Deliverable 3.1: Potential investment strategies and job creation in European renewable energy systems

Thellufsen, Jakob Zinck; Korberg, Andrei David; Chang, Miguel; Petersen, Uni Reinert; Victoria, Marta

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Renewable Energy Investment Strategies –
A two-dimensional interconnectivity approach

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D-3.1 2021: Potential investment strategies and job creation in European renewable energy systems

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Work Package Leaders	Jakob Zinck Thellufsen & Marta Victoria
Author(s):	Jakob Zinck Thellufsen, Andrei David, Miguel Chang, Uni Reinert Petersen
Reviewer	Brian Vad Mathiesen, Marta Victoria, Gorm Bruun Andresen, Poul Alberg Østergaard
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Contents

1 Main findings

This report describes potential scenarios towards renewable energy supply and decarbonisation in Europe. From these pathways the goal is to discuss investment strategies and impacts on job creation. The main pathways included are the following:

1. The European Commission's "A Clean Planet for All" scenarios. Here, the 1.5 TECH scenario is highlighted, which is the scenario that suggests how Europe can meet the 1.5-degree target by mostly technical solutions.
2. The RE-INVEST *A Smart Energy Europe* scenario, representing an alternative pathway to the European Commission's scenarios.
3. A study investigating an early and steady transition path versus a late and rapid transition path for Europe.
4. The analyses are preliminary, and a final Smart Energy Europe will be presented in the final Deliverable 3.3 of the RE-INVEST project

Within these studies, a number of sensitivity analyses and investigated studies are also presented in the report, to further discussions regarding the investment strategies.

To conclude, the following main findings have been identified throughout the work:

1. Expansion of the renewable energy sources in the form of onshore and offshore wind turbines, photovoltaics and solar thermal panels form the backbone of the energy transition. These four are well known technologies that already now can be invested in.
2. Electrification of the transport sector is key to a more efficient energy system, so electric vehicles are important and should gain precedence wherever it is possible to less fuel-efficient options such as hydrogen or internal combustion cars running on green fuels.
3. Energy savings through e.g., building renovations are important. All three decarbonisation scenarios depend on energy savings in buildings to achieve a cost-efficient energy system.
4. Investment in energy transition should start now. An early and steady transition pathway is more cost-effective than a late and rapid transition. This entails that there is a need to invest in necessary, even though not completely developed technology early. Examples are more efficient electrolysers, carbon capture and utilisation technologies, large hydrogen storages and complete e-fuel production facilities. All are necessary for the transition but currently not commercially competitive or indeed openly available.
5. Sector integration is key to achieve system flexibility and ensure temporal balance between supply and demand in highly renewable energy systems. This is illustrated in the comparison between the Smart Energy Europe scenario and the EU Commission's decarbonisation scenarios. By promoting sector integration, investing in technologies that can link electricity and heating, utilise waste heat from industry and e-fuel production, and produce fuels and gasses from renewable electricity, it is possible to find a renewable energy system that is more efficient than a system relying primarily on electricity and electricity storage. The reason is both a broader use of renewable energy resources and excess energy, as well as access to cheaper storage. The alternative is a more extensive reliance on battery and electricity storage, which can potentially lead to large increases in system costs, especially if needed for mid- and long-term storages. Thus, green gas and liquid fuels from carbon capture and utilisation can instead be used as a long-term storage in combination with peak load gas turbines.

5. The heating and cooling sector must be transformed. This includes replacing oil and gas boiler with individual heat pumps in areas where district heating is not suitable. In regions where district heating is feasible this should be established or expanded if existing in adjacent areas established. District heating allows for the utilisation of waste heat sources, the implementation of cost-efficient storage, and it improves the flexibility of the energy system through sector integration. This includes the investment in new district heating systems in countries that currently do not have district heating, and the expansion of district heating in countries that currently have district heating. Furthermore, with the need for renewable heat sources and use of excess heat from industry, special attention should be given to investing and developing 4th generation district heating, that lowers supply and return temperature, making more waste heat resources feasible for exploitation while decreasing grid losses.
6. Hydrogen can play a large role in the energy transition in most of the scenarios but should mainly be used in combination with a carbon source for the production of electrofuels, while direct hydrogen utilisation should only have a small role. The analyses show that the direct use of hydrogen in power plants, heating purposes or transport has no real benefit to the energy system, making it more expensive and more inefficient. However, hydrogen may be suited for industrial purposes, in particular, if it can replace biomass or biomass-based fuels, in which case the cost of replacing a TWh of biomass has the lowest cost among all energy sectors analysed. In all cases, this requires a sustained development of electrolysis and hydrogen infrastructure and storage technologies.
7. Sustainable biomass should remain a key component of future energy systems as it can decrease the reliance on carbon capture and electrolysis and can help stabilise the energy system in times of low wind or solar production while also decreasing the system costs. This requires the development and deployment of biomass conversion technologies as thermal gasification, anaerobic digestion, hydrothermal liquefaction, and pyrolysis for the production of liquid and gaseous fuels. Electrofuels from carbon capture and utilisation and electrolysis can supplement bioenergy products and together, the produced fuels can aid in decarbonising power production, industry, some types of road transport, shipping and aviation that may be more difficult to electrify. Therefore, these sectors must be developed within the next decade. Thus, such green fuels can be produced and implemented directly, instead of using hydrogen directly which would require new infrastructures.
8. After this implementation of e-fuels, there may still be anthropogenic emissions or activities with global warming potential that are not handled. None of these are dealt with in RE-INVEST, but here carbon capture and storage can play a role in mitigating the impacts from e.g., contrails from aeroplanes and methane emissions from farming. In this perspective, carbon capture and storage must be utilised in a way where it should achieve actual negative CO_2 emissions, in particular through biochar from biomass conversion technologies. Direct air capture can be an alternative solution, but the associated energy consumption is likely to remain high. CCS combined fossil fuel combustion will not provide negative emissions and is this insufficient. Thus, a priority should be given to transitioning the energy system before investing in carbon capture and storage solutions.
9. Nuclear is not a cost-efficient solution in a decarbonised energy system, and both the Smart Energy Europe and analyses in “Early and Steady vs Late and Rapid”, show that a more cost-efficient solution can be found without nuclear.

Regarding job creation potentials from the renewable energy systems compared to a baseline, fossil fuel systems, the increased investments result in a higher employment related to the energy sector. This is due to investments in renewable energy sources such as wind and solar power. Furthermore, investments in district heating and heat savings also provide jobs in the energy sector. The employment tied to the

investment in renewable energy technology is higher than the employment associated with fossil fuels. These numbers are shown in the figure below.

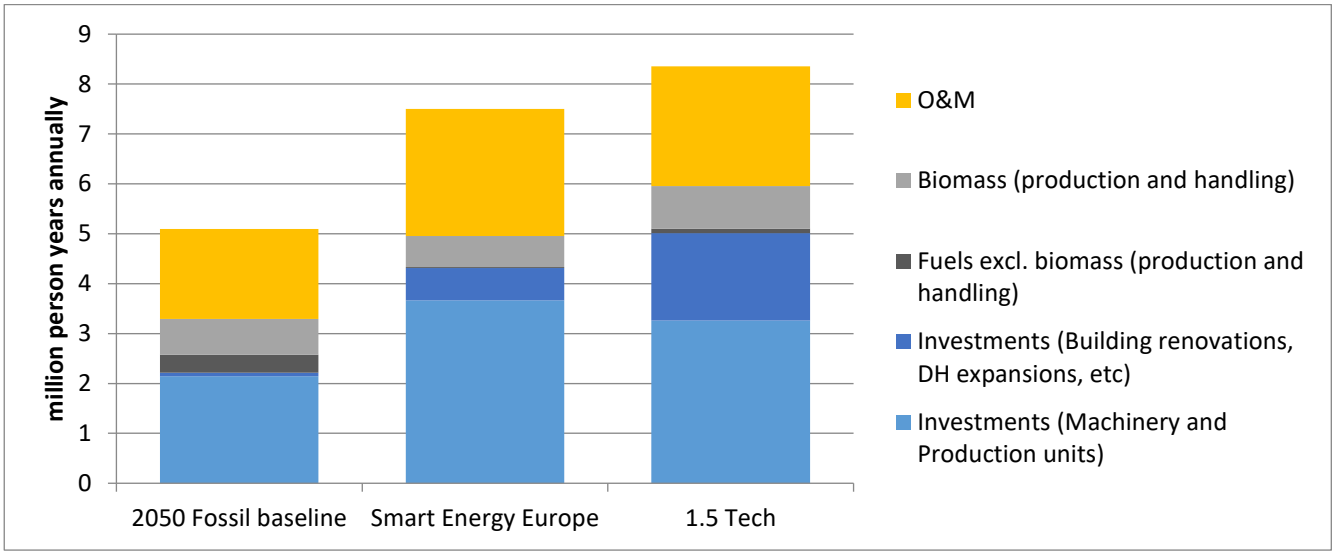

Figure 1.1. Annual employment in the Smart Energy Europe scenario compared to a fossil baseline scenario and the European Commission's 1.5 Tech scenario.

2 Introduction

A number of potential scenarios exist towards a renewable energy-based Europe. For instance, the "A Clean Planet for All" scenarios suggested by the European Commission. These scenarios differ in terms of targets, technologies to apply – and the methodological approach taken in designing them. This introduces an uncertainty in what investment strategies that needs to be considered, and what role technologies can and should play in the decarbonisation. This report, deliverable 3.1, has the objective of investigating a range of potential scenarios, and identify investment strategies for the renewable energy transition. This includes both identifying necessary energy system changes, key technologies, infrastructures, energy storages and implementation rates. To do this, the report discusses and compares the different scenarios, and identifies common findings as well as where differences exist, and what to recommend in these cases.

Concretely, the investment strategies are be founded on a number of different analyses and sensitivity calculations carried out in the RE-INVEST project. The main analyses are:

- Replication of the scenarios established by the European Commission to fulfil the 1.5 °C zero emissions targets. These are modelled in the PRIMES modelling tool which show paths towards a decarbonised Europe [1]. These scenarios are the official pathways for the decarbonization of the European Union, and there of great importance to discuss from both a Danish and European perspective. In RE-INVEST, the PRIMES scenarios have been modelled in EnergyPLAN [2] for us to be able to test different technology developments and discuss the different aspects of European decarbonisation. Our baseline scenarios presented later are based on this work. See appendix A for documentation.
- The Smart Energy Europe scenario. From the PRIMES scenarios, an alternative path has been established based on the principles of Smart Energy Systems, using sector integration to achieve a more efficient energy transition. The Smart Energy Europe scenarios are also established in EnergyPLAN. See appendix B for documentation.
- Modelling of early-steady transition paths versus late-rapid transition paths using the PyPSA analysis tool [3]. Based on current system layouts, a number of scenarios for European countries have been established with the goal of investigating the economic consequences of different pathways for decarbonising Europe in terms of implementation rates. These are described in detail in [4].

For all these analyses a number of sensitivity and technology studies have been made, to increase the perspectives on the investment strategies for key technologies and sectors.

Documentation and description of the specific methodologies behind these main analyses are documented in Appendix A-D, with the main results presented in Section 3.

3 Investment strategies

This chapter dives into the overall perspectives for the energy system for Europe, highlighting both the Smart Energy Europe system, and discussion of whether renewable energy systems should be invested in early and steady or late and rapid. Within these discussions a number of studies are carried out and also documented here, to illustrate the benefits of certain investment strategies within electricity capacity expansion, district heating and power to x and hydrogen in the transport and gas sector.

3.1 Smart Energy Europe and the PRIMES scenarios

In the transition towards a renewable energy-based society and a decarbonisation of Europe, the European Commission has established a number of scenarios, modelled in the model PRIMES. These are known as the "Clean Planet for All" Scenarios [1]. The overall scenarios, and key differences are highlighted in Figure 3.1.

Long Term Strategy Options

	Electrification (ELEC)	Hydrogen (H2)	Power-to-X (P2X)	Energy Efficiency (EE)	Circular Economy (CIRC)	Combination (COMBO)	1.5°C Technical (1.5TECH)	1.5°C Sustainable Lifestyles (1.5LIFE)
Main Drivers	Electrification in all sectors	Hydrogen in industry, transport and buildings	E-fuels in industry, transport and buildings	Pursuing deep energy efficiency in all sectors	Increased resource and material efficiency	Cost-efficient combination of options from 2°C scenarios	Based on COMBO with more BECCS, CCS	Based on COMBO and CIRC with lifestyle changes
GHG target in 2050	-80% GHG (excluding sinks) ["well below 2°C" ambition]					-90% GHG (incl. sinks)	-100% GHG (incl. sinks) ["1.5°C" ambition]	
Major Common Assumptions	• Higher energy efficiency post 2030 • Deployment of sustainable, advanced biofuels • Moderate circular economy measures • Digitilisation				• Market coordination for infrastructure deployment • BECCS present only post-2050 in 2°C scenarios • Significant learning by doing for low carbon technologies • Significant improvements in the efficiency of the transport system.			
Power sector	Power is nearly decarbonised by 2050. Strong penetration of RES facilitated by system optimization (demand-side response, storage, interconnections, role of prosumers). Nuclear still plays a role in the power sector and CCS deployment faces limitations.							
Industry	Electrification of processes	Use of H2 in targeted applications	Use of e-gas in targeted applications	Reducing energy demand via Energy Efficiency	Higher recycling rates, material substitution, circular measures	Combination of most Cost-efficient options from "well below 2°C" scenarios with targeted application (excluding CIRC)	COMBO but stronger	CIRC+COMBO but stronger
Buildings	Increased deployment of heat pumps	Deployment of H2 for heating	Deployment of e-gas for heating	Increased renovation rates and depth	Sustainable buildings			CIRC+COMBO but stronger
Transport sector	Faster electrification for all transport modes	H2 deployment for HDVs and some for LDVs	E-fuels deployment for all modes	Increased modal shift	Mobility as a service			• CIRC+COMBO but stronger • Alternatives to air travel
Other Drivers		H2 in gas distribution grid	E-gas in gas distribution grid				Limited enhancement natural sink	• Dietary changes • Enhancement natural sink

Figure 3.1. The European Commission's 'A Clean Planet for All' Scenarios and the changes and developments identified in each sector. [1]

These "A Clean Planet for all" -scenarios focus on several different solutions, including energy savings, deployment of renewable energy sources, utilising power to X for hydrogen production, and potentially e-gas and e-fuel production, lifestyle changes and other aspects. Through these changes, they model both scenarios for the 2°C target and 1.5°C target according to the IPCC. In this report, the focus will be on the COMBO (2°C target) scenario, and the 1.5 TECH and 1.5 LIFE scenarios (the 1.5°C target). Furthermore, the study also includes two baselines for 2015 and 2050 that are business as usual scenario which do not achieve decarbonisation targets but represents current trends scenarios. The key parameters for the energy systems suggested can be seen in Figures 3.2-3.3, showing the primary energy supply and energy carriers.

What is evident from Figures 3.2-3.3 is that they are all implementing a large degree of renewable energy sources, and furthermore the following are also consistently identified throughout the scenarios:

1) They all rely on fossil fuels. The CO_2 emissions from this use are offset through carbon capture and storage (CCS) and land use changes.
2) They all rely on an expansion of nuclear power compared to the baseline scenarios.
3) They all disregard expansion of district heating.
4) They all have various levels of direct use of hydrogen.

Besides, these main bullet points, the scenarios primarily focus on individual heating solutions, with various technologies, including gas, hydrogen, electric and biomass boilers, as well as heat pumps. Furthermore, the scenarios include an extensive use of energy savings to be able to make a carbon neutral transition of the heating sector.

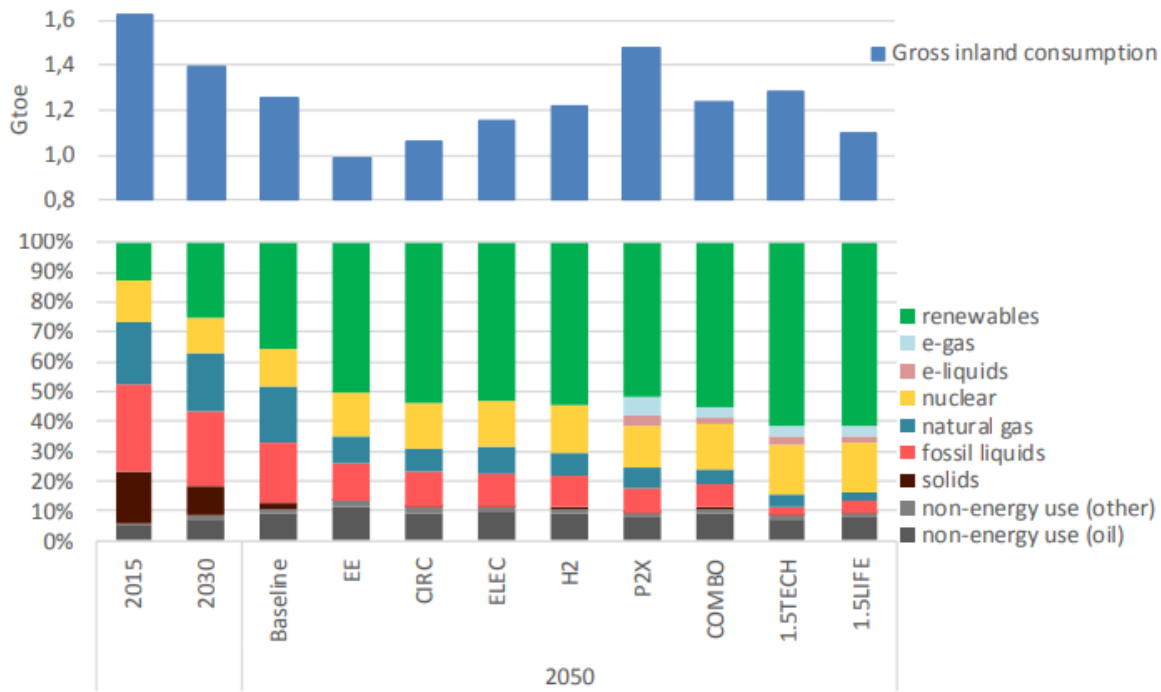

Figure 3.2. Primary energy consumption for the different "A Clean Planet for All" scenarios. [1]

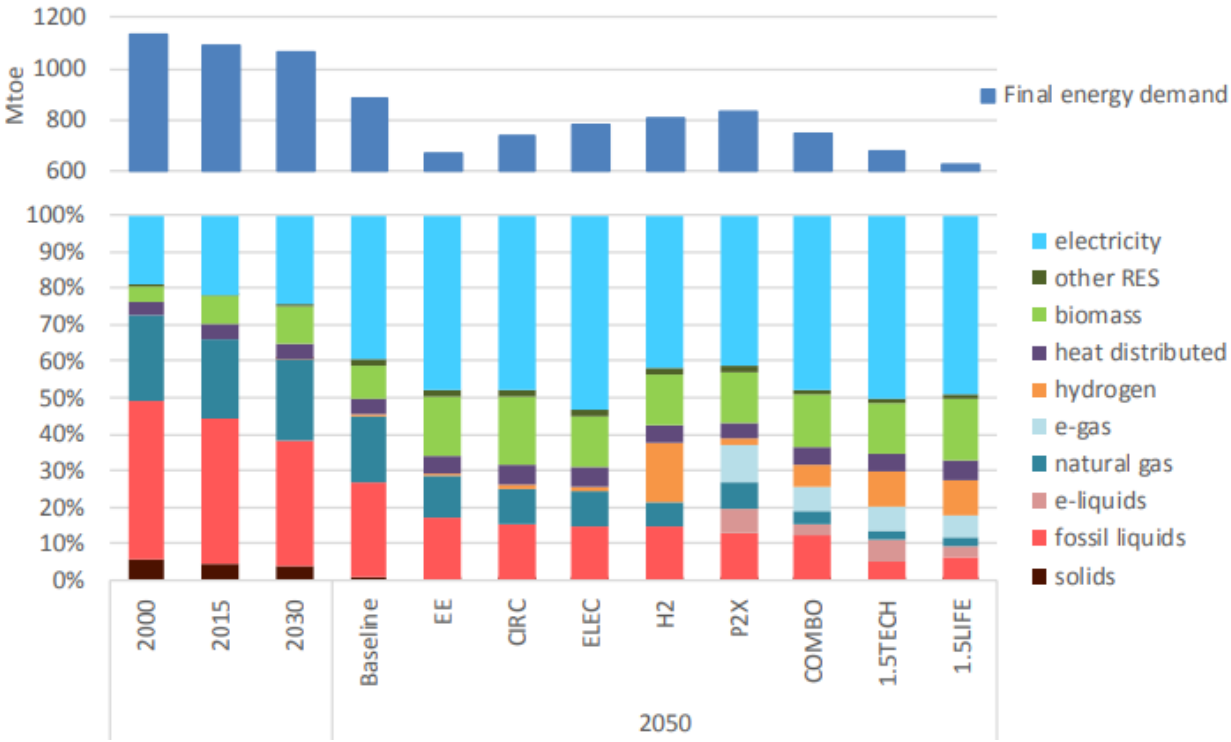

Figure 3.3 Energy carriers used in the different "A Clean Planet for All" scenarios. [1]

Thus, the suggestion carried out in the RE-INVEST project, is to further investigate other potential investment patterns, looking into the principle of Smart Energy Systems and comparing scenarios designed from the approach of Smart Energy System to the European plans from "A Clean Planet for All" developed in PRIMES. This includes investigation of district heating, system integration, and energy efficiency throughout the system and not only at the end user. Furthermore, different implementations of hydrogen, power-to-x and e-fuels are also worthy or further discussion. Therefore, a Smart Energy Europe scenario is established and compared to the European Commission's scenarios. These are replicated in EnergyPLAN and documented in Appendix A.

The detailed design process of the Smart Energy Europe scenario is detailed in Appendix B and is in this section summarized and compared to the 1.5 Tech scenario from "A Clean Planet for All".

The Smart Energy Europe scenario is established based on the following design steps. These steps are in parallel with previous studies [5,6]:

- Establishing a reference system. In this case, the offset is the 2050 Baseline from "A Clean planet for All" reconstructed in EnergyPLAN. The reference system is adjusted to include sufficient power plant capacities to avoid additional import and export from countries outside EU (+ UK, Norway, and Switzerland). Furthermore, a deliberate choice is made to have a 2050 baseline both including nuclear at the current 2050 level, and one excluding nuclear, replacing it with more offshore wind power.

- Implementing efficiency improvements. Here, based on the Heat Roadmap Europe studies [7–10] and the sEEnergies project[1], efficiency measures are implemented in both the heating demand and the industrial demands.
- Implementing district heating and power-to-heat. Here, the district heating scenario from Heat Roadmap Europe is implemented, including the use of geothermal and solar heat, excess heat from industry, and heat pumps. The remaining heating demand is predominantly covered with individual heat pumps, with a few electric boilers and biomass boilers at the same share of individual heating as the 2050 baseline scenario.
- Electrification of vehicles. Based on the assumptions of a fully electrified personal vehicle fleet, 50% electrification of light duty vehicles and 20% in heavy duty vehicles, it is possible to determine the consequences of an electrified transport sector.
- E-fuels for the rest of the transport sector. The remaining transport demand needs to be covered by an alternative fuel. In the main Smart Energy Europe scenario this is covered by e-methane and e-jetfuel produced by combining carbon from biomass gasification or CO_2 capture with hydrogen produced by electrolysers using renewable energy.
- To eliminate any remaining use of natural gas in industry and peak load power stations, two scenarios are shown: One with the utilization of biogas and one with an increased e-gas production.

The overall technical results are illustrated in Figure 3.4, while more details are found in Appendix B. From Figure 3.4 , it is possible to see that not only is it possible to create a renewable energy-based scenario that is more fuel efficient than the 1.5 TECH scenario; it is also possible to do so without including fossil fuels and nuclear energy. This is achieved through a more efficient energy system due to electrification of the heating sector and a wider implementation of district heating, as well as a more efficient transport sector with larger reliance on electric vehicles instead of hydrogen and gas cars. The biomass constraint and use are similar throughout the scenarios.

When looking at the total annual costs, shown in Figure 3.5, the Smart Energy Europe scenario also represents a lower annual cost. This is especially due to a lower fuel consumption.

When looking at the investments, the scenarios have different key investments. The amount of energy savings is quite higher in the 1.5 TECH scenario, whereas the Smart Energy Europe includes higher costs for district heating, the transport sector and renewable energy. The 1.5 TECH scenario on the other hand still have investment costs tied to nuclear power.

[1] Heat Roadmap Europe: www.heatroadmap.eu
sEEnergies: www.seenergies.eu

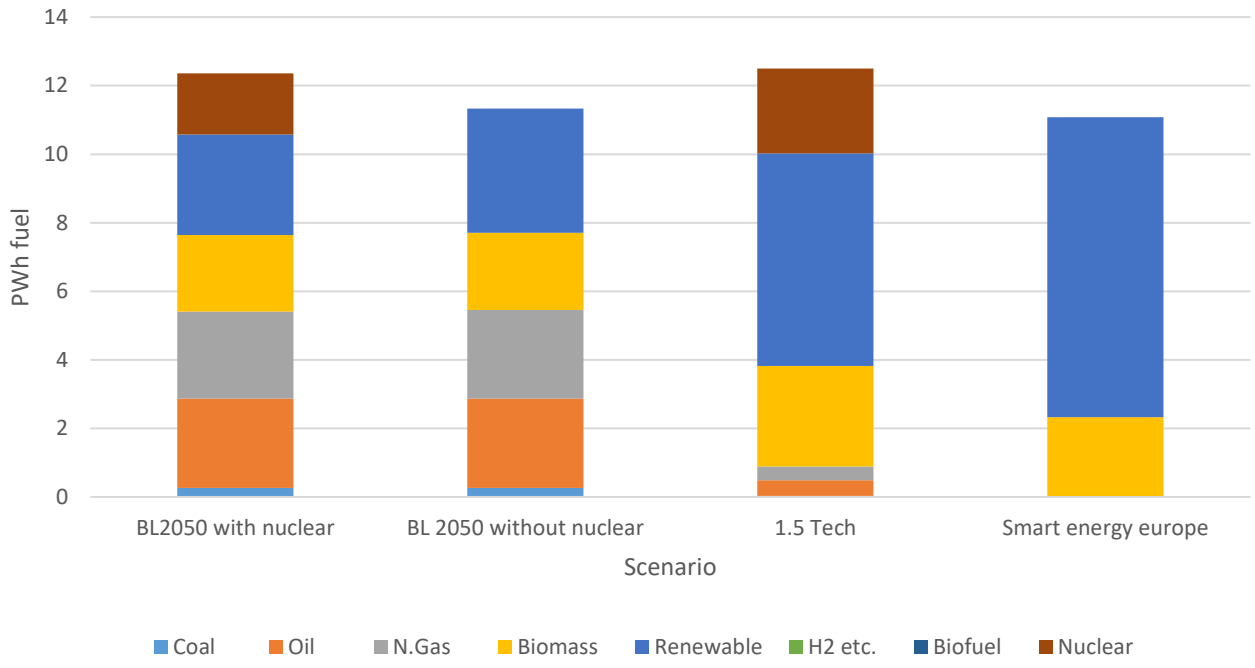

Figure 3.4. Primary energy consumption Smart Energy Europe, compared to the two 2050 baselines and the 1.5 Tech scenario.

Overall, the analysis shows a potential better path for the European energy sector with a stronger reliance on system integration and the utilization of smart energy systems, which include not only flexibility through electricity grids but also by utilizing smart heating and smart gas grids. The further perspective on different investments is elaborated in the following subsections.

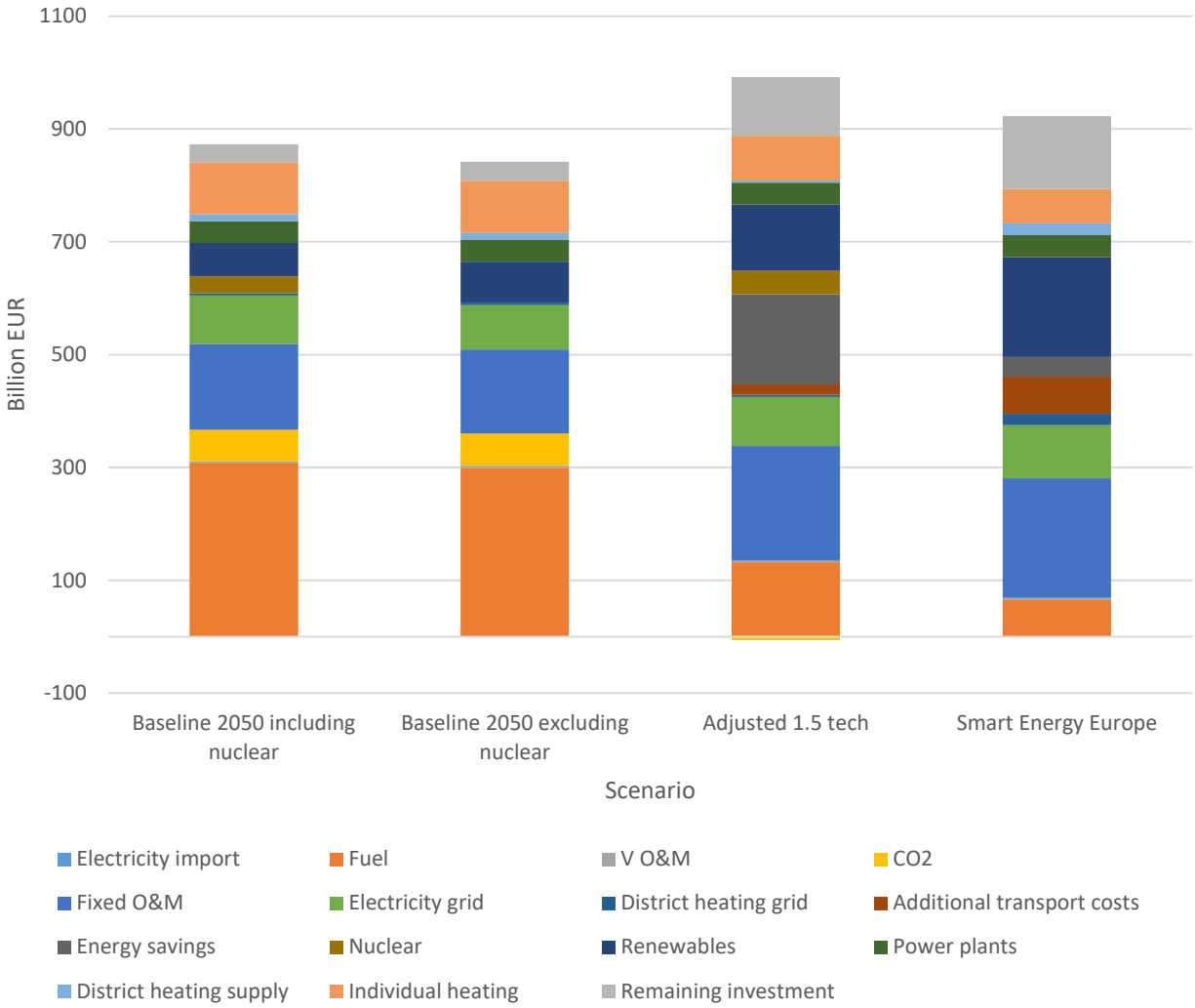

Figure 3.5. Total annual costs, including fuel, operation and investment costs in the baseline scenarios and the Smart Energy Europe and 1.5 Tech.

3.2 Alternative transition paths: Early and Steady vs Late and Rapid

In the study "Early decarbonisation of the European energy system pays off" [4], the PyPSA-Eur-Sec, an open-access, hourly-resolved, networked model of the sector-coupled European energy system is applied to investigate the transition of the energy system in Europe. The goal is to analyze the consequences of following alternative decarbonisation pathways. For a given carbon budget over several decades, different transformation rates for the energy system yield starkly different results. The assumed carbon budget is 33 $GtCO_2$ for the cumulative carbon dioxide emissions from the European electricity, heating, and transport sectors between 2020 and 2050, which represents Europe's contribution to the Paris Agreement. Although some analyses use carbon budget util 2100, this typically triggers a significant contribution from negative emissions technologies. Since the EU has the commitment to attain carbon neutrality by 2050, we decided to use a carbon budget until 2050.

The conclusion found is that following an early and steady path in which emissions are strongly reduced in the first decade is more cost-effective than following a late and rapid path in which low initial reduction targets quickly deplete the carbon budget and require a sharp reduction later. A further conclusion is that solar photovoltaic, onshore and offshore wind can become the cornerstone of a fully decarbonised energy system and that installation rates similar to historical maxima are required to achieve timely decarbonisation.

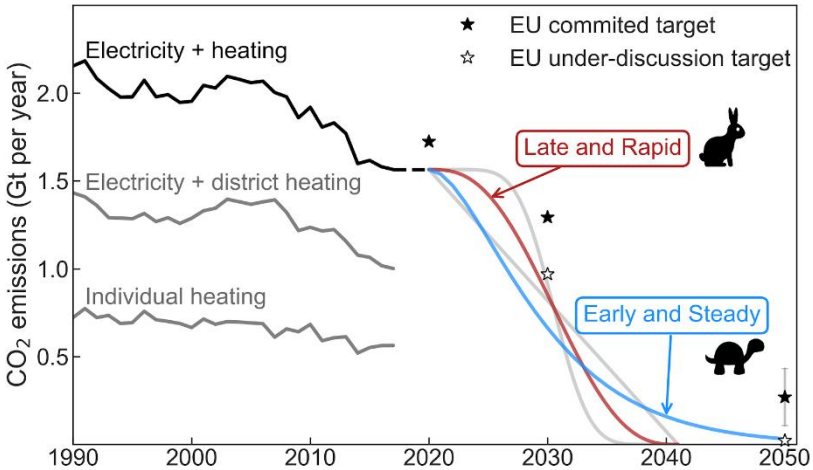

Figure 3.6. Historical CO_2 emissions from the European power system and heating supply in the residential and services sectors. The various future transition paths shown in the figure have the same cumulative CO_2 emissions, which correspond to the remaining 21 GtCO2 budget to avoid human-induced warming above 1.75 °C with a probability of >66%, assuming current sectoral distribution for Europe, and equity sharing principle among regions. The 21 $GtCO_2$ budget in this case corresponds only to the electricity and heating sector. Black stars indicate committed EU reduction targets, while white stars mark targets under discussion when the paper was published.

The baseline analysis assumes that district heating penetration remains constant at present values, annual heat demand is constant throughout the transition paths, and power transmission capacities are expanded as planned in the Ten Years Network Development Plan (TYNDP 2018) up to 2030 and fixed after that year. The impacts of these assumptions are assessed in Table 3.1.

The Early and Steady path represents a cautious approach in which significant emissions reductions are attained in the early years. In the Late and Rapid path, the low initial reduction targets quickly deplete the carbon budget, requiring a sharp reduction later.

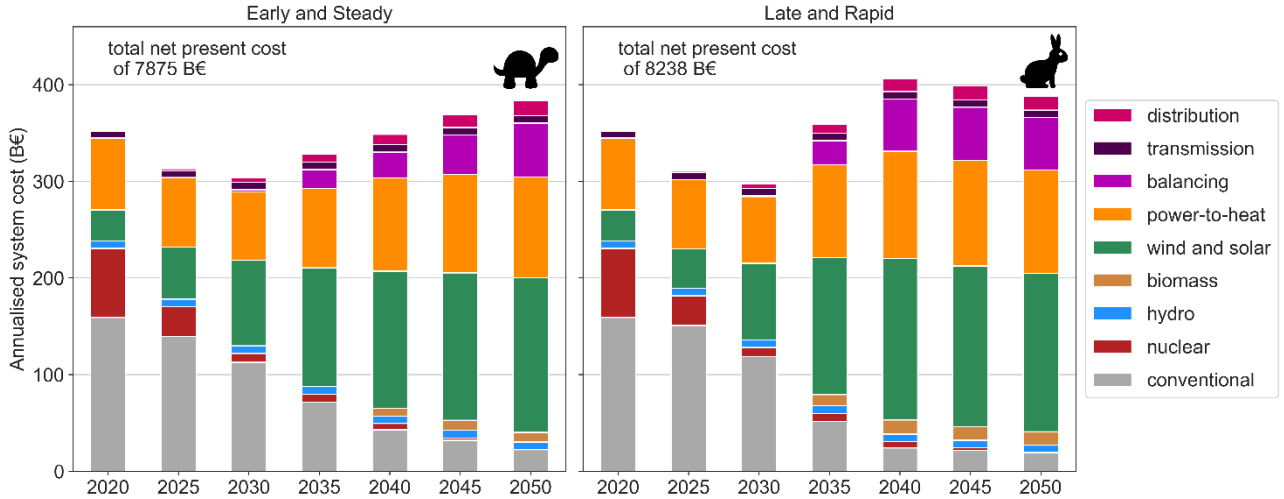

Figure 3.7. Annualised system cost for the European electricity and heating system throughout transition paths Early and Steady and Late and Rapid shown in Figure 3.6. Conventional includes costs associated with coal, lignite and gas power plants producing electricity as well as costs for fossil-fuelled boilers and CHP units. Power-to-heat includes costs associated with heat pumps and heat resistors. Balancing includes costs of electric batteries, hydrogen storage and methanation. For the nuclear power plants, it is assumed that they are decommissioned when they reach their assumed lifetime. Potential decision to delay or accelerated nuclear power plant decommissioning could alter this picture.

The two alternative paths arrive at a similar system configuration in 2050, Figure 3.7. Towards the end of the period, under heavy CO_2 restriction, balancing technologies appear in the system. They include large storage capacities comprising electric batteries and hydrogen storage, and production of synthetic methane. Cumulative system cost for the Early and Steady path represents 7,875 billion euros (B€), while the Late and Rapid path accounts for 8,238 B€. It is worth remarking that the cumulative cost remains lower for the Early and Steady path provided that social discount rates below 15% are assumed. Thus, a preference for the Early and Steady alternative is clear at all reasonable social discount rates.

At every time step, the optimal renewable mix in every country depends on the local resources and the already existing capacities, see Figs. 16 and 17 in the Supplementary Materials of the paper [11]. Nevertheless, the analysis of near-optimal solutions has recently shown that country-specific mixes can vary significantly while keeping the total system cost only slightly higher than the minimum [12,13].

In 2050, the cost per unit of delivered energy (including electricity and thermal energy) is ~59 €/MWh. The newly built conventional capacity for electricity generation is very modest in both cases. No new lignite, coal or nuclear capacity is installed. Thus, at the end of both paths, conventional technologies include only gas-fuelled power plants, CHP units, and boilers. Biomass contributes to balancing renewable power but plays a minor role. Decarbonising the power system has proven to be cheaper than the heating sector. Consequently, although CO_2 allowances differ, the electricity sector gets quickly decarbonised in both paths and more notable differences appear in new conventional heating capacities. In both paths, yearly costs initially decrease as the power system takes advantage of the low costs of wind and solar. Removing the final emissions in heating causes total costs to rise again towards 2050. The main reason behind the higher cumulative system cost for the Late and Rapid strategy is that the earlier depletion of carbon budget forces it to reach zero emissions by 2040 when renewable generation and balancing technologies are more expensive than in 2050.

Part of the already existing conventional capacity become stranded assets, in particular, coal, lignite, combined cycle gas turbines (CCGT) (which was heavily deployed in the early 2000s) and gas boilers. As renewable capacities deploy, utilisation factors for conventional power plants decline and they do not recover their total expenditure via market revenues. Up to 2035, operational expenditure for gas-fuelled technologies are lower than market revenues so they are expected to remain in operation. Contrary to what was expected, the sum of expenditures not recovered via market revenues is similar for both paths. In the Late and Rapid path, the high CO_2 price resulting from the zero-emissions constraint, justify producing up to 220 TWh/a of synthetic methane already in 2040. This enables CCGT and gas boilers to keep operating allowing them to recover part of their capital expenditure, but the consequence is a higher cumulative system cost, as previously discussed. Stranded costs, that is the sum of expenditures not recovered via market revenues, represent ~12% of the total cumulative system cost in both paths. Although closing plants early might be seen as an unnecessary contribution to a higher cost of energy, it must be remarked that the early retirement of power plants has been identified as one of the most cost-effective actions to reduce committed emissions and enable a 2 °C-compatible future evolution of global emissions.

In the baseline scenario far, we have assumed that district heating (DH) penetration remains constant at 2015 values. When DH is assumed to expand linearly so that in 2050 it supplies the entire urban heating demand in every country, cumulative system cost for the Early and Steady path reduces by 2.4%. This roughly offsets the cost of extending and maintaining the DH networks and avoids the additional expansion of gas distribution networks. Now, we look at the impact of efficiency measurements by modifying the constant heat demand assumption. When a 2% reduction of space heating demand per year is assumed due to renovations of the building stock, while demand for hot water is kept constant and rebound effects are neglected, cumulative system cost decreases by 11.3%, significantly offsetting costs of renovations. When the model is allowed to optimise transmission capacities after 2030, together with the generation and storage assets, the optimal configuration at the end of the paths includes a transmission volume approximately three times higher than that of 2030. The reinforced interconnections contribute to the spatial smoothing of wind fluctuations, increasing the optimal onshore and offshore wind capacities at the end of the path. The required energy capacity for hydrogen storage is reduced due to the contribution of interconnections to balancing wind generation. Although the cumulative system cost is 1.3% lower, it is unclear to what extent it compensates the social acceptance issues associated with extending transmission capacities. Neither of the paths installs new nuclear capacity. This technology is only part of the optimal system in 2050 when nuclear costs are lower by 15% compared to the reference cost and no transmission capacity expansion is allowed. In all the previous scenarios, the difference in cumulative system cost for the Early and Steady and the Late and Rapid path is roughly the same, Table 1.

Table 1 Cumulative system costs (B€) for additional analyses.

Analysis	Early and Steady path	Late and Rapid path	Difference	Change relative to Baseline (Early and Steady) (%)
Baseline	7875	8238	363	
District heating expansion	7688	8003	315	−187 (−2.4)
Space heat savings due to building renovation	6989	7319	330	−886 (−11.3)
Transmission expansion after 2030	7771	8081	310	−104 (−1.3)
Including road and rail transport	8303	8753	450	+428 (+5.4)

Table 3.1 Cumulative system costs (B€) for additional analyses.

3.3 Renewable energy capacity

In the proposed Smart Energy Europe scenario, renewable energy plays a critical role as an enabling component in the decarbonisation of the system. In such a system design, fluctuating renewable energy sources must be adequately dimensioned and balanced to provide a secure supply and reduce additional system costs. Moreover, renewable energy capacity will not only cover end-use electricity demands but also the demands from other sectors such as heating, transport, and industry, as well as hydrogen and synthetic fuel production. This sector integration provides flexibility to the energy system, allowing high shares of variable renewable energy across the different sector in hours of high resource availability, thereby keeping energy curtailment low. Likewise, it facilitates the use of different forms of energy storage found in these sectors which can be utilize when fluctuating renewable production is lower.

Throughout the design steps towards the Smart Energy Europe scenario, higher amounts of renewable energy capacity compared to the Baseline are included, as seen in Figure 3.8. Meanwhile, the existing power plant capacity (both cogeneration of heat and power (CHP) and condensing mode plants) is only marginally increased across the steps towards a Smart Energy scenario in 2050, with an eventual replacement of the fuel mix with biofuels as the main source.

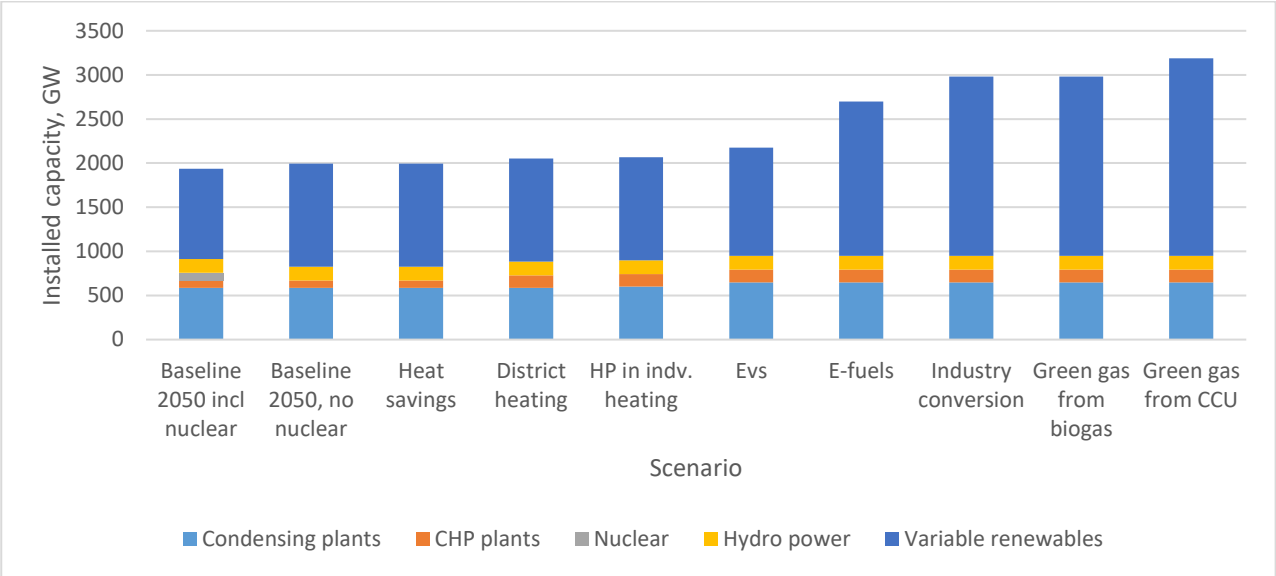

Figure 3.8. Installed capacity for electricity generation in the design steps from baseline to smart energy scenario.

In a highly sector-coupled system like the one proposed in the Smart Energy Europe scenario, investments in the electrification of heating, transport and industry will lead to an overall higher electricity demand. In turn, investments in renewable capacity will be needed to have a secure and sustainable energy supply.

Given the flexibility of the system and this increase in renewable capacity, the expected increase in fluctuating renewable production can be adequately balanced, thereby limiting the amount of electricity production exceeding demand requirements. As depicted in Figure 3.9, this means that even with high shares of variable renewable energy, curtailment can be kept low and, in fact, constitute a lower share of the overall electricity demand when compared to the Baseline scenario. In turn, this could signal at potential savings in associated curtailment costs and additional investments for balancing services and technologies.

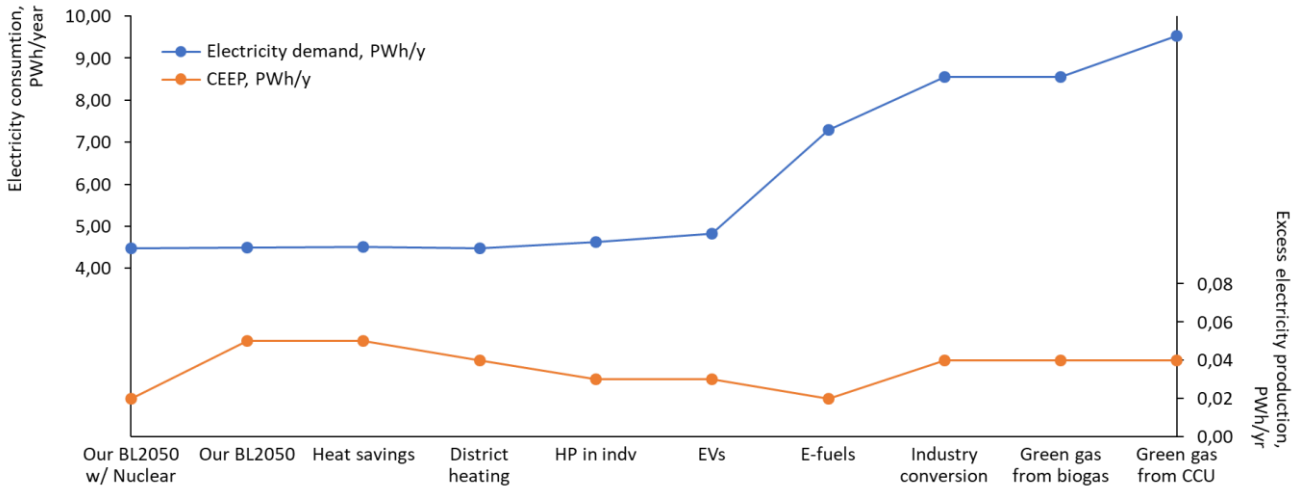

Figure 3.9. Electricity consumption and critical excess electricity production (expected curtailment) in the cumulative steps towards a Smart Energy Europe.

3.3.1 Electricity storage and additional renewable capacity

Additional energy storage can be used for balancing purposes, and thus also handling excess production from variable renewable energy. However, the Smart Energy Scenario already presents a highly flexible and balanced system with limited excess electricity production. Nonetheless, investments in battery storage can also be considered as an alternative for relying on power plant capacity, thereby reducing fuel consumption and associated costs, while allowing even more variable renewable energy production in the system.

Thus, a sensitivity analysis has been conducted to consider incremental steps of additional storage, while also exploring the possibility of adding variable renewable production from offshore wind in increments of 50 GW of capacity, which represents about 1.5% of the total installed capacity in the Smart Energy Scenario. By using both energy storage and additional wind production it is possible to reduce power plant operation. For this reason, a phase-out of power plant capacity is also explored at each step of the analysis keeping enough capacity in place to avoid electricity imports to the system, namely by phasing out 25 GW of capacity at each step. With this replacement of power plant utilization, we also assess the impacts on fuel consumption, namely reducing the strain on biomass resources.

Adding batteries increase the energy system costs, however there may be other benefits from a limited level of battery capacity in the system. In Figure**Fejl! Henvisningskilde ikke fundet.**.10., the primary supply for the Smart Energy Europe scenarios is presented at increasing levels of battery storage capacity, represented here in relation to the average electricity load throughout the year. The two leftmost steps represent – first – a scenario without battery storage capacity and then the main Smart Energy Europe scenario, the latter corresponding to a storage capacity equivalent to 13% of the average electricity load. In these two, the primary energy supply only changes marginally when introducing battery storage, while contributing to additional costs, due to low utilization rates and low excess electricity production going into the storage. In the subsequent steps with more battery storage, the total primary energy supply can be lowered up to a point where battery storage covers up to about 20% of the average electricity load; thereafter, it rises. Similarly, total system costs can be kept within a short range of the original Smart Energy Europe scenario when considering a battery storage sized to 20% of the average hourly electricity load and becoming more expensive in subsequent steps.

This gain in efficiency from the second step (the reference battery storage for the Smart Energy scenario) to the third (with 20% of storage capacity covering the average electricity load) can be attributed to the reduced

consumption of biomass, and a negative natural gas balance from the production of green gas from both biogas and CCU, despite the increased production from offshore wind at each step. Meanwhile, the total system costs will be lowered at this point due to a reduction in fuel costs but are subsequently offset again by the additional investments in capacity.

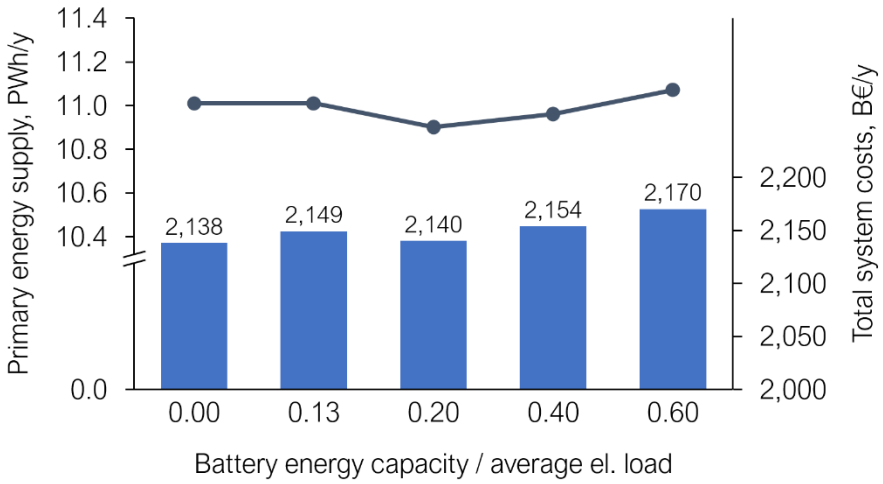

Figure 3.10. Primary energy supply and total system costs at different steps of battery storage capacity represented as a fraction of the average electricity load, the reference storage considered for the Smart Energy Europe scenario is presented as the second step in the bar chart (i.e. 0.13).

In all, additional investments in battery storage can be implemented to tap into additional renewable production, enabling an alternative pathway to reduce the pressure on biomass consumption. However, in conclusion, the investments in battery storage in all cases increase – albeit by very small margins – the total system costs relative to a scenario with no storage.

3.4 Direct use of hydrogen in the energy system

Electrolysis and P2X are credited with great potential in the efforts to phase out fossil fuels. However, today, these are often hampered by the low price of fossil fuels and by the inexistence of a regulatory framework to support their uptake, which ultimately still favours old technologies. But in the future, these must become more interesting for private investments, in a place where market regulators must steer future investments towards those technologies and parts of the energy system that need electrolysis and P2X the most.

Existing hydrogen strategies appear sector agnostic, suggesting that green hydrogen from electrolysis can be a solution in all parts of the energy system [14]. However, the analyses in RE-INVEST indicate that direct green hydrogen is only useful in specific parts of the energy system where it can often act as complementary solution to other more efficient technologies.

The Smart Energy Europe scenario proposes hydrogen as feedstock for long-distance transport and industry sectors in the form of electro-methanol for heavy-duty road transport and shipping, electro-methanol-to-kerosene for aviation and electro-methane for industry. Even after maximising the electrification potential, electrofuel production still requires approximately 3,000 TWh of hydrogen annually. It is clear then that supplying such demands cannot rely on excess wind production, but require 4,000 TWh of dedicated renewable electricity production, which is a third of all energy consumption in the model for Europe.

Therefore, using hydrogen in more parts of the energy system will create additional demands, reason why careful consideration should be put towards where and why hydrogen should be used.

One of the analyses in RE-INVEST aims towards identifying the potential of direct hydrogen utilisation in all four sectors of the energy system: electricity, heating, industry and transport. The results indicate that out of all energy sectors, hydrogen is the least recommended solution for the heating sector, where district heating and heat pumps show lower energy system costs, higher efficiency and more diversity on the production side, making use of energy sources that could not be used if district heating was not in place. This is discussed further in Section 3.5.1. Figure 3.11 illustrates different heating scenarios, where it is shown that the scenarios without district heating, or with low levels of district heating, but with high levels of individual hydrogen boilers, are also the most expensive solutions, more expensive than the scenarios with electric boilers. In the scenarios with individual hydrogen boilers, one can observe that hydrogen transport and distribution infrastructure does not drive the increase in the total energy system costs, but it is the additional investments in wind turbines, electrolysers, hydrogen storage and hydrogen boilers that are the main cost drivers.

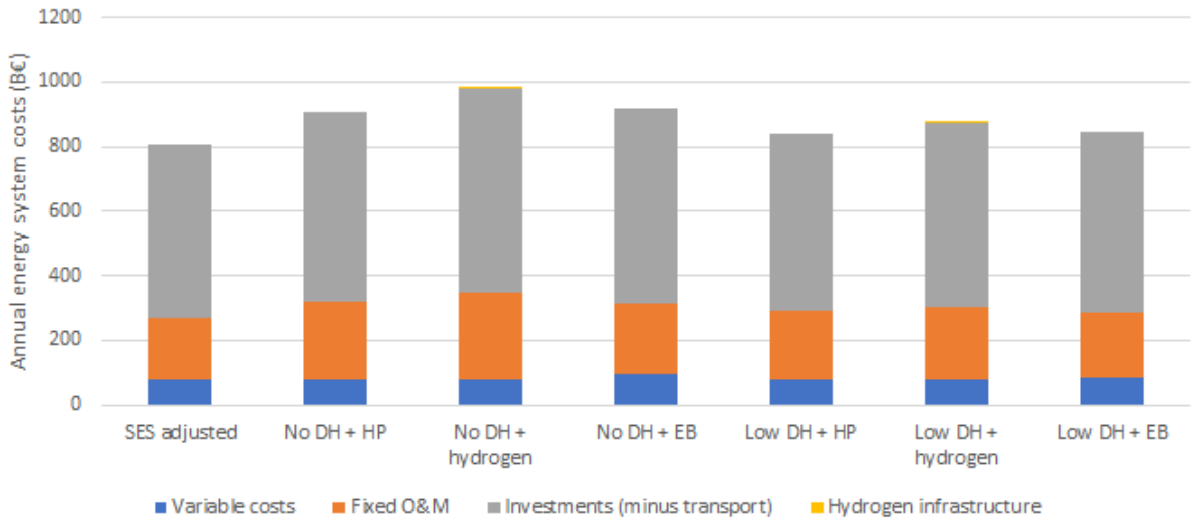

Figure 3.11. Cost breakdown of different heating scenarios compared to the SEE scenario

When used for electricity production, hydrogen can be useful for reducing the overall biomass consumption when such a fuel (either directly used or converted to syngas) is used for this purpose. The overall biomass consumption is reduced effectively when 300-600 TWh of hydrogen is added to the energy system, but when even more hydrogen is added then the biomass reduction effects are lower. In all cases though, the addition of hydrogen to the energy system increases the demand for renewable electricity, making the energy system less efficient, as illustrated in Figure 3.12.

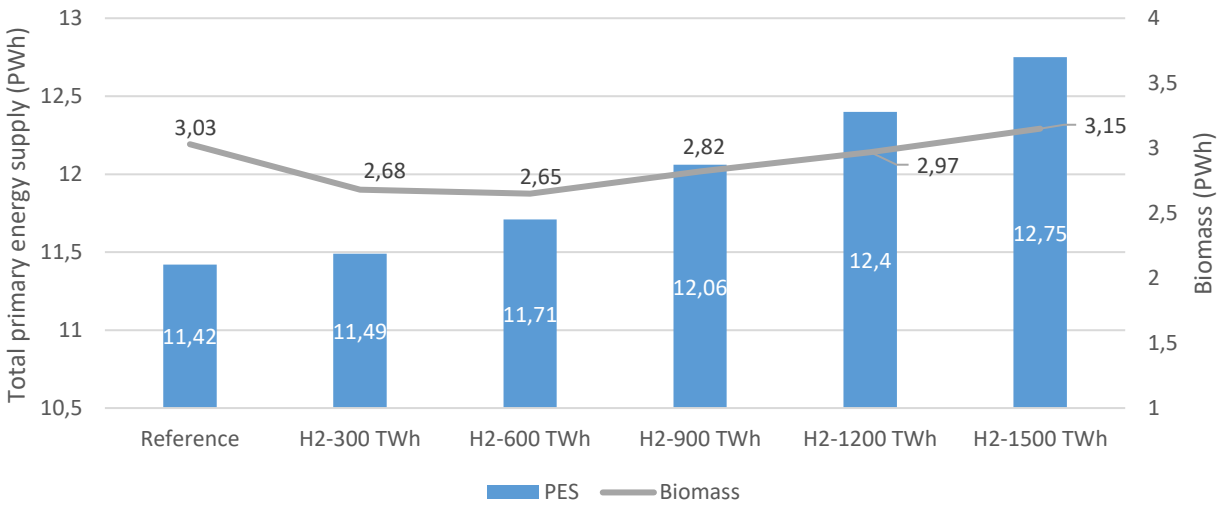

Figure 3.12. Total Primary energy supply and biomass consumption for the scenarios with hydrogen in power production versus the reference Smart Energy Europe scenario.

The energy system analysis also revealed that hydrogen cannot replace completely the methane used in Smart Energy Europe scenario for electricity production when considering the same level of offshore wind curtailment. But if such a gas should replace methane, then it will have to do it with large levels of curtailment, which effectively reduce the efficiency of an energy system. If curtailment is limited as in the Smart Energy Europe scenario, as well as including constraints on hydrogen storage and electrolyser capacity, then the addition of hydrogen does not replace methane, but increases the overall amount of gas combusted in power plants since the energy system needs more capacity to support the increased hydrogen production. This is illustrated in Figure 3.13. If a hydrogen is to completely replace methane, a very large over capacity of storage and electrolysers would be needed.

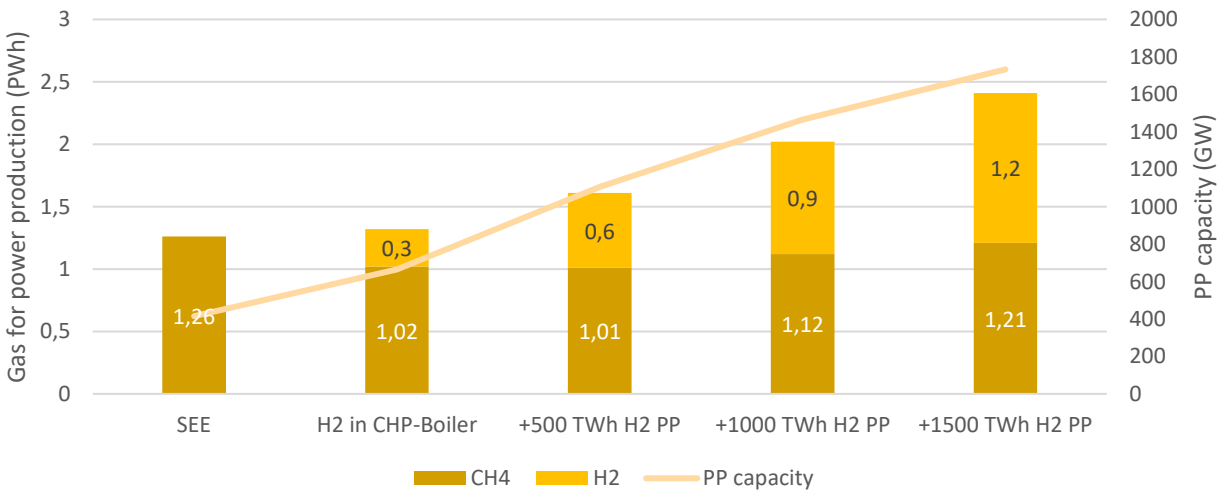

Figure 3.13. Gas consumption in power production and overall power plant capacity in the different scenarios

Therefore, the addition of hydrogen to the power production sector does come with a cost penalty, and in all scenarios the total cost of the energy system increases from the reference scenario by 5-40%. The least

cost increase occurs when adding 300 TWh hydrogen to the gas grid, so the additional 50 B€ for this scenario indicate that hydrogen can save 350 TWh of hydrogen at a cost of 142 M€/TWh. In the next scenario, with 600 TWh hydrogen, the cost of saving biomass by replacing with hydrogen is significantly higher, at >400 M€/TWh.

In all scenarios, as also indicated in Figure 3.14, the cost difference between the scenarios is primarily given by the investments in offshore wind, electrolysis and hydrogen storage, but also by the increased fuel consumption and capacity in the power plants. However, the costs related to hydrogen infrastructure are marginal in the overall picture of the energy system.

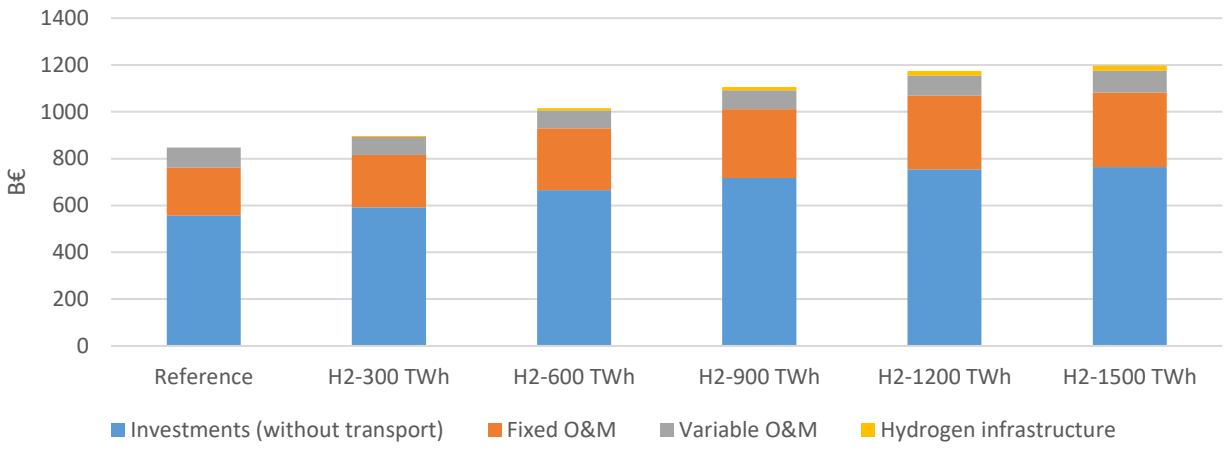

Figure 3.14. Total annual costs for the scenarios where hydrogen replaces biomass in power production versus the reference Smart Energy Europe scenario.

The use of hydrogen as fuel for industrial purposes may be another alternative. In the Smart Energy Europe scenario industry is electrified to a high extent, so when assessing the potential of hydrogen in this sector we do not replace electrification with hydrogen, but only the other fuels, as electro-methane and direct biomass consumption. The results show that replacing electro-methane is not necessarily a way to save on costs nor biomass, since production costs of both gases are high, and since none rely directly on biomass as feedstock, the biomass consumption is similar.

Since carbon capture sourced electro-methane is one of the most expensive ways to produce a combustible gas, it can be said that using hydrogen to replace any type of methane (except electro-methane) is in general a more expensive solution. On the other hand, replacing biomass in industry can reduce direct biomass consumption significantly, but more biomass is necessary in power plants to balance the additional electricity for hydrogen production. This also increases the cost by 9% compared to the reference scenario. Not the least, as also illustrated in Figure 3.15, replacing both electro-methane and biomass with hydrogen can reduce both biomass and energy system costs, which is explained through the system effects, where the energy system can gain flexibility by using only hydrogen than a combination of the two gases.

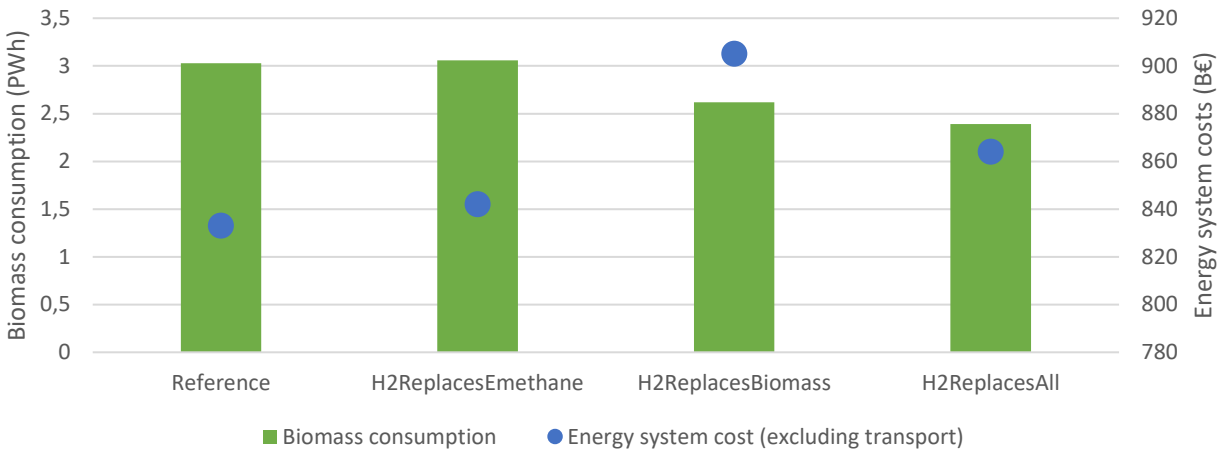

Figure 3.15: Biomass consumption and energy system costs when replacing electro-methane and biomass with hydrogen.

The use of hydrogen as compressed or liquefied fuel in the transport sector to replace liquid electro-methanol also shows high costs and a higher biomass consumption than the reference Smart Energy Europe model. First, the higher costs are primarily determined by the necessity of a more expensive distribution and fuelling infrastructure for hydrogen rather than more expensive vehicles. Secondly, a higher biomass consumption is identified in such a scenario, which is partly a result of modelling, indicating a higher reliance on power plants than in the scenario with the more flexible electro-methanol production.

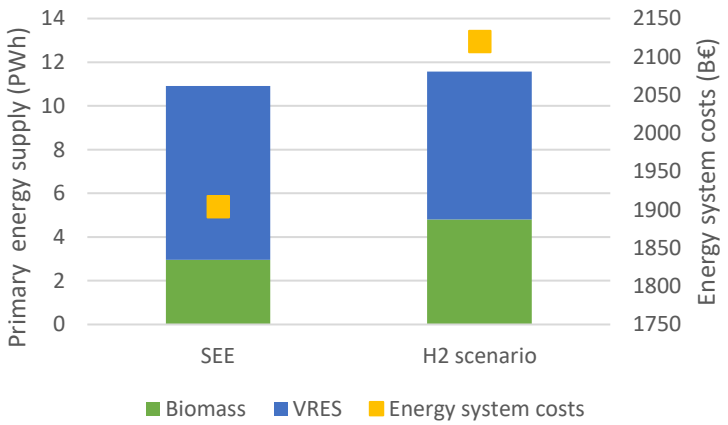

Figure 3.16: Primary energy supply and energy system costs in the SEE scenario and a full hydrogen scenario for the transport sector.

In all parts of the energy system the results indicate that the use of hydrogen is not a universal solution, and in all cases, replacing gaseous and liquid fuels in Smart Energy Europe with hydrogen increases the overall costs and total primary energy consumption, since the reference model is designed with energy efficiency as a key criterion. From the same perspective, using biomass is more efficient than using green hydrogen, and this is the reason why sustainable biomass resources should be maximised to the extent possible. However, biomass is a limited resource, so hydrogen can play a role for reducing the reliance on it. This can be for industrial purposes and power production sector in limited quantities, and as an addition to other methane bases gases.

Energy efficiency is a critical aspect in the choice of future renewable fuels, and hydrogen production is bound to energy losses. In the Smart Energy Europe scenario, overall electricity-to-hydrogen efficiency is estimated at 75% (or 70% when considering hydrogen compression), which also means that 450-750 GWe electrolysis will be needed just to supply the demands for transport and industry. The large variation in electrolysis capacity relates to the potential for flexible operation. 500 GWe of electrolysis is the minimum needed to supply the hydrogen demands on a constant operation. But future electrolysis should be operated flexibly to take advantage of renewable wind production and thus offer a balancing effect on the energy system. Flexible operation also links to the availability of storage, and some type of energy storage is necessary to deal with the load variations.

The smart energy Europe scenario considers hydrogen storage to manage the flexible operation of electrolysers, and for the 3,000 TWh of hydrogen production, 32 TWh of storage is needed (considering 4 days of storage). These are massive capacities, much of which is assumed to take place in steel tanks, better suited for intermediate storage compared to underground storage. However, these capacities may be lower if hydrogen storage can be dimensioned differently or not included at all, depending on the design of the electrolysis plant, its purpose and location. This would also entail that fuel synthesis can be operated flexibly, if the technology allows it, as the storage of liquid fuels has a lower cost than that of hydrogen.

The design of the plant and its location can significantly influence the hydrogen cost. In connection to the development of renewable energy islands and new offshore wind farms, hybrid turbines combined with electrolysers (either with individual electrolyser or grouped to a central unit) can make use of the high offshore wind capacity factor for in the North Sea to produce hydrogen. This hydrogen can then be transported onshore at a lower cost than electricity and used in a specially designed hydrogen grid. Since electricity costs take a large share of the hydrogen production costs, such a design ensures a low electricity cost, which will reflect in the production cost of hydrogen. Such a system design would, in this case, require the presence of large hydrogen storage that can balance supply and demand of hydrogen. Other uncertainties and potential costs must also be considered, such as the necessary energy for transporting hydrogen, a gas with a much lower energy density than methane gases or the potential energy losses from such an extensive grid.

3.5 District heating and power to heat

3.5.1 Consequences of lower district heating implementation

Based on the Smart Energy Europe scenario it is relevant to investigate the implication if the district heating options cannot be achieved. This can be due to lack of expansion in current grids or that district heating is not rolled out in countries that currently have very little district heating.

To do this, two alternative district heating scenarios have been investigated.

- No district heating scenario. Here, all heat demand is moved to individual heating solutions.
- Only expansion in countries which currently have district heating. Based on the Heat Roadmap Europe study, district heating is only kept and expanded in countries with district heating today. Other countries will still have individual heating solutions.

The study investigates three types of individual heating solutions to cover the demand not being supplied by district heating. These are hydrogen boilers, electric boilers and heat pumps.

In Scenario 1, no demand is covered by district heating, whereas in Scenario 2, the district heating demand is lowered from 1.09 PWh in Smart Energy Europe to 0.660 PWh. Cost and capacities for DH are reduced with the same share (100% in Scenario 1 and 39.5% in Scenario 2).

With these changes, the systems need to be rebalanced; i.e. more capacity needs to be installed. For heat pumps and electric boilers, offshore wind capacity is increased, and to balance the amount of curtailment potentially an increase in biomass CHP is included to represent that the individual solutions cannot provide the same flexibility as district heating grids. For the hydrogen boilers, wind power is increased alongside electrolysers as well as potentially increasing the hydrogen storage to provide the same flexibility as the district heating grid.

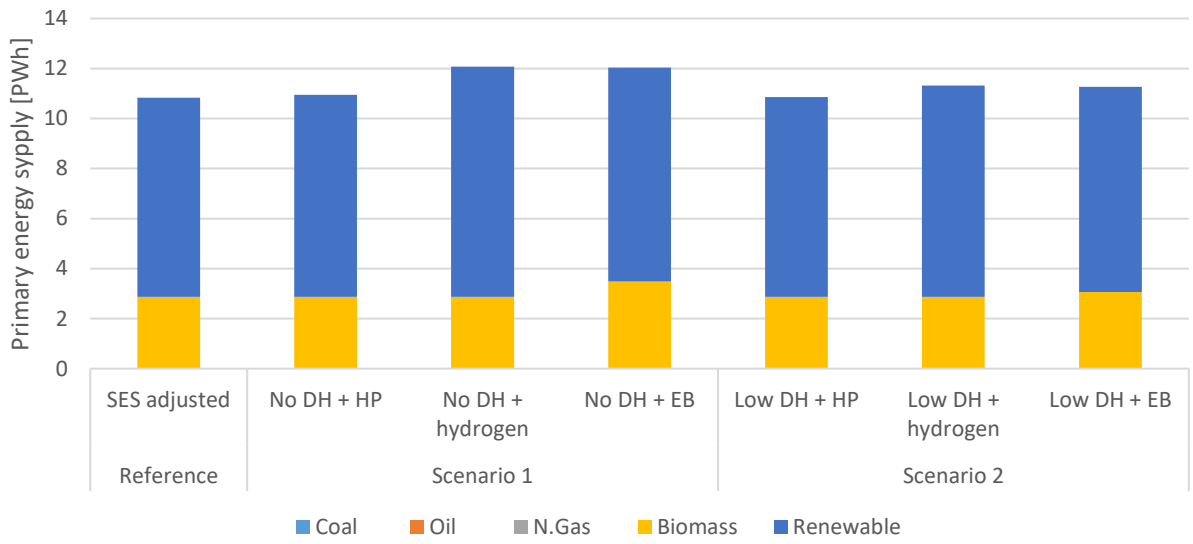

Figure 3.17. Primary energy supply in the different heating scenarios.

From figure 3.17 it is possible to see that the most fuel-efficient scenario is the reference, tightly followed by the scenarios where heat pumps cover the demand no longer supplied by district heating. The all-individual solutions are in general worse, and especially the hydrogen scenario offer the worst fuel efficiency, due to conversion losses into the hydrogen system. The electric boiler scenario is hard for balancing the system, and either individual thermal storage needs to be installed, or as here, more electricity needs to come from for instance biomass.

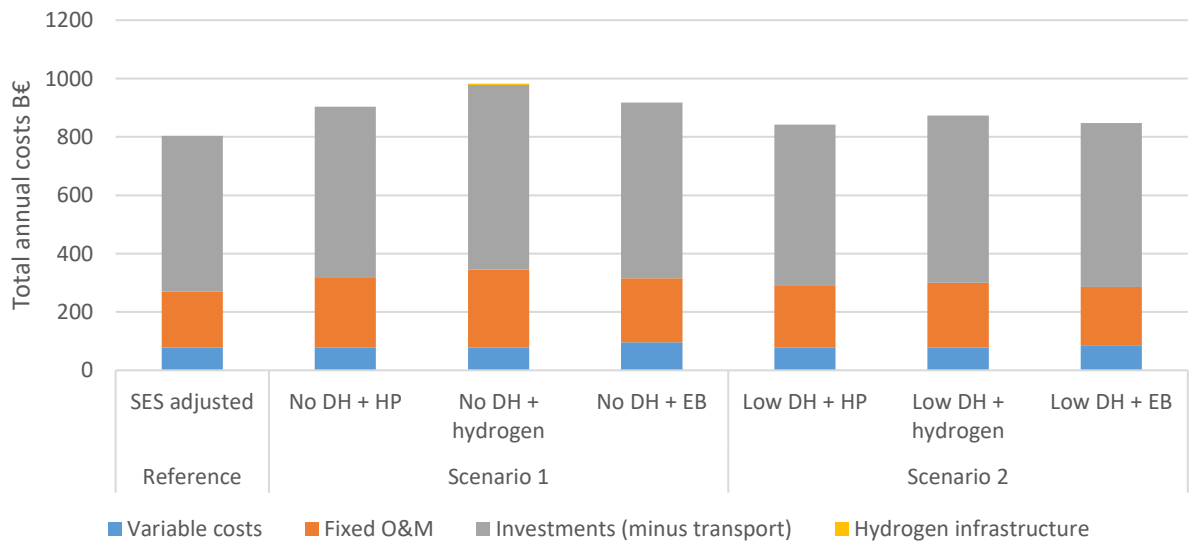

Figure 3.18. Total annual costs for the different heating scenarios, including operation and investment costs.

From Figure 3.18 it may be observed that while the no DH scenario with heat pump, was close primary energy supply, the investment costs are impacted significantly, thus leading to a more expensive heating scenario. This consequence is lower, if DH is only disregarded in countries without pre-existing DH. Hydrogen for heating comes out as the most expensive solution, not due to the extra hydrogen grid but due to investments in renewables, electrolysers and hydrogen storage.

Overall, this study emphasises the certainty of investing in district heating as a good idea from both a technical and economic perspective. Furthermore, hydrogen should be avoided in the heating sector as other more fuel efficient and cheaper technologies exist.

3.5.2 Potentials from expanding district heating in the European Commission's scenarios

This section presents an analysis that demonstrates the effect of implementing the heating sector system from the Smart Energy Europe scenario into the 1.5 TECH scenario. By showing that the design of the SEE heating sector can improve the efficiency of the 1.5 TECH scenario, the purpose of this analysis is to demonstrate the potentials of having a high share of district heating in the European energy system.

One significant difference between 1.5 TECH and the SEE scenario is the design of the heating sector, both in terms of heating demand and in terms of heating technology mix. While 1.5 TECH includes significant heat savings in households of around 31% additional to the savings reached in the Baseline 2050 scenario and around 47% compared to the historical demand of 2015, SEE includes slightly lower savings of about 10% savings additional to the savings reached in the Baseline 2050, or about 27% compared to 2015. The argument for not implementing as significant savings in SEE is the assumption that such significant heat savings are not economically feasible, since it is cheaper to produce the needed heat than to save it by investing in more refurbishment.

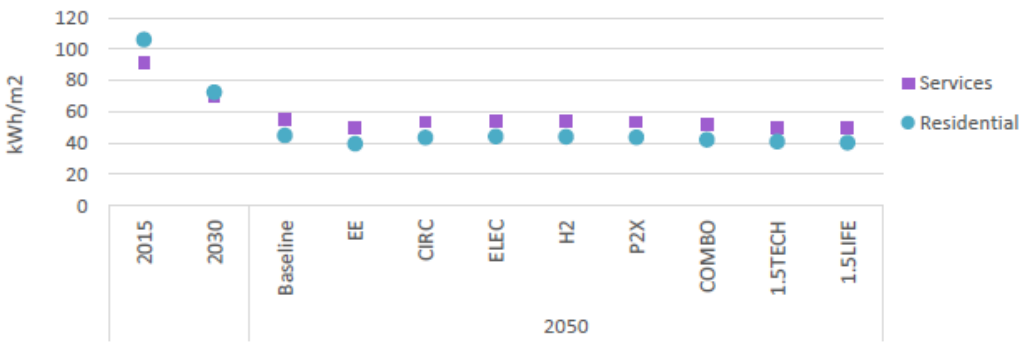

Figure 3.19. [15] *Assumed reduction in energy demand for heating in the services and the residential sector from 2015 towards each of the 2050 scenarios.*

Furthermore, while the European Commission's scenarios suggest~~s~~ a heating technology mix based largely on individual heat pumps and natural gas boilers as well as some district heating, biomass boilers, hydrogen boilers and electric heating, the SEE scenario finds, that roughly haft of the heating demand should be supplied by district heating, while most of the remaining heat demand should be supplied by individual heat pumps. The technology mix of the two scenarios is shown in Figure 3.20.

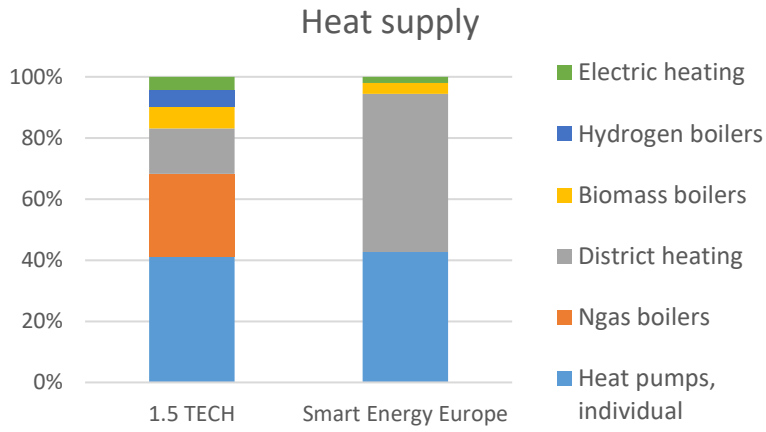

Figure 3.20. Heating supply shares in 1.5 TECH and in Smart Energy Europe.

Four new scenarios are created, which combine the 1.5 TECH and the SEE. To create these scenarios, inputs that relate to the 1.5 TECH heating sector in EnergyPLAN are replaced with SEE values. The new scenarios are described in Table 3.2 and Appendix 4 shows how the heating sector inputs of 1.5 TECH are changed in EnergyPLAN for each of the new scenarios.

Scenario Description	**Scenario 1.1** Scenario 1.1 replaces the 1.5 TECH heating sector with the SEE heating sector. However, the scenario keeps the same energy savings of 1.5 TECH, which means that the heating technology-mix of SEE and their annual generation are scaled down relative to the lower demand for heat.	**Scenario 1.2** As Scenario 1.1, but here the offshore wind capacity is adjusted down, so that the critical electricity excess matches that of 1.5 TECH	**Scenario 2.1** Scenario 2.1 also replaces the 1.5 TECH heating sector with the SEE heating sector. The scenario assumes the same heat savings as SEE, which means that the heating technology mix and their annual generation is identical to the SEE scenario.	**Scenario 2.2** As Scenario 2.1, but here the offshore wind capacity is adjusted down, so that the critical electricity excess matches that of 1.5 TECH.

Table 3.2. Description of the four scenarios developed to analyse the effect of implementing the SEE heating sector in the 1.5 Tech scenario.

In terms of excess electricity production (CEEP), Scenarios 1.1 and 2.1 show an increase of 0.14 PWh and 0.09 PWh, respectively. Due to the added efficiency of replacing the 1.5 TECH heating technology mix with that of SEE, and due to the added CHP capacity, there is less need for offshore wind capacity. Therefore, both scenarios are adjusted for CEEP by reducing the offshore wind capacity to reach the same level of CEEP as in 1.5 TECH, which is 0.58 PWh.

In terms of PES, Scenario 1.1 shows that replacing the 1.5 TECH heating technology mix with that of SEE increases the efficiency of the system and reduces the PES by 0.3 PWh. This is shown on **Fejl! Henvisningskilde ikke fundet.**. To put this into perspective, the total heating demand of 1.5 TECH is 1.3 PWh and the total PES is 12.51 PWh.

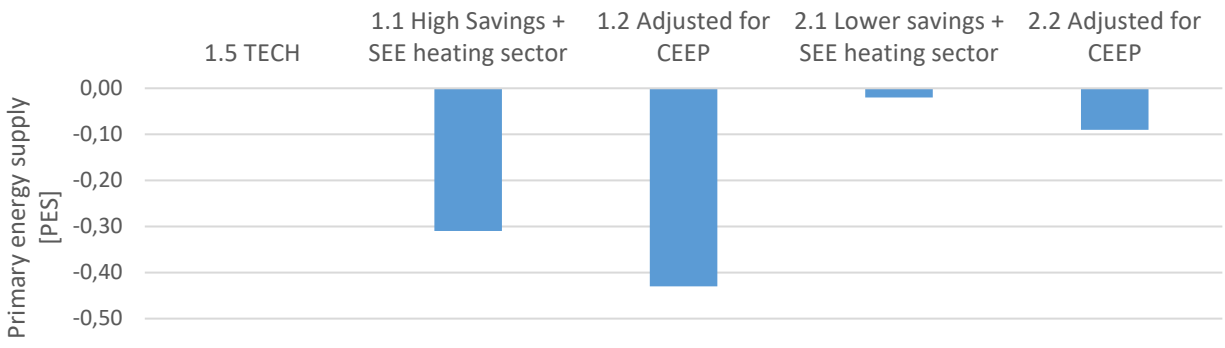

Figure 3.21. Difference in PES in the scenarios from Table 3.2 compared to 1.5 TECH.

In terms of total annual costs, replacing the 1.5 TECH heating technology mix with that of SEE brings about savings in total annual costs of around 48 billion EUR, as shown on Figure . Reducing the curtailment by adjusting the offshore wind power capacity brings the savings down to about 51 billion EUR. Lower heat savings, and thereby significantly lower investment costs, and the heating technology mix of SEE, brings about savings of about 141 billion EUR. Adjusting for CEEP by lowering the offshore wind capacity to match the CEEP of 1.5 TECH improves this slightly and shows total annual cost savings of 143 billion EUR. To put this into perspective, the total annual cost of the 1.5 TECH scenario (omitting the cost for the transportation sector, which makes up approximately half of the costs) is 966 billion EUR. This means that the new scenarios show total annual cost savings of about 5 % and 15%.

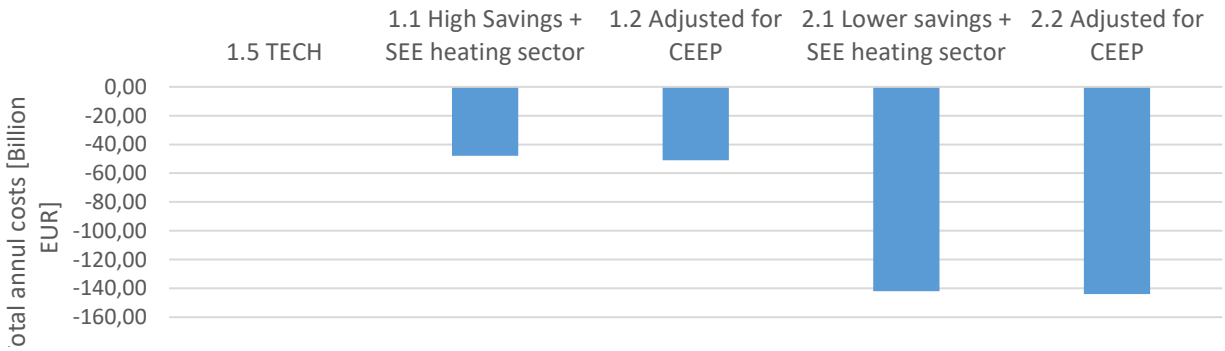

Figure 3.22. Difference in total annual costs in the scenarios from Table 3.2 compared to 1.5 TECH

The results above indicate, that the even though the European Commission's scenarios were not designed in a similar way as the SEE scenario with the Smart Energy Systems perspective, the design of the SEE heating sector could still improve the European Commission's scenarios, both in terms of lowering the costs and lowering PES. Furthermore, aiming for lower heat savings while implementing district heating would significantly lower the costs of the energy system.

4 Employment creation potentials

Based on the Smart Energy Europe scenario, a potential employment generation estimate has been made. This takes a starting point in the concrete investment costs, and factors determining the employment generated per total investment measured in person years. The factors are currently based on Danish assumptions, which may result in an under estimation on a European level. The reason is that while materials and goods are imported in a Danish context, this might be imports from a European level. For the national analyses, employment generation only factors in employment in the given country through a split of costs into domestic and foreign expenditures, where foreign expenditures are disregarded in the employment generation assessment. Thus, from a European perspective a given activity generates more employment. Table 4.1 shows the factors for employment used.

Employment when investing in machinery	600 person years/b EUR
Employment when investing in district heating and energy savings	700 person years/b EUR
Employment from the fossil fuel industry	100 person years/b EUR
Employment from biomass industry	800 person years/b EUR
Employment tied to operation and maintenance	800 person years/b EUR

Table 4.1. Employment factors used to calculate annual employment in the different scenarios.

When applying these factors to the investments to the baseline scenario, the Smart Energy Europe scenario and the 1.5 Tech scenario a total number of annual jobs are estimated. These are shown in Figure 4.1

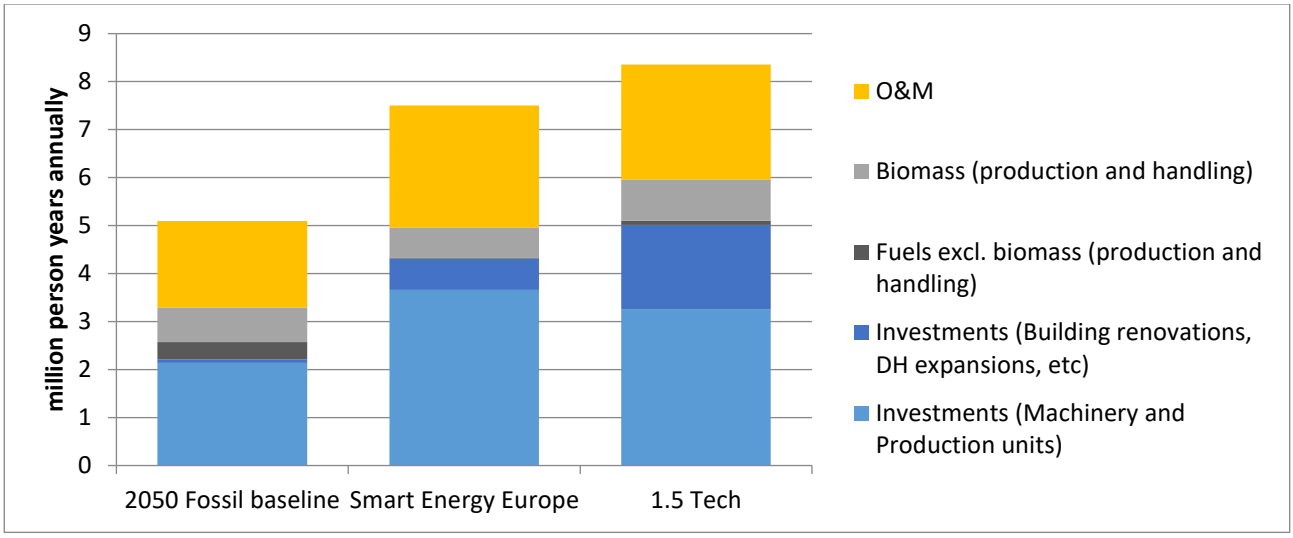

Figure 4.1 Annual employment in the three scenarios measured in person years for EU27 + UK.

Here it is possible to see that the baseline scenario has the lowest level of employment generation, however most tied to fossil fuel industry. These jobs are almost gone in the Smart Energy Europe scenario as well as the 1.5 TECH scenario. Here instead most of the jobs are tied to investments in renewable energy and other production units, however with the Smart Energy Europe having the most jobs in the renewable energy sector.

With the large amounts of heat savings in the 1.5 TECH scenario, it generates more employment in the building sector, compared to the Smart Energy Europe scenario, where there are fewer investments in heating, due to efficiency being implemented also in the district heating sector. All three scenarios have similar employment in the biomass sector, whereas the Smart Energy Europe and the 1.5 Tech scenario have similar employment for the operation and maintenance of the energy system. When comparing the Smart Energy Europe scenario and the 1.5 Tech to the baseline scenarios, it is possible to generate more jobs in the energy sector by converting to renewable energy.

When including the perspectives from the early and steady, and late and rapid energy transitions, the conclusion is that both paths will ensure almost the same employment within the solar, wind and biomass sectors – however the timing differs as illustrated in Figure 4.2., where the steady path ensures a more even employment throughout the period. The impact of a potential increase in number of jobs depends on the economic situation at a given time, thus the positive impact of job creation is context dependent. Here an early transition path will ensure a more stable job creation pathway, compared to the late and rapid which shows more sensitivity towards timing.

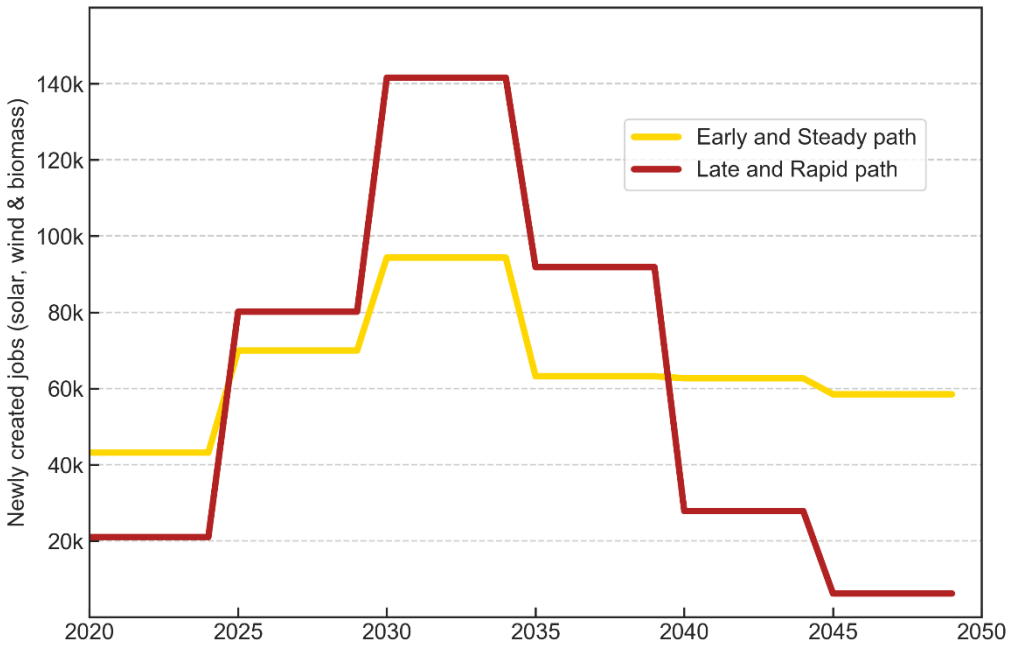

Figure 4.2: Newly created jobs associated with the expansion of solar PV, wind and biomass capacities throughout transition paths Early and Steady, and Late and rapid transition.. Cumulative new jobs represent 1.9 and 1.8 million for the Early and Steady and Late and Rapid path respectively. This is in agreement with the analysis included in the Clean Energy for All strategy which estimates the creation of 2.1 million jobs under the 1.5

C scenario

It should be emphasized that employment generation not per se is favourable. It will have a positive societal impact if there is unemployment and especially if it is the result of technology development inside a country. If there is full employment, the situation is different as it will create competition for the available employment resources – unless the labour force is expanded.

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Appendix A

Documentation for re-creating PRIMES scenario in EnergyPLAN

Appendix B

Designing a Smart Energy Europe from the PRIMES scenarios.

Authors: Jakob Zinck Thellufsen, Henrik Lund, Brian Vad Mathiesen, Poul Alberg Østergaard, Miguel Chang

1 Identifying a baseline scenario

The first step is to identify a baseline scenario. Based on the process in replicating the PRIMES scenarios in EnergyPLAN an adjusted baseline is identified. The reason for adjusting the baseline is to ensure the modelling of the energy efficiency steps can be done coherently. Specifically, this means updating the heating and industry demands.

The first step is to increase the power plant capacity to allow for all electricity production in Europe to be handled internally. This increase means the PP capacity is moved from 310.9 GW to 575 GW.

Furthermore, the electricity storages has been updated based on the following inputs:

- Batteries have 4 hour storage capacity and a roundtrip efficiency of 0.85 (0.92 charge, and 0.92 discharge). Batteries cost 300 M€/MWh
- Hydro storage: 10 hour of storage, pump efficiency of 0.8, turbine efficiency of 0.8. Cost of 175 M€/MWh.

The goal of RE-INVEST is to find robust investment strategies for renewable energy. Thus, as part of the smart energy Europe scenario, the existing capacity of 86.82 GW of Nuclear power (with a production of 0.69 PWh of electricity) is replaced by a corresponding capacity of offshore wind.

1.1 Updating transport demand

Based on the sEEnergies research project, a new interpretation have been made of the transport demand in the PRIMES scenarios, thus the following is assumed for 2050.

PWh	Fossil	Biofuel	Electrofuel
JP	0.73	0.02	0
Diesel	1.17	0.11	0
Petrol	0.52	0.07	0
Ngas	0.16		
LPG	0		
Ammonia			0

Table 2

PWh	
H2	0.06
Electricity, dump	0.21
Electricity, smart	0.31

1.2 Updating heat demand

The heat demand is specifically for space heating. Here we have used Heat Roadmap Europe 4 to update the heating demand. This is done by scaling the current heating system defined in PRIMES BL 2050, with the heat demand identified in Heat Roadmap Europe. It is important to note that Heat Roadmap Europe accounts for 90% of the heating demand in Europe, as such everything is scaled afterwards. The table below illustrates the updated heat demands:

Scenario	BL 2050	HRE14	HRE14 scaled to 28 countries
Heat demand [PWh]	2.01	2.095	2.328

This gives a ratio of 1.16 that all heat demands are scaled within the system.

1.3 Updating industry demand

This updates the heating demand to reflect the heating for industry from sEEnergies and likewise for electricity for industry.

In terms of fuel consumption, the difference between the PRIMES baseline, and the adjusted baseline can be seen below.

Here we implement the heat demand, electricity demand and fuel demand for industry. These are as follows

Industry demand [PWh]	BL 2050 + HRE	sEEnergies Frozen
Coal in industry	0.306	0.578
Oil in industry	0.528	0.446
Gas in industry	0.872	1.211
Biomass in industry	0.512	0.365
Electricity	1.195	1.199
Heat	0.236	0.243

The main thing here is to note that the assumption for how much of the district heating demand is due to industry comes from sEEnergies. Thus the DH system changes. Based on Heat Roadmap Europe, the total district heating demand was 0.332 PWh.

From Heat Roadmap Europe, the district heating for industry can be divided into 0.041 PWh for space heating and 0.195 PWh for industrial processes. In total 0.236 PWh. sEEnergies uses 0.243 PWh for industry. We adjust, by assuming the space heating is industry is equal to Heat Roadmap Europe, but the total heat demand for industry is equal to sEEnergies. This changes the baseline as follows

PWh	BL + HRE	sEEnergies adjustment
DH for space heating in commercial and residential	0.096	0.096
DH for space heating in industry	0.041	0.041
DH for industrial process	0.195	0.202
TOTAL	0.332	0.339
The first step is to investigate the demands and identify potential system efficiencies. **TOTAL**	0.338	0.365

1.4 Reference industry demand

With implementing reference industry demand, coal is almost eliminated from the system, alongside a reduction in oil and gas demands.

Here the “Reference” scenario for industry demand is implemented. Furthermore, the heat demand savings potential from heat roadmap Europe 4 is also implemented, as the overall heat demand in Europe. The heat savings are implemented equally in all sectors of the energy system.

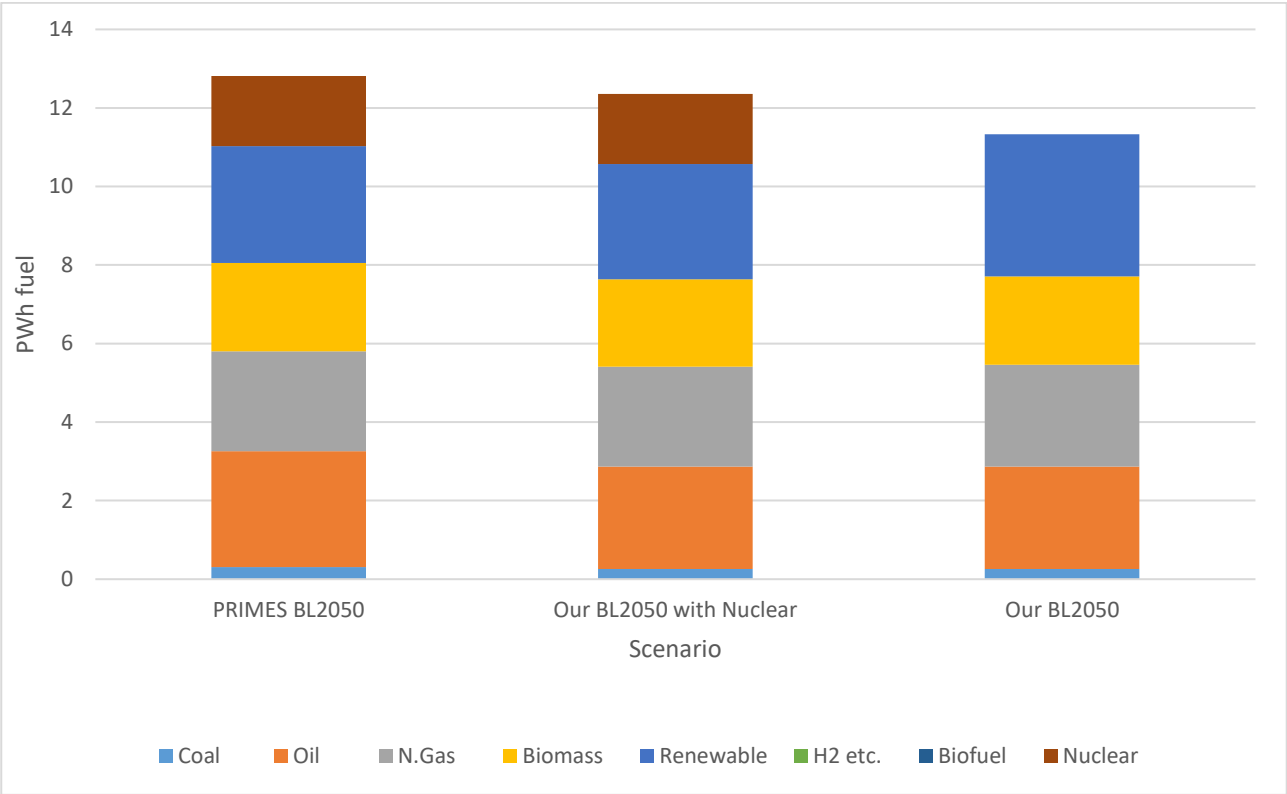
Industry demand [PWh]	sEEnergies Frozen	sEEnergies Reference
Coal in industry	0.578	0.264
Oil in industry	0.446	0.179

Gas in industry	1.211	0.638
Biomass in industry	0.365	0.446
Electricity	1.199	1.145
Heat	0.243	0.270

This changes the DH system to look like this.

PWh	sEEnergies frozen	sEEnergies Reference
DH for space heating in commercial and residential	0.096	0.096
DH for space heating in industry	0.041	0.041
DH for industrial process	0.202	0.229
TOTAL	0.339	0.366

This gives the following



Finally, we also remove CCS from the process, so all systems below do not have any CCS, but might utilize CCS.

2 Step 1: Efficient heat demands

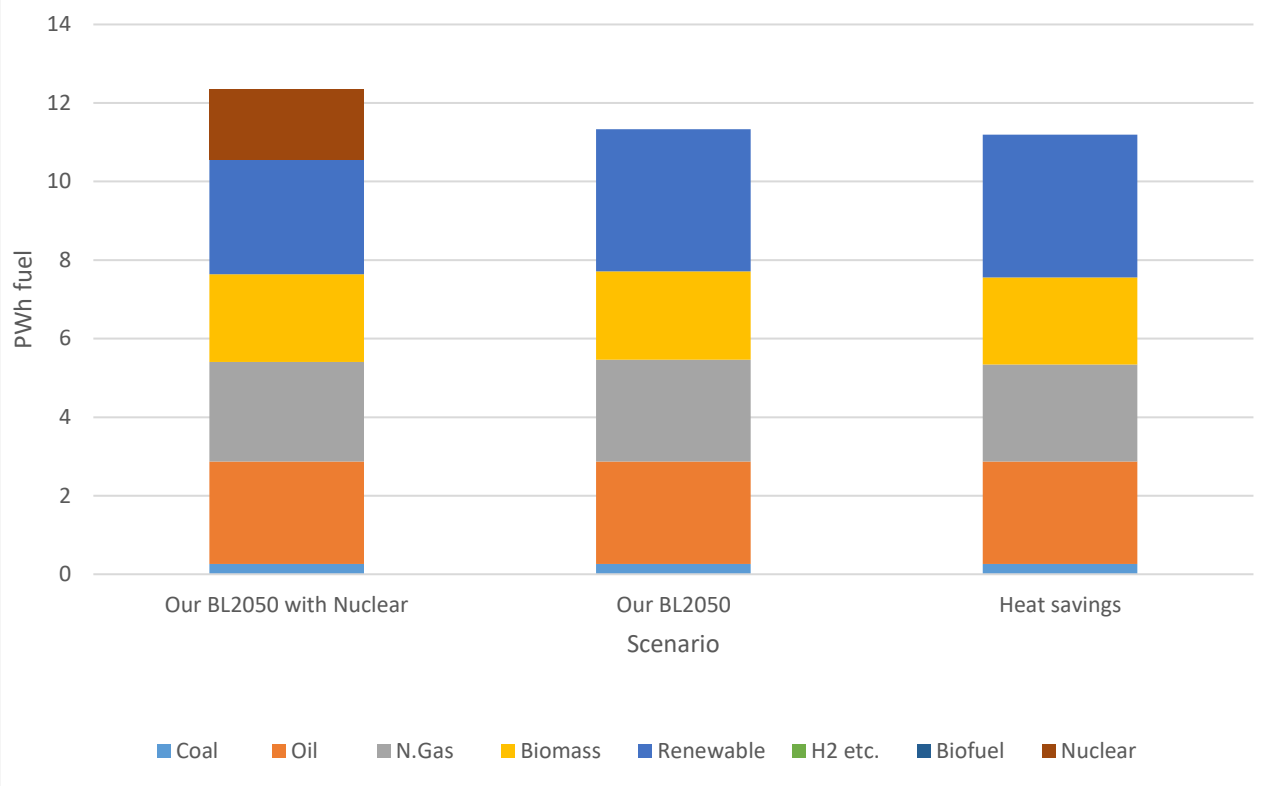
To reduce heat demands, the change in heating demand from Heat Roadmap Europe is assumed. The heat savings are conducted for space heating in both industry, residential and service buildings.

- Heating demand for residential houses and services based on heat roadmap Europe
- Space heating demand for industry based on heat roadmap Europe.
- District heating demands for industry processes are kept fixed.

This gives an overall heat saving in space heating demand of approximately 10% additional to the base step identified in HRE14.

The heat demands therefore changes to the following:

PWh	Our Baseline	Our baseline + heat savings
Indv. Oil boiler	0.01	0.01
Indv. Gas boiler	0.94	0.83
Indv. Biomass boiler	0.15	0.13
Indv. Heat pump	0.81	0.72
Indv. Electric boiler	0.08	0.07
DH	0.37	0.35



3 Step 2: Implementing district heating and updating heat supply

The step here is to implement district heating. Based on heat roadmap Europe 4, the amount of heating in district heating is determined. This is adjusted for district heating for industry determined by sEEnergies data. In total the district heating in Europe covers 52% of the total heating demand (1.091 PWh out of 2.11 PWh). This includes heat for industry.

The scenario therefore becomes like follows:

PWh	Individual	District heating
Indv. Oil boiler	0.007	0.004
Indv. Gas boiler	0.847	0.481
Indv. Biomass boiler	0.133	0.075
Indv. Heat pump	0.733	0.416
Indv. Electric boiler	0.075	0.042
DH	0.357	1.091

3.1 Step 2.1 Dimensioning the heating system

Based on peak district heating demand of: 298 GW, the DH boiler capacity is dimensioned to be that +20% = 358 GW

The CHP electric capacity is determined to be equal the average DH demand 144 GW. The CHP efficiency is determined to be 0.45 electric and 0.45 thermal, based on a combination of biomass CHP, single cycle and combined cycle gas turbines.

3.2 Step 2.2 Including thermal storage

The system includes a thermal storage capable of storing 8 hours of the average district heating demand.

The average heat demand is 144 GW which results in 1152 GWh ~ 1.2 TWh of thermal storage.

3.3 Step 2.2 Including industrial excess heat, geothermal and solar thermal

According to the Heat Roadmap Europe study the following amount of energy can be delivered from industrial excess heat: 0.096 PWh. This is 90% of Europe, so scaling up 0.107 PWh excess heat is implemented.

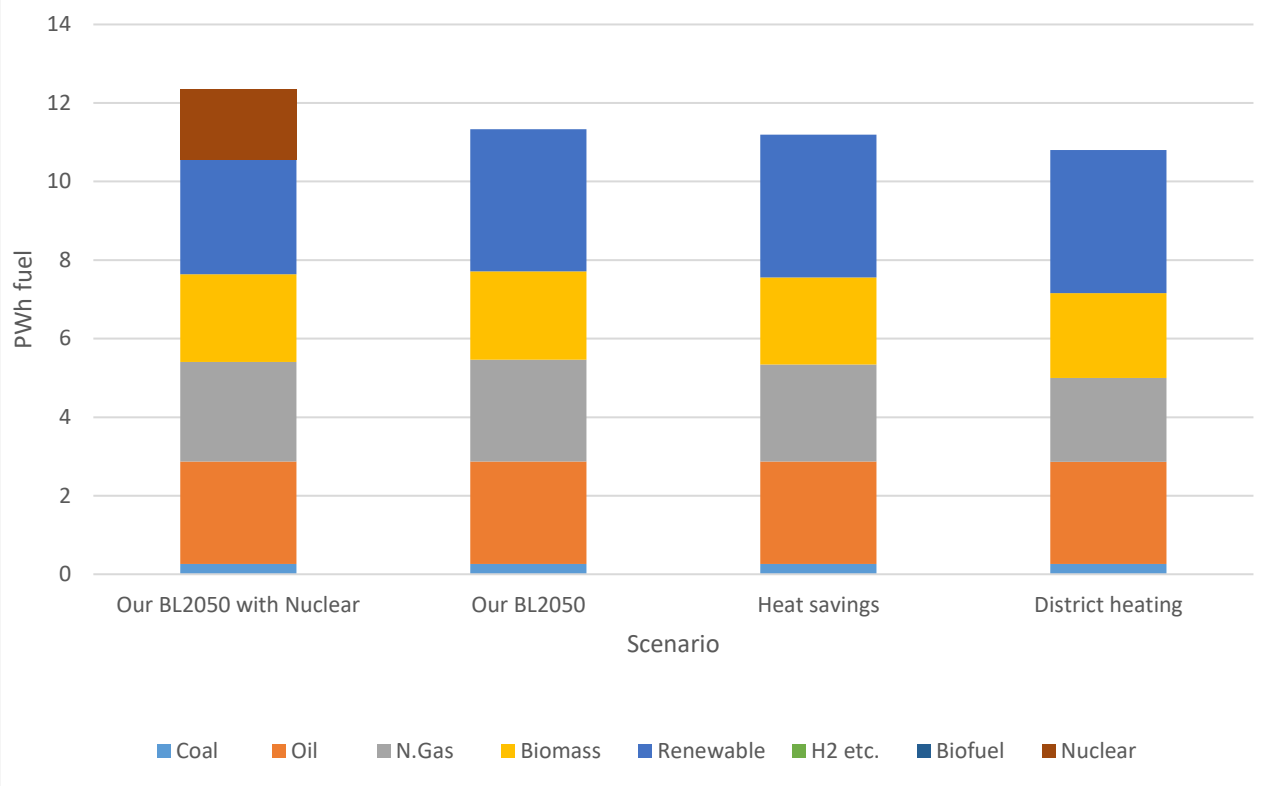
Solar thermal can deliver 0.016 PWh in HRE4, resulting in 0.018 PWh used in this study.

3.4 Heat pumps in district heating system

Heat pumps are included in the system. The technology catalogue for RE-INVEST specifies the following efficiencies:

District heating heat pumps have a COP of 4.

The first step is to implement the average heat load of 144 GW, as thermal capacity of heat pumps in the district heating grids. This gives the following result for fuel consumption



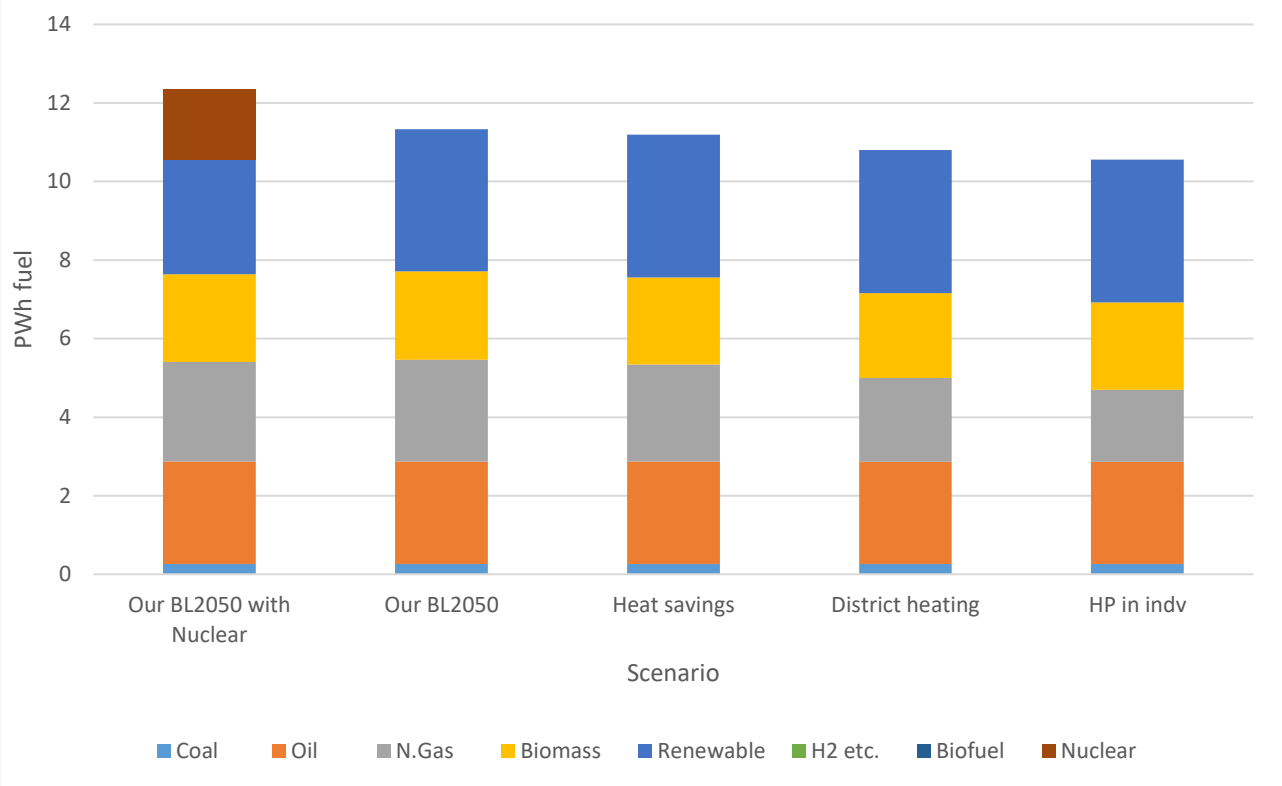
3.5 Heat pumps in the individual heating system

The next step is to change the individual gas and oil boiler to heat pumps (potentially we could also do something with biomass and electric boilers??).

The COP of the heat pumps are determined to be: 3

This means the heat pumps now cover 0.900 PWh of heating demand of the total 2.15 PWh.

This requires increased power plant capacity of 25 GW. The total is 600 GW of PP capacity.



4 Step 5: Demand side management and EVs

The next step is to convert the possible transport demand to electric vehicles. Based on the sEEnergies project a complete revamp of the transport sector is made. This assumes the following electrification rates. IN total this translates the system into the following demands

	Car		Light Duty		Heavy duty (based on bus)	
	Fuel to Electric	Gas to electric	Fuel to Electric	Gas to electric	Fuel to Electric	Gas to electric
Converted to electricity	100%	100%	50%	-	20%	0%

Car and light duty vehicles are assumed to smart charge vehicles with heavy duty is dump charge. Adding these values to the existing electricity demand and subtracting the determined fuel and gas demands, the transport scenario looks the following:

PWh	Fossil	Biofuel	Electrofuel
JP	0.73	0.02	0
Diesel	0.63	0.11	0

Petrol	0	0	0
Ngas	0.07		
LPG	0		
Ammonia			0

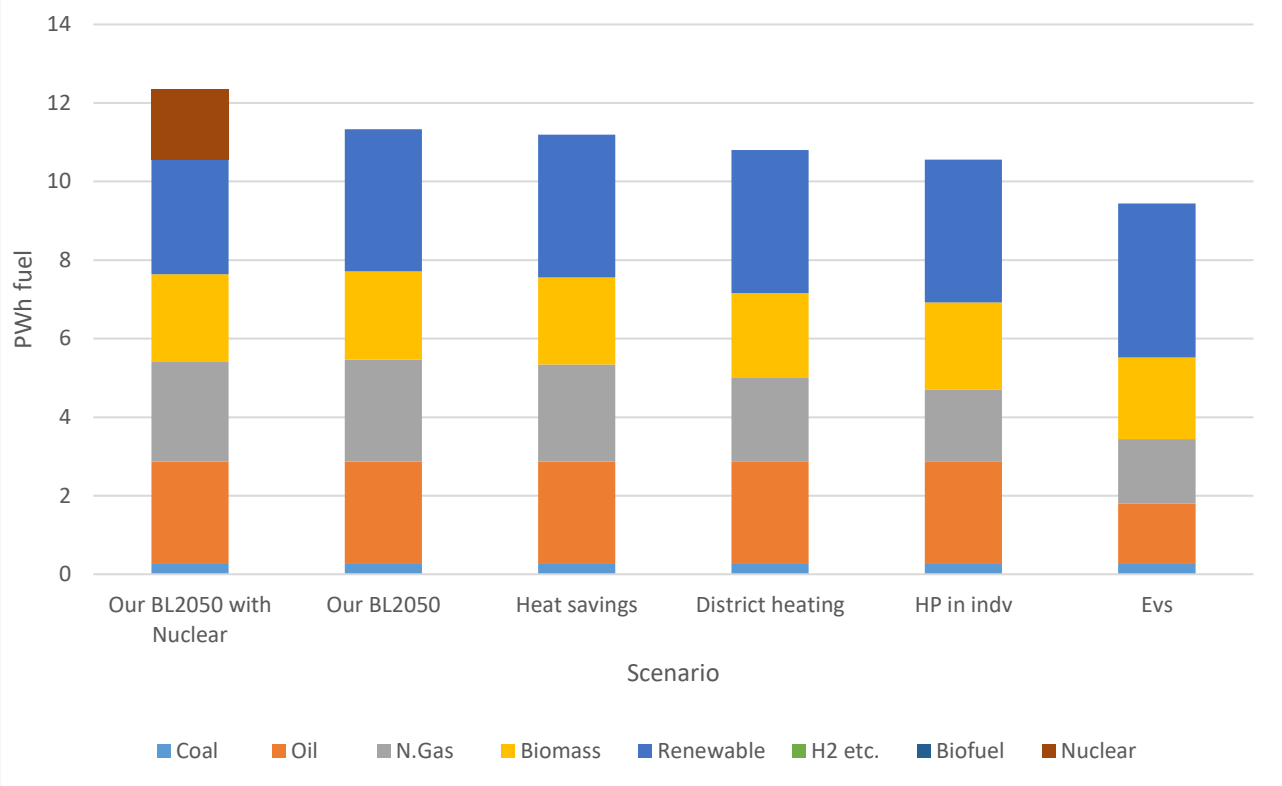
PWh	
H2	0
Electricity, dump	0.25
Electricity, smart	0.531

Based on the increase in smart charge, the capacities on cables and batteries are increased with the same ratio:

	Baseline	New
Max share	0.2	0.2
Capacity (charge) GW	1800	3301.65775
Share of parked	0.7	0.7
Charge efficiency	0.9	0.9
Storage cap TWh	3	5.50276292
Capacity (discharge	90	165
Discharge efficiency	0.9	0.9

To balance electricity with the new technology 50 GW of PP capacity is added, to a total 650 GW. Also, Offshore wind is increased to accommodate for the new demand

GW	Baseline	New
Onshore wind	441	441
Offshore wind	143	200
Photovoltaic	441	441



5 Step 6: Synthetic fuel for transport(DME/Methanol/JP)

This step converts all liquid fuels to e-fuels, produced on hydrogen and carbon. The gas driven vehicles will use biogas, so the production of biogas will be equal to the gas demand for vehicles.

Thus the transport scenario looks like this.

New Energy Plan scenario + Electrofuel

	Fossil	Biofuel	Electrofuel
JP	0	0	0.75
Diesel	0	0	0.74
Petrol	0	0	0
Ngas	0.07	0	0
LPG	0	0	0
Ammonia	0	0	0

TWh electricity

H2	0

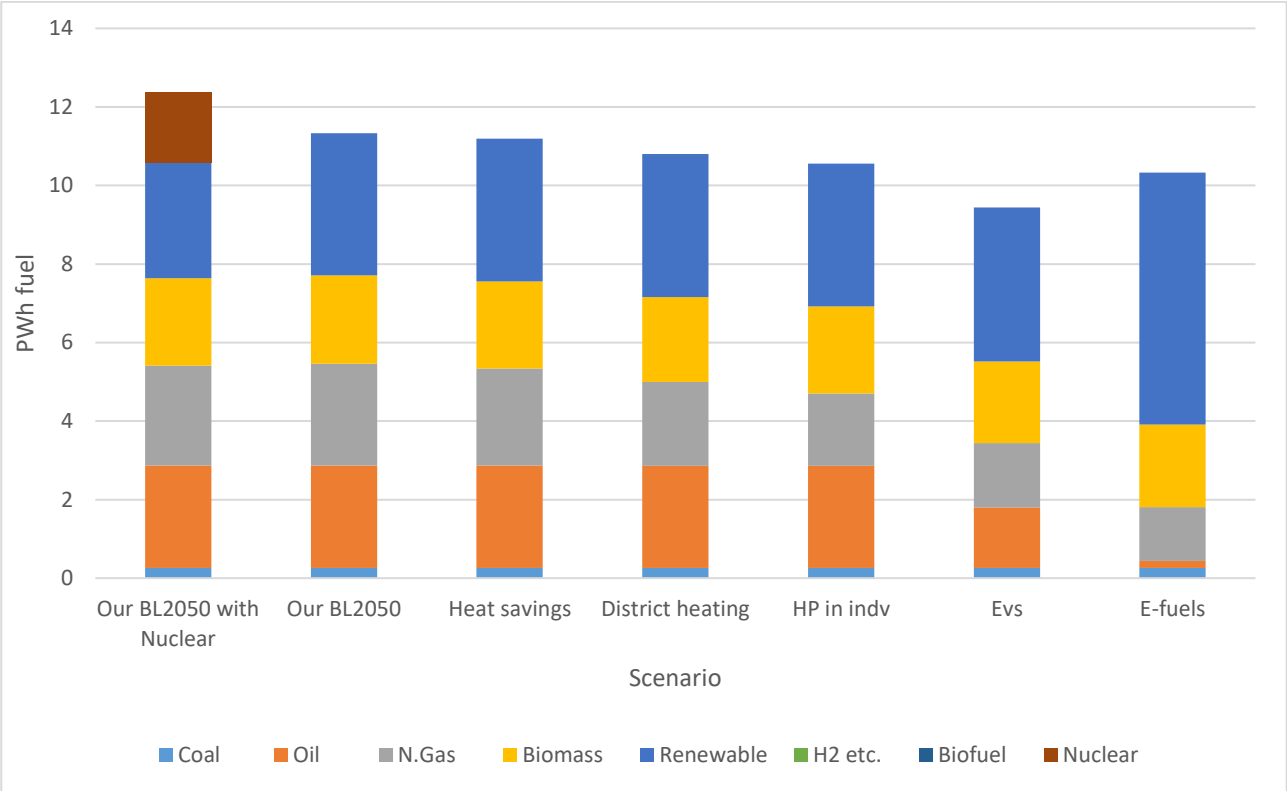
Electricity, dump	0.25
Electricity, smart	0.53

The same amount of biomass used for biofuel will not be hydrogenated that was: 0.21 PWh in the original. This results in a production of 0.27 PWh of liquid fuel from biomass hydrogenation. The remaining 1.48 PWh (before loss in e-JP of 20%), will be produced from CO2 hydrogenatoin.

The electrolysers will be dimensioned to cover 1.6 times the average demand. This results in a capacity of 440 GW. These are accompanied with a storage that can store 4 days of average load = 34 TWh.

This results in a hydrogen demand 1.93 PWh, thus the VRES production has to increase.

GW	Baseline	New
Onshore wind	441	441
Offshore wind	200	725
Photovoltaic	441	441



6 Step 7: Synthetic fuel power plants/backup electricity production

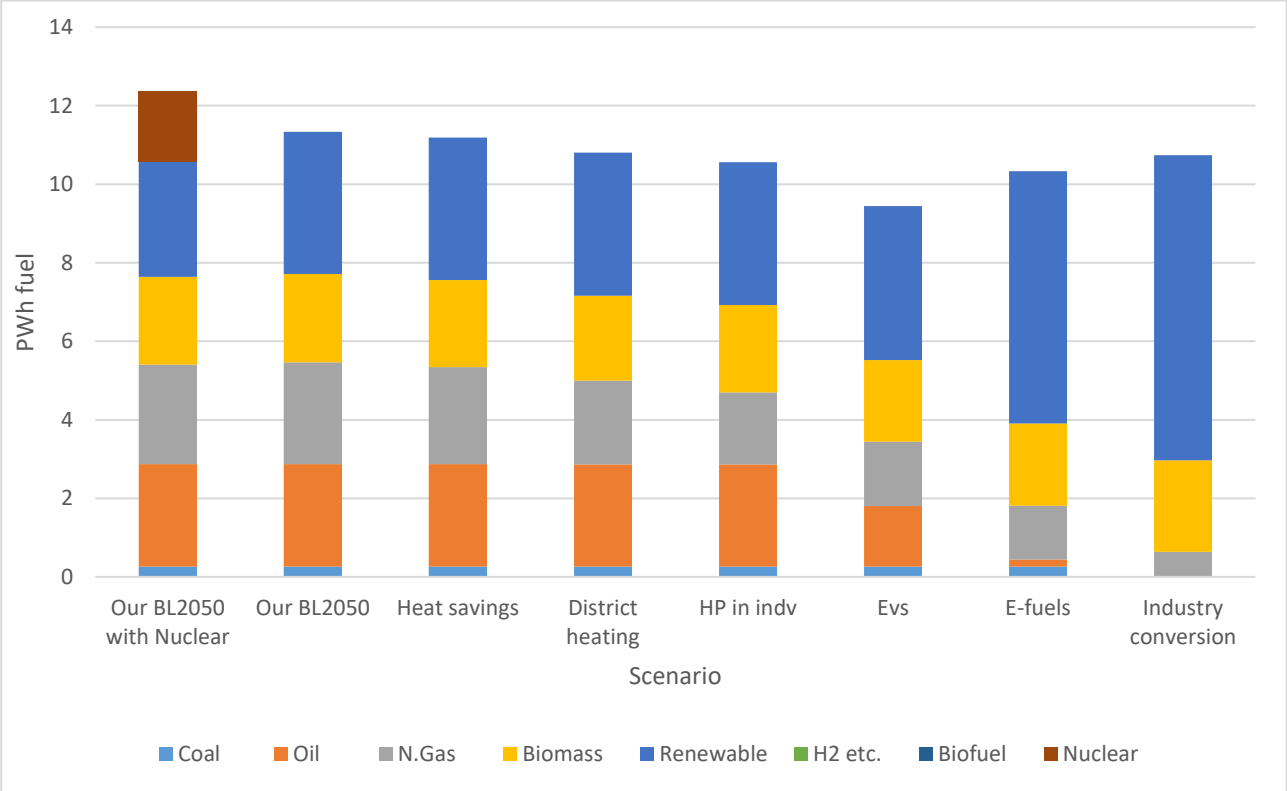
The first step here is to transform the industry to renewable energy. Here coal will be replaced with biomass and oil with gas. The gas will now be produced by e-gas from CO2 hydrogenation.

The industry will therefore change like this:

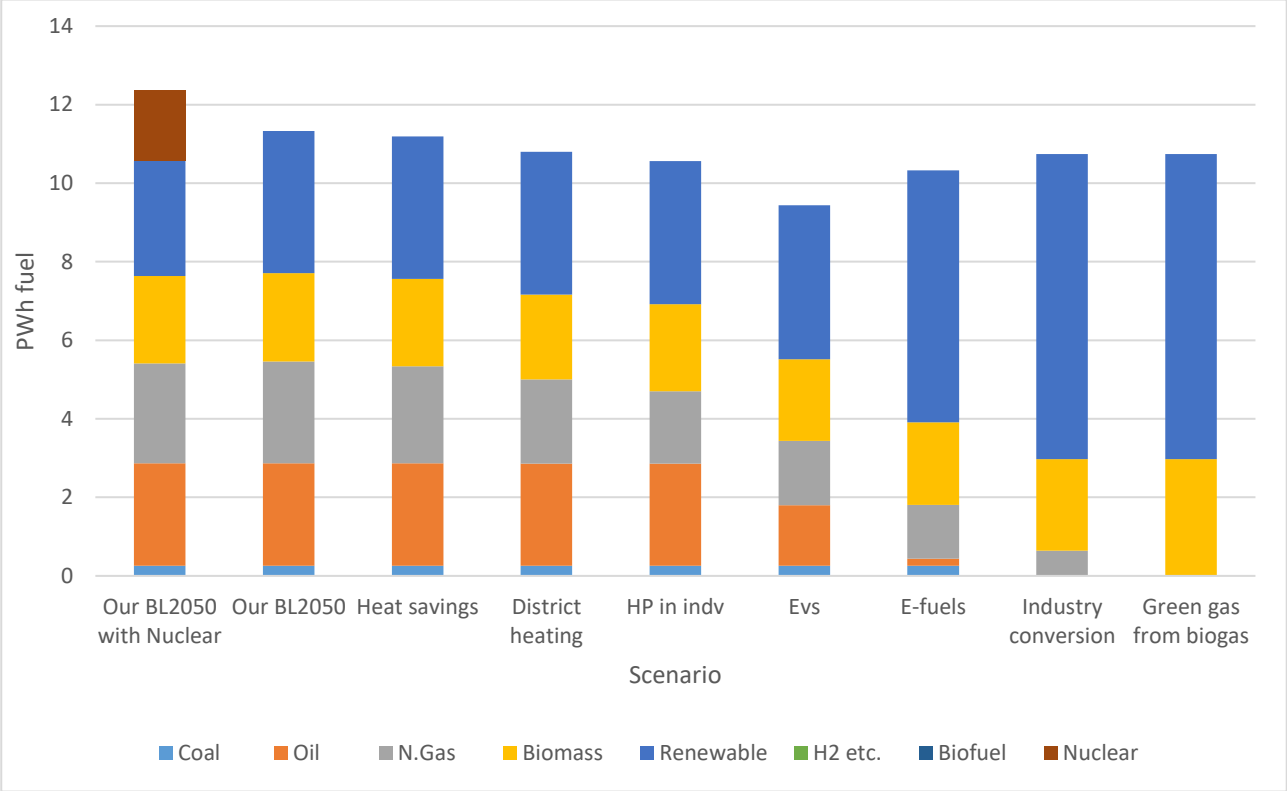
PWh	Reference	New
Coal	0.264	0
Oil	0.179	0
Ngas	0.638	0.817
Biomass	0.446	0.710

This increases the hydrogen demand to 2.92 PWh. Thus the electrolysers capacity is increased to 664 GW and the storage to 51 TWh. Thus the VRES demand increases.

GW	Baseline	New
Onshore wind	441	441
Offshore wind	725	1008
Photovoltaic	441	441



The final step comes from eliminating the last natural gas amount. This is done by increasing biogas production by 0.59 PWh. In total this brings the biogas production to 1.23 PWh.



A final step is added as an alternative to increased biogas. That is to increase CO2 hydrogenation again.

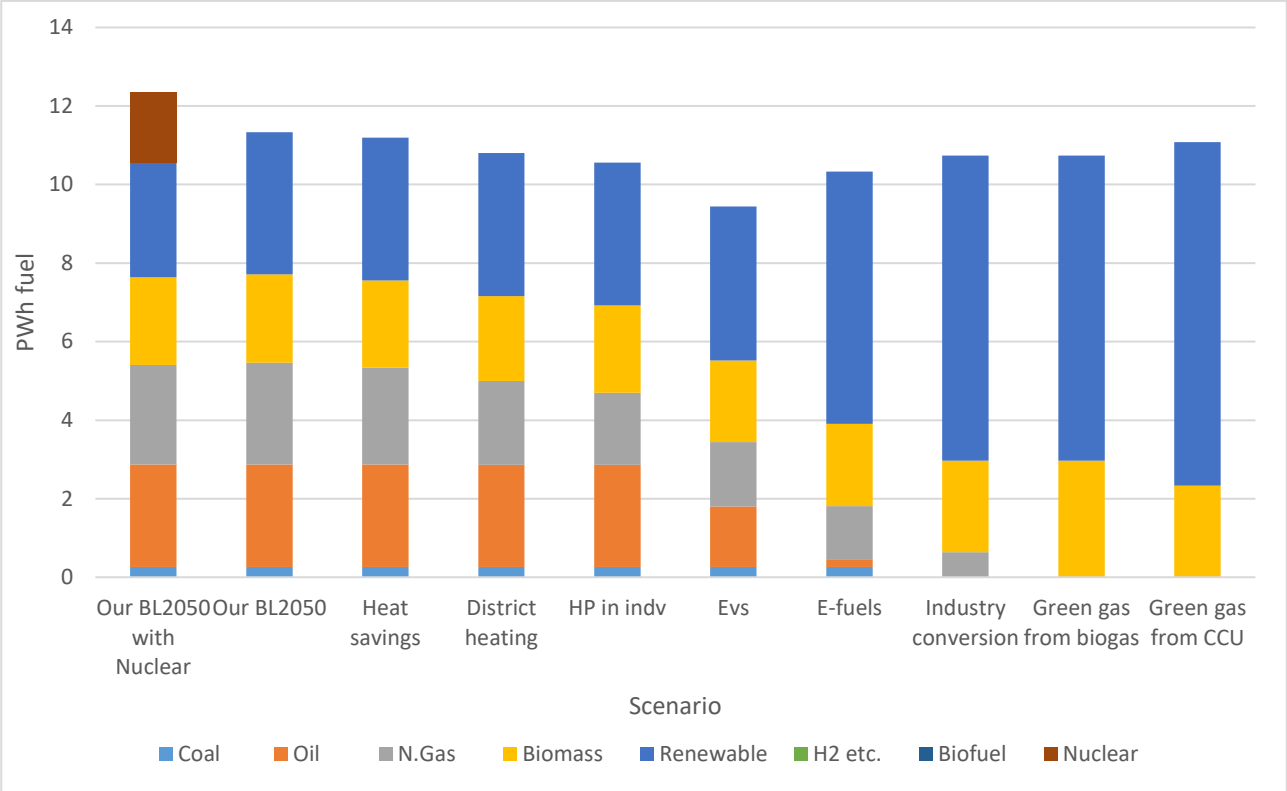
This means the output from CO2 hydrogenatoin has to be 1.457 PWh.

This increases H2 electrolyser capacity to: 838 GW and H2 storage to 64 TWh

We increase renewable to become CO2 emissions of zero is an increase in VRES sources to

GW	Baseline	New
Onshore wind	441	441
Offshore wind	1008	1212
Photovoltaic	441	441

Primary energy results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12
10
8
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PWh fuel
Our BL2050 with Nuclear
Our BL2050
Heat savings
District heating
HP in indv
Evs
E-fuels
Industry conversion
Green gas from biogas
Green gas from CCU
Scenario
Coal
Oil
N.Gas
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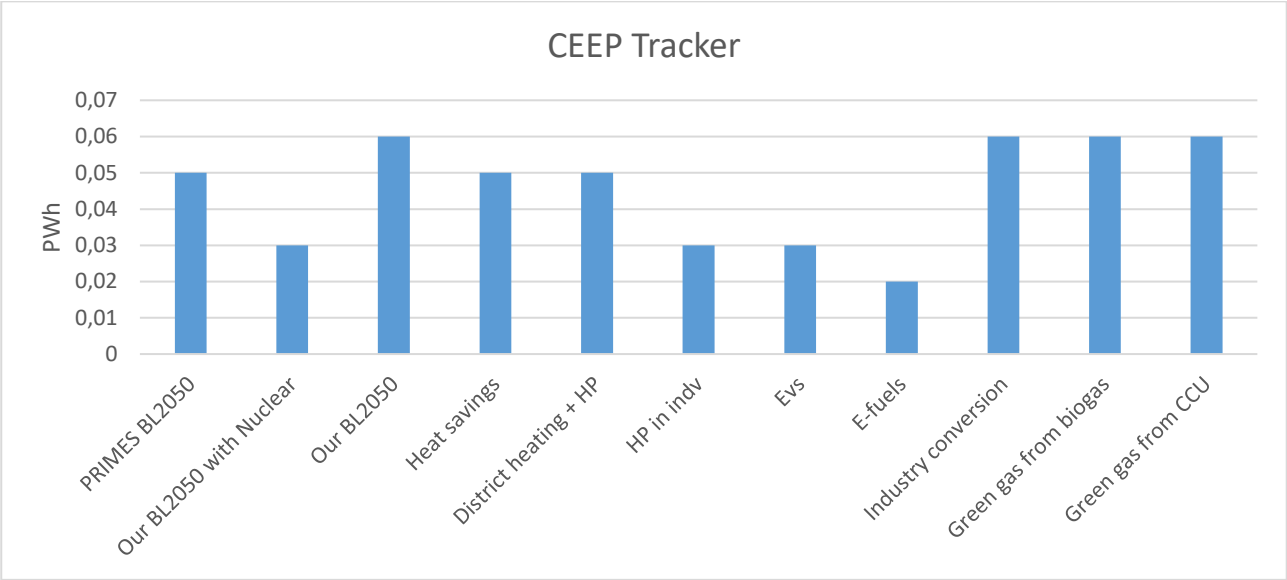
Renewable
H2 etc.
Biofuel
Nuclear


CEEP Tracker
0,07
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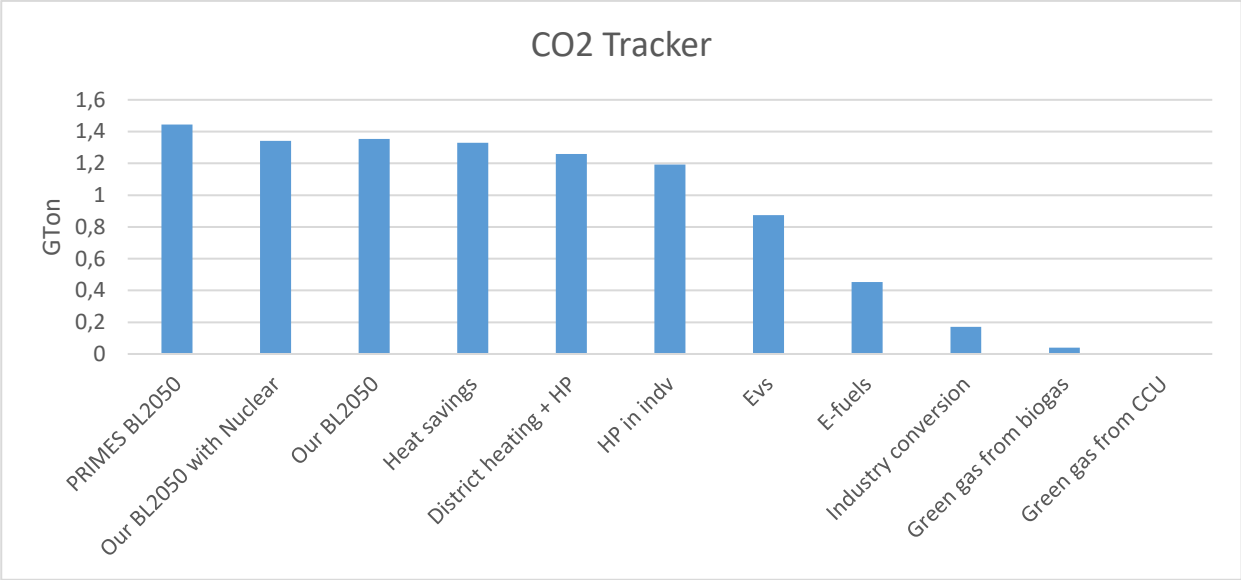
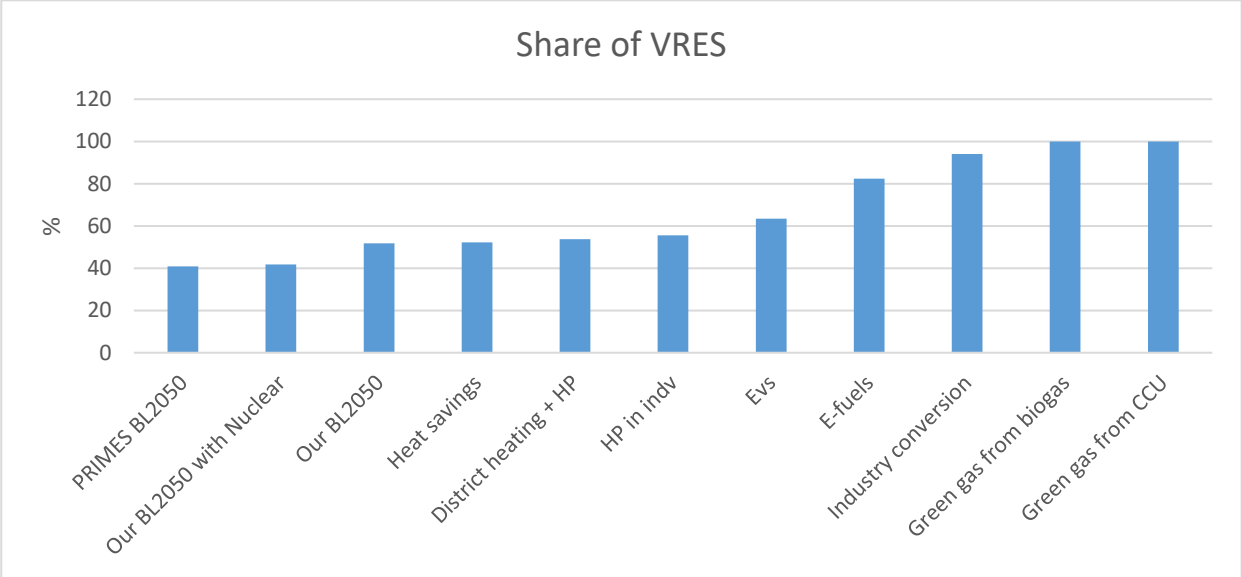
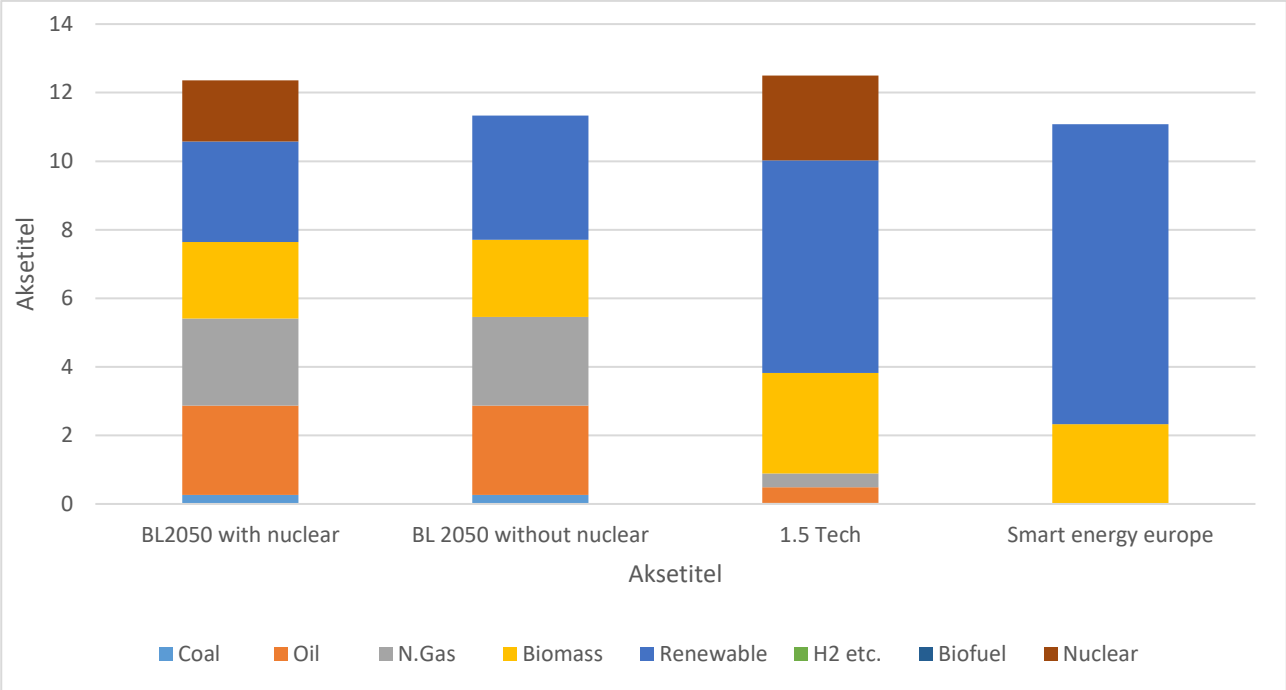
PWh
PRIMES BL2050
Our BL2050 with Nuclear
Our BL2050
Heat savings
District heating + HP
HP in indv
Evs
E-fuels
Industry conversion
Green gas from biogas
Green gas from CCU

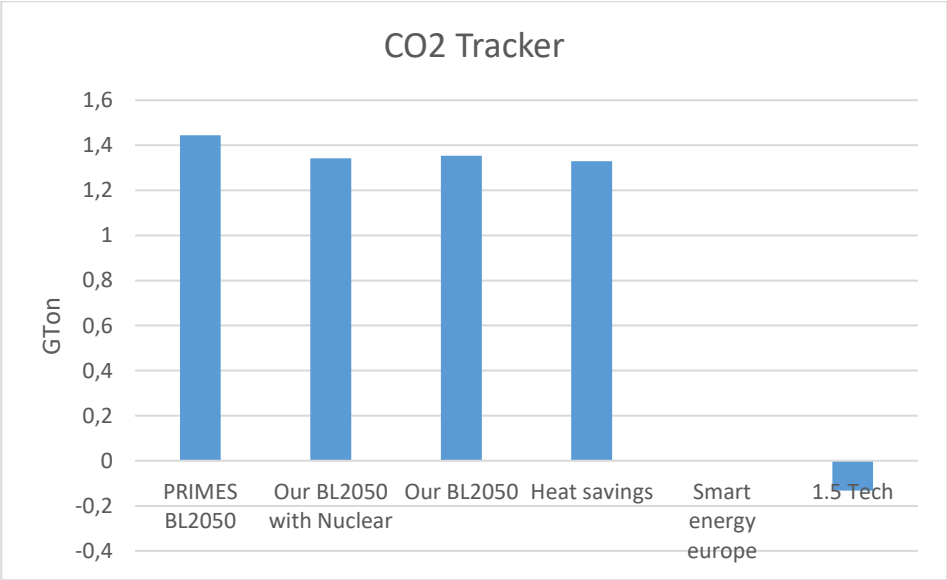




Thus, the compare, this final Smart Energy Europe system is compared to the 1.5 Tech and the Baseline scenarios in the figures below.



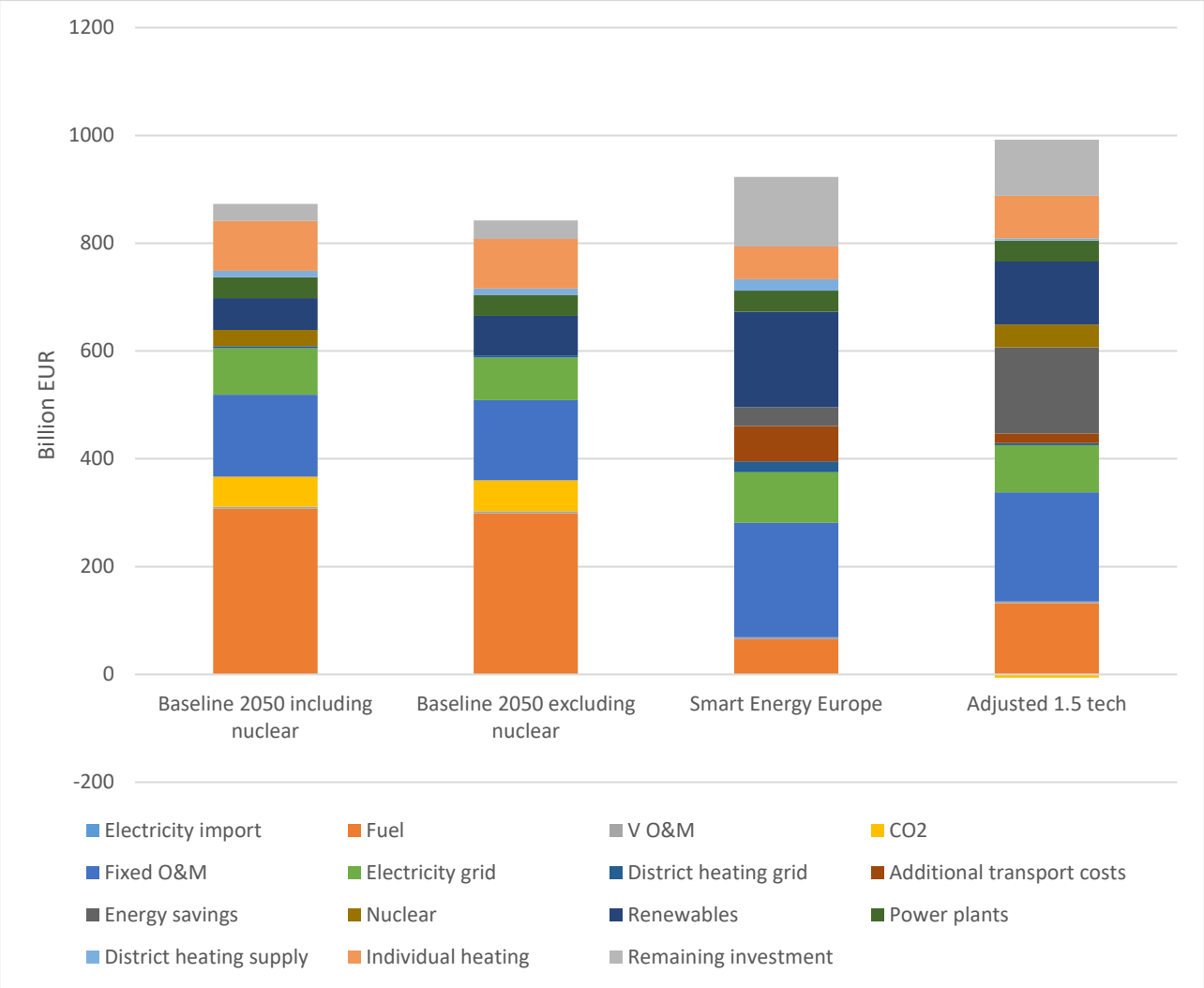
Primary energy consumption



CO2 emissions from the scenarios

7 Implementing costs

Cost comparison between the baseline and smart energy Europe and the 1.5 tech



Primarily the costs are taken from the RE-INVEST technology catalogue, however some are from Danish Energy Agencies cost catalogue, others from specific research in electrofuels. A full detail of costs can be found below in a number of tables. These tables also specify reference for the cost. A discount rate of 3% is assumed.

Technology	Unit	Cost	Lifetime	F O&M [%]	Note	Reference
Large CHP Units	GWe	1.35	25	3.3	Mix of steam and gas turbines	
Heat storage	TWh	3	20	0.5		
Waste incineration	PWh	201.25	25	2.3		

DH heat pumps	GWe	2.218	25	0.3		
DH boilers	GW th	0.2275	25	3.55		
Large power plants	GWe	1.35	25	3.3		
Hydrostorage	TWh	175	80	1		
Battery	TWh	300	20	0		
Onshore wind	GWe	0.963	27	1.3		
Offshore wind	GWe	1.777	27	1.9		
Solar PV	GWe	0.345	30	2.5		
Hydro power	GWe	2.76	80	1.15		
Geothermal heat	PWh	396.67	30	0.83		
Solar thermal	PWh	325	30	0		
Industrial excess heat	PWh	30	30	1		
Biogas plant	PWh	196	20	15		
Thermal gasification	GW	1.1	20	1.47		
Biogas upgrade	GW	0.25	15	2.5		
Biofuel plant	GW bio	1.45	25	6.2		
Bio jetfuel plant	GW bio	1.776	25	5.1		
Carbon recycling	GT	200	20	4.3		
Methanation	GW	0.2	25	4		
Fuel synthesis	GW	0.3	25	4		
JP synthesis	GW	0.5	25	4		
Electrolyser	GW	0.5	25	5		
Hyrdogen storage	TWh	15.06	48	1.37		Mixture of caverns and tanks
Individual boilers						
Individual biomass boilers	Mio units	5.9	20	7.42		20% in reference 25% in 1.5 tech 100% in smart energy
Individual natural gas boilers	Mio Units	2.7	20	6.74		80% in reference 75% in 1.5 tech

						0% in smart energy
Individual heat pumps	Mio units	5	18	4.78		
Indv. Electric heating	Mio units	2.5	30	0.84		

7.1 Additional costs

7.1.1 District heating substations and district heating grid costs

District heating substations cost and grid costs are based on the heat roadmap Europe 4 studies, with an additional 10% costs to reflect the entire European heating system.

This means that DH substations have a cost of:

Technology	Total investment [B€]	Lifetime	Fixed O&M
Susbtations – reference	53.53	25	2.47
Substations – Smart Energy Europe	117.68	25	2.47

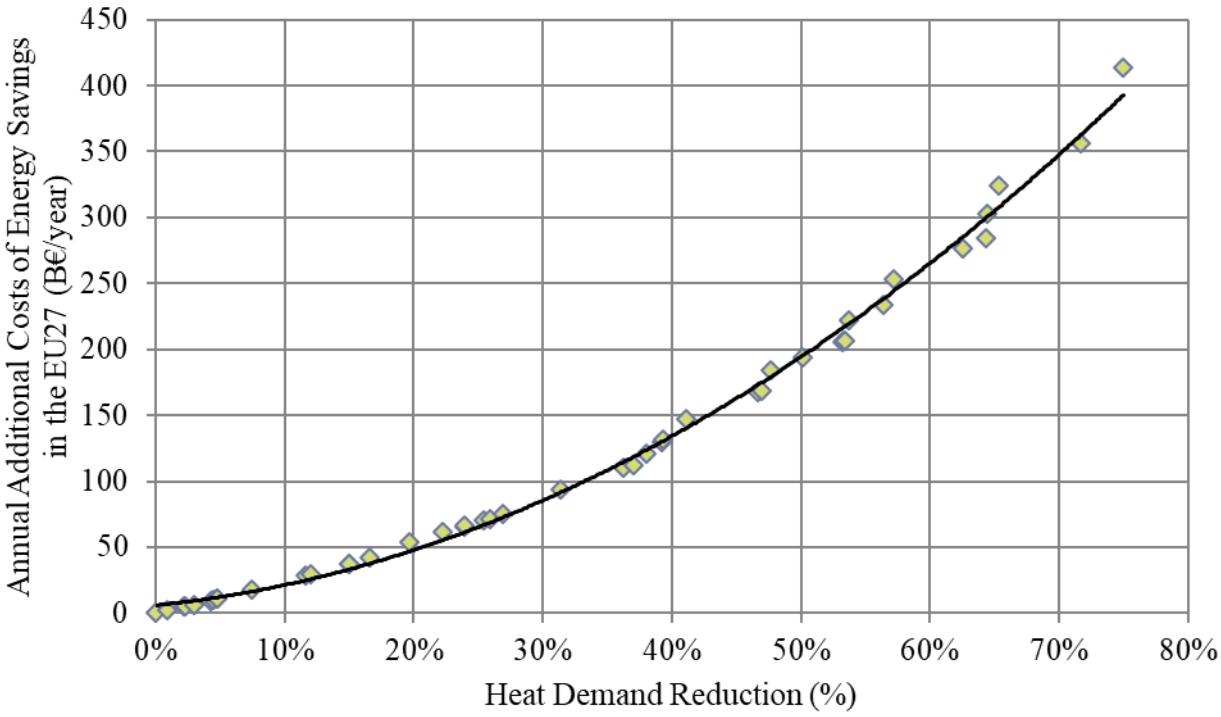
Annual costs for DH grid:

DH grid reference: 3.95 B €

DH grid smart energy Europe: 20.06 B €

7.1.2 Heat savings

The heat savings costs are based on the figure below, coming from the Heat Roadmap Europe 2 studies



In the baseline, it is expected that already 29% heat savings have been achieved. Thus, the additional savings in the smart energy Europe and the 1.5 tech is determined as follows:

0%	3.28	PWh
29%	2.33	PWh
36%	2.11	PWh
54%	1.51	PWh

This results in the following additional costs compared to the reference:

Smart Energy Europe: 35 B€ annually

1.5 Tech scenario: 160 B€ annually

7.1.3 Transport costs

The annual transport costs are estimated from sEEnergies research project. Here the reference, smart energy Europe and 1.5 Tech transport have the following costs. The costs include vehicles and infrastructure:

Reference: 1228 B€ annually

Smart Energy Europe: 1294 B€ annually

1.5 Tech: 1246 B€ annually

In the graphs we only illustrate the increase in transport costs compared to the 2050 reference.

7.1.4 Electricity distribution grid

The distribution grid costs are identified by identifying the hourly electricity demand that is assumed distributed to invidiual users. This includes the classical electricity demand, electric vehicle demand and electric heating demand for individual households. The grids lifetime is 50 years and cost on average 3.3 B€/GW.

Reference: 2217 B€ totally

Smart Energy Europe: 2408 B€ totally

1.5 Tech: 2245 B€ totally

7.1.5 Carbon capture and storage

Carbon and capture and storage are divided into two costs. The carbon and capture unit is assumed to cost the same as the carbon recycling unit. Thus 200 GEUR/Gton CO2 captured annually. The lifetime is 20 years with a fixed O&M of 4.3%. The 1.5 Tech scenario therefore has carbon capture units for a total investment of 74.8 B€.

For storage, it depends on how big the total storage should be.

The assumption here is:

I assume 15 €/tonne

Lifetime: 40 years

2 % O&M

Based on the Danish technology catalogue:

The ZEP report [14] also provides an update on storage costs:

Case			Cost range (€/tonne CO2 stored)		
			Low	Medium	High
Onshore	Depleted oil and gas fields	Existing well	1	3	7
Onshore	Depleted oil and gas fields	New well	1	4	10
Onshore	Saline aquifer	New well	2	5	12
Offshore	Depleted oil and gas fields	Existing well	2	6	9
Offshore	Depleted oil and gas fields	New well	3	10	14
Offshore	Saline aquifer	New well	6	14	20

The assumption is that the storage should be able to store for the entire lifetime of 40 years. Thus a total of 224 B€ has to be invested in storage.

7.1.6 Other adjustments for costs in 1.5 Tech

Boiler costs equals 75% gas boilers and 25% biomass boilers = 5.9 x 0.25 + 2.7x0.75 = 3.5GEUR/Unit and O&M: 443 x 0.25 + 182 x 0.75 = 220 EUR/unit. The same is used for the reference costs.

Hydrogen boiler cost assumption = upper limit of gas boilers = 4000 €/unit, O&M = 218 €/Unit

Updated electricity storages to fit the operation hours described in the main text.

Changed PP capacity to be able to cover all unbalances left

- New PP capacity 530 GW (previous 266 GW)

7.2 Documentation of e-fuel costs

CCU, capture from point soure
Essentially, we are looking at 500 €/tCO2/a in 2050 with a lifetime of 25 years and 5.5% if investment for O&M.

This is based on the assumption point source capture with 8000hours of operation. For biomass plants, if flexible operation is assumed, i.e. ~4000h, then you double the costs.

Cement capture 2050		Large biomass 2050		Direct air	
160	tCO2/hour	173	tCO2/hour	125	tCO2/hour
8000	hours	8000	hours	8000	hours
1280000	tCO2	1384000	tCO2	1000000	tCO2
Cost		Cost		Cost	
1.8	mil €/tCO2/hour	1.6	mil €/tCO2/hour	4	mil €/tCO2/hour
288	mil €/plan	276.8	mil €/plan	500	mil €/plant
225	**€/tCO2**	**200**	€/tCO2	**500**	€/tCO2
O&M fixed		O&M fixed		O&M fixed	
8.64	mil €	8.304		25	
O&M variable		O&M variable		O&M variable	
3.2	mil €	3.46		2.5	
11.84		11.764		27.5	
4.1%		**4.3%**		**5.5%**	

Methanation and DAC should be split, also for EP purposes. For methanation we are looking at 0.2 M€/MW, 25 years lifetime and 4% O&M in 2050.

Liquid fuels:

0.3 M€/MW, 25 years, O&M 4%

For JP synthesis I estimated based on what I found in the literature 0.5 M€/MW, 25 years, 4% O&M.

Appendix C

Sensitivity analysis of energy storage and additional renewable capacity

The Smart Energy Europe scenario, assumes the same levels of electricity storage capacity as the Adjusted Baseline 2050 scenario, corresponding to a load capacity of 139 GW and 0.556 TWh (4 hours) of energy storage. Similarly, thermal and hydrogen storage capacities are set to be 8 hours (1.2 TWh) and 4 days (64 TWh) of energy storage, respectively. Given these initial assumptions, the goal of this analysis is to identify the impacts of additional storage capacities.

To this end, we have conducted a sensitivity analysis with different storage alternatives and capacities across the different scenarios, as summarized in Table 1. These are modelled starting first with a no storage case, then considering the reference capacity from the main scenario, followed by incremental steps of additional storage capacities.

This additional energy storage can be used for balancing purposes, handling excess production from variable renewable energy. However, the Smart Energy Scenario already presents a highly flexible and balanced system with limited excess electricity production. Thus, for each incremental step of additional storage, we also explore the possibility of adding variable renewable production from offshore wind in increments of 50 GW of capacity. By using both energy storage and additional wind production it is possible to reduce power plant operation. For this reason, a phase-out of power plant capacity is also explored at each step of the analysis keeping enough capacity in place to avoid electricity imports to the system, namely by phasing out 25 GW of capacity at each step. With this replacement of power plant utilization, we also assess the impacts on fuel consumption, namely reducing the strain of using biomass resources.

Table 1. Matrix of scenarios and storage options used in the sensitivity analysis

	Baseline 2050	**1.5 TECH**	**Smart Energy Europe**
Electricity storage (battery)	X	X	X
Thermal storage (DH)			X
Hydrogen storage		X	X

First, we start by comparing battery electricity storage in the 2050 Baseline and 1.5TECH scenarios adjusted from the PRIMES model, and the Smart Energy Scenario. This is done taking the battery capacity and normalizing it based on the average electricity load considered in each scenario to facilitate the comparison of potentially different storage dimensions. Then, thermal energy storage is only explored in the Smart Energy Europe scenario, assuming large-scale thermal storage in district heating (which is not present in the PRIMES scenarios). Finally, hydrogen storage is also sensitized in the 1.5 TECH and Smart Energy scenarios, which are designed with electrolyser production

As mentioned, the Smart Energy Europe scenario assumes the same capacity of battery storage as the Baseline; however, this battery capacity covers a relatively lower percentage of the average electricity load in the Smart Energy Scenario compared to the Baseline, as outlined in the second step of the sensitivity curves in Figure 1. In the case of the 1.5 TECH scenario, a different reference battery size is considered (also outline at the second step of its respective sensitivity curve in Figure 1), with a load capacity of 68.7 GW and 0.275 TWh of storage capacity.

In Figure 1, it is possible to see that the 1.5 TECH scenario ends up with a less efficient systems when considering battery storage along with power plant replacements and additional wind capacity. Meanwhile, the gain in efficiency is only marginal when increasing battery storage in the Baseline. On the other hand, the

flexible system proposed in the Smart Energy Europe scenario allows for a slightly higher gain in efficiency when increasing battery storage compared to the former PRIMES scenarios. In the case of both the Baseline and the Smart Energy Europe scenario, diminishing returns can be seen at higher levels of battery capacities.

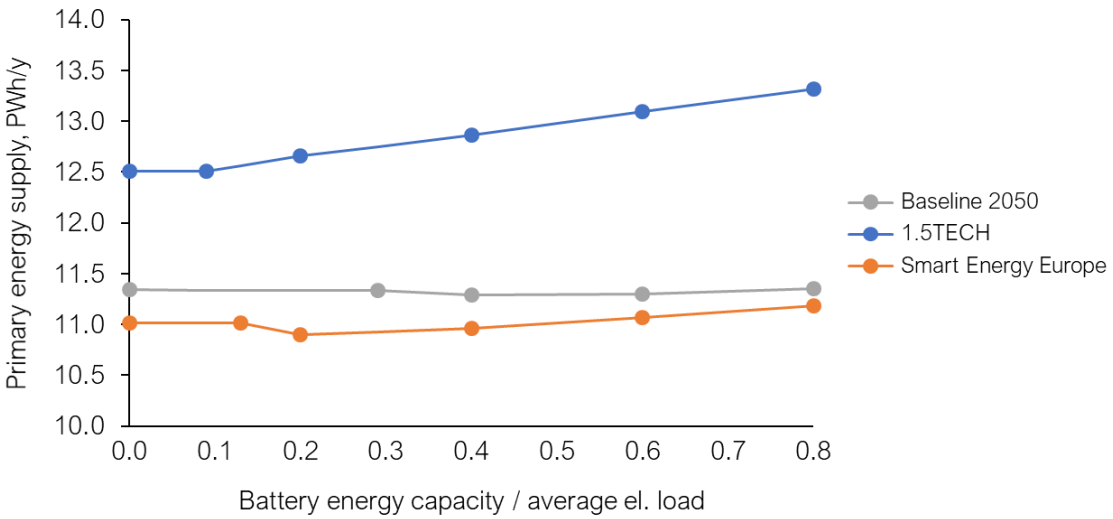


Figure 1. Sensitivity of battery storage for the Baseline 2050 and Smart Energy Europe scenarios.

Zooming into the Smart Energy Europe scenario, we can note that in the initial step adding battery storage carries no significant added benefit in terms of overall fuel efficiency, contributes to higher total system costs, while at this point there is neither additional wind capacity nor power plant phaseouts. However, in the following steps when considering wind expansion and power plant replacement, it is possible to see some fuel savings and comparable costs to the case of having no storage. This hold true up until the point where battery storage is dimensioned to cover around 40% of the average electricity load. After this point, additional capacity does not equate to additional benefits.

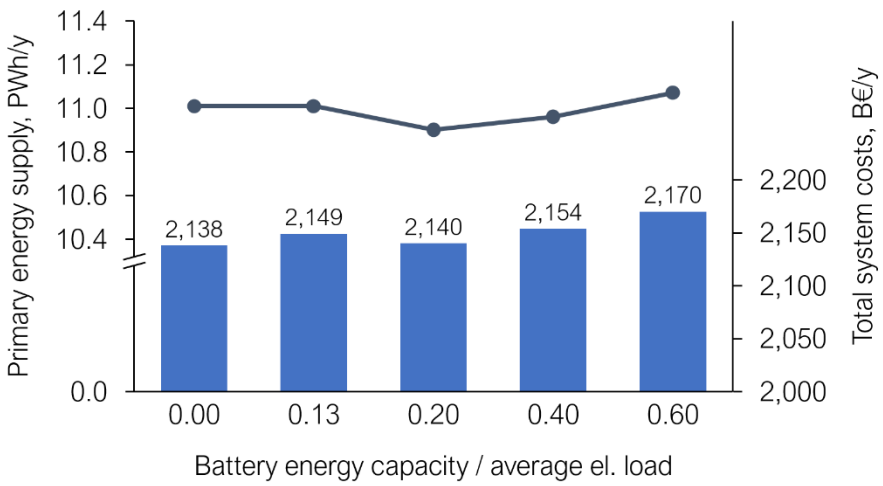


Figure 2. Total primary energy supply and total system costs at different steps of battery storage capacity represented as a fraction of the average electricity load for the Smart Energy Europe scenario.

In terms of the primary energy supply, the efficiency gains stem from lowering the overall fuel consumption due to lower biomass consumption despite the increase in wind production, as seen in Figure 3. Meanwhile,

there is also some additional production of green gas – produced from biogas and CCU – which is accounted here as an offset to natural gas consumption, therefore lowering the overall fuel consumption.

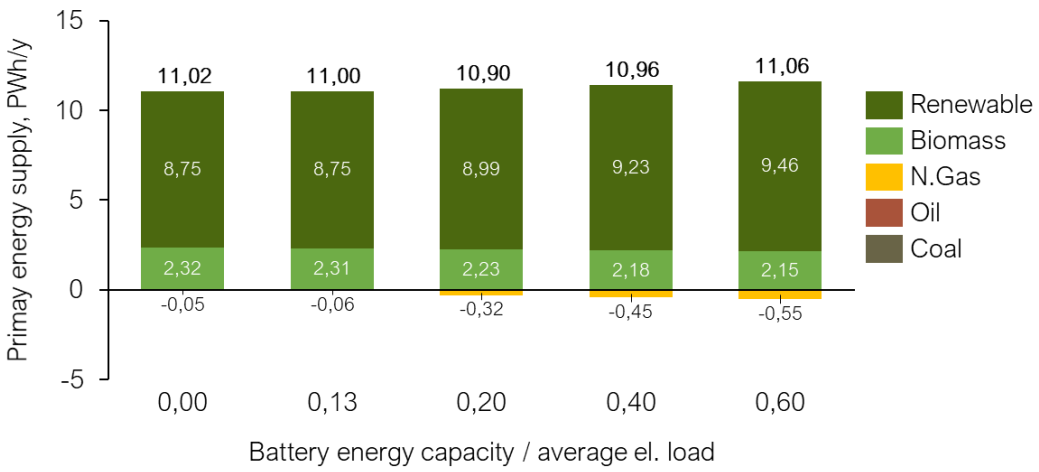


Figure 3. Primary energy supply by fuel type at different steps of battery storage capacity represented as a fraction of the average electricity load for the Smart Energy Europe scenario.

Turning to thermal energy storage, we can first see that in the initial step adding has negligible effects on the system, since the smart energy scenario is already quite flexible. In the following steps when we considering this wind expansion and replacement we can see that some fuel savings and comparable costs to having no storage, up until the point where thermal storage is dimensioned to cover roughly 12 hours of the average district heating demand. After this point, additional capacity does not equate to additional benefits.

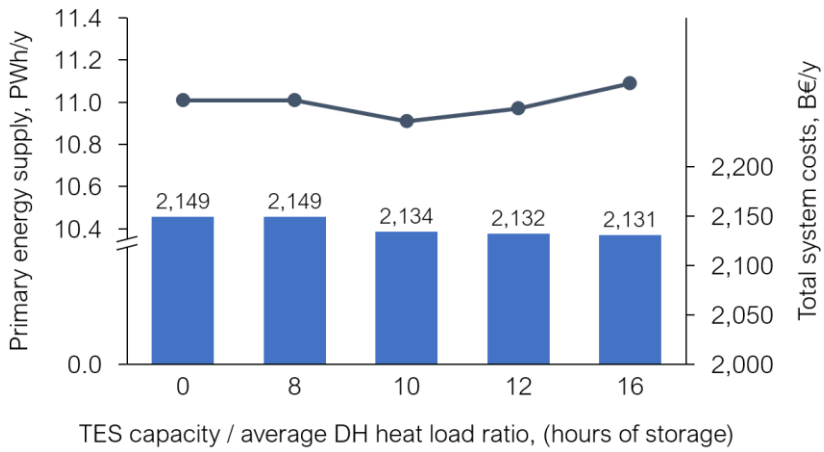


Figure 4. Total primary energy supply and total system costs at different steps of thermal energy storage capacity represented as a fraction of the average district heating load for the Smart Energy Europe scenario.

Similarly, looking into to hydrogen storage in the Smart Energy Europe scenario, more noticeable effects can be seen with an evident gain in efficiency when increasing this storage. However, the overall system costs are correspondingly higher at each incremental step. On the other hand, increasing hydrogen storage in the 1.5 TECH scenario does not allow for further integration of wind capacity, driving both the primary energy supply and costs up.

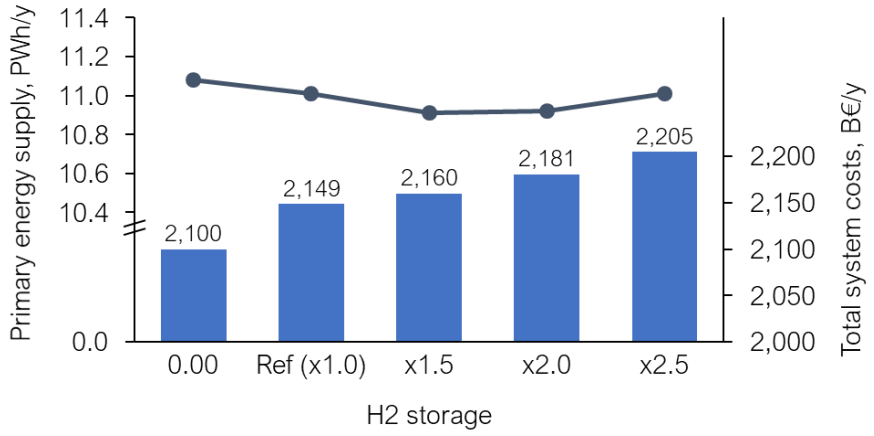


Figure 5. Sensitivity analysis of hydrogen storage capacities in the Smart Energy scenario, with the reference case covering 4 days of the average hourly hydrogen production.

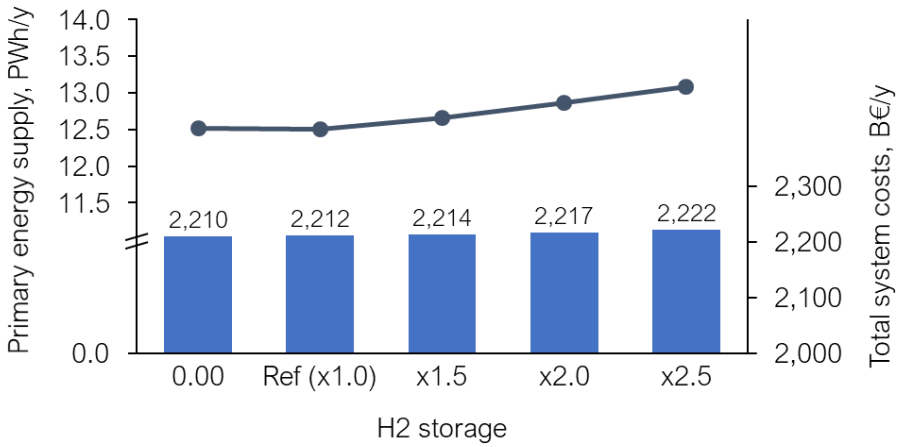


Figure 6. Sensitivity analysis of hydrogen storage capacities in the 1.5 TECH adjusted scenario, with the reference case covering 10 hours of the average hourly hydrogen production.

Appendix D

Table with inputs changed for district heating analysis in Section 3.5

Table 2. Changes done to the 1.5TECH scenario to create the new scenarios.

Category	Description and unit	1.5 TECH	Scenario 1.1	Scenario 1.2	Scenario 2.1	Scenario 2.2
Demand	Demand per building (kWh/year)	4100	4100	4100	6000	6000
	Total heating demand (PWh/year)	1.38	1.38	1.38	2.11	2.11
Costs	Residential savings costs (GEUR)	160	160	160	35	35
	DH grid costs (GEUR)	3.95	13.16	13.16	20.06	20.06
	Substations Period (Years)	26	25	25	25	25
	Substations O&M (% of inv.)	0.50	1.62	1.62	2.47	2.47
	Substations Total inv. Cost (GEUR)	53.53	77.23	77.23	117.68	117.68
Oil boilers	Fuel input (PWh/year)	0.01	0.00	0.00	0.00	0.00
	Efficiency (%)	0.97	0.00	0.00	0.00	0.00
	Heat demand (PWh/year)	0.01	0.00	0.00	0.00	0.00
Ngas boilers	Fuel input (PWh/year)	0.38	0.00	0.00	0.00	0.00
	Efficiency (%)	0.98	0.00	0.00	0.00	0.00
	Heat demand (PWh/year)	0.37	0.00	0.00	0.00	0.00
Biomass boilers	Fuel input (PWh/year)	0.12	0.06	0.06	0.10	0.10
	Efficiency (%)	0.79	0.79	0.79	0.79	0.79
	Heat demand (PWh/year)	0.10	0.05	0.05	0.08	0.08
H2 Micro CHP	Efficiency (%)	0.98	0.00	0.00	0.00	0.00
	Heat demand (PWh/year)	0.08	0.00	0.00	0.00	0.00
Heat pump	Efficiency (%)	3.00	3.00	3.00	3.00	3.00
	Heat demand (PWh/year)	0.57	0.59	0.59	0.90	0.90
Solar thermal	Input (PWh/year)	0.04	0.00	0.00	0.00	0.00
Electric heating	Efficiency (%)	1.00	1.00	1.00	1.00	1.00
	Heat demand (PWh/year)	0.06	0.03	0.03	0.04	0.04
District heating	Production (PWh/year)	0.24	0.83	0.83	1.27	1.27
	Network losses (%)	0.14	0.14	0.14	0.14	0.14
	Demand (PWh/year)	0.20	0.72	0.72	1.09	1.09
Compression Heat pumps	Electric capacity (GWe)	0.00	23.63	23.63	36.00	36.00
	%	0.00	4.00	4.00	4.00	4.00
CHP	Electric capacity (GWe)	25.00	95.00	95.00	144.00	144.00
	Thermal Capacity (GJs)	25.00	107.00	107.00	162.00	162.00
Boilers gr. 3	Thermal Capacity (GJs)	55.00	234.00	234.00	358.00	358.00
	Efficiency (%)	0.94	0.95	0.95	0.95	0.95
Solar thermal production	PWh/year	0.00	0.01	0.01	0.02	0.02
Geothermal from abs. HP	PWh/year	0.04	0.04	0.04	0.06	0.06
Industrial excess heat	PWh/year	0.00	0.07	0.07	0.11	0.11

Thermal storage gr. 3	TWh	0	1,2	1,2	1,2	1,2
Offshore wind capacity	GW	451.38	451.38	515.38	451.38	424.38