Assessing the impact of location-specific characteristics on the profitability and emission mitigation potential of local energy systems applying sector coupling

Frida Huglen Revheim[a,*], Daniel Schwabeneder[a], Georg Lettner[a]

[a] *TU Wien*
Institute of Energy Systems and Electrical Drives
Energy Economics Group (EEG)
Gußhausstraße 25-29/E370-3, A-1040 Vienna

Abstract

Continued implementation of renewable energy sources could face an uncertain future in the current energy economic environment, due to low electricity prices and expiring subsidies. Energy sector coupling could be a financially viable strategy to assure the continued implementation and operation of renewable energy sources. By utilizing the concepts of sector coupling to produce green hydrogen and green heat, significant emission reductions can be achieved. Furthermore, curtailment of renewable electricity generation can be reduced. This study utilizes energy modeling to investigate how local energy systems that apply sector coupling concepts may prove more profitable and more adept at mitigating greenhouse gas emissions, depending on system location and site-specific characteristics (e.g. electricity generation, gas demand, and accessible fuel alternatives). An optimization model is developed with the objective to optimize the operation of the defined system and maximize profit while fulfilling local energy demand requirements at all times. To thoroughly assess the system operation at various geographic locations, three separate use cases with individual scenarios are defined. The results show a clear correlation between utilization of sector coupling concepts and the system's potential to mitigate greenhouse gas emissions, increase the degree of energy self-reliance and reduce curtailment. A cost-benefit analysis is performed and the results indicate that the profitability of local sector coupled systems heavily depend on the hydrogen market value.

Keywords: Sector coupling, Local energy system, Energy modeling, Greenhouse gas emission reduction, Local renewable energy

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*Corresponding author. Phone: +43-(0)1-58801-370375
Email address: `revheim@eeg.tuwien.ac.at` (Frida Huglen Revheim)

Nomenclature

Abbreviations

AGGM Austrian Gas Grid Management
CBA Cost-Benefit analysis
CHP Combined Heat and Power
COP Coefficient of performance
EV Electric vehicles
GHG Greenhouse gas
LP Linear programming
NVE The Norwegian Water Resources and Energy Directorate
O&M Operation and Maintenance
P2G Power-to-Gas
P2H Power-to-Heat
RES Key performance indicator
RES Renewable energy sources

Parameters

η efficiency parameter
λ annuity rate of technology
ϕ charging or discharging rate of storage unit
ρ parameter for level of hydrogen in storage unit
θ standby losses factor
C parameter associated with costs [EUR/MWh]
Cap capacity of technology [MWh]
COP heat pump COP
D parameter associated with energy demand [MWh]
$Limit$ hydrogen feed-in limit [MWh]
P parameter associated with price for selling energy [EUR/MWh]

Sets

t $\in \mathcal{T}$ = {1, ..., T} Time steps

Decision variables

x variable associated with energy flows [MWh]

Superscripts

buy energy bought from an external source
ely electrolyzer
$Gmarket$ gas market
$H2market$ hydrogen market
hp heat pump
max maximum
min minimum
$sell$ energy sold to an external market
soc state of charge

Subscripts

$annual$ annualized investment
cap capital cost of technology
$charge$ charging rate
$discharge$ discharging rate
el electricity
h hydrogen
ng natural gas
$O\&M$ operation and maintenance
t time step
th heat

1. Introduction

The share of local energy sources is rapidly increasing together with the growing implementation of renewable volatile energy sources. Nevertheless, low electricity prices and expiring subsidies result in challenging economic operation of renewable energy sources (RES) [1]. Hence, further implementation of RES could face an uncertain future in the current energy economic environment [2, 3].

Innovative operating concepts are therefore needed to ensure continued operation and expansion of generation, conversion, and storage capacities based on RES. Energy sector coupling could be an economically viable solution to ensure the continuation of RES implementation and operation [4]. The concept opens up market segments for new energy services and products by coupling electricity, heating, and gas sectors. By utilizing the concepts of sector coupling to produce green hydrogen and green heat, significant emission reductions can be achieved in emission-prone sectors such as the heating sector and the mobility sector [5, 6, 7]. Especially the heating sector has proven challenging to decarbonize, due to the high flexibility of supply needed to cover the varying demand as well as the great span of requirements (from low-temperature space heating to high-temperature heat required in industrial processes) [8]. Additionally, large heat demands in some countries make decarbonizing the heating sector a problem of scale [8]. Green hydrogen and green heat can be produced through the utilization of sector coupling technologies, and applied, depending on its qualities, as heat for industrial processes, fed into district heating networks, or as an alternative to natural gas. Furthermore, curtailment of renewable electricity generation can be reduced [4, 6]. Depending on system location and location-specific variables (e.g. electricity generation, gas demand, and fuel options available), the investigated sector coupling concept may prove more profitable and more adept at mitigating greenhouse gas emissions in certain areas.

The economic and environmental potentials of exploiting synergies through sector coupling have gained increased attention, as the concept facilitates an economically efficient green transition [9]. Robinius et al. (2017) provide a thorough review of the general principles behind sector coupling as well as an overview of the various pathways which connect the power sector and the transport sector [10]. These concepts are investigated further through a case study of sector coupling applied in Germany, and the economic feasibility of sector coupling is evaluated [11]. Victoria et al. (2019) explore the benefits of coupling the electricity, heating, and mobility sectors for a European energy system. The study concludes that electric vehicles (EV) have the potential to help balance the system in the short-term, while large-scale thermal storage may assist in balancing at long-term level [12]. The flexibility offered by sector coupling is investigated by Pfeifer et al. (2021), which model different flexibility options and evaluate their economic impact on the energy transition [13]. The flexibility offered by Power-2-Heat (P2H) was investigated by Gjorgievski et al. (2021), who propose that the concept offers a wide range of capabilities and demand response benefits [14]. Energy conversion through Power-2-Gas (P2G) technology is the focal point of a study conducted by Vandewalle et al. (2015), and falling gas prices were observed by utilizing an operational model to assess the interactions between the electricity, gas, and CO_2 sectors [15]. An economic analysis of a German case study applying energy conversion technology is assessed by Schiebahn et al. (2015), concluding that P2G technology may serve as long-term electricity storage, however, costs related to the electrolysis process must be reduced to encourage P2G conversion [16]. Brown et al. (2018) propose that the benefits achieved through grid expansion, including reduced total system costs, were weaker when applying tighter sector coupling [17]. The utilization of green hydrogen as fuel in the German passenger car transportation sector is investigated through a pathway analysis by Emonts et al. (2019). The study considers scenarios with different degrees of hydrogen demands in order to establish robust infrastructure design in a cost-optimal manner [18]. Research by Moriarty and Honnery (2019) investigates the potential of hydrogen as fuel in the transport sector, stating that hydrogen has a clear advantage over electricity when it comes to heavy freight transport [19].

In this paper, a comparative analysis is performed to evaluate the influence of site-specific conditions, such as electricity generation, local energy demands, and available fuel options, on system operation and profitability. The effect of sector coupling on the system operation, and its potential benefits related to cost reductions and emission mitigation, are analyzed in the modeled use cases and scenarios. The use cases are defined on a local scale, to ensure that local benefits are detected and that the complexity of the evaluated energy system is accounted for. Synergies between the electricity, heat, and gas sectors are evaluated, as the exclusion of sectors may result in an overestimation of the significance of some technologies [5, 17]. Furthermore, the contributions of this paper include an assessment of the correlation between operating the system in a cost-optimal manner and the aim to reduce emissions by utilizing green heat and green hydrogen.

The method applied to perform the analysis needed for the contributions of this paper includes the development of a linear programming (LP) operational optimization model. The model enables optimization of local energy systems with the objective to maximize profit and cover all local energy demands over the course of the complete period of analysis (i.e. one year). Individual scenarios with varying technological topology are explored and serve as a basis for comparison of the influence of site-specific conditions on the system operation. In addition to the analyses done by the operational model, a Cost-Benefit analysis (CBA) is performed to include investment costs in the profitability evaluation and the monetary benefit of GHG emission reduction, thus increasing the validity of the results of this work.

The paper is structured as follows: Section 2 presents the applied methodology, including a description of the model development, the analyzed use cases, and scenarios. Section 3 includes an overview of the results of this work for each investigated use case, as well as the results from the CBA. Section 4 concludes the paper.

2. Materials and methods

This section provides an overview of the model development, including the formulation of the optimization problem and the cost-benefit analysis (CBA) evaluated. Furthermore, the investigated use cases and scenarios are described.

2.1. Model development

To evaluate the technical and organizational requirements for synergetic operations of coupled electricity, district heating, and gas networks, a mathematical optimization model is developed in Julia [20]. An overview of the modeled system is presented in Figure 1. The investigated system includes both P2H and P2G concepts, through the implementation of a heat pump and an electrolyzer. The model aims to optimize the operation of the defined system and maximize the profit while fulfilling local energy demand requirements related to electricity, district heating, and gas at all times.

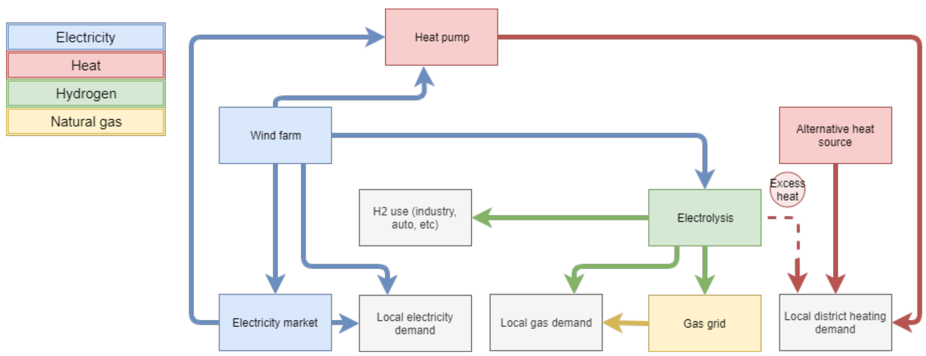


Figure 1: Schematic model overview

The P2H concept and its central aspects are implemented by connecting a wind farm to a district heating network via a heat pump. The heat pump is supplied with electricity from the wind farm as well as from the power grid and consequently generates renewable heat. This heat can be fed into the district heating network, reducing the need for alternatively generated heat to cover the local district heating demand. In addition, restrictions and expensive grid reinforcements can be avoided or delayed by feeding excess electricity into the heat pump. By producing hydrogen through an electrolysis process, which utilizes electricity from a wind farm, a renewable gas feed-in product is developed. The green hydrogen can either be sold to the gas market, sold to a hydrogen market (i.e. hydrogen demand from industry or mobility), or used to cover the local gas demand. Natural gas is supplied from the gas market to ensure that the local gas demand is met during the entire analysis horizon. Excess heat generated by the electrolyzer assists in covering the local district heating demand.

2.2. Formulation of optimization problem

The utilized model is designed as a linear programming (LP) problem that uses an hourly resolution. The temporal scope of the analysis is one year, whereas the spatial scope is limited to the processes depicted in Figure 1.

2.2.1. Objective function

The objective of the investigated LP model is to determine the schedule which maximizes the profit of the assessed scenario, while considering various costs, such as fuel costs and Operation and Maintenance (O&M) costs. Let $\mathcal{T} = \{1, ..., T\}$ denote the set of all time steps considered in the optimization model. The decision variables are denoted as x in MWh at each time step, with the subscript declaring the energy carrier and the superscript declaring the utilization. $P_{el,t}$, P_{NG}, P_{H2} represent the day-ahead spot market price for electricity at each time step in EUR/MWh, the average annual spot market price for natural gas in EUR/MWh, and the assumed price for green hydrogen in EUR/MWh. Costs for procuring electricity from the electricity market, natural gas from the gas market, and heat from an alternative heat source include relevant grid tariffs and fees and are denoted as $C_{el,t}$, C_{NG}, C_{th}, respectively. Costs related to the operation and maintenance are denoted by $C_{O\&M,t}$ at each time step in EUR/MWh. No investment costs are considered in the objective function. The objective function is given in equation 1.

$$\begin{aligned} \text{maxProfit} = \sum_{t \in T} (&P_{el,t} \cdot x_{el,t}^{sell} + P_{NG} \cdot x_{h,t}^{Gmarket,sell} + P_{H2} \cdot x_{h,t}^{H2market,sell} \\ &- C_{NG} \cdot x_{ng,t}^{buy} - C_{th} \cdot x_{th,t}^{buy} - C_{el,t} \cdot x_{el,t}^{buy} - C_{O\&M,t}) \end{aligned} \tag{1}$$

2.2.2. Constraints

2.2.2.1 Local energy demands

The electricity demand is met by electricity from the wind farm, $x_{el,t}^{windfarm,demand}$, and electricity bought from the electricity market, $x_{el,t}^{buy,demand}$. The constraint which ensures the coverage of the electricity demand in all time steps is given in equation 2. The district heating demand is represented in equation 3. The demand is met by heat from the heat pump, excess heat from the electrolyzer, and heat bought from an alternative heat source which are denoted as $x_{th,t}^{hp}$, $x_{th,t}^{ely}$, and $x_{th,t}^{buy}$, respectively. Equation 4 presents the covering of the local gas demand, which is reliant on hydrogen supplied from the electrolyzer, $x_{h,t}^{ely}$, and hydrogen supplied from the hydrogen storage unit (when applicable), $x_{h,t}^{storage}$, as well as natural gas bought from the gas market, $x_{ng,t}^{buy}$.

$\forall t \in \mathcal{T}$:

$$D_{el,t} = x_{el,t}^{windfarm,demand} + x_{el,t}^{buy,demand} \tag{2}$$

$$D_{th,t} = x_{th,t}^{hp} + x_{th,t}^{ely} + x_{th,t}^{buy} \tag{3}$$

$$D_{gas,t} = x_{h,t}^{ely} + x_{h,t}^{storage} + x_{ng,t}^{buy} \tag{4}$$

2.2.2.2 Technical constraints

Modeling the heat pump requires several heat pump specific constraints. Equation 5 regards the heat pump capacity, denoted Cap_{th}^{hp}. The actual heat produced by the heat pump is defined in equation 6. The production depends on the COP, which varies seasonally, and the amount of incoming electricity, $x_{el,t}^{windfarm,hp}$ and $x_{el,t}^{buy,hp}$, in the investigated time step.

$\forall t \in \mathcal{T}$:

$$x_{th,t}^{hp} \leq Cap_{th}^{hp} \tag{5}$$

$$x_{th,t}^{hp} = COP_t^{hp} * (x_{el,t}^{windfarm,hp} + x_{el,t}^{buy,hp}) \tag{6}$$

The capacity of the electrolyzer, Cap_{el}^{ely}, regulates the amount of electricity fed into the electrolyzer at each time step, as shown in equation 7. The hydrogen production by the electrolyzer is defined in equation 8, with $x_{h,t}^{ely}$ denoting the hydrogen output. The production depends on the efficiency of the electrolyzer, η_h^{ely}, as well as the amount of incoming electricity at the given time step. The amount of excess heat generated during the electrolysis process, $x_{th,t}^{ely}$ depends on the thermal efficiency, η_{th}^{ely}, of the electrolyzer and is given in equation 9.

$\forall t \in \mathcal{T}$:

$$x_{el,t}^{windfarm,ely} \leq Cap_{el}^{ely} \tag{7}$$

$$x_{h,t}^{ely} = \eta_h^{ely} * x_{el,t}^{windfarm,ely} \tag{8}$$

$$x_{th,t}^{ely} = \eta_{th}^{ely} * x_{el,t}^{windfarm,ely} \tag{9}$$

The amount of electricity sold from the wind farm to the electricity market, $x_{el,t}^{sell}$, must not exceed the capacity of the connecting power grid, as seen in equation 10.

$\forall t \in \mathcal{T}$:

$$x_{el,t}^{sell} \leq Cap_{el}^{powergrid} \tag{10}$$

A feed-in limit is defined to regulate the amount of hydrogen entering the gas market, presented in equation 11. The limit is set to 4% of the national gas demand [21].

$\forall t \in \mathcal{T}$:

$$x_{h,t}^{Gmarket,sell} \leq Limit_{h,t} \tag{11}$$

The state of charge of the hydrogen storage tank is represented by equation 12, where $x_{h,t}^{soc}$ denote the state of charge and $x_{h,t}^{loss}$ denote the standby losses. The input and output of hydrogen to the storage tank is written as $x_{h,t}^{ely,storage}$ and $x_{h,t}^{storage}$, respectively. The standby losses are calculated in equation 13 where θ_h^{loss} represent the assumed coefficient for losses. Equation 14 regulates the state of charge, where $Cap_h^{storage}$ denotes the storage capacity and ρ_h^{min} is the minimum level of hydrogen. ϕ_{charge}^{max} and $\phi_{discharge}^{max}$ represent the maximum charging and discharging rate of the hydrogen storage unit, as seen in equations 15 and 16.

$\forall t \in \mathcal{T}:$

$$x_{h,t}^{soc} = x_{h,t-1}^{soc} + x_{h,t}^{ely,storage} - x_{h,t}^{storage} - x_{h,t}^{loss} \tag{12}$$

$$x_{h,t}^{loss} = x_{h,t-1}^{soc} \cdot \theta_h^{loss} \tag{13}$$

$$Cap_h^{storage} \cdot \rho_h^{min} \leq x_{h,t}^{soc} \leq Cap_h^{storage} \tag{14}$$

$$x_{h,t}^{ely,storage} \leq Cap_h^{storage} \cdot \phi_{charge}^{max} \tag{15}$$

$$x_{h,t}^{storage} \leq Cap_h^{storage} \cdot \phi_{discharge}^{max} \tag{16}$$

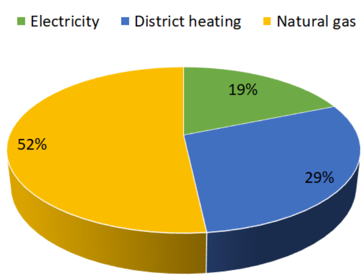
2.3. Description of use cases

To thoroughly assess the system operation at various geographic locations, three separate use cases are defined to represent local energy systems within Austria, Norway, and Spain. Relevant parameters and input data from each respective country are gathered and used as input for the model. It is assumed that all use cases have a wind farm installed. The installed capacity of the individual wind farms is based on real-life values [22, 23, 24]. The transmission capacity between the wind farm and the electricity market is assumed to equal the installed capacity of the individual wind farms. Unless otherwise stated, the price for green hydrogen is assumed to be 170 EUR/MWh [25, 26], which is based on what industry is willing to pay and the production costs for green hydrogen. All information regarding energy demands is gathered from the Eurostat database [27] and scaled to the respective use cases. Electricity prices are obtained from the ENTSO-e Transparency platform [28] and standard electricity load profiles and heat load profiles are used to simulate the change in demand over the year. The gas load profile is based on consumption data from AGGM [29] and scaled to the respective use cases.

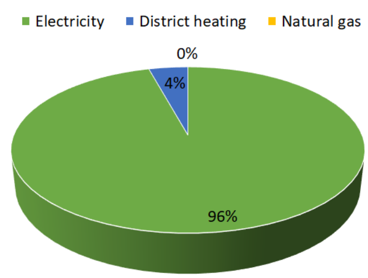
A local electricity demand, a local district heating demand, and a local gas demand are assumed for all use cases. The individual demands are scaled to the different use cases, based on use case size and local energy consumption. The electricity demand includes both electricity used for heating purposes as well as electricity used for lighting, cooling, and other electric appliances. The local district heating demand is based on information regarding the utilization of district heating in the different use cases. The gas demand includes the demand for gas that is used for heating by the considered households. Gas utilized for other purposes than heating is excluded from the considered demand. The composition of the heat demand of the different use cases are shown in figure 10. Around half of the heat demand in the Austrian use case is covered by gas and the remaining parts are covered by electricity and district heating. For the Norwegian use case, approximately 96% of the heat demand is met by electric heating, while the remaining demand is covered by district heating. No district heating demand is considered for the Spanish use case, where the heat demand is met by gas- and electricity-based heat sources. An overview of the individual parameters for each use case is presented in table 1.

	Austria	*Norway*	*Spain*
Number of households [24, 30, 31]	4290	1961	1000
Installed capacity wind farm [MWh] [22, 23, 24]	32	57.5	31.5
Transmission capacity between wind farm and electricity market [MWh]	32	57.5	31.5
Alternative heat source	Natural gas	Bio-pellets	Natural gas
Total local electricity demand [MWh] [27]	19406	9697	17031
Total local district heating demand [MWh] [27]	32390	1034	0
Total local gas demand [MWh] [27]	4046	0	1524
Price natural gas [EUR/MWh] [32, 33]	21	-	25
Price alternatively produced heat [EUR/MWh] [32, 33, 34]	26	42	31
Price hydrogen [EUR/MWh] [25, 26]	170	170	170

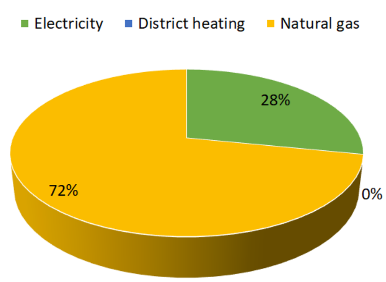
Table 1: Overview of individual parameters assumed for each investigated use case



(a) *Austrian use case*



(b) *Norwegian use case*



(c) *Spanish use case*

Figure 2: Composition of heat demand for the investigated use cases

2.3.1. Austria

The Austrian use case is based in the area of Neusiedl am See in the region of Burgenland, located in the eastern part of Austria. The number of households considered in this use case is 4290 [30]. The local wind farm is assumed to have 32 MW installed capacity based on data obtained in the SektoKop Net project [22] and the generation profile is based on generation data from ENTSO-e [35]. Day-ahead electricity prices are obtained from the ENTSOE-e transparency platform [28]. Relevant power grid tariffs are obtained from RIS [36, 37], while relevant gas grid tariffs are obtained from E-Control [38]. Data regarding the electricity, district heating, and gas demands are obtained from Eurostat's database [27] and scaled accordingly. The price for natural gas in the Austrian use case is assumed to be approximately 21 EUR/MWh [32].

2.3.2. Norway

The Norwegian use case is based on the area of Åfjord municipality, located in the middle region of Norway. A total of 1961 households are considered [31]. The installed capacity of the considered wind farm is 57.5 MW, based on information regarding Bessakerfjellet wind farm [23]. Information regarding the wind energy generation for this specific area (bidding zone 3), as well as national electricity prices, are provided by ENTSO-e [28], [35]. The grid tariffs are obtained from NVE [39]. Data regarding the local electricity, district heating, and gas demands are obtained from Eurostat's database [27] and scaled accordingly. Bio pellets are assumed as the alternative heating source with a price of around 42[1] EUR/MWh [34]. Furthermore, the local gas demand is assumed to be negligible.

2.3.3. Spain

The Spanish use case is based on the Orbaneja wind farm, located in the municipalities of Isar, Las Quintanillas, Rabé de las Calzadas and Estepar, with an installed capacity of 31.5 MW [24]. The generation profile is based on national generation data provided by ENTSO-e [35] and scaled to fit the use case. The size of the Spanish use case is assumed to be 1000 households. Electricity prices are obtained from the ENTSO-e Transparency platform [28] and power grid tariffs are obtained from Eurostat's database [27]. The price for natural gas utilized in the model is assumed to be an average of the daily reference prices provided by MIBGAS [33]. The demand for district heating in the Spanish use case is assumed to be negligible.

2.4. Description of scenarios

Three separate scenarios are defined and investigated for each use case. The first scenario serves as a baseline scenario, while energy conversion technologies are implemented in the other scenarios to better accommodate the different energy demands in the use cases. Moreover, two additional scenarios are defined and investigated for the Austrian and the Spanish use case. These two latter scenarios aim to reduce the reliance on natural gas to cover the local gas demand. Each scenario is described in sections 2.4.1-2.4.5. An overview of the installed

[1]Exchange rate: 1 EUR = 10.42 NOK

capacity of the implemented technologies in the different scenarios is given in table 2, while the technical parameters are presented in table 3.

Installed capacity [MW]		*Austria*	*Norway*	*Spain*
Heat pump	Scenario 1	0	0	0
	Scenario 2	7	0.4	0.5
	Scenario 3	3	0.4	0
	Scenario 4	3	-	0
	Scenario 5	3	-	0
Electrolyzer	Scenario 1	0	0	0
	Scenario 2	0	0	0
	Scenario 3	7	0	0.6
	Scenario 4	7	-	0.6
	Scenario 5	7	-	0.6
Hydrogen storage unit	Scenario 5	5	-	-

Table 2: Installed capacity of the implemented technology for each investigated scenario and use case [MW]

Parameter	*Symbol*	*Value*
Heat pump COP [-]	COP_t^{hp}	1.5-3.5
Hydrogen efficiency of electrolyzer [%]	η_h^{ely}	75
Thermal efficiency of electrolyzer [%]	η_{th}^{ely}	20
Standby losses hydrogen storage [%]	θ_h^{loss}	0.04
Minimum level of hydrogen in storage [%]	ρ_h^{min}	0
Maximum charge rate [%]	ϕ_{charge}^{max}	100
Maximum discharge rate [%]	$\phi_{discharge}^{max}$	100

Table 3: Technical parameters of the utilized technology [40, 41, 42, 43]

2.4.1. Scenario 1 - baseline

Scenario 1 is considered the baseline scenario. No energy conversion technology is implemented, hence no sector coupling is present. In case of insufficient wind generation, electricity is bought from the electricity market to ensure that the local electricity demand is covered at all times. The local gas demand is covered by natural gas bought from the gas market and the local district heating demand is met by heat produced by an alternative heat source.

2.4.2. Scenario 2 - heat pump

Scenario 2 includes P2H technology by implementing a heat pump. It is assumed that all households that rely on gas for heating will switch to district heating in the second scenario. Thus, the considered local district heating demand will increase and the local gas demand is assumed nonexistent. Scenario 2 involves no changes in the Norwegian local energy demands, as no local gas demand is considered in the original assumptions.

2.4.3. Scenario 3 - heat pump and electrolyzer

Scenario 3 includes both P2H and P2G concepts by implementing a heat pump and an electrolyzer. All local energy demands are considered as originally assumed in scenario 3.

2.4.4. Scenario 4 - covering local gas demand by rising natural gas prices

Scenario 4 aims to ensure that green hydrogen produced by the electrolyzer is utilized to cover the local gas demand. This is attempted by basing the price of hydrogen on the electricity price, while also considering the efficiency of the electrolyzer. Thus, a lower hydrogen price is considered in the optimization model. Furthermore, the price for natural gas is assumed to be three times the price of hydrogen, due to the energy density of hydrogen being around three times higher than the energy density of natural gas [44]. As a consequence of the risen natural gas price, the price for alternatively produced heat is increased in the use cases that rely on heat produced by natural gas. Scenario 4 is only investigated for the Austrian and Spanish use case, as no gas demand is considered in the Norwegian use case.

2.4.5. Scenario 5 - covering local gas demand by tightening model constraints

Scenario 5 tightens the constraints related to covering the local gas demand to ensure that the demand is fully met by locally produced green hydrogen. Due to insufficient wind generation in periods with high local gas demand, an additional hydrogen storage unit is implemented in the Austrian use case to obtain a feasible solution. Furthermore, electricity from the electricity market can be fed into the electrolyzer if needed. Scenario 5 is only investigated for the Austrian and Spanish use case, as no gas demand is considered in the Norwegian use case.

2.5. Key performance indicators (KPIs)

Dedicated KPIs allow for a systematic characterization and qualitative assessment of the use cases as well as a comparison of scenarios. The identified KPIs are adjusted to the investigated use cases and do not claim to be complete. In particular, the following KPIs are evaluated:

- *Utilization of implemented technologies* describes how the different energy conversion technologies are utilized.
- *Greenhouse gas emission mitigation potential* evaluates the amount of CO_2 emissions the system is able to avoid by utilizing sector coupling concepts. To quantify the mitigation potential, emissions occurring without the implemented energy conversion technologies must be determined. Emissions considered within the scope of this analysis are tied to the use-phase of the technologies and depend on the national electricity mix, the type of alternative heat source utilized, and emissions tied to natural gas usage. An overview of the assumed emission factors is given in table 4.

	Emission factor [gCO_2/kWh]
Electricity-mix Austria	105
Electricity-mix Norway	31
Electricity-mix Spain	104
Natural gas	440
Bio-pellets	12

Table 4: Assumed emission factors [gCO_2/kWh] [45, 46, 47, 48, 49, 50]

- *Renewable energy self-reliance* indicates how well the system is able to cover the individual local energy demands by using electricity, heat, and gas produced within the system boundaries.
- *External energy purchase* includes all externally produced energy needed to ensure that the local demands are met during the entire analysis horizon. Externally purchased energy includes electricity bought from the electricity market, natural gas bought from the gas market, and heat bought from an alternative heat source.
- *Curtailment reduction* represents the reduction of curtailed electricity achieved through the implementation and utilization of sector coupling technologies.

2.6. Cost-benefit analysis (CBA)

A CBA is performed to further evaluate the potential costs and benefits present in the sector-coupled system. The economic benefits and the O&M costs are quantified by the optimization model for each investigated scenario and are therefore included in the profitability calculations. The investment cost per technology is annualized as in equation 17, where C_{cap} denotes the total upfront capital costs of technology and λ represents the annuity rate. For the determination of λ, an interest rate of 3% is assumed [40]. Information regarding capital costs and technology lifetime is obtained from [40, 51, 52]. Fixed capital costs are assumed to be negligible compared to the variable capital costs of the implemented technologies [42, 53, 54]. Furthermore, capital costs related to the installation of cables and pipes are omitted from this CBA. The relevant parameters are presented in table 5.

$$C_{annual} = C_{cap} * \lambda \tag{17}$$

Technology	*Lifetime [yr]*	*Variable capital cost [EUR/kW or kWh]*
Wind farm	15	1247
Heat pump	25	860
Electrolyzer	25	920
Hydrogen storage tank	25	57

Table 5: Overview of technology parameters utilized in CBA calculations [40, 51, 52]

The avoided greenhouse gas emissions achieved through sector coupling can be monetized by considering the carbon price and is seen as an additional benefit in the CBA. A carbon price of 54 EUR/tonne CO_2 is assumed [55].

3. Results and discussions

This section presents and evaluates the results of the analyzed use cases. Section 3.1 presents the results for the Austrian use case, 3.2 presents the results for the Norwegian use case and 3.3 presents the results for the Spanish use case. Each section includes an overview of the profitability of the evaluated system under the given conditions, together with the main revenues and costs. Section 3.4 compares the results of the evaluated use cases and scenarios in regards to the related KPIs. The results of the CBA are presented and discussed in section 3.5.

3.1. Austrian use case

An overview of the economic performance of the Austrian use case is presented in figure 3. The Austrian use case experiences a rise of profitability compared to baseline scenario 1 in every investigated scenario except scenario 4. Significant revenue increases are observed when an electrolyzer is implemented and the assumed market value hydrogen is high (i.e. scenario 3 and scenario 5) where an increase of 237 % and 140 % of the total profit are achieved, respectively. A consequence of implementing an electrolyzer and enabling the lucrative option of selling hydrogen directly to the hydrogen market is that less electricity is available to cover the electricity demand and to feed into the heat pump. Hence, more electricity must be bought from the electricity market, which results in higher costs related to covering the local electricity demand. A similar effect can be seen in scenario 2, where the implementation of a heat pump leads to less revenue from selling electricity to the electricity market compared to scenario 1, as some of the generated electricity is utilized for heat production. However, due to the assumption that gas-dependent households have switched to district heating, costs related to covering the local gas demand are nonexistent and the total profitability of scenario 2 is 3 % higher than in the baseline scenario 1.

Scenario 3 has proven to be the most profitable scenario, with the produced hydrogen being sold to the hydrogen market without any incentive to utilize it internally. Thus, the entire local gas demand is met with natural gas bought from the gas grid. Scenario 4 is designed to stimulate the utilization of hydrogen within the system through altered gas prices. Consequently, the majority of the green hydrogen is used to cover the local gas demand. However, due to periods of insufficient electricity generation and high local gas demand, it is necessary to purchase natural gas from the gas market to ensure that the local gas demand is met at all times. The increased natural gas price results in higher costs of covering the local gas demand. This additional cost, combined with reduced hydrogen market value and increased amount of electricity bought from the electricity market, results in a 74 % reduction of the total profit compared to scenario 1. Scenario 5 includes a constraint stating that the local gas demand must be met in its entirety by hydrogen produced by the electrolyzer. Hence, the costs of covering the gas demand are equal to zero. The remaining hydrogen is sold to the hydrogen market. Costs increases compared to scenario 1 can be observed related to covering the electricity demand, as more electricity is utilized in the electrolysis process and therefore more electricity is needed from the electricity market to ensure that the demand is met at all times. Furthermore, the electrolyzer relies on electricity purchased from the electricity market to produce hydrogen, resulting in additional costs. Nonetheless, scenario 5 achieves a 140 % increase in the total profit compared to scenario 1.

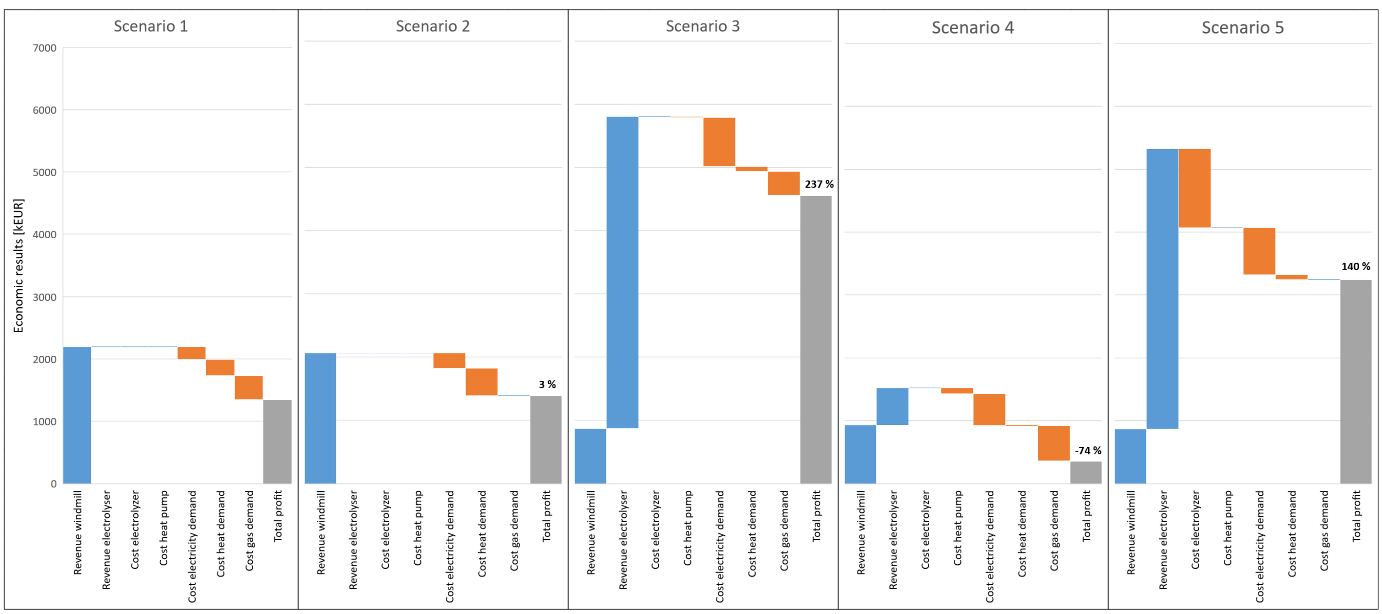


Figure 3: Economic performance - Austrian use case

3.2. Norwegian use case

An overview of the economic performance of the Norwegian use case is presented in figure 4. Comparing the total profit of scenario 2 and scenario 3 with the baseline scenario 1, it can be observed that only a slight increase in profitability is achieved (around 1%). This increase in profit is a result of a heat pump being implemented, and consequently lower costs related to covering the local district heating demand. No local gas demand is assumed for the Norwegian use case, thus, no electrolyzer is implemented as the capacity of the electrolyzer is determined by the maximum local gas demand. In consequence, this means that scenario 2 and scenario 3 are identical.

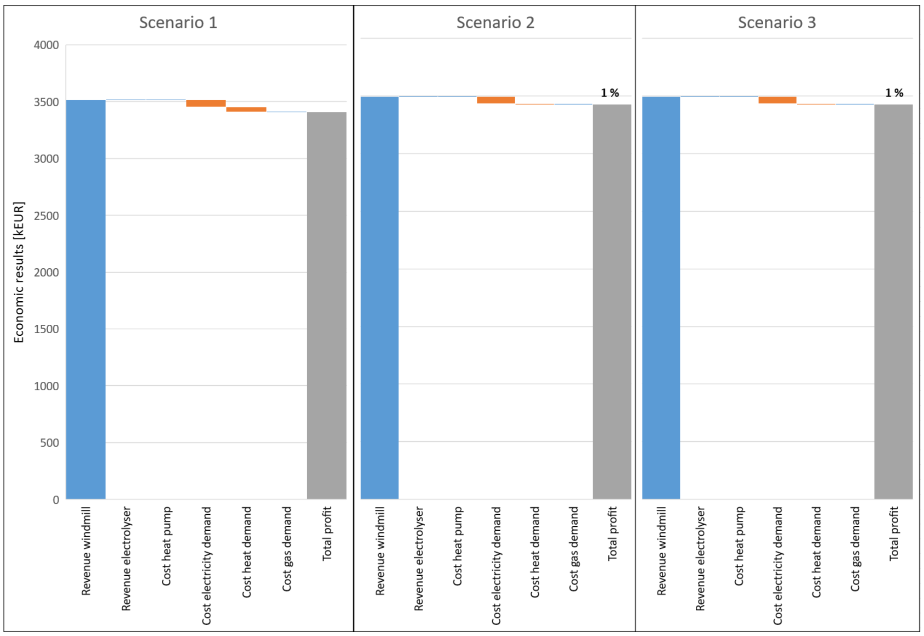


Figure 4: Economic performance - Norwegian use case

3.3. Spanish use case

An overview of the economic performance of the Spanish use case is presented in figure 5. No local district heating demand is assumed for the Spanish use case. A negligible impact on the profitability of the investigated system is observed when implementing a heat pump and assuming that gas-dependent households switch to rely on district heating, as seen when comparing scenario 2 with scenario 1. Implementing an electrolyzer and allowing for sale of hydrogen to the hydrogen market results in an 11 % increase in the profitability compared to scenario 1 due to the increase of revenue tied to the hydrogen sales, as seen in scenario 3. Scenario 4 and scenario 5 eliminate the costs related to covering the local gas demand by utilizing green hydrogen. The difference in revenue related to the sale of hydrogen is tied to the assumed price for hydrogen, which is higher in scenario 5 than in scenario 4. Scenario 5 achieves a 5 % increase of the total profit compared to scenario 1 and scenario 4 obtains a 1 % increase of total profit compared to scenario 1.

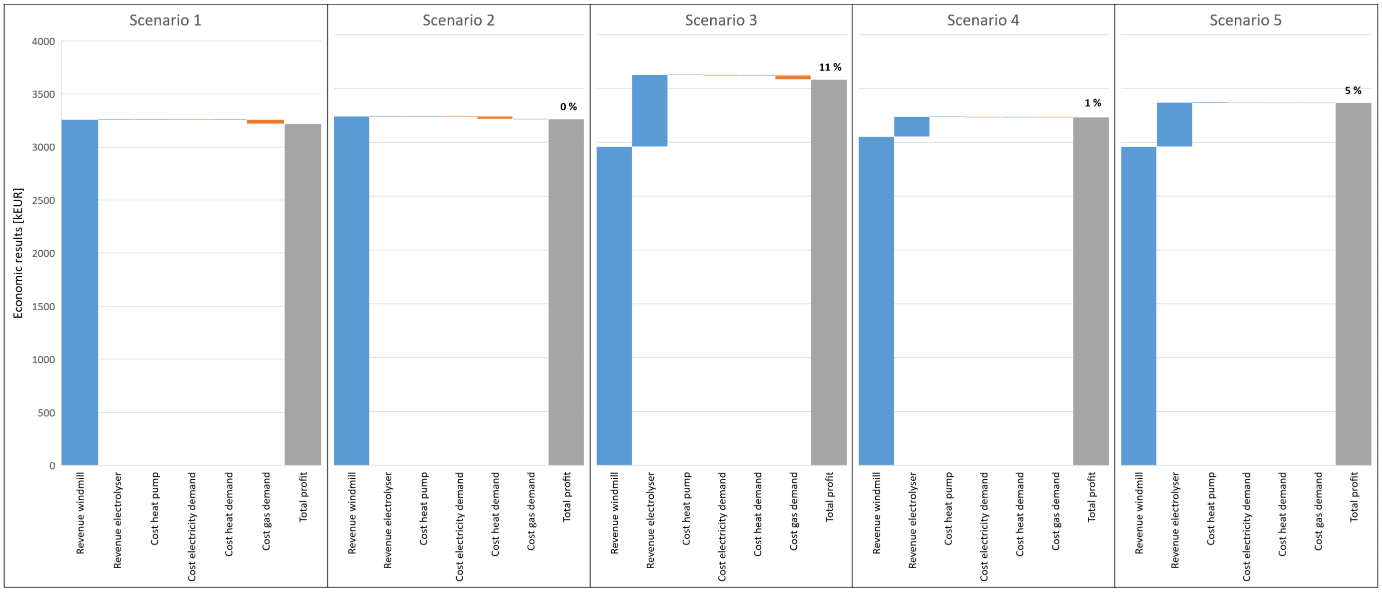
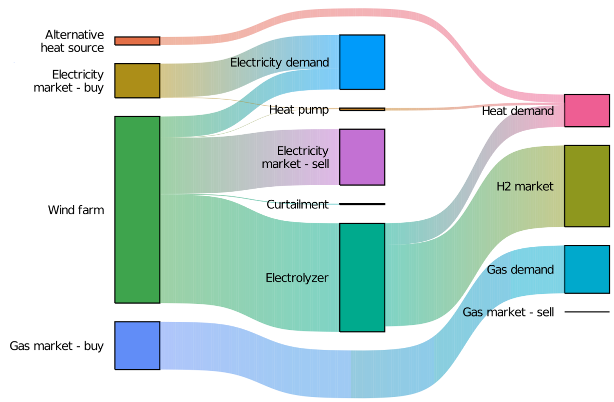


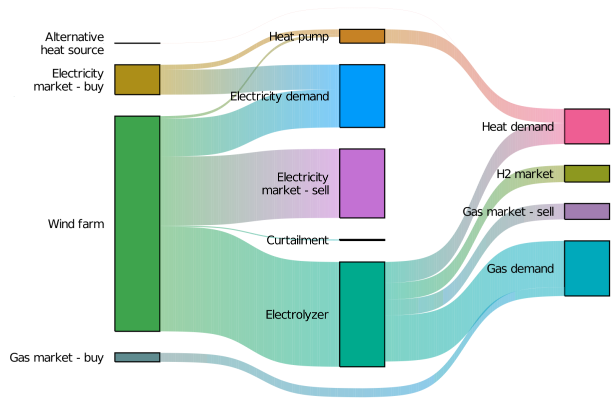
Figure 5: Economic performance - Spanish use case

3.4. Evaluation of KPIs

In the following section, the results of the different use cases and investigated scenarios are compared on the basis of the defined KPIs. An overview of the utilization of implemented technologies for the Austrian scenario 3 is presented in figure 6a. The majority of the generated electricity is either sold to the electricity market, used to cover the electricity demand, or fed into the electrolyzer. As there are no incentives to utilize the green hydrogen to cover local demands, the hydrogen is sold to the hydrogen market in its entirety. Hence, the local gas demand is completely covered by natural gas bought from the gas grid. A change in the utilization can be observed when comparing the energy flows occurring within the system in scenario 3 with the energy flows occurring in scenario 4, as presented in figure 6b. The prices for natural gas and hydrogen encourage the utilization of green hydrogen within the system. Consequently, the majority of the produced hydrogen is now utilized to cover the local gas demand.



(a) *Overview of technology utilization for the Austrian scenario 3*



(b) *Overview of technology utilization for the Austrian scenario 4*

The avoided emissions achieved in scenario 3 for all three use cases are presented in figure 7. When studying the emissions related to covering the local electricity demand, it can be observed that the Norwegian and Spanish use cases have a greater potential for reducing emissions by applying sector coupling technologies. This is mainly due to Norway and Spain, under the given assumptions, having low or non-existing local district heating and gas demands. Thus, a higher share of the generated electricity is available for covering the local electricity demand. Furthermore, it must be noted that the size of the Norwegian and Spanish use cases (i.e. the number of households considered in this study) are lower than for the Austrian use case, therefore resulting in a lower total electricity demand. The heat pump implemented in scenario 3 leads to a reduction of the emissions related to covering the local district heating demands for the Austrian and Norwegian use cases. No district heating demand is considered for the Spanish use case, thus, no emission reduction is possible. Similarly, no local gas demand is assumed for the Norwegian use case, therefore, no greenhouse gas emission mitigation can be achieved when considering emissions tied to the covering of the local gas demand. The green hydrogen is sold to the hydrogen market in its entirety, resulting in no reduction of emissions being achieved neither in the Austrian use case nor in the Spanish use case.

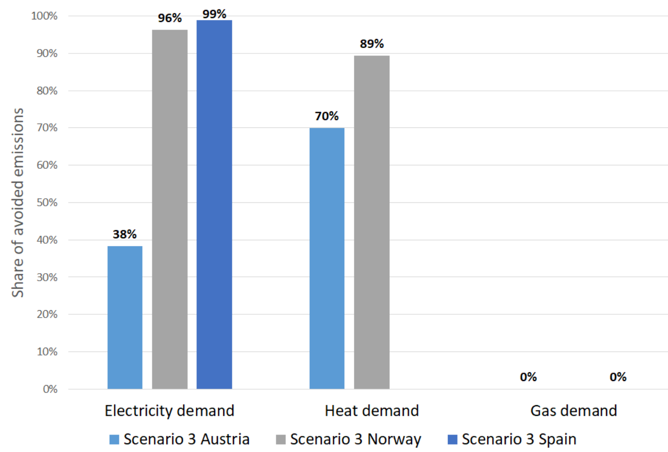


Figure 7: Greenhouse gas emission reduction achieved in scenario 3 for all investigated use cases

Renewable energy self-reliance indicates how well the system is able to cover the individual local energy demands by using electricity, heat, and gas produced within the system boundaries. An overview of the system performance with regards to this specific KPI can be found in figure 8, which presents how the local district heating demand is met in the various scenarios for each use case. A high degree of renewable energy self-reliance is achieved in the Austrian use case, especially when utilizing heat produced from both a heat pump and excess heat from the electrolysis process. The heat pump implemented in the Norwegian use case ensures that about 90 % of the local district heating demand is met with renewable heat. A local district heating demand is only considered in scenario 2 of the Spanish use case. By utilizing the implemented heat pump, the Spanish use case is able to cover about half of the assumed local district heating demand with renewable heat.

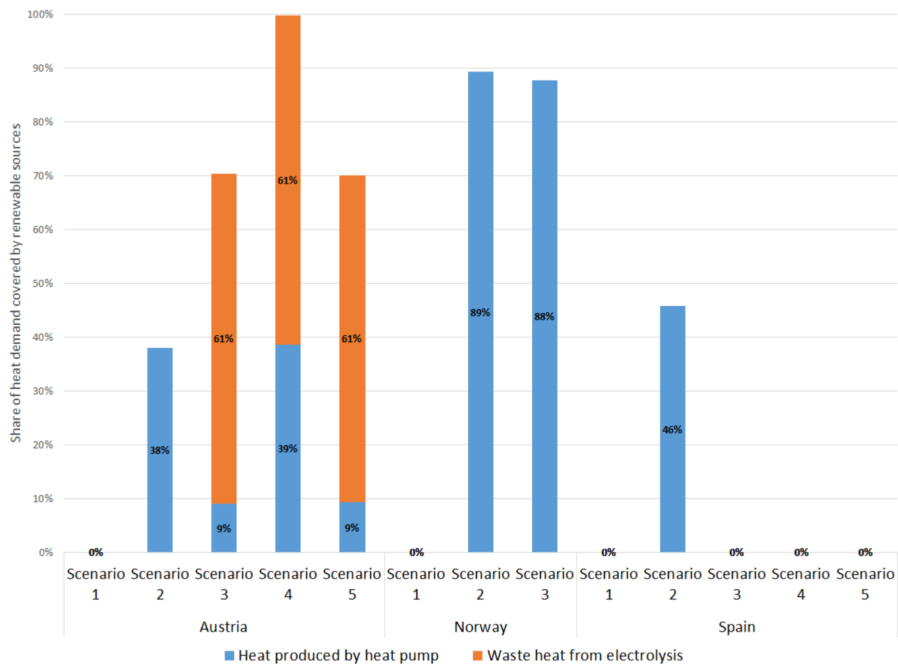


Figure 8: Renewable energy self-reliance

Figure 9 provides an overview of the amount of externally purchased energy in the various use cases and scenarios investigated. There is a clear correlation between external energy purchase and the degree of energy self-reliance. The system relies on natural gas from the gas grid to cover the local gas demand in all scenarios where a local gas demand is considered without specific incentives to utilize green hydrogen internally. Furthermore, electricity from the electricity market is needed in all investigated Austrian and Norwegian scenarios, as the amount of electricity generated by the wind farm is insufficient to cover the electricity demand. The amount of electricity bought from the electricity market depends on the degree of utilization and size of the implemented energy conversion technologies.

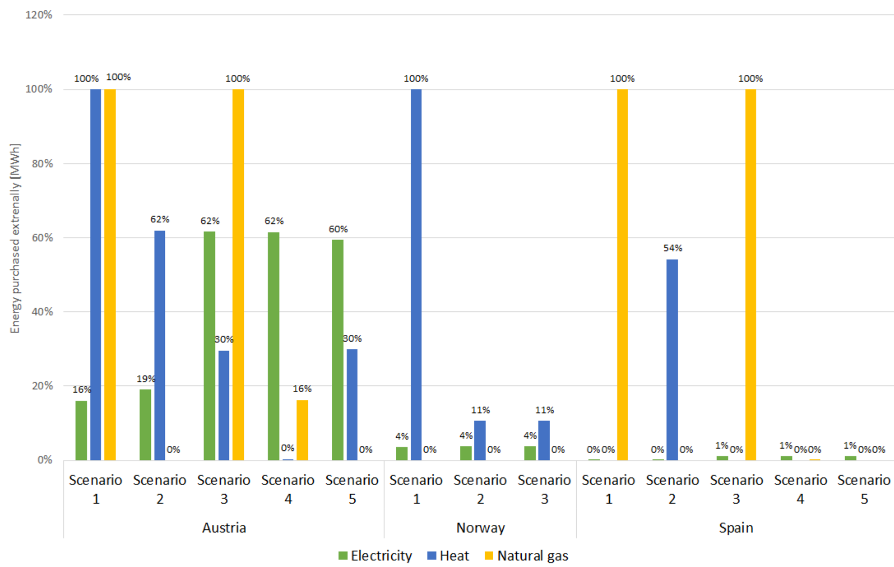
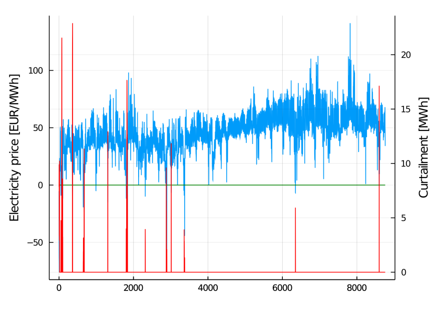
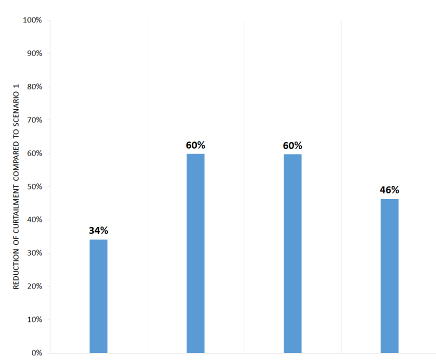


Figure 9: Overview of external energy purchase in the investigated scenarios

No curtailment is observed during the investigated period for the Norwegian and Spanish use cases. As seen in figure 10a, there is a correlation between the occurrence of negative electricity prices and curtailment for the Austrian use case. By implementing and utilizing sector coupling technologies, curtailment can be reduced, as shown in figure 10b. By implementing a heat pump, the system reduces curtailment by approximately 34 % compared to scenario 1, while implementing both a heat pump and an electrolyzer results in a reduction of curtailment of between 46-60 % compared to scenario 1.



(a) *Correlation between negative electricity prices and curtailment occurring in Austria scenario 1*



(b) *Reduction of curtailment achieved through the implementation of sector coupling technologies for the Austrian use case*

Figure 10: Curtailment occurrence and curtailment reduction potential for the Austrian use case

3.5. Cost-benefit analysis

The system profitability after consideration of CBA results is presented in figure 11. A clear reduction of profitability is found for all scenarios when comparing with the results from the operation optimization. The profitability of the Austrian use case is only positive when the option to sell hydrogen for a high market value is present (scenario 3 and scenario 5). Reducing the market value of hydrogen (scenario 4) and tightening the constraints related to covering the local gas demand resulted in a profitability reduction of 109 %. The Norwegian use case is profitable in the baseline scenario 1, due to the absence of a local gas demand. Thus, no costs related to buying natural gas apply to this scenario. However, by implementing a heat pump (scenario 2 and scenario 3), the profitability of the use case decreases drastically and results in a negative overall profit. The Spanish use case increases profitability by applying sector coupling technology. The relatively low local energy demands considered compared to the installed capacity of the wind farm, combined with no local district heating demand, are important factors of the system's profitability.

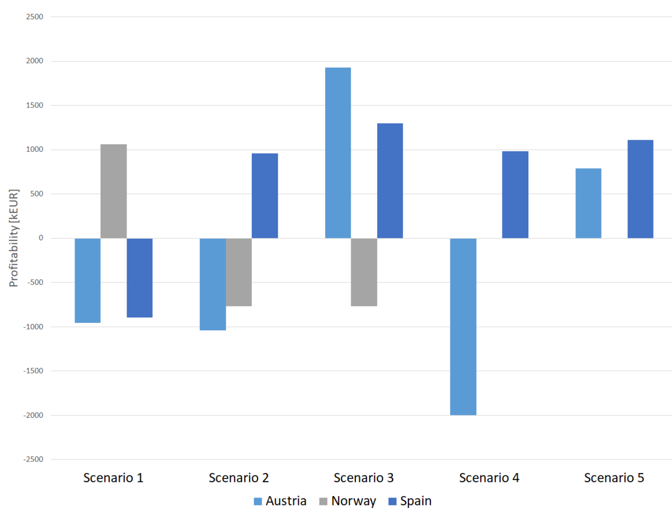


Figure 11: System profitability after consideration of CBA results [kEUR]

4. Conclusion

This research contributes to exploring solutions for the urgent and critical issue of decarbonization. It takes into account three regional case studies in Austria, Norway, and Spain. The main focal point is to emphasize the relevance of renewable energy-based hydrogen and heat generation and consumption through the application of an LP-based optimization framework in the context of a local energy system. This work examines how a hybrid sector-coupled system, including both P2H and P2G technologies, can be utilized to achieve both cost and

GHG emission reductions. Significant emission reduction is found for the Norwegian use case, however, implementing and utilizing a heat pump to produce green heat results in negative system profitability. Particular focus is put on mitigating emissions tied to covering local gas demands by utilizing green heat and green hydrogen. Both the Austrian and Spanish use case experience high emission mitigation potential when utilizing green hydrogen to cover the local gas demand. The results demonstrate the significance of the hydrogen market value on the system profitability.

Systems that apply sector coupling concepts become more renewable energy self-reliant than systems that do not. Consequently, the same systems are able to reduce the amount of externally purchased energy needed to cover local demands. The profitability of sector-coupled systems can be expected to increase in the future, as investment costs decrease with technological development and the carbon price increases.

It is critical to acquire insight into the comprehensive allocation of costs across technologies within the investigated sector-coupled system. Changes in the composition of the energy supply and local energy demands, and therefore the allocation of costs in the various scenarios, may have an impact on future implementation and utilization of sector-coupled energy systems.

The economic revenue mainly stems from selling green hydrogen to an external market (when applicable). This necessitates further investigations on possible future hydrogen market values which facilitates internal utilization of green hydrogen and understand its impact on customer and system level. Further work could investigate at least the following aspects: an impact analysis of local policy levers on influential parameters, an extension of functionalities of the model, an extension and enhancement of investigated KPIs, an evolvement of investigated use cases, a portfolio optimization.

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