LAPPEENRANTA-LAHTI UNIVERSITY OF TECHNOLOGY LUT
School of Engineering Science
Degree Programme Industrial Engineering and Management
Global Management of Innovation and Technology

Rasul Satymov

The value of fast transitioning to a fully sustainable energy system: The case of Turkmenistan

Master's thesis

Examiners: Professor Ville Ojanen
Professor Christian Breyer

Supervisors: Dmitrii Bogdanov
Professor Christian Breyer

ABSTRACT

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Master's thesis
2020
64 pages, 35 figures, 6 table and 1 appendix
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Keywords: *100% renewable energy, energy transition, policy scenario, sector coupling, sustainable development, Turkmenistan*

The Paris Agreement within United Nations Framework Convention on Climate Change aims to mitigate effects of greenhouse gas emissions to limit global warming. Turkmenistan ratified the Agreement and is a country with absolute reliance on fossil fuels and practically zero installed renewable energy capacity. This study provides potential transition scenarios to full sustainability for Turkmenistan in power, heat and transport sectors. Vast sunny desert plains of Turkmenistan could enable the country to switch to 100% renewable energy by 2050, with prospects to have 76% solar photovoltaics and 8.5% wind power capacities in a Best Policy Scenario. Seven different transition scenarios, with different GHG emissions cost assumptions and transition rates, have been analysed to demonstrate different possible paths towards full sustainability in a cost-efficient way. The results of the study demonstrate that a 100% renewable energy system, regardless of the transition rate, will be lower in cost than a continual reliance on fossil fuels. The scenario with the highest rate of renewable energy integration enables the least cost and quickest reduction of greenhouse gas emissions. The results are expected to serve as a guideline to policymakers, investors and other stakeholders in Turkmenistan. The structural results for transition speed options and respective costs and benefits from switching a practically fully fossil fuels to a fully renewable energy system are expected to be transferable to many countries.

ACKNOWLEDGEMENTS

My sincere gratitude goes to Professor Christian Breyer and Dmitrii Bogdanov for their continuous guidance and support through my Master's thesis research journey and Professor Ville Ojanen for his support of my venture into a new field.

I would like to also thank my Solar Economy teammates Arman Aghahosseini for his support with data visualization and Theophilus Nii Odai Mensah for his help with data collection.

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ABBREVIATIONS

a	annum (year)
A-CAES	Adiabatic Compressed Air Energy Storage
BEV	Battery Electric Vehicle
BPS	Best Policy Scenario
BPSwoCC	Best Policy Scenario without Carbon Costs
CAPEX	Capital Expenditures
CCGT	Combined-Cycle Gas Turbine
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CPS	Current Policy Scenario
CSP	Concentrated Solar Thermal Power
DAC	CO_2 Direct Air Capture
DH	District Heating
FCEV	Fuel Cell Electric Vehicle
FT	Fischer-Tropsch
GHG	Greenhouse Gas
GT	Gas Turbine
GW(h)	Gigawatt(hour)
H_2	Hydrogen
HDV	Heavy Duty Vehicle
HHB	Hot Heat Burner
HP	Heat Pump
HT	High Temperature
HVAC	High Voltage Alternating Current

HVDC	High Voltage Direct Current
ICE	Internal Combustion Engine
IH	Individual Heating
kW(h)	kilowatt(hour)
LCOC	Levelised Cost of Curtailment
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Heat
LCOS	Levelised Cost of Storage
LCOT	Levelised Cost of Transmission
LDV	Light Duty Vehicle
LNG	Liquefied Natural Gas
LT	Low Temperature
LUT	Lappeenranta-Lahti University of Technology LUT
MDV	Medium Duty Vehicle
MT	Medium Temperature
Mt	Megatonne (10^9 kg)
MW(h)	Megawatt(hour)
OCGT	Open Cycle Gas Turbine
$OPEX_{fix}$	Fixed Operational Expenditures
$OPEX_{var}$	Variable Operational Expenditures
PHEV	Plug-in Hybrid Electric Vehicle
PHS	Pumped Hydro Energy Storage
PP	Power Plant
PtG	Power-To-Gas
p-km	passenger kilometre
PV	Photovoltaic

RE	Renewable Energy
SNG	Synthetic Natural Gas
ST	Steam Turbine
TES	Thermal Energy Storage
TTW	Tank-To-Wheel
TW(h)	Terawatt(hour)
t-km	tonne kilometre
2W	two wheelers
3W	three wheelers
°C	degrees Celsius

1. Introduction

This section provides an introduction to the research problem, an overview of Turkmenistan's current energy system, objectives of the thesis and research questions, and a brief outline of the thesis structure.

1.1. Background

The anthropogenic global warming poses an existential threat to humankind. Rising sea levels, extreme droughts, increase in occurrences of extreme weather events, among other things, can adversely alter life on earth (IPCC, 2018). Humanity has a great responsibility to address the issue of climate change in an urgent manner and the highest priority is to reduce and eliminate anthropogenic emissions of greenhouse gases (GHG). As the energy sector is the biggest contributor of carbon dioxide, a transition to renewable energy sources can sharply reduce GHG emissions, and enable to reach ambitions climate targets, preferably the 1.5°C limit to global warming above pre-industrial levels (IEA, 2019). However, this challenge requires the cooperation of all nations with no exceptions, and Turkmenistan cannot continue heavily relying on fossil fuels.

Turkmenistan is a Central Asian country with a population of 5.5 million people and an area of 488,100 km^2 mostly covered by arid deserts. The electricity consumed in 2019 had been 25.7 TWh, which equals 4,392 kWh/person per year, a relatively high consumption compared to its Central Asian neighbouring countries (BP, 2020), thanks to high electricity penetration over 99%. People of Turkmenistan have had access to free utilities since the end of Soviet Union until very recently, when electricity rate was set in place at 0.0065 €/kWh in 2014. Turkmenistan is completely self-sufficient energy-wise and one of the few countries with absolute dependence on fossil fuels, with sixth largest proven natural gas reserve in the world (EIA, 2016). Natural gas fired power plants provide 99% of the electricity in the country, while the remaining 1% is covered by a small hydropower plant of 1.2 MW in the Mary region and some individual diesel power generators. Electricity generation, transmission and distribution are controlled by Turkmenenergo State Corporation, as a single vertically integrated entity (EBRD, 2012). The state-owned oil company TurkmenNebit supplies heavily subsidised fuel for the transportation needs of Turkmenistan. Heating demands are covered by individual gas boilers in 95% of households and the remaining 5%

is covered by electricity. There is insufficient political and social will to change the state of the current energy system in Turkmenistan. Heavily subsidised utilities and lack of awareness has kept the citizens ignorant regarding the environmental effects of the reliance on fossil fuels. There are little to no incentives for citizens to consider energy efficiency and conscientious use of resources. The historically high level of corruption (Transparency International, 2020) and inefficient legal and regulatory frameworks have barely attracted foreign investments in renewable energy (RE).

The Figure 1 shows the current energy system, tracing the energy flow from primary fuels to final energy demands. The figure shows the relatively straightforward energy flows with almost non-existent sector coupling. The losses mostly consist of inefficiencies from generating electricity in gas turbines but do not include the losses from oil use in the transport sector. The losses in the transport sector vary greatly depending on transport mode (Khalili *et al.*, 2019) and are harder to quantify for presentation purposes.

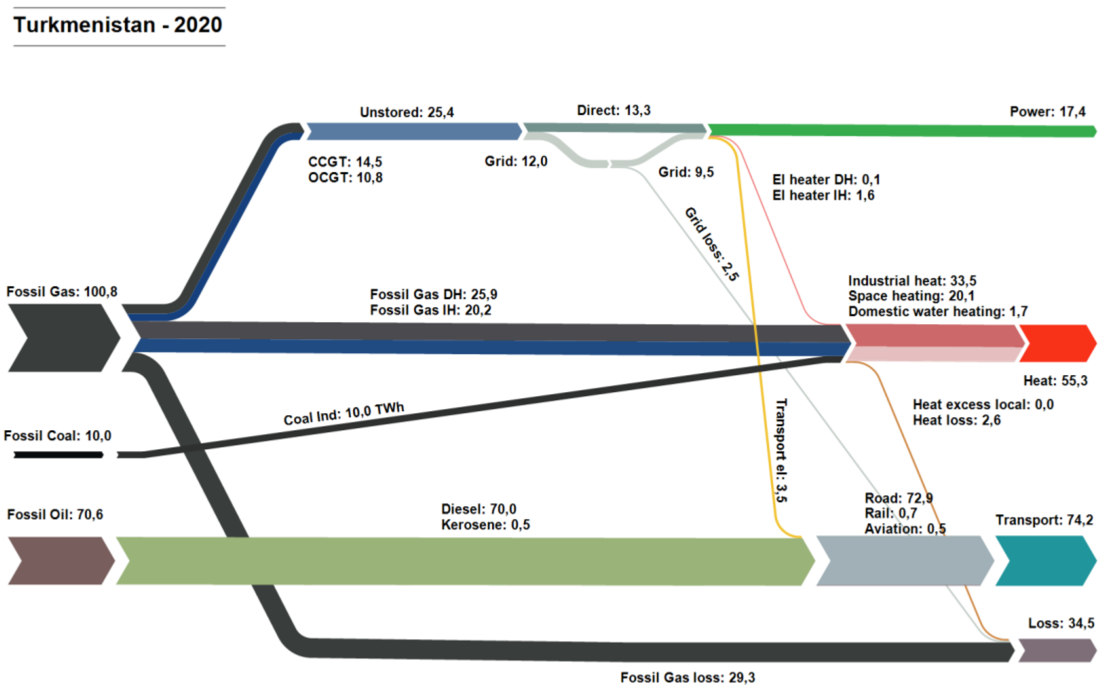


Figure 1. Energy flows in the energy system of Turkmenistan for the year 2020 status. All units are in TWh.

Despite having vast potential for solar and wind power, 655 GW and 10 GW, respectively (UNDP, 2014), there is practically zero installed RE capacity in Turkmenistan (EIA, 2016; IRENA, 2020). The vast desert plains, with close to 300 days of sunshine at a global horizontal irradiation of 4.72 kWh/(m^2·day), or 1722 kWh/(m^2·a) (World Bank, 2017) and a wind power generation potential of up to 222 W/m^2 at 50 m hub height (Bahrami *et al.*, 2019), can potentially enable enormous RE-based electricity generation to cover domestic demand and maybe even enable electricity export to neighbouring countries.

The intended nationally determined contribution (INDC) of Turkmenistan within the UNFCCC framework (Turkmenistan, 2015), highlighted aimed sustainable development and energy efficiency investments, however little tangible actions are undertaken in the country so far. Practically zero new RE capacity was installed in Turkmenistan since the hydropower plant installation in Mary in 1913 (IRENA, 2020), besides the experimental few kW solar PV installed by the Institute of Solar Energy "Gun", however, there may be a few MW of independent PV systems, as Werner *et al.* (2017) have indicated with a different method based on international tariffs data about 5 MW end of 2017. The national strategy represents the government's vision on the issue of climate change in vague terms, but no effective legal frameworks have been established so far.

No updates or reports have been published by the government of Turkmenistan since the INDC report, to the knowledge of the author. However, some international organisations and corporations have assessed Turkmenistan's current state and current policy scenarios, such as an energy sector assessment (EBRD, 2012), a holistic review of energy efficiency and RE sectors in Central Asia (Kouzmitch, 2013), and a survey of the current state of infrastructure developments (OECD, 2019). The European Bank for Reconstruction and Development (EBRD, 2012) provides an analysis of the legal and regulatory frameworks in Turkmenistan and concludes that the current institutional structure favours fossil fuels. Korpeyev (2007) provides an overview on the benefits of switching to RE in Turkmenistan, such as increasing standards of living, creating local jobs, addressing the short-term issues of providing energy to remote settlements and helping the country to realise its environmental protection liabilities. All aforementioned reports further confirm the inadequacy of the development towards sustainability in the country.

1.2. Objectives and Research Questions

The aim of this research is to analyse energy system pathways for Turkmenistan for power, heat and transport sectors to design a cost-optimal fully sustainable energy system aimed for the mid-century. The results of the research are intended to serve as a guide for policymakers, investors and other stakeholders in Turkmenistan for future energy system developments. Therefore, the research questions are:

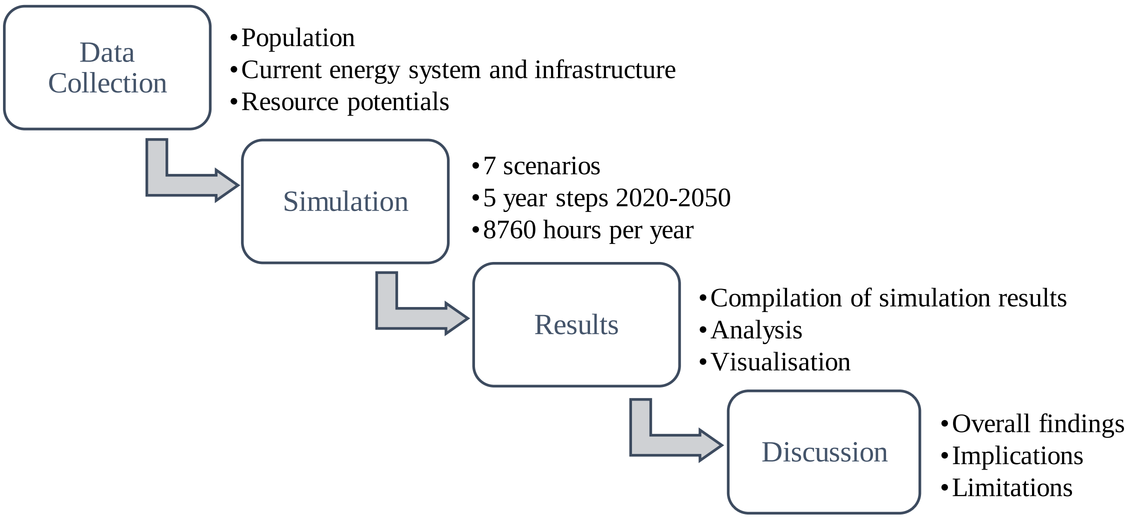
1. How Turkmenistan can transition its energy system to full sustainability from its current fossil-fuel based state?
2. How can the current state and policies affect the pace of transition to full sustainability?
3. What are the environmental and economic benefits of transitioning to full sustainability?
4. What are the effects of different rates of transitioning to a 100% renewables-based energy system?

1.3. Research Methods

LUT Energy System Transition Model (Bogdanov *et al.*, 2019; Child *et al.*, 2020) was utilised to simulate Turkmenistan's energy transition fully integrating power, heat and transport sectors. The model enables to simulate an energy system in high temporal and spatial resolution. The hour-by-hour simulation enables to accommodate the intermittent nature of renewable energy sources, accounting the ebbs and flows of sunshine and wind resources. The high temporal resolution is necessary to fully understand the interplay of energy demand, energy supply and energy storage needed in a 100% RE system.

1.4. The Structure of the Thesis

The thesis research was done in the following steps:



2. Materials and Methods

This section describes the model used in this study, data collection process, renewable resource potentials and description of the scenarios simulated in this study.

2.1. Model

LUT Energy System Transition Model takes as input the current state of the energy system and resource potentials. First of all, current power, heat and transport energy demands are applied to the model. Then, renewable energy potentials, including solar, wind, bioenergy, geothermal and hydropower, are considered. Energy infrastructure, including currently installed power capacities, grid connections and power flow between the nodes, is taken into account. In addition, population density and distribution and electricity market prices are included. The model allows to set different assumptions regarding costs of various electricity production and storage technologies and the pace of the transition such as the rate of integration of RE technologies. It is also possible to set different constraints such as CO_2 emissions cost, area availability, biomass potential, etc. The model utilises linear optimisation with a spatial resolution of solar and wind resources of 0.45ºx0.45º. The target function is to achieve a least cost energy system given the constraints.

The fundamental structure of the LUT Energy System Transition Model is displayed in Figure 2. The model simulates not only the power sector, but also heat and transport sectors and the interplay between the sectors. It also considers prosumers' interplay with the system, i.e. the consumers of electricity that also produce their own electricity on site.

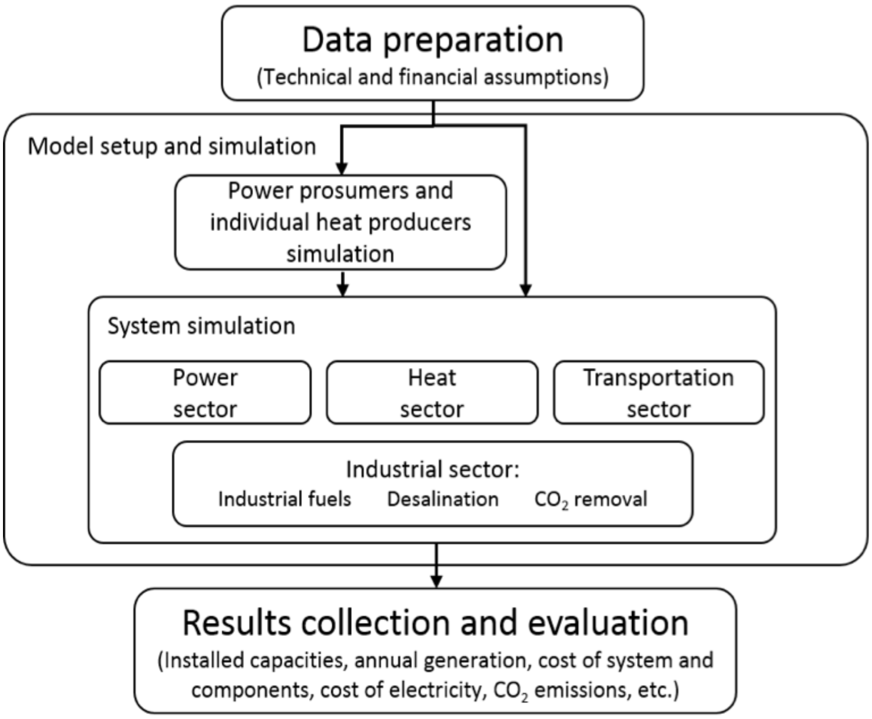


Figure 2. Fundamental structure of the LUT Energy System Transition Model (Bogdanov *et al.*, 2019).

The model considers 108 different generation and storage technologies and their corresponding costs of installation, fixed and variable operational costs, operational lifetime, costs of fuel for fossil fuels and biofuels and renewable energy potentials for solar, wind and hydro resources. The main energy system components are displayed in Figure 3.

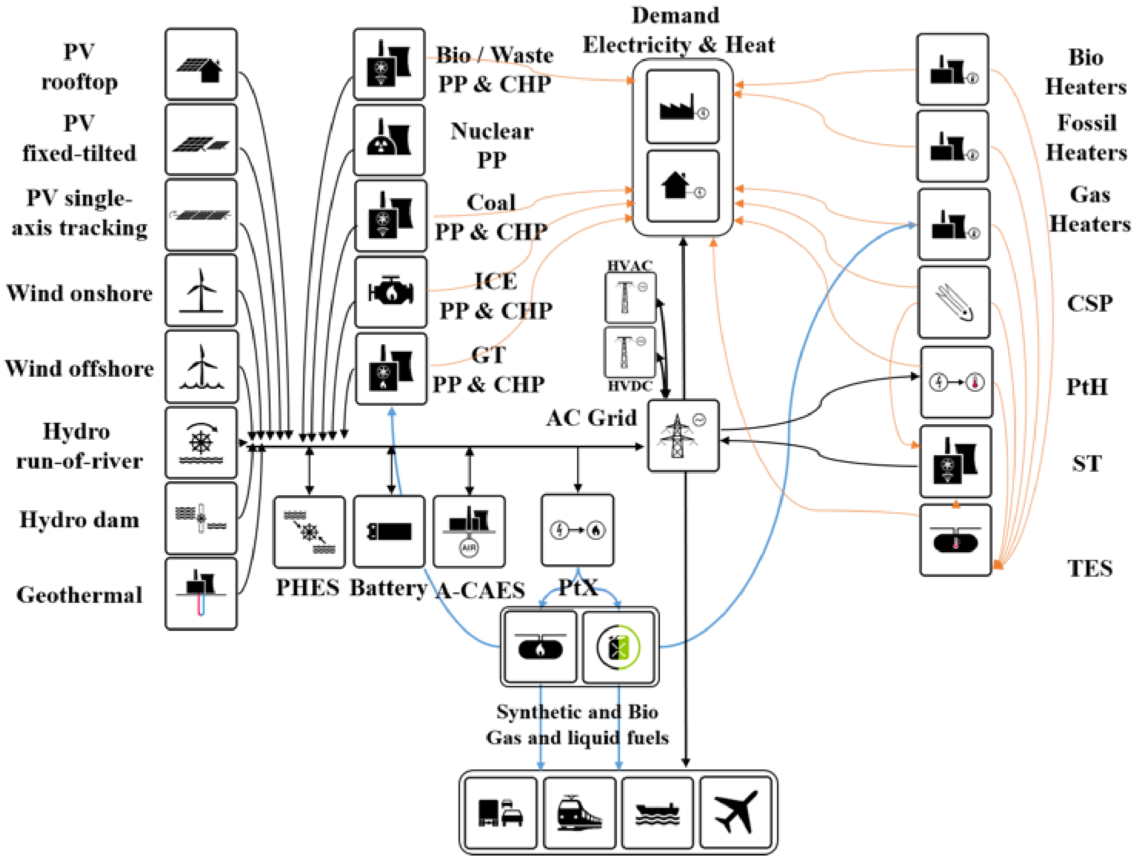


Figure 3. Schematic of the LUT Energy System Transition model for power, heat and transport sectors (Bogdanov *et al.*, 2021).

The three energy sectors are divided into different types of demand. The power sector consists of residential, commercial and industrial end-users. Prosumers are divided in a similar way, where residential houses, commercial facilities and industrial sites can install rooftop solar PV systems and batteries on-site. The future power load projection was calculated based on methods from Toktarova *et al.* (2019). The heat sector consists of space heating, domestic hot water, industrial process heat demand and biomass for cooking. However, the heat needed for these subsectors is not equal. Whereas space heating may require ~25 °C of heat and domestic hot water demand may range and top at 70 °C, industrial processes can usually require an order of magnitude higher temperatures in hundreds or more than thousand degrees Celsius. Therefore, heat is further divided into low-, mid- and high temperature heat. The transport sector is also subdivided into passenger and freight transportation. The two transportation demands are met by different modes of transport and respective final energy requirement, according to Khalili *et al.* (2019):

Passengers road transport (LDV, busses, 2-3 wheelers) and freight road transport (MDV, HDV):

- BEV – battery electric vehicle;
- FCEV – fuel cell electric vehicle;
- PHEV – plug-in hybrid electric vehicle;
- ICE – internal combustion engine.

Passengers and freight rail transport:

- electricity;
- liquid fuel.

Passengers and freight aviation:

- electricity;
- hydrogen;
- liquid fuel**Error! Reference source not found.**.

The model outputs possible scenarios which are optimised towards full sustainability on an hourly basis in five-year intervals from the year 2020 to 2050. This includes the shares of individual renewable energy resources and costs of implementing such a transition and related greenhouse gas (GHG) emissions, assuming projected population growth, energy demand growth, energy storage demand, diversified energy mix and minimisation of reliance on fossil fuels. The model had been described in great detail in (Bogdanov and Breyer, 2016; Bogdanov *et al.*, 2019; Child *et al.*, 2020).

2.2. Data

In the face of absence of up-to-date and reliable data from state institutions of Turkmenistan, various secondary international sources, databases, fact books and organisations, such as United Nations (UNDP, 2014; UN, 2019), Central Intelligence Agency of United States (CIA, 2020), International Energy Agency (IEA, 2018) and several others (BP, 2020), (REEEP, 2013), (FAO, 2020) have served as data sources for this research.

This study was conducted primarily relying on data from secondary sources. Demographics data were taken from international organisations, as the census report from the state of Turkmenistan was not possible to obtain. The demographics data used in this study may be out of date and distorted (UN, 2019), as it fails to account for the latest trends in the country such as a mass emigration of people abroad in search for jobs is locally noticed, in addition to a migration in between the administrative regions inside the country in face of economic difficulties. Nevertheless, the study was conducted based on accessible demographics data.

The data regarding current installed power capacity and power plants were taken from governmental internet portals and websites of contractors of said power plants (Ministry of Energy of Turkmenistan, 2016; Turkmen Portal, 2017; Calik Energy, 2018; Ronesans Holding, 2019).

2.3. Assumptions

The heating demand was found based on population and average space heating demand per person and average hot water demand per person (Barbosa, Bogdanov and Breyer, 2016). Biomass for cooking demand is set to zero, as there is no reason for households to use biomass due to subsidised supply of fossil gas almost everywhere with a well-developed gas infrastructure. Final heat demand projections are presented in Figure 4 divided by temperature levels and heat segments. Absolute energy demand for the heat sector is expected to grow due to the growing population and increasing industrial heat demand from 55 TWh in the year 2020 to 90 TWh in 2050. The relative share of subsectors of heat demand are not expected to change with industrial heat demand having the largest share at around 60% of total demand, followed by space heating demand representing 37%, and domestic water heating demand having the smallest share of all at only 3% of total demand.

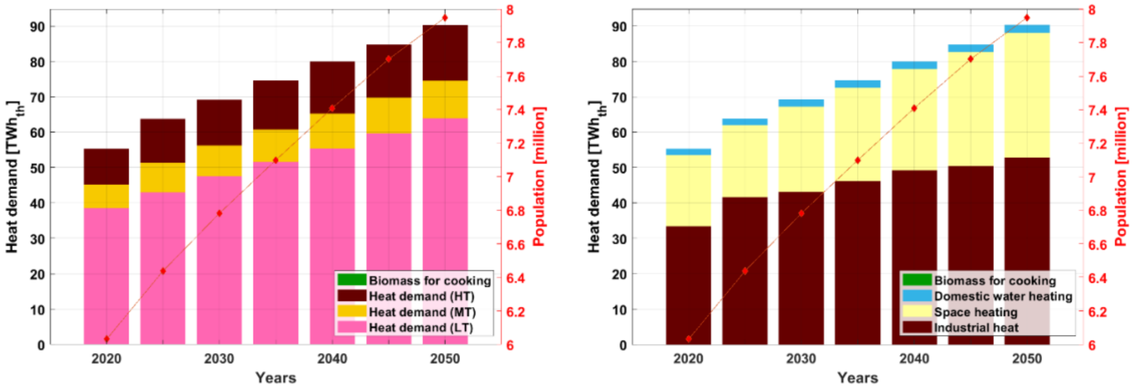


Figure 4. Heat demand by temperature levels (left) and by segment (right) through the transition.

Final transport passenger and freight demand are expected to grow along with the population, from 13 billion p-km and 42 billion t-km to over 22 billion p-km and 63 billion t-km by mid-century (Figure 5). Road and rail modes make up the majority of the total demand and represent about 40% and 56% of total passenger transport demand and about 85% and 5% of total freight transport demand. Share of aviation among the different transport modes is very small at the beginning of the energy transition period, but is expected to grow in the future, both in passenger and freight transportation. Demand for marine transport is not considered in this study for Turkmenistan, as no reliable source marine transport demand was found. The future growth trajectories of various transport segments were obtained from Khalili *et al.* (Khalili *et al.*, 2019).

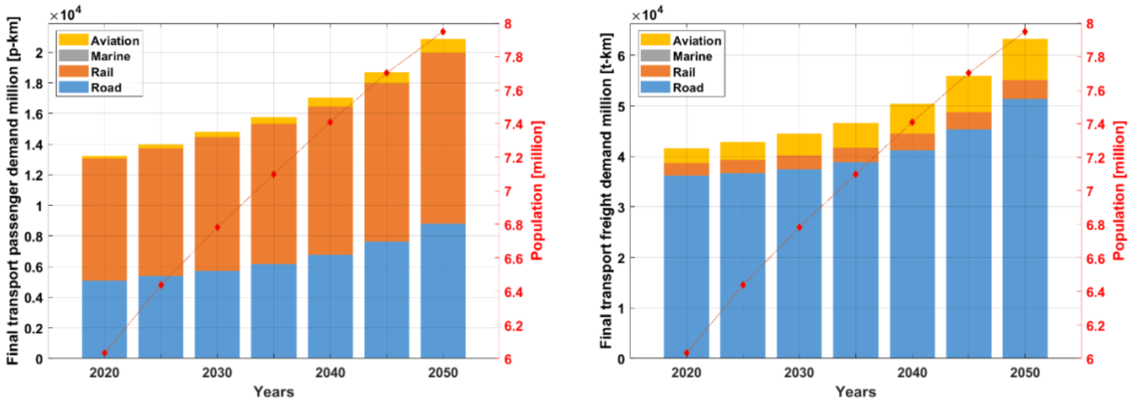


Figure 5. Final transport passenger (left) and freight (right) demand projections.

Majority of GHG emissions in the transport sector is generally reduced by switch to highly efficient electric vehicles that are powered with renewables-based electricity (Brown *et al.*, 2018). However, aviation sector is not expected to be fully electrified in the foreseeable future, though some short-haul routes may be electrified (Khalili *et al.*, 2019). While hydrogen powered airplanes may pick-up some of the aviation share, the global international aviation system (airplanes, infrastructure, fuel supply) is built around kerosene-type jet fuel. The continual reliance on fossil oil is not sustainable, therefore LUT Energy System Transition Model assumes a switch to sustainably sourced Fischer-Tropsch fuels. The Fischer-Tropsch process is a well-understood technology developed in early 20th century in Germany and it enables to create liquid hydrocarbons via a collection of chemical processes mixing carbon and hydrogen. Fischer-Tropsch fuels can decarbonize the aviation sector, that relies on energy carriers with high specific energy density. 100% renewables-based electricity can enable to obtain carbon from the atmosphere with direct air capture technologies and hydrogen with water electrolysis (Fasihi, Bogdanov and Breyer, 2016).

2.4. Renewable Resource Potentials

The renewable resource potentials were calculated based on available area, average annual solar irradiation and real-world historical weather data. The country was subdivided into five demand centres according to administrative regions: Ahal, Balkan, Dashoguz, Lebap, Mary (Figure 6).

Figure 6. Turkmenistan and administrative regions.

The solar PV resource potential was calculated based on the area of each region, assuming AC capacity density of 75 MW/km^2 and 18% PV module efficiency in 2015 and linearly increasing up to 30% efficiency and capacity density of 125 MW/km^2 in 2050, according to the projection in Vartiainen *et al.* (2020). Similarly, the wind turbine installation density was assumed to 8.4 MW/km^2, which was determined by Bogdanov and Breyer (2016) based on a 3 MW E-101 wind turbine. Wind turbine power ratings have been steadily increasing year-by-year and are expected to continue increasing upwards (Kumar *et al.*, 2016). There is a strong positive correlation between power ratings and blade diameters, as manufacturers have been achieving greater power ratings thanks to bigger swept area of the rotor. However, an optimal wind turbine installation requires roughly a distance between each turbine of about 5 to 7 times the rotor diameter, thus bigger rotor diameters require bigger distance between each turbine, thereby counteracting the power ratings gain when it comes to land density. Therefore, the aforementioned 8.4 MW/km^2 is assumed throughout the years until 2050. The fixed tilted solar PV and onshore wind resource potential maps are displayed in Figure 7.

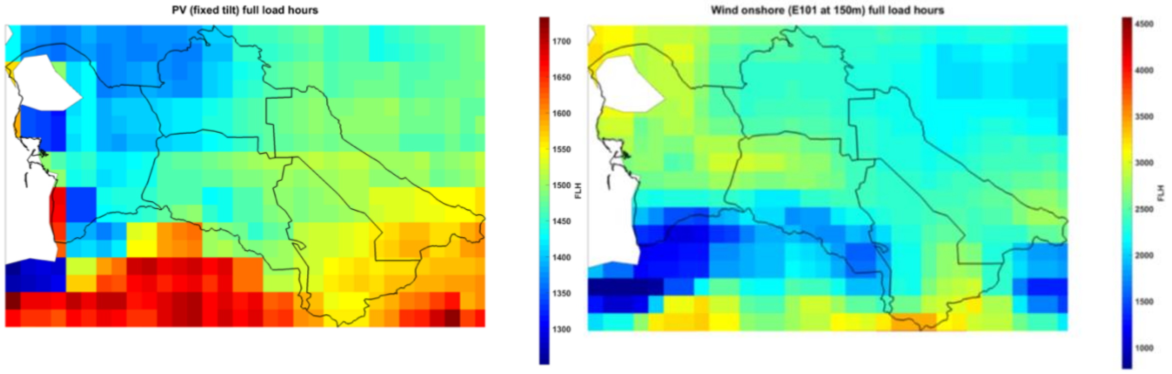


Figure 7. Fixed tilted solar PV (left) and onshore wind (right) resource potentials in Turkmenistan.

The data regarding biomass were taken from United Nations Food and Agriculture Organization (FAO, 2020), which in fact were statistically imputed based on data from neighbouring Central Asian states. The biomass potential consists of crop and forest residue, biowaste and municipal solid waste. The applied method is detailed in Mensah *et al.* (2021).

More detailed data regarding financial and technical assumptions can be found in the Appendix (Tables A1-A9).

2.5. Energy Transition Pathways

The consequence of heavy government subsidies is relatively very low costs of electricity and gas in the country and these numbers were used as inputs for the model. The abnormally low prices and unusual absolute reliance on gas turbines in the power sector necessitated a slightly different approach in simulation. Several different scenarios were simulated to accommodate the transition challenges, as can be seen in Table I that shows the details of different scenarios studied here. The different scenarios enabled deeper understanding of the possible future paths for energy transition in Turkmenistan. First, a Current Policy Scenario (CPS) was simulated with business-as-usual assumptions, with no objective to cut GHG emissions and switch to sustainable energy resources. The CPS describes the consequences of state inaction towards climate change and serves as a baseline in the discussion. Next, the CPS30 scenario was simulated assuming introduction of RE technologies in the year 2030, to imitate a scenario where the country is left with no choice but to start transitioning in the future with increasing international pressure. As the leading developed countries in the world are expected to be in later stages of their energy transition and as people around the world start experiencing worsening extreme events more frequently, it is expected that the pressure will start mounting on environmentally underperforming nations, such as Turkmenistan. Next, a Best Policy Scenario Standard (BPS-St) was simulated with gradually increasing the pace of RE integration: maximum 3% per year RE share in total capacity increase between 2020-2025 and 4% afterwards, until 100% RE in 2050. Similarly, BPS-3, BPS-4 and BPS-5 scenarios were simulated to better understand the effects of different RE integration rates, with 3%, 4% and 5% maximum RE share in total capacity increase per year, respectively. Finally, a Best Policy Scenario without Carbon Costs (BPSwoCC) was simulated to understand the impact of a carbon emission pricing on the energy transition pace and costs.

Table I. Energy Transition Scenarios applied.

Scenario	**RE integration rate [%]**	**GHG emissions cost [€/tCO_{2eq}]**	**Fisher-Tropsch [yes/no]**
CPS	0%	0	No
CPS30	2020-2030: 0% 2030-2050: 4%	2020-2030: 0 2035: 68 2040: 75 2045: 100 2050: 150	Yes, after 2030
BPS-St	2020-2025: 3% 2025-2050: 4%	2020: 28 2025: 52 2030: 61 2035: 68 2040: 75 2045: 100 2050: 150	Yes
BPS-3	3%		Yes
BPS-4	4%		Yes
BPS-5	5%		Yes
BPSwoCC	4%	0	Yes, but never installed

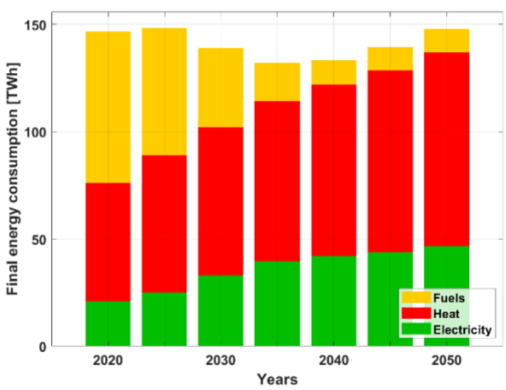
3. Results

The results of all scenarios are presented in a concise manner as follows: overview of the scenarios will be presented and general trends are noted in section A, next, section B presents how electricity generation and storage across all sectors develops throughout the transition; it is followed by energy supply for power, heat and transport sectors in section C, and finally, annualised energy system costs and GHG emissions are presented in section D.

3.1. General Trends in the Applied Scenarios

Among the seven scenarios, the BPS-5, that had the most rapid rate of renewable energy integration, enables the least levelised cost of energy, fastest reduction of GHG emissions and thus the least cumulative GHG emissions in 2050. The BPS-5 reaches the second lowest cumulative pathway cost, only the BPSwoCC is lower in cost, as cost for GHG emissions are not considered. Henceforth, the BPS-5 scenario shall be used as the benchmark.

Final energy demand goes through a phase of lower demand mid-transition and grows again to the initial level in 2050. Figure 8 (left) and Table II demonstrates that final energy demand falls to 133 TWh in 2035 thanks to efficiency gains related to reduction in fuel consumption in transport due to fast efficiency gain in road transport and grows again to 148 TWh in 2050, while the electricity consumption per capita grows from slightly less than 4 MWh up to 5.4 MWh (Figure 8, right). Primary energy demand per capita can be found in the Appendix (Figure A32).



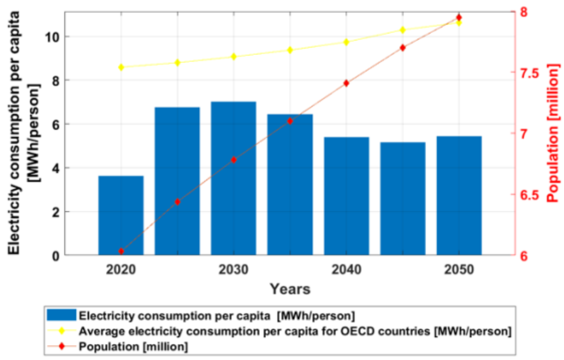


Figure 8. Final energy demand (left) and electricity consumption per capita with population (right) through the transition in the BPS-5.

Table II. Projected final energy demand by energy form [TWh].

Energy Form	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Electricity	20.90	25.17	32.88	39.50	42.03	43.87	46.55
Heat	55.26	63.83	69.15	74.63	79.93	84.77	90.28
Fuel	70.64	59.43	37.05	17.91	11.37	10.96	11.11
Total	146.80	148.43	139.08	132.04	133.32	139.61	147.94

The final energy demand and electricity per capita growth is limited as Turkmenistan already has achieved a high electricity penetration and subsidised access to fuels for heating and transportation, so the final energy demand only slightly increases with rising population.

Figure 9 shows the energy flow in Turkmenistan's 2050 energy system in the BPS-5. The energy system becomes much more complex with intensive sector coupling. Majority of primary energy is used in the form of electricity, mostly from solar PV and wind. Heat demand is mostly satisfied by environmental heat via heat pumps. Transport sector final energy demand is much lower in contrast to the year 2020 situation (Figure 1) and it is mostly satisfied by electricity and some synthetic fuels. Losses mostly consist of heat losses in fuel conversion units producing hydrogen and synthetic fuels, and some curtailment in the power sector. The losses and curtailment are recoverable, and they may be further reduced with industry integration and international power exchange. Curtailment over the transition and ratio of curtailment to generated electricity can be found in the Figure 34.

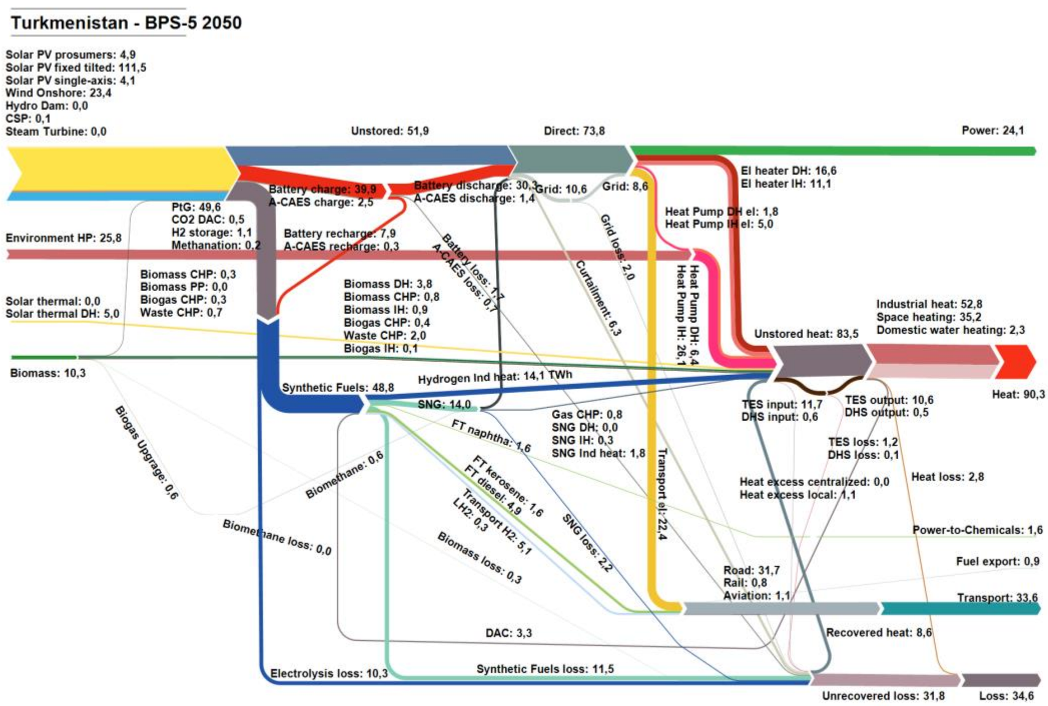


Figure 9. Energy system of Turkmenistan in 2050 in the BPS-5. All units are in TWh.

Due to high electrification of the entire energy system and subsequent energy efficiency gains (Figure 10), primary energy demand is projected to decrease in almost all scenarios, except for CPS, for which fossil fuel use and its overall low efficiency level is continued without much changes (

Figure 11). The composition of primary energy supply shifts from fossil gas, oil and coal today to RE sources in 2050 in the BPS-5. RE sources, such as solar PV and wind, supply electricity as primary energy at the first point of extraction from nature and thus electrifies the primary energy supply. Direct electricity supply from renewables removes one major point of losses where usually fossil fuels are converted to electricity in thermal power plants with efficiencies less than 40%. This electrification happens uniformly in all BPS variations, except the BPSwoCC where the rate dwindles down in later years because there are no incentives to fully get rid of fossil fuels in this scenario. The CPS continues relying on fossil fuels thus the electrification does not happen in primary energy supply, whereas CPS30 starts electrifying as soon as it is allowed to install renewables in 2030.

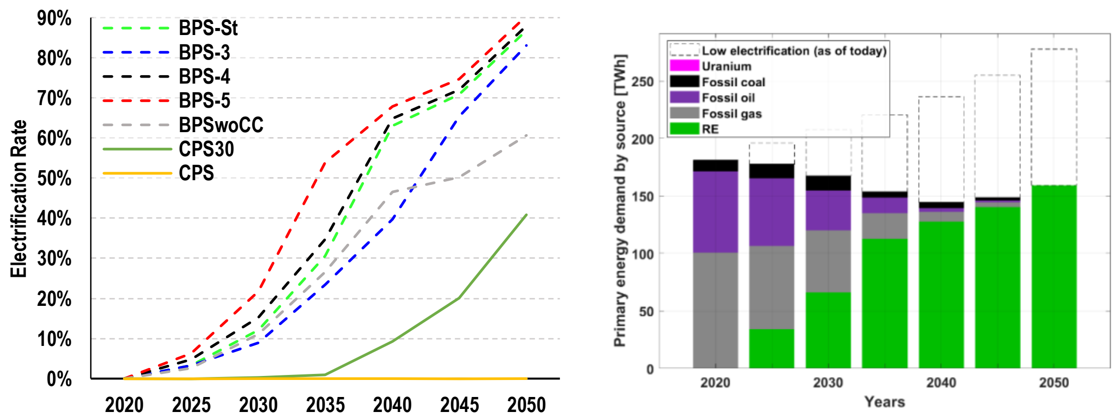


Figure 10. Electrification rate among all scenarios (left) and efficiency gains in primary energy demand in BPS-5 scenario (right) through the transition. Electrification rate is defined as the share of electricity in total primary energy supply.

High electrification also takes place in heat and transport sectors, as electric heat pumps and electric resistance heaters become major heat generation technologies and EVs replace ICE cars. The electric counterparts offer efficiency gains of several factors. The electric resistance heaters convert all consumed electric energy into heat, therefore offering 100% efficiency. Heat pumps allow to utilise the "free" ambient heat of the environment, providing 3.2 kWh and 4.5 kWh of heat for each kWh of electricity for district heating and individual heating heat pumps, thus effectively offering a coefficient of performance of 3.2 and 4.5, respectively. Similarly, electric drives convert almost all electric current into kinetic motion, with some losses related to electricity inversion, storage and friction, in practice offering >80% efficiency (Brown *et al.*, 2018). In addition, renewable sources of electricity, such as solar PV and wind, enable a much more direct extraction of energy from nature and for the highest possible exergy level, as electricity is generated directly, thus eliminating many conversion losses, compared to relatively inefficient fossil fuel fired thermal power and heat plants. Accordingly, primary energy demand falls sharply in all scenarios mid-transition in 2040, except CPS and CPS30. Though primary energy demand grows later in 2050, due to overall growth of final energy demand, it still remains below the primary energy demand as of today and then CPS in 2050. Figure 10 (right) demonstrates the reduction in primary energy demand due to the high electrification rate in the BPS-5; the solid bars show the potential gains in efficiency relative to the business-as-usual path (dashed). The primary energy demand breakdown by fuel and sector can be found in the Appendix (Figure A30 and Table A13).

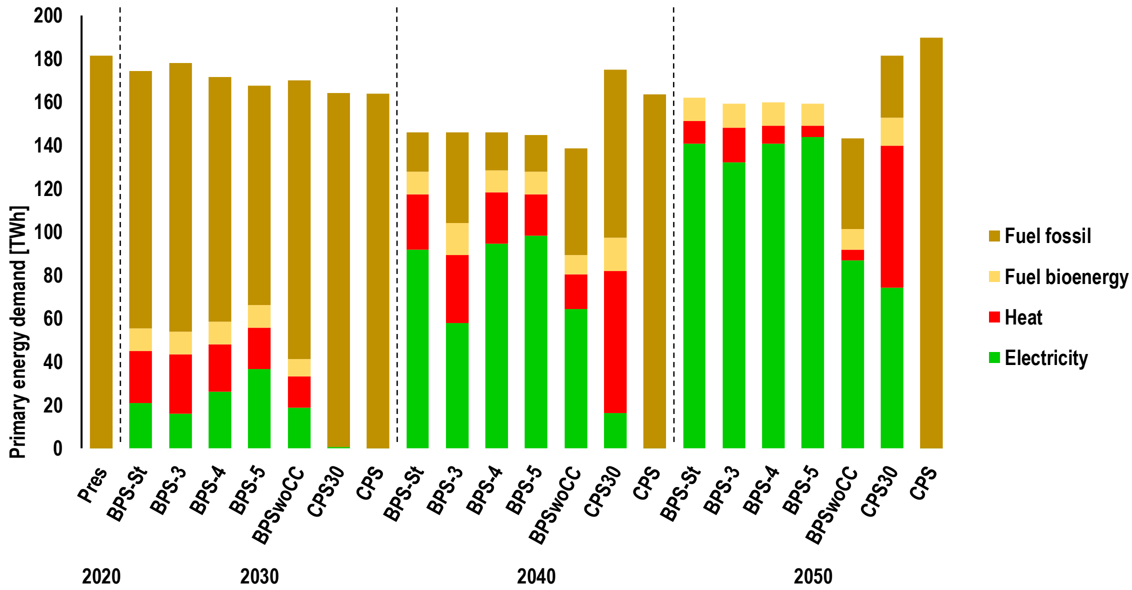


Figure 11. Primary energy demand among all scenarios through the transition.

The BPSwoCC demonstrates the least primary energy demand in 2050. The absence of carbon pricing in this scenario removes the pressure to switch away from fossil fuels, therefore the transport sector, that is harder to electrify (aviation), continues relying on fossil kerosene and marine fuel, instead of switching to RE-based Power-to-X fuels (Fasihi, Bogdanov and Breyer, 2016; Horvath, Fasihi and Breyer, 2018).

3.2. Electricity Generation and Energy Storage

While solar PV and wind power provide over 90% of electricity in 2050 in all BPS variations (Figure 12), except BPSwoCC, gas turbines continue playing a vital role in the energy system of Turkmenistan and are run with renewable synthetic natural gas (SNG) with zero net GHG emissions, as the CO_2 is provided by direct air capture units (Fasihi, Efimova and Breyer, 2019). In the BPS-5, electricity from gas turbines solely comes from combined-cycle gas turbines (CCGT) at about 640 full load hours (FLH) in 2050, while the fuel used is RE-based. Notably, in the BPSwoCC gas turbines still constitute an even higher share of about 20% of electricity generation capacity mainly CCGT at 730 FLH and some open-cycle gas turbines (OCGT) at very low FLH in 2050, because there is less economic pressure to cut GHG emission in this scenario. The CPS30 follows the CPS until the year 2030, but swiftly installs RE capacities and a majority of electricity comes from solar PV and wind sources by 2050, cutting GHG emissions and reducing levelised cost of electricity (LCOE).

Wind electricity generation dominates RE generation in the beginning of the transition, providing over 80% of renewable electricity in 2030. However, solar PV overtakes all other forms of electricity generation and becomes the major electricity supply source in 2040 in all scenarios except the CPS, thanks to ever declining costs and improving efficiencies, as described in Vartiainen *et al.* (2020). Solar PV provides over 75% of electricity in all BPS variations and almost 60% in the BPSwoCC. Over 47% of electricity comes from solar PV in the CPS30, overtaking all other forms of electricity generation in mere 20 years.

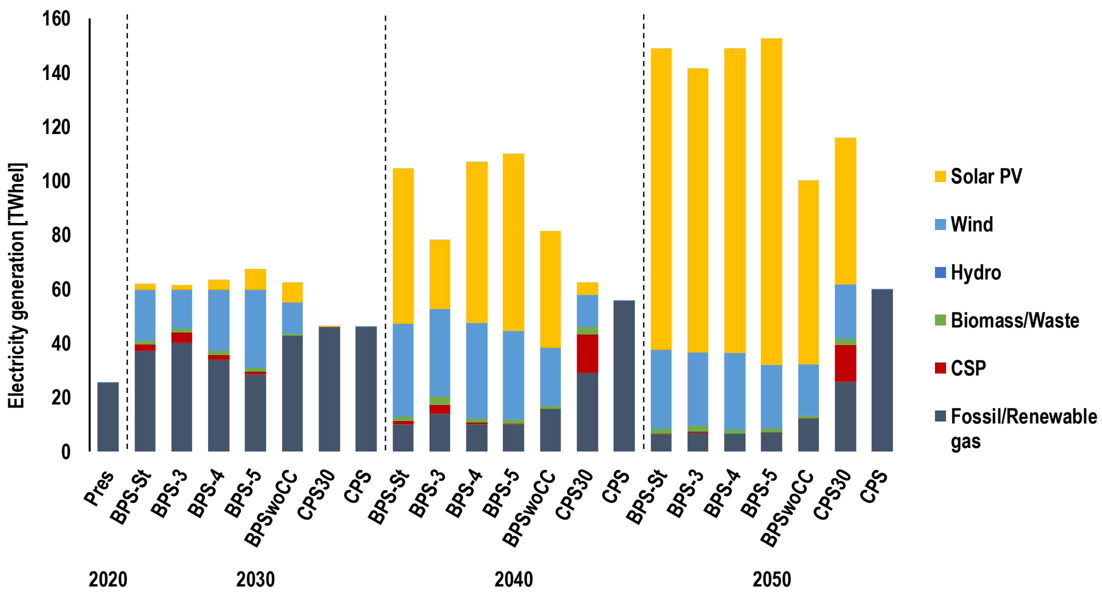


Figure 12: Electricity generation among all scenarios through the transition.

Unsurprisingly, bioenergy plays a miniscule role in electricity generation among all scenarios through the transition, owing to the fact that there is little biomass available in Turkmenistan.

Hydropower electricity generation is nearly absent in all scenarios. No new hydroelectric power plant installations are planned in Turkmenistan owing to the limited resource availability and only one currently existing 1.2 MW hydropower plant is operating in all scenarios. Hydro resource availability is infinitesimal next to solar and wind resources in Turkmenistan.

Breakdown of electricity generation over the transition by sector can be found in the Appendix (Figure A10).

The transition away from dispatchable thermal power plants necessitates utilization of flexibility options which can be provided by sector coupling, in particular by electrolysers, but also by installing energy storage technologies. Considering that no geothermal, hydropower, or almost no bioenergy is present in any of the scenarios, and as the energy system is mainly based on variable wind and solar, adequate storage technologies and capacities are very important, next to other flexibility options, as detailed in (Child *et al.*, 2018), to be able to sustain stable and secure electricity supply especially in the times when neither of the main energy sources are available. One way to secure a stable supply of electricity is open cycle gas turbines that stay in the system from the pre-transition period. Their advantage is that open cycle gas turbines with short start-up time provide flexibility in ensuring electricity supply for peak-demand and the used fuel can be fully switched from fossil gas to biomethane and SNG. Storage technologies such as utility-scale batteries are necessary in order to store the direct electricity of solar PV and wind turbines. Learning rates are high and so the costs are declining rapidly (Vartiainen *et al.*, 2020). Thus, utility-scale batteries become the dominant energy storage option in terms of throughput in almost all scenarios, except the CPS30 and CPS. While capacity-wise gas storage stands out as the largest energy storage capacity (Figure 13, left), batteries cover diurnal energy needs, going through full cycles every day, thus making up the majority of storage throughput (Figure 13, right).

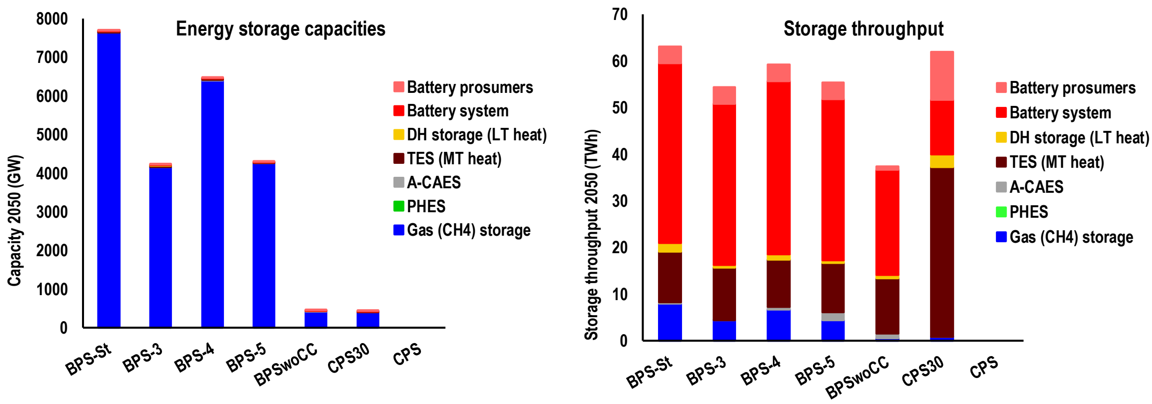


Figure 13. Energy storage capacities (left) and storage throughput (right) in 2050 among all scenarios.

Gas storage ensures energy availability for seasonal and heating needs. It is important to notice that gas storage here is not referring to underground reservoirs for fossil gas, but storage for synthetic natural gas. In order to cut net GHG emissions, it is important to phase out fossil gas usage in power and heat sectors and use electricity-based Power-to-X methane to power gas turbines, next to biomethane.

Figure 14 (left) demonstrates the state-of-charge pattern for gas storage in Turkmenistan throughout a year in the BPS-5 in 2050. As can be seen, gas storage starts being discharged in the winter months when there is less sunshine available for solar PV electricity generation, and it starts being charged in mid-spring as more and more sunshine is available to power water electrolysis and methanation plants to produce SNG for charging the storage.

In contrast, battery storage demonstrates a daily charging and discharging profile (Figure 14, right). Charging periods are during the sunshine hours and discharging started in the later afternoon hours.

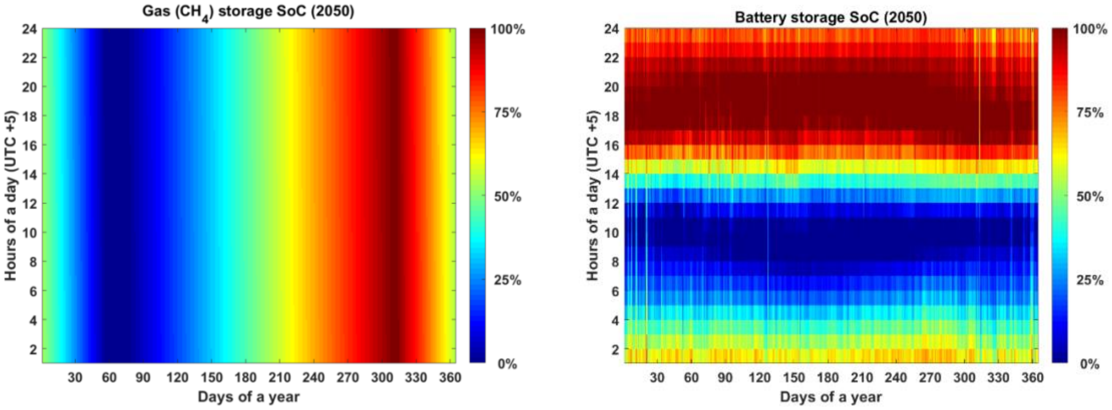


Figure 14. Gas (left) and battery (right) storage annual state-of-charge patterns in the BPS-5 in 2050.

In addition to electricity storage, heat storage technologies will also play a significant role in the energy system to match heat supply and demand in an optimised way (Figure 15). Thermal energy storage covers about 15% of heat demand at 11 TWh of the total of 75 TWh in the BPS-5 in 2050. Heat generation and storage stands out in the CPS30 due to the fact that the CPS30 heavily leans on concentrated solar power (CSP) installations, therefore heat contributes more to primary energy supply (

Figure 11). The high CSP share in the CPS30 is related to the high LCOE (Figure 22), which blocks Power-to-Heat routes. Subsequently, more heat storage is utilised in the CPS30 compared to other scenarios.

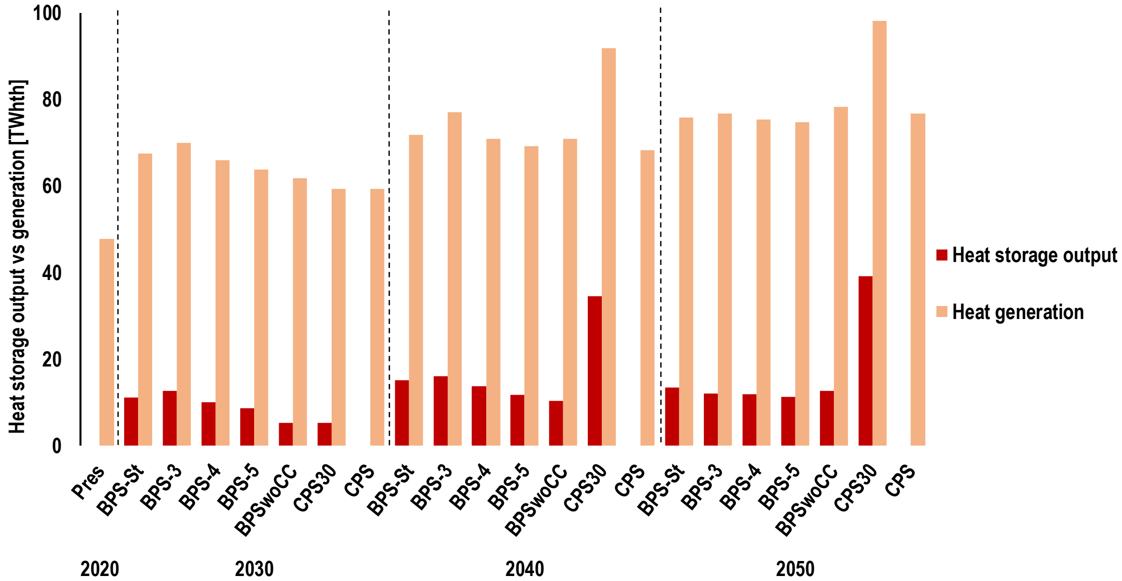


Figure 15. Heat storage output vs. generation among all scenarios through the transition.

3.3. Energy Supply for Power, Heat and Transport

Primary energy demand decreases due to high electrification in all scenarios, excluding the CPS. High electrification is simply inevitable as electric appliances and technologies offer much higher efficiencies compared to their non-electric counterparts. As can be seen in Figure 16, it is possible to reach 100% renewable electricity generation if right incentives and mechanisms are set in place, as in the BPS variations.

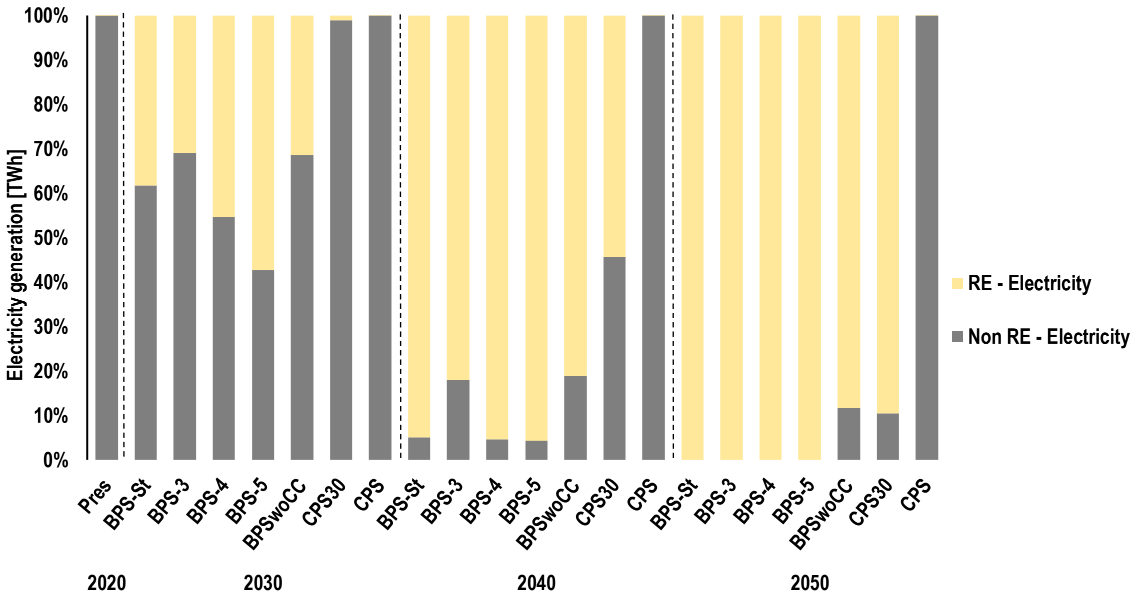


Figure 16: Electricity generation among all scenarios through the transition.

In the BPS variations the power sector undergoes a radical transformation from fossil fuel thermal power plants to renewable energy and inverter-based technologies. As can be seen in Figure 17, the majority of newly installed RE capacities consist of wind power 3.5 GW in 2025 and 7 GW in the BPS-5 in 2030, whereas utility-scale solar PV takes off from 2035 onwards as the least cost option, totalling 79 GW in 2050 in the BPS-5. Subsequently, almost all electricity is supplied by solar PV and wind power in the BPS-5 in 2050. The installation of CAPEX dominated RE technologies and diminishing use of fossil fuels has a strong impact on the LCOE structure, as discussed in section 3.4.

Wind power consists of onshore wind, as offshore territories of Turkmenistan were not considered in this study. Moreover, the best sites for wind power are found in the north-western region of Turkmenistan, with consistent winds above 6 m/s (Korpeyev, 2007; Bahrami *et al.*, 2019).

Among solar PV technologies, fixed-tilted PV power plants at an optimal tilt angle constitute the majority of installations, compared to single-axis tracking and rooftop PV (Figure 17). Though on average single-axis tracking PV systems are economically better performing globally (Afanasyeva, Bogdanov and Breyer, 2018), fixed-tilted PV is able to deliver electricity in Turkmenistan at lower cost in the energy system.

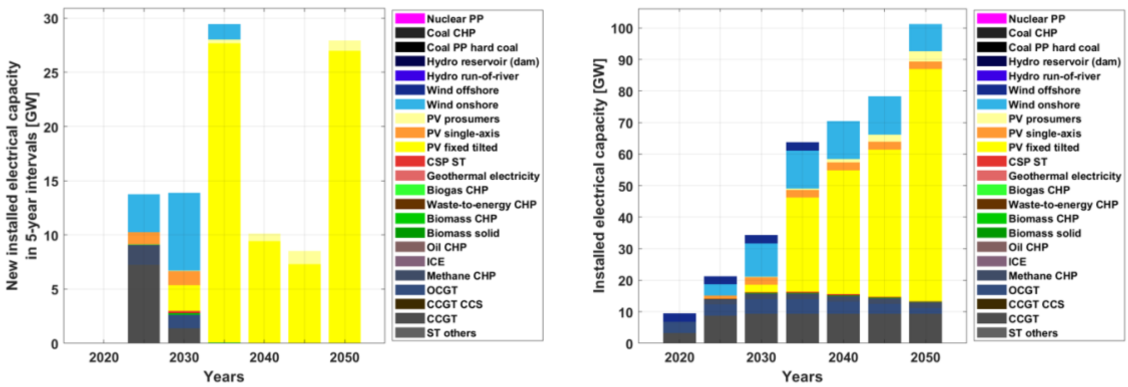


Figure 17. New installations (left) and cumulative (right) electricity generation capacities in 5-year intervals in the BPS-5 through the transition.

The heat supply mix is expected to change significantly from today's fossil gas-powered boilers to mostly electric, solar thermal and biomass heaters in 2050 in all scenarios, except the CPS (Figure 18). This supply mix helps to cut GHG emissions in the heat sector (Knobloch *et al.*, 2020). Electric heating includes electric resistance heaters and heat pumps. Electrification is inevitable, as the electric counterparts offer a much higher efficiency. Solar thermal heat supply includes solar thermal collectors and concentrated solar thermal plants. The CPS30, in contrast to other scenarios, relies strongly on solar thermal heat generation, which coincides with substantially higher LCOE. CPS30 has similar technical and financial assumptions as in the BPS variations, however, due to the delayed RE technologies implementation in 2030 the LCOE strongly suffers from earlier high-cost investments, blocking more use of direct electric heat supply options. Still solar thermal is a very good zero GHG emissions replacement to fossil gas heat boilers that takes advantage of high direct solar irradiance availability in Turkmenistan.

Final heat energy demand breakdown by fuel can be found in the Appendix (Figure A20 and Table A11).

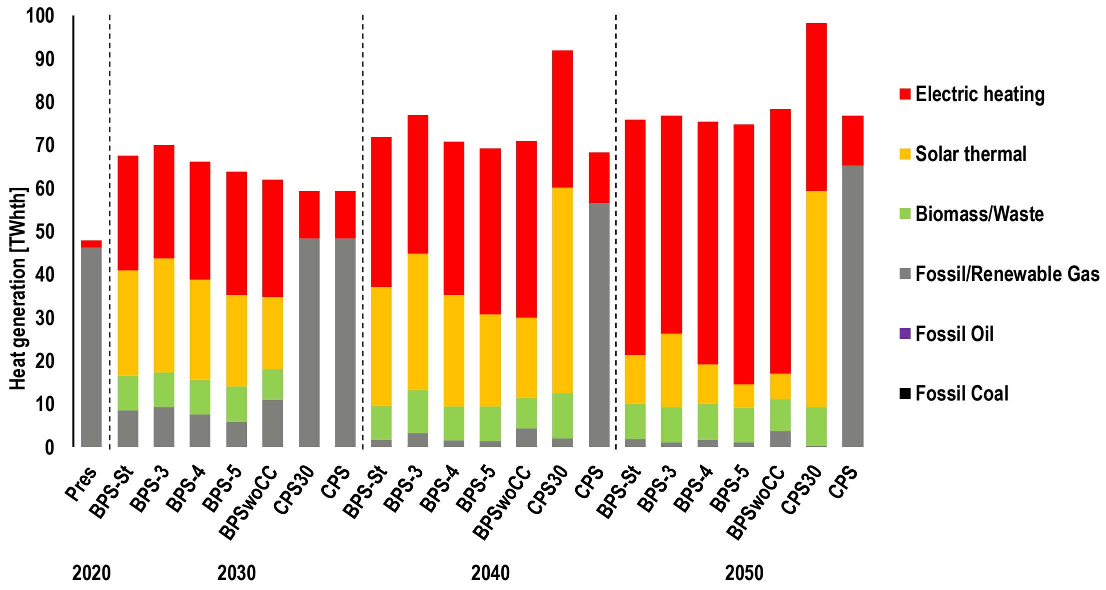


Figure 18. Heat generation among all scenarios through the transition.

With high electrification, final energy demand for transport sector is expected to fall significantly in all scenarios, from 74 TWh today to slightly more than 30 TWh (Final transport energy demand breakdown by fuel can be found in the Appendix (Figure A21 and Table A12).

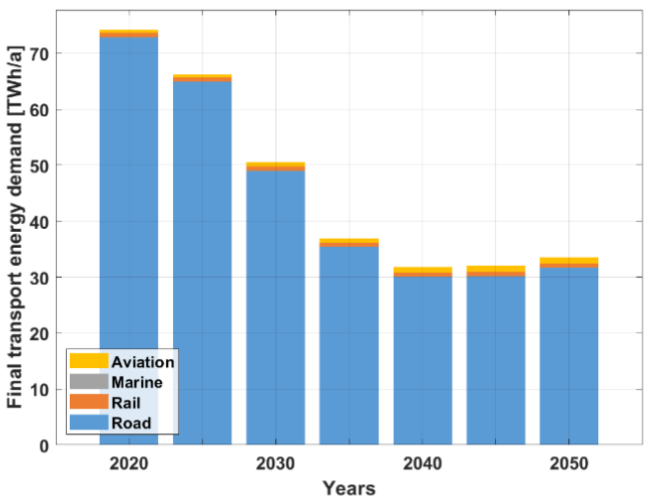


Figure 1919). Highly efficient electric drives will cover the land mobility needs of future Turkmens while simultaneously cutting GHG emissions (Knobloch *et al.*, 2020). Final transport energy demand breakdown by fuel can be found in the Appendix (Figure A21 and Table A12).

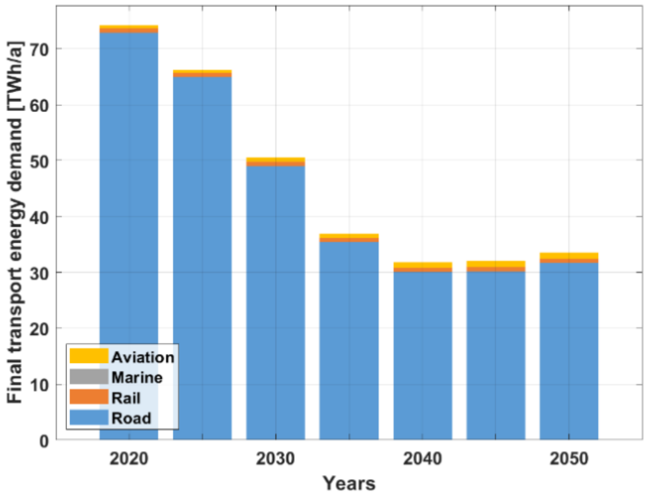


Figure 19. Final energy demand for transport among all scenarios through the transition.

Aviation energy demand will be covered by sustainably sourced hydrogen and Fischer-Tropsch fuels (Figure 21). Weight sensitive aircrafts rely on fuels with high energy density, where lithium-ion batteries with relatively low energy density of the fuel, i.e., stored electricity, are not optimal. Power-to-Fuels technologies, such as water electrolysis and the Fischer-Tropsch process (Fasihi, Bogdanov and Breyer, 2016) allow to move from fossil to sustainable fuels in the transport sector and cut GHG emissions. Newly installed fuel conversion technologies, mainly water electrolysis, CO_2 direct air capture units and Fischer-Tropsch units (Figure 20) will enable to produce 7 TWh of electricity-based kerosene-type jet fuel and diesel (Figure 21). However, the fuel conversion technologies will increase the cost of fuel for the aviation sector and it is reflected in final transportation costs, shown in the next section. A more detailed breakdown of final energy demand of the transport sector can be found in the Appendix (Figure A1-A5).

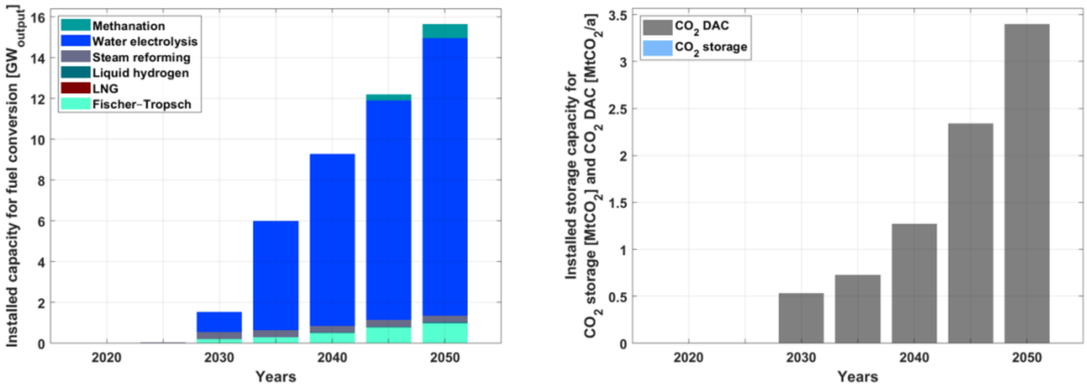


Figure 20. Installed capacities for fuel conversion technologies (left) and CO_2 direct air capture and CO_2 storage (right) in the BPS-5 scenario through the transition.

Table III. Sustainable fuel production output for the transport sector in BPS-5 [GWh_{th}].

Technology	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Electrolyser	0	0	2 231	19 545	29 514	37 145	47 549
Methanation	0	0	0	1	1	1 633	3 818
Fischer-Tropsch [FT]	0	0	1 772	2 434	4 248	6 578	8 225
FT kerosene	0	0	355	487	850	1 316	1 645
FT diesel	0	0	1 063	1 461	2 549	3 947	4 935
FT naphtha	0	0	354	487	850	1 316	1 645
LNG	0	0	0	0	0	0	0
LH2	0	0	0	13	60	159	322

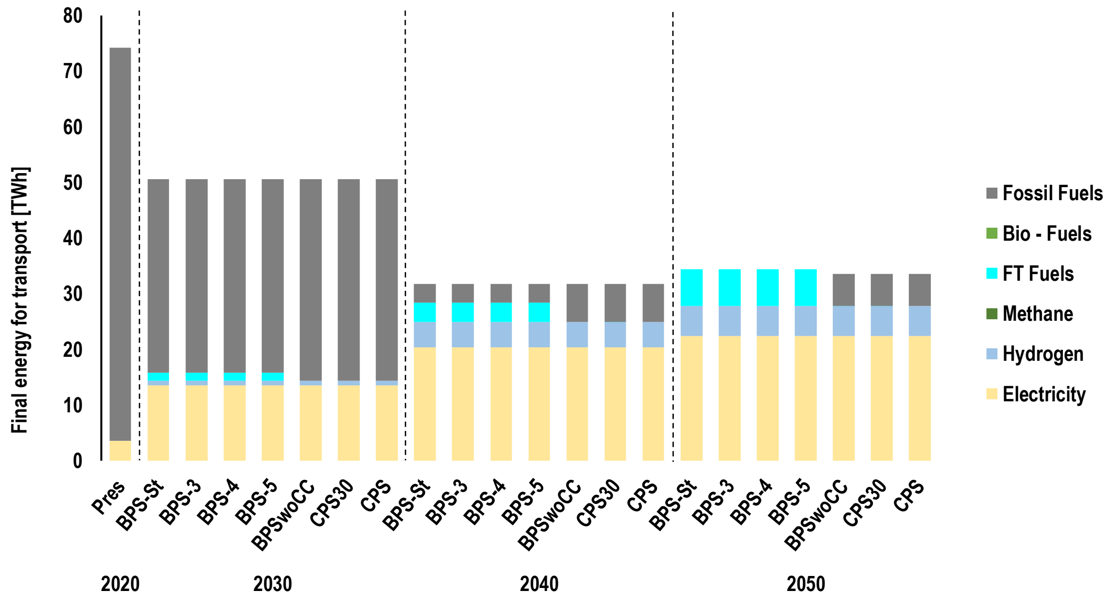


Figure 21. Final energy demand for the transport sector by sources among all scenarios through the transition.

Notably, the BPSwoCC continues relying on some amount of fossil fuels for transportation. Switching to Power-to-X fuels would not be the best economic option in this artificial scenario, where there are no societal costs of emitting CO_2. More importantly, even this scenario switches the majority of transportation to electricity as it is economically disadvantageous to continue relying on traditional internal combustion engines (Knobloch *et al.*, 2020).

3.4. Annualised Energy System Costs and GHG Emissions

All scenarios that introduce renewable energy into the energy mix demonstrate lower LCOE (Figure 22, left) and lower total annualised cost (Figure 22, right), thanks to ever falling costs of RE technologies and practically infinite supply of solar irradiation and wind. The BPS-5 with the highest share of renewables can reach LCOE of less than 45 €/MWh in 2050. Solar PV technology, the main energy supply source in the BPS variations, has demonstrated a steady decline in cost over the last few decades and is already more cost-effective in comparison to fossil fuel generation sources today and it will certainly continue to decline in cost even further (IRENA, 2019; Vartiainen *et al.*, 2020). Wind power converting technologies have also demonstrated a steady decline in energy generation costs. The trends in the wind turbine industry enable further cost reduction per unit of energy, due to larger blade diameters, higher hub heights, more efficient power electronics and better wind forecasting systems (Kumar *et al.*, 2016). The main takeaway among the scenarios in this study is that RE-based energy system reduces the LCOE and annualised system costs relative to the CPS regardless of the rate of integration of RE technologies.

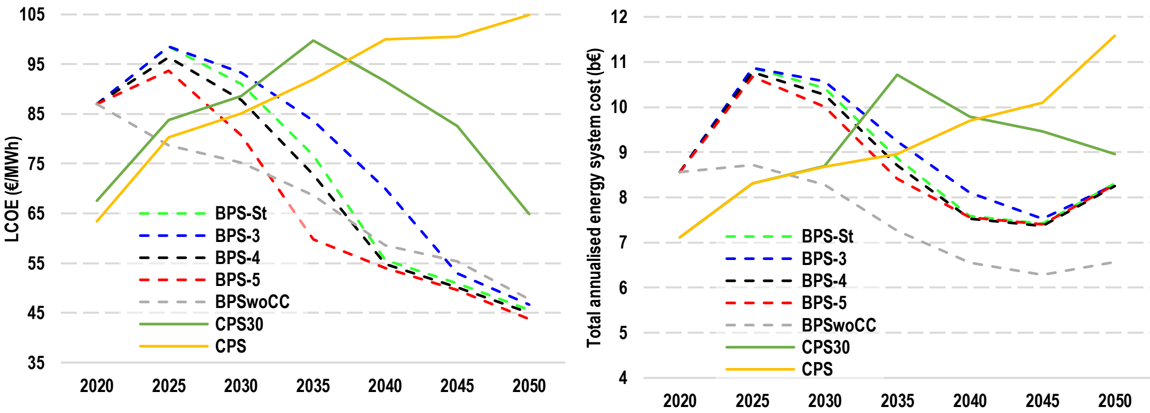


Figure 22. Levelised cost of electricity (left) and total annualised energy system cost (right) among all scenarios through the transition.

Figure 23 shows the composition of total annualised energy system costs in the BPS-5 and CPS scenarios. As can be seen, the energy system costs in the CPS continue consisting of mainly fuel cost and increasing GHG emissions cost. The composition of energy system costs in the BPS-5 becomes CAPEX dominant. Notably, fixed OPEX grows in the BPS-5 energy system costs and it entails some indirect benefits discussed below. Most importantly, the total annualised energy system costs are lower in the BPS-5 in 2050 (note the vertical axes limits) compared to the CPS.

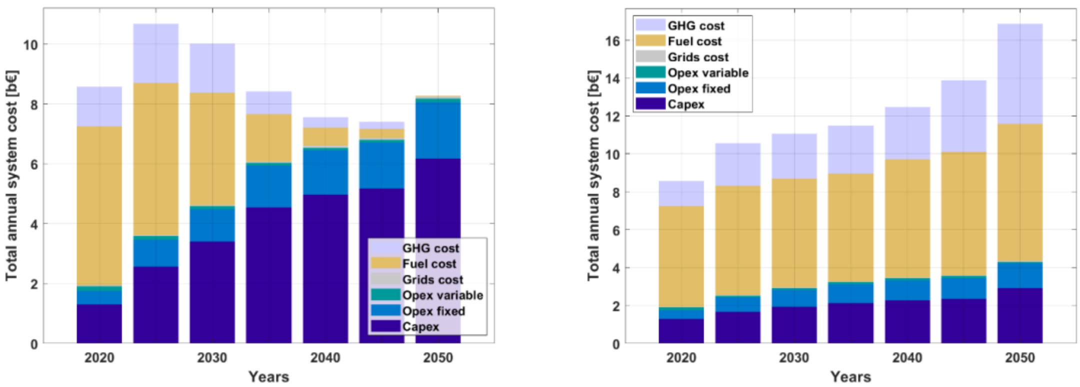


Figure 23. Total annualised energy system cost in the BPS-5 (left) and CPS (right).

The BPS variations result in lower cumulative costs by 2050 than the CPS (Figure 24). The BPSwoCC has even lower annualised cost but that is due to the fact that it artificially does not include CO_2 costs. It leads to least cumulative pathway costs but that could be only a thinkable scenario, if there were no impacts from GHG emissions. While the differences between the scenarios remain small by 2050, the BPS scenarios enable to cut GHG emissions to zero and diversify energy supply mix.

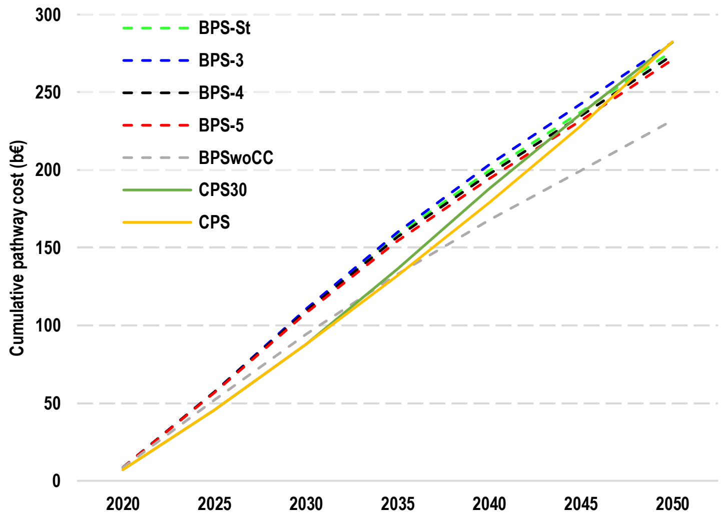


Figure 24. Cumulative pathway costs among all scenarios through the transition.

A more detailed breakdown of transition costs can be found in the Appendix in Table A10 and Figure A16-A8, Figure A12 for the power sector, Figure A16-A17, Figure A19 for the heat sector, Figure A22-A27 for the transport sector.

The composition of the levelised cost of energy is expected to move from fuel cost and GHG emissions cost dominance today and become dominated by capital and operations expenditures by 2050 (Figure 25, left). Though a 100% RE system allows to decrease the overall cost per unit of energy, from over 58 €/MWh to 56 €/MWh, the renewable energy and storage technologies require higher capital investments per MWh compared to the fossil fuel powered counterparts (Figure 25, right). Capital investments in the order of more than 10 b€ will be required in the upcoming decades to upgrade the fossil fuel-based energy system to a RE-based system. As can be seen in Figure 25 (right), the investments are not only in power generation technologies, such as wind and solar PV, but also in heat generation, energy storage and fuel conversion technologies. The increase in fixed operational expenditure entails more local jobs in operations and maintenance that are required to keep the energy system up and running, resulting in another indirect benefit of switching to a 100% RE-based energy system (Ram, Aghahosseini and Breyer, 2020).

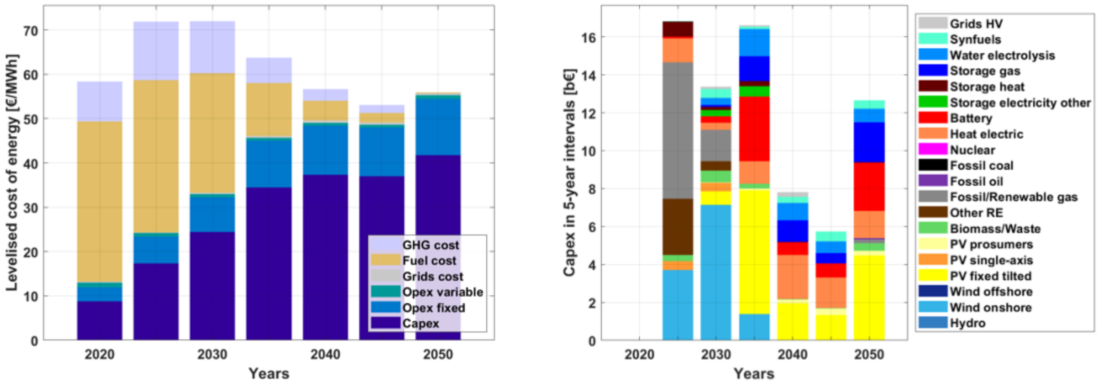


Figure 25. Levelised cost of energy (left) and capital expenditures in 5-year intervals (right) in the BPS-5 through the transition.

Figure 26 (left) shows the domination of CAPEX and fixed OPEX in levelised cost of electricity (LCOE) in the BPS-5. Yet again it is important to note the reduction of costs indicated by the vertical axes' limits. The Table IV shows a detailed breakdown of the composition of LCOE in the BPS-5 through the transition.

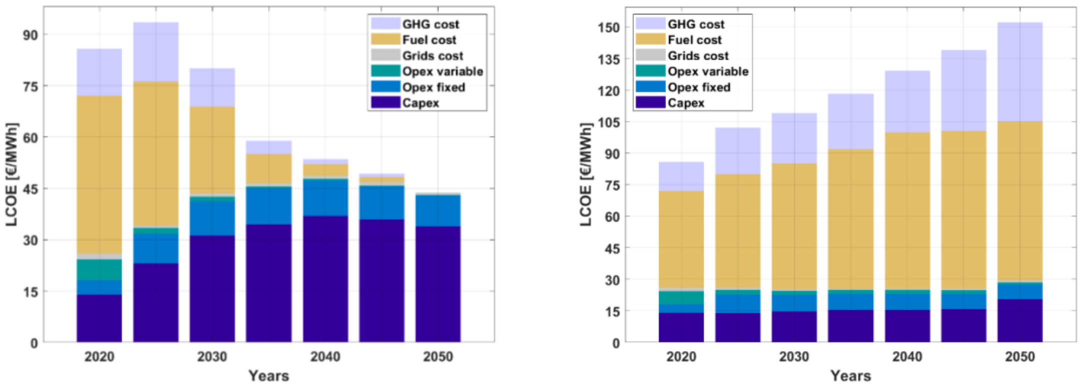


Figure 26. Levelised cost of electricity composition in the BPS-5 (left) and CPS (right).

Table IV. Levelised cost of electricity expenditures in the BPS-5 [€/MWh].

LCOE	2020	2025	2030	2035	2040	2045	2050
Capex	14.1	23.1	31.1	34.4	36.9	36	33.9
Opex fixed	4	8.6	10.3	10.6	10.3	9.6	8.8
Opex variable	6.2	1.9	1.2	0.7	0.5	0.4	0.3

Grids cost	1.6	0.7	0.9	0.8	1	0.9	0.7
Fuel cost	46.1	42	25.3	8.5	3.3	1.6	0
GHG cost	13.8	17.3	11.2	3.8	1.5	0.9	0
Total	**85.8**	**93.6**	**80**	**58.8**	**53.5**	**49.4**	**43.7**

The Figure 27 shows detailed LCOE breakdown by technologies that supply electricity in the BPS-5 and CPS scenarios. The BPS-5 demonstrates a diversified mix of electricity generation and storage technologies in contrast to the CPS.

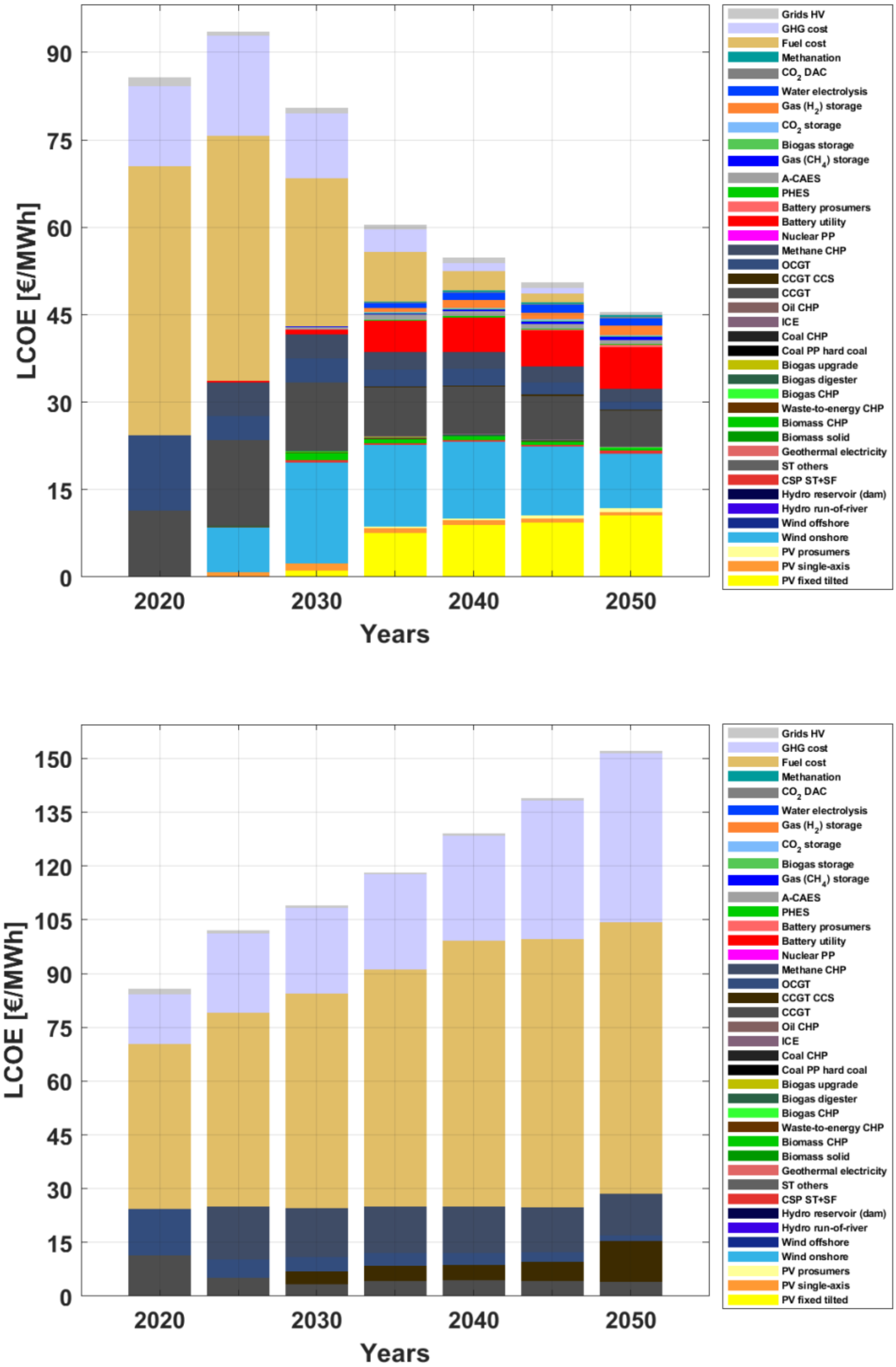


Figure 27. Levelised cost of electricity by technology in the BPS-5 (top) and CPS (bottom).

The Figure 28 shows the breakdown of levelised costs of heat (LCOH) in the BPS-5 and CPS scenarios. Here the breakdown shows the different components that constitute the final LCOH. LCOH primary include the costs of installing and operating the heat generation technologies, while LCOS consists of costs of installing and operating heat storage technologies. As the LCOH indicates, the use of fuels in heat generation is phased out quickly, due to enormous efficiency gains offered by electric heating technologies, including heat pumps. The reliance on tradition gas boilers in the CPS result in higher LCOH at over 90 €/MWh through the transition and continually increasing GHG emissions costs.

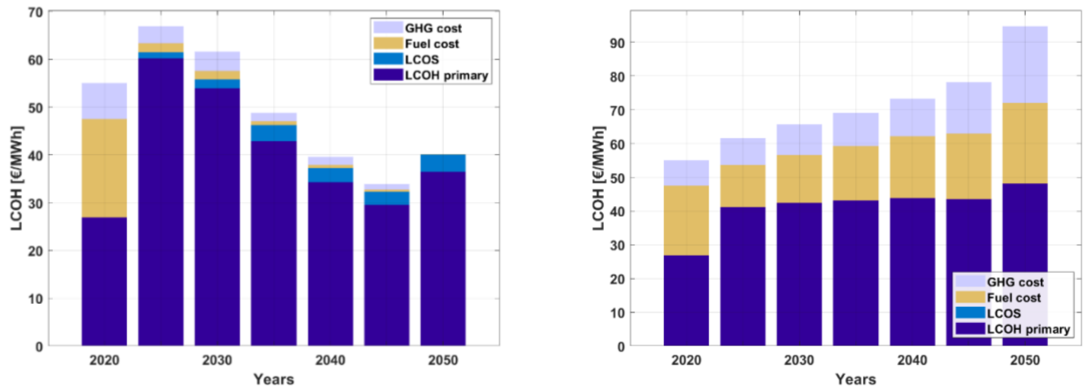


Figure 28. Levelised cost of heat components in the BPS-5 (left) and CPS (right).

The Table V shows the precise LCOH component numbers in the BPS-5. The jump in LCOH from 2020 to 2025 can be explained by rapid electrification of the heat sector. Electrification enables to significantly cut GHG emissions in the heat sector, while slightly increasing the costs. However, overall LCOH declines through the transition in the BPS-5.

Table V. Levelised cost of heat components in the BPS-5.

LCOH	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
LCOH primary	26.9	60.2	53.9	42.8	34.3	29.5	36.4
LCOS	0	1.3	1.8	3.4	2.9	2.7	3.6
Fuel cost	20.7	1.8	1.8	0.8	0.7	0.4	0.1
GHG cost	7.5	3.6	4	1.7	1.7	1.2	0
Total	**55.1**	**66.9**	**61.5**	**48.7**	**39.6**	**33.8**	**40.1**

The Figure 29 shows the detailed LCOH breakdown by technologies in the BPS-5 and CPS scenarios. Electric heating quickly dominates the LCOH in 2025 in the BPS-5. This significantly increases efficiency, reduces GHG emissions in the heat sector but slightly increases the LCOH. However, the overall LCOH declines through the transition in the BPS-5.

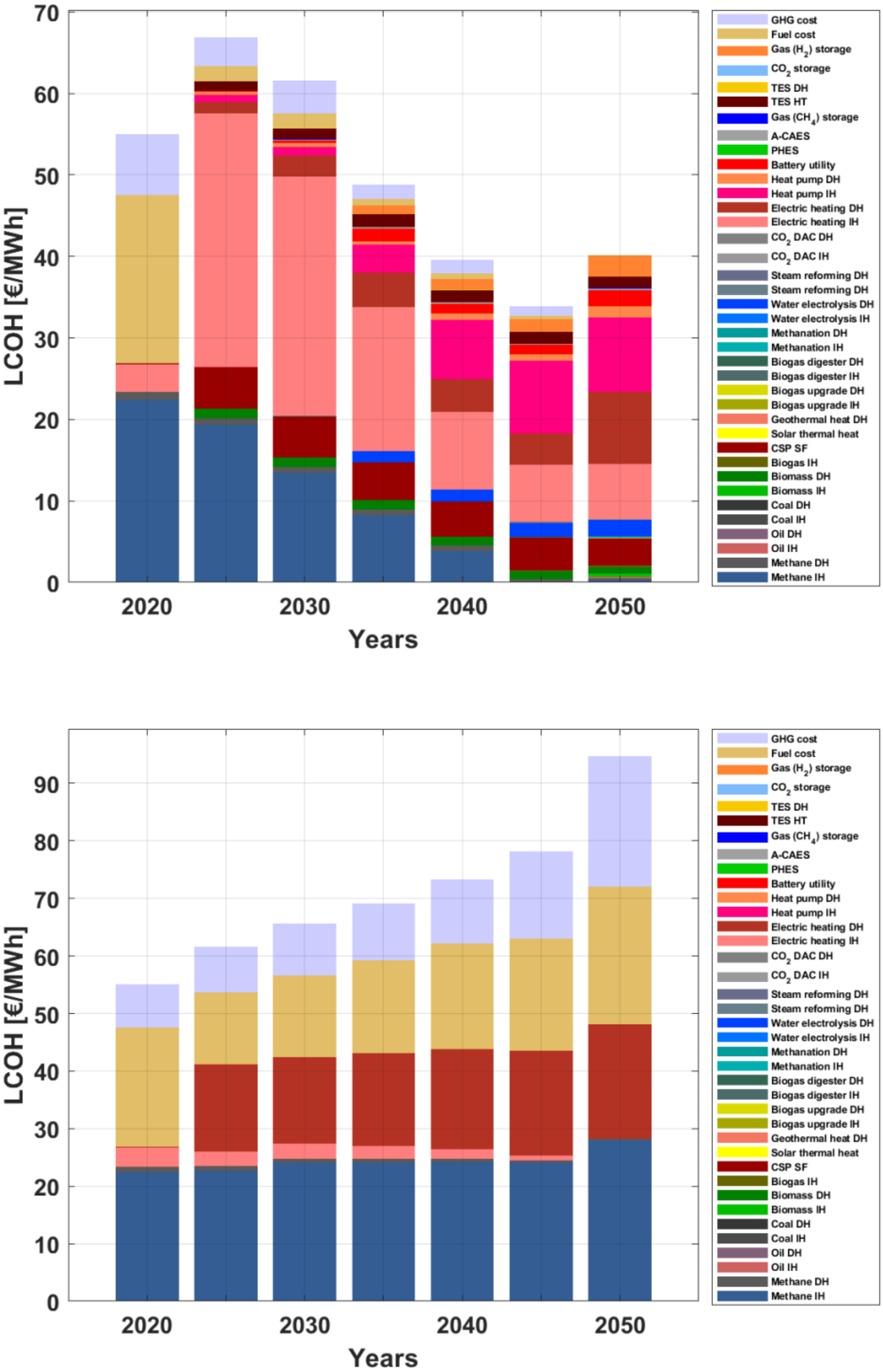


Figure 29. Levelised cost of heat by technologies in the BPS-5 (top) and CPS (bottom).

The decrease in final energy demand in the transport sector helps to decrease the final transport energy cost as well, from 3.8 b€ today to 2.3 b€ in 2050 (Figure 30).

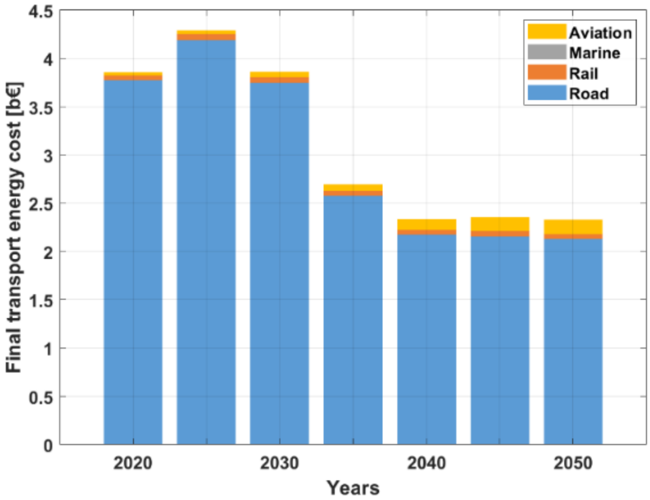


Figure 30. Final transport energy cost in the BPS-5 through the transition.

Moreover, thanks to a high electrification, the cost of transport per kilometre is also expected to drop (Figure 31, right). While the cost of road transport per kilometre drops by over 50%, both in passenger and freight transport, the aviation cost per kilometre slightly rises, because the switch to Power-to-X fuels is expected to increase the cost of fuel for aviation.

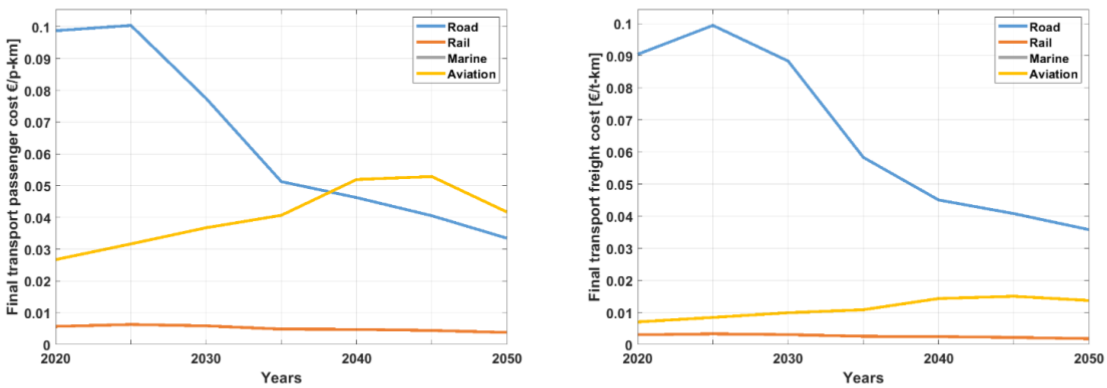


Figure 31. Final transport passenger (left) and freight (right) kilometer costs in the BPS-5 through the transition.

The CPS results in over 47 $MtCO_{2eq}$ annual emissions (Figure 32, left) and leads to over 1300 $MtCO_{2eq}$ cumulative emissions by 2050 (Figure 32, right). While short-term emissions may fall thanks to high electrification and efficiency improvements in combined cycle gas turbines, such as the recently installed Mary Hydroelectric Power Station, long-term emissions will remain at unsustainable levels. The introduction of low to zero GHG emitting RE technologies will help to significantly cut GHG emissions as seen in all other scenarios. The CO_2 emissions related to solar PV and wind power converting technologies only occur during their manufacturing phase (IPCC, 2011). Without a fundamental breakthrough in energy storage technologies, the aviation transport mode is expected to continue relying primarily on jet fuel. However, Power-to-X technologies, such as the well understood Fischer-Tropsch process developed in the beginning of 20th century, allows to cut the GHG emissions of the transport sector to zero. It is worth noting the GHG emissions in the CPS30 compared to the BPSwoCC in 2050: the CPS30 is capable of reaching lower annual GHG emissions in 2050 even though it only starts introducing RE technologies a decade later than the BPSwoCC. BPSwoCC fails to cut GHG emissions down to zero as there is no economic pressure to do so and for this reason it is important to include societal costs of emitting GHG to fully get rid of them.

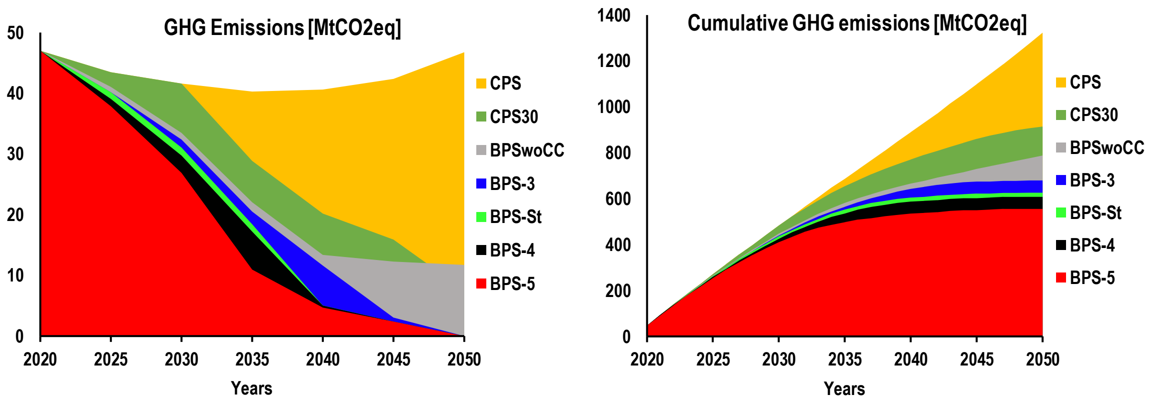


Figure 32. Annual (left) and cumulative (right) GHG emissions among all scenarios through the transition.

Figure 33 shows the GHG emissions breakdown by sectors through the transition in the BPS-5 and CPS scenarios. The 100% renewables-based energy system enables to cut GHG emissions to zero in the BPS-5 in contrast to CPS. The GHG emissions in the heat sector in the BPS-5 shrinks rapidly from 2020 to 2025 due to electrification of the heat sector, as can be seen in Figure 29. The electrification of the heat sector shifts the GHG emissions to the power sector, thus the increase in the power sector observed in the BPS-5 in 2025 (Table VI). However, overall GHG emissions fall from 2020 to 2025.

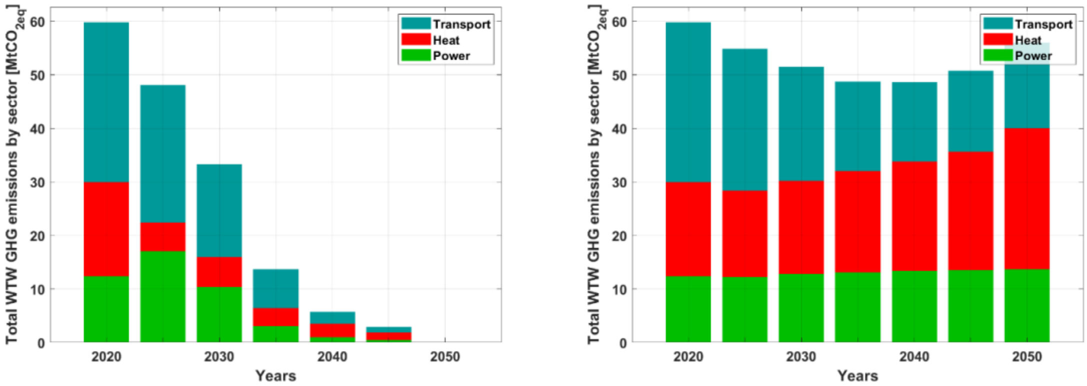


Figure 33. Total Well-to-Wheel GHG emissions by sector in BPS-5 (left) and CPS (right).

Table VI. Total WTW GHG emissions by sector in BPS-5 [MtCO2eq].

Sector	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Power	12.3	17	10.3	3.1	1	0.5	0
Heat	17.5	5.4	5.6	3.4	2.5	1.4	0
Transport	29.9	25.7	17.3	7.2	2.2	1	0
Total	**59.7**	**48.1**	**33.2**	**13.7**	**5.7**	**2.9**	**0**

A more detailed breakdown of GHG emissions can be found in the Appendix in Figure A11 for the power sector, Figure A18 for the heat sector, Figure A28 for the transport sector.

4. Discussion

4.1. Overall Findings

This study with various transition pathways demonstrates that a 100% RE system in Turkmenistan is economically viable and technically feasible. Seven scenarios demonstrate the effects of different rates of RE integration into the energy system and can help policymakers, potential investors, and other stakeholders in Turkmenistan to shape the future development in the country. All scenarios, except the CPS, demonstrate that it is possible to quickly switch to renewable sources of energy in Turkmenistan in a cost-effective way. The CPS confirms this fundamental finding, since it is the least efficient and highest cost option among all scenarios and the CPS30 demonstrates the positive effects of these two key system metrics, if the energy system receives more freedom from the year 2030 onwards to switch to a RE dominated system. Turkmenistan, awash with solar irradiation year-round and with its desert plains with strong winds, is one of the best regions for solar PV systems and wind power, with FLH of up to 1710 and 2733 for solar PV and wind energy, leading to LCOE of 80.6 €/MWh in 2030 and 44 €/MWh in 2050, respectively.

Growing population along with a growing economy, increasing standards of living and access to low-cost energy is projected to result in both relative and absolute growth in final energy demand in all scenarios. Continual reliance on fossil fuels as primary energy supply results in growth of fossil fuel consumption and ever increasing GHG emissions and associated costs. As demonstrated in the BPS and CPS30 scenarios, switching to RE resources helps to cut primary energy demand and minimise GHG emissions.

The BPS variations and the CPS30 demonstrate that it not only helps to cut GHG emissions but also it is economically advantageous to switch to renewable sources of energy. The BPS-5 scenario with a 5% rate of increasing the capacity share of annual RE integration not only enables the lowest LCOE but also the least total annualised costs, in addition to quickly cutting GHG emissions down to zero. However, it needs to be noted that such a high RE phase-in has not yet been observed historically in the world, as more than 3% of annual capacity share growth of RE is hardly detectable (Farfan and Breyer, 2017). One of the fastest RE ramps in generation ever recorded has been Uruguay with generation increase from 60% to 98% renewables within eight years, which reveals a phase-in rate of 4.75% for the increase of annual generation shares.

This study also demonstrates the effects of different RE integration rates into an energy system that relies solely on fossil gas power generation. The common thread among all scenarios is that any rate of RE integration cuts costs on top of reducing GHG emissions. There is neither environmental nor economic advantage of continuing the reliance on fossil fuels. However, all scenarios imply a strong uncertainty of possible future paths of Turkmenistan's national energy system and it is impossible to predict the actual development with high certainty. Besides the assumptions made in this study, several other factors will influence and shape the future development such as social acceptance of RE investments and installations or acceptance of continuing the present path of destroying economic value for the country in avoiding RE investments, while uncertainties related to the economic health of the nation may influence both fundamental policy options. Some factors, such as an almost inevitable increase in frequencies of extreme natural events (IPCC, 2018), may even urge the government to switch to renewable sources of energy in a quicker manner than the most rapid scenario in this study. However, the example of Norway may be a blueprint for the government of Turkmenistan: achieving highest levels of RE utilisation for domestic least cost energy supply, while maximising exports of fossil gas to laggard countries in the energy transition, which obviously seems to be a strategy for generating highest societal welfare.

The abundance of natural resources and relatively recent investments in gas turbines and gas infrastructure lead to some interesting results. This built out gas infrastructure continues to play a vital role in the energy system of Turkmenistan in all scenarios. As can be seen in results, gas turbines can facilitate the transition to variable renewable energy sources by providing flexibility to the system. In short to mid-term, fossil gas can serve as a crucial balancing option during particularly cloudy or windless days in a cost-optimal way while simultaneously avoiding becoming stranded assets.

Flexibility and energy storage as a key flexibility option will play a vital role in a 100% RE system, enabling temporal shift in energy supply and thus providing flexibility for variable RE. With continuously declining cost, batteries become the main energy storage technology in all scenarios, except the CPS and CPS30. On top of that, thermal energy storage technologies facilitate the integration of variable renewable heat generation resources, such as solar heat collectors and concentrating solar power plants. Smart charging of BEV and vehicle-to-grid (V2G), an emerging new approach to flexibility and energy storage, was not considered in this study, although it may play a relevant role in 100% RE energy systems of the future (Liu *et al.*, 2013). It is demonstrated in Child, Nordling and Breyer (2018) and Taljegard *et al.* (2019) that high V2G participation can help decrease the need for peak power capacity, long-term gas storage, water electrolysis and fuel conversion capacities and subsequently lower total annualised costs. The curtailment in the BPS variations reaches values between 4.1% to 4.8% in 2040 (except the BPS-3 with only 1.2% due to a slow RE phase-in) and 5.0% to 5.9% in 2050. Such values are regularly observed in sector coupled 100% RE systems (Lopez *et al.*, 2020; Ram *et al.*, 2020) and further confirm the RE penetration-storage-curtailment nexus found on the case of Israel (Solomon, Bogdanov and Breyer, 2019), which has similar resource conditions as Turkmenistan. The Figure 34 shows the amount of electricity curtailment in blue bars and ratio of curtailment to generated electricity in the BPS-5.

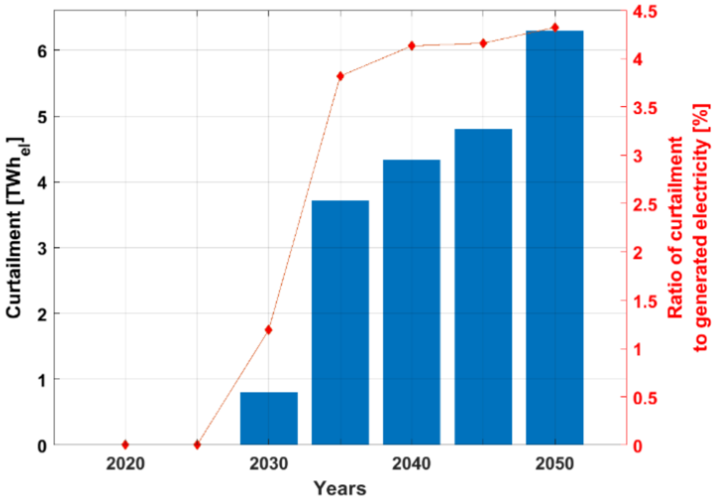


Figure 34. Electricity curtailment and ratio of curtailment to generated electricity in BPS-5.

Theoretically, Turkmenistan should be able to bypass utilising energy storage all together, thanks to huge proven reserves of fossil gas. Gas turbines would be able to supply power absent the sunshine or wind. However, that would entail more GHG emissions and the associated costs of GHG emissions, while it would block least cost energy system solutions. The combination of RE sources and storage technologies is the best environmental and economic option even for a country with domestic fossil fuel supply such as Turkmenistan as an existing domestic energy supply option is substituted with an even more beneficial sustainable domestic energy supply option.

The transport sector shall undergo a radical transformation, switching to much more efficient vehicles and cutting final energy demand by half. Though transportation demand rises overall, the final energy demand decreases due to electrification of the road vehicles fleet thanks to efficiency gains of several factors. Direct electrification of the aviation sector will be possible for short distance flights after 2030 (Khalili *et al.*, 2019) whereas longer distance aviation can be indirectly electrified thanks to Power-to-X technologies. Indirect electrification does not have a strong negative effect on efficiency, but it helps to cut GHG emissions of the aviation sector. The Power-to-Fuels technologies allow to create liquid hydrocarbons by combining carbon from the CO_2 captured from the atmosphere and hydrogen from the water. However, it is important to have sustainably sourced carbon and hydrogen in order to have zero net-emissions of CO_2. CO_2 direct air capture (Fasihi, Efimova and Breyer, 2019) or point source CO_2 capture technologies, such as for cement mills (Farfan, Fasihi and Breyer, 2019), will be able to provide sustainable or otherwise unavoidable carbon, whereas water electrolysis will allow to create hydrogen by the well-known water electrolysis process. In addition, these energy-intensive PtX technologies convert large amounts of electricity from solar PV and wind turbines into hydrocarbons, while providing a very high flexibility to the entire energy system (Bogdanov *et al.*, 2020; Ram *et al.*, 2020), which also effectively limits curtailment of electricity. Figure 35 shows the operational dynamics of the entire energy system and thereof in particular of electrolysers providing the green hydrogen for the PtX routes. The best and worst week of the BPS-5 for the 2050 energy system design is shown and documents the enormous flexibility enabled by electrolysers, but also the diurnal energy storage function of batteries.

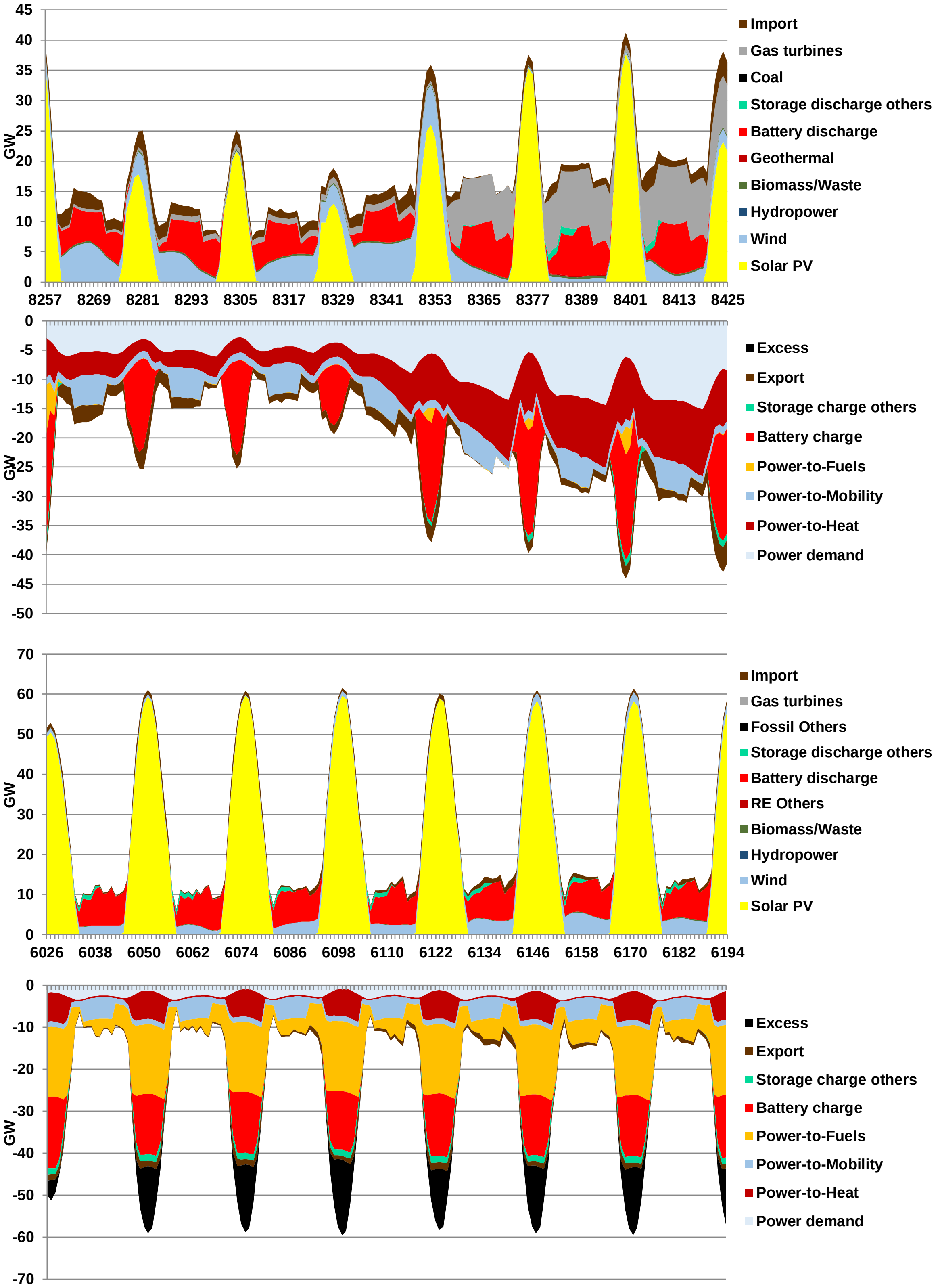


Figure 35. Worst (top) and best (bottom) week of solar electricity production in Turkmenistan in the BPS-5 in 2050.

4.2. Related Studies

The results of this study are in line with the findings of recent energy transition studies in other countries around the world, specifically the dominance of solar PV in electricity generation (Breyer *et al.*, 2017; Tavana *et al.*, 2019; Bogdanov *et al.*, 2020; Ghorbani, Aghahosseini and Breyer, 2020) and cost savings related to transitioning to sustainable forms of energy (Bogdanov, Toktarova and Breyer, 2019). Breyer *et al.* (2017) investigate the role of solar PV in energy transition on a global level, employing high temporal and high spatial modelling and conclude that solar PV technology will emerge to be the "most relevant source of energy in the mid-term to long-term for the global energy supply" thanks to ever decreasing costs of PV systems and battery storage technologies. Bogdanov *et al.* (2019) identified that the global average of solar PV share in electricity generation can be expected to reach about 70% in mid-century, while this can reach levels of beyond 90% in Sun Belt countries (Oyewo *et al.*, 2018; Sadiqa, Gulagi and Breyer, 2018; Solomon, Bogdanov and Breyer, 2018; Azzuni *et al.*, 2020; Gulagi *et al.*, 2020; Lopez *et al.*, 2020). Tavana *et al.* (2019) studied the RE potential for the energy transition of Iran, a geographically similar country to Turkmenistan with a comparable energy system heavily dependent on fossil fuels. Tavana *et al.* (2019) similarly present several transition scenarios with different RE integration rates and demonstrate the high potential of solar PV and wind power technologies and that they are technically and economically feasible, albeit with slightly conservative solar PV cost and efficiency assumptions. Ghorbani *et al.* (2020) have undertaken a detailed energy transition study for Iran in high geo-spatial resolution to determine cost-optimal pathways towards full sustainability of Iran's energy system; though only power sector and desalination sectors along with non-energetic gas sector were simulated, the authors similarly conclude that solar PV will dominate the electricity supply in the BPS in 2050.

4.3. Implications

Turkmenistan's lack of national determination towards concrete sustainability targets is alarming and should be addressed immediately. Specifically, more focus must be paid to the promotion of RE technologies. The current business-as-usual case is unsustainable, and high in cost as clearly documented by the CPS. A renewables-based energy system enables progress on all three pillars of sustainability: environment, economy and society.

The results for the case of Turkmenistan strongly indicates that accelerated phase-in policies for renewables are of high economic relevance in a general perspective. Empiric data indicates that only a few countries had been able to phase-in RE capacities at an annal rate of 3% increase in relative capacity share over periods of five years or longer, while only Uruguay is known for ramping the relative RE generation share close to 5% for almost a decade. However, the BPS-5 for the case of Turkmenistan shows that such a very high RE phase-in rate is the economically most beneficial case, while it reduces the GHG emissions in the fastest way. Given the fast decline in remaining carbon budgets, it is of highest relevance that very fast declining GHG emissions pathways positively coincidence with economic performance.

It is important to note the cumulative GHG emissions in the BPS variations in later years of the transition – they flatten out and remain almost constant throughout the later years (Figure 32, right). According to Rogelj *et al.*(2016), intended nationally determined contributions by members states of UNFCCC will not be enough to keep the global warming below 2°C, in stating that "substantial over-delivery on current INDCs" will be needed to achieve the goal of keeping global warming below 2°C and even further efforts to keep it below 1.5°C, while the remaining carbon budgets further decline due to triggered feedback loops of the planetary climate system (Rogelj *et al.*, 2019). The CO_2 emitted to the atmosphere will have to go down and either utilised or stored, for which CO_2 direct air capture is a major option as it may enable the massive utilisation of CO_2 as a raw material and in a second phase the transition to negative CO_2 emissions in the future (Breyer *et al.*, 2019).

4.4. Limitations and Recommendations for Future Research

This study is one of the first of its kind for investigating the pathway options of Turkmenistan's energy system, for which more research is required. There is a dire need to study the energy system of Turkmenistan from different perspectives with more granular data. The data used in this study, such as energy demand profile and population, may not fully match the latest numbers. As an example, the unusual bulge in the electricity per capita mid-transition (Figure 8, right) is probably related to mismatch between real population and data used for this study. A 100% renewables based energy system potentially offers even more benefits to the nation when considering job creation (Ram, Aghahosseini and Breyer, 2020), water desalination, (Caldera and Breyer, 2020) industry sector integration (Bogdanov *et al.*, 2020) and power exchange over regional cross-border grids (Aghahosseini, Bogdanov and Breyer, 2020). The results of this research clearly indicate that it would be beneficial to conduct further studies on societal benefits of renewables-based energy system, grid capacity requirements intra-regional within Turkmenistan and international cross-border grid capacity, but also water demand, supply and desalination aspects in Turkmenistan.

5. Conclusions

To conclude, the study enabled to answer to the research questions:

How Turkmenistan can transition its energy system to full sustainability from its current fossil-fuel based state?

The results of the study demonstrate the different pathways that Turkmenistan can take its energy system from its current fossil fuel reliance. The path to sustainability not only involves switch to 100% RE system, but also sector coupling, energy storage, efficiency improvements via electrification and diversification of energy supply mix.

How can the current state and policies affect the pace of transition to full sustainability?

What are the effects of different rates of transitioning to a 100% renewables-based energy system?

The abundance of natural resources, recent investments in gas infrastructure and lack of political will to change the current state of the energy system necessitated a simulation with different rates of RE integration at different points in time. A scenario where the nation is forced to switch away from fossil fuels is simulated to understand how the energy system behaves in such conditions. Ranging from laggard to highly progressive quick pace, the simulation results present the benefits and drawbacks of different rates of integration of RE technologies. The overarching thread among all scenarios is that any rate of RE integration enables lower levelised costs of energy. Interestingly, late introduction of RE technologies (CPS30) blocks some routes for energy supply, while strongly leaning on concentrated solar power production that is not observed in other scenarios.

What are the environmental and economic benefits of transitioning to full sustainability?

Solar PV and wind power can lead the transition to a fully sustainable 100% renewable energy system in Turkmenistan, cutting GHG emissions to zero. Low-cost solar PV and wind electricity, efficiency gains and effective energy sector coupling can enable a reduction in levelised cost of electricity in Turkmenistan from 87 €/MWh in 2020 to 44 €/MWh in

2050, while the overall levelised cost of energy in 2050 will stay on the same level as in 2020.

Turkmenistan has been blessed with natural fossil fuel resources and it is awash in renewable energy resources to an even greater extent. The LUT Energy System Transition model was used to analyse seven different energy system pathways for Turkmenistan, employing a multi-node high resolution sector coupling approach. The results of this study show that RE, sector coupling, and storage technologies can sufficiently cover the national energy demand at every hour throughout a year. Pathways of delayed or blocked renewable energy investments lead to higher energy system cost and higher GHG emissions. Direct and indirect electrification of heat and transport sectors will help to cut GHG emissions in these sectors to zero and reduce the cost for the entire energy system. The fast worsening of climate change may lead to international attention to Turkmenistan’s inadequate actions regarding GHG emissions, sooner or later, and this might enforce drastic measures for Turkmenistan’s energy policy. Decision-makers in Turkmenistan should strongly consider enabling investments in RE through solid frameworks and legislation, as this enhances the welfare of the country.

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Appendix

Table A1. Population projection (UN, 2019).

Region	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Ahal	2 782 500	3 015 500	3 219 000	3 391 000	3 549 500	3 704 500	3 850 500	3 974 500
Balkan	834 750	904 650	965 700	1 017 300	1 064 850	1 111 350	1 155 150	1 192 350
Dashoguz	500 850	542 790	579 420	610 380	638 910	666 810	693 090	715 410
Lebap	667 800	723 720	772 560	813 840	851 880	889 080	924 120	953 880
Mary	779 100	844 340	901 320	949 480	993 860	1 037 260	1 078 140	1 112 860
Total	**5 565 000**	**6 031 000**	**6 438 000**	**6 782 000**	**7 099 000**	**7 409 000**	**7 701 000**	**7 949 000**

Table A2. Projection of power, heat and transport demand (Barbosa, Bogdanov and Breyer, 2016; State Committee of Statistics of Turkmenistan, 2018; Khalili *et al.*, 2019).

Energy service demand	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Power	[TWh]	17.36	18.34	19.37	20.46	21.61	22.83	24.11
Industrial process heat	[TWh_{th}]	33.46	41.67	43.08	46.17	49.12	50.32	52.79
Domestic hot water heat	[TWh_{th}]	1.75	1.86	1.96	2.06	2.15	2.23	2.30
Space heating heat	[TWh_{th}]	20.06	20.30	24.10	26.40	28.66	32.22	35.19
Road LDV passenger transport	[mil p-km]	4 458.4	4 758.9	5 088.8	5 500.4	6 066.8	6 851.8	7 925.5
Road 2W/3W passenger transport	[mil p-km]	199.6	218.3	238.2	262.4	294.7	337.6	395.9
Road BUS passenger transport	[mil p-km]	424.0	416.9	409.0	409.2	415.5	436.6	467.6
Road MDV freight transport	[mil t-km]	3 399.1	3 465.9	3 543.1	3 685.3	3 935.7	4 337.4	4 924.7
Road HDV freight transport	[mil t-km]	32 805	33 256	33 887	35 103	37 338	40 983	46 403
Rail passenger transport	[mil p-km]	7 965	8 329	8 724	9 168	9 692	10 335	11 152
Rail freight transport	[mil t-km]	2 442	2 591	2 757	2 945	3 164	3 423	3 730
Aviation passenger transport	[mil p-km]	193	253	330	427	562	731	931
Aviation freight transport	[mil t-km]	2 979	3 524	4 248	4 861	5 981	7 113	8 173

Table A3. Projected specific energy demand by transport mode and vehicle type (Khalili *et al.*, 2019).

Mode and vehicle type	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
LDV ICE	[kWh_{th}/km]	0.747	0.686	0.617	0.565	0.521	0.443	0.365
LDV BEV	[kWh_{el}/km]	0.165	0.148	0.130	0.122	0.113	0.104	0.096
LDV FCEV	[kWh_{H2}/km]	0.269	0.226	0.217	0.200	0.200	0.165	0.156
LDV PHEV	[kWh_{th}/km]	0.187	0.151	0.136	0.124	0.115	0.097	0.080
LDV PHEV	[kWh_{el}/km]	0.124	0.115	0.102	0.095	0.088	0.081	0.075
2,3W ICE	[kWh_{th}/km]	0.143	0.143	0.143	0.143	0.143	0.143	0.143
2,3W BEV	[kWh_{el}/km]	0.050	0.050	0.050	0.050	0.050	0.050	0.050
BUS ICE	[kWh_{th}/km]	4.023	3.957	3.890	3.826	3.762	3.700	3.638
BUS BEV	[kWh_{el}/km]	1.808	1.744	1.680	1.621	1.563	1.508	1.455
BUS FCEV	[kWh_{H2}/km]	2.987	2.853	2.720	2.598	2.482	2.371	2.265
BUS PHEV	[kWh_{th}/km]	2.012	1.918	1.945	1.913	1.881	1.850	1.819
BUS PHEV	[kWh_{el}/km]	0.904	0.872	0.840	0.810	0.782	0.754	0.727
MDV ICE	[kWh_{th}/km]	2.270	2.144	2.023	1.904	1.796	1.685	1.571
MDV BEV	[kWh_{el}/km]	0.836	0.747	0.668	0.618	0.572	0.529	0.490
MDV FCEV	[kWh_{H2}/km]	1.362	1.286	1.214	1.142	1.078	1.011	0.943
MDV PHEV	[kWh_{th}/km]	1.362	1.286	1.214	1.142	1.078	1.011	0.943
MDV PHEV	[kWh_{el}/km]	0.334	0.299	0.267	0.247	0.229	0.212	0.196
HDV ICE	[kWh_{th}/km]	3.253	3.009	2.784	2.571	2.378	2.192	2.013
HDV BEV	[kWh_{el}/km]	1.671	1.494	1.336	1.236	1.144	1.058	0.979
HDV FCEV	[kWh_{H2}/km]	1.952	1.805	1.670	1.543	1.427	1.315	1.208
HDV PHEV	[kWh_{th}/km]	2.277	2.106	1.949	1.800	1.664	1.534	1.409
HDV PHEV	[kWh_{el}/km]	0.501	0.448	0.401	0.371	0.343	0.318	0.294
Rail passenger liquid fuel	[kWh_{th}/p-km]	0.104	0.102	0.101	0.099	0.098	0.096	0.094

Rail passenger electrical	[kWh_{el}/p-km]	0.065	0.063	0.060	0.058	0.055	0.053	0.050
Rail freight liquid fuel	[kWh_{th}/t-km]	0.063	0.060	0.058	0.056	0.054	0.052	0.050
Rail freight electrical	[kWh_{el}/t-km]	0.032	0.030	0.028	0.026	0.024	0.022	0.019
Aviation passenger liquid fuel	[kWh_{th}/p-km]	0.517	0.490	0.466	0.442	0.419	0.398	0.377
Aviation passenger electrical	[kWh_{el}/p-km]	0.194	0.184	0.175	0.166	0.157	0.149	0.141
Aviation passenger liquid hydrogen	[kWh_{H2}/p-km]	0.335	0.335	0.335	0.318	0.302	0.286	0.271
Aviation freight liquid fuel	[kWh_{th}/t-km]	0.134	0.128	0.121	0.115	0.109	0.104	0.098
Aviation freight liquid hydrogen	[kWh_{el}/t-km]	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Aviation freight electrical	[kWh_{H2}/t-km]	0.087	0.087	0.087	0.083	0.079	0.075	0.071

Table A4. Projected shares of passenger demand by transport mode and vehicle type (Khalili *et al.*, 2019).

Passenger mode and vehicle type	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Road – LDV – BEV	3.0%	10.0%	39.0%	68.0%	74.0%	73.0%	76.0%
Road – LDV – FCEV	0.0%	0.1%	1.0%	2.0%	5.0%	10.0%	10.0%
Road – LDV – ICE	94.0%	79.9%	50.0%	20.0%	11.0%	7.0%	4.0%
Road – LDV – PHEV	3.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Road – BUS – BEV	20.0%	50.0%	80.0%	90.0%	90.0%	90.0%	90.0%
Road – BUS – FCEV	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Road – BUS – ICE	78.9%	47.9%	16.9%	5.9%	4.9%	3.9%	2.9%
Road – BUS – PHEV	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%
Road – 2W/3W – BEV	35.0%	40.0%	60.0%	75.0%	85.0%	90.0%	95.0%
Road – 2W/3W – ICE	65.0%	60.0%	40.0%	25.0%	15.0%	10.0%	5.0%
Rail – electricity	65.60%	70.87%	76.02%	80.29%	84.56%	89.03%	93.50%
Rail – liquid fuel	34.40%	29.13%	23.98%	19.71%	15.44%	10.97%	6.50%
Aviation – electricity	0.0%	0.0%	0.0%	1.2%	4.7%	10.5%	18.7%
Aviation – hydrogen	0.0%	0.0%	0.0%	2.3%	9.3%	21.0%	37.4%

Aviation – liquid fuel	100.0%	100.0%	100.0%	96.5%	86.0%	68.5%	43.9%

Table A5. Projected share of freight demand by transport mode and vehicle type (Khalili *et al.*, 2019).

Freight mode and vehicle type	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Road MDV ICE	88.90%	78.00%	47.00%	16.00%	5.00%	4.0%	3.00%
Road MDV BEV	10.00%	19.00%	48.00%	75.00%	80.00%	80.00%	80.00%
Road MDV FCEV	0.10%	1.00%	2.00%	5.00%	10.00%	10.00%	10.00%
Road MDV PHEV	1.00%	2.00%	3.00%	4.00%	5.00%	6.00%	7.00%
Road HDV ICE	97.50%	88.00%	77.00%	46.00%	12.00%	4.00%	3.00%
Road HDV BEV	1.00%	8.00%	15.00%	30.00%	50.00%	50.00%	50.00%
Road HDV FCEV	0.50%	2.00%	5.00%	20.00%	30.00%	30.00%	30.00%
Road HDV PHEV	1.00%	2.00%	3.00%	4.00%	8.00%	16.00%	17.00%
Rail - electricity	14.70%	24.10%	39.70%	54.30%	68.80%	81.80%	94.70%
Rail - liquid fuel	85.30%	75.90%	60.30%	45.70%	31.20%	18.20%	5.30%
Aviation - liquid fuel	100%	100%	100%	97.70%	90.70%	79.00%	62.60%
Aviation - electricity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Aviation - hydrogen	0.00%	0.00%	0.00%	2.30%	9.30%	21.00%	37.40%

Table A6. Projected final energy demand by sector [TWh].

Sector	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Power	17.36	18.34	19.37	20.46	21.61	22.83	24.11
Heat	55.26	63.83	69.15	74.63	79.93	84.77	90.28
Transport	74.17	66.26	50.56	36.95	31.78	32.01	33.55
Total	146.80	148.43	139.08	132.04	133.32	139.61	147.94

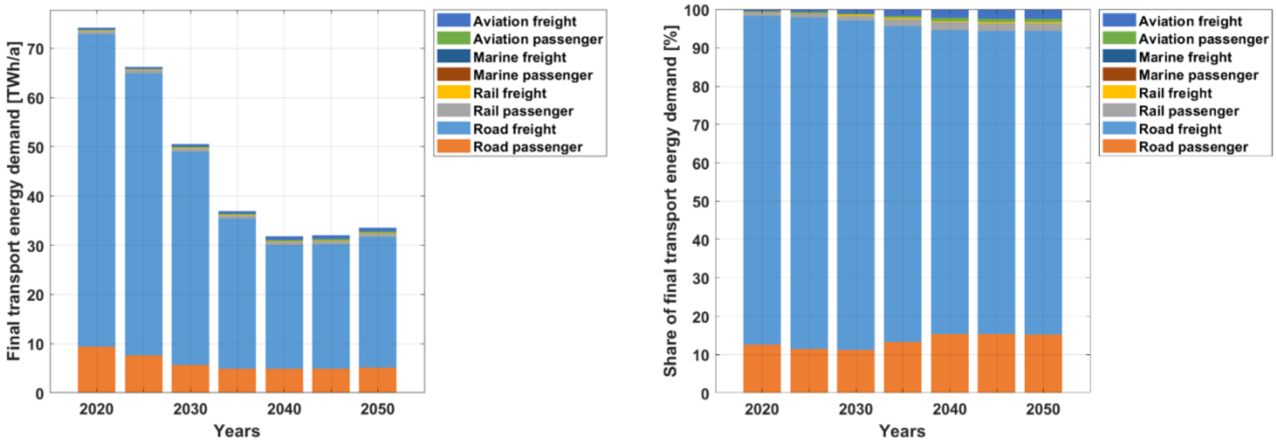

Figure A1. Absolute (left) and relative (right) final transport energy demand by means of transport.

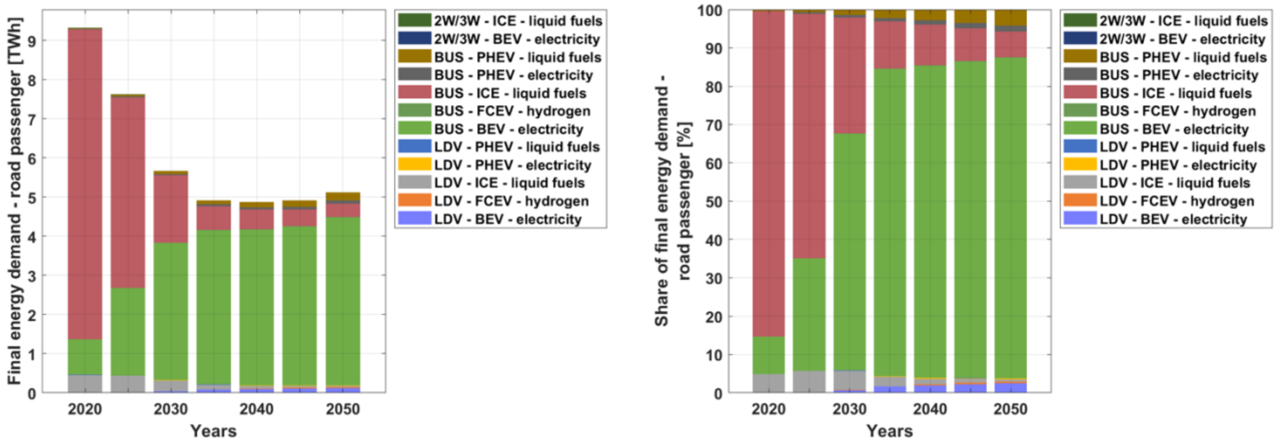

Figure A2. Absolute (left) and relative (right) final energy demand for road passenger transport.

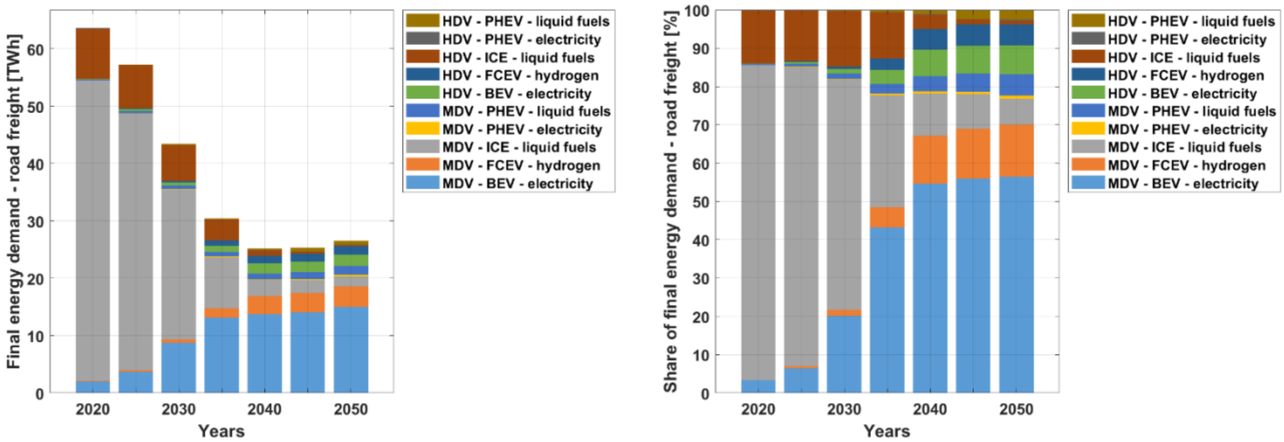

Figure A3. Absolute (left) and relative (right) final energy demand for road freight transport.

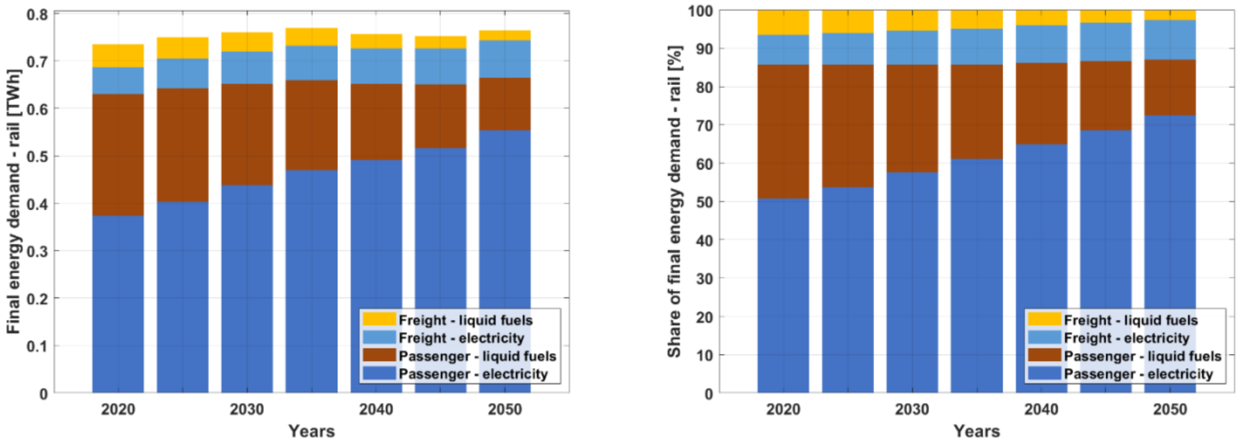

Figure A4. Absolute (left) and relative (right) final energy demand for rail transport.

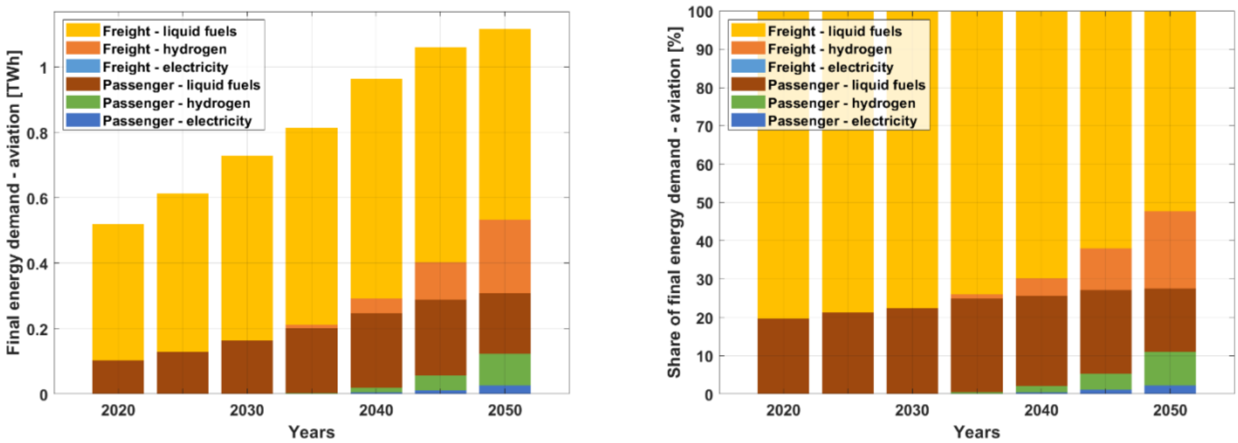

Figure A5. Absolute (left) and relative (right) final energy demand for aviation transport.

Table A7. Financial and technical assumptions of energy system technologies used.

Technologies		**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Source**
PV fixed tilted	Capex	€/kW$_{el}$	475	370	306	237	207	184	166	(ETIP-PV, 2019; Vartiainen *et al.*, 2020), (Mann *et al.*, 2014)
	Opex fix	€/(kW$_{el}$*a)	7.76	6.51	5.66	5	4.47	4.04	3.7	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	30	35	35	35	40	40	40	
PV rooftop – residential	Capex	€/kW$_{el}$	1150	926	787	622	551	496	453	(ETIP-PV, 2019),(Mann *et al.*, 2014)
	Opex fix	€/(kW$_{el}$*a)	9.13	7.66	6.66	5.88	5.26	4.75	4.36	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	30	35	35	35	40	40	40	
	Capex	€/kW$_{el}$	758	598	502	393	345	308	280	

PV rooftop – commercial	Opex fix	€/(kW$_{el}$*a)	9.13	7.66	6.66	5.88	5.26	4.75	4.36	(Mann *et al.*, 2014; ETIP-PV, 2019)
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	30	35	35	35	40	40	40	
PV rooftop – industrial	Capex	€/kW$_{el}$	563	437	362	281	245	217	197	(Mann *et al.*, 2014; ETIP-PV, 2019)
	Opex fix	€/(kW$_{el}$*a)	9.13	7.66	6.66	5.88	5.26	4.75	4.36	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	30	35	35	35	40	40	40	
PV single-axis	Capex	€/kW$_{el}$	523	407	337	261	228	202	183	(Mann *et al.*, 2014; Bolinger, Seel and Lacommare, 2017; ETIP-PV, 2019)
	Opex fix	€/(kW$_{el}$*a)	8.54	7.16	6.23	5.5	4.92	4.44	4.07	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	30	35	35	35	40	40	40	
Wind onshore	Capex	€/kW$_{el}$	1150	1060	1000	965	940	915	900	(EC, 2014; Lazard, 2016; Wiser *et al.*, 2017)
	Opex fix	€/(kW$_{el}$*a)	23	21.2	20	19.3	18.8	18.3	18	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	25	25	25	
Hydro Run-of-River	Capex	€/kW$_{el}$	2560	2560	2560	2560	2560	2560	2560	(EC, 2014)
	Opex fix	€/(kW$_{el}$*a)	76.8	76.8	76.8	76.8	76.8	76.8	76.8	
	Opex var	€/kWh$_{el}$	0.005	0.005	0.005	0.005	0.005	0.005	0.005	
	Lifetime	years	50	50	50	50	50	50	50	
Concentrating Solar Heat	Capex	€/kW$_{th}$	344.5	303.6	274.7	251.1	230.2	211.9	196	(Agora Energiewende, 2014; Haysom *et al.*, 2015; Breyer *et al.*, 2017)
	Opex fix	€/(kW$_{th}$*a)	7.9	7	6.3	5.8	5.3	4.9	4.5	
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	25	25	25	
Residential Solar Heat Collectors - space heating	Capex	€/kW$_{th}$	1214	1179	1143	1071	1000	929	857	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{th}$*a)	14.8	14.8	14.8	14.8	14.8	14.8	14.8	
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0	

	Lifetime	years	25	25	30	30	30	30	30	
Residential Solar Heat Collectors - hot water	Capex	€/kW$_{th}$	485	485	485	485	485	485	485	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{th}$*a)	4.85	4.85	4.85	4.85	4.85	4.85	4.85	
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	15	15	15	15	15	15	15	
Steam turbine (CSP)	Capex	€/kW$_{el}$	968	946	923	902	880	860	840	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{el}$*a)	19.4	18.9	18.5	18	17.6	17.2	16.8	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	30	30	30	30	
	Efficiency	coeff	0.383	0.403	0.43	0.43	0.43	0.43	0.43	
CCGT	Capex	€/kW$_{el}$	775	775	775	775	775	775	775	(IEA, 2016)
	Opex fix	€/(kW$_{el}$*a)	19.375	19.375	19.375	19.375	19.375	19.375	19.375	
	Opex var	€/kWh$_{el}$	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency	coeff	0.58	0.58	0.58	0.59	0.6	0.6	0.6	
CCGT + CCS	Capex	€/kW$_{el}$	2565	2272.5	1980	1845	1710	1640	1570	(IEA, 2016)
	Opex fix	€/(kW$_{el}$*a)	81	72	63	58.5	54	52	50	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency	coeff	0.52	0.525	0.53	0.535	0.54	0.545	0.55	
OCGT	Capex	€/kW$_{el}$	475	475	475	475	475	475	475	(Urban, Lohmann and Girod, 2009)
	Opex fix	€/(kW$_{el}$*a)	14.25	14.25	14.25	14.25	14.25	14.25	14.25	
	Opex var	€/kWh$_{el}$	0.011	0.011	0.011	0.011	0.011	0.011	0.011	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency	coeff	0.4	0.415	0.43	0.435	0.44	0.445	0.45	
	Capex	€/kW$_{el}$	385	385	385	385	385	385	385	

Int Combust Generator	Opex fix	€/(kW$_{el}$*a)	11.5	11.5	11.5	11.5	11.5	11.5	11.5	(Urban, Lohmann and Girod, 2009)
	Opex var	€/kWh$_{el}$	0.0047	0.0047	0.0047	0.0047	0.0047	0.0047	0.0047	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency	coeff	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Int Combust Generator modern Multifuel	Capex	€/kW$_{el}$	569	553	537	522	506	491	475	(Urban, Lohmann and Girod, 2009)
	Opex fix	€/(kW$_{el}$*a)	6.2	6.2	6.2	6.2	6.2	6.2	6.2	
	Opex var	€/kWh$_{el}$	0.011	0.011	0.011	0.011	0.011	0.011	0.011	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency	coeff	0.47	0.47	0.47	0.47	0.47	0.47	0.47	
Coal Power Plant	Capex	€/kW$_{el}$	1600	1600	1600	1600	1600	1600	1600	(McDonald and Schrattenholzer, 2001; IEA, 2016)
	Opex fix	€/(kW$_{el}$*a)	20	20	20	20	20	20	20	
	Opex var	€/kWh$_{el}$	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
	Lifetime	years	45	45	45	45	45	45	45	
	Efficiency	coeff	0.43	0.43	0.43	0.43	0.43	0.43	0.43	
Biomass - new Fluidised bed boiler	Capex	€/kW$_{el}$	2620	2475	2330	2195	2060	1945	1830	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{el}$*a)	47.2	44.6	41.9	39.5	37.1	35	32.9	
	Opex var	€/kWh$_{el}$	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	
	Lifetime	years	25	25	25	25	25	25	25	
	Efficiency	coeff	0.36	0.13505	0.37	0.13875	0.38	0.14245	0.39	
CHP NG Heating	Capex	€/kW$_{el}$	880	880	880	880	880	880	880	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{el}$*a)	74.8	74.8	74.8	74.8	74.8	74.8	74.8	
	Opex var	€/kWh$_{el}$	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency el	coeff	0.36556	0.37278	0.38	0.38342	0.38722	0.39064	0.39444	
	Efficiency he	coeff	0.50986	0.51993	0.53	0.53477	0.54007	0.54484	0.55014	

CHP Oil Heating	Capex	€/kW$_{el}$	880	880	880	880	880	880	880	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{el}$*a)	74.8	74.8	74.8	74.8	74.8	74.8	74.8	
	Opex var	€/kWh$_{el}$	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	0.0024	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency el	coeff	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
	Efficiency he	coeff	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
CHP Coal Heating	Capex	€/kW$_{el}$	2030	2030	2030	2030	2030	2030	2030	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{el}$*a)	46.7	46.7	46.7	46.7	46.7	46.7	46.7	
	Opex var	€/kWh$_{el}$	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	
	Lifetime	years	40	40	40	40	40	40	40	
	Efficiency el	coeff	0.42829	0.43814	0.448	0.45427	0.46099	0.46726	0.47398	
	Efficiency he	coeff	0.41108	0.42054	0.43	0.43602	0.44247	0.44849	0.45494	
CHP Biomass Heating	Capex	€/kW$_{el}$	3400	3300	3200	3125	3050	2975	2900	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{el}$*a)	97.6	94.95	92.3	90.8	89.3	87.8	86.3	
	Opex var	€/kWh$_{el}$	0.0038	0.00375	0.0037	0.003725	0.00375	0.003775	0.0038	
	Lifetime	years	25	25	25	25	25	25	25	
	Efficiency el	coeff	0.65103	0.65214	0.65324	0.65048	0.64772	0.64497	0.64221	
	Efficiency he	coeff	0.295	0.2955	0.296	0.29475	0.2935	0.29225	0.291	
CHP Biogas	Capex	€/kW$_{el}$	429.2	399.6	370	340.4	325.6	310.8	296	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{el}$*a)	17.168	15.984	14.8	13.616	13.024	12.432	11.84	
	Opex var	€/kWh$_{el}$	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
	Lifetime	years	30	30	30	30	30	30	30	

	Efficiency el	coeff	0.43023	0.46512	0.5	0.52326	0.54651	0.55233	0.55814	
	Efficiency he	coeff	0.34419	0.37209	0.4	0.4186	0.43721	0.44186	0.44651	
Municipal Solid Waste Incinerator	Capex	€/kW$_{el}$	5630	5440	5240	5030	4870	4690	4540	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{el}$*a)	253.35	244.8	235.8	226.35	219.15	211.05	204.3	
	Opex var	€/kWh$_{el}$	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency el	coeff	0.71	0.71	0.71	0.71	0.71	0.71	0.71	
	Efficiency he	coeff	0.26	0.26	0.26	0.26	0.26	0.26	0.26	
DH Rod Heating	Capex	€/kW$_{th}$	100	100	75	75	75	75	75	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{th}$*a)	1.47	1.47	1.47	1.47	1.47	1.47	1.47	
	Opex var	€/kWh$_{th}$	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency	coeff	1	1	1	1	1	1	1	
DH Heat Pump	Capex	€/kW$_{th}$	660	618	590	568	554	540	530	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{th}$*a)	2	2	2	2	2	2	2	
	Opex var	€/kWh$_{th}$	0.0018	0.0017	0.0017	0.0016	0.0016	0.0016	0.0016	
	Lifetime	years	25	25	25	25	25	25	25	
	Efficiency	coeff	3.29142	10.8836	3.47427	26.8042	11.6443	22.102	3.74858	
DH NG Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{th}$*a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency	coeff	0.97	0.97	0.97	0.97	0.97	0.97	0.97	
	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	(Ram *et al.*, 2019)

DH Oil Heating	Opex fix	€/(kW$_{th}$*a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency	coeff	0.97	0.97	0.97	0.97	0.97	0.97	0.97	
DH Coal Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{th}$*a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency	coeff	0.97	0.97	0.97	0.97	0.97	0.97	0.97	
DH Biomass Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{th}$*a)	2.8	2.8	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015	0.00015	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency	coeff	0.97	0.97	0.97	0.97	0.97	0.97	0.97	
Local Rod Heating	Capex	€/kW$_{th}$	100	100	100	100	100	100	100	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{th}$*a)	2	2	2	2	2	2	2	
	Opex var	€/kWh$_{th}$	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency	coeff	1	1	1	1	1	1	1	
Local Heat Pump	Capex	€/kW$_{th}$	780	750	730	706	690	666	650	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{th}$*a)	15.6	15	7.3	7.1	6.9	6.7	6.5	
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
	Efficiency	coeff	4.70079	4.87085	4.98425	5.14157	5.24646	5.35131	5.42124	
Local NG Heating	Capex	€/kW$_{th}$	800	800	800	800	800	800	800	(Ram *et al.*, 2019)
	Opex fix	€/(kW$_{th}$*a)	27	27	27	27	27	27	27	

	Opex var	€/kWh_{th}	0	0	0	0	0	0	0	
	Lifetime	years	22	22	22	22	22	22	22	
	Efficiency	coeff	0.95	0.95	0.95	0.95	0.95	0.95	0.95	
Local Oil Heating	Capex	€/kW_{th}	440	440	440	440	440	440	440	(Ram *et al.*, 2019)
	Opex fix	€/(kW_{th}*a)	18	18	18	18	18	18	18	
	Opex var	€/kWh_{th}	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
	Efficiency	coeff	0.95	0.95	0.95	0.95	0.95	0.95	0.95	
Local Biomass Heating	Capex	€/kW_{th}	675	675	750	750	750	750	750	(Ram *et al.*, 2019)
	Opex fix	€/(kW_{th}*a)	2	2	3	3	3	3	3	
	Opex var	€/kWh_{th}	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
	Efficiency	coeff	1.03313	1.03313	1.08063	1.08063	1.08063	1.12813	1.12813	
Local Biogas Heating	Capex	€/kW_{th}	800	800	800	800	800	800	800	(Ram *et al.*, 2019)
	Opex fix	€/(kW_{th}*a)	27	27	27	27	27	27	27	
	Opex var	€/kWh_{th}	0	0	0	0	0	0	0	
	Lifetime	years	22	22	22	22	22	22	22	
	Efficiency	coeff	0.95	0.95	0.95	0.95	0.95	0.95	0.95	
Water Electrolysis	Capex	€/kW_{H2}	685	500	380	325	296	267	248	(Hoffmann, 2014; Breyer *et al.*, 2015)
	Opex fix	€/kW_{H2}*a	23.98	17.5	13.3	11.38	10.36	9.35	8.68	
	Opex var	€/kWh_{H2}	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency	coeff	0.822	0.822	0.822	0.822	0.822	0.822	0.822	
CO_2 direct air capture	Capex	€/(tCO_2*a)	730	481	338	281	237	217	199	(Svensson *et al.*, 2004)
	Opex fix	€/(tCO_2*a)	29.2	19.2	13.5	11.2	9.5	8.7	8	
	Opex var	€/$kgCO_2$	0	0	0	0	0	0	0	

	Lifetime	years	20	30	25	30	30	30	30	
	CO_2 scrubbing efficiency	kWh_{el}/tCO_2	242	236	225	214	203	192	182	
		kWh_{th}/tCO_2	1670	1590	1500	1393	1286	1194	1102	
Methanation	Capex	€/kW_{SNG}	502	368	278	247	226	204	190	(Hoffmann, 2014; Breyer *et al.*, 2015)
	Opex fix		23.09	16.93	12.79	11.36	10.4	9.38	8.74	
	Opex var	€/MWh_{SNG}	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency	coeff	0.778	0.778	0.778	0.778	0.778	0.778	0.778	
Biogas digester	Capex	€/kW_{th}	730.611	705.954	680	652.748	631.985	608.626	589.16	(Ram *et al.*, 2019)
	Opex fix	€/(kW_{th}*a)	29.2244	28.2382	27.2	26.1099	25.2794	24.345	23.5664	
	Opex var	€/kWh_{th}	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	25	25	25	25	
Biogas Upgrade	Capex	€/kW_{th}	290	270	250	230	220	210	200	(Kutscher *et al.*, 2010)
	Opex fix	€/(kW_{th}*a)	23.2	21.6	20	18.4	17.6	16.8	16	
	Opex var	€/kWh_{th}	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
	Efficiency	coeff	0.98	0.98	0.98	0.98	0.98	0.98	0.98	
Fischer-Tropsch unit	Capex	€/kW_{FTLiq}	947	947	947	947	852.3	852.3	852.3	(Ram *et al.*, 2019)
	Opex fix	€/kW_{FTLiq}	28.41	28.41	28.41	28.41	25.57	25.57	25.57	
	Opex var	€/kWh_{FTLiq}	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency	coeff	0.6338	0.6338	0.6338	0.6338	0.6338	0.6338	0.6338	
Gas Liquifaction	Capex	€/kW_{Liq}	181.1	181.1	181.1	181.1	181.1	181.1	181.1	(Schwartz, 2011; Ainscough and Leachman, 2017; Ram *et al.*, 2019)
	Opex fix	€/kW_{Liq}	6.34	6.34	6.34	6.34	6.34	6.34	6.34	
	Opex var	€/kWh_{Liq}	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	25	25	25	

	Efficiency	coeff	0.987	0.987	0.987	0.987	0.987	0.987	0.987	
H_2 Liqiufaction	Capex	€/kW_{Liq}	358.1	358.1	358.1	175.9	152.9	145.2	137.9	(Schwartz, 2011; IEA, 2015; Ainscough and Leachman, 2017)
	Opex fix	€/kW_{Liq}	14.32	14.32	14.32	7.03	6.11	5.81	5.52	
	Opex var	€/kWh_{Liq}	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency	coeff	0.983	0.983	0.983	0.983	0.983	0.983	0.983	
Steam Methane Reforming	Capex	€/kW_{H2}	320	320	320	320	320	320	320	(IEA, 2015)
	Opex fix	€/kW_{H2}	16	16	16	16	16	16	16	
	Opex var	€/kWh_{H2}	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency	coeff	0.845	0.845	0.845	0.845	0.845	0.845	0.845	
Battery utility-scale Storage	Capex	€/kWh_{el}	234	153	110	89	76	68	61	(Giuliano *et al.*, 2016; ETIP-PV, 2019; Vartiainen *et al.*, 2020)
	Opex fix	€/(kWh_{el}*a)	3.28	2.6	2.2	2.05	1.9	1.77	1.71	
	Opex var	€/kWh_{el}	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
	Round-trip	coeff	0.91	0.92	0.93	0.94	0.95	0.95	0.95	
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
Battery utility-scale Interface	Capex	€/kW_{el}	117	76	55	44	37	33	30	(Giuliano *et al.*, 2016; ETIP-PV, 2019; Vartiainen *et al.*, 2020)
	Opex fix	€/(kW_{el}*a)	1.64	1.29	1.1	1.01	0.93	0.86	0.84	
	Opex var	€/kWh_{el}	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
Battery PV prosumer residential Storage	Capex	€/kWh_{el}	462	308	224	182	156	140	127	(ETIP-PV, 2019; Vartiainen *et al.*, 2020)
	Opex fix	€/(kWh_{el}*a)	5.08	4	3.36	3.09	2.81	2.8	2.54	
	Opex var	€/kWh_{el}	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
	Round-trip	coeff	0.91	0.92	0.93	0.94	0.95	0.95	0.95	

	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
Battery PV prosumer residential Interface	Capex	€/kW$_{el}$	231	153	112	90	76	68	62	(ETIP-PV, 2019; Vartiainen *et al.*, 2020)
	Opex fix	€/(kW$_{el}$*a)	2.54	1.99	1.68	1.53	1.37	1.36	1.24	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
Battery PV prosumer commercial Storage	Capex	€/kWh$_{el}$	366	240	175	141	121	108	98	(ETIP-PV, 2019; Vartiainen *et al.*, 2020)
	Opex fix	€/(kWh$_{el}$*a)	4.39	3.6	2.98	2.68	2.54	2.38	2.25	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
	Round-trip	coeff	0.91	0.92	0.93	0.94	0.95	0.95	0.95	
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
Battery PV prosumer commercial Interface	Capex	€/kW$_{el}$	183	119	88	70	59	53	48	(ETIP-PV, 2019; Vartiainen *et al.*, 2020)
	Opex fix	€/(kW$_{el}$*a)	2.2	1.79	1.5	1.33	1.24	1.17	1.1	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
Battery PV prosumer industrial Storage	Capex	€/kWh$_{el}$	278	181	131	105	90	80	72	(ETIP-PV, 2019; Vartiainen *et al.*, 2020)
	Opex fix	€/(kWh$_{el}$*a)	3.89	3.08	2.62	2.42	2.25	2.08	1.94	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
	Round-trip	coeff	0.91	0.92	0.93	0.94	0.95	0.95	0.95	
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
Battery PV prosumer industrial Interface	Capex	€/kW$_{el}$	139	90	66	52	44	39	35	(ETIP-PV, 2019; Vartiainen *et al.*, 2020)
	Opex fix	€/(kW$_{el}$*a)	1.95	1.53	1.32	1.2	1.1	1.01	0.95	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	

PHES Storage	Capex	€/kWh$_{el}$	7.7	7.7	7.7	7.7	7.7	7.7	7.7	(EC, 2014)
	Opex fix	€/(kWh$_{el}$*a)	1.335	1.335	1.335	1.335	1.335	1.335	1.335	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	
	Round-trip	coeff	0.85	0.85	0.85	0.85	0.85	0.85	0.85	
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
PHES Interface	Capex	€/kW$_{el}$	650	650	650	650	650	650	650	(EC, 2014)
	Opex fix	€/(kW$_{el}$*a)	0	0	0	0	0	0	0	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	
A-CAES Storage	Capex	€/kWh$_{el}$	35	32.6	31.1	30.3	29.8	27.7	26.3	(EC, 2014)
	Opex fix	€/(kWh$_{el}$*a)	0.533	0.49634	0.4732	0.46124	0.4537	0.42172	0.4004	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	55	55	55	55	55	55	55	
	Round-trip	coeff	0.59	0.65	0.70	0.70	0.70	0.70	0.70	
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
A-CAES Interface	Capex	€/kW$_{el}$	600	558	530	518	510	474	450	(EC, 2014)
	Opex fix	€/(kW$_{el}$*a)	0	0	0	0	0	0	0	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	55	55	55	55	55	55	55	
Hot Heat Storage	Capex	€/kWh$_{th}$	41.8	32.7	26.8	23.3	21	19.3	17.5	(Ram *et al.*, 2019)
	Opex fix	€/(kWh$_{th}$*a)	0.63	0.49	0.4	0.35	0.32	0.29	0.26	
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	30	30	30	30	
	Round-trip	coeff	0.9	0.9	0.9	0.9	0.9	0.9	0.9	

	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
Hot Heat Storage Interface	Capex	€/kW_{th}	0	0	0	0	0	0	0	(Ram *et al.*, 2019)
	Opex fix	€/(kW_{th}*a)	0	0	0	0	0	0	0	
	Opex var	€/kW_{th}	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	30	30	30	30	
Hydrogen Storage	Capex	€/kWh_{th}	0.24	0.24	0.24	0.24	0.24	0.24	0.24	(BNEF, 2015)
	Opex fix	€/(kWh_{th}*a)	0.0096	0.0096	0.0096	0.0096	0.0096	0.0096	0.0096	
	Opex var	€/kWh_{th}	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	
	Lifetime	years	30	30	30	30	30	30	30	
	Round-trip	coeff	1	1	1	1	1	1	1	
	Self-discharge	coeff	0	0	0	0	0	0	0	
Hydrogen Storage Interface	Capex	€/kW_{th}	100	100	100	100	100	100	100	(BNEF, 2015)
	Opex fix	€/(kW_{th}*a)	4	4	4	4	4	4	4	
	Opex var	€/kW_{th}	0	0	0	0	0	0	0	
	Lifetime	years	15	15	15	15	15	15	15	
CO_2 Storage	Capex	€/ton	142	142	142	142	142	142	142	(Svensson *et al.*, 2004)
	Opex fix	€/(ton*a)	9.94	9.94	9.94	9.94	9.94	9.94	9.94	
	Opex var	€/ton	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	
	Lifetime	years	30	30	30	30	30	30	30	
	Round-trip	coeff	1	1	1	1	1	1	1	
	Self-discharge	coeff	0	0	0	0	0	0	0	
CO_2 Storage Interface	Capex	€/ton/h	0	0	0	0	0	0	0	(Svensson *et al.*, 2004)
	Opex fix	€/(ton/h*a)	0	0	0	0	0	0	0	
	Opex var	€/ton	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	

Gas Storage	Capex	€/kWh$_{th}$	0.05	0.05	0.05	0.05	0.05	0.05	0.05	(BNEF, 2015), (Michalski *et al.*, 2017)
	Opex fix	€/(kWh$_{th}$*a)	0.001	0.001	0.001	0.001	0.001	0.001	0.001	
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	
	Round-trip	coeff	1	1	1	1	1	1	1	
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
Gas Storage Interface	Capex	€/kW$_{th}$	25.8	25.8	25.8	25.8	25.8	25.8	25.8	(BNEF, 2015), (Michalski *et al.*, 2017)
	Opex fix	€/(kW$_{th}$*a)	31	31	31	31	31	31	31	
	Opex var	€/kW$_{th}$	36.2	36.2	36.2	36.2	36.2	36.2	36.2	
	Lifetime	years	41.4	41.4	41.4	41.4	41.4	41.4	41.4	
	Efficiency	coeff	46.6	46.6	46.6	46.6	46.6	46.6	46.6	
District Heat Storage	Capex	€/kWh$_{th}$	40	30	30	25	20	20	20	(Ram *et al.*, 2019), (BNEF, 2015)
	Opex fix	€/(kWh$_{th}$*a)	0.6	0.45	0.45	0.375	0.3	0.3	0.3	
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	30	30	30	30	
	Round-trip	coeff	0.9	0.9	0.9	0.9	0.9	0.9	0.9	
	Self-discharge	coeff	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
District Heat Storage Interface	Capex	€/kW$_{th}$	0	0	0	0	0	0	0	(Ram *et al.*, 2019), (BNEF, 2015)
	Opex fix	€/(kW$_{th}$*a)	0	0	0	0	0	0	0	
	Opex var	€/kW$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	30	30	30	30	
HVDC Transmission Line	Capex	€/(kW*km)	0.9233	0.9233	0.9233	0.9233	1.0467	1.0467	1.0467	(Bogdanov and Breyer, 2016)
	Opex fix	€/(kW*km)	0.0015	0.0015	0.0015	0.0015	0.0019	0.0019	0.0019	
	Opex var	€/(kWh*km)	0	0	0	0	0	0	0	
	Lifeteime	year	50	50	50	50	50	50	50	

	Efficiency	coeff	0.934	0.934	0.934	0.934	0.984	0.984	0.984	
HVDC Transmission Line (Cable)	Capex	€/(kW*km)	1.2333	1.2333	1.2333	1.2333	1.3667	1.3667	1.3667	(Zickfeld *et al.*, 2012; Bogdanov and Breyer, 2016)
	Opex fix	€/(kW*km)	0.0012	0.0012	0.0012	0.0012	0.0014	0.0014	0.0014	
	Opex var	€/(kWh*km)	0	0	0	0	0	0	0	
	Lifeteime	year	50	50	50	50	50	50	50	
	Efficiency	coeff	0.934	0.934	0.934	0.934	0.984	0.984	0.984	
HVDC Transmission Line (Overhead)	Capex	€/(kW*km)	0.2	0.2	0.2	0.2	0.3	0.3	0.3	(Bogdanov and Breyer, 2016)
	Opex fix	€/(kW*km)	0.002	0.002	0.002	0.002	0.003	0.003	0.003	
	Opex var	€/(kWh*km)	0	0	0	0	0	0	0	
	Lifeteime	year	50	50	50	50	50	50	50	
	Efficiency	coeff	0.934	0.934	0.934	0.934	0.984	0.984	0.984	
HVAC Transmission Line	Capex	€/(kW*km)	0.4576	0.4576	0.4576	0.4576	0.4576	0.4576	0.4576	(Zickfeld *et al.*, 2012; Bogdanov and Breyer, 2016)
	Opex fix	€/(kW*km)	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	
	Opex var	€/(kWh*km)	0	0	0	0	0	0	0	
	Lifeteime	year	50	50	50	50	50	50	50	
	Efficiency	coeff	0.906	0.906	0.906	0.906	0.906	0.906	0.906	
Converter Station	Capex	€/(kW)	150	150	150	150	180	180	180	(Zickfeld *et al.*, 2012; Bogdanov and Breyer, 2016)
	Opex fix	€/(kW)	1.5	1.5	1.5	1.5	1.8	1.8	1.8	
	Opex var	€/(kWh)	0	0	0	0	0	0	0	
	Lifeteime	year	50	50	50	50	50	50	50	
	Efficiency	coeff	0.986	0.986	0.986	0.986	0.986	0.986	0.986	

Table A8. Financial assumptions for the fossil fuel price and GHG emission cost.

Component	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Sources**
Coal	€/MWh_{th}	7.7	8.4	9.2	10.2	11.1	11.1	11.1	(Edwards *et al.*, 1996)
Oil	€/MWh_{th}	35.24	39.82	44.40	43.94	43.48	43.48	43.48	(Urban, Lohmann and Girod, 2009)

Natural gas	€/MWh_{th}	22.2	30	32.7	36.1	40.2	40.2	40.2	(Edwards *et al.*, 1996)
GHG emissions	€/CO_{2eq}	28	52	61	68	75	100	150	(Edwards *et al.*, 1996)

Table A9. Well-to-wheel GHG emissions by fuel type.

Fuel	**GHG emissions [tCO_{2eq}/MWh_{th}]**	**Source**
Coal	0.389	(EPA, 2013)
Oil	0.387	(EPA, 2013)
Natural gas	0.283	(Zickfeld *et al.*, 2012)

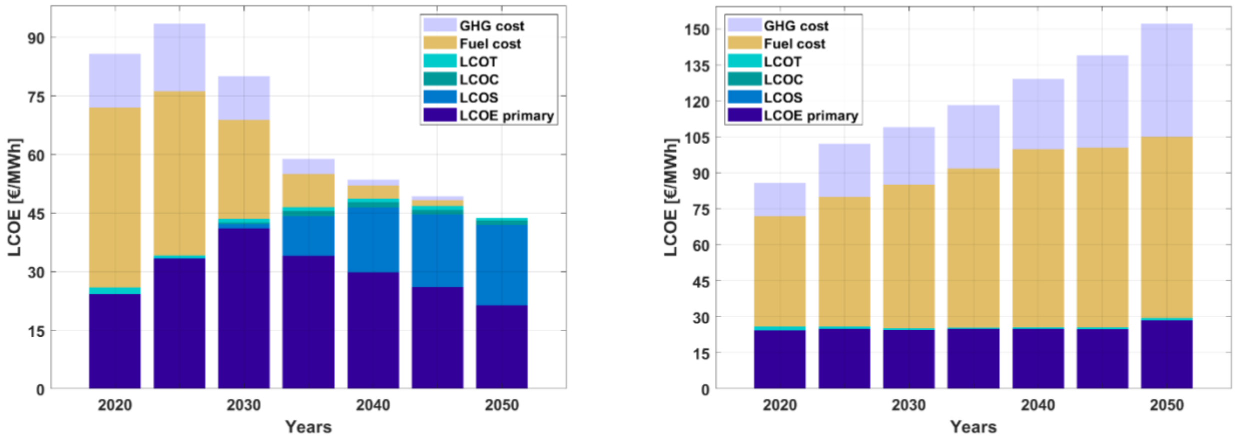

Figure A6. Levelised cost of electricity components in BPS-5 (left) and CPS (right).

Table A10. Levelised cost of electricity components in the BPS-5 [€/MWh].

LCOE	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
LCOE primary	24.3	33.4	41.1	34	29.8	26	21.5
LCOS	0	0.2	1	10.2	16.6	18.6	20.6
LCOC	0	0	0.5	1.5	1.4	1.2	1.1
LCOT	1.6	0.7	0.9	0.8	1	0.9	0.7
Fuel cost	46.1	42	25.3	8.5	3.3	1.6	0
GHG cost	13.8	17.3	11.2	3.8	1.5	0.9	0
Total	**85.8**	**93.6**	**80**	**58.8**	**53.6**	**49.2**	**43.9**

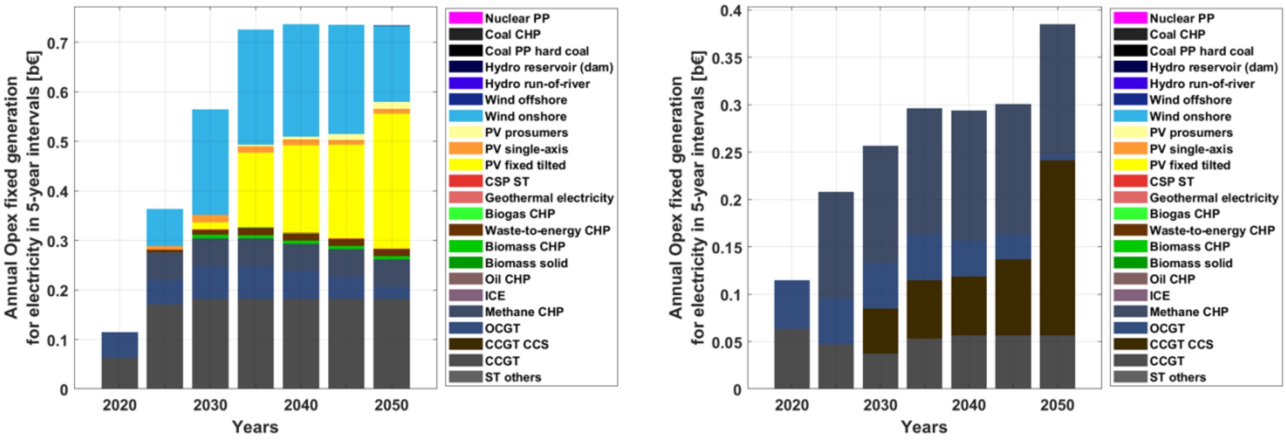

Figure A7. Annual fixed operational expenditures for electricity by technology in BPS-5 (left) and CPS (right).

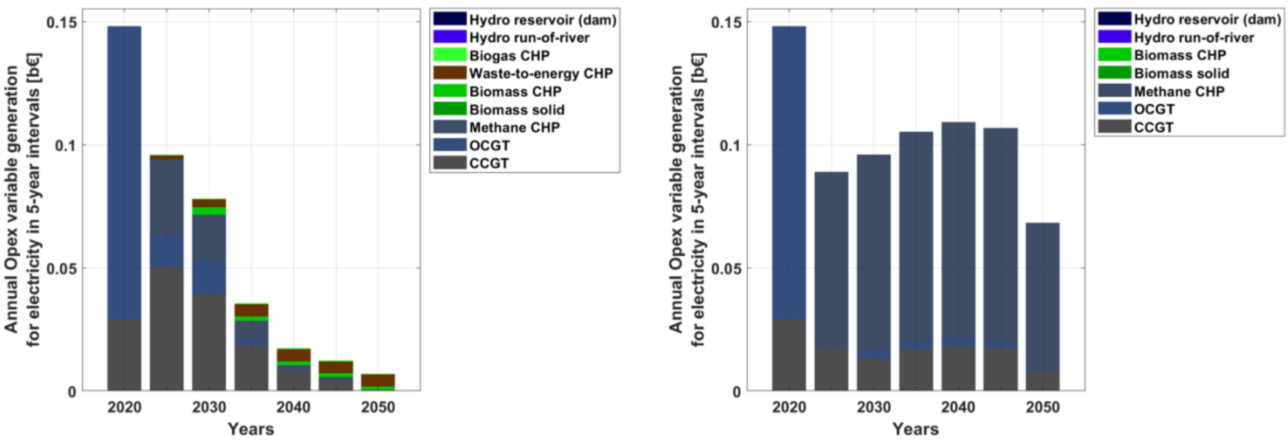

Figure A8. Annual variable operational expenditures for electricity by technology in BPS-5 (left) and CPS (right).

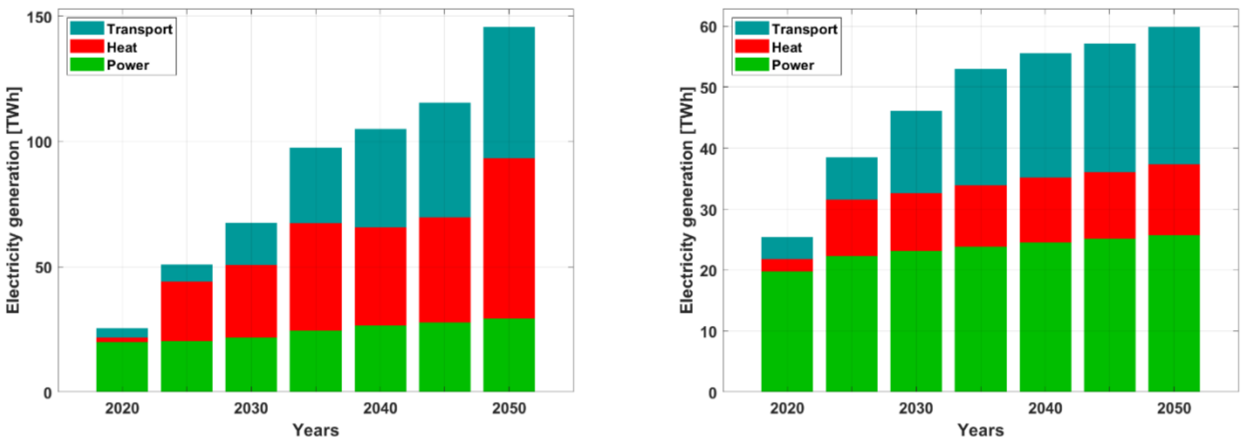

Figure A9. Electricity generation by sector in BPS-5 (left) and CPS (right).

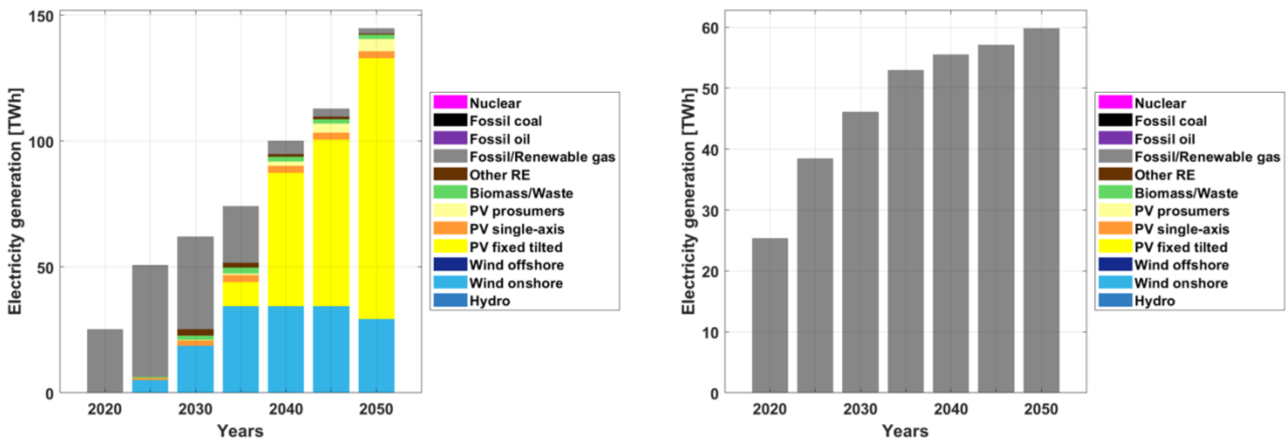

Figure A10. Electricity generation by technology in BPS-5 (left) and CPS (right).

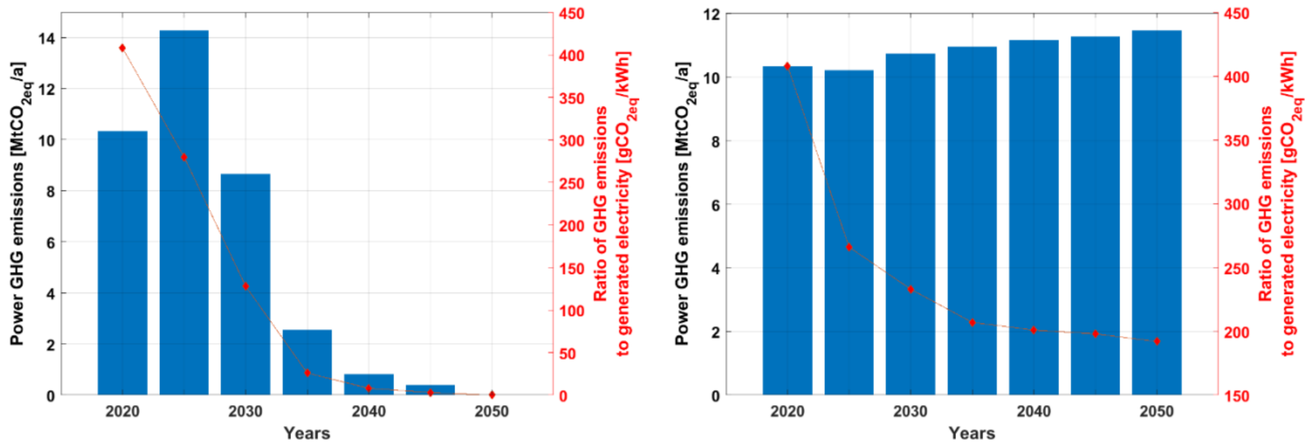

Figure A11. GHG emissions in the power sector and ratio of GHG emissions to generated electricity in BPS-5 (left) and CPS (right).

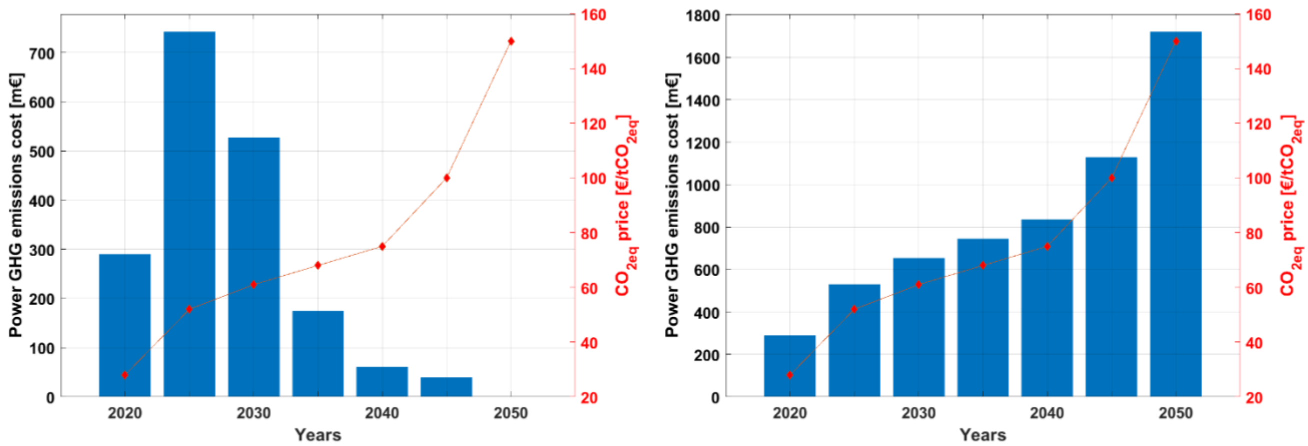

Figure A12. Cost of GHG emissions in the power sector and cost of CO_{2eq} emissions in BPS-5 (left) and CPS (right).

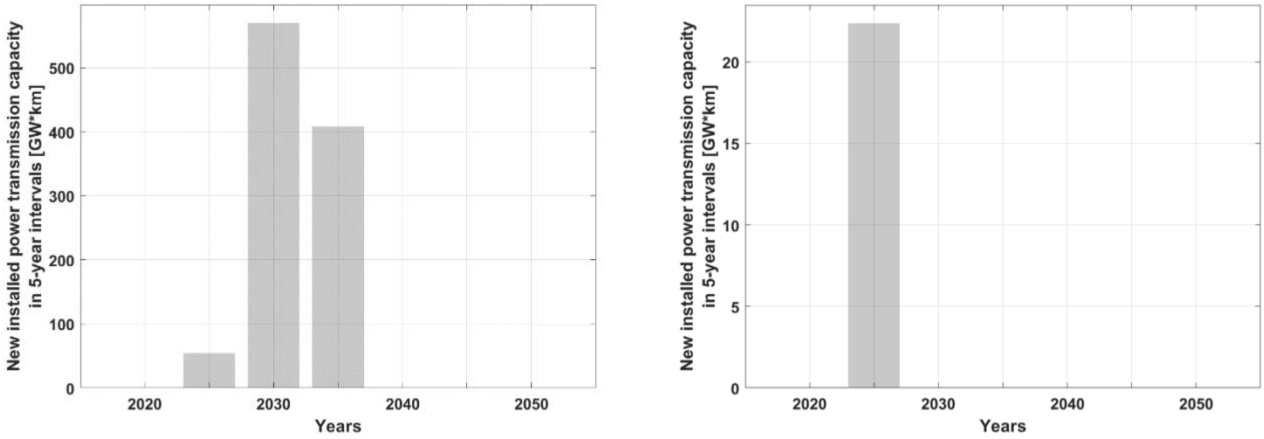

Figure A13. New installed power transmission capacity in BPS-5 (left) and CPS (right).

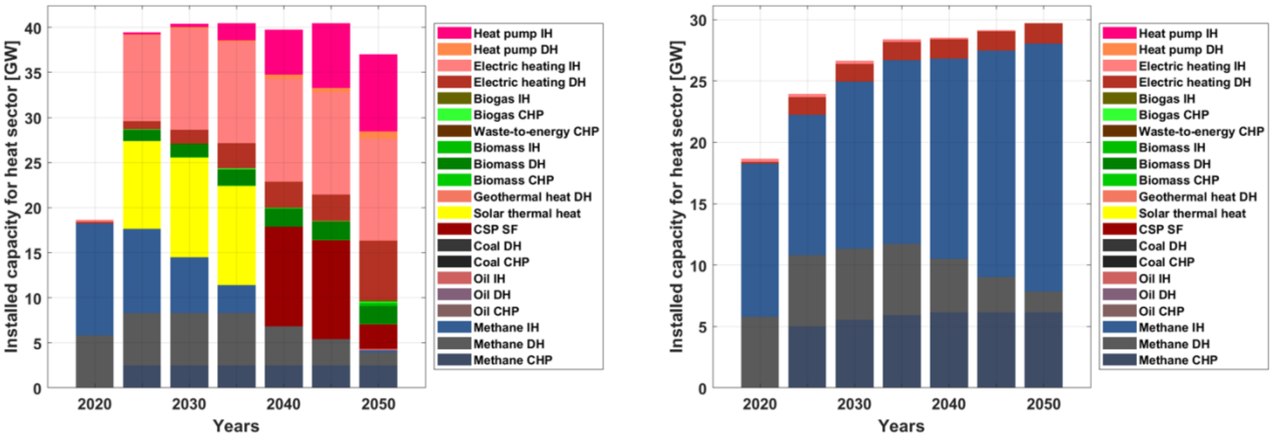

Figure A14. Installed capacity for the heat sector in BPS-5 (left) and CPS (right).

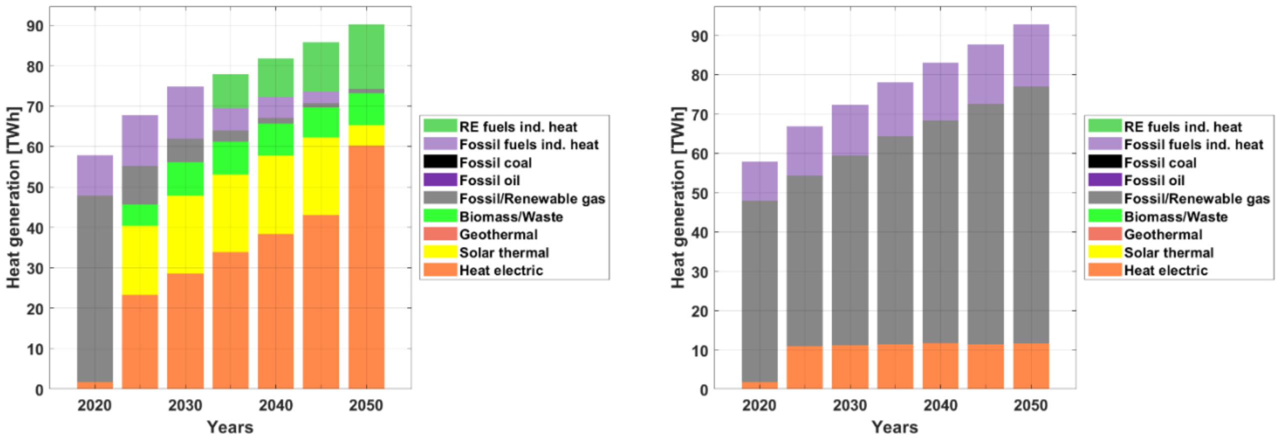

Figure A15. Heat generation by source in BPS-5 (left) and CPS (right).

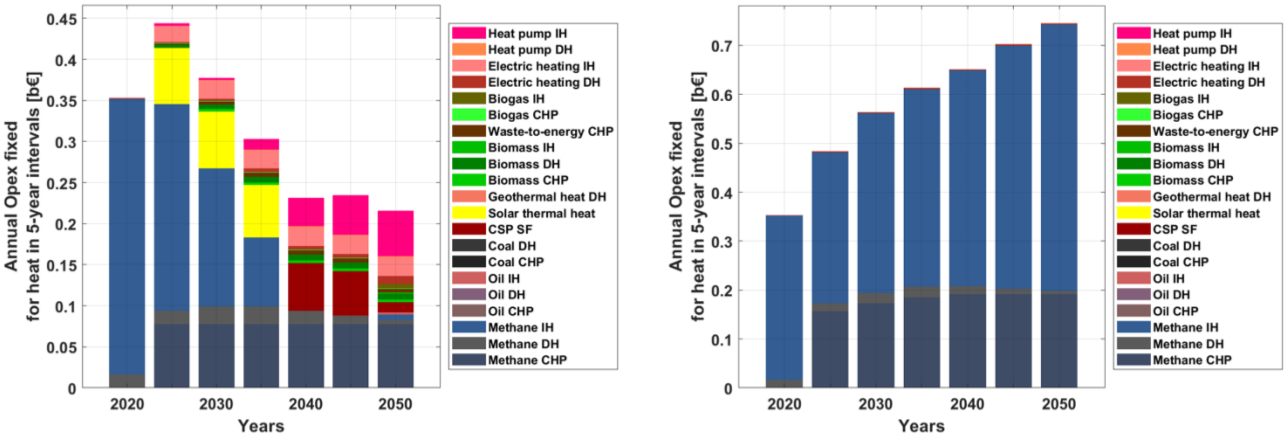

Figure A16. Annual fixed operational expenditures for heat in BPS-5 (left) and CPS (right).

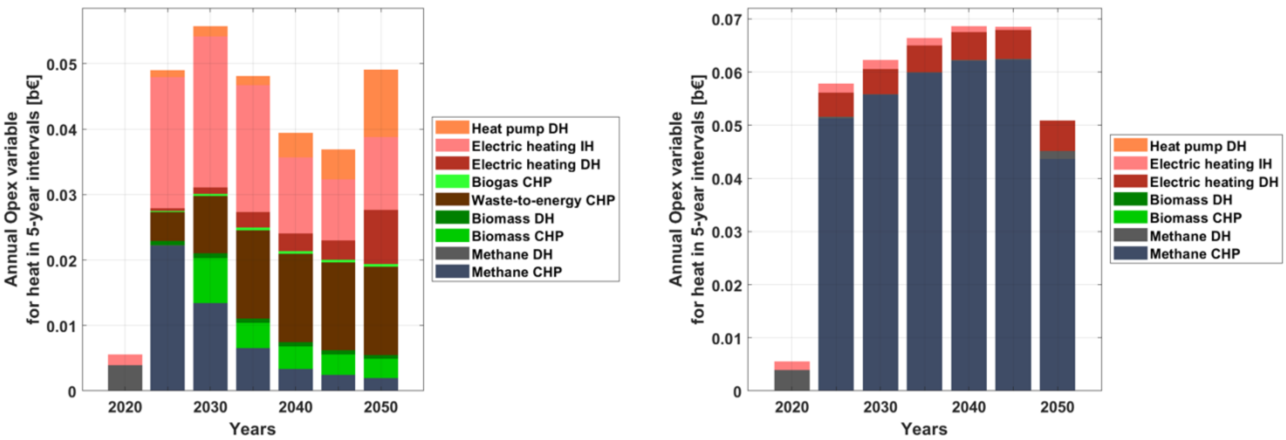

Figure A17. Annual variable operational expenditures for heat in BPS-5 (left) and CPS (right).

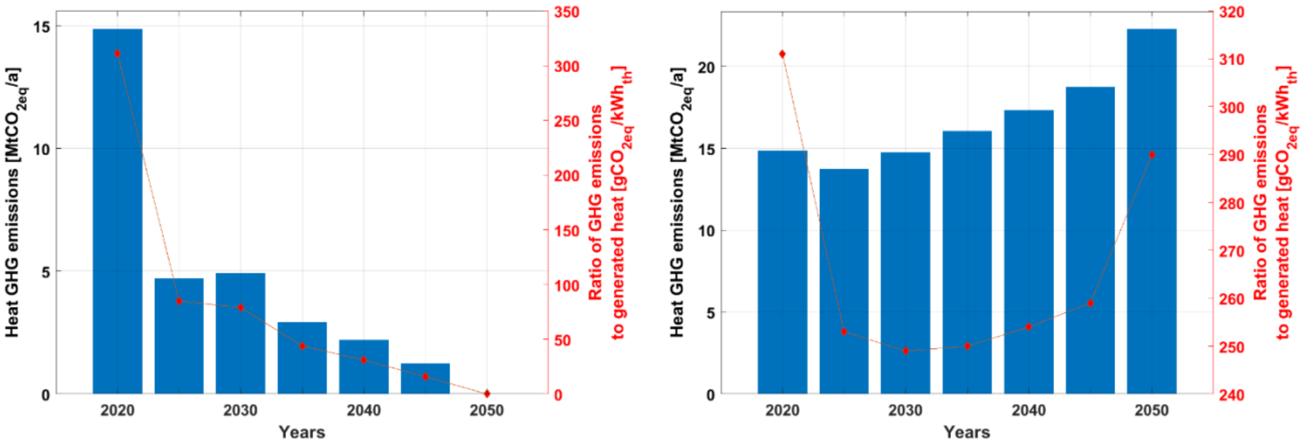

Figure A18. GHG emissions in the heat sector and ratio of GHG emissions to generation heat in BPS-5 (left) and CPS (right).

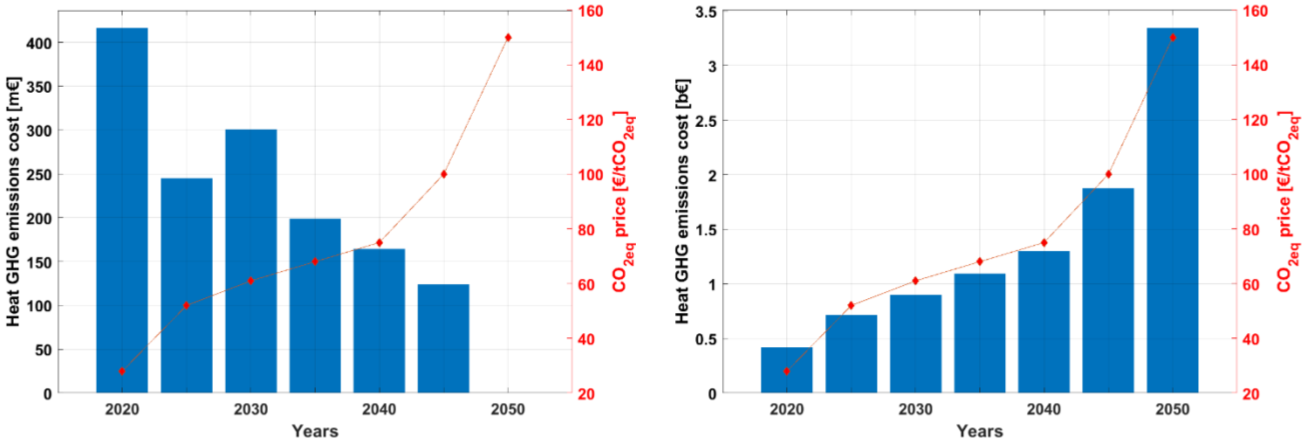

Figure A19. Cost of GHG emissions in the heat sector and cost of CO2eq emissions in BPS-5 (left) and CPS (right).

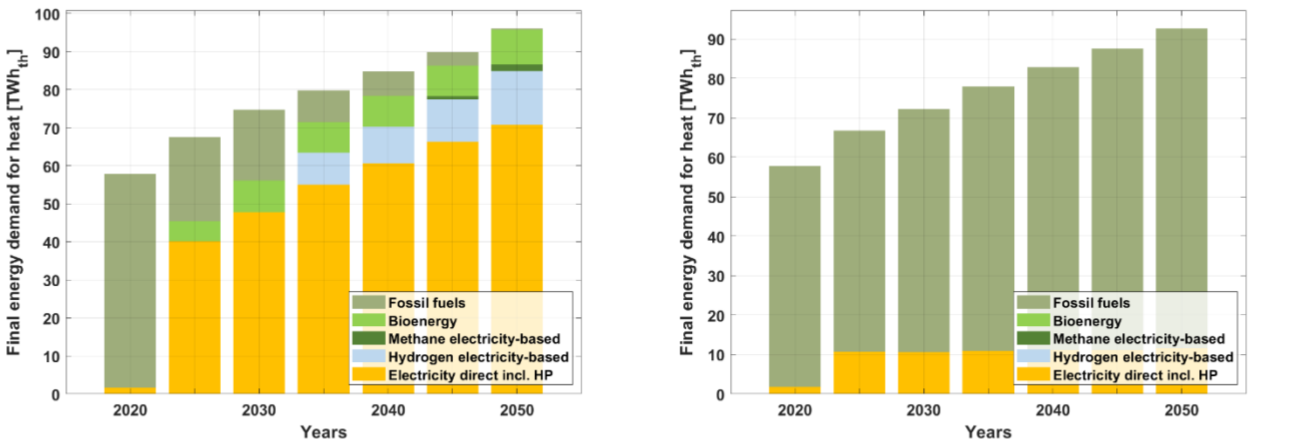

Figure A20. Fuel energy demand for heat by fuel in BPS-5 (left) and CPS (right).

Table A11. Final energy demand for heat by fuel in BPS-5 [TWh_{th}].

Source	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Electricity direct incl. HP	1.7	40.2	47.8	55	60.7	66.3	70.8
Hydrogen electricity-based	0	0	0	8.4	9.5	11.1	14.1
Methane electricity-based	0	0	0	0	0	0.8	1.8
Bioenergy	0	5.2	8.3	8.1	8.2	8.1	9.1
Fossil fuels	56.2	22.1	18.7	8.2	6.5	3.6	0.3
Total	**57.9**	**67.5**	**74.8**	**79.7**	**84.9**	**89.9**	**96.1**

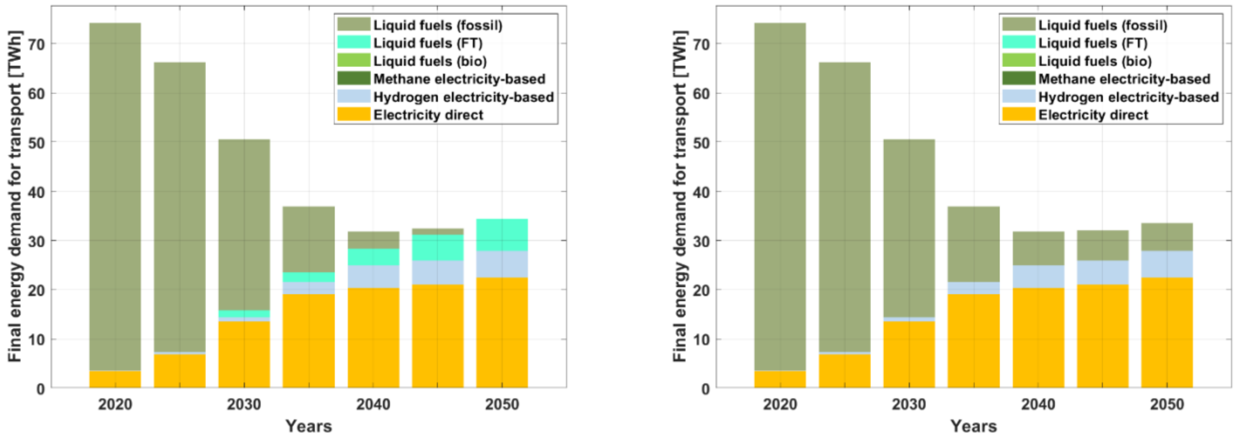

Figure A21. Fuel energy demand for transport by fuel in BPS-5 (left) and CPS (right).

Table A12. Final energy demand for transport by fuel in BPS-5 [TWh].

Fuel	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Electricity direct	3.5	6.8	13.5	19	20.4	21	22.4
Hydrogen electricity-based	0.1	0.4	0.9	2.5	4.5	4.9	5.4
Methane electricity-based	0	0	0	0	0	0	0
Liquid fuels (bio)	0	0	0	0	0	0	0
Liquid fuels (FT)	0	0	1.4	1.9	3.4	5.3	6.6
Liquid fuels (fossil)	70.6	59	34.8	13.5	3.4	1.2	0
Total	**74.2**	**66.2**	**50.6**	**36.9**	**31.7**	**32.4**	**34.4**

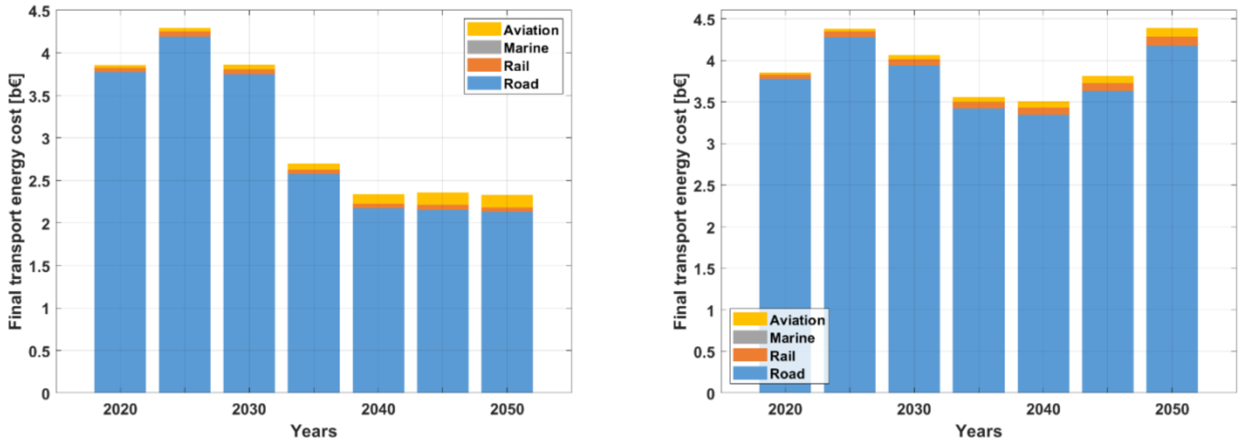

Figure A22. Final transport energy cost in BPS-5 (left) and CPS (right).

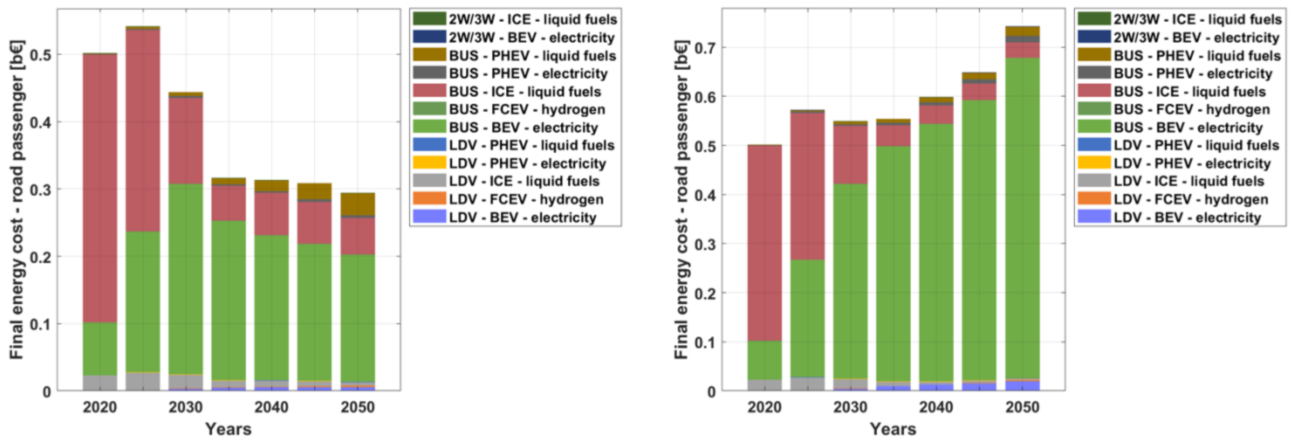

Figure A23. Final energy cost for road passenger transport in BPS-5 (left) and CPS (right).

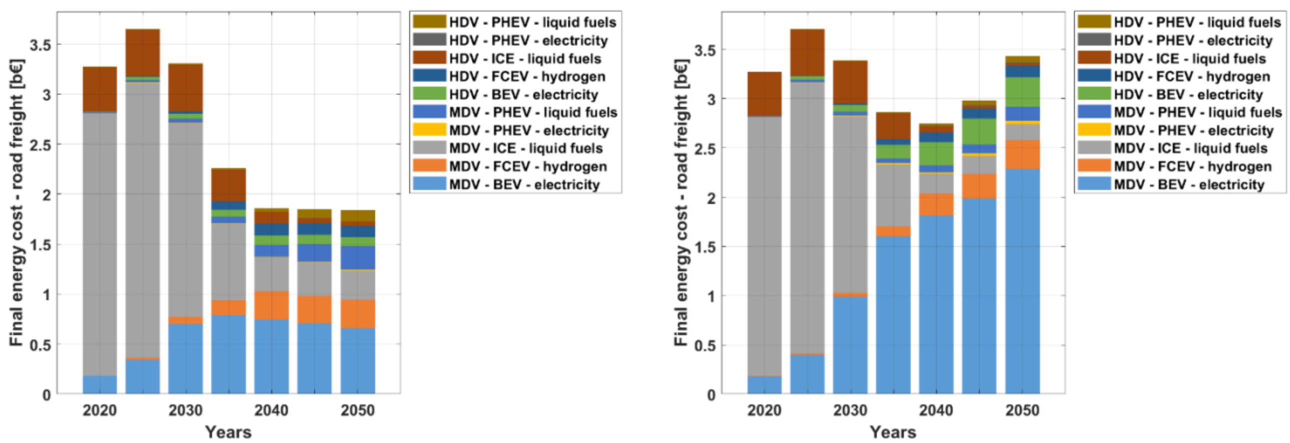

Figure A24. Final energy cost for road freight transport in BPS-5 (left) and CPS (right).

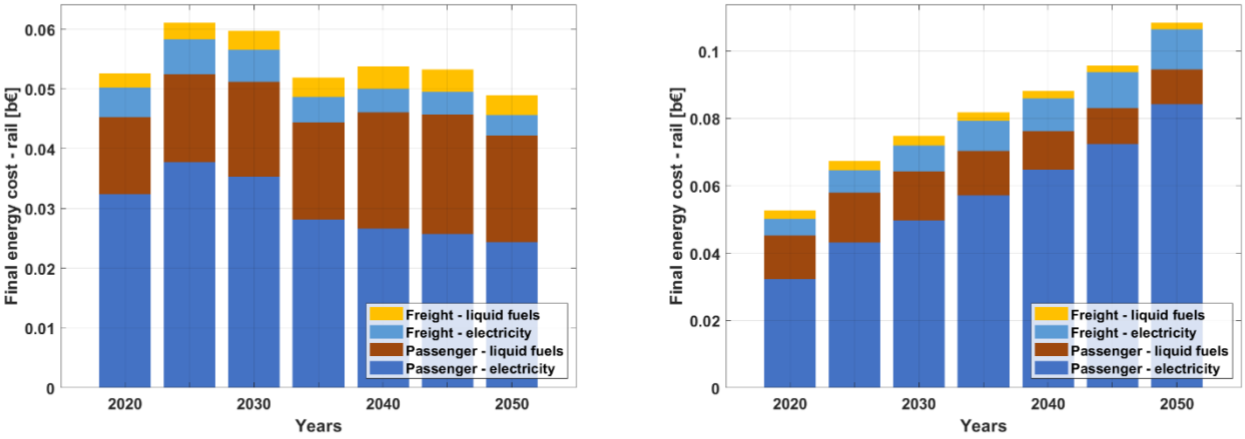

Figure A25. Final energy cost for rail transport in BPS-5 (left) and CPS (right).

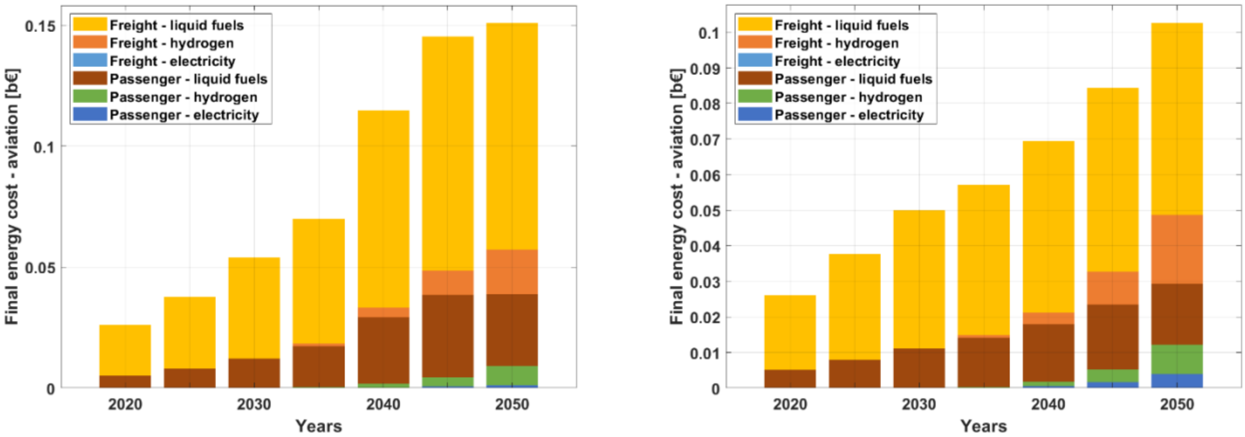

Figure A26. Final energy cost for aviation transport in BPS-5 (left) and CPS (right).

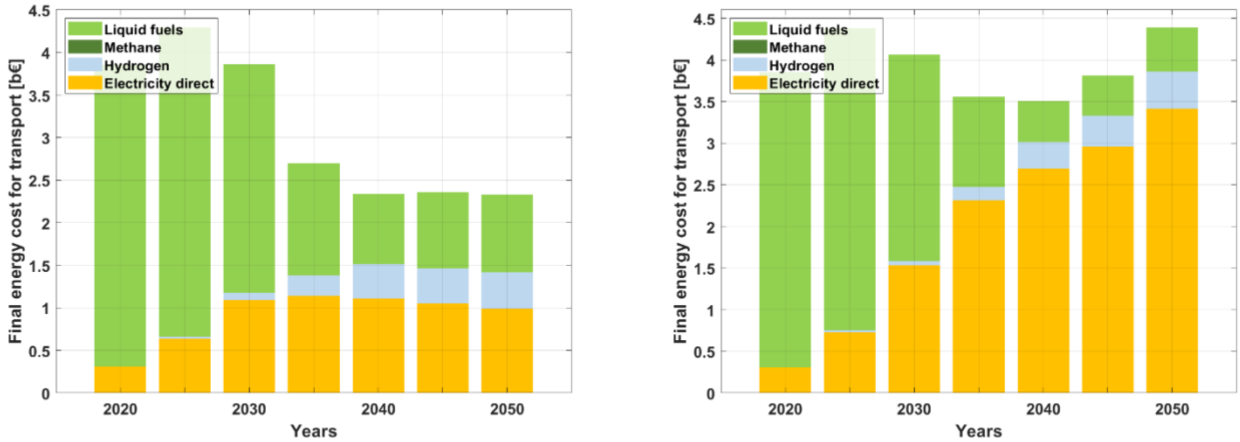

Figure A27. Final energy cost for transport by fuel in BPS-5 (left) and CPS (right).

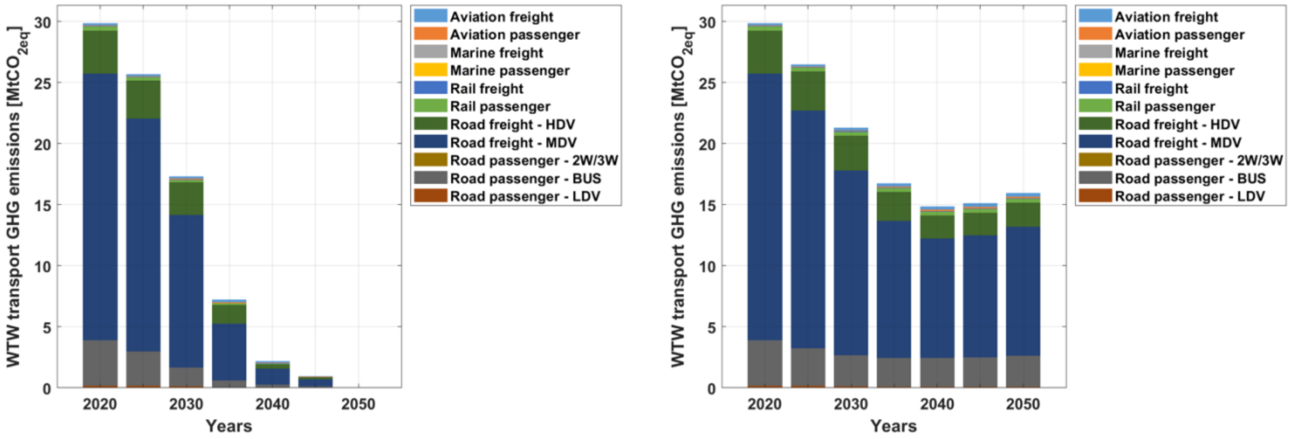

Figure A28. Well-to-wheel transport GHG emissions in BPS-5 (left) and CPS (right).

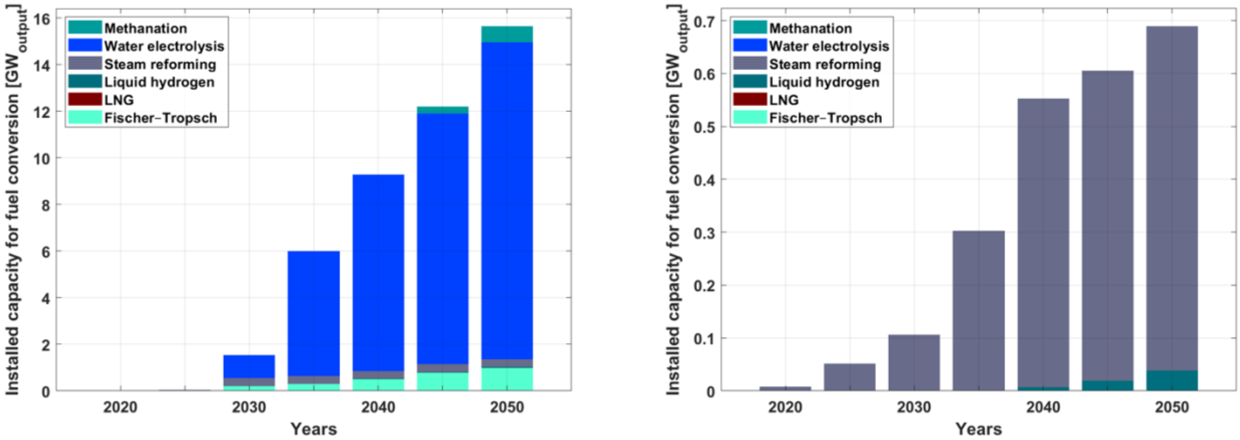

Figure A29. Installed capacity for fuel conversion in BPS-5 (left) and CPS (right).

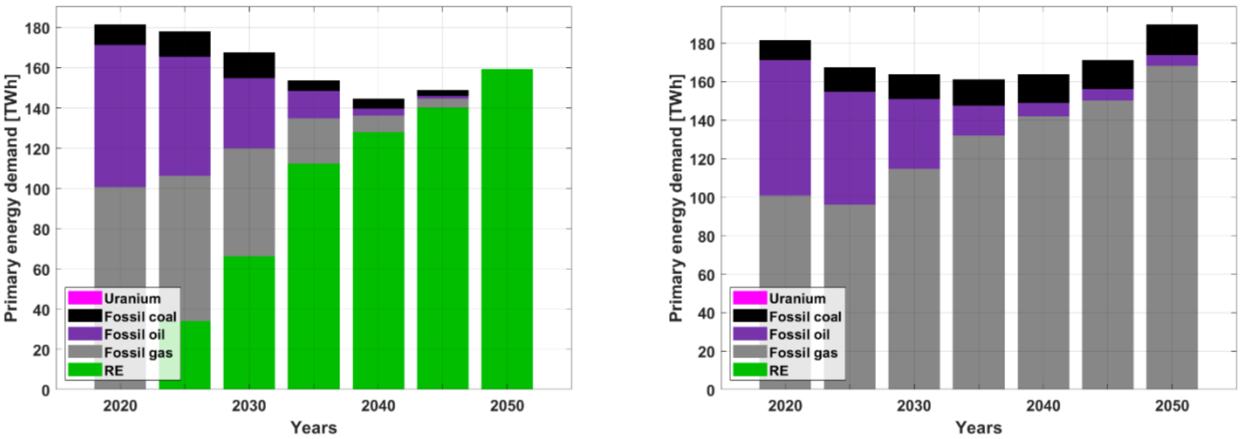

Figure A30. Primary energy demand by source in BPS-5 (left) and CPS (right).

Table A13. Primary energy demand in BPS-5 [TWh].

Energy source	2020	2025	2030	2035	2040	2045	2050
RE	0	34.2	66.3	112.5	127.8	140.2	159.2

Fossil gas	100.8	72.2	53.7	22.4	8.3	4.4	0
Fossil oil	70.6	59	34.8	13.5	3.4	1.2	0
Fossil coal	10	12.5	12.9	5.4	5.2	2.9	0
Uranium	0	0	0	0	0	0	0
Total	**181.4**	**177.9**	**167.7**	**153.8**	**144.7**	**148.7**	**159.2**

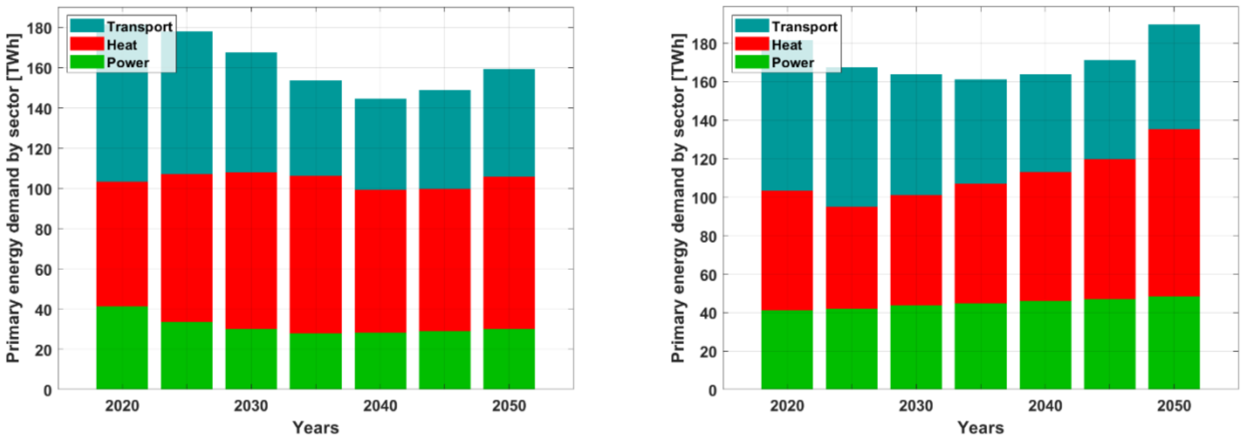

Figure A31. Primary energy demand by sector in BPS-5 (left) and CPS (right).

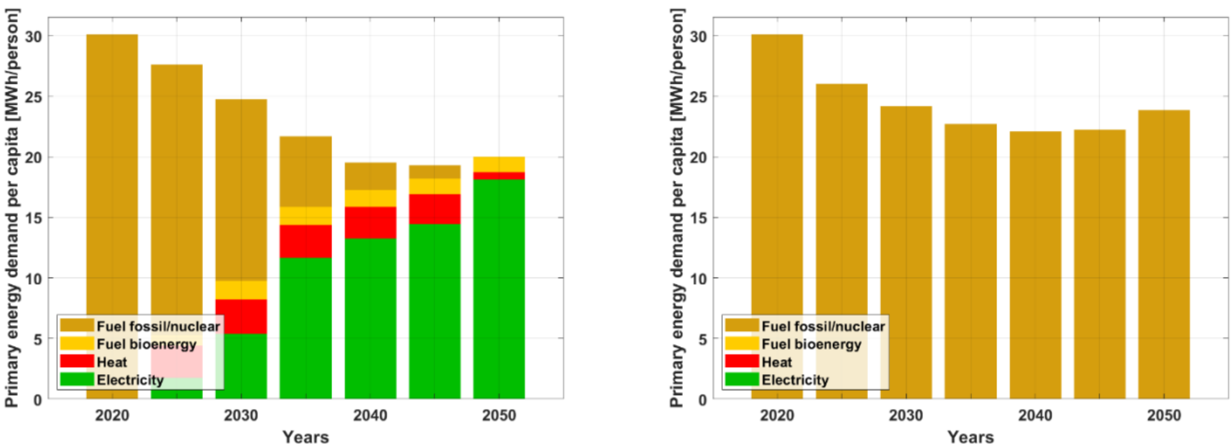

Figure A32. Primary energy demand per capita by source in BPS-5 (left) and CPS (right).

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