645 TWh (annual value). Since in this study hydrogen is only produced within Europe by electrolysis (as opposed to importing it from abroad), the final demand for hydrogen eventually results in an additional final demand for electricity equal to 2'056 TWh (see Figure 5b) compared to scenario 1[22]. Since in scenario 2 it is assumed that hydrogen has an overall considerable penetration in the European energy system, it is assumed that 2/3 of the gas power plants and the gas storage are used for hydrogen (as shown in Tables 14 15), the gas network is partly dedicated to hydrogen according the "Hydrogen Roadmap Europe" (as shown in Table 11). In other words, scenario 2 is identical to the "Hydrogen 2/3 of gas infra" sub-scenario of scenario 1, except that in scenario 2 the process heating is served by hydrogen-fired boilers (instead of methane-fired ones).

In Figures 21, 22 and 23, scenario 2 is compared with the baseline scenario 1 as well as the sub-

[22] This number results from the assumed efficiency of the electrolyser which is 0.80.



(a) Scenario 2: Demand Curtailment



(b) Scenario 2: Wind and Solar curtailment

Figure 21: Scenario 2: Sensitivity analysis

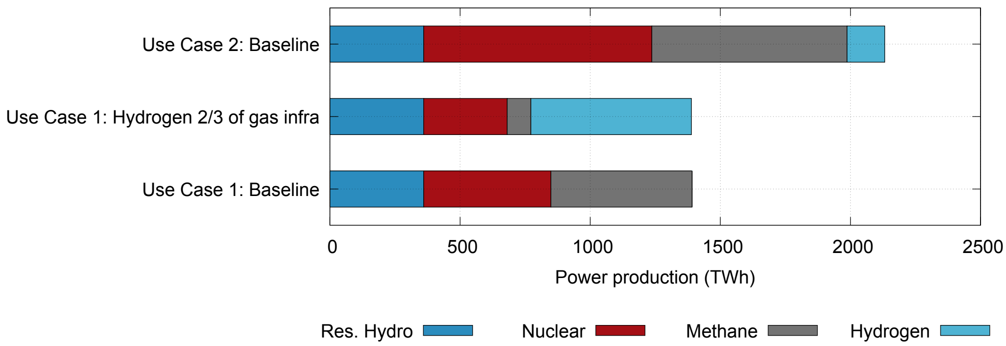


Figure 22: Scenario 2: Power production

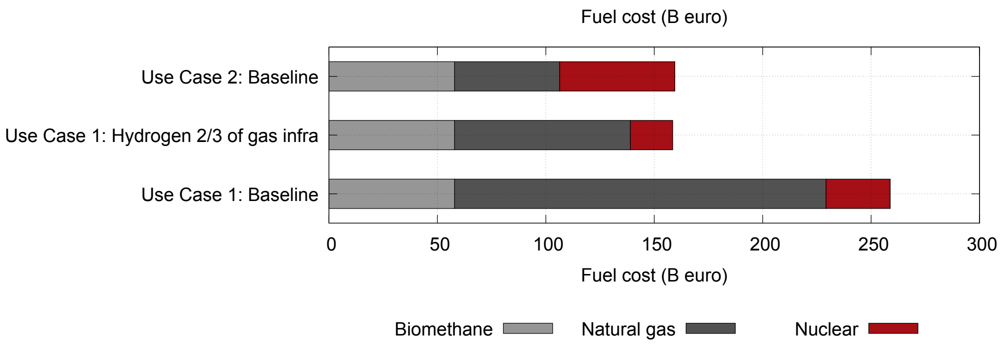
scenario "Hydrogen 2/3 of gas infra" of scenario 1. The same metrics as in Section 4.5 are used, i.e. the amount of demand and of wind & solar curtailment, the power generation from dispatchable sources, the total fuel cost and the CO2 emissions.

The following observations can be made:

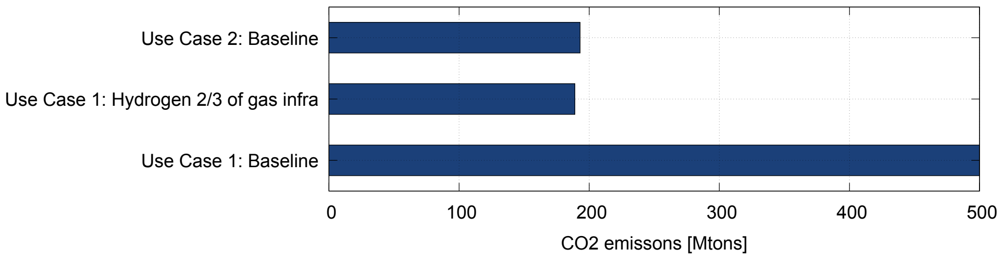
1. Introducing a final demand for hydrogen (instead of methane) turns out to make the satisfaction of end energy demand rather more difficult than easier; more demand needs to be curtailed (Figure 21a).

2. The availability of adequate amount of hydrogen storage allows to utilise almost the entire available wind and solar energy (Figure 21b). Replacing demand for methane with demand for hydrogen does not alter this.

3. The increased electricity demand from electrolysers (to produce the hydrogen which is to be



(a) Scenario 2: Fuel cost



(b) Scenario 2: CO2 emissions

Figure 23: Scenario 2: Sensitivity analysis

burned in the hydrogen boilers) requires more power to be generated by nuclear and methane power plants (Figure 22).

4. The CO2 emissions and total fuel cost are a result of the aforementioned points 2 and 3.

For the understanding of these results, it is helpful to review the flows of energy among the different energy carriers and sectors between scenario 2 and the sub-scenario "Hydrogen 2/3 gas infra" of scenario 1, presented as follows.

Common in both cases:

- Available methane = 4'125 TWh
  - Out of which 3'109 TWh from natural gas, which the solver tries to use as little as possible
- Available renewable electricity from wind, solar and hydro = 6'948 TWh[23]
- Final electricity demand = 6'328 TWh (Figure 5a)
- Excess renewable energy which could be converted to hydrogen to satisfy a hydrogen demand (if there is any), otherwise it will be wasted = 620 TWh (i.e. 6'948 - 6'328)
  - Amount of hydrogen which can be produced from this energy surplus = 496 TWh
- Maximum potential electricity production from methane due to installed generation capacity = 838 TWh[24]
- Maximum potential electricity production from hydrogen due to installed generation capacity =

[23] It stems from summing the available energy from wind, solar and run-of-river as provided in Table 7 and the available energy from reservoir-hydro which is derived from the value in Table 7 multiplied by the efficiency of the turbine provided in Table 3.
[24] It stems from multiplying the installed capacity of methane-fired power plants (95.67 GW) by 8'760 hours.

1’676 TWh[25]

Scenario 1 ("hydrogen 2/3 of gas infra"):

- Methane consumed for process heating = 1’650 TWh[26]
  - That is, all the available biogas, which equals 1’016 TWh, needs to be used. The remaining demand shall be met by natural gas.
- Methane remaining for electricity generation = 2’475 TWh (i.e. 4’125 - 1’650)
- Maximum amount of electricity that could be generated by methane if enough power capacity was available = 1’238 TWh (i.e. 0.5 x 2’475)
  - As this value is larger than 838 TWh (see above), the latter is the binding
  - The solver tries to use as little of this electricity as possible, since it can be produced only by consuming natural gas

Scenario 2:

- Available methane (which is all available for electricity generation since there is no demand for methane) = 4’125 TWh
  - out of which 3’109 TWh from natural gas, which the solver tries to use as little as possible
- Maximum amount of electricity that could be generated by methane if enough power capacity was available = 2’063 TWh
  - Since there is no demand for methane, it can all be used for electricity generation
  - However, in practice only 838 TWh could at most be produced, due to the installed power plant capacity as shown above
  - 508 TWh can come from biogas, the solver tries to use as little as possible of the remaining, since it can be produced only by consuming natural gas
- Hydrogen consumed for process heating = 1’650 TWh
  - As mentioned above, the renewable energy annual surplus can generate 496 TWh of hydrogen.
  - Hence, in order to satisfy the final demand for hydrogen, an additional 1’154 TWh (i.e. 1650 - 496) of hydrogen needs to be produced, which cannot be "matched" by available renewable energy.
- Electricity required to produce the aforementioned hydrogen = 1’443 TWh

From the above analysis, one can observe that, for the installed capacities assumed in these scenarios, creating a considerable amount of final demand for hydrogen (instead of it being demand for methane) results in a need for electricity generation that cannot be covered by the available renewable energy. As a result, nuclear and methane need to be used (see Figure 22).

Furthermore, as discussed in Section 4.2, the challenge that eventually leads to demand curtailment is the missing power generation capacity which would satisfy the final electricity demand even during hours of extremely low wind and solar availability. Clearly, adding an additional electricity demand (for

[25] It stems from multiplying the installed capacity of hydrogen-fired power plants (191.33 GW) by 8’760 hours.

[26] It stems from multiplying the demand for process heating in Table 5 with the efficiency of the methane boiler provided in Table 3.

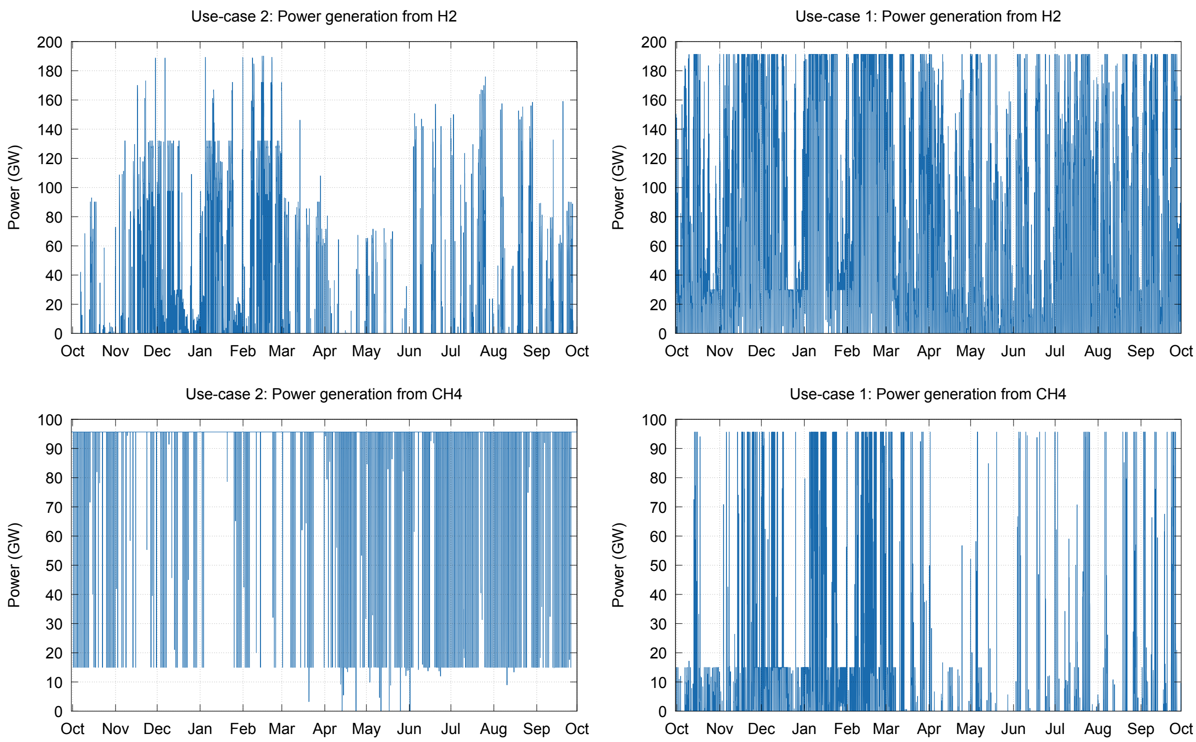


Figure 24: Scenario 2 vs Scenario 1 - sub-scenario "Hydrogen 2/3 of gas infra": Power production by hydrogen-fired and methane-fired power plants (GW)

electrolysers) in scenario 2 does not help alleviate the problem. As illustratively shown in Figure 24, while in scenario 1 - sub-scenario "Hydrogen 2/3 of gas infra" it was mostly hydrogen-fired plants which were providing the required flexibility, with methane-fired plants being used only in the hours of the highest deficit, in scenario 2 this is reversed: now it is mostly the methane-fired plants that are used to cover the demand deficit, while the hydrogen-fired ones are used only in moments of scarcity.

Finally, by looking at the duration curves of the use of hydrogen storage (Figure 25), one can observe that, in scenario 2, there are a few hundred hours (precisely 348) during which hydrogen is extracted from the hydrogen storage at its maximum possible rate (see value of "generating capacity" in Table 15). This practically means that, that during these hours the system needs to use more hydrogen (which is stored), but cannot extract it as fast as needed.

All in all, simply said, the available renewable energy supply considered in this study as "reference" scenario is not enough to support a full electrification (direct or indirect, by means of hydrogen) of the end energy demand. For this reason, keeping a part of the demand served by methane has value. Even if this demand is served by means of hydrogen, still keeping a part of the gas network and storage for methane has value, since methane is needed for electricity generation.

In the following sections, we will investigate whether increasing the supply of renewable energy (by means of more installed wind and solar capacity) might change the aforementioned observation.

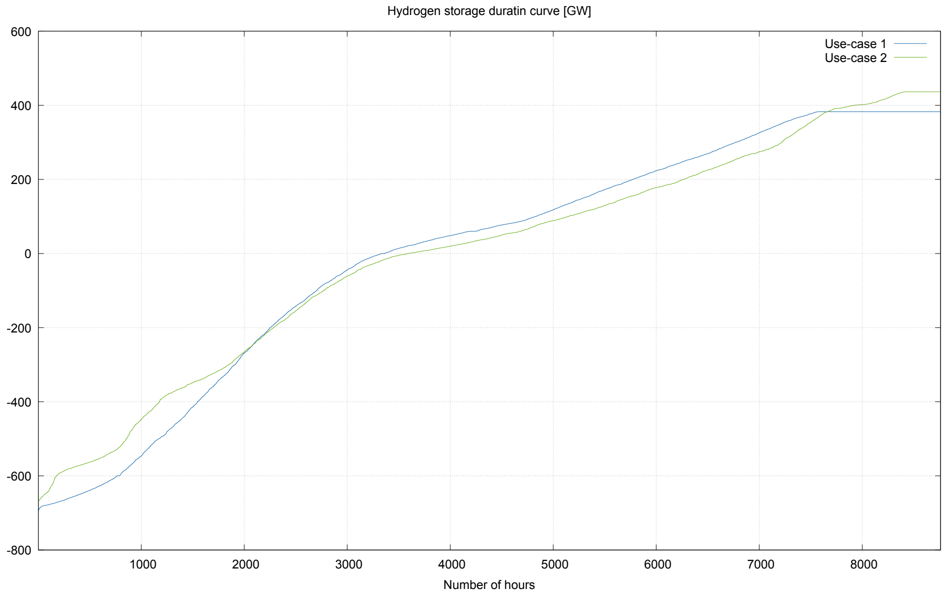


Figure 25: Scenario 2 vs Scenario 1 - "Hydrogen 2/3 of gas infra": Duration curve of hydrogen storage generation and storage (GW). Positive signs corresponds to injection of hydrogen into the network.

4.7 Scenario 2: Increasing the installed wind and solar capacity

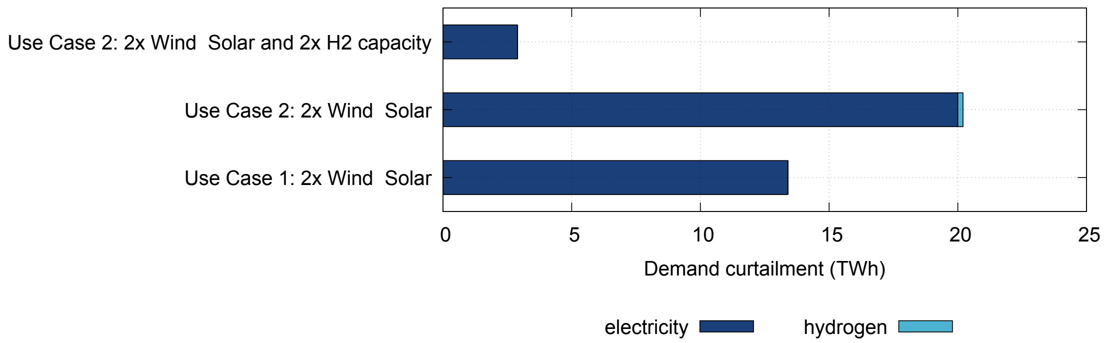
Similarly to scenario 1 - sub-scenario "2x Wind & Solar", in this section we investigate the impact that doubling the amount of installed wind and solar capacity would have on scenario 2. The results of this new scenario 2 (which we call scenario 2 - sub-scenario "2x Wind & Solar"), presented in Figures 26, 27 and 28, are compared with the results stemming from scenario 1 - sub-scenario "2x Wind & Solar", as well as a sub-scenario, inspired by the finding of Figure 25, where in addition to doubling the installed wind and solar we also double the hydrogen storage injection and extraction power capacities and the capacity of hydrogen-fired power plants.

One can observe that, in the two sub-scenarios of scenario 2, the increase in wind and solar capacity is enough to almost completely eliminate the use of natural gas (see zero CO2 emissions in Figure 28) and minimally use nuclear. Clearly, this is an improvement compared to the corresponding sub-scenario of scenario 1, where the demand for methane could not be met solely by biogas. Contrary to the baseline scenario 2 sub-scenario, the increased wind and solar allows to fully utilise renewable energy (including biogas). Slightly more than 5'000 TWh of wind and solar energy are redundant and need to be curtailed.

Notably, thanks to the increased wind and solar capacity, the amount of demand curtailment is drastically decreased (by 9-fold; compare Figure 26a with 21a). However, it is not entirely eliminated. Enough dispatchable generation is missing at moments with very low wind and solar availability. Adding such capacity in sub-scenario "2x Wind & Solar and 2x H2 capacity" reduces the demand curtailment to 3 TWh per year. It is however impressive that even in this sub-scenario with a total dispatchable capacity equal to 730 GW (see Table 17), there is still need for more dispatchability (or demand flexibility).

Clearly, even with the use of hydrogen as a supplementary energy carrier, very large power capacity investments are required in order for an (almost) 100% renewable energy system to be reached without compromising its reliability.

However, if the appropriate investments are made, it seems that natural gas (and nuclear) can be fully removed from the energy mix.



(a) Scenario 2: Demand Curtailment

(b) Scenario 2: Wind and Solar curtailment

Figure 26: Scenario 2: Sensitivity analysis

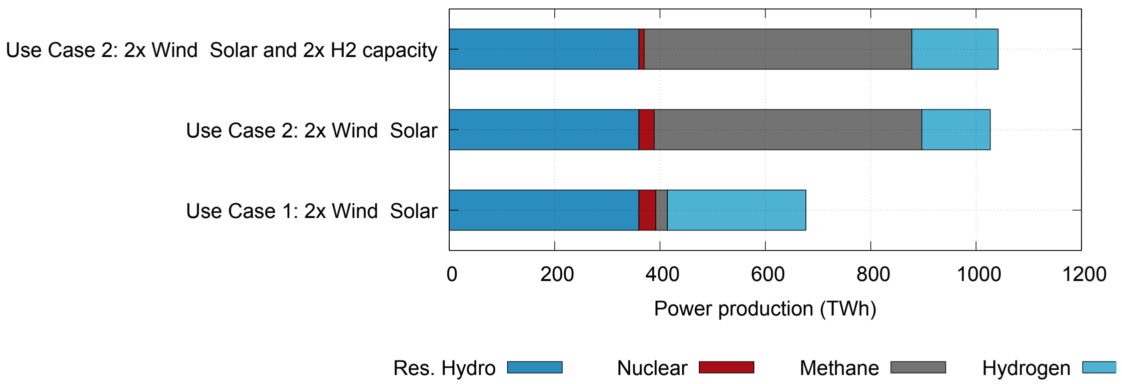


Figure 27: Scenario 2: Power production

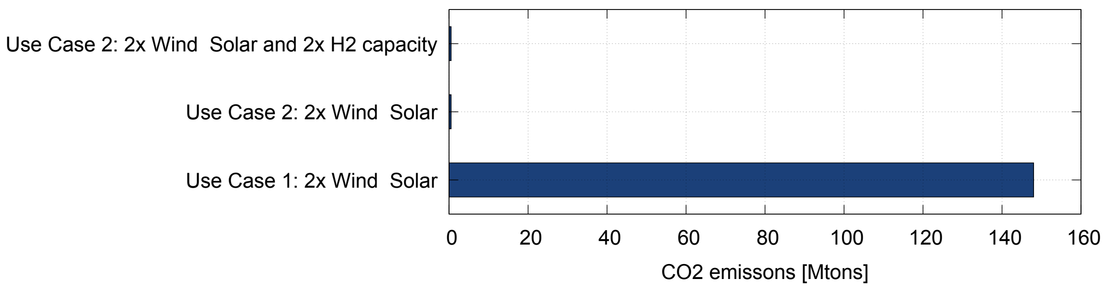


Figure 28: Scenario 2: CO2 emissions

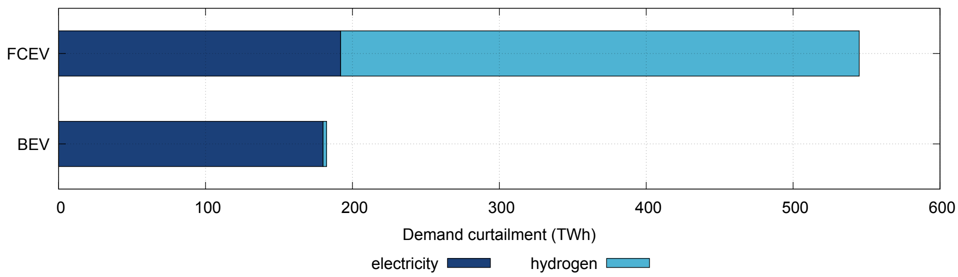
Table 17: Dispatchable power generation capacity in the sub-scenario "2x Wind & Solar and 2x H2 capacity"

Type	CH	IT	EU	Total
Nuclear	0.0	0.0	110.0	110.0
Methane-fired	0.0	15.0	80.7	95.7
Hydrogen-fired	0.0	60.0	322.7	382.7
Reservoir hydro	9.9	4.2	75.7	89.8
Pumped hydro	3.9	7.8	40.0	51.6
Total	13.8	87.0	629.0	729.7

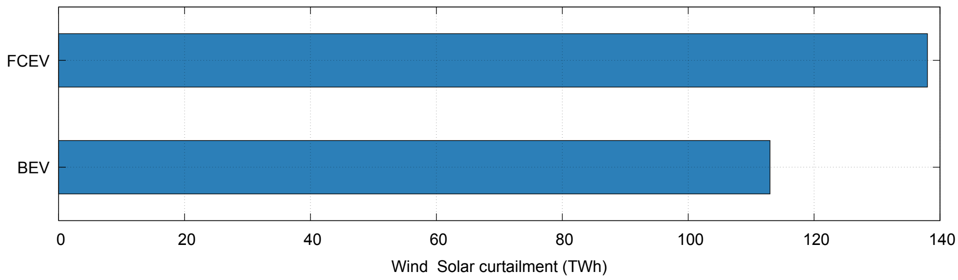
4.8 Scenario 3: Replacing electricity demand with hydrogen demand

Section 4.6 illustrated the impact of converting methane demand (for process heating) to hydrogen demand. In this section an additional step is made: the fleet of heavy duty trucks is assumed to be made of FCEV (instead of BEV so far). Process heating is met by hydrogen boilers as in scenario 2.

Figures 29a, 30 and 31 compare the results of this new scenario 3 with the ones of scenario 2. One can observe that replacing BEV trucks with FCEV makes it more difficult to satisfy the demand. The reason is the same as already explained in Sections 4.6 and 4.7: increasing the net electricity demand by converting BEV trucks to FCEV exacerbates the already existing and challenging problem of lack of dispatchability at moments with low wind and solar power.



(a) Scenario 3: Demand Curtailment



(b) Scenario 3: Wind and Solar curtailment

Figure 29: Scenario 3: Sensitivity analysis

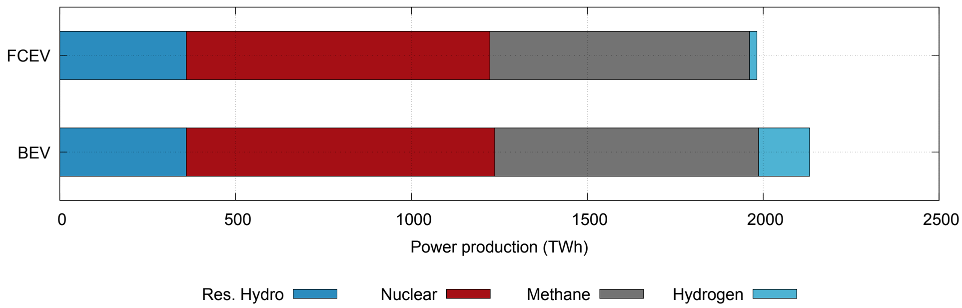


Figure 30: Scenario 3: Power production

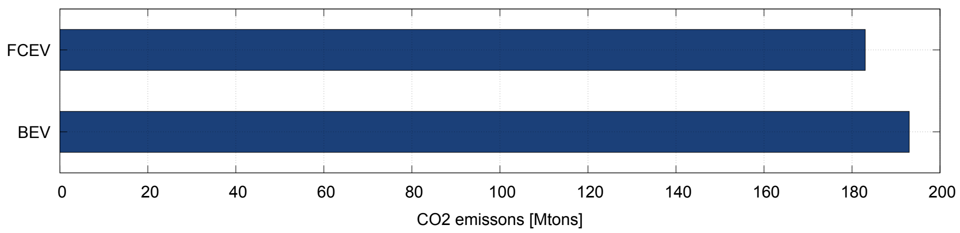


Figure 31: Scenario 3: CO2 emissions

5 Conclusions

The analysis presented in this report puts emphasis on considering the energy system as a whole, simultaneously modelling and optimising the utilisation of all energy carriers and demand sectors within one single framework. This allows to identify the optimal ways in which the various involved technologies can complement each other. Importantly, the performed analysis allows to optimise (i) the utilisation of energy storage resources and (ii) the flows of energy among different sectors of the energy system. The conclusions derived in this study are mostly generic, referring to the entire Europe[27]. Since Switzerland has been modelled as a separate node, while considering its connections to the rest-of-Europe, conclusions are also derived with respect to the dependence of the Swiss energy system on the developments outside the Swiss territory.

5.1 Summary of main findings

In short, the main findings derived from the performed analysis are summarised below together with associated discussion points.

1. Huge investments in electricity generation technologies are needed in order to maintain energy adequacy (measured annually)
   - Eliminating the use of fossil fuels (oil and natural gas) in the heating and transport sectors creates a very large energy deficit (in the order of 1’000s TWh annually for the entire Europe).
   - If, as expected (or even planned), the demand of those sectors is satisfied mostly by means of electric heat pumps and battery electric vehicles and complemented by technologies such as hydrogen boilers, fuel cells and fuel cell electric vehicles, this would require a need for a tremendous increase of electricity generation (in the order of 1’000s TWh annually for the entire Europe) as well as an infrastructure that is able to produce and distribute hydrogen.
   - A few thousand GW (for the entire Europe) of new wind and solar capacity (large- or small-scale) will be required in order to provide the energy stemming from the increase in electricity demand. If this is combined with a progressive removal of coal and, to a certain extent, of nuclear and natural gas-based power generation capacity, then even higher wind and solar investments will be required.
   - It is documented that there is a potential of ~1’000 TWh of energy in form of biomethane in Europe. Clearly this is not enough to play a dominant role or cover a demand sector alone (e.g. process heating). However, ramping up biogas production has the advantage of being directly accommodatable by today’s energy system, hence it can serve as a transition fuel, partially replacing natural gas.
2. Even with extremely high wind and solar penetration levels, reliably satisfying the final demand requires the presence of very high levels of installed peak power generation capacity and/or very aggressive demand-side flexibility schemes
   - In this study, it was clearly observed that even when enough wind and solar energy is available to cover the final electricity demand on an annual basis, there is often hours or periods of time

[27] For which time-series of wind, solar, run-of-river and reservoir-hydro energy inflows were used and for which the cross-country transmission capacities and the natural gas inflow and local biogas production potential were considered. Also, the utilised scenarios (of end energy demand and installed technologies) were taken from reference studies made for the EU and Switzerland.

during which there is a considerable deficit of available renewable energy which needs to be covered by dispatchable power generation. This deficit can be extremely high, close to the peak electricity demand. As a result, the installed peak power capacity that needs to be available is almost as high as what would be needed if no wind and solar installations were there.

- As there is not enough dispatchable hydro capacity to cover this peak, fuel-based (nuclear, methane, hydrogen) power generation is needed.
- Demand-side flexibility (either by means of shifting of the actual use, or by means of local energy storage, such as in batteries or in form of thermal) is the necessary complement to peak power capacity. The amount of demand-side flexibility that would be required to bridge the temporal mismatch between demand and non-dispatchable power supply is clearly unrealistic (in the order of postponing consumption of electricity by more than 24 hours). But, on the other hand, demand-side flexibility is often a relatively low cost option, which can alleviate the burden from peak power capacity.
- Supply-demand mismatch: All-in-all, the temporal mismatch between renewable supply and electricity demand has been identified in this study as a very challenging problem, which will probably stress the reliable operation of the future energy system as wind and solar increasingly dominate the supply side and end demand is increasingly being electrified.

3. Energy storage has a high value in the future energy system, at all time-scales (from diurnal to seasonal). Hydrogen storage, in specific, is a great enabler for higher utilisation of wind and solar.
   - Role of energy storage: Energy storage can play a significant role in both challenges of the future energy system (which one can see as the two faces of the same coin). It can (i) contribute to bridging the temporal mismatch between available renewable energy supply and final demand, while it can also (ii) allow enough fuel to be accumulated so that it can be used by peak power units when needed.
   - Hydrogen for large-scale energy storage: In order for energy storage to be beneficial for item (i) above, the storage system needs to be able to "consume electricity" (optionally, it could also "produce electricity"). Pumped-hydro and batteries can facilitate the short-time regulation, but they cannot accommodate the storage of large amounts of energy. For the envisioned future levels of renewable penetration and demand electrification, large-scale storage is important. This role can be practically fulfilled by hydrogen storage, since it combines the following three characteristics:
     – Ability to store longer term in large quantities. The existing natural gas storage formations can be used for this purpose.
     – Ability to efficiently be produced by consuming electricity. Electrolysers are relatively mature technologies nowadays.
     – Ability to either act as an energy carrier used to serve the end demand (by means of hydrogen boilers and fuel cells) or to be converted back to electricity (by means of hydrogen-fired turbines and fuel cells), injected to the electricity network when there is a wind and solar deficit.
   - Energy storage as a means to meet the peak demand: Energy storage can also be beneficial for item (ii) above. Reservoirs can store water and gas formations can store methane gas

(natural gas or biogas) to be fed to peak dispatchable units (hydro and, respectively, gas turbines) to produce electricity when needed, thus allowing to decouple the inflow of primary energy from its utilisation. Hydrogen storage can also play this role, provided that hydrogen-fired power generation capacity is there.

4. It is questionable whether satisfaction of the end demand by means of hydrogen (instead of electrifying) brings value from the overall energy system perspective.
    - Utilising hydrogen technologies in order to satisfy the end demand for energy eventually results in an increased need for supply of electricity, since hydrogen needs to be produced by means of electrolysers.
    - Even though this new electricity demand (i.e. the input to electrolysers) is flexible, thanks to the possibility to store hydrogen, it still increases the challenge of meeting the net demand peaks at all moments.
5. It seems that a progressive repurposing of today's gas infrastructure (network, storage and power plants) from methane to hydrogen will have value in the future energy system
    - An important driver behind repurposing is the need to reduce utilisation of natural gas as a fuel, due to CO2 footprint and maybe security of supply reasons. If the above motivation disappears, then natural gas shall probably have a role in the future energy system, thus decreasing the value of hydrogen.
    - Biogas availability is not enough to allow it to replace natural gas.
    - As explained above, hydrogen is well suited for enabling a very high utilisation rate of the available wind and solar energy, hence allowing to operate the energy system solely based on renewable energy supply.
    - Existing gas storage formations today offer enough storage capacity.
    - The existing fleet of methane-fired power plants can be progressively converted to hydrogen-fired. More peak power capacity will be required though, as explained in point 2 above.
6. Switzerland relying on rest-of-Europe acting as a buffer entails risks
    - If the entire Europe follows a similar path towards non-dispatchable renewable energy supply and electrification of end demand, the moments when Switzerland will experience an energy deficit will highly correlate with the rest-of-Europe experiencing energy deficit as well.
    - That being said, Switzerland being integrated in the greater European energy market is of high value as it allows to indirectly access the gas storage locations, as well as take advantage of the electricity interconnects since aggregating over a larger geographical area clearly smoothens the supply-demand mismatch problem compared to each country solving it solely by its own means.

Further discussion points:

- The fact that methane boilers are already readily in use in the energy system (burning natural gas) allows to easily accommodate biogas injections to the network. Methane can also make up a fuel for transport (methane motor engines). However, this would require infrastructure updates and it is not clear whether it is worth doing so as part of an energy transition if natural gas is to be eliminated in the mid-term, since these technologies (namely trucks and gas distribution stations) have a long lifetime.

- Heat pumps seems to be the dominant solution for heating (at least low temperature heating) due to their very high performance (since they draw most of the energy from the environment). Clearly, the heat pumps' compressors are electric, making heating by means of heat pumps essentially electricity load. However, in principle, the compressor could be powered by another energy carrier, such as hydrogen. This would make hydrogen-driven heat pumps extremely more efficient compared to hydrogen boilers and, possibly, a valid competitor to electric heat pumps. This option has not been considered in this study.

5.2 Addressing the questions of this study

Clearly, this study does not provide "definite" answer to any of the questions raised in Section 1.3. However, it provides valuable insights, summarised as follows.

- Which of the three pathways outlined in Section 1.1 is preferable?
  - Probably a pathway closer to the "full electrification pathway with storage in intermediate energy carriers", as explained in Findings 3 and 4.
- What is the value of cross-country exchanges of energy carriers?
  - Very high value as the aggregation over a larger geographical area allows to "smoothen" the mismatch between renewable availability and energy demand, while cross-country flows of energy carriers allow to explore the best locations (for wind and solar) and to maximise the utilisation of resources such as gas storage, hydro and peak power units.
- To what extent the optimal design of Switzerland's future energy system depends on the developments in the rest of Europe? Which of those developments are the most critical for Switzerland?
  - As stated in Finding 6, Switzerland shall be prepared to face the "lack of peak capacity" problem explained in Finding 2, if Europe follows a pathway similar to the Swiss Energy strategy.
  - Assuming that energy storage and hydrogen play a role in the future Swiss energy system (according to Findings 3 and 5), Switzerland shall probably plan to what extent it shall invest in local infrastructure and to what extent it shall rely to the rest of Europe.
  - Since there is enough gas storage capacity in Europe, it might be reasonable that Switzerland relies mostly to this capacity as its source of long-term hydrogen storage (similarly to the way that it is using it today for storage of natural gas). Of course, in such a case, Switzerland is dependent on Europe actually pursuing a "hydrogen proliferation" pathway.
  - Switzerland can "use" the hydrogen storage in Europe to address the "renewable supply - demand mismatch" challenge, either by importing hydrogen and generating electricity locally or by importing directly electricity, generated by hydrogen in Europe. Probably a middle-ground solution would make sense, as solely importing electricity might be too dependent on it being available in Europe, while it might not be accommodatable by the interconnectors' transfer capacity.
- What is the best way to bridge the higher energy demand in winter with the expected energy surplus in summer?

  - For a result with net-zero CO2 emissions and maximum utilisation of wind and solar installed capacities, hydrogen storage seems the best option, progressively converting today's natural gas infrastructure (see Findings 2, 3 and 5).
  - If some CO2 emissions are permissible (or if carbon capture and storage is pursued), natural gas could also play an important role, accumulated in storage over the year and used at moments of deficit (as in Figure 11a).

- What is the future importance of gas networks? Shall new investments in gas infrastructure be made?
  - For gas storage and gas networks, probably the investments shall be focusing on their progressive repurposing in order for them to accommodate hydrogen (see Findings 3 and 5).
  - The long-term value of gas distribution infrastructure depends on the extent to which demand for methane or hydrogen remains in the long-term. From the system optimisation viewpoint, this does not seem to be necessary (see Finding 4). However the existence of such demand might be driven by the end need itself, which has been out of scope of this study. See proposed future work in Section 6.
  - On the country, gas transmission networks and large-scale storage will have value in the future energy system, as they will play an important role in the overall system optimisation (see Findings 2 and 3).
- Shall today's gas infrastructure be progressively converted such that it becomes suitable for hydrogen or shall (a part of) it continue transport methane (renewable synthetic or biogas) until 2050?
  - Already covered by previous questions. Conversion seems making more sense. See discussion in Finding 5, as well as the proposed future work in Section 6 (a dedicated project to address the question in more detail building upon the present study might make sense).
- Which energy carrier shall be used per demand sector/application?
  - It seems that this depends on the demand sector and the available technologies. See also Finding 4.

6 Future work

6.1 Potential of extensions within the context of the current study

This report contains a set of representative illustrative results, computed based on the future end demand and future installed generation capacities presented in Sections 3.2 and 3.3, derived from reputable documented sources. The study can be extended to accommodate a plurality of such future evolution scenarios.

In addition, more scenarios and sub-scenarios can be quantified leading to a more granulated sensitivity analysis.

The quantification framework can be extended by a module which would quantify the investment cost corresponding to different potential future pathways. This will allow to put a total "price tag" on each scenario, adding one more comparison metric (in addition to "demand curtailment", "wind & solar curtailment", "CO2 emissions" and "fuel cost" utilised in this study so far).

6.2 Potential follow-up studies

With this study as a starting point, the following topics are worth further more detailed investigation:

1. Analyse in adequate level of detail a "gas infrastructure pathway", devising step-wise strategies on how today's infrastructure, designed and used for accommodation of natural gas, with emphasis on the delivery of energy (to end customer and gas power plants) can be transformed to an infrastructure which will progressively accommodate hydrogen and will act as an enabler to an energy system where the primary energy supply comes from non-dispatchable renewable energy resources.
2. Analyse in adequate level of detail the ability of the distribution networks (electricity, gas and thermal) to accommodate the trajectory towards a future energy system. In specific, consider the potential needs for electricity distribution network upgrades, as well as the potential of locally using excess heat from various processes, thus enhancing the overall system efficiency.
3. Analyse in adequate level of detail the ability of the end customers to engage into "flexibility provision" schemes. Identify the associated capabilities and constraints.

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