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Institut des sciences de l'environnement

Professeur Martin Kumar Patel

Future energy system -

Analysis of flexibility options and sector coupling for integration of clean energy
technologies

THÈSE

Présentée à la Faculté des sciences de l'Université de Genève
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Ruchi Gupta

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2023



**UNIVERSITÉ
DE GENÈVE**

FACULTÉ DES SCIENCES

**DOCTORAT ÈS SCIENCES, MENTION SCIENCES DE
L'ENVIRONNEMENT**

Thèse de Madame Ruchi GUPTA

intitulée :

**«Analysis of Flexibility Options and Sector Coupling for
Integration of Clean Energy Technologies»**

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Genève, le 8 juin 2023

Thèse - 5731 -

Le Doyen

N.B. - La thèse doit porter la déclaration précédente et remplir les conditions énumérées dans les "Informations relatives aux thèses de doctorat à l'Université de Genève".

To my family and friends

"Live as if you were to die tomorrow. Learn as if you were to live forever."
Mahatma Gandhi

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1

2 *Be a doctor, serve humanity* – A quote from my dad that he used to write
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4 humanity, which he finally fulfilled. Dad, today after almost 50 years, I would like
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Future energy system:

Analysis of flexibility options and sector coupling for integration of clean energy technologies

Abstract

In line with the efforts to achieve net-zero carbon emissions, the energy system is experiencing significant paradigm shifts, both on the supply and the demand side. On the supply side, the capacity of variable renewable energy (RE) is markedly growing at the expense of conventional fossil power generation plants. On the demand side, there has been an increasing thrust for electrification of sectors, in particular heating and mobility. Additionally, other sector coupling options, such as the use of green hydrogen in hard-to-electrify sectors are being developed.

This thesis aims at analyzing the potential of flexibility and sector coupling to support the integration of RE and low carbon technologies as part of the energy transition in Switzerland. Various models and methodologies are developed for this purpose:

i) In the first study (**Chapter 2**), RE technologies are combined with different energy storage (ES) technologies to form hybrid systems supplying firm electricity under various supply strategies at three different scales of deployment. For this purpose, a method to simulate the performance and calculate the levelized cost of hybrid systems was developed. The key finding of this study is that the optimal choice for a hybrid system depends on the scale rather than the supply mode strategy and that the hybrid systems were still not cost competitive with conventional supply systems.

ii) The second study (**Chapter 3**) focuses on distribution grid reinforcement needs to facilitate integration of rooftop PV on the supply side and electrification of heating and mobility on the demand side. To evaluate this, a Geographic Information System (GIS) based method was created to first map the technical potential for rooftop solar (PV), heat pumps (HP) and electric vehicles (EV) in 2035 and 2050. Next, various scenarios of deployment were built based on different levels of technology penetration. These were included in a large-scale distribution grid planning model with high spatial resolution developed and operated by a distribution system operator (DSO) to calculate the required distribution grid reinforcement costs. The results from the model indicate that the specific grid reinforcement costs are remarkably higher in rural areas compared to suburban and urban areas. Further, rooftop PV leads to clearly more voltage violation issues compared to HP and EV respectively, which on the other hand, create only slightly more line overloading. Finally, batteries, even with current cost, have the potential to defer grid reinforcement in 15% of the transformer stations.

iii) The third study (**Chapter 4**) identifies hotspots for green hydrogen and power-to-methane plants deployment across Switzerland. A detailed GIS assessment method was developed to map various RE and CO₂ supply sources, as well as demand centers across the country. This data is then used as an input to the techno-economic model to calculate the profitability of power-to-gas plants directly connected to run-of-river hydropower plants, embedded into demand centres and next to CO₂ supply sources. It is found that only green hydrogen plants directly connected to run-of-river hydropower plants are currently profitable in Switzerland. Moreover, a few synthetic methane plants connected to run-of-river hydropower plants currently show slight profitability. The study also presents a roadmap with potential hotspots for green

hydrogen deployment in the mid (2030) and long (2050) term.

iv) Finally, in the last study (**Chapter 5**), the work on green hydrogen deployment is expanded to also assess macroeconomic impacts of a new green hydrogen sector on the Swiss economy. An expanded input-output model was developed, adding the new green hydrogen industry to the existing Swiss economy. According to the analysis of the gross impacts, it emerges that for each kg of green hydrogen produced, the operational phase creates 6.0, 5.9 and 9.5 times more GDP, employment and GHG emissions respectively compared to the construction phase (all values in gross terms). Furthermore, the analysis of the net impacts considering the shift of spending from diesel to green hydrogen for passenger cars confirms that the green hydrogen industry contributes to at least 28% higher GDP, 43% higher employment, 18% lower GHG emissions, compared to diesel and other industries across all the three studied cases.

Overall, the studies carried out in this thesis lead to the following key results of relevance for decision-makers:

i) The first study presents a new model on the operation of renewable hybrid systems to supply firm electricity across three different scales of deployment - residential, utility, and bulk level, thereby providing results on the levelized cost of hybrid systems (LCOHS) across different cantons in Switzerland. This model is then used to point to the optimal combination of renewable and storage technologies depending on the scale and supply mode. A freely available online LCOHS calculator was developed as part of this work to provide a graphical interface, where the user can change the input assumptions (e.g. costs, capacity, operational parameters of RE and ES technologies) to obtain the LCOHS in return. Finally, this study also underlines the need for further cost reductions of RE and ES technologies to make renewable hybrid systems cost competitive with conventional energy technologies. This may require further policy and institutional support.

ii) The second study estimates the cost required to reinforce the distribution grid under different penetration scenarios of rooftop solar PV, heat pumps and electric vehicles charging, all modelled at high spatial resolution. This type of information is highly valuable for DSOs to plan the investments for future grid development. Additionally, the study highlights the role of batteries in deferring distribution grid upgrades, besides offering additional services (benefit stacking). Under different ownership models, batteries as community energy systems could benefit both consumers and DSOs, creating a win-win relationship.

iii) The third study presents hotspots for deployment of green hydrogen and power-to-methane plants in Switzerland by mapping different supply and demand sources at a high spatial resolution. This study can provide guidance to project developers and investors for profitable deployment of green hydrogen and methane plants across Switzerland. The study also showcases a roadmap for green hydrogen deployment from now until 2050, considering the estimated reduction in technology costs. Thus, this roadmap provides a clear pathway for the development of future green hydrogen projects in Switzerland.

iv) The fourth study provides insights into the macroeconomic impacts of a green hydrogen industry from both construction and operation phases, at a country level. Using input-output modelling, the study provides a transparent and replicable approach for assessing the direct and indirect impacts of this emerging industry. The results suggest that shifting spending from diesel to green hydrogen as a transportation fuel can lead to higher GDP, employment, and reduced GHG emissions, emphasizing the need to prioritize green hydrogen in the future energy mix.

Le système énergétique du futur:

Analyse des options de flexibilité et du couplage sectoriel pour
l'intégration des technologies d'énergie propre

Résumé

Dans le cadre des efforts déployés pour parvenir à réduire à zéro les émissions nettes de carbone, le système énergétique connaît d'importants changements de paradigme, tant du côté de l'offre que de celui de la demande. Du côté de l'offre, la capacité des énergies renouvelables variables (EnR) augmente considérablement au détriment des centrales électriques fossiles conventionnelles. Du côté de la demande, l'électrification des secteurs, en particulier le chauffage et la mobilité, est de plus en plus recherchée. En outre, d'autres options de couplage sectoriel, telles que l'utilisation de l'hydrogène vert dans les secteurs difficiles à électrifier, sont en cours de développement.

Cette thèse vise à analyser le potentiel de la flexibilité et du couplage sectoriel pour soutenir l'intégration des énergies renouvelables et des technologies à faible émission de carbone dans le cadre de la transition énergétique en Suisse. Différents modèles et méthodologies sont développés à cette fin :

i) Dans la première étude (**Chapitre 2**), les technologies EnR sont combinées avec différentes technologies de stockage d'énergie pour former des systèmes hybrides fournissant de l'électricité à la demande dans le cadre de diverses stratégies d'approvisionnement à trois échelles de déploiement différentes. À cette fin, une méthode de simulation de la performance et de calcul du coût actualisé de l'énergie des systèmes hybrides a été développée. La principale conclusion de cette étude est que le choix optimal d'un système hybride dépend de l'échelle plutôt que de la stratégie du mode d'approvisionnement et que les systèmes hybrides ne sont toujours pas compétitifs en termes de coûts par rapport aux systèmes d'approvisionnement conventionnels.

ii) La deuxième étude (**Chapitre 3**) se concentre sur les besoins de renforcement du réseau de distribution pour faciliter l'intégration du photovoltaïque en toiture du côté de l'offre et l'électrification du chauffage et de la mobilité du côté de la demande. Pour ce faire, une méthode basée sur un système d'information géographique (SIG) a été créée pour cartographier le potentiel technique de l'énergie solaire (PV) sur les toits, des pompes à chaleur et des véhicules électriques à l'horizon 2035 et 2050. Ensuite, divers scénarios de déploiement ont été élaborés sur la base de différents niveaux de pénétration de la technologie. Ils ont été inclus dans un modèle de planification du réseau de distribution à grande échelle et à haute résolution spatiale développé et exploité par un gestionnaire de réseau de distribution (GRD) afin de calculer les coûts de renforcement du réseau de distribution nécessaires. Les résultats du modèle indiquent que les coûts spécifiques de renforcement du réseau sont remarquablement plus élevés dans les zones rurales que dans les zones suburbaines et urbaines. En outre, le photovoltaïque en toiture entraîne nettement plus de problèmes de dépassement de tension que les pompes à chaleur et les véhicules électriques, qui, eux, n'entraînent qu'une surcharge légèrement plus importante des lignes. Enfin, les batteries, même avec le coût actuel, ont le potentiel de retarder le renforcement du réseau dans 15% des transformateurs.

iii) La troisième étude (**Chapitre 4**) identifie les points névralgiques pour le déploiement d'installations d'hydrogène vert et de production de méthane à partir

180 d'électricité dans toute la Suisse. Une méthode d'évaluation SIG détaillée a été
181 développée pour cartographier les différentes sources d'approvisionnement en EnR
182 et en CO₂, ainsi que les centres de demande à travers le pays. Ces données sont
183 ensuite utilisées dans le modèle technico-économique pour calculer la rentabilité des
184 centrales de production de gaz à partir d'électricité directement connectées aux cen-
185 trales hydroélectriques au fil de l'eau, intégrées aux centres de demande et situées
186 à proximité des sources d'approvisionnement en CO₂. Il s'avère que seules les cen-
187 trales à hydrogène vert directement connectées aux centrales hydroélectriques au fil
188 de l'eau sont actuellement rentables en Suisse. En outre, quelques installations de
189 production de méthane synthétique raccordées à des centrales hydroélectriques au
190 fil de l'eau atteignent actuellement une légère rentabilité. L'étude présente égale-
191 ment une feuille de route avec des points critiques potentiels pour le déploiement de
192 l'hydrogène vert à moyen (2030) et long (2050) terme.

193 iv) Enfin, dans la dernière étude (chapitre 5), les travaux sur le déploiement de
194 l'hydrogène vert sont étendus à l'évaluation des impacts macroéconomiques d'un
195 nouveau secteur de l'hydrogène vert sur l'économie suisse. Un modèle input-output
196 élargi a été développé, ajoutant la nouvelle industrie de l'hydrogène vert à l'économie
197 suisse existante. L'analyse des impacts bruts montre que pour chaque kilo d'hydrogène
198 vert produit, la phase opérationnelle génère respectivement 6,0, 5,9 et 9,5 fois plus
199 de PIB, d'emplois et d'émissions de gaz à effet de serre que la phase de construction
200 (toutes les valeurs sont exprimées en termes bruts). En outre, l'analyse de l'impact
201 net du passage du diesel à l'hydrogène vert pour les véhicules de tourisme confirme
202 que l'industrie de l'hydrogène vert contribue à augmenter le PIB d'au moins 28%,
203 l'emploi de 43% et à diminuer les émissions de gaz à effet de serre de 18% par rapport
204 au diesel et à d'autres industries dans les trois cas étudiés.

205 Dans l'ensemble, les études réalisées dans le cadre de cette thèse ont permis
206 d'obtenir les résultats clés suivants, pertinents pour les décideurs politiques:

207 i) La première étude présente un nouveau modèle sur l'exploitation des sys-
208 tèmes hybrides renouvelables pour fournir de l'électricité garantie à trois niveaux
209 différents de déploiement - résidentiel, utilitaire et en grand échelle, fournissant
210 ainsi des résultats sur le coût actualisé de l'énergie des systèmes hybrides (LCOHS)
211 dans différents cantons en Suisse. Ce modèle est ensuite utilisé pour déterminer la
212 combinaison optimale de technologies renouvelables et de stockage en fonction de
213 l'échelle et du mode d'approvisionnement. Un calculateur LCOHS disponible gratu-
214 itement en ligne a été développé dans le cadre de ce travail pour fournir une interface
215 graphique, où l'utilisateur peut modifier les hypothèses d'entrée (par exemple, les
216 coûts, la capacité, les paramètres opérationnels des technologies EnR et stockage
217 d'énergie) pour obtenir le LCOHS en sortie. Enfin, cette étude souligne également
218 la nécessité de réduire encore les coûts des technologies EnR et stockage d'énergie
219 pour rendre les systèmes hybrides renouvelables compétitifs par rapport aux tech-
220 nologies conventionnelles de l'énergie. Cela peut nécessiter un soutien politique et
221 institutionnel supplémentaire.

222 ii) La deuxième étude estime le coût nécessaire pour renforcer le réseau de distri-
223 bution selon différents scénarios de pénétration de l'énergie solaire photovoltaïque
224 sur les toits, des pompes à chaleur et de la recharge des véhicules électriques, le tout
225 modélisé avec une haute résolution spatiale. Ce type d'information est très utile
226 pour les GRD afin de planifier les investissements pour le développement futur du
227 réseau. En outre, l'étude met en évidence le rôle des batteries dans le report des
228 mises à niveau du réseau de distribution, tout en offrant des services supplémentaires
229 (cumul des sources de revenus). Selon différents modèles de propriété, les batteries

230 en tant que systèmes énergétiques communautaires pourraient bénéficier à la fois
231 aux consommateurs et aux GRD, créant ainsi une relation gagnant-gagnant.

232 iii) La troisième étude présente les points névralgiques pour le déploiement
233 d'usines d'hydrogène vert et de production de méthane à partir d'électricité en Su-
234 isse en cartographiant les différentes sources d'offre et de demande à une résolution
235 spatiale élevée. Cette étude peut fournir des conseils aux développeurs de projets
236 et aux investisseurs pour un déploiement rentable des usines d'hydrogène vert et de
237 méthane dans toute la Suisse. L'étude présente également une feuille de route pour
238 le déploiement de l'hydrogène vert à l'horizon 2050, compte tenu de la réduction
239 estimée des coûts technologiques. Ainsi, cette feuille de route fournit une voie claire
240 pour le développement de futurs projets d'hydrogène vert en Suisse.

241 iv) La quatrième étude donne un aperçu des impacts macroéconomiques d'une
242 industrie de l'hydrogène vert, tant au niveau de la construction que de l'exploitation,
243 à l'échelle d'un pays. En utilisant la modélisation des input-output, l'étude four-
244 nit une approche transparente et reproductible pour évaluer les impacts directs et
245 indirects de cette industrie émergente. Les résultats suggèrent que le passage du
246 diesel à l'hydrogène vert comme carburant pour les transports peut entraîner une
247 augmentation du PIB et de l'emploi, ainsi qu'une réduction des émissions de gaz à
248 effet de serre, ce qui souligne la nécessité d'accorder la priorité à l'hydrogène vert
249 dans le futur système énergétique.

List of papers constituting this thesis

250

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252

253

I **Gupta R**, Soini MC, Patel MK, Parra D. Levelized cost of solar photovoltaics and wind supported by storage technologies to supply firm electricity. *Journal of Energy Storage* 2020;27:101027.

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II **Gupta R**, Pena-Bello, A., Streicher, K.N., Roduner, C.; Thöni, D., Patel, M.K., Parra, D. Spatial analysis of distribution grid capacity and costs to enable massive deployment of PV, electric mobility and electric heating. *Applied Energy* 2021, 287, 116504.

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III **Gupta R**; Rüdisüli M, Patel MK, Parra D. Smart power-to-gas deployment strategies informed by spatially explicit cost and value models. *Applied Energy* 2022;327:120015.

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IV **Gupta R**, Guibentif, MM T., Friedl, M., Parra, D., Patel, M.K. Macroeconomic analysis of new green hydrogen industry using Input-Output analysis: the case of Switzerland. *Energy Policy Manuscript under submission.*

List of abbreviations

AA-CAES	Advanced adiabatic compressed air energy storage	IT	Information technology
AEL	Alkaline electrolysis	LCOE	Levelized cost of electricity
B CHF	Billion CHF (10 ⁹ CHF)	LCOHS	Levelized cost of hybrid systems
BEV	Battery electric vehicles	Li-ion	Lithium-ion battery
BL	Backward linkage	M CHF	Million CHF (10 ⁶ CHF)
CAES	Compressed air energy storage	MFH	Multi-family house/s
CAPEX	Capital expenditure	M USD	Million US Dollars
CEM	Cement plant/s	MWIP	Municipal waste incineration plant/s
CES	Community energy storage	NCT	Net Commodity Taxes
CHF	Swiss Francs	NMC	Nickel manganese cobalt oxide
CH ₄	Synthetic methane	NOGA	General Classification of Economic Activities
COP	Coefficient of performance	NPV	Net present value
CO ₂	Carbon dioxide	OPEX	Operational and maintenance expenditure
DAC	Direct air capture	O ₂	Oxygen
DOD	Depth of discharge	P2G2P	Power-to-gas-to-power
DSO	Distribution system operator/s	P2H2P	Power-to-hydrogen-to-power
EP2050+	Energy Perspectives 2050+	P2M2P	Power-to-methane-to-power
ERA	Energy reference area	Pb-acid	Lead-acid battery
ES	Energy storage	PEM	Polymer electrolyte membrane
EU	European Union	PHEV	Plug-in hybrid electric vehicles
EUR	Euros	PHS	Pumped hydro storage
EV	Electric vehicle/s	PPA	Power purchase agreement
FL	Forward linkage	PtG	Power-to-Gas
FTE	Full-time equivalent	PtH	Power-to-Hydrogen
GDP	Gross Domestic Product	PtM	Power-to-Methane
GHG	Greenhouse gas/es	PV	Solar photovoltaics
GIS	Geographic information system	RAS	A method for data reconciliation named after the economist Richard Stone
GO	Guarantee of origin	RD	Residual demand
GRAS	Generalized RAS	RE	Renewable energy
HP	Heat pump/s	RoR	Run-of-the-river hydropower
HPP	Hydropower plant/s	SFH	Single family house/s
HRS	Hydrogen refuelling station/s	SI	Supplementary Information
H ₂	Hydrogen	TEN-T	Trans-European Transport
I-CAES	Isothermal compressed air energy storage	ToD	Time of day
IND	Industrial site/s	VRB	Vanadium redox battery
I-O	Input-Output	VRLA	Valve-regulated lead-acid
IPCEI	Important Projects of Common European Interest	WWTP	Wastewater treatment plant/s
IQR	Interquartile range	ZERO	Net-zero emissions scenario

List of important variables

η	Roundtrip efficiency of an Energy Storage (ES) technology
P_{RE}	Normalized renewable energy (RE) generation. Normalization is done by dividing generation by the maximum RE generation in that year.
$P_{\text{RE,direct}}$	Part of the RE generation that is supplied directly to the demand load
$P_{\text{ES,charge}}$	Surplus renewable electricity that is used to charge an ES system
$P_{\text{ES,discharge}}$	Electricity discharge from the ES system after taking into account its round trip efficiency, η
E_{stored}	Electricity stored within an ES system
EUR/kW	Euros per kilowatt
EUR/kWh	Euros per kilowatt hour
P	Power capacity
E	Energy capacity
C_{P}	Power-related CAPEX component
C_{E}	Energy-related CAPEX component
λ	Firm RE output profile
CC_{peak}	Capacity Credit peak
C_{RE}	RE installed capacity
D	Peak demand
CAPEX_{RE}	Capital expenditure of RE system
CAPEX_{ES}	Capital expenditure of an ES system
OPEX_{RE}	Operational and maintenance expenditure of RE system
OPEX_{ES}	Operational and maintenance expenditure of ES system
n	Lifetime of a RE hybrid system
δ	Degradation rate
l	Lifetime of a technology
rl	Remaining lifetime of a technology

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^bsimilarly published in: Applied Energy, Volume 287, April 2021 [125]

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Chapter 1

Introduction

“We are on a highway to climate hell with our foot on the accelerator”, said António Guterres, the UN Secretary General at the 27th Conference of the Parties of the UNFCCC (COP27) [292]. This statement emphasizes that the world is still far away from reaching the climate goals defined in the Paris Agreement. The Emissions Gap Report 2022 released by the UN Environmental Programme just a few days before the COP27, concluded that the updated Nationally Determined Contributions (NDCs, or the country pledges) will likely result in a 2.4-2.6°C increase in global temperature by 2100 compared to pre-industrial levels, far beyond the Paris Agreement’s 1.5°C goal [360]. This highlights a significant gap between commitments and ambitions, and thereby, is an urgent call for countries to accelerate their efforts towards climate change, well beyond what has been done so far. To limit the global warming to 1.5 degree, we must cut down the current emissions level by 45% by 2030, requiring complete withdrawal from fossil fuels and system-wide transformation across different sectors [360].

1.1 Clean energy transition: What does it entail?

The clean energy transition essentially means a paradigm shift from a fossil-fuel based energy system to a system based on renewable energy (RE). Over the past decade, countries have been increasingly switching from fossil fuels to RE sources such as solar and wind, owing to the global attention to mitigate greenhouse gas (GHG) emissions following the signing of the Paris Agreement in December 2015 [348]. This momentum for solar and wind is driven by climate and energy policies, along with technological advancement and cost reductions [172]. Since the start of the war in Ukraine, this momentum has gained even more traction in European countries (including Switzerland), which have the mission to achieve energy supply security and reduced their dependence from fossil fuels [90]. Under these circumstances, the goal to expand domestic renewable energy technologies is far more important and ambitious than ever.

However, an energy transition aiming at achieving carbon neutrality should cover other sectors beyond electricity. Moreover, it should target the entire energy system including the demand side, i.e. transportation, heating and carbon-intensive industries dependent on fossil fuels. Renewable electricity is foreseen to be used to charge electric vehicles (EV), operate heat pumps (HP) to meet heat demand and to produce hydrogen through electrolysis, respectively. Currently, a well established strategy consists of the electrification of various demand sectors using renewable

electricity, such as light-duty transportation and heating. However, electrifying heavy-duty transportation and energy intensive industries still remains a challenge [96]. To decarbonize these hard-to-abate sectors, hydrogen produced via electrolysis of water using renewable electricity, referred to as green hydrogen, is expected to play a significant role. In addition, the production of hydrogen can provide significant flexibility for the power system if electrolyzers are used as flexible loads [144].

1.1.1 Expansion of renewable electricity supply

The world's energy menu is changing. Globally, countries have set up ambitious targets for RE expansion. The energy transition has been most apparent in the power sector, where in fact, in the last years, power capacity additions of wind and solar technologies have surpassed those of coal and gas. For instance, in 2021, renewable power accounted for 81% of the total expansion in terms of capacity, and outpaced fossil fuels growth by a factor of 4.4 [173]. However, the current pace is not considered adequate for keeping up the 1.5 degree goal and therefore, further accelerated efforts for renewable capacity expansion are envisaged [57]. Switzerland ratified the Paris Agreement on 6 October 2017, thereby committing itself to reduce emissions by 50% by 2030 from 1990 levels and to reach net-zero by 2050 [347]. Switzerland's domestic electricity mix is largely carbon-neutral dominated by hydro (61.5%) and nuclear (28.5%) generation [157]. The Swiss Federal Council has developed the Swiss Energy Strategy 2050 since 2011 based on three strategic objectives: increasing the use of renewable energy, increasing energy efficiency and withdrawing from nuclear energy [89]. By the end of 2021, the Swiss Government released the Energy Perspectives 2050+, aiming to achieve carbon neutrality by 2050 [86]. Recently, the war in Ukraine has triggered a global energy crisis, also affecting Switzerland. In order to increase its energy security and independence, the Federal Government, the Cantons and the Federal Electricity Commission (ElCom), together with the electricity and gas industries, have been working closely to reduce dependence on oil and gas and expand RE deployment [90].

1.1.2 Electrification of demand

The rapid way to decarbonization is through 'direct' renewable electrification of the end-use sectors such as mobility and heating [262]. To achieve a 55% reduction in GHG emissions compared to 1990 levels by 2030 in the European Union (EU), the penetration of electricity in the final demand is expected to grow from 23% today to around 32% by 2030, and up to 60% by 2050 [262]. As per the Energy Perspective 2050+ ZERO basis scenario, Switzerland expects the electricity share to grow up to 44% of the final energy consumption by 2050, compared to the current 25% [86].

Electric mobility

Road transport is a major contributor to global warming, currently accounting for around 16% of global GHG emissions [153]. The transport sector is responsible for nearly 25% of Europe's [119] and 27% of the US' GHG emissions [101]. This high share of GHG emissions make transportation an exceptionally important segment to decarbonize. The EU has introduced the 'Fit for 55' package to achieve the ambitious target of reducing net GHG emissions by at least 55% by 2030, including increasingly stringent emission reductions targets for passenger cars and light commercial vehicles

[95]. This includes the promotion of electric mobility to achieve low carbon targets in the transportation sector. The share of newly registered electric cars (battery and plug-in hybrid) in the EU increased to almost 18% in 2021 [231]. Also, the first stage of the electromobility roadmap from 2018 to 2022 in Switzerland pursued the goal of increasing the share of electric cars and plug-in hybrids in new passenger car registrations to 15% by 2022, which was already achieved in 2021. The Swiss electromobility roadmap defines three goals for 2025: i) increasing the share of electric cars and plug-in hybrids in new registrations to reach 50%; ii) having in place 20,000 public charging stations from the current 8,648 (October, 2022), iii) installing “user-friendly and grid-friendly charging – at home, at the place of work and on the road” [280].

Electric heat pumps

Heating is one of the largest energy end-use, with more than 60% of the heating energy demand globally still being met through fossil fuels [132]. Following the global increase in renewable electricity penetration, there has been a push for electrification of the heating sector using HP. The International Energy Agency’s pathway to net-zero by 2050 aims to increase the global share of HP in buildings by 55% in 2050, compared to just 7% in 2022 [156]. HP, using renewable electricity, are significantly more efficient (typically at least three times) than conventional fossil fuel based heating systems and also contribute to reducing GHG emissions [392].

In Europe, residential heating is dominated by the use of natural gas (39%), followed by wood (25.4%), fuel oil (5%), electricity (5.8%) and coal (4.1%) [98]. The sales of HP grew by 34% in Europe in 2021, covering around 14% of the heating market [214].

In Switzerland, residential buildings are mainly dominated (more than 70%) by conventional heating systems based on fuel oil and natural gas. However, the proportion of buildings with HP (17%) has increased fourfold since 2000 [110]. Remarkably, 54% of all heating systems sold in Switzerland in 2021 were HP, making it the dominant heating technology, not only in new buildings, but also for retrofitting, in particular for single-family houses [110]. The growth of HP in Switzerland is attributed to a variety of drivers such as CO₂ levy, subsidies from the Building Programme and voluntary approaches such as Minergie [392].

1.1.3 Green hydrogen for hard-to-electrify sectors

The decarbonization of the energy system will involve profound electrification of the demand sectors, specifically mobility and heating as highlighted above. However, some end uses such as heavy-duty transportation, carbon intensive industries, and aviation, are difficult to electrify. The decarbonization of these sectors requires a complementary strategy to electrification, such as, the use of carbon-neutral fuels.

In 2020, the European Union published the hydrogen strategy with the goals to decarbonize hydrogen production in Europe and expand its use into hard-to-abate sectors, such as steel making, trucks, rail and some maritime transport applications. The strategy aims to install at least 40 GW of electrolyzers by 2030 compared to 1 GW in 2020 [96].

In Switzerland, the domestic hydrogen strategy and long-term roadmap is still under preparation. However, under the ‘Net zero emissions (ZERO)’ scenario in the Swiss Energy Perspectives 2050+ report, green hydrogen has been identified to contribute 16 PJ by 2050 (3% of final energy consumption in Switzerland), mainly

produced through the run-of-river hydroelectricity [295]. Currently, the green hydrogen market in Switzerland is relatively small (1% of natural gas market size) [290]. The Swiss Federal Office of Energy has been supporting a number of research projects as well as pilot and demonstration projects in Switzerland. For example, Hyundai Hydrogen Mobility AG, which is a partnership between Hyundai and H2 Energy, started to operate 50 fuel cell trucks (18-tonne) in 2020. Moreover, their aim is to roll out a total of 1'600 fuel cell trucks by 2025. To refuel these trucks with green hydrogen, around 100 MW of electrolyzer capacity will be required [149].

1.2 Challenges in the path to net-zero

Decarbonization as described in Section 1.1 requires significant changes to the current energy system and a major need for flexibility resources and sector coupling. For instance, the stochastic nature of solar photovoltaics (PV) and wind generation prevents them from supplying electricity on demand, posing substantial challenges for the stability of the power sector across many regions. As the share of variable RE increases, energy storage is playing an increasingly important role in bridging the gap in time between RE production and energy demand [93]. Additionally, fossil-based heating and mobility systems are being replaced with HP and EV respectively. The use of HP and EV charging, on the other hand, increases the peak electricity demand, posing challenges for the distribution grid and therefore calling for the implementation of additional flexibility solutions [125].

Need and key drivers for flexibility and sector coupling

Flexibility is an important attribute of future power systems. The International Energy Agency defines power system flexibility as the “ability of a power system to reliably and cost-effectively manage the variability and uncertainty of demand and supply across all relevant timescales” [6]. In traditional power systems, the conventional flexibility primarily implied modifying flexible electricity generation assets such as fossil-based and hydro power plants to follow electricity demand (load). Therefore, flexibility needs were driven by the accuracy of demand forecasting. However, with the introduction of stochastic RE sources, such as solar and wind in the power systems, as well as other low carbon technologies such as EV and HP, flexibility needs are markedly increasing. For example, variable renewable electricity output needs to be balanced by a flexibility option on a real time basis to be able to keep the energy system reliable and stable [215].

Sector coupling essentially involves the integration of the supply sector with various end-use demand sectors. For example, electrification of heating and mobility is a straightforward strategy for sector coupling. The primary aim of this is to increasingly shift from the use of fossil-fuel energy sources to renewable electricity. One of the key challenges is, however, the availability of large amounts of affordable renewable electricity.

1.3 Flexibility and sector coupling options to facilitate the energy transition

There are several options to supply RE on demand as well as to fully decarbonize the energy sector, namely flexible generation, demand-side management, interconnection, grid reinforcement, energy storage, sector coupling and RE curtailment [220]. In this thesis, the focus is on two different flexibility options, namely, energy storage, grid reinforcement, as well as sector coupling to support integration of low carbon technologies. These options are further detailed in the next subsections. Fig. 1.1 presents the some of the flexibility and sector coupling options to support RE expansion. In this thesis, only technical flexibility options such as energy storage, grid reinforcement and sector coupling are studied. Other flexibility options involving behavioural aspects such as demand side management are outside the scope of the current work.

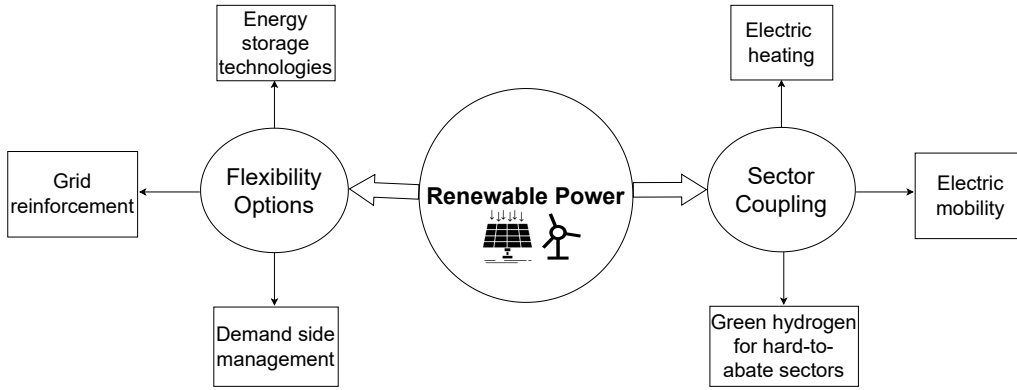


Figure 1.1: Overview of some flexibility and sector coupling measures to facilitate renewable energy integration and energy system decarbonization.

1.3.1 Energy Storage

Energy storage technologies can help RE technologies to supply energy on demand. They can be categorized by discharge time, system power rating and storage principle. For instance, the typical discharge time of lithium-ion batteries is less than 4 hr, pumped-hydro storage is more flexible and discharge times ranges from a few hours to several months, whereas hydrogen storage could contribute to meeting seasonal flexibility needs [62]. In this thesis, the main focus is on daily storage to allow RE technologies to contribute to the balance on the daily electricity market. For this specific role, various storage technologies such as pumped-hydro storage (PHS), compressed air energy storage (CAES), various battery technologies and power-to-gas-to-power (P2G2P) via hydrogen and methane qualify. Other technologies such as flywheels and supercapacitors which are suitable for short-term discharges (<1 hr) associated with ancillary services such as voltage control and power quality are therefore outside the scope of this thesis [123].

1.3.2 Grid reinforcement

Electricity grids are usually classified in three different levels depending on the voltage, namely high voltage, medium voltage and low voltage. The high voltage grid is mainly connected to large power plants and heavy industries. Moreover, high voltage

is used to transport electricity across countries and regions with little losses (Ohm's law). The medium voltage grid is connected to medium-sized energy sources and to high and low voltage grid, therefore distributing electricity across smaller regions. Finally, the low voltage grid (also referred to as distribution grid) distributes electricity across final consumers, such as residential buildings and offices. Since rooftop solar PV as well as EV and HP are connected to the distribution grid, distributed assets such as lines and transformers are subject to changes in the voltage level, as well as overloading. Fig. 1.2 depicts a scenario where houses are connected to the transformer station within the local distribution grid with rooftop PV, EV chargers or HP installed on them.

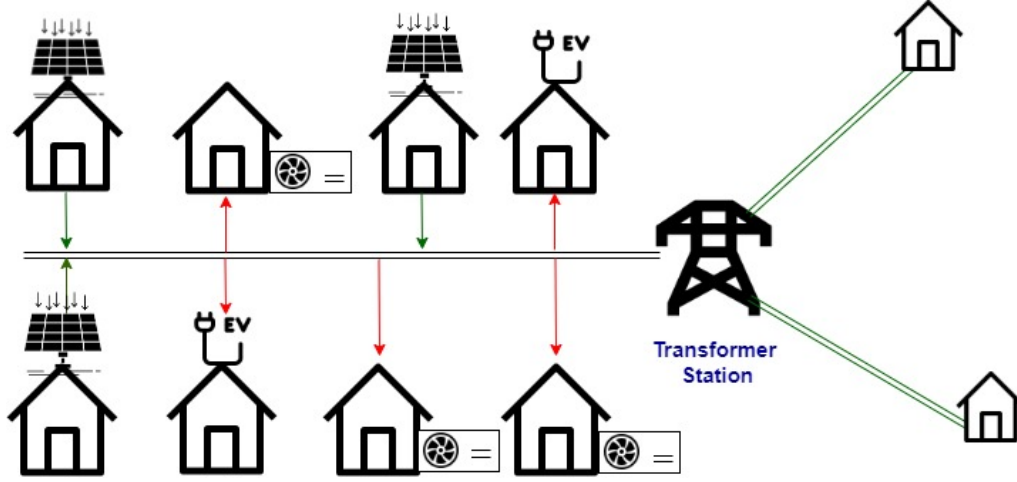


Figure 1.2: Power flow from/to the group of houses connected to the transformer station within the distribution grid network with rooftop PV, EV charging or HP installed.

The hosting capacity of a distribution grid refers to the maximum amount of PV generation that it can accommodate without violations of its operational constraints. On the demand side, increasing levels of electrification can also introduce a range of issues impacting its operation, and finally limiting the hosting capacity of the distribution feeders. Overall, issues such as overloading of lines/congestion in distribution feeders, and voltage violations can require the upgrade of a distribution grid, which can be a costly investment [141].

1.3.3 Sector coupling

The recently launched REPowerEU plan aims to increase clean energy production, promote energy efficiency and diversify the energy supplies within Europe [97]. Sector coupling, essentially power-to-X, can help to reduce CO₂ emissions and achieve the objectives enshrined in the plan. It primarily refers to the interconnection of the energy demand sectors such as building, transport and industry with the power producing sectors such as renewable electricity as illustrated in Fig. 1.3. The use of renewable electricity in passenger cars and heating is considered as the fastest and reliable way to decarbonize these sectors. Further, green hydrogen produced with renewable electricity is key for decarbonization in the hard-to-abate sectors where electricity is not a viable option [262]. Green hydrogen would not only help to decarbonize the carbon intensive industries, heavy duty transportation and other sectors dependent on fossil hydrogen or act as a storage option, but would also help in achieving energy supply diversification and energy security [97].

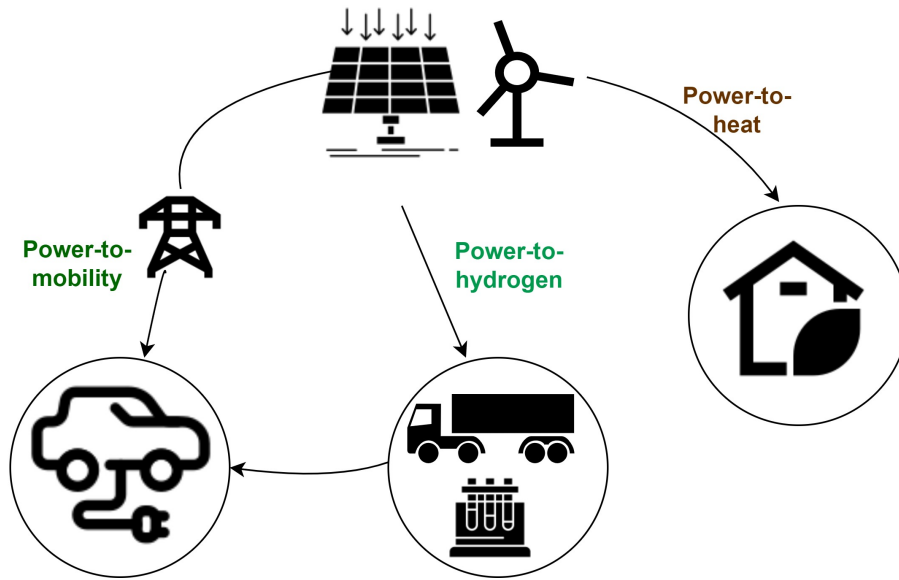


Figure 1.3: Sector coupling between solar PV plant and mobility, industry and building sector.

1.4 Scope and outline of the thesis

The transition to a net-zero energy system requires the massive deployment of renewable and low carbon technologies. The overall aim of this thesis is to analyze various flexibility options and sector coupling to enable the integration of renewable and low-carbon technologies. The studies presented in this thesis are carried out for Switzerland, yet the methodologies and models developed can be used for other countries and regions. Finally, the aim of this thesis is to guide decision makers on development strategies of flexibility and sector coupling options, both at the technology and energy system levels.

Chapter 2 compares various energy storage technologies on how they can assist RE technologies by forming hybrid systems to supply firm (i.e. constant) electricity on demand at residential, utility and bulk scale. Within the RE technologies, PV and wind power were considered. For energy storage technologies, three types of battery technologies, namely, lead-acid (valve-regulated lead-acid), lithium-ion (nickel manganese cobalt oxide) and flow batteries are considered, and moreover pumped hydro storage, compressed air energy storage (isothermal and advanced adiabatic) and power-to-gas-to-power systems. PV and wind power generation profiles as well as the selected supply mode strategy determine the optimal charging and discharging behaviour of a hybrid system. In order to estimate the required size and schedule of the selected energy storage technology to provide a firm electricity supply, a model was developed with a temporal resolution of 10 minutes, considering a 24 h modelling framework and a perfect day-ahead forecast of the electricity demand and RE generation. The objective function is to create a firm RE output supply on a daily basis. The storage operation of a hybrid system depends on the RE profile, energy storage round-trip efficiency and the type of supply mode. The capacity credit was used as a key performance indicator to determine the amount of RE generation that can be reliably supplied at the time of peak demand. Finally, the levelized cost, which is the main indicator to compare the cost of generation and storage technologies, was extended to hybrid systems incorporating both RE and energy storage technologies to compare cost-competitiveness of hybrid systems with conventional generators such as nuclear and gas, depending on the supply mode

strategy.

The key research questions answered in this chapter are:

RQ 1. What are the best-suited energy storage technologies that can support solar PV and wind power to supply firm electricity under different supply modes and scales of deployment?

RQ 2. What are the implications of different relative mixes of solar PV and wind on the levelized cost of electricity supply?

RQ 3. How do levelized costs of hybrid systems compare with other conventional supply technologies (e.g., gas, hydro and nuclear)?

Chapter 3 focuses on how distribution grid reinforcement, as a flexibility option, can help in integration of the increasing levels of rooftop PV on the supply side as well as increasing electricity needs for HP and EV on the demand side. In addition, the potential of battery storage as an alternative flexibility option to defer distribution grid upgrades was studied. In this study, a GIS-based model was developed to understand the potential for rooftop solar PV, HP and EV charging penetration in Switzerland for the years 2035 and 2050. Then, deployment scenarios, using a spatial distribution grid planning model owned and operated by BKW (Swiss utility company), were defined to calculate grid impacts and reinforcement costs for a distribution grid network serving 170'000 households in Switzerland. Finally, the regional results were scaled up to the national level to evaluate the long-term grid impact of decarbonization in Switzerland.

The key research questions answered in this chapter are:

RQ 4. What are the impacts of massive deployment of rooftop solar PV, HP and EV charging and their combinations on the distribution grid?

RQ 5. How do the grid reinforcement costs vary as a function of technology, type of urban setting and other different factors?

RQ 6. What is the potential of battery storage as an alternative flexibility option to defer grid reinforcement?

Chapter 4 and **Chapter 5** examine the potential of sector coupling, in particular power-to-gas (P2G) as a flexibility option for Switzerland. In **Chapter 4**, we identify hotspots for future deployment of power-to-hydrogen and power-to-methane plants across Switzerland. This is achieved by evaluating their profitability based on the comparison between the levelized cost and levelized value of green hydrogen and methane. Here, a detailed GIS based model was developed to map renewable electricity and CO₂ supply sources, as well as various demand centers across the country. The model was then applied to analyze the following potential deployment strategies for power-to-hydrogen and power-to-methane plant/s in the: (i) vicinity of renewable electricity supply; (ii) vicinity of CO₂ sources; and (iii) vicinity of demand centers.

The key research questions answered in this chapter are:

RQ 7. What are the potential hotspots for power-to-hydrogen and power-to-methane plants deployment considering that they should be located, next to renewable electricity generation, a CO₂ source, a gas grid and/or the demand centres?

RQ 8. Which cost reduction targets would ensure the economic viability of a power-to-gas plant?

In **Chapter 5**, a model of the macroeconomic impacts of a green hydrogen industry on Switzerland's GDP, employment and GHG emissions is presented, including both the construction and operation phases. In particular, an input-output model is developed by adding a new green hydrogen industry to the existing input-output table of Switzerland. The gross impacts generated by both construction and opera-

tion phase considering all the produced hydrogen is allocated to passenger cars, and the net impacts assuming the replacement of diesel by green hydrogen in passenger cars were assessed.

The key research questions answered in this chapter are:

RQ 9. What are the gross macroeconomic impacts generated by the construction and operation phase of the green hydrogen industry?

RQ 10. What are the net macroeconomic impacts due to replacing diesel with green hydrogen as a transportation fuel?

Chapter 6 summarizes the research work and provides the overall conclusions, proposing critical insights about the different flexibility options and sector coupling approaches. The objective is to support the energy transition considering geographical constraints, e.g., at the regional and national levels, as well as to provide recommendations for the policy makers, distribution system operators, project developers, investors and other stakeholders. For example, the recommendations include cost reduction targets for renewable and energy storage technologies, vis-à-vis conventional electricity, to supply firm electricity; interventions needed to minimize grid reinforcement costs; a roadmap for green hydrogen production; and an analysis of the impact of domestic green hydrogen production on Swiss GDP, employment and emissions. Recommendations for future research are also made in this chapter. Table 1.1 provides an overview of the four papers outlined in the above mentioned Chapters 2-5, and the various modelling and analytic methods developed.

Table 1.1: Overview of publications covered in this thesis and key methods used to perform the analysis.

Publication Number	1	2	3	4
Type of study	Techno-economic assessment	Scenario analysis	Scenario analysis & Techno-economic assessment	Macroeconomic analysis
Statistical analysis	Yes	Yes	Yes	Yes
Technology assessment	Yes	Yes	Yes	Yes
Modelling and Simulation	Yes	Yes	Yes	No
GIS-based spatial analysis	No	Yes	Yes	No

Chapter 2

Solar photovoltaics and wind supported by storage technologies to supply firm electricity ^a

Energy storage (ES) technologies can assist intermittent solar and wind power to supply firm electricity by forming flexible hybrid systems. However, evaluating these hybrid systems has proved to be a major challenge, since their techno-economic performance depends on a large number of parameters, including the renewable energy generation profile, operational parameters of storage technologies and their associated costs. In this chapter, we develop a method to simulate the performance and determine the levelized cost of hybrid systems to provide firm electricity supply under various supply strategies such as peak demand and baseload at three different scales (representative sizes). The methodology is implemented for Switzerland, however, it can also be replicated for other geographies. Our results show that the optimal choice for a hybrid system depends on the scale rather than the supply mode strategy. We find that solar photovoltaics in combination with lithium-ion battery at the residential (0.39 to 0.77 EUR/kWh) and utility scale (0.17 to 0.36 EUR/kWh) as well as with pumped hydro storage at the bulk scale (0.13 to 0.18 EUR/kWh) offer the lowest levelized costs. Reducing the cost of both renewable and storage technologies as well as the ES size by allowing some level of curtailment or distortion in the firm supply profile improves the cost-competitiveness of hybrid systems.

2.1 Introduction

Renewable energy (RE) technologies, in particular, solar photovoltaics (PV) and wind are currently the most deployed energy resources, which are transforming the face of the global energy system [179]. In 2018, RE technologies represented 84% of all the new electricity capacity added worldwide and already accounted for one third of the global power capacity by the end of 2018 [180]. This is mainly supported by rapidly falling prices, increasing climate concerns and favourable energy policies all across the world. For example, the cost of wind turbines and PV modules have fallen by about 54% and 90% respectively from 2009 until the end of 2018 [181].

Governments around the world are taking steps to revisit their energy sector strategy and embrace RE as part of their energy supply mix [179]. By 2016, 173

^asimilarly published in: Journal of Energy Storage, Volume 2, February 2020 [123]

countries had established RE targets at the national level, with most countries also adopting related policies [179]. Triggered by the Fukushima disaster, Switzerland also decided to gradually phase out nuclear energy and replace the majority of it by RE, in particular by distributed PV and wind energy [329]. For example, Switzerland pledges to increase the average domestic RE generation excluding hydropower from 1,260 GWh in 2015 to around 4,400 GWh by 2020 and to around 11,400 GWh by 2035 [329, 104].

However, wind and PV generation are stochastic, since their outputs are intermittent and cannot be fully predicted in advance [258]. This intrinsic characteristic prevents them from supplying large fractions of electricity on demand and is one of the barriers to more significant deployments. Thus, understanding the intermittent patterns of PV and wind as well as finding solutions to increase their dispatchability is central to the attractiveness of RE technologies, the stability of the power network and for achievement of decarbonization targets [212].

In order to tackle RE intermittency, several options are under discussion by all relevant stakeholders around the world. Some of them include: flexible generation, demand-side management, interconnection, grid reinforcement, curtailment and energy storage [220]. Considering the still relatively small share of RE in the global electricity supply (approximately 26.5% by end of 2017) [273], the most widely applied solution has been the use of existing dispatchable generators, typically fossil fuels or hydropower, to respond quickly to changes in the RE supply and electricity demand. However, hydropower is limited geographically and the operation of fossil fuel generators is not compatible with increasing climatic concerns [19]. Despite some recent research claims that nuclear power can also provide flexibility at time scales over 1 h [48, 326, 94, 186], there are public concerns about nuclear safety across several countries [326, 194]. While fossil fuels, hydropower and nuclear plants may still balance RE generation at the high-voltage grid level (centralized level), imbalances between RE supply and demand together with other related problems remain to be solved at the distribution level. Furthermore, grid interconnection is a solution to transfer surplus RE generation between two different regions or countries. Adding interconnection capacity is a capital intensive measure and in addition, the transfer of electricity may not be possible if both the neighboring regions have similar weather conditions (for example, anticyclone conditions sometimes last for a few weeks in central Europe) [61, 309, 41]. Demand side management is also a technical solution to match variable generation and demand locally. However, certain limitations such as low economic incentives and resistance from consumers to change their behaviour patterns restrict its widespread adoption [248, 218]. RE curtailment could also be used as a strategy to manage surplus electricity but its substantial application contrasts with the objective of maximizing RE supply [33, 254].

Finally, ES technologies can help to balance high shares of variable RE and its application is gradually becoming more important [296, 38]. It can help RE technologies to supply electricity on demand and become dispatchable [294]. There are various technologies available which can shift both supply and demand to different time scales and can be applied at various geographical scales, namely distributed and bulk [247, 191]. However, selecting an optimal ES technology to match RE generation is challenging due to the varying generation profiles of PV and wind power technologies as well as the wide portfolio of existing ES technologies with different techno-economic characteristics [38]. Also, for several technologies such as pumped hydro storage (PHS), compressed air energy storage (CAES), flow batteries and hydrogen, the energy and power capacities are decoupled, however, this is not the case

for electrochemical batteries, namely lithium-ion (Li-ion) and lead-acid (Pb-acid) [382, 106].

2.2 Literature review

Many papers in the past have explored the variable and complementary characteristics of wind and solar resources. While the solar resource has a marked diurnal profile and is not present during the night, wind availability does not depend on the time of the day and is highly variable especially in locations with complex topography [200, 337]. Furthermore, both solar irradiance and wind can show strong seasonal variations depending on the geography, e.g., solar in high-latitude areas [29, 3, 200]. A study conducted in Sweden confirmed that there are negative correlations across various time scales between solar and wind power and that they were strongest for monthly totals due to variations in seasonal availability of solar and wind [374]. Prasad et. al found strong complementarity between solar and wind in Australia. They concluded that the future hybrid solar-wind power systems would significantly reduce the intermittency impacts and energy production costs compared to stand-alone solar/wind power generating systems [258].

It has been widely suggested that ES can play a pivotal role in reducing the intermittency associated with RE generation and helping to increase its dispatchability on demand [325, 296, 102, 115, 24]. This has been supported by numerous research efforts aiming to quantify optimal storage size required to increase the attractiveness of RE supply. Focusing on the problem of capacity adequacy^b with different levels of PV penetration, Fattori et al. determined the ES capacity required to smooth residual load over time. It was found out that smoothing the net load by a few hours requires 2-7 GWh of storage per GW of PV installed [102]. Sulaeman et al. presented a method for quantifying the amount of ES required to firm up wind power [325]. Shaner et al. analyzed 36 years of global, hourly weather data to assess the co-variability of solar and wind power over the United States. Their results indicate the need for a low cost ES solution as well as strategic combination of flexible generation and demand side management to achieve higher reliability with solar and wind energy systems. For instance, they found that meeting 80% of the total demand by solar and wind would require 12 hours worth of energy storage (5.4 TWh) [296]. Denholm and Margolis, on the other hand, calculated the capacity credit (also discussed in Section 2.3.6 of this chapter) of ES to meet the peak demand of electricity under increasing levels of PV penetration [74].

Beyond the huge potential of ES technologies in tackling intermittency associated with RE deployment, it is crucial to also assess their costs. The most extensively used indicator to compare the techno-economic attractiveness of RE as well as ES technologies is the levelized cost of electricity (LCOE) [75, 39, 21] or levelized cost of energy storage [238, 387, 191, 301, 304]. However, the levelized cost of hybrid systems (LCOHS) incorporating both RE and ES technologies has been marginally used so far [225, 202, 342, 130]. It was discussed by Lai and McCulloch, who introduced the concept of the LCOHS for a PV system coupled with two different kinds of battery technologies [202]. Tervo et al. modelled the lifetime performance and costs of residential PV with Li-ion batteries across all states in the U.S. They concluded that in some cases, it is economically more attractive to install Li-ion

^b *Capacity adequacy* is defined as the ability to provide the power required by the system under steady-state conditions, throughout the year, with a given probability [102].

battery in addition to a PV system instead of having PV alone. They demonstrated that the performance and economics of PV-battery system vary geographically and that they can be competitive with grid prices in the case of tax credits and favourable financing mechanisms. For example, for a storage size of 7 kWh, the minimum LCOE of a hybrid system is calculated to be about \$0.11/kWh in California which is lower than California’s levelized costs of grid electricity [342].

On the other hand, a number of tools have also been developed to assess the techno-economic potential of the renewable hybrid systems. The most popular ones include HOMER, HYBRID 2, RETScreen, iHOGA, HYBRIDS [164, 302, 201]. HOMER, for instance, is found to be the most widely used tool which can simulate a hybrid system on an hourly basis and sort the list of feasible hybrid system configurations on the basis of net present cost (NPC) [302]. However, HOMER does not consider inter-hour variability of the renewable resources and neither various types of supply strategies. We attempt to fill this gap in the literature. In this chapter, we develop a model which allows to identify the best-suited ES technologies that can support PV and wind power to supply firm electricity depending on the supply mode^c and scale^d of deployment. This allows us to assess and compare hybrid systems with conventional power generators on a levelized cost basis. Key characteristics of the proposed model making it different from the other existing models are: ease of use across different geographies, transparency on the input data used and flexibility to include various types of RE sources, ES technologies as well as various supply mode strategies. The chapter proceeds as follows: First, we study the temporal matching of RE generation and electricity demand. Second, we assess the performance of hybrid systems integrating RE and ES technologies for various supply modes and scales, as well as calculate their levelized costs. This helps us to determine the optimal hybrid solution for each case. Third, we combine PV and wind technologies and study the implications of their different relative mixes on the levelized cost of electricity supply. Finally, we compare hybrid systems with other conventional supply technologies (e.g., gas, hydro and nuclear) and discuss the implications for the future energy system.

2.3 Data and methods

The broad framework of our approach is schematically depicted in Figure 2.1. The input data for modelling hybrid systems comprises renewable and storage technologies characteristics as well as the definition of the supply modes. We also present the algorithm devised to obtain the schedule and size of an ES system to provide firm electricity supply depending on the supply mode.

^cSupply mode is defined by a set of hours in a day during which the RE hybrid system is supplying firm electricity. Different types of supply modes considered in the study are discussed in section 2.3.2 of this chapter and illustrated in section A.3 under Appendix A.

^dScale represents the geographical area/extent to be served i.e. residential, utility or bulk. The scale defines the nominal power rating of both renewable and energy storage technologies, as schematically depicted in Fig. 2.3

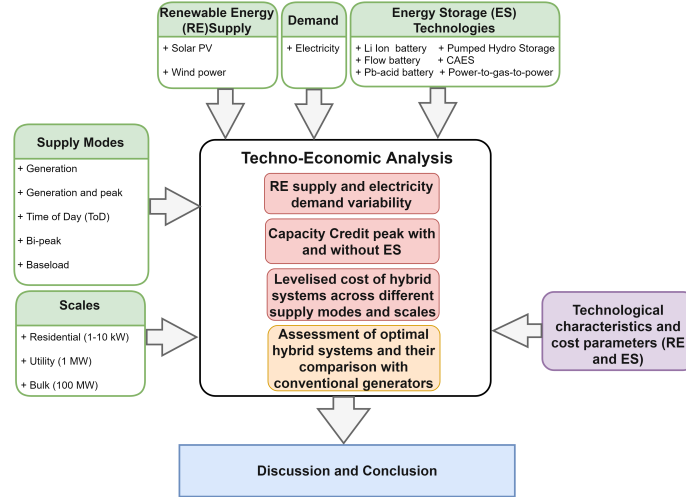


Figure 2.1: Method developed in this chapter to evaluate the levelised costs for different hybrid systems.

2.3.1 Input data

PV generation

To model PV generation and its intrinsic intermittency, we use global irradiance with a temporal resolution of 10 min monitored by MeteoSwiss (Swiss Federal Office of Meteorology and Climatology) for the most representative city in each canton^e across Switzerland [70] (Supplementary Table A.1). The temporal resolution is, however, 1 h for outdoor temperature considering that the value of this environmental variable does not vary so rapidly. Both, global irradiance and outdoor temperature are used as inputs for estimating the PV generation. The global horizontal irradiance is transformed into tilted irradiance at 30°, with this tilt being the optimal value for Swiss latitudes [331] using a sky model presented by Duffie and Beckham [188]. The annual average value of global irradiance of Switzerland is around 1191 kWh/m²/year. PV generation is finally simulated using a single diode model including a maximum power point tracking system [367], and assuming a nominal module efficiency of 18.6% based on standard silicon monocrystalline technology, which is also representative of the current state (Supplementary Table A.2) [331]. The performance ratio of PV systems across cantons varies between 74% and 79%, depending on the values of annual global irradiance.

Wind power generation

A total of 64 wind turbines had been installed across 37 different locations in Switzerland by 2016, out of which 36 are above 100 kW capacity [378]. In this chapter, we focus only on the existing wind turbines having a nominal capacity higher than 100 kW (as small wind turbines (<100 kW) will have a niche market in the future) as well as other potential future wind turbine sites across various cantons (Appendix A Table A.4 and A.5). We select the potential sites considering the annual average modelled wind speed above the ground, areas with reported wind-power potential and federal government interests across Switzerland [378]. For wind speed, we use a temporal resolution of 1 hour at the hub height of the wind turbine which is a

^eSwitzerland is divided into 26 different areas called cantons. The 26 ‘cantons’ are the states of the country of Switzerland.

trade-off for more accurate estimates. This is because of wind speed data with a temporal resolution of 10 min is only available at the 10m height from the ground [67] and the most commonly used logarithmic method for calculating the wind speed at the hub height does not always hold good due to the complex Swiss orography [200]. The annual average value of wind speed across cantons is 4.5 m/s. We select the power curve of Enercon E-82 wind turbine with a rated capacity of 2 MW as a representative of the current state to simulate wind generation (Appendix A Table A.6). Table A.7 presented under Appendix A, shows the annual average values of global irradiance and wind speed across different cantons of Switzerland.

Electricity demand

We use electricity demand data to define the hour of peak demand on a daily basis. In particular, demand data with a temporal resolution of 15 min for each canton and the whole country, provided by the Swiss grid operator is used in this chapter [330]. In some cases, the electricity demand of 2-3 neighbouring cantons are combined by SwissGrid. In those cases, groups of cantons are analyzed together (Supplementary Table A.8).

We normalise the PV and wind power generation as well as the electricity demand values by dividing with their respective peak values in order to make results comparable regardless of the scale.

2.3.2 Definition of a hybrid system, supply modes and scales

This section introduces the concept of a hybrid system incorporating a RE and an ES system as well as the different demand load profiles that can be supplied, referred to as supply modes in this chapter. A schematic diagram of the energy flow through a RE hybrid system is shown in Figure 2.2. Part of the RE generation is supplied directly to the demand load using a pre-defined supply mode ($P_{RE,direct}$), while the surplus renewable electricity is used to charge an ES system ($P_{ES,charge}$). $P_{ES,discharge}$ is the electricity discharge from the ES system after taking into account its round trip efficiency, η .

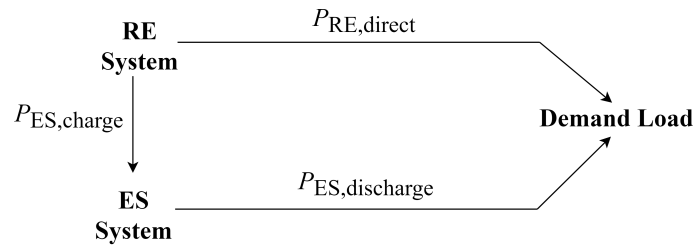


Figure 2.2: Energy flow through a RE Hybrid System incorporating a RE and an ES system. Demand load is predefined by the type of supply mode in this chapter, e.g., peak demand and baseload.

Within this hybrid system configuration, a supply mode is defined with the objective of providing a firm RE supply during certain hours of the day on a daily basis. A firm electricity supply enables RE generation to be traded on the electricity markets and it contributes to grid stability just as other conventional flexible generators such as fossil power plants and hydro storage [294]. In particular, the following supply modes, inspired by the role of generators in the wholesale markets as well as some regulatory duties for renewable generators, are compared in this chapter (illustrations in Supplementary Figures A.2 - A.6):

(i) **Generation hours:** Firm electricity supply during RE generation hours e.g., between sunrise and sunset in case of solar PV (varying every day). In the literature, this is also referred to as RE capacity firming [325]. In this chapter, this supply mode is referred to as ‘Generation’.

(ii) **Generation hours and hour of maximum demand:** Equal to supply mode (i) but the firm electricity supply is also extended to the hour with the maximum electricity demand every day unless the hour of peak demand anyway coincides with the RE generation hours. This supply mode is referred to as ‘Generation and peak’.

(iii) **Day Tariff:** Firm electricity supply during daytime hours from 7 h to 21 h, therefore, typically also covering the electricity peak demand. This supply mode is referred to as ‘Time of Day (ToD)’.

(iv) **Bi-peak:** Firm electricity supply occurs two times a day, one in the morning (from 6 h to 12 h) and the other one in the evening (from 18 h to 22 h). This originates from the fact that the average electricity demand profile of Switzerland typically has two peaks (see Figure 2.6). This supply mode is referred to as ‘Bi-Peak’.

(v) **Baseload:** Firm electricity supply throughout 24 hrs on a daily basis. This supply mode is referred to as ‘Baseload’.

Furthermore, RE hybrid systems are assessed at three different scales, namely, residential (1-10 kW), utility (1 MW), and bulk (100 MW). These scales are schematically represented in Figure 2.3, which also shows the typical power rating of solar and wind technologies in Switzerland, together with typical range of power rating and discharge duration of various ES technologies. Furthermore, Figure A.1 in the Appendix A showcases the representative sizes of various technologies globally for wider applicability.

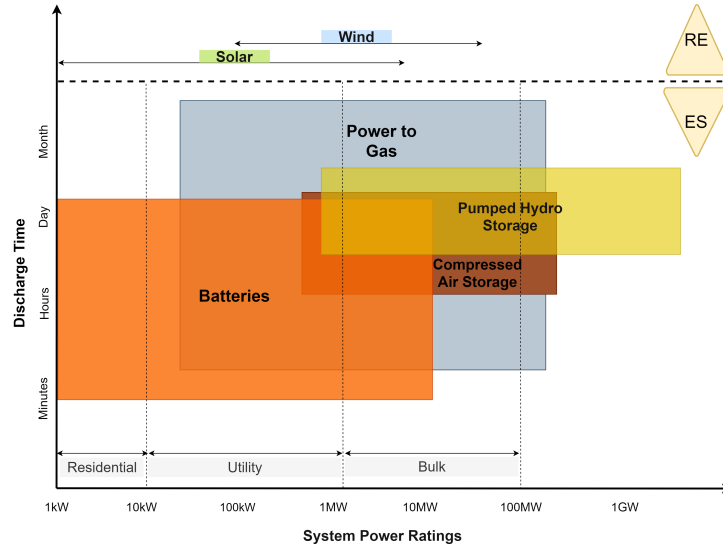


Figure 2.3: Typical sizes of the selected technologies to form hybrid systems. The horizontal axis gives the nominal power range for both RE and ES technologies while the vertical axis represents discharge time only for ES technologies. The system ratings presented in this figure refer to Switzerland where solar installations are confined to rooftops and wind energy faces limited acceptance [168, 21].

Solar PV systems in Switzerland are usually rooftop, which is expected to remain as the dominant choice also in the future [21]. Hence, the rating of PV is assumed to range from 1 kW to 10 MW. In case of wind power, we only consider turbines greater than 100 kW and therefore, the scale for future wind farms is assumed to range from 100 kW up to 50-70 MW [377].

2.3.3 Energy storage technologies

Here, we focus on the energy storage technologies which can sustain discharges of several hours in order to help the RE technologies to provide electricity for the aforementioned supply modes and scales (see Figure 2.3). This condition, therefore, qualifies PHS, CAES, various battery technologies and power-to-gas-to-power (P2G2P) via hydrogen and methane and excludes other technologies such as flywheels and supercapacitors which are suitable for short-term discharges associated with ancillary services such as voltage control and power quality [179].

For the selected ES technology families, we pre-select the best-suited subtechnologies/types considering their current cost-competitiveness and the future potential. In the case of CAES, Isothermal (I-CAES) and Advanced Adiabatic (AA-CAES) are selected for the utility and bulk scales respectively. For P2G2P, power-to-hydrogen-to-power (P2H2P) and power-to-methane-to-power (P2M2P) are considered at the utility and bulk scales respectively. Similarly, for PHS, we consider utility and bulk scales. The reasoning for selecting certain subtechnologies of CAES, P2G2P and PHS for different scales follows the logic explained in a previous publication by Abdon et al. [2]. For Li-ion and Pb-acid batteries, we select nickel manganese cobalt oxide (NMC) and valve-regulated lead-acid (VRLA) types respectively, at both the residential and utility scales. For flow batteries, vanadium redox battery (VRB) type is considered at the utility scale [287, 250].

Table 2.1 displays all the hybrid systems analyzed in this chapter, defined by the physical scale and supply mode, which fix the range of RE and ES technologies. For example, at the residential scale (1- 10 kW), PV is only combined with Li-ion and Pb-acid batteries. At the utility scale (1MW), PV and wind technologies are combined with batteries, I-CAES (1MW), PHS (1MW) and P2H2P (1MW), whereas, they are combined with P2M2P (100MW), PHS (100MW) and AA-CAES (100MW) at the bulk scale (100MW).

2.3.4 Techno-economic data

Techno-economic data of renewable energy technologies

Table 2.2 presents the average techno-economic data^f of PV and wind power technologies for Switzerland [21]. The capital expenditure (CAPEX) is the one time initial investment while the operational and maintenance expenditure (OPEX) represents the annual maintenance costs [21]. The CAPEX for RE technologies includes the cost of generators (PV panels and wind turbines), inverters, balance of plant and one time labour installation costs. The lifetime of a PV inverter is assumed to be 15 years [21], and therefore its future replacement costs are also considered (in view of the longer lifetime of the PV panels). The cost of PV technology decreases with increasing scale (from residential to utility and bulk) due to economies of scale. The CAPEX for future replacement of the wind turbine is also presented. It is assumed that the cost of wind turbines will decrease in the future due to technological advancements and economies of scale associated with the increasing size of installations [21]. The cost levels in Switzerland are in general higher compared with other countries (e.g. total installation cost of residential PV in Switzerland is assumed to be around 2145 EUR/kW (2016) [21] compared with India, China and Germany where the residential PV installation costs (2016) are around 1175 EUR/kW, 1410

^fThe exchange rate assumed is 1 EUR equals 1.09 CHF

Table 2.1: RE and ES technologies used to form hybrid systems depending on the scale and supply mode.

Renewable Energy Supply	Scale	Supply Modes				
		Generation	Generation and peak	ToD	Bi-peak	Baseload
PV	Residential (1- 10 kW)	Li-ion				
		Pb-acid				
	Utility (1MW)	Li-ion				
		Flow				
		Pb-acid				
		I-CAES				
		P2H2P				
		PHS				
	Bulk (100MW)	AA-CAES				
		PHS				
		P2M2P				
Wind	Utility (1MW)	Li-ion				
		Flow				
		Pb-acid				
		I-CAES				
		P2H2P				
		PHS				
	Bulk (100MW)	AA-CAES				
		PHS				
		P2M2P				
	PV and Wind combination	AA-CAES				
		PHS				
		P2M2P				

EUR/kW and 1500 EUR/kW respectively [177, 176]). Higher costs in Switzerland are mainly attributed to the higher labour costs. Other driving factors are long duration of proceedings as well as demanding requirements for environmental impact assessment [21].

Table 2.2: Techno-economic specifications of PV and wind turbines. The data is taken from up-to-date sources representative for Switzerland [21, 342, 130, 38, 388, 158].

RE Technology Type	Scale	Lifetime (yrs)	CAPEX (EUR/kW)	OPEX (EUR/kW/year)	Inverter placement (EUR/kW)	re-cost	Wind turbine replacement CAPEX (EUR/kW)
Solar PV	Residential	25	2145	95	69		NA
Solar PV	Utility & Bulk	25	1193	14	67		NA
Onshore Wind Turbine	Utility & Bulk	20	2009	74	NA		1738

Techno-economic data of energy storage technologies

Table 2.3 presents the techno-economic input data for the various ES technologies considered in this chapter. The total cost is divided into CAPEX and OPEX. The CAPEX is further divided into a power-related (EUR/kW) and energy-related (EUR/kWh) component [2, 38], given by:

$$\text{CAPEX} = P \cdot C_P + E \cdot C_E \quad (2.1)$$

where, P = Power capacity (kW), C_P = Power-related CAPEX component (EUR/kW),
 E = Energy capacity (kWh), C_E = Energy-related CAPEX component (EUR/kWh)

The energy-related CAPEX component includes the storage medium e.g., cells for battery and reservoir for PHS, while the power-related CAPEX component includes the balance of plant and power electronics as well as the turbomachinery for CAES and PHS.

Table 2.3: Techno-economic input data for the various energy storage technologies compared in this chapter for hybrid systems. The data is taken from up-to-date sources representative for Switzerland [287, 2, 175, 191].

ES Technology Type	Lifetime (yrs)	C_E (EUR/kWh)	C_P (EUR/kW)	O&M Cost (EUR/kW/year)	Round Trip Efficiency (%)	Depth of Discharge (%)
Li-ion battery (1 and 100MW)	12	335	316	9	89	93
Li-ion battery (1-10kW)	12	335	2187	0	89	93
Flow battery (1 and 100MW)	19	428	1064	43	66	100
Flow battery (1-10kW)	19	642	1596	43	66	100
Pb-acid battery (1 and 100MW)	9	263	316	9	75	55
Pb-acid battery (1-10kW)	9	263	1143	0	75	55
PHS (1MW)	80	892	2847	4.5% of the power based component	78	90
PHS (100MW)	80	50	1250	0.7% of the power based component	78	90
I-CAES (1MW)	40	142	1423	5.1% of the power based component	75	81
AA-CAES (100MW)	60	128	605	5.1% of the power based component	68	47.5
P2H + H ₂ storage + Fuel Cell (1MW)	20	9	3189	5.1% of the power based component	28	100
P2M + Natural Gas Network + Combined Cycle Plant (100MW)	25	0	1901	5.1% of the power based component	27	100

2.3.5 Energy storage sizing

The PV and wind power generation profiles as well as the selected supply mode determine the optimal charging and discharging behaviour of a hybrid system. In order to estimate the required size and schedule of the selected ES technology, we develop a model with a temporal resolution of 10 min considering the following assumptions: (i) a 24 h modelling framework, i.e. a hybrid system is assumed to operate on a daily basis with an ES schedule determined on a day-ahead basis; and (ii) perfect day-ahead forecast of the electricity demand and RE generation. Figure 2.4 displays a flowchart providing an overview of the steps employed by the model. The objective function is to create a firm RE output level (λ) on a daily basis (e.g. see Figure 2.5). As mentioned in section 2.3.2, P_{RE} is the total generation from a RE system while $P_{RE,direct}$ is the part of the RE generation which is directly supplied to the supply mode. $P_{ES,charge}$ and $P_{ES,discharge}$ are the surplus RE generation which is charged to and discharged from the ES system respectively. The storage operation of a hybrid system depends on the RE profile, ES round-trip efficiency (η), and the type of supply mode. Performing a daily energy balance of a hybrid system in Eqn. (2.2), the electricity supply equals the RE production minus the storage losses.

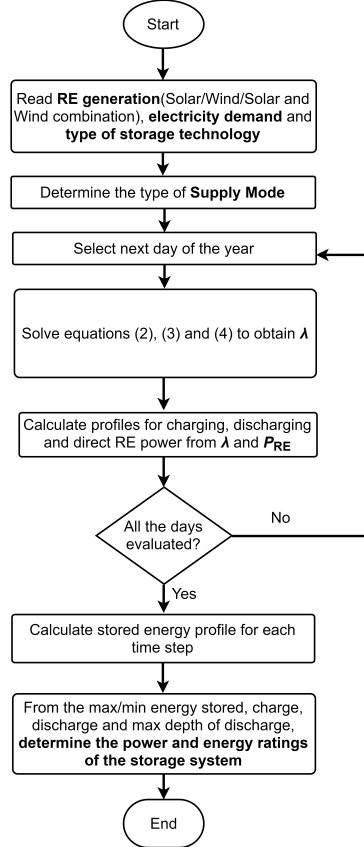


Figure 2.4: Flowchart of the model operation.

$$\sum_{i=0}^{23} P_{RE,i} - \left(\sum_{i=0}^{23} P_{RE,direct,i} + \sum_{i=0}^{23} \frac{P_{RE,discharge,i}}{\eta} \right) = 0 \quad (2.2)$$

As illustrated in Figure 2.5, the charging and discharging power and the direct RE power are functions of the variable λ , which corresponds to the upper level of a supply mode:

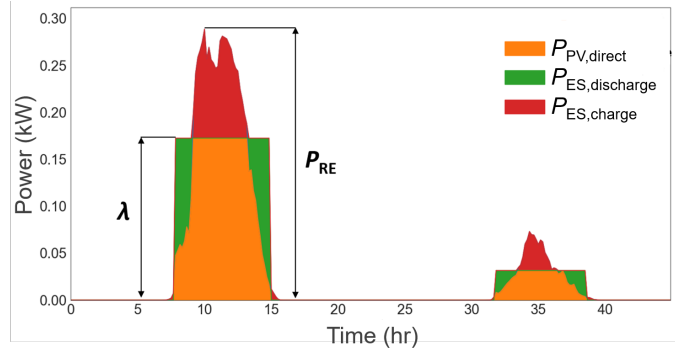


Figure 2.5: Illustration of a firm RE supply during generation hours, referred to as ‘Generation’, for two consecutive days with the help of an ES system.

$$P_{RE,direct,i} = \min(\lambda, P_{RE,i}) \quad (2.3)$$

$$P_{ES,discharge,i} = \max(0, \lambda - P_{RE,i}) \quad (2.4)$$

$$P_{ES,charge,i} = \max(0, P_{RE,i} - \lambda) \quad (2.5)$$

Eqns. 2.2-2.4 are solved for λ using the Python SciPy optimizer. For this purpose, the absolute value of the left-hand side of Eqn. (2.2) is minimized.

The results from the ES schedule ($P_{ES,charge}$ and $P_{ES,discharge}$) are then used to calculate the amount of electricity stored by the ES system (E_{stored}) for each time step (10 mins given by $1/6$ h as shown in Eqns. (2.6) & (2.7)). Then, the simulation is looped back to the next day till the end of the year.

$$E_{stored,t}^0 = \sum_{t_0=0}^t (P_{ES,charge,t_0} - \frac{P_{ES,discharge,t_0}}{\eta}) * \frac{1}{6} \quad (2.6)$$

$$E_{stored,t} = E_{stored}^0 - \min(E_{stored}^0) \quad (2.7)$$

The amount of electricity stored (E_{stored}) along with the depth of discharge (DOD) of the ES system are used to calculate the capacity of the storage unit in energy terms, E (kWh), given by the Eqn. (2.8). Finally, the capacity of the storage unit in power terms, P (kW) is determined by the maximum charge or discharge in power terms throughout the year at any time, t , as shown in Eqn. (2.9).

$$E = \max(\frac{E_{stored,t}}{DOD}) \quad (2.8)$$

$$P = \max(P_{ES,charge/discharge}) \quad (2.9)$$

2.3.6 Performance analysis

The capacity credit peak (CC_{peak}) is an indicator used to estimate the reliability of a power system to meet the peak demand load [91, 369]. It refers to the amount of renewable power that can reliably be supplied at the time of peak demand (D) as given by Eqn. (2.10). Since the RE generation (P_{RE}) is normalized in this chapter (by dividing by maximum RE generation), the value of C_{RE} (RE Capacity) is taken as 1.

$$CC_{\text{peak}} = \frac{\max_t(D_t) - \max_t(R_t)}{C_{\text{RE}}} \quad (2.10)$$

where, Residual Demand (R) is defined by Eqn. (2.11)

$$R_t = D_t - P_{\text{RE},t} \quad (2.11)$$

2.3.7 Techno-economic analysis

The levelized cost of energy is the most widely used techno-economic indicator to compare the cost-competitiveness of RE and ES technologies. In this chapter, we extend the definition of the levelized cost to hybrid systems (LCOHS) incorporating both RE and ES technologies, defined by Eqn. 2.12. This extension allows us to compare hybrid systems with the conventional generators, depending on the type of supply mode. Eqn. 2.12 accounts for the CAPEX and OPEX of both the RE and ES technologies (CAPEX_{RE} , CAPEX_{ES} , OPEX_{RE} and OPEX_{ES}), as well as the annual electricity supply directly from the RE system ($P_{\text{RE,direct}}$) and annual electricity discharged from the ES system ($P_{\text{ES,discharge}}$). Finally, r represents the discount rate which is set to 5%, n corresponds to the calculation period of a RE hybrid system, l represents the lifetime of a technology (eg. ES system, inverter or wind turbine), rl represents the remaining lifetime of a technology beyond the calculation period of a RE hybrid system and δ represents the degradation rate, which is assumed to be 0.5% p.a. and 1.2% p.a. for PV panels and wind turbines respectively. All these values are representative of the Swiss case [21].

The calculation period of PV hybrid as well as PV & wind hybrid systems is considered to be 25 years, same as the PV lifetime, whereas it is assumed to be 20 years for wind hybrid systems, which is same as wind turbine's lifetime. If the lifetime of a technology (e.g. inverter, ES system or wind turbine) is shorter than the calculation period of a RE hybrid system, further reinvestments are considered in addition to the initial CAPEX. The CAPEX assigned for future battery replacements is based on the most expected cost reduction trajectory using existing published data. This corresponds to 0.4, 0.3 and 0.5 times the present CAPEX by 2030 for Li-ion, flow and Pb-acid batteries respectively [175]. In case the lifetime of a technology is longer than the calculation period of a RE hybrid system, the discounted remaining value of the technology (beyond the calculation period of a RE hybrid system) is deducted from the total CAPEX of the technology.

$$\text{LCOHS} = \frac{(\text{CAPEX}_{\text{RE}} + \sum_{i=1}^n \frac{\text{OPEX}_{\text{RE}}}{(1+r)^i}) + (\text{CAPEX}_{\text{ES}} + \sum_{i=1}^n \frac{\text{OPEX}_{\text{ES}}}{(1+r)^i}) - ((\frac{rl}{l}) \frac{\text{CAPEX}_{\text{ES}}}{(1+r)^n})}{(\sum_{i=1}^n \frac{P_{\text{RE,direct}}(1-\delta)^i}{(1+r)^i}) + (\sum_{i=1}^n \frac{P_{\text{ES,discharge}}}{(1+r)^i})} \quad (2.12)$$

2.4 Results

We first present the performance results of hybrid systems, in particular, matching of electricity supply with the demand load and the capacity credit. We then present the LCOHS at the various scales (residential, utility and bulk) for each supply mode. This allows us to discuss the optimal choice of a hybrid system for a given scale and supply mode as well as to compare them with conventional technologies.

Furthermore, we determine the sensitivity of the LCOHS to the size of ES systems in both power and energy terms. Finally, we also test the sensitivity of LCOHS to the CAPEX of both RE and ES technologies. For the residential and utility scales, results are determined for each canton of Switzerland, while results at the bulk scale correspond to the aggregation of various cantonal results for Switzerland. This, for example, means that the PV and wind power generation values at the bulk scale have been calculated by the weighted averages of their respective installed capacities at the cantonal level (Supplementary section A.1.1 and Table A.3). The quantification of the required energy storage sizes (in energy and power terms) per unit of PV or wind installed within a hybrid system are presented in section A.6 under Appendix A.

2.4.1 Capacity Credit

Figure 2.6 presents Switzerland’s normalized daily averages of PV and wind power generation with the electricity demand in the year 2016. Demand profiles are plotted with 10 min and 1h resolution to match the supply curves of PV and wind respectively. The demand profile shows two distinct peaks — one in the early afternoon and a second one in the evening. PV generation, on the other hand, shows a diurnal profile, peaking in the afternoon (around 11:40 hrs), and is well-aligned with the peak demand. In contrast to PV, the average daily wind power profile is present throughout the day (peaking around midnight) and varies strongly between cantons. We therefore anticipate that, in the case of PV, energy storage can help to even out the intermittency and provide a firm supply, whereas, it helps to meet the peak demand in case of wind.

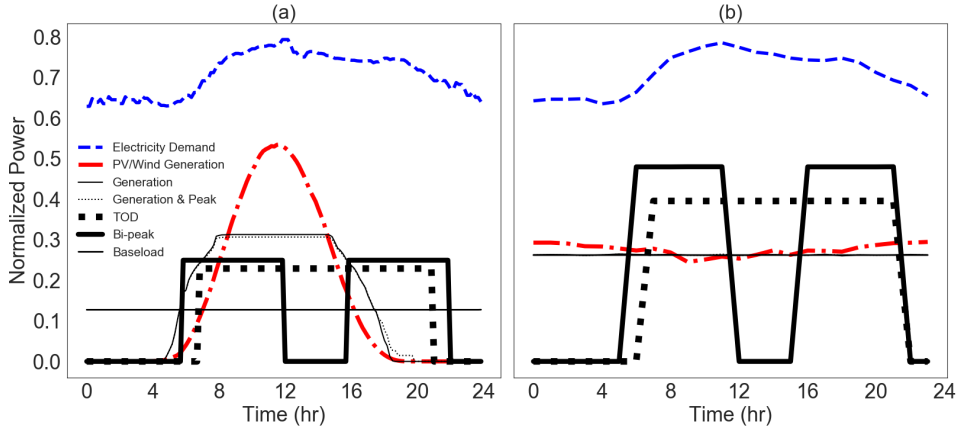


Figure 2.6: Normalized (a) PV generation (b) wind power generation and demand of Switzerland.

Figure 2.7 presents the annual PV and wind capacity credits with and without ES, at the national scale. Without ES, PV offers substantially more annual capacity credit (26.5%) than wind (3.61%). This is largely attributed to higher co-incidence of the electricity peak demand with the PV generation. This is, however, not the case for wind power. Wind is available almost 24 h per day, however, its peak production does not frequently coincide with period of high electricity demand (see Figure 2.6).

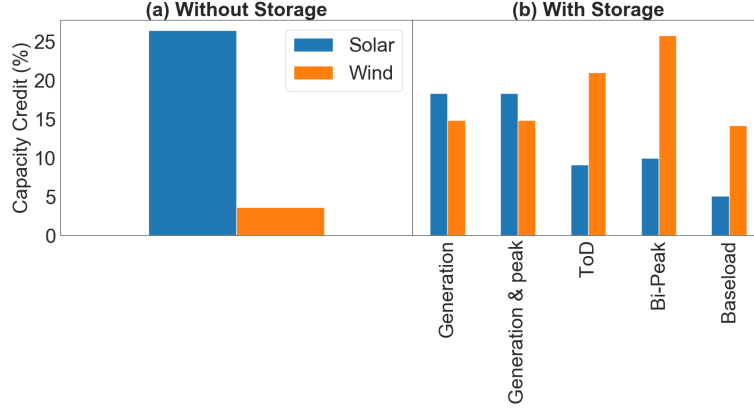


Figure 2.7: PV and Wind annual Capacity Credit for Switzerland ((a) without and (b) with I-CAES for illustration).

We use I-CAES technology to illustrate the impact of ES on the capacity credit of PV and wind. Interestingly, ES does not help to increase the capacity credit of PV, regardless of the supply mode. The reason is that storage helps PV to provide a firm supply across various supply modes, however, it reduces the match between PV output profile and the peak demand. Since the occurrence of peak demand coincides with the PV generation hours, the capacity credit is the same for ‘Generation’ and ‘Generation and peak’ supply modes. However, ES (I-CAES is considered as an example) significantly improves the capacity credit of wind power, from 4% to 26%. The ‘Bi-peak’ and ‘ToD’ supply modes have much higher capacity credits because of the higher firm supply (due to fewer supply hours compared to ‘Generation’, ‘Generation and peak’ and ‘Baseload’). We also study the distribution of daily capacity credit of PV and wind, shown in Supplementary Figures A.7 and A.8.

2.4.2 Techno-economic results

Residential scale

Figure 2.8 shows that PV & Li-ion hybrid systems are significantly more cost-effective than PV & Pb-acid regardless of the supply mode. The techno-economic attractiveness of the latter (PV & Pb-acid hybrid systems) is hindered by Pb-acid’s low depth of discharge (55%), short lifespan (9 years) and lower round trip efficiency (75%). This calls for higher battery capacity and several battery replacements to match the PV’s lifetime. Finally this results in a significantly higher LCOHS, despite Pb-acid’s initial lower CAPEX of 263 EUR/kWh and 1143 EUR/kW in energy and power terms respectively compared to 335 EUR/kWh and 2187 EUR/kW for Li-ion batteries.

PV & Li-ion hybrid systems offer lower levelized cost when supplying a firm profile during generation hours due to lower battery capacity requirements. For example, the median LCOHS of the PV & Li-ion hybrid system across cantons is 0.48 EUR/kWh (range between 0.39 to 0.58 EUR/kWh) for the ‘Generation’ supply mode, compared to 0.54 EUR/kWh (0.45 to 0.66 EUR/kWh), 0.67 EUR/kWh (0.54 to 0.77 EUR/kWh) and 0.61 EUR/kWh (0.51 to 0.74 EUR/kWh) for ToD, Bi-Peak and Baseload supply modes respectively. This is because the major portion of PV generation (76%) is supplied directly to the demand load in case of the ‘Genera-

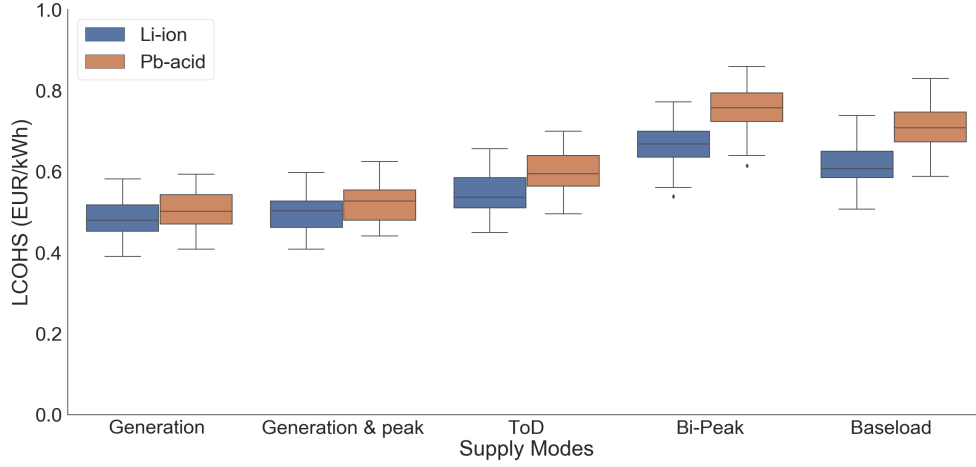


Figure 2.8: Levelized costs of PV hybrid systems with Li-ion and Pb-acid batteries at the residential scale depending on the electricity supply mode.

tion' supply mode, with this share being modest for other supply modes such as ToD (61%), Bi-peak (42%) and Baseload (40%) due to PV supply and demand mismatch. This leads to an increase in the battery capacity by more than double and hence increased energy-related battery CAPEX in case of 'Bi-peak' and 'Baseload' compared with 'Generation' supply mode. The average LCOHS for 'Generation' (0.48 EUR/kWh) and 'Generation & peak' (0.50 EUR/kWh) supply modes show a negligible difference because of the higher coincidence between PV generation hours and the peak electricity demand on a daily basis across the various cantons. Therefore, the battery energy capacity increases by only 0.25% in the case of Generation & peak compared with Generation supply mode.

Utility scale

For LCOHS at the utility scale (Figure 2.9), the following major observations can be made.

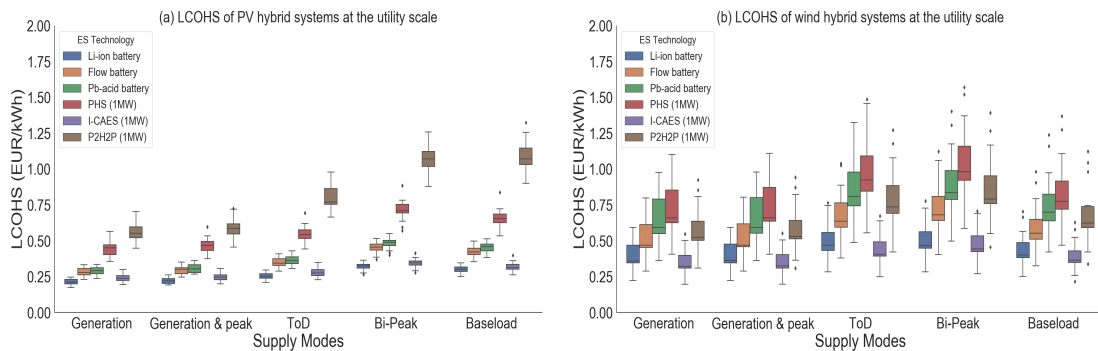


Figure 2.9: LCOHS for (a) PV and (b) wind hybrid systems at the utility scale depending on the electricity supply mode for the various type of energy storage technologies.

First, I-CAES offers lower LCOHS in case of wind hybrid systems whereas Li-ion battery in case of PV hybrid systems. Second, we find that I-CAES and Li-ion battery technologies rank second for solar and wind hybrid systems respectively. Third, the range of LCOHS in case of PV hybrid systems shows less variation compared to wind hybrid systems. For example, in case of the Generation supply mode, the

1762 LCOHS for a PV & I-CAES hybrid system varies between 0.19 EUR/kWh and 0.30
1763 EUR/kWh. In contrast, it varies between 0.20 EUR/kWh and 0.55 EUR/kWh for
1764 wind & I-CAES hybrid systems. This is due to practically uniform presence of solar
1765 resources across the cantons. In contrast, wind power shows substantial variations.
1766 Similar to the residential scale, we also find that providing a firm supply at gener-
1767 ation hours offers the lowest levelized costs for both PV and wind hybrid systems.
1768 For PV hybrid systems, Bi-peak followed by Baseload is the least optimal choice of
1769 supply mode, whereas, it is Bi-peak followed by ToD in case of wind hybrid systems.

1770 Bulk scale

1771 Figure 2.10 shows the LCOHS of PV, wind as well as the combination of PV and wind
1772 hybrid systems at the bulk scale and their comparison with conventional electricity
1773 generation technologies. For Generation, Generation & Peak and ToD supply modes,
1774 only PV in combination with PHS is found to be the most optimal hybrid systems
1775 (0.13 to 0.18 EUR/kWh, depending on the supply mode) compared to wind hybrid
1776 systems (0.15 to 0.18 EUR/kWh, depending on the supply mode) and combinations
1777 of PV & wind hybrid systems. However, for Bi-peak and Baseload, 50% wind &
1778 50% PV with PHS offers the lowest levelized cost (0.17 EUR/kWh for Bi-peak and
1779 0.15 EUR/kWh for Baseload). Hybrid systems with an aggregated supply of 50%
1780 wind & 50% PV offer the lowest levelized costs for Generation (0.14 EUR/kWh),
1781 Generation & peak (0.14 EUR/kWh), Bi-peak (0.17 EUR/kWh) and Baseload (0.15
1782 EUR/kWh) compared with all other combinations of PV & wind hybrid systems.
1783 On the other hand, 25% wind & 75% PV offers the lowest levelized costs for ToD
1784 (0.14 EUR/kWh).

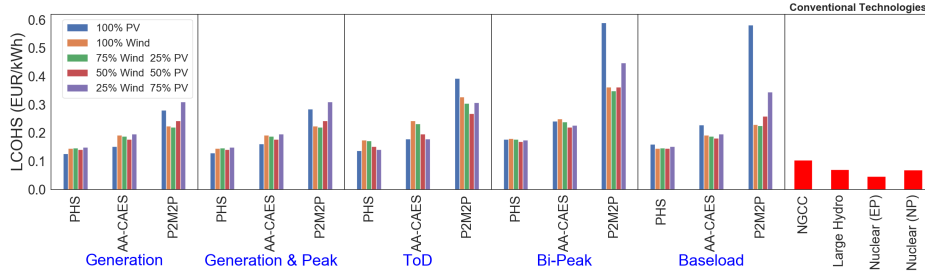


Figure 2.10: LCOHS for all combinations of solar, wind and combination of solar and wind hybrid systems at the bulk scale and their comparison with the levelized cost of conventional technologies (National level). Nuclear (EP) represents the Nuclear (Existing Plants) in Switzerland and Nuclear (NP) represents Nuclear (New Plants) outside Switzerland (New Gen III/III+ reactors as primarily built in Asia (China, South Korea) today)[21]. Generation costs of new nuclear plants are not applicable in the Swiss case since the construction of new nuclear power plants in Switzerland is no longer allowed after the agreement on the energy strategy 2050 (May 25, 2017).

1785 Furthermore, PV & AA-CAES hybrid systems offer lower levelized costs com-
1786 pared with the wind & AA-CAES hybrid systems for all the supply modes except
1787 Baseload. This is due to AA-CAES's relatively low DOD (47.5%) which increases
1788 the required energy capacity of a PV hybrid system in Baseload supply mode (as
1789 surplus PV during the day is sent to AA-CAES which is then discharged later during
1790 hours of no PV generation, unlike wind which is mostly present throughout day and
1791 night).

1792 Similar to the residential and utility scales, we find also for the bulk scale that
1793 providing firm supply via the Generation supply mode offers the lowest levelized
1794 costs for all combinations of RE hybrid systems. Furthermore, we find that LCOHS

of RE hybrid systems are still high compared to generation costs of natural gas combined cycle (NGCC) (average levelized cost of 0.10 EUR/kWh in Switzerland), large hydro (average levelized cost of 0.07 EUR/kWh in Switzerland) and nuclear (average levelized cost of 0.046 EUR/kWh for the existing plants in Switzerland and 0.069 EUR/kWh for the newly built plants outside Switzerland).

Trade-off between storage capacity, both in power and energy terms, and firm output supply

The model presented in this chapter allows the hybrid system to provide electricity according to a given supply mode without any RE curtailment. This improves the match between supply and demand and although not addressed in this chapter, it increases the value of RE technologies in the wholesale markets. However, it comes with a price since the ES technology is sized, both in power and energy terms, for the day with the highest RE generation, while not necessitating curtailment of RE. In this section, we explore the sensitivity of LCOHS to the size of the ES system in energy and power terms.

This sensitivity, therefore, considers that the ES system does not accommodate all the RE generation peaks. This surplus portion of the peak RE generation is supplied directly to the demand load. This implies some distortion in the firm electricity supply during days with very high RE generation. In particular, we test how the reduction of $P_{\text{ES,charge}}$ by up to 5%, leads to the reductions in storage capacity, which in turn allows for LCOHS reductions. This analysis represents a pessimistic case since the power and energy capacities are independently reduced. This implicitly assumes that synergies between the power and energy capacity reductions cannot be exploited. In the case of some storage technologies such as PHS, CAES and large flow batteries power and energy capacities can be treated independently, which may not hold for Li-ion or Pb-Acid batteries. However, since ratio between power and energy capacities is very low for the various supply modes considered in this chapter (Supplementary Table A.11 and A.12), we have the leverage to reduce the energy capacity (up to a certain extent) without reducing the power capacity of the Li-ion battery as part of our sensitivity analysis.^g

This sensitivity is shown in Figure 2.11 and Figure 2.12 for PV hybrid systems with Li-ion and PHS at the residential and bulk scale, respectively, for two supply modes (Generation and Baseload). We can see that a 5% reduction in the $P_{\text{ES,charge}}$ allows for up to 13% and 12% reduction in LCOHS for Generation and Baseload supply mode respectively in case of PV & Li-ion hybrid system. On the other hand, reducing the power capacity alone by allowing 5% reduction in $P_{\text{ES,charge}}$, enables up to 13% and 14% reduction for Generation and Baseload supply mode respectively in case of PV & PHS hybrid system. This reduction in the LCOHS would enhance the competitiveness of hybrid systems at the bulk scale with respect to the current generation costs of conventional technologies discussed in section 2.4.2. But interestingly, the reduction of the power and energy size has different impacts depending on the ES technology and supply mode. In the case of a PV & Li-ion hybrid system at the residential scale, reduction in both the energy and

^gFor the Li-ion (NMC) battery technologies considered in this chapter, the typical power to energy ratio is 0.5. This means that the energy capacity (kWh) should be at least twice the power capacity (kW). For the supply modes considered, the energy capacity is always much higher than this threshold since the storage technology should discharge for several hours. For example in the case of “Generation supply mode”, which requires the minimum discharge duration, the energy and power capacity of a Li-ion battery are 2.3 kWh and 0.56 kW respectively.

1838 power capacities lead to considerable reduction in the LCOHS. For a PV & PHS
 1839 hybrid system, on the other hand, reduction in power capacity has more impact on
 1840 LCOHS reduction than energy capacity reduction. This is due to the fact that PHS
 1841 has high power related CAPEX and very low energy CAPEX. Therefore, reduction
 1842 in the energy capacity of PHS does not have much impact on the LCOHS.

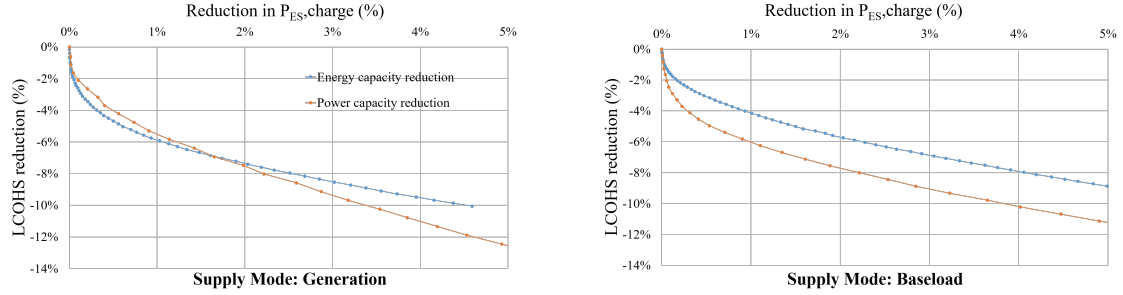


Figure 2.11: PV & Li-ion hybrid system at the residential scale: (a) Generation supply mode, (b) Baseload supply mode.

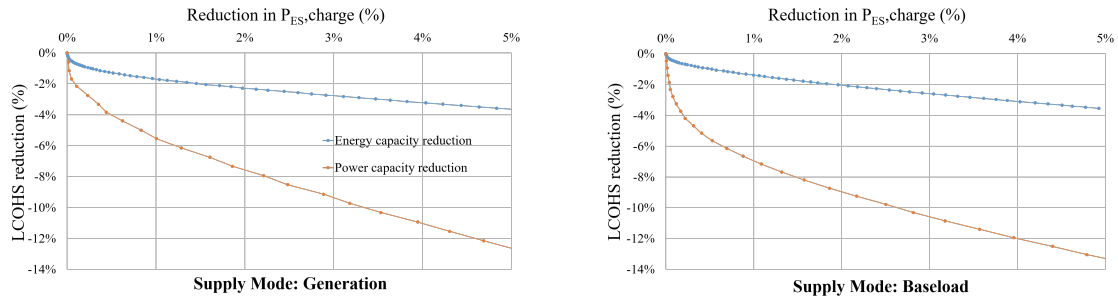


Figure 2.12: PV & PHS hybrid system at the bulk scale: (a) Generation supply mode, (b) Baseload supply mode.

1843 Sensitivity analysis

1844 Since the levelized cost is most sensitive to the CAPEX [379], we perform a sensi-
 1845 tivity analysis on the CAPEX of RE and ES technologies to understand the impact
 1846 of future cost developments on the levelized cost of hybrid systems. For example,
 1847 future cost reductions of PV and onshore wind turbines could reach up to 60%
 1848 and 20% respectively [178, 379] and those of I-CAES and Li-ion up to 20% and
 1849 60% respectively [175]. On the other hand, we assume no change in the CAPEX
 1850 of PHS since it is already a mature technology in the market and no major cost
 1851 improvements are anticipated [175].

1852 We illustrate the sensitivity analysis of wind in combination with I-CAES and
 1853 PV in combination with Li-ion battery for the utility scale in Figure 2.13 and Figure
 1854 2.14 respectively. Figure 2.13 shows a decrease of up to 14% in LCOHS from the
 1855 base case across all supply modes with 20% reduction in CAPEX of both wind
 1856 and I-CAES respectively. Additionally, we can see that CAPEX reduction of wind
 1857 technology has almost the same impact on LCOHS as CAPEX reduction of I-CAES
 1858 on the LCOHS. Secondly, Figure 2.14 presents LCOHS reduction upto 55% from
 1859 the base case across different supply modes with a CAPEX reduction of up to 60%
 1860 for both PV and Li-ion respectively. This makes the LCOHS of PV & Li-ion hybrid
 1861 system at the Generation supply mode (0.08 EUR/kWh) competitive with levelized
 1862 cost of NGCC (0.10 EUR/kWh) in Switzerland.

1863 The cost reduction trajectory of other ES technologies and their sensitivity anal-
 1864 ysis are presented in Appendix A Section A.5 and Figs A.9 - A.22. For example,
 1865 Figure A.20 in Appendix A shows that a 60% reduction of the CAPEX of PV alone
 1866 means improvements between 29% and 34% on the LCOHS of PV & PHS hybrid
 1867 systems supplying at Baseload and Generation respectively, thereby becoming cost-
 1868 competitive with conventional technologies such as NGCC and large hydro.

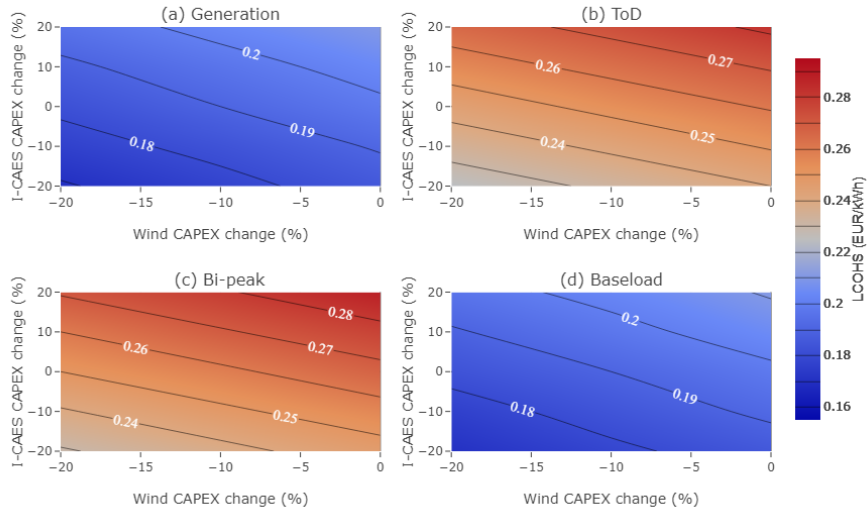


Figure 2.13: Sensitivity analysis of the LCOHS at the utility scale to the CAPEX of wind and I-CAES technologies for four different supply modes (a-d).

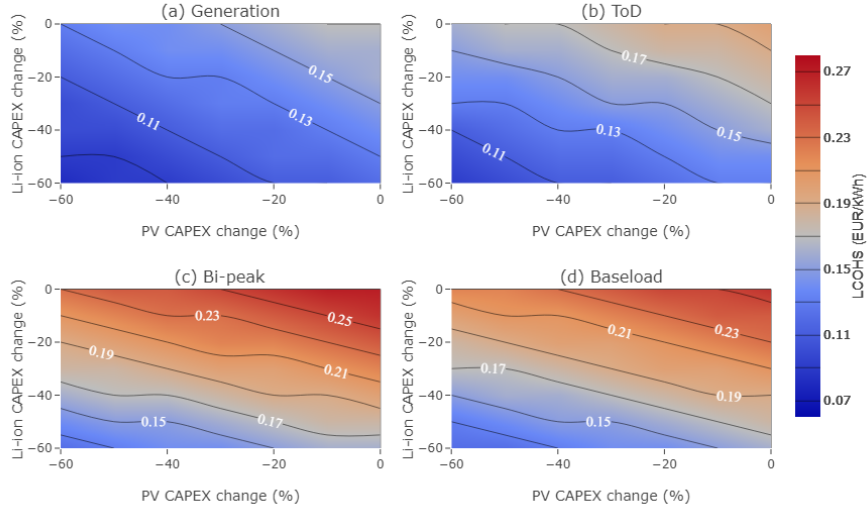


Figure 2.14: Sensitivity analysis of the LCOHS at the utility scale to the CAPEX of PV and Li-ion for four different supply modes (a-d).

2.5 Discussion

The temporal mismatch between renewable generation and electricity demand suggests that energy storage can play a significant role to substantially improve the capacity credit peak in case of wind. This is not the case for PV but energy storage helps to even out the variability patterns associated with PV generation. However, it must be appreciated that values of capacity credit are very region specific and that they depend on the demand profile as well as the selected RE sources to meet the peak demand.

Furthermore, we find that the optimal choice for an ES technology within a hybrid system depends on the scale rather than the supply mode. Our results show that Li-ion and PHS are optimal ES options at the residential and bulk scales for PV hybrid systems, whereas, Li-ion and I-CAES are optimal ES technologies for PV and wind hybrid systems at the utility scale, irrespective of the supply modes. On the other hand, the largely varying performance of various ES technologies such as round trip efficiency, depth of discharge and lifetime influences the economic viability of the hybrid systems. For example, at the residential scale, Li-ion is a better suited option for storage in a PV hybrid system due to Li-ion's higher round trip efficiency (89%), deeper depth of discharge (93%) and higher lifetime (12 yrs) than Pb-acid. The scale influences the levelized costs due to cost reductions of renewable and storage technologies with higher capacities, mainly profiting from economies of scale. The chapter confirms that across the different scales, PV in combination with PHS at the bulk level (0.13 to 0.18 EUR/kWh) is more cost competitive than PV with Li-ion at the utility scale (0.17 to 0.36 EUR/kWh) and PV with Li-ion at the residential scale (0.39 to 0.77 EUR/kWh) with ranges depending on the type of supply mode (Appendix A section A.3).

Importantly, the chapter showcases the most cost effective supply mode for supplying electricity under different scales. For instance, the LCOHS for Baseload is on average 33% and 27% higher than Generation supply mode for PV in combination with I-CAES and Li-ion at the utility and residential scale respectively. Conversely, wind hybrid systems offer a similar levelized cost when supplying electricity

at Baseload, Generation and Generation & peak. This is due to the significant presence of wind throughout the day and night, unlike solar which has a diurnal nature. The Bi-peak supply mode offers the highest LCOHS for PV, wind and combination of PV & wind hybrid systems. Technology developers and investors could benefit from these recommendations given the RE technology and the scale.

Despite cost improvements of RE and ES technologies at the utility and bulk scale compared to the residential scale, RE hybrid systems are still not cost competitive with other conventional electricity supply technologies. For instance, PV & Li-ion in case of Generation & peak at the utility scale offers a LCOHS between 0.19 to 0.26 EUR/kWh (depending on the canton), which is higher than the current levelized costs offered by NGCC (around 0.10 EUR/kWh in Switzerland) and large hydro (around 0.07 EUR/kWh in Switzerland). Similarly, wind & PHS for Baseload at the bulk scale offers a LCOHS of around 0.15 EUR/kWh which is presently much higher than nuclear (average levelized cost of 0.046 EUR/kWh for existing plants in Switzerland). However, it is important to note that the proposed method does not account for so-called externalities, e.g. social and environmental costs, degradation of assets and other impacts. Internalizing these externalities could have a positive impact on the competitiveness of renewable hybrid systems viz-a-viz the conventional electricity generation technologies. This is supported by results from previous studies which show that some renewable technologies become competitive against conventional power plants when the ‘damage costs’ caused by the latter are internalized [243, 111, 120].

Finally, this chapter provides a model to calculate the LCOHS of hybrid systems for multiple configurations but it has some limitations which call for further research. Firstly, our model assumes a perfect day-ahead forecasting of RE supply and electricity demand, which cannot be realized under real life conditions. Secondly, the proposed model could also be expanded to include ageing of electrochemical ES technologies. Additionally, the decision whether to invest in a hybrid system should also consider market revenues and their consideration within this framework is a subject of future research. Finally, the hybrid system model can also be extended to serve alternative supply modes apart from those included in this chapter (i.e. alternative demand profiles) across other regions/countries around the globe.

2.6 Conclusion

In this chapter, we present a hybrid system model for assessing the capacity credit and the total costs of RE and ES technologies for various supply modes (Generation, Generation and peak, ToD, Bi-peak and Baseload) at three different scales (Residential, Utility and Bulk). The analysis on the LCOHS shows that PHS and I-CAES are the most cost-effective energy storage technologies for wind hybrid systems at the bulk and utility scales respectively. On the other hand, for the PV hybrid systems, PHS is an optimal ES solution for the bulk scale, whereas Li-ion battery is more cost-effective for the utility and residential scales. Another key finding of this chapter is that the optimal choice for a hybrid system depends on the scale rather than the supply mode strategy.

Our results show that renewable hybrid systems are still not cost competitive with conventional supply generators, therefore we pinpoint key levers for improving their cost-competitiveness. First, allowing some distortion in the firm output profile for a few days in a year or some level of curtailment, can significantly reduce the

energy storage size requirements. In particular, this translates into a reduction of the energy and/or power capacity of storage technologies, and a CAPEX reduction as a result. Then, whether to concentrate on reducing the energy or the power component is a matter of choice depending on the type of ES technology and its intrinsic characteristics. For instance, storage technologies such as PHS or P2G2P has more power-related CAPEX and less energy-related CAPEX. Therefore, reducing the power capacity of PHS or P2G2P within the hybrid system configuration has more impact on the resulting LCOHS than reducing their energy capacity.

Furthermore, the sensitivity analysis confirmed that the LCOHS is equally influenced by the reduction of the CAPEX of both RE and ES technologies. Therefore, we conclude that aggressive cost reductions of both RE and ES technologies are still required in order to boost higher uptake of RE hybrid systems to serve as a source of firm electricity supply. The findings from this chapter can serve as a guide for technology developers, investors and policymakers aiming to promote the transition to a sustainable energy future using firm renewable electricity.

2.7 Additional output - Online Levelized Cost of Hybrid System Calculator

The LCOHS model developed as part of this chapter is made available online free of cost to the users [10]. A link to the online LCOHS calculator is given here [LCOHS calculator](#). It helps the user to examine a range of ES technologies to support RE technologies for different types of supply mode strategy and scale of deployment defined in this chapter for cantons across Switzerland. This graphical interface allows the user to choose the type of supply mode, scale, canton and type of RE and ES technology from the drop down menu. Further, the user can use a slider to control or manually enter input values for various input parameters of RE and ES technologies (CAPEX, OPEX, lifetime, degradation rate, round trip efficiency etc.). After choosing the input data, the calculator automatically calculates the LCOHS in EUR/kWh, which can be visualized at the bottom left of the web page. A documentation page as well as typical techno-economic specifications for PV, wind and various ES technologies (considering their current state-of-art in Switzerland) are also provided on the website to maximise ease of use. Key distinctive features of the calculator are: 1) it is very easy to use and comprehend; 2) it can be used to calculate LCOHS for number of combinations of hybrid systems across different cantons in Switzerland; 3) the transparency on the input data used and flexibility to choose different RE sources, ES technologies as well as different supply mode strategies and scales, across Switzerland. It aims to serve as a guide for researchers, technology developers, investors and policymakers aiming to promote the transition to a sustainable energy future using firm renewable electricity.

Chapter 3

Distribution grid capacity and costs to enable massive deployment of PV, electric mobility and electric heating

Rapid deployment of solar photovoltaics (PV), electric heat pumps (HP) and electric vehicles (EV) is needed to decarbonize the economy. However, the integration of these technologies into the power system creates challenges for the distribution grid infrastructure. It is therefore vital to analyze to which extent grid reinforcement is needed to enable these decarbonization strategies while also studying alternative flexibility measures. In this GIS-based study, we model the impact of the deployment of PV, HP and EV charging on a distribution grid network serving 170'000 households in Switzerland, and we analyze scenarios for their penetration in the years 2035 and 2050. Using a detailed grid model in collaboration with a distribution system operator, we find that PV leads to 18.5% and 13.7% more voltage violation issues compared to HP and EV respectively, which on the other hand, cause slightly more line overloading, 0.5% and 2.5%, respectively. We also find that the grid reinforcement costs markedly depend on the type of urban setting ranging between 51-213 CHF/kW_p, 46-1'385 CHF/kW and 34-143 CHF/kW for PV, HP and EV respectively, with the higher limit corresponding to rural areas. The total distribution grid reinforcement costs can amount up to 11 billion CHF until 2050 i.e. 2'900 CHF per household in Switzerland. Interestingly, we find that batteries, even with current costs, have the potential to defer grid reinforcement for up to 15% of the transformer stations with the highest specific grid reinforcement costs. Our study aims to inform various stakeholders about the required grid investments to enable the massive deployment of low carbon technologies.

3.1 Introduction

The energy system is undergoing a transformation from fossil fuels to renewable energy (RE) [170]. In 2018, RE technologies represented 84% of all the new electricity capacity added worldwide and already accounted for one third of the global power capacity [180]. At the same time, the decarbonization of the various demand sectors, namely mobility, heating and industry is resulting in additional electricity demand

^asimilarly published in: Applied Energy, Volume 287, April 2021 [125]

[264]. For instance, the global share of electricity in final energy use is projected to increase to 50% by 2050 compared with 20% in 2018 [170].

Switzerland has committed itself to halve its greenhouse gas emissions by 2030 compared to 1990 levels, and to reach a reduction of 70-85% by 2050 in the context of the Paris Agreement [335]. In view of the latest findings of the Intergovernmental Panel on Climate Change, the Swiss Federal Council took the decision in summer 2019 to tighten the targets and to reach net zero carbon emissions by 2050 [103]. To achieve these targets, Switzerland is taking steps to increase renewable generation and to curb CO₂ emissions from transport and heating sectors [328], which jointly contribute to 60% of all CO₂ emissions [30]. Solar photovoltaics (PV) is expected to become the prime RE technology, growing from an annual electricity generation of 2.2 TWh in 2019 to 34 TWh by 2050 [260]. To meet the need for space heating, fossil-based heating systems are being replaced with electric heat pumps (HP) with significantly higher efficiency [339, 209], potentially reducing the final energy consumption in households by up to 70% [310, 323]. A study by the Swiss heat pumps association estimated that the number of HP sold in Switzerland would increase from 20'000 p.a. in 2020 to 40'000 p.a. by 2030 [313]. Additionally, electric vehicles (EV) (both battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV)) sales are markedly increasing relative to petrol and diesel vehicles [281, 228, 116]. It is estimated that the share of newly registered EV in Switzerland will reach 15% in 2022 (from 2.7% in 2017) [65]. EV are about 3-5 times more efficient than fossil-based vehicles and contribute to reducing urban pollution [353].

The use of PV, HP and EV significantly modifies the load profile of the buildings where they are installed, both in energy and power terms. PV can create a reverse power flow in the distribution feeders, potentially resulting in voltage violations and overloading of the distribution lines [265, 32, 60]. The use of HP and EV, on the other hand, increases the peak electricity demand [281]. So far, these three technologies have been integrated into the distribution networks without reaching the limit ('hosting capacity'), i.e. with a limited impact on the existing grid infrastructure [182, 317, 47, 143]. However, once the hosting capacity is reached after continued technology additions, upgrading or even a complete rebuilding of the existing transformer stations (also known as 'secondary substations') and reinforcement of the lines will be needed to integrate these technologies [163, 182, 264, 235]. Thus, PV, HP and EV charging additions can lead to huge investments for the distribution system operators (DSO), finally affecting the electricity bill of final consumers [263, 264, 143, 142]. Therefore, DSO^b need to carefully plan the deployment of PV, HP and EV to ensure a smooth and cost-effective energy transition [299].

The major steps involved in grid planning are: (i) electricity load and infeed forecast, (ii) analysis of grid adequacy for the future load, (iii) modelling of the future grid to allocate the new loads, and (iv) grid reinforcement [136]. Since estimates of grid reinforcement costs are seldomly reported by the distribution system operators and the data availability at high RE penetration is scarce [134], it is paramount to estimate the distribution grid impacts and reinforcement costs needed to enable increasing deployment of PV, HP, and EV charging in line with the net zero targets. Additionally, there are flexibility alternatives to grid reinforcement, such as active power curtailment [182, 299], reactive power control [299], demand side management [264, 384] and energy storage [364, 47, 123]. Battery storage systems are becoming very attractive for DSO since they can secure grid stability, improve asset utilisation and potentially defer grid reinforcements [293, 364]. This chapter provides distri-

^bThe same acronym is used both for singular and plural depending on the context.

bution grid impacts and costs to inform DSO, regulators, policy makers, and new market actors and help them to navigate the energy transition.

3.1.1 Literature review and research objectives

Prior work focusing on the impact of PV generation, heating and transport electrification on distributed power systems has addressed various topics, namely: (i) quantification of the future electricity load, (ii) assessment of the grid adequacy and (iii) techno-economic analysis of potential flexibility options to enable the penetration of PV, HP and EV. In this section, we review the related work falling in each of these categories.

Luthander et al. assessed the impact of PV and EV on the Swedish distribution grid. They found that a fully electrified car fleet increases the electricity consumption by 9.3% and 17.1% during critical weeks in winter and summer respectively. Also, 71% of the PV systems need to be curtailed during summer if PV generation equals electricity consumption throughout the year [210]. Another study analysed the impact of uncoordinated charging of EV on a distribution grid with 1200 nodes [184]. The authors reported an increase between approximately 60-110% in the distribution transformer power load in case of 15-30% EV penetration, respectively. The reason for this significant increase was attributed to the simultaneity of EV charging and the traditional peak residential load occurring in the evening. Also, Rüdüsüli et al. also studied the impact of the electric mobility and heating in Switzerland using a temporal resolution of 1 h, however, without considering spatial distribution of technologies [281]. It was shown that with an electrification share of 75% and 20% for heating and mobility, the annual electricity demand increases by 10 TWh and 3.7 TWh respectively, which translates to around 25% increase in total electricity demand. However, the above-mentioned studies did not evaluate the impact of these new electricity demand loads on the distribution grids.

To assess grid adequacy, Salah et al. analyzed the impact of EV charging on Swiss distribution substations under different penetration and electricity tariffs [283]. This study found that with an EV penetration of 16% of all vehicles in Switzerland and under a flat electricity tariff, the existing substation capacity is adequate to integrate EV. However, beyond this limit, EV charging is expected to cause overloading of the substations. Another study shows that if 20% of households own a HP in the UK, the peak electricity load increases by 72% above the baseline, and that the transformers have to be reinforced [32]. PV penetration beyond 25-30% would also require distribution grid reinforcements. Pillai et al. assessed the capability of the three Danish distribution grids to incorporate EV for low (4 h) and peak demand (17 h) hours of a selected day. Their results show that depending on the robustness of the distribution grids, they can handle between 6-40% of EV loads for the peak and low hours, respectively [255]. While the above-mentioned studies quantify the grid impacts associated with the penetration of PV, HP and EV, they did not calculate the grid reinforcement costs needed to enable their penetration. In short, the studies on grid adequacy indicate that grid reinforcement is not needed with low diffusion of EV, HP and PV (e.g. up to 15%), with the exception of EV charged during peak hours, which however does become necessary for higher penetration levels.

Finally, multiple papers have already attempted to quantify and discuss the costs required for upgrading the distribution grids. Horowitz et al. carried out a detailed review on this topic and concluded that these costs are greatly case-dependent [143]. Pudjianto et al. quantified the cost of integrating PV for 11 key countries in the

EU and found that for a PV penetration between 2%-18%, the distribution reinforcement costs varies between -25 to 9 EUR^c/MWh [263]. The cost is positive when PV deployment results in net additional cost for the distribution line upgrade compared to the base case, but it is negative when PV reduces the distribution network capacity due to the correlation between PV generation and the peak demand. In a different study focusing only on the UK, the same authors simulated various scenarios for EV and HP in different distribution network topologies to determine reinforcement costs up to 2050 [264]. Their results show that the electricity peak demand can increase by 2 to 3 times, requiring an investment of £36^d billion by 2050. The study also emphasizes the role of smart EV charging and HP operation to reduce the reinforcement costs. Fernández et al. found that for an urban distribution network, the investment costs could increase by up to 15% of the total actual investment costs in case of 60% EV penetration scenario [253]. Due to lack of publicly available grid data, Gupta et al. proposed an unsupervised method to investigate the PV hosting capacity of medium voltage grid for Switzerland and assessed the costs of battery storage to accommodate PV beyond the hosting capacity [122]. This study however neither assessed the cost of grid reinforcement nor the impact on the grid due to HP or EV charging deployment. Previous studies, therefore, typically focused on integration of the low carbon technologies, either on the supply or the demand side. However, since all the three technologies (PV, HP and EV) are needed to achieve the energy transition objectives, it is important to study the aggregated impact of their simultaneous deployment on the distribution grid. Only a recent study assessed the impact of PV, HP and EV on a distribution grid, but it was carried out for a medium sized town (population of 40'000) in Germany covering only the residential sector [338]. The authors simulated three different scenarios for combined HP and EV and one scenario considering only PV deployment. Their results show that the peak electricity load increases by a maximum of 74% for the combined HP and EV penetration scenarios, while the feed-in power due to PV (8.8 MW_p) increases by 73% compared to the baseline decentralized generation. However, this study neither discusses the cost of grid reinforcement nor potential solutions to avoid grid reinforcement.

Against this background, this chapter aims to expand the existing body of literature by: (i) analyzing a large-scale real distribution area covering 170'000 households located in the second-largest Swiss canton by both surface area and population distinguishing different urban settings, namely urban, suburban and rural, (ii) using a geographic information system (GIS)-based model to carry out long-term forecasting (for 2035 and 2050) of PV installations as well as electricity loads due to HP and EV charging deployment, (iii) comparing the individual and aggregated impacts of PV, HP and EV charging based on different scenarios with a detailed distribution grid model developed by the DSO, (iv) analysing the reinforcement costs as a function of technology and type of urban setting and (v) analyzing the potential of battery storage to defer distribution grid reinforcement. Finally, we scale up our results to the national level to evaluate the long-term grid impact of decarbonization in Switzerland. The proposed method developed and implemented in collaboration with one of the largest DSO in Switzerland allows to provide technical and regulatory recommendations which are important for DSO, regulators and policy makers to design a flexible electricity grid infrastructure including sector coupling. Further, this methodology could be extended to other countries/regions to account for

^c1 EUR = 1.0852 CHF (2019)

^d1 GBP = 1.2739 CHF (2019)

2161 region-dependant capital and operational expenditures.

2162 3.2 Input data and method

2163 In this section, we give an overview of the input data including the electricity grid
2164 structure, scenarios for technology penetration and technology characteristics. Long-
2165 term forecasting of the electricity demand with geographical resolution is a challeng-
2166 ing task since it depends on various economic, social, environmental and political
2167 factors [370]. We therefore use scenario analysis in this chapter.

2168 3.2.1 Current structure of electricity grid in Switzerland

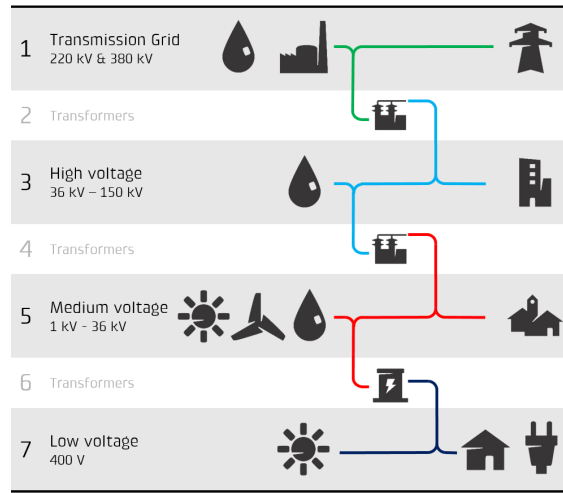


Figure 3.1: Basic structure of the Swiss electricity grid. This chapter focuses on the low voltage distribution grid depicted as level 6 and 7 in this figure.

2169 The Swiss electricity grid comprises different layers ranging from extra-high volt-
2170 age (220 kV and 380 kV) to low voltage (400 V) as illustrated in Fig. 3.1. The high
2171 voltage grid is operated in a meshed way and has a large capacity reserve, since
2172 each point is connected to more than one supply point. On the other hand, the
2173 medium and low voltage grids (the latter is referred to as **distribution grid** in this
2174 chapter) are operated radially, where normally each point is connected to only one
2175 supply point and hence exposed to higher risks, in particular with the deployment
2176 of PV, HP and EV charging. Therefore, in this chapter, we focus on the low voltage
2177 distribution grid at the level of transformer stations (see level 6 and 7 in Fig. 3.1).
2178 We use a real distribution grid which is owned and operated by the utility, BKW^e
2179 in parts of the canton of Bern, Solothurn and Jura in Switzerland, referred to as
2180 **supply area** in this chapter. Fig. B.1 under Appendix B shows the supply area.

2181 3.2.2 PV deployment in Switzerland

2182 In Switzerland, PV installations are so far limited to rooftops and this is expected to
2183 remain the same in the future [306]. Therefore, to assess the future PV deployment in
2184 Switzerland, we develop a method to select the rooftops with high PV potential. For
2185 this purpose, we use the Sonnendach database [308], which provides information on

^eBKW Energie AG is one of Switzerland’s largest utilities companies serving mostly as a rural electricity distribution system operator.

the solar potential of each building rooftop in Switzerland by taking into account its exposure to solar radiation, area, orientation, inclination and exposure to shade. The parameters used in this chapter for selecting the rooftops for future PV deployment are inclination, orientation and available surface area.

First, all rooftops within the supply area are categorized as flat ($i = 0^\circ$) or non-flat ($i > 0^\circ$), depending on their inclination angle (i). Non-flat rooftops are further categorized on the basis of their orientation. We select rooftops receiving good annual solar radiation ($\geq 1000 \text{ kWh/m}^2/\text{year}$) (grey shaded area in Fig. B.4 under Appendix B). This equals 271'249 non-flat rooftops oriented between -90° and $+90^\circ$ and 57'469 rooftops with flat inclination. On the other hand, all rooftops facing from northwest to northeast receive low and medium solar radiation ($< 1000 \text{ kWh/m}^2/\text{year}$) and are therefore excluded from the analysis. Rooftops with an area smaller than 10 m^2 are also excluded [350]. For the selected rooftops, we calculate the PV installed capacity, P_{PV} using Eqn. (3.1) considering the area (A), a typical PV production (O) of $187.5 \text{ W}_p/\text{m}^2$ [307] and the final assumption that only 70% of the rooftop area would be effectively available for PV installations [350].

$$P_{PV} = A \cdot O \cdot 0.7 \quad (3.1)$$

3.2.3 Heat electrification with heat pumps

In this chapter, we determine the demand for space heating and domestic hot water only for the residential sector, which is analysed with the Swiss Residential Building Stock (SwissRes) model, described in previous publications [320, 319, 233]. It is a bottom-up model which allows to calculate the monthly space heating demand based on the balance between energy gains and losses of the different building elements [319]. Input data are derived from a dataset of 50'000 Cantonal Energy Certificates for Buildings [50]. The residential stock is represented by archetype buildings which are defined by various categories together with their respective number of classes, which are given in brackets, as follows: construction period (9), building type (2, namely single-family houses (SFH) and multi-family houses (MFH)), urban setting (3, namely urban, suburban and rural) and heating system type (6) [320] (see Table B.1 in Appendix B). To account for the regional climate, the energy model uses daily mean temperature and daily global horizontal irradiance data with a high resolution of 1 km by 1 km for the base year of 2015 [322]. This allows to calculate the energy demand for each residential building that is then aggregated to 972 archetype buildings in the supply area.

Once the heating demand is calculated, the HP electrical nominal capacity is determined using Eqn. (3.2) and the following method. Firstly, the specific annual useful heating demand, Q_{m^2} ($\text{kWh/m}^2 \text{ p.a.}$), provided for the different archetypes by the SwissRes model is multiplied by the respective energy reference area, ERA (m^2) for each building [81]. The nominal thermal capacity of a HP is derived from a regression with the useful heating demand extracted from more than 6,000 energy certificates, resulting in a value (f_{power}) of $4.58\text{E-}04 \text{ kW}_{th}$ per kWh of useful energy demand [324]. Finally, the nominal HP electrical capacity is calculated after dividing by the seasonal coefficient of performance ($\text{COP}_{seasonal}$), assumed as 2.7 [183].

$$P_{HP} = \frac{(Q_{m^2} \cdot ERA) f_{power}}{\text{COP}_{seasonal}} \quad (3.2)$$

3.2.4 Electrification of mobility

EV are connected to the distribution grid network using charging stations. The number of EV sales over the total passenger car fleet until 2035 and the specific share of BEV and PHEV in Switzerland were determined in the former studies [105, 128] (Table B.4 in Appendix B gives the current distribution of passenger vehicles in each canton of Switzerland).

The number of EV chargers is a function of the EV penetration. EV chargers are assumed to be deployed both in residential and public places. The residential sector is categorized into three main classes: one-unit SFH, two-unit SFH and MFH. We assume that every EV owner has access to one charger at home, in addition to the public chargers at various locations. We further assume that every MFH with EV owners has 2-5 chargers, depending on the EV penetration scenario. In addition, EV charges are located in the following public zones^f: 1) zones for public use, 2) work zones, 3) tourism and leisure zones, 4) centre zones, 5) mixing zones, 6) traffic zones, and 7) further construction zones. We then assume for public areas a ratio of 1 EV charger per 10 EV in the stock [217]. Regarding the nominal capacity, private charging stations at home are assumed to range from low power (7 kW) to high power (22 kW), whereas public chargers are assumed to be high power (22 kW). Table B.5 and B.6 under Appendix B show the distribution of nominal capacities of EV charging plugs for residential and public charging [105] respectively. Finally, the charging power depending on the type of EV model are illustrated in Table B.7 in Appendix B.

3.2.5 Scenarios

Various scenarios are built to determine the individual and aggregated nominal capacity of PV, HP and EV chargers for the years 2035 and 2050 as shown in Fig. 3.2. The scenarios refer to the supply area of BKW with 170'000 households and a total population of 379'100. The proposed scenarios consider different cases ranging from a highly pessimistic least effort scenario to the highly optimistic heroic effort scenario. The additional electricity load due to HP and EV charging as well as the maximum PV feed-in are aggregated at the level of transformer stations of the distribution grid. We do not consider PV self consumption and demand side management as this chapter deals with preparing the grid for the worst case scenarios. However, we consider simultaneity factors to calculate the contribution of HP and EV charging to the total electricity load at the transformer station level as follows. We simulate several PV-coupled HP systems in houses with different heating demand. Subsequently, we calculate the simultaneity factor among houses for a randomly selected pool of households, whose size varies from 2 to 100, with and without PV and with and without HP. This was repeated 1'000 times and we take the median results of the distribution. The simultaneity factor among houses is calculated as the ratio of the simultaneous maximum demand (with HP) of a group of consumers within 15-minutes, to the sum of their individual maximum demands (with HP) in the year (Eqn B.1 in Appendix B). For EV, we use the simultaneity factors for EV charging from an open-source simultaneity factor tool [216] using the input data from this study, specifically, number of EV chargers,

^fThe Swiss Federal Office of Spatial Development has divided areas in different zones. The definition of each construction zone is available at <https://www.are.admin.ch/are/fr/home/developpement-et-amenagement-du-territoire/bases-et-donnees/statistique-suisse-des-zones-a-batir.html>

share of charging power (7 kW, 11 kW and 22 kW), share of EV class (BEV and PHEV) and their respective energy capacities (kWh). The different simultaneity factors used for HP and EV charging are detailed under section B.2 in Appendix B. To reflect the stochastic nature of spatial diffusion, the deployment of PV, HP and EV chargers are assumed to occur randomly in the future. However, to obtain more robust results, we perform several simulation tests to understand the sensitivity of grid reinforcement costs to spatial diffusion of technologies.

	PV	HP	EV	HP + EV	PV + HP + EV
Basic assumption	All the flat rooftops and those oriented between -90° to +90° within the supply area are considered for PV installations	Existing heating systems in the residential sector within the supply area are replaced with electric HP	Residential sector and public zones within the supply area are considered for EV chargers deployment	Same as for deployment of HP and EV chargers	Same as for deployment of PV, HP and EV chargers
2035	Least	Least	Least	Least	Least
	Determined	Determined	Determined	Determined	Determined
	Aggressive	Aggressive	Aggressive	Aggressive	Aggressive
	Heroic				
2050	Least	Least	Heroic		
	Determined				
	Aggressive	Aggressive			
	Heroic				

Figure 3.2: Scenario development across different technologies and their combinations in 2035 and 2050.

We investigate PV deployment under four different scenarios, mainly differentiated by the level of PV penetration, from a highly pessimistic ‘least effort’ scenario to a highly optimistic ‘heroic effort’ scenario. The **least effort** scenario assumes that the past trend of PV deployment would continue, corresponding to 20% of the best exhaustible PV potential in 2050. The **determined effort** scenario corresponds to 50% of the best exhaustible potential in 2050 and implies dedicated support of the government and commitments inline with the low carbon pathway. The **aggressive effort** scenario assumes a significant PV deployment which is ambitious, but achievable with aggressive efforts, accounting to 70% of the best exhaustible potential in 2050. Lastly, **heroic effort** scenario assumes that all the rooftops, oriented between -90° to +90° and with flat roof, have PV panels installed on them in 2050, which represents 100% of the best exhaustible potential. The PV installed capacity in 2035 and 2050 under each scenario is illustrated in Table 3.1. Further, we assume a linear PV deployment between 2020 and 2050. Fig. 3.3 shows a histogram of the PV installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area.

Future HP deployment in the residential sector is based on the replacement of the existing heating systems, as a function of their installation year and assuming a lifetime of 25 yr for the existing heating system [183], under three different scenarios which are shown in Table 3.2. The **least effort** scenario is based on historical and envisaged sales of HP in Switzerland (see Table B.3 in Appendix B) [313]. The **determined effort** scenario is driven by the new Energy Act in the canton of Basel-Stadt, which aims at replacing all the fossil-based heating systems at the end of their lifetime by renewable-based heating systems [240]. Here, we assume that all fossil-based heating systems are replaced by HP in 2035. Finally, all heating systems

Table 3.1: Projected PV installed capacity addition for the supply area in 2035 and 2050 under four different scenarios.

Scenario	Projected PV Installed Capacity (MW _p)	
	2035	2050
Heroic Effort	1'492	2'983
Aggressive Effort	1'044	2'088
Determined Effort	746	1'491
Least Effort	299	597

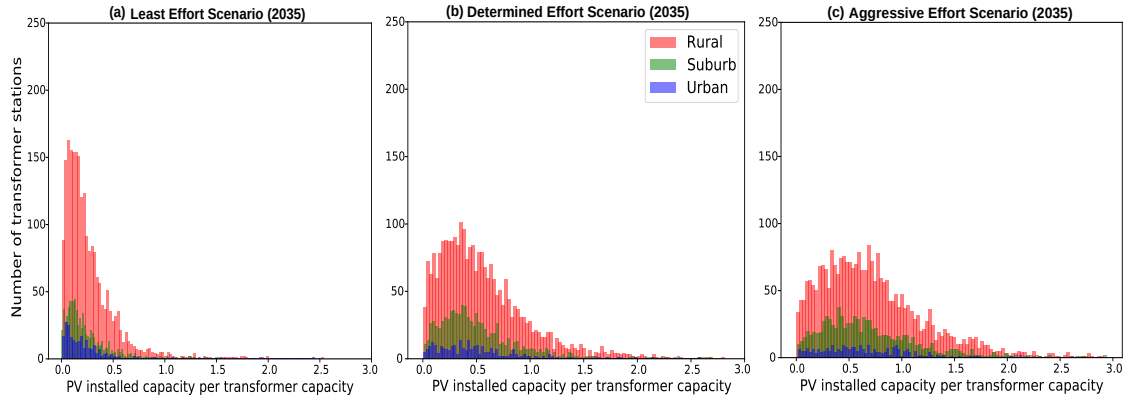


Figure 3.3: Histogram of the PV installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area for (a) least, (b) determined, and (c) aggressive effort scenarios in 2035.

(including wood and direct electric) are replaced by HP in the **aggressive effort** scenario in 2050. Since, we consider deployment of HP only in the residential sector, we do not consider heroic effort scenario for HP. Fig. 3.4 shows a histogram of the HP installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area.

Table 3.2: Projected number of existing heating systems replaced by HP and projected installed capacities addition of HP under three different scenarios for the supply area in 2035 and 2050.

Scenario	2035		2050	
	Number of heating systems replaced by HP	Projected HP installed capacity (MW)	Number of heating systems replaced by HP	Projected HP installed capacity (MW)
Aggressive Effort	69'830	350	111'210	570
Determined Effort	74'900	410	-	-
Least Effort	19'000	100	44'930	230

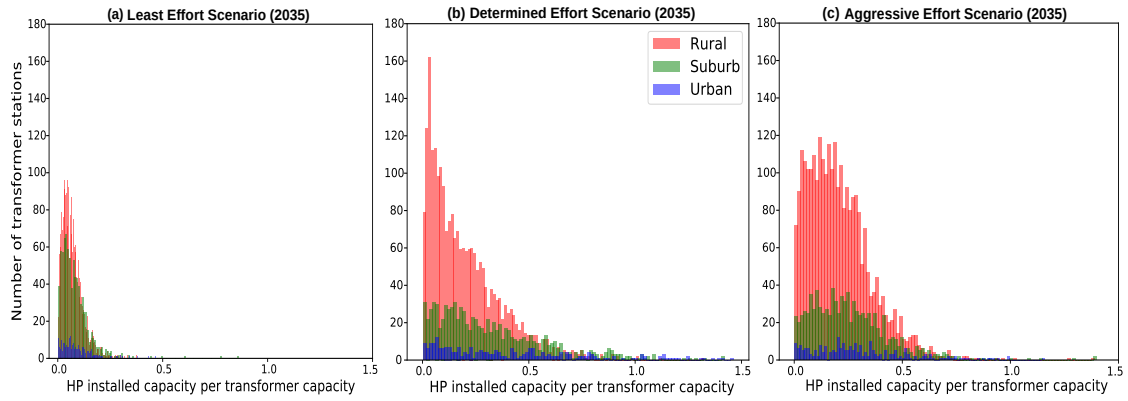


Figure 3.4: Histogram of the HP installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area for (a) least, (b) determined, and (c) aggressive effort scenarios in 2035.

Under the **least effort** scenario, EV are envisaged to constitute only 15% of the total passenger vehicles fleet in Switzerland in 2035, whereas, this figure corresponds to 24% and 33% in case of **determined effort** and **aggressive effort** scenarios, respectively. In 2050, we base our analysis on a single scenario which assumes that 100% of the passenger cars will be electric (BEV or PHEV) (referred to as **heroic effort** scenario). Further, the total number of passenger cars are considered to remain unchanged between 2035 and 2050. Table 3.3 presents the number of EV charging stations deployed across the supply area in 2035 and 2050 for the various scenarios (for details refer to subsection B.1.4 in Appendix B). Fig. 3.5 depicts a histogram of EV chargers installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area.

The installed capacities of technologies calculated for each house connection are aggregated at the level of transformer stations and plotted relative to the nominal capacities of their respective transformer stations in the form of a histogram presented in Figs. 3.3-3.5. While for the least effort scenario, the installed PV capacity

only represents about half of the installed transformer capacity for most transformer stations, this ratio increases with the ambition level of the scenario (Fig. 3.3). For the aggressive effort scenario, for example, the installed PV capacity represents more than 50% of the total transformer capacity for most transformers. The number of transformers for which the installed PV capacity exceeds the total transformer capacity (values >1 on x-axis) becomes significant, especially in rural areas. Similar patterns are found for HP (Fig. 3.4) and EV (Fig. 3.5), however with the difference that the HP capacity per transformer capacity remains relatively low (nearly always below 0.5 across the scenarios).

Table 3.3: Projected number of EV charging stations deployed and the total installed capacity (MW) under three different scenarios for the supply area in 2035 and 2050. The number of charging stations deployed are a function of the number of EV penetration.

Building Type	Power	Number of EV charging points and installed capacity addition			
		2035			2050
		Aggressive Effort	Determined Effort	Least Effort	Heroic Effort
SFH (<i>one-unit</i> and two-unit)	7kW	105'788	75'790	48'514	136'880
MFH	7 kW	6'059	4'335	2'816	160'695
	11 kW	41'161	29'549	18'952	0
	22 kW	2'666	1'998	1'300	0
Public	22 kW	26'700	19'129	12'243	75'587
Total number of EV chargers		182'374	130'801	83'825	373'162
Total installed capacity (MW)		1'882	1'350	865	3'746

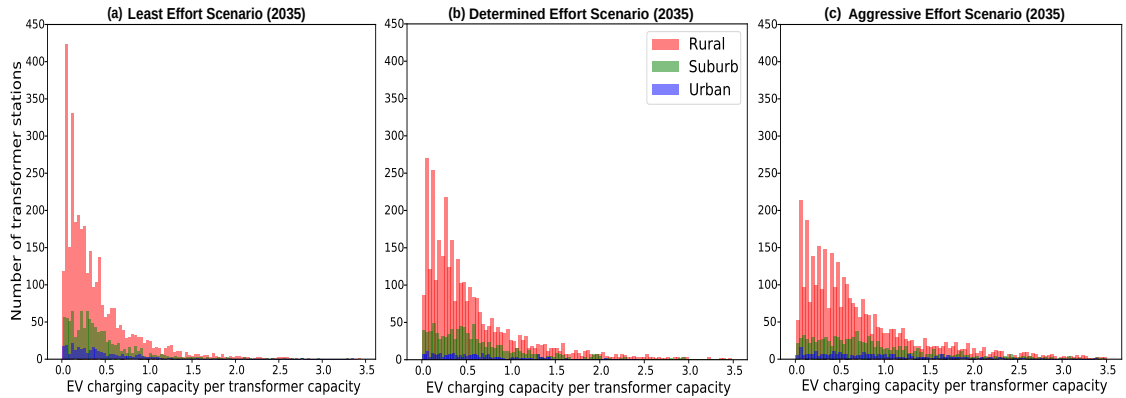


Figure 3.5: Histogram of EV chargers installed capacity relative to the nominal capacity of the transformer stations for various urban settings within the supply area for (a) least, (b) determined, and (c) aggressive effort scenarios in 2035.

Further, the combination of HP and EV as well as PV along with HP and EV are analysed for least, determined and aggressive scenarios in 2035.

3.2.6 Distribution grid modelling

Table 3.4 displays various electric components within the supply area. Around 72% of the transformer stations within the supply area are in rural areas, 22% in

suburban and 6% in urban areas. A large-scale distribution grid planning model with a high spatial resolution, developed and operated by the DSO (BKW), is used to calculate the required network investment for the different future levels of technology penetration according to the scenarios defined in section 3.2.5. The model consists of all electrical components of the low voltage grid, which are exported from BKW's geographical information system (GIS), starting at the medium to low voltage transformer (see level 6 Fig. 3.1) down to every house connection. During the export, the elements such as transformers and lines are enhanced with electrical parameters (resistance, reactance, technical limits etc.) according to their type. For lines and transformers, BKW maintains a library of technical parameters given by the relevant manufacturers. The model runs load flow calculations for various technology diffusion scenarios which allow us to determine the current and/or voltage limit violations, the subsequent reinforcement of the existing lines and transformers and the total reinforcement cost. The steps involved in the modelling process are illustrated in Fig. 3.6.

Table 3.4: Key parameters of the current distribution grid within the supply area

Parameter	Value
Number of transformer stations	5'879
Number of house connections	163'756
Total length of lines (km)	13'987
Estimated cumulative maximum load without considering simultaneity (GW)	4.2

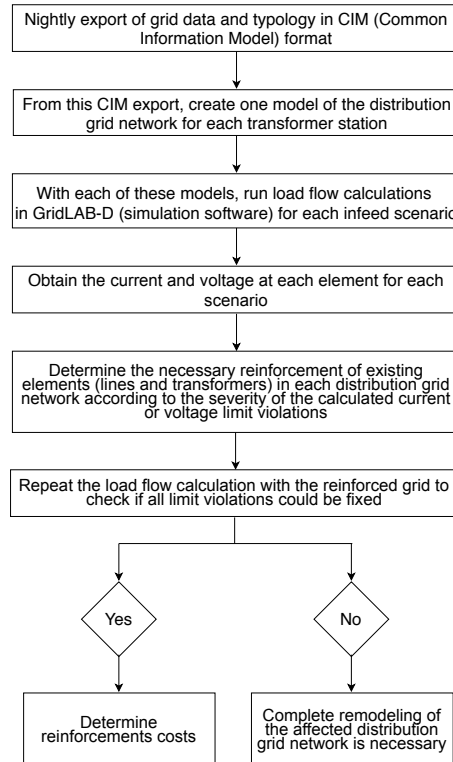


Figure 3.6: Flowchart showing steps involved in modelling of the distribution grid.

First, after the initial load flow calculation, the various grid elements (transformer or line) which are overloaded are replaced with elements of a higher capacity. An element is considered overloaded if its load exceeds its nominal capacity established by the manufacturer. Next, the load flow calculation is repeated to check any remaining voltage violations. The following cases are considered as voltage limit violations:

1. A voltage increase of more than 3% due to PV power infeed compared to the situation without PV power infeed according to the DACHCZ technical rules for assessing network perturbations [34].

2. The voltage at any point in the distribution grid is lower than 90% of the nominal voltage for load simulations according to EN 50160 [34].

If there is any voltage violation, the grid is reinforced following a step-wise iterative approach. Once all violations are resolved, we determine the costs for these reinforcements. The reinforcement cost of a low voltage grid is zero if the aggregated load after deployment of technologies is lower than the nominal capacity of the transformer in the area and if there are no line overloading or voltage violation issues. Otherwise, grid reinforcement costs account for both upgrading and/or rebuilding of the transformer stations as well as reinforcing of the lines. We determine grid reinforcement costs using empirical values provided by the DSO. For example, for the reinforced lines, the unit costs contain average values for both the material and the installation of the new lines and dismantling costs for the existing lines. For cabling of the overhead lines, average civil engineering costs for new pipes are considered. For reinforced transformers, we consider the material and installation costs, as well as conversion or construction costs of the transformer station building which needs to be extended. The values primarily represent investment costs for the physical grid, whereas planning costs or the change in operational costs are not considered. If grid violations cannot be eliminated using a simple reinforcement (upgrading) of the grid elements, we assume a complete rebuilding of the affected part of the distribution grid network. This includes costs for an additional transformer station as well as for completely new low and medium voltage lines according to the size of this distribution grid network. We use average costs for rebuilding a complete low voltage grid based on existing projects of the DSO.

Grid reinforcement costs are affected by several factors, such as i) the capacity of technologies installed (according to the scenarios above) vis-a-vis the capacity of the transformer stations, ii) distribution of technologies across rural, suburban or urban areas, iii) increase in electricity load at the transformer stations, iv) number of house connections within the transformer station network undergoing voltage violation, v) total segments and length of lines overloaded, and vi) the ratio of the number of transformer stations requiring rebuilding to the number of transformer stations only requiring upgrade under different scenarios.

In case the load flow calculation in one part of the supply area does not converge (typically due to a significant PV reverse flow and/or a very high load in locations where the grid is very weak), we still assume a fixed reference reinforcement cost for that transformer station. To get a realistic cost estimate, we group the distribution grid networks into three different sizes (see section B.3 in Appendix B) and we assume for each a different fixed reference cost for remodelling the network. The transformer stations with convergence problems in the load flow calculations are filtered out when we calculate the specific grid reinforcement costs (CHF/kW).

3.2.7 Upscaling of results to the national scale

We scale-up our results from the supply area to the national level in order to estimate grid reinforcements costs for Switzerland. To do so, we extend the PV, HP and EV models and scenarios to the whole of Switzerland (see sections 3.2.2, 3.2.3 and 3.2.4). We use the results presented in the regression analysis (Section 3.3.5) per technology type (which is the output from our model described in section 3.2.6) from the supply area. Thus, we assume that the specific grid reinforcement costs per urban setting from the DSO's supply area are representative for rest of the country. While this is a strong assumption, since grid costs are region dependant [263], this gives a first estimation of the range of grid reinforcement costs needed to promote the mass deployment of PV, HP and EV charging in Switzerland.

3.3 Results

We first present the total grid reinforcement costs to enable the deployment of different technologies, both individually and in combination, for least, determined and aggressive effort scenarios within the supply area. This allows us to discuss the impact of various technologies on the distribution grid as well as the corresponding reinforcement costs needed to enable such deployments in the supply area. Since the heroic effort scenario is considered only in case of PV and EV, and not for HP nor the combination of technologies, their results are presented under section B.3.1 in Appendix B. We present the median values of the total grid reinforcement cost and their respective ranges from 12 simulation runs. Interestingly, the results from different runs show no significant variation. Furthermore, we compare the median total grid reinforcement costs across all scenarios for PV, HP and EV charging in Fig. B.11 in Appendix B.

Secondly, specific grid reinforcement costs defined as the cost of grid reinforcement (CHF) per unit of technology installed (kW) are analyzed at the level of transformer stations for different urban settings, namely rural, suburban and urban for the least and determined effort scenarios. The results of the aggressive effort scenario are presented under Section B.3.2 in Appendix B. Furthermore, we examine battery storage as a flexibility option to defer grid reinforcement. Finally, the results are scaled up to the Swiss level.

3.3.1 Least effort scenario

Fig. 3.7(a) presents a boxen plot of the grid reinforcement costs needed to deploy PV, HP EV and their combination for the least effort scenario in 2035 and 2050. The grid reinforcement costs depend on a number of factors as outlined in section 3.2.6 and Figs. 3.7(b) to 3.7(g) compares the most relevant ones, i.e. percentage of house connections undergoing voltage violation, length of line overloaded as well as the share of transformer stations undergoing upgrade and rebuilding for 2035 and 2050. For 2035, we find that 5.8% of the house connections undergo voltage violation and around 222 km of lines are overloaded due to deployment of EV chargers (865 MW), compared to only 3.6% and 111 km for HP (100 MW) and 3.8% and 19 km for PV (299 MW_p), respectively. Interestingly, HP leads to more line overloading compared to PV, despite the fact that HP installed capacity is one third of PV capacity. This results in 27% of the transformer stations requiring upgrading in case of HP compared to 20% for PV. EV deployment on the other hand result in

39% of transformer stations requiring an upgrade. These issues, overall, lead to a median grid reinforcement cost of 109M CHF (ranging between 108 - 109M CHF) for EV, as opposed to 79M CHF (ranging between 78 - 79M CHF) and 78M CHF (ranging between 76 - 82M CHF) for HP and PV, respectively, in 2035. Jointly, HP and EV increase the median cost of grid reinforcements to 113M CHF, while the addition of PV raises the total cost to 176M CHF (i.e., an increase of 63M CHF).

In 2050, the expected PV capacity in the least effort scenario is 597 MW_p (100% higher than in 2035), causing a voltage violation in 11% of the house connections compared to only around 4% in case of HP (with a installed capacity of 230 MW in 2050). To enable this PV deployment, 8% of transformer stations should be rebuilt, which is a markedly higher percentage than for HP (only 1%). PV deployment in 2050 results in approximately doubled grid reinforcement costs compared to 2035, with a median value of 159M CHF (ranging between 153 - 165M CHF). This is significantly higher than for HP with a median value of 84M CHF (ranging between 84 - 86M CHF), representing less than 10% increase compared to 2035.

3.3.2 Determined effort scenario

For the grid reinforcement costs in the determined effort scenario (Fig. 3.8(a)), the following observations can be made. Contrary to the least effort scenario for 2035 where grid reinforcement for PV is least expensive, grid reinforcement costs for PV in the determined scenario for 2035 are most expensive, with a median value of 201M CHF (ranging between 195 - 206M CHF) as opposed to a median value of 129M CHF (ranging between 128 - 131M CHF) and 85M CHF for EV and HP respectively. This is despite the fact that installed capacity of EV chargers (1'350 MW) is much higher compared to PV (745 MW_p) and HP (410 MW) in 2035. The reason is that PV causes voltage violation in 15% of the house connections compared to 7% and 4% in case of EV and HP respectively (see Figs. 3.8(b) to 3.8(g)). Overall, 10% of the transformer stations for PV need to be rebuilt, compared to only 1% and 2% for HP and EV respectively, thereby leading to higher costs. The combined deployment of HP along with EV results in a median grid reinforcement cost of 147M CHF (ranging between 145 - 148M CHF) in 2035. The simultaneous deployment of PV along with HP and EV leads to high grid reinforcement cost with the median value of 305M CHF (ranging between 301 - 310M CHF). Finally, doubling PV deployment in 2050, relative to 2035, leads to 34% of the house connections having voltage violations along with 104 km of lines overloading, resulting in a median grid reinforcement cost of 400M CHF (ranging between 395 - 406M CHF) in 2050.

3.3.3 Aggressive effort scenario

Fig. 3.9(a) shows the grid reinforcement costs needed to enable the deployment of PV, HP and EV and their combination under the aggressive effort scenario. First, in 2035, similar as in determined effort, PV deployment leads to relatively higher grid reinforcement costs with a median value of 282M CHF (ranging between 278 - 288M CHF) compared to a median value of 155M CHF (ranging between 154 - 156M CHF) and 90M CHF (ranging between 88 - 90M CHF) for EV and HP respectively. Although the deployment of HP and EV lead to a higher length of lines being overloaded compared to PV (422 km, 136 km and 72 km for EV, HP, and PV respectively), the cost related to PV-induced voltage violation issues becomes dominant. In particular, PV causes 23% of the house connections undergoing voltage

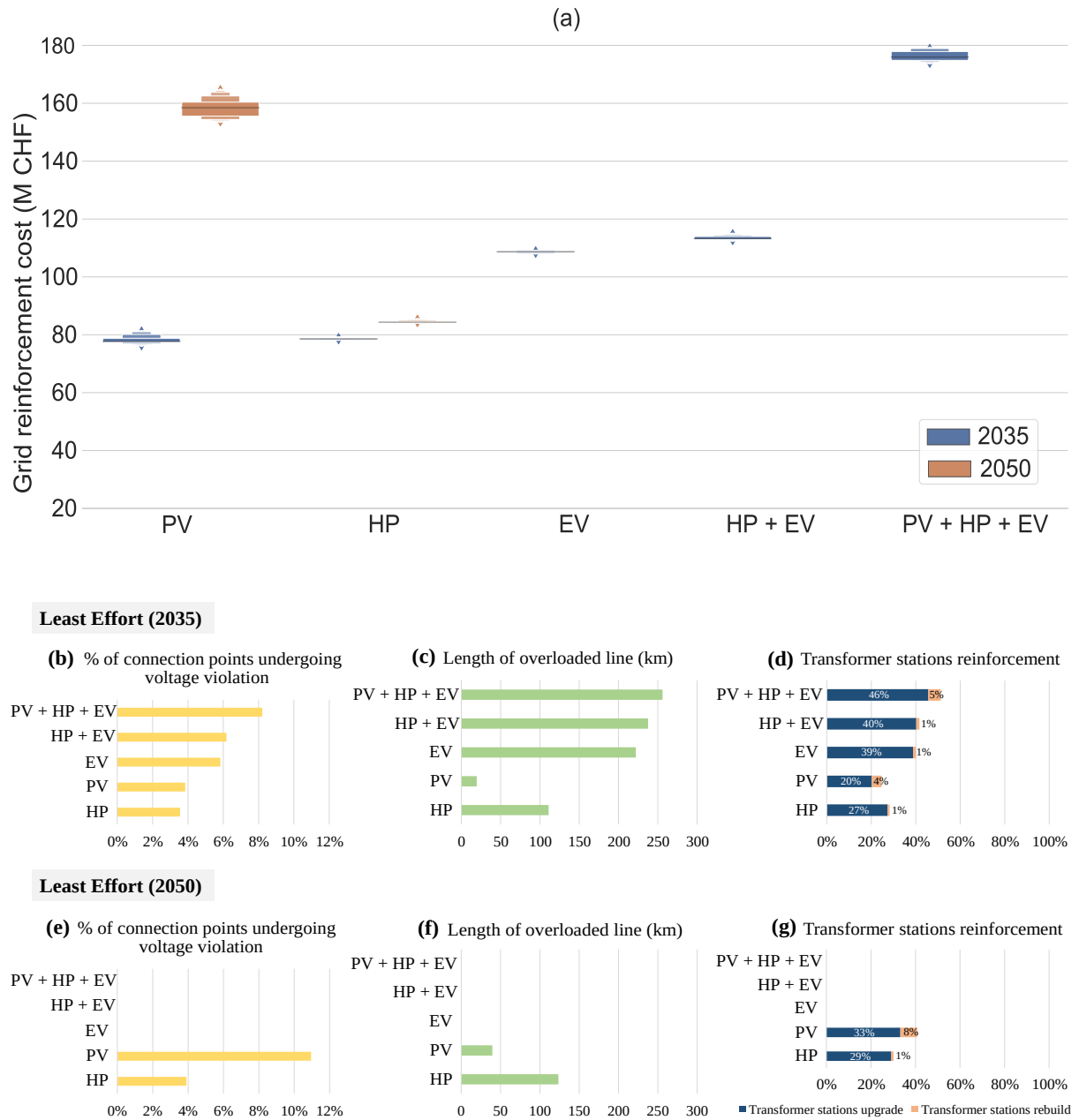


Figure 3.7: Results for the least effort scenario in 2035 and 2050: (a) Grid reinforcement costs and driving factors for grid reinforcement costs: Percentage of house connections undergoing voltage violation, length of overloaded lines and share of transformer stations undergoing a upgrade or rebuilding due to penetration of PV, HP, EV and their combinations in 2035 ((b) to (d)) and 2050 ((e) to (g)). Since, there is no least effort scenario for EV, HP+EV and PV+EV+HP in 2050, there are no boxes and bars for these technologies in 2050.

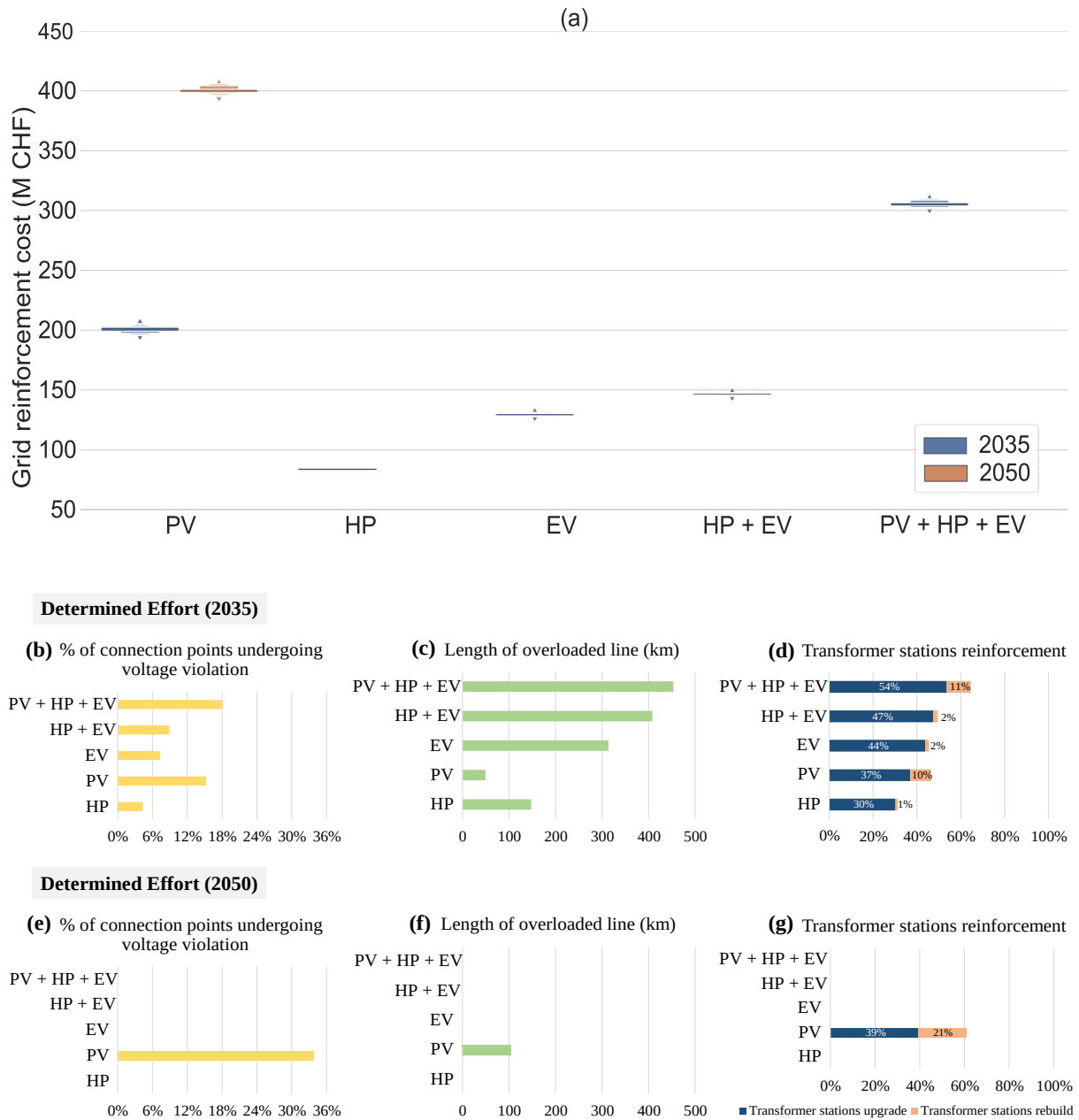


Figure 3.8: Results for the determined effort scenario in 2035 and 2050: (a) Grid reinforcement costs and driving factors for grid reinforcement costs: Percentage of house connections undergoing voltage violation, length of overloaded lines and share of transformer stations undergoing a upgrade or rebuilding due to penetration of PV, HP, EV and their combinations in 2035 ((b) to (d)) and 2050 ((e) to (g)). Since, there is no determined effort scenario for HP, EV, HP+EV and PV+EV+HP in 2050, there are no boxes and bars for these technologies in 2050.

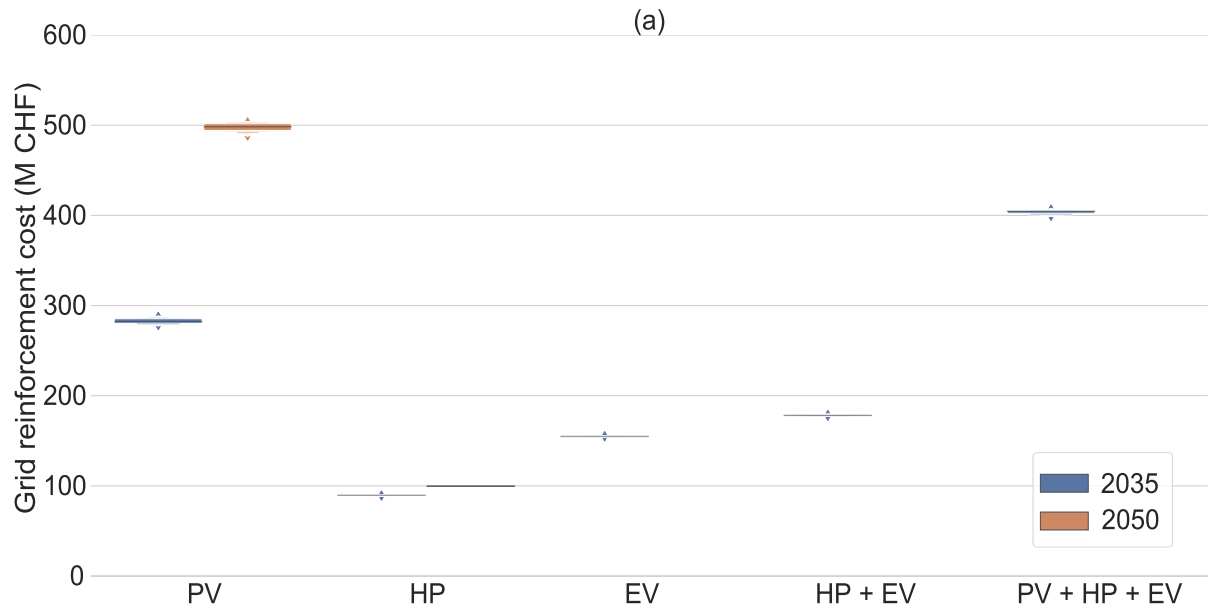
violation compared to 9% and 4% for EV and HP respectively. As a result, 14% of the transformer stations should be completely rebuilt to allow PV penetration, compared to only 2% and 1% for EV and HP respectively, thereby resulting in higher reinforcements costs for PV (see Figs. 3.9(b) to 3.9(g)). Furthermore, the combined deployment of HP and EV results in grid reinforcement costs with a median value of 178M CHF (ranging between 177 - 179M CHF). However, the simultaneous deployment of PV along with HP and EV leads to a remarkable increase, with the median cost of around 405M CHF (ranging 399 - 407M CHF). In 2050, the grid reinforcement needed to deploy 2'088 MW_p of PV is almost 5 times higher than to deploy 570 MW of HP. PV causes around 44% of the house connections undergoing voltage violation compared to only 5% for HP.

3.3.4 Grid reinforcement costs per urban setting

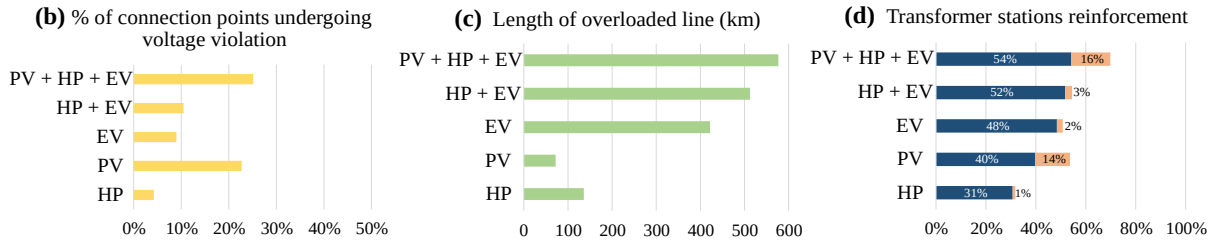
In this section, we analyse the specific grid reinforcement cost (CHF/kW) for deployment of PV, HP and EV chargers at the level of transformer stations under different urban settings (rural, suburban and urban). We present the medians and interquartile ranges (IQR) of specific grid reinforcement costs while comparing different technologies, as the median values are less affected by the outliers than the mean and therefore a better measure of central tendency. Our random allocation together with the characteristics of the supply area result in the following distributions for various technologies in 2035: 59%, 31% and 10% of the total PV capacity is installed in rural, suburban and urban areas respectively across all scenarios: 50%, 36% and 14% of the total HP capacity is installed in rural, suburban and urban areas respectively, whereas, 61%, 29.5% and 9.5% of the total EV charging capacity is installed in rural, suburban and urban areas respectively.

Fig. 3.10 shows vertical boxplots of the specific grid reinforcement costs for PV, HP and EV in case of the least effort scenario for 2035. The following common observations can be made. First, the specific grid reinforcement costs are remarkably higher for rural areas compared to suburban and urban areas. For instance, the specific grid reinforcement costs for PV deployment in rural areas is around 170% and 290% higher than in suburban and urban areas, respectively. The reason for higher costs in rural areas is because the grid in rural area is generally weaker and more spread out. It is therefore more prone to voltage violation issues due to differences in length and strength of the grid network compared to the grid in urban area. For instance, HP results show that only 2% of the house connections in the urban areas undergo voltage violation compared to 12% in the rural areas. Second, the position of the median in all the boxes is closer to the lower quartile than the upper quartile. Also the whiskers (lines) on the bottom are much shorter than the whiskers on the top of the boxplots. This indicates that the specific grid reinforcement costs for various technologies is highly skewed to the right. The boxplots with outliers are presented in section B.3.2 in Appendix B.

While comparing specific grid reinforcement costs per urban setting across technologies, we find that the median for EV is lower than for HP and PV. In rural areas, the median (IQR values reported in brackets) specific grid reinforcement cost for EV is 143 (29 to 1'058) CHF/kW compared to 1'385 (280 to 6'413) CHF/kW and 201 (52 to 796) CHF/kW_p for HP and PV respectively. For suburban areas, the median (IQR) specific grid reinforcement costs reduces substantially to 49 (16 to 150) CHF/kW, 199 (64 to 878) CHF/kW and 76 (24 to 259) CHF/kW_p for EV, HP and PV respectively. The values reduce even further for PV, however, increase



Aggressive Effort (2035)



Aggressive Effort (2050)

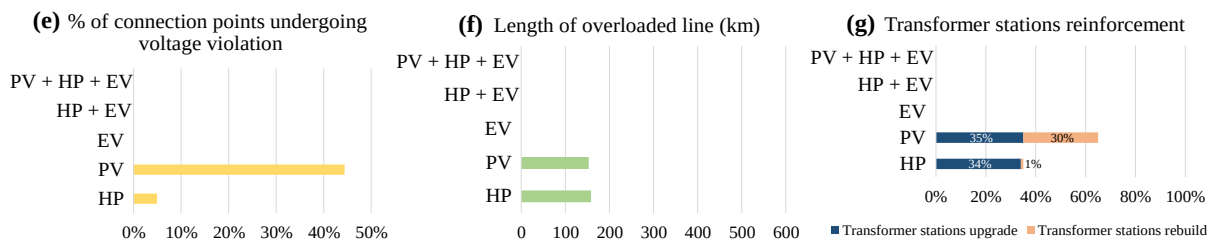


Figure 3.9: Results for the aggressive effort scenario in 2035 and 2050: (a) Grid reinforcement costs and driving factors for grid reinforcement costs: Percentage of house connections undergoing voltage violation, length of overloaded lines and share of transformer stations undergoing a upgrade or rebuilding due to penetration of PV, HP, EV and their combinations in 2035 ((b) to (d)) and 2050 ((e) to (g)). Since, there is no aggressive effort scenario for EV, HP+EV and PV+EV+HP in 2050, there are no boxes and bars for these technologies in 2050.

for HP and EV in urban areas, where the median (IQR) specific grid reinforcement costs are 63 (28 to 104) CHF/kW, 206 (81 to 397) CHF/kW and 51 (15 to 185) CHF/kW_p for EV, HP and PV respectively. We also find that the IQR of the box for HP is larger than for PV and EV. This suggests that there is more spread or variation in the specific grid reinforcement cost values in case of HP. For the same grid reinforcement cost at the transformer station, the installed capacity of HP is low compared to EV for the least effort scenario, which leads to much higher and varied specific grid reinforcement costs for HP compared to EV.

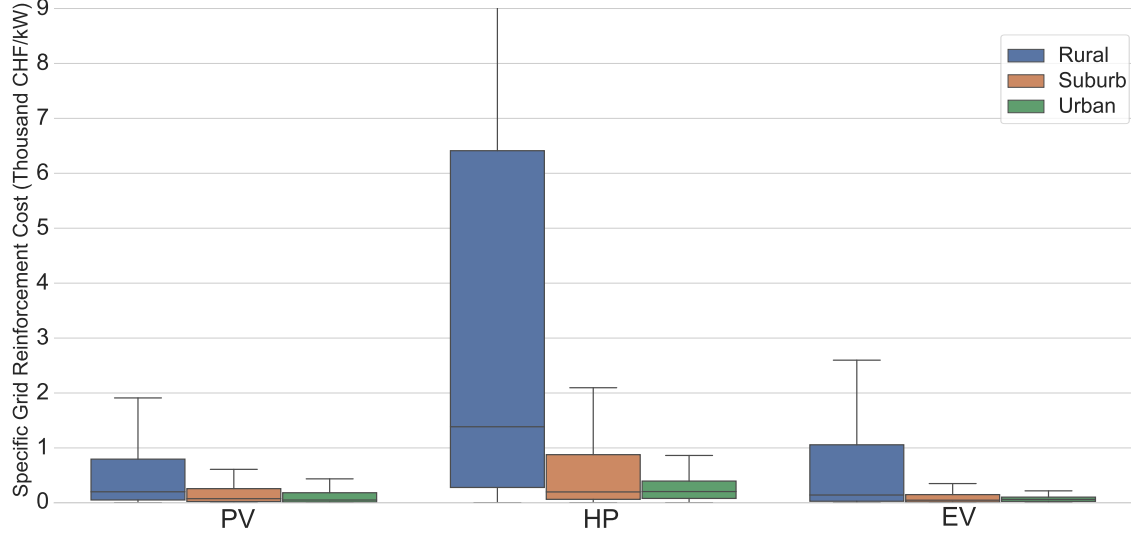


Figure 3.10: Least effort scenario - Specific grid reinforcement costs for PV, HP and EV chargers for different urban settings in 2035.

Fig. 3.11 shows the specific grid reinforcement costs for PV, HP and EV deployment for the determined effort scenario for 2035. We find that, in rural areas, the median specific grid reinforcement costs for HP is higher compared to PV and EV, while it is the contrary for suburban and urban areas. The median (IQR values reported in brackets) specific grid reinforcement cost for HP in rural areas is 326 (66 to 2'607) CHF/kW, compared to 200 (65 to 619) CHF/kW_p and 95 (23 to 677) CHF/kW in case of PV and EV respectively. Compared to the least effort scenario, here we see that the difference is quite substantial in case of HP (median from 1'385 to 326 CHF/kW). This is due to the fact that for the same cost of grid reinforcement at several transformer stations, the installed capacity of HP is significantly higher in determined effort compared to the least effort scenario, thereby, resulting in relatively lower specific grid reinforcement costs for HP in determined effort. For suburban areas, the median (IQR) grid cost is 102 (36 to 276) CHF/kW, 46 (17 to 229) CHF/kW and 37 (14 to 111) CHF/kW for PV, HP and EV respectively. For urban areas, the median (IQR) grid cost is 72 (25 to 243) CHF/kW_p, 57 (27 to 82) CHF/kW and 47 (25 to 77) CHF/kW for PV, HP and EV respectively. Similar to the least effort scenario, we find that the specific grid reinforcement costs are higher in rural areas compared to suburban and urban areas.

3.3.5 Regression analysis

The relationship between the grid reinforcement costs and total technology capacity aggregated at the supply area level (results from sections 3.3.1 to 3.3.3) is further analysed for each urban setting using linear regression as shown in Fig. 3.12. According to the regression analysis covering all urban settings and all scenarios, adding

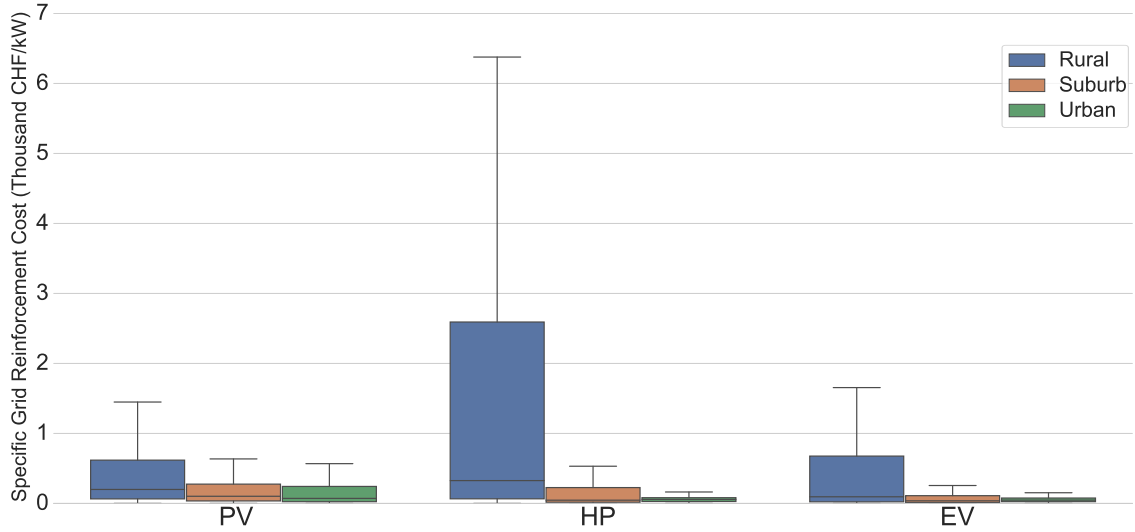


Figure 3.11: Determined effort scenario - Specific grid reinforcement costs for PV, HP and EV chargers for different urban settings in 2035.

1 kW_p of PV increases the grid reinforcement costs by 248 CHF, 188 CHF and 166 CHF for rural, suburban and urban areas respectively. Interestingly, the last point on the PV graph showcasing the heroic PV penetration (1480 MWp) suggests a saturation (Fig. 3.12(a)). This implies that the linear dependency does not hold for very high PV capacities. We obtain a coefficient of determination, R² of 95%, 98% and 97% for PV in rural, suburban and urban areas, which implies a good fit (see Fig. 3.12 (a)). The slope in Fig. 3.12(b) suggests that with each additional kW of HP capacity, the grid reinforcement cost increases by 178 CHF, 43 CHF and 33 CHF for rural, suburban and urban areas respectively and HP capacity explains the variance in grid reinforcement costs by R² of 94%, 95% and 97% across rural, suburban and urban areas respectively. Fig. 3.12(c) for EV shows a similar trend where EV charging explains the variance in grid reinforcement costs by 99% (R²) across the three urban settings. Further, the slope suggests that adding 1 kW of EV chargers increases the grid reinforcement cost by 63 CHF, 46 CHF and 32 CHF for rural, suburban and urban areas respectively. For the three regressions, the independent variable (installed capacity) is significant at 1% level (p-value < 0.01), which means that grid reinforcement costs (dependent variable) can be explained very accurately by capacity additions of technologies (independent variable).

3.3.6 Battery storage to defer distribution grid reinforcement costs

Our results show that for some transformer stations, even very limited capacity addition can undermine the existing distribution grid capacity, in terms of peak load or voltage limits, which would then need to be replaced/reinforced. In this case, the model replaces the line/transformer with one with higher capacity and then calculates the reinforcement cost. For some cases, the specific grid reinforcement costs (CHF/kW) is exceptionally high (e.g., by one order of magnitude), for example if the line is a long overhead line and requires new piping for reinforcement. DSO could filter out those transformer stations with extremely high specific grid reinforcement costs (CHF/kW) and consider other flexibility options such as energy storage. For instance, battery storage can be installed at the house connections within the distri-

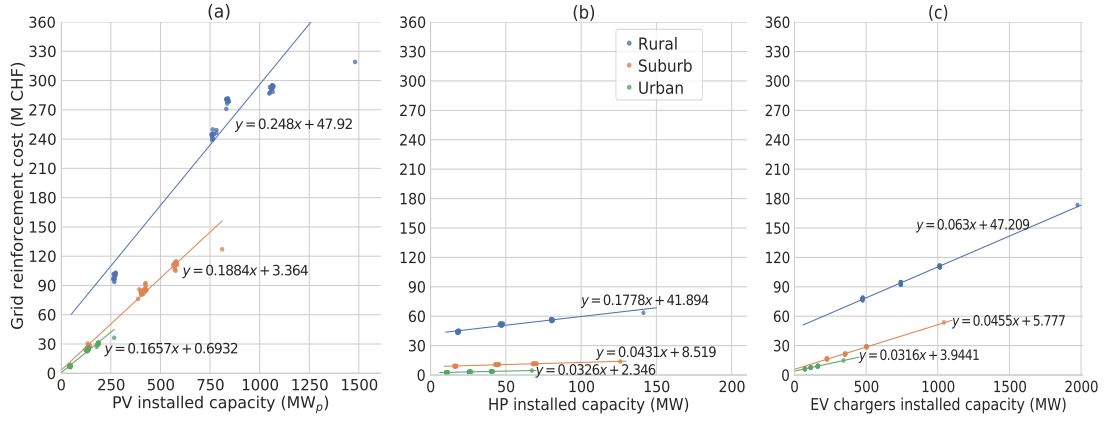


Figure 3.12: Regression analysis between (a) PV and (b) HP (c) EV chargers installed capacity and grid reinforcement costs under different scenarios at the supply area level for both 2035 and 2050. Linear regression trend lines are marked in blue for rural, orange for suburban and green for urban. Regression equations are given against trend lines of each urban setting.

bution transformer, as an alternative to defer expensive grid reinforcement [364, 47]. For our analysis, we select Li-ion batteries, since they are the benchmark technology for distributed applications [293, 135, 315].

The size of the batteries is such that the power capacity is equal to the PV capacity whereas the energy capacity considers a discharge duration of 2.5 h which has been found to be sufficient to defer the upgrade of distribution assets [9]. The total battery cost is divided into capital expenditure (CAPEX) (assumed to be paid at the installation) as well as annual operational and maintenance expenses (OPEX) (see Appendix B section B.4). The CAPEX considers the power-related (EUR/kW) and energy-related (EUR/kWh) cost components [2]. Furthermore, we use a scaling factor of 0.6 beyond an inverter capacity of 3 kW to model cost reduction with size [18]. Other costs such as labour expenses and land development expenses are not taken into account. To calculate the net present value (NPV) of the battery OPEX, we set the discount rate to 3.8% [372]. Finally, we consider the time period for distribution grid reinforcement deferral as 15 years, in agreement with the lifetime of a Li-ion battery based on Lithium Nickel Manganese Cobalt Oxide (NMC) technology [358], which is the baseline Li-ion chemistry at the moment. Table 3.5 compares grid reinforcement and battery costs for different PV scenarios. Considering the current costs, batteries are found to be more cost effective than grid reinforcement for 15% of the transformer stations with the highest specific grid reinforcement costs in the least effort scenario. However, as PV penetration increases, it becomes cheaper to reinforce the grid than to install batteries. For example, for the determined and aggressive effort scenarios, batteries are more competitive than reinforcement only for 5% of the transformer stations with the highest specific grid reinforcement costs. Beyond that, grid reinforcement becomes a more attractive flexibility option.

3.3.7 National distribution grid reinforcement costs

In this section, we make use of the results from the regression analysis (presented in section 3.3.5) in order to estimate the total distribution grid reinforcement costs at the national level. Fig. 3.13 shows the resulting distribution grid reinforcement costs linked to the deployment of PV, HP and EV charging across Switzerland. For

Table 3.5: Comparison between grid reinforcement and current battery costs to enable PV deployment. Costs are calculated as a function of the percentage of transformers stations with the highest specific grid reinforcement cost. Values in bold mark the amount of transformer stations, when the battery cost are still below the grid reinforcement cost.

Transformer stations (%)	PV Least 2035			PV Determined 2035			PV Aggressive 2035		
	PV capacity (MW _p)	Grid reinforcement cost (M CHF)	Battery cost (M CHF)	PV capacity (MW _p)	Grid reinforcement cost (M CHF)	Battery cost (M CHF)	PV capacity (MW _p)	Grid reinforcement cost (M CHF)	Battery cost (M CHF)
1%	0.3	2.6	0.6	0.9	5.4	2.1	1.5	6.9	3.4
5%	2.5	11.8	5.4	9.1	24.3	20.2	13.8	32.2	30.2
10%	6.5	20.0	14.1	25.6	46.8	55.9	40.0	64.3	86.7
15%	12.8	28.5	27.0	48.9	69.3	106.0	70.5	90.9	151.3
20%	19.8	35.0	41.4	75.9	89.2	162.7	113.5	120.1	241.9
30%	37.1	45.0	75.5	136.9	119.4	289.2	203.1	163.8	428.8
40%	53.7	50.5	108.7	199.4	137.5	416.8	294.7	192.7	617.0
50%	73.1	54.4	145.0	265.4	149.9	550.2	403.0	215.6	835.6

PV, the distribution grid reinforcement costs range between 0.9B CHF and 4.3B CHF in 2035, corresponding to 4.2 GW_p (least effort 2035) and 21.1 GW_p (heroic effort 2035) respectively. The cost increases to 8.6B CHF to enable the deployment of 42 GW_p (heroic effort 2050) of PV in 2050.

Using 6.4 GW of HP (in electrical terms) to fully replace all the fossil-based heating systems in the Swiss residential sector (determined effort 2035), would imply a grid reinforcement cost of 0.5B CHF. This value increases up to 0.7B CHF if also wood and direct electric heating systems are replaced in addition to ones based on fossil fuels, amounting to a nominal HP electrical capacity of 7.8 GW (heroic effort 2050). Finally, assuming a 7 kW charger for each EV (equally distributed in rural, suburban and urban) in a fully electrified passenger cars fleet in 2050, would add up to 35.4 GW (heroic effort 2050), requiring an investment of 1.7B CHF for grid reinforcement.

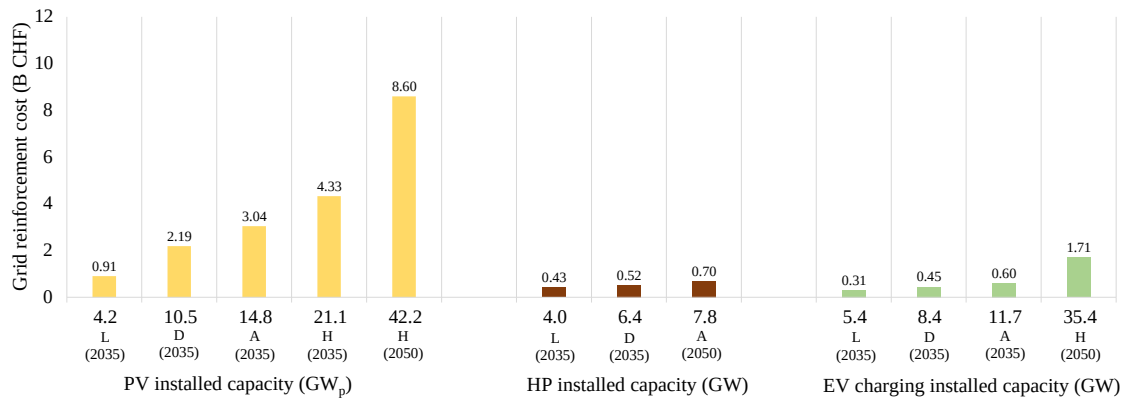


Figure 3.13: Distribution grid reinforcement costs in B CHF for PV, HP and EV chargers deployment for whole of Switzerland. The abbreviations L, D, A and H represent least, determined, aggressive and heroic effort scenarios respectively.

3.4 Discussion

In this chapter, we determine grid reinforcement costs required to enable the massive deployment of PV, HP, EV charging and their combinations as a function of the type of urban setting. The results show that the specific grid reinforcement

costs are remarkably higher in rural areas compared to suburban and urban areas. For instance, across all scenarios presented in section 3.3.4, the median specific grid reinforcement costs varies between 51-213[§] CHF/kW_p, 46-1385 CHF/kW and 34-143 CHF/kW for PV, HP and EV respectively, with the higher limit corresponding to rural areas. These findings have important practical implications. For instance, a recent study on spatial diffusion patterns of PV projects shows that rural areas in Switzerland tend to be hot spots for PV installations compared to urban areas which have relatively less number of PV projects [351]. An important recommendation is to think of a policy framework which promotes more PV installations in urban areas and thereafter progressively in rural areas, while also considering other flexibility alternatives to grid reinforcement. The chapter also confirms that the specific grid reinforcement cost is much lower for ambitious scenarios (determined and aggressive effort) than for low-ambition scenario (least effort), specifically in case of HP deployment (see section 3.3.4). This is an important policy conclusion which suggests that replacement of *all* fossil-based heating systems with HP (determined effort) is more cost-effective for the grid than continuing with the current pace of HP deployment (least effort).

The chapter evaluates the application of battery storage as a potential alternative to defer distribution grid reinforcement. Our results show that even with the current costs, batteries have the potential to defer grid reinforcement in up to 15% of the transformer stations with the highest specific grid reinforcement costs (CHF/kW) across different PV scenarios. Since the lifetime of grid reinforcement is usually considered between 40 and 50 yrs [54], batteries replacement after 15 yrs would have to be considered in case the time period of distribution grid reinforcement deferral is assumed to be more than 15 yrs. This would make batteries more costly than grid reinforcement. However, on the other hand, it is expected that the CAPEX of stationary Li-ion batteries will decrease by 54-61% by 2030 [175], making batteries a good flexible solution to support the distribution grid expansion. [364, 47]. Moreover, batteries can provide up to 15 different services at the grid, generation and end-user level [129, 174] and combining different applications (also referred to as benefit stacking) would substantially increase the value of batteries, and their profitability as shown by previous studies [246, 316, 249]. Community energy storage (CES) has also been suggested as a possible strategy to reduce the CAPEX and OPEX, regarding residential batteries, due larger sizes [129, 247]. Under different ownership models, batteries as CES could benefit both consumers and DSO, creating a win-win relationship [293, 129, 247]. The new regulatory context in the European Union and Switzerland states that the ownership and operation of energy storage is restricted for DSO, however, they could use tenders to engage market actors (like prosumers and aggregators) who own energy storage to provide grid services [261]. This is being already tested in the United States and Australia [390].

Our GIS-based method can be used to quantify the impacts of PV, HP and EV charging on distribution grids and our results help to plan the distribution grid infrastructure including sector coupling. However, it is not without limitations, which in turn calls for future research. First, our model assumes that capacity additions and grid reinforcement occur all at once. However, in reality, technology capacity is added across the energy transition and thus could lead to higher cumulative reinforcement costs. Secondly, the assumed grid reinforcement costs for transformers

[§]see Fig. B.14 in Appendix B for results of specific grid reinforcement costs in case of aggressive effort scenario.

and line are average costs. Cost values can vary depending on the project characteristics and local circumstances. It is also important to note that other measures such as retrofitting of buildings can reduce the peak load of HP by 42-73% [324, 275] while local demand side flexibility can be used to decrease the grid impacts of all technologies [152]. This is not considered by this chapter, thus, our reinforcement costs correspond to extreme cases without inherent behind-the-meter flexibility. While this study focuses on the analysis of grid impacts and reinforcement costs at the low voltage distribution grid level, future work should include the assessment of grid reinforcement costs at the various voltage levels. The redundancy is typically higher in the medium voltage/high voltage grid in Switzerland, and there are more reserves (higher hosting capacity) compared to the low voltage grid [17]. This means that it could accommodate more PV, HP or EV before it would need to be reinforced. However, once the hosting capacity of the medium/high voltage grid has been reached, the costs for grid reinforcement projects are much higher than for the low voltage grid. Therefore, with high penetration levels of PV, HP or EV, the grid reinforcement costs for medium/high voltage grid may exceed the cost established for the low voltage grid in this study. The total grid reinforcement cost is equal to the sum of cost for reinforcing the low, medium and high voltage grid. Finally, similar country-specific analyses are recommended as the grid impacts and reinforcement costs are highly region and grid dependent.

3.5 Conclusions

This chapter presents the low voltage distribution grid impacts and reinforcement costs required to enable a massive deployment of solar photovoltaics (PV), heat pumps (HP) and electric vehicles (EV) depending on the type of urban setting (namely, rural, suburban and urban). We develop a GIS-based method to map the technical potential and develop scenarios for rooftop PV, HP and EV charging deployment in 2035 and 2050, which is tested with a distribution grid model covering 170'000 households in Switzerland. Grid impacts are evaluated at the level of transformer stations, which serve several houses. The results are then upscaled to the national level. Overall, we calculate that the total distribution grid reinforcement cost for Switzerland in 2035 amounts to 5.4B CHF for heroic effort scenario corresponding to PV nominal capacity of 21.1 GW_p, HP nominal capacity of 6.4 GW (corresponding to the replacement of all the fossil-based heating) and 11.7 GW of EV charging. In 2050, the total cost amounts to 11B CHF when considering 42.2 GW_p, 7.8 GW and 35.4 GW for PV, HP and EV charging respectively. With 3.8M households in Switzerland (assuming the same number as today), the cost of reinforcement would translate to around 1'440 CHF and 2'900 CHF per household in 2035 and 2050 respectively (1 Swiss Franc = 1 CHF $\approx$ 1 USD).

Based on a linear regression model, we explain grid reinforcement costs as function of the installed nominal capacity of various technologies ($R^2 > 94\%$). Furthermore, we explain the sensitivity of grid reinforcement costs to the type of urban setting. We find that specific grid reinforcement costs are remarkably higher in rural areas compared to suburban and urban areas, in particular, by 150%, 410% and 90% for PV, HP and EV respectively, in an aggressive effort scenario.

Importantly, we also compare grid reinforcement with energy storage, assuming lithium-ion batteries, which are considered as a key flexibility option to enable further renewable energy penetration. Based on our results, we conclude that lithium-

2743 ion batteries are already attractive to defer grid reinforcement for up to 15% of the
2744 transformer stations with the highest specific grid reinforcement costs. The use of
2745 batteries as a distribution asset could be extended further considering future cost
2746 projections as well as benefit stacking and co-ownership models, if enabled by the
2747 regulatory environment. Considering the high relevance of PV, HP and EV for cli-
2748 mate change mitigation and the challenges to integrate them in the existing grid
2749 infrastructure, this chapter aims to help various decision-makers such as the DSO,
2750 policy makers and regulators to better plan the future distribution grid infrastruc-
2751 ture which maximises renewable energy and sector coupling.

Chapter 4

Smart power-to-gas deployment strategies informed by spatially explicit cost and value models ^a

Green hydrogen allows coupling renewable electricity to hard-to-decarbonize sectors, such as long-distance transport and carbon-intensive industries in order to achieve net zero emissions. Evaluating the cost and value of power-to-gas is a major challenge, owing to the spatial distribution and temporal variability of renewable electricity, CO₂ and energy demand. Here, we propose a method, based on geographic information system (GIS) and techno-economic modelling, to: i) compare the levelized cost and value of power-to-gas systems across locations; ii) identify potential hotspots for their future implementation in Switzerland; and iii) set cost improvement targets as well as smart deployment strategies for green hydrogen and methane plants. Our analysis accounts for the spatial and temporal (both hourly and seasonal) variation of the availability of renewable electricity and CO₂ sources, as well as the presence of gas infrastructure, heating networks, oxygen and gas demand centers. We find that only green hydrogen plants connected directly to run-of-river hydropower plants are currently profitable in Switzerland (with NPV per CAPEX ranging between 2.3 and 5.6). However, considering technological progress by 2050, a few green hydrogen plants deployed in the demand centers and powered by rooftop PV electricity will also become economically attractive. Moreover, a few methane plants connected to run-of-river hydropower plants currently show slight profitability (NPV per CAPEX reaching values up to 1.3) and in 2050 (NPV per CAPEX up to 3.1), whereas those connected to rooftop PV will remain uneconomical even in 2050. Based on our findings, we devise a long-term roadmap for policy makers and project developers to plan future green hydrogen projects. The proposed methodology, which is applied to Switzerland, can be extended to other countries.

4.1 Introduction

Energy-related carbon dioxide (CO₂) emissions are responsible for the lion's share (73%) of global anthropogenic greenhouse gas (GHG) emissions [380]. Renewable energy (RE) technologies accompanied by energy efficiency are the main mitigation strategies to cut GHG emissions [161, 87]. So far, RE has been mainly introduced in the power sector, where it is projected to contribute 33% of the global electricity

^asimilarly published in: Applied Energy, Volume 327, December 2022 [124]

generation by 2025 [152]. However, the decarbonization of other hard-to-abate sectors, such as carbon-intensive industries and long-distance transport, still remains a key challenge [87]. Green hydrogen is expected to play an important role in complementing electrification to achieve net zero goals [154, 63]. It can replace fossil fuels in many carbon intensive industrial processes, such as in the steel, refinery or chemical industries [154, 151]. Additionally, it can also decarbonize heavy duty trucks and large passenger vehicles within the transport sector [154, 68], which in total contributed to 27% of the global emissions in 2019 [162] and to $\approx 32\%$ of all GHG emissions in Switzerland [334].

In 2020, the global demand of hydrogen, which nowadays is mostly used in refining and in industrial applications, was about 90 Mt_{H₂} [154]. In Switzerland, the total hydrogen demand of the industrial sector is about 13 kt_{H₂} per annum [206]. Today, 88% of the hydrogen production in Switzerland comes from fossil sources (also referred to as grey hydrogen), such as steam methane reforming using natural gas (21%), steam cracking of liquefied petroleum gas (29%), and reforming of naphtha in refinery (38%). The other production sources include chlor-alkali electrolysis (7%), and water electrolysis (3%) using electricity. The remaining 2% is imported from abroad [206]. When using renewable electricity (solar photovoltaics (PV), wind and/or hydropower) for electrolysis, the process is referred to as green hydrogen production or (renewable) *Power-to-Hydrogen* (PtH). Hydrogen can further react with CO₂ to produce synthetic methane (CH₄) [282]. This conversion process is known as methanation, which can be integrated with electrolysis to form *Power-to-Methane* (PtM). The process of producing hydrogen or methane from electricity is commonly referred to as *Power-to-Gas* (PtG). Methane has a high volumetric energy density (3.2 times higher than hydrogen) and can either be transported using the existing natural gas network or consumed directly as a fuel [199]. The reliance on the existing natural gas infrastructure reduces the need for additional capital investments, e.g. by hydrogen blending [196]. The cost of key inputs for producing green hydrogen and synthetic methane, namely renewable electricity and CO₂, is very sensitive to the geographical location and time of the year [252, 219].

Further, PtG generates various by-products which can be harvested for additional applications. For example, oxygen (O₂) generated during electrolysis can be captured and used for secondary treatment in wastewater treatment plants, in hospitals, for chemical syntheses or for combustion processes [192]. Similarly, heat from electrolysis and methanation processes can either be used onsite, or injected into the low and high temperature district heating networks, respectively [165]. In addition, PtG can also act as a flexibility instrument for the electricity grid, e.g., providing frequency control, and as a seasonal electricity storage option [247, 131]. Making use of the economic value of these various by-products, referred to as *benefit stacking*, can substantially increase the profitability of a PtG plant. Therefore, to identify optimal deployment sites [73], and to reduce deployment costs during up-scaling, this chapter identifies attractive locations (hotspots) for PtG deployment taking into account not only the proximity to renewable electricity and CO₂ sources, but also to demand centers to sell the produced gases and additional by-products [232]. This is an important topic for project investors, policy makers, regulators, and new market actors promoting green hydrogen.

4.2 Literature review and research objectives

The techno-economic potential of PtG and its role in the future low-carbon energy systems have been studied by numerous authors [285, 388, 366, 118, 187, 267, 36, 198, 197, 35], and several pilot/demonstration plants have been set up to test the technology and its economic feasibility [73].

Schnuelle et al. developed a model for both alkaline (AEL) and polymer electrolyte membrane (PEM) electrolysis considering PV and wind power in the north-west of Germany [289]. The authors showed that the calculated cost of hydrogen ranged between 130-372 €^b/MWh (4.3-12.4 €/kg), not being competitive with industrial hydrogen production from fossil resources which is currently produced for around 1.5 €/kg. Along the similar lines, Leeuwen et al. also found that PtG plants are not profitable under current market conditions, even under the most optimistic assumptions for the cost and revenue parameters [205]. It was argued that a profitable business case would require a significant capital expenditure (CAPEX) reduction for PtG technology (from 1250 to 500 €/kW_{el}), also combined with a higher electrolyzer efficiency (from 67% to 75%), and higher hydrogen revenues (from 1.25 to 2.25 €/kg). Previously, Parra and Patel also developed a model to determine the performance, levelized cost and value of PtG plants purchasing electricity and selling gas in the wholesale market for Switzerland [245]. Their results show that the technical and economic benefits increase with the nominal capacity of the PtG plant and that higher capacity factors (by $\approx 11\%$) are needed for PEM electrolyzers due to its higher CAPEX compared to AEL electrolyzers. Further, the impact of the type of RE supply such as PV, wind, hydro, wholesale market electricity and their combinations on the cost and value of PtG systems was studied by Hassan et al. [131]. They found that the capacity factor of a PtG system drives the economic case and therefore PV and wind supply are recommended to be combined with wholesale-based electricity to reduce the levelized cost (up to 47%). A study by Gorre et al. assessing the production costs of methane under various operation scenarios concluded that synthetic methane production costs could reach 50–90 €/MWh by 2030 and 25–65 €/MWh by 2050, under optimal conditions for plant scales of 10 MW_{el} [117]. While these previous studies provided valuable insights into the economics of PtG as a function of size, technology, electricity supply and combination of by-products, the underlying models did not account for the geographical availability of inputs for PtG such as RE and CO₂ (including cement and municipal waste incineration plants), and neither for the location of demand centers for hydrogen, methane, heat, and oxygen, which remain a research gaps.

Analyses of the hydrogen production potential considering spatial mapping of RE resources only are present in the literature for various countries like Argentina [298], Venezuela [256], Sweden [303], Ecuador [257], Algeria [269], Morocco [354], Iran [230], United States [66], Germany [22, 383], Denmark [232]. However, these studies did not assess the proximity of hydrogen production site/s to various demand centers and associated infrastructure such as CO₂ sources or natural gas pipelines. This gap to some extent is addressed by Messaoudi et al. who assessed suitable locations for solar hydrogen in Algeria combining multi-criteria decision making with GIS [221]. The criteria included hydrogen demand, PV potential, proximity to roads, railways, and power lines. Schneider et al., additionally, identified CO₂ sources to quantify potential locations for PtG plants in Germany [288]. All this information was then presented in a detailed map showing restrictive and favourable areas for

^b1 € = 1.119 USD

PtG. However, also the above mentioned studies neither analyze the profitability of PtG plants nor assess their potential deployment sites, considering the proximity and spatial variability of various local supply and demand centers. This is an important limitation considering the green hydrogen deployment mandate across the world.

Against this background, this chapter fills this important research gap in the literature and expands the existing knowledge by developing a novel spatially explicit and dynamic model of PtG deployment considering its proximity to the existing/planned RE sources, CO₂ sources, hydrogen, methane, and oxygen demand centers, natural gas and power networks, as well as low and high temperature district heating networks. We take the investor perspective^c [389, 123] using data with high spatial and temporal resolution (1 hr) to carry out the techno-economic analysis of PtG systems under different scenarios across Switzerland. This GIS-based model is then applied to analyze the following potential deployment strategies by placing a PtH/PtM plant in the: i) vicinity of renewable electricity supply; ii) vicinity of CO₂ sources; and iii) vicinity of demand centers as illustrated in Fig 4.1. The objective is to identify hotspots for future deployment of PtG plants across Switzerland by evaluating their profitability based on the comparison between the levelized cost and levelized value of hydrogen or methane. Based on these results, we finally propose a long-term roadmap and set cost improvement targets to inform project investors, developers, regulators and policy makers. In this chapter, the proposed methodology is applied for Switzerland, however, it could be readily extended to other geographies by incorporating the country/region GIS-based RE supply source/s, CO₂ source/s as well as different demand centres for PtG.

	(a) PtH at HPP	(b) PtH at HRS	(c) PtH at IND	(d) PtM at HPP	(e) PtM at NG	(f) PtM at IND	(g) PtM at CO ₂
Placement	Supply site	Demand site	Demand site	Supply site	Demand site	Demand site	Supply site
Electricity source	Hydroelectricity supplied directly from RoR hydropower plant	Electricity supplied directly from rooftop PV	Electricity supplied directly from rooftop PV	Hydroelectricity supplied directly from RoR hydropower plant	Electricity supplied directly from rooftop PV	Electricity supplied directly from rooftop PV	Electricity supplied directly from rooftop PV
Supply side variables	- Hydroelectricity - Water	- PV electricity - Water	- PV electricity - Water	- Hydroelectricity - Water - CO ₂ source - industry or DAC	- PV electricity - Water - CO ₂ source - industry or DAC	- PV electricity - Water - CO ₂ source - industry or DAC	- PV electricity - Water - CO ₂ source - industry
Demand side variables	- For green H ₂ - HRS or industries - For O ₂ - WWTP or hospital - For low temperature heat - DHN	- For green H ₂ - HRS - For O ₂ - WWTP or hospital - For low temperature heat - DHN	- For green H ₂ - industries - For O ₂ - WWTP or hospital - For low temperature heat - DHN	- For CH ₄ - Existing NG station - For O ₂ - WWTP or hospital - For high temperature heat - DHN	- For CH ₄ - Existing NG station - For O ₂ - WWTP or hospital - For high temperature heat - DHN	- For CH ₄ - Existing NG station - For O ₂ - WWTP or hospital - For high temperature heat - DHN	- For CH ₄ - Existing NG station - For O ₂ - WWTP or hospital - For high temperature heat - DHN

Figure 4.1: Green hydrogen (PtH) and power-to-methane (PtM) deployment strategies compared in this chapter for following locations: a) PtH at run-of-river (RoR) hydropower plant (PtH at HPP); b) PtH at hydrogen refuelling station (PtH at HRS); c) PtH at industrial site (PtH at IND); d) PtM at run-of-river hydropower plant (PtM at HPP); e) PtM at natural gas network station (PtM at NG); f) PtM at industrial site (PtM at IND); and g) PtM at industrial CO₂ source (PtM at CO₂). The location of the PtG plant determines the electricity source, the CO₂ source and the opportunities to create value by selling gas and by-products. Abbreviations used: H₂ stands for hydrogen, O₂ for oxygen, CO₂ for carbon dioxide, CH₄ for synthetic methane, WWTP for wastewater treatment plants, DHN for district heating networks and DAC for direct air capture.

^cOptimising the techno-economic benefit for any location without maximising the national welfare.

4.3 Input data and method

In this section, we provide an overview of the input data including the PtG model, the supply characteristics and demand centers, GIS analysis, and finally also present the techno-economic model.

4.3.1 Power-to-Gas modelling

Fig. 4.2 shows a schematic representation of a PtG (PtH/PtM) system including its main components. Since this chapter focuses on green hydrogen and methane in Switzerland, we assume that RE is either supplied from a hydropower plant or solar PV since hydroelectricity is the largest RE source (39.1 TWh in 2020) and solar (2.5 TWh in 2020) is foreseen to become the second largest RE source [88]. Other RE sources such as wind or geothermal are not included since generation of electricity from wind faces public acceptance issues along with complex administrative processes with only 0.2 TWh generation in 2020 [40, 88] and since currently no electricity is being produced from geothermal sources in Switzerland [114, 88]. Therefore, the use of conventional electricity from the grid is not considered. A PtH plant includes an electrolyzer and a compressor. The compressed hydrogen is transported via truck trailers [64, 147]. We select PEM as electrolyzer technology since it offers a dynamic response and its cost is expected to become competitive with traditional alkaline (AEL) technology by 2030 [286, 354, 118, 131]. A PtG plant producing synthetic methane requires a CO₂ supply, and a methanation reactor. In this case, we select thermo-chemical (catalytic) methanation because of its higher technology readiness, efficiency, and because the process setup is relatively simple [118, 131]. Importantly, we select a nominal capacity of 1 MW_{el} as a representative deployment scale for PtG applications and compare its associated levelized cost and value depending on the deployment strategy. More details of the various components and technical parameters of a PtG plant is given in Table C.1 and C.2 of supplementary information presented under Appendix C.

To model PtG plants, we use a bottom-up dynamic GIS-based model with a temporal resolution of 1 hr. A PtG system consists of an electrolyzer system (stack and balance-of-plant (BoP)) along with an AC/DC converter, a hydrogen compressor and a methanation reactor (in case of PtM systems). The electricity consumption of the BoP, hydrogen compressor as well as the efficiency of the rectifier as a function of the load (Fig. C.2) is presented under Section C.1.1 in Appendix C. The stack efficiency, which is represented in Appendix C Fig. C.3, decreases with the load due to higher losses associated with high current density [76]. However, the PtH system efficiency further accounts for the electricity consumption by the stack BoP, hydrogen compressor, as well as the efficiency penalty due to the rectifier, and is therefore lower than the stack efficiency (around 9% lower at nominal load) as shown in Appendix C Fig. C.3. The system efficiency increases up to a load factor of 40%, and then levels off due the high stack losses at high load factor.

The model is informed by empirical data from PtG systems already installed in Europe as well as future cost trajectories. The CAPEX, BoP-CAPEX and operational expenditure (OPEX) of the key components of a PtG system are given in Table 4.1. For more details on the techno-economic model, please refer to section C.1.1 in Appendix C and two previous studies [247, 131]. The PtG model is developed in Matlab, whereas geographical analysis and processing is carried out using QGIS and Python respectively. It is considered that the produced green hydrogen

from electrolysis (PtH) is either sent to the hydrogen refuelling stations or to industries demanding hydrogen as feedstock. We hereby focus on the direct use of green hydrogen with the objective to decarbonize the hard-to-abate sectors, namely heavy-duty transportation, and carbon intensive industries. Alternatively, synthetic methane produced from methanation (PtM) is injected into the existing natural gas network and sold to the wholesale natural gas market (details in Appendix C section C.1.5). Low- and high-temperature heat generated by the electrolysis and methanation processes respectively and oxygen from electrolysis can be sold to their respective demand centers, namely low and high temperature district heating networks, hospitals and/or waste water treatment plants.

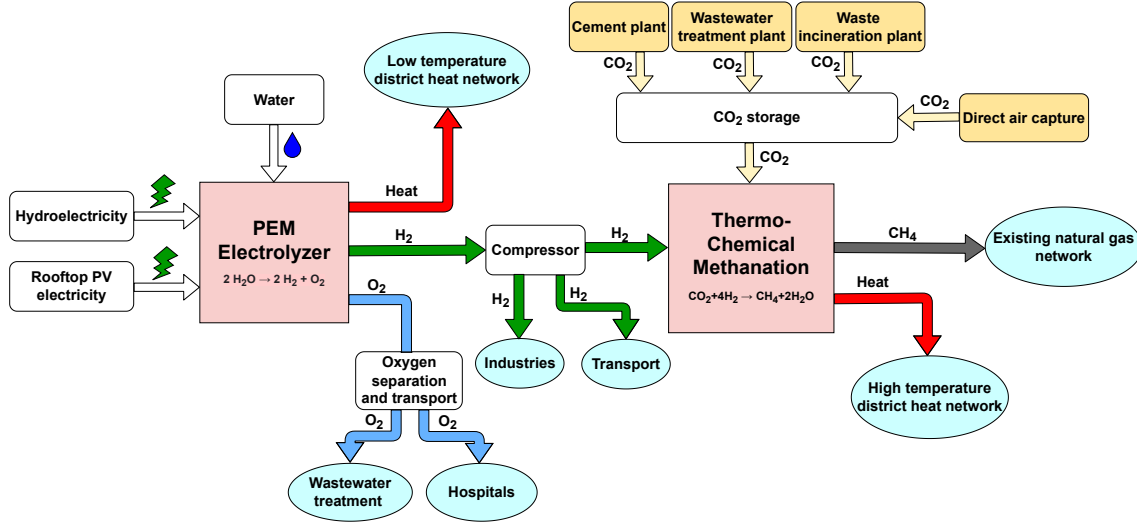


Figure 4.2: Schematic representation of a PtG system including the sources of electricity and CO_2 considered in this chapter, and the processes involved in hydrogen and synthetic methane production. Potential applications of main products (hydrogen and synthetic methane) and by-products (O_2 and heat) are also depicted.

4.3.2 Electricity supply sources

Two different electricity supply options for PtG systems are considered in this chapter, namely run-of-river (RoR) hydropower plants and rooftop PV. Currently around 57% of the Swiss electricity production is provided by hydropower, of which around half corresponds to RoR hydropower plants [204]. We select only RoR hydropower plants as they are ‘must-runs’ without storage capacity and therefore cannot shift their generation to periods of high electricity demand and electricity price. The RoR hydropower plants with generation equal to or higher than 1 MW_{el} are selected (61 in total) [204], since the nominal capacity of PtG plants is selected to be 1 MW_{el} . For the deployment strategies of *PtH at HPP* and of *PtM at HPP*, we assume that the plant is directly connected to a pre-existing RoR hydropower plant for electricity supply, i.e. buying hydroelectricity at the wholesale prices under a long term power purchase agreement (PPA). This solution is preferred to avoid additional grid charges and public fees associated to a connection to the main grid (contrary to pumped hydro storage, PtG are not exempted from grid charges) [199]. Future wholesale electricity prices for Switzerland are obtained using the open-source energy system model GRIMSEL-FLEX [305, 277, 276], which models Switzerland and its four neighboring countries as a function of fuel prices, carbon tax and targeted policies, e.g. nuclear phase-out (details in section C.1.2 under Appendix C).

Table 4.1: CAPEX and OPEX input data for various components of PtG system considered. The data is taken from up-to-date references representative for Switzerland.

Parameter	Unit	Value	Reference
Electrolyzer stack CAPEX	USD/kW _e	400	[171, 55, 365]
Electrolyzer BoP-CAPEX	USD/kW _e	1050	[171, 55, 365]
Compressor CAPEX	USD/kW _e	134	[140]
Methanation reactor CAPEX	USD/kW _e	120	[365]
Methanation reactor's BoP-CAPEX	USD/kW _e	280	[365]
General BoP-CAPEX	USD/kW _e	300	[140]
Electrolyzer OPEX	% CAPEX	4	[365]
Methanation OPEX	% CAPEX	10	[365]
BoP-OPEX	% CAPEX	7	[140]
PV CAPEX (for PV system ≥ 1000 kW)	USD/kW	775	[284]
PV OPEX (for PV system ≥ 1000 kW)	USD/kWh _e	0.035	[239]
CO ₂ direct air capture (DAC)	USD/tCO ₂	163	[193, 365]
CO ₂ separation cost ^a	USD/tCO ₂	35	[16]
CO ₂ /O ₂ transportation cost	USD ct/km/t	9.6	[79]
Capacity of CO ₂ /O ₂ truck	t	25	[79]
H ₂ distribution cost via truck trailer	USD/km	1.6	[242]
H ₂ truck trailer capacity	bar/kg	350/600	[147, 64]
CH ₄ pipeline CAPEX	USD/km	85'000	[365]
OPEX CH ₄ pipeline	% of pipeline CAPEX	2	[365]

^aFrom flue gas and process emissions

If a PtG plant is located far from a RoR hydropower plant/ at the demand center, we assume electricity supply from rooftop PV, which is built exclusively to supply electricity to the PtG plant. We select only rooftop PV since majority of the PV systems in Switzerland are installed on the roof, which is also expected to remain as the dominant choice in the future. Large ground mounted PV systems are rare because of high land prices, scarcity of land, complicated licencing procedures and problems with public acceptance [266, 21]. Additionally, the surplus PV electricity is sold to the grid at the wholesale electricity prices (Fig C.4 in Appendix C). To model the PV system, a panel with a nominal efficiency of 18.6% (provided by the manufacturer) was selected, which is representative of the current technology state. A sky model is applied to transform satellite data of horizontal solar irradiance into irradiance with a tilt angle of 30 degrees, which corresponds to the optimal PV tilt for Swiss latitudes [189]. Further, a validated single diode model developed by Villalva et al. [368] is utilised to calculate the PV generation for each canton of Switzerland ^d, using outdoor temperature as an additional input. The model also includes a maximum power point tracker system, as is the case of most PV systems to maximize the output regardless of the environmental conditions (temperature and solar irradiance). Likewise, grid fees and taxes (Section C.1.3 in Appendix C) are avoided considering that PtH/PtM plants are located in the premises of rooftop PV systems assuming a microgrid approach.

The supply of electricity is optimised to minimize the levelized cost of green hydrogen and synthetic methane production. For RoR, the optimization is based on a maximum wholesale price threshold beyond which the electrolyzer should not

^dSwitzerland is divided into 26 different areas called cantons. The 'cantons' are the states of the country of Switzerland.

operate (Fig. C.5 in Appendix C), while for PV, the optimization is based on an optimal ratio between the nominal capacities of the PV and PtG plants. For example, the optimal size of PV system is found to be 1.56 MW_e for a 1 MW_e PtG system. For details on the optimisation methods, please refer to [245, 131]. As mentioned above, no grid electricity is assumed to be used, i.e. the electrolyser is operated at lower capacity factor when less PV power is available and it is not operated when no PV power is available (the use of electricity from RoR is considered by analogy).

4.3.3 CO₂ supply sources

The supply of CO₂ is a requirement for the production of synthetic methane. Besides being present in the atmosphere with a volumetric percentage of 410 ppm (0.04%) [11], CO₂ is available in relatively high concentrations from industrial sources, such as cement (CEM), wastewater treatment plants (WWTP), and (municipal) waste incineration plants (MWIP) [219]. All these CO₂ supply options are considered in this chapter for PtM plants. Biogas and biowaste treatment plants are not considered as CO₂ sources since they are typically small and decentralized with less than the quarter of the produced biogas being fed into gas grid facilities [381]. There are in total six large-scale CEM plants in Switzerland [51]. CO₂ from the CEM industry requires some upgrading to remove trace components such as sulphur (which is poisonous to the methanation catalyst). The volumetric CO₂ content in the exhaust air flow is approximately 14-35% [219]. The relevant CO₂ quantities are determined from the volumes published by the CEM plants and using an emission factor of 0.59 tCO₂ per tonne of cement (including both mineral and fuel-related CO₂) [85]. Currently, there are 742 WWTP in Switzerland which produce CO₂ by anaerobic sludge digestion (fermentation) [92], i.e. from biogenic sources. Here, CO₂ together with methane is the main constituent of the sewage gas [121], with a volumetric fraction of 33% for the former. The 30 MWIP in Switzerland also emit CO₂ as an output of the combustion process [371]. In order to estimate CO₂ potential from MWIP, we multiply the annual amount of combustible waste by an emission factor of 1.09 tCO₂ per ton of waste [15]. Table C.4. in Appendix C, gives an overview of various CO₂ sources, including the theoretical, and technical CO₂ potentials across Switzerland [343].

4.3.4 Demand centers

The following carbon intensive industrial subsectors requiring hydrogen as feed-stock are considered in this chapter: metal processing, refined petroleum products, production of fertilizers and nitrogen compounds, pharmaceutical products and electronic components [206]. Out of the total 646 companies in the above mentioned categories, we include only medium and large companies with at least 100 employees [251], totalling to 95 companies across Switzerland. For green hydrogen supply to refuelling stations, existing CNG stations [58], as well as existing and planned hydrogen stations (167 in total) are considered [126].

For selling O₂, only cantonal hospitals (155 in total) and large (≥ 24000 population equivalent) WWTP plants (104 in total) which have enough capacity to consume all the O₂ produced by a 1 MW_{el} PtG plant are considered. For selling low and high temperature heat produced from PtH and PtM processes respectively, the current as well as the potential low temperature (4024 in total) and high temper-

ature (5672 in total) district heating networks are considered [52]. To avoid heat losses, heat is only sold if a district heating network is located within 500 m buffer of a PtG plant.

4.3.5 GIS model

Fig. 4.3 shows the GIS model developed to perform the spatially-explicit techno-economic analysis of green hydrogen. The potential PtH/PtM deployment locations mentioned in Fig. 4.1 are first determined through spatial data processing with QGIS [373]. Fig. 4.3-(a), illustrates the GIS sequence with various relevant layers, namely existing hydropower plants, industrial CO₂ sources, industries requiring hydrogen, building zones, natural gas stations and pipelines and industrial buildings rooftops available for PV installation. Fig. 4.3-(b) shows overlapped layers to assess the locations that are suitable for the deployment of PtH/PtM plants. For each deployment strategy, every PtH/PtM potential site receives the corresponding information of various supply and demand centers in the area, including the suitable areas for construction as per the building zones. From this analysis, we compute the Euclidean distance between the potential PtH/PtM sites and various supply and demand centers, which are then fed to the techno-economic PtG model. The ‘nearest-neighbour’ rule is adopted, i.e., the products (gases) and by-products (O₂ and heat) are always sold to the respective demand center which is closest to the PtG plant.

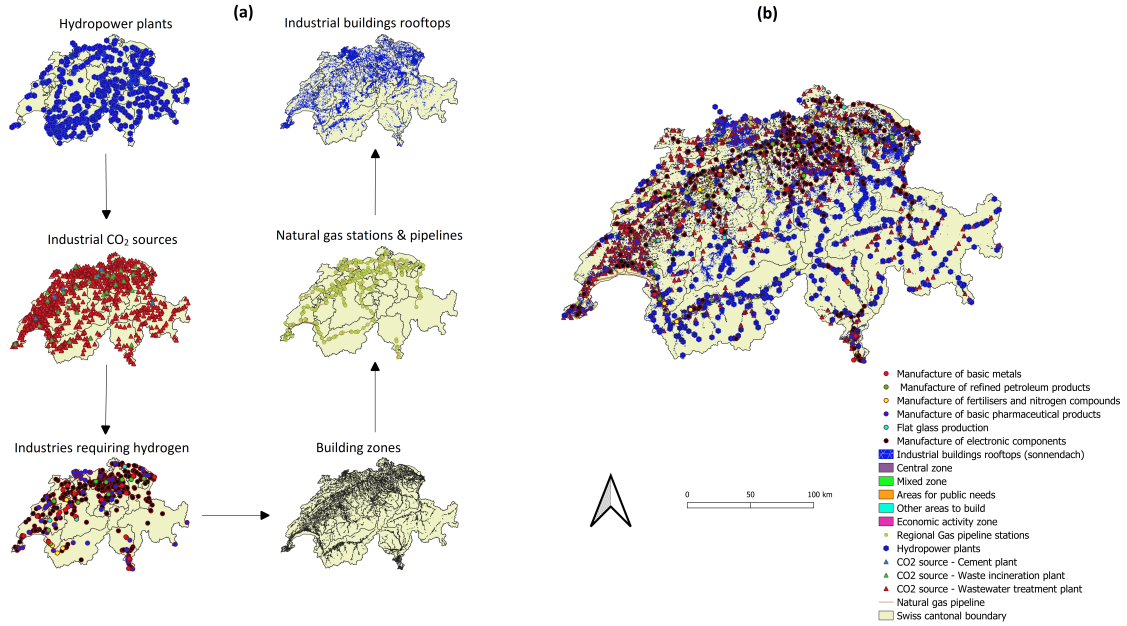


Figure 4.3: Map of the combined geographical data of Switzerland: (a) showing the geographical locations of hydropower plants, industrial CO₂ sources, industries requiring hydrogen, building zones, natural gas stations along with pipelines and industrial buildings rooftops available for PV installation; (b) showing all the features (shown in (a)) integrated on a single map.

4.3.6 Techno-economic performance indicators

Our spatially-explicit techno-economic analysis is based on three indicators, namely 1) levelized cost, 2) levelized value and 3) net present value (NPV) per unit of CAPEX. The levelized cost of hydrogen (LCOH) or synthetic methane (LCOM) (USD/MWh_{HHV}), calculated using Eqn. 4.1, is the cost of producing one energy

unit of gas (hydrogen or synthetic methane) over the project lifetime. A social discount factor of 8% is assumed in agreement with previous PtG studies [131, 247, 140]. The CAPEX refers to the total capital expenditure of a PtG system, including an electrolyzer system (both stack and BoP), compressor, methanation reactor, CO₂ capture facility, and general BoP. If electricity is supplied from rooftop PV, the CAPEX of PV including an inverter, and the electronics for the electrolyser connection is also added. The OPEX refers to the total value of operational and maintenance costs of all the above mentioned components including the electricity and transportation costs depending on the deployment strategy. $E_{i,Gas}$ (MWh) refer to the gas generated by the PtH or PtM system respectively during any hour. The cost of water supply does not significantly impact the total cost of the PtG system, and is therefore neglected [365, 131, 140].

$$LCOH \text{ or } LCOM = \frac{CAPEX + \sum_{i=1}^n \frac{OPEX}{(1+r)^i}}{\sum_{i=1}^n \frac{E_{i,Gas}}{(1+r)^i}} \quad (4.1)$$

Eqn. 4.2 is used to calculate the levelized value of hydrogen (LVOH) or synthetic methane (LVOM) (USD/MWh_{HHV}), which represents the total revenue generated by gas over the project lifetime. $Revenues_i$, correspond to the value generated by selling the gas (hydrogen or synthetic methane) in the wholesale market, in addition to selling by-products, such as O₂, heat, and surplus PV generation to the grid, as well as ancillary electricity services, and avoided CO₂ taxes as shown in Table 4.2. The selling price of hydrogen and methane are given in section C.1.5 in Appendix C. The value of the avoided CO₂ taxes is calculated on the basis of CO₂ levy which amounts to 96 USD/tCO₂ since 2018 [59]. In Switzerland, the CO₂ levy applies for fossil gas used for heating purposes, while the mineral oil tax applies for fossil gas used as a fuel for transport [140]. Here, since we consider that green hydrogen is used in both transport and industry sectors, we select the CO₂ levy as uniform approximation. In addition, emission allowances are assumed to be granted to PtG systems supplied by 100% renewable electricity [140]. Regarding electricity ancillary services, PtG systems are assumed to take part in the secondary control market, which is the most valuable frequency market in Switzerland, except for the scenarios where electricity is supplied by PV as a flexible operation of PtG system cannot be achieved due to the intermittent nature of PV supply [131]. Finally, a residual value is assigned to the components which last longer than the project lifetime^e

$$LVOH \text{ or } LVOM = \frac{\sum_{i=1}^n \frac{Revenue_i}{(1+r)^i}}{\sum_{i=1}^n \frac{E_{i,Gas}}{(1+r)^i}} \quad (4.2)$$

Finally, the NPV per unit of CAPEX is used to evaluate the profitability of a project considering the streams of costs and values (revenue generated) over its lifetime as given in Eqn. 4.3. It is calculated based on the annual cash flows CF_i (Eqn. 4.4) which balance revenues and various costs.

$$NPV_{perCAPEX} = \sum_{i=1}^n \frac{CF_i}{(1+r)^i \cdot CAPEX} - 1 \quad (4.3)$$

$$CF_i = Revenues_i - OPEX_i \quad (4.4)$$

^eThe lifetime of PV system is taken as 30 years [363, 131]. For hydropower based PtG systems, the lifetime is based on the electrolyser stack lifetime (see Table C.1. in Appendix C).

Table 4.2: Input value/s considered for different revenue streams for a PtG system.

PtG revenue stream (unit)	Value	Reference
Oxygen supply (USD/kg)	0.1	[140]
Heat supply (USD/MWh _{HHV})	60	[140]
Secondary frequency control (USD/MW _e .year)	236'094	[196]
Premium due to renewable content (USD/MWh _{HHV})	70	[140]
CO ₂ levy in Switzerland (USD/tCO ₂)	96	[59]
Emission allowances (USD/tCO ₂)	40-50	[327]
Natural Gas price (USD/MWh)	70-98	Appendix C Table. C.5
Hydrogen price (USD/kg)	5-3	Appendix C Table. C.6

4.4 Results

We first present the levelized cost and value for PtH and PtM plants across Switzerland depending on the different deployment strategies presented in Fig. 4.1. Results are given in USD per unit of thermal content of the gas (green hydrogen or methane) using the higher heating value (USD/MWh_{HHV}). We present the median values and their respective ranges corresponding to the number of deployment sites. Since direct air capture (DAC) is still an expensive option due to additional costs (electricity consumption by the CO₂ capture plant and CAPEX), the LCOM of PtM plants using CO₂ via DAC are on average 14%-17% higher than the systems where CO₂ is captured from industrial sources. Therefore in this section, we present only the results of PtM plants with CO₂ procured from industrial sources, while the results for PtM plants using CO₂ via DAC are presented under section C.2.3 in Appendix C. The percentage contribution of different components to the total levelized cost and value of hydrogen/methane using PV or hydroelectricity is presented in section C.2.1 and C.2.2 of Appendix C.

Further, we rank the profitability of PtH and PtM plants using NPV per unit of CAPEX to pinpoint geographical hotspots for hydrogen deployment across Switzerland. Finally, we show the sensitivity of the profitability of PtH and PtM to the CAPEX of PV, electrolyzer and methanation reactor systems in the mid (2030) and long (2050) term.

4.4.1 PtH plant deployment across different scenarios

Fig. 4.4 shows the boxenplots [291] of the levelized cost and value for different PtH deployment scenarios at the supply (PtH at HPP) and demand (PtH at HRS and PtH at IND) locations. We find that PtH plants located next to RoR hydropower plants can create more value than the associated cost, with a median LVOH of 186 USD/MWh_{HHV} (range 186-197 USD/MWh_{HHV}) and a median LCOH of 109 USD/MWh_{HHV} (range 99-146 USD/MWh_{HHV}). The LCOH boxenplot shows right skewness (skewness = 1.32) with a few outliers, meaning that 50% of PtH plants at RoR hydropower plants have LCOH values concentrated between minimum and median, while the other 50% show higher variability. On the contrary, PtH plants deployed at hydrogen refuelling stations and industrial sites are characterized by a higher cost, with a median LCOH of 287 USD/MWh_{HHV} (range 249-332 USD/MWh_{HHV}) and 285 USD/MWh_{HHV} (range 256-294 USD/MWh_{HHV}), respectively, compared to a median LVOH of 170 USD/MWh_{HHV} (range 163-172 USD/MWh_{HHV}) in both locations. The LCOH boxenplot of PtH at hydrogen re-

fuelling stations shows nearly symmetrical distribution (skewness = 0.10), whereas that at industrial sites shows skewness to the left (skewness = -1.88). The LCOH boxenplots show a much higher spread because of the varied distances between the PtH plants and various supply and demand centers. This contributes to different supply and transportation costs for each PtH plant, thereby leading to a large range of levelized costs. On the other hand, levelized values generated by each plant differ only depending on whether the heat is sold or not, explaining the much narrower range.

The intermittent and diurnal nature of PV generation limits the operating hours of PtH system located at hydrogen refuelling stations and industrial sites, resulting in an average annual capacity factor of 15% for the electrolyser, compared to values over 80% for electrolysers supplied by hydroelectricity. Therefore, the type of renewable electricity supply has a high impact on the levelized cost of PtH. On the other hand, PtH plants using hydroelectricity create high levelized value since they additionally act as a secondary control reserve, compared to PtH plants depending solely on rooftop PV electricity.

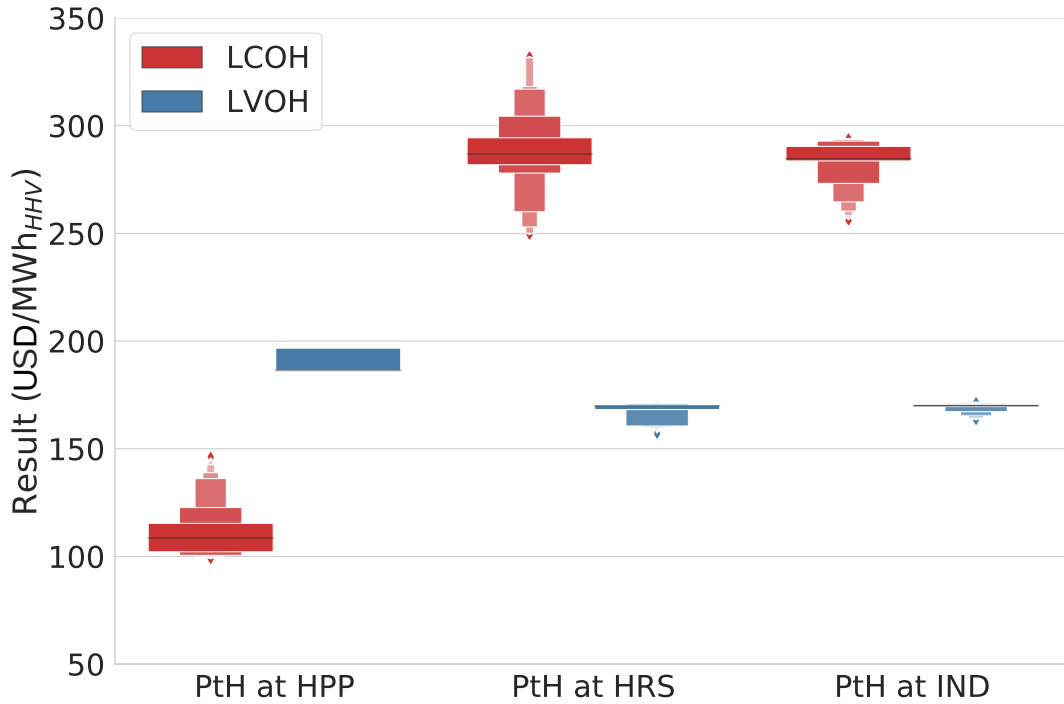


Figure 4.4: Levelized cost and value of hydrogen for a 1 MW_e PtH plants deployed at RoR hydropower plants (PtH at HPP), hydrogen refuelling stations (PtH at HRS) and industrial sites (PtH at IND) across Switzerland.

4.4.2 PtM plant deployment across different scenarios

By analogy with the results just presented for PtH, Fig. 4.5 shows the boxenplots of the levelized cost and levelized value for PtM deployment at the supply (PtM at HPP and PtM at CO₂) and demand (PtM at NG and PtM at IND) locations. PtM plants deployed at RoR hydropower plants operate with a median LCOM of 210 USD/MWh_{HHV} (range 179-352 USD/MWh_{HHV}) compared to a median LVOM of 218 USD/MWh_{HHV} (range 218-231 USD/MWh_{HHV}), showcasing profitability in 37 out of 61 (61%) locations. The LCOM plot is skewed right (skewness = 1.0786)

with 61% of the plants offering higher LVOM compared to LCOM. On the other hand, PtM plants deployed at natural gas stations, industrial sites and CO₂ sources powered by rooftop PV remain unprofitable, with the LCOM always being higher than the LVOM. For instance, PtM operated at natural gas stations, industrial sites and CO₂ sources imply a median LCOM of 431 USD/MWh_{HHV} (range 377-487 USD/MWh_{HHV}), 456 USD/MWh_{HHV} (range 411-502 USD/MWh_{HHV}) and 475 USD/MWh_{HHV} (range 377-796 USD/MWh_{HHV}), respectively, compared to a median LVOM of 217 USD/MWh_{HHV}, 228 USD/MWh_{HHV} and 228 USD/MWh_{HHV} (range 212-230 USD/MWh_{HHV} in all the three cases), respectively. Compared to PtH, PtM plants operate with a higher levelized cost resulting from the CAPEX for the methanation system, a higher OPEX due to CO₂ procurement as well as lower efficiency, which make them unprofitable for all the deployment scenarios except for some locations where electricity is directly supplied by RoR hydropower plants.

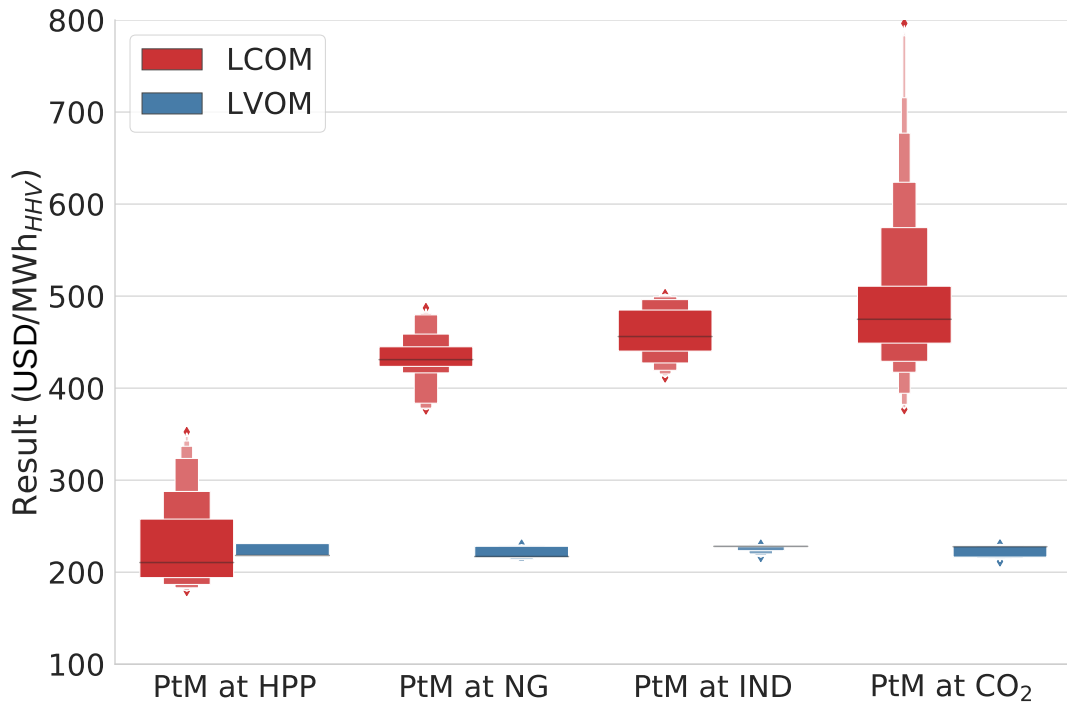


Figure 4.5: Levelized cost and value of methane for a 1 MW_e PtM plants using CO₂ captured from cement, wastewater and waste incineration plants - deployed at RoR hydropower plants (PtM at HPP), natural gas stations (PtM at NG), industrial sites (PtM at IND) and industrial CO₂ source (PtM at CO₂) across Switzerland.

4.4.3 Geographical hotspots for deployment of green hydrogen and power-to-methane plants

Figs. 4.6 and 4.7 present maps of Switzerland with hotspots for the deployment of PtH and PtM plants, respectively. PtH plants located at all 61 RoR hydropower plants are profitable regardless of the amount of products and services provided, e.g., heat supply. However, in Fig. 4.6, we show only the top 20 PtH hotspots with the highest NPV per unit of CAPEX (i.e. with the highest difference between LVOH and LCOH). On the other hand, none of the PtH plants located at the demand centers (hydrogen refuelling stations and industrial sites) using rooftop PV electricity offers

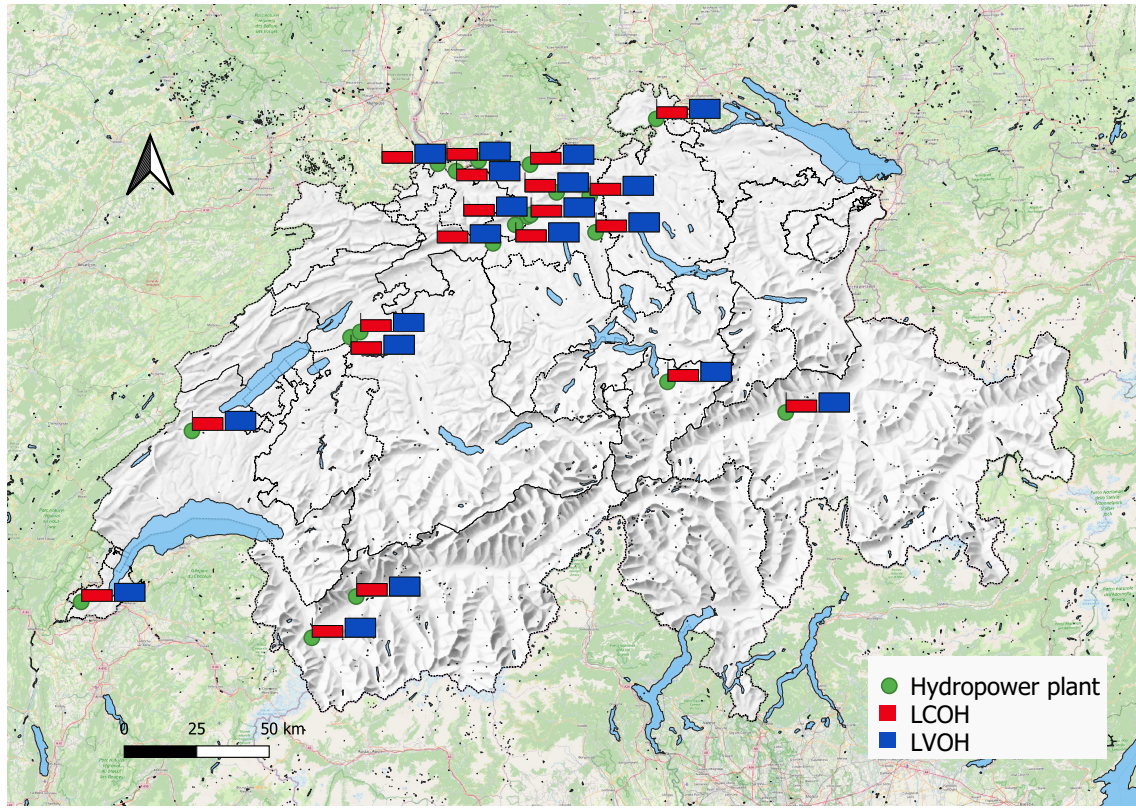


Figure 4.6: Top 20 hotspots (located at RoR hydropower plants) for deployment of green hydrogen plants across Switzerland on the basis of highest NPV per unit of CAPEX.

profitability. Considering the 61 profitable locations, our analysis shows that the maximum distance from a PtH plant to the nearest hydrogen and O₂ demand center is 25 km and 23 km, respectively, considering both the cases in which heat is sold or not.

Since all the 61 PtH RoR hydropower locations show profitability, we went a step further and estimated the maximum distance at which hydrogen and oxygen can be sold for the PtH plant to still remain profitable. As the NPV per unit of CAPEX for PtH plant is highly sensitive to selling green hydrogen (23%) and to a lesser extent to O₂ (14%) and heat (8%), finding a hydrogen demand center matters most. Therefore, we consider selling green hydrogen over longer distances and limiting O₂ transport within 20 km and heat within 0.5 km. Our results show that when considering selling low-temperature heat, PtH plants are profitable if the H₂ and O₂ demand centers is within 280 km and 20 km distance, respectively. Beyond these distances, the plants are no more economically viable. However, when the heat is not sold, PtH plants are profitable only if the H₂ demand center is within 200 km and within 20 km for O₂. This is because selling heat increases the value of the PtH plants and hence relaxes the geographical constraints associated with hydrogen and oxygen demand centers.

In 2020, 37 out of 61 hydropower (61%) plant locations show higher LVOM than LCOM values for PtM plants (positive NPV per unit of CAPEX), implying economically attractive locations for deploying PtM plants. Fig. 4.7 showcases the top 20 with the highest NPV per unit of CAPEX. Similar to the case of PtH plants, only PtM plants located at RoR hydropower plants show profitability, however, the viable cases are reduced due to the higher CAPEX, OPEX and lower efficiency. PtM plants selling heat are found to be profitable if a CO₂ source, natural gas station and O₂ demand center are located within a 15 km, 10 km and 11 km distance

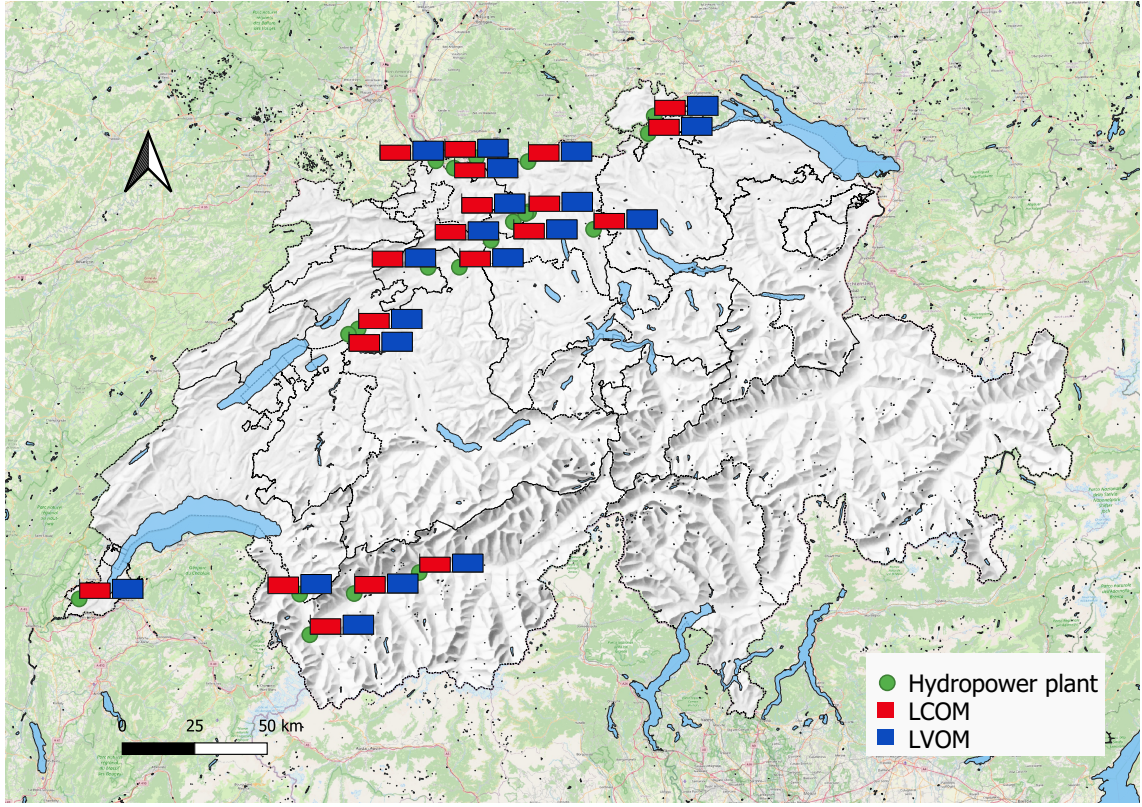


Figure 4.7: Top 20 hotspots (located at RoR hydropower plants) for deployment of PtM plants across Switzerland with a positive NPV per unit of CAPEX.

respectively. However, when heat cannot be monetized, the distance to a CO₂ source, natural gas station and O₂ demand center should be limited to only 10km, 8km and 8km, respectively. Similar to PtH, the NPV per unit CAPEX of PtM plant is highly sensitive to selling methane (31%), followed by O₂ (12%) and heat (6%). More details regarding the geo-coordinates of PtH and PtM hotspots across Switzerland are presented in section C.2.5 in Appendix C.

4.4.4 Sensitivity Analysis

Since PtH and PtM plants connected to rooftop PV are not yet profitable, we perform a sensitivity analysis on the CAPEX of PV, electrolyzers and methanation systems to understand the impact of the cost trajectories of key technologies on the profitability of green hydrogen and methane by 2030 and 2050. Based on the previous literature of learning curves [169, 171, 352], future cost reductions could reach for PV up to 51% by 2030 and 73% by 2050 [169], for electrolysis systems up to 40% by 2030 and 80% by 2050 [171], and for methanation reactors up to 24% and 51% by 2030 and 2050, compared to current costs [352]. In case of PtH at run-of-river hydropower plants, only electrolysis cost reduction is considered, while cost reductions for both electrolysis and methanation systems are considered in the case of PtM at run-of-river hydropower plants. When PtH or PtM plants are supplied by rooftop PV electricity, the reduction in PV technology costs is also considered in addition to the electrolysis or/and methanation systems. Further, the sensitivity analysis is also carried out for other key parameters such as the impact of CO₂ levy, natural gas prices, and guarantee of origin (GO) on the profitability of PtG plants, which are included under subsection C.2.4 in Appendix C.

Figs. 4.8 and 4.9 illustrate the current (2020) NPV per unit of CAPEX of

PtH and PtM plants, respectively, and their evolution considering cost reduction trajectories for electrolysis, methanation systems, and PV technologies in 2030 and 2050. According to Fig. 4.8, the NPV per unit of CAPEX in case of PtH at HPP improves by more than 50% and by nearly a factor of more than two by 2030 and 2050, respectively, compared to 2020 considering only reduction in electrolysis system costs (Fig. 4.8 (a)). Additionally, the NPV per unit of CAPEX of PtH plants becomes less negative, and even positive for a few hydrogen refuelling stations and industrial sites supplied by PV electricity by 2050 (Fig. 4.8 (b)). For instance, the median NPV per unit of CAPEX increases by approximately 20% in 2030 and 70% in 2050 compared to 2020 for PtH at both hydrogen refuelling stations and industrial sites. Since PV contributes more to the LCOH ($\approx 50\%$), a CAPEX reduction on PV, interestingly, has more impact on the overall NPV per unit of CAPEX than a reduction in electrolysis system costs.

For PtM at run-of-river hydropower plant, Fig. 4.9 shows that the median NPV per unit of CAPEX improves by 110% and 260% by 2030 and 2050, respectively, compared to 2020, based only on the cost reduction of electrolyzers and methanation systems. By 2050, 42 out of 61 (69%) PtM plants at ROR hydropower plants become profitable compared to 37 in 2020, which is only a gentle increase. PtM plants located at the natural gas stations supplied by PV electricity, show the greatest improvement in the median NPV per unit of CAPEX, by 44% in 2050 compared to 2020. The median NPV per unit of CAPEX for PtM located at industrial demand centers and CO₂ source also improves, however only 33% and 30% in 2050 respectively compared to 2020. However, their NPV/CAPEX remains negative but reaches closer to zero in 2050. Despite the significant cost reductions of electrolysis, methanation and PV systems, PtM plants located at natural gas stations, CO₂ sources and industrial sites are neither profitable in the mid (2030) nor in the long (2050) term. Deploying PtM at the run-of-river hydroelectricity source hence represents the most promising economic case and will continue to be a suitable option for several locations in both the mid (2030) and long (2050) term.

Further, we extend our analysis to set cost improvement targets for electrolyzer, PV and/or methanation reactor systems to enable the future profitability of PtM plants deployed next to CO₂ sources, at natural gas stations and industrial sites (details in section C.2.6 in Appendix C). Based on our results, PtM plants located at natural gas stations, and PtM next to CO₂ sources would begin to be profitable if the CAPEX of PV or/and electrolyzer system reduced by 90% compared to the values in 2020. Particularly, we see that 5% and 16% of the all PtM plants deployed next to CO₂ sources, and at natural gas stations, respectively, would become profitable with this level of CAPEX reduction for both PV and electrolyzer systems. For PtM plants located at industrial sites, a 90% CAPEX reduction of the methanation reactor compared to 2020 would also be needed additionally. This may not be possible considering the existing learning rates and projections for methanation technology [196]. Therefore, we can conclude that PtM plants located at industrial sites may not become profitable in Switzerland for the assumed energy and hydrogen prices.

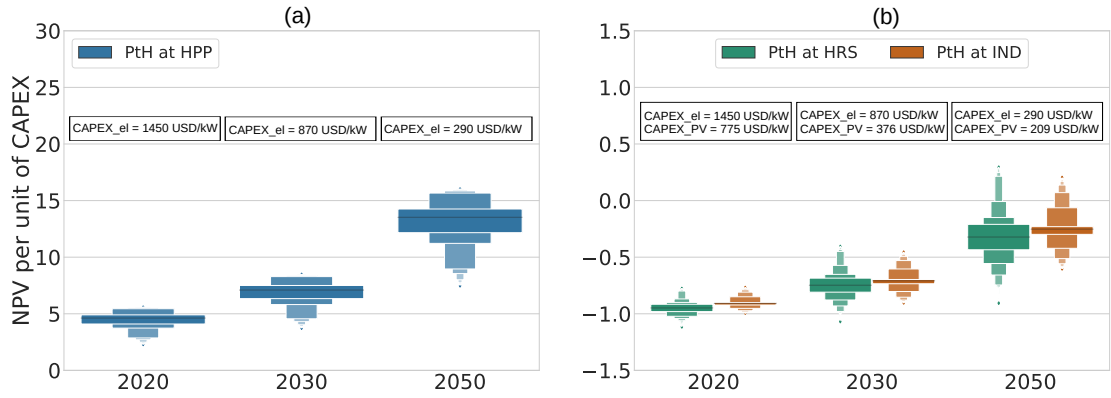


Figure 4.8: Evolution of the NPV per unit of CAPEX for PtH plants deployed at (a) hydropower plants (PtH at HPP); (b) hydrogen refuelling stations (PtH at HRS), and industrial sites (PtH at IND) as a function of projected CAPEX reductions of PV and electrolysis systems in 2030 and 2050 compared to 2020. Abbreviations used: CAPEX_{PV} refers to CAPEX of PV and CAPEX_{el} to CAPEX of electrolyzer systems.

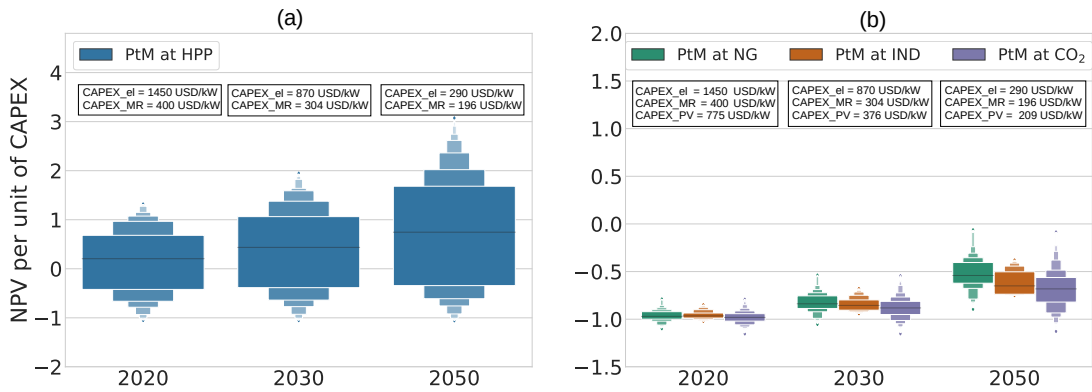


Figure 4.9: Evolution of the NPV per unit of CAPEX for PtM plants deployed at (a) hydropower plants (PtM at HPP); (b) natural gas stations (PtM at NG), industrial sites (PtM at IND), and CO₂ source (PtM at CO₂) to the projected CAPEX reductions of PV, electrolysis and methanation systems in 2030 and 2050 compared to 2020. Abbreviations used: CAPEX_{PV} refers to the CAPEX of PV, CAPEX_{el} to CAPEX of electrolyzer systems and CAPEX_{MR} to CAPEX of methanation systems.

4.5 Discussion

In this chapter, we determine the levelized cost and levelized value of green hydrogen and power-to-methane plants deployed across different supply and demand locations in Switzerland by 2020, and we also analyze their profitability in 2035 and 2050 compared to 2020. Our analysis shows that current levelized costs of green hydrogen plants connected directly to run-of-river hydropower plants range between 3.6-5.4 €/kg_{H₂}, whereas those at hydrogen refuelling stations and industrial sites using rooftop PV electricity range between 9.2-12.1 €/kg_{H₂} and 9.4-10.8 €/kg_{H₂}, respectively. Since electricity is the major contributor to the levelized cost of green hydrogen (50-80%), cost reductions in electricity supply combined with increased taxation of non-renewable energy and/or of CO₂ are key to improve the cost competitiveness with grey hydrogen (current costs around 1.5 €/kg_{H₂}) [159]. Based on our GIS-based techno-economic analysis, we identify hotspots for deployment of green hydrogen plants in Switzerland. First, it is economically viable to deploy green hydrogen plants connected to run-of-river hydropower plants for the next 20-25 years. In the long term (2050), deployment at the demand sites such as hydrogen refuelling stations and industrial sites supplied by rooftop PV electricity should be further explored, since a few locations will become profitable considering the projected cost reduction for electrolyzers and PV. These recommendations are well aligned with the objective of Swiss Energy Strategy 2050+ for hydrogen production of 7 PJ at run-of-river hydropower sites by 2050 [260]. Switzerland currently has several green hydrogen plants connected to the run-of-river hydropower plants operational or in the pipeline [49, 12, 13].

We finally use our profitability results based on the levelized cost and levelized value to provide specific recommendations to project developers and policy makers in the form of a roadmap for green hydrogen and methane plants deployment in Switzerland in Fig. 4.10. For the years 2030 and 2050, the profitability analysis of the plants takes into account the cost improvement targets of PV, electrolyzer and methanation systems.

Since our findings clearly show that the production of green hydrogen is currently only profitable at run-of-river hydropower plant locations and not at demand centers, more efforts are needed to accelerate the deployment of green hydrogen plants in locations close to demand centers, which can be key to decarbonize hard-to-abate sectors such as industry and heavy-duty transportation. In order to accelerate green hydrogen deployment, creation of mandate for green hydrogen demand, targeted policies and financial incentives for green hydrogen are prime, with some first examples given by leading countries such as Germany, Spain, France, Italy, Netherlands, UK, Australia and Japan [203, 63]. These measures are expected to have a positive impact on electrolyzers production, thereby reducing their costs due to learning-by doing, economies of scale, automation and technology capacity, similar to PV technology [286]. Furthermore, a higher carbon price can help to further improve a business case for green hydrogen by increasing the cost associated with alternative production methods based on fossil fuels (i.e. steam methane reforming and coal gasification) [7]. Finally, the introduction of a binding or legal classification for the green hydrogen production process in the form of a green hydrogen certification may also serve as a tool to incentivize and create market demand for hydrogen as a zero-carbon feedstock in many sectors of the economy [20]. Policies in this area must be carefully designed, e.g. to ensure power-to-gas supply with renewable electricity from *additional* plants (instead of depriving other sectors of scarce renewable

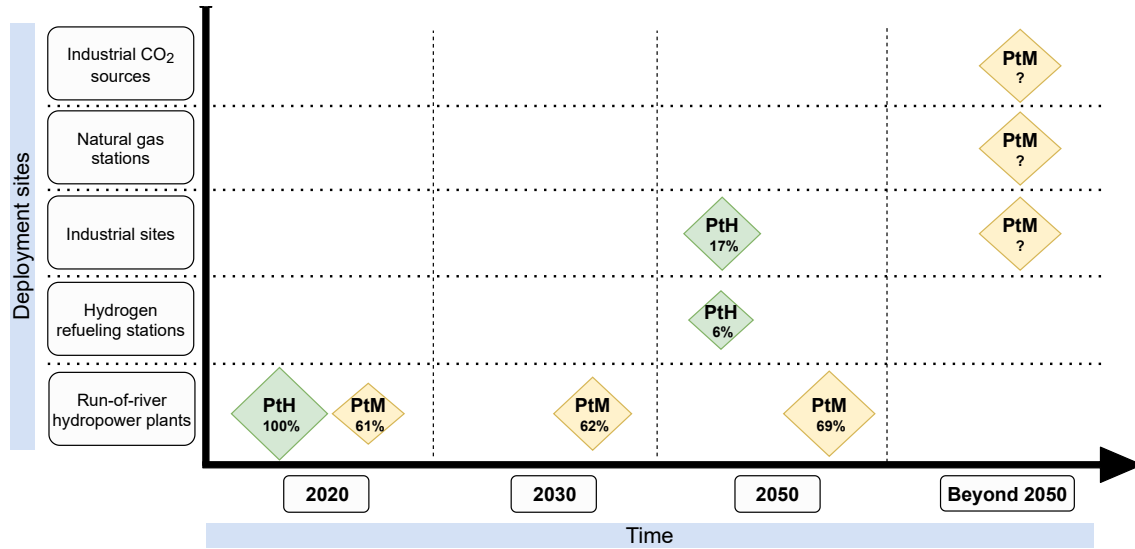


Figure 4.10: Roadmap for green hydrogen (PtH) and synthetic methane (PtM) plants deployment across different locations in Switzerland. The PtH and PtM deployed at the run-of-river hydropower plants use hydroelectricity, while those at other locations use electricity from rooftop PV. The percentage represents the ratio of plants that show profitability. The presented roadmap is subject to change if the cost assumptions and other parameters vary. Beyond 2050, uncertainty remains on the profitability of PtM plants powered with rooftop PV electricity, which is represented by question marks.

energy) and they must prioritize energy efficiency improvement, hence covering only the remaining demand with power-to-gas.

This chapter proposes a GIS-based smart deployment strategy for green hydrogen and power-to-methane plants, but it is not without limitations, which in turn, calls for future research. This chapter primarily focussed on assessing the profitability of power-to-gas plants. Future research should also analyse the impact of hydrogen and power-to-gas on other important indicators, such as CO₂ emissions, employment, etc., due to deployment of green power-to-gas plants. The size of power-to-gas plants is set to 1 MW and not optimized. The inclusion of sizing becomes important in case of energy system analysis and planning which is outside the scope of this chapter, considering the GIS-based energy system analysis are still computationally too heavy [276]. Future research should therefore compare results between the investor and the social planner perspectives. The use of solid oxide electrolysis (SOE) with significantly increased efficiency (90%) could be potentially interesting in the long-term (2050) and subject to consideration in future work [229]. In our model, we assumed the size of the electrolyzer and methanation reactor as 1:1 in terms of hydrogen input, which is a simplification. An additional hydrogen storage between the electrolyzer and methanation reactor may add flexibility to the system and decrease the size of the system in power terms, which could be added to the model for future studies. Further, the proposed method does not account for externalities in economic assessment. Internalizing externalities by monetizing the environmental impacts (on human health, ecosystem quality and resources depletion) would extend the proposed levelized cost and value analysis [268]. Finally, long-distance hydrogen imports associated with international trade may also be considered as a hydrogen supply option. Our methodology could be extended to other countries to identify green hydrogen production hotspots.

4.6 Conclusions

This chapter presents a spatially and temporally-explicit techno-economic analysis of green hydrogen and synthetic methane plants throughout the energy transition. First, we develop a detailed GIS assessment method to map various electricity and CO₂ supply sources, as well as demand centers across the country. This data is then used as an input to the techno-economic model which calculates levelized cost and levelized value of hydrogen and synthetic methane across different deployment locations. Importantly, we identify hotspots for green hydrogen deployment, set cost improvement targets which are geographically explicit, and propose smart deployment strategies for the mid (2030) and long (2050) term. In terms of revenue creation, the hotspot analysis shows that the NPV per unit of CAPEX is most sensitive to the sales of green hydrogen (or synthetic methane) (23-31%), followed by the sales of oxygen (14-16%) and heat (6-8%). Therefore, proximity to gas demand centers matters most, followed by oxygen and heat. Furthermore, selling heat to a district heating networks located within 500m of the PtG plant, increases the levelized value of hydrogen or methane, thereby relaxing the geographical constraint to some extent, compared to the scenarios when heat is not sold.

A sensitivity analysis of the profitability to the CAPEX of PV, electrolyzers and methanation reactor systems in the years 2030 and 2050 shows that for the mid term (2030), only green hydrogen plants connected directly to run-of-river hydropower plants offer an attractive business case (the NPV per unit of CAPEX ranges between 2.3-5.6 in 2020, and between 7.5-16.5 in 2050). However, in the long term, some green hydrogen plants connected directly to rooftop PV will gradually become profitable in refuelling stations (the NPV per unit of CAPEX ranges from -0.9 to 0.3 in 2050), and in industrial sites (the NPV per unit of CAPEX ranges from -0.6 to 0.2 in 2050) in Switzerland. For synthetic methane, only plants connected directly to run-of-river hydropower plants currently show profitability for some locations, while plants supplied with rooftop PV which are located next to natural gas stations, next to CO₂ sources, and embedded into industrial sites will remain uneconomical. However, we conclude that that some power-to-methane plants located next to CO₂ sources, and next to natural gas stations would show profitability if the CAPEX of PV or electrolyzer reduces by 90% compared to 2020. Given the high relevance of green hydrogen to decarbonize hard-to-abate sectors, our proposed smart deployment strategies can be used to inform decision makers, regulators, project developers and implementing agencies about hotspots and cost targets for the deployment of green hydrogen and synthetic methane plants.

Chapter 5

Macroeconomic analysis of a green hydrogen sector using Input-Output analysis

Hydrogen is receiving increasing attention to decarbonize hard-to-abate sectors, such as carbon intensive industries and long-distance transport, with the ultimate goal of reducing greenhouse gas (GHG) emissions to net-zero. However, limited knowledge exists so far on the socio-economic and environmental impacts for countries moving towards green hydrogen. Here, we analyze the macroeconomic impacts, both direct and indirect, in terms of GDP growth, employment generation and GHG emissions, of green hydrogen production in Switzerland. The results are first presented in gross terms for the construction and operation of a new green hydrogen industry considering that all the produced hydrogen is allocated to passenger cars (final demand). We find that, for each kg of green hydrogen produced, the operational phase creates 6.0, 5.9 and 9.5 times more GDP, employment and GHG emissions respectively compared to the construction phase (all values in gross terms). Additionally, the net impacts are calculated by assuming replacement of diesel by green hydrogen as fuel for passenger cars. We find that green hydrogen compared to diesel contributes to a higher GDP and employment, while reducing GHG emissions. For instance, in all the three cases, namely, ‘Equal Cost’, ‘Equal Energy’ and ‘Equal Service’, we find that the green hydrogen industry generates around 106%, 28% and 45% higher GDP respectively; 163%, 43% and 65% more full-time equivalent jobs respectively; and finally 45%, 18% and 29% lower emissions respectively, compared to diesel and other industries. This study aims to inform policymakers on how green hydrogen can contribute to a decarbonized economy, and it provides recommendations for the future development of the green hydrogen industry. Finally, the methodology developed in this study can be extended to other countries using country-specific data.

5.1 Introduction

In the run-up to net zero emissions, countries across the globe are developing strategies to decarbonize their energy systems. While electrification using renewable energy (RE) is a rather mature solution to decarbonize a wide range of sectors including light-duty transport, residential and service sectors [71], achieving carbon neutrality in hard-to-abate sectors such as carbon intensive industries and heavy-duty trans-

port still remains a key challenge [87]. The transport sector is one of the largest contributors to greenhouse gas (GHG) emissions, with heavy-duty vehicles alone currently contributing to about 6% and 14% of the total GHG emissions in the European Union (EU) [119] and Switzerland [208], respectively. For the EU to be carbon neutral by 2050, the transport sector needs to undergo a transformational reduction in GHG emissions (by 90%) compared to the 1990 levels [356]. Also, the net-zero carbon scenarios for Switzerland identify this as a priority [37].

Green hydrogen as a transport fuel is gaining attention as increasing fossil fuel prices and decreasing production costs (due to lower RE prices and technological improvements) enhance its competitiveness [154]. So far within Europe, 11 countries including Denmark, Portugal, Spain, France, Belgium, Italy, Germany, Austria, United Kingdom, Netherlands and Switzerland have set hydrogen targets for the future in terms of electrolyzer capacity and/or hydrogen production [361]. In June 2021, the Swiss Parliament voted to create a national green hydrogen strategy with timelines until 2035, 2050 and beyond [1]. In addition, several economies are investing in the green hydrogen sector, as illustrated by EU’s 2 billion EUR industrial partnership on clean hydrogen [99]. The EU is preparing regulation to boost green hydrogen production along with the mandate to deploy hydrogen refuelling stations every 150 km on the Trans-European Transport (TEN-T) network by 2030 [78]. Lately, in reaction to the energy crisis triggered by the Ukraine war, the EU presented the REPowerEU plan to rapidly secure independence from Russian fossil fuels and fast forward the green transition including the use of renewable hydrogen [97]. To this end, also demonstration projects are being promoted. The European Commission approved public funding for Important Projects of Common European Interest (IPCEI) on hydrogen, namely ‘IPCEI Hy2Tech’ (5.4 billion EUR) and ‘IPCEI Hy2Use’ (5.2 billion EUR) in July 2022 and September 2022 respectively [145].

In recent years, Switzerland has been demonstrating the use of green hydrogen to replace diesel for heavy-duty transportation [344]. Within Europe, Switzerland today is pioneering the use of hydrogen in road haulage industry [290]. Around 50 hydrogen-powered trucks are already out on Switzerland’s roads and this number is expected to rise to 1600 trucks by 2025 [150]. This would require around 100 MW of green hydrogen capacity. Recently, the Generation Of Hydrogen (GoH!) project was launched in Switzerland with the support of a consortium of four local companies to demonstrate the economic and technical viability of the Swiss hydrogen sector [345].

Hydrogen produced via electrolysis involves splitting water into hydrogen and oxygen by using electricity. The development of industrial water electrolysis dates back to 1888 [155], and several studies focusing on the techno-economic [131, 53, 190] and environmental assessments (such as life cycle assessment) [244, 195] involving green hydrogen production via electrolysis using renewable electricity have been carried out in the recent years. However, the macroeconomic impact of the green hydrogen industry on welfare, the labour market and emissions reduction at the country level has so far hardly been assessed (see section below). Moreover, green hydrogen impacts should be quantified relative to fossil fuels [137]. An analysis of the macroeconomic impacts of such a strategic industry can be pivotal to recommend policy measures, allowing to enhance positive macroeconomic impacts and increase the acceptance of green hydrogen. The aim of this study is therefore to analyze the implications of the green hydrogen industry on the country’s GDP, employment and GHG emissions in CO_{2eq} (thereafter referred to as ‘*emissions*’ in this study). In this chapter, the proposed methodology is applied for Switzerland, however, it could be

readily extended to other countries/regions.

This chapter is structured as follows: Section 5.2 presents the review of existing literature on macroeconomic impact assessment of existing clean energy technologies and highlights the novelty of this study; Section 5.3 presents the input data and methodology, Section 5.4 showcases the results divided into gross and net impacts (including the upscaled results at the Swiss level) as well as the inter-industry linkage effect; Section 5.5 discusses the implications of the results and limitations; and finally Section 5.6 summarizes the key findings and takeaways for policymakers and stakeholders.

5.2 Literature review and research objective

In this section, we analyze different studies assessing the macroeconomic impacts of investments in clean energy using various economic models such as employment rate analysis, supply chain analysis, econometric models, Input-Output (I-O) analysis, and computable general equilibrium (CGE) models [213, 300, 386, 43, 23]. In addition, there are several models based on I-O such as Jobs and Economic Development Impact (JEDI) [185], Regional Input-Output Modeling System (RIMS II) [272], IMPLAN [80], Dynamic Energy Efficiency Policy Evaluation Routine (DEEPER) [72] and Regional Economics Applications Laboratory (REAL) [271] which have been deployed by various institutions for carrying out macroeconomic impacts analysis.

While existing studies have mainly focused on the employment impacts due to investments in RE and energy efficiency programmes [46, 237, 112, 355, 77, 241], some others have also analysed the economic (e.g., GDP) [113, 227] and environmental (e.g., emissions) impacts [297]. For instance, employment impacts due to investments in RE or energy efficiency programmes have been studied for Greece [213, 311], Portugal [241], Czech Republic [77], Netherlands [43], China [54], United States (US) [112], Brazil [300], Switzerland [386], and United Kingdom (UK) [133]. Using the I-O method for the US, Garrett-Peltier found that 1 M USD spending on RE (solar PV, wind, bioenergy, geothermal, and hydro) creates on average 7.49 full-time equivalent (FTE) jobs, as opposed to only 2.65 FTE jobs for an equivalent spending in fossil fuels (coal, oil & gas) [112]. Using the same method, Chen arrived at a similar conclusion for employment generation considering investments in RE versus fossil fuels, although the magnitude (number of FTE jobs per 1 M USD created) in both sectors is substantially higher in China compared to the US. Specifically, spending 1 M USD on RE (solar PV, wind, and bioenergy) generates 162.3 jobs while the same spending on fossil fuels (coal, oil & gas) generates 96.7 jobs in China [54]. Significantly higher employment generation in case of China could be due to lower labour productivity and consideration of both formal (long-term employment) and informal (seasonal workers) by the author. Furthermore, using the three-sector general equilibrium model, Rivers concluded that RE support policies (such as subsidies) lead to an increase in the unemployment rate in contrast to the previous findings [278]. This is due to the increase in the labour tax rate to maintain government budget balance because of RE subsidies and taxes on conventional electricity. In addition to analyzing the employment impacts using an I-O model, Gelo et al. studied the impact on value-added and GDP due to investment in RE sources for electricity production in Croatia [113]. Their results show that every 1 M EUR^a of RE investment in the Croatian economy generates directly and

^a1 EUR₂₀₂₂ = 1.06 USD₂₀₂₂

indirectly, 0.336 M EUR of value-added, 0.410 M EUR of additional GDP and 14 new jobs. In a study carried out for an energy efficiency programme in Switzerland, Yushchenko et al. found that every 1 M CHF^b spent creates approximately 0.2 M CHF of additional GDP and up to 1.6 FTE jobs compared to a reference case considering a standard household expenditure [386]. Yet, Afonso et al. performed a study on 28 countries using an Autoregressive Distributed Lag model (ARDL) and found the opposite showing that RE sources have a negative effect on the economic growth (GDP per capita) [5]. These few examples of previous studies illustrate the diversity of macro-economic approaches and corresponding results in studying RE and energy efficiency programmes investment impacts. They also underline the role played by specific contexts and technologies. However, green hydrogen has not yet been in the focus, despite the increasing attention in the clean energy sector.

Furthermore, while some of the previous literature showcases the economic and environmental impacts of hydrogen technologies at the level of plants (e.g., electrolysis [137, 56, 211, 236, 244, 195]), the impact of a whole sector at the level of a national economy is still lacking. For example, using I-O tables, Hienuki analyzed the environmental and socio-economic effects during the entire life cycle of a hydrogen system (including hydrogen production, transportation and refilling), but the author focused on grey hydrogen produced by reforming of naphtha (i.e. fossil-based) [137]. The study concludes that producing hydrogen from fossil fuels leads to high GHG emissions, which could be drastically reduced by opting for renewable hydrogen production options. Smith et al. assessed the impact of hydrogen on the UK's GDP and employment, using existing *electricity* and *gas* industries in the I-O table as proxies for a hydrogen industry [211]. Following the same approach, O'Connor used the *electricity generation* industry as a proxy for hydrogen industry in his I-O analysis [236]. The author compared economic impacts of hydrogen produced from fossil fuels by steam methane reforming (SMR) (i.e. grey hydrogen) with hydrogen produced with electrolysis (i.e. green hydrogen) in Australia. He concluded that hydrogen produced via electrolysis contributes more to the Australian economy in terms of value-added, GDP and employment compared to SMR for each unit of hydrogen output across three different scenarios considered in the study. For instance, in the 'Energy of the Future 2040' scenario, hydrogen from electrolysis generates 14,743 jobs compared to 4,532 jobs in case of hydrogen from SMR. However, O'Connor did not study the net impact due to hydrogen displacing other fossil fuels such as petroleum, natural gas and coal. Moreover, previous studies have used the electricity and natural gas industries to model a green hydrogen industry, which remains a key limitation.

Against this background, the contribution of this chapter to the existing body of literature is threefold. First, we estimate the structure of a standalone green hydrogen industry within the Swiss I-O table based on existing data from the literature as well as consultation with industry experts. Second, we evaluate the gross impacts on key macroeconomic indicators, namely GDP, employment and emissions, for both the construction and operational phases of a green hydrogen industry. Third, we also assess the net impacts on the above macroeconomic indicators considering replacement of diesel by green hydrogen as a transportation fuel in passenger cars.

^b1 CHF₂₀₂₂ = 1.05 USD₂₀₂₂

5.3 Input data and method

In this section, we provide an overview of an I-O model, system boundary, input data for the construction, operation and maintenance of the green hydrogen industry, as well as the macroeconomic impact analysis.

5.3.1 I-O analysis

I-O analysis is a modeling technique introduced by Wassily Leontief in the 1930s [349] and later adapted for the purposes of regional analysis by Walter Isard in the 1950s [226]. I-O tables provide a detailed description of an economy's circular flow of goods and services. We employ an I-O model to conduct our analysis for the following reasons. First, I-O analysis is a quantitative economic technique that represents the inter-dependencies between different industries and is therefore useful for economy-wide analysis. This makes it a suitable method to study a new sector, in our case the green hydrogen industry, as well as its interactions with other industries [56]. Second, I-O models provide reasonable indications of direct and indirect impacts of an emerging sector while being transparent and easily reproducible. This makes them more policy-relevant for an early development stage of the industry than more elaborated models, for which even more assumptions on the structure of the future economy would have to be made [211].

The basic representation of an I-O table is presented in Fig. 5.1. The output from industry i , is supplied as input to industry j (*Intermediate demand*) and to *Final demand* (households and government consumption, capital expenditure and exports). The sum of intermediate demand and final demand from one sector equals the *Total Output* of that sector. This in turn must always be equal to the *Total Input* which is the sum of intermediate demand, net commodity taxes (NCT), value-added and imports of the said sector. In Switzerland, the I-O tables are published every few years by the Federal Statistical Office following the general format of I-O tables [167]. The sectors of the economy within the I-O table are classified based on the General Classification of Economic Activities (NOGA) code [234].

	Output to receiving industries, j			FINAL DEMAND				TOTAL OUTPUT
	Industry 1	Industry 2	Industry 3	Households	Governments	Capital	Exports	
Industry 1								
Industry 2	INTERMEDIATE DEMAND							
Industry 3								
Net commodity taxes								
Value added								
Imports cif (Cost, insurance, and freight)								
TOTAL INPUT								

Figure 5.1: Schematic representation of an Input-Output table.

3595 In this study, the green hydrogen industry essentially comprises green hydrogen
3596 production by electrolysis, transportation of hydrogen and the refuelling stations,
3597 excluding manufacturing of fuel cells and hydrogen vehicles. Fig. 5.2 illustrates the
3598 system boundary and key components of the green hydrogen industry considered in
3599 this study. In order to evaluate the economic impact of the green hydrogen industry,
3600 the latest I-O table available from 2017 (consisting of 49 industries) published by
3601 the Swiss Federal Statistical office is used [167]. Since today the size of the green
3602 hydrogen industry is small in Switzerland (around 1% of the size of the natural gas
3603 market in 2021 [290]), it does not feature as a standalone industry in the Swiss I-O
3604 table. We estimate the input components of the green hydrogen industry by as-
3605 signing collected expenditure data to the existing sectors. For example, production
3606 of green hydrogen requires an electrolyzer system as capital expenditure (CAPEX)
3607 and renewable electricity for its operation. While the purchase of an electrolyzer
3608 system is accounted for under the industry titled '*Manufacture of machinery and
3609 equipment*', the renewable electricity used to run the electrolyzer is accounted under
3610 '*Electricity, gas, steam and air-conditioning supply*' industry. Therefore, we divide
3611 the investments required for establishing a green hydrogen industry into two cate-
3612 gories – 1) Infrastructure CAPEX (or simply CAPEX) which are incurred once and,
3613 2) Annual costs (also OPEX) for operation and maintenance. In this study, the
3614 green hydrogen industry is modelled as a new and separate sector in the Swiss I-O
3615 table.

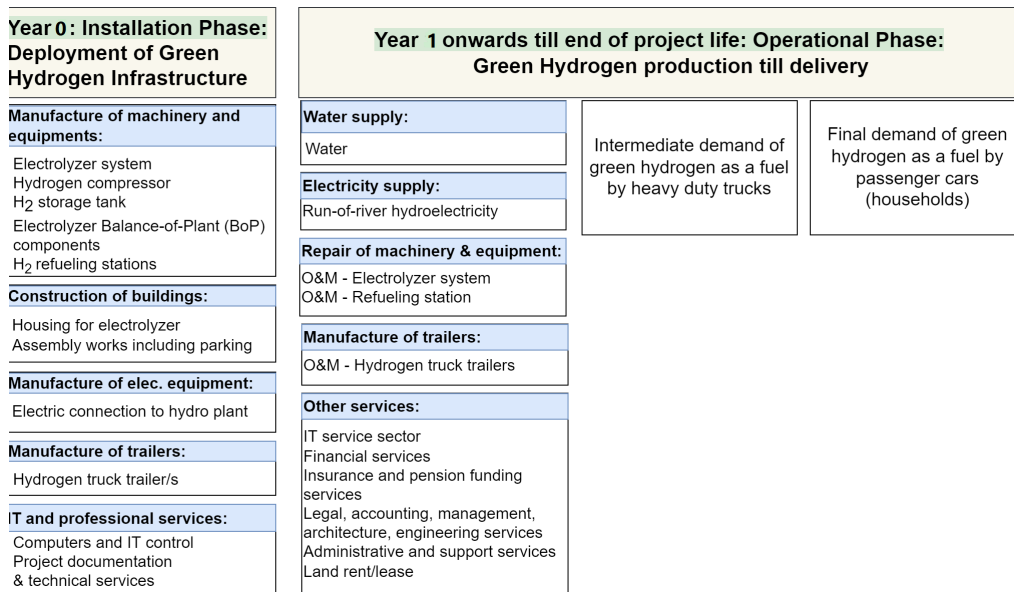


Figure 5.2: System boundary of the green hydrogen industry considered in this study. Capital expenditures and installation of the green hydrogen industry infrastructure occurs in year 0, followed by its operation & maintenance from the year 1 until the plant reaches its lifetime. For the gross and net impact analysis in this study, we assume that all the produced hydrogen is demanded by the passenger cars (final demand by households).

Input data for construction and operation phase of a green hydrogen industry

The CAPEX and OPEX data are generally available in terms of producer prices^c. However, in order to use them for the I-O analysis, they need to be transformed into basic prices by deducting the NCT. The rates of NCT for each industrial category are taken from the Swiss 2017 I-O table (see section D.1 in Appendix D for more information on NCT). Importantly, we assume that all production activities occur in Switzerland to study the direct and indirect impacts on each industry within the green hydrogen industry system as well as the impact of green hydrogen industry on the whole Swiss economy. Green hydrogen is assumed to be produced from electrolysis using renewable hydroelectricity, which is the dominant electricity source ($\approx 57\%$) in Switzerland [204]. The project life is assumed to be 15 years for this study [385, 131]. Finally, we select a nominal capacity of 1 MW_{el} as a representative deployment scale to represent a green hydrogen industry [44, 131]. The results of the model can be linearly scaled to suit any sized system, provided the cost of the components follow a linear relationship with the scale.

Capital formation in year 0 involves investment in CAPEX for building up the green hydrogen infrastructure including a green hydrogen plant, hydrogen delivery transport and distribution. The various CAPEX elements include an electrolyzer system (including water treatment system), hydrogen compressor, high-pressure hydrogen storage tank, electric connection to a hydropower plant, hydrogen truck trailers, construction of housing for electrolyzer system, parking for truck trailers, refuelling station/s, IT control, communications, computers and other electronic equipment, electrical connection to the grid, consultancy and technical services (Fig. 5.2). The disaggregation of CAPEX under different industry sectors is performed according to NOGA 2008 General Classification of Economic Activities [234]. The producer prices of various CAPEX elements are presented in Table 5.1. The CAPEX of the elements which are available for the EU but not for Switzerland, are converted to Swiss prices by taking into account the purchasing power parity for each sector, as given under section D.2 in Appendix D.

The time period from year 1 until the end of project life represents the OPEX phase, during which the infrastructure built in year one is brought to use to produce and deliver green hydrogen to its intermediate and final consumers. Since our focus is on domestic production and consumption, it is assumed that no green hydrogen is imported from or exported to other countries.

In order to assess the macroeconomic impacts of the green hydrogen industry, the new independent green hydrogen industry created within the existing I-O table is furnished with the inputs from other industries: Water, hydro electricity, O&M of machinery and refuelling station, fuel (diesel/hydrogen) for hydrogen truck trailers, IT service sector, banking & insurance and employees (Table 5.2). The relevant input data for the various components and services needed for operation of the green hydrogen industry is collected from the literature, and by consultation with industry experts. The major green hydrogen producing companies in Switzerland were contacted through e-mails and phone calls to obtain information on the costs and other input data. In some cases, the data was confidential and access was denied for confidentiality reasons. In those cases, secondary research through existing literature is carried out. No payments were made to the companies/participants for consultation.

^cProducer price is the sum of basic price and the net commodity taxes (NCT).

Table 5.1: Producer prices of components and services required for construction (capital formation) of a 1 MW green hydrogen industry, including green hydrogen production via electrolysis, its transportation via truck trailers, refuelling station as well as some additional costs.

Components	CAPEX (USD)	Reference	Industry Name	Swiss NOGA code [234]
Electrolyzer system	614'093	[171, 55, 53]	Manufacture of machinery and equipment	28
Hydrogen compressor	169'988	[171, 55, 53]	Manufacture of machinery and equipment	28
Electrolyzer Balance-of-plants (BoP) components	1'611'994	[171, 55, 53]	Manufacture of machinery and equipment	28
Electric connection to Run-of-the-river (RoR) hydropower plant	122'139	[190]	Manufacture of electrical equipment	27
Construction of housing for electrolyzer system and assembly works including parking for truck trailers	169'187	[190]	Construction	41 - 43
Hydrogen refueling station (2 nozzles - 400 kg/day)	1'600'000	[148, 207]	Manufacture of machinery and equipment n.e.c.	28
Hydrogen truck trailer cost (1 number)	151'199	[274]	Manufacture of motor vehicles, trailers and semi-trailers	29
Computers and IT control	59'695	Authors' own estimate	IT and other information services	62 - 63
Project administration, consultancy and technical services	200'000	[190]	Other professional, scientific and technical activities	73 - 75
Total	4'698'295			

For shares of expenditure data on *financial services, telecommunications, insurance and pension funding services, legal and accounting, and communication*, we take the existing Swiss electricity and gas supply sectors as a proxy for the green hydrogen sector [211]. In Switzerland, hydrogen is currently not subjected to federal taxes or subsidies [166, 196]. However a value added tax (VAT) of 7.7% is applied on the the selling price paid by the consumer [69]. This VAT is assigned to the final demand satisfied by the green hydrogen industry. Further, for a 1 MW green hydrogen industry, it is assumed that 2 full-time equivalents (FTE) are employed, considering 1 FTE, 0.5 FTE and 0.5 FTE for the 1 MW_{el} electrolyzer plant, hydrogen transportation, and for maintenance and supervision of a refuelling station respectively [343]. This would result in added value (aggregated salary) of 230,000 USD per annum (assuming 115,000 USD/FTE/year [343]).

5.3.2 Switzerland hydrogen demand scenario for transportation sector

The net-zero emissions scenario (ZERO) under the Swiss Energy Perspectives 2050+ (EP 2050+) [259] represents a future evolution of the energy system in which climate neutrality along with a secured energy supply is achieved by 2050. The ZERO scenario includes different variants (Zero A, Zero B, Zero C) considering different combinations of technologies and the acceleration of renewable penetration in the electricity sector [259]. In Table 5.3, we report the results for the ZERO basis (baseline) scenario according to the EP 2050+. In this study, we model the total hydrogen demand in 2035, as the change in final demand to study the gross and net impacts from the green hydrogen industry in Switzerland. The hydrogen demand for 2050 has not been modelled using the latest (2017) model, since 2050 is very far in time and the accuracy of model would decrease over time, given various factors, such

Table 5.2: Inputs from different industries for the operational phase of green hydrogen industry.

Input components needed from different sectors for Operation & Maintenance of 1 MW green hydrogen system	OPEX (USD/year)	Reference	Industry Name	Swiss NOGA code [234]
Water	3'991	[53, 346]	Water supply, other sewage and refuse disposal etc.	39
RoR hydroelectricity	629'495	[53, 346]	Electricity, gas, steam and air-conditioning supply	35
O&M - Electrolyzer & distribution system	90'643	[53]	Repair and installation of machinery and equipment	33
O&M - Hydrogen truck trailers for transporting hydrogen	18'144	[274]	Manufacture of motor vehicles, trailers and semi-trailers	29
Fuel (diesel/hydrogen) for hydrogen truck trailers	15'424	[274]	Diesel used for transportation is mostly imported Also produced by refineries in Switzerland but mostly self-consumed	
Construction (Maintenance)	53'101	From electricity & gas sector	Construction	41 - 43
IT service sector	15'000	From electricity & gas sector	IT and other information services	62 - 63
Financial services	16'500	From electricity & gas sector	Financial services	64
Insurance and pension funding services	35'000	From electricity & gas sector	Insurance and pension funding services	65
Legal, accounting, management, architecture, engineering services	80'000	From electricity & gas sector	Legal, accounting, management, architecture, engineering services	69-71
Administrative and support services	60'000	From electricity & gas sector	Administrative and support services	77-82
Land rent/lease	15'000	[171]	Rental and leasing activities	77
Communication	1'500	From electricity & gas sector	Publishing, audiovisual and broadcasting activities	58 - 60
Telecommunications	3'500	From electricity & gas sector	Telecommunications	61
Total	1'037'298			

as advancement in technologies, government policies, changing consumer preferences etc.

Table 5.3: Hydrogen demand by passenger cars, light-duty vehicles (LDV) , heavy-duty vehicles (HDV), coaches and buses as per the net-zero (ZERO basis) scenario of Swiss Energy Perspectives 2050+. Shares estimated based on [314, 31]

Transportation type	2035 Hydrogen demand in PJ (%)	2021 Petrol and diesel demand in PJ (%)
Passenger cars	1.27 PJ (38%)	141.9 PJ (71%)
LDV + HDV + coaches + buses	2.08 PJ (62%)	57.3 PJ (29%)
Total	3.35 PJ (100%)	199.2 PJ (100%)

5.3.3 Balancing of updated I-O table

After the addition of the green hydrogen sector to the existing I-O table, the updated I-O table needs to be re-balanced to ensure that the total input (addition of various columns) is equal to the total output (addition of all rows). Several methods have been reported in the literature for balancing I-O tables, with the two popular methods being RAS and constraint optimization. The RAS adjustment is an iterative process in which columns and row elements are scaled and rescaled within the given constraints, in order to respect the equality of the totals of all rows and of all columns [357, 362, 318, 14]. However, one of the major limitations of the RAS method is that it can only handle matrices with non-negative elements [270, 318, 14]. This problem is solved by the Generalized RAS (GRAS) method, which can be used for balancing I-O matrices including both positive and negative elements. Another advantage of GRAS is that this iterative approach can easily be applied with widely available programming languages such as R and MATLAB®. Therefore, in this study, we use the GRAS method in MATLAB® developed by Umed

et al. for balancing the updated I-O table with the newly added green hydrogen industry [341, 340].

5.3.4 Impact analysis for GDP, employment and GHG emissions

The I-O method [349] is used to calculate the change in GDP, employment and emissions due to construction (year 0) and OPEX (from year 1 till 15) of a green hydrogen industry. The Leontief inverse matrix (P) represents the amount of gross (direct and indirect) output from industry i that is produced to satisfy a unit of final demand from industry j and is calculated using Eqn. 5.1 [359]. Here, I is the identity matrix and A represents the coefficient matrix representing shares of intermediate demand of domestic goods and services in total supply.

$$\begin{aligned} P &= I + A + A^2 + A^3 + A^4 + \dots \\ P &= (I - A)^{-1} \end{aligned} \quad (5.1)$$

Using Eqn. 5.2, the vector of change in output (ΔX) due to the change in final demand (column vector (ΔF)) is calculated by multiplying the Leontief inverse matrix (P).

$$\Delta X = P \cdot \Delta F \quad (5.2)$$

For a given macroeconomic indicator (e.g., employment), we define a technical coefficient (γ_i), as shown in Eqn. 5.3:

$$\gamma_i = q_i / x_i \quad (5.3)$$

where, q_i is the total value of the indicator for industry i , and x_i represents the total output per industry i .

Further, the multiplier matrix for a given macroeconomic indicator ($\hat{\Gamma}$) is constructed by multiplying the diagonal matrix of technical coefficients (Γ) with the Leontief inverse matrix (P) using Eqn. 5.4. The multipliers provide information on the impact of an industry sector on the other economic sectors.

$$\hat{\Gamma} = \Gamma \cdot P \quad (5.4)$$

where, Γ is represented by

$$\Gamma = \begin{bmatrix} \gamma_1 & 0 & 0 \\ 0 & \ddots & 0 \\ 0 & 0 & \gamma_n \end{bmatrix}$$

Finally, the change in quantity of a given macroeconomic indicator is estimated by multiplying $\hat{\Gamma}$ with the change in final demand vector (ΔF) as presented in Eqn. 5.5.

$$\Delta Q = \hat{\Gamma} \cdot \Delta F \quad (5.5)$$

The three macroeconomic indicators calculated in this study are GDP, employment and emissions. We calculate GDP as a sum of value-added and NCT from

the I-O table [359]. For employment data (FTE) per industrial sector, the source STAT-TAB (self-tabulation tool) from the Swiss Federal Statistical Office is used [312]. Finally, GHG emissions (ktCO_{2eq}) per industry are also obtained from the Swiss Federal Statistical Office [8] (Appendix D section D.4).

Impact indicators

Broadly, the macroeconomic implications of a green hydrogen industry in terms of gross and net impacts comprise (i) direct impacts and, (ii) indirect impacts. Direct impacts occur in economic sectors that supply goods and services directly to the green hydrogen industry. For instance, employment or emissions generated in the industry sector providing direct input to the green hydrogen industry. In contrast, indirect impacts represent upstream multiplier effects on industry sector that supply goods and services for intermediate consumption. We define total impacts as the sum of the direct and indirect impacts due to the deployment of the new green hydrogen industry.

In this study, gross impacts related to the green hydrogen industry include both the construction and operational phase. While this gives useful information regarding the overall impact on the economy, it does not allow comparison with incumbent energy/fuel source. Therefore in addition to calculating the gross impacts, we also calculate the net impacts considering the replacement of diesel by green hydrogen as a fuel for passenger cars driven by the change in final demand. For the gross and net impact analysis, it is assumed that all the produced green hydrogen is demanded as a fuel by passenger cars (final demand by households). Further, we account for the different energy content based on the lower heating value, useful energy (considering the efficiency of final demand), and costs per unit of hydrogen and diesel to compare the two fuels on a common scale (given in Table 5.4). For example, 1 kg of hydrogen has the same energy content as around 3 kg of diesel.

In this study, we analyse three cases comparing green hydrogen and diesel on the basis of fuel energy content (kWh), useful energy (kWh), final demand change (USD). We then calculate the corresponding changes in the GDP (USD), employment (FTE jobs), and emissions (kgCO_{2eq}). The first case ‘Equal Cost’ represents a situation where final consumers (or households) have a fixed budget to spend for transportation fuel and are willing to spend equal money on green hydrogen as on diesel. The second case ‘Equal Energy’ considers the fact that both hydrogen and diesel have different energy content, which means that for the equivalent amount of fuels, hydrogen delivers more energy compared to diesel. Finally, the ‘Equal Service’ case assumes the same useful energy (also known as traction/energy at the wheels) considering the higher conversion efficiency of a fuel cell engine (50%) compared to the diesel combustion engine (30%). Here, the households is willing to pay more for hydrogen to travel the same distance as before when using diesel. Both in the ‘Equal Energy’ and the ‘Equal Service’ case, the households compensate the additional spending on hydrogen (because of its high cost compared to diesel) by spending proportionally less money on other goods and services.

Table 5.4: Technical and cost assumptions of hydrogen and diesel for net impact analysis [146, 127, 108, 224]

Fuel	Energy content of fuel (Lower heating value)	Conversion efficiency	Traction (useful) energy	Basic price per unit
Green Hydrogen	33 kWh/kg	50%	16.5 kWh/kg	10.14 USD/kg
Diesel	11.6 kWh/kg	30%	3.5 kWh/kg	1.1 USD/kg

5.3.5 Inter-industry linkage effect

The concept of inter-industry linkages was established by Hirschman in 1958 [139] and has been studied since then to identify key industries that are central for economic development. In this study, we use the I-O method to assess the new green hydrogen industry and its placement in the economic system by carrying out the linkage effect analysis. An industry linkage effect can be measured by backward and forward linkages [223]. The change in final demand of a given industry, j by one unit, changes the output of all other industries whose goods are used as inputs for production in the given industry sector, j . This effect is called as backward linkage BL_j and is defined by Eqn. 5.6, where n is the number of industries, and $\sum_i P_{ij}$ is the sum of the column elements in the Leontief inverse matrix $P=(I-A)^{-1}$. On the contrary, the forward linkage indicates the connection of an industry to its users, i.e. the output from industry, j , which is available as supplies for use by other industries in their production. The forward linkage is defined in Eqn. 5.7 where n again is the number of industries, and $\sum_j P_{ij}$ is the sum of the row elements in the Leontief inverse matrix P . In summary, forward linkage measures the change in the production of industry i , driven by a unit change in the final demand for all industries. The industries with high BL and FL (≥ 1) have higher economic growth potential [223].

$$BL_j = \frac{\frac{1}{n} \sum_i P_{ij}}{\frac{1}{n^2} \sum_{ij} P_{ij}} \quad (5.6)$$

$$FL_i = \frac{\frac{1}{n} \sum_j P_{ij}}{\frac{1}{n^2} \sum_{ij} P_{ij}} \quad (5.7)$$

The results of the backward and forward linkage can be classified into four categories as presented in Table 5.5. For instance, (I) means that the given industry is overall independent of (not strongly connected to) other industries (both linkage measures less than 1) whereas category (IV) represents an overall dependence on (a connection to) other industries (both linkage measures are greater than 1).

Table 5.5: Classification of Backward and Forward Linkage results

		Forward Linkage	
		Low (<1)	High (>1)
Backward Linkage	Low (<1)	(I) Overall independent	(II) Dependent on inter-industry demand
	High (>1)	(III) Dependent on inter-industry supply	(IV) Overall dependent

5.4 Results

The results of our I-O analysis are structured in five sections. Section 5.4.1 describes the expenditure incurred across different industries to provide goods and services for the construction of a new green hydrogen industry as well as the associated GDP, employment and emissions multipliers. Section 5.4.2 presents and compares the gross impacts from the construction and operational phases, whereas the net impacts considering replacement of diesel by green hydrogen fuel for passenger cars under three different scenarios are showcased under section 5.4.3. We further upscale the gross and net impacts results to the Swiss level for the ZERO basis (baseline)

2035 scenario of the Swiss EP 2050+ [259] (section 5.4.4). Finally, section 5.4.5 presents the findings of the inter-industry linkage effect analysis.

5.4.1 Initial expenditure and key multipliers of the construction phase

The expenditure incurred across different industries in the construction phase of a new green hydrogen industry (including production, transportation and refuelling stations) is summarized in Table 5.1. The total expenditure (producer prices) incurred in the construction (capital formation) of a 1 MW green hydrogen industry in Switzerland is around 4.70 M USD (see Table 5.1). After the deduction of NCT from the expenditure incurred per industrial sector (totalling to 31'173 USD), we obtain the final demand at basic prices amounting to 4.67 M USD. Fig. 5.3 shows that the majority of the expenditure during the construction phase is spent in procuring the machinery and equipment (such as electrolyzer system including the stack and BoP, compressor, refuelling stations etc.), accounting for 85% of the total expenditure. Table 5.6 gives the GDP, employment and emissions multipliers of each industrial sector involved in the construction phase. The multipliers describe the impacts resulting from a unit change in the output of a given industry. Among the industries, *construction* sector has the highest emission multiplier (68.2 tCO_{2eq}/M USD) and the second highest GDP and employment multipliers.

Table 5.6: GDP, employment and emissions multipliers of key industries involved in the construction phase of the green hydrogen industry.

NOGA code	Industry name	GDP multipliers (USD/USD)	Employment multipliers (FTE/M USD)	GHG emissions multipliers (tCO _{2eq} /M USD)
27	Manufacture of electrical equipment	0.47	2.84	24.48
28	Manufacture of machinery and equipment n.e.c.	0.50	3.02	16.28
29	Manufacture of motor vehicles, trailers and semi-trailers	0.07	0.43	1.95
41 - 43	Construction	0.79	6.66	68.27
62 - 63	IT and other information services	0.58	2.98	6.79
73 - 75	Other professional, scientific and technical activities	0.85	6.84	21.31

The second, third and fourth bars in Fig. 5.3 represent the contributions (in percentage) of the various industries to GDP, employment and emissions during the construction phase, which are calculated by multiplying the sector specific multipliers with their respective sectoral change in final demand. While *Manufacture of machinery and equipment* sector is responsible for most of the additional GDP (83%), employment (80%) and emissions (77%), Fig. 5.3 shows that the *construction* sector contributes to approximately 14% of the additional emissions. Moreover, about 9% of the newly created jobs fall into the category of *other professional, scientific and technical activities*.

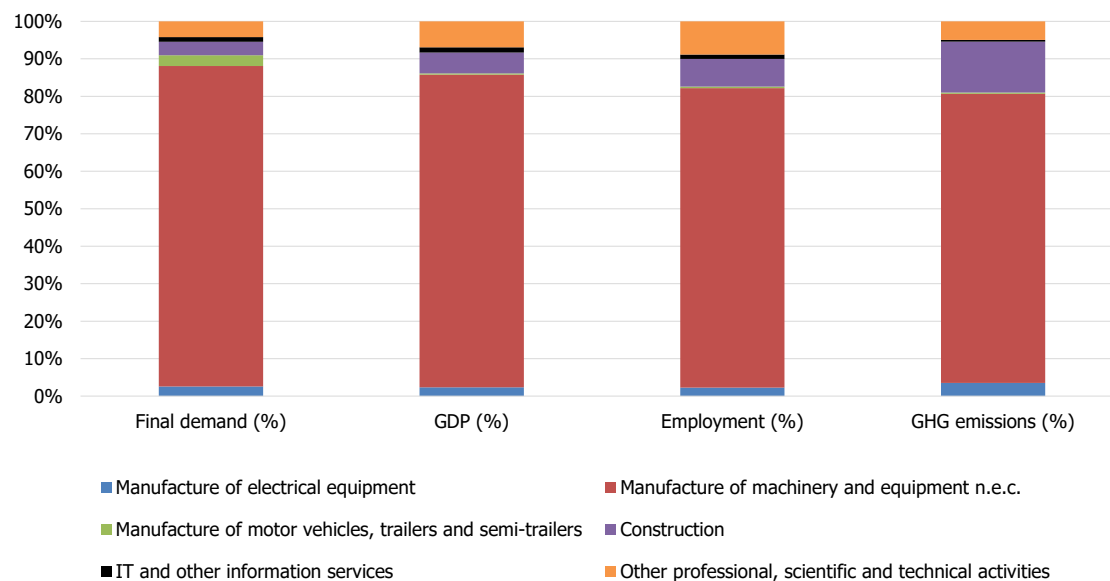


Figure 5.3: Relative share of gross impact on GDP, employment and emissions due to expenditures (change in final demand) in the construction phase of a new green hydrogen industry by type of industry.

5.4.2 Gross impact analysis for construction and operational phases

Table 5.7 shows the results of the gross impact analysis for the construction and operational phases of a 1 MW green hydrogen industry, considering all the produced hydrogen is demanded by the households. We calculate that the investment of 4.67 M USD/MW at basic prices generates 2.40 M USD/MW (out of which 53% is direct and 47% is indirect) of gross GDP by the industries providing goods and services to a new green hydrogen industry in the construction phase. This gross GDP translates to roughly 0.15 M USD/MW/year considering the total lifetime of the project of 16 years (including one year of construction and 15 years of operation). On the contrary, the gross GDP impact created in the operational phase is 0.95 M USD/MW/year (24% direct and 76% indirect).

Further, the gross employment impact due to the construction phase is calculated to be 15.08 FTE jobs/MW (or 0.94 FTE/MW/year), out of which 56% are directly created whereas 44% are created indirectly by the other industries in the value chain. On the other hand, the operational phase contributes 5.96 FTE jobs/MW/year (34% direct and 66% indirect).

Lastly, the emissions generated by the construction of a 1 MW green hydrogen plant are equal to around 84.17 tCO_{2eq}/MW (or 5.26 tCO_{2eq}/MW/year), of which 30% are direct emissions and 70% are indirect emissions. During the operational phase of the plant, the total emissions are around 53.15 tCO_{2eq}/MW/year, corresponding to indirect emissions, while the direct emissions (i.e. use of green hydrogen as transport fuel) are considered zero.

Although the construction of a new green hydrogen industry creates 2.5, 2.5, and 1.6 times more gross GDP, gross employment, and gross emissions compared to the operational phase of producing green hydrogen in one year, respectively, the aggregated operational impact over the lifetime (15 years) is higher than the construction (see Table 5.7). This is well depicted in Fig. 5.4, which shows the

gross impact on GDP, the gross employment, and the gross emissions per 1000 kg of hydrogen produced including both the construction and operational phases of the green hydrogen industry. Here we see that the total gross impacts on GDP, employment, and emissions in the operational phase are 6.0, 5.9, and 9.5 times higher than in the construction phase respectively. The cost of renewable electricity is by far the most important expenditure element in the operational phase of a green hydrogen plant (around 61%).

Table 5.7: Total Gross (direct + indirect) macroeconomic impacts generated due to the construction (Year 0) and operational phase (Year 1 to 15) of a new 1 MW green hydrogen industry.

Macroeconomic indicator	Construction phase (Year 0)	Operation & Maintenance phase (Year 1 to 15)
Gross GDP contribution per installed capacity of green hydrogen industry	2.40 M USD/MW	0.95 M USD/MW/year
Gross employment contribution per installed capacity of green hydrogen industry	15.08 FTE jobs/MW	5.96 FTE jobs/MW/year
Gross emissions contribution per installed capacity of green hydrogen industry	84.18 tCO _{2eq} /MW	53.15 tCO _{2eq} /MW/year

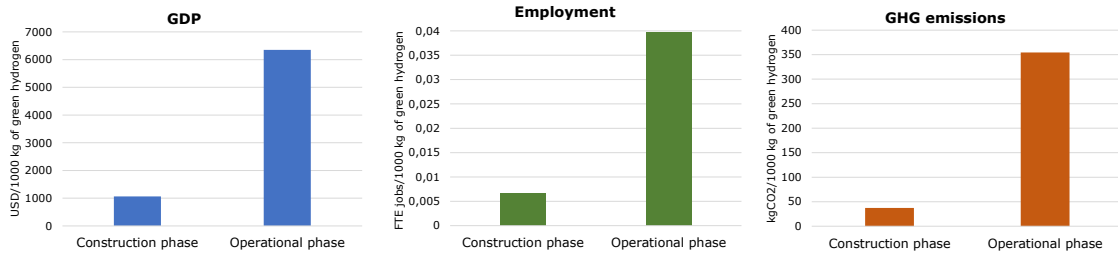


Figure 5.4: Gross impact on GDP, gross employment and gross GHG emissions per 1000 kg of hydrogen due to the construction and operational phases of a new green hydrogen industry.

5.4.3 Net impacts analysis considering replacement of diesel by green hydrogen in passenger cars

In this section, we present the results from the net impact analysis considering replacement of diesel by green hydrogen as a transportation fuel in passenger cars, implying change in final demand or expenditure pattern of households. Fig. 5.5, 5.6 and 5.7 showcase the normalized net impacts on GDP, employment and emissions by comparing the fuel energy content (kWh/kg), useful energy (kWh/kg) and final demand change (USD) of green hydrogen and diesel for ‘Equal Cost’, ‘Equal Energy’ and ‘Equal Service’ scenarios, respectively. For absolute values of net impacts, please refer to Table D.5 in Appendix D. The ‘Final demand change’ bar in Fig. 5.5 refers to spending on hydrogen and on diesel, which is equal in this scenario. In Fig. 5.6, the ‘fuel energy content’ bar is the same, however, hydrogen has a higher conversion efficiency (50%) than diesel (30%, see Table 5.4), resulting in a longer transportation distance. Finally, in Fig. 5.7, the ‘useful energy’ of hydrogen and diesel is the same, which implies the same transportation distance for hydrogen and diesel; the ‘Fuel

energy content' of diesel is higher compared to hydrogen because of the difference in their conversion efficiencies explained above. As illustrated in both Fig. 5.6 and Fig. 5.7, the additional expenditure (final demand change) incurred for green hydrogen is compensated by decreasing the balance of spending on goods and services of other industrial sectors in order to satisfy the new demand for green hydrogen.

Overall, all three cases imply a net positive impact of green hydrogen sector on Switzerland's GDP and employment and a net negative impact on emissions. For instance, Fig. 5.5 shows that the gross GDP generated in the case of green hydrogen is almost twice as high (952'849 USD) as the diesel value (461'763 USD) for an equal amount of spending for fuel (1'251'874 USD). This implies that the GDP generated by green hydrogen is 106% higher than that generated by investing the same amount in the industry producing diesel. Similarly in green hydrogen results in 5.96 gross FTE jobs compared to only 2.27 FTE jobs in the case of diesel (+166%). On the other hand, the gross emissions generated by green hydrogen fuel equal 53.15 tCO_{2eq} compared to 96.71 tCO_{2eq} for diesel. This shows a net decrease in emissions (by 45%) when choosing green hydrogen instead of diesel. These emissions values only refer to the production of the fuels and therefore do not capture the benefit of zero emissions when operating a vehicle based on hydrogen. The above-mentioned results are attributed to high GDP and employment multipliers of green hydrogen compared to diesel (Table 5.8).

Table 5.8: GDP, employment and GHG emissions multipliers of the green hydrogen and diesel industry.

Industry name	GDP multipliers (USD/USD)	Employment multipliers (FTE/M USD)	GHG emissions multipliers (tCO _{2eq} /M USD)
Green Hydrogen	0.76	4.76	42.45
Diesel	0.37	1.81	77.25

For example, the GDP (0.37 USD/USD) and employment (1.81 FTE/M USD) multipliers of *Manufacture of coke, chemicals, and chemical products* industry associated with diesel fuel are lower than GDP (0.76 USD/USD) and employment (4.76 FTE/M USD) multipliers of the *green hydrogen* industry. This suggests that the total net impact of any reallocation of spending away from refined fuels (diesel in our case) to green hydrogen will have a positive impact on the economy. Similarly, the higher emissions multiplier of *Manufacture of coke, chemicals and chemical products* (77.25 tCO_{2eq}/M USD) compared to *green hydrogen* industry (42.45 tCO_{2eq}/M USD) suggests that any spending away from refined fuels (diesel in our case) to green hydrogen will also have a positive impact in terms of net emissions reduction.

Fig. 5.6, which illustrates the case of identical 'fuel energy content' of both diesel and green hydrogen, shows a net increase in GDP for green hydrogen. For example, the gross GDP generated by the green hydrogen industry, in this case, is 28% higher (952'849 USD) compared to the combined gross GDP generated by diesel (143'025 USD) and all other industries (599'302 USD). We see a similar net positive impact also in the case of FTE of jobs created by spending on green hydrogen (43% more FTE jobs created by green hydrogen (5.96 FTE) compared to the total combined jobs created by diesel (0.07 FTE) and other industries (3.48 FTE)). Finally, the total emissions generated by hydrogen (53.15 tCO_{2eq}) are 18% lower than when investing in diesel (29.96 tCO_{2eq}) plus the other industries (35.06 tCO_{2eq}). Lastly, Fig. 5.7 refers to a scenario with the same 'Useful energy' of both diesel and green



Figure 5.5: Net impacts on GDP, employment (FTE jobs) and GHG emissions due to green hydrogen and diesel in the 'Equal Cost' case which depicts equal monetary spending on hydrogen and diesel. The values of all the parameters on the x-axis are normalized with respect to green hydrogen.

hydrogen and it shows similar results as Fig. 5.6 in terms of a net positive GDP and employment, and net emissions reduction by green hydrogen.

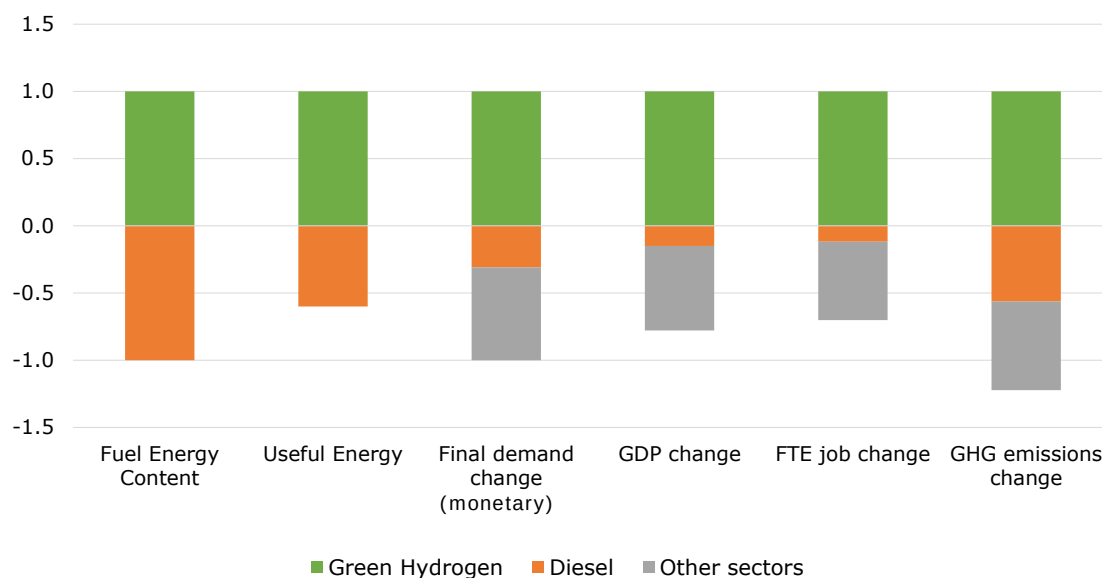


Figure 5.6: Net impacts on GDP, employment (FTE jobs) and GHG emissions due to green hydrogen and diesel in the 'Equal Energy' case which depicts equal energy content of hydrogen and diesel. The values of all the parameters on the x-axis are normalized with respect to green hydrogen.

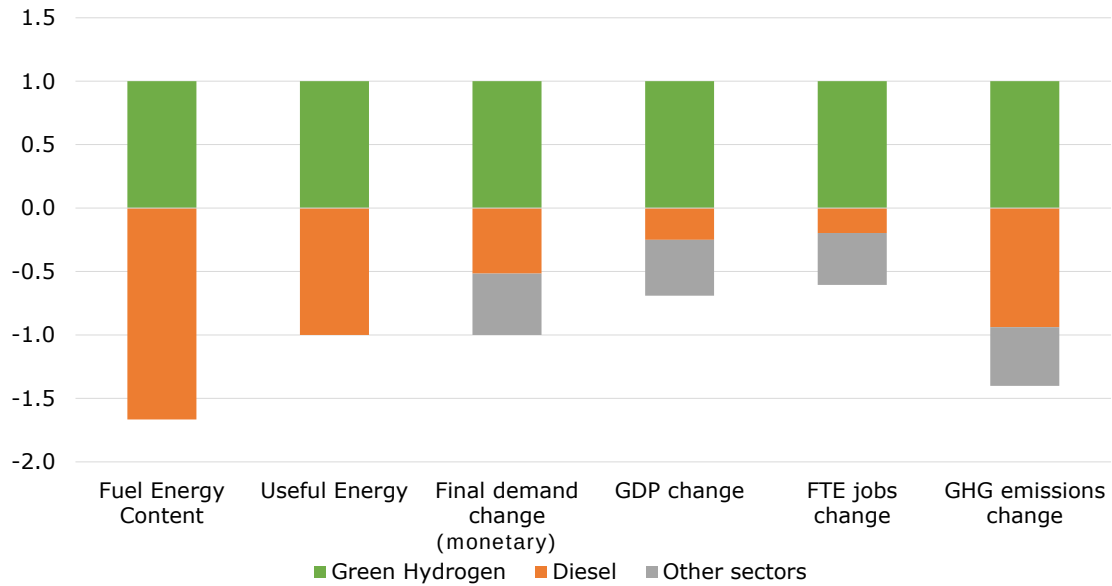


Figure 5.7: Net impacts on GDP, employment (FTE jobs) and GHG emissions due to green hydrogen and diesel in the ‘Equal Service’ case which depicts equal useful energy of hydrogen and diesel. The values of all the parameters on the x-axis are normalized with respect to green hydrogen.

5.4.4 Switzerland hydrogen demand scenario 2035

In this section, we make use of the results from the gross and net impact analysis of a 1 MW green hydrogen industry (presented in Sections 4.2 and 4.3) to estimate the total impacts at the national level. In order to satisfy the total projected hydrogen demand of 3.35 PJ from the transportation sector in 2035 (see section 3.2), 23.3 kilotonnes of green hydrogen are required [259]. This would translate into a production capacity of 155 MW of green hydrogen. Here, we present the macroeconomic impacts (on GDP, employment and GHG emissions) on the Swiss economy for the hydrogen demand targets in 2035 specified under the ZERO basis scenario of EP 2050+.

The total gross (direct plus indirect) GDP, employment and emissions from the construction phase of a 155 MW green hydrogen industry corresponds to 372 M USD, 2’337 FTE jobs and 13’048 tCO_{2eq}. Additionally, the operational phase contributes to a total gross GDP, employment and emissions of around 148 M USD/year, 923 FTE jobs/year and 8’238 tCO_{2eq}/year respectively.

Furthermore, for the net impact analysis, we assume that 100% of the hydrogen in 2035 (i.e. 3.35 PJ) is allocated to the final demand change assuming replacement of diesel by green hydrogen in passenger cars. The results are presented in Table 5.9 which show that the ‘Equal Cost’ case, considering spending 194 M USD on green hydrogen fuel in place of 194 M USD on diesel as a transport fuel, would generate 76 M USD of additional net GDP, 572 net additional FTE jobs and net abatement of 6’753 tCO_{2eq} of GHG emissions. For the ‘Equal Energy’ case assuming equal energy content of hydrogen and diesel, hydrogen would generate 33 M USD of net additional GDP, 275 net additional FTE jobs and 1’839 tCO_{2eq} of net GHG emissions reduction. Finally, in the ‘Equal Service’ case, shifting spending from diesel and other industries to green hydrogen fuel would generate 46 M USD of net additional GDP, 364 net additional FTE jobs, and 3’309 tCO_{2eq} of net GHG emissions reduction.

Overall, in all the three analyzed cases, investment in green hydrogen would lead to a net positive impact on the Swiss economy. The net benefits are small because the projected hydrogen use of 3.35 PJ in 2035 is still very small, representing only 1.7% of today's fuel use for road transport (199.2 PJ in 2021, compare Table 5.3). Under the hypothetical case that today's total fuel use for road transport were replaced by hydrogen, the macroeconomic would be sizable, e.g. with employment effects ranging between 16'635 FTE and 34'532 FTE.

When comparing the results of all three above-mentioned cases, it is evident that the 'Equal Cost' case maximizes the net additional GDP as well as the net additional FTE generated and lead to a net emissions reduction, however the consumer is able to travel only half of the distance now compared to diesel because of the different energy and useful energy content of the two fuels (Table 5.4. Even in the 'Equal Service' case, when the distance travelled is the same (same useful energy for hydrogen and diesel), we see a net positive GDP and FTE jobs, and a net reduction in the emissions.

Table 5.9: Net impacts on GDP, employment (FTE jobs) and GHG emissions due to replacement of diesel by green hydrogen under the Swiss ZERO 2035 scenario for three different cases.

Case 1: Equal Cost						
Industry	Fuel energy content (GWh)	Useful energy (GWh)	Final demand change (M USD)	GDP change (M USD)	Employment change (FTE)	GHG emissions change (tCO _{2eq})
Green Hydrogen	631	316	194	148	923	8238
Diesel	-2038	-611	-194	-72	-352	-14990
Others	0	0	0	0	0	0
Net change	-1406	-296	0	76	572	-6753
Case 2: Equal Energy						
Industry	Fuel energy content (GWh)	Useful energy (GWh)	Final demand change (M USD)	GDP change (M USD)	Employment change (FTE)	GHG emissions change (tCO _{2eq})
Green Hydrogen	631	316	194	148	923	8238
Diesel	-631	-189	-60	-22	-109	-4643
Others	0	0	-134	-93	-539	-5434
Net change	0	126	0	33	275	-1839
Case 3: Equal Service						
Industry	Fuel energy content (GWh)	Useful energy (GWh)	Final demand change (M USD)	GDP change (M USD)	Employment change (FTE)	GHG emissions change (tCO _{2eq})
Green Hydrogen	631	316	194	148	923	8238
Diesel	-1052	-316	-100	-37	-181	-7738
Others	0	0	-94	-65	-378	-3808
Net change	-421	0	0	46	364	-3309

5.4.5 Analysis of Inter-industry linkage effect

Fig. 5.8 shows the backward and forward linkage effects of all 50 industries in Switzerland including green hydrogen. The pattern shows the impact of ‘economy push’ and ‘economy pull’ in determining the positioning of an industry sector within the economy. First, we see that the backward linkage effect of a new green hydrogen industry is greater than one. This implies that the green hydrogen industry has a larger impact in terms of investment expenditures on the national economy than other industries. It means that the green hydrogen industry would play an important role in supporting/boosting other production sectors and supporting the national economy. Second, the forward linkage effect of the green hydrogen industry is smaller than one, which means that the green hydrogen industry is less stimulated by overall industrial growth than other sectors when economic activities are booming. In other words, green hydrogen industry is not influenced much by business fluctuations and would be a net contributor to the Swiss economic growth, provided that it can rely on domestically produced equipment, as assumed throughout this work. The *Electricity, gas, steam and air conditioning supply* sector shows a higher forward linkage implying larger impacts from economic fluctuations.

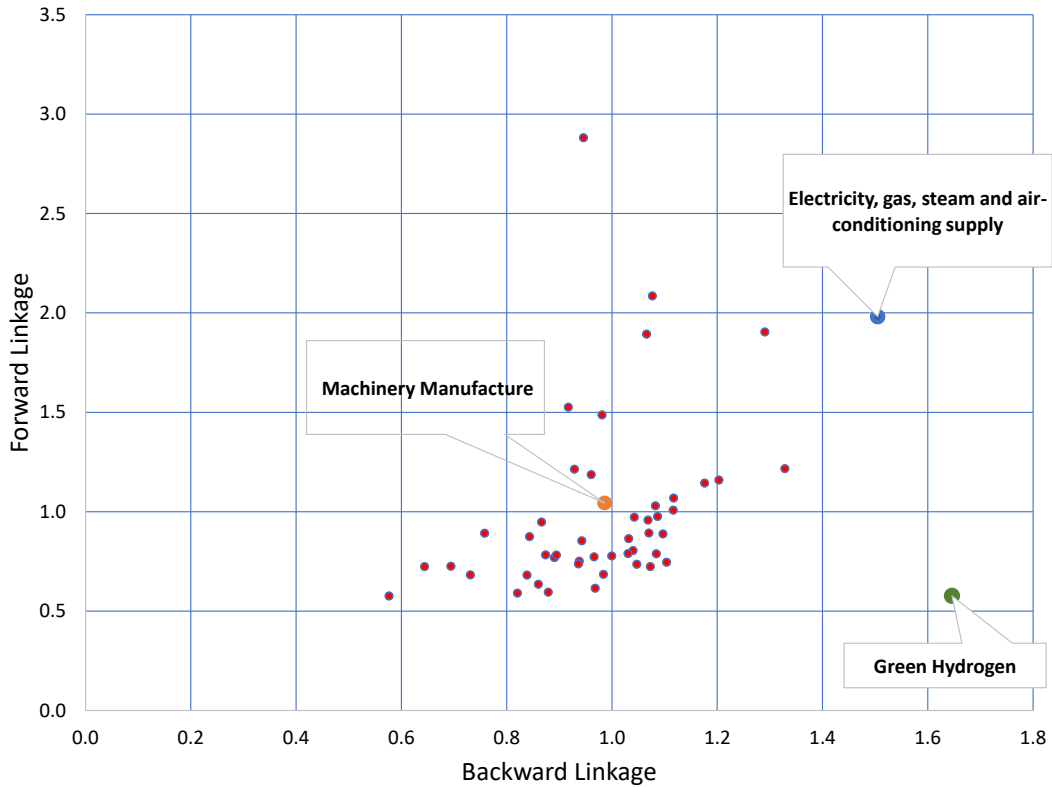


Figure 5.8: Sectoral/Inter-industry linkage patterns of all industry sectors in Switzerland including the new green hydrogen industry highlighted in green colour.

5.5 Discussion

In this chapter, we analyze the gross macroeconomic impacts (both direct and indirect) of a new green hydrogen industry on Switzerland's GDP, employment, and GHG emissions for both the construction and operational phase. We find that the construction phase creates a more direct impact on the above macroeconomic indicators, whereas the operational phase creates a more indirect impact on the associated industry sectors providing goods and services across the green hydrogen production value chain. Based on our calculations, the *Manufacture of machinery and equipment* industry has the highest contribution in terms of GDP and FTE jobs in the construction phase since it incurs around 85% of the total capital expenditure. Therefore, from a macroeconomic perspective, it is recommended to focus on/promote domestic manufacturing of machinery and other equipment such as electrolyzers and compressors in order to maximize the positive impact on the economy. It should be kept in mind that our analysis is based on the assumption that all key components of the hydrogen economy (electrolyzer system, hydrogen compressor, etc.; see Table 5.1) are manufactured in Switzerland. If part of the machinery is imported from abroad, the final demand change and hence the GDP, FTE jobs, and emissions generated would decrease proportionately (see table D.3 in Appendix D).

Most commonly in the literature, the emissions from green hydrogen fuel are considered to be zero. This mostly refers to the Scope 1 emissions^d. However, Scope 2^e, and mostly importantly, Scope 3 emissions^f are more difficult to measure. Here, we provide the overall emissions to analyse the footprint of green hydrogen throughout its value chain, and we find that the CO_{2eq} emissions of the green hydrogen industry are found to be higher than zero (see Results section 5.4). This is because the green hydrogen industry is dependent on a number of industries for its operation, which in turn are dependent on other industry sectors, all of which use fossil fuels to a significant extent. While the use of green hydrogen as a transport fuel does not lead to greenhouse gas emissions, a fair comparison with diesel use requires that the emissions related to combustion (around 2.68 kgCO₂/kg diesel [45]) are taken into account. If we also account these tailpipe emissions associated with diesel consumption, our Input-Output model shows that green hydrogen leads to a net reduction of around 96.4% of GHG emissions compared to diesel.

The results of the net impact analysis considering change in final demand show that green hydrogen leads to a net increase in GDP and employment and a net decrease in GHG emissions, regardless of the scenario, in comparison with the use of diesel as a transport fuel in passenger cars. However, the still high price of green hydrogen (around 10 USD/kg [393]) remains a key challenge for hydrogen use as fuel in cars, resulting in considerably higher spending for potential consumers. This directly translates to the fact that spending more on green hydrogen by households would mean extra costs and/or shifting spending from other sectors. On the other hand, increasing diesel prices would further add to the business case for green hydrogen in terms of positive macroeconomic impacts. For instance, the sensitivity analysis shows that doubling the price of diesel while assuming that the green hydrogen price remains constant (as considered), would double the net GDP and net FTE jobs and would double the net reduction in GHG emissions.

^dScope 1 emissions are all direct GHG emissions [4].

^eScope 2 emissions are indirect emissions from the generation of purchased energy [4].

^fScope 3 emissions are all indirect emissions (not included in scope 2) that occur in the value chain of the reporting entity[4].

In light of the ongoing Ukraine war, there has been turmoil in the global energy markets with Europe being the epicenter. Less dependency on fossil fuels and increased energy security would call for a diversification of the energy mix. Green hydrogen is well placed to contribute to improved energy security by providing a medium-term opportunity to reduce demand for fossil fuels. However, at the same time, the high targets for green hydrogen imply the need for more surplus renewable electricity which is currently limited [290]. Additional demand of renewable energy capacity would imply additional CAPEX, which needs to be considered in the construction phase. Further, the gradual withdrawal of nuclear electricity (35% of the total electricity produced) in Switzerland along with rapid electrification of the heating and transportation sectors is likely to create more pressure on the Swiss electricity system. While this situation calls for more imports of renewable electricity from neighbouring European Union countries, these are also currently facing electricity shortages. This creates a trade-off for green hydrogen production and needs attention while designing the near and long-term energy independence strategy.

This chapter highlights important positive impacts of a new green hydrogen industry at the national level from a macroeconomic and environmental perspective and discusses some important implications considering the current energy crisis, but it is not without limitations. This study relies on the Input-Output method to assess the macroeconomic impacts of the economy as a whole. However, for detailed emissions analysis, other methods such as life cycle assessment are more suitable. We use the latest available Input-Output table (2017) to assess the impact of future scenarios proposed under the Swiss Energy Strategy. Yet, the 2017 Input-Output table does not take into account the economic impacts of COVID-19 and the ongoing Ukraine war. Further, we assume no imports of goods and services nor exports of green hydrogen. This is done to assess the impact of a new green hydrogen industry with all its goods and service produced and used within the country, i.e. to set the best scenario. However, given the globalized nature of current energy and technology markets, reality may be different with several goods and services being imported/exported to/from Switzerland. Further, only the transportation sector is considered as the demand sector for green hydrogen, which makes it fragile to demand shocks. This is because, in Switzerland, the use of green hydrogen is earmarked for use by the transport sector. Furthermore, the results presented in this study are dependent on the assumptions and country-specific data. For example, the impacts would change depending on the cost of renewable electricity/other components, as well as the demand for hydrogen by other sectors. Yet, the tool developed for this study could be used for sensitivity analysis, as more actual data on green infrastructure cost and demand is made available. Finally, in this study we presented the net impact analysis considering only the replacement of diesel by green hydrogen in passenger cars. This is because the Input-Output model is typically used by assuming exogenous changes to final demand (e.g. household expenditure) and using respective multipliers to estimate the direct and indirect impacts. Commercial transport services are part of the supply chain and the economic interactions are reflected by intermediate demand of an Input-Output model. However, simulating changes in the intermediate demand that affect multiple sectors becomes challenging because changes in one sector can have a ripple effect across intermediate demand of other sectors. In addition, the transition to hydrogen trucks for transporting goods is likely to increase the costs of intermediate and final products depending on their elasticity, but the extent of the price increase is not known. Therefore, studying the impact due to changes in intermediate demand is not straightforward

using Input-Output method, and some other macroeconomic methods such as computable general equilibrium models or dynamic stochastic general equilibrium may be a better solution.

5.6 Conclusions and policy implications

Green hydrogen is currently the focus of numerous decarbonization plans and accelerating initiatives across the economy and is expected to play a key role in decarbonizing the hard-to-abate economic sectors such as transport. In this chapter, we analyze the macroeconomic impacts of a new green hydrogen industry, including both the construction and operation phases, at a country level. We develop an Input-Output model by adding a new green hydrogen industry to the existing Input-Output table of Switzerland. The Input-Output model provides a simplified representation of a country's economy and facilitate the understanding of complex direct and indirect supply chain impacts allowing to establish multiplier effects. In this study, we use country-specific data from Switzerland, however, the model can easily be replicated for any other country by using their country-specific data.

The objective of the study is to compare the gross macroeconomic impacts generated by the construction and operational phase of a green hydrogen industry and the net impacts assuming the replacement of diesel by green hydrogen as a transportation fuel in passenger cars. According to the results of our gross impacts analysis, the total gross impacts on GDP, employment, and emissions in the operational phase are 6.0, 5.9, and 9.5 times for the operational phase (15 years) compared to the construction phase. Considering the effects of both the operational phase and the construction phase, an additional GDP of 7'418 USD, 0.064 additional FTE jobs, and 392 kgCO_{2eq} additional GHG emissions per 1000 kg of green hydrogen produced is generated (Fig. 5.4). Importantly, shifting the spending on green hydrogen in place of diesel for households has a net positive impact on GDP and employment and a net negative impact (reduction) in GHG emissions across three different cases, namely 'Equal Cost', 'Equal Energy' and 'Equal Service'. For instance, for the 'Equal Service' case, we find that the green hydrogen industry generates nearly 45% higher GDP, 65% more jobs, and 29% lower emissions when shifting spending from diesel and other industries to green hydrogen. This positive impact is explained by a relatively higher employment and GDP multiplier and a relatively lower emissions multiplier of the green hydrogen industry compared to the industry producing diesel. The fact that spending on hydrogen as a transport fuel more than compensate the losses resulting from reduced demand for diesel is an element that should receive particular attention of the policymakers in view of the development of the future energy system. It can be argued that passenger cars do not represent a hard-to-abate sector because battery-driven electric vehicles represent a viable alternative. While it would therefore be more adequate to conduct the analysis for heavy-duty trucks, the limitations of Input-Output modelling for intermediate supply (i.e., freight) made us analyze passenger cars (for more details see discussion section). It could be argued that an analysis for heavy duty transport would show similar interactions and would result in similar findings as established for passenger cars. However, this should be further studied by a more advanced version of the Input-Output model used for the present paper and/or by developing other approaches.

Overall, our study shows that the establishment of a green hydrogen industry

has a net positive impact on the economy. Since renewable electricity represents the most significant cost factor in the operational phase of green hydrogen, policy support for a more rapid deployment of renewable sources of energy would become essential to bring down the cost of hydrogen. Furthermore, as reflected in the discussion section, domestic manufacturing of machinery and equipment during the construction phase of a green hydrogen industry would contribute to 83% and 80% of the gross GDP and employment, respectively. Therefore, policymakers should focus on creating a framework encouraging investments in domestic manufacturing of machinery, specifically electrolyzers.

However, it should be noted that from the viewpoint of achieving the net-zero targets, creating a green hydrogen industry is not a universal cure for achieving global decarbonization. There are indirect emissions along the value chain as presented in this study and therefore it is important to keep decarbonizing other key industries which have relatively high emissions multipliers such as the construction sector. Finally, our study, which is focused on Switzerland, provides an important policy message for the decision-makers who are designing hydrogen strategies: investing in green hydrogen does not only reduce carbon dioxide emissions, it also has net positive impacts on GDP and employment and their significantly reduced GHG emissions, under the assumptions made in the study. This conclusion calls for similar studies in other countries, as well as uptake of national green hydrogen industries across the globe.

Chapter 6

Conclusions

6.1 Summary

This thesis contributes to the existing literature by analyzing different flexibility options and sector coupling strategies to support the energy transition, encompassing both renewable generation and the urgent need to decarbonize various demand sectors. In this thesis, key flexibility options, i.e. energy storage technologies and grid reinforcement have been studied as well as sector coupling, i.e. the direct use of renewable electricity in the demand sectors, via electricity or green hydrogen. The studies presented in Chapters 2-5 showcase various methodologies and models developed in this thesis, whose results are used to answer the key research questions (RQ) posed in the introduction of this thesis for each chapter.

Chapter 2 on Solar photovoltaics and wind supported by storage technologies to supply firm electricity poses 3 key research questions on how different energy storage technologies can be combined with intermittent solar PV and wind power to supply firm electricity by forming flexible hybrid systems:

Research question 1

What are the best-suited energy storage technologies that can complement solar PV and wind power to supply firm electricity under different supply modes and scales of deployment?

Research question 2

What are the implications of different mixes of solar PV and wind on the levelized cost of electricity supply?

Research question 3

How do levelized costs of hybrid systems compare with conventional supply technologies (e.g., gas, hydro and nuclear)?

To answer these questions, a method to simulate the performance of hybrid systems (i.e. a system both renewable and storage technologies) and calculate their levelized cost was developed. This allows to identify the best-suited energy storage

technologies that can support solar PV and wind power to supply firm electricity depending on the supply mode (defined set of hours in a day at firm capacity) and scale of deployment (residential, utility and bulk). It also enables comparison of renewable hybrid systems with conventional power generators on a levelized cost basis.

The proposed results answer RQ 1 aiming at identifying hybrid systems offering the lowest levelized cost for different supply modes and scales. It is shown that pumped hydro storage and isothermal-compressed air energy storage are the most cost-effective storage technologies to support wind systems at the bulk (0.15-0.18 EUR/kWh) and utility (0.20-0.55 EUR/kWh) scales respectively. For the solar PV hybrid systems, pumped hydro storage is the most optimal storage technology for the bulk scale (0.13-0.18 EUR/kWh), whereas Li-ion batteries are more cost-effective for the utility (0.17-0.36 EUR/kWh) and residential (0.39-0.77 EUR/kWh) scales. Further, it is concluded that the optimal choice for a hybrid system depends on the scale of deployment rather than the supply mode strategy, and that irrespective of the scale of deployment (residential, utility or bulk), providing firm supply via the ‘Generation’ supply mode always offers the lowest levelized costs for all combinations of renewable hybrid systems.

Furthermore, to answer RQ 2, both wind and solar PV technologies were combined with various energy storage technologies at the bulk scale to evaluate the cost optimal solution for each supply mode at the national level. The results reveal that for ‘Generation’, ‘Generation & Peak’ and ‘ToD’ supply modes, solar PV in combination with pumped hydro storage is the optimal hybrid system (0.13-0.18 EUR/kWh, depending on the supply mode). However, for ‘Bi-peak’ and ‘Baseload’, 50% wind & 50% solar PV with pumped hydro storage offers the lowest levelized cost (0.17 EUR/kWh for ‘Bi-peak’ and 0.15 EUR/kWh for ‘Baseload’).

Finally for RQ 3, it is showcased that the levelized costs of renewable hybrid systems (minimum 0.13 EUR/kWh) are still high compared to the generation costs of natural gas combined cycle (average levelized cost of 0.10 EUR/kWh in Switzerland), large hydro (average levelized cost of 0.07 EUR/kWh in Switzerland) and nuclear (average levelized cost of 0.046 EUR/kWh for the existing plants in Switzerland and 0.069 EUR/kWh for the newly built plants outside Switzerland). Following the war in Ukraine, the median electricity prices for households and small and medium enterprises in Switzerland increased by around 27% and 24% in 2023 compared to 2022 respectively [82].

Chapter 3 on Distribution grid capacity and costs to enable massive deployment of PV, electric mobility and electric heating answers the following 3 key research questions by conducting a spatial analysis of distribution grid capacity and of the level and cost of reinforcement needed to enable integration of increasing shares of rooftop PV, heat pumps and electric vehicles charging into the power system:

Research question 4

What are the impacts of massive deployment of PV, HP and EV charging and their combinations on the distribution grid?

Research question 5

How do the grid reinforcement costs vary as a function of technology and type of urban setting and which other factors does this depend on?

Research question 6

What is the potential of battery storage as an alternative flexibility option to defer grid reinforcement?

In order to answer RQ 4, a GIS-based spatial model was developed to first assess the potential of rooftop PV, heat pumps and electric vehicles charging infrastructure in Switzerland, and then to build scenarios for their future penetration in 2035 and 2050. Using a detailed distribution grid model in collaboration with a distribution system operator, we find that solar PV leads to 18.5% and 13.7% more voltage violation issues compared to heat pumps and electric vehicles, respectively, which on the other hand, cause slightly more line overloading than solar PV, 0.5% and 2.5%, respectively.

In response to RQ5, we found median specific grid reinforcement costs ranging between 51-213 CHF/kWp, 46-1385 CHF/kW and 34-143 CHF/kW for deployment of rooftop PV, electric heat pumps and electric vehicles, respectively, with the higher limit corresponding to rural areas. The total distribution grid reinforcement costs can amount up to 11 billion CHF until 2050. The total distribution grid reinforcement costs at the regional and national levels are influenced by several factors, such as (i) the capacity of technologies installed vis-a-vis the capacity of the transformer stations, (ii) deployment across rural, suburban or urban areas, (iii) voltage violations and lines overloading, and (iv) the number of transformer stations requiring rebuilding versus those requiring only upgrading.

In addition, the potential of lithium-ion battery storage to defer grid reinforcement is studied, thereby answering RQ 6. An important finding is that even with the current costs, batteries have the potential to defer grid reinforcement in up to 15% of the transformer stations (in particular, for those stations with the highest specific grid reinforcement costs (CHF/kW) across different rooftop PV deployment scenarios). Batteries could also offer other services in stacked business models and/or co-ownership models, under the appropriate regulatory environment.

Chapter 4 entitled Smart power-to-gas deployment strategies informed by spatially explicit cost and value models aims at identifying hotspots for future deployment of power-to-hydrogen and power-to-methane plants across Switzerland by evaluating their profitability based on the comparison between the levelized cost and levelized value of green hydrogen and methane. The following research questions are addressed in this study:

Research question 7

What are the potential hotspots for power-to-hydrogen and power-to-methane plants deployment considering that they should be located, next to renewable electricity generation, a CO₂ source, a gas grid and/or the demand centres?

Research question 8

Which cost reduction targets would ensure the economic viability of a power-to-gas plant?

To answer RQ 7 and RQ 8, a method based on GIS and techno-economic modeling was developed to: (i) compare the levelized cost and levelized value of green hydrogen and power-to-methane across different locations; (ii) identify potential hotspots for their future implementation in Switzerland; and (iii) determine cost reduction targets as well as smart deployment strategies. Based on the results, a roadmap and smart green hydrogen deployment strategies for the mid (2030) and long (2050) term have been developed. The results of the model show that primarily green hydrogen plants directly connected to run-of-river hydropower plants are profitable in Switzerland (the NPV per unit of CAPEX ranges between 2.3–5.6 in 2020, and between 7.5–16.5 in 2050). In the long term (2050), assuming cost reductions by 2050 due to technological progress, a few green hydrogen plants deployed at the demand centers and powered by rooftop PV electricity would also become economically attractive. For synthetic methane, only power-to-methane plants directly connected to run-of-river hydropower plants show profitability for some locations at the moment, while the plants supplied with rooftop PV which are located next to natural gas refuelling stations, next to CO₂ sources, and which are embedded into industrial sites, would remain uneconomical even in 2050. According to a sensitivity analysis, some power-to methane plants located next to CO₂ sources, and next to natural gas stations would become profitable if the CAPEX of PV or electrolyzers decreased by 90% compared to 2020.

Finally, **Chapter 5 focuses on the macroeconomic impacts of a green hydrogen sector using Input-Output analysis.** Here, both direct and indirect impacts, in terms of GDP growth, employment generation and GHG emissions of green hydrogen production in Switzerland were assessed. The key research questions answered in this study are:

Research question 9

What are the gross macroeconomic impacts generated by the construction and the operation phase of the green hydrogen industry?

Research question 10

What are the net macroeconomic impacts due to replacing diesel with green hydrogen as a transportation fuel?

To answer RQ 9 and RQ 10, an input-output model was developed by adding a new green hydrogen industry to the existing input-output table of Switzerland. The model was used to calculate changes in GDP, employment and GHG emissions due to construction (year 0) and OPEX (from year 1 till 15) of a green hydrogen industry. For the gross and net impact analysis, it is assumed that all the produced green hydrogen is demanded as a fuel by passenger cars (final demand by households). The results of the gross impacts analysis show that for each kg of green hydrogen produced, the operational phase creates 6.0, 5.9 and 9.5 times more GDP, employment and GHG emissions respectively compared to the construction phase.

On the other hand, the net impact analysis considering shifting of spending from diesel to green hydrogen in passenger cars shows a net positive impact on Swiss GDP and employment and a net negative impact (reduction) on the GHG emissions. It was found that in all the three cases, namely, *Equal Cost* (same spending in green hydrogen and diesel, *Equal Energy* (same energy content of the two fuels) and *Equal Service* (same travel distance), the green hydrogen industry generates around 106%, 28% and 45% higher GDP respectively; 163%, 43% and 65% more full-time equivalent jobs respectively; and finally 45%, 18% and 29% lower emissions respectively, compared to diesel and other industries.

6.2 Key takeaways and recommendations for policymakers and other stakeholders

A key aim of this thesis is to assist policymakers and other stakeholders in taking informed decisions for building a net-zero energy system. As evident from all the above-mentioned studies, flexibility options such as energy storage technologies and grid reinforcement are playing an important role in integrating renewable and low carbon technologies at different scales. The levelized cost of hybrid systems and the grid integration costs depend on a number of factors such as techno-economic characteristics, geographical location, time of peak demand etc. Therefore, there is no ‘one size fits all’ flexibility solution. What matters to the policymakers and stakeholders is how to make the systems flexible in a cost-effective and smart way. Further, this thesis discusses the potential deployment of green hydrogen in Switzerland by analyzing its role, not only as a energy storage option to help the integration of renewable generation (solar and wind), but also in sector coupling to help decarbonize hard-to-abate sectors. This section presents some key policy recommendations translated from the results of the various studies undertaken as part of this thesis:

Recommendation I:

Renewable energy technologies combined with energy storage technologies to form hybrid systems can offer a promising solution to decarbonize the energy system at the utility and bulk scale. However, the focus should be on bringing down the cost of both renewable energy and storage technologies even further to make them cost competitive compared to conventional energy system supply. For instance, reducing CAPEX of both PV and Li-ion batteries by 60% make the PV & Li-ion hybrid systems at the utility scale competitive with natural gas combined cycle plants for ‘Generation’ supply mode in Switzerland. At the bulk scale, a 60% reduction of the CAPEX of PV alone improves the levelized cost of PV & pumped hydro storage hybrid systems by 34% for ‘Generation’ supply mode, thereby becoming cost-competitive with conventional technologies such as natural gas combined cycle and large hydro. Having said that, it is recognized that the cost of technologies is dependant on a variety of factors including technological advancement, economies of scale etc, which are only partially influenced by policymakers’ decisions.

Recommendation II:

Currently, the rural areas in Switzerland tend to be hotspots for PV installations compared to urban areas, while the specific grid reinforcement costs are remarkably higher in rural areas compared to suburban and urban areas. For example, the median specific distribution grid reinforcement costs vary between 51–213 CHF/kW_p, 46–1'385 CHF/kW and 34–143 CHF/kW for rooftop PV, heat pumps and electric vehicles charging respectively, with the higher limit corresponding to the rural areas. This suggests a need for a policy framework to promote more rooftop PV installations in urban areas first and thereafter progressively expanding to rural areas.

4314

Recommendation III:

Batteries were found to defer grid reinforcement for up to 15% of transformer stations, i.e. those stations with the highest specific grid reinforcement costs. However, the ownership and operation of energy storage is restricted for the distribution system operators under the current regulatory context. The use of batteries as a distribution asset could be further extended by enabling various stakeholders and market actors such as prosumers and aggregators who own energy storage to provide grid services.

4315

Recommendation IV:

The hotspot analysis shows that it is profitable to deploy green hydrogen plants connected to run-of-river hydropower plants for the next 20–25 years. In order to transport green hydrogen from the hydro plants to the demand centers, a dedicated and efficient infrastructure, apart from truck trailers would be needed. In the long term (2050), their deployment at the demand sites such as close to the hydrogen refueling stations and industrial sites supplied by rooftop PV electricity should be further explored, since a few of these locations are expected to become profitable based on the projected cost reduction for electrolyzers and solar PV.

4316

Recommendation V:

The creation of a green hydrogen demand mandate, the implementation of financial incentives as well as availability of surplus and affordable renewable electricity are prerequisites for the accelerated deployment of the green hydrogen sector at the national level.

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Recommendation VI:

The presented mid and long term roadmap provides valuable insights for green hydrogen and power-to-methane plants deployment in Switzerland considering cost reduction targets for rooftop PV, electrolyzer and methanation systems. Further support may be needed to decarbonize the demand centres. Enabling green hydrogen imports could be a possibility, but this would limit the positive macroeconomic impacts for the country.

4318

Recommendation VII:

From a macroeconomic perspective, domestic manufacturing of machinery and other equipment required during the construction phase of a green hydrogen industry contribute to 83% and 80% of the additional gross GDP and employment generated, respectively. Policymakers should focus on creating a framework encouraging investments in domestic manufacturing of machinery, specifically electrolyzers.

Recommendation VIII:

The net impact analysis considering replacement of diesel by green hydrogen as a transportation fuel in passenger cars confirms the net positive impact of the green hydrogen industry on the Swiss economy. This is an important takeaway for policymakers, highlighting not only the environmental, but also the additional economic and social opportunities arising from the deployment of green hydrogen industry in Switzerland.

6.3 Future work

Avenues for future research based on the presented models/methods are underlined in the discussion section of each study (Chapters 2-5). Here, the most relevant ones are summarized. In this thesis, the operation of the renewable energy hybrid systems to supply firm electricity is carried out on a daily basis, i.e. considering day market. In the future work, other time periods (weekly or monthly), could also be studied considering for example, a long-term contract with industrial consumers. Future work can also focus on internalizing externalities, such as social and environmental costs, degradation of assets and other impacts while calculating the levelized costs of renewable energy hybrid systems. This may make some of the hybrid systems cost competitive compared to the conventional energy systems.

Self-consumption of rooftop PV generation for households, EV charging and heat pumps as well as demand side management were not analyzed since the focus of the work was to study the impact on the grid in the extreme scenarios. However, it should be studied how increasing levels of self-consumption or demand side management would reduce the grid impacts and hence the needed reinforcement costs. It would also be important to study the role of Vehicle-to-Grid and smart grid technologies in grid balancing and in influencing reinforcement costs.

For assessing the hotspots for power-to-gas deployment, this thesis assumes an investor perspective, while, it would be relevant for policy making to also assume an energy system perspective. Finally, the import and export of green hydrogen and other components through international trade may also be considered as a option. This will influence the macroeconomic impacts of the green hydrogen sector on the GDP, employment, emissions and other aspects such as supply security and resilience. Moreover, given the limitations of Input-Output models for establishing macroeconomic effects, further advancement of the method (to better represent the hard-to-abate heavy-duty transport sector) and/or the further development of other approaches is recommended. Finally, various methodologies and models developed as part of this thesis have been applied to Switzerland. Further extension of this work to other regions/countries considering region/country specific data and limitations would be worthwhile.

Appendices

Appendix A

Supplementary Information - Solar photovoltaics and wind supported by storage technologies to supply firm electricity

A.1 Data and methods

In this section, we specify the input data for PV and wind power generation as well as the electricity demand (Section 1.1, 1.2 and 1.3).

A.1.1 PV generation

Swiss Federal Office of Meteorology and Climatology (Meteoswiss) has deployed an automatic monitoring network, SwissMetNet comprising around 160 automated measuring stations across Switzerland to measure multitude of weather and climate variables (MeteoSwiss, 2017). In order to calculate the PV generation across Switzerland, we choose one representative city in each canton across the country (Table A.1).

We use global irradiance (with temporal resolution of 10 mins) and outdoor temperature (with 1 h resolution) monitored across these representative cities to model PV generation for each canton and average for Switzerland. The hourly temperature values are resampled to generate 10 mins time series by forward fill from the previous hour matching the one of the model. We simulate PV generation using a standard one-diode model and PV panel input data with a nominal efficiency of 18.6%, representative of the current state of the art [21]. The model also includes a maximum power point tracker system, as is the case of most PV systems, to maximize the output regardless of the environmental conditions. The PV generation is normalized to generation from a 1 kW PV panel. PV panel HIT-N235SE10 manufactured by Sanyo using silicon monocrystalline technology was used to estimate PV generation using the model. Key PV panel parameters assumed for the model are given in Table A.2.

The PV generation is estimated at the cantonal level for the residential and utility scale whereas it is aggregated at the national level for the bulk scale by summing up the total generation at the level of each canton (as per the PV installed capacity in each canton) divided by the total PV installed capacity of all the cantons ((A.1)).

Table A.1: List of representative cities in each canton across Switzerland.

S.No.	Canton Name and Abbreviation	Representative City
1	Zurich (ZH)	Zurich
2	BE (Bern)	Bern
3	LU (Lucerne)	Lucerne
4	UR (Uri)	Altdorf
5	Schwyz (SZ)	Schwyz
6	Obwalden (OW)	Sarnen
7	Nidwalden (NW)	Stans
8	Glarus (GL)	Glarus
9	Zug (ZG)	Zug
10	Fribourg (FR)	Fribourg
11	Solothurn (SO)	Olten
12	Basel-Stadt (BS)	Basel
13	Basel-Landschaft (BL)	Liestal
14	Schaffhausen (SH)	Schaffhausen
15	Appenzell Ausserrhoden (AR)	Herisau
16	Appenzell Innerrhoden (AI)	Appenzell
17	Saint Gallen (SG)	St.Gallen
18	Graubünden (GR)	Chur
19	Aargau (AG)	Wettingen
20	Thurgau (TG)	Frauenfeld
21	Ticino (TI)	Lugano
22	Vaud (VD)	Lausanne
23	Valais (VS)	Sion
24	Neuchâtel (NE)	La Chaux-de-Fonds
25	Geneva (GE)	Geneva
26	Jura (JU)	Delemont

Table A.2: List of parameters used to model a PV system and the value used in this study.

PV panel parameters	Value
Maximum power (W)	235
Voltage at maximum power (V)	43
Current at maximum power (A)	5.48
Open circuit voltage voltage (V)	51.8
Module efficiency (%)	18.6
Temperature coefficient at open circuit voltage (V/K)	-0.13
Inclination	30 degree

$$PV_{\text{National}} = \frac{\sum_{C \in \text{CL}} (PV_{C,t} * IC_C)}{\sum_{C \in \text{CL}} (IC_C)} \quad (\text{A.1})$$

4385 where, C represents the canton within the list of cantons (CL) given in table A.3,
4386 IC_C represents the PV installed capacity in each canton across Switzerland given in
4387 table A.3 and PV_C represents the PV generation from a 1 kW panel in the respective
4388 cantons.

Table A.3: PV installed capacity in each canton across Switzerland (approximate figures up to 2016), NA represents values which are not available. Data collected from the energy departments of the respective cantons.

S.No.	Canton	PV Installed Capacity (MW) (2016)
1	ZH	200
2	BE	208
3	LU	69
4	UR	3.5
5	SZ	11.11
6	GL	4.2
7	SG	114.78
8	AG	111
9	TG	93
10	NW	2.24
11	TI	44.4
12	SO	38.5
13	ZG	7.63
14	SH	14.6
15	GR	46.41
16	VD	59.8
17	VS	67
18	NE	26
19	GE	46.3
20	FR	20.24
21	JU	31.85
22	BL	64.37
23	OW	9.1
24	BS	NA
25	AR	NA
26	AI	NA
	Switzerland Total	1663.92

A.1.2 Wind power generation

The study focuses on the existing wind turbines sites across Switzerland with the rated capacity of 100 kW (0.1 MW) and above as given in Table A.4.

Table A.4: Existing wind turbines (above 100 kW) in Switzerland by location.

Location/Canton	Number of Turbines	Total (MW)
Mont-Crosin / Bern	16	37.2
Le Peuchapatte / Jura	3	6.9
Entlebuch / Lucerne (Feldmoos/Rengg and Lutersarni)	3	4.15
Saint-Brais / Jura	2	4
Haldenstein / Grisons	1	3
Charrat / Valais	1	3
Gütsch-Andermatt / Uri	4	3.3
Griespass-Nufenen / Valais	4	9.36
Vernayaz-Martigny / Valais	1	2
Collonges / Valais	1	2
Oberer Grenchenberg / Solothurn	1	0.15
Total	37	74.9

Apart from the above, potential future wind turbine sites in each canton are selected considering the annual average modelled wind speed at five different heights above the ground, areas with wind-power potential and federal government interests across Switzerland[376]. Table A.5 presents the coordinates of the additional future locations for wind turbines in each canton considered in this study.

For simulating wind generation, Enercon E-82 wind turbine with rated capacity of 2000 kW is used as a reference. We choose Enercon because of its dominance in the European market due to several reasons like relatively low cut in speed of 2.5 m/s, which is thought to be favourable in lower wind conditions such as Switzerland [200]. Also, since most of the favourable wind energy sites in Switzerland are located above 800 meters above sea level, about 90% of the entire wind potential sites are in cold climate or at icing sites. Among the actual installations, only the Enercon E-82 in Collonges is not affected by rime, ice and cold temperatures [379]. Power curve (detailing a quantitative relationship between wind speed and the output power) and the power coefficient (C_p) of Enercon E-82 wind turbine are detailed in Table A.6.

Table A.7 shows the annual average values of global irradiance and wind speed across different cantons of Switzerland.

A.1.3 Electricity demand

Electricity demand data used in the study is sourced from Swissgrid and then re-sampled by mean to 10-min time series to match with other data sets. In many cases, electricity demand data of few neighbouring cantons are grouped together by SwissGrid as shown in Table A.8.

Table A.5: Additional potential wind turbine sites across cantons.

Canton	Latitude	Longitude
Vaud	46.66432	6.5986
Bern	47.03304	7.21315
Bern	47.02482	7.05851
Jura	47.40536	7.35907
Appenzell Ausserrhoden	47.29962	9.24897
Grissons	46.69796	10.05337
Grissons	46.69939	8.78662
Valais	46.0232	7.79485
Schwyz	47.05748	8.67033
Schwyz	46.96473	8.71742
Uri	46.92549	8.68221
Zurich	47.34097	8.90623
Saint Gallen	47.43517	9.31418
Lucerne	47.09864	8.39424
Solothurn	47.28195	7.6475
Nidwalden	46.9039	8.36637
Aargau	47.35878	8.21129
Geneva	46.1661	6.03018
Ticino	46.18592	9.13031
Thurgau	47.55622	8.97982
Basel-Stadt	47.59383	7.67903
Basel-Land	47.40824	7.85839
Neuchâtel	47.02453	6.94193
Obwalden	46.81529	8.19973
Zug	47.14664	8.54086
Schaffhausen	47.75089	8.73362
Appenzell Innerrhoden	47.34031	9.37374
Freiburg	46.93653	7.15897
Glarus	47.06801	9.02727

Table A.6: Power curve of Enercon E-82.

Wind(m/s)	Power (KW)	Power Coefficient (Cp)
1	0	0
2	3	0.12
3	25	0.29
4	82	0.4
5	174	0.43
6	321	0.46
7	532	0.48
8	815	0.49
9	1180	0.5
10	1580	0.49
11	1810	0.42
12	1980	0.35
13	2050	0.29
14	2050	0.23
15	2050	0.19
16	2050	0.15
17	2050	0.13
18	2050	0.11
19	2050	0.09
20	2050	0.08
21	2050	0.07
22	2050	0.06
23	2050	0.05
24	2050	0.05
25	2050	0.04

4415 Table A.9 presents the whole description of renewable energy and electricity
4416 demand datasets considered for this study.

Table A.7: Annual average values of global irradiance (2016) and wind speed (2016) across different cantons of Switzerland

Canton	Annual global irradiance (2016) (kWh/m ² /year)	Annual average value of wind speed (2016) (m/s/day)
Zurich (ZH)	1156.8	5.59
BE (Bern)	1250.4	3.55
LU (Lucerne)	1121.1	3.53
UR (Uri)	1175.1	5.50
Schwyz (SZ)	989.3	4.74
Obwalden (OW)	1136.3	4.36
Nidwalden (NW)	1068.3	3.20
Glarus (GL)	1102.3	4.94
Zug (ZG)	1138.9	4.57
Fribourg (FR)	1261.7	3.90
Solothurn (SO)	1245.1	6.29
Basel-Landschaft (BL)	1168.2	5.72
Schaffhausen (SH)	1128.4	4.41
Saint Gallen (SG)	1147.9	4.92
Graubnden (GR)	1328.1	3.84
Aargau (AG)	1183.9	4.40
Thurgau (TG)	1031.3	5.07
Ticino (TI)	1380.7	4.85
Vaud (VD)	1252.2	4.97
Valais (VS)	1456.6	3.11
Neuchâtel (NE)	1231.6	5.20
Geneva (GE)	1321.1	3.76
Jura (JU)	1121.1	4.34

Table A.8: Grouping of cantons for analysis as per the electricity demand data availability from Swiss Grid.

S.No.	Cantons
1	Aargau
2	Freiburg
3	Glarus
4	Grissons
5	Lucerne
6	Neuchâtel
7	Solothurn
8	SGallen
9	Ticino
10	Thurgau
11	Valais
12	Appenzell Innerrhoden
	Appenzell Ausserrhoden
13	Basel-Landschaft
	Basel-Stadt
14	Bern
	Jura
15	Schwyz
	Zug
16	Obwald
	Nidwalden
	Uri
17	Geneva
	Vaud
18	Schaffhausen
	Zurich

Table A.9: Description of RE and electricity demand data sets.

Dataset	Dataset Variables	Temporal Resolution	Spatial Resolution	Data Period
Solar	- Global Irradiance (GR) - Temperature (T)	GR - 10 min T - Hourly	24 reference cities in 26 cantons covering whole of Switzerland	Jan 2008 till Dec 2016
	- Lifetime of PV - CAPEX (PV module, balance of system, inverter, labor and other costs) - OPEX		Switzerland	2016
	- Installed Capacity		26 cantons covering whole of Switzerland	2016
Wind	- Wind Speed (WS)	1 Hour at the Hub Height	36 wind turbines with capacity > 100 KW and 26 additional wind potential sites, one in each canton	Apr 2016 till Dec 2016 Jan 2008 till Mar 2016
	- Lifetime of Wind Turbine - CAPEX (production, transportation and installation of all wind turbines parts) - OPEX			
	- Installed Capacity		Switzerland	2016

4417 A.2 System power ratings of selected technologies

4418 Figure A.1 shows the typical power rating of solar and wind technologies globally,
 4419 together with typical range of power rating and discharge duration of various ES
 technologies.

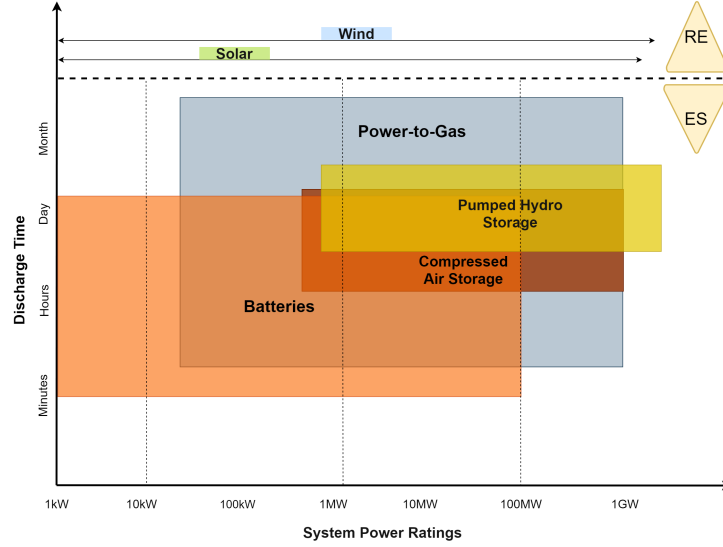


Figure A.1: Typical sizes of the selected technologies to form hybrid systems. The horizontal axis gives the nominal power range for both RE and ES technologies across geographies (based on solar and wind installations in countries like India and China) while the vertical axis represents discharge time only for ES technologies.

4421 A.3 Supply modes

4422 Demand load within the hybrid system configuration is defined by the pre-defined
 4423 supply modes. In this section, we provide illustrations of various supply mode
 4424 scenarios for the first four days of 2016 (time step of 10 mins) at the national
 4425 level. Figure A.2, Figure A.3, Figure A.4, Figure A.5 and Figure A.6 illustrates
 4426 the 'Generation', 'Generation and peak', 'Time of Day', 'Bi-Peak' and 'Baseload'
 4427 supply modes respectively for a PV & I-CAES hybrid system at the utility scale for
 4428 Switzerland.

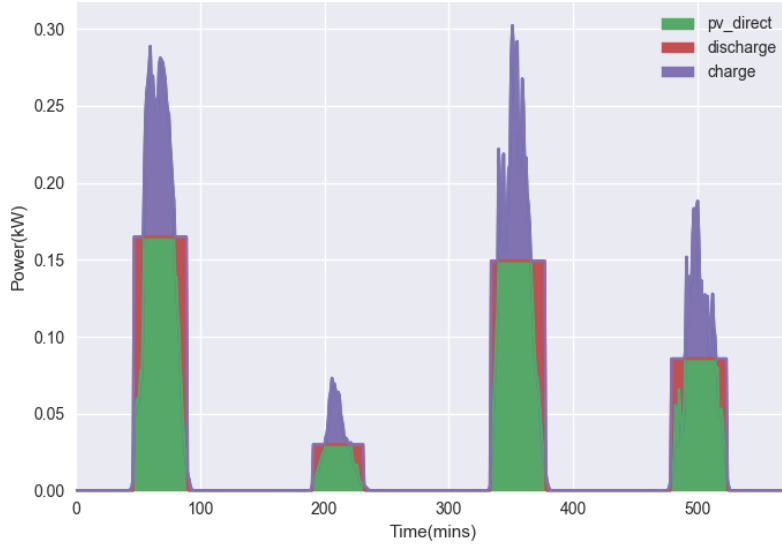


Figure A.2: Illustration of Generation supply mode for a PV & I-CAES hybrid system

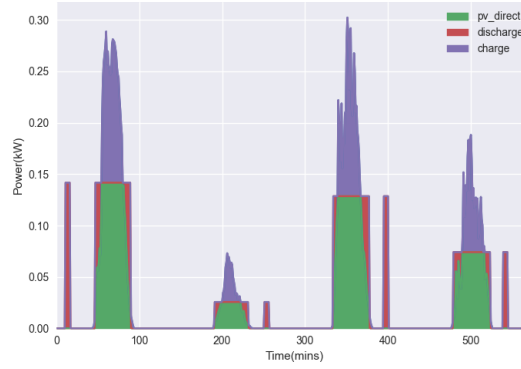


Figure A.3: Illustration of Generation & peak supply mode for a PV & I-CAES hybrid system

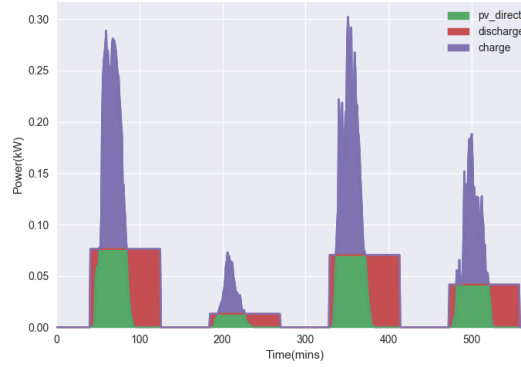


Figure A.4: Illustration of ToD supply mode for a PV & I-CAES hybrid system

A.4 Daily Capacity Credit

This section presents the box plot showing the range of daily capacity credit values of PV (Figure A.7) and wind power (Figure A.8) with and without storage at the national scale. We use I-CAES technology to illustrate the impact of ES on the daily capacity credit of PV and wind. PV without storage offers substantially more capacity credit on an average than PV with storage for all the supply modes, but, varies significantly on a daily basis depending on the peak generation and demand. On the other hand, storage helps to improve the capacity credit of wind. The ‘Bi-peak’ and ‘ToD’ supply modes have much higher capacity credits because of the

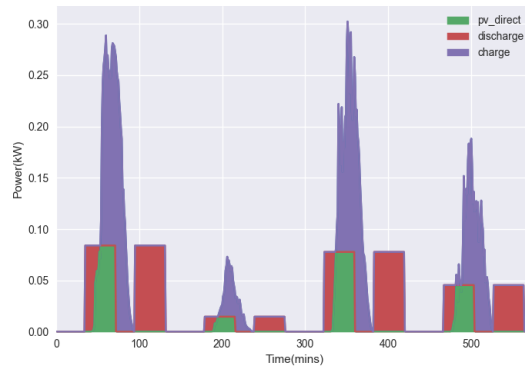


Figure A.5: Illustration of Bi-peak supply mode for a PV & I-CAES hybrid system

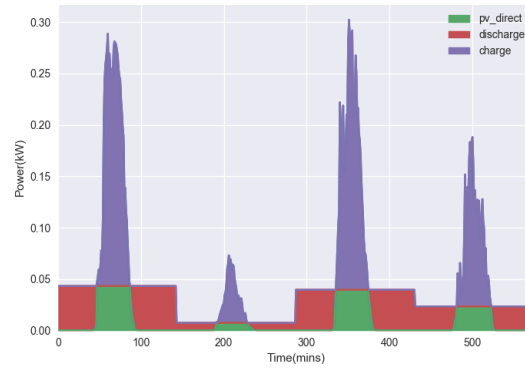


Figure A.6: Illustration of Baseload supply mode for a PV & I-CAES hybrid system

4438 higher constant output profile (due to less supply hours compared to ‘Generation’,
 4439 ‘Generation and peak’ and ‘Baseload’).

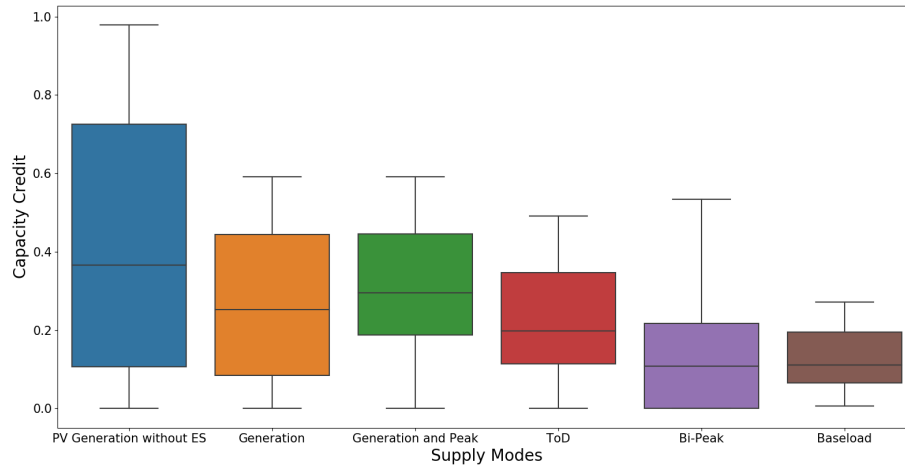


Figure A.7: Daily Capacity Credit of PV & I-CAES hybrid system for Switzerland

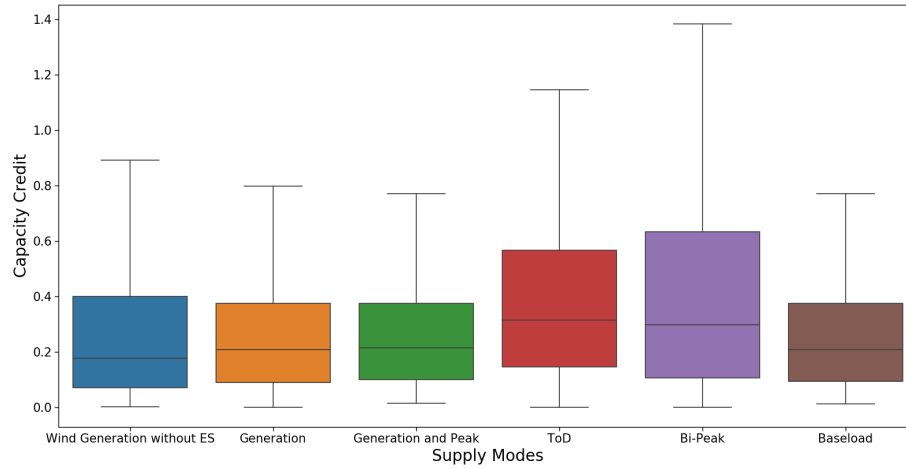


Figure A.8: Daily Capacity Credit of Wind & I-CAES hybrid system for Switzerland

Table A.10: Projected CAPEX reduction of selected technologies

Future CAPEX of technologies by 2025-2030	Selected values	Values in the literature
PV	-60%	-57% on CAPEX[178]
Wind turbine	-20%	-12% on CAPEX[178]
P2G system cost	-40%	600-900\$/kWh[26]
CAES	-20%, +20%	-17% on CAPEX[175] (Estimating the cost of a CAES system is extremely challenging, as the cost is site-specific and depends largely on local environmental constraints for the reservoir. Hence, in case of CAES, we assumed possibility of decrease as well as increase in CAPEX in the future)
PHS	0%	0% [175]
Li-ion battery	-60%	-60% on CAPEX[175]
Flow battery	-70%	-66% on CAPEX[175]
Lead-acid battery	-50%	-50% on CAPEX[175]

A.5 Sensitivity Analysis

A.5.1 Projected CAPEX reduction of selected technologies

4442 A.5.2 Wind hybrid systems sensitivity analysis

4443 We illustrate the sensitivity analysis of wind in combination with I-CAES, PHS and
 4444 P2H2P at the utility scale and in combination with PHS, AA-CAES and P2M2P at
 4445 the bulk scale from Figure A.15 to Figure A.22 respectively.

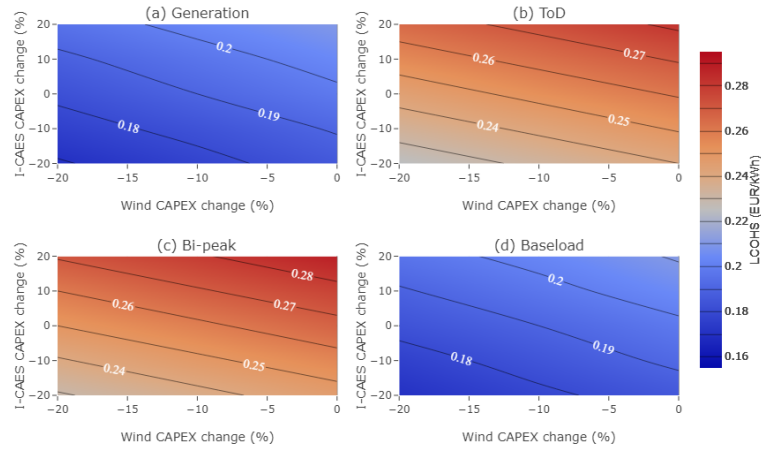


Figure A.9: Sensitivity analysis of the LCOHS at the utility scale to the CAPEX of Wind and I-CAES technologies for four different supply modes.

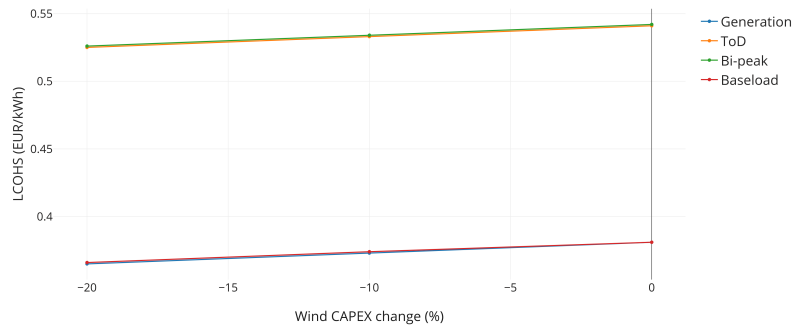


Figure A.10: Sensitivity analysis of the LCOHS at the utility scale to the CAPEX of Wind and PHS technologies for four different supply modes.

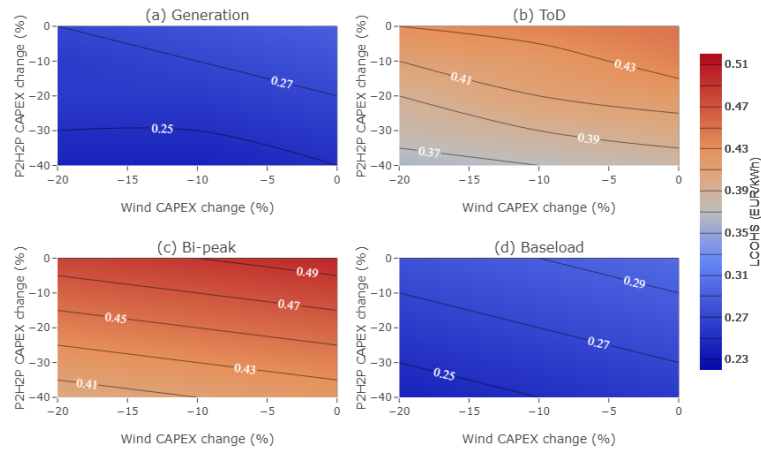


Figure A.11: Sensitivity analysis of the LCOHS at the utility scale to the CAPEX of Wind and P2H2P technologies for four different supply modes.

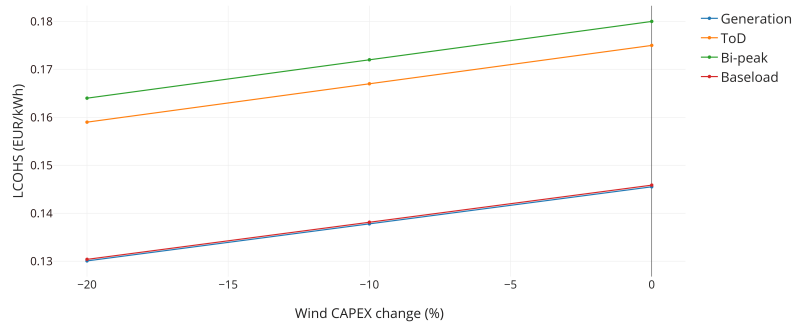


Figure A.12: Sensitivity analysis of the LCOHS at the bulk scale to the CAPEX of Wind and PHS technologies for four different supply modes.

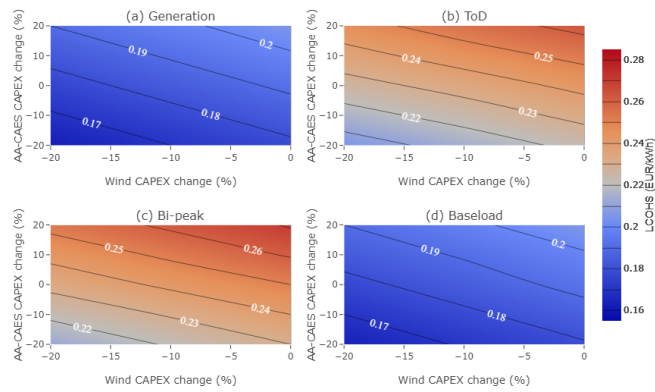


Figure A.13: Sensitivity analysis of the LCOHS at the bulk scale to the CAPEX of Wind and AA-CAES technologies for four different supply modes.

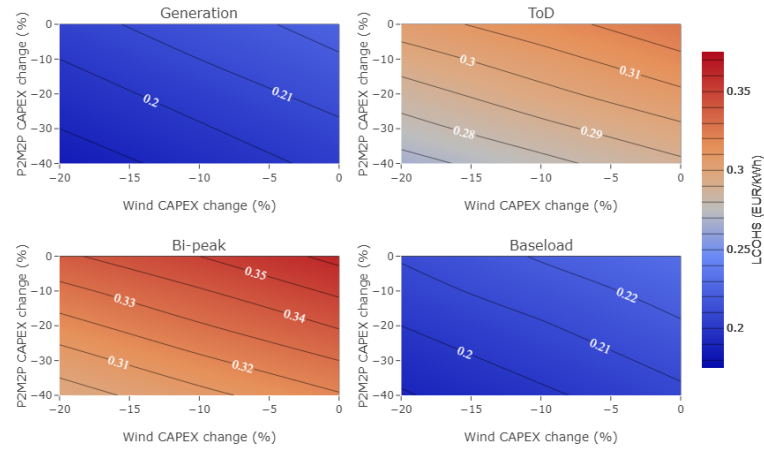


Figure A.14: Sensitivity analysis of the LCOHS at the bulk scale to the CAPEX of Wind and P2M2P technologies for four different supply modes.

A.5.3 PV hybrid systems sensitivity analysis

We illustrate the sensitivity analysis of PV in combination with I-CAES, flow battery, lead-acid battery, PHS and P2H2P at the utility scale and in combination with PHS, AA-CAES and P2M2P at the bulk scale in Figure A.16 to Figure A.22 respectively.

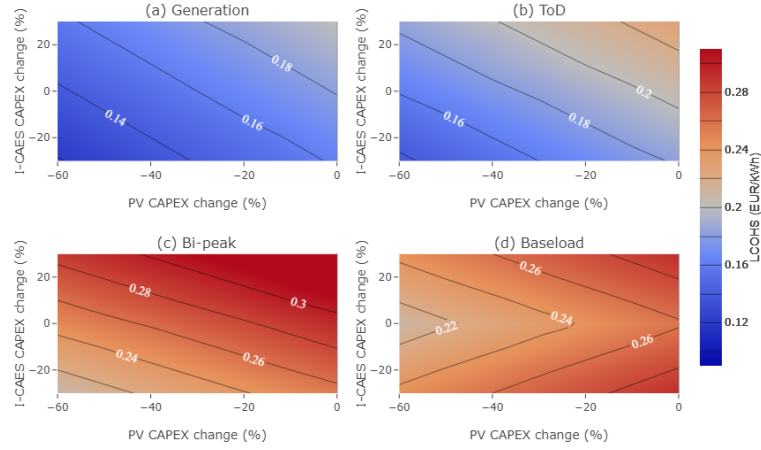


Figure A.15: Sensitivity analysis of the LCOHS at the utility scale to the CAPEX of PV and I-CAES technologies for four different supply modes.

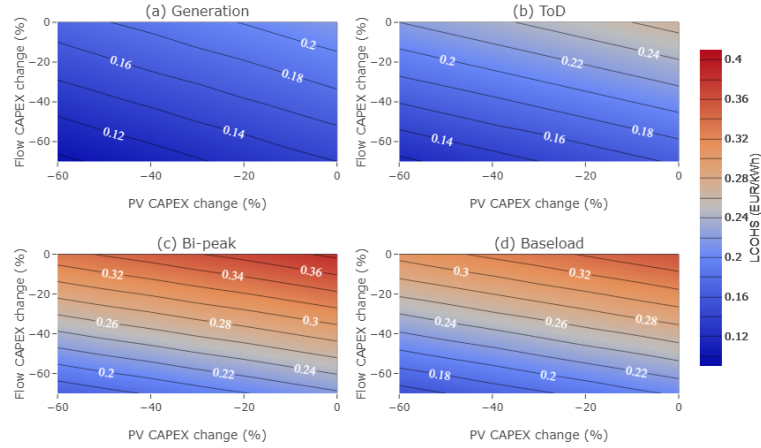


Figure A.16: Sensitivity analysis of the LCOHS at the utility scale to the CAPEX of PV and Flow battery technologies for four different supply modes.

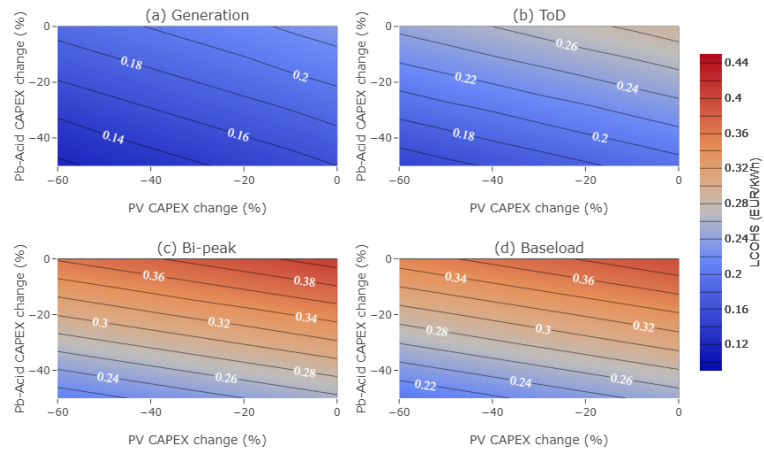


Figure A.17: Sensitivity analysis of the LCOHS at the utility scale to the CAPEX of PV and Lead-acid battery technologies for four different supply modes.

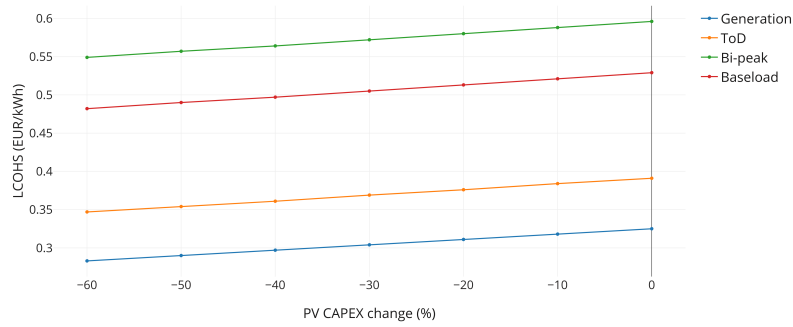


Figure A.18: Sensitivity analysis of the LCOHS at the utility scale to the CAPEX of PV and PHS technologies for four different supply modes.

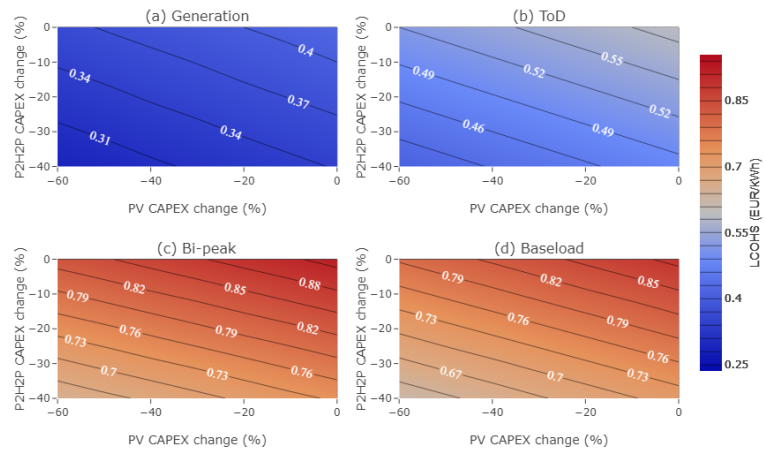


Figure A.19: Sensitivity analysis of the LCOHS at the utility scale to the CAPEX of PV and P2H2P technologies for four different supply modes.

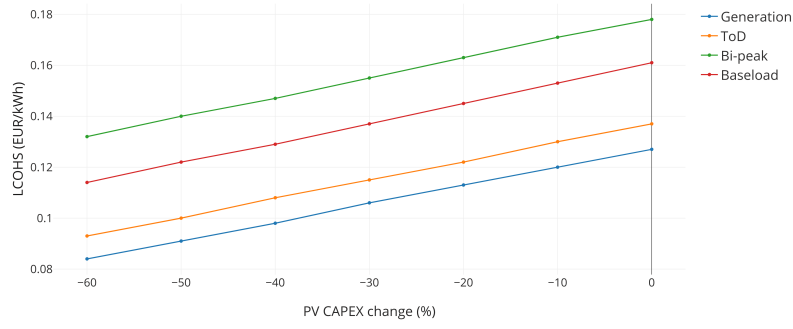


Figure A.20: Sensitivity analysis of LCOHS of PV & PHS hybrid system for four different supply modes based on future cost reduction estimates of PV at the bulk scale

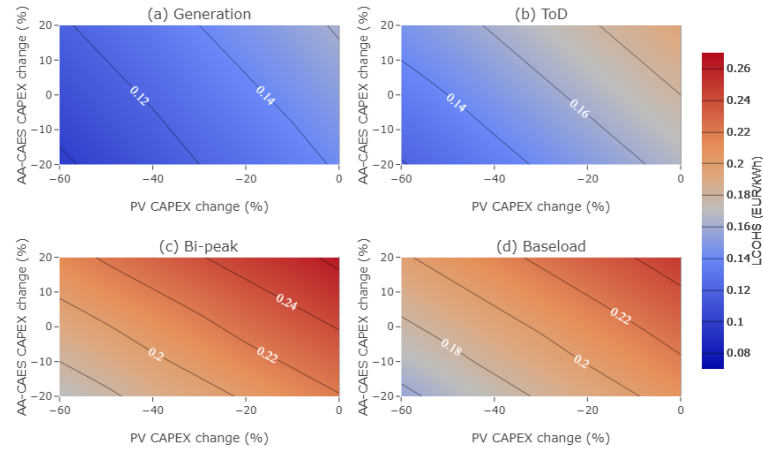


Figure A.21: Sensitivity analysis of the LCOHS at the bulk scale to the CAPEX of PV and AA-CAES technologies for four different supply modes.

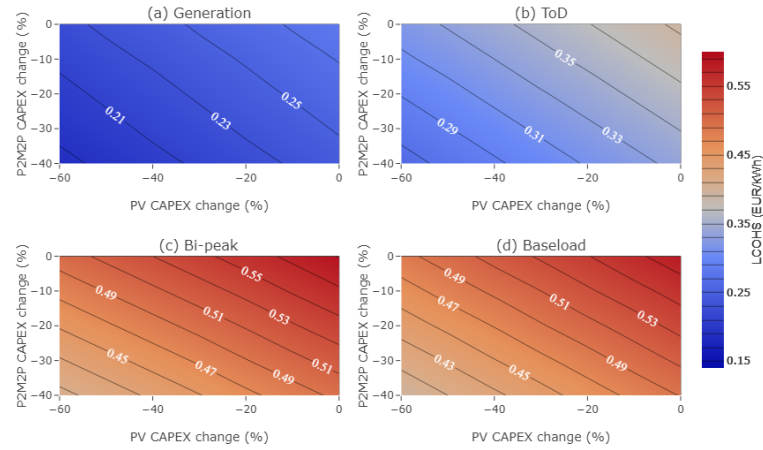


Figure A.22: Sensitivity analysis of the LCOHS at the bulk scale to the CAPEX of PV and P2M2P technologies for four different supply modes.

4451 A.6 Energy Storage Sizing

Table A.11: Required energy and power capacities for various energy storage technologies in combination with PV for various supply modes at residential, utility and bulk scales (Swiss average).

ES Technology	Supply Mode	PV Installed Capacity (kW)	Required Energy Capacity (kWh) of the ES Technology	Required Power Capacity (kW) of the ES Technology
Li-ion battery (Residential)	Generation	1	2.30	0.56
Li-ion battery (Residential)	Generation & peak	1	2.90	0.56
Li-ion battery (Residential)	ToD	1	3.14	0.56
Li-ion battery (Residential)	Bi-peak	1	4.73	0.99
Li-ion battery (Residential)	Baseload	1	4.63	0.73
Flow battery (Residential)	Generation	1	2.46	0.53
Flow battery (Residential)	Generation & peak	1	3.16	0.53
Flow battery (Residential)	ToD	1	3.40	0.61
Flow battery (Residential)	Bi-peak	1	4.84	0.99
Flow battery (Residential)	Baseload	1	4.80	0.77
Pb-acid battery (Residential)	Generation	1	4.22	0.53
Pb-acid battery (Residential)	Generation & peak	1	5.38	0.53
Pb-acid battery (Residential)	ToD	1	5.80	0.59
Pb-acid battery (Residential)	Bi-peak	1	8.46	0.99
Pb-acid battery (Residential)	Baseload	1	8.35	0.75
Li-ion battery (Utility)	Generation	1	2.30	0.56
Li-ion battery (Utility)	Generation & peak	1	2.90	0.56
Li-ion battery (Utility)	ToD	1	3.14	0.56
Li-ion battery (Utility)	Bi-peak	1	4.73	0.99
Li-ion battery (Utility)	Baseload	1	4.63	0.73
Flow battery (Utility)	Generation	1	2.46	0.53
Flow battery (Utility)	Generation & peak	1	3.16	0.53
Flow battery (Utility)	ToD	1	3.40	0.61
Flow battery (Utility)	Bi-peak	1	4.84	0.99
Flow battery (Utility)	Baseload	1	4.80	0.77
Pb-acid battery (Utility)	Generation	1	4.22	0.53
Pb-acid battery (Utility)	Generation & peak	1	5.38	0.53
Pb-acid battery (Utility)	ToD	1	5.80	0.59
Pb-acid battery (Utility)	Bi-peak	1	8.46	0.99
Pb-acid battery (Utility)	Baseload	1	8.35	0.75
PHS (Utility)	Generation	1	2.53	0.54
PHS (Utility)	Generation & peak	1	3.22	0.54
PHS (Utility)	ToD	1	3.47	0.58
PHS (Utility)	Bi-peak	1	5.10	0.99
PHS (Utility)	Baseload	1	5.03	0.74
L-CAES (Utility)	Generation	1	2.86	0.53
L-CAES (Utility)	Generation & peak	1	3.64	0.53
L-CAES (Utility)	ToD	1	3.93	0.59
L-CAES (Utility)	Bi-peak	1	5.73	0.99
L-CAES (Utility)	Baseload	1	5.66	0.75
P2H2P (Utility)	Generation	1	3.45	0.64
P2H2P (Utility)	Generation & peak	1	4.74	0.64
P2H2P (Utility)	ToD	1	4.83	0.73
P2H2P (Utility)	Bi-peak	1	6.04	0.99
P2H2P (Utility)	Baseload	1	6.05	0.87
PHS (Bulk)	Generation	1	2.53	0.54
PHS (Bulk)	Generation & peak	1	3.22	0.54
PHS (Bulk)	ToD	1	3.47	0.58
PHS (Bulk)	Bi-peak	1	5.10	0.99
PHS (Bulk)	Baseload	1	5.03	0.74
AA-CAES (Bulk)	Generation	1	5.10	0.53
AA-CAES (Bulk)	Generation & peak	1	6.54	0.53
AA-CAES (Bulk)	ToD	1	7.04	0.60
AA-CAES (Bulk)	Bi-peak	1	10.08	0.99
AA-CAES (Bulk)	Baseload	1	9.99	0.76
P2M2P (Bulk)	Generation	1	3.49	0.64
P2M2P (Bulk)	Generation & peak	1	4.81	0.64
P2M2P (Bulk)	ToD	1	4.89	0.73
P2M2P (Bulk)	Bi-peak	1	6.09	0.99
P2M2P (Bulk)	Baseload	1	6.09	0.87

Table A.12: Required energy and power capacities for various energy storage technologies in combination with wind for various supply modes at utility and bulk scales (Swiss average).

ES Technology	Supply Mode	Wind Installed Capacity (kW)	Required Energy Capacity (kWh) of the ES Technology	Required Power Capacity (kW) of the ES Technology
Li-ion battery (Utility)	Generation	1	6.77	0.56
Li-ion battery (Utility)	Generation & peak	1	6.78	0.56
Li-ion battery (Utility)	ToD	1	9.85	1.00
Li-ion battery (Utility)	Bi-peak	1	9.17	1.11
Li-ion battery (Utility)	Baseload	1	6.78	0.57
Flow battery (Utility)	Generation	1	7.20	0.59
Flow battery (Utility)	Generation & peak	1	7.20	0.59
Flow battery (Utility)	ToD	1	9.52	1.00
Flow battery (Utility)	Bi-peak	1	9.38	1.00
Flow battery (Utility)	Baseload	1	7.20	0.60
Pb-acid battery (Utility)	Generation	1	12.40	0.58
Pb-acid battery (Utility)	Generation & peak	1	12.40	0.58
Pb-acid battery (Utility)	ToD	1	17.01	1.00
Pb-acid battery (Utility)	Bi-peak	1	16.05	1.02
Pb-acid battery (Utility)	Baseload	1	12.39	0.58
PHS (Utility)	Generation	1	7.45	0.58
PHS (Utility)	Generation & peak	1	7.45	0.58
PHS (Utility)	ToD	1	10.34	1.00
PHS (Utility)	Bi-peak	1	9.67	1.04
PHS (Utility)	Baseload	1	7.44	0.58
I-CAES (Utility)	Generation	1	8.41	0.58
I-CAES (Utility)	Generation & peak	1	8.41	0.58
I-CAES (Utility)	ToD	1	11.53	1.00
I-CAES (Utility)	Bi-peak	1	10.88	1.02
I-CAES (Utility)	Baseload	1	8.40	0.58
P2H2P (Utility)	Generation	1	10.42	0.65
P2H2P (Utility)	Generation & peak	1	10.41	0.65
P2H2P (Utility)	ToD	1	11.25	1.00
P2H2P (Utility)	Bi-peak	1	13.25	1.00
P2H2P (Utility)	Baseload	1	10.42	0.68
PHS (Bulk)	Generation	1	7.45	0.58
PHS (Bulk)	Generation & peak	1	7.45	0.58
PHS (Bulk)	ToD	1	10.34	1.00
PHS (Bulk)	Bi-peak	1	9.67	1.04
PHS (Bulk)	Baseload	1	7.44	0.58
AA-CAES (Bulk)	Generation	1	14.94	0.59
AA-CAES (Bulk)	Generation & peak	1	14.94	0.59
AA-CAES (Bulk)	ToD	1	19.93	1.00
AA-CAES (Bulk)	Bi-peak	1	19.44	1.00
AA-CAES (Bulk)	Baseload	1	14.96	0.59
P2M2P (Bulk)	Generation	1	10.55	0.65
P2M2P (Bulk)	Generation & peak	1	10.55	0.65
P2M2P (Bulk)	ToD	1	11.33	1.00
P2M2P (Bulk)	Bi-peak	1	13.37	1.00
P2M2P (Bulk)	Baseload	1	10.56	0.68

Appendix B

Supplementary Information - Distribution grid capacity and costs to enable massive deployment of PV, electric mobility and electric heating

B.1 Input data and methods

B.1.1 Supply area

Fig. B.1 shows the study boundary highlighted in red, referred to as ‘supply area’ in this paper. The supply area covers parts of cantons of Bern, Solothurn and Jura in Switzerland. Each building within the supply area is identified by a unique identification number called as ‘EGID’ (the federal building identifier). The EGID is generated by the RegBL (Registre fédéral des bâtiments et des logements) and allows each building to be uniquely identified throughout Switzerland [81]. Further, each EGID is connected to their respective house connection point. A single house connection can have more than one EGID connected to it. Further, group of house connections are then connected to their respective transformer station (TS) (also known as ‘secondary substation’). Fig. B.2 illustrates how the each EGID is connected to a house connection, which is further connected to a TS at the low-voltage grid level (referred as **distribution grid**).

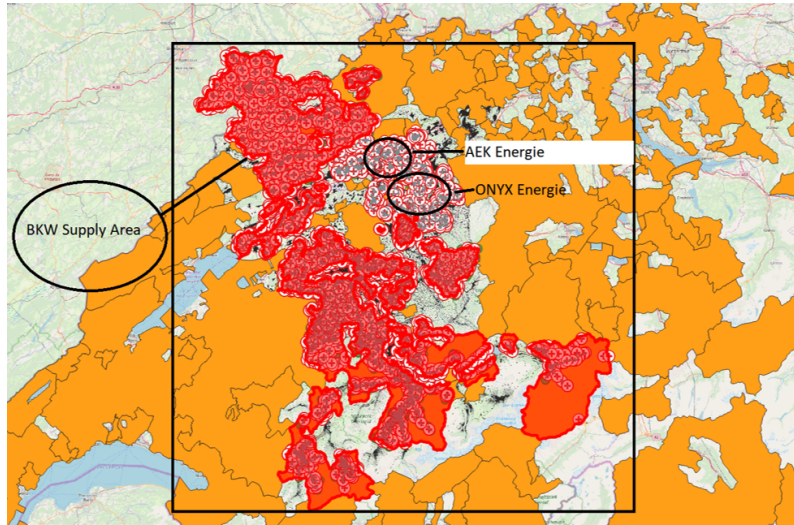


Figure B.1: Illustration showing the supply area (highlighted in red) containing the distribution grids owned and operated by BKW and its sister companies, AEK Energie and ONYX Energie in parts of Bern, Solothurn and Jura

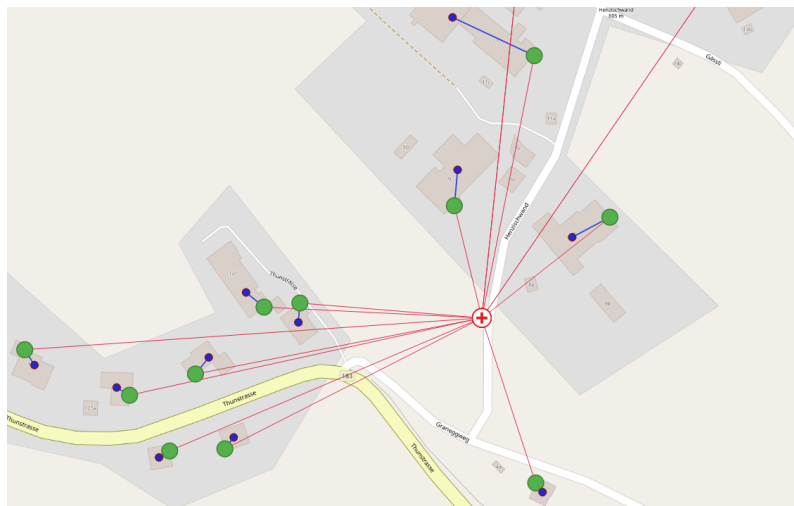


Figure B.2: Illustration showing the connection between EGID (purple point), house connection (green point) and transformer station (red plus symbol) at the distribution grid level.

B.1.2 Rooftop PV deployment in Switzerland

First, all the rooftops within the supply area are categorized as flat ($i = 0^\circ$) or non-flat ($i > 0^\circ$), depending on their inclination angle (i). Non-flat rooftops are further categorized on the basis of their orientation as illustrated in Fig. B.3. The orientation of a rooftop is an important parameter for determining its suitability for PV and output of the installed PV modules. We excluded any rooftop that did not meet our set criteria for orientation. We pre-selected rooftops oriented between -90° (East) to $+90^\circ$ (West) receiving a good annual solar radiation (area shaded in grey in Fig. B.4).

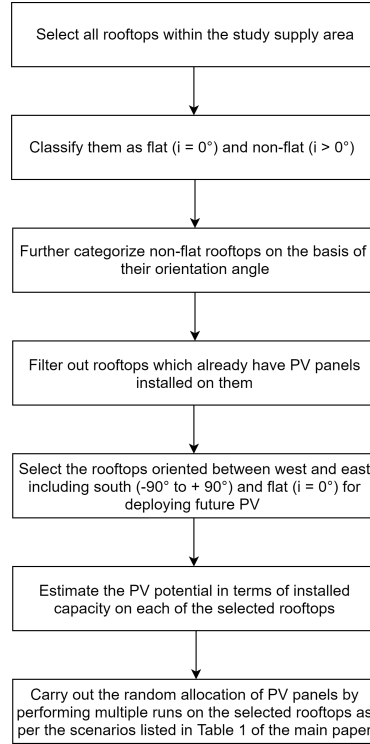


Figure B.3: Methodology for determining suitability of rooftops for future PV deployment.

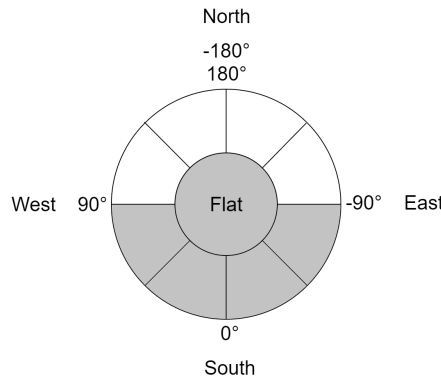


Figure B.4: Orientation of rooftops. Area shaded in grey representing the rooftops oriented between -90° to $+90^\circ$ are considered in this study.

B.1.3 Electrification of heat in Switzerland

The residential stock is represented by archetype buildings with the following categories and respective number of classes: construction period (9), building type (2), urban/rural typology (3) and heating system type (6) [321] as shown in Table B.1. Table B.2 shows the number of residential buildings within the supply area installed with different kinds of heating systems. Table B.3 shows the number of HP units sold in Switzerland from 2010 to 2018.

Table B.1: Building archetype categories and classes

Category	Class	Description
AGE	1920	Construction period before 1920
	1945	Construction period between 1921 and 1945
	1950	Construction period between 1946 and 1960
	1960	Construction period between 1961 and 1970
	1970	Construction period between 1971 and 1980
	1980	Construction period between 1981 and 1990
	1990	Construction period between 1991 and 2000
	2000	Construction period between 2001 and 2010
	2010	Construction period between 2011 and 2020
TYPE	SFH	Single-Family House (1–2 residential dwellings)
	MFH	Multi-Family House (3+ dwellings)
TPOLOGY	URBAN	(1) Large center, (2) Secondary center of large center (ARE 2014 urban typology classes), (4) Medium center
	SUBURBAN	(3) Belt of large center, (5) Belt of medium center (ARE 2014 urban typology classes)
	RURAL	(6) Small center, (7) Sub-urban rural commune, (8) Rural commune, (9) Touristical commune (ARE 2014 urban typology classes)
HEATING SUPPLY OPTION	Oil	Oil boiler
	Gas	Gas-based heating
	Electro	Direct electric heating
	DH	District heating
	HP	Heat pump
	Wood	Wood-based heating

B.1.4 Electrification of mobility in Switzerland

Table B.4 shows the current distribution of passenger cars across Switzerland with Bern, Solothurn and Jura owning 12%, 3% and 1% share of the total vehicle fleet in Switzerland respectively [279]. Table B.5 and Table B.6 shows the distribution of EV charging plugs by charging speed in residential and public respectively for future scenarios [105]. Table B.7 shows the capacity of the battery for every vehicle type and the share of each vehicle class in the future fleet [105].

Table B.2: Number of residential buildings within the supply area installed with different kinds of heating systems

Type of heating system installed	Total no. of residential buildings within the supply area
Gas	7122
Oil	67869
Wood	24189
Electro	12137
Heat Pumps (HP)	15039
District Heating (DH)	1366
Total	127722

Table B.3: Number of heat pump units sold in Switzerland from 2010-2018

Year	Number of heat pump units sold
2010	20044
2011	18905
2012	19443
2013	19350
2014	18507
2015	18318
2016	18472
2017	19995
2018	21964
Total	174998

Table B.4: Current distribution of passenger cars in each canton of Switzerland

Cantons	Share of Swiss vehicle fleet
Vaud	9%
Valais	5%
Geneva	5%
Bern	12%
Fribourg	4%
Solothurn	3%
Neuchâtel	2%
Jura	1%
Basel-Stadt	1%
Basel-Landschaft	3%
Aargau	8%
Zürich	16%
Glarus	1%
Schaffhausen	1%
Appenzell A.Rh.	1%
Appenzell I.Rh.	0%
St. Gallen	6%
Graubünden	3%
Thurgau	4%
Lucerne	5%
Uri	0%
Schwyz	2%
Obwalden	1%
Nidwalden	1%
Zug	2%
Ticino	5%

In 2035, single family houses (SFH) and multifamily houses (MFH) with a EV has access to a 7 kW and 11 kW charger respectively, plus another charger of capacity ranging from 7-22 kW for the latter. In 2050, a 7 kW EV charger is installed for all the residences in SFH and MFH (i.e. corresponding to a flat in a MFH). The public places are equipped with 22 kW chargers and the number of EV chargers correspond to at least 10% and 50% of the total number of parking spots available in 2035 and 2050 respectively [28]. Furthermore, in 2035, the allocation of public EV chargers happens primarily across four major zones, namely, zone for public use, work zones, tourism and leisure zones and centre zones. In 2050, the public zones for EV charging also include mixing zones, traffic zones and further construction zones.

Table B.5: Distribution of EV charging plugs by charging speed for residential charging

Type	Power	Share
Standard	7kW	68%
Mid – accelerated	11 kW	30%
Accelerated	22 kW	2%

Table B.6: Distribution of EV charging plugs by charging speed for public charging

Type	Power	Share
Accelerated	22 kW	100%

Table B.7: Battery capacity for each vehicle type and share in the future fleet

Type	Share on total fleet	Battery BEV	Battery PHEV
Small	24%	60 kWh	10 kWh
Medium	64%	75 kWh	12 kWh
Large	12%	100 kWh	15 kWh

B.2 Simultaneity factors

B.2.1 Heat pump model description to calculate simultaneity factor

We simulate the behavior of an air-source heat pump providing space heating in three types of single family houses. We follow the reference framework for system

simulations of the International Energy Agency (IEA) and consider three reference buildings with different energetic performance, named SFH15, SFH45 and SFH100 according to their space heating energy demand which is approximately 15, 45 and 100 kWh/m²a (140 m² floor area) in Geneva. We consider the heat pump to be coupled with a PV system of 4.8 kW peak and analyze the PV-coupled heat pump system in 549 Swiss households for which we have 15-minute resolution electricity profiles (original demand).

Heat demand is calculated using Heat4Cool, a platform that enables dynamic simulations of the heating systems using the associated consumption at different temporal resolutions and comfort indicators during a full year in less than 5 s for a conventional PC. The three types of houses are modeled in the online-tool and heat demand profiles are calculated with 15-minute temporal resolution. The heat pump is sized considering the heat load at the design temperature (-11°C) following the reference framework for system simulations of the IEA and consider the distribution of the ambient temperature. The heat pumps heating capacity are 4, 6 and 16 kW thermal for the SFH15, SFH45 and SFH100, respectively. The coefficient of performance (COP), the maximum thermal power output and the electric power consumption are calculated at each time-step as a function of the ambient temperature and the supply temperature (35°C for SFH15 and SFH45 and 50°C for SFH100) using a lookup table from a recognized heat pump manufacturer. Additionally, to cover the peak heat demand we include a backup electric heater of 2, 5 and 16 kW with a coefficient of performance of one. The provision of space heating is done following the heat demand, thus, without flexibility.

As for PV generation, environmental variables including outdoor temperature and horizontal solar irradiance monitored in Geneva are used to model PV generation, using a single-diode PV cell model. We focus on the median PV size of the empirical distribution across Switzerland (i.e., 4.8 kW_p).

The system power flows are illustrated in Fig. B.5 for an exemplary day for an SFH45 household:

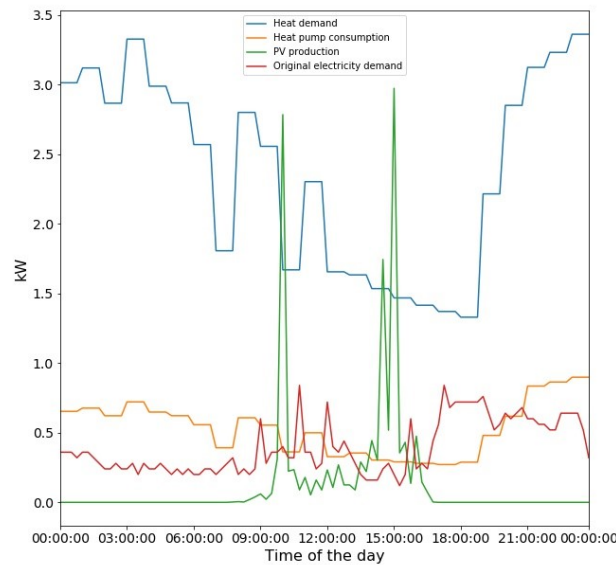


Figure B.5: System power flows for an exemplary day for an SFH45 household.

With the 549 simulations of PV-coupled heat pump systems we calculate the

total energy consumption for every 15 minutes (original electricity demand + heat pump electricity demand – PV generation) and then we calculate the simultaneity factor among houses for the original electricity load, taking one hundred random samples of different number of households (2 to 100). The simultaneity factor among houses is calculated as the ratio of the simultaneous maximum demand (with HP) of a group of consumers within 15-minutes, to the sum of their individual maximum demands (with HP) in the year (Eqn (B.1)).

$$\frac{\max(\sum_{i=1}^{549}(P_{od_i} + P_{HP_i}))}{\sum_{i=1}^{549} \max(P_{od_i} + P_{HP_i})} \forall i \in hh \quad (B.1)$$

where P_{od_i} is the original power demand, P_{HP_i} is the power of HP and hh is the pool of houses.

We repeat this method six times, selecting only houses without heat pump (original demand only), selecting houses of the same type (SFH15, SFH45 and SFH100), selecting houses of different types but all with heat pumps and selecting houses of different types and houses without heat pump (mixed HP & no HP) (Fig. B.6).

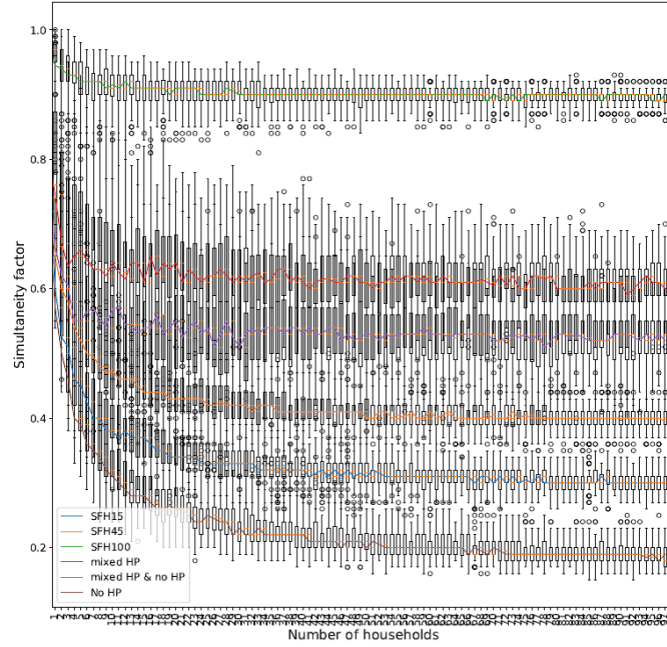


Figure B.6: Heat pumps simultaneity factor for pools of houses.

B.2.2 Simultaneity of EV charging

We use the simultaneity factors of EV charging from an open-source tool [216] using number of EV chargers, share of charging power (7 kW, 11 kW and 22 kW), share of EV class (BEV and PHEV) and their respective energy capacities (kWh) as input data from our study. Figs. B.7, B.8 and B.9 shows the simultaneity factors due to EV charging in SFH, MFH and public.

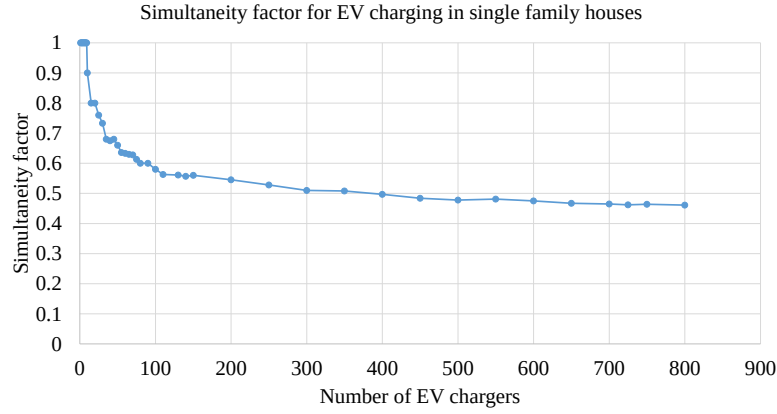


Figure B.7: Simultaneity of EV charging in SFH.

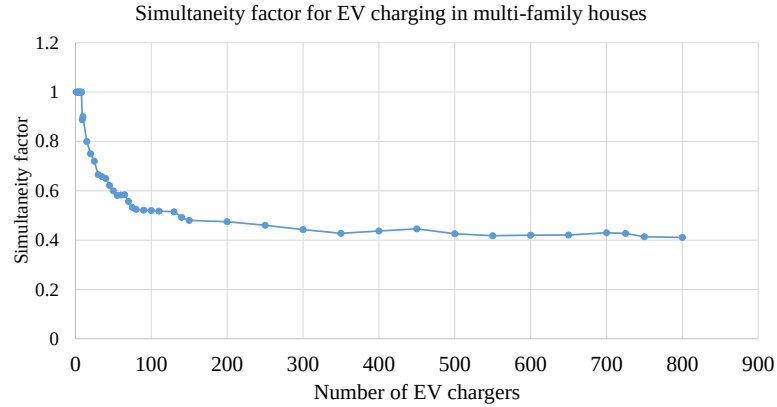


Figure B.8: Simultaneity of EV charging in MFH.

B.3 Results

Distribution grids with less than 7 connection points, less or equal to 1000 meters of total line length and a total installed power of less or equal to 230 kVA are considered **small**; whereas, all the distribution grids with more than 50 connection points, more or equal to 3500 meters of total line length and a total installed power of more or equal to 900 kVA are considered **large**. Finally all the grids in between are considered **medium**.

B.3.1 Heroic effort scenario

Fig. B.11 shows the total grid reinforcement costs needed for PV, HP, EV charging deployment and their combinations under the least, determined and aggressive

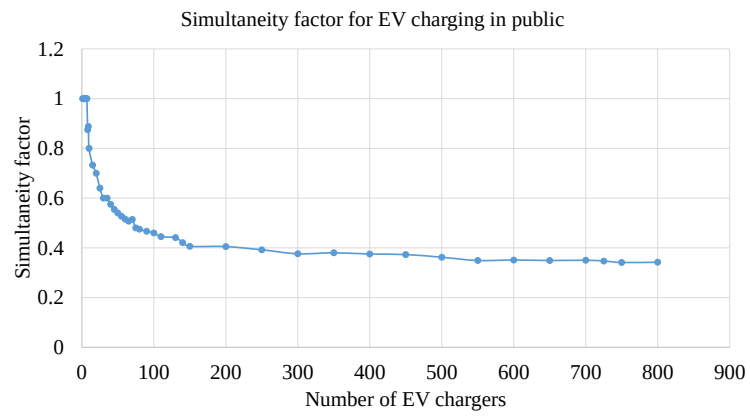


Figure B.9: Simultaneity of EV charging in public.

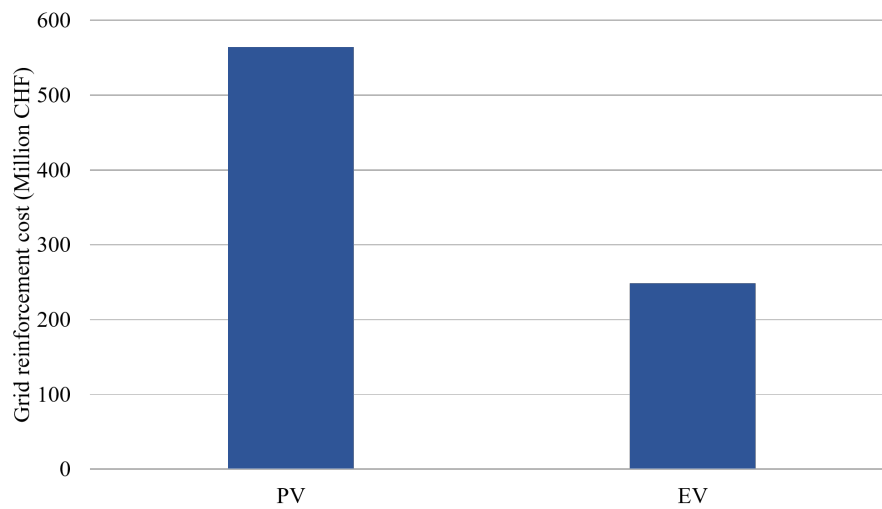


Figure B.10: Total grid reinforcement cost needed for PV and EV charging deployment under the heroic effort scenario in 2050.

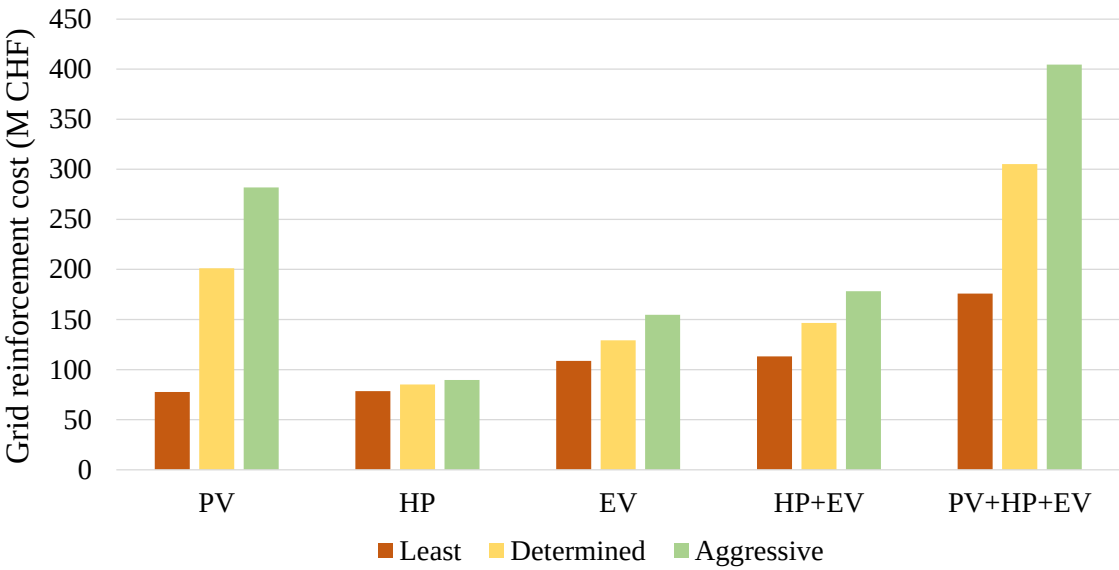


Figure B.11: Total grid reinforcement costs needed for PV, HP, EV charging deployment and their combinations under the least, determined and aggressive scenarios in 2035.

B.3.2 Grid reinforcement costs per urban setting

Fig. B.12 shows the specific grid reinforcement cost for PV, HP and EV chargers deployment in least effort scenario.

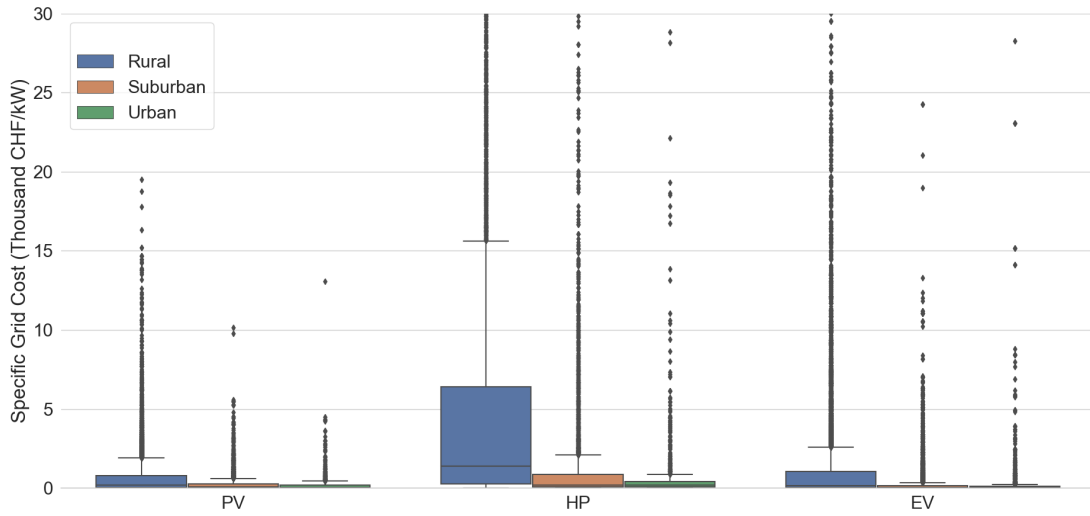


Figure B.12: Least effort scenario - Specific grid reinforcement costs for PV, HP and EV chargers for different urban settings in 2035 with outliers.

Fig. B.13 shows the specific grid reinforcement cost for PV, HP and EV chargers deployment in determined effort scenario.

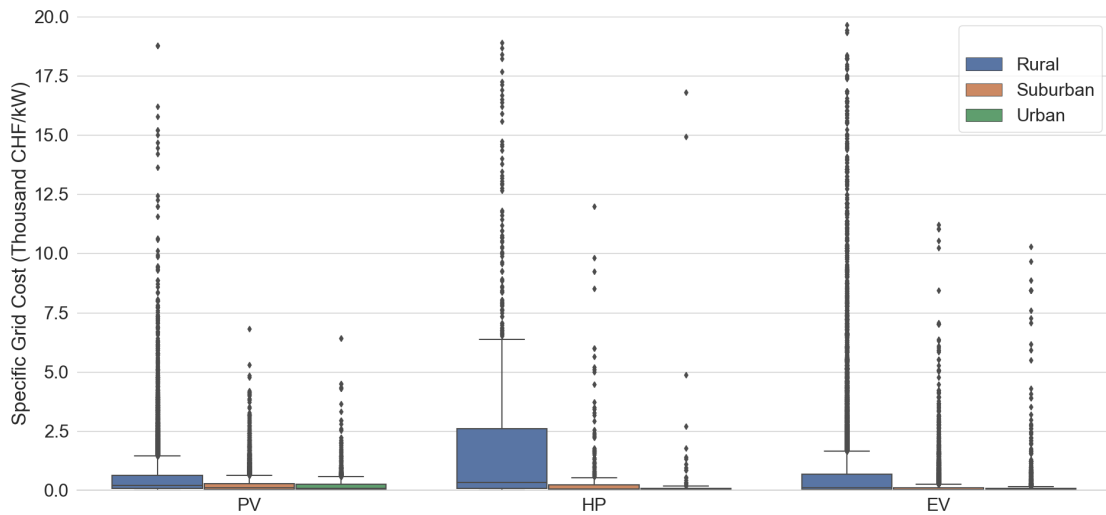


Figure B.13: Determined effort scenario - Specific grid reinforcement costs for PV, HP and EV chargers for different urban settings in 2035 with outliers.

Fig. B.14 and B.15 shows the specific grid reinforcement cost for PV, HP and EV chargers deployment in aggressive effort scenario. The median (Interquartile range (IQR) values reported in brackets) specific grid reinforcement cost for PV in rural areas is 213 (76-590) CHF/kW_p compared to 375 (87-2016) CHF/kW and 74 (21-489) CHF/kW in case of HP and EV respectively. For suburban areas, the

4580 median (IQR) grid cost is 113 (45-292) CHF/kW, 65 (23-274) CHF/kW and 34 (14-
 4581 90) CHF/kW for PV, HP and EV respectively. For urban areas, the median (IQR)
 4582 grid cost is 84 (32-265) CHF/kW for PV and 73 (32-121) CHF/kW for HP and 39
 4583 (23-63) CHF/kW for EV.

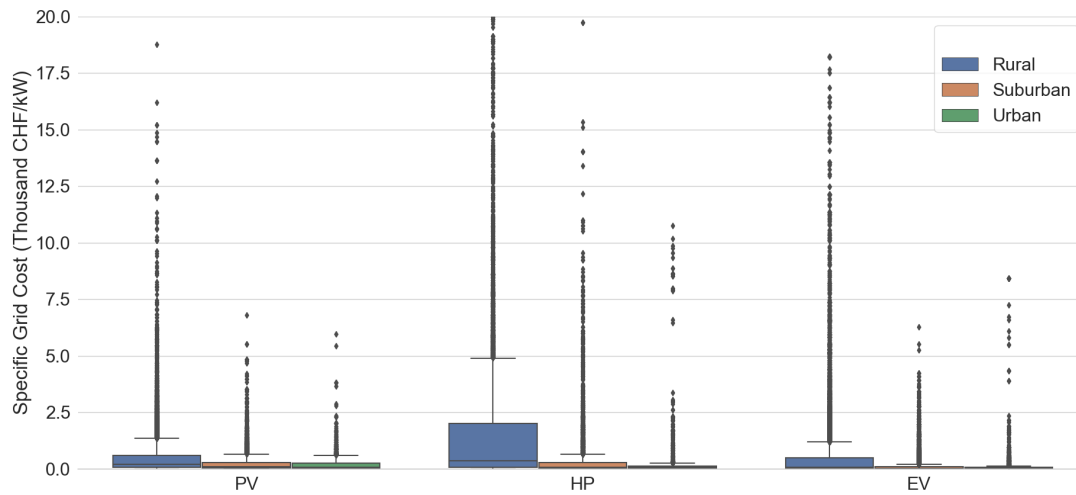


Figure B.14: Aggressive effort scenario - Specific grid reinforcement costs for PV, HP and EV chargers for different urban settings in 2035 with outliers.

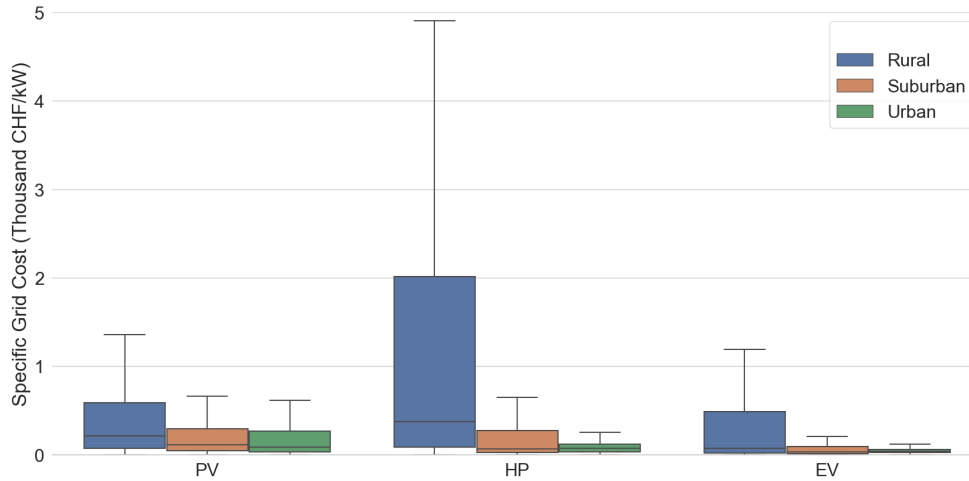


Figure B.15: Aggressive effort scenario - Specific grid reinforcement costs for PV, HP and EV chargers for different urban settings in 2035.

B.4 Battery costs

Table B.8: Techno-economic input data for Lithium-ion (NMC) battery considered in this study. The data is taken from up-to-date sources representative for Switzerland [287, 358]

ES technology type	Lifetime (yrs)	Energy related CAPEX (CHF/kWh)	Power related CAPEX (CHF/kW)	OM cost (CHF/kW/year)
Li-ion battery (NMC) (<1MW)	15	363.54	2373.33	0
Li-ion battery (NMC) (1-100 MW)	15	363.54	342.92	9.76

B.5 Comparison of low and medium voltage grid studies for Switzerland

Table B.9: Comparison of low and medium voltage grid studies for Switzerland

Parameter	Our study	Gupta et. al, 2021 [122]
Grid level	Low voltage	Medium voltage
Country	Switzerland	Switzerland
Technology integration	PV, heat pumps and EV charging	PV
Flexibility option	Grid reinforcement	Li-ion battery
PV capacity	10.5 GW _p (Determined effort 2035)	10.5 GW _p
Investment needed	2.19 BCHF (Grid reinforcement cost)	0 BCHF (Li-ion battery cost)
PV capacity	14.8 GW _p (Aggressive effort 2035)	14.8 GW _p
Investment needed	3.04 BCHF (Grid reinforcement cost)	0-5-1.5 BCHF (Li-ion battery cost)
PV capacity	21.1 GW _p (Heroic effort 2035)	21.1 GW _p
Investment needed	4.33 BCHF (Grid reinforcement cost)	9-10 BCHF (Li-ion battery cost)

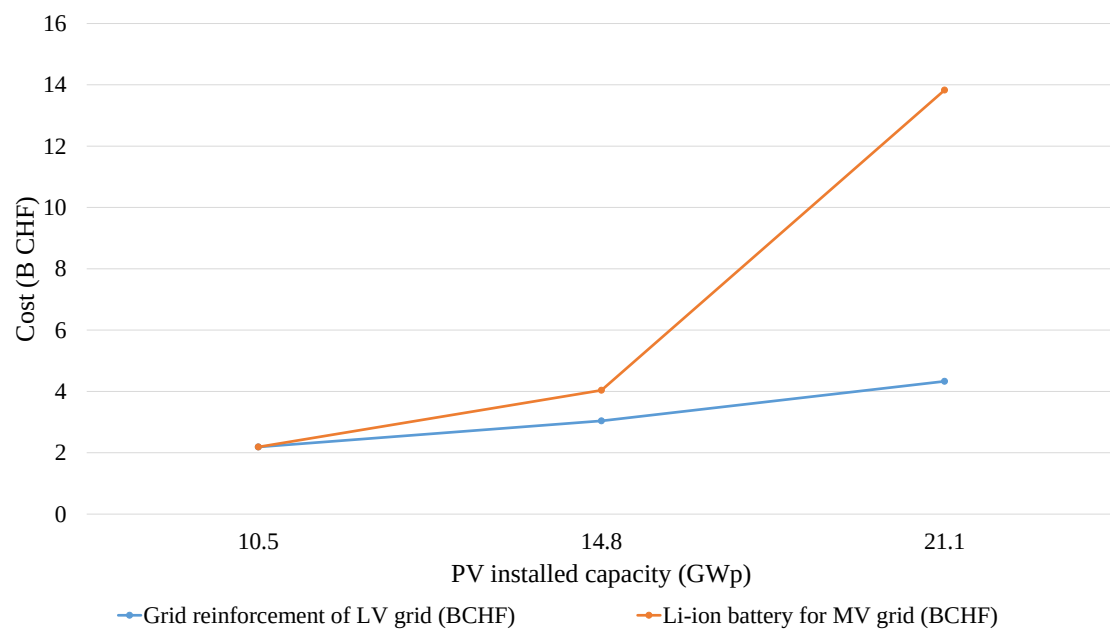


Figure B.16: Comparison of grid reinforcement (our results) and battery storage costs [Gupta2021] for low (LV) and medium voltage (MV) grid respectively in Switzerland.

Appendix C

Supplementary Information - Smart power-to-gas deployment strategies informed by spatially explicit cost and value models

C.1 Input data and method

C.1.1 Techno-economic power-to-gas model

The techno-economic power-to-gas (PtG) model is based on energy balance principle, involving the relationship between PtG plant (physical system) and electricity consumption, carbon dioxide (CO₂) and gas supply to the demand centre/s. For each component of the PtG system, a dedicated submodel was developed to model the energy conversion and related losses (for details, please refer to Parra et al. [245, 247]). As depicted in the schematic representation of a P2G system in manuscript Fig. 2, heat is a key by-product generated by the electrolyzer (80°C) and methanation reactor (250-300°C). The model includes a heat exchanger with an efficiency of 90% to account for losses.

The total electricity consumption of a PtG system (MWh_e), is equal to the sum of electricity consumption of an electrolyzer system (including both stack and its specific balance-of-plant (BoP)), an AC/DC converter, a hydrogen compressor, and a methanation reactor (the latter, only in case of methane production). Some of the key performance indicators include electricity consumption per unit of generated gas, EC_g (Eq. C.1), overall stack efficiency (Eq. C.2), system efficiency (Eq. C.3) and capacity factor C_f (Eq. C.4). W_(system,h) is the electricity (kWh_e) with one hour temporal resolution, feeding into the PtG system including various components. m_{gas} refers to the quantity of the gas produced in Nm³, HHV_{gas} is the high heating value of the gas (equal to 141.8 MJ/kg for hydrogen and 55.5 MJ/kg for methane) and W_(system,nom) is the electrolyzer nominal capacity.

The electrolyzer system's technical performance is modelled following a bottom-up approach considering both the cell stack and BoP. The performance of a PEM electrolyzer cell was characterised by means of its polarisation curve (Fig. C.1). The technical parameters of electrolyzer and other components used in this analysis are given in Table C.1. A converter is used to convert AC electricity to DC before being injected into the electrolyzer; the efficiency of the rectifier as a function of the load

factor is given in Fig. C.2. The BOP rating for 1 MW_e PtG plant is determined according to the experimental observations explained in [247]. The BoP rating of a 1 MW electrolyzer system is assumed to be 25 kW based on empirical data [27], and it is assumed that BoP operate at a constant load of 25 kW independently of green hydrogen generation [245]. The reason for this is that elements such as pumps, fans and monitoring system operate with a rather constant load. The electricity consumption by hydrogen compressor is assumed to be a function of the generated gas at a rate of 0.1 kWh_e per Nm³ of gas generated [247, 131]. The electricity and heat requirements for CO₂ captured from air (Direct Air Capture) are taken from manufacturer's data (Table C.1). For PtG plants powered by rooftop PV electricity, we model them as a hybrid system considering the total CAPEX and OPEX of the hybrid system. Rooftop PV system include a DC/AC inverter with dynamic efficiency. Table C.2 shows the stack and system electricity consumption per Nm³ of gas (hydrogen or methane) generated as well as stack and system efficiency of power-to-hydrogen (PtH) and power-to-methane (PtM) plants using run-of-river hydroelectricity and PV electricity.

Fig. C.3 presents the stack and PtH system efficiency plotted against the load factor (i.e. a load factor of 1 corresponds to the nominal capacity). It is shown that the overall efficiency of a PtH system is lower than the stack because of the additional electricity consumption by the BoP and hydrogen compressor which becomes a parasitic load, along with the efficiency penalty in the AC/DC converter. For example, the difference in efficiency of a PtH system versus the stack at the nominal load (around 9% loss in energy efficiency at nominal load) is explained by electricity loss not only by the BoP (2.5%) but also by the hydrogen compressor (1.8%) and efficiency penalty due to the AC/DC converter or rectifier (5%). In case of PtM system/s, the system efficiency drops further due to the presence of a methanation reactor (with an assumed nominal efficiency of 80%). Importantly, the efficiency of the electrolyzer stack decreases with the load due to more losses associated with high current density. On the other hand, the efficiency of a PtH system increases up to approximately 40%, and then becomes more or less constant until the nominal load.

$$EC_g = \frac{\sum_{h=1}^{Life} W_{system,h}}{\sum_{h=1}^{Life} m_{gas}} \quad (C.1)$$

$$\eta_{stack} = \frac{\sum_{h=1}^{Life} m_{gas.HHV_{gas}}}{\sum_{h=1}^{Life} W_{stack,h}} \quad (C.2)$$

$$\eta_{system} = \frac{\sum_{h=1}^{Life} m_{gas.HHV_{gas}}}{\sum_{h=1}^{Life} W_{system,h}} \quad (C.3)$$

$$C_f = \frac{\sum_{h=1}^{Life} W_{system,h}}{W_{system,nom.Life}} \quad (C.4)$$

C.1.2 Wholesale electricity price

Fig. C.4 presents the boxplot showing hourly wholesale electricity prices in Switzerland from current (2020) to long-term (2050). Wholesale electricity prices for Switzerland are obtained using the open-source energy system model, GRIMSEL-FLEX [305, 277, 276]. The model includes Switzerland and its four neighboring

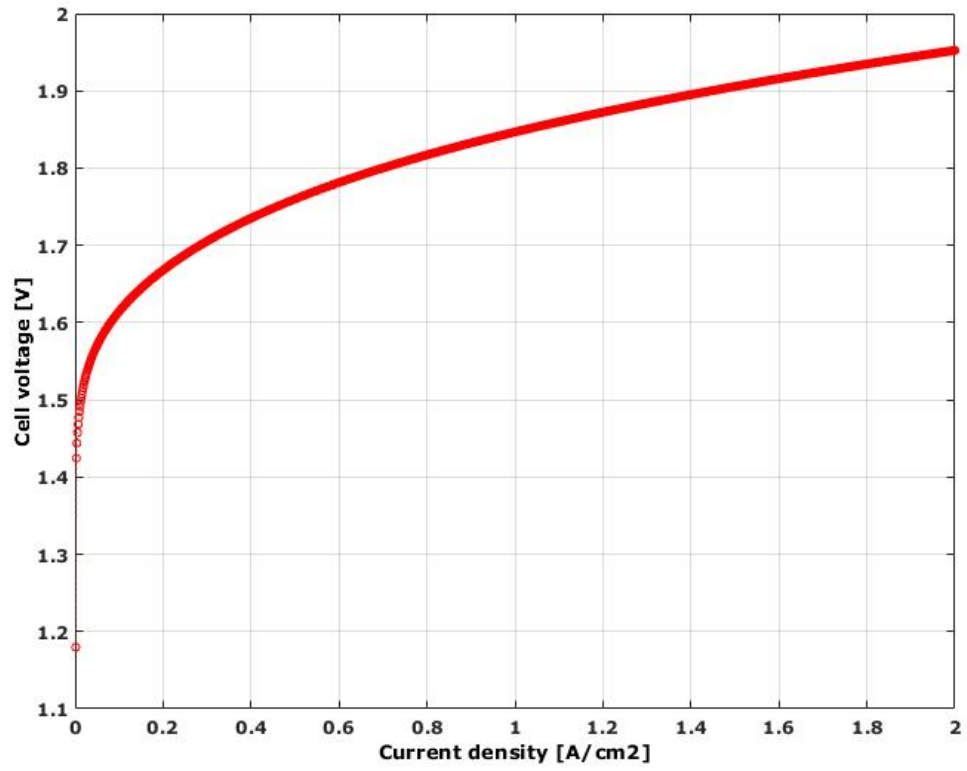


Figure C.1: Polarisation curve of the PEM electrolyzer cell

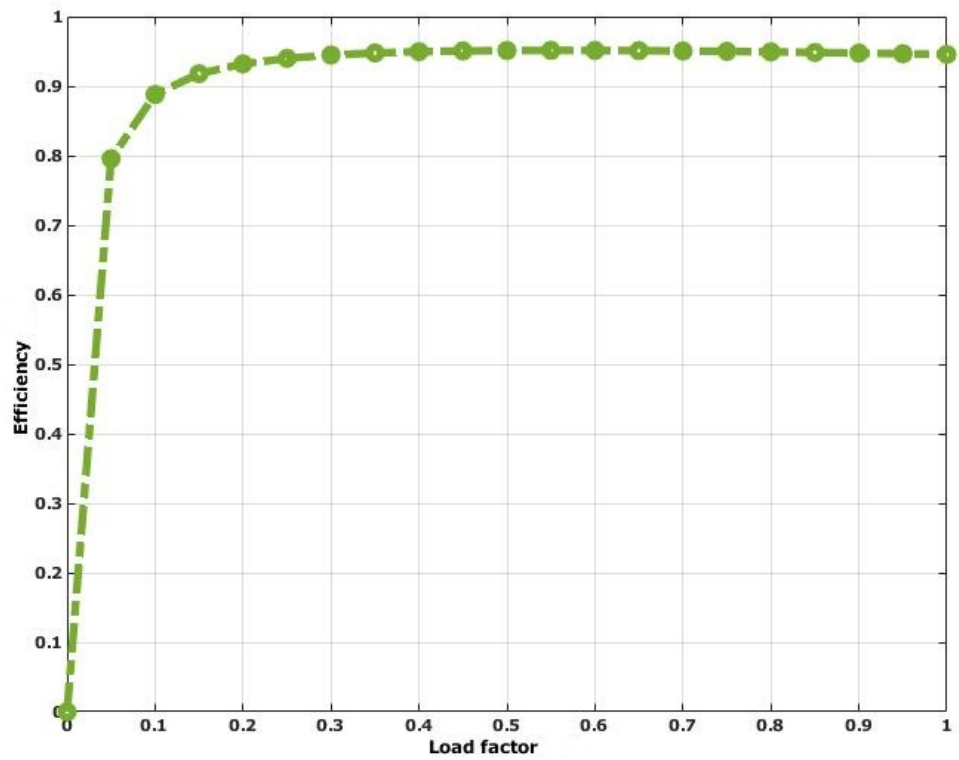


Figure C.2: AC/DC converter efficiency as a function of the load factor

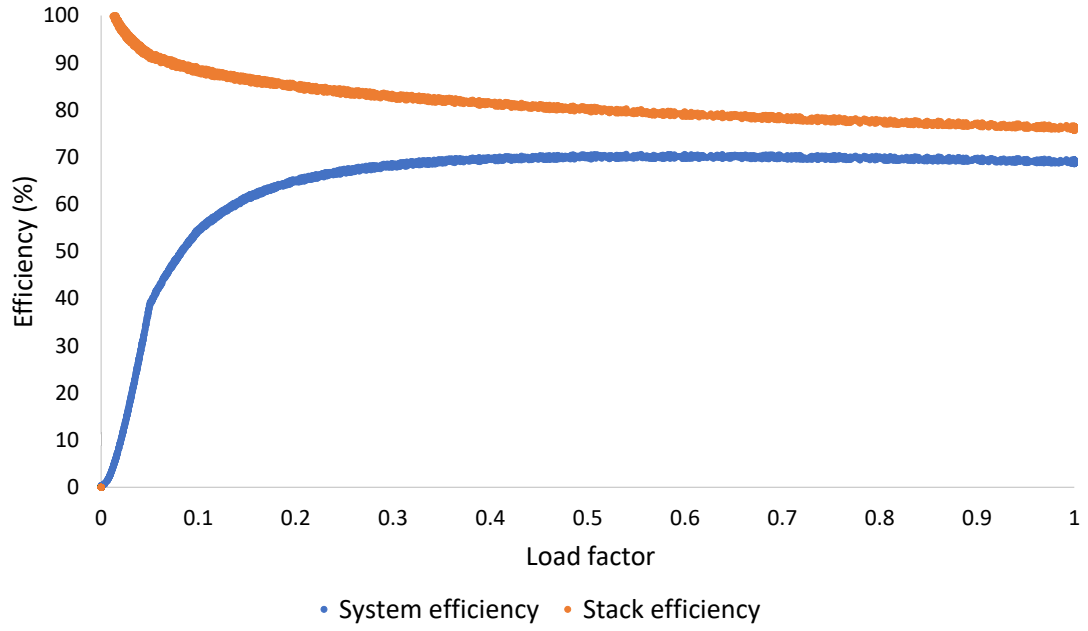


Figure C.3: Stack and power-to-hydrogen system efficiency as a function of the load factor

Table C.1: Technical parameters of power-to-hydrogen and power-to-methane systems considered in the study.

Technical parameter	Value
Degradation rate ($\mu\text{V/h}$) - PEM electrolyzer	3 [25]
Current density at operating point (A/m^2)	1'800 [25, 138]
Electrolyzer stack life (h)	60'000 [365, 42]
General BoP life (years)	30 [42]
Methanation reactor efficiency (%)	80 [365]
Average electricity consumption for direct CO_2 capture from air (DAC) ($\text{kWh}_e/\text{t}_{\text{CO}_2}$)	200 [222]
DAC plant life (years)	30 [100]
Heat required for CO_2 capture from air ($\text{kWh}_t/\text{t}_{\text{CO}_2}$)	1'500 [222]
Heat exchanger efficiency (%)	90 [247]
Methanation reactor life (years)	20 [365]

Table C.2: Stack and system electricity consumption and efficiency of PtH and PtM systems using hydro or PV electricity.

	Stack consumption (kWh/Nm³)	Stack efficiency	System electricity consumption (kWh/Nm³)	System efficiency
PtH using PV electricity	4.85	73%	5.64	63%
PtH using hydroelectricity	4.92	72%	5.29	67%
PtM using PV electricity	4.85	73%	22.52	50%
PtM using hydroelectricity	4.92	72%	20.97	54%

countries and the authors carried out future projections based on fuel prices, carbon tax and technologies installed capacities. We assume the wholesale electricity prices considering a cost-optimal solution for Switzerland leads to the deployment of 24.6 GW_p of PV combined with 14.6 GW (29.2 GWh) of storage capacity by 2050.

C.1.3 Grid fees across Switzerland

Table C.3 presents the average grid fees per canton for consumer C7 corresponding to a large company (7,500,000 kWh/year) with maximum power of 1630 kW on medium voltage current with their own transformer station [83].

C.1.4 CO₂ potential in Switzerland

A compilation of the theoretical and technical CO₂ potential in Switzerland can be found in Table C.4.

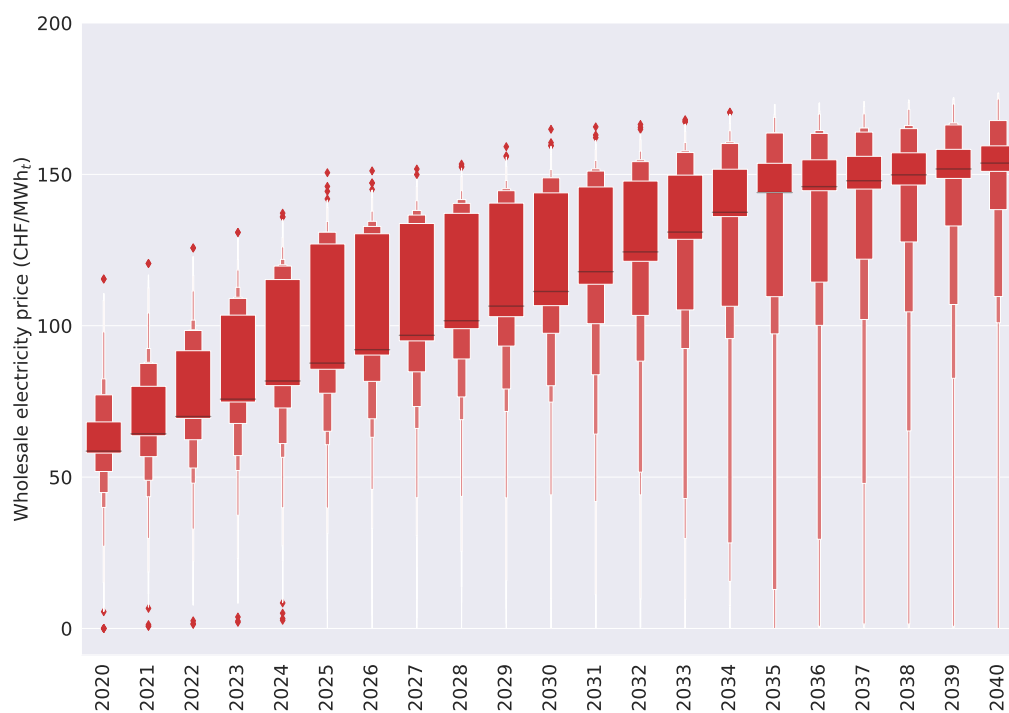


Figure C.4: Hourly wholesale electricity prices in Switzerland from 2020 to 2040 [277, 276]

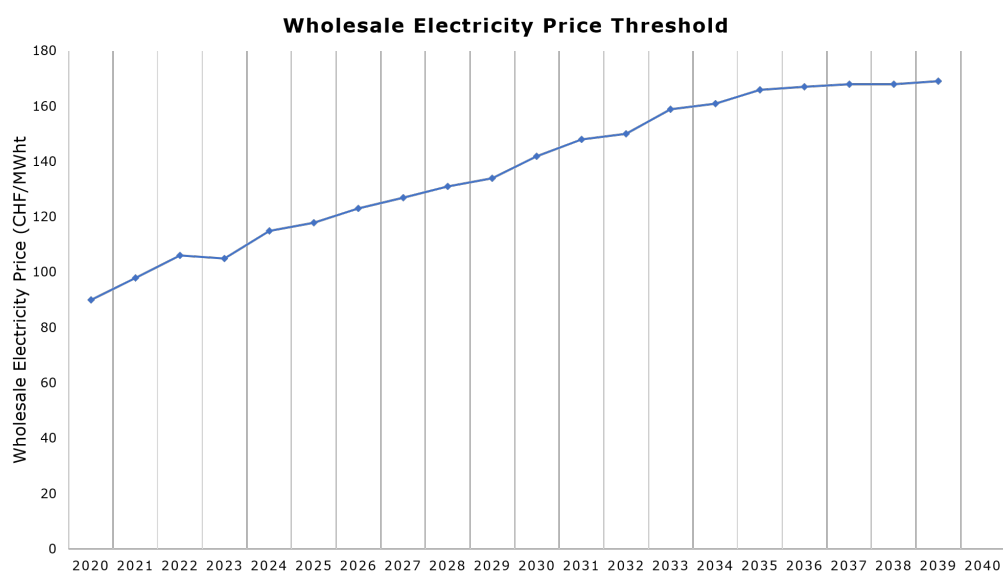


Figure C.5: Maximum price threshold beyond which the electrolyzer would not operate for each year of operation [277, 276]

Table C.3: Grid fees (2020) for C7 consumer - C7 : 7,500,000 kWh/year: large company, maximum power: 1,630 kW, medium voltage current, own transformer station.

Canton	Network (Grid) fees (cents/kWh excluding VAT)
Geneva	3.65
Vaud	3.92
Neuchâtel	3.88
Freiburg	3.4
Valais	3.21
Bern	4.64
Jura	4.64
Solothurn	4.37
Basel-Landschaft	3.43
Basel-Stadt	5.98
Aargau	3.14
Luzern	3.32
Obwalden	4.32
Nidwalden	3.93
Uri	3.73
Ticino	4.77
Graubünden	5.6
Glarus	4.39
Zurich	3.56
Schaffhausen	4.34
Thurgau	4.25
St. Gallen	4.05
Appenzell Ausserrhoden	4.59
Appenzell Innerrhoden	3.72
Schwyz	4.96
Zug	4.29

Table C.4: Overview of the theoretically (100% CO₂ separation) and technically (limited CO₂ separation) available CO₂ amounts per year and their potentials to be converted to SNG by means of PtG. CEM stands for cement plants, MWIP stands for (municipal) waste incineration plants and WWTP for wastewater treatment plants.

CO₂ source	Theoretical CO₂ potential (100% separation)	Technical CO₂ potential (limited separation)
Type	tCO₂	tCO₂
CEM (all)	2'710'000	2'032'500
MWIP (all)	4'237'763	3'178'322
WWTP (all)	170'000	170'000
Total	7'117'763	5'380'822

C.1.5 Natural gas and green hydrogen selling price

The exposed natural gas prices are obtained for 2017 from [160] and then later projected for the future using the methodology explained by Jibran et. al. [391]

Table C.5: Evolution of natural gas prices from 2020 to 2050 in Switzerland.

Year	Natural Gas price (USD/MWh)
2020	70.36
2021	71.76
2022	73.24
2023	74.85
2024	76.01
2025	76.93
2026	78.23
2027	79.52
2028	81.29
2029	82.34
2030	83.81
2031	84.81
2032	86.20
2033	87.49
2034	88.88
2035	90.27
2036	90.73
2037	91.24
2038	92.28
2039	93.26
2040	94.03
2041	94.36
2042	94.48
2043	94.81
2044	95.34
2045	96.17
2046	96.45
2047	96.84
2048	97.15
2049	97.36
2050	97.66

The current (2020) hydrogen selling price based on natural gas price plus renewable energy premium based on biogas [140]. The future reductions in the hydrogen selling price is based on projections made by [109].

Table C.6: Evolution of hydrogen prices from 2020 to 2050 in Switzerland.

Year	H ₂ price (USD/kg)
2020	4.67
2021	4.53
2022	4.38
2023	4.23
2024	4.09
2025	3.94
2026	3.80
2027	3.65
2028	3.50
2029	3.43
2030	3.36
2031	3.28
2032	3.21
2033	3.14
2034	3.06
2035	2.99
2036	2.92
2037	2.88
2038	2.84
2039	2.81
2040	2.77
2041	2.73
2042	2.70
2043	2.66
2044	2.62
2045	2.61
2046	2.59
2047	2.57
2048	2.55
2049	2.53
2050	2.51

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C.2 Results

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C.2.1 Levelized cost and value of Hydrogen - PtH at industrial location using rooftop PV electricity and at run-of-river hydropower plant using hydroelectricity

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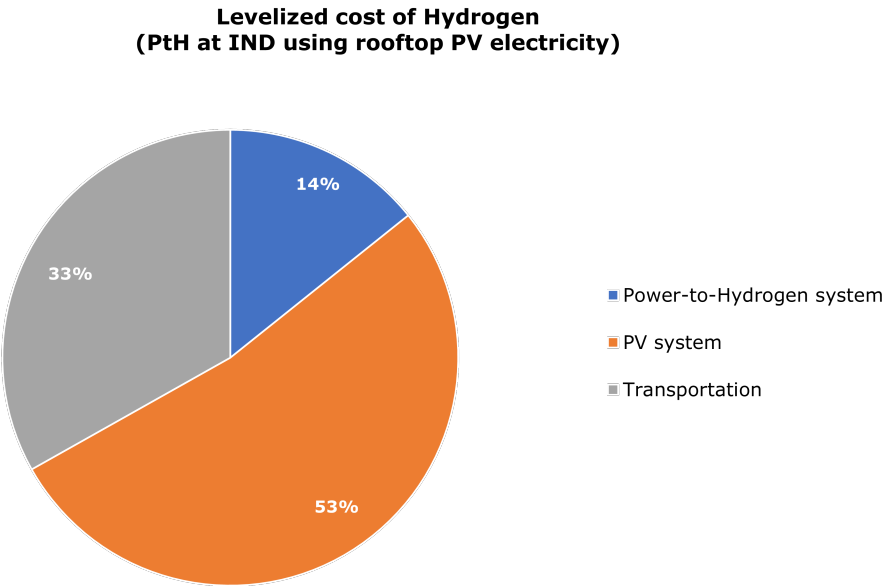


Figure C.6: Breakdown of average levelised cost of hydrogen for a 1 MW_e PtH plant deployed at industrial site (PtH at IND) using rooftop PV electricity

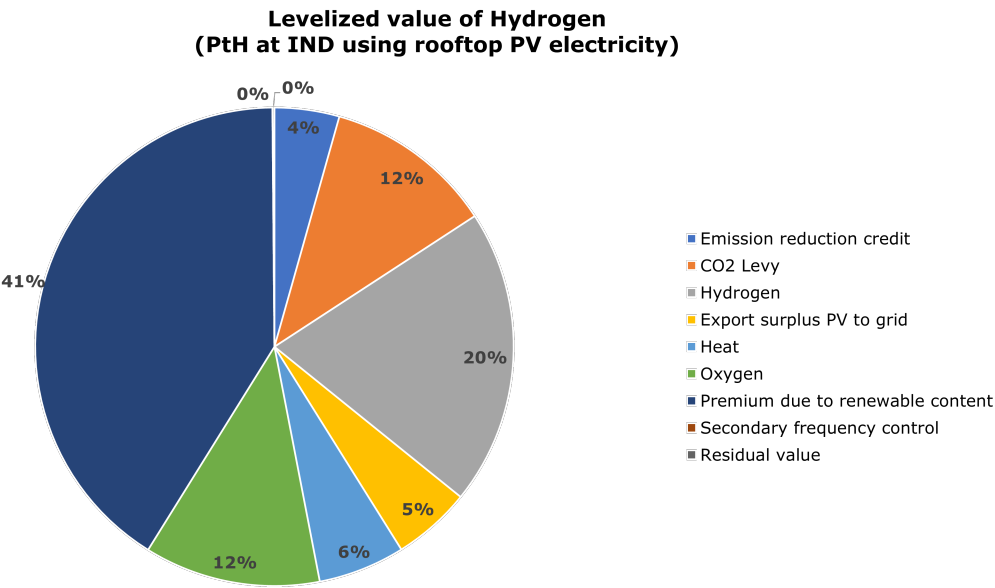


Figure C.7: Breakdown of average levelised value of hydrogen for a 1 MW_e PtH plant deployed at industrial site (PtH at IND) using rooftop PV electricity

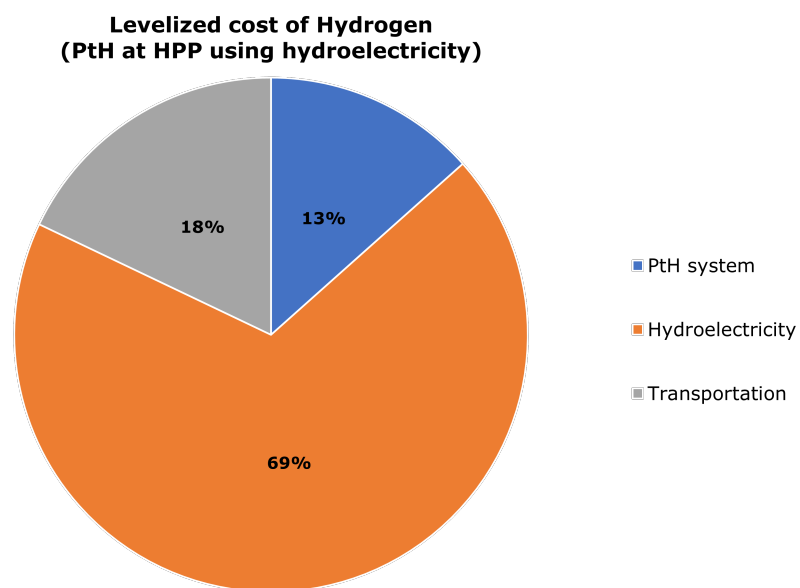


Figure C.8: Breakdown of average levelised cost of hydrogen for a 1 MW_e PtH plant deployed at run-of-river hydropower plant (PtH at HPP) using hydroelectricity

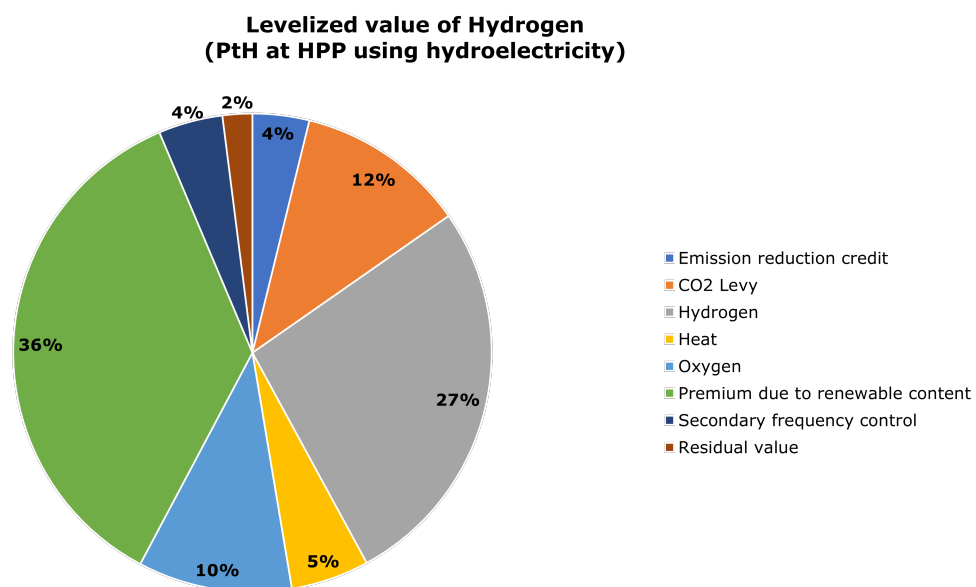


Figure C.9: Breakdown of average levelised value of hydrogen for a 1 MW_e PtH plant deployed at run-of-river hydropower plant (PtH at HPP) using hydroelectricity

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C.2.2 Levelized cost and value of Methane - PtM at industrial location using rooftop PV electricity and at run-of-river hydropower plant using hydroelectricity

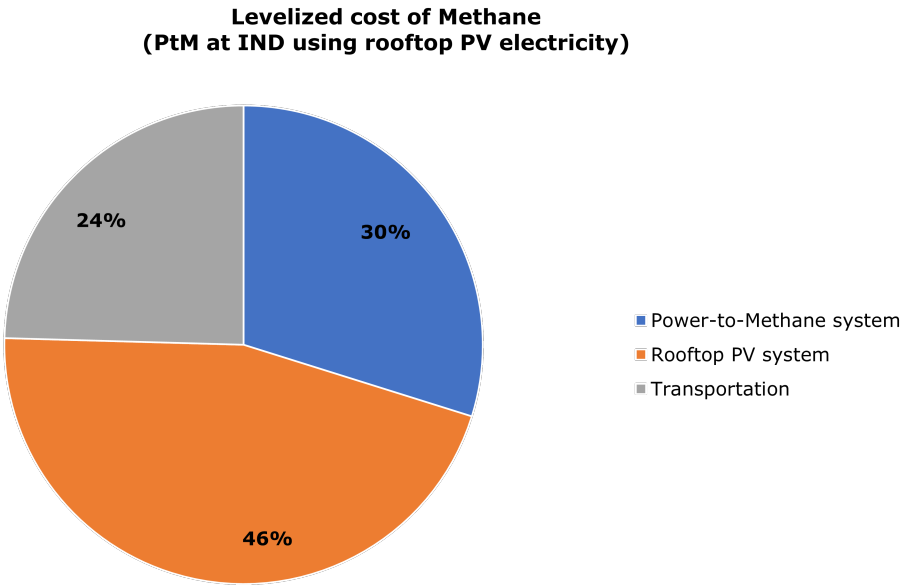


Figure C.10: Breakdown of average levelised cost of methane for a 1 MW_e PtM plant deployed at industrial site (PtM at IND) using rooftop PV electricity

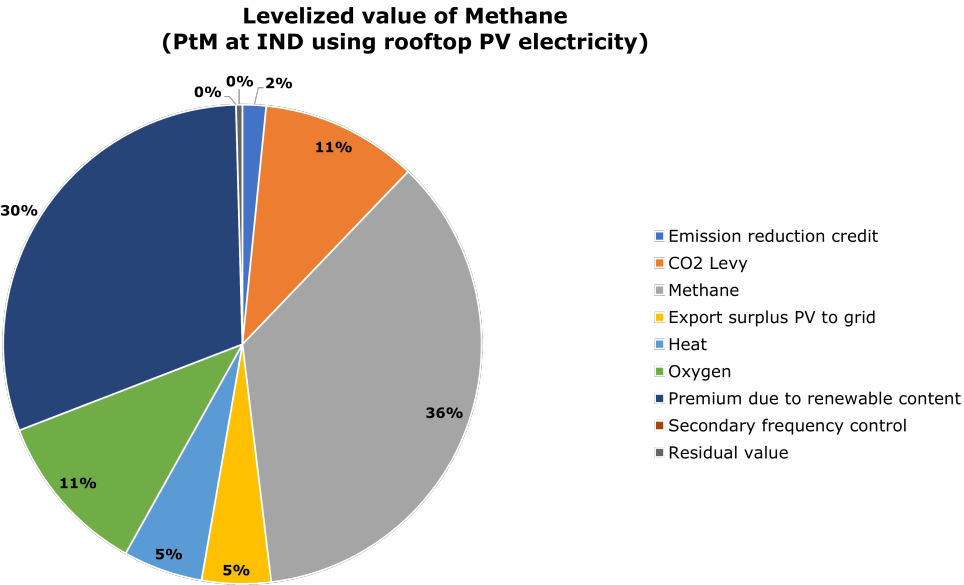


Figure C.11: Breakdown of average levelised value of methane for a 1 MW_e PtM plant deployed at industrial site (PtM at IND) using rooftop PV electricity

**Levelized cost of Methane
(PtM at HPP using hydroelectricity)**

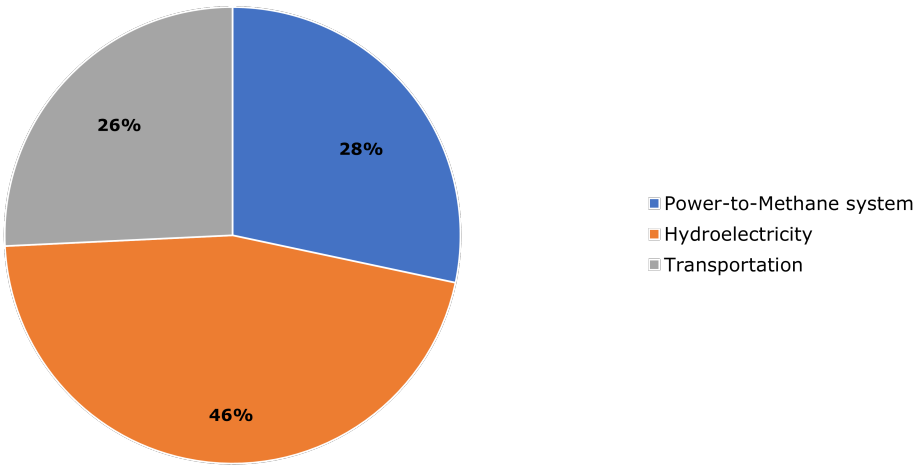


Figure C.12: Breakdown of average levelised cost of methane for a 1 MW_e PtM plant deployed at run-of-river hydropower plant (PtM at HPP) using hydroelectricity

**Levelized value of Methane
(PtM at HPP using hydroelectricity)**

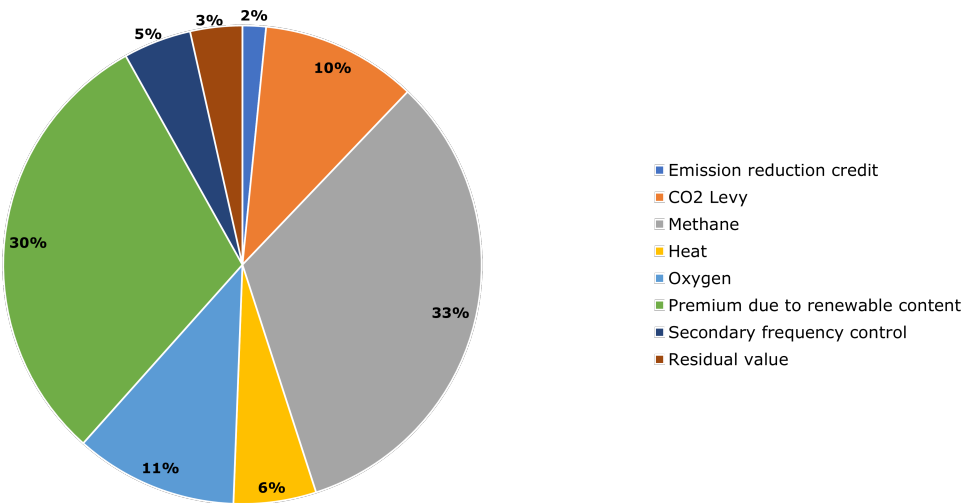


Figure C.13: Breakdown of average levelised value of methane for a 1 MW_e PtM plant deployed at run-of-river hydropower plant (PtM at HPP) using hydroelectricity

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C.2.3 PtM plant deployment across different scenarios using CO₂ via direct air capture

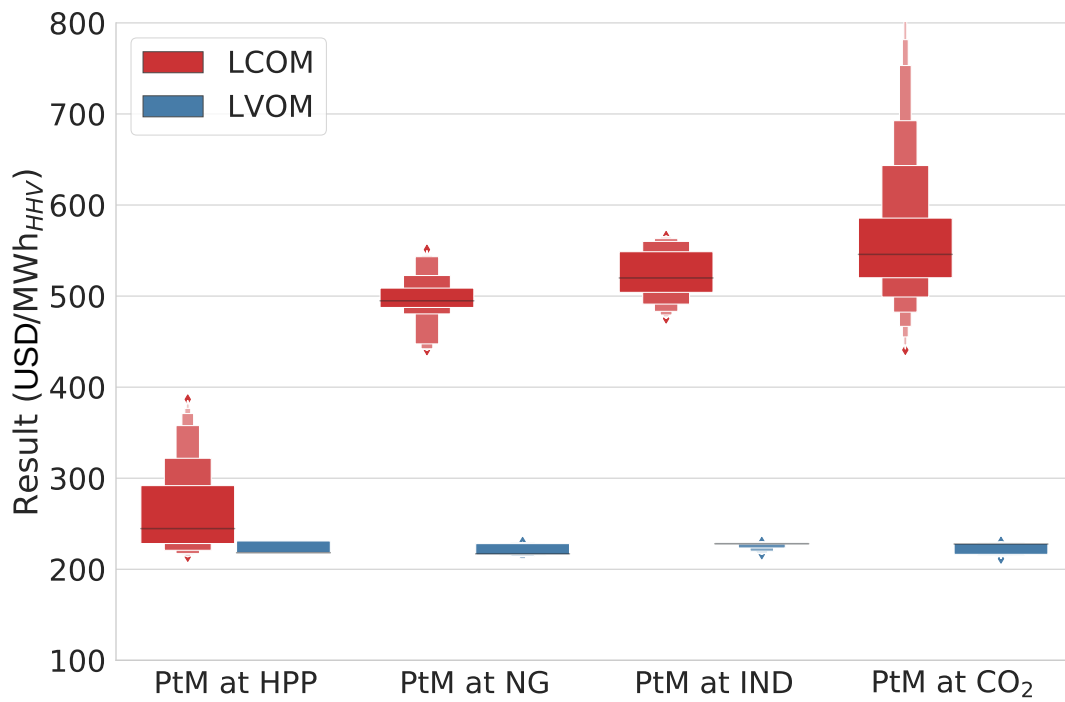


Figure C.14: Levelised cost and value of methane for a 1 MW_e PtM plant using CO₂ captured from air - deployed at RoR hydropower plants (PtM at HPP), natural gas stations (PtM at NG), industrial sites (PtM at IND) and industrial CO₂ supply sites (PtM at CO₂) across Switzerland.

C.2.4 Sensitivity Analysis

For PtM plants located at run-of-river hydropower plant (PtM at HPP), Fig. C.15 shows that the median NPV per unit of CAPEX improves by nearly 60% by 2022 and nearly 270% by 2030 compared to 2020, considering an increase of the Swiss CO₂ levy from 96 USD/tCO₂ in 2020 to 120 USD/tCO₂ in 2022 [59] and to 210 USD/tCO₂ in 2030 ^a.

Further, Fig. C.16 shows that for PtM at HPP, the median NPV per unit of CAPEX improves by up to 356% for a 50% increase in the price of natural gas relative to 2020, thereby assuming that the electricity price remains unchanged.

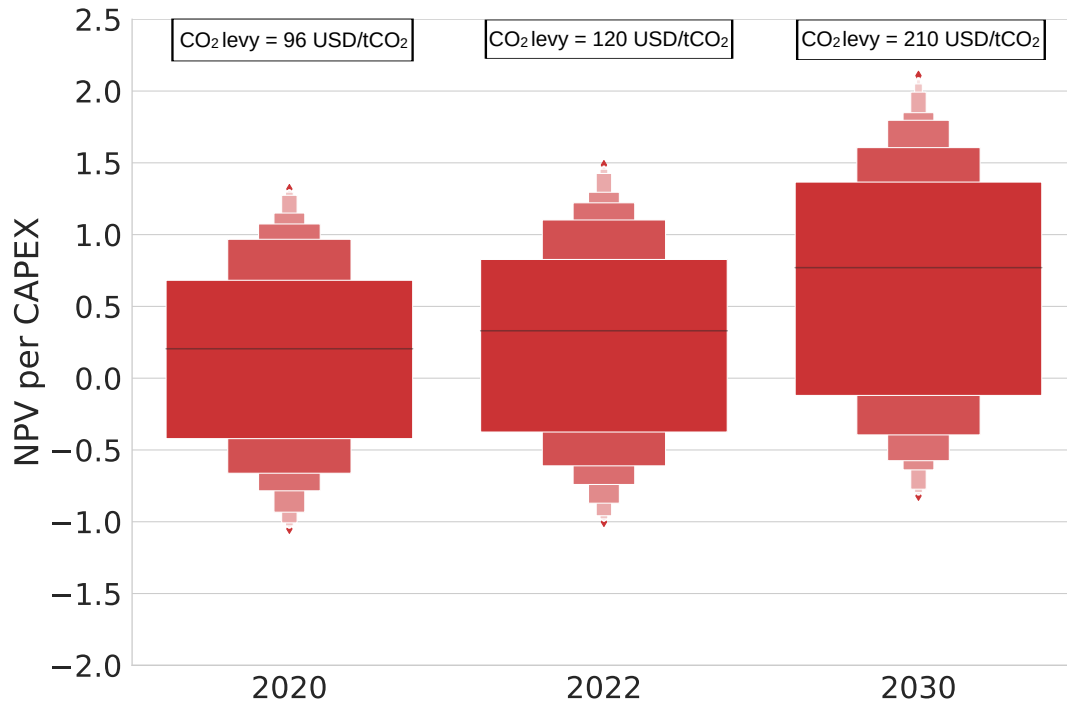


Figure C.15: Evolution of the NPV per unit of CAPEX for PtM plants deployed at the run-of-river hydropower plants (PtM at HPP) for the projected increase in CO₂ levy in 2022 and 2030 compared to 2020.

Fig. C.17 shows that the median NPV per unit CAPEX decreases by 2.4% when adding 2.5 USD/MWh as the average value of hydro guarantee of origin (GO) in 2018 to the wholesale electricity price [375], while keeping all other parameters unchanged. All PtH plants deployed at run-of-river hydropower plants (PtH at HPP) remain profitable when adding GO to the wholesale electricity price. On the other hand, Fig. C.18 presenting PtM deployed at run-of-river hydropower plants (PtM at HPP) shows that the median NPV per unit CAPEX decreases by approximately 80% with the inclusion of GO [375]. As a consequence, only 32 out of 61 PtM plants at HPP are profitable when GO is included, compared to 37 out of 61 plants when the electricity is purchased at the wholesale electricity price without any cost for GO. The reason for this different decrease in the NPV per unit CAPEX of PtH and PtM plants is explained by the different level of system efficiency (67% and 54% respectively), with PtM plans consuming more electricity for a given amount

^aWhile the values of 96 USD/tCO₂ in 2020 to 120 USD/tCO₂ as of 2022 have been enacted, the value of 210 USD/tCO₂ was not endorsed by the recent referendum [333, 336]

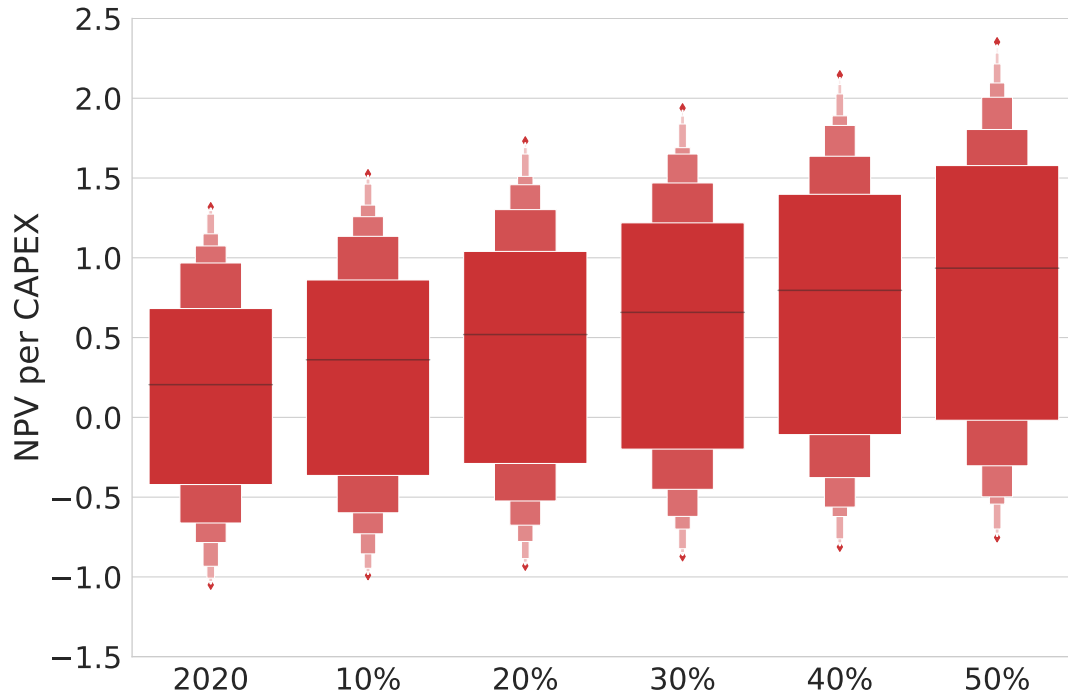


Figure C.16: Evolution of the NPV per unit of CAPEX for PtM plants deployed at the run-of-river hydropower plants (PtM at HPP) to the projected increase in natural gas price by up to 50% compared to 2020.

of energy output (based on the high heating value of the generated gas, namely hydrogen and synthetic methane) (presented in Table C.2). Since a PtM plant consumes more electricity to produce 1 MWh of methane, it is more sensitive to an increase of the electricity prices with GO.

Further, an entity can benefit either from the exemption (avoided cost) of the (Swiss) CO₂ levy or emission allowances under the EU-ETS system, depending on the type of entity which is buying renewable gas from PtG plant [84]. We therefore show the profitability analysis of PtH and PtM plants considering GO as an additional cost and CO₂ levy as an avoided cost (added value) for PtG plants, keeping the other parameters same (SI Fig. C.19, C.20). We do not conduct the same type of analysis for the avoided emission allowances under the EU Emissions Trading System (EU-ETS) system because the related credits have been ranging between 40 USD/tCO₂ in 2014 and 17 USD/tCO₂ in 2019, i.e. the related results lie within the range of the sensitivity analysis assuming the CO₂ levy [332]. Fig. C.19 shows that all the PtH plants deployed at 61 run-of-river hydropower plants (represented in boxen plot) continue to be profitable but only 28 out of 61 PtM plants at HPP (Fig. C.20) show profitability when GO is added to the wholesale electricity price and CO₂ levy (without emission allowances) is considered as an additional value (avoided cost), keeping all other parameters constant.

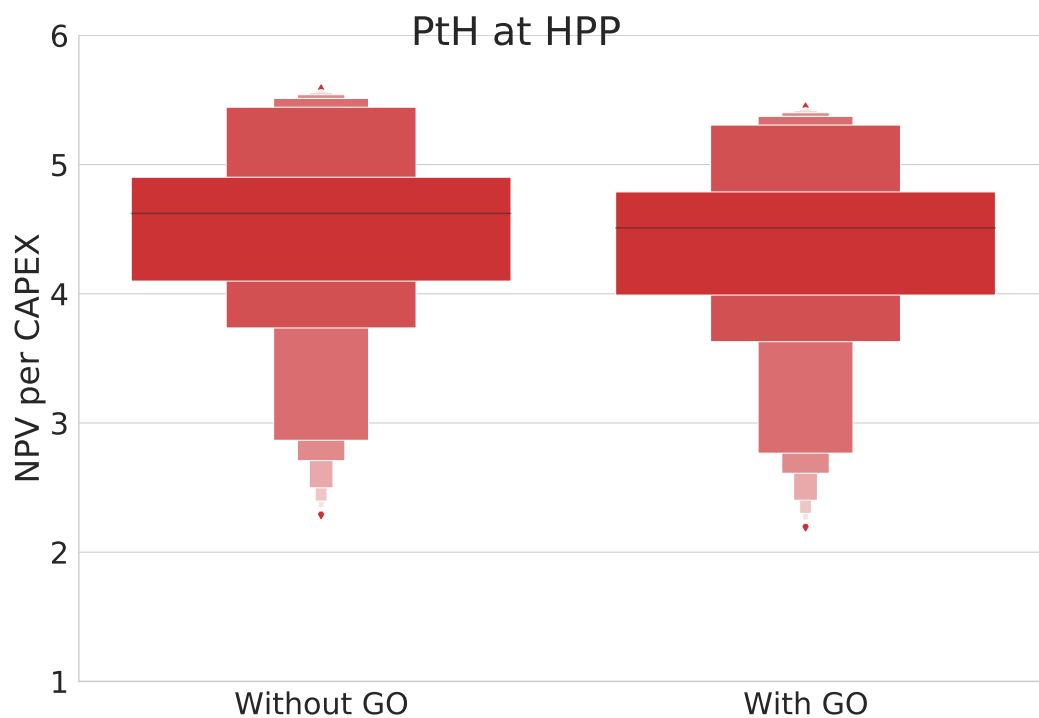


Figure C.17: Evolution of the NPV per unit of CAPEX for PtH plants deployed at the run-of-river hydropower plants (PtH at HPP) with and without addition of Guarantee of Origin (GO) to the wholesale electricity price.

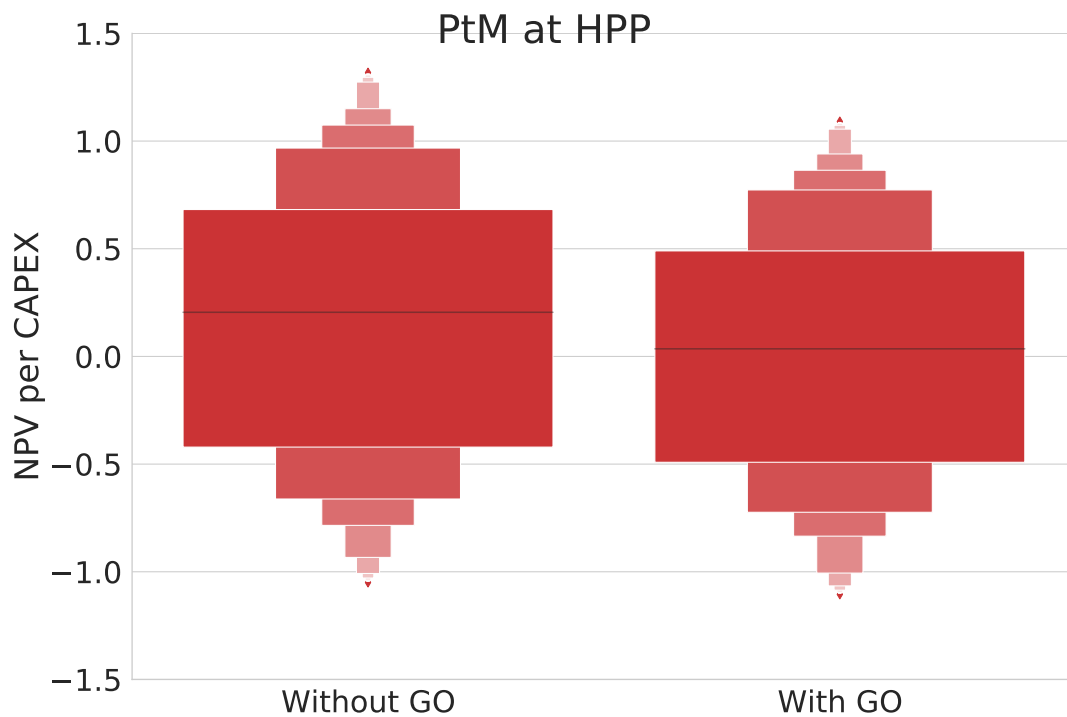
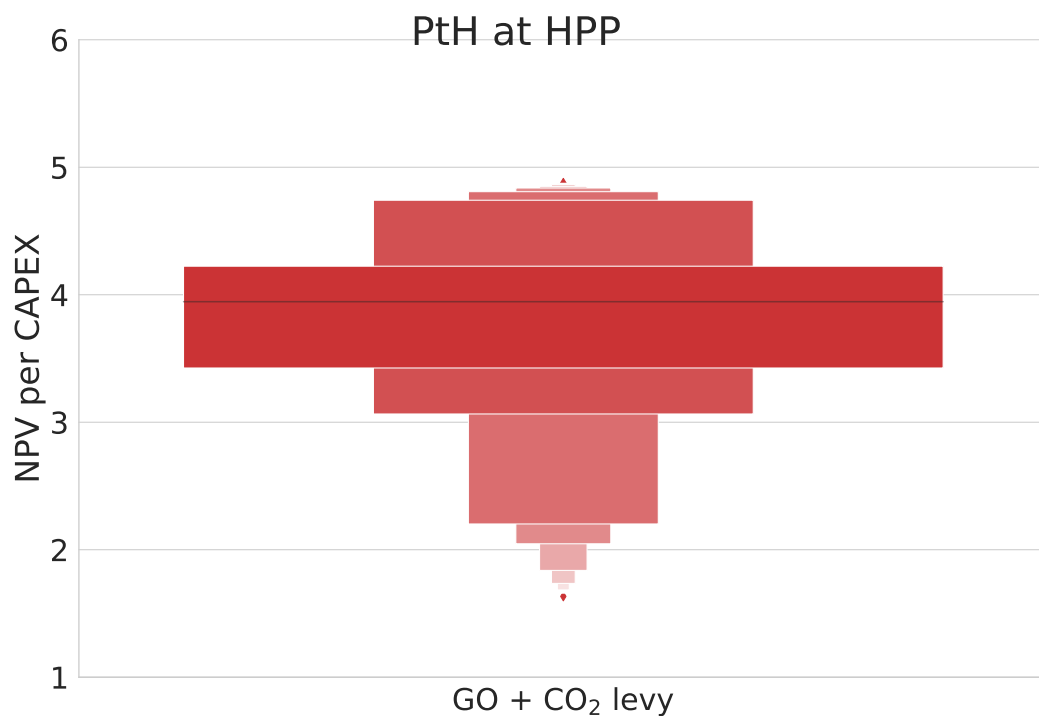


Figure C.18: Evolution of the NPV per unit of CAPEX for PtM plants deployed at the run-of-river hydropower plants (PtM at HPP) with and without addition of Guarantee of Origin (GO) to the wholesale electricity price.



4723 **C.2.5 Power-to-Hydrogen and Power-to-Methane**
4724 **geographical hotspots**

Table C.7: Geographical hotspots for green hydrogen plants deployment across Switzerland along with their geo-coordinates (Coordinate Reference System (CRS)- CH1903/LV03).

HPP plant ID	LCOH	LVOH	NPV per CAPEX	x	y
601600	0.146	0.186	2.293	736530	133880
601700	0.142	0.186	2.512	736340	131600
603500	0.138	0.186	2.737	654960	116310
300700	0.138	0.186	2.777	689570	174490
500500	0.136	0.186	2.896	654000	141880
500600	0.129	0.186	3.286	653190	137990
601900	0.123	0.186	3.629	732260	122620
303000	0.123	0.186	3.637	671330	188310
104400	0.119	0.186	3.834	778490	198540
602000	0.118	0.186	3.922	729570	122250
601000	0.118	0.186	3.925	714670	135930
103300	0.117	0.186	3.969	762540	170330
102900	0.115	0.186	4.050	763840	169970
205400	0.115	0.186	4.054	524050	176030
300900	0.126	0.197	4.054	694280	180250
205150	0.115	0.186	4.098	580200	212100
108700	0.114	0.186	4.151	677850	269870
203800	0.113	0.186	4.166	570030	148590
102800	0.122	0.197	4.243	772200	171210
509700	0.112	0.186	4.258	487060	113160
203500	0.112	0.186	4.260	588270	202020
502500	0.122	0.197	4.269	623540	129860
501000	0.111	0.186	4.281	646430	133600
204800	0.110	0.186	4.329	584980	205810
600800	0.110	0.186	4.376	707690	143960
204200	0.109	0.186	4.438	574770	162120
202400	0.108	0.186	4.481	616940	154630
509900	0.107	0.186	4.535	549560	219100
106500	0.107	0.186	4.537	687400	277120
108950	0.106	0.186	4.563	655130	272150
208600	0.105	0.186	4.622	651030	251440
207800	0.105	0.186	4.645	622240	230980
208900	0.105	0.186	4.650	660100	267760
400500	0.104	0.186	4.678	718010	197210
301700	0.104	0.186	4.703	687990	194880
202500	0.113	0.197	4.749	617310	171740
103700	0.113	0.197	4.792	753220	189360
503000	0.102	0.186	4.805	608390	125620
207700	0.102	0.186	4.835	611460	230920
209000	0.102	0.186	4.838	659200	271840
507900	0.111	0.197	4.863	567150	118200
205500	0.111	0.197	4.874	529280	175530
208100	0.101	0.186	4.886	633200	240250
204900	0.101	0.186	4.887	587330	209660
509600	0.100	0.186	4.899	491050	116530
109400	0.100	0.186	4.902	628170	268750
205000	0.109	0.197	5.029	584000	207850
208800	0.108	0.197	5.052	655130	257820
504400	0.108	0.197	5.057	585950	118380
405300	0.104	0.197	5.293	666530	256630
208300	0.104	0.197	5.301	640850	246650
100900	0.102	0.197	5.389	734150	181900
301400	0.102	0.197	5.427	693360	192440
305300	0.101	0.197	5.461	668540	244040
109100	0.101	0.197	5.484	645930	267420
506400	0.100	0.197	5.495	570640	104160
109700	0.100	0.197	5.505	614130	267700
208500	0.100	0.197	5.531	646140	250060
109500	0.100	0.197	5.539	620410	265150
106200	0.099	0.197	5.552	689470	283180
208400	0.099	0.197	5.582	645090	249500

Table C.8: Geographical hotspots for methanation plants deployment across Switzerland along with their geo-coordinates (Coordinate Reference System (CRS)- CH1903/LV03).

HPP plant ID	LCOM	LVOM	NPV per CAPEX	x	y
204900	0.183	0.231	1.318	587330	209660
109500	0.179	0.231	1.271	620410	265150
109700	0.183	0.231	1.133	614130	267700
106200	0.183	0.231	1.117	689470	283180
208300	0.187	0.231	1.060	640850	246650
503000	0.180	0.218	1.038	608390	125620
208500	0.186	0.231	0.995	646140	250060
305300	0.186	0.231	0.968	668540	244040
506400	0.188	0.231	0.967	570640	104160
509600	0.187	0.231	0.931	491050	116530
208400	0.187	0.231	0.920	645090	249500
109100	0.198	0.231	0.794	645930	267420
207800	0.188	0.218	0.769	622240	230980
208100	0.185	0.218	0.740	633200	240250
507900	0.200	0.231	0.723	567150	118200
205000	0.202	0.231	0.682	584000	207850
504400	0.200	0.231	0.628	585950	118380
207700	0.191	0.218	0.573	611460	230920
106500	0.194	0.218	0.559	687400	277120
109400	0.192	0.218	0.535	628170	268750
502500	0.210	0.231	0.495	623540	129860
208600	0.196	0.218	0.459	651030	251440
208900	0.197	0.218	0.450	660100	267760
405300	0.210	0.231	0.356	666530	256630
205500	0.204	0.218	0.326	529280	175530
501000	0.206	0.218	0.274	646430	133600
209000	0.205	0.218	0.244	659200	271840
509900	0.206	0.218	0.241	549560	219100
208800	0.207	0.218	0.221	655130	257820
205150	0.209	0.218	0.209	580200	212100
103700	0.219	0.231	0.205	753220	189360
203500	0.208	0.218	0.203	588270	202020
204800	0.211	0.218	0.143	584980	205810
108950	0.223	0.231	0.125	655130	272150
108700	0.213	0.218	0.115	677850	269870
202500	0.227	0.231	0.073	617310	171740
509700	0.216	0.218	0.039	487060	113160

C.2.6 Cost improvement targets

In the sensitivity analysis presented under section 4.4 of the manuscript, we find that the PtM plants deployed at industrial CO₂ source, natural gas stations and industrial sites do not show profitability even with envisaged cost reductions in PV (73%), electrolyzer (80%) and methanation reactor (51%) systems cost by 2050. Therefore, we went a step further to set cost improvement targets for electrolzer, PV and/or methanation reactor systems which will allow profitability for PtM plants deployed at CO₂ source, natural gas stations and industrial sites utilizing rooftop

4733 PV electricity. Table C.9 shows the percentage of PtM plants showing profitability
4734 when cost of a given technology are reduced (for e.g. by 90%) beyond the cost
4735 envisaged by 2050, while the cost of other technologies are reduced as envisaged
4736 in 2050. Our results show that the PtM plants at natural gas stations and CO₂
4737 sources begin to show profitability if PV or electrolyzer system costs reduce by 90%
4738 compared to 2020. We see that 16% and 5% of the total PtM plants deployed at
4739 CO₂ sources and natural gas stations respectively become profitable with both PV
4740 and electrolyzer systems cost reduction by 90% compared to 2020. While for PtM
4741 at industrial sites to become economically attractive, aggressive cost reduction of
4742 PV, electrolyzer and also methanation reactor systems by upto 90% compared to
4743 2020 would be needed.

Table C.9: Improvement in profitability of power-to-methane plants at industrial CO₂ source (PtM at CO₂), natural gas station (PtM at NG), industrial sites (PtM at NG) and hydropower plants (PtM at HPP). Abbreviations used: CAPEX_{el} for electrolyzer system CAPEX, CAPEX_{PV} for PV CAPEX and CAPEX_{MR} for methanation reactor CAPEX.

Deployment site	CAPEX _{el} reduced by 90% compared to 80% as envisaged in 2050	CAPEX _{PV} reduced by 90% compared to 73% as envisaged in 2050	Both CAPEX _{el} and CAPEX _{PV} reduced by 90% respectively in 2050 compared to 80% for CAPEX _{el} and 73% for CAPEX _{PV}	CAPEX _{el} reduced by 90% compared to 80% (2050), CAPEX _{PV} reduced by 90% compared to 73% (2050), CAPEX _{MR} reduced by 90% compared to 51% (2050)
PtM at CO ₂ (% of plant profitable)	1%	2%	5%	
PtM at NG (% of plant profitable)	2%	5%	16%	
PtM at IND (% of plant profitable)	0%	0%	0%	17%
PtM at HPP (% of plant profitable)	69%	NA		

Appendix D

Supplementary Information - Macroeconomic analysis of a green hydrogen sector using Input-Output analysis

D.1 Input data

Net commodity taxes (NCT) are defined as taxes minus subsidies on domestic and imported goods. Within the Swiss Input-Output (I-O) table, the NCT (%) per sector is calculated by dividing ‘Taxes less subsidies on products’ divided by ‘Total supply at basic prices incl. net commodity taxes’ as detailed in Table S. D.1.

Table D.1: Net Commodity Taxes (%) of different sector within the IOT table

NOGA code	Industrial sector	Net commodity taxes (%)
01	Agriculture	7,1%
02	Forestry	3,6%
03	Fishing	3,6%
05 - 09	Mining and quarrying	0,5%
10 - 12	Manufacture of food and tobacco products	10,0%
13 - 15	Manufacture of textiles and apparel	5,2%
16	Manufacture of wood and of products of wood and cork, except furniture	0,9%
17	Manufacture of paper and paper products	2,8%
18	Printing and reproduction of recorded media	3,6%
19 - 20	Manufacture of coke, chemicals and chemical products	9,6%
21	Manufacture of basic pharmaceutical products and pharmaceutical preparations	0,7%
22	Manufacture of rubber and plastic products	1,7%
23	Manufacture of other non-metallic mineral products	0,9%
24	Manufacture of basic metals	0,7%
25	Manufacture of fabricated metal products, except machinery and equipment	1,0%
26	Manufacture of computer, electronic and optical products	0,4%
27	Manufacture of electrical equipment	0,7%
28	Manufacture of machinery and equipment n.e.c.	0,1%
29	Manufacture of motor vehicles, trailers and semi-trailers	11,4%
30	Manufacture of other transport equipment	1,1%
31	Manufacture of furniture	3,2%
32	Other manufacturing	1,0%
33	Repair and installation of machinery and equipment	1,0%
35	Electricity, gas, steam and air-conditioning supply	3,6%
36 - 39	Water supply, waste management	1,8%
41 - 43	Construction	1,0%
45	Wholesale and retail trade and repair of motor vehicles and motorcycles	3,4%
46	Wholesale trade, except of motor vehicles and motorcycles	0,2%
47	Retail trade, except of motor vehicles and motorcycles	0,3%
49 - 51	Land, water and air transport and transport via pipelines	-5,8%
52	Warehousing and support activities for transportation	0,1%
53	Postal and courier activities	2,6%
55	Accommodation	3,9%
56	Food and beverage service activities	5,4%
58 - 60	Publishing, audiovisual and broadcasting activities	2,2%
61	Telecommunications	4,5%
62 - 63	IT and other information services	0,7%
64	Financial service activities	5,0%
65	Insurance	0,5%
68	Real estate activities	
69 - 71	Legal, accounting, management, architecture, engineering activities	2,4%
72	Scientific research and development	0,4%
73 - 75	Other professional, scientific and technical activities	2,5%
77 - 82	Administrative and support service activities	2,8%
84	Public administration	0,1%
85	Education	0,6%
86	Human health activities	-22,4%
87 - 88	Residential care and social work activities	0,0%
90 - 93	Arts, entertainment and recreation	2,5%
94 - 96	Other service activities	0,5%
97 - 98	Activities of households as employers of domestic personnel / Undifferentiated goods- and services-producing activities of private households for own use	

D.2 Purchasing Power Parity

Purchasing power parities are indicators of price level differences across countries. They indicate the difference in the cost level of goods and services in different countries. In this study, we use it as a currency conversion rate to convert expenditures expressed in different national currencies into a common currency (the Purchasing Power Standard), thus eliminating the effect of price level differences across countries [107]. Table S. D.2 compares the purchasing price parity of European Union (27 countries) with Switzerland.

Table D.2: Purchasing power parities (38 European countries)

Sector	European Union (27 countries)	Switzerland
	EUR	CHF
Fabricated metal products and equipment (except electrical and optical equipment)	1.0	1.4
Electrical and optical equipment	1.0	1.1
Transport equipment	1.0	1.2
Construction	1.0	1.8
Residential buildings	1.0	1.8
Non-residential buildings	1.0	1.9
Civil engineering works	1.0	1.8
Software	1.0	1.2

D.3 Sensitivity Analysis

Table D.3: Sensitivity analysis to calculate the impact of importing part of the machinery on GDP, employment and GHG emissions

Scenario	Final Demand (M USD)	GDP (M USD)	Employment (FTE)	GHG Emissions (tCO ₂ eq)
All machinery is manufactured within Switzerland	4.67	2.40	15.08	84.18
Half of the machinery is imported	2.67	1.40	9.05	51.70
All the machinery is imported	0.68	0.40	3.03	19.23

D.4 Sectorwise employment and emissions in Switzerland

STAT-TAB presents the information on establishments and jobs per canton and economic division on a yearly basis. Table S. D.4 presents the total FTE jobs [312] and GHG emissions [8] per industrial sector as per NOGA categorization.

Table D.4: FTE jobs and GHG emissions per sector as per NOGA categorization in Switzerland

NOGA code	Industrial sector	Employment (FTE jobs)	GHG emissions in thousand tons of CO ₂ -equivalents
01	Agriculture	100925	7149
02	Forestry	5254	
03	Fishing	398	
05 - 09	Mining and quarrying	4418	80
10 - 12	Manufacture of food and tobacco products	76656	1204
13 - 15	Manufacture of textiles and apparel	11928	73
16	Manufacture of wood and of products of wood and cork, except furniture	35750	416
17	Manufacture of paper and paper products	7043	326
18	Printing and reproduction of recorded media	16746	80
19 - 20	Manufacture of coke, chemicals and chemical products	28006	2264
21	Manufacture of basic pharmaceutical products and pharmaceutical preparations	43319	215
22	Manufacture of rubber and plastic products	20638	75
23	Manufacture of other non-metallic mineral products	16082	3257
24	Manufacture of basic metals	11421	422
25	Manufacture of fabricated metal products, except machinery and equipment	77588	284
26	Manufacture of computer, electronic and optical products	100335	181
27	Manufacture of electrical equipment	30872	92
28	Manufacture of machinery and equipment n.e.c.	71456	215
29	Manufacture of motor vehicles, trailers and semi-trailers	4428	14
30	Manufacture of other transport equipment	10620	34
31	Manufacture of furniture	8748	87
32	Other manufacturing	22812	26
33	Repair and installation of machinery and equipment	17599	28
35	Electricity, gas, steam and air-conditioning supply	25126	1199
36 - 39	Water supply, waste management	16520	6294
41 - 43	Construction	326474	1579
45	Wholesale and retail trade and repair of motor vehicles and motorcycles	77930	315
46	Wholesale trade, except of motor vehicles and motorcycles	198800	843
47	Retail trade, except of motor vehicles and motorcycles	231521	1035
49 - 51	Land, water and air transport and transport via pipelines	120159	7893
52	Warehousing and support activities for transportation	52020	278
53	Postal and courier activities	32061	88
55	Accommodation	61901	407
56	Food and beverage service activities	124984	287
58 - 60	Publishing, audiovisual and broadcasting activities	27428	57
61	Telecommunications	25518	38
62 - 63	IT and other information services	93185	95
64	Financial service activities	109255	189
65	Insurance	45023	91
68	Real estate activities	41004	144
69 - 71	Legal, accounting, management, architecture, engineering activities	279256	414
72	Scientific research and development	23442	121
73 - 75	Other professional, scientific and technical activities	46592	69
77 - 82	Administrative and support service activities	237916	485
84	Public administration	159434	1432
85	Education	227144	73
86	Human health activities	292535	471
87 - 88	Residential care and social work activities	217098	381
90 - 93	Arts, entertainment and recreation	57305	188
94 - 96	Other service activities	110595	274

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D.5 Net impacts analysis considering replacement of diesel by green hydrogen in passenger cars

Table D.5: Net impacts on GDP, employment (FTE jobs) and GHG emissions due to green hydrogen and diesel in the ‘Equal Cost’, ‘Equal Energy’ and ‘Equal Service’ cases - considering all the hydrogen produced from a 1 MW green hydrogen industry is demanded by passenger cars.

Case 1: Equal Cost						
Industry	Fuel energy content (GWh)	Useful energy (GWh)	Final demand change (M USD)	GDP change (M USD)	Employment change (FTE)	GHG emissions change (tCO _{2eq})
Green Hydrogen	4.07	2.04	1.25	0.95	5.96	53.15
Diesel	-13.15	-3.94	-1.25	-0.46	-2.27	-96.71
Others	0.00	0.00	0.00	0.00	0.00	0.00
Net change	-9.07	-1.91	0.00	0.49	3.69	-43.57
Case 2: Equal Energy						
Industry	Fuel energy content (GWh)	Useful energy (GWh)	Final demand change (M USD)	GDP change (M USD)	Employment change (FTE)	GHG emissions change (tCO _{2eq})
Green Hydrogen	4.07	2.04	1.25	0.95	5.96	53.15
Diesel	-4.07	-1.22	-0.39	-0.14	-0.70	-29.96
Others	0.00	0.00	-0.86	-0.60	-3.48	-35.06
Net change	0.00	0.81	0.00	0.21	1.78	-11.86
Case 3: Equal Service						
Industry	Fuel energy content (GWh)	Useful energy (GWh)	Final demand change (M USD)	GDP change (M USD)	Employment change (FTE)	GHG emissions change (tCO _{2eq})
Green Hydrogen	4.07	2.04	1.25	0.95	5.96	53.15
Diesel	-6.79	-2.04	-0.65	-0.24	-1.17	-49.92
Others	0.00	0.00	-0.61	-0.42	-2.44	-24.57
Net change	-2.71	0.00	0.00	0.29	2.35	-21.35

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Summary

Ruchi Gupta is an experienced clean energy professional with over 11 years of experience working under different capacities for the government, industry, and academia. She joined VITO as Senior R&D, International Energy and Climate Strategy in July 2022. In her PhD work at the University of Geneva, she focused on three different flexibility options, namely energy storage technologies, grid reinforcement and sector coupling (green hydrogen) to support decarbonization. In her tenure prior to PhD, Ms. Gupta worked for the Government of India on policy and strategy formulation, international cooperation, strategic designing to leading programmes, research and modelling, project management, liaising, communications, training and capacity building in the field of renewable energy and sustainability. She made significant contributions to the work on power sector, renewable energy integration, off-grid rural electrification, electricity market, energy efficiency, sustainable development goals and G20 energy policy. Ms. Gupta was also instrumental in setting up the Centre of Excellence for Sustainable Development at the Indian Institute of Corporate Affairs. In her role as a consultant, she trained around 200 Corporate Social Responsibility (CSR) & Sustainability officers in the area of environmental sustainability. Ms. Gupta earned her master's degree in environmental sciences from TERI University, New Delhi.

Work Experience

Genk, Belgium

July 2022 – till date

Senior R&D – International Energy and Climate Strategy

Flemish institute for technological research (Dutch: *Vlaamse Instelling voor Technologisch Onderzoek* or VITO)

- Involved in international (outside EU) climate and energy projects with European and international, local partners and stakeholders.
- Coordinating and participating in model development, scenario analysis and scientific reporting on techno-economic optimization as well as simulation models.
- Leading the preparation of client offers, research proposals and seeking funding opportunities.
- Conducting and coordinating consultative assignments.
- Conducting research on energy efficiency, electrification, power-to-X, carbon capture storage and utilization and infrastructure development to reach net-zero carbon emissions.
- Business development activities in exploring research questions for energy and climate related areas.

Geneva, Switzerland

Aug. 2017 – June 2022

Researcher and PhD Fellow – Renewable Energy and Storage

University of Geneva (UNIGE)

Focus on different **flexibility options** to support the integration of renewable energy and low carbon technologies.

Responsible for **structuring** independent energy projects – conceptualization and defining timelines, developing methodology and models, input data, formal analysis, investigation, visualization, writing and review.

Important outcomes:

- Developed a method and [calculator](#) to simulate the performance and levelized cost of **hybrid systems (renewable energy and storage)** to provide firm electricity supply under various supply strategies and scale ([Gupta R et al. 2020](#)).

- Collaborated with BKW (Swiss utility company) to calculate the level and cost of distribution **grid reinforcement** needed to integrate **PV, heat pumps** and **electric vehicles** charging, and how **battery** storage can help to defer reinforcement ([Gupta R et al. 2021](#)).
- Assessed the geographical potential of **green hydrogen** as a flexibility option for Switzerland by: i) comparing the levelized cost and value of green hydrogen plants across locations; ii) identifying hotspots for hydrogen deployment; iii) setting cost improvement targets; and iv) deployment strategies and roadmap ([Gupta R et al. 2022](#)).
- Evaluated the macroeconomic impacts (GDP, employment, and emissions) of **green hydrogen** industry in Switzerland.

New Delhi, India

Mar. 2016 – Jul. 2017

Young Professional – Energy and Climate Change

NITI Aayog (Government of India)

Conducted policy research and strategy formulation in renewable energy, environment, and climate change.

Important outcomes:

- Contributed to the **India's National Energy Policy** and Three-Year Action Agenda on Energy.
- **Undertook collaborative research** on '[Assessing impact of high penetration of renewable electricity on the Indian grid in FY 2046-47](#)' with the Institute of Energy Economics, Japan and Lawrence Berkeley National Laboratory.
- Selected to represent India at the US DoE under the **US-India Partnership to Advance Clean Energy (PACE) Fellowship** and counselled the Government of India to refine their energy data management (EDM) practices.
- Made significant contributions to the work on decentralized renewable energy for rural electrification, electricity markets, renewable energy roadmap, power sector reforms, energy efficiency, GIS energy map of India and G20 Energy Policy.

New Delhi, India

Jun. 2011 – Mar. 2016

Consultant – Renewable Energy and Environmental Sustainability

Indian Institute of Corporate Affairs (IICA), Ministry of Corporate Affairs

Responsible for energy and environmental sustainability projects under Corporate Social Responsibility (CSR) at the Centre of Excellence for Sustainable Development.

Important outcomes:

- **Key person** in setting up the Centre of Excellence for Sustainable Development within IICA.
- **Trained** around 200 CSR & sustainability officers from different corporates
- **Designed, defined budget and timelines** for projects/programmes in environmental sustainability (focus on solar and wind).
- **Liaising** between corporates and project implementing partners for deploying real-time projects on ground.
- **Devised** baseline survey & micro plan reports for villages under the 'Smart Village – Smart Ward' programme.
- Active **member** of the **tender and evaluation committee** for granting funds and awarding research projects
- Authored **articles** for the IICA quarterly newsletter 'Corporate Odyssey'.

Gurgaon, India
Dec. 2010 – Jun. 2011

Environmental Scientist (Master Thesis)
J.M. EnviroNet (P) Ltd.

- Involved in the formulation of **Environmental Management Plan**, Social Impact Assessment plan for various cement and thermal plant projects.
- Assessed the **environmental impacts** of an integrated cement plant (air quality modelling and life cycle assessment).

New Delhi, India
May 2010 – Jul. 2010

Intern
PepsiCo

- Studied water management systems and water analysis at various stages of the plant.

International Projects

Washington D.C., United States
Jun. 2017 (3 weeks)

US-India PACE Fellowship
US Department of Energy and Pacific Northwest National Laboratory

Learnt from US best practices on EDM and modelling, and then prepared recommendations for the Government of India for establishing an integrated EDM cell.

Lausanne, Switzerland
Nov. 2014 – Jan. 2015

Visiting Research Fellow
École Polytechnique Fédérale de Lausanne (EPFL)

Project title: Smart Microgrid Technology as a potential intervention under CSR to address the issue of electricity in rural India using renewable energy sources.

**Erlangen, Augsburg
& Berlin, Germany Erlangen,**
Oct. 2013 (4 weeks)

Business Development for Renewable Hybrid Systems (Wind & Solar)
Spitzenenergie, Dosch Messapparate & Kraus Elektrotechnik
Project title: Understanding of wind-solar hybrid systems and exploring their potential for rural electrification in India

Education

New Delhi, India
Aug. 2009 – Aug. 2011

MSc in Environmental Sciences (Grade: 8.47/10)
The Energy & Resources Institute (TERI)

New Delhi, India
Aug. 2006 – Jul. 2009

BSc (Hons) (Grade: 75.8%)
Sri Venkateswara College, Delhi University

Secured 2nd rank in college and 3rd rank in UDSC (University of Delhi, South Campus 2006-07)

Languages

English & Hindi	Mother Tongue
French	A2

Computer Skills

Programming & Database management	Python, Matlab, PostgreSQL
Statistics & GIS	Minitab, QGIS
Modelling tools	IESS, ISC-AERMOD, SimaPro 7.3, Qual2K, LINGO
General	Microsoft Office (Word, Excel, PowerPoint), Latex