LAPPEENRANTA-LAHTI UNIVERSITY OF TECHNOLOGY
School of Energy Systems
Degree Programme in Electrical Engineering

Energy transition options for Bolivia in a climate-constrained world

Examiners: Professor Christian Breyer
M.Sc. Arman Aghahosseini

Author Gabriel Lopez

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Abstract

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Renewable energy system; Energy transition; Energy storage; Hourly resolved spatial-temporal data; South America; Bolivia; Energy transition modelling; simulation model, investment optimisation model; EnergyPLAN; LUT model

Under the Paris Climate Agreement, sustainable energy supply will largely be achieved through renewable energies. Each country will have its own unique optimal pathway to transition to a fully sustainable system. The first chapter of this thesis demonstrates two such pathways for Bolivia that are both technically feasible and cost-competitive to a scenario without proper renewable energy targets, and significantly more cost-efficient than the current system. This transition for Bolivia would be driven by solar PV based electricity and high electrification across all energy sectors. Simulations performed using the LUT Energy System Transition model comprising 108 technology components show that electricity demand in Bolivia would rise from the present 12 TWh to 230 TWh in 2050, and electricity would comprise 82% of primary energy demand. The remaining 18% would then be covered by renewable heat and sustainable biomass resources. Solar PV sees massive increases in capacity from 0.13 GW in 2020 to a maximum of 113 GW in 2050, corresponding to 93% of electricity generation in 2050. In a high transmission scenario, levelised cost of energy reduces 27% during the transition. All scenarios studied see significant reductions in greenhouse gas emissions, with two scenarios demonstrating a Bolivian energy system with no greenhouse gas emissions in 2050. Further, such scenarios outline a sustainable and import-free supply of energy for Bolivia that will provide additional social benefits for the people of Bolivia.

As the discourse surrounding 100% renewable energy systems has evolved, several energy system modelling tools have been developed to demonstrate the technical feasibility and economic viability of fully sustainable, sector coupled energy systems. While the characteristics of these tools vary among each other, their purpose remains consistent in integrating renewable energy technologies into future energy systems. The second chapter of this thesis examines two such energy system models, the LUT Energy System Transition model, an optimisation model, and the EnergyPLAN simulation tool, a simulation model, and

develops cost-optimal scenarios under identical assumptions. This chapter further analyses different novel modelling approaches used by modellers. Scenarios are developed using the LUT model for Sun Belt countries, for the case of Bolivia, to examine the effects of multi and single-node structuring, and the effects of overnight and energy transition scenarios are analysed. Results for all scenarios indicate a solar PV dominated energy system; however, limitations arise in the sector coupling capabilities in EnergyPLAN, leading it to have noticeably higher annualised costs compared to the single-node scenario from the LUT model despite similar primary levelised costs of electricity. Multi-nodal results reveal that for countries with rich solar resources, high transmission from regions of best solar resources adds little value compared to fully decentralised systems. Finally, compared to the overnight scenarios, transition scenarios demonstrate the impact of considering legacy energy systems in sustainable energy system analyses.

Acknowledgements

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Gabriel Lopez
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Abbreviations

ABEN	Bolivian Agency of Nuclear Energy (“Agencia Boliviana de Energía Nuclear” in Spanish)
A-CAES	Adiabatic compressed air energy storage
CAPEX	Capital expenditures
CB	Cochabamba
CCGT	Combined cycle gas turbine
CHP	Combined heat and power
CH	Chuquisaca
CSP	Concentrated solar thermal power
DAC	CO_2 direct air capture
DH	District heating
ENDE	National Company of Electricity (“Empresa Nacional de Electricidad” in Spanish)
EMS	Energy system model
FLH	Full load hours
FT	Fischer-Tropsch
GHG	Greenhouse gas
GT	Gas turbine
GTL	Gas-to-liquid
HVAC	High voltage alternating current
HVDC	High voltage direct current
HDV	Heavy duty vehicle
HT	High temperature
ICE	Internal combustion engine
INDC	Intended Nationally Determined Contribution
IH	Individual heating
LCOC	Levelised cost of curtailment
LCOE	Levelised cost of electricity
LCOH	Levelised cost of heat
LCOS	Levelised cost of storage
LCOW	Levelised cost of water

LDV	Light duty vehicle
LNG	Liquefied natural gas
LP	La Paz
LPG	Liquefied petroleum gas
LUT	LUT University
LT	Low temperature
MED	Multi effect distillation
MDV	Medium duty vehicle
MHE	Ministerio de Hidrocarburos y Energía
OCGT	Open cycle gas turbine
OECD	Organization for Economic Co-operation and Development
OPEX	Operational expenditures
OR	Oruro
PDBE	Pando and Beni
PHES	Pumped hydro energy storage
PT	Potosí
PP	Power plant
PtG	Power-to-gas
PtGtL	Power-to-gas-to-liquid
PtH	Power-to-heat
PV	Photovoltaic
p-km	passenger-kilometre
RE	Renewable Energy
RO	Reverse Osmosis desalination
SA	Isolated systems ("Sistemas Aislados" in Spanish)
SC	Santa Cruz
SIN	National Interconnected System ("Sistema Interconectado Nacional" in Spanish)
SF	Solar field
SNG	Synthetic natural gas
ST	Steam turbine
TES	Thermal energy storage
TJ	Tarija
TTW	Tank-to-wheel

TPES	Total primary energy supply
t-km	tonne-kilometre
2W	two-wheelers
3W	three-wheelers
USD	United States dollar
€	Euro

Chapter 1: Pathway to a fully sustainable energy system for Bolivia across power, heat, and transport sector by 2050

1. INTRODUCTION

With plans to be the energetic heart of South America, Bolivia has ambitious plans to become a primary net exporter of energy to the region [1]. Similarly, the government has set out thirteen pillars in a plan to "Live Well" ("Vivir Bien" in Spanish) [2] among which include eliminating extreme poverty, universalization of basic services, and environmental sovereignty when it comes to the country's development with respect to the rights of the Earth. With Bolivia being a signatory of the Paris Climate Agreement [3] to reduce the effects of climate change and limit temperature growth to 1.5 °C as well as considering their pillars of development, their energetic development must be done with an energy system aimed towards net zero emissions by 2050.

Bolivia's total primary energy supply (TPES) in 2015 was 93.6 TWh, with 85% of the supply coming from fossil sources [4]. Increased petrol consumption has increased the amount of energy imports from 10.3% of total final energy demand in 2000 to 15.6% in 2015. Conversely, increased natural gas production has resulted in a significant increase in the percentage exported of produced natural gas from 37% in 2000 to 67% in 2015. In terms of total exports of the country, hydrocarbons, primarily composing of natural gas, made up 45.6% of the total value of 8.7 mUSD with most natural gas exports going to Brazil and Argentina [5].

Similar to the country's total energy system, the power sector relies heavily on natural gas [6]. The electricity network in Bolivia is broken into two classifications: the National Interconnected System (SIN) and the Isolated Systems (SAs). Natural gas is primarily used for thermoelectric generation with nearly 95% of this generation capacity. Given Bolivia's low electricity consumption, the Bolivian government heavily subsidizes electricity generation from natural gas, leading to generation costs that correspond to less than a quarter of the international market value of natural gas [7]. This subsidy is intended to enhance rural and urban residential electricity consumption and allows a "dignity rate" of 25% off the electricity for residential consumers who use up to 70 kWh/month [7].

Despite their small relative emissions compared to world emissions, Bolivia is one of the most vulnerable countries to the impacts of climate change [8]. This highlights the need for intelligent energy policy and emission reduction targets for Bolivia to protect its most vulnerable communities and rich biodiversity. This is also specifically concerning when considering that deforestation and land use have caused a loss of 430,000 hectares of forest annually between 2000-2010 [9]. This deforestation has caused CO_2 emissions of about one hundred million tons per year, over 80% of Bolivia's CO_2 emissions [1]. By sector, land use and change of land use result in 77% of emissions, followed by the energy sector at 21%, and industrial processes with 1.8% [8].

The Bolivian government has established the following policy guidelines for the energy sector: energy sovereignty, energy security, energy universalization, energy efficiency, industrialization, energy integration, and strengthening of the energy sector [10]. The characteristics of such an energy development have been defined as including increased production and consumption of natural gas, reduction of consumption of LPG and other petroleum derivatives, reduced importation of diesel oil, reduced use of biomass, increased use of renewable energy (RE) for electricity generation, increased use of electricity, and exportation of energy [11]. However, most of Bolivia's energy goals and projections are based on data from 2007 and are projected up until 2027. There have been more recent development plans for the electricity sector, though these plans are aimed towards 2025.

The 2014 Electric Plan from the Ministry of Hydrocarbons and Energy (MHE) set a target to install 183 MW of renewable power by 2025 [12]. More recently, Bolivia's national electricity company (ENDE) projected that by 2025, 74% of the installed capacity will be from hydropower, 4% from non-hydro renewables energy, 12% from combined cycle plants, and 10% from thermal power plants [13]. These projections, though, only take into consideration the SIN. While the MHE plans to integrate the SIN and SA by 2025, plans for electrification for rural communities that cannot be incorporated into the SIN are also needed [12]. Bolivia also plans on using large hydropower plants in their plans to become an electricity exporter to neighbouring countries [12]. With this added capacity, Bolivia could account for up to 21% of electricity exports in South America [14].

While the Constitution of Bolivia implies changes in rules and regulations regarding the use of natural resources for the generation of electricity, specific regulations do not exist, which pose a challenge to the development of RE, particularly in off-grid electrical systems [10]. MHE has identified that there are insufficient research incentives, technological development, and distribution of knowledge and information similarly as problems inhibiting the growth of RE [10].

Energy prices and tariffs within the SIN are not currently in line with the intention of promoting RE, and the cost of subsidies, particularly for oil, are over 5% of Bolivia's GDP [15]. Similarly, subsidies of the price of natural gas have resulted in a price of 1.3 USD/thousand m^3 for electricity generation [10]. As a result, electricity prices in Bolivia remain low compared to other South American countries [16]. Bolivia currently has no greenhouse gas (GHG) emissions pricing instruments nor strict emissions reduction targets, although the submitted Intended Nationally Determined Contribution (INDC) reports projected GHG emissions reduction in the Bolivian power sector from 0.41 tCO_{2eq}/MWh in 2015 to 0.04 tCO_{2eq}/MWh by 2030 [16, 17]. For further reduction, a GHG emission tax of 30 USD/tCO_2 was found to produce the lowest abated emissions reduction for Bolivia's power sector by 2040 [16]. These subsidies, those for oil, and lack of GHG emission taxing with respect to an emission reduction target negatively affect the economic competitiveness of RE.

As a signatory of the Paris Agreement, development of the Bolivian energy system must be done with high levels of sustainability. To the knowledge of the authors, there are no scientific articles that outline a pathway for a 100% RE supply in all energy sectors for Bolivia. Previous analysis focuses primarily on the power sector only and avoid very high shares of RE [16, 18, 19], or comprise a larger area for a target energy system, neither highlighting Bolivia much nor describing an energy transition pathway [20, 21]. The focus of this study is therefore to model a fully sustainable transition for Bolivia across all energy sectors and assess the viability of such a transition in terms of economics, technical feasibility, and social and environmental effects. Results of this study could prove useful for countries in the region as well as other high solar resource countries in other parts of the world.

2. METHODS

This research utilised the LUT Energy System Transition model [22–24] to study the Bolivian energy transition. Figure 1 shows the process flow of the LUT model. This model was originally developed for the power sector only, with coupling of power and heat sectors [22,24], but has since been updated to couple the power, heat, transport [23], and desalination [25] sectors, and finally industry sector [26]. All sectors are fully coupled, as shown in Figure 2, as described with the target function and the energy balance in Equations 1 and 2 [22]. Equation 1 uses the abbreviations: sub-regions (*r, reg*), generation, storage and transmission technologies (*t, tech*), capital expenditures for technology *t* ($CAPEX_t$), capital recovery factor for technology *t* (crf_t), fixed operational expenditures for technology *t* ($OPEXfix_t$), variable operational expenditures technology *t* ($OPEXvar_t$), installed capacity in the region *r* of technology *t* ($instCap_{t,r}$), annual generation by technology *t* in region *r* ($\mathrm{E}_{\mathrm{gen}_{t,r}}$), cost of ramping of technology *t* ($rampCost_t$) and sum of power ramping values during the year for the technology *t* in the region *r* ($totRamp_{t,r}$).

$$\min\left(\sum_{r=1}^{reg} \sum_{t=1}^{tech} \left(\mathrm{CAPEX}_f \cdot \mathrm{crf}_t + \mathrm{OPEXfix}_t\right) \cdot \mathrm{instCap}_{t,r} + \mathrm{OPEXvar}_t \cdot \mathrm{E}_{gen_{t,r}} + \mathrm{rampCost}_t \cdot \mathrm{totRamp}_{t,r} \right) \qquad (1)$$

Equation 2 uses the following variables to match balance with demand to optimise the power sector for each year: hours (*h*), technology (*t*), all modelled power generation technologies (*tech*), sub-region (*r*), all sub-regions (*reg*), electricity generation (E_{gen}), electricity import (E_{imp}), storage technologies (*stor*), electricity from discharging storage ($E_{stor,disch}$), electricity demand (E_{demand}), electricity exported (E_{exp}), electricity for charging storage ($E_{stor,ch}$), electricity consumed by other sectors (Heat, Transport, Desalination, Industrial fuels production) (E_{other}), curtailed excess energy (E_{curt}). The energy loss in the high voltage transmission grids and energy storage technologies are considered in storage discharge and grid import value calculations

$$\forall h \in [1,8760] \ \sum_t^{tech} \mathrm{E}_{gen,t} + \sum_r^{reg} \mathrm{E}_{imp,r} + \sum_t^{stor} \mathrm{E}_{stor,disch} = \mathrm{E}_{demand} + \sum_r^{reg} \mathrm{E}_{exp,r} + \sum_t^{stor} \mathrm{E}_{stor,ch} + \mathrm{E}_{curt} + \mathrm{E}_{other} \qquad (2)$$

The model works with linear optimisation under given constraints, in full hourly resolution for an entire year, and applies cost-optimal simulations. Weather year data for the year 2005 is used to determine resource availability as described in Bogdanov et al. [22]. Using historical installed capacities in a given energy system and other defined constraints, the model determines the least cost energy system in full hourly resolution for all hours of a year from 2020 to 2050, in five-year intervals.

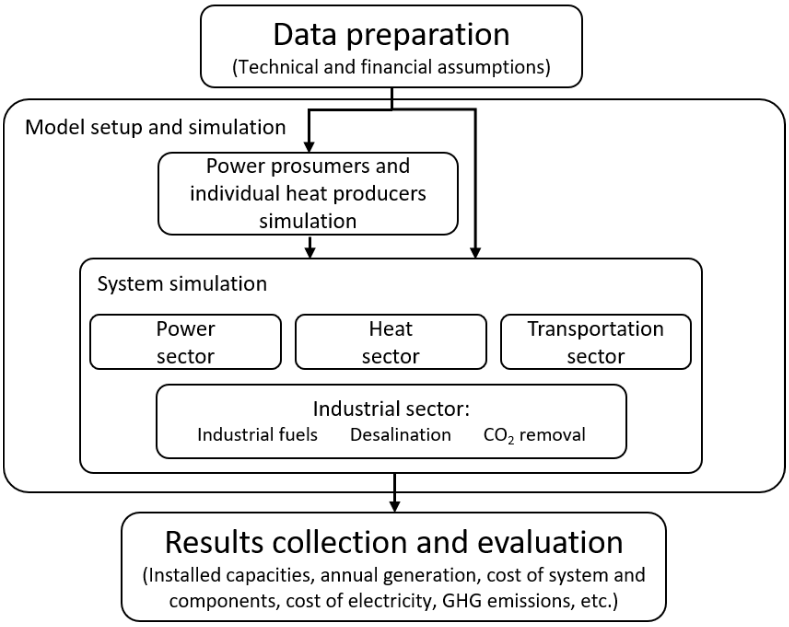


Figure 1. Fundamental structure of LUT Energy System Transition model [22,23].

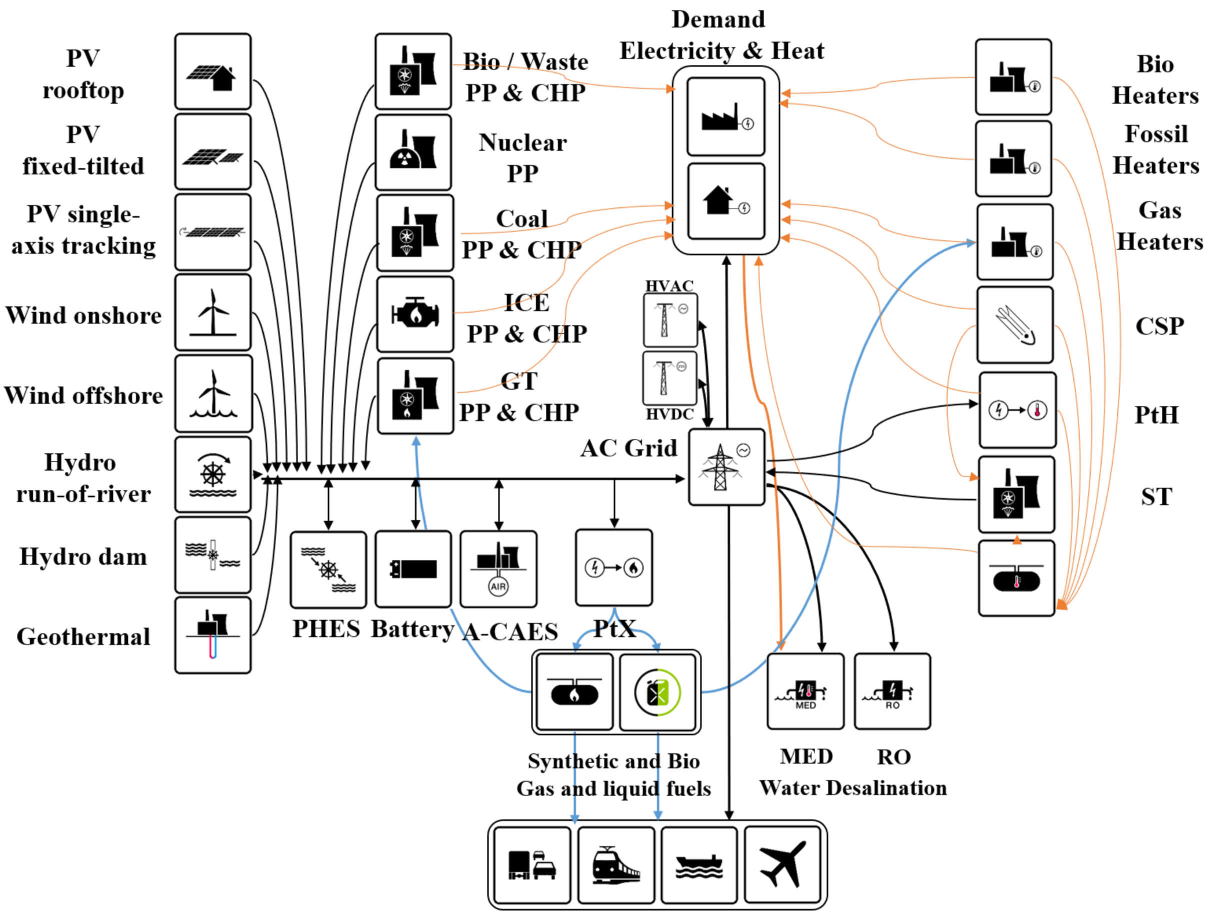


Figure 2. Schematic of the LUT Energy System Transition model for the coupled sectors power and heat [24], transport [23], and desalination [25].

Data collection for the model began with statistics for the Bolivian energy system in 2015, excluding non-energetic uses, and the energy flow of the current system is shown in Figure 3 [4]. Data reported in [4] was provided according to Bolivia's nine administrative regions, or departments. Given how data is reported by Bolivian authorities, Bolivia was divided into eight regions, considering the capitals of each region as a centre of consumption, and is shown in Figure 4. Bolivia's subdivisions are structured as follows: Pando and El Beni (PDBE), La Paz (LP), Santa Cruz (SC), Cochabamba (CB), Oruro (OR), Potosí (PT), Chuquisaca (CH), and Tarija (TJ). Interregional grid data was gathered from [27] to model the electricity trade for Bolivia. Using this data, and data from [11], a long-term energy demand was developed for power, heat, and transport sectors as main sectors, and seawater desalination as a minor sector (see Figure 5). Because energy demand projections beyond 2030 are not available for Bolivia, final energy demand was extrapolated from the trends between 2015 and 2030. Continuous energetic growth was assumed to occur as population and energy access increase. With technological changes, the final energy demand had an average annual growth rate of 5.4%, where heat demand was assumed to grow the largest of any sector, with 9.7% annual growth, largely due to growth in industrial heat demand.

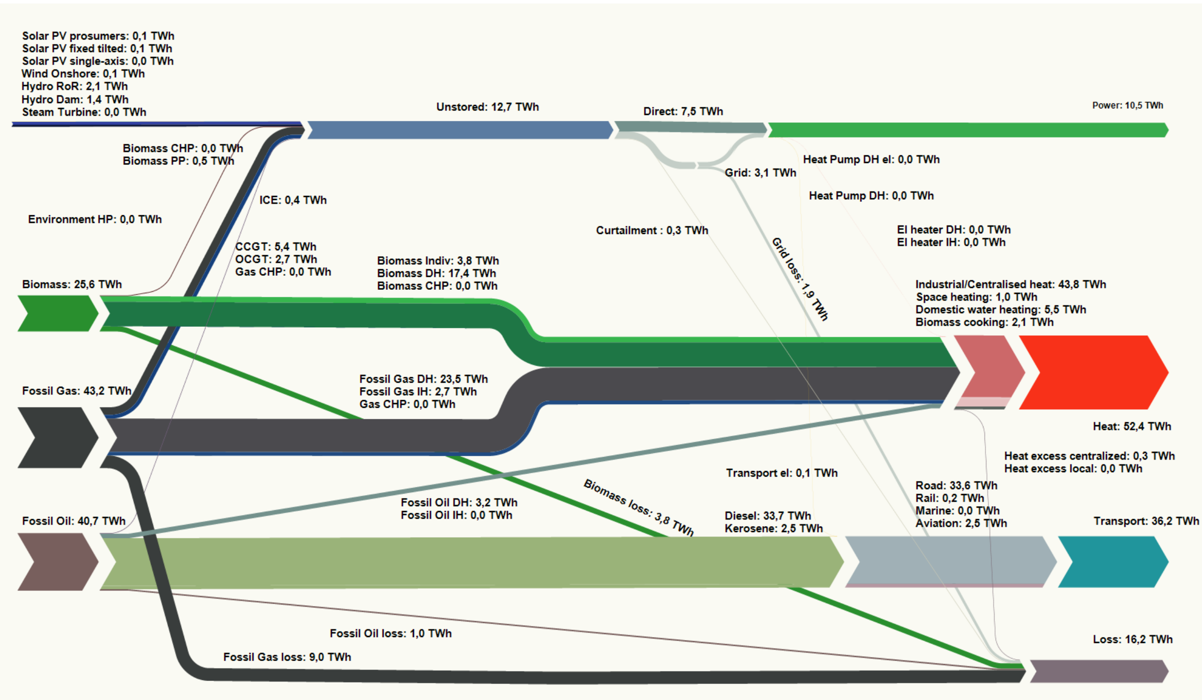


Figure 3. Energy flow for the Bolivian energy system in 2020.

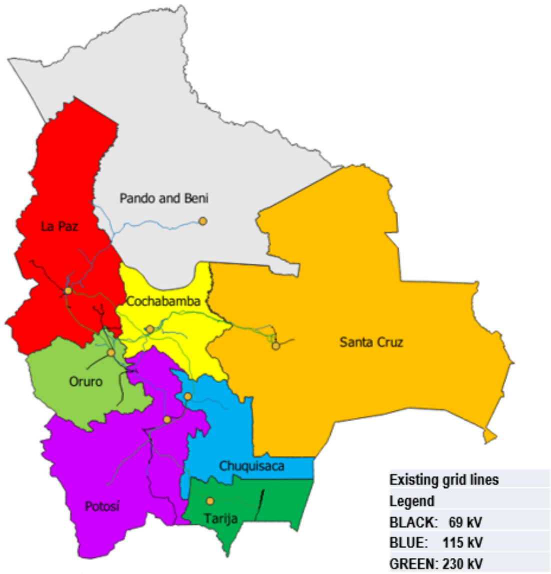


Figure 4. Bolivia separated into its respective subregions with existing grid infrastructure.

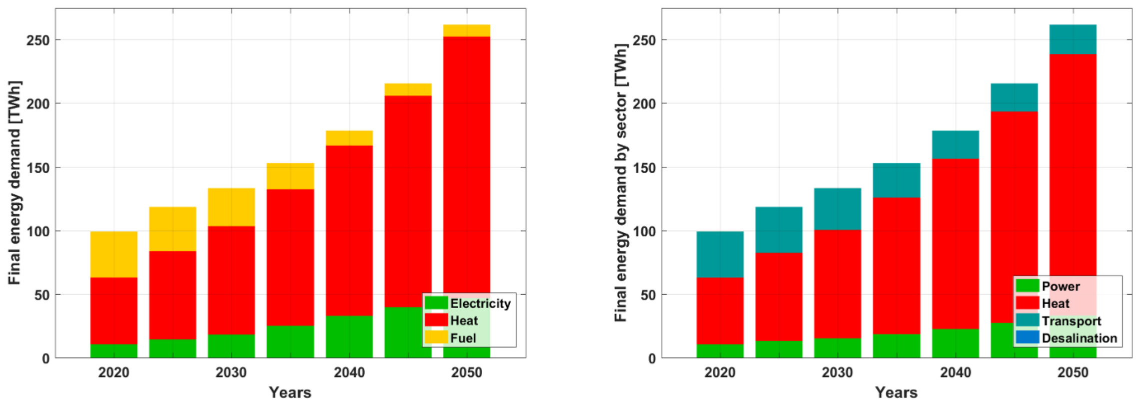


Figure 5. Final energy demand by energy form (left) and by sector (right) from 2020 to 2050.

By sector, demands were categorised into their respective final uses. Power sector was distributed into residential, commercial and industrial end-users. Heat demand was categorised to four different final heat uses of space heating, domestic hot water heating, industrial process heat, and biomass for cooking. These heating demands were further classified into low, medium, and high temperature heating demands.

For the transport sector, transport demands were divided into road, rail, marine, and aviation segments according to Breyer et al. [28], Khalili et al. [29], and Balderrama et al. [16] and were then further separated into passenger (in p-km) and freight (in t-km) for each transport segment. The road segment was then divided into passenger light-duty vehicles, 2-wheelers/3-wheelers. passenger bus, freight medium-duty vehicles, and freight heavy-duty vehicles. Using [28], the final transport demand was calculated based on specific vehicle energy demand and vehicle technology. As the penetration of electric vehicles increases, smart charging and vehicle-to-grid capacities may develop, the impact of which is discussed in Child et al. [30], but these capabilities are not considered in this study.

Further details of the sector-wide assumptions can be found in Appendix I (Tables AI1-AI7 and Figures AI1-AI10).

Resource potentials for Bolivia were then estimated for various RE technologies. Real weather data was used to estimate the solar, wind and hydro resources [31–33]. Potentials for biomass and waste resources were classified into solid biomass wastes, residues, and biogas according to the methods of Mensah et al. [34] applied for the case of Bolivia. Additionally, geothermal potential estimates were determined according to Aghahosseini et al. [35] and pumped hydro energy storage (PHES) potential estimates were done according to Ghorbani et al. [36]. Resource distributions for solar PV single-axis tracking, fixed-tilted, Direct Normal Irradiance (DNI), and wind onshore (E-101 at 150 m) are shown in Figure 6.

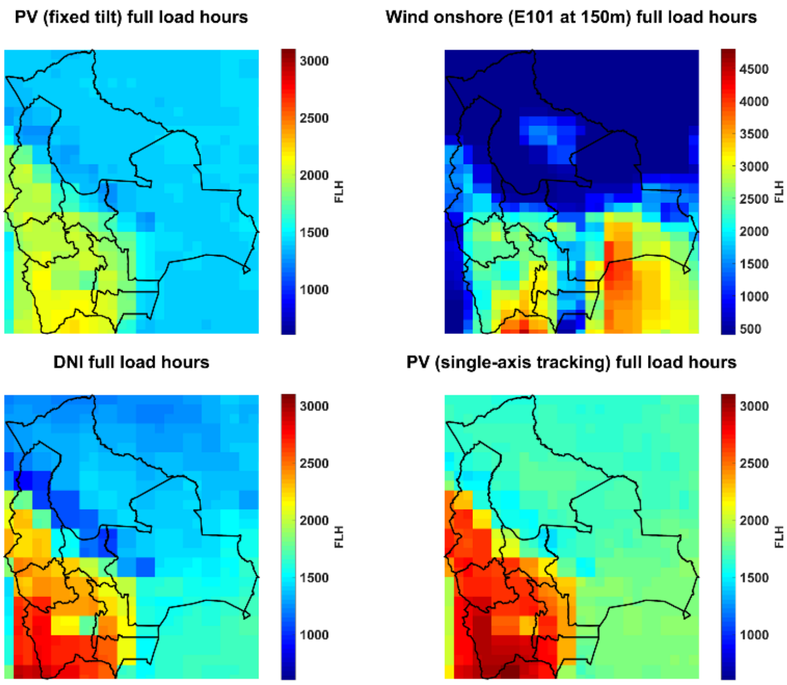


Figure 6. Full load hour profiles in Bolivia for PV fixed-tilted (top left), wind onshore (top right), DNI (bottom left), and PV single-axis tracking (bottom right).

Financial assumptions have been obtained from an array of sources and can be found in Appendix I (Tables AI8-AI10). These financial assumptions include a learning curve for all key technologies, which is particularly influential in determining the feasibility of key technologies in a cost-optimised energy transition.

Simulations were then carried out using the LUT model for three scenarios, detailed in Table 1. The tool integrates 108 technologies to include and couple the power, heat, transport, and desalination sectors. The scenarios here are developed to compare a more distributed and prosumer heavy energy system, to one in which primary energy generation is centralised to those regions with highest resource availability. Further, by eliminating GHG emission costs and allowing fossil fuels to remain in the transport sector, the economic competitiveness of a fully RE system can be compared to one in which the transport sector is not forced to be fully sustainable. The objective of BPS-1 and BPS-2 was to develop a fully sustainable energy system, as outlined by Child et al. [37], for Bolivia whereby GHG emissions would be eliminated by 2050 and Bolivia would become completely energy independent. Due to a lack of government data beyond 2030, no current policy scenario was developed. For all scenarios, key economic indicators were compared to analyse the viability of such a sustainable energy system.

Table 1. Overview of scenarios

Scenario Name	Description
Best Policy Scenario (BPS-1)	This scenario targets 100% RE by 2050, with the addition of GHG emission costs. This scenario prioritises distributed generation and minimises utilisation of interregional grid transmission.
Best Policy Scenario High Transmission (BPS-2)	This scenario similarly targets 100% RE by 2050. However, this scenario develops a more centralised energy system. It focuses energy production in areas with best available resources.
Best Policy Scenario Unconstraint (BPS-3)	In this scenario, no GHG emissions costs are assumed and transport is not forced to utilise synthetic fuels, but can be used for economic reasons.

3. RESULTS

The results are presented here as follows: Section 3.1 discusses the major trends in the Bolivian energy system throughout the transition. The results for power, heat, transport, and desalination are provided in Sections 3.2-3.5. Section 3.6 presents the role of heat and electricity storage capacity and throughput. In Section 3.7, the findings of interregional electricity transmission are shown for BPS-1 and BPS-2. Section 3.9 and 3.10 show the costs and investments and relevant GHG emissions, respectively, related to each of the 3 scenarios. For each section, the results from the scenarios developed in Table 1 will be discussed and compared. More detailed results for each scenario can be found in Appendix I (Tables AI11-AI30 and Figures AI11-AI40).

The energy flow for Bolivia is shown in Figure 7 and shows an energy system dominated by renewable solar PV. It shows the flow of energy by resource from primary energy supply (left) to final energy demand (right). For each energy form, and most energy conversion steps, output by technology and losses are shown. The energy flow for Bolivia in 2050 demonstrates the electrified (both direct and indirect) nature of RE systems, as well as highlights the importance of hydrogen as a central energy carrier in its roles as a transport fuel and input to both methanation and Fischer-Tropsch (FT) processes. The central flexibility for the energy system is the sector coupling of power, heat and transport to electricity in as directly as possible, but also indirectly via heat pumps and, in particular, via electrolysers and further conversion steps, if needed.

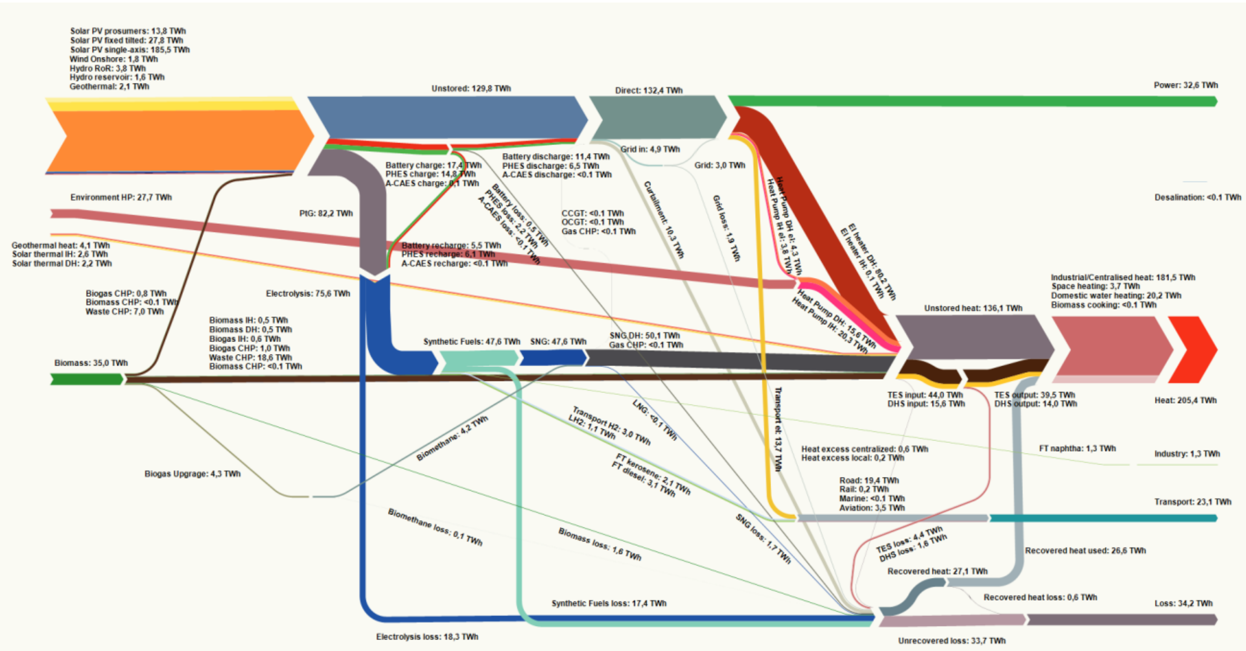


Figure 7. Energy flow for Bolivia in 2050 for BPS-1 showing high sector integration.

3.1 Major trends in long-term energy demand

Figure 8 shows the primary energy supply by energy form and demand by sector throughout the transition for each scenario. According to these graphs, the heat sector sees a significant increase, largely due to significant increases in industrial heating demands. Conversely, primary energy for electricity and transport only see marginal increases, or even decrease in the case of BPS-3, because of increases in efficiency. While primary energy demand for heat increases, all scenarios show high electrification for primary energy supply, with fossil fuels being completely phased out in BPS-1 and BPS-2. These results suggest that renewable electricity will be the dominant component of primary energy, and that the Bolivian energy transition will undergo massive electrification. Of the primary energy demand in 2050, renewable electricity increases from 12.7 TWh in 2020 to 244 TWh, 245 TWh, and 204 TWh in BPS-1, BPS-2, and BPS-3, respectively. For BPS-1 and BPS-2, the remaining primary energy generation would come from bioenergy sources and renewable heat production, such as geothermal and solar thermal heating.

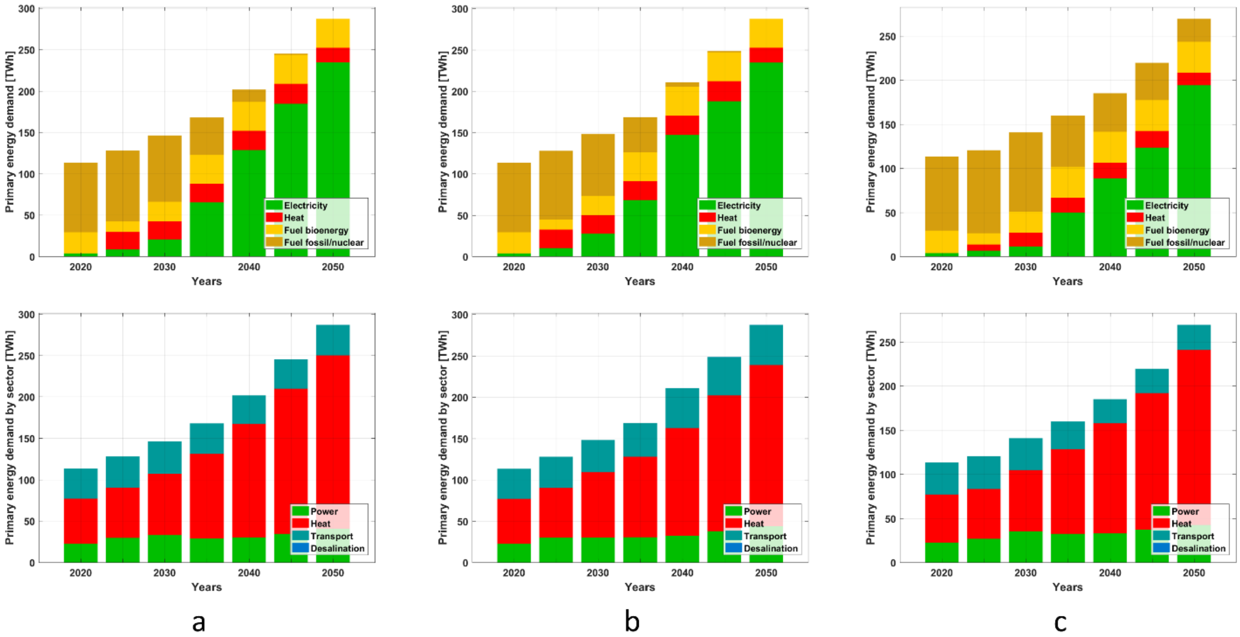


Figure 8. Primary energy demand by energy form (top) and primary energy demand by sector (bottom) for BPS-1 (a), BPS-2 (b), can BPS-3 (c) from 2020 to 2050.

Figure 9 shows that with the population increase from 12.5 million in 2020 to 16.5 million in 2050 [38], and assuming continuous economic growth, the electricity consumption per capita increases steadily. However, this electricity consumption per capita by 2050 is well below that for OECD countries. Although primary energy demands are expected to increase significantly, the graphs of Figure 10 show that quite a large amount of primary energy is saved due to gains in efficiency.

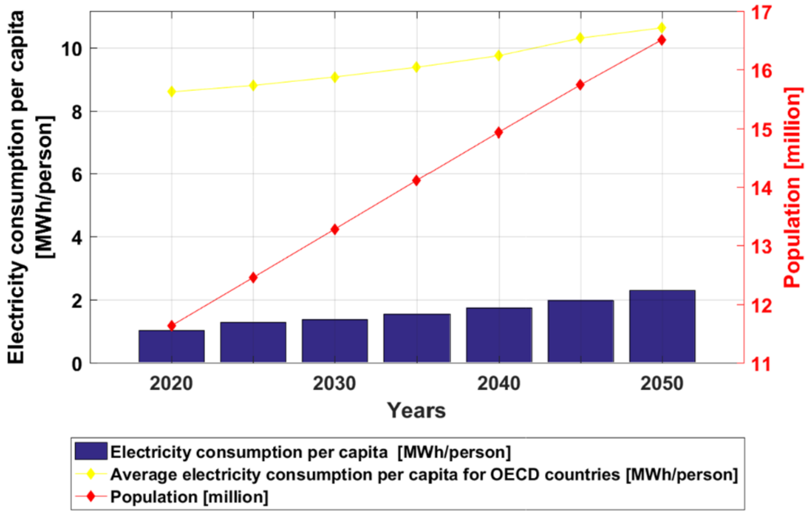


Figure 9. Electricity consumption per capita and population for Bolivia from 2020 to 2050.

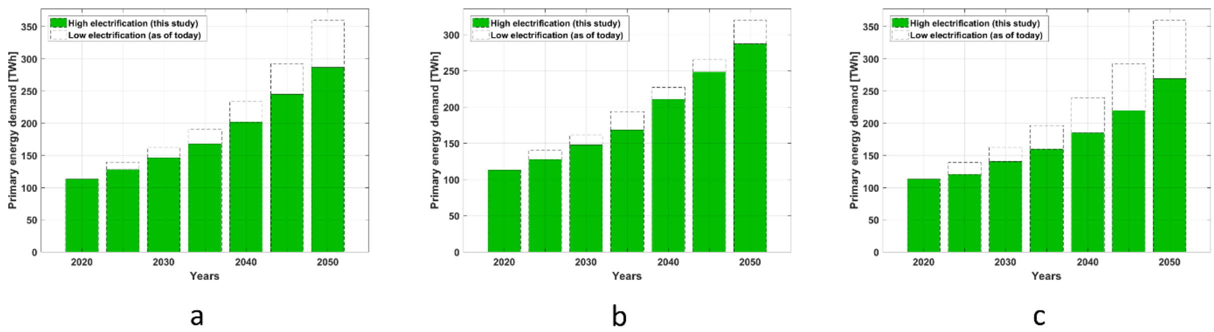
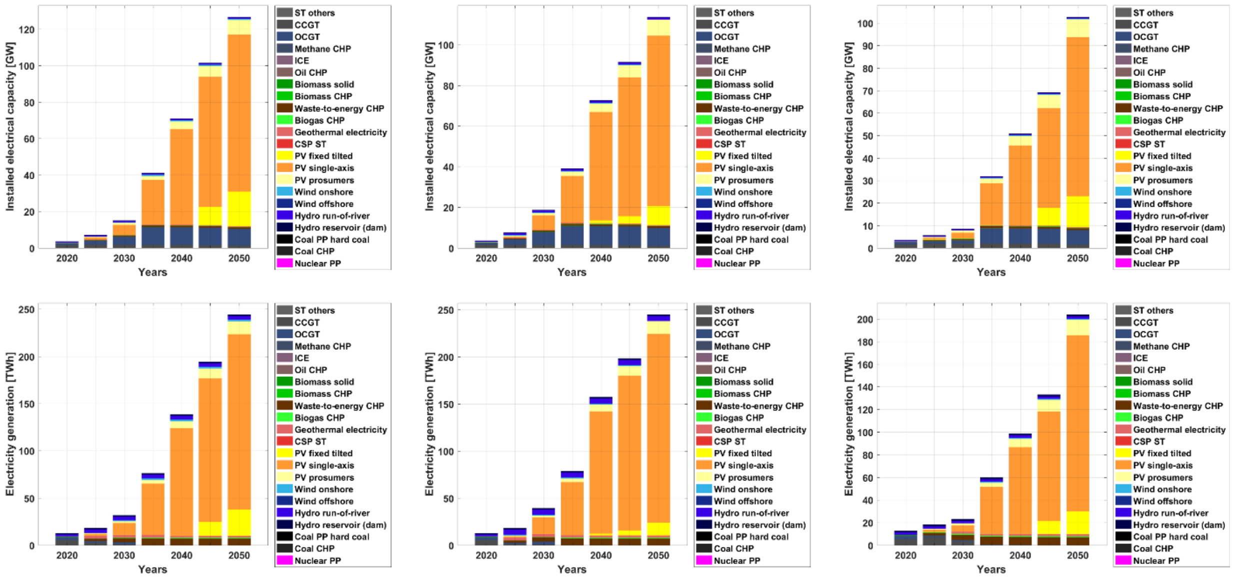


Figure 10. Efficiency gain in primary energy demand throughout the transition for BPS-1 (a), BPS-2 (b), and BPS-3 (c) from 2020 to 2050.

3.2 Power sector

Total electricity generation and installed capacity during the transition is shown in Figure 11 for each scenario. For all scenarios, solar PV, specifically, PV single-axis tracking, is the dominant producer of electricity by 2050, with 93% generation share in all scenarios. Even by 2030, solar PV can be the most significant share of electricity, with the largest generation share of the scenarios being 49.4%. Of the solar capacity, PV prosumers will generate 5.6%, 5.6%, and 6.7% of electricity in 2050 for BPS-1, BPS-2, and BPS-3, respectively. The remaining capacity shares come from hydropower (about 2%), wind energy (around 0.5%), geothermal (about 1%), waste CHP (about 3%), and biogas CHP (0.4%) in all scenarios. While the installed capacity of gas turbines (OCGT and CCGT) remain in the electricity generation matrix, their generation share is well below 1%, and they are supplied only by synthetic gas and biomethane in later periods of the transition.

In terms of total installed capacity by 2050, BPS-1 has the largest electric capacity in 2050 with 126 GW, followed by BPS-2 with 114 GW, and BPS-3 with the smallest installed capacity of 103 GW. This result across scenarios show that total installed capacity is largely influenced by the transport sector, which is discussed in section 3.4, where significant amounts of electricity are required to produce synthetic fuels. Due to the mass electrification that occurs over all sectors, the difference in installed capacity is less significant between fully renewable scenarios (BPS-1 and BPS-2) and BPS-3.



a b c

Figure 11. Cumulative installed power capacity (top) and electricity generation (bottom) by technology throughout the transition from 2020 to 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

3.3 Heat sector

Heat demand for all three scenarios are identical and are shown in Figure 12 for specific demands and by demand temperature. These figures demonstrate a key assumption of this scenario, that large scale industrialisation, and corresponding industrial heat demands, will develop over the course of the transition. Residential heating demands in Bolivia are quite low, though they do notably increase throughout the transition as access to energy services increase, except for biomass for cooking, which is phased out by the end of the transition. Heating demands are projected to increase from 52 TWh in 2015 to 205 TWh in 2050.

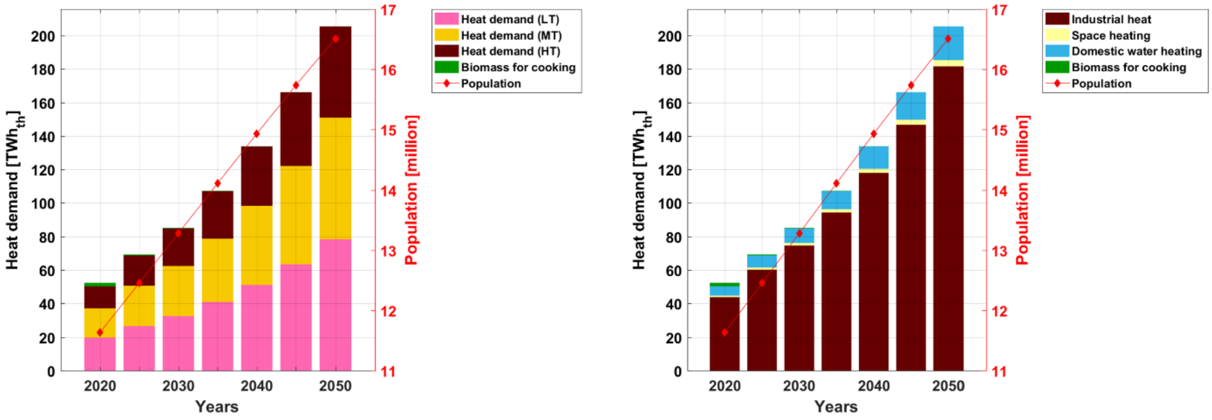
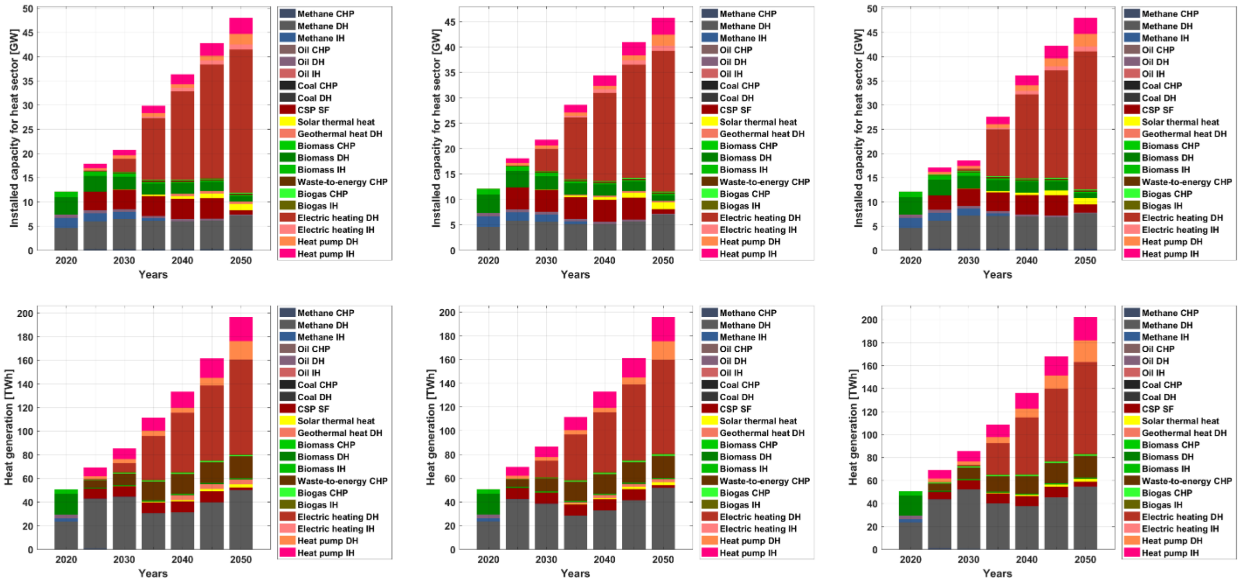


Figure 12. Heat demand by temperature (left) and heat demand by final heating process (right) throughout the transition.

To meet the heat demand, electric based heating, either direct or through heat pumps, compose the largest share of capacity and generation. Gas based heating remains in both capacity and generation, transitioning from fossil gas to synthetic gas during the transition. Figure 13 provides the installed heat capacities and heat generation for each scenario. In these graphs, the total capacities installed for the three scenarios in 2050 are quite similar, each between 45 and 50 GW. Similarly, heat generation is around 200 TWh for each scenario. Electric district heating (DH) become the dominant heat technology in 2050 (with around 40%), followed by methane DH (around 26%), heat pumps (around 18%), biomass-based technologies (around 10%), and limited shares of solar thermal and geothermal heat in all scenarios. Heating demand in Bolivia transitions from a system dominated by natural gas and biomass to a largely electrified heating sector. Because of the low cost of renewable electricity, electric based heating will drive the transition for Bolivia’s heat sector.



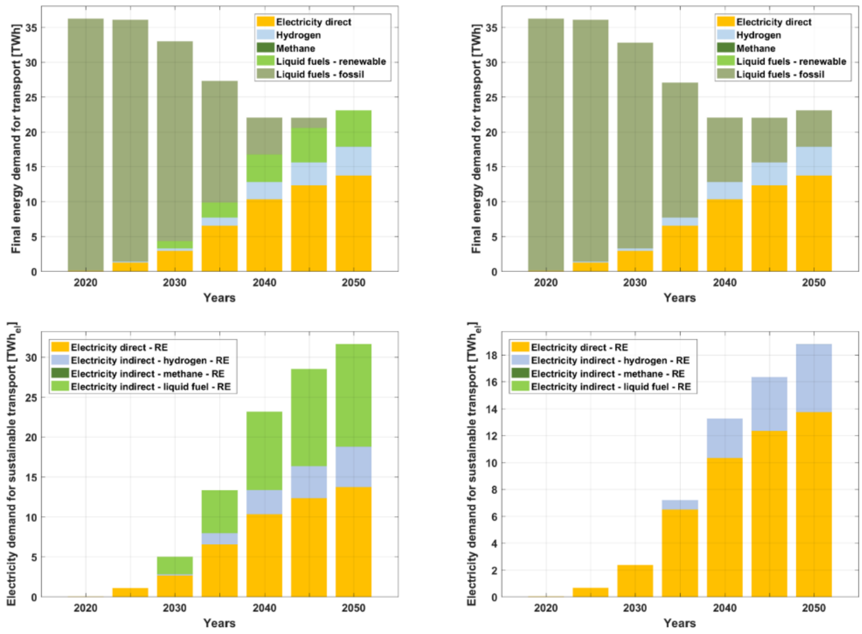
a b c

Figure 13. Installed capacities for heat sector (top) and heat generation by technology throughout transition for BPS-1 (a), BPS-2, (b), and BPS-3 (c).

3.4 Transport sector

Figure 14 shows the final energy demand for transport for the scenarios. These graphs highlight a key difference in the results of these scenarios. Although the final energy demand for the transport sector is the same for all scenarios, the remaining liquid fuel segments in BPS-1 and BPS-2 are based on renewable FT fuels whereas BPS-3 still utilises fossil liquid fuels. The result is, therefore, a significantly decreased electricity demand for transport, which is 32 TWh_{el} for BPS-1 and BPS-2, and 19 TWh_{el} for BPS-3.

During the transition, there is a major shift from fuel-based vehicles to hybrid and battery electric vehicles, and renewable liquid fuels can be introduced on a noticeable scale starting in 2030. For BPS-1 and BPS-2, the final energy demand for a fully sustainable transport sector would be covered by direct electricity (59%), synthetic fuels (liquid and gas) (23%), and hydrogen (18%). For BPS-3, the only difference is that fossil fuels (liquid and gas) would have a share of 23% of the total transport final energy demand. Renewable liquid fuels would largely be utilised in the aviation and marine segments, while road and rail segments will be overwhelmingly electrified. Such development in renewable fuel production will require significant development of electrolysers and CO_2 direct air capture technologies [29]. The results by individual mode and segment of transport, vehicle type, and synthetic fuel production can be found in Appendix I (Figure AI17, Tables AI29-AI30).



a, b c

Figure 14. Final transport energy demand by fuel (top) and electricity demand transport sector (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3 (c). Note here that BPS-1 and BPS-2 have identical energy demands for the transport sector.

3.5 Desalination sector

Figure 15 shows that water demand in Bolivia is projected to grow from 10 million m^3/day in 2020 to 25 million m^3/day in 2050. Despite this growth in water demand, desalination demand by 2050 is a small fraction of total water demand, as desalinated water demand goes from 96 m^3/day in 2020 to 11,544 m^3/day in 2050. Further, as Bolivia has no direct access to ocean water, crossing borders would be necessary to provide desalinated water supply. For all scenarios, reverse osmosis (RO) desalination is the dominant technology used for desalination capacity (Figure 16). Interestingly, in Figure 15, BPS-1, water storage is developed as the largest share of desalinated water capacity, whereas the other two scenarios do not demonstrate any water storage capacity. The higher water storage capacity in the BPS-1 occurs due to decrease in full load hours of RO in 2050. In terms of total electricity demand in 2050, desalination demand comprises less than 1%, with a demand of 0.013 TWh.

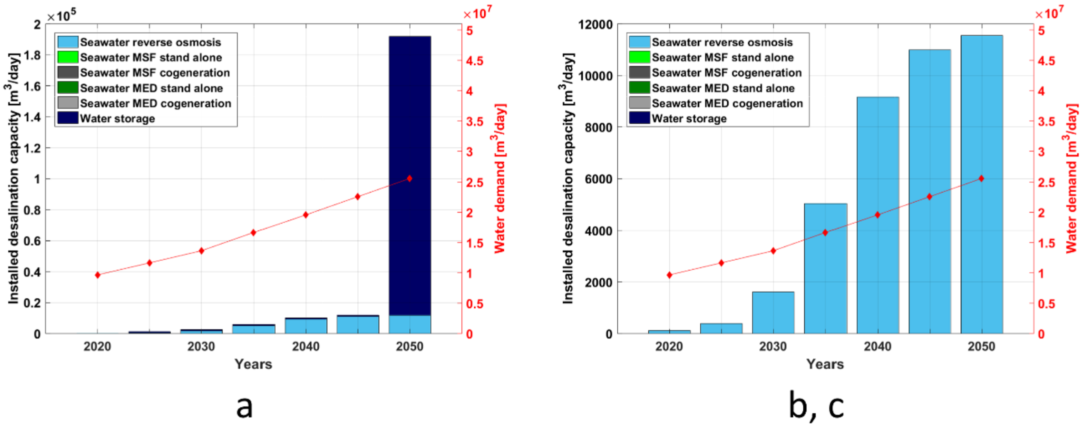


Figure 15. Installed desalination capacities by technology and total projected water demand for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

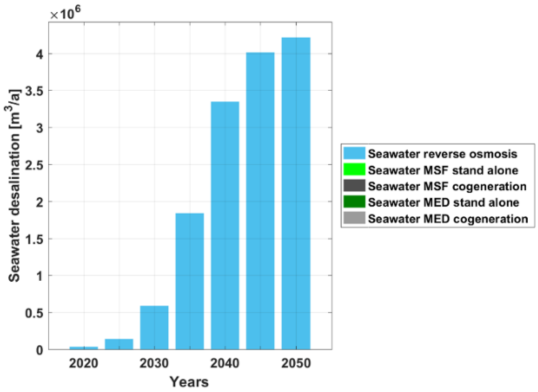
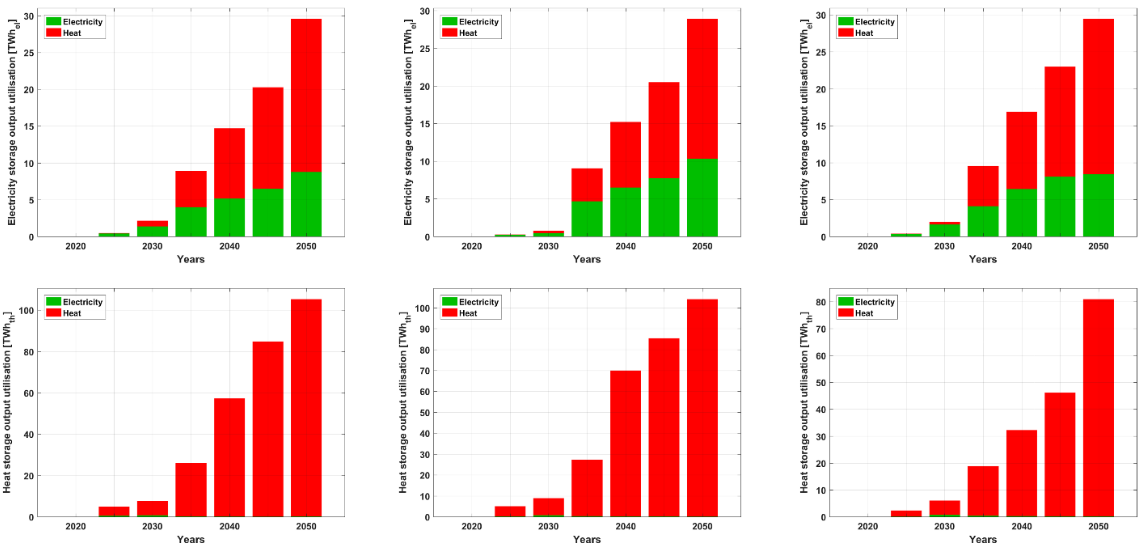


Figure 16. Seawater desalination production by technology for all scenarios

3.6 Storage capacities and throughput

Figure 17 shows the storage capacity supply for heat and electricity by storage type. Electricity storage provides energy output of 29.6 TWh_{el}, 28.9 TWh_{el} and 29.5 TWh_{el} and heat storage provides 105 TWh_{th}, 104 TWh_{th}, and 81 TWh_{th} for BPS-1, BPS-2, and BPS-3, respectively. These values correspond to 42%, 41%, and 51% of the total electricity demand and 49%, 48%, and 34% of the total heat demand for BPS-1, BPS-2, and BPS-3, respectively. In terms of total energy supply, electrical and thermal energy storage would be responsible for about 51%, 51%, and 42% of total energy demand from all sectors by 2050 for the three scenarios, respectively.



a b c

Figure 17. Electricity (top) and heat (bottom) storage output utilisation during the transition from 2020 to 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

As suggested by the electrical and thermal energy storage outputs, storage will play an important role in balancing a solar-dominated energy system. Installed electrical storage capacity is introduced into the energy system in 2025 with about 1 GWh of installed capacity to a range of 82 to 89 GWh in 2050 for all scenarios, as seen in the top graphs of Figure 18. PHES emerges initially as the primary electrical storage technology, with small share of battery prosumers being introduced. Utility-scale batteries are not introduced on a large scale until 2045, and A-CAES is not introduced until 2050, with a very small share of installed capacity. BPS-1 shows the largest installed PHES capacity whereas BPS-1 has the largest installed battery capacity. Of the total electrical storage output (Figure 19, top), batteries (system and prosumer) have the largest output in BPS-1 and BPS-3 with 17 TWh and 15 TWh, respectively. Conversely, PHES has the largest electrical storage output in BPS-2 with 15 TWh.

Further, as the heating sector is largely electrified, thermal energy storage will be needed to transition away from fossil fuel-based heating. The bottom graphs of Figure 18 show the thermal energy storage needed throughout the transition for all scenarios, which increases to about 2.5 TWh_{th}, 3.5 TWh_{th}, and 1.5 TWh_{th} for each of the respective scenarios. While gas storage dominates the thermal energy storage capacities for each scenario, thermal energy storage outputs have roughly equal shares of TES (DH and high temperature (HT)) and gas storage. Due to existing fossil gas heating in BPS-3, thermal energy storage provides only 81 TWh_{th} in 2050, compared to BPS-1 and BPS-2, which have thermal storage outputs of 105 and 104 TWh_{th}, respectively.

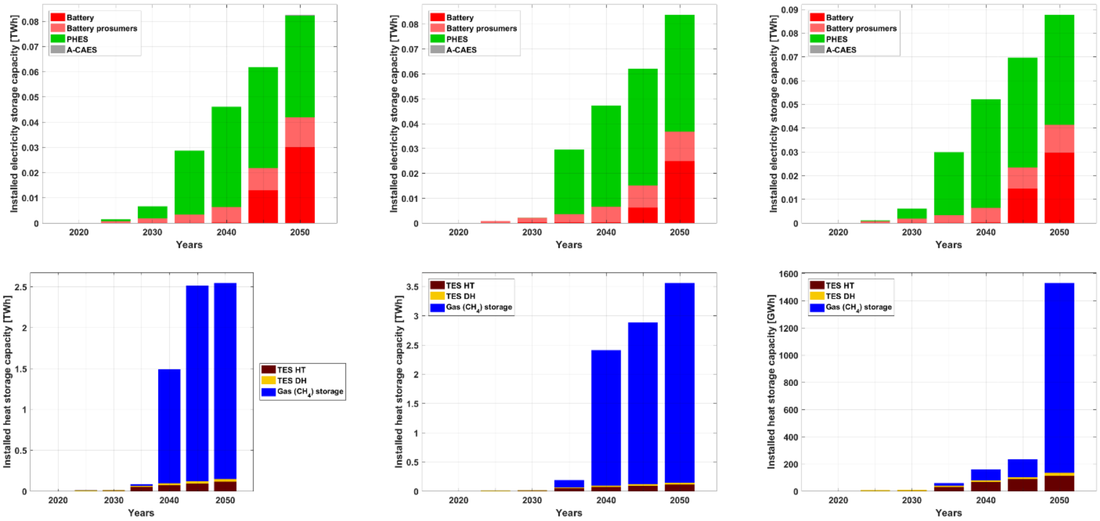


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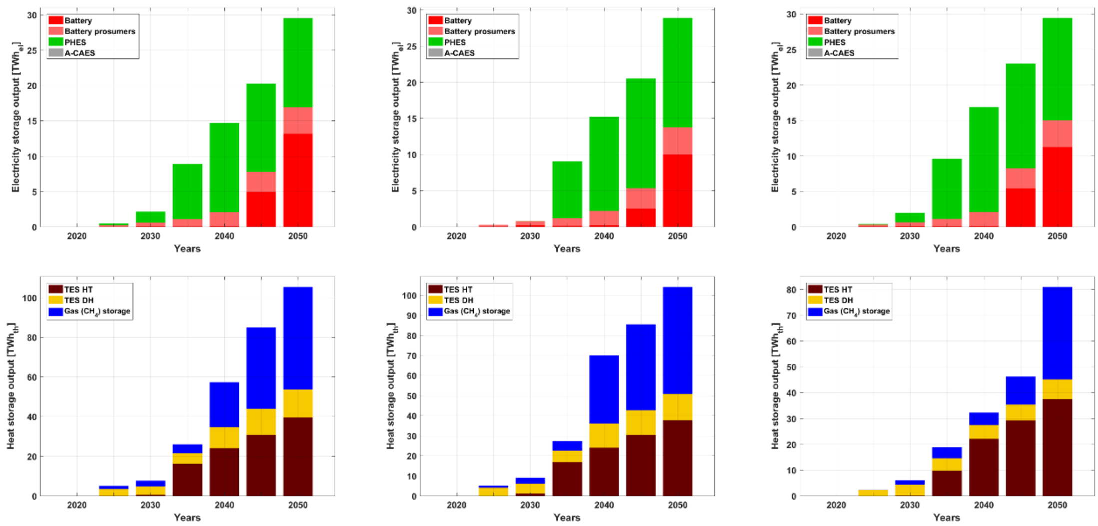
Figure 18. Installed electrical (top) and thermal (bottom) storage capacities for BPS-1 (a), BPS-2 (b), and BPS-3 (c).



a b c

Figure 19. Electrical (top) and thermal (bottom) storage outputs for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

3.7 Interregional transmission

Figure 20 shows that interregional grid transmission varies significantly between BPS-1 and BPS-3, and BPS-2. The overall patterns for each scenario are similar, as grid utilisation largely follows solar production patterns, with the primary difference between the scenarios being the grid transmission capacity required, which reaches a maximum of 6 to 7 GW in BPS-1 and BPS-3, respectively, compared to BPS-2, which has a maximum capacity of around 25 GW. Figure 20 further highlights this difference, as BPS-1 has a total grid export of 4.9 TWh whereas BPS-2 has a total grid export of 105 TWh.

In terms of structure of interregional transmission, shown in Figure 21, the same regions that are net importers in BPS-1 generally remain importers, except for CH, and those that are net exporters remain exporters. These results show that in BPS-1, regions are more energy independent when it comes to their electricity production than in BPS-2. For all scenarios, the regions with the best resources become exporters and the others become importers. BPS-1 shows that CH becomes the largest electricity exporter, whereas BPS-2 shows PT as the main exporting region. Both regions share excellent solar resources and have low electricity demands. This is a significant shift compared to the current electricity trade, where TJ is the primary electricity exporter due to its large share of gas turbine power plants.

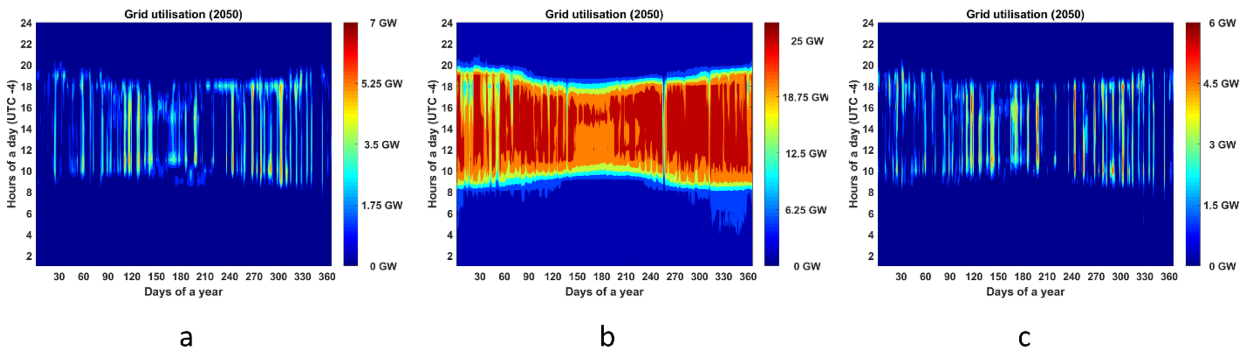


Figure 20. Interregional grid utilisation for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

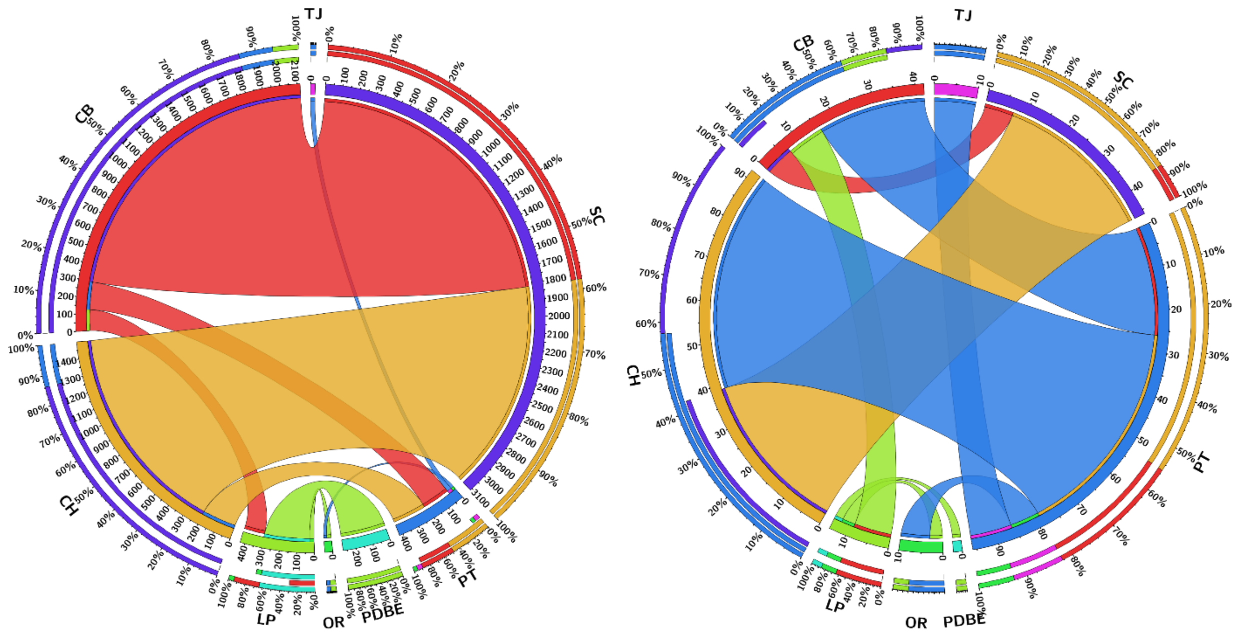


Figure 21. Interregional electricity trade for BPS-1 (in GWh) (left) and BPS-2 (in TWh) (right).

3.8 Regional supply shares

Figure 22 shows the transformation of installed power capacities from 2020 to 2050. Nearly all regions with large power plant capacities have significant shares of gas turbine power plants. By 2050, all regions have significant capacities of solar PV installed, particularly PV single-axis tracking, followed by PV fixed tilted. PV single-axis tracking comprises 76% of solar PV capacity with 86 GW in BPS-1, while PV fixed tilted has 19 GW of installed capacity. Solar PV comes out as the dominant capacity in all regions because of the excellent solar resources located throughout the country. The distribution of installed capacities differs primarily between BPS-1 and BPS-2, however, as BPS-1 has the largest installed capacities in regions with largest energy consumption, in this case SC, CB, and LP. Hydropower existing in the system is kept and slightly expanded during the transition, and is utilised in regions with available hydropower resource, but its role is primarily as balancing solar PV generation. Additional results on the sub-region generation, installed capacity, regional storage capacities, and regional storage output for all scenarios can be found in Appendix I (Figures AI21-AI39).

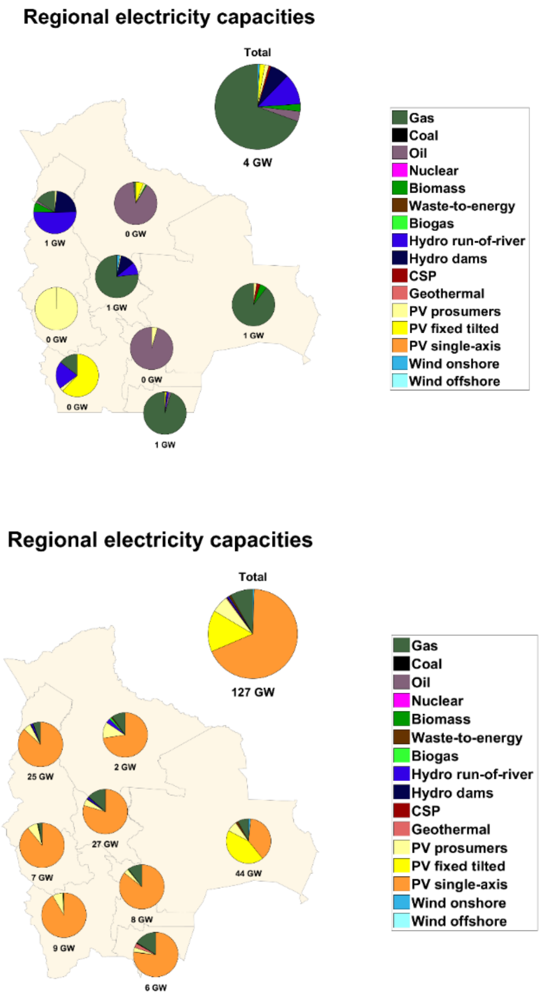


Figure 22. Regional installed electricity capacities in 2015 (left) and 2050 (right) for BPS-1.

3.9 Energy costs and investments

A highly renewable and more efficient energy system naturally implies a reduction in costs for energy services. While a significant increase in primary and final energy demands suggest a rise in energy system costs, a fully sustainable energy system has a notably lower price per unit energy compared to today's levels. Further, while the total final energy demand increases by a factor of roughly 2.5, annual system costs only increase by a maximum of 1.8, as the three scenarios show an increase from 4.4 b€ in 2020 to 8.1 b€, 7.9 b€, and 7.4 b€ in 2050 for the three respective scenarios (see Figure 23). Annual system cost structure transitions from being largely fuel cost dominated to being primarily capital expenditures (CAPEX). Increase in CAPEX suggests that during the transition, fuel imports will reduce, particularly those for fossil oil. Using Bolivia's own excellent solar resources to generate synthetic fuels in BPS-1 and

BPS-2 would result in energy independence and security. Due to the lack of GHG emission costs in BPS-3 fuel costs remain for the fossil fuels used in the heat and transport sectors.

Figure 24 (top) shows that the CAPEX is not dominated by a single technology. While solar PV costs have a significant share of capital costs due to the large capacity of solar PV in all scenarios, large investments are required for TES, PHES, electrolysers, and batteries. During the early years of the transition, this results in a higher cost of energy in 2025 and 2030 for BPS-1 and BPS-2. However, as fossil fuels are removed from the energy system, energy costs are reduced substantially and the total levelised cost of energy decreases from about 45 €/MWh in 2015 to about 33 €/MWh for a fully sustainable energy system. Without GHG emissions costs, this cost is further reduced to about 30 €/MWh. This reduction in energy cost is driven by low cost electricity from solar PV, the levelised cost of electricity (LCOE) of which are reduced by the largest amount in BPS-2 from 105 €/MWh in 2020 to 21.7 €/MWh in 2050. All scenarios see similar reductions in LCOE as BPS-1 has an LCOE of 22.2 €/MWh and BPS-3 has an LCOE of 22.7 €/MWh in 2050. All energy costs and investment results by sector and fuel costs throughout the transition are available in Appendix I (Tables AI31-AI39 and Figures AI40-AI52).

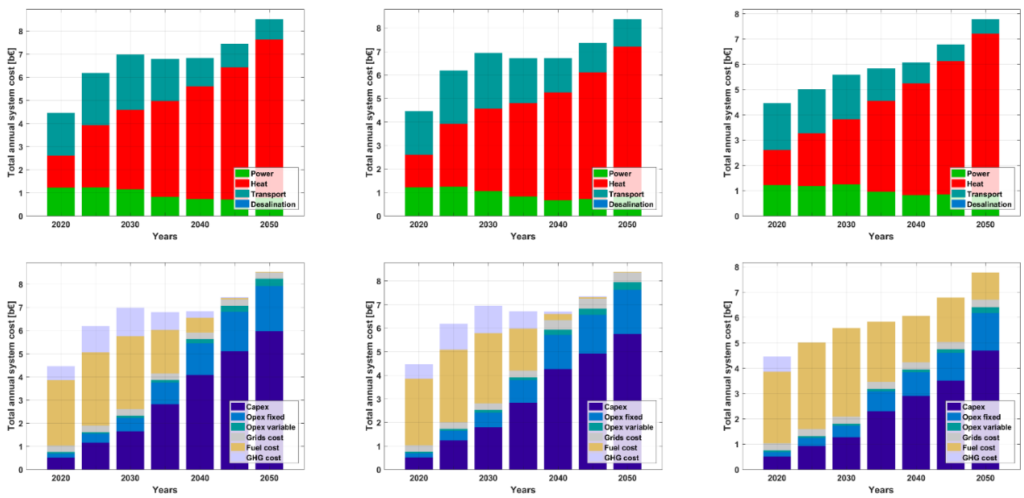


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Figure 23. Annual systems costs by sector (top) and main cost category (bottom) during the transition for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

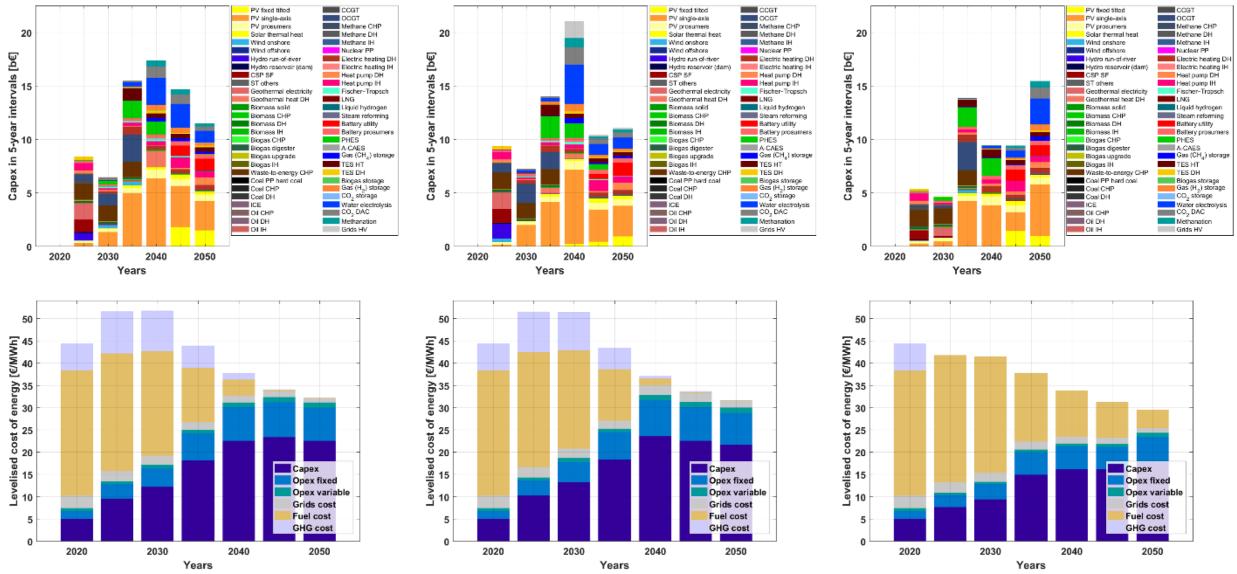

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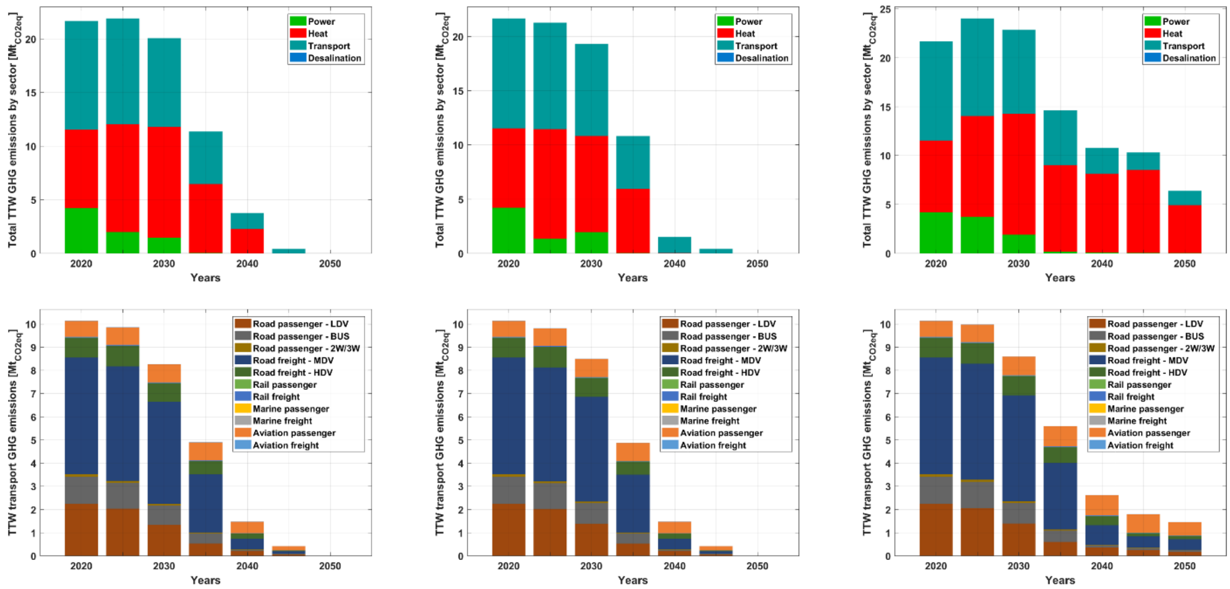
Figure 24. Capital expenditures in 5-year intervals (top) and levelized cost of energy (bottom) through the transition for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

3.10 Greenhouse gas emissions reduction

A transition from fossil fuels to sustainable sources naturally implies an elimination of GHG emissions from the energy system. As depicted in Figure 25 (top), the GHG emissions from the Bolivian energy system can be eliminated from 22 $MtCO_2$ in 2020 to zero by 2050. This reduction can be done drastically in the 2020s from the power sector, and in the 2030s in the heat sector. Conversely, the transport sector remains resilient to phasing out of fossil fuels, and, without GHG emissions pricing and some regulation, will remain in the energy system, as seen in Figure 25c (top). Additionally, BPS-3 shows a notable amount of GHG emissions in the heat sector if no RE targets and GHG emission costs are not applied.



a b c

Figure 25. GHG emissions by sector (top) and in the transport sector by mode and segment (bottom) during the energy transition for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

These simulation results suggest that a fully sustainable energy system for power, heat, transport, and desalination sectors for Bolivia by 2050 is both technically feasible and economically viable, even considering significant growth in Bolivia's energy demand. Scenarios in which primary generation is distributed locally throughout the country and where generation is centralised in regions of best resource availability are both viable alternatives to a scenario without RE targets or GHG emission costs. However, these results also imply that GHG emission costs are required for a fully renewable cost-optimised scenario. Regardless, these results highlight a pathway along which Bolivia can eliminate its direct GHG emissions by 2050 while becoming completely energy independent, thereby ensuring a secure and sustainable energy future.

4. DISCUSSION

The discussion of results is separated into three parts. First, the major findings are discussed within the context of previous works (section 4.1). Second, section 4.2 outlines the limitations of this study. Third, in section 4.3, recommendations for further research in Bolivia, as well as in the sustainable energy transition field, are given.

4.1 Main findings

This study outlines a pathway for Bolivia to achieve a 100% RE system that is both technically and economically feasible. Results of a Bolivian energy transition towards 100% RE by 2050 for power, heat transport, and desalination sectors are the first in this field. Importantly this research provides more detailed results for the South American region, a region of the world that is not well covered by 100% RE research according to Hansen et al. [39]. BPS-1 and BPS-2 show that such a transition is viable for both distributed and centralised (or high transmission) energy systems. Curtailment levels across scenarios amounted to 4.5%, 2.5%, and 4.2% of total electricity demand, respectively. Levelised cost of energy across scenarios have similar findings, with BPS-3 having slightly lower levelised cost of energy compared to BPS-1 and 2. However, these costs do not account for other non-financial benefits to an energy system, such as an energy supply that is fully domestic and sustainable, without GHG emissions, and lower risk, lead to the determination that a fully RE system is of higher quality for the same cost and therefore superior. From strictly economic terms, though, BPS-3 suggests that to achieve a fully RE system, a smart energy policy initiatives are required to properly tax harmful GHG emissions and provide proper supportive incentives for the development of renewables [40].

For the fully renewable scenarios, there are key drivers that lead to low-cost energy, primarily low-cost solar PV [39], affordability of different storage options, particularly with high sector coupling [41], high electrification across sectors, and affordable PtX process primarily starting with renewable hydrogen generated through electrolysers. Further, electric based heating, particularly with heat pumps and direct electric DH, can utilise otherwise excess generation of electricity. Such variable production patterns, though, even with storage options, require flexibility in demand. With such requirements, electrolysers can be organised to operate only at peak hours of production, and following PtX processes, such as FT and methanation, can be operated nearly continuously to generate the synthetic fuels required in the heat and transport sectors.

Previous studies on Bolivia's energy system [16,18,19] primarily consider Bolivia's power sector, and none highlight a 100% renewable electricity system. Candia et al. [18] shows that high non-hydro renewable penetration is technically feasible as early as 2021 and 50% of total capacity being evenly distributed between solar PV and wind penetration provides savings in electricity cost even compared to Bolivia's subsidised natural gas price. Other research, as well as government projections, in [11,13,16,20], show large shares of installed hydropower capacity, with more limited shares of solar PV and wind energy. Moreover, large hydropower installations planned by the Bolivian government is intended to produce export electricity, rather than for use within Bolivia [11]. Social and environmental constraints outlined for different forms of hydropower [42–44] can further extend to future hydropower development and can result in loss of economic value and viability of hydropower installations if construction is delayed.

Additionally, the results show a very limited desalination demand, despite Bolivia's large water resources. In principle, the water resources may be available, but not always where it is finally needed. Further, any water supply to be utilised must fulfil sustainability criteria. Therefore, seawater is preferred to unsustainable freshwater resources. Developing the infrastructure necessary for saltwater desalination requires crossing land outside of Bolivia. Chile in theory would make the most sense, however, existing political issues may prove to be a major burden. A more realistic pathway can be developed through Peru, though it will be much more expensive due to the longer distance.

Sauer et al. [7] study the potential impact of high locally produced electric vehicles in the Bolivian transport sector. These results demonstrate that, given Bolivia's lithium reserves, high electric LDV penetration can provide both economic savings the scale of millions of USD as well several social benefits resulting from local development of lithium and of the vehicles themselves. Such results are dependent on low electricity production costs (LCOE), which this study's findings show reduce most significantly during the transition in BPS-2 from 105 €/MWh in 2020 to 21.7 €/MWh in 2050. However, results from BPS-3 show that without the application of 100% RE targets and GHG emission costs in energy pricing, fossil fuels may remain in the system, so that only 90% RE in TPES can be achieved.

Furthermore, development of gas-to-liquid (GTL) industry in Bolivia through FT processes, according to Velasco et al. [45], can provide a pathway to eliminate oil importation. Considering that this study's results show a notable share of synthetic fuels by the end of the transition, development of such GTL capacities could be done in the short- and mid-term with Bolivia's natural gas resources but the risk of stranded investments for an investment for 20-30 years is high, since importing countries may ban fossil fuels and request fuels free of fossil emissions. Given Bolivia's role as a gas exporter in the region, production and exportation may be able to continue in the short term, as Bolivia has sufficient gas resources [46], and the revenues from natural gas can be used to fund large scale renewable projects. Such has been the case Norway, where a petroleum sector, which is projected to decline in the long-term, dominates the economy, and renewable electricity supplies an increasingly electrified domestic demand [47,48]. Bolivia's natural gas policy has outlined the hydrocarbon sector in a developmental model whose income can be utilised by the State to other economic and social field [49]. However, Ramírez Cendrero [49] also highlights that a surplus based characterisation of the hydrocarbon sector can conflict with other key objectives of an energy sector such as efficiency, energy diversification, energy security, universal supply, and management of environmental impacts.

As previously mentioned, the Bolivian government does not provide any long-term energy planning study, however, [17] states that RE will compose 81% of electricity generation by 2030. Bolivia's scenario for 2027 in [11] states that biomass sources will comprise 8% of total final energy demand. Therefore, this study provides the first results, in BPS-1 and BPS-2, outlining a pathway for defossilisation of Bolivia's energy system that is technically feasible and more cost-efficient, in line with Bolivia's stated development pillars [2]. These efficiency savings can be estimated to about 22%, 14%, and 26% for BPS-1, BPS-2, and BPS-3, respectively. Furthermore, large-scale development of solar PV, particularly in off-grid communities, can serve to reduce energy poverty in Bolivia [50]. These results also highlight the need for smart policy making to promote the development and investment in renewable technologies, many of which are lacking in Bolivia according to Washburn and Pablo-Romero [51].

The primary source of energy for Bolivia from this study is solar PV. Such high shares of solar PV in Bolivia are supported by solar resource findings in [52], which determined Bolivia to be among the ten countries with the maximum solar irradiation for fixed optimally tilted PV systems. Further, such results support the findings of Haegel et al. [53] and Strauch [54] which suggest that solar PV technologies are ready for global scale-up as a central contributor to all energy segments, and that a solar-dominated transition will be done as a complete, disruptive overhaul rather than gradual shift [40]. The share of generated electricity needed for all sectors by 2050 in BPS-1 will be 89% solar PV, 7% OCGT, and 4% from others, including wind energy and hydropower. Similar results can be seen in BPS-2 and BPS-3. Correspondingly, electricity generation across all sectors in BPS-1 would be 93% solar PV, 3% waste CHP, 2%

hydropower, and 3% from others. Bolivia's solar resource has such high abundance that installed solar PV capacity is only 2.3% of the upper limit, corresponding to 0.1% of Bolivia's total area. These results appear to differ somewhat from global and regional South American studies [20,23,55–57] for all energy sectors to achieve the targets of the Paris Climate Agreement [3].

Studies analysing an energy transition pathway for all sectors for South America that consider Bolivia as a region with other countries provide largely varying insights towards a future energy system for Bolivia. Teske [55] suggests for Central South America, which includes Bolivia, that for a 1.5 °C scenario, the power generation structure would be composed of 29% variable RE (mainly solar PV, CSP, and wind energy), 49% dispatchable RE (mainly hydropower and biomass), and 22% dispatchable hydrogen-gas power plants (non-fossil), according to the reference. Ram et al. [23], conversely, find that the region including Bolivia would be one that is based on solar PV, with almost 75% of electricity generation coming from solar PV. In the study of Jacobson et al. [56], Bolivia's all-purpose end load would be covered by 22% wind energy, 15% geothermal, 3% hydropower, 49% solar PV, and 10% CSP. For the whole of South America, Löffler et al. [57], find roughly 40% shares of both hydropower and solar PV, with the remaining 10% covered by wind offshore and onshore. Differences between these studies and the results of this study can be largely attributed to methodological differences and differences in assumptions, in particular cost assumptions as also discussed in [58].

Results from the LUT model for regions with Bolivia [20,21] demonstrates the impact of regional structuring on the outcome of energy transition studies. The multimodal approach of this study allows for diversity in topography, climate, and geographic distributions of resources and consumption to be considered. This is especially relevant given the vast topological and climate differences throughout Bolivia, from the forests of the northeast to the Altiplano in the southwest. In comparison to a neighbouring country with similar conditions [59], results indicate largely differing shares of primary electricity generation; however, the structure of the energy system remains consistent with the results of this study, with all sectors being highly electrified and electricity and heat storage capacities being major drivers of the transition.

Important to note further is that each of these scenarios have a unifying assumption, that nuclear energy is not part of the solution for a 100% RE system. Bolivia currently has no plans to install nuclear capacity, however, the agency for nuclear energy (ABEN) signed a contract in 2017 with Russia to begin studying nuclear reactors of small capacity and develop Bolivia's nuclear competencies [60]. Child et al. [37], Ram et al. [61], and Grubler [62] discuss the risks associated with nuclear power plants including high economic investment, as well as social and environmental risks regarding potential failure, the decommissioning of nuclear plants and treatment of nuclear waste.

4.2 Limitations

Main limitations of this study largely consisted of a lack of information provided by government channels, particularly regarding specific end use demands. While information was provided in a manner that allowed the analysis of Bolivia in a multi-node approach, a method that considers existing transmission capacity and proper geographic distribution of demand and resources, specific end uses of energy by sector were largely lacking. Once data was gathered for 2015, demand and installed capacity was extrapolated for the year 2020. This extrapolation will undoubtedly have some disparity with official numbers that will be published by the Bolivian government and other organizations, such as the International Energy Agency.

Additionally, lack of government projections to 2050 for all energy sectors does not allow for the ability to compare a Best Policy Scenario with the current policies of Bolivia. Such a comparison could provide key insights given the trajectory of government electricity plans to install large hydropower plants, with only limited shares of solar PV, the dominant energy supply technology of this study. Similarly, without resource potential estimates from the Bolivian government aside from hydropower, the results of installed renewable capacity cannot be compared with what the government finds to be technically or economically feasible. A further limitation in this regard is that Bolivia, for the sake of this study, is treated as an energy island. Therefore, the model does not treat excess electricity as exportable and such electricity is curtailed, incurring extra system costs. Given Bolivia's potential to be an exporter of electricity according to Pinto de Moura et al. [14], further investigation of Bolivia's regional export potential would be of interest in a high solar PV penetration scenario.

While a RE system would have clear social and economic benefits and limited social and environmental impact, public attitudes towards RE installations can vary among socio-demographics and political preferences [63]. Availability of low-cost RE is especially important with regards to inclusive development and development of low-income, remote communities, which typically pay proportionately more for energy services, improves household standards of living, particularly among women [40,44,64]. Such projects can affect further diversification of Bolivia's economy and reduce Bolivia's dependency on gas exports [49]. Remote communities can benefit much from a stepwise electrification with RE, in particular solar PV for least cost in a challenging economic environment [65]. Considering that future gas exports would require development of unutilised reserves, increased socio-environmental scrutiny must be placed on the evaluation of such sites.

Given that Bolivia's PT region is home to the largest lithium reserve in the world [7], development of cost of Bolivia's own lithium usage as extraction of this resource develops may influence decision makers regarding lithium applications in the Bolivian energy system. Lu et al. [66] highlight lithium as a key to low carbon global transitions, particularly for its use in batteries. However, Hancock et al. [67] state that while lithium mining could bring development and fiscal flows to underdeveloped parts of the country, it is a water intensive process that uses toxic chemicals that bring along waste disposal issues beyond those that exist in Bolivia's public waste management system [68]. While Ali et al. [69] and Hancock et al. [67] suggest mineral development frameworks that involve public-private partnerships, Bolivia is a country that is vulnerable to the downfalls of such partnerships. Furthermore, lithium mining could detract from eco-tourism in the Uyuni salt flats, which is home to a significant amount of Bolivia's lithium resource [67].

The results of this study find that a system that prioritises interregional transmission rather than a more distributed generation is slightly more cost-efficient, however, value added from inter-department electricity trade compared to increased utility-scale electricity storage may be of interest for future policymakers in Bolivia. The development of Bolivia's lithium mining industry may further influence the discussion regarding the trade-offs between increased utility-scale storage and power transmission. Previous analysis and development goals of Bolivia to become an electricity exporter can similarly affect the additional value created from development of internal grid transmission.

4.3 Future works recommendation

This study acts as a first step in developing a dialogue and initial understanding of how a transition for Bolivia could occur. As a next step, the authors propose further research in

Bolivia's energy system, and additional studies of Bolivia's energy transition utilising different models. If the Bolivian government provides policy projecting Bolivia's energy development to 2050, additional research should be conducted to compare that policy with this study's Best Policy Scenarios. Furthermore, analysis of social acceptance and use of distributed renewables to reach universal access to basic services can provide more depth in the social aspects of an energy transition. Finally, future studies can estimate other socio-economic and environmental effects during the transition to a fully sustainable system, such as health costs savings, job creation [70], and other reduction of harmful materials.

5. CONCLUSIONS

Bolivia is home to some of the highest solar resources in the world, and other renewable resources are abundant, which results in RE and storage technologies being able to meet high growth energy demands for all sectors at every hour throughout the year. Low-cost solar PV drives this transition to a fully sustainable energy system. BPS-1 and BPS-2 show renewable electricity as a base for a 100% RE system that is technically and economically competitive to a scenario that does not include GHG emissions pricing. Such a system that is driven by renewable electricity is significantly more efficient than current practices. An increase in efficiency and significant investment in solar PV are key reasons for a reduction in levelised cost of energy from 45 €/MWh in 2020 to 33 €/MWh in 2050. Additionally, BPS-1 and BPS-2 both imply zero GHG emissions from all energy sectors, supporting Bolivia's commitments to the Paris Climate Agreement and achieving independence from fossil fuels by 2050.

While current policy places Bolivia's power sector in a strong position to achieve zero GHG emissions, heat and transport sectors require ambitious national policy targets. Future studies can further analyse the effects of a transition for Bolivians, in order to understand the Bolivian energy transition in socio-economic terms. Results of this study show that Bolivia has the potential of becoming one of the first countries with a sustainable energy system, which can be achieved in conjunction with significant increases in energy demands.

Chapter 2: Assessment of the evolution of energy transition, multi-nodal structuring and model flexibility in sector coupled 100% renewable energy system analyses

1. INTRODUCTION

In response to growing threats from the climate crisis, research in design of 100% renewable energy (RE) systems has gained increased focus to outline pathways through which countries, regions, and the world can transition away from fossil fuels and towards large-scale RE supply in energy systems. Since the mid-2000s, over 180 articles have been published within the field of 100% RE system research [39]. Such research has employed many different energy system models (ESMs) to verify the viability of overnight and transition scenarios, demonstrating how variable RE generation can be balanced through storage, sector coupling, grid interconnection, supply and demand side management, and load shifting [41,71]. Compounded by radical cost reductions in solar PV and wind technologies, presenting the technical feasibility of 100% RE [41] has increased decisionmakers' interest, as more and more countries set targets for renewable electricity by 2045 or 2050 [72].

ESMs embody a wide array of characteristics that influence the results from these models. With energy systems based on variable RE sources and with increased flexibility in future energy systems, the temporal resolution of an ESM is of utmost importance, with hourly resolution being considered most suitable for analysis of 100% RE systems. However, a number of tools reviewed by [73,74] show several tools with high numbers of users based on aggregated annual energy balances. By modelling based on aggregated time slices, Kotzur et al. [75] find that existing approaches are unable to achieve seasonal storage system design similar to that based on full hourly resolution. Spatial resolution, similarly, allows for more detailed modelling of a country or regions, which can account for geographical differences in topology, resource distribution, demand, and distribution systems. Brown et al. [71] find that for the region of Europe, a multi-node approach finds a similar structure of results as the single node case of [76]; however, a multi-nodal approach allows a greater understanding of the system characteristics between regions and transmission bottlenecks that may exist in interregional transmission. These effects are further studied by Child et al. [77], finding that for the case of Europe, interregional transmission can reduce the total power system cost by about 10%, while about 15% of the total generated electricity is exchanged, leading to higher shares of wind electricity, compared to a case of separated nodes. Such a modelling approach can be similarly applied in studying the techno-economic viability of interregional power transmission on a global scale, as discussed in [78]. This study that reduced benefits are achieved through global grid interconnections due to low-cost abundant renewable electricity, the respective cost of very long power transmission lines, and the increased complexity of a global electric interconnection.

Although studies have analysed multiple ESMs [2], no research has compared the cost optimisation LUT Energy System Transition model [22,23,79] to other widely used ESMs, such as the simulation model EnergyPLAN [80,81]. These two models have been selected since they are the most applied models for 100% RE scenarios, which are further detailed in section 2. Consequently, this research serves to provide a detailed analysis between the LUT Energy System Transition model and EnergyPLAN, by comparing cost-optimised 100% RE scenarios with identical assumptions for the Sun Belt for the case country Bolivia. The Sun Belt region is selected since most people in the world live there, and most additional energy demand can be expected in the Sun Belt in the decades to come [22,23,79]. The ESM comparison also includes an investigation of the differences of overnight and transition approaches and the consequences of single-node to multi-node approaches. The paper begins after the review of ESMs for 100% RE scenarios in section 2 by describing the methods of each of the two ESMs and their major differences, followed by results of fully sector coupled, least-cost overnight scenarios, where the difference of overnight to transition scenarios and deviations of single-node to multi-node scenarios can be observed. Afterwards, the structure of the results is discussed between the two models, and limitations from the models are described.

2. REVIEW OF ENERGY SYSTEM MODELS FOR 100% RENEWABLE ENERGY SCENARIOS

The following review of ESMs is focussed on those models used for 100% renewable energy system analyses, which can cover a multi-sector energy system while enabling sector coupling and full hourly resolution. This focus is applied to sharpen the view on the research questions of this article.

ESMs that have been utilized in research have a variety of differing characteristics, as discussed in Connolly et al. [73]. A limitation historically in 100% RE research has been a lack of a universal definition of 100% RE, as many studies focus solely on the power sector, while an increasing share of research in the past five years has expanded its scope to the heat and transport sectors [39]. At the same time, the industry sector is still not yet covered well in the research of 100% RE, and negative CO_2 emission options [82–84] are practically ignored. A lack of sector integration in RE research has corresponded to 100% RE targets at national and local levels to be focused primarily on the power sector, with Denmark being the only country with a target of 100% RE for all sectors [72]. Additionally, while many ESMs have been shown to be adequate in satisfying techno-economic requirements of fully sustainable energy systems, ESMs and publications of their results have been faced with challenges affecting their comparability of results. Some of the challenges include uncertainty and transparency of assumptions, optimization of complex and interconnected systems, and capturing the potential socio-political and human barriers to a low carbon energy transition [85,86].

ESMs that have been utilised for analysing 100% RE systems are, for instance, EnergyPLAN [80,81], the LUT model [22,23,79], TIMES [87], HOMER [88], REMix [89], AU model [90], PyPSA [71], LOADMATCH [91], NEMO [92], ISA model [93], H_2RES [94], GENeSYS-MOD [57], MESAP/PlaNet [95], among others, as summarized in Table 2. The analyses presented in Table 2 are based on the latest status of the 100% RE system analyses published in scientific journals as continuously recorded at LUT. In total 386 articles are recorded as of May 2020. The displayed citations are as of early January 2020 recorded by Scopus. The by far most used ESMs for 100% RE studies in scientific articles are EnergyPLAN and the LUT model. The only discontinued model is H_2RES, while the learnings with the AU model seem to be integrated in PyPSA, which is thus used instead. Only half of the most used models are able to describe interconnected nodes, thereof EnergyPLAN caught up recently, and not all are capable of full hourly resolution. However, almost all are capable of multi-sector modelling, and only two models are capable of detailed industry modelling, thereof the LUT model caught up recently [26]. Not a single ESM used for 100% RE system analyses is able to describe the most relevant CO_2 direct removal (CDR) options [96], which is a clear deficit to be overcome. At least the LUT model started to describe direct air carbon capture and storage (DACCS) [83,84]. Almost all leading ESMs are able to develop optimised solutions, while all ESMs capable of optimisation can be also used for simulation type modelling, as regularly demonstrated in respective scenarios. Interestingly, only half of the leading ESMs can describe transition pathways, which is a most relevant functionality to describe trajectories from the present energy system to a 100% renewable future status. The LUT model is the only ESM combining the key features for comprehensive energy system analyses: full hourly resolution, multi-node, multi-sector, optimisation and transition model. Since most of the leading ESMs are continuously further developed, limitations could be already overcome for the one or other ESM. However, this has not yet been seen in scientific journal publications.

Table 2. Leading Energy System Models ranked by number of published journal articles. Some selected key functionalities of the leading ESMs are displayed, as they are regarded to be key for further progress in the field of 100% RE system analyses.

		citations		model used for 100% RE		inter-connected multi-node	full hourly	multi-sector	detailed industry	relevant CDR	optimi-sation	simu-lation	transi-tion	over-night
Model	articles	total	2019	earliest	latest									
EnergyPLAN	55	4259	822	2006	2020	yes	yes	yes	no	no	no	yes	no	yes
LUT model	50	795	377	2015	2020	yes	yes	yes	yes	no	yes	yes	yes	yes
TIMES	14	341	108	2011	2020	no	no	yes	yes	no	yes	yes	yes	yes
HOMER	14	652	146	2007	2020	no	yes	no	no	no	yes	yes	no	yes
REMix	9	252	97	2016	2018	yes	yes	yes	no	no	yes	yes	no	yes
AU model	16	989	187	2010	2018	yes	yes	no	no	no	yes	yes	no	yes
PyPSA	11	142	87	2017	2020	yes	yes	yes	no	no	yes	no	no	yes
LOADMATCH	7	519	212	2015	2019	no	yes	yes	no	no	no	yes	yes	no
NEMO	7	428	78	2012	2017	yes	yes	no	no	no	yes	no	no	yes
ISA model	7	41	18	2016	2020	no	yes	yes	no	no	yes	no	no	yes
H_2RES	6	595	53	2004	2011	no	yes	yes	no	no	no	yes	no	yes
GENeSYS-MOD	6	36	24	2017	2019	yes	no	yes	no	no	yes	no	yes	no
MESAP/PlaNet	5	134	43	2009	2018	no	no	yes	no	no	no	yes	yes	yes
others	187	6311	1390											
total	389	15494	3642											

Some key features of ESMs in the recorded 389 scientific journal articles on 100% RE system analyses are reported in the following. Full hourly resolution is developing increasingly as a standard, as 73% of all articles use that temporal resolution. Three quarters of all articles analyse features of fully 100% RE systems in the overnight approach, while already 24% of the analyses describe pathways of how to transition from the present state to the 100% RE target system. About half of all 100% RE system analyses research the power sector without interaction of other energy sectors, while a quarter of all analyses analyse integrated energy systems of at least the power, heat and transport sectors, and about 10% each of all articles analyse integrated power and heat, and power and desalination systems. Nearly 60% of all 100% RE system analyses are of the cost optimisation type, while 30% of all analyses are of the simulation type.

All leading ESMs fail to offer an alternative for Integrated Assessment Models (IAMs) for sophisticated energy system analyses under long-term climate change constraints [39]. The major gaps for emerging to an alternative to IAMs are a full and more detailed industry sector representation, covering the relevant CDR options, and covering the full 21st century, as most leading ESMs for 100% RE systems try to find pathways for a fully RE system until 2050, but with no longer term energy system description.

In the following, EnergyPLAN and the LUT model are considered in more depth. EnergyPLAN, introduced in 2006 [97], has been used in multi-sector 100% RE studies for the Aalborg Municipality [98], Åland Islands [30,99], Macedonia [100], Denmark [101,102], Scotland [103], Ireland [104,105], Finland [106], South East Europe [107], and the European Union [76], among others. The LUT model, introduced in 2015 [108] and inspired by an earlier model [109], has been utilised in 100% RE studies for global analyses of the power sector [22] but also all sectors [23,79], detail sector coupling studies including the industry sector [26], applied for major regions as transition model for Europe [110] and Northeast Asia [111], while overnight scenarios have been applied for all major regions [78], country studies have been applied for single-node overnight [112], single-node transition [113] and multi-node transition [114] cases. The latest studies utilising the LUT model cover multi-sector, transition scenarios with partial sector coupling [59], and with multi-node, full sector coupling comparing different scenarios (Chapter 1).

3. METHODS

This section describes the methods through which the overnight scenarios for the selected case country Bolivia were developed and is divided into two main sections. First, the LUT Energy System Transition model [22,23,79] is described for its single-node and multi-node overnight and transition scenarios, as it forms the basis and assumptions used in the setup of EnergyPLAN. Second, the modelling tool EnergyPLAN [80,81] is discussed. These model results are then compared to each other through a reference scenario set in 2020. Last, the assumptions made in EnergyPLAN to meet those in the LUT model are discussed in detail, and a description of scenarios developed will be introduced. Results for an overnight scenario in EnergyPLAN will then be presented along with overnight and transition scenarios from the LUT model for the case of Bolivia.

3.1 LUT Energy System Transition model

This research utilised the LUT Energy System Transition model [22–24] to develop overnight scenarios for the Bolivian energy transition. Figure 26 shows the process flow of the LUT model. This model was originally developed for the power sector only in an overnight design [32], further developed for describing a full transition scenario [22], and in a subsequent step designed with a full coupling of power and heat sectors [24]. In the meantime, the LUT model has been updated to integrate the power, heat, transport [23,79], and desalination [25] sectors, and, finally, the industry sector [26]. An important update to the model inputs, though, was made in this research, as financial and physical input parameters were updated to be fully based on lower heating values (LHV) rather than a mix of lower and higher heating values (HHV), as detailed in section 3.6. All sectors are fully coupled, as shown in Figure 27, as described with the target function and the energy balance in Equations 1 and 2 shown in section 2 of Chapter 1.

The model functions with linear optimisation under predefined constraints, in full hourly resolution for an entire year, applying cost-optimal simulations. Weather data for the year 2005 is used to determine resource availability as described in Bogdanov et al. [22]. Typically, this model uses historical installed capacities in a given energy system and other constraints to determine a least cost energy system. However, in this study, overnight scenarios are developed to determine the least cost energy system in full hourly resolution for all hours of the year in 2050, without considering currently installed capacity.

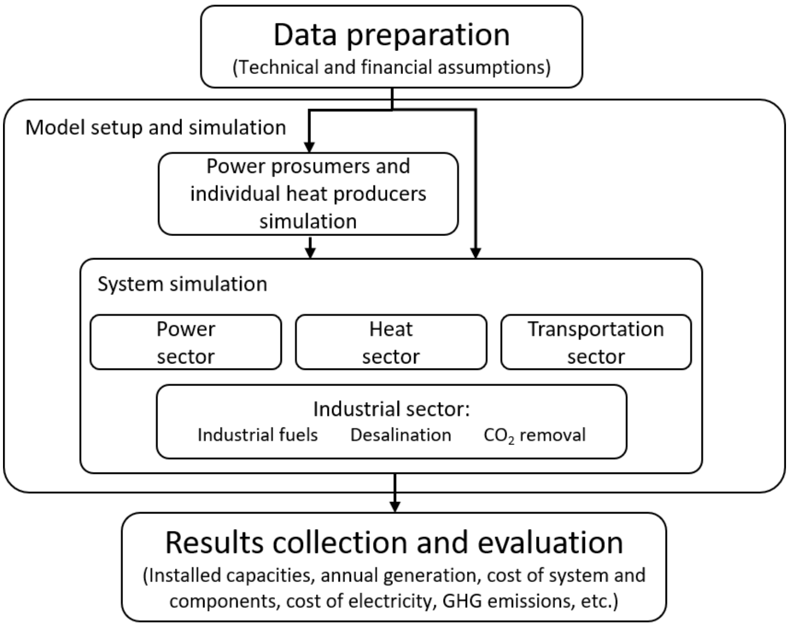


Figure 26. Fundamental structure of LUT Energy System Transition model [22,23,79], similar to Figure 1 of Chapter 1.

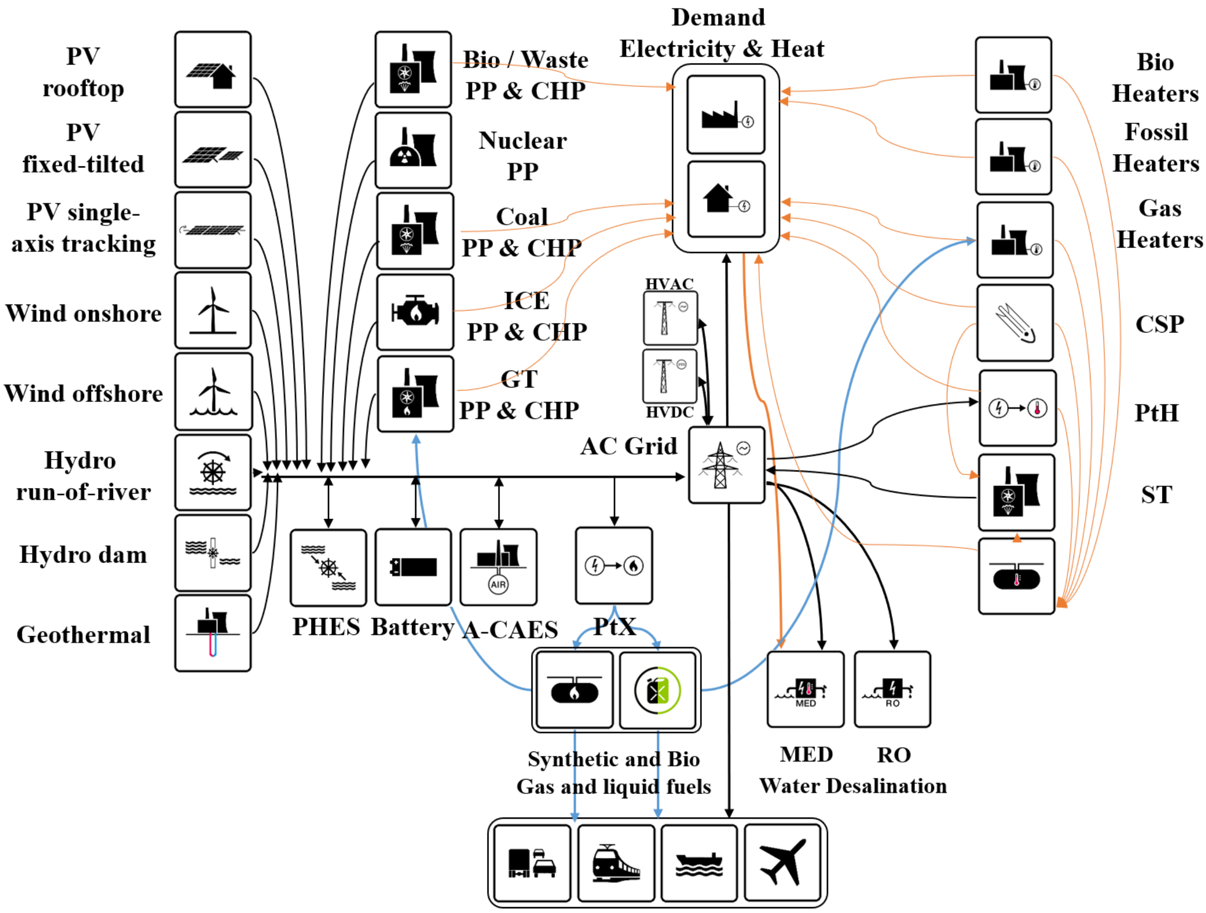


Figure 27. Schematic of the LUT Energy System Transition model for the coupled sectors power and heat [24], transport [23], and desalination [25], similar to Figure 2 of Chapter 1.

3.2 The EnergyPLAN simulation tool

The EnergyPLAN system analysis tool is a deterministic input/output computer modelling tool that has been used in the design of regional, national, and local energy systems. As a deterministic model, EnergyPLAN will always provide the same output for a given input. The structure of the EnergyPLAN model is shown in Figure 28. Since its release in 1999, the tool has been continuously updated, with its most recent version (15.0) being released in September 2019. Due to familiarity with a previous version (13.2), this version was utilised in this research. Documentation for the EnergyPLAN tool version 13.2 detailing its full functionality can be found in [115], and its advantages have been discussed extensively [73,80,116]. An important distinction between EnergyPLAN and the LUT model is that EnergyPLAN is a simulation tool, rather than an optimisation tool. Therefore, optimisation must be done manually by the user through multiple iterations. Due to the quick simulation time, though, iterations can be performed in a timely manner, allowing the modeller to see how input adjustments affect results and take the role of the optimiser. As the optimiser, the user must define the optimisation criteria, and those that have been applied in studies using EnergyPLAN have been detailed in [80]. To maintain consistency in assumptions between the two models, this study seeks to optimise the Bolivian energy system in 2050 by finding the system with least annualised costs in a system with zero greenhouse gas emissions for fulfilling the ambitious target of the Paris Agreement and the Sustainable Development Goals of United Nations [3,117].

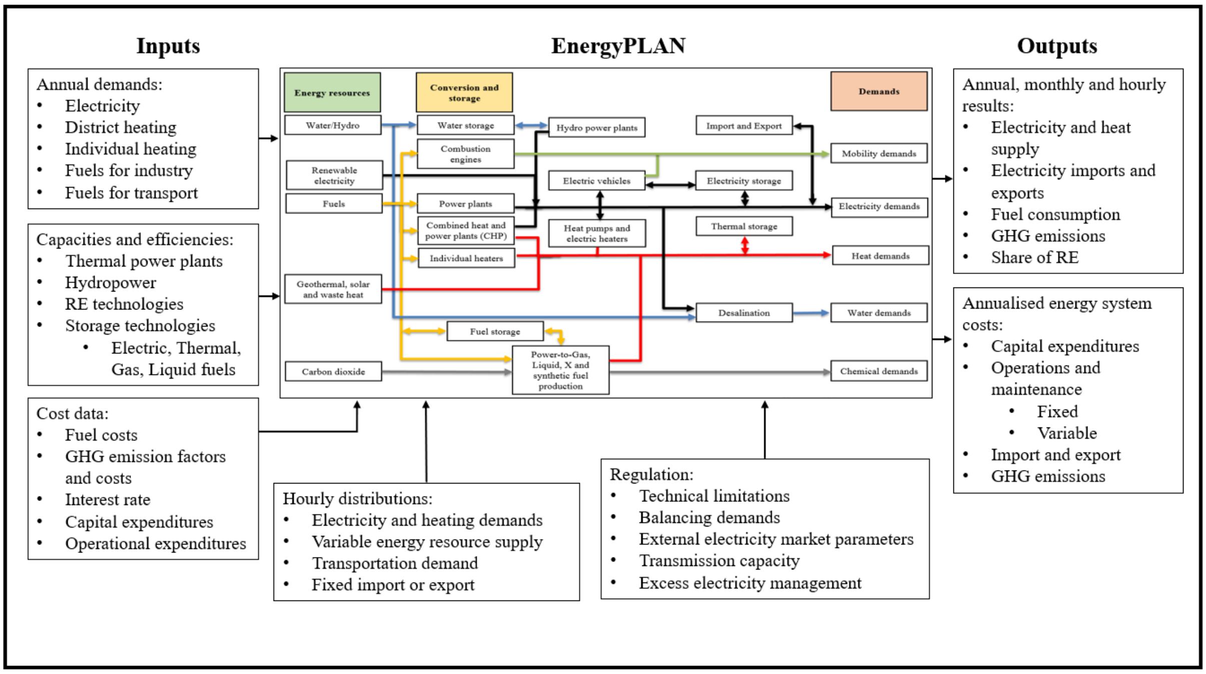


Figure 28. Main inputs and outputs from EnergyPLAN simulation tool. Adapted from [103].

3.3 Geographic application for a Sun Belt country

Data was collected as described in Chapter 1, to develop demand projections for Bolivia. In the multi-node scenario, Bolivia was separated into 8 regions according to Bolivia's 9 administrative regions, combining Pando and Beni into one region due to their low energy consumption, especially with respect to its regional neighbours. Bolivia's subdivisions are structured as follows: Pando and Beni (PDBE), La Paz (LP), Santa Cruz (SC), Cochabamba (CB), Oruro (OR), Potosí (PT), Chuquisaca (CH), and Tarija (TJ). Figure 29 shows Bolivia separated into its subdivisions with capitals of the regions being marked as centres of consumption. In the single-node scenario, Bolivia is modelled as a single region, and data was aggregated into single values for Bolivia as a whole, rather than having data categorised by sub-regions.

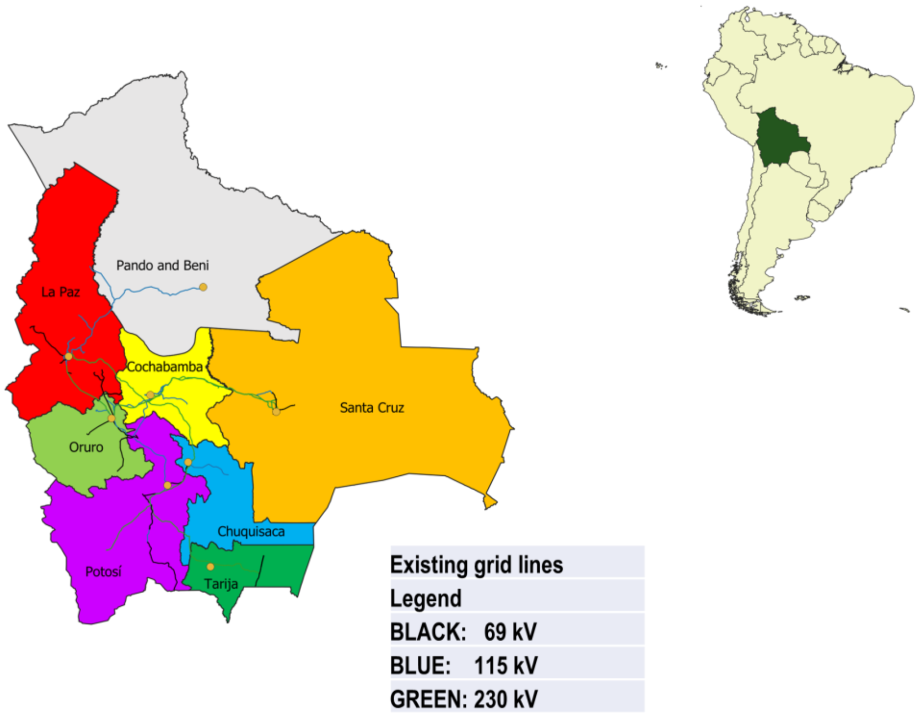


Figure 29. Bolivia separated into its respective subregions, centres of consumption and existing grid infrastructure, as adopted from Chapter 1.

By sector, demands were categorised into their respective final uses. The power sector was categorised among residential, commercial and industrial end-users. Heat demand was attributed to four different final heat uses of space heating, domestic hot water heating, industrial process heat, and biomass for cooking. Water-based heating demands were further organised into low, medium, and high temperature heating demands.

For the transport sector, transport demands data from the Bolivian government [4] were separated into road, rail, marine, and aviation segments according to Khalili et al. [29] and Balderrama et al. [16] and were then further divided into passenger (in p-km) and freight (in t-km) for each transport segment. The road segment demand was then allocated to passenger light-duty vehicles, 2-wheelers/3-wheelers, passenger bus, freight medium-duty vehicles, and freight heavy-duty vehicles. Using [29], the final transport demand was calculated based on specific vehicle energy demand and vehicle technology. As described in Chapter 1, the future projections for final energy demand were done largely based on government projections to 2030 [11], which projected significant growth in heat demand for industry and universalisation of basic services and access to electricity, and extrapolated to 2050 assuming a similar growth rate.

Resource potentials for Bolivia were then estimated for an array of RE technologies. Real weather data was used to estimate the solar, wind and hydro resources [31–33]. Potentials for biomass and waste resources were classified into solid biomass wastes, residues, and biogas according to Chapter 1, and are shown in Table 3. Additionally, geothermal potential estimates were determined according to Aghahosseini et al. [35] and pumped hydro energy storage (PHES) potential estimates were done according to Ghorbani et al. [36]. Resource profiles for solar PV fixed-tilted, single-axis tracking, and wind onshore (E-101 at 150 m) are shown in Figure 30. Upper capacity limits for renewable resources are shown in Table 4.

Table 3. Sustainable annual biomass resource potentials for Bolivia in TWh per year.

Region	Biomass Solid waste	Biomass Solid residues	Biomass Biogas
PDBE	0.47	0.25	1.06
LP	2.04	0.15	1.52
SC	20.12	0.42	0.98
CBBA	2.08	0.07	0.69
OR	0.53	0.01	0.72
POT	0.52	0.02	1.02
CQ	0.60	0.02	0.78
TJ	0.50	0.02	0.39
Total	26.86	0.96	7.16

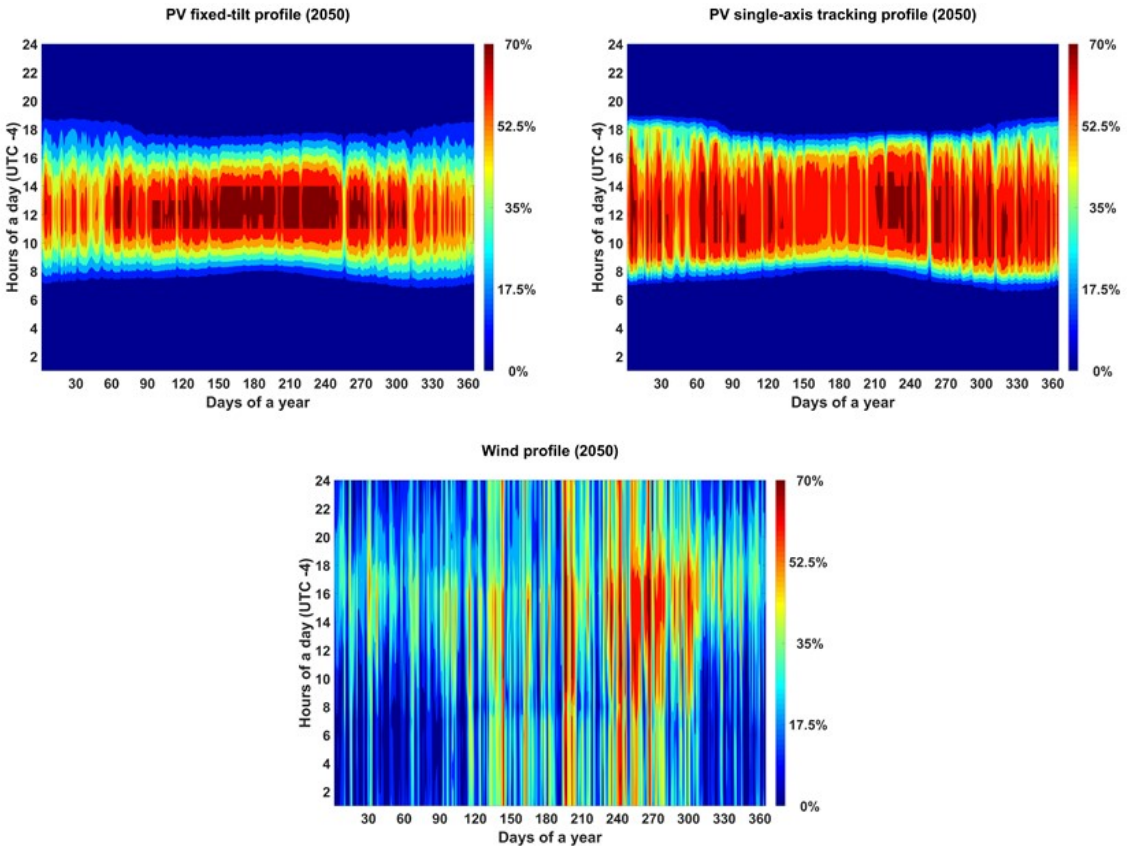


Figure 30. Renewable resource profiles for PV fixed-tilted (top left), PV single-axis tracking (top right), and wind onshore (bottom).

Table 4. Renewable resource capacity upper limits for Bolivia.

Region	PV optimally titled (GW)	PV single-axis (GW)	CSP field (GW_{th})	Wind onshore (GW)	Hydropower (GW)	Geothermal (GWh_{th}/a)
PDBE	1248	1248	2497	93	4.1	0
LP	603	603	1206	45	1.3	0
SC	1668	1668	3336	125	0.4	6152
CBBA	250	250	501	19	2.2	0
OR	241	241	482	18	0	429
POT	532	532	1064	40	0.1	0
CQ	232	232	464	17	0.3	0
TJ	169	169	339	13	0.6	6464
Total	4944	4944	9887	369	9.0	13044

3.4 Verification of EnergyPLAN and LUT model reference

To demonstrate the accuracy of results between EnergyPLAN and the LUT model under identical inputs, a reference scenario was constructed for the year 2020. Input data was extrapolated from 2015 fuel consumption and power plant data available from Bolivia's Ministerio de Hidrocarburos and Autoridad de Fiscalización de Electricidad y Tecnología Nuclear [4,6]. Final power demand was defined as 10.5 TWh_e and final heat demand was set at 52.4 TWh_{th}. Distributions were established based on demand distributions utilised in Chapter 1 as representative of the whole country, shown in Figure 31. Similarly, PV, wind, and hydro resource distributions used in the LUT 2020 reference were also used in EnergyPLAN. To account for the fact that EnergyPLAN utilises a 8784-hour year (with leap year) while most other models use the standard of 8760, data for December 31 was duplicated when being converted from LUT model data. Fuel demands by sector were then established based on data from the 2020 results from the LUT model. Household heating was modelled solely through individual heating, while industrial heating was modelled using district heating (DH) Group 3 in EnergyPLAN (large scale, centralised). A comparison between the two models for the year 2020 is shown in Table 5. A noticeable difference can be seen in the condensing power plant (PP) production, as the LUT model produces about 2 TWh_e more than that of EnergyPLAN. This is largely due to grid losses that exist in the modelling of Bolivia, which considers real grid distances. This result affects the total fuel consumption, shown in Table 6, and was adjusted for by reducing the efficiency of the condensing PP input as well as by manually adjusting the fuel inputs. Because EnergyPLAN models condensing PP as one aggregate power plant, different power plant technologies cannot be individually defined not can there be an accounting of differing efficiencies. However, with manual manipulation, fuel consumption differences were brought within acceptable margins. This issue, though, will not be as significant of a problem as fossil fuel consumption is completely phased out in the 2050 Bolivian energy system.

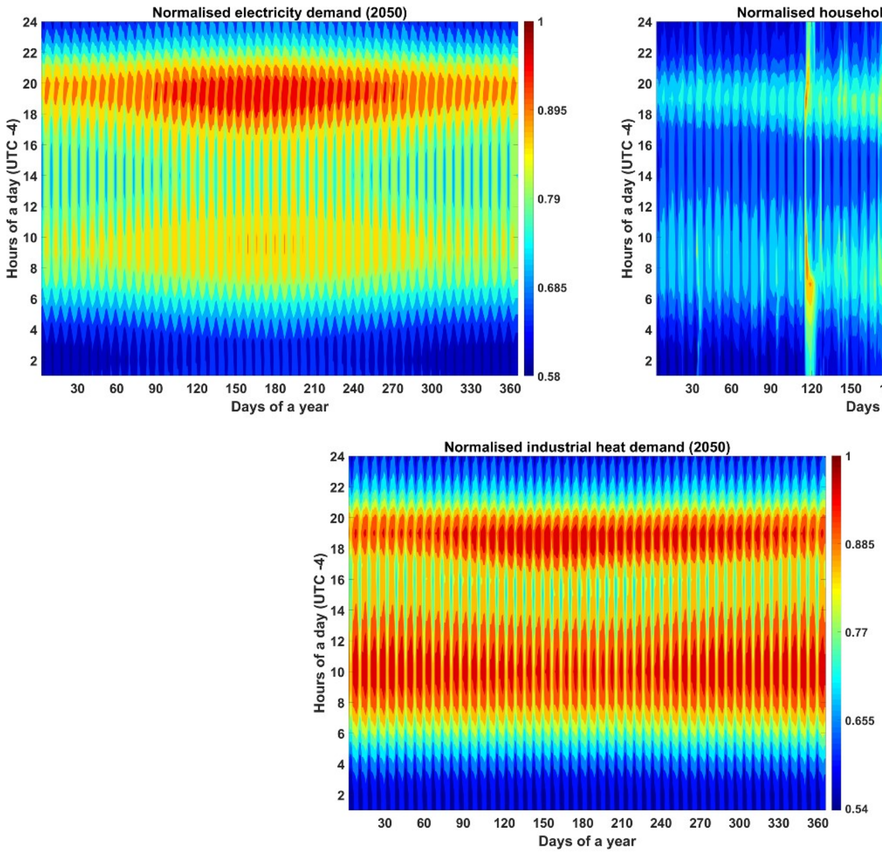


Figure 31. Normalised demand distribution for power sector (top left), household heat (top right), and industrial heat (bottom) demands.

Table 5.Comparison of EnergyPLAN and LUT model power production results for the year 2020.

Production mode	*Annual Production calculated by EnergyPLAN (TWh$_e$)*	*Annual production calculated by LUT model (TWh$_e$)*	*Difference (absolute) (TWh$_e$)*	*Difference (relative)*
Hydro run-of-river	2.00	2.088	-0.088	-4.4%
Hydro dam	1.37	1.368	0.002	0.1%
Wind onshore	0.06	0.056	0.004	6.7%
Solar PV	0.23	0.238	-0.008	-3.5%
Condensing PP (OCGT, CCGT, ICE, ST)	6.90	8.993	-2.093	-30.3%
Grid losses	-	1.9	-	-
Curtailment	0	0.283	-0.283	-

Total domestic production	10.56	10.562	-0.002	<0.1%

Table 6.Comparison of EnergyPLAN and LUT model fuel consumption results for the year 2020.

Consumption parameter	*Fuel use by EnergyPLAN (TWh)*	*Fuel use by LUT model (TWh)*	*Difference (absolute) (TWh_e)*	*Difference (relative)*
Coal	0	0	0	-
Oil	40.40	40.75	-0.35	-0.9%
Gas	43.19	43.20	-0.01	<0.1%
Nuclear energy	0	0	0	-
Biomass	25.79	25.57	0.22	0.9%
Wind	0.06	0.056	0.014	6.7%
Solar PV	0.23	0.238	-0.008	-3.5%
Hydropower	3.37	3.456	-0.086	-2.6%
Total fuel consumption	113.03	113.27	-0.24	-0.2%
CO_2 emissions (Mtons)	21.501	21.5	0.001	<0.1%

3.5 Fundamental differences between EnergyPLAN and LUT model

This section addresses some of the modelling differences that exist between the two ESMs used in this study. The first modelling difference that needed to be addressed is the way that the LUT model classifies heating demands. Industrial heating demands are classified at three temperature levels, as described in [24], and all individual heating demands are considered LT demands:

- High temperature (HT) heat, greater than 1000-1150 °C, which can be provided by fuel-based boiler/furnaces;
- Medium temperature (MT) heat, between 150-1000 °C, which can be provided by heating rod and stored in thermal energy storage;
- Low temperature (LT) heat, below 100-150 °C, which can be provided by CHP plants, heat pumps, and solar thermal collectors, and can be stored in district heating storage.

Higher temperature supply can be used to cover lower temperature demand. MT can cover LT and HT can cover MT and LT. Steam turbine installations consume both MT and HT heat.

In EnergyPLAN, industrial heating demands are modelled through fuel inputs to industrial heating processes, without considering the technologies used to supply the heating demands, with DH and individual heating (IH) supplying household demands. District heating in EnergyPLAN is separated based on technologies available, with the following groups:

- Group 1 representing DH systems with no CHP;
- Group 2 representing DH systems based on small CHP plants;
- Group 3 representing DH systems based on large CHP plants.

To address the differences in heat classification, household heat was limited to individual heating technologies, and industrial heating demands were distributed among the three groups with HT in Group 1, MT in Group 3, and LT in Group 2. This setup allowed for the most consistent availability of technologies between the two ESMs. Even so, there still exist several differences in how heat is produced. DH groups in EnergyPLAN, unlike the LUT model, have no intersection and heat supply in Group 1 cannot be used to supply Groups 2 or 3. Additionally, direct electric rod heating to meet MT and LT demands, modelled as electric boilers, can only be operated at the maximum capacity of fuel-based boilers. Thermal energy storage is, therefore, only available as LT DH storage.

Electricity storage options in EnergyPLAN are treated similarly to condensing PPs in that there is one aggregate electricity storage option in the version used (13.2), compared to the LUT model which has batteries, pumped hydro storage (PHES), and adiabatic compressed air energy storage (A-CAES). Due to this, batteries were chosen as the electricity storage option, and costs were modelled as a combination of utility-scale and prosumer batteries. PHES exists in the "Water" tab in EnergyPLAN; however, it is tied to freshwater demand and production. EnergyPLAN allows for smart charging and Vehicle-to-Grid (V2G) connections as additional forms of flexibility storage, whose benefits are discussed in [30,106]. However, because the LUT model does not yet have smart charging or V2G capability, these options were not utilised, and all electricity for the road mode in the transport sector was treated as dump charge in EnergyPLAN. It must be noted, though, that in the most recent version of EnergyPLAN, two centralised electricity storage options are available to model different electricity storage technologies in addition to the category of rockbed storage.

The final major modelling difference between the LUT model and EnergyPLAN is how synthetic fuels are developed. In the LUT model, sustainable transport for ICE-based road transport can be met through the development of Fischer-Tropsch (FT) processes to produce synthetic diesel, gasoline and jet fuel [29]. This power-to-fuel value chain, along with all sustainable fuels, is shown in Figure 32. Conversely, EnergyPLAN utilises a power-to-gas-to-liquid (PtGtL) route in a Chemical Synthesis function although the most recent version of EnergyPLAN can model the PtL route. To most closely model the FT synthesis process, which is more efficient than the PtGtL process [118,119], efficiencies and costs were adjusted to most closely follow the power-to-liquid process. However, one aspect that cannot be properly adjusted between the models is the amount of CO_2 that needs to be captured and the amount of electricity needed for the process because of the different CO_2 demands for the respective functions. This has been accounted for in an increased cost of extra CO_2 air capture. Additionally, costs for the PtGtL route in EnergyPLAN were determined based on fixed ratios for a power-to-liquid production facility that produces jet fuel, diesel, and gasoline. The costs utilised in this study are based on a jet fuel mode of production, whereby jet fuel production is maximised, with a ratio of 1.1 units of diesel/2.1 units of jet fuel/1 unit of gasoline. Remaining liquid fuel demand from the LUT model that could not be met with this production schema were met with biofuels. The effects of this difference will be seen particularly with respect to the methanation capacity needed (section 4.7) and the total annualised costs (section 4.8) between the two models.

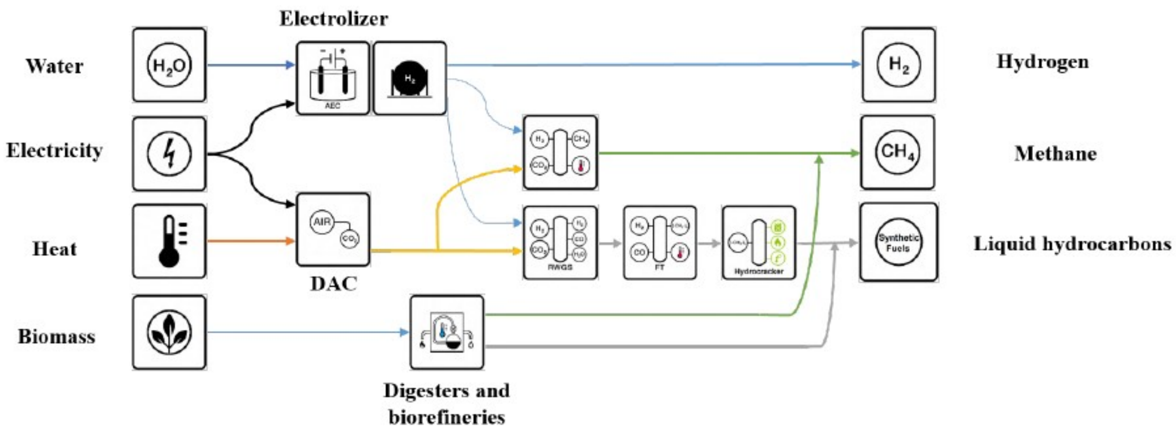


Figure 32. Schematic of the value chain elements involved in the production of sustainable fuels in the LUT model [29].

3.6 Heating values for impact analysis

It is still common practice that fuel to electricity conversion is reported in LHV, such as efficiencies and financial costs for power plants, while electricity to fuel conversion is often discussed on HHV, as for electrolysers, methanation units and other synthesis units. It is standard convention that prices for conventional fuels are expressed in HHV, named as gross caloric values, whereas most of the conventional fuels are traded in their specific units, such as barrel or tonne of oil, norm cubic meter of natural gas or tonne of coal. The results of energy system analyses are consistent, as long as one heating value is consistently used for all conversion efficiencies, costs of fuels and cost of capacities. The impact of inconsistent heating value assumptions is analysed in this research. The LUT model scenarios, as defined in section 3.7, are aligned for the standard analyses consistently to LHV, while an HHV/LHV mixed scenario variation is also analysed to detect the impact of such mixed assumptions. For the HHV/LHV mixed scenario variation all fuel to electricity conversion units are based on LHV for efficiencies, capital and operational expenditures, which are based on output capacity, while the electricity to fuel units are set on the HHV for technical and financial parameters. The technical and financial parameters can be easily converted by an HHV/LHV conversion factor per fuel type, as summarised in Table 7.

Table 7. Higher heating value (HHV) and lower heating value (LHV) and HHV/LHV conversion factor for all fuels used in the LUT model. Biogas is assumed to be a 60% CH_4 and 40% CO_2 molar mix. Fischer-Tropsch is assumed to be in kerosene mode and for the mix of all output.

	LHV MJ/kg	HHV MJ/kg	factor for adjustment
H_2	121.00	141.88	1.173
CH_4	50.00	55.53	1.111
Natural gas	47.14	52.23	1.108
Biogas	17.65	19.60	1.111
Fischer-Tropsch mix	42.98	46.15	1.074
Methanol	19.90	22.88	1.150
Dimethylether (DME)	28.87	31.67	1.097
Ammonia	18.65	22.50	1.207

3.7 Scenario definition for studying the research questions

With the aforementioned differences in mind, three overnights scenarios were developed for the Sun Belt case country Bolivia, summarised in Table 8. All scenarios seek to find a cost-optimal 100% RE energy system, a "Best Policy Scenario", as defined by Child et al. [37], under the same assumptions. BPS-MNT, BPS-MHT and BPS-S seek to show the impacts of regional modelling on the outcome of a Best Policy Scenario using the LUT model, especially for a case country with widely varying geographic conditions. These scenarios in comparison to BPS-EP aim to demonstrate the modelling differences in determining a fully sustainable energy system, and the implications of modelling tools on the economic and technical viability of sustainable energy systems. Additionally, each LUT model scenario is compared on mixed HHV/LHV and full LHV basis, as defined in section 3.6, with the mixed HHV/LHV results being denoted with an 'M' i.e. "BPS-S M".

Table 8. Overview of scenarios.

Scenario Name	Description
Best Policy Scenario Multi-Node No Transmission (BPS-MNT)	This overnight scenario targets 100% RE by 2050, with the addition of GHG emission costs. This scenario utilises a multi-nodal approach in the LUT model to the modelling of Bolivia without grid interconnections.
Best Policy Scenario Multi-Node High Transmission (BPS-MHT)	This overnight scenario targets 100% RE using a multi-nodal approach and allowing for grid interconnection between regions.
Best Policy Scenario Single-Node (BPS-S)	This overnight scenario similarly targets 100% RE by 2050. However, this scenario models Bolivia as a single node in the LUT model.
Best Policy Scenario EnergyPLAN (BPS-EP)	This overnight scenario, performed using EnergyPLAN, similarly models Bolivia as a single node with a target of 100% RE by 2050.
Best Policy Scenario Energy Transition (BPS-ET)	This transition scenario uses BPS-2 results from Chapter 1, using a multi-nodal approach allowing for grid interconnection and targeting 100% RE by 2050.

4. RESULTS

The results for the EnergyPLAN and LUT scenarios are presented here as follows: section 4.1 will discuss the primary energy supply to meet the 2050 final energy demand of the case country Bolivia. The structure of results for power, heat, transport and desalination sectors are then presented across scenarios in sections 4.2, 4.3, 4.4 and 4.5, respectively. The role and characteristics of heat and electricity storage are then presented in section 4.6. The structure of synthetic fuel production for all scenarios is then shown in section 4.7. Section 4.8 then discusses the annualised investment structure of cost-optimised scenarios for the case country and show the impact by technology on total investment costs. Finally, the impact of the change of the LUT model from a mixed HHV/LHV basis to full LHV basis is presented in section 4.9. More detailed results for each scenario can be found in the Supplementary Material (Tables AII4-AII22 and Figures AII1-AII25).

4.1 Primary and final energy demands

Final energy structure and demands by sector, shown in Figure 33, transforms as industrial heating is projected to grow significantly between 2020-2050, from 99 TWh in 2020 to 263 TWh in 2050. Both ESMs were set up to develop an energy supply to satisfy these 2050 demands, and results indicate that both the LUT model and EnergyPLAN develop a primary energy supply founded on renewable energy, particularly low-cost solar PV.

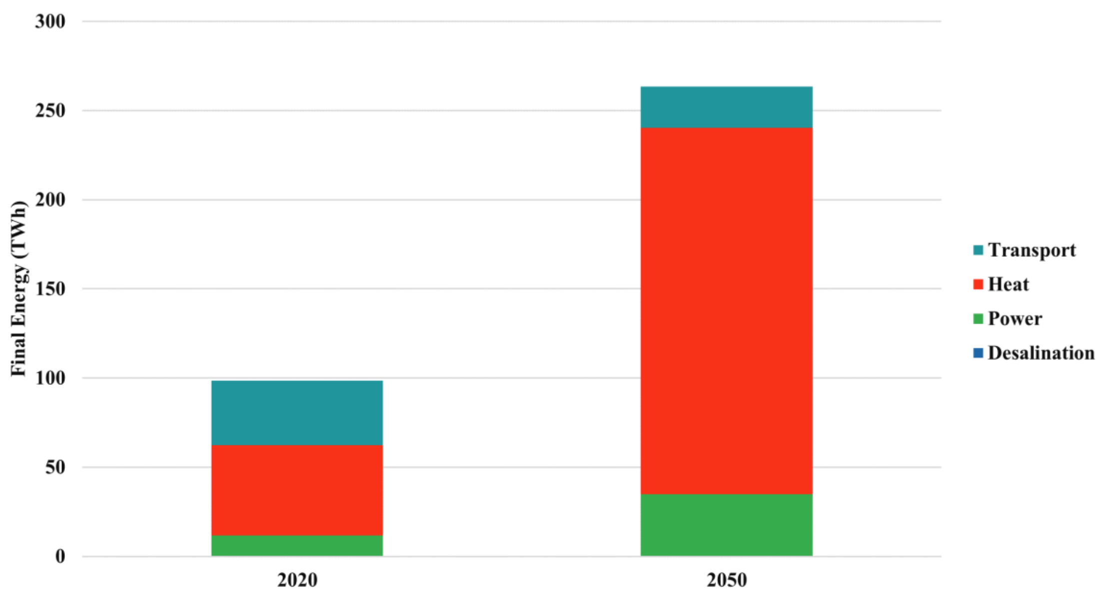


Figure 33. Final energy demand for Bolivia by sector.

Figure 34 shows primary energy supply across scenarios, with varying levels of primary energy being developed to satisfy final energy demands. Primary energy supply reaches 298 TWh, 283 TWh, 275 TWh, 274 TWh, and 279 TWh for each of the scenarios, respectively. Among single-node scenarios, BPS-EP shows the larger primary energy supply and among multi-node scenarios, BPS-MHT has the lowest primary energy supply. Larger primary energy supply implies that the system developed in BPS-EP is less efficient than the BPS-S, which will be the case as there are less avenues available for electrification in EnergyPLAN compared to the LUT model, particularly in the heat sector. Conversely, given a more decentralised and distributed energy system, as is the case in BPS-MNT, transmission systems will be less utilised, suggesting there will be reduced transmission losses compared to BPS-MHT and BPS-ET as energy is supplied where immediately needed.

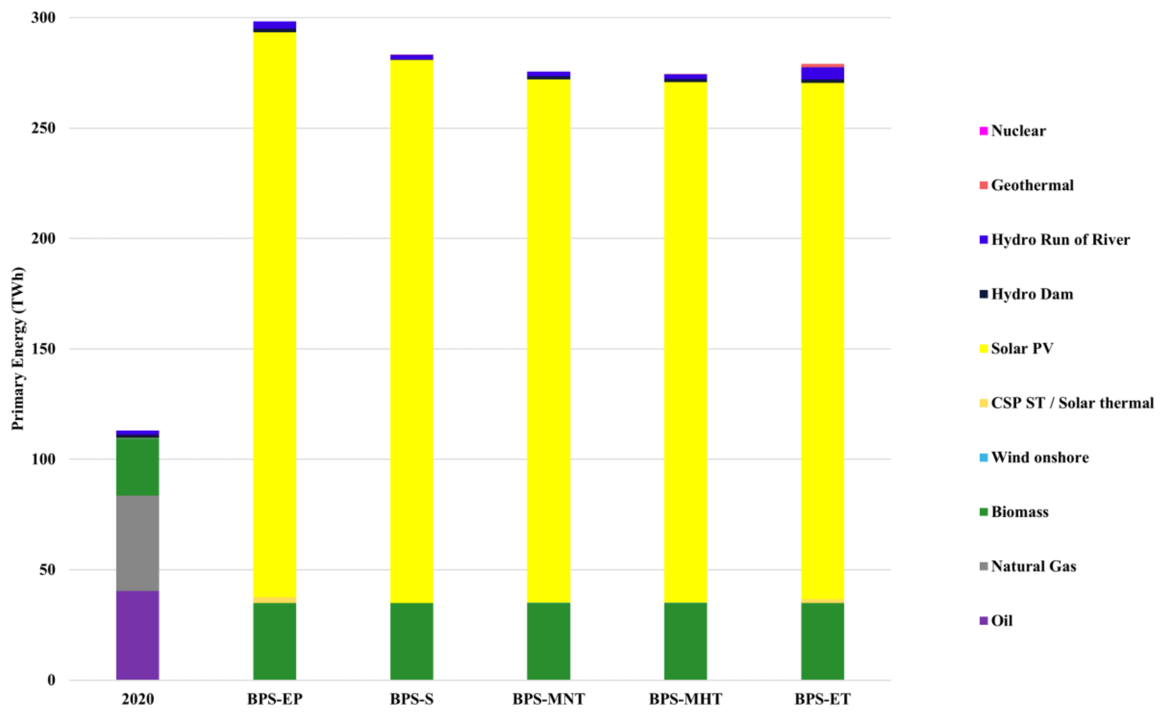


Figure 34. Primary energy supply for all scenarios in 2050, except the 2020 reference.

4.2 Power sector

Total installed electrical capacity and generation are shown in Figures 35 and 36, respectively. All scenarios show a power sector dominated by solar PV, and, interestingly, all overnight scenarios do not much utilise wind onshore. The multi-node overnight and transition scenarios use small amounts of wind onshore, and the single-node overnight scenarios do not utilise wind onshore at all. Further, condensing PP capacities are only present in BPS-ET. However, due to their low electricity production, their presence in the electricity generation mix suggests that these are historical or transitionary capacities that have not reached the end of their technical lifetimes. For all scenarios, solar PV single-axis has the largest share of installed capacity and electricity generation. However, the extent to which it is the largest share varies. For the multi-nodal decentralised energy systems, fixed tilted solar PV has larger shares of capacity and generation, as the benefits of single-axis tracking systems are diminished in regions with less abundant solar resources. Conversely, in scenarios with high interregional transmission, solar PV production is concentrated in the regions of best resources where the full load hours (FLH) of solar PV single-axis can be maximised, largely in the southwestern regions of LP, POT, and CQ. The single node scenarios, BPS-EP and BPS-S, both develop electricity generation structures that are primarily single-axis solar PV, with fixed titled solar PV capacities coming largely from residential, commercial, and industrial prosumers.

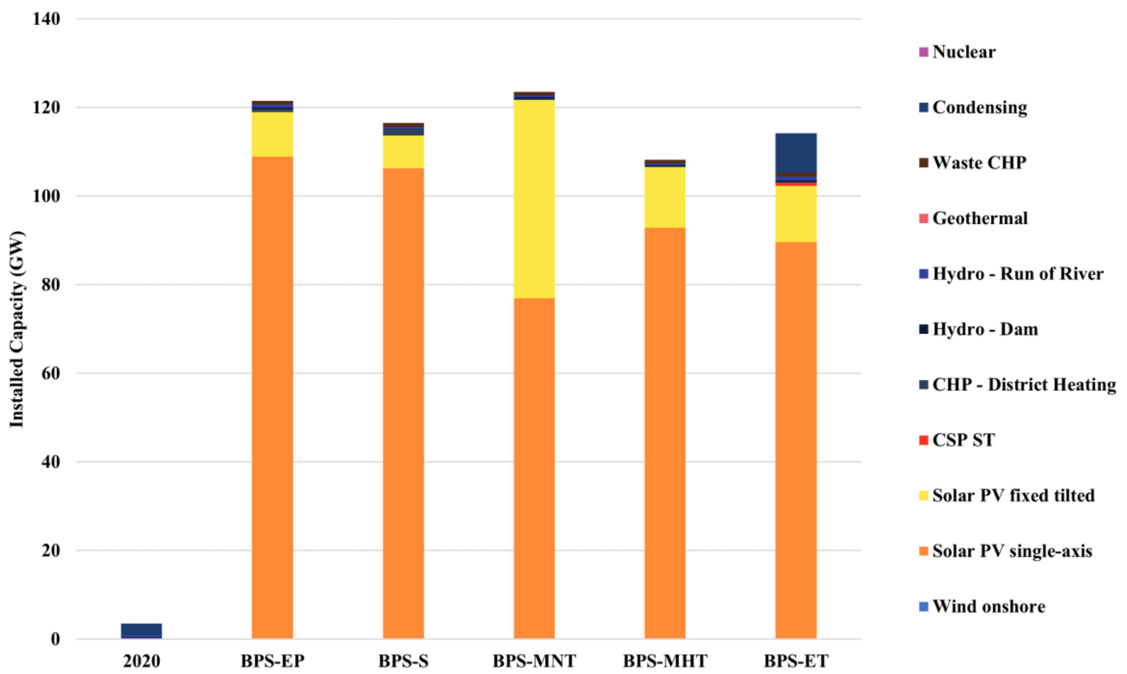


Figure 35. Installed electrical capacity for all scenarios.

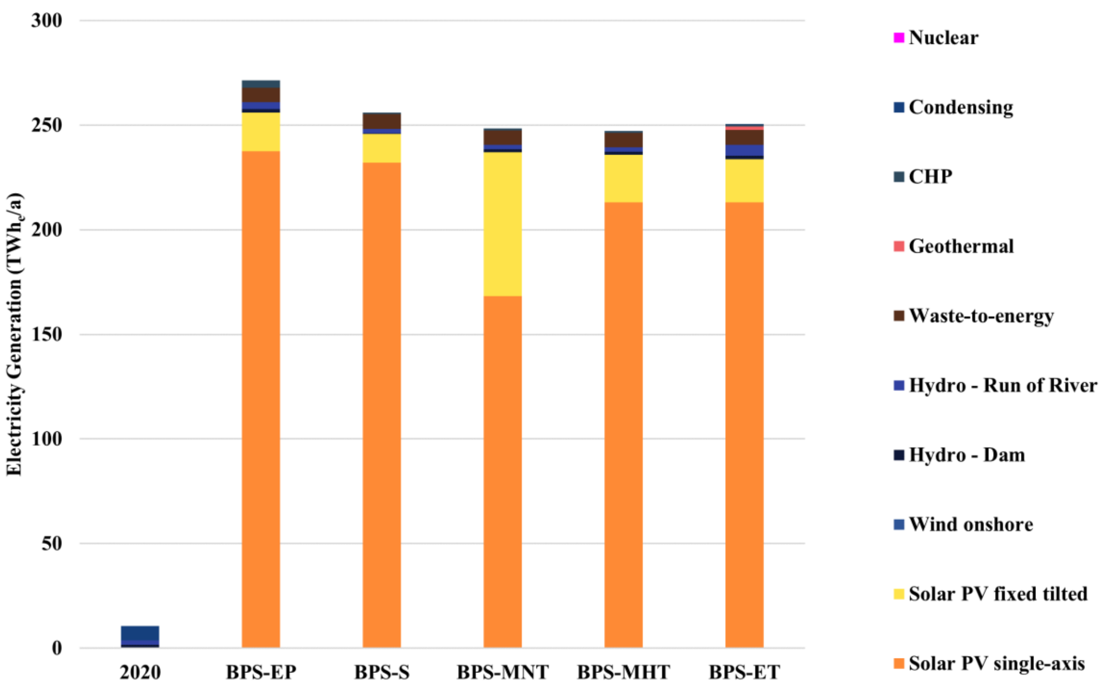


Figure 36. Electricity generation by capacity for all scenarios.

Consumption of electricity can be seen in Figure 37, and the LUT model and EnergyPLAN results show significant structural differences in how electricity is used. The most noticeable difference can be seen in electricity consumption shares for PtG and electric rod heating for DH. In BPS-EP, the PtG process alone is responsible for 66% of total electricity consumption, whereas in BPS-S, PtG makes up 43% of electricity consumption. Further, electric DH comprises 31% of electricity consumption in BPS-S, but is only 7% of electricity consumption in BPS-EP. This difference can be similarly visualised in the following section which compares the heat sector between scenarios.

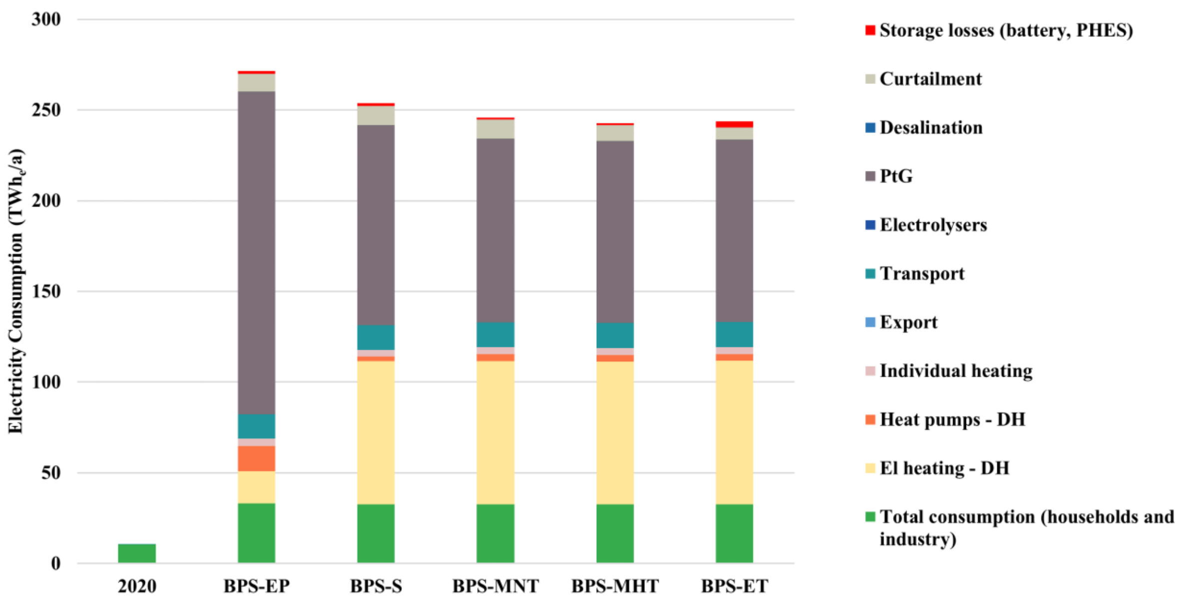


Figure 37. Total electricity consumption for all scenarios.

4.3 Heat sector

The heat capacities and generation are shown in Figures 38 and 39, highlighting the heating structure differences explained in section 2.4. Across scenarios, installed heat capacities are similar, with BPS-S having the lowest capacity compared to the other LUT scenarios. However, BPS-EP has the largest heat production as the LUT model allows for heat recovered from PtG processes to be used to satisfy heat demands from industry and CO_2 DAC, whereas in EnergyPLAN, it was assumed that all excess heat was needed for CO_2 DAC. Within EnergyPLAN, there is no way to define heat demands for this process, which makes available heat from related processes impossible to accurately account. In the LUT model scenarios, centralised heating, largely for industrial heat, is supplied primarily by electric rod heating for MT and LT heat, while SNG and biomass-based boilers supply HT industrial heat demand. Although thermal energy storage is available to be used in DH Group 3 in EnergyPLAN, electricity-based DH capacity is limited by fuel-based boiler capacity and cannot be operated to charge the thermal energy storage in this group. Therefore, the role of electric DH in BPS-EP is much more limited than BPS-S as electric DH composes only 9% of heat production in BPS-EP and 43% of heat production in BPS-S. Therefore, fuel-based boilers play a much larger role in BPS-EP, with 43% of heat production, compared to 30% in BPS-S. In the BPS-EP, these boilers are largely supplied by SNG, with limited shares of biomass, as most available biomass resources are solid wastes used in waste CHP plants. For all scenarios, SNG DH composes 99% of boiler-based DH and biomass DH accounts for the remaining 1%. IH for both single and multi-node scenarios is supplied almost entirely by air-to-air heat pumps, with small shares of biomass and direct electric IH remaining.

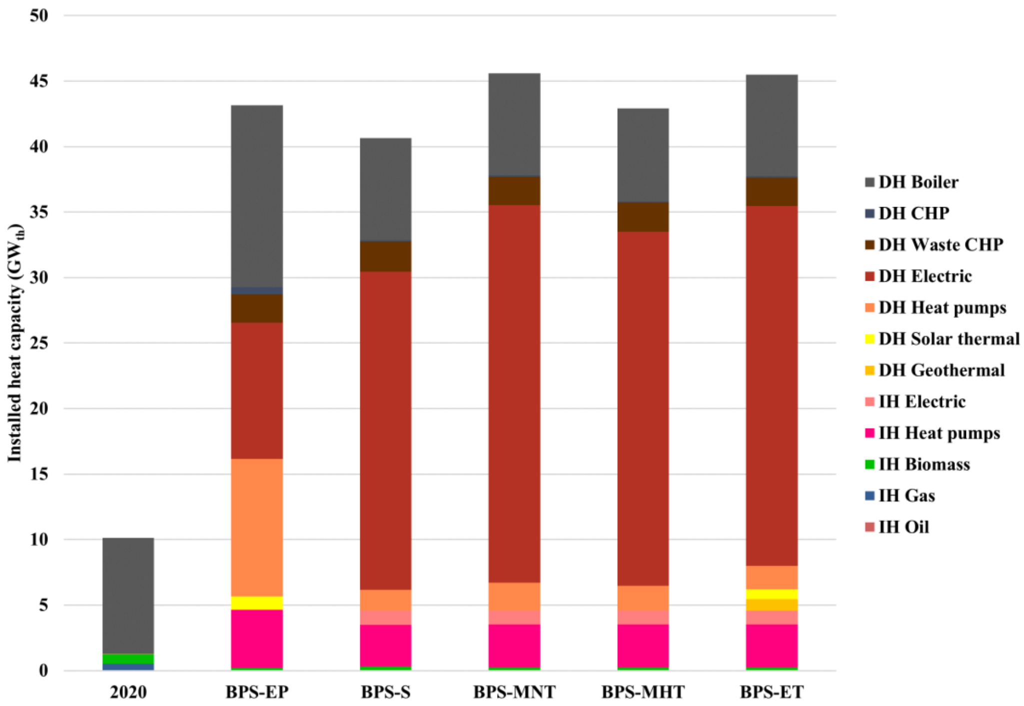


Figure 38. Installed heat capacities by technology for all scenarios.

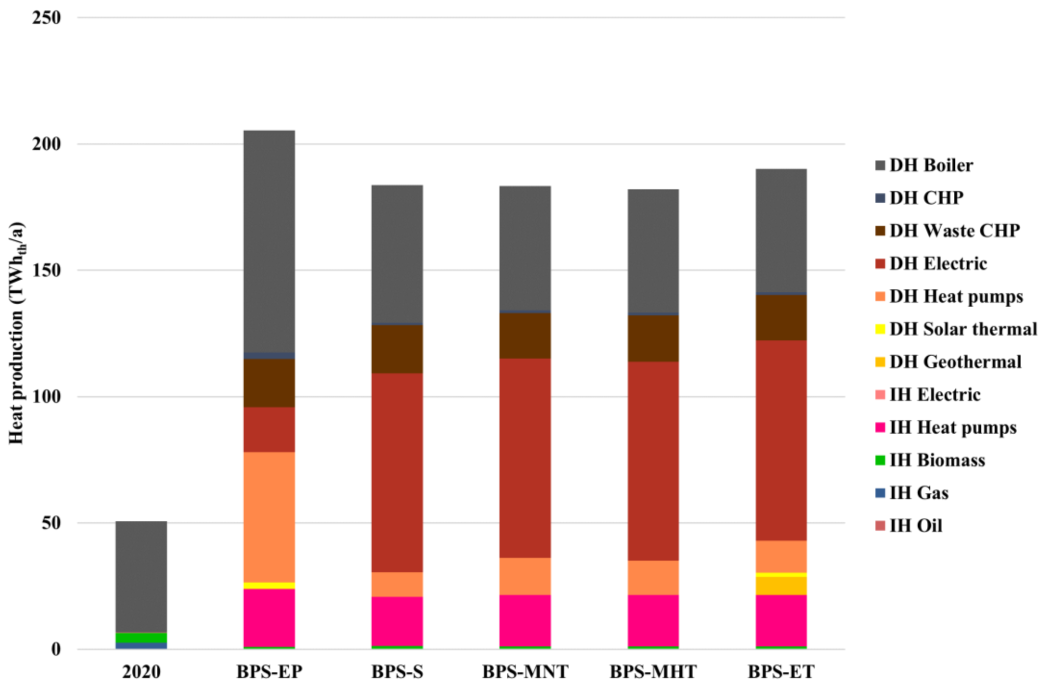


Figure 39. Heat production by technology for all scenarios.

4.4 Transport sector

Across scenarios, the structure of final energy demand in the transport sector remains consistent, as shown in Figure 40. Transport demand is satisfied by electricity, with 60% of demand, hydrogen, with 18%, sustainable biofuels, with 4% and 0% in BPS-EP and BPS-S, or synthetic fuels, with 18% and 23% in BPS-EP and BPS-S. There is one key difference between the BPS-S and BPS-EP, which is the synthetic fuel production schema discussed in section 2.4. The result is that the PtGtL route cannot produce the diesel that is required to satisfy the diesel demand. Therefore, 1 TWh of biodiesel was produced in EnergyPLAN, whereas the LUT model did not utilise any biofuels to satisfy road transport demands using ICE. Another interesting result can be seen in BPS-MNT, where a small excess of FT fuels is produced, exceeding the fuel-based transport demand. Such excess fuels are considered by the model as a fuel export, and similar results were found for Europe in [110].

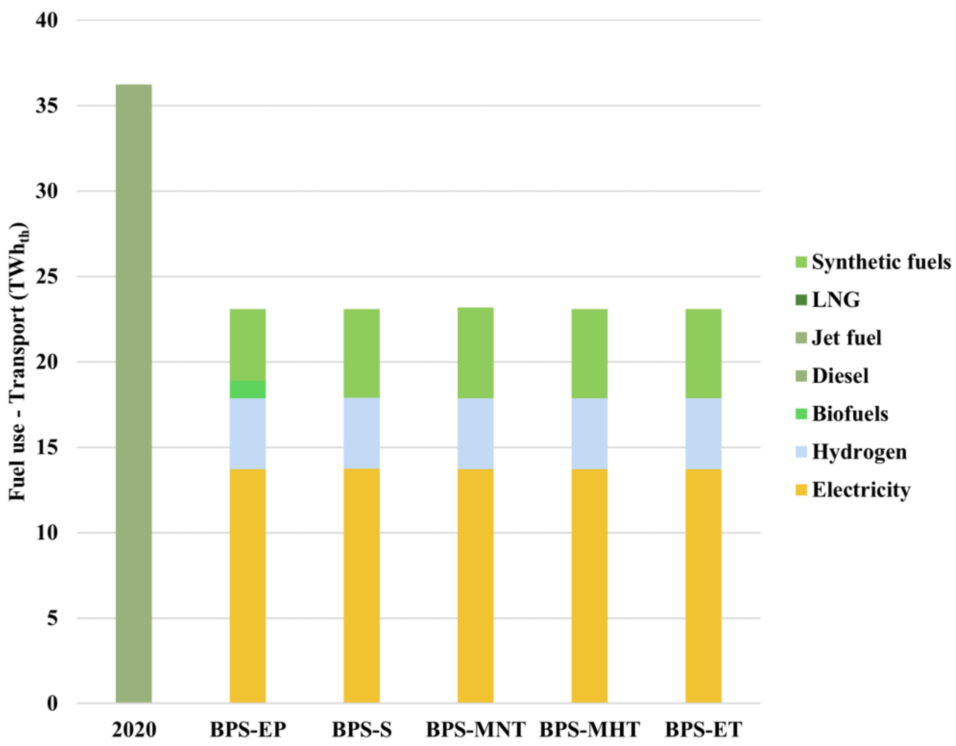


Figure 40. Final energy demand by fuel type in transport sector for all scenarios.

4.5 Desalination sector

In 2050, a limited desalinated water demand for Bolivia exists of 4.2 Mm^3/a, which is dominantly supplied by reverse osmosis (RO) seawater desalination, as shown in Figures 41 and 42. In BPS-S and BPS-ET, though, a small share of stand alone Multi Effect Distillation (MED) exists, whereas the desalinated water demand for all other scenarios is met solely by RO desalination. The total electricity demand for seawater desalination across scenarios is less than 0.1 TWh, suggesting that desalination will play a very small role in total water demand in the Bolivian energy system and will only be utilised for specific parts of the country that may not be able to secure a sustainable freshwater supply.

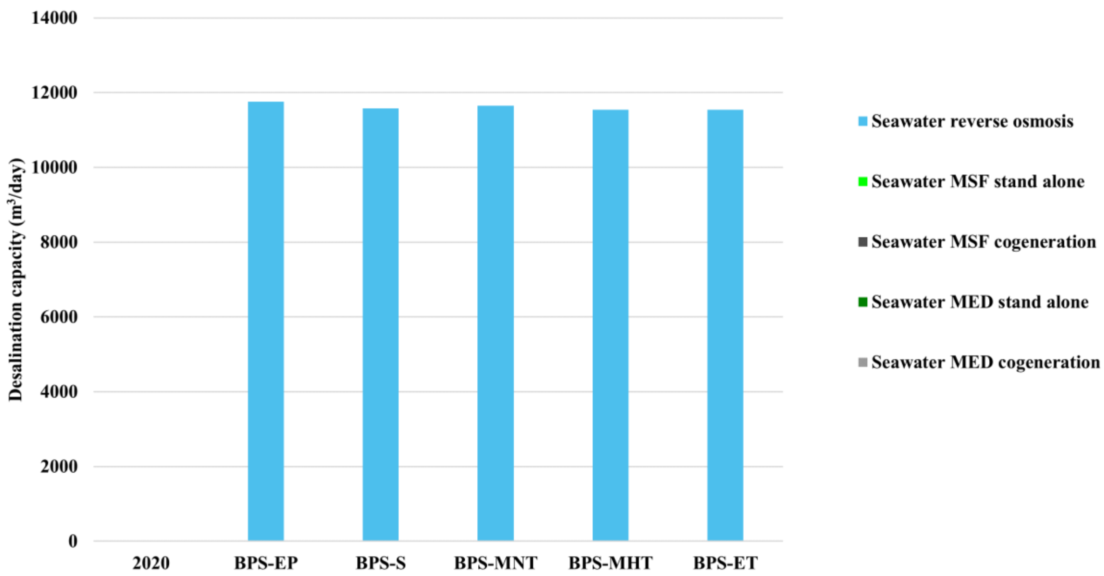


Figure 41. Installed desalination capacity across all scenarios.

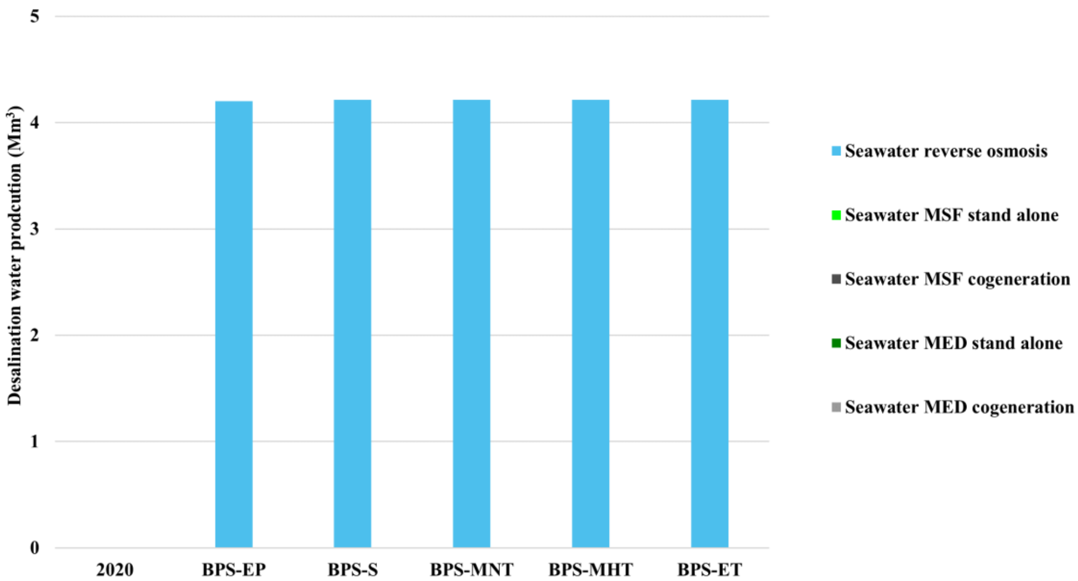


Figure 42. Desalinated water production for all scenarios.

4.6 Storage capacities and throughput

For all scenarios, storage plays an important role in balancing a primary energy supply structured around solar PV. Electricity storage serves to balance a variable supply for all hours of the day and has varying capacities and outputs across scenarios. Interestingly, BPS-S has a noticeably larger electricity storage capacity and throughput, shown in Figures 43 and 44, compared to BPS-EP. Among multi-node scenarios, only BPS-ET utilises PHES, whereas the overnight scenarios prefer utility-scale batteries as the dominant storage technology. This is caused by the evolution of the energy system, since in earlier periods, PHES is economically more favourable than battery storage, and PHES is kept in the system due to its long technical lifetime. Despite similar storage capacities among between BPS-EP and BPS-MNT, MHT, and ET, the throughput of electricity storage is lower in BPS-EP with a throughput of 24 TWh, compared to the other scenarios with 49 TWh (BPS-S), 33.7-34.5 TWh (BPS-MHT, BPS-MNT) and 29 TWh (BPS-ET). However, this can be understood from the electricity storage profile shown in Figure 45. Compared to BPS-S, considered exemplary of battery storage for all LUT model scenarios, BPS-EP has much more seasonal variation of state-of-charge (SOC) characteristics. In BPS-S, battery storage has a relatively even SOC profile throughout the year. However, the fundamental nature of electricity storage as being a form of short-term, daily storage remains consistent across ESMs.

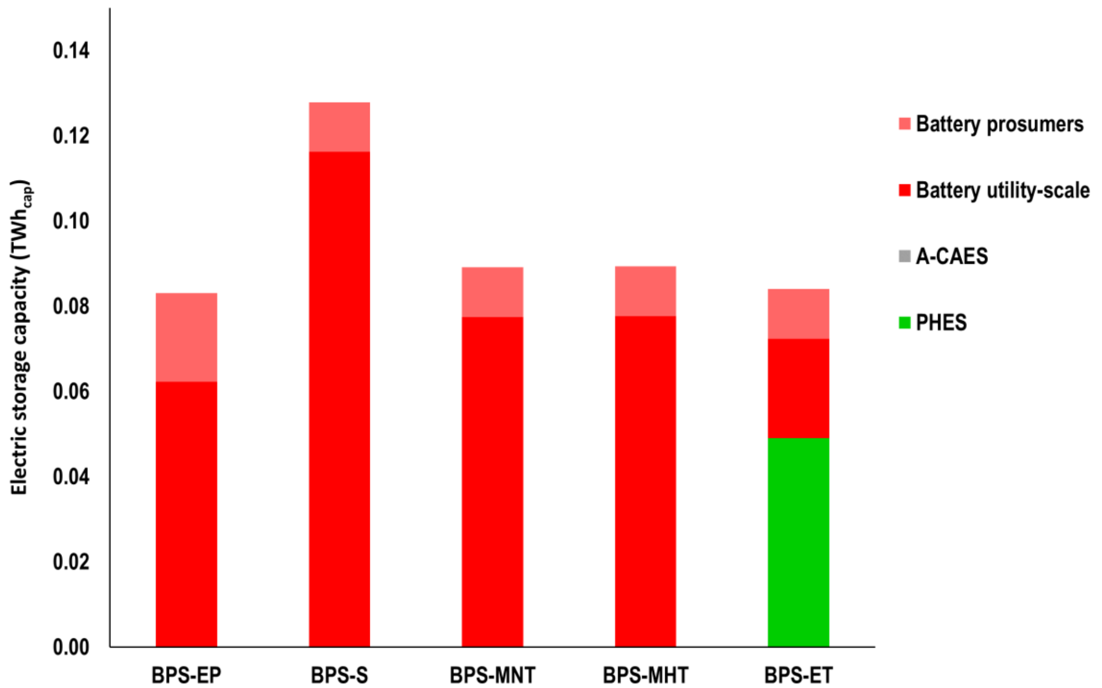


Figure 43. Electric storage capacities by technology for all scenarios.

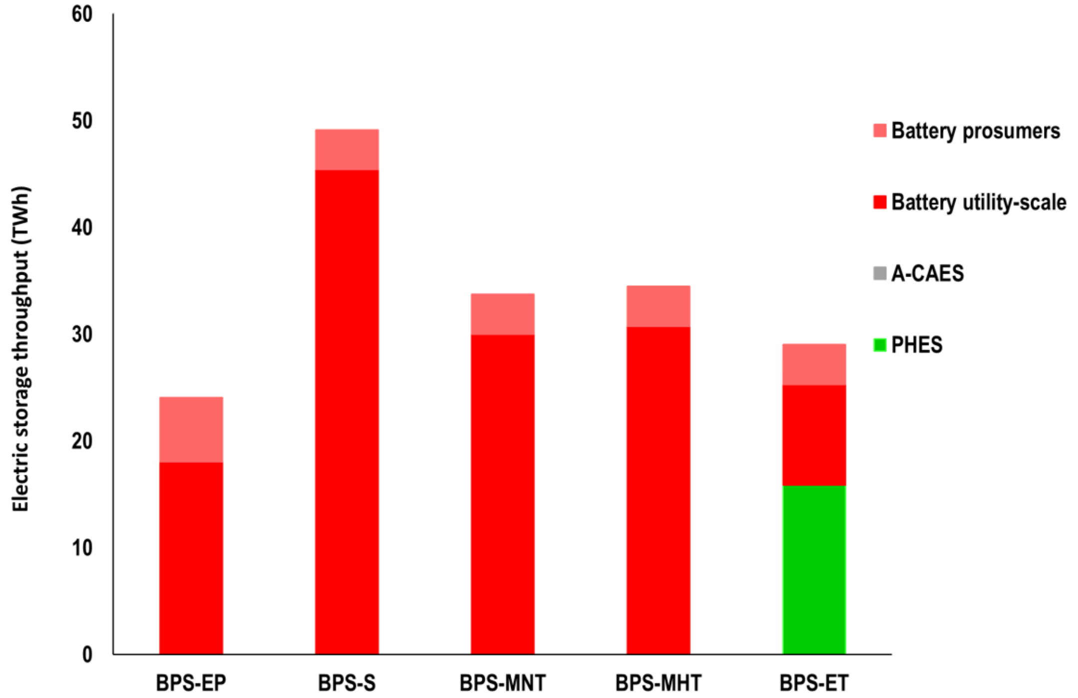


Figure 44. Electric storage throughput by technology for all scenarios.

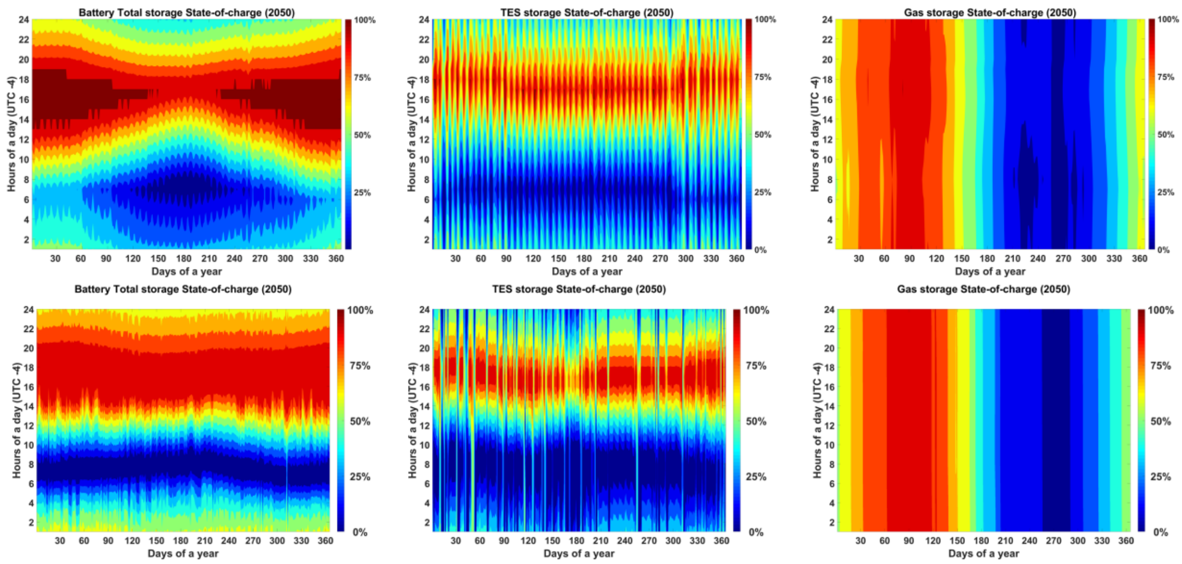


Figure 45. Battery (left), DH (center), and gas (right) storage SOC profiles for BPS-EP (top) and BPS-S (bottom).

Thermal energy storage, whose capacities and throughput are shown in Figures 46 and 47, show varying levels of storage capacity required among scenarios. Interestingly, the single-node scenarios of BPS-S and BPS-EP require the largest amounts of storage capacity, though levels of storage throughput are larger in multi-nodal scenarios. In the multi-node scenarios, thermal energy storage (TES), is utilised on higher levels than DH storage, as electric DH was largely used for MT heating demands. Additionally, the high transmission scenarios of BPS-MHT and BPS-ET utilise TES capacity on a higher level than BPS-MNT, although throughput is on a similar level. In all scenarios, gas storage composes the largest share of TES capacity, and a significant share of storage throughput. This is most observed in BPS-EP, where gas storage is the dominant TES technology. Given a larger SNG demand in BPS-EP compared to BPS-S, the result that gas storage plays a larger role in BPS-EP can be expected.

Despite the differing capacities across scenarios, the TES profiles shown in Figure 45 demonstrate that the nature of TES in DH systems and for gas storage are the same, as DH-based storage is diurnal by nature, going through daily charging and discharging, whereas gas storage provides long-term seasonal storage that is charged during the summer months when solar PV production is at its peak and discharged during winter months when there is slightly reduced sunlight hours and higher peak electric and heating demands.

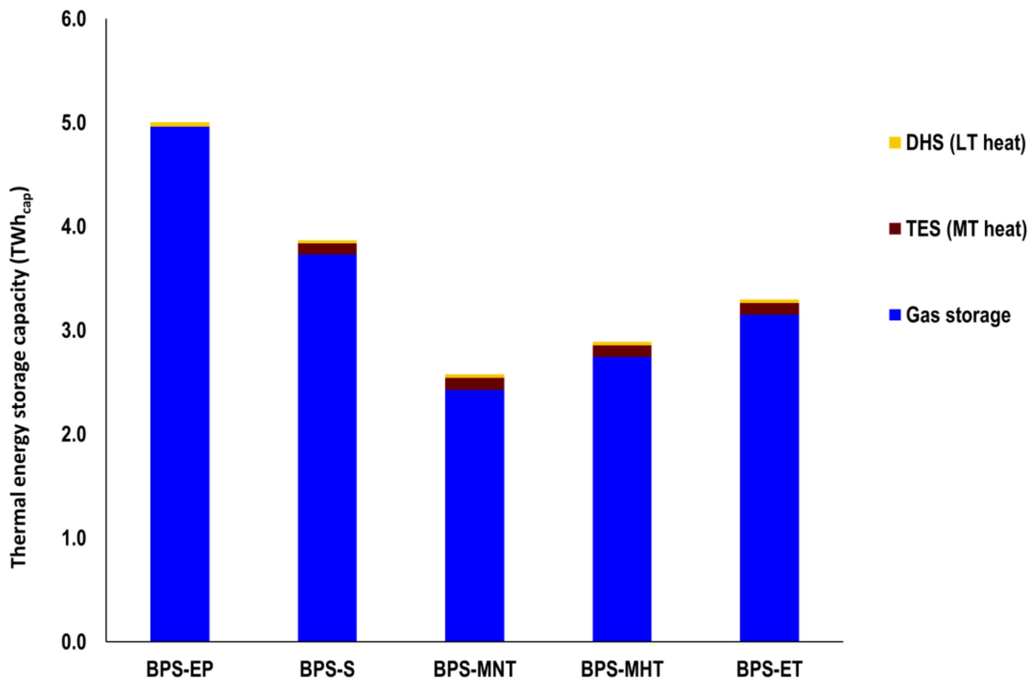


Figure 46. Thermal energy storage capacity by technology for all scenarios.

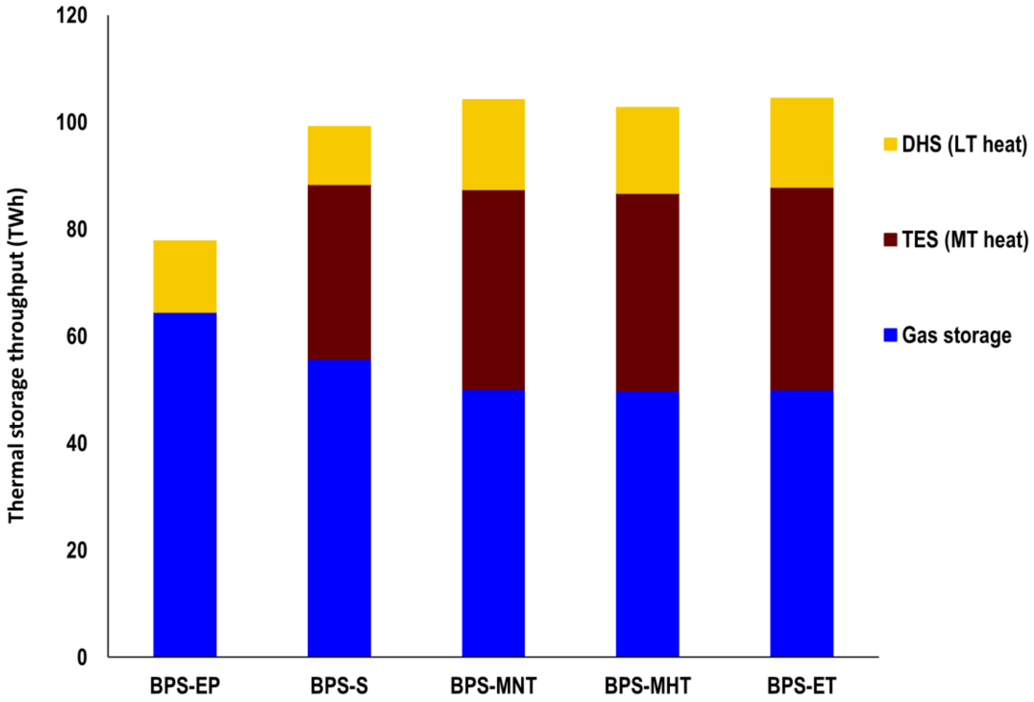


Figure 47. Thermal energy storage throughput by technology for all scenarios.

4.7 Synthetic fuel production

Production of synthetic fuels for heat and transport requires significant capacity of electrolyser, methanation units, CO_2 DAC, and fuel synthesis through FT in the LUT model and PtGtL in EnergyPLAN. Figure 48 shows the capacities required for all scenarios. BPS-EP has the largest capacity of both electrolysers and methanation with 37 GW_{H2} and 30 GW_{SNG}, respectively. These capacities are larger primarily due to larger SNG demands in BPS-EP, the use of SNG in fuel synthesis as well as the operation schema of methanation in EnergyPLAN, which is discussed in section 5.2.1. The production outputs of electrolysers and methanation units are shown in Figure 49. These results indicate that limitations, particularly those in the heating sector for BPS-EP, result in much larger hydrogen and SNG production, as the sum of synthetic fuel production reaches 226 TWh compared to BPS-S which has total synthetic fuel production of around 133 TWh. Among multi-scenarios, BPS-MNT, BPS-MHT, and BPS-ET have similar production levels of 122, 121 TWh and 121 TWh, respectively.

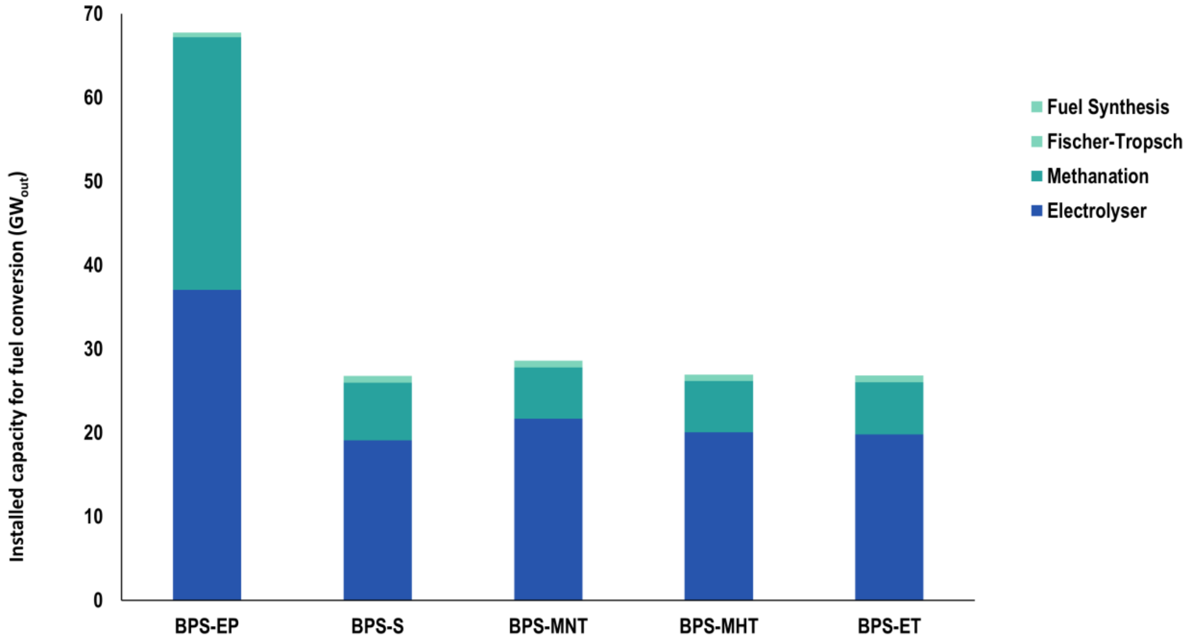


Figure 48. Synthetic fuel production capacities by technology for all scenarios.

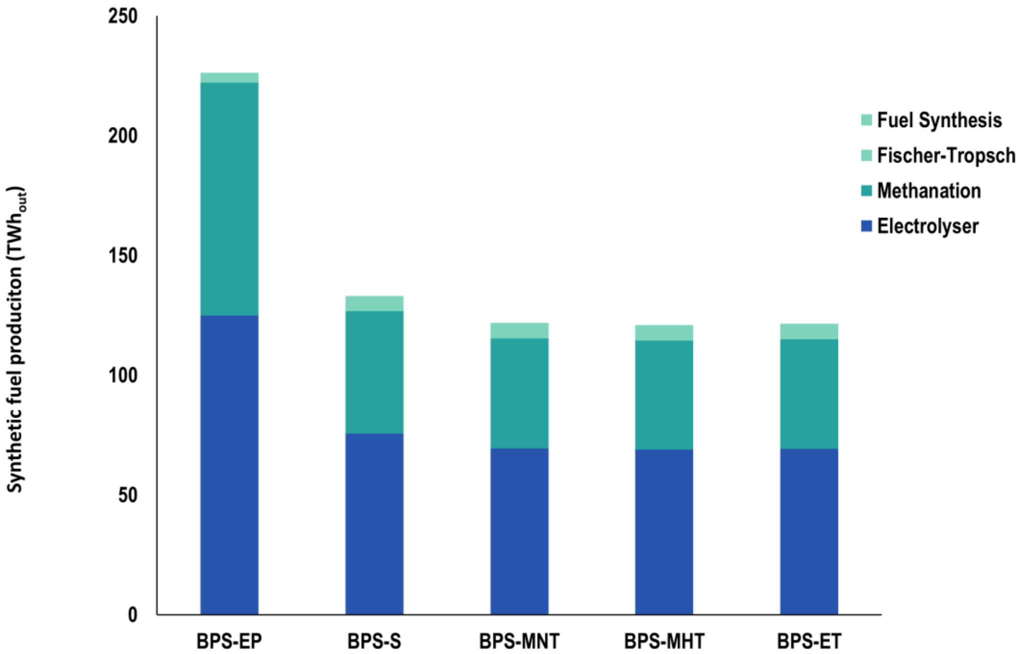


Figure 49. Synthetic fuel production by technology for all scenarios.

4.8 Energy system costs and investments

In scenarios structured in a country such as Bolivia and with results that indicate a solar PV-dominated energy system, the financial implications are a reduction in the cost in electricity while massive solar PV capacities are installed. This is demonstrated in the primary levelised cost of electricity (LCOE) shown in Figure 50, as LCOE from primary electricity generation is reduced from 75.0 €/MWh in 2020 (see Supplementary Material Table AII16) to 11.6 €/MWh (BPS-EP), 10.6 €/MWh (BPS-S), 11.1 €/MWh (BPS-MNT), 10.1 €/MWh (BPS-MHT) and 13.7 €/MWh (BPS-ET). Given such low electricity costs, the total annualised system costs, presented in Figure 51, are therefore dependent on the extent to which an energy system can be electrified. Here, varying results can be found between scenarios. Additionally, the annualised system costs are further broken down between BPS-EP and BPS-S in Figures 52 and 53 to highlight where financial differences in the two single-node overnight scenarios arise. Multi-node scenarios find annualised costs of 6.81, 6.69, and 8.5 b€ for BPS-MNT, BPS-MHT, and BPS-ET, respectively. Such results show the effect of considering historical capacities in developing energy transition scenarios compared to overnight scenarios, as 27% higher historic cost have been found for the transition method compared to the overnight approach. Within single-node scenarios, BPS-EP finds the larger annualised system costs, with 8.8 b€, compared to BPS-S, which finds annualised costs of 6.66 b€, representing 25% lower costs. This result can largely be attributed to two characteristics of BPS-EP, the modelling differences in industrial heat classification and capacity utilisation of CO_2 hydrogenation (CO_2 DAC and methanation). The latter can be visualised in Table 9, which shows the FLH for major technologies. Here, the FLH for the PtG process in BPS-EP is less than half of those for the LUT model scenarios, resulting in increased capacity required to produce the already larger amounts of SNG needed in BPS-EP. This effect is further discussed in section 5.2.1, as its result is increased investment in PtG capacities and resulting higher annualised energy system cost.

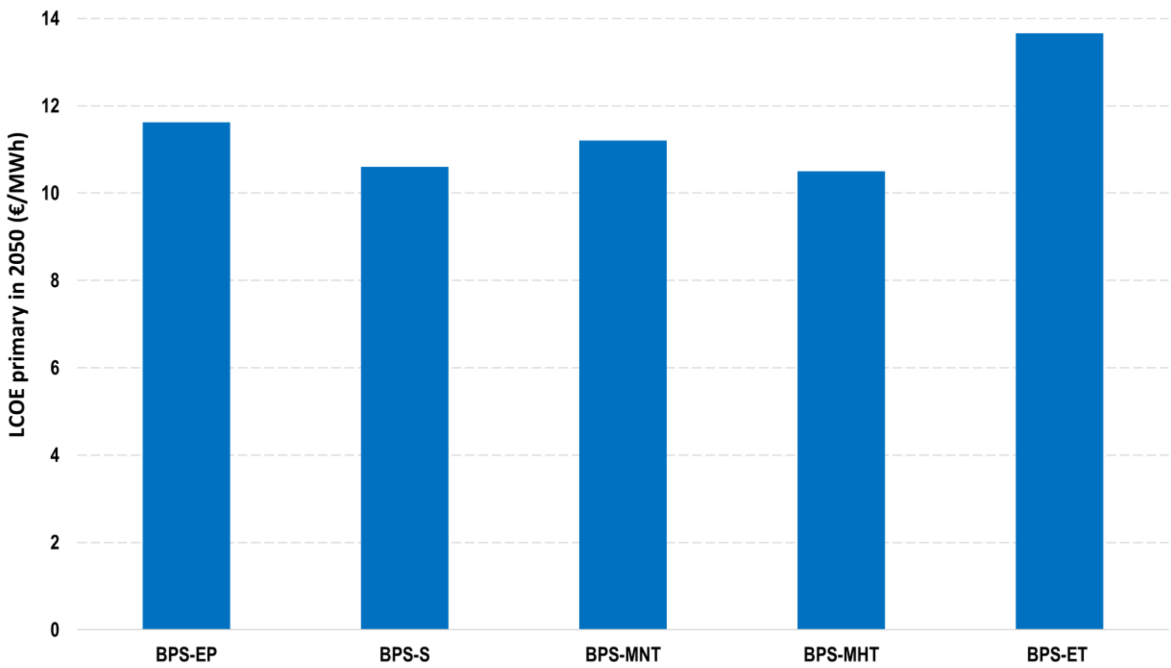


Figure 50. LCOE of primary electricity generation for all scenarios.

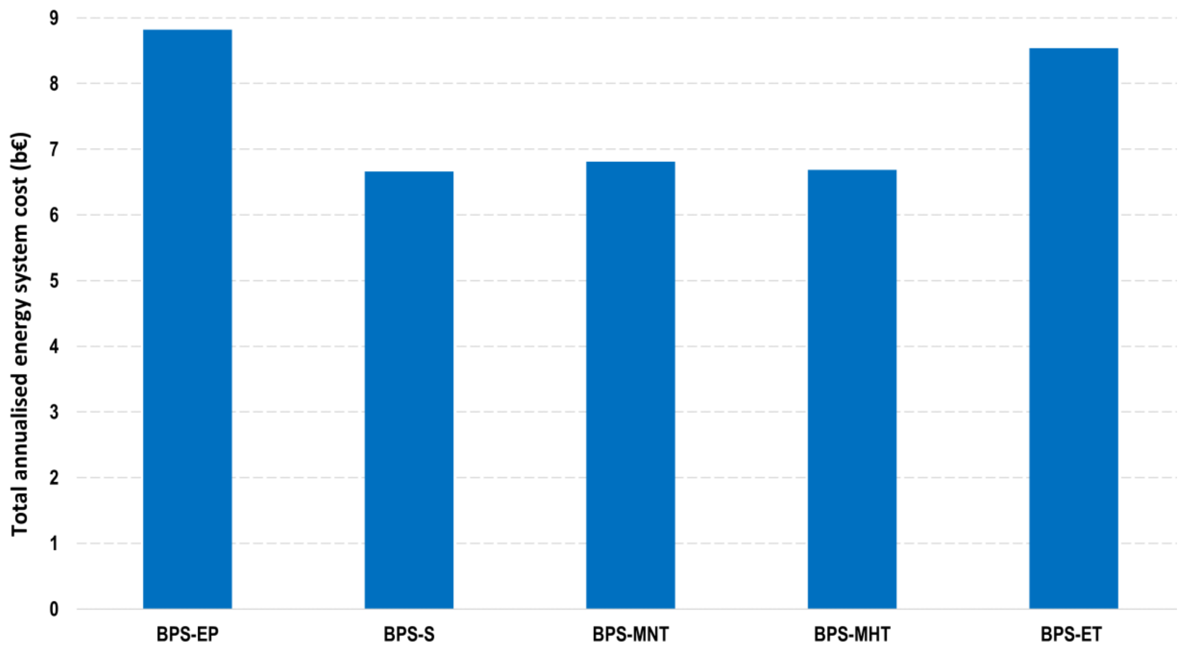


Figure 51. Total annualised energy system costs for all scenarios.

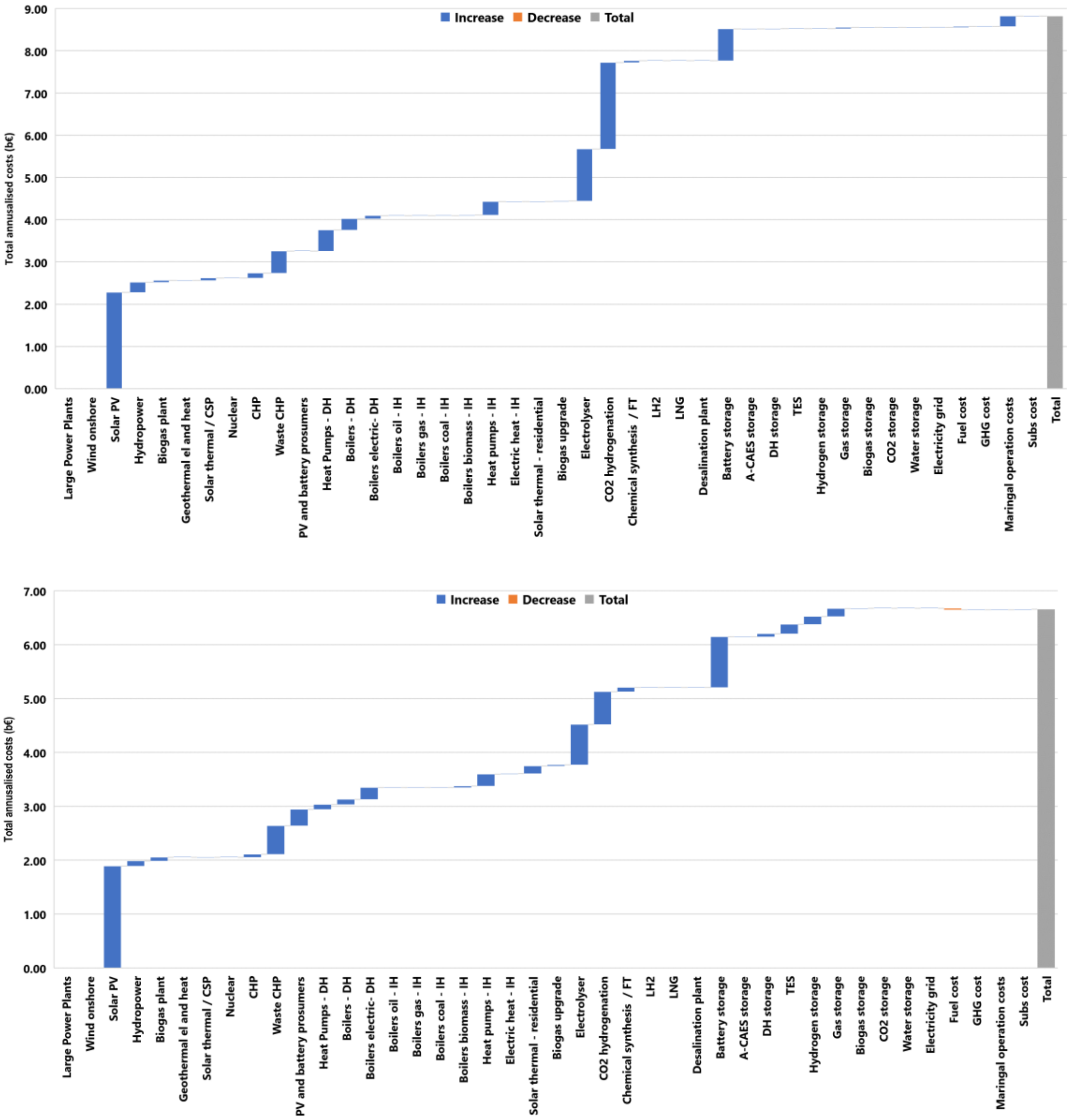


Figure 52. Breakdown of total annualised costs by technology for BPS-EP (top) and BPS-S (bottom).

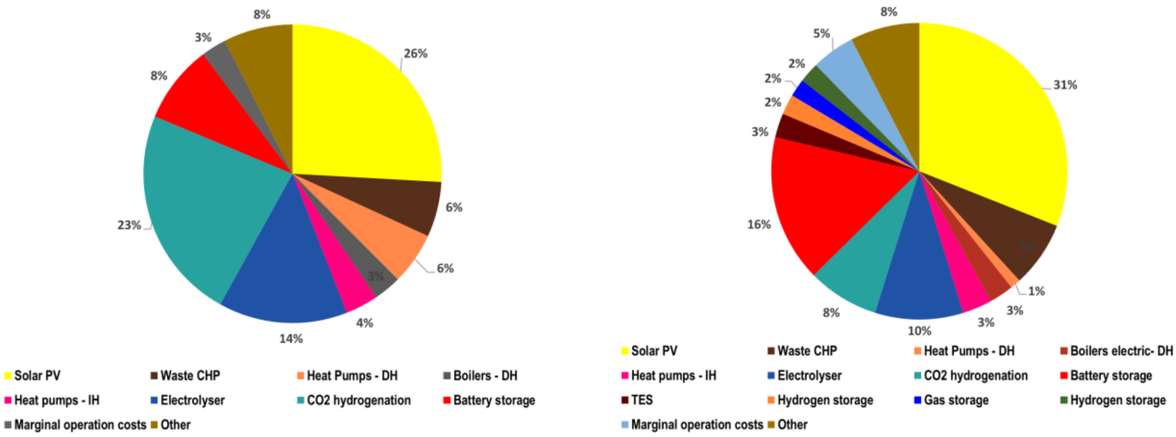


Figure 53. Share of annualised investment cost by technology for BPS-EP (left) and BPS-S (right).

Table 9. Full load hours for major technologies in all scenarios.

	2020	BPS-EP	BPS-S	BPS-MNT	BPS-MHT	BPS-ET
Wind onshore	2222	-	0	2303	2303	2792
Solar PV single-axis	-	2180	2183	2191	2295	2377
Solar PV fixed tilted	1840	1841	1869	1487	1557	1461
Hydro - Dam	5364	5359	5094	5356	5356	5356
Hydro - Run of River	4771	4780	5094	4980	4980	5575
CHP	0	-	-	-	-	-
Condensing	2924	4760	465	2721	5211	5171
PtG (CH_4)	-	3253	7379	7475	7450	7339
Electrolyser	-	3386	3969	3211	3439	3495

4.9 Impact of heating values on LUT model results

Upon making the alignment of the LUT model to full LHV basis, differences are immediately noticeable in the primary energy demand, as for BPS-S M, BPS-MNT M, and BPS-ET M, there is a noticeable decrease in solar PV electricity, particularly solar PV single-axis, compared to their respective full LHV scenarios, shown in Figures AII26-29. However, BPS-MHT M sees a slight increase in electricity production of 1 TWh, corresponding to an increase in electricity consumption for DH heat pumps, shown in Figure AII29 from 3.61 in BPS-MHT to 4.75 TWh in BPS-MHT M, which is a comparable result to the other scenarios. The main difference that can be observed, though, is the electricity required for PtG decreasing by 11 TWh (BPS-S M), 9 TWh (BPS-MNT M), and 4 TWh (BPS-ET M), but only by 0.1 TWh for BPS-MHT M.

The heat sector has an inverse effect than that observed in the power sector. Figures AII30 and AII31 show that for all LUT model scenarios, the required heat capacity and production increase. Because of LHV physical parameters, the synthetic fuel production components produce more waste heat that can be recovered and utilised in DH systems. The technology mix for heat production remains relatively constant for each mixed HHV/LHV scenario compared to their mixed full LHV counterparts, though, as suggested by the electricity consumption in Figure AII29, DH heat pumps find their heat production and capacities increased in all scenarios.

An interesting effect of this change can be seen in the storage capacities and throughput shown in Figures AII32 and AII33. While mixed HHV/LHV results show smaller total storage capacities, the total storage throughput increases. This appears to be due to differences in DH storage and gas storage. For all scenarios, DH storage capacity decreases by 9 (BPS-S M), 7 (BPS-MNT M), 7 (BPS-MHT M), and 5 GWh (BPS-ET M) and DH storage throughput decreases accordingly. Conversely, gas storage increases in both capacity and throughput for all scenarios, and electric storage and TES remain relatively unchanged.

Synthetic fuel production capacities and production, being directly affected by the update from full LHV alignment to mixed HHV/LHV, see noticeable change for all scenarios, as can be seen in Figures AII34 and AII35. Due to an increased electrical efficiency of electrolysis on LHV basis, the capacity for electrolysers decreases for all scenarios; however, a growth in hydrogen required per SNG output increases the methanation capacity required. Correspondingly, under near identical FLH synthetic fuel production increases for all scenarios, and the high transmission scenarios see the largest growth in total synthetic fuel production from 121 to 139 TWh in BPS-MHT and from 121 to 133 TWh in BPS-ET.

On the financial results of these scenarios, reduced capacity for solar PV and electrolysers decrease total annualised system costs but increase the total LCOE for each scenario except for BPS-MHT M, which finds a 0.1% decrease in total LCOE. Figures AII36 and AII37 show that for each scenario, there is a 2-3% decrease in total annualised costs, though for BPS-S M, BPS-MNT M, and BPS-ET M, there are increases in total LCOE of 1.7%, 1.8%, and 2.0%, respectively. For BPS-ET M, this effect is more pronounced on the historical total LCOE, which sees a growth of 1.8% from 21.3 €/MWh to 21.7 MWh. This increase in LCOE, although there is a decrease in total electric capacity that in part leads to larger annualised costs, is likely due to lower shares of single-axis solar PV installations, which are the more financially competitive solar PV technology for Bolivia. Key number deviations reported for BPS-S and BPS-ET are summarised in Table 10.

Table 10. Key result differences in the adjustment of the LUT model from full LHV alignment to mixed HHV/LHV based input parameters for BPS-S and BPS-ET.

	Unit	BPS-S	BPS-S M	Deviation from LHV	BPS-ET	BPS-ET M	Deviation from LHV
Annualised cost	[b€]	6.66	6.46	-3.0%	8.54	8.37	-2.0%
LCOE	[€/MWh]	15.77	16.04	1.7%	21.34	21.71	1.8%
Electricity generation	[TWh]	255.9	246.5	-3.7%	250.3	245.0	-1.7%
Electrolyser capacity	[GW_{el}]	27.18	24.28	-10.7%	28.24	26.89	-4.8%
Methanation capacity	[GW_{CH4}]	6.91	6.94	0.4%	6.62	6.65	0.5%
PV utility-scale capacity	[GW_{el}]	106.3	102.0	-4.1%	94.4	93.1	-1.4%
H_2 output	[TWh_{H2}]	75.6	79.9	5.7%	69.2	77.5	12.0%
CH_4 output	[TWh_{CH4}]	50.97	50.98	0.01%	45.7	49.1	7.5%
DH heat pump production	[TWh_{th}]	9.64	15.86	64.5%	12.70	15.68	23.4%
DH storage capacity	[GWh]	30.10	20.78	-31.0%	34.22	29.31	-14.3%
Gas storage capacity	[GWh]	3731	3783	1.4%	3152	3419	8.5%
DH storage throughput	[TWh]	10.77	7.35	-31.7	16.65	13.10	-21.4%
Gas storage throughput	[TWh]	55.72	55.72	<0.01%	49.98	53.39	6.8%

5. DISCUSSION

Discussion of results will be separated into three subsections. First, section 5.1 discusses the major findings of the results, particularly in the context of previous works. Second, the limitations of this study are discussed. Third, section 5.3 outlines recommendations for future research in the evaluation and comparison of ESMs under identical assumptions.

5.1 Main findings

This study provides a direct comparison between two of the most used ESMs in the field of 100% RE research and, under identical physical and financial assumptions, find similar structures for fully sustainable energy systems for the case of Bolivia. Further, this research provides insights in the value of energy transition scenarios compared to overnight scenarios and multi-nodal compared to single-node approach in 100% RE research. The structure of the energy system for all scenarios remains consistently dominated by solar PV due to Bolivia's excellent solar resource throughout the country, which suggests that modelling differences ultimately lead to similar results, as found in Brown et al. [71]. This outcome is especially significant in the context of Brown et al. [71], as it supports the major conclusion between the LUT model and EnergyPLAN ESMs that cost-optimised results maintain a similar energy system structure. The structural results for the case of Bolivia may be representative for many countries in the Sun Belt, due to comparable dominant solar PV electricity supply shares, as found by Bogdanov et al. [22,79].

5.1.1 EnergyPLAN versus LUT single-node results

Across scenarios, results indicate varying levels of electricity storage, while curtailment remains at similar levels of total electricity generation of around 4%. Curtailment has been a subject of analysis in studies utilising both EnergyPLAN [80] as a performance indicator and the LUT model [120]. With proper system flexibility and integration, Solomon et al. [120] found that allowing for larger levels of curtailment can provide an economic advantage by allowing for higher penetration of variable renewable electricity and reducing storage capacity and flexibility in demand. In the latest, fully sector coupled energy system analyses, curtailment levels of 2-4% have been found in Chapter 1 and in [110,121]. In the manual cost optimisation of EnergyPLAN, similar results were realised as flexible operation of electrolysers, electric boilers, and DH heat pumps during hours of peak production reduced the amount of storage required to satisfy more inflexible electricity demands and increased the economic viability of a solar PV dominated primary energy supply. Despite similar primary energy structures, overnight annualised cost disparities are noticeable between BPS-S and BPS-EP, although primary LCOE is at a similar level across overnight scenarios. The increased annualised costs in BPS-EP compared to BPS-S can therefore be attributed to increased synthetic fuel usage in the heat sector and larger required methanation capacity for SNG production, which is further discussed in section 5.2.1. Nevertheless, for Sun Belt countries such as Bolivia with practically unlimited solar resources, as the solar PV capacity installed in BPS-EP represents 2.4% of Bolivia's upper capacity limit, excess electricity production that cannot be utilised need not be considered as a waste of solar resources, and an optimal amount can be allowed to increase the economic competitiveness of 100% RE systems.

5.1.2 Spatial resolution and scenario definition in energy system modelling

Among the multi-nodal overnight scenarios of BPS-MHT and BPS-MNT, the results indicate that there is little benefit of a highly interconnected power transmission for a Sun Belt country such as Bolivia, with excellent solar resources. In these scenarios, total LCOE decreases only marginally between BPS-MNT and BPS-MHT, from 15.2 €/MWh to 15.0 €/MWh for the two respective scenarios. Such findings are supported by Breyer et al. [78] and Barasa et al. [122], as well as previous energy transition research for Bolivia [123]. However, Child el al. [77] and Brown et al. [71] find that for the region of Europe, high interregional integration leads to more pronounced economic benefits despite increases in system complexity. This is largely due to larger shares of more centralised renewable technologies such as wind and hydropower as well large spatial disparity in distribution of RE resources, whereas, for Sun Belt countries, such as Bolivia, these characteristics are largely non-factors. Moreover, inclusion of real grid infrastructure as well as storage and curtailment cost elements further strengthen the argument for energy autonomy at a regional level, and have typically not been included in regional analysis of the viability of decentralised energy systems [124]. Excellent solar resource conditions finally lead to a solar PV, battery and electrolyser driven energy system backbone, which does not require a strong grid infrastructure for balancing, since the solar resource is available practically everywhere. As a result, in BPS-MNT, the structure of solar PV generation varies notably compared to BPS-MHT, as fixed-titled solar PV composes a larger share.

Similarly, total annualised costs see only minor reductions from 6.81 b€ to 6.69 b€ from BPS-MNT to BPS-MHT. Between overnight and energy transition scenarios from the LUT model, a more substantial difference between both LCOE and annualised costs can be observed. Total LCOE has a 18-23% reduction between BPS-ET and the LUT model overnight scenarios and total annualised costs similarly see a 20-22% reduction when not accounting for legacy capacities that exist in the reference energy system. These findings are confirmed by power sector studies for the solar resource rich countries Iran [113] and India [125], since Sun Belt countries can further benefit from the step cost decline of solar PV and batteries [126], while this effect has been found less pronounced for higher wind and bioenergy shares as for Ukraine [127].

When adjusting the model of the Bolivian energy system from multi to single-node, total LCOE and annualised costs surprisingly are not reduced; rather, the annualised costs are in between the two multi-node scenarios and total LCOE is larger than both multi-node scenarios. In theory, more constraints from a multi-nodal modelling approach should lead to a higher cost, which was the case in Europe [110] and in a global energy interconnection [128]. This result is likely due to the aggregation of wind and solar resources in a single-node approach, which is particularly impactful for a country such as Bolivia, where solar resources are particularly abundant in the Altiplano to the southwest. Between BPS-S and BPS-MHT, there is a difference in capacity weighted PV yield values of 2.8% for single-axis solar PV, which in large part would explain the increased LCOE of BPS-S compared to BPS-MHT considering their significant roles in these scenarios, and more capacity allocation in resource-rich regions in the BPS-MHT, while the BPS-S cannot optimise the cost accordingly, but has to use the slightly lower nationally averaged PV yield.

In the modelling step from a multi to single-nodal approach, an optimisation of component performance should occur. This can be observed in the FLH of electrolysers from Table 9, and the financial consequence for synthetic fuels is particularly apparent when comparing the average cost of renewable hydrogen and SNG from BPS-MHT to BPS-S, where a reduction occurs from 48 to 34 €/MWh for hydrogen and 56 to 48 €/MWh for SNG. Consequently, a similar result due to improved performance of electrolysers can be expected for FT fuels, as reduced capacities of electrolysis as well as CO_2 and hydrogen storage will be required to satisfy the same FT fuel demand. However, while FT fuel costs see reductions between BPS-MNT to BPS-S, from 78 to 71 €/MWh, a comparable reduction cannot be observed between BPS-MHT to BPS-S. Rather, under near identical FLH, FT fuels cost increases slightly from 70.6 to 71.1 €/MWh.

5.1.3 Impact of mixed HHV/LHV versus full LHV alignment

In the scenario variation of the LUT model from a standard full LHV basis to a mix of HHV and LHV based values, a number of effects were observed particularly surrounding synthetic fuel production, which had ripple effects throughout the different scenarios represented by the LUT model. An increase of electrolyser efficiency from 70% (LHV) to 82% (HHV) required decreased electrical capacity to produce similar levels of hydrogen, while a decreased methanation efficiency from 82% (LHV) to 78% (HHV) increased the methanation capacity. Decreased capacity of electrolysers resulted in smaller total electricity capacities for all scenarios except for BPS-MHT, and smaller waste heat from fuel conversion processes increased the role of heat pumps for LT demands while decreasing the capacities and throughput for DH storage. Decreased capacities for electricity and synthetic fuel production resulted in lower annualised costs of about 2-3%, but did not necessarily result in lower LCOE, as seen in BPS-MHT. These effects highlight the importance of clarity regarding the basis for physical and financial assumptions, particularly considering synthetic fuel production in an energy system with significant SNG demands, as the results from the scenario variation of mixed HHV and LHV values of the LUT model suggest, while the impact of mixed heating values on the total annualised system cost is rather small with about 2-4% lower cost.

5.2 Limitations

When developing overnight scenarios between multiple ESMs, one will encounter limitations that prevent a perfect one-to-one comparison, whether these limitations are technological or financial. While many of the technological limitations have been discussed in section 3.5, their effects are noticeable in the results; therefore, they are worth discussing again in the context of the results.

5.2.1 Annualised cost structure between ESMs

One such limitation exists in the variable operation and management cost structure of EnergyPLAN compared to the LUT model. In the LUT model financial data inputs, each technology has defined capital expenditures (CAPEX), fixed operational and management expenditures ($OPEX_{fix}$), and variable operational and management expenditures ($OPEX_{var}$). However, in EnergyPLAN, $OPEX_{var}$ is not available to be input for all technologies. While most $OPEX_{var}$ were able to be properly input, the $OPEX_{var}$ for CO_2 hydrogenation was not available in EnergyPLAN, though it exists in the LUT model. Given the significant SNG usage in BPS-EP, this cost would certainly further highlight the annualised cost differences, primarily those between BPS-EP and BPS-S.

The annualised cost differences shown in Figure 54 point particularly to synthetic fuel production, and the increased solar PV capacity required to operate electrolysers and CO_2 hydrogenation to meet the increased SNG demand in BPS-EP. Quantitatively, solar PV, electrolysers and CO_2 hydrogenation account for 0.2, 0.6 and 1.5 b€ increases in annualised costs from BPS-EP to BPS-S, with these components accounting for 51% of total annualised cost difference. The effects of DH structure between ESMs are also apparent in Figure 54, as DH heat pumps and boilers are 0.4 and 0.2 b€, or 9% and 4%, larger in BPS-EP compared to BPS-S. While BPS-S has larger annualised costs from DH electric heating compared to BPS-EP, the difference is only 0.1 b€, or 2% of total difference. Figure 55 further shows the sources of annualised cost difference between these two scenarios and demonstrates that roughly 12 cost components compose much of the cost difference.

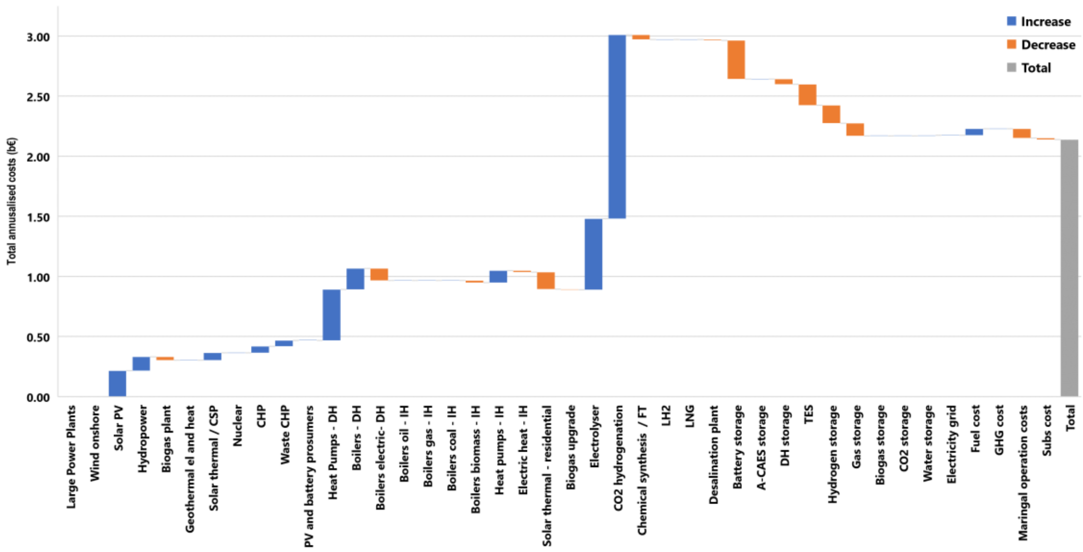


Figure 54. Annualised cost difference between BPS-EP and BPS-S by technology.

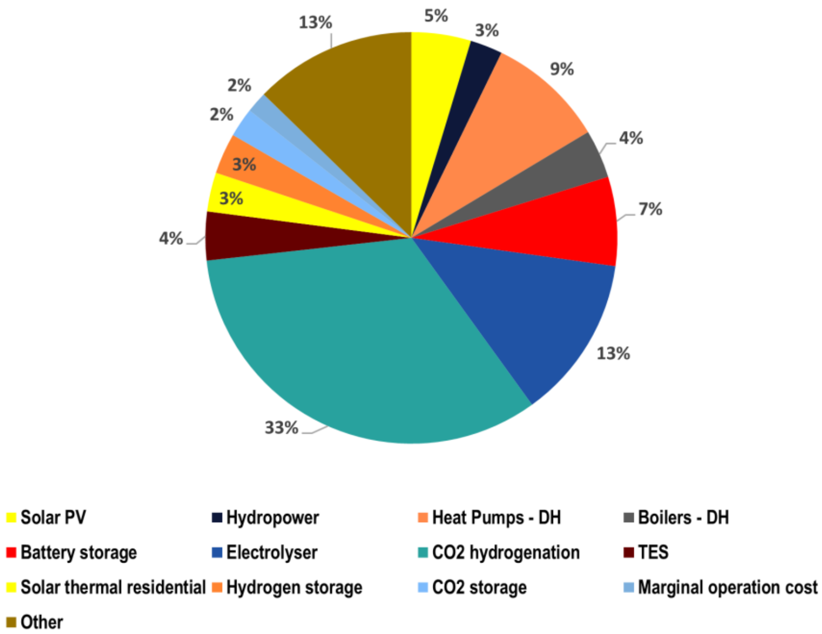


Figure 55. Share of annualised cost difference between BPS-EP and BPS-S by technology.

Conversely, EnergyPLAN provides cost inputs for fuel handling costs separately from individual fuel costs to represent the refining and distribution of fuels to different technologies. While these costs are built into the fuel costs of the LUT model, how these costs are represented vary between the two ESMs. EnergyPLAN also allows for different tax schema to be input relating to the use of fuels and electricity for energy conversion, which can be useful especially in the analysis of national energy systems. However, separate fuel handling costs and taxes were set to zero for the best possible model comparison. Such additional costs would certainly affect a cost-optimal solution, though, for the LUT model, the aim is primarily to determine a cost-optimised scenario based on the technological and financial merits of the technologies involved, largely without external pressure aside from a CO_2 price mechanisms.

An additional limitation in the methods by which annualised costs are determined can also be observed in how interest rates are established between the two models. The LUT model allows for different interest rates to be applied, particularly between residential, commercial, industrial PV prosumer and battery and centralised systems components. Conversely, EnergyPLAN uses a single interest rate for all technologies. Although the difference in total annualised costs is small, there is an effect as residential PV and battery have the highest capex of PV systems, and using an interest rate of 4% compared to 7% has an influence on the economic viability of residential PV and battery systems in a cost-optimised scenario, on a level of 0.1 b€, or 2.1% of total annualised cost difference between BPS-EP and BPS-S.

Results indicate that due to a lack of avenues for electrification in heating systems, as discussed in section 3.5, significantly more SNG, 46 TWh, is required in BPS-EP than in BPS-S. Because electric DH systems are not allowed to operate beyond the capacity of fuel-based boilers in EnergyPLAN, which is possible in the LUT model, capacities for SNG production are noticeably larger, and are the main source of difference in total annualised costs, with electrolyser, CO_2 DAC, and methanation units composing 46% of total annualised difference between the two scenarios. Furthermore, EnergyPLAN and the LUT model have different operating schema to produce SNG through methanation using CO_2 DAC and hydrogen from water electrolysers. Without a defined, constant SNG output, EnergyPLAN will only produce SNG during production of excess electricity, through critical excess electricity production (CEEP) regulation 8. Under this CEEP regulation, SNG production is tied to the operation of electrolysers, and hydrogen storage is not utilised to reduce the peak capacity needed for CO_2 hydrogenation. Conversely, in the LUT model, hydrogen storage can be used to increase the operating time of the methanation process, so that it is operating on a high utilization of around 7500 full load hours, while operating electrolysers for around 3200-4000 full load hours, depending on scenario, which is a much higher utilization, as it would be ever possible in excess hours according to the CEEP definition. The effect of these operating schema can be most visualised in the breakdown of annualised costs in Figure 53, where CO_2 hydrogenation annualised costs are more than double those of BPS-S. Therefore, the EnergyPLAN default model mechanism cannot lead to cost optimised solutions, since for the energy system case of Bolivia 38-40% of all electricity generation is required to produce hydrogen, which is far from cost optimisation, if only excess electricity can be used, and if utilisation of energy system components are linked to the CEEP. To the knowledge of the authors, this characteristic of SNG production still exists in the most recent version of EnergyPLAN, version 15.0 [81].

5.2.2 Limitations in utilizing full ESM functionality

A further limitation in fuel conversion in EnergyPLAN compared to the LUT model is how waste heat from fuel conversion is utilised. In the LUT model, detailed parameters are provided regarding the heat demand of CO_2 DAC and excess heat from the FT process, and this excess heat can be recovered and utilised in centralised heating. The co-location of CO_2 DAC and FT units also follows an industrial rationale. For BPS-S, this recovered heat amounts to a supply of 37 TWh, reducing the amount of heat required to be produced by DH heating technologies, as seen in section 4.3. In EnergyPLAN, it is possible to direct heat from electrolysis and methanation, however, a heat demand cannot be set for CO_2 DAC; therefore, it is assumed that any excess heat from the PtG or PtL processes would be directed to CO_2 DAC, and not available to be recovered.

While these limitations exist within EnergyPLAN, there are features that EnergyPLAN provides that could not be utilised to maintain consistency between the models. As discussed in section 3.5, EnergyPLAN allows for EV smart charging and V2G capacities to be established as a decentralised form of storage. Previous studies using EnergyPLAN have found that V2G capacities can provide important storage capacities at low investment costs for both wind [129] and solar PV [130] based electricity supply. Child et al. [30] further discusses the benefits of smart charging and V2G capacities on an energy system which can be utilised in multiple transport modes and greatly reduce the need for centralised storage solutions, or completely eliminate their necessity. However, EnergyPLAN will only allow V2G discharge as a substitute for condensing PP capacity, and, as BPS-EP results do not utilise any such capacity, V2G cannot be utilised to reduce stationary battery capacity in the context of this study. An additional feature that is allowed in EnergyPLAN but not capable in the LUT model is the capability to define flexible electricity demands on a daily, weekly, and monthly basis. While flexible electricity demand is not a requirement for the integration of RE as demonstrated by this study and found by Kwon and Østergaard [131], Child and Breyer [106,132] find that flexible demand has a role in offsetting household and industrial electricity demands according to PV generation profiles, which can serve to reduce storage requirements and curtailment levels. With 50% of transport electricity demands being allocated to smart charging and daily flexibility corresponding to 10% of total annual electricity demand, total annualised system costs could be reduced by 0.13 b€. In DH systems, EnergyPLAN allows for losses in distribution systems to be defined; however, because the LUT model does not account for DH losses, these have been set to zero. Conversely, EnergyPLAN does not have a mechanism to account for electric grid losses, which has been demonstrated for the LUT model.

5.2.3 Optimisation versus simulation

Given the nature of the ESMs involved in this study, the discussion of optimisation versus simulation in energy system modelling research deserves attention. Limitations of optimisation models are particularly apparent when only one cost optimal solution is found based on the objective function of the model; whereas, simulation models have the capacity to compare different future scenarios based on different input parameters determined by the user [116]. Recently, though, multi-objective analyses have been developed [133], which develop several optimal solutions in terms of costs and GHG emission reductions, as a compromise between the simulation and optimisation approaches. In the context of the nature of ESMs utilised in this research, though, Lund et al. [116] argue that, although different scenarios can be developed in optimisation models, the model has to be manually adjusted to include technologies that would not be utilised otherwise, and that simulation modelling allows for a wide range of technically-feasible scenarios to be presented. However, optimisation modelling has the potential to reveal new insights in the operation of a future energy system when the user is not the optimiser. Such insights may allow for an energy system structure that may not be contemplated under conventional wisdom to be considered by decisionmakers. Examples for found optimisation modelling solutions which hardly would have been discovered otherwise are the battery-to-PtG effect describing discharging of batteries in early morning hours and enhancing hydrogen production so that overall curtailment and battery and electrolyser capacity can be further optimised [134] and the monsoon mitigation pattern transition from wind and hydropower balancing to a PV, battery, power transmission solution including regions being not affected by the monsoon [135]. Similarly, optimisation modelling solutions have revealed the much greater role of solar PV in a sector coupled energy system with PtX for least cost P-to-H_2 conversion, while a low-cost H_2 storage enables near to baseload operation of H_2-to-X synthesis routes [110]. Comparison of results between optimisation and simulation models under identical assumptions, though, allows for shortcomings in model design to be identified and improved upon, which is beneficial for all.

5.3 Future works recommendation

Considering the discussion of results, direct comparison of ESM results to one another can provide valuable insights and there is benefit in performing direct analyses of widely used ESMs. In the context of this research, cost-optimal results from the LUT model can be compared to the most recent version of EnergyPLAN, which has certain new features not considered in this research. By extension, future research can perform similar analyses using other widely used ESMs such as PyPSA, REMix, GENeSYS-MOD, and TIMES. It would also be of high value to start cross-validations for all ESMs which are used on a global level, or at least on a continental level. Such research contributes to the dialogue of modelling approaches and methods utilised in sustainable and renewable energy research.

6. CONCLUSIONS

The LUT Energy System Transition model and EnergyPLAN simulation tool are two of the most widely used ESMs in the field of 100% RE research. When performing cost-optimised analysis for the case of Bolivia using both ESMs under identical scenarios, the story regarding the primary energy and electricity structure for Bolivia remains the same, a fully sustainable energy system with solar PV becoming the backbone of the Bolivian energy system. However, differences in the models become apparent in the structure of heating supply and demand, particularly that to industry, and SNG production. These differences lead to a 30% increase in annualised costs for BPS-EP compared to BPS-S. Therefore, these limitations lead to the conclusion that a fully cost-optimised solution for the case of Bolivia, where SNG plays a significant role, cannot be achieved using EnergyPLAN.

This research also demonstrates the consequences of overnight versus energy transition scenarios and multi versus single-node approaches through BPS-ET and the LUT model's overnight scenario. Results from BPS-ET compared to LUT model overnight scenarios suggest that overnight scenarios undershoot LCOE and annualised costs due to legacy energy system components in the reference year by 20-30% compared to energy transition scenarios. The multi-nodal approach in this study show that increased spatial resolution can decrease system costs for a country such as Bolivia, where best solar resources are concentrated among a few regions rather than using aggregated resource potentials, despite the additional constraints that are introduced when increasing the number of nodes in energy system modelling. Furthermore, a variation of the LUT model from full LHV alignment to a mixed HHV/LHV basis results in 2-4% lower annualised costs, mainly due to less primary energy supplies and capacities related to synthetic fuel production. Although the differences are small, full alignment of LHV assumptions are essential for consistent results. The results of this research suggest that Sun Belt countries have the opportunity to develop highly decentralised fully sustainable energy systems that do not require large interregional transmission networks, with solar PV, batteries and electrolysers providing the foundation of such energy systems.

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APPENDIX I. SUPPLEMENTARY MATERIAL FOR CHAPTER 1

Table AI1. Population Projection [1]

Region	Unit	2020	2025	2030	2035	2040	2045	2050
PDBE	[mil]	0.62	0.67	0.71	0.75	0.80	0.84	0.88
LP	[mil]	3.03	3.25	3.46	3.68	3.89	4.10	4.30
SC	[mil]	3.23	3.46	3.69	3.92	4.15	4.37	4.58
CB	[mil]	2.03	2.17	2.32	2.46	2.60	2.75	2.88
OR	[mil]	0.56	0.60	0.64	0.68	0.72	0.76	0.79
PT	[mil]	0.93	1.00	1.06	1.13	1.20	1.26	1.32
CH	[mil]	0.66	0.70	0.75	0.80	0.84	0.89	0.93
TJ	[mil]	0.57	0.61	0.65	0.69	0.74	0.77	0.81
Bolivia	[mil]	11.63	12.45	13.28	14.11	14.93	15.74	16.51

Table AI2: Projection of the power, heat, transportation, and desalination demand [2–4]

Energy service demand	Unit	2020	2025	2030	2035	2040	2045	2050
Power demand	[TWh_{el}]	10.5	13.0	15.1	18.3	22.2	27.0	32.6
Industrial heat demand	[TWh_{th}]	43.8	60.2	74.6	94.3	118.0	146.7	181.5
Space heating demand	[TWh_{th}]	5.5	7.2	8.6	10.7	13.3	16.4	20.2
Domestic water heating demand	[TWh_{th}]	5.5	7.2	8.6	10.7	13.3	16.4	20.2
Biomass cooking heat demand	[TWh_{th}]	2.1	0.6	0.4	0.2	0.1	0.0	0.0
Road LDV passenger transport demand	[mil p-km]	10477	12056	13325	15703	18667	22310	26867
Road 2W/3W passenger transport demand	[mil p-km]	2680	3120	3489	4157	4992	6020	7327
Road Bus passenger transport demand	[mil p-km]	1037	1107	1127	1216	1316	1429	1522
Road Bus passenger transport demand	[mil p-km]	7728	8733	9473	10953	12780	15006	17699
Road MDV freight transport demand	[mil t-km]	891	1007	1093	1263	1474	1731	2041
Road HDV	[mil t-km]	361	408	442	511	597	701	826

freight transport demand								
Rail passenger transport demand	[mil p-km]	1762	1991	2160	2497	2914	3421	4036
Rail freight transport demand	[mil t-km]	2680	3120	3489	4157	4992	6020	7327
Marine passenger transport demand	[mil p-km]	376	425	461	533	622	731	862
Marine freight transport demand	[mil t-km]	4548	5139	5575	6446	7521	8831	10416
Aviation passenger transport demand	[mil p-km]	177	200	217	250	292	343	405
Aviation freight transport demand	[mil t-km]	376	425	461	533	622	731	862
Water desalination demand	[m^3/day]	96	384	1608	5040	9168	10992	11544

Table AI3: Projected specific energy demand by transport mode and vehicle type [3]

Mode and vehicle type	Unit	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Road LDV ICE	[kWh_{th}/km]	0.767	0.737	0.695	0.641	0.583	0.525	0.458
Road LDV BEV	[kWh_{el}/km]	0.175	0.148	0.134	0.126	0.119	0.112	0.103
Road LDV FCEV	[kWh_{th}/km]	0.000	0.226	0.218	0.205	0.201	0.178	0.166
Road LDV PHEV	[kWh_{el}/km]	0.215	0.153	0.144	0.135	0.123	0.111	0.095
Road LDV PHEV	[kWh_{th}/km]	0.126	0.116	0.108	0.102	0.094	0.087	0.080
Road 2,3W ICE	[kWh_{th}/km]	0.143	0.143	0.143	0.143	0.143	0.143	0.143
Road 2,3W BEV	[kWh_{el}/km]	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Road 2,3W FCEV	[kWh_{th}/km]	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Road 2,3W PHEV	[kWh_{el}/km]	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Road 2,3W PHEV	[kWh_{th}/km]	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Road Bus ICE	[kWh_{th}/km]	4.067	4.023	3.966	3.908	3.858	3.808	3.714

Road Bus BEV	[kWh_{el}/km]	0.000	1.744	1.698	1.648	1.598	1.559	1.512
Road Bus FCEV	[kWh_{th}/km]	0.000	2.853	2.791	2.720	2.589	2.487	2.379
Road Bus PHEV	[kWh_{el}/km]	2.028	1.952	1.940	1.923	1.905	1.878	1.849
Road Bus PHEV	[kWh_{th}/km]	0.919	0.887	0.858	0.833	0.803	0.779	0.753
Road MDV ICE	[kWh_{th}/km]	2.340	2.259	2.156	2.039	1.950	1.866	1.719
Road MDV BEV	[kWh_{el}/km]	0.895	0.751	0.697	0.641	0.596	0.564	0.525
Road MDV FCEV	[kWh_{th}/km]	0.000	1.286	1.239	1.171	1.106	1.062	1.002
Road MDV PHEV	[kWh_{el}/km]	1.404	1.301	1.248	1.189	1.123	1.065	0.995
Road MDV PHEV	[kWh_{th}/km]	0.358	0.306	0.282	0.263	0.242	0.226	0.208
Road HDV ICE	[kWh_{th}/km]	3.406	3.233	3.029	2.797	2.604	2.485	2.320
Road HDV BEV	[kWh_{el}/km]	0.000	1.494	1.354	1.270	1.188	1.110	1.038
Road HDV FCEV	[kWh_{th}/km]	0.000	1.805	1.711	1.575	1.482	1.409	1.303
Road HDV PHEV	[kWh_{el}/km]	0.000	2.106	2.015	1.899	1.739	1.605	1.494
Road HDV PHEV	[kWh_{th}/km]	0.000	0.448	0.421	0.394	0.358	0.332	0.310
Rail pass fuel	[kWh_{th}/(p-km)]	0.079	0.078	0.078	0.078	0.077	0.076	0.074
Rail pass elec.	[kWh_{el}/(p-km)]	0.049	0.047	0.046	0.045	0.043	0.042	0.041
Rail freight fuel	[kWh_{th}/(t-km)]	0.048	0.048	0.047	0.047	0.046	0.045	0.042
Rail freight elec.	[kWh_{el}/(t-km)]	0.024	0.022	0.021	0.020	0.019	0.018	0.017
Marine pass fuel	[kWh_{th}/(p-km)]	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Marine pass elec.	[kWh_{el}/(p-km)]	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Marine pass LH2	[kWh_{th}/(p-km)]	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Marine pass LNG	[kWh_{th}/(p-km)]	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Marine freight fuel	[kWh_{th}/(t-km)]	0.026	0.026	0.026	0.026	0.026	0.023	0.023
Marine freight elec.	[kWh_{el}/(t-km)]	0.012	0.012	0.013	0.013	0.013	0.013	0.013
Marine freight LH2	[kWh_{th}/(t-km)]	0.000	0.000	0.022	0.021	0.019	0.019	0.018
Marine freight LNG	[kWh_{th}/(t-km)]	0.025	0.025	0.024	0.024	0.024	0.023	0.023
Aviation pass fuel	[kWh_{th}/(p-km)]	0.470	0.459	0.448	0.432	0.418	0.407	0.395
Aviation pass elec.	[kWh_{el}/(p-km)]	0.000	0.000	0.000	0.145	0.139	0.134	0.129
Aviation pass LH2	[kWh_{th}/(p-km)]	0.000	0.000	0.000	0.278	0.267	0.257	0.247
Aviation freight fuel	[kWh_{th}/(t-km)]	0.122	0.119	0.116	0.112	0.108	0.104	0.099
Aviation freight elec.	[kWh_{el}/(t-km)]	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Aviation freight LH2	[kWh_{th}/(t-km)]	0.000	0.000	0.000	0.072	0.070	0.067	0.064

Table AI4: Projected shares of passenger demand by transport node and vehicle type [3]

Passenger mode and vehicle type	2020	2025	2030	2035	2040	2045	2050
Road LDV ICE – liquid fuel	94.0%	79.9%	50.0%	20.0%	11.0%	7.0%	4.0%
Road LDV BEV – electricity	3.0%	10.0%	39.0%	68.0%	74.0%	73.0%	76.0%
Road LDV FCEV – hydrogen	3.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Road LDV PHEV – electricity/liquid fuel	3.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Road 2W/3W ICE – liquid fuel	65.0%	60.0%	40.0%	25.0%	15.0%	10.0%	5.0%
Road 2W/3W BEV - electricity	35.0%	40.0%	60.0%	75.0%	85.0%	90.0%	95.0%
Road BUS ICE – liquid fuel	78.9%	47.9%	16.9%	5.9%	4.9%	3.9%	2.9%
Road BUS BEV – electricity	20.0%	50.0%	80.0%	90.0%	90.0%	90.0%	90.0%
Road BUS FCEV – hydrogen	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Road BUS PHEV – electricity/liquid fuel	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%
Rail - electrical	14.7%	24.1%	39.7%	54.3%	68.8%	81.8%	94.7%
Rail – liquid fuel	85.3%	75.9%	60.3%	45.7%	31.2%	18.2%	5.3%
Aviation – electricity	0.0%	0.0%	0.0%	1.2%	4.7%	10.5%	18.7%
Aviation – liquid fuel	100%	100%	100%	96.5%	86.0%	68.5%	43.9%
Aviation - hydrogen	0.0%	0.0%	0.0%	2.3%	9.3%	21.0%	37.4%

Table AI5: Projected share of freight demand by transport mode and vehicle type [3]

Freight more and vehicle type	2020	2025	2030	2035	2040	2045	2050
Road MDV ICE – liquid fuel	88.9%	78.0%	47.0%	16.0%	5.0%	4.0%	3.0%
Road MDV BEV – electricity	10.0%	19.0%	48.0%	75.0%	80.0%	80.0%	80.0%
Road MDV FCEV – hydrogen	0.1%	1.0%	2.0%	5.0%	10.0%	10.0%	10.0%
Road MDV PHEV – electricity/liquid fuel	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%
Road HDV ICE – liquid fuel	97.5%	88.0%	77.0%	46.0%	12.0%	4.0%	3.0%
Road HDV BEV – electricity	1.0%	8.0%	15.0%	30.0%	50.0%	50.0%	50.0%
Road HDV FCEV – hydrogen	0.5%	2.0%	5.0%	20.0%	30.0%	30.0%	30.0%
Road HDV PHEV – electricity/liquid fuel	1.0%	2.0%	3.0%	4.0%	8.0%	16.0%	17.0%
Rail – electricity	14.7%	24.1%	39.7%	54.3%	68.8%	81.8%	94.7%
Rail - liquid	85.3%	75.9%	60.3%	45.7%	31.2%	18.2%	5.3%
Marine – electricity	0.1%	0.6%	1.1%	2.8%	5.6%	7.2%	8.3%
Marine – liquid fuel	99.4%	98.4%	95.9%	91.2%	79.4%	57.8%	26.7%
Marine – hydrogen	0.0%	0.0%	1.0%	3.0%	10.0%	25.0%	45.0%
Marine – LNG	0.5%	1.0%	2.0%	3.0%	5.0%	10.0%	20.0%
Aviation – electricity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Aviation – liquid fuel	100%	100%	100%	97.7%	90.7%	79.0%	62.6%
Aviation – hydrogen	0.0%	0.0%	0.0%	2.3%	9.3%	21.0%	37.4%

Table AI6: Projected final energy demand by energy form

Energy form	Unit	2020	2025	2030	2035	2040	2045	2050
Electricity demand	[TWh_{el}]	10.5	14.3	18.0	24.9	32.6	39.3	46.4
Heat demand	[TWh_{th}]	52.4	69.3	85.2	107	134	166	205
Fuel demand	[TWh]	36.2	34.8	29.9	20.5	11.7	9.7	9.4
Total	[TWh]	99.1	118	133	153	178	215	261

Table AI7: Projected final energy demand by sector

Energy form	Unit	2020	2025	2030	2035	2040	2045	2050
Power demand	[TWh_{el}]	10.5	13.0	15.1	18.3	22.2	27.0	32.6
Heat demand	[TWh_{th}]	52.4	69.3	85.2	107	134	166	205
Transport demand	[TWh]	36.2	36.1	32.8	27.1	22.0	22.0	23.1
Desalination demand	[TWh]	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Total	[TWh]	99.1	118	133	153	178	215	261

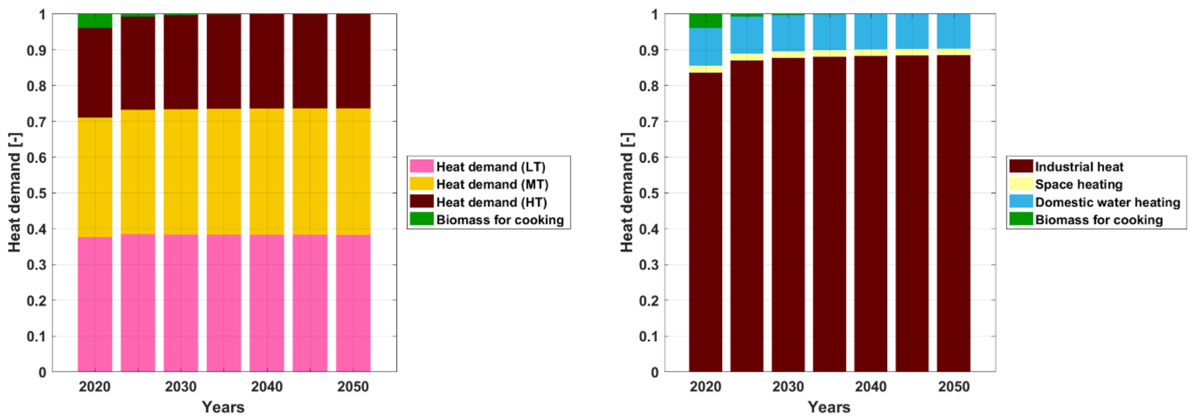


Figure AI1: Relative shares of heat demand by application (left) and by category (right).

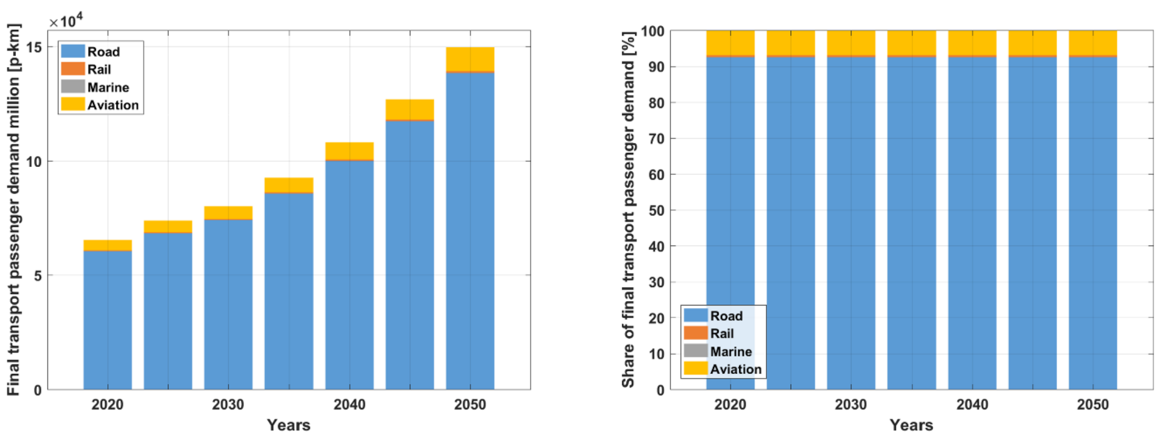


Figure AI2: Final transport passenger demand in absolute (left) and relative (right) shares.

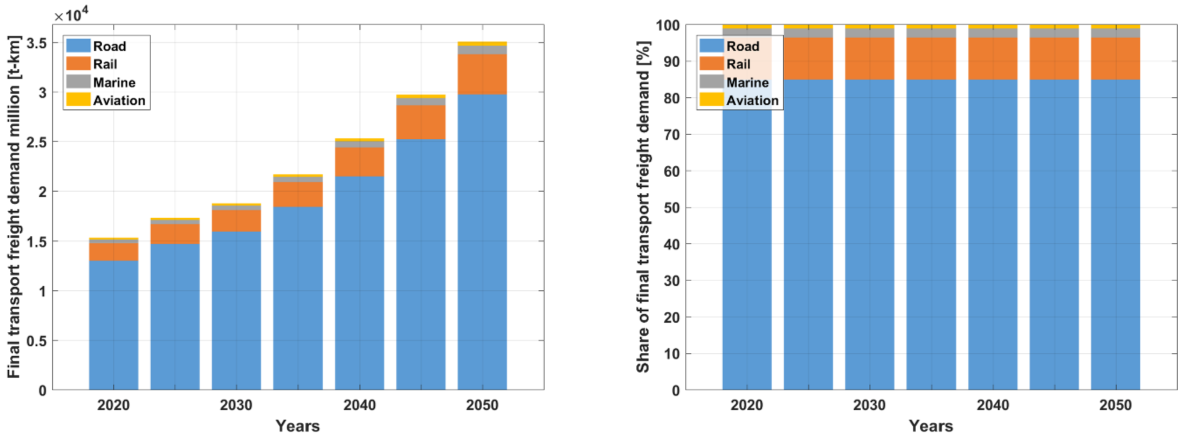


Figure AI3: Final transport freight demand in absolute (left) and relative (right) shares.

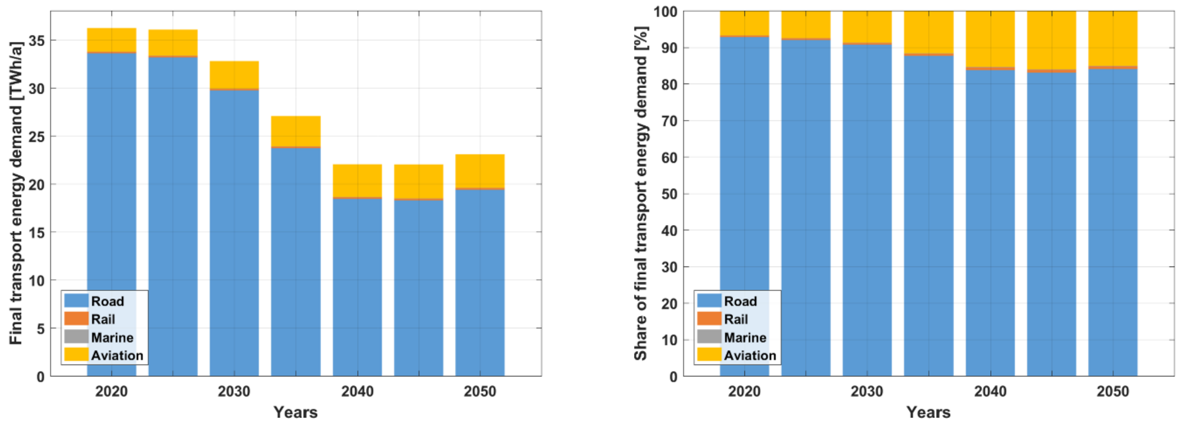


Figure AI4: Final transport energy demand by mode of transport in absolute (left) and relative (right) shares.

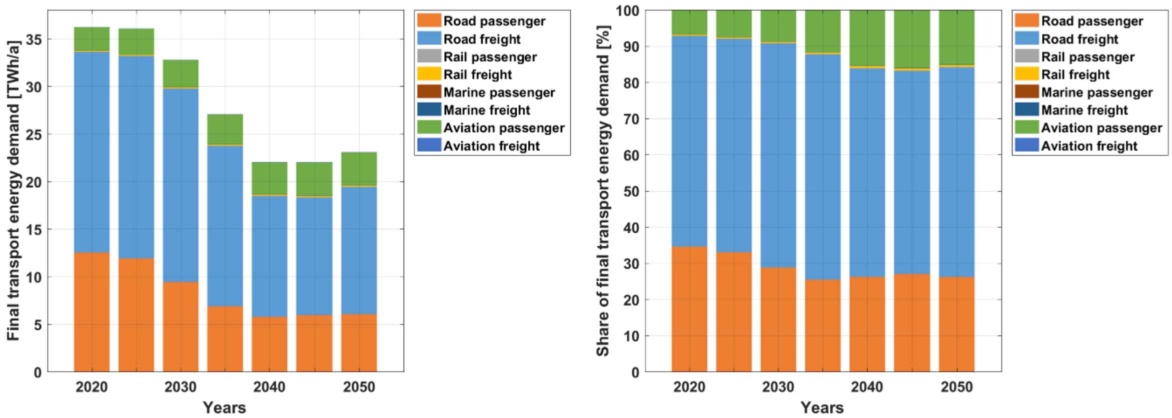


Figure AI5: Final passenger and freight transport energy demand by transport mode in absolute (left) and relative (right) shares.

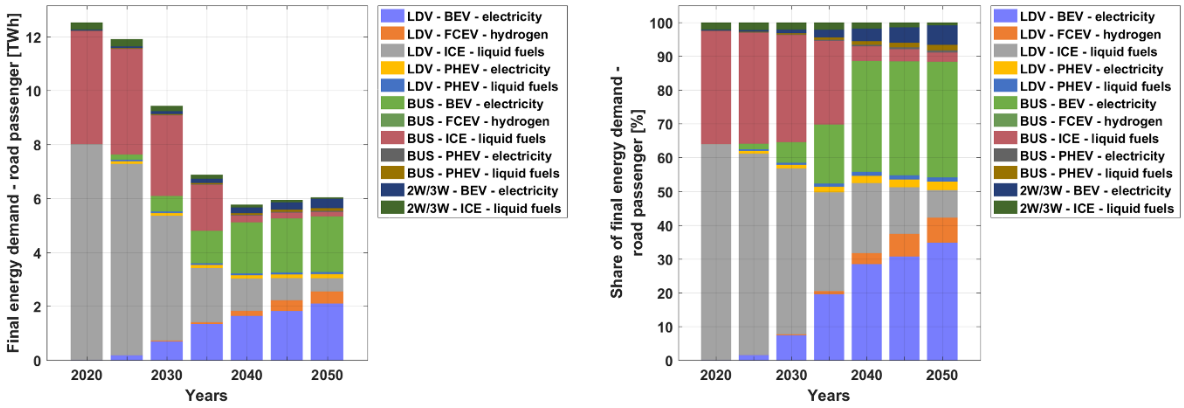


Figure AI6. Final energy demand – road passenger by type of vehicle in absolute (left) and relative (right) shares.

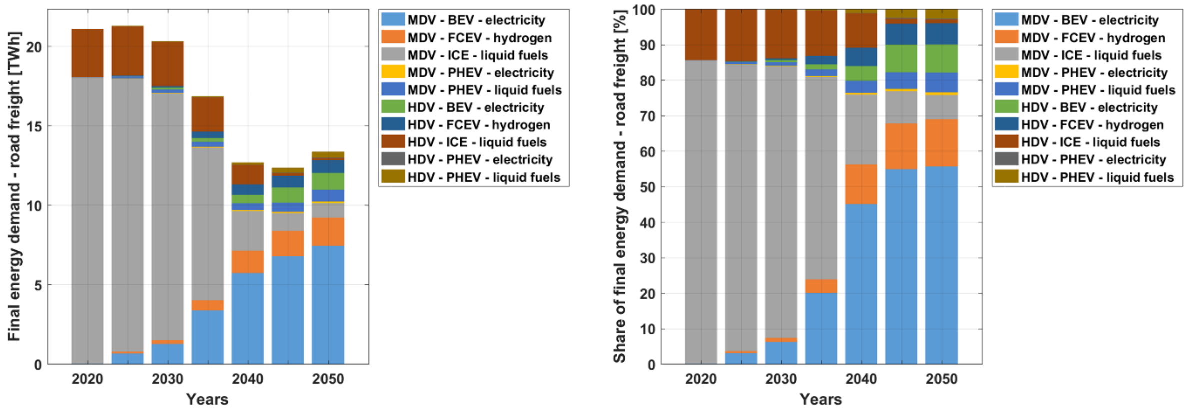


Figure AI7: Final energy demand – road freight by type of vehicle in absolute (left) and relative (right) shares.

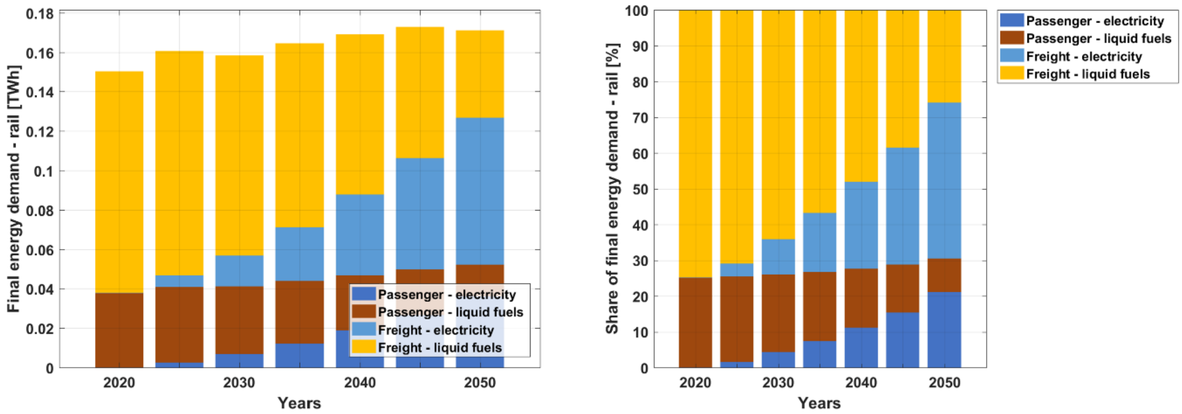


Figure AI8: Final energy demand – rail in absolute (left) and relative (right) shares.

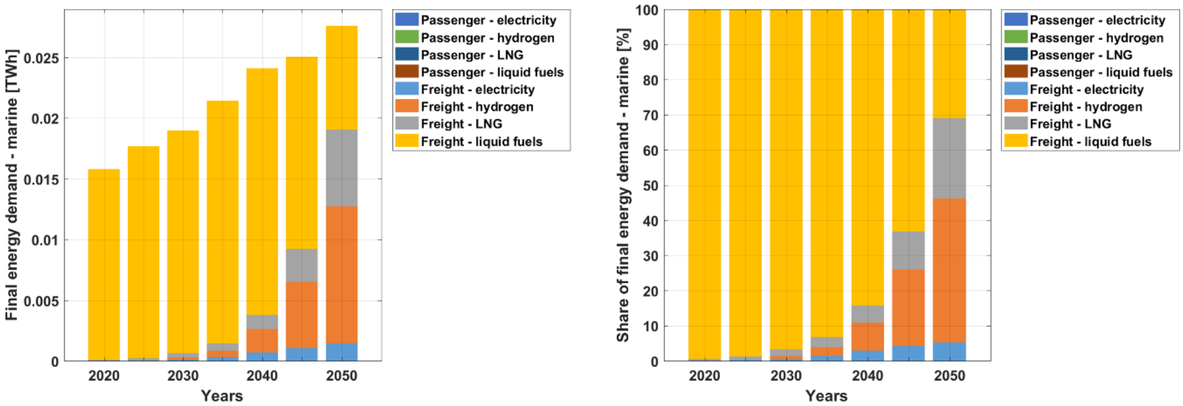


Figure AI9: Final energy demand – marine in absolute (left) and relative (right) shares.

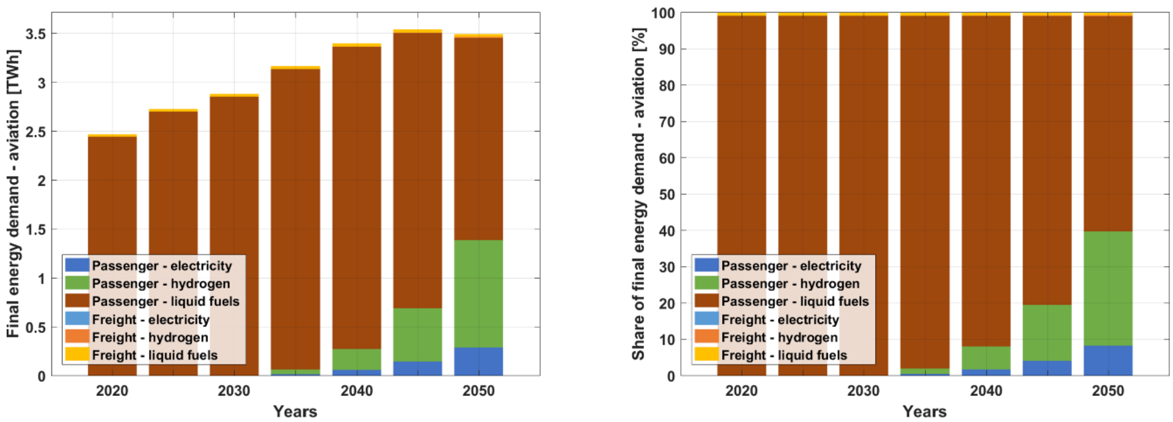


Figure AI10: Final energy demand – aviation in absolute (left) and relative (right) shares.

Table AI8: Financial and technical assumptions of energy system technologies used

Technologies		Unit	2020	2025	2030	2035	2040	2045	2050	Sources
PV fixed tilted PP	Capex	€/kW_{el}	432	336	278	237	207	184	166	[5,6]
	Opex fix	€/(kW_{el} a)	7.76	6.51	5.66	5	4.47	4.04	3.7	
	Opex var	€/kWel	0	0	0	0	0	0	0	
	Lifetime	years	30	35	35	35	40	40	40	
PV rooftop - residential	Capex	€/kW_{el}	1045	842	715	622	551	496	453	[5]
	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 rooftop - commercial	Capex	€/kW_{el}	689	544	456	393	345	308	280	[5]
	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 rooftop - industrial	Capex	€/kW_{el}	512	397	329	281	245	217	197	[5]
	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 PP	Capex	€/kW$_{el}$	475	370	306	261	228	202	183	[5–7]
	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 PP	Capex	€/kW$_{el}$	1150	1060	1000	965	940	915	900	[8]
	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 PP	Capex	€/kW$_{el}$	2560	2560	2560	2560	2560	2560	2560	[9]
	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	
Hydro Reservoir/ Dam	Capex	€/kW$_{el}$	1650	1650	1650	1650	1650	1650	1650	[9]
	Opex fix	€/(kW$_{el}$ a)	49.5	49.5	49.5	49.5	49.5	49.5	49.5	
	Opex var	€/kWh$_{el}$	0.003	0.003	0.003	0.003	0.003	0.003	0.003	
	Lifetime	years	50	50	50	50	50	50	50	
Geothermal PP	Capex	€/kW$_{el}$	4970	4720	4470	4245	4020	3815	3610	[9,10]
	Opex fix	€/(kW$_{el}$ a)	80	80	80	80	80	80	80	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	40	40	40	40	40	40	40	
	Efficiency		23.9%	23.9%	23.9%	23.9%	23.9%	23.9%	23.9%	
Steam turbine (CSP)	Capex	€/kW$_{el}$	968	946	923	902	880	860	840	[11]
	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		38.3%	40.3%	43.0%	43.0%	43.0%	43.0%	43.0%	
CCGT PP	Capex	€/kW$_{el}$	775	775	775	775	775	775	775	[12]
	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		58.0%	58.0%	58.0%	59.0%	60.0%	60.0%	60.0%	
OCGT PP	Capex	€/kW$_{el}$	475	475	475	475	475	475	475	[13]
	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		40.0%	41.5%	43.0%	43.5%	44.0%	44.5%	45.0%	
Int Combust Generator	Capex	€/kW$_{el}$	385	385	385	385	385	385	385	[13]
	Opex fix	€/(kW$_{el}$ a)	11.5	11.5	11.5	11.5	11.5	11.5	11.5	
	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		30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	

Coal PP	Capex	€/kW$_{el}$	1500	1500	1500	1500	1500	1500	1500	[12,14]
	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	40	40	40	40	40	40	40	
	Efficiency		43.0%	43.0%	43.0%	43.0%	43.0%	43.0%	43.0%	
Biomass PP	Capex	€/kW$_{el}$	2620	2475	2330	2195	2060	1945	1830	[11]
	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		36.0%	36.5%	37.0%	37.5%	38.0%	38.5%	39.0%	
Nuclear PP	Capex	€/kW$_{el}$	6003	6003	5658	5658	5244	5244	5175	[12,15, 16]
	Opex fix	€/(kW$_{el}$ a)	113.1	113.1	98.4	98.4	83.6	83.6	78.8	
	Opex var	€/kWh$_{el}$	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	
	Lifetime	years	40	40	40	40	40	40	40	
	Efficiency		37.0%	37.0%	38.0%	38.0%	38.0%	38.0%	38.0%	
CHP NG Heating	Capex	€/kW$_{el}$	880	880	880	880	880	880	880	[11]
	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$_{el}$		51.0%	52.0%	53.0%	53.5%	54.0%	54.5%	55.0%	
	Efficiency$_{th}$		36.6%	37.3%	38.0%	38.3%	38.7%	39.1%	39.4%	
CHP Oil Heating	Capex	€/kW$_{el}$	880	880	880	880	880	880	880	[11]
	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$_{el}$		30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	
	Efficiency$_{th}$		50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	
CHP Coal Heating	Capex	€/kW$_{el}$	2030	2030	2030	2030	2030	2030	2030	[11]
	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$_{el}$		41.1%	42.1%	43.0%	43.6%	44.2%	44.8%	45.5%	
	Efficiency$_{th}$		42.8%	43.8%	44.8%	45.4%	46.1%	46.7%	47.4%	
CHP Biomass Heating	Capex	€/kW$_{el}$	3400	3300	3200	3125	3050	2975	2900	[11]
	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	0.0038	0.0037	0.0037	0.0038	0.0038	0.0038	
	Lifetime	years	25	25	25	25	25	25	25	
	Efficiency$_{el}$		29.5%	29.6%	29.6%	29.5%	29.4%	29.2%	29.1%	
	Efficiency$_{th}$		65.1%	65.2%	65.3%	65.0%	64.8%	64.5%	64.2%	
CHP Biogas	Capex	€/kW$_{el}$	429.2	399.6	370	340.4	325.6	310.8	296	[11]
	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$_{el}$		43.0%	46.5%	50.0%	52.3%	54.7%	54.7%	54.7%	

	Efficiency$_{th}$		34.4%	37.2%	40.0%	41.9%	43.7%	43.7%	43.7%	
MSW incinerator	Capex	€/kW$_{el}$	5630	5440	5240	5030	4870	4690	4540	[11]
	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$_{el}$		26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	
	Efficiency$_{th}$		71.0%	71.0%	71.0%	71.0%	71.0%	71.0%	71.0%	
Concentrating Solar Heat	Capex	€/kW$_{th}$	344.5	303.6	274.7	251.1	230.2	211.9	196	[17,18]
	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	[11]
	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	[11]
	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	
DH Electric Heating	Capex	€/kW$_{th}$	100	100	75	75	75	75	75	[11]
	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		100%	100%	100%	100%	100%	100%	100%	
DH Heat Pump	Capex	€/kW$_{th}$	660	618	590	568	554	540	530	[11]
	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		329%	340%	347%	357%	364%	370%	375%	
DH NG Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	[11]
	Opex fix	€/(kW$_{th}$ a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency		97%	97%	97%	97%	97%	97%	97%	
DH Oil Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	[11]
	Opex fix	€/(kW$_{th}$ a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency		97%	97%	97%	97%	97%	97%	97%	
DH Coal Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	[11]
	Opex fix	€/(kW$_{th}$ a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency		97%	97%	97%	97%	97%	97%	97%	

DH Biomass Heating	Capex	€/kW_{th}	75	75	100	100	100	100	100	[11]
	Opex fix	€/(kW_{th} a)	2.8	2.8	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh_{th}	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency		97%	97%	97%	97%	97%	97%	97%	
DH Geothermal Heat	Capex	€/kW_{th}	3642	3384	3200	3180	3160	3150	3146	[11]
	Opex fix	€/(kW_{th} a)	133	124	117	116	115	115	115	
	Opex var	€/kWh_{th}	0	0	0	0	0	0	0	
	Lifetime	years	22	22	22	22	22	22	22	
	Efficiency		97%	97%	97%	97%	97%	97%	97%	
Local Electric Heating	Capex	€/kW_{th}	100	100	100	100	100	100	100	[11]
	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		100%	100%	100%	100%	100%	100%	100%	
Local Heat Pump	Capex	€/kW_{th}	780	750	730	706	690	666	650	[11]
	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		470%	487%	498%	514%	525%	535%	542%	
Local NG Heating	Capex	€/kW_{th}	800	800	800	800	800	800	800	[11]
	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		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Local Oil Heating	Capex	€/kW_{th}	440	440	440	440	440	440	440	[11]
	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		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Local Biomass Heating	Capex	€/kW_{th}	675	675	750	750	750	750	750	[11]
	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		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Local Biogas Heating	Capex	€/kW_{th}	800	800	800	800	800	800	800	[11]
	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		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Water Electrolysis	Capex	€/kW_{H2}	685	500	380	325	296	267	248	[19,20]
	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		82.2%	82.2%	82.2%	82.2%	82.2%	82.2%	82.2%	
CO_2 direct air capture	Capex	€/(t_{CO2} a)	730	481	338	281	237	217	199	[21]
	Opex fix	€/(t_{CO2} a)	29.2	19.2	13.5	11.2	9.5	8.7	8	
	Opex var	€/t_{CO2}	0	0	0	0	0	0	0	
	Lifetime	years	20	30	25	30	30	30	30	
	Consumption	kWh_{el}/t_{CO2}	250	237	225	213	202.5	192	182.3	
	Consumption	kWh_{th}/t_{CO2}	1750	1618	1500	1387	1286	1189	1102	
Methanation	Capex	€/kW_{SNG}	502	368	278	247	226	204	190	[19,20]
	Opex fix	€/(kW_{SNG} a)	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		77.8%	77.8%	77.8%	77.8%	77.8%	77.8%	77.8%	
Biogas digester	Capex	€/kW_{th}	730.61	705.95	680	652.75	631.98	608.63	589.16	[11]
	Opex fix	€/(kW_{th} a)	29.22	28.24	27.2	26.11	25.28	24.35	23.57	
	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	[22]
	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		98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	
Fischer-Tropsch unit	Capex	€/kW,FT_{Liq}	947	947	947	947	852.3	852.3	852.3	[11]
	Opex fix	€/kW,FT_{Liq}	28.41	28.41	28.41	28.41	25.57	25.57	25.57	
	Opex var	€/kWh,FT_{Liq}	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency		63.4%	63.4%	63.4%	63.4%	63.4%	63.4%	63.4%	
Gas Liquefaction	Capex	€/kW_{Liq}	181.1	181.1	181.1	181.1	181.1	181.1	181.1	[11]
	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		98.7%	98.7%	98.7%	98.7%	98.7%	98.7%	98.7%	
H_2 Liquefaction	Capex	€/kW_{Liq}	358.1	358.1	358.1	175.9	152.9	145.2	137.9	[23–25]
	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		98.3%	98.3%	98.3%	98.3%	98.3%	98.3%	98.3%	
Steam Methane Reforming	Capex	€/kW_{H2}	320	320	320	320	320	320	320	[26]
	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		84.5%	84.5%	84.5%	84.5%	84.5%	84.5%	84.5%	
Battery Storage	Capex	€/kWh_{el}	234	153	110	89	76	68	61	[27]
	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	
	Efficiency		91.0%	92.0%	93.0%	94.0%	95.0%	95.0%	95.0%	
Battery Interface	Capex	€/kW_{el}	117	76	55	44	37	33	30	[27]
	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 pros residential Storage	Capex	€/kWh_{el}	462	308	224	182	156	140	127	[11]
	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	
	Efficiency		91.0%	92.0%	93.0%	94.0%	95.0%	95.0%	95.0%	
Battery PV pros residential Interface	Capex	€/kW_{el}	231	153	112	90	76	68	62	[11]
	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 pros commercial Storage	Capex	€/kWh_{el}	366	240	175	141	121	108	98	[11]
	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	
	Efficiency		91.0%	92.0%	93.0%	94.0%	95.0%	95.0%	95.0%	
Battery PV pros commercial Interface	Capex	€/kW_{el}	183	119	88	70	59	53	48	[11]
	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 pros industrial Storage	Capex	€/kWh_{el}	278	181	131	105	90	80	72	[11]
	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	
	Efficiency		91.0%	92.0%	93.0%	94.0%	95.0%	95.0%	95.0%	
Battery PV pros industrial Interface	Capex	€/kW_{el}	139	90	66	52	44	39	35	[11]
	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	[9]
	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	
	Efficiency		85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	
PHES Interface	Capex	€/kW_{el}	650	650	650	650	650	650	650	[9]
	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}	75	65.3	57.9	53.6	50.8	47	43.8	[9]
	Opex fix	€/(kWh_{el} a)	1.16	0.99	0.87	0.81	0.77	0.71	0.66	

	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	40	40	40	40	40	40	40	
	Efficiency		59.3%	64.7%	70.0%	70.0%	70.0%	70.0%	70.0%	
A-CAES Interface	Capex	€/kW$_{el}$	540	540	540	540	540	540	540	[9]
	Opex fix	€/(kW$_{el}$ a)	17.5	17.5	17.5	17.5	17.5	17.5	17.5	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	40	40	40	40	40	40	40	
Hot Heat Storage Storage	Capex	€/kWh$_{th}$	41.8	32.7	26.8	23.3	21	19.3	17.5	[11]
	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	
	Efficiency		90%	90%	90%	90%	90%	90%	90%	
Hot Heat Storage Interface	Capex	€/kW$_{th}$	0	0	0	0	0	0	0	[11]
	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	[28]
	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	
	Efficiency		100%	100%	100%	100%	100%	100%	100%	
Hydrogen Storage Interface	Capex	€/kW$_{th}$	100	100	100	100	100	100	100	[28]
	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	[1]
	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	
	Efficiency		100%	100%	100%	100%	100%	100%	100%	
CO_2 Storage Interface	Capex	€/ton/h	0	0	0	0	0	0	0	[21]
	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	[29]
	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	
	Efficiency		100%	100%	100%	100%	100%	100%	100%	
Gas Storage Interface	Capex	€/kW$_{th}$	100	100	100	100	100	100	100	[29]
	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	
	Capex	€/kWh$_{th}$	40	30	30	25	20	20	20	[11]

District Heat Storage	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	
	Efficiency		90%	90%	90%	90%	90%	90%	90%	
District Heat Storage Interface	Capex	€/kW$_{th}$	0	0	0	0	0	0	0	[11]
	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	
Reverse Osmosis Seawater Desalination	Capex	€/(m^3/day)	960	835	725	630	550	480	415	[30]
	Opex fix	€/(m^3/day)	38.4	33.4	29	25.2	22	19.2	16.6	
	Consumption	kWh$_{th}$/m^3	0	0	0	0	0	0	0	
	Lifetime	years	25	30	30	30	30	30	30	
	Consumption	kWh$_{el}$/m^3	3.6	3.35	3.15	3	2.85	2.7	2.6	
Multi-Stage Flash Stand-alone	Capex	€/(m^3/day)	2000	2000	2000	2000	2000	2000	2000	[30]
	Opex fix	€/(m^3/day)	100	100	100	100	100	100	100	
	Consumption	kWh$_{th}$/m^3	85	85	85	85	85	85	85	
	Lifetime	years	25	25	25	25	25	25	25	
	Consumption	kWh$_{el}$/m^3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	
Multi-Stage Flash Cogeneration	Capex	€/(m^3/day)	3069	3069	3069	3069	3069	3069	3069	[11]
	Opex fix	€/(m^3/day)	121.4	121.4	121.4	121.4	121.4	121.4	132.1	
	Consumption	kWh$_{th}$/m^3	202.5	202.5	202.5	202.5	202.5	202.5	202.5	
	Lifetime	years	25	25	25	25	25	25	25	
	Consumption	kWh$_{el}$/m^3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	
Multi Effect Distillation Stand-alone	Capex	€/(m^3/day)	1200	1044	906.3	787.5	687.5	600	518.8	[30]
	Opex fix	€/(m^3/day)	39.6	34.44	29.91	25.99	22.69	19.8	17.12	
	Consumption	kWh$_{th}$/m^3	51	44	38	32	28	28	28	
	Lifetime	years	25	25	25	25	25	25	25	
	Consumption	kWh$_{el}$/m^3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
Multi Effect Distillation Cogeneration	Capex	€/(m^3/day)	2150	2150	2150	2150	2150	2150	2150	[11]
	Opex fix	€/(m^3/day)	61.69	61.69	61.69	61.69	61.69	61.69	68.81	
	Consumption	kWh$_{th}$/m^3	168	168	168	168	168	168	168	
	Lifetime	years	25	25	25	25	25	25	25	
	Consumption	kWh$_{el}$/m^3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
Water Storage	Capex	€/m^3	64.59	64.59	64.59	64.59	64.59	64.59	64.59	[11]
	Opex fix	€/m^3	1.29	1.29	1.29	1.29	1.29	1.29	1.29	
	Opex var	€/m^3	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	

Table AI9: Energy to power ratio and self-discharge rates of storage technologies. Energy/Power ratios values by 2050 are individually optimised

Technology	Efficiency [%] input	Energy/Power Ratio [h] BPS-1; BPS-2; BPS-3 result	Self-Discharge [%/h] input	Sources
Battery	95	5.53; 6.06; 6.0	1	[29]

PHES	85	8.76; 8.57; 8.68	1	[9]
A-CAES	70	8.31; 74.3; 7.38	0.9999	[9]
Hot Heat TES	90	3.59; 2.83; 2.6	0.9999	[29]
District Heat TES	90	8.31; 1.11; 1.13	0.9999	[29]

Table AI10: Financial assumptions for fossil-nuclear fuels and GHG emissions

Component	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**Sources**
Coal	€/MWh_{th}	9.9	10.8	11.8	13.1	14.3	14.3	14.3	[2]
Fuel Oil	€/MWh_{th}	101.1	114.3	127.5	126.0	124.9	124.9	124.9	[3]
Fossil gas	€/MWh_{th}	36.1	48.8	53.2	58.8	65.4	65.4	65.4	[31]
Uranium	€/MWh_{th}	2.6	2.6	2.6	2.6	2.6	2.6	2.6	[15]
GHG emissions	€/tCO_2	28	52	61	68	75	100	150	[31]
GHG emissions by fuel type									
Coal				tCO_{2eq}/MWh_{th}		0.34			[32]
Oil				tCO_{2eq}/MWh_{th}		0.25			[32]
Fossil gas				tCO_{2eq}/MWh_{th}		0.21			[33]

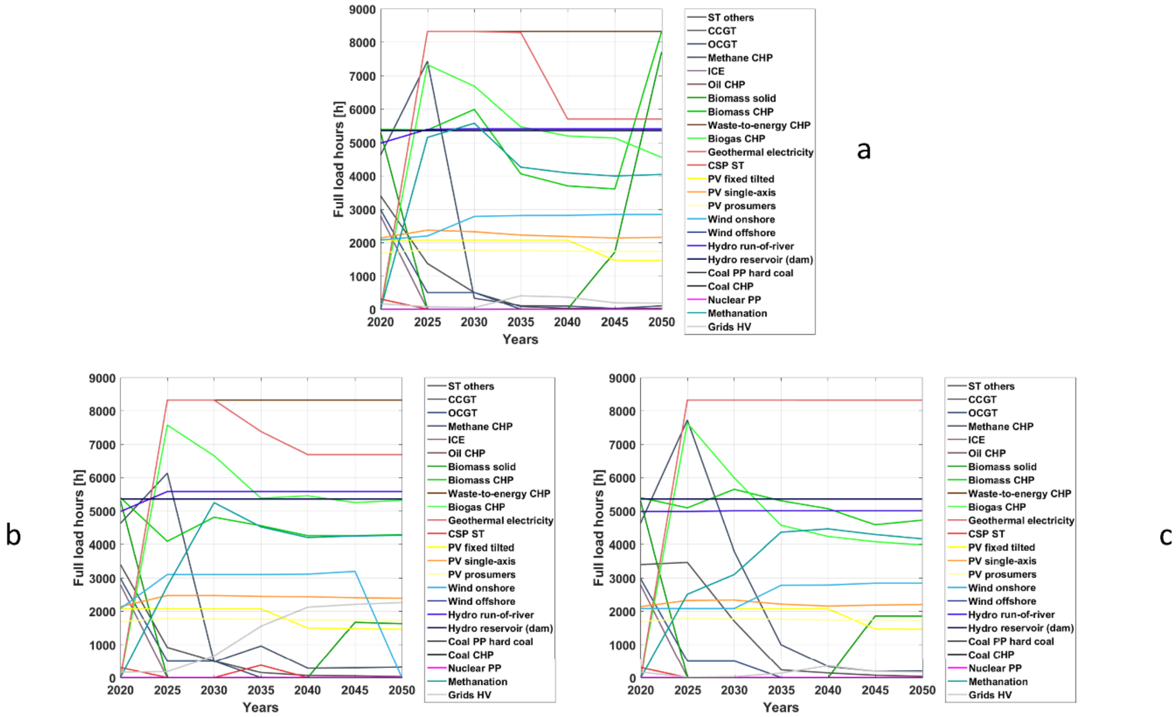


Figure AI11: Full load hours – BPS-1 (top), BPS-2 (bottom left), BPS-3 (bottom right).

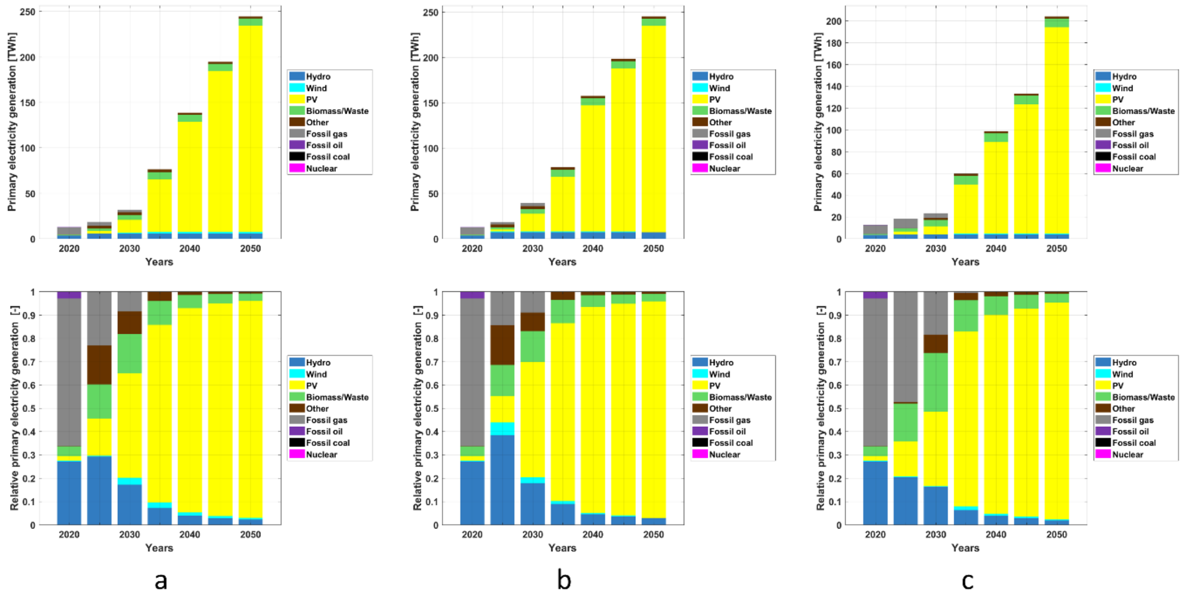
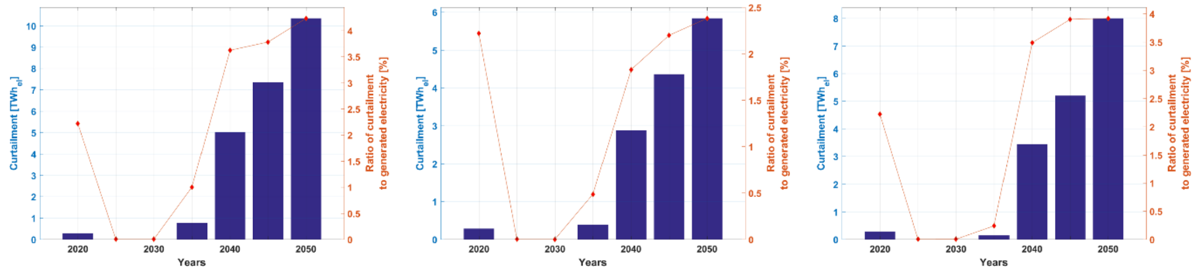
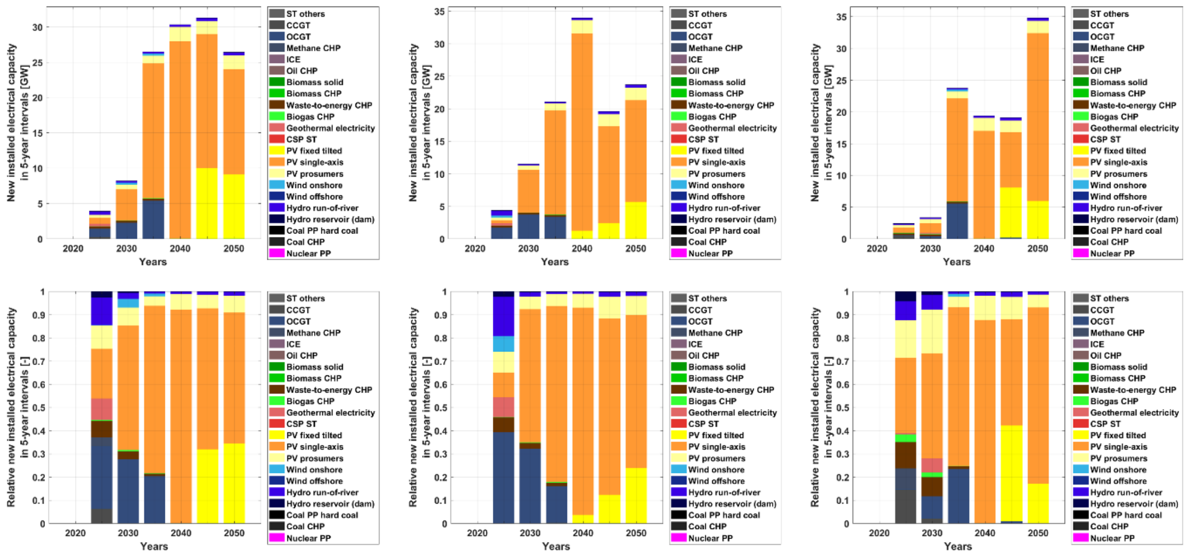


Figure AI12: Primary electricity generation in absolute (top) and relative (bottom) shares for BPS-1 (a), BPS-2 (b), and BPS-3 (c).



a b c

Figure AI13: Curtailment of generated electricity for BPS-1 (a), BPS-2 (b), and BPS-3 (c).



a b c

Figure AI14: Technology-wise installed electrical capacities in 5-year intervals in GW (top) and relative shares (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

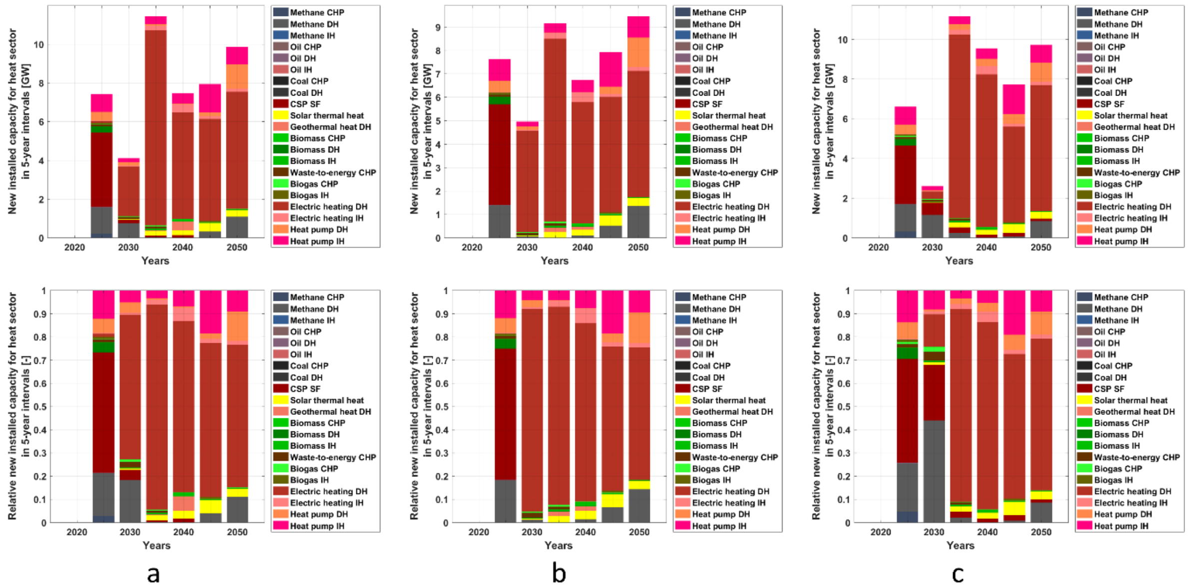


Figure AI15: Technology-wise installed heat capacities in 5-year intervals in GW (top) and relative shares (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

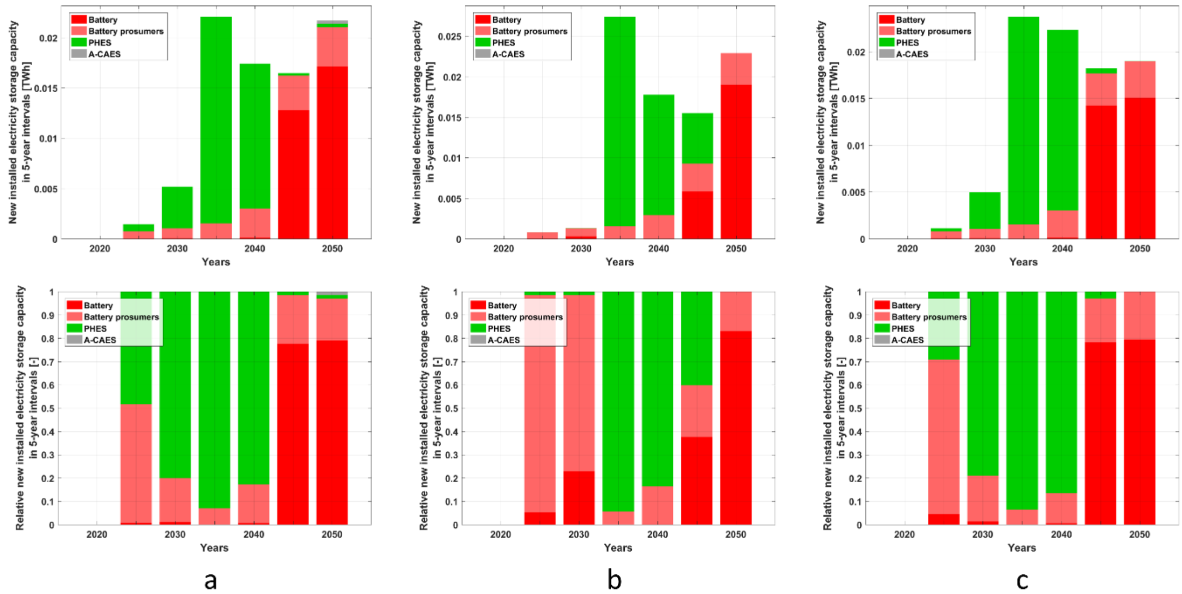


Figure AI16: Technology-wise installed storage capacity in 5-year intervals in TWh (top) and relative shares (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

Table AI11: Installed capacity – BPS-1

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
PV prosumers RES	[GW]	0.03	0.15	0.39	0.82	1.69	2.43	3.23
PV prosumers COM	[GW]	0.03	0.12	0.28	0.61	1.06	1.48	1.89
PV prosumers IND	[GW]	0.00	0.16	0.39	0.71	1.44	2.09	2.82
PV fixed tilted system	[GW]	0.07	0.07	0.07	0.07	0.07	10.03	19.04

PV single-axis system	[GW]	0.00	0.85	5.25	24.34	52.25	71.24	86.15
CSP	[GW]	0.00	3.84	4.02	4.10	4.22	4.22	0.92
Wind onshore	[GW]	0.03	0.03	0.34	0.66	0.65	0.63	0.63
Hydro run-of-river	[GW]	0.42	0.69	0.70	0.70	0.70	0.70	0.70
Hydro reservoir (dam)	[GW]	0.26	0.31	0.31	0.31	0.31	0.31	0.31
Geothermal	[GW]	0.00	0.37	0.37	0.37	0.37	0.37	0.37
CCGT	[GW]	1.59	1.79	1.77	1.65	1.65	1.59	1.29
OCGT	[GW]	0.90	1.95	4.21	9.58	9.56	9.42	9.03
ST others	[GW]	0.031	0.031	0.031	0.01	0	0	0
Biomass PP	[GW]	0.10	0.10	0.10	0.10	0.02	0.00	0.00
Biogas dig	[GW]	0.00	0.28	0.57	0.86	0.86	0.86	0.86
Biogas Upgrade	[GW]	0.00	0.17	0.34	0.52	0.52	0.52	0.50
ICE	[GW]	0.14	0.11	0.09	0.08	0.06	0.01	0
Methane CHP	[GW]	0	0.15	0.15	0.15	0.15	0.15	0.15
Waste CHP	[GW]	0.00	0.28	0.55	0.84	0.84	0.84	0.84
Biomass CHP	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biogas CHP	[GW]	0.00	0.02	0.07	0.13	0.15	0.16	0.19
El heater DH	[GW]	0.00	0.09	2.65	12.72	18.22	23.48	29.53
Heat pump DH	[GW]	0.00	0.45	0.63	0.71	0.75	0.94	2.17
Methane DH	[GW]	4.59	5.76	6.27	5.85	5.76	5.93	6.99
Oil DH	[GW]	0.64	0.61	0.54	0.46	0.43	0.38	0.15
Coal DH	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass DH	[GW]	3.61	3.26	2.64	2.29	2.22	1.92	1.07
El heater IH	[GW]	0.03	0.05	0.08	0.32	0.74	0.87	1.04
Heat pump IH	[GW]	0.00	0.91	1.13	1.52	2.04	2.61	3.29
Methane IH	[GW]	2.09	1.66	1.46	0.54	0.00	0.00	0.00
Oil IH	[GW]	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Biomass IH	[GW]	1.16	0.84	0.71	0.32	0.20	0.23	0.24
Biogas IH	[GW]	0.00	0.07	0.07	0.07	0.08	0.08	0.08
Battery RES	[GWh]	0.00	0.29	0.71	1.35	2.62	3.79	5.07
Battery RES	[GWh]	0.00	0.22	0.44	0.87	1.42	1.99	2.54
Battery IND	[GWh]	0.00	0.23	0.56	1.03	2.10	3.06	4.15
Battery System	[GWh]	0.00	0.01	0.06	0.07	0.18	12.95	30.08

PHES storage	[GWh]	0.00	0.70	4.84	25.37	39.76	40.01	40.35
TES HT	[GWh]	0.00	0.03	1.41	50.33	70.99	90.77	115.52
TES DH	[GWh]	0.00	10.47	10.01	12.22	24.96	30.40	31.36
A-CAES	[GWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.32
Gas (CH_4) storage	[GWh]	0.00	1.53	1.54	22.11	1394	2391	2398
Electrolyser	[GW_{el}]	0.00	0.00	0.27	1.84	12.29	22.29	27.68
Electrolyser	[GW_{H2}]	0.00	0.00	0.22	1.51	10.10	18.32	22.76
Steam methane reforming	[GW_{H2}]	0.00	0.02	0.18	0.18	0.18	0.18	0.18
CO_2 DAC	[$MtCO_2$/a]	0.00	0.00	0.40	0.83	5.34	9.42	11.56
Methanation	[GW_{CH4}]	0.00	0.00	0.00	0.02	2.52	4.91	6.26
Fischer-Tropsch	[GW_{liq}]	0.00	0.00	0.16	0.33	0.60	0.74	0.78

Table AI12: Installed capacities for BPS-3

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
PV prosumers RES	[GW]	0.03	0.15	0.39	0.82	1.69	2.43	3.23
PV prosumers COM	[GW]	0.03	0.12	0.28	0.61	1.06	1.48	1.89
PV prosumers IND	[GW]	0.00	0.16	0.39	0.71	1.44	2.09	2.82
PV fixed-titled system	[GW]	0.07	0.07	0.07	0.07	0.07	7.93	13.80
PV single-axis system	[GW]	0.00	0.79	2.31	18.55	35.53	44.26	70.70
CSP	[GW]	0.00	2.95	3.57	3.86	4.01	4.19	1.69
Wind onshore	[GW]	0.03	0.03	0.03	0.33	0.32	0.30	0.30
Hydro run-of-river	[GW]	0.42	0.42	0.43	0.43	0.43	0.43	0.43
Hydro reservoir (dam)	[GW]	0.26	0.31	0.31	0.31	0.31	0.31	0.31
Geothermal	[GW]	0.00	0.01	0.22	0.22	0.22	0.22	0.22
CCGT	[GW]	1.59	1.90	1.95	1.82	1.82	1.76	1.46
OCGT	[GW]	0.90	0.87	1.09	6.64	6.62	6.67	6.28
ST others	[GW]	0.03	0.03	0.03	0.01	0.00	0.00	0.00
Biomass PP	[GW]	0.10	0.10	0.10	0.10	0.02	0.00	0.00
Biogas dig	[GW]	0.00	0.28	0.57	0.86	0.86	0.86	0.86
Biogas Upgrade	[GW]	0.00	0.01	0.20	0.51	0.52	0.52	0.52
ICE	[GW]	0.14	0.11	0.09	0.08	0.06	0.01	0.00
Methane CHP	[GW]	0.00	0.22	0.22	0.22	0.22	0.22	0.22
Waste CHP	[GW]	0.00	0.28	0.55	0.84	0.84	0.84	0.84

Biomass CHP	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biogas CHP	[GW]	0.00	0.08	0.15	0.18	0.20	0.20	0.21
El heater DH	[GW]	0.00	0.00	0.36	9.60	17.30	22.11	28.46
Heat pump DH	[GW]	0.00	0.46	0.48	0.76	1.12	1.62	2.58
Methane DH	[GW]	4.59	5.78	6.82	6.78	6.65	6.49	7.32
Oil DH	[GW]	0.64	0.61	0.54	0.46	0.43	0.38	0.15
Coal DH	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass DH	[GW]	3.61	3.26	2.64	2.29	2.23	1.92	1.04
El heater IH	[GW]	0.03	0.05	0.08	0.32	0.74	0.87	1.04
Heat pump IH	[GW]	0.00	0.91	1.13	1.52	2.04	2.61	3.29
Methane IH	[GW]	2.09	1.66	1.46	0.54	0.00	0.00	0.00
Oil IH	[GW]	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Biomass IH	[GW]	1.16	0.84	0.71	0.32	0.20	0.23	0.24
Biogas IH	[GW]	0.00	0.07	0.07	0.07	0.08	0.08	0.08
Battery RES	[GWh]	0.00	0.29	0.71	1.35	2.62	3.79	5.07
Battery RES	[GWh]	0.00	0.22	0.44	0.87	1.42	1.99	2.54
Battery IND	[GWh]	0.00	0.23	0.56	1.03	2.10	3.06	4.15
Battery System	[GWh]	0.00	0.05	0.12	0.12	0.24	14.49	29.57
PHES storage	[GWh]	0.00	0.32	4.25	26.44	45.74	46.28	46.29
TES HT	[GWh]	0.00	0.01	0.19	29.69	67.33	88.06	111.78
TES DH	[GWh]	0.00	6.63	7.98	9.93	11.91	14.71	22.48
A-CAES	[GWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas (CH_4) storage	[GWh]	0.00	0.26	0.33	18.95	80.26	130.62	1395
Electrolyser	[GW_{el}]	0.00	0.00	0.00	0.20	1.02	4.03	15.90
Electrolyser	[GW_{H2}]	0.00	0.00	0.00	0.16	0.84	3.31	13.07
Steam reforming	[GW_{H2}]	0.00	0.02	0.04	0.09	0.09	0.09	0.09
CO_2 DAC	[$MtCO_2$/a]	0.00	0.00	0.00	0.00	0.15	1.52	6.58
Methanation	[GW_{CH4}]	0.00	0.00	0.00	0.00	0.10	0.98	4.22
Fischer-Tropsch	[GW_{liq}]	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table AI13: Electricity generation – BPS-1

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
PV prosumers RES	[GWh]	50	267	677	1415	2873	4117	5469

PV prosumers COM	[GWh]	43	206	485	1056	1790	2490	3156
PV prosumers IND	[GWh]	0	291	716	1301	2619	3812	5133
PV fixed-tilted system	[GWh]	146	146	146	146	146	14700	27825
PV single-axis system	[GWh]	0	2014	12207	54122	113798	152110	185548
Wind onshore	[GWh]	56	68	943	1845	1838	1788	1777
Hydro run-of-river	[GWh]	2088	3725	3813	3813	3813	3813	3813
Hydro reservoir (dam)	[GWh]	1368	1642	1642	1642	1642	1642	1642
Geothermal	[GWh]	0	3051	3059	3047	2097	2097	2096
CCGT	[GWh]	5399	2457	885	134	63	34	46
OCGT	[GWh]	2671	975	2102	5	1	0	2
ST others	[GWh]	9	0	0	0	0	0	0
Biomass PP	[GWh]	532	0	0	0	0	0	1
ICE	[GWh]	383	0	0	0	0	0	0
Methane CHP	[GWh]	0	1101	49	16	16	8	35
Waste CHP	[GWh]	0	2305	4609	6984	6984	6984	6984
Biomass CHP	[GWh]	0	0	0	0	0	0	1
Biogas CHP	[GWh]	0	122	442	728	793	830	845

Table AI14: Electricity storage output – BPS-1

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Battery	[TWh]	0.00	0.25	0.61	1.09	2.05	7.77	16.89
PHES storage	[TWh]	0.00	0.22	1.53	7.81	12.65	12.51	12.61
A-CAES	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.06
TES HT	[TWh]	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Gas (CH_4) storage	[TWh]	0.00	0.00	0.00	0.00	0.02	0.01	0.04

Table AI15: Heat generation – BPS-1

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Methane CHP	[GWh]	0	789	35	8	10	5	19
Waste CHP	[GWh]	0	6260	9858	16019	17000	17573	18645
Biomass CHP	[GWh]	0	0	0	0	0	0	1
Biogas CHP	[GWh]	0	149	520	816	902	972	993
CSP	[GWh]	0	8457	8859	9042	9326	9326	2218

Geothermal DH	[GWh]	0	12765	12799	12747	8773	8773	8771
El heater DH	[GWh]	0	186	7720	37118	50197	63187	80174
Heat pump DH	[GWh]	0	2484	3312	4375	4151	6462	15558
Methane DH	[GWh]	23460	41817	44193	30370	31216	39720	50075
Oil DH	[GWh]	3206	0	1	0	0	0	0
Coal DH	[GWh]	0	0	0	0	0	0	0
Biomass DH	[GWh]	17411	558	558	532	529	524	519
El heater IH	[GWh]	43	3	6	23	52	53	58
Heat pump IH	[GWh]	0	7415	9003	11016	13602	16463	20321
Methane IH	[GWh]	2656	177	167	68	0	0	0
Oil IH	[GWh]	0	0	0	1	0	0	0
Biomass IH	[GWh]	3846	372	374	427	444	450	453
Biogas IH	[GWh]	0	557	594	611	628	634	635

Table AI16: Heat storage output – BPS-1

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
TES HT	[TWh]	0.00	0.01	0.50	16.09	23.94	30.78	39.54
TES DH	[TWh]	0.00	3.51	4.24	5.43	10.64	13.06	14.01
Gas (CH_4) storage	[TWh]	0.00	0.00	0.00	0.21	17.67	35.50	46.11

Table AI17: Sustainable fuel production (output) – BPS-1

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Electrolyser	[TWh]	0.00	0.00	1.02	5.30	33.92	60.15	75.61
Methanation	[TWh]	0.00	0.00	0.00	0.11	18.37	36.67	47.60
FT	[TWh]	0.00	0.00	1.33	2.71	4.96	6.16	6.51
FT kerosene	[TWh]	0.00	0.00	0.27	0.54	1.34	2.19	2.10
FT diesel	[TWh]	0.00	0.00	0.80	1.63	2.63	2.74	3.11
FT naphtha	[TWh]	0.00	0.00	0.27	0.54	0.99	1.23	1.30
LNG	[TWh]	0.00	0.00	3.61	11.20	43.00	77.00	100.00
LH2	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.01

Table AI18: Installed capacity – BPS-2

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
PV prosumers RES	[GW]	0.03	0.15	0.39	0.82	1.69	2.43	3.23
PV prosumers COM	[GW]	0.03	0.12	0.28	0.61	1.06	1.48	1.89
PV prosumers IND	[GW]	0.00	0.16	0.39	0.71	1.44	2.09	2.82
PV fixed-tilted system	[GW]	0.07	0.07	0.07	0.07	1.29	3.68	9.28
PV single-axis system	[GW]	0.00	0.47	7.06	23.03	53.36	68.24	83.87
CSP	[GW]	0.00	4.30	4.30	4.30	4.30	4.30	0.92
Wind onshore	[GW]	0.03	0.32	0.32	0.32	0.32	0.29	0.00
Hydro run-of-river	[GW]	0.42	0.96	0.96	0.96	0.96	0.96	0.96
Hydro reservoir (dam)	[GW]	0.26	0.31	0.31	0.31	0.31	0.31	0.31
Geothermal	[GW]	0.00	0.37	0.37	0.37	0.37	0.37	0.37
CCGT	[GW]	1.59	1.55	1.53	1.45	1.45	1.39	1.09
OCGT	[GW]	0.90	2.61	6.23	9.35	9.33	9.19	8.80
ST others	[GW]	0.03	0.03	0.03	0.01	0.00	0.00	0.00
Biomass PP	[GW]	0.10	0.10	0.10	0.10	0.02	0.00	0.00
Biogas dig	[GW]	0.00	0.28	0.57	0.86	0.86	0.86	0.86
Biogas Upgrade	[GW]	0.00	0.12	0.34	0.52	0.52	0.52	0.52
ICE	[GW]	0.14	0.11	0.09	0.08	0.06	0.01	0.00
Methane CHP	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste CHP	[GW]	0.00	0.28	0.55	0.84	0.84	0.84	0.84
Biomass CHP	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biogas CHP	[GW]	0.00	0.01	0.04	0.14	0.15	0.16	0.16
El heater DH	[GW]	0.00	0.00	4.32	12.13	17.31	22.23	27.62
Heat pump DH	[GW]	0.00	0.48	0.63	0.65	0.66	0.96	2.16
Methane DH	[GW]	4.59	5.78	5.58	5.15	5.16	5.66	7.01
Oil DH	[GW]	0.64	0.61	0.54	0.46	0.43	0.38	0.15
Coal DH	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass DH	[GW]	3.61	3.26	2.64	2.29	2.23	1.94	1.14
El heater IH	[GW]	0.03	0.05	0.08	0.32	0.74	0.87	1.04
Heat pump IH	[GW]	0.00	0.91	1.13	1.52	2.04	2.61	3.29
Methane IH	[GW]	2.09	1.66	1.46	0.54	0.00	0.00	0.00

Oil IH	[GW]	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Biomass IH	[GW]	1.16	0.84	0.71	0.32	0.20	0.23	0.24
Biogas IH	[GW]	0.00	0.07	0.07	0.07	0.08	0.08	0.08
Battery RES	[GWh]	0.00	0.29	0.71	1.35	2.62	3.79	5.07
Battery RES	[GWh]	0.00	0.22	0.44	0.87	1.42	1.99	2.54
Battery IND	[GWh]	0.00	0.23	0.56	1.03	2.10	3.06	4.15
Battery System	[GWh]	0.00	0.04	0.34	0.34	0.35	6.18	24.93
PHES storage	[GWh]	0.00	0.01	0.03	25.89	40.75	46.99	46.99
TES HT	[GWh]	0.00	0.01	2.90	49.63	69.68	88.99	110.96
TES DH	[GWh]	0.00	12.00	11.15	12.51	24.23	31.02	29.31
A-CAES	[GWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas (CH_4) storage	[GWh]	0.00	0.18	1.80	126.77	2316	2762	3419
Electrolyser	[GW_{el}]	0.00	0.00	0.58	1.89	17.01	21.73	26.89
Electrolyser	[GW_{H2}]	0.00	0.00	0.47	1.55	13.98	17.86	22.10
Steam reforming	[GW_{H2}]	0.00	0.02	0.05	0.05	0.05	0.05	0.05
CO_2 DAC	[$MtCO_2$/a]	0.00	0.00	0.40	0.86	7.63	9.82	12.21
Methanation	[GW_{CH4}]	0.00	0.00	0.00	0.05	3.99	5.18	6.65
Fischer-Tropsch	[GW_{liq}]	0.00	0.00	0.16	0.33	0.60	0.74	0.78

Table AI19: Electricity generation – BPS-2

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
PV prosumers RES	[GWh]	50	267	677	1415	2873	4117	5469
PV prosumers COM	[GWh]	43	206	485	1056	1790	2490	3156
PV prosumers IND	[GWh]	0	291	716	1301	2619	3812	5133
PV fixed-tilted system	[GWh]	146	146	146	146	1932	5424	13553
PV single-axis system	[GWh]	0	1150	17441	56262	129791	164009	200300
Wind onshore	[GWh]	56	989	989	989	982	932	0
Hydro run-of-river	[GWh]	2088	5375	5375	5375	5375	5375	5375
Hydro reservoir (dam)	[GWh]	1368	1642	1642	1642	1642	1642	1642
Geothermal	[GWh]	0	3117	3117	2764	2505	2505	2505
CCGT	[GWh]	5399	1407	762	221	96	82	51
OCGT	[GWh]	2671	1301	3108	2	1	1	0
ST others	[GWh]	9	0	0	4	0	0	0

Biomass PP	[GWh]	532	0	0	0	0	0	0
ICE	[GWh]	383	0	0	0	0	0	0
Methane CHP	[GWh]	0	1	0	0	0	0	0
Waste CHP	[GWh]	0	2305	4609	6984	6984	6984	6984
Biomass CHP	[GWh]	0	0	0	0	0	0	0
Biogas CHP	[GWh]	0	70	298	727	801	851	872

Table AI20: Electricity storage output – BPS-2

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
Battery	[TWh]	0.00	0.27	0.76	1.19	2.20	5.34	13.73
PHES storage	[TWh]	0.00	0.00	0.01	7.87	13.02	15.15	15.16
A-CAES	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TES HT	[TWh]	0.01	0.00	0.00	0.00	0.00	0.00	0.00
Gas (CH_4) storage	[TWh]	0.00	0.00	0.00	0.00	0.00	0.01	0.02

Table AI21: Heat generation – BPS-2

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
Methane CHP	[GWh]	0	1	0	0	0	0	0
Waste CHP	[GWh]	0	6265	11061	16160	16662	17389	18675
Biomass CHP	[GWh]	0	0	0	0	0	0	0
Biogas CHP	[GWh]	0	84	361	833	929	1007	1076
CSP	[GWh]	0	9384	9384	9384	9384	9384	2294
Geothermal DH	[GWh]	0	13044	13044	11566	10481	10481	10481
El heater DH	[GWh]	0	0	13853	38398	50524	63714	79169
Heat pump DH	[GWh]	0	2502	2952	3640	3737	5852	15675
Methane DH	[GWh]	23460	42019	38157	28288	32778	41278	51697
Oil DH	[GWh]	3206	1	0	0	2	0	0
Coal DH	[GWh]	0	0	0	0	0	0	0
Biomass DH	[GWh]	17411	558	558	532	529	524	524
El heater IH	[GWh]	43	3	6	23	52	53	58
Heat pump IH	[GWh]	0	7415	9003	11016	13602	16463	20321
Methane IH	[GWh]	2656	177	167	68	0	0	0
Oil IH	[GWh]	0	0	0	1	0	0	0

Biomass IH	[GWh]	3846	372	374	427	444	450	453
Biogas IH	[GWh]	0	557	594	611	628	634	635

Table AI22: Heat storage output – BPS-2

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
TES HT	[TWh]	0.00	0.00	1.11	16.74	24.00	30.35	37.61
TES DH	[TWh]	0.00	4.02	4.93	5.85	12.09	12.35	13.10
Gas (CH_4) storage	[TWh]	0.00	0.00	0.00	0.63	25.29	37.18	47.57

Table AI23: Sustainable fuel production – BPS-2

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Electrolyser	[TWh]	0.00	0.00	2.04	5.76	48.26	62.35	77.51
Methanation	[TWh]	0.00	0.00	0.00	0.25	29.53	38.38	49.08
FT	[TWh]	0.00	0.00	1.33	2.71	4.96	6.16	6.51
FT kerosene	[TWh]	0.00	0.00	0.27	0.54	1.34	2.19	2.10
FT diesel	[TWh]	0.00	0.00	0.80	1.63	2.63	2.74	3.11
FT naphtha	[TWh]	0.00	0.00	0.27	0.54	0.99	1.23	1.30
LNG	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.01
LH2	[TWh]	0.00	0.00	0.00	0.05	0.22	0.56	1.12

Table AI24: Installed capacity – BPS-3

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
PV prosumers RES	[GW]	0.03	0.15	0.39	0.82	1.69	2.43	3.23
PV prosumers COM	[GW]	0.03	0.12	0.28	0.61	1.06	1.48	1.89
PV prosumers IND	[GW]	0.00	0.16	0.39	0.71	1.44	2.09	2.82
PV fixed-tilted system	[GW]	0.07	0.07	0.07	0.07	0.07	7.93	13.80
PV single-axis system	[GW]	0.00	0.79	2.31	18.55	35.53	44.26	70.70
CSP	[GW]	0.00	2.95	3.57	3.86	4.01	4.19	1.69
Wind onshore	[GW]	0.03	0.03	0.03	0.33	0.32	0.30	0.30
Hydro run-of-river	[GW]	0.42	0.42	0.43	0.43	0.43	0.43	0.43
Hydro reservoir (dam)	[GW]	0.26	0.31	0.31	0.31	0.31	0.31	0.31
Geothermal	[GW]	0.00	0.01	0.22	0.22	0.22	0.22	0.22

CCGT	[GW]	1.59	1.90	1.95	1.82	1.82	1.76	1.46
OCGT	[GW]	0.90	0.87	1.09	6.64	6.62	6.67	6.28
ST others	[GW]	0.03	0.03	0.03	0.01	0.00	0.00	0.00
Biomass PP	[GW]	0.10	0.10	0.10	0.10	0.02	0.00	0.00
Biogas dig	[GW]	0.00	0.28	0.57	0.86	0.86	0.86	0.86
Biogas Upgrade	[GW]	0.00	0.01	0.20	0.51	0.52	0.52	0.52
ICE	[GW]	0.14	0.11	0.09	0.08	0.06	0.01	0.00
Methane CHP	[GW]	0.00	0.22	0.22	0.22	0.22	0.22	0.22
Waste CHP	[GW]	0.00	0.28	0.55	0.84	0.84	0.84	0.84
Biomass CHP	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biogas CHP	[GW]	0.00	0.08	0.15	0.18	0.20	0.20	0.21
El heater DH	[GW]	0.00	0.00	0.36	9.60	17.30	22.11	28.46
Heat pump DH	[GW]	0.00	0.46	0.48	0.76	1.12	1.62	2.58
Methane DH	[GW]	4.59	5.78	6.82	6.78	6.65	6.49	7.32
Oil DH	[GW]	0.64	0.61	0.54	0.46	0.43	0.38	0.15
Coal DH	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass DH	[GW]	3.61	3.26	2.64	2.29	2.23	1.92	1.04
El heater IH	[GW]	0.03	0.05	0.08	0.32	0.74	0.87	1.04
Heat pump IH	[GW]	0.00	0.91	1.13	1.52	2.04	2.61	3.29
Methane IH	[GW]	2.09	1.66	1.46	0.54	0.00	0.00	0.00
Oil IH	[GW]	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Biomass IH	[GW]	1.16	0.84	0.71	0.32	0.20	0.23	0.24
Biogas IH	[GW]	0.00	0.07	0.07	0.07	0.08	0.08	0.08
Battery RES	[GWh]	0.00	0.29	0.71	1.35	2.62	3.79	5.07
Battery RES	[GWh]	0.00	0.22	0.44	0.87	1.42	1.99	2.54
Battery IND	[GWh]	0.00	0.23	0.56	1.03	2.10	3.06	4.15
Battery System	[GWh]	0.00	0.05	0.12	0.12	0.24	14.49	29.57
PHES storage	[GWh]	0.00	0.32	4.25	26.44	45.74	46.28	46.29
TES HT	[GWh]	0.00	0.01	0.19	29.69	67.33	88.06	111.78
TES DH	[GWh]	0.00	6.63	7.98	9.93	11.91	14.71	22.48
A-CAES	[GWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas (CH_4) storage	[GWh]	0.00	0.26	0.33	18.95	80.26	130.62	1395
Electrolyser	[GW_{el}]	0.00	0.00	0.00	0.20	1.02	4.03	15.90

Electrolyser	[GW_{H2}]	0.00	0.00	0.00	0.16	0.84	3.31	13.07
Steam reforming	[GW_{H2}]	0.00	0.02	0.04	0.09	0.09	0.09	0.09
CO_2 DAC	[$MtCO_2/a$]	0.00	0.00	0.00	0.00	0.15	1.52	6.58
Methanation	[GW_{CH4}]	0.00	0.00	0.00	0.00	0.10	0.98	4.22
Fischer-Tropsch	[GW_{liq}]	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table AI25: Electricity generation – BPS-3

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
PV prosumers RES	[GWh]	50	267	677	1415	2873	4117	5469
PV prosumers COM	[GWh]	43	206	485	1056	1790	2490	3156
PV prosumers IND	[GWh]	0	291	716	1301	2619	3812	5133
PV fixed-tilted system	[GWh]	146	146	146	146	146	11631	20171
PV single-axis system	[GWh]	0	1839	5389	41022	76542	96647	155561
Wind onshore	[GWh]	56	56	56	907	900	850	850
Hydro run-of-river	[GWh]	2088	2088	2142	2142	2142	2142	2142
Hydro reservoir (dam)	[GWh]	1368	1642	1642	1642	1642	1642	1642
Geothermal	[GWh]	0	124	1818	1834	1834	1834	1834
CCGT	[GWh]	5399	6581	3311	420	255	124	60
OCGT	[GWh]	2671	433	545	0	0	0	0
ST others	[GWh]	9	0	0	0	0	0	0
Biomass PP	[GWh]	532	0	0	0	0	0	0
ICE	[GWh]	383	0	0	0	0	0	0
Methane CHP	[GWh]	0	1687	829	216	79	59	78
Waste CHP	[GWh]	0	2305	4609	6984	6984	6984	6984
Biomass CHP	[GWh]	0	0	0	0	0	0	0
Biogas CHP	[GWh]	0	621	883	840	826	816	830

Table AI26: Electricity storage output – BPS-3

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Battery	[TWh]	0.00	0.29	0.64	1.12	2.09	8.25	14.99
PHES storage	[TWh]	0.00	0.11	1.34	8.45	14.79	14.74	14.47
A-CAES	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TES HT	[TWh]	0.01	0.00	0.00	0.00	0.00	0.00	0.00

Gas (CH_4) storage	[TWh]	0.00	0.00	0.00	0.00	0.01	0.02	0.04

Table AI27: Heat generation – BPS-3

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
Methane CHP	[GWh]	0	1209	594	155	57	42	56
Waste CHP	[GWh]	0	6290	10002	13448	15388	17832	19068
Biomass CHP	[GWh]	0	0	0	0	0	0	0
Biogas CHP	[GWh]	0	773	1079	979	971	982	1037
CSP	[GWh]	0	6506	7909	8580	8919	9344	4066
Geothermal DH	[GWh]	0	518	7606	7672	7673	7673	7673
El heater DH	[GWh]	0	0	651	27190	49403	62979	79898
Heat pump DH	[GWh]	0	3072	3018	5183	7636	11505	18820
Methane DH	[GWh]	23460	42077	51381	39803	37358	44954	54336
Oil DH	[GWh]	3206	1	3	5	10	90	270
Coal DH	[GWh]	0	0	0	0	0	0	0
Biomass DH	[GWh]	17411	558	558	533	529	524	524
El heater IH	[GWh]	43	3	6	23	52	53	58
Heat pump IH	[GWh]	0	7415	9003	11016	13602	16463	20321
Methane IH	[GWh]	2656	177	167	68	0	0	0
Oil IH	[GWh]	0	0	0	1	0	0	0
Biomass IH	[GWh]	3846	372	374	427	444	450	453
Biogas IH	[GWh]	0	557	594	611	628	634	635

Table AI28: Heat storage output – BPS-3

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
TES HT	[TWh]	0.00	0.01	0.08	9.68	22.06	29.20	37.49
TES DH	[TWh]	0.00	2.22	4.26	4.89	5.38	6.12	7.61
Gas (CH_4) storage	[TWh]	0.00	0.00	0.00	0.00	1.07	8.48	24.71

Table AI29: Synthetic fuel production – BPS-3

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
Electrolyser	[TWh]	0.00	0.00	0.00	0.00	0.52	6.53	31.54

Methanation	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FT	[TWh]	0.00	0.00	0.00	0.00	0.52	6.53	31.54
FT kerosene	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FT diesel	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FT naphtha	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LNG	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.01
LH2	[TWh]	0.00	0.00	0.00	0.05	0.22	0.56	1.12

Table AI30: Final transport energy demand by mode, segment, and vehicle type

	Unit	2020	2025	2030	2035	2040	2045	2050
Road LDV ICE fuel	[TWh_{th}]	8.01	7.10	4.63	2.01	1.20	0.82	0.49
Road LDV BEV elec	[TWh_{el}]	0.00	0.18	0.70	1.34	1.64	1.82	2.10
Road LDV FCEV H2	[TWh_{th}]	0.00	0.00	0.03	0.06	0.19	0.40	0.45
Road LDV PHEV fuel	[TWh_{th}]	0.00	0.06	0.06	0.06	0.07	0.07	0.08
Road LDV PHEV elec	[TWh_{el}]	0.00	0.10	0.10	0.11	0.12	0.14	0.15
Road 2.3W ICE fuel	[TWh_{th}]	0.27	0.27	0.20	0.15	0.11	0.09	0.05
Road 2.3W BEV elec	[TWh_{el}]	0.04	0.06	0.10	0.16	0.21	0.27	0.35
Road 2.3W FCEV H2	[TWh_{th}]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Road 2.3W PHEV fuel	[TWh_{th}]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Road 2.3W PHEV elec	[TWh_{el}]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Road Bus ICE fuel	[TWh_{th}]	4.19	3.91	2.99	1.71	0.25	0.21	0.16
Road Bus BEV elec	[TWh_{el}]	0.00	0.19	0.57	1.20	1.89	2.00	2.06
Road Bus FCEV H2	[TWh_{th}]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Road Bus PHEV fuel	[TWh_{th}]	0.01	0.02	0.03	0.05	0.06	0.08	0.10
Road Bus PHEV elec	[TWh_{el}]	0.00	0.01	0.01	0.02	0.03	0.03	0.04
Road MDV ICE fuel	[TWh_{th}]	18.01	17.16	15.52	9.60	2.49	1.12	0.91
Road MDV BEV elec	[TWh_{el}]	0.01	0.66	1.26	3.37	5.71	6.77	7.43
Road MDV FCEV H2	[TWh_{th}]	0.00	0.11	0.23	0.64	1.41	1.59	1.77
Road MDV PHEV fuel	[TWh_{th}]	0.01	0.14	0.21	0.31	0.43	0.58	0.74
Road MDV PHEV elec	[TWh_{el}]	0.00	0.02	0.03	0.05	0.06	0.08	0.10
Road HDV ICE fuel	[TWh_{th}]	3.04	3.09	2.78	2.16	1.23	0.17	0.14
Road HDV BEV elec	[TWh_{el}]	0.00	0.02	0.12	0.24	0.53	0.96	1.06
Road HDV FCEV H2	[TWh_{th}]	0.00	0.04	0.09	0.40	0.66	0.73	0.80

Road HDV PHEV fuel	[TWh$_{th}$]	0.00	0.03	0.05	0.07	0.14	0.31	0.36
Road HDV PHEV elec	[TWh$_{el}$]	0.00	0.00	0.00	0.01	0.01	0.03	0.03
Road fuel	[TWh$_{th}$]	33.54	31.78	26.47	16.11	5.98	3.45	3.04
Road elec	[TWh$_{el}$]	0.06	1.24	2.90	6.49	10.20	12.11	13.33
Road H2	[TWh$_{th}$]	0.00	0.15	0.36	1.11	2.26	2.73	3.02
Rail pass fuel	[TWh$_{el}$]	0.04	0.04	0.03	0.03	0.03	0.02	0.02
Rail pass elec	[TWh$_{el}$]	0.00	0.00	0.01	0.01	0.02	0.03	0.04
Rail freight fuel	[TWh$_{th}$]	0.11	0.11	0.10	0.09	0.08	0.07	0.04
Rail freight elec	[TWh$_{el}$]	0.00	0.01	0.02	0.03	0.04	0.06	0.07
Marine pass fuel	[TWh$_{th}$]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Marine pass elec	[TWh$_{el}$]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Marine pass LH2	[TWh$_{th}$]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Marine pass LNG	[TWh$_{th}$]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Marine freight fuel	[TWh$_{th}$]	0.02	0.02	0.02	0.02	0.02	0.02	0.01
Marine freight elec	[TWh$_{el}$]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Marine freight LH2	[TWh$_{th}$]	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Marine freight LNG	[TWh$_{th}$]	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Aviation pass fuel	[TWh$_{th}$]	2.44	2.70	2.85	3.07	3.09	2.81	2.07
Aviation pass elec	[TWh$_{el}$]	0.00	0.00	0.00	0.01	0.06	0.14	0.29
Aviation pass LH2	[TWh$_{th}$]	0.00	0.00	0.00	0.05	0.21	0.54	1.10
Aviation freight fuel	[TWh$_{th}$]	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Aviation freight elec	[TWh$_{el}$]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Aviation freight LH2	[TWh$_{th}$]	0.00	0.00	0.00	0.00	0.00	0.01	0.01

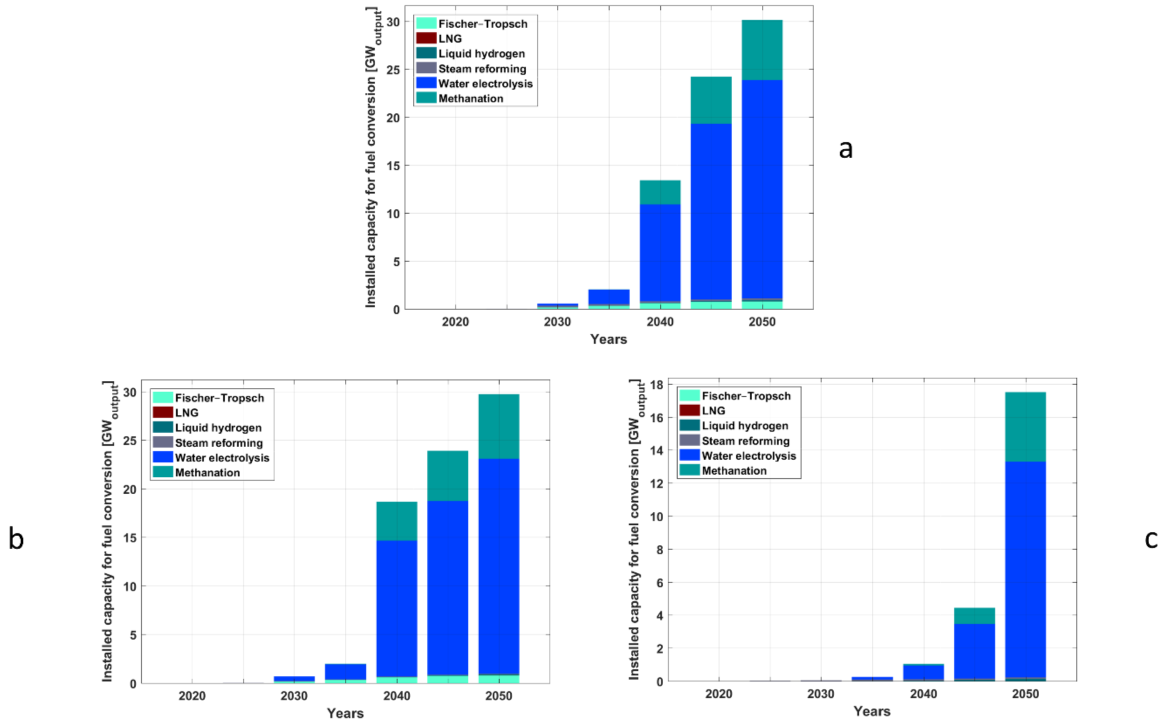


Figure AI17: Installed capacity for fuel conversion for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

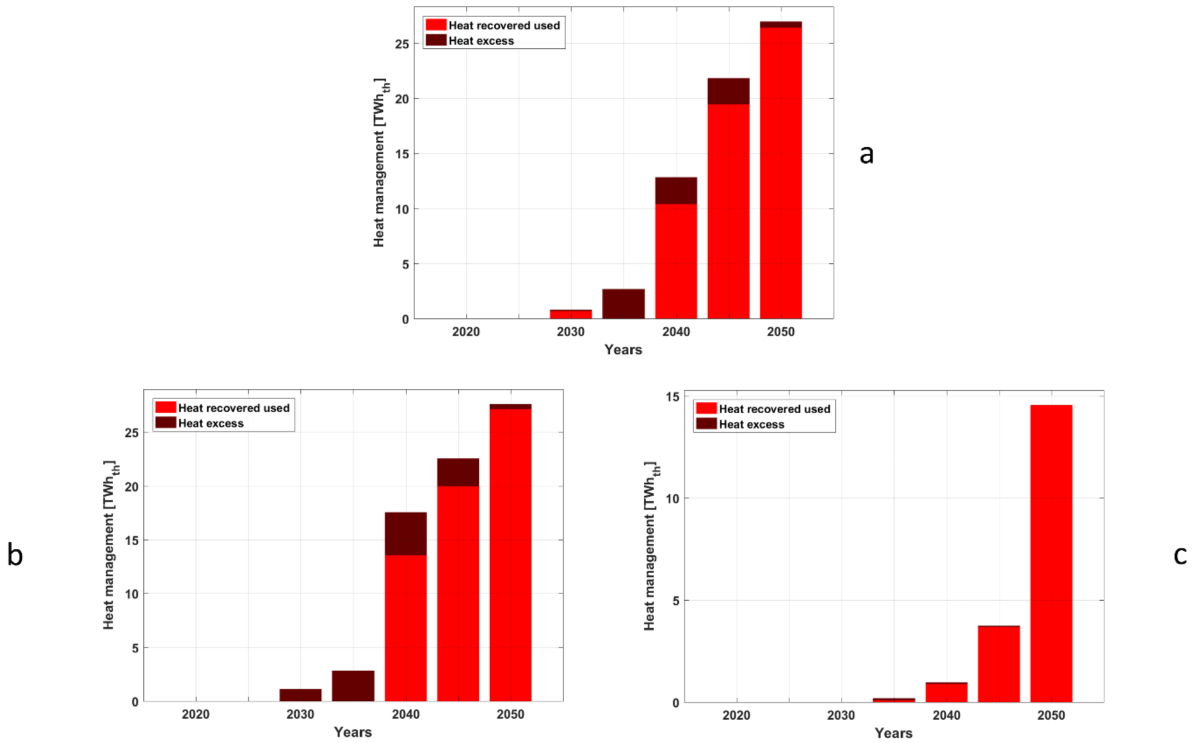


Figure AI18: Heat management for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

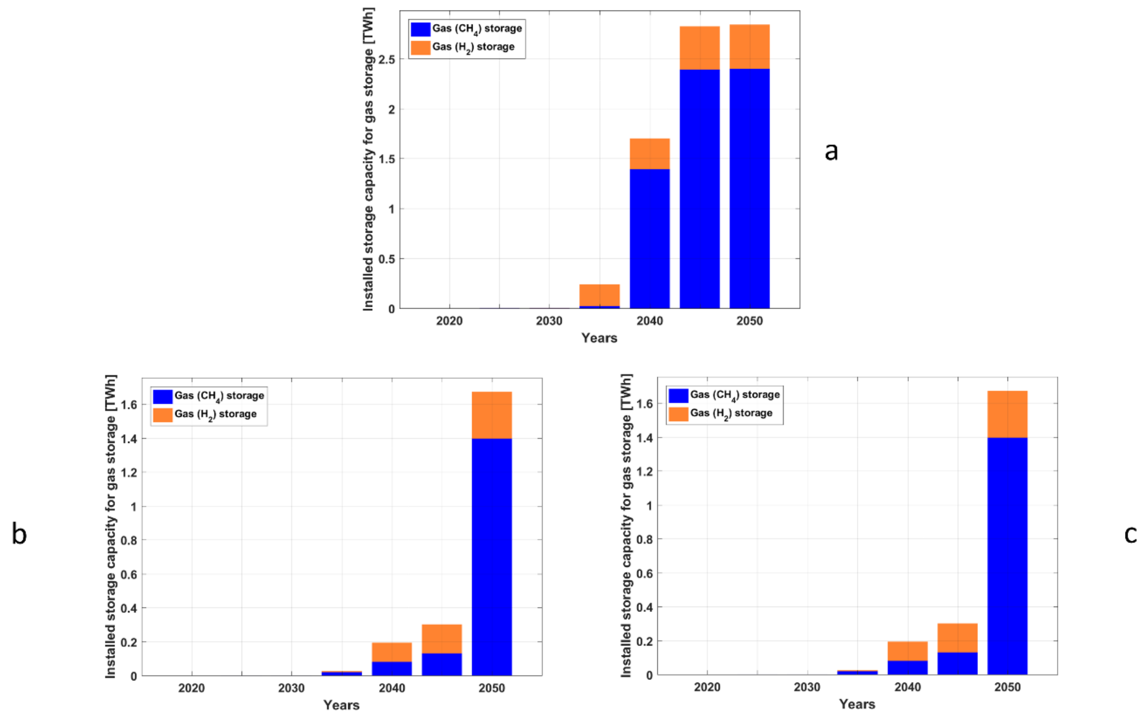


Figure AI19: Installed capacity for gas storage for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

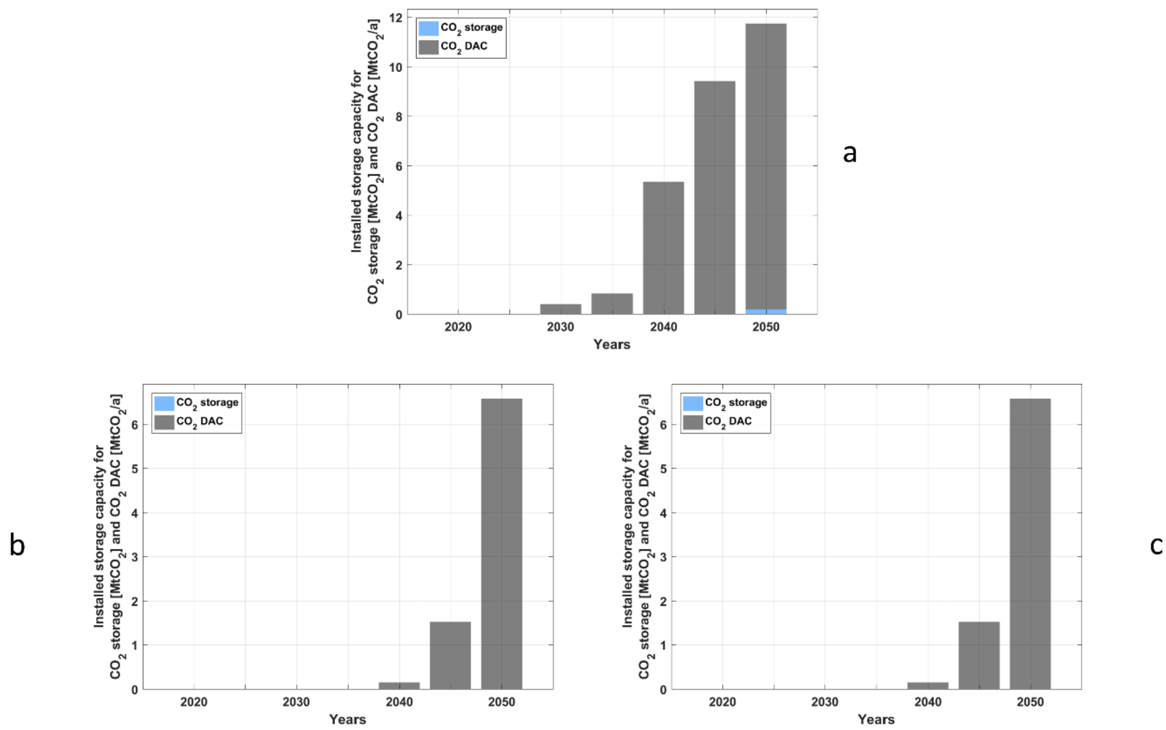


Figure AI20: Installed capacity for CO_2 direct air capture and CO_2 storage for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

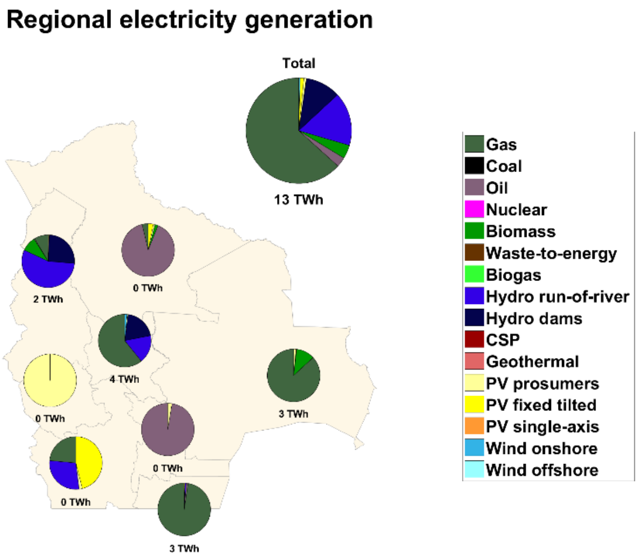
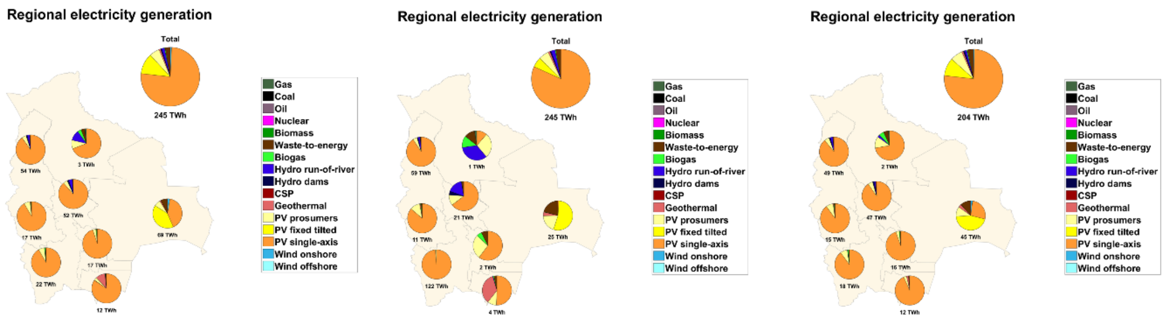
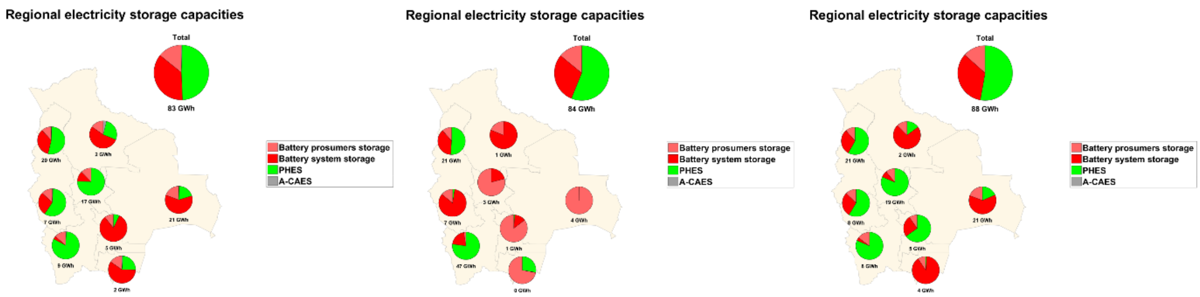


Figure AI21: Regional electricity generation by technology in 2020.



a b c

Figure AI22: Regional electricity generation by technology in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).



a b c

Figure AI23: Regional electricity storage capacities be technology in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

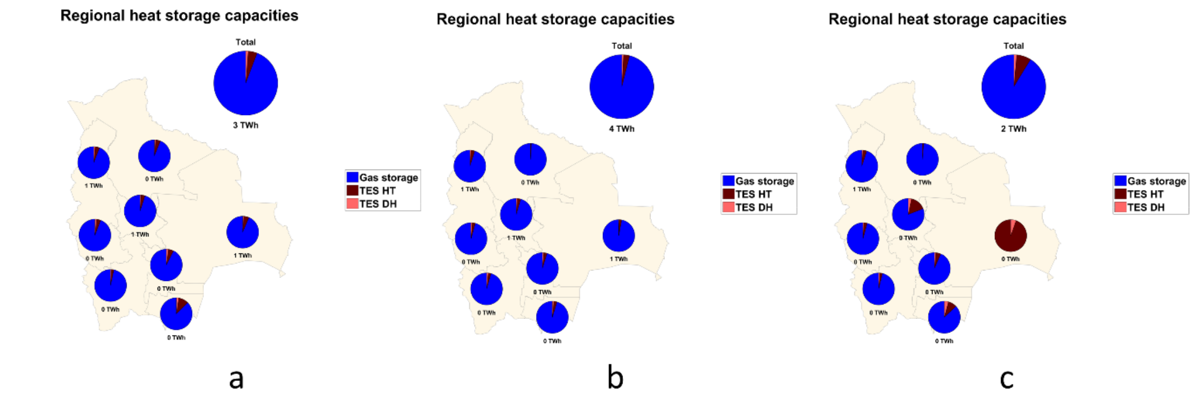


Figure AI24: Regional heat storage capacities by technology in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

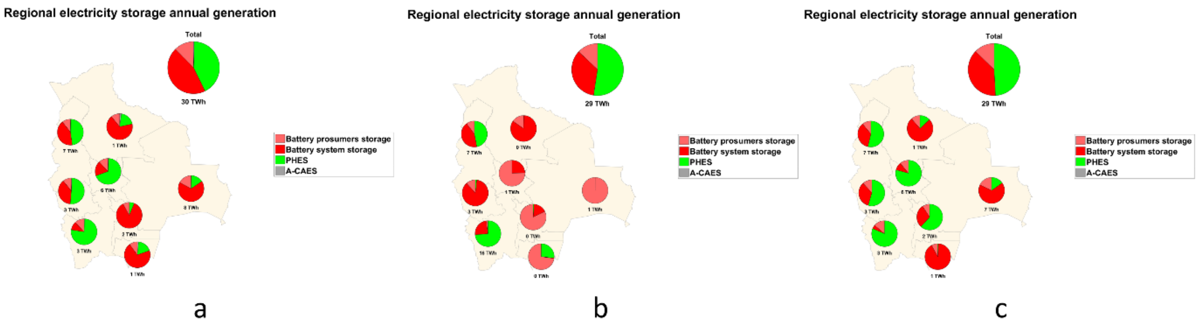


Figure AI25: Regional electricity storage annual generation by technology for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

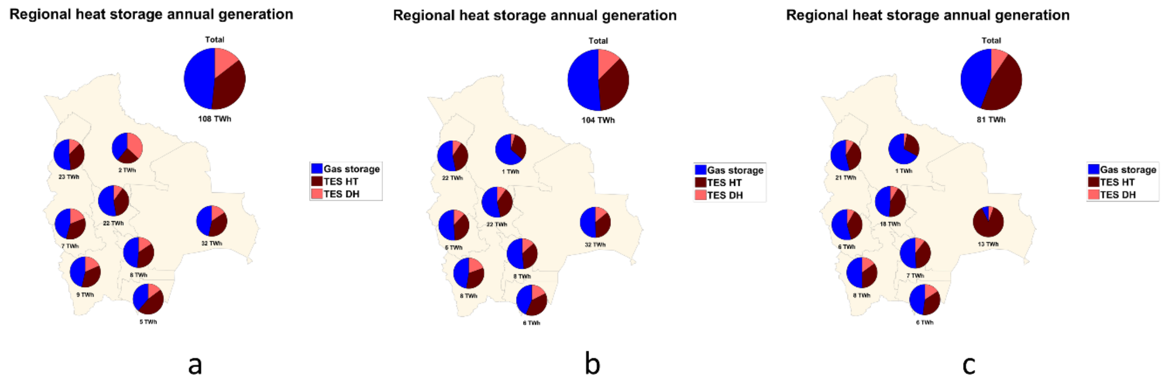


Figure AI26: Regional heat storage annual generation in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

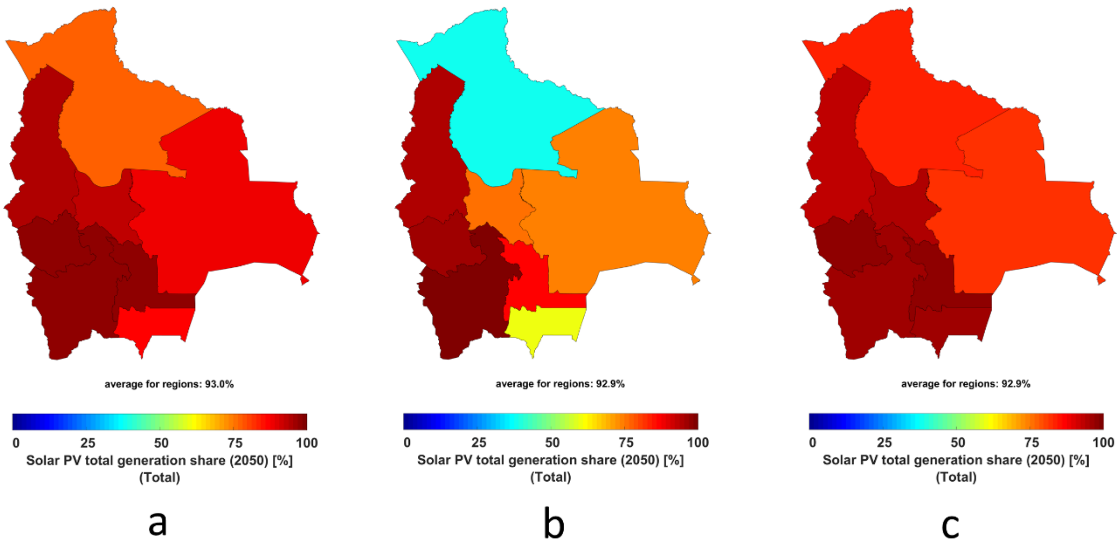


Figure AI27: Regional Solar PV generation shares in 2050 for BPS-1 (a), BPS-2, and BPS-3 (c).

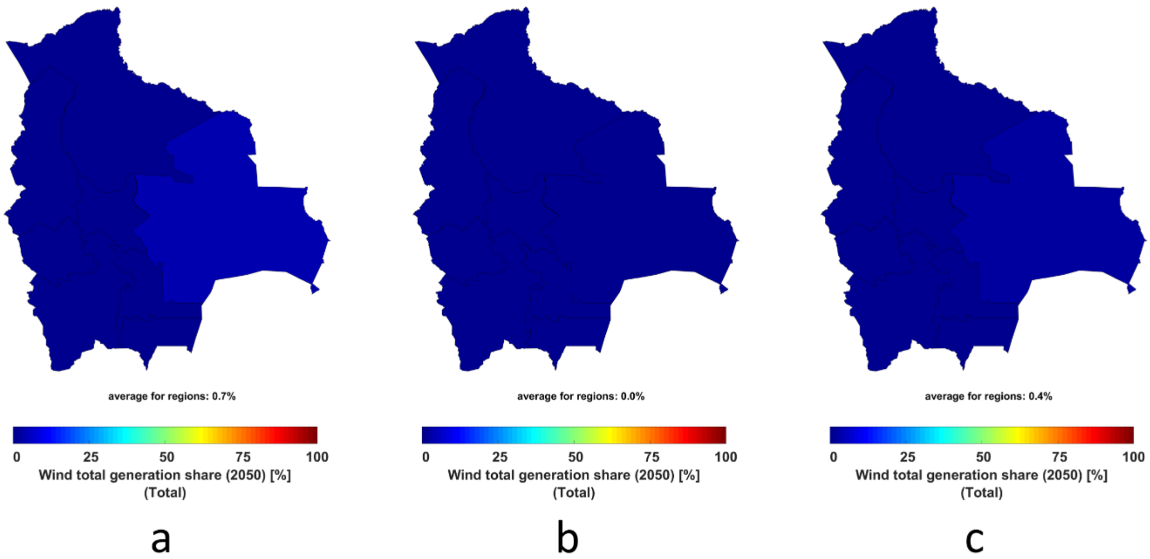


Figure AI28: Regional wind generation shares in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

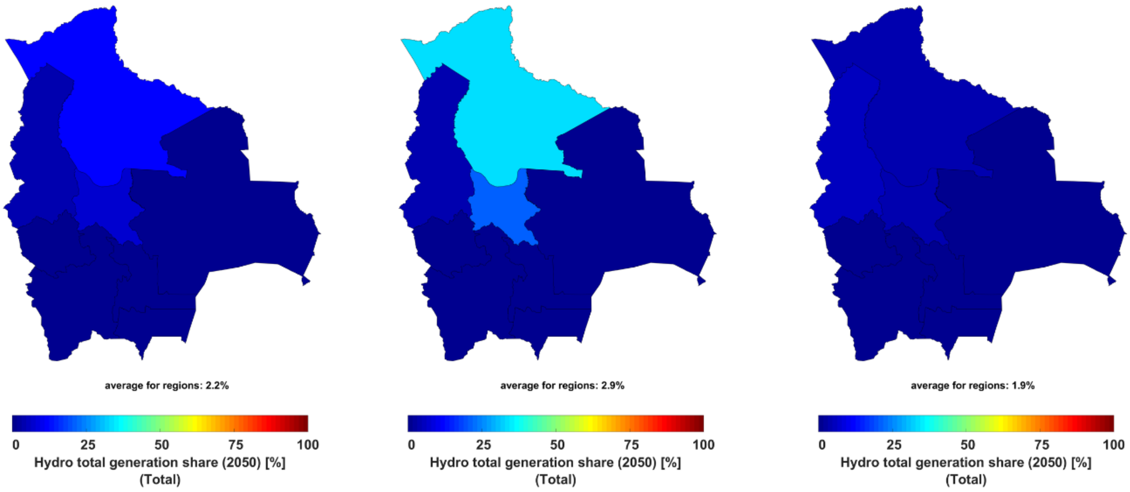


Figure AI29: Regional hydropower generation shares in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

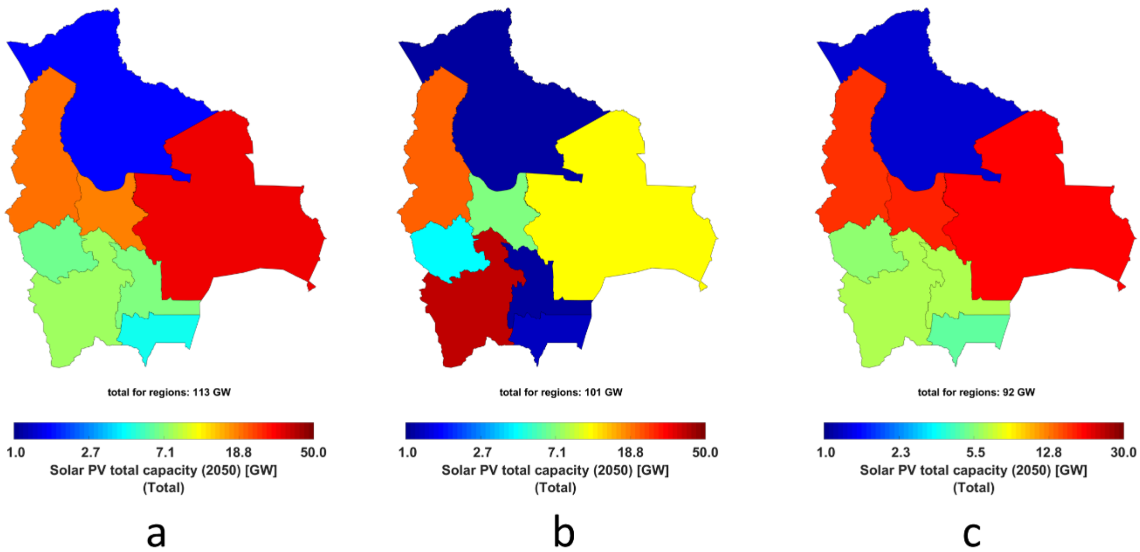


Figure AI30: Regional solar PV capacities in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

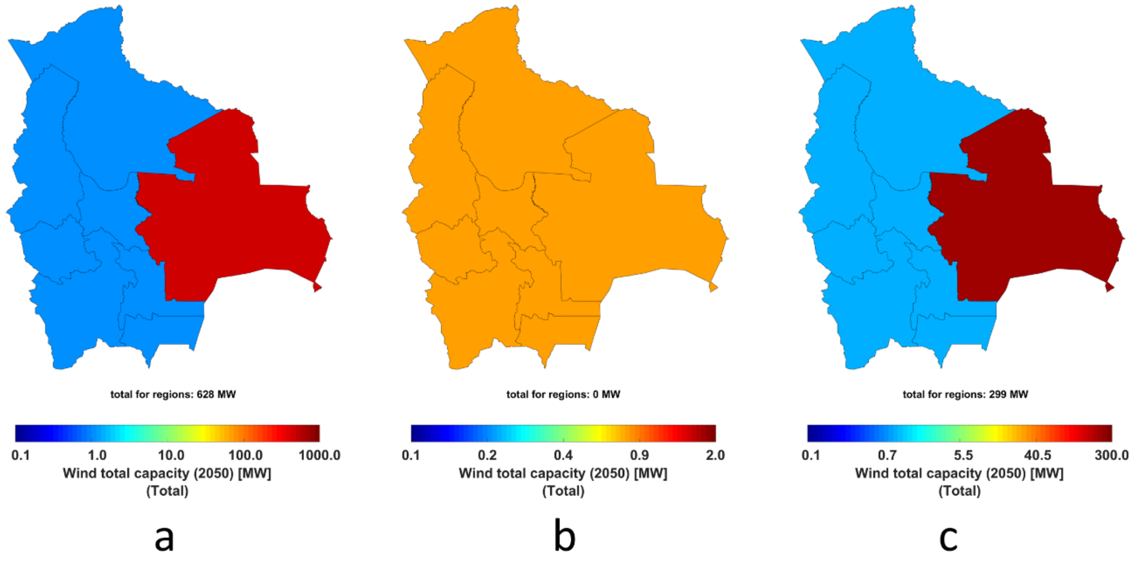


Figure AI31: Regional wind capacities in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

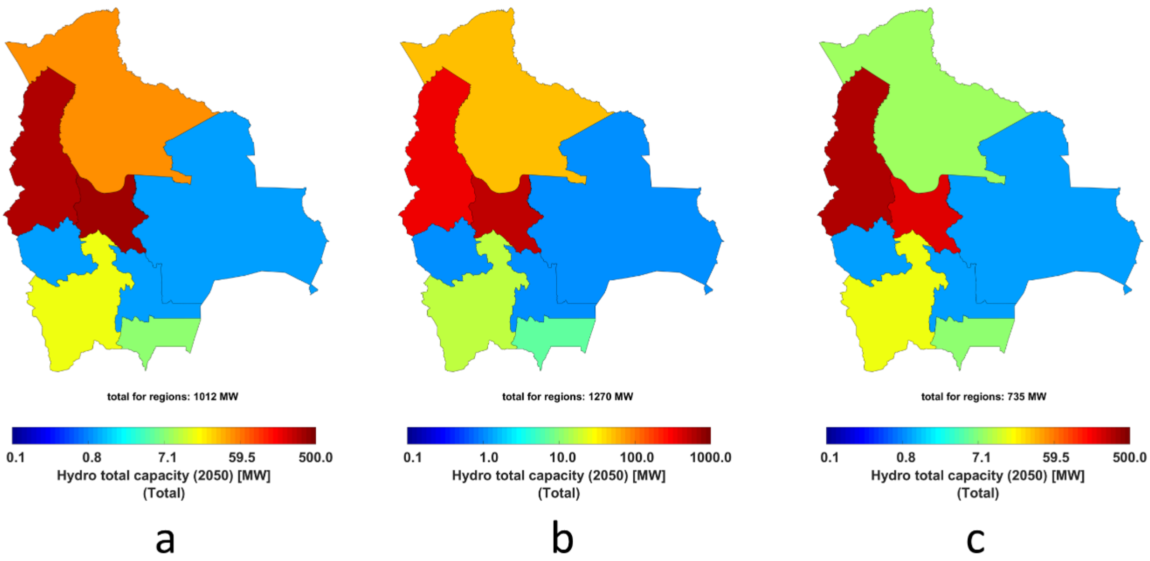


Figure AI32: Regional hydropower capacities in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

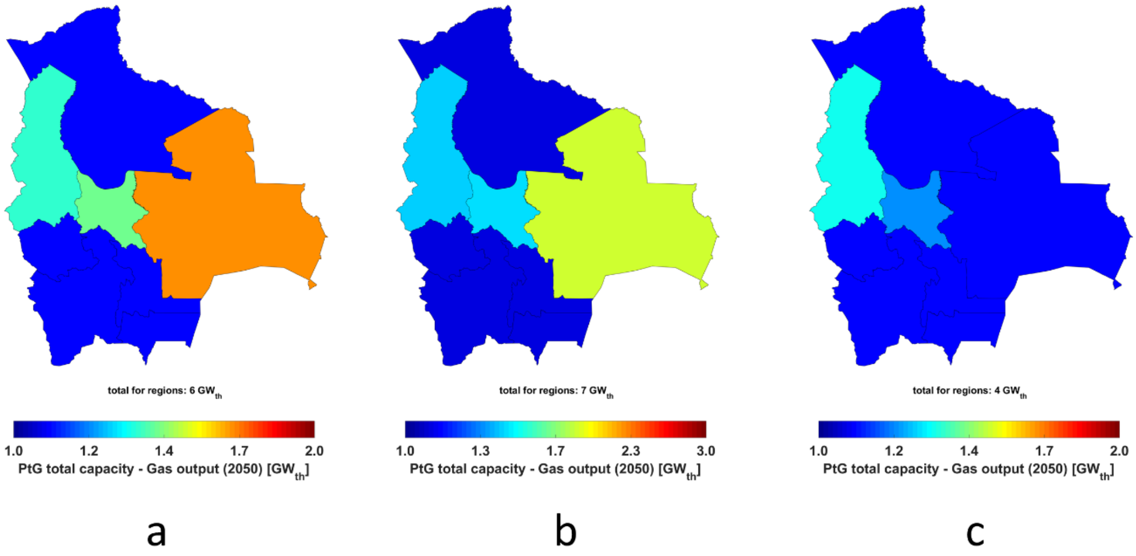


Figure AI33: Regional PtG capacities in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

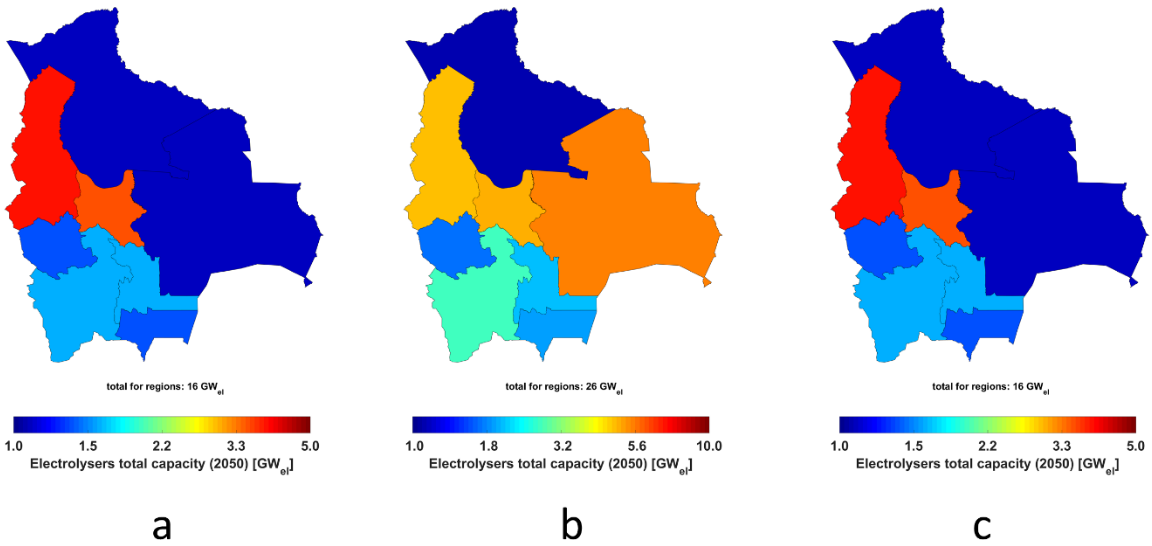


Figure AI34: Regional electrolyser capacities in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

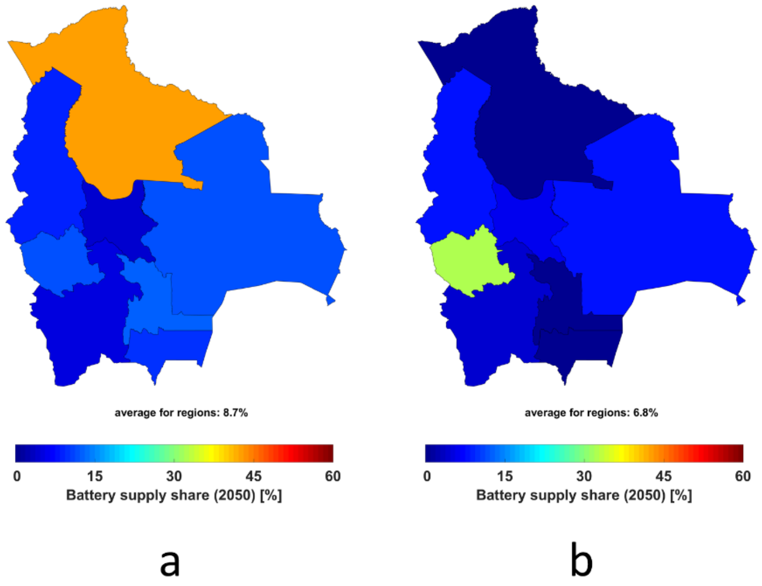


Figure AI35: Regional battery supply shares in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

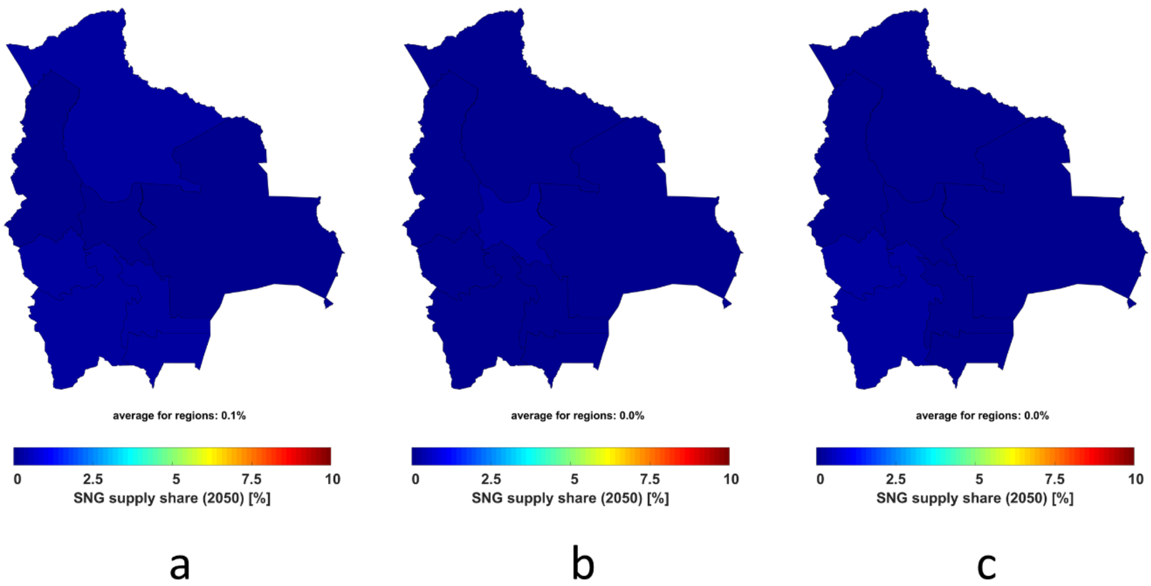


Figure AI36: Regional SNG supply share in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

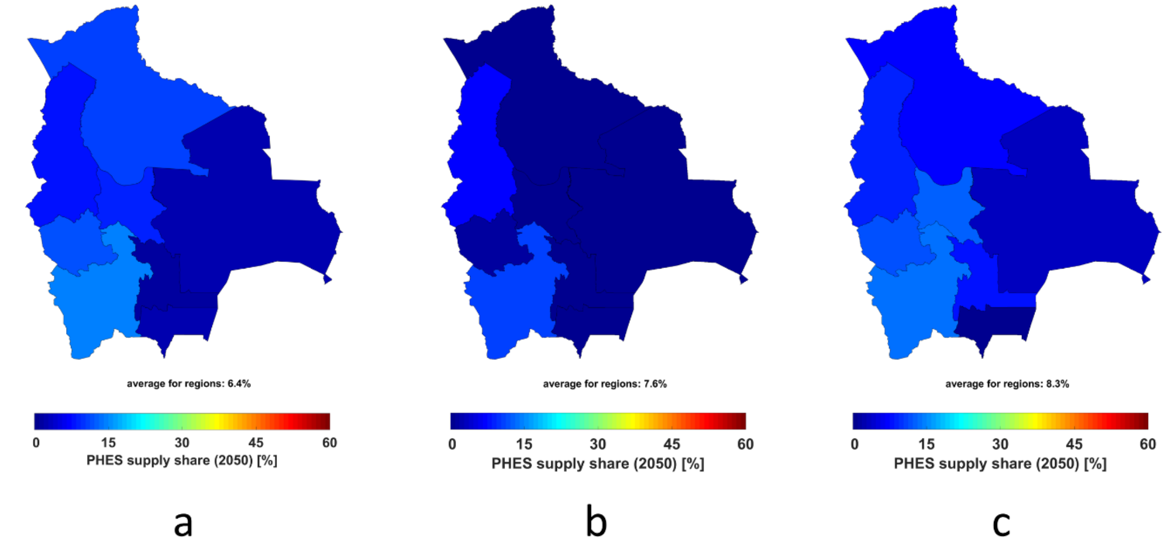


Figure AI37: Regional PHES supply share in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

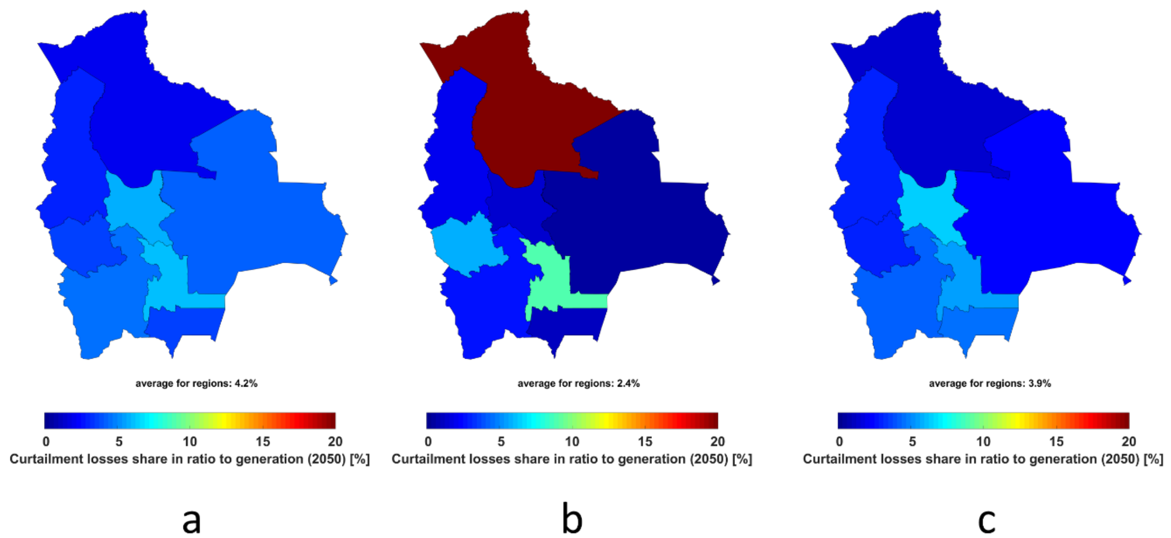


Figure AI38: Regional curtailment losses in ratio to generation in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

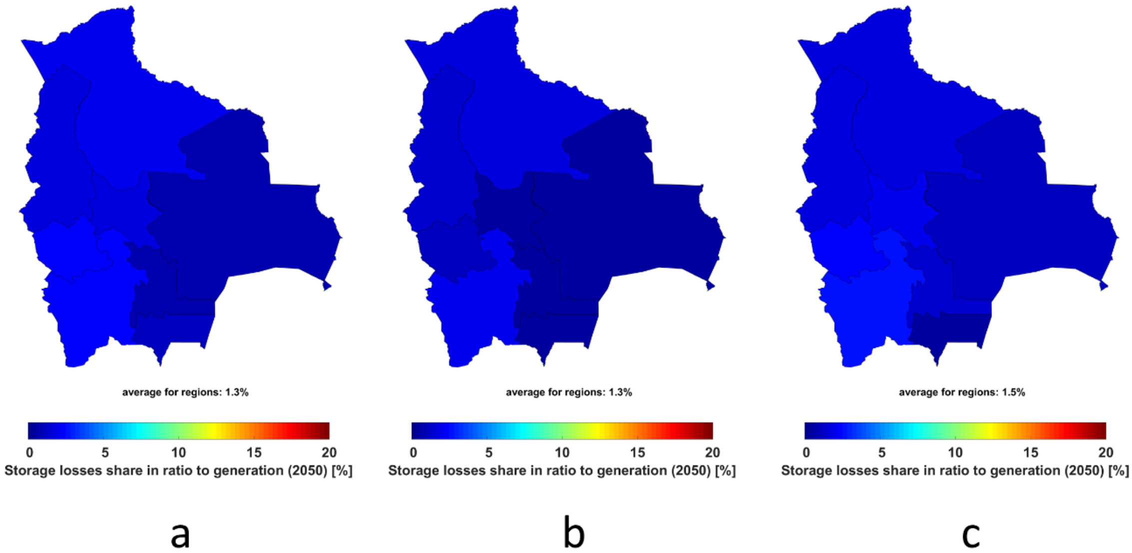


Figure AI39: Regional storage losses in ratio to electricity generation in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

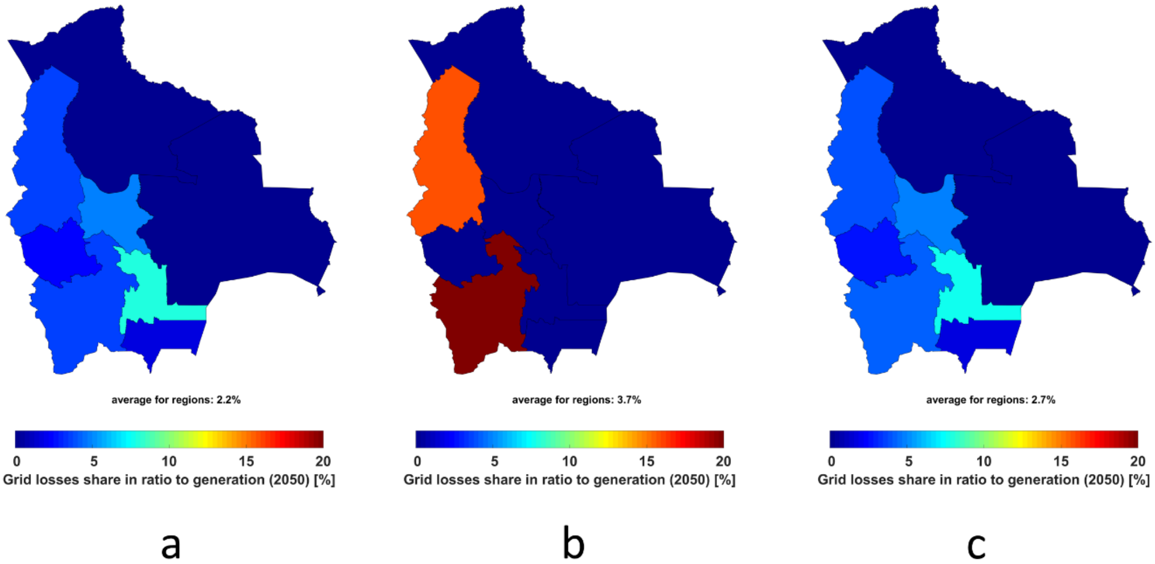


Figure AI40: Regional grid losses in ratio to electricity generation in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

Table AI31: Electricity costs for BPS-1

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOE – Generation	$[€/MWh_{el}]$	32.19	52.66	47.11	33.08	20.68	16.18	14.64
GHG emissions cost	[€/MWh]	9.49	5.71	2.87	0.03	0.00	0.00	0.00
Fuel costs	[€/MWh]	34.08	13.57	6.09	-0.23	-0.18	-0.16	-0.15
LCOC – Curtailment	[€/MWh]	0.75	0.00	0.00	0.18	0.56	0.62	0.64
LCOS – Storage	[€/MWh]	0.00	1.64	2.81	3.84	5.96	6.35	5.87
LCOT – Transmission	[€/MWh]	28.23	15.61	8.98	4.00	2.20	1.54	1.23
Total LCOE	[€/MWh]	104.73	89.18	67.85	40.90	29.23	24.53	22.23

Table AI32: Heat costs for BPS-1

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOH – Generation	[€/MWh_{th}]	26.37	37.33	39.25	37.98	25.25	17.23	16.39
LCOH – Storage	[€/MWh_{th}]	0.00	0.54	0.73	2.39	6.75	9.08	9.24
Total LCOH	[€/MWh_{th}]	26.37	37.87	39.98	40.37	31.74	25.82	25.12

Table AI33: Sustainable fuel and water costs for BPS-1

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOE – Generation	[€/MWh]	32.19	52.66	47.11	33.08	20.68	16.18	14.64
Hydrogen	[€/MWh]	0.00	55.26	63.99	77.42	61.39	47.03	43.15
LH2	[€/MWh]	0.00	0.00	67.58	87.29	70.57	52.72	48.20
SNG	[€/MWh]	0.00	270.50	32.96	65.27	62.41	63.03	58.68
LNG	[€/MWh]	31.38	29.06	34.51	26.31	36.00	43.97	41.98
Fischer-Tropsch	[€/MWh]	0.00	3.62	135.93	124.07	96.89	85.48	80.59
LCOW	[€/m^3]	1.62	1.55	1.38	1.40	1.61	1.57	1.68

Table AI34: Electricity costs for BPS-2

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOE – Generation	[€/MWh]	32.19	57.62	42.81	31.08	17.24	14.98	14.15
GHG emissions cost	[€/MWh]	9.49	3.86	3.08	0.02	0.00	0.00	0.00
Fuel costs	[€/MWh]	34.08	9.06	6.65	-0.24	-0.16	-0.15	-0.15
LCOC – Curtailment	[€/MWh]	0.75	0.00	0.00	0.27	0.37	0.44	0.39
LCOS – Storage	[€/MWh]	0.00	1.27	1.27	3.81	5.23	5.28	5.19
LCOT – Transmission	[€/MWh]	28.23	16.22	8.18	4.72	3.41	2.68	2.14
Total LCOE	[€/MWh]	104.73	88.02	61.99	39.65	26.08	23.23	21.71

Table AI35: Heat costs for BPS-2

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOH – Generation	[€/MWh_{th}]	26.37	37.65	47.24	51.29	27.69	24.33	18.98
LCOH – Storage	[€/MWh_{th}]	0.00	0.60	0.82	2.30	9.37	9.51	9.25
Total LCOH	[€/MWh_{th}]	26.37	38.25	48.06	53.56	35.11	32.24	27.04

Table AI36: Sustainable fuel and water costs for BPS-2

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOE – Generation	[€/MWh]	32.19	57.62	42.81	31.08	17.24	14.98	14.15
Hydrogen	[€/MWh]	0.00	55.11	83.86	122.97	80.60	70.04	54.27
LH2	[€/MWh]	0.00	0.00	81.30	130.05	90.18	80.01	62.97
SNG	[€/MWh]	0.00	0.00	0.00	148.18	95.21	86.31	68.04

LNG	[€/MWh]	31.38	33.61	36.28	28.56	63.77	57.09	47.23
Fischer-Tropsch	[€/MWh]	0.00	0.00	193.50	199.03	118.99	114.30	92.88
LCOW	[€/m^3]	1.62	1.38	1.37	1.40	1.60	1.57	1.57

Table AI37: Electricity costs for BPS-3

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOE – Generation	[€/MWh]	32.20	39.58	47.60	34.32	25.10	20.25	15.68
GHG emissions cost	[€/MWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel costs	[€/MWh]	34.10	25.91	11.20	0.11	-0.13	-0.19	-0.16
LCOC – Curtailment	[€/MWh]	0.75	0.00	0.00	0.05	0.70	0.78	0.59
LCOS – Storage	[€/MWh]	0.00	1.42	3.74	5.29	5.53	6.01	5.17
LCOT – Transmission	[€/MWh]	27.68	15.42	12.28	4.92	3.15	2.28	1.47
Total LCOE	[€/MWh]	94.73	82.33	74.82	44.69	34.37	29.12	22.74

Table AI38: Heat costs for BPS-3

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOH – Generation	[€/MWh$_{th}$]	22.81	29.46	29.73	32.17	31.03	26.56	19.92
LCOH – Storage	[€/MWh$_{th}$]	0.00	0.30	0.41	1.88	2.70	3.88	6.69
Total LCOH	[€/MWh$_{th}$]	22.81	29.76	30.14	34.04	33.73	30.39	26.32

Table AI39: Sustainable fuel and water costs for BPS-3

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOE – Generation	[€/MWh]	32.20	39.58	47.60	34.32	25.10	20.25	15.68
Hydrogen	[€/MWh]	0.00	40.53	43.72	57.68	64.28	54.80	45.70
LH2	[€/MWh]	0.00	0.00	49.47	57.68	71.28	62.22	52.09
SNG	[€/MWh]	0.00	0.00	0.00	0.00	63.00	58.19	51.33
LNG	[€/MWh]	24.76	28.39	28.79	24.13	26.20	29.75	32.38
Fischer-Tropsch	[€/MWh]	0.00	0.00	88.89	107.54	91.88	82.08	74.37
LCOW	[€/m^3]	1.59	1.43	1.44	1.42	1.62	1.58	1.57

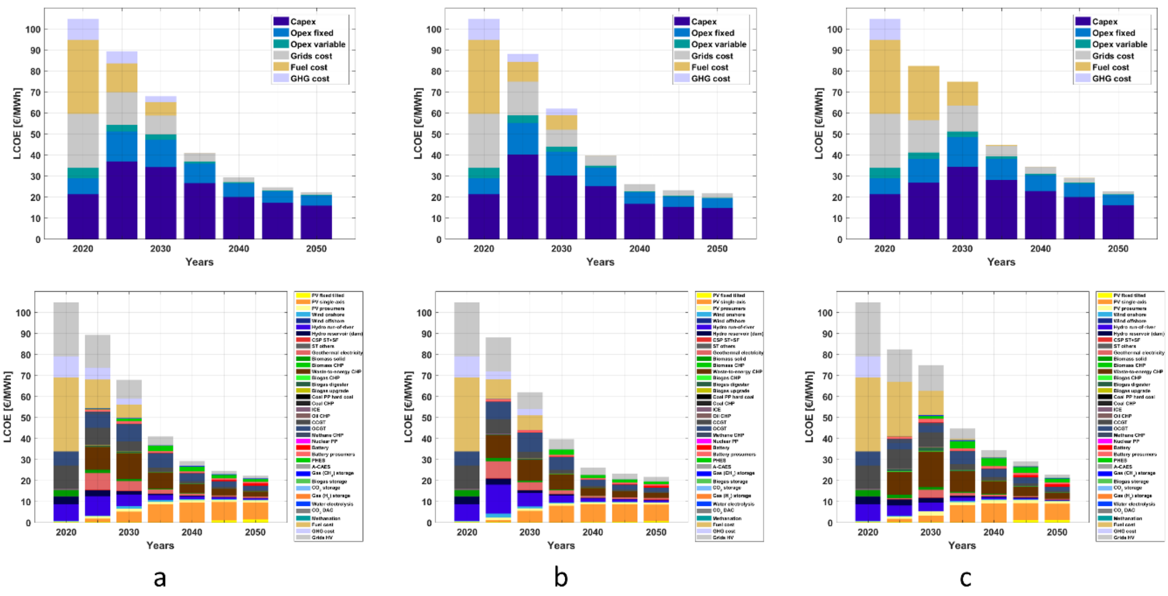


Figure AI41: Levelised cost of electricity by main cost category (top) and technology (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3.

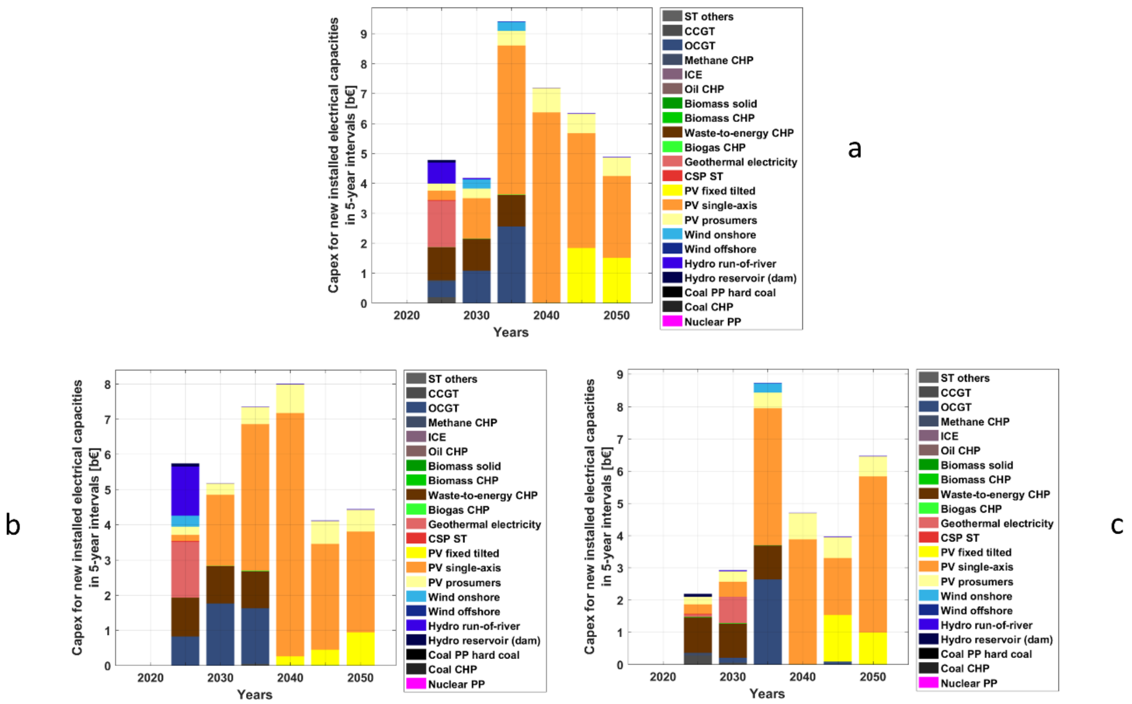
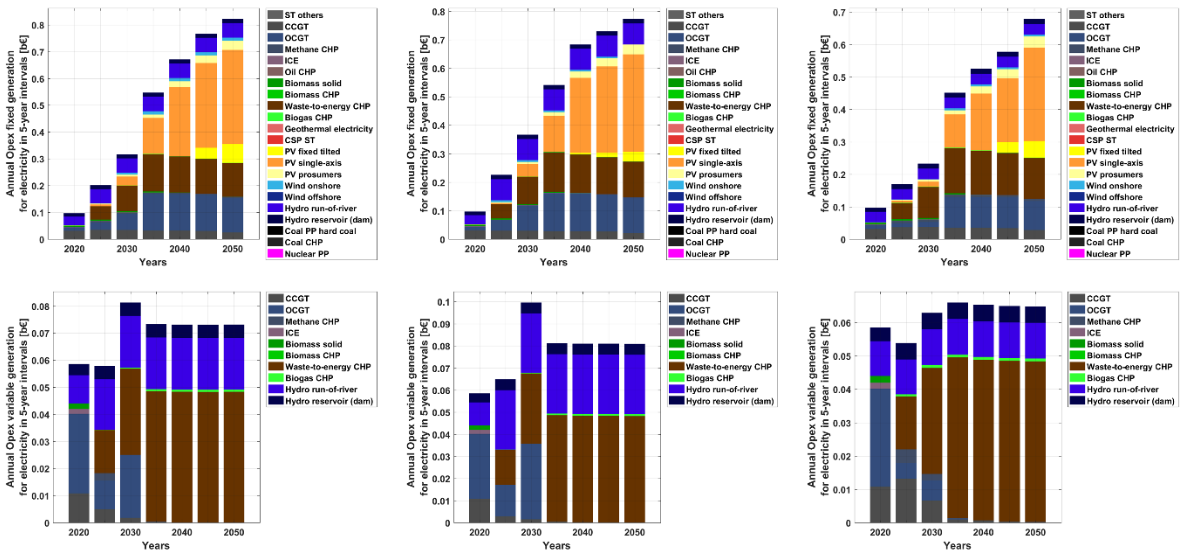
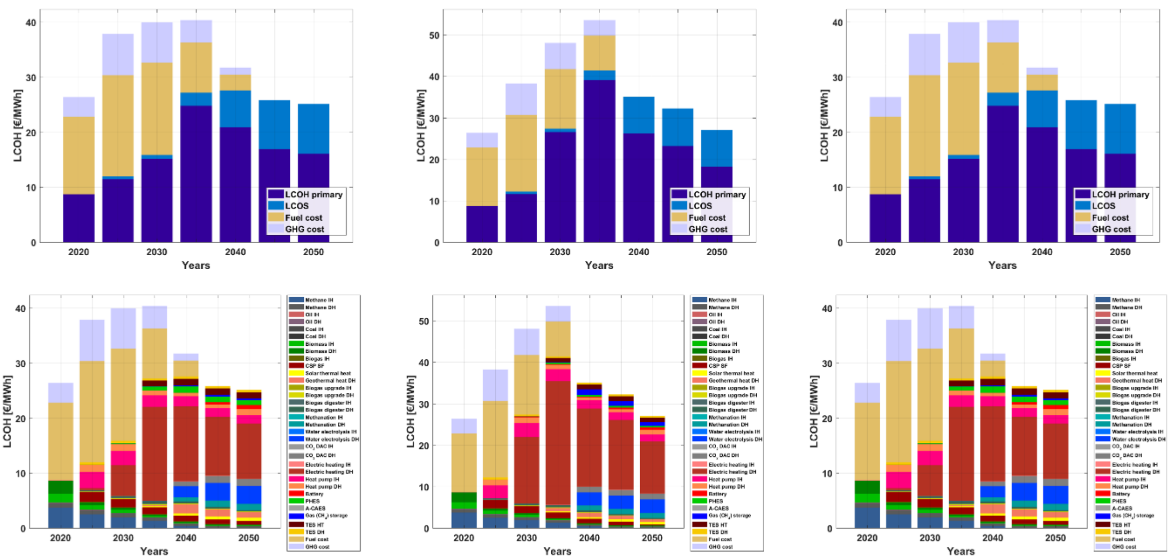


Figure AI42: Power sector Capex for BPS-1 (a), BPS-2 (b), and BPS-3.



a b c

Figure AI43: Power sector Opex fixed (top) and Opex variable (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3.



a b c

Figure AI44: Levelised cost of heat by main cost category (top) and technology (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

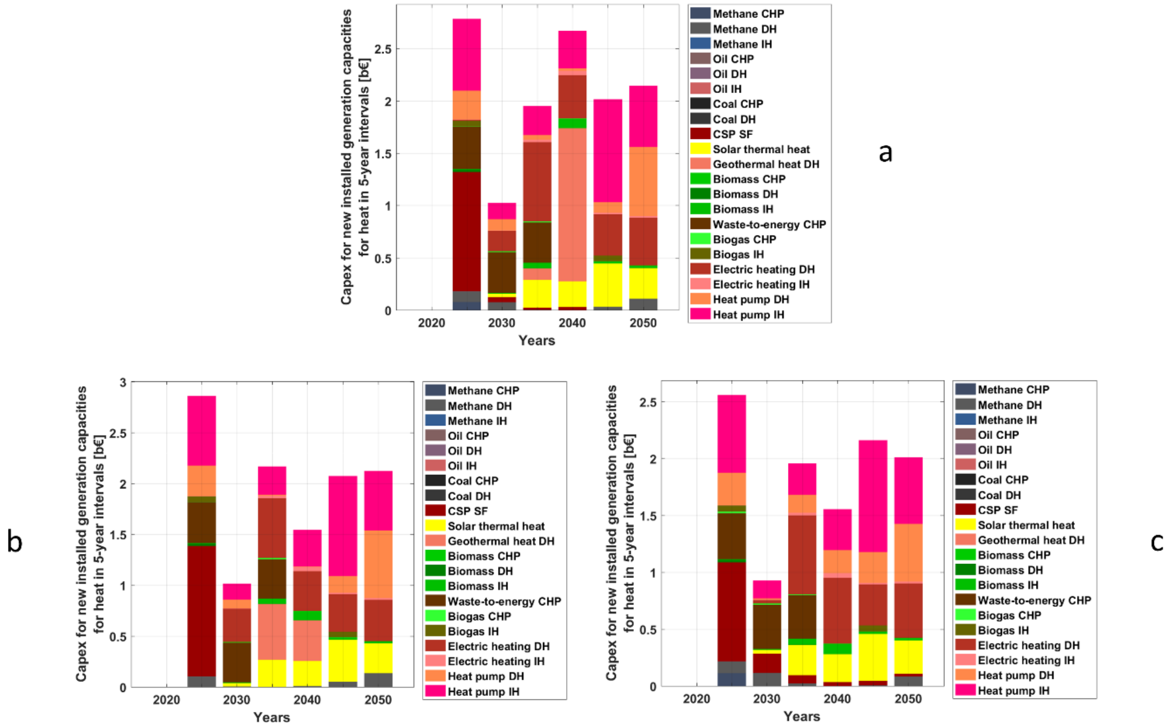


Figure AI45: Heat sector Capex for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

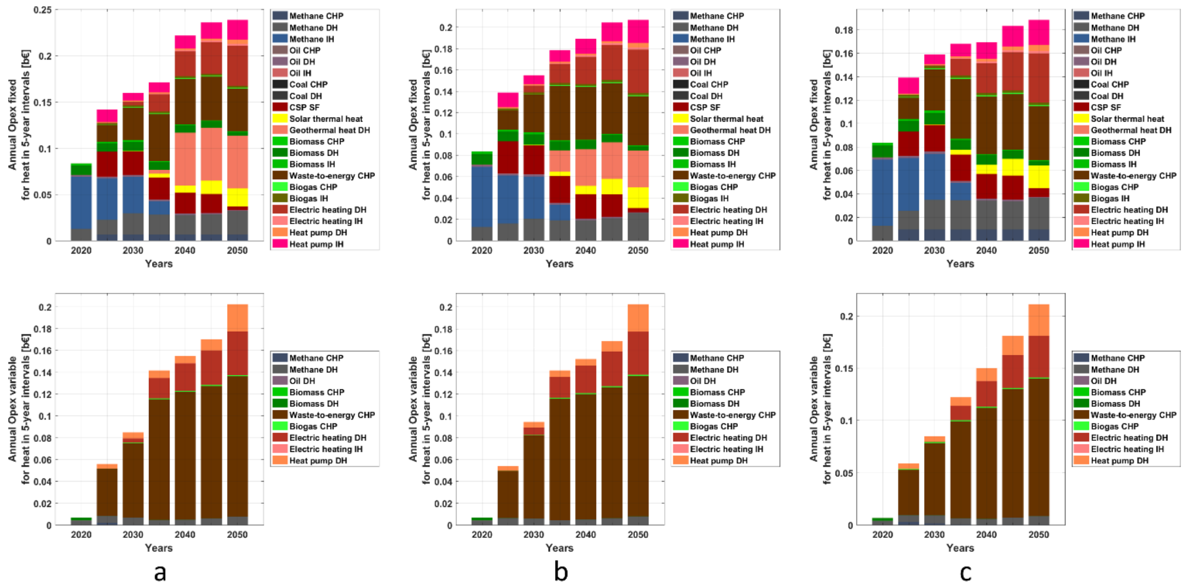
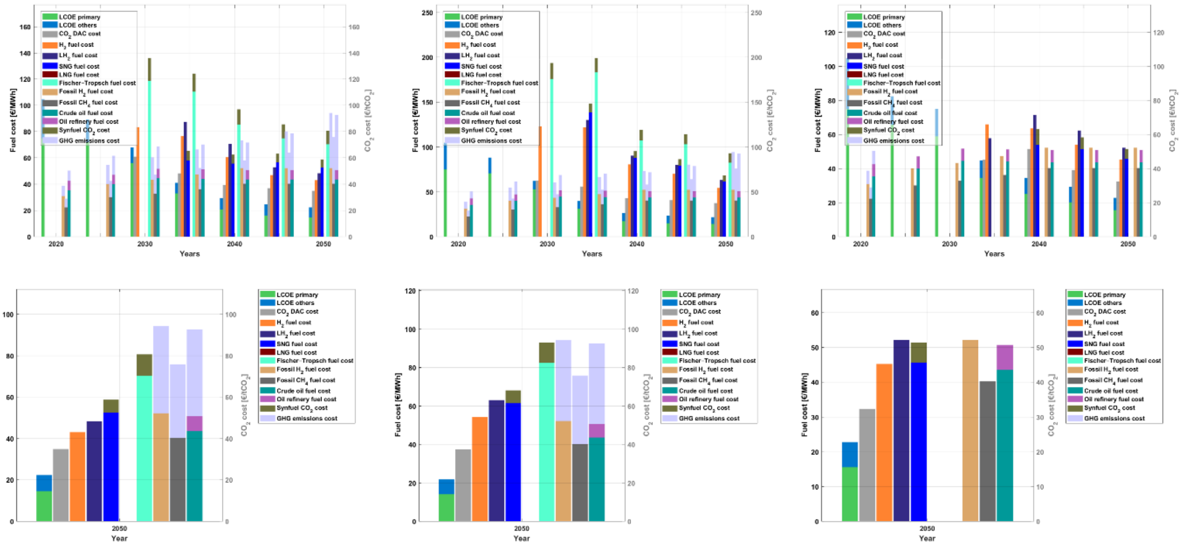
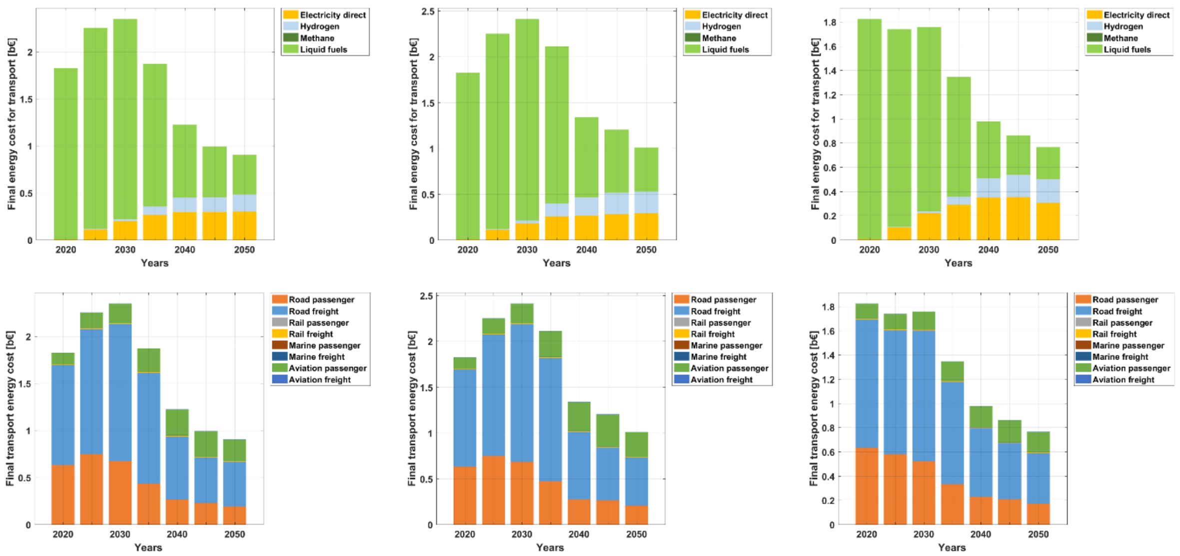


Figure AI46: Heat sector Opex fixed (top) and Opex variable (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3 (c).



a b c

Figure AI47: Fuel costs for the transport sector during the transition (top) and fuel costs in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).



a b c

Figure AI48: Final transport energy costs based on fuel form (top) and mode of transport (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

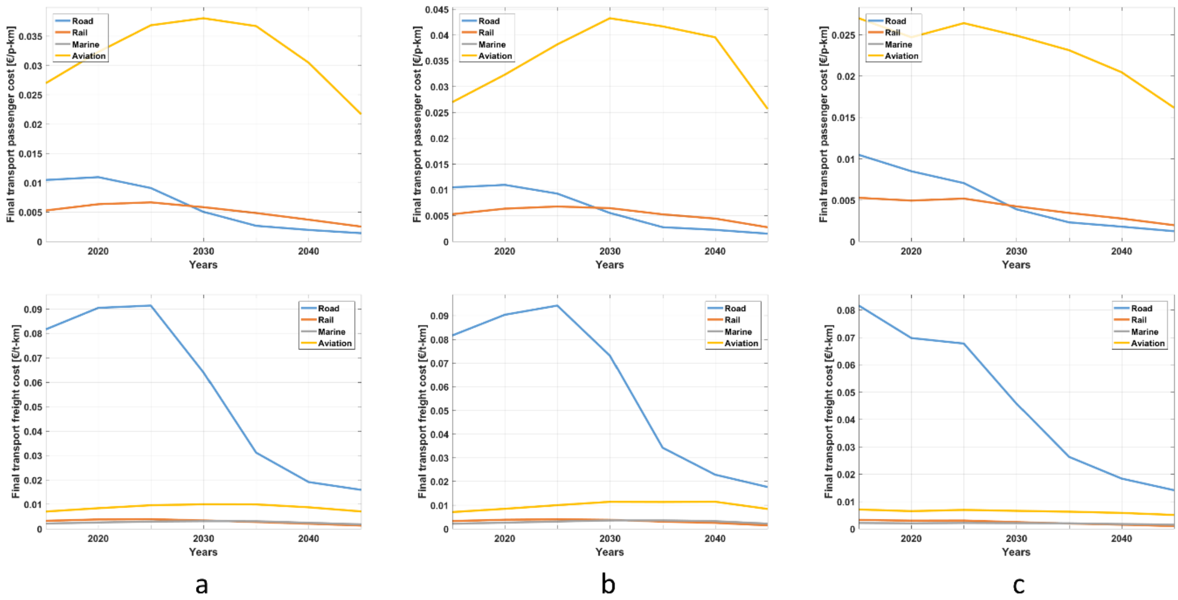


Figure AI49: Final transport costs by mode – passenger (top) and freight (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

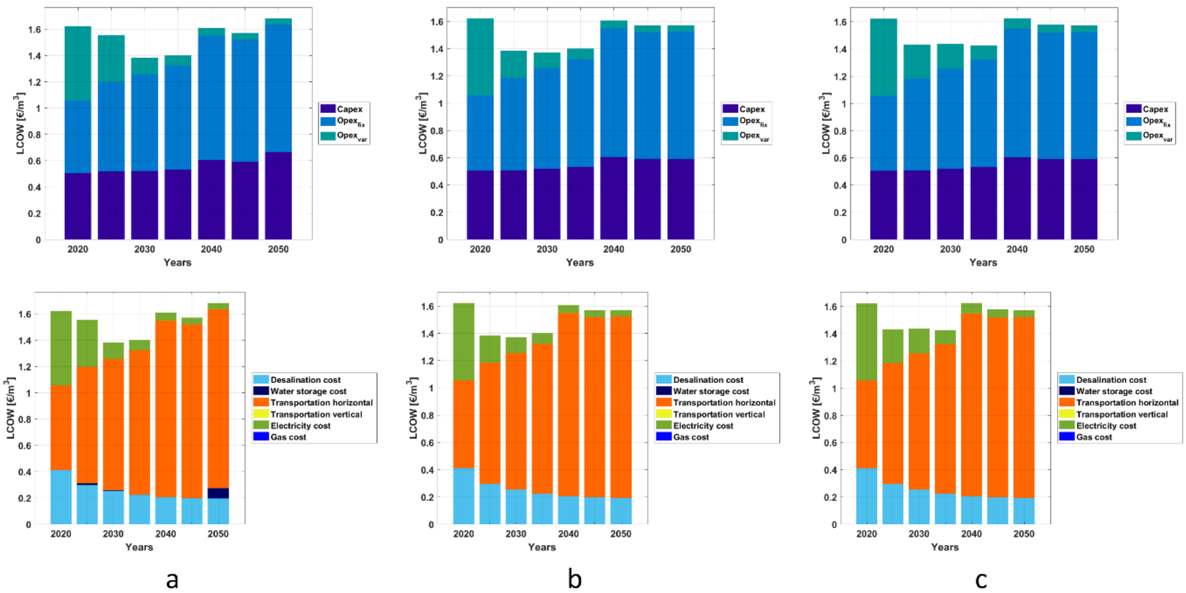


Figure AI50: Desalination sector – Levelised cost of water by main cost categories (top) and process/fuel (bottom) for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

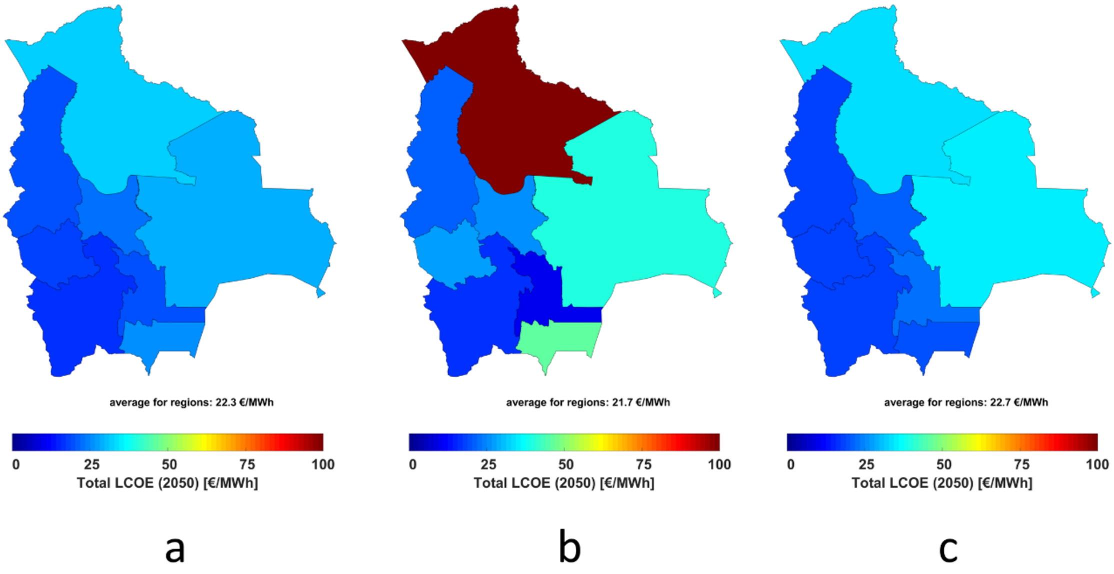


Figure AI51: Regional LCOE in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

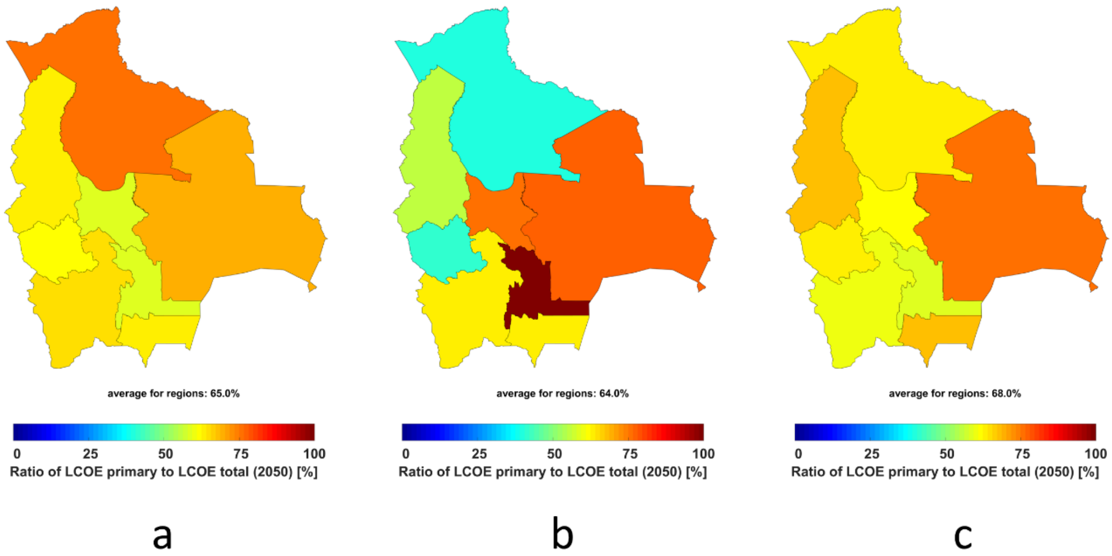


Figure AI52: Regional ratio of LCOE primary to total LCOE in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

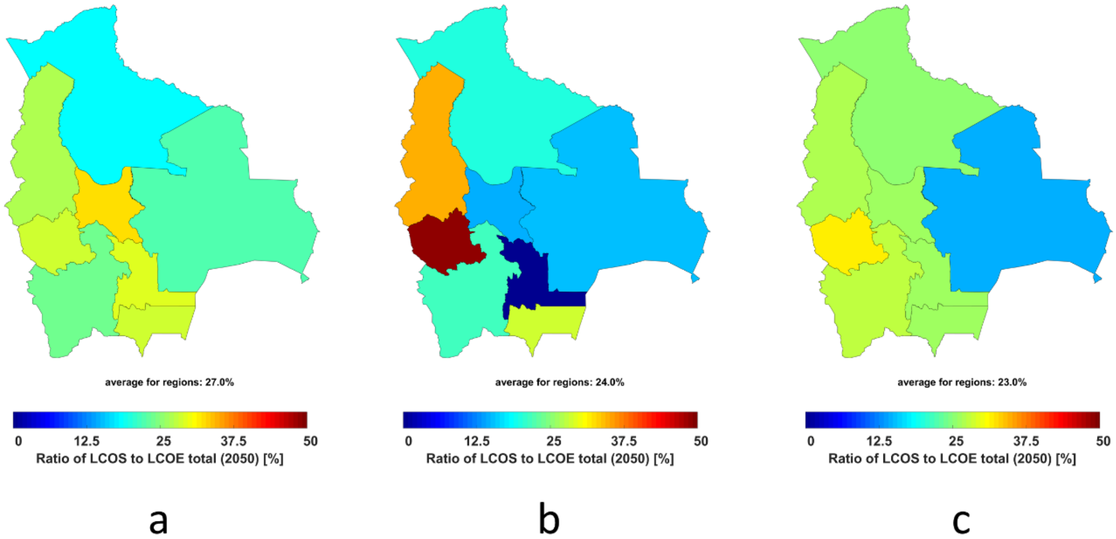


Figure AI53: Regional ratio of LCOS to total LCOE in 2050 for BPS-1 (a), BPS-2 (b), and BPS-3 (c).

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APPENDIX II. SUPPLEMENTARY MATERIAL FOR CHAPTER 2

Data regarding projections of Bolivia's population and demands by sector and by form, projected passenger and freight transport demands, as well specific transport energy demands by technology can be found in [1]. Additionally, financial and technical assumptions used by technology are provided Table AII1. Updated values on full LHV aligned basis are denoted with the subscript "LHV".

Table AII1. Financial and technical assumptions of energy system technologies used.

Technologies		Unit	2020	2025	2030	2035	2040	2045	2050	Sources
PV fixed tilted PP	Capex	€/kW_{el}	432	336	278	237	207	184	166	[2,3]
	Opex fix	€/(kW_{el} a)	7.76	6.51	5.66	5	4.47	4.04	3.7	
	Opex var	€/kWel	0	0	0	0	0	0	0	
	Lifetime	years	30	35	35	35	40	40	40	
PV rooftop - residential	Capex	€/kW_{el}	1045	842	715	622	551	496	453	[2]
	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 rooftop - commercial	Capex	€/kW_{el}	689	544	456	393	345	308	280	[2]
	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 rooftop - industrial	Capex	€/kW_{el}	512	397	329	281	245	217	197	[2]
	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 PP	Capex	€/kW_{el}	475	370	306	261	228	202	183	[2–4]
	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 PP	Capex	€/kW_{el}	1150	1060	1000	965	940	915	900	[5]
	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 PP	Capex	€/kW_{el}	2560	2560	2560	2560	2560	2560	2560	[6]
	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	
Hydro Reservoir/ Dam	Capex	€/kW_{el}	1650	1650	1650	1650	1650	1650	1650	[6]
	Opex fix	€/(kW_{el} a)	49.5	49.5	49.5	49.5	49.5	49.5	49.5	

	Opex var	€/kWh_{el}	0.003	0.003	0.003	0.003	0.003	0.003	0.003	
	Lifetime	years	50	50	50	50	50	50	50	
Geothermal PP	Capex	€/kW_{el}	4970	4720	4470	4245	4020	3815	3610	[6,7]
	Opex fix	€/(kW_{el} a)	80	80	80	80	80	80	80	
	Opex var	€/kWh_{el}	0	0	0	0	0	0	0	
	Lifetime	years	40	40	40	40	40	40	40	
	Efficiency		23.9%	23.9%	23.9%	23.9%	23.9%	23.9%	23.9%	
Steam turbine (CSP)	Capex	€/kW_{el}	968	946	923	902	880	860	840	[8]
	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		38.3%	40.3%	43.0%	43.0%	43.0%	43.0%	43.0%	
CCGT PP	Capex	€/kW_{el}	775	775	775	775	775	775	775	[9]
	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		58.0%	58.0%	58.0%	59.0%	60.0%	60.0%	60.0%	
OCGT PP	Capex	€/kW_{el}	475	475	475	475	475	475	475	[9]
	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		40.0%	41.5%	43.0%	43.5%	44.0%	44.5%	45.0%	
Int Combust Generator	Capex	€/kW_{el}	385	385	385	385	385	385	385	[10]
	Opex fix	€/(kW_{el} a)	11.5	11.5	11.5	11.5	11.5	11.5	11.5	
	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		30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	
Coal PP	Capex	€/kW_{el}	1500	1500	1500	1500	1500	1500	1500	[9,11]
	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	40	40	40	40	40	40	40	
	Efficiency		43.0%	43.0%	43.0%	43.0%	43.0%	43.0%	43.0%	
Biomass PP	Capex	€/kW_{el}	2620	2475	2330	2195	2060	1945	1830	[6]
	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		36.0%	36.5%	37.0%	37.5%	38.0%	38.5%	39.0%	
Nuclear PP	Capex	€/kW_{el}	6003	6003	5658	5658	5244	5244	5175	[9,12,13]
	Opex fix	€/(kW_{el} a)	113.1	113.1	98.4	98.4	83.6	83.6	78.8	
	Opex var	€/kWh_{el}	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	
	Lifetime	years	40	40	40	40	40	40	40	
	Efficiency		37.0%	37.0%	38.0%	38.0%	38.0%	38.0%	38.0%	
CHP NG Heating	Capex	€/kW_{el}	880	880	880	880	880	880	880	[6]
	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$_{el}$		51.0%	52.0%	53.0%	53.5%	54.0%	54.5%	55.0%	
	Efficiency$_{th}$		36.6%	37.3%	38.0%	38.3%	38.7%	39.1%	39.4%	
CHP Oil Heating	Capex	€/kW$_{el}$	880	880	880	880	880	880	880	[6]
	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$_{el}$		30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	
	Efficiency$_{th}$		50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	
CHP Coal Heating	Capex	€/kW$_{el}$	2030	2030	2030	2030	2030	2030	2030	[6]
	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$_{el}$		41.1%	42.1%	43.0%	43.6%	44.2%	44.8%	45.5%	
	Efficiency$_{th}$		42.8%	43.8%	44.8%	45.4%	46.1%	46.7%	47.4%	
CHP Biomass Heating	Capex	€/kW$_{el}$	3400	3300	3200	3125	3050	2975	2900	[8]
	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	0.0038	0.0037	0.0037	0.0038	0.0038	0.0038	
	Lifetime	years	25	25	25	25	25	25	25	
	Efficiency$_{el}$		29.5%	29.6%	29.6%	29.5%	29.4%	29.2%	29.1%	
	Efficiency$_{th}$		65.1%	65.2%	65.3%	65.0%	64.8%	64.5%	64.2%	
CHP Biogas	Capex	€/kW$_{el}$	429.2	399.6	370	340.4	325.6	310.8	296	[8]
	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$_{el}$		43.0%	46.5%	50.0%	52.3%	54.7%	54.7%	54.7%	
	Efficiency$_{th}$		34.4%	37.2%	40.0%	41.9%	43.7%	43.7%	43.7%	
MSW incinerator	Capex	€/kW$_{el}$	5630	5440	5240	5030	4870	4690	4540	[6]
	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$_{el}$		26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	
	Efficiency$_{th}$		71.0%	71.0%	71.0%	71.0%	71.0%	71.0%	71.0%	
Concentrating Solar Heat	Capex	€/kW$_{th}$	344.5	303.6	274.7	251.1	230.2	211.9	196	[14,15]
	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	[16]
	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 -	Capex	€/kW$_{th}$	485	485	485	485	485	485	485	[17]
	Opex fix	€/(kW$_{th}$ a)	4.85	4.85	4.85	4.85	4.85	4.85	4.85	

Collectors - Hot Water	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	15	15	15	15	15	15	15	
DH Electric Heating	Capex	€/kW$_{th}$	100	100	75	75	75	75	75	[18]
	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		100%	100%	100%	100%	100%	100%	100%	
DH Heat Pump	Capex	€/kW$_{th}$	660	618	590	568	554	540	530	[19]
	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		329%	340%	347%	357%	364%	370%	375%	
DH NG Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	[18]
	Opex fix	€/(kW$_{th}$ a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency		97%	97%	97%	97%	97%	97%	97%	
DH Oil Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	[18]
	Opex fix	€/(kW$_{th}$ a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency		97%	97%	97%	97%	97%	97%	97%	
DH Coal Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	[18]
	Opex fix	€/(kW$_{th}$ a)	2.775	2.775	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency		97%	97%	97%	97%	97%	97%	97%	
DH Biomass Heating	Capex	€/kW$_{th}$	75	75	100	100	100	100	100	[18]
	Opex fix	€/(kW$_{th}$ a)	2.8	2.8	3.7	3.7	3.7	3.7	3.7	
	Opex var	€/kWh$_{th}$	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
	Lifetime	years	35	35	35	35	35	35	35	
	Efficiency		97%	97%	97%	97%	97%	97%	97%	
DH Geothermal Heat	Capex	€/kW$_{th}$	3642	3384	3200	3180	3160	3150	3146	[20]
	Opex fix	€/(kW$_{th}$ a)	133	124	117	116	115	115	115	
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	22	22	22	22	22	22	22	
	Efficiency		97%	97%	97%	97%	97%	97%	97%	
Local Electric Heating	Capex	€/kW$_{th}$	100	100	100	100	100	100	100	[8]
	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		100%	100%	100%	100%	100%	100%	100%	
Local Heat Pump	Capex	€/kW$_{th}$	780	750	730	706	690	666	650	[6]
	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		470%	487%	498%	514%	525%	535%	542%	
Local NG Heating	Capex	€/kW$_{th}$	800	800	800	800	800	800	800	[16]
	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		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Local Oil Heating	Capex	€/kW$_{th}$	440	440	440	440	440	440	440	[16]
	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		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Local Biomass Heating	Capex	€/kW$_{th}$	675	675	750	750	750	750	750	[16]
	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		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Local Biogas Heating	Capex	€/kW$_{th}$	800	800	800	800	800	800	800	[16]
	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		95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	
Water Electrolysis	Capex	€/kW$_{H2,LHV}$	803	586	446	381	347	313	291	[21,22]
	Opex fix	€/(kW$_{H2,LHV}$ a)	28.1	20.5	15.6	13.3	12.1	11	10.2	
	Opex var	€/kWh$_{H2,LHV}$	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency		70%	70%	70%	70%	70%	70%	70%	
CO_2 direct air capture	Capex	€/(t$_{CO2}$ a)	730	481	338	281	237	217	199	[23]
	Opex fix	€/(t$_{CO2}$ a)	29.2	19.2	13.5	11.2	9.5	8.7	8	
	Opex var	€/t$_{CO2}$	0	0	0	0	0	0	0	
	Lifetime	years	20	30	25	30	30	30	30	
	Consumption	kWh$_{el}$/t$_{CO2}$	250	237	225	213	202.5	192	182.3	
	Consumption	kWh$_{th}$/t$_{CO2}$	1750	1618	1500	1387	1286	1189	1102	
Methanation	Capex	€/kW$_{SNG,LHV}$	558	409	309	274	251	227	211	[21,22]
	Opex fix	€/(kW$_{SNG,LHV}$ a)	25.7	18.8	14.2	12.6	11.5	10.4	9.7	
	Opex var	€/MWh$_{SNG,LHV}$	0.0017	0.0017	0.0017	0.0017	0.0017	0.0017	0.0017	
	Lifetime	years	30	30	30	30	30	30	30	
	Consumption	kg$_{CO2}$/kWh$_{th}$	0.1976	0.1976	0.1976	0.1976	0.1976	0.1976	0.1976	
	Efficiency		82%	82%	82%	82%	82%	82%	82%	
Biogas digester	Capex	€/kW$_{th,LHV}$	811	784	755	725	702	676	654	[10]
	Opex fix	€/(kW$_{th,LHV}$ a)	32.5	31.4	30.2	29	28.1	27	26.2	

	Opex var	€/kWh$_{th,LHV}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	25	25	25	25	
Biogas Upgrade	Capex	€/kW$_{th}$	322	300	278	255	244	233	222	[10]
	Opex fix	€/(kW$_{th}$ a)	25.8	24	22.2	20.4	19.5	18.7	17.8	
	Opex var	€/kWh$_{th}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
	Efficiency		98%	98%	98%	98%	98%	98%	98%	
Fischer-Tropsch unit	Capex	€/kW,FT$_{Liq,LHV}$	1017	1017	1017	1017	915	915	915	[24]
	Opex fix	€/kW,FT$_{Liq,LHV}$	30.5	30.5	30.5	30.5	27.5	27.5	27.5	
	Opex var	€/kWh,FT$_{Liq,LHV}$	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency		69.2%	69.2%	69.2%	69.2%	69.2%	69.2%	69.2%	
Gas Liquefaction	Capex	€/kW$_{Liq,LHV}$	201	201	201	201	201	201	201	[8]
	Opex fix	€/kW$_{Liq,LHV}$	7	7	7	7	7	7	7	
	Opex var	€/kWh$_{Liq,LHV}$	0	0	0	0	0	0	0	
	Lifetime	years	25	25	25	25	25	25	25	
	Efficiency		98.7%	98.7%	98.7%	98.7%	98.7%	98.7%	98.7%	
H_2 Liquefaction	Capex	€/kW$_{Liq,LHV}$	420	420	420	206	179	170	162	[25–27]
	Opex fix	€/kW$_{Liq, LHV}$	16.8	16.8	16.8	8.2	7.2	6.8	6.5	
	Opex var	€/kWh$_{Liq,LHV}$	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency		98.3%	98.3%	98.3%	98.3%	98.3%	98.3%	98.3%	
Steam Methane Reforming	Capex	€/kW$_{H2,LHV}$	320	320	320	320	320	320	320	[28]
	Opex fix	€/kW$_{H2,LHV}$	16	16	16	16	16	16	16	
	Opex var	€/kWh$_{H2,LHV}$	0	0	0	0	0	0	0	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency		84.5%	84.5%	84.5%	84.5%	84.5%	84.5%	84.5%	
Battery Storage	Capex	€/kWh$_{el}$	234	153	110	89	76	68	61	[29]
	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	
	Efficiency		91.0%	92.0%	93.0%	94.0%	95.0%	95.0%	95.0%	
Battery Interface	Capex	€/kW$_{el}$	117	76	55	44	37	33	30	[30]
	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 pros residential Storage	Capex	€/kWh$_{el}$	462	308	224	182	156	140	127	[8]
	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	
	Efficiency		91.0%	92.0%	93.0%	94.0%	95.0%	95.0%	95.0%	
Battery PV pros residential	Capex	€/kW$_{el}$	231	153	112	90	76	68	62	[8]
	Opex fix	€/(kW$_{el}$ a)	2.54	1.99	1.68	1.53	1.37	1.36	1.24	

Interface	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	20	20	20	20	20	20	20	
Battery PV pros commercial Storage	Capex	€/kWh$_{el}$	366	240	175	141	121	108	98	[8]
	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	
	Efficiency		91.0%	92.0%	93.0%	94.0%	95.0%	95.0%	95.0%	
Battery PV pros commercial Interface	Capex	€/kW$_{el}$	183	119	88	70	59	53	48	[8]
	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 pros industrial Storage	Capex	€/kWh$_{el}$	278	181	131	105	90	80	72	[8]
	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	
	Efficiency		91.0%	92.0%	93.0%	94.0%	95.0%	95.0%	95.0%	
Battery PV pros industrial Interface	Capex	€/kW$_{el}$	139	90	66	52	44	39	35	[8]
	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	[31]
	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	
	Efficiency		85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	85.0%	
PHES Interface	Capex	€/kW$_{el}$	650	650	650	650	650	650	650	[6]
	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$_{el}$	75	65.3	57.9	53.6	50.8	47	43.8	[6]
	Opex fix	€/(kWh$_{el}$ a)	1.16	0.99	0.87	0.81	0.77	0.71	0.66	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	40	40	40	40	40	40	40	
	Efficiency		59.3%	64.7%	70.0%	70.0%	70.0%	70.0%	70.0%	
A-CAES Interface	Capex	€/kW$_{el}$	540	540	540	540	540	540	540	[6]
	Opex fix	€/(kW$_{el}$ a)	17.5	17.5	17.5	17.5	17.5	17.5	17.5	
	Opex var	€/kWh$_{el}$	0	0	0	0	0	0	0	
	Lifetime	years	40	40	40	40	40	40	40	
Hot Heat Storage Storage	Capex	€/kWh$_{th}$	41.8	32.7	26.8	23.3	21	19.3	17.5	[8]
	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	
	Efficiency		90%	90%	90%	90%	90%	90%	90%	
	Capex	€/kW$_{th}$	0	0	0	0	0	0	0	[8]

Hot Heat Storage Interface	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$_{th,LHV}$	0.28	0.28	0.28	0.28	0.28	0.28	0.28	[32]
	Opex fix	€/(kWh$_{th,LHV}$ a)	0.0112	0.0112	0.0112	0.0112	0.0112	0.0112	0.0112	
	Opex var	€/kWh$_{th,LHV}$	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	
	Lifetime	years	30	30	30	30	30	30	30	
	Efficiency		100%	100%	100%	100%	100%	100%	100%	
Hydrogen Storage Interface	Capex	€/kW$_{th,LHV}$	100	100	100	100	100	100	100	[32]
	Opex fix	€/(kW$_{th,LHV}$ a)	4	4	4	4	4	4	4	
	Opex var	€/kW$_{th,LHV}$	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	[33]
	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	
	Efficiency		100%	100%	100%	100%	100%	100%	100%	
CO_2 Storage Interface	Capex	€/ton/h	0	0	0	0	0	0	0	[32]
	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	[33]
	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	
	Efficiency		100%	100%	100%	100%	100%	100%	100%	
Gas Storage Interface	Capex	€/kW$_{th}$	100	100	100	100	100	100	100	[33]
	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	
District Heat Storage	Capex	€/kWh$_{th}$	40	30	30	25	20	20	20	[8]
	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	
	Efficiency		90%	90%	90%	90%	90%	90%	90%	
District Heat Storage Interface	Capex	€/kW$_{th}$	0	0	0	0	0	0	0	[8]
	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	
Reverse Osmosis Seawater Desalination	Capex	€/(m^3/day)	960	835	725	630	550	480	415	[34]
	Opex fix	€/(m^3/day)	38.4	33.4	29	25.2	22	19.2	16.6	
	Consumption	kWh$_{th}$/m^3	0	0	0	0	0	0	0	
	Lifetime	years	25	30	30	30	30	30	30	

	Consumption	kWh_{el}/m^3	3.6	3.35	3.15	3	2.85	2.7	2.6	
Multi-Stage Flash Stand-alone	Capex	€/(m^3/day)	2000	2000	2000	2000	2000	2000	2000	[34]
	Opex fix	€/(m^3/day)	100	100	100	100	100	100	100	
	Consumption	kWh_{th}/m^3	85	85	85	85	85	85	85	
	Lifetime	years	25	25	25	25	25	25	25	
	Consumption	kWh_{el}/m^3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	
Multi-Stage Flash Cogeneration	Capex	€/(m^3/day)	3069	3069	3069	3069	3069	3069	3069	[8]
	Opex fix	€/(m^3/day)	121.4	121.4	121.4	121.4	121.4	121.4	132.1	
	Consumption	kWh_{th}/m^3	202.5	202.5	202.5	202.5	202.5	202.5	202.5	
	Lifetime	years	25	25	25	25	25	25	25	
	Consumption	kWh_{el}/m^3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	
Multi Effect Distillation Stand-alone	Capex	€/(m^3/day)	1200	1044	906.3	787.5	687.5	600	518.8	[34]
	Opex fix	€/(m^3/day)	39.6	34.44	29.91	25.99	22.69	19.8	17.12	
	Consumption	kWh_{th}/m^3	51	44	38	32	28	28	28	
	Lifetime	years	25	25	25	25	25	25	25	
	Consumption	kWh_{el}/m^3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
Multi Effect Distillation Cogeneration	Capex	€/(m^3/day)	2150	2150	2150	2150	2150	2150	2150	[8]
	Opex fix	€/(m^3/day)	61.69	61.69	61.69	61.69	61.69	61.69	68.81	
	Consumption	kWh_{th}/m^3	168	168	168	168	168	168	168	
	Lifetime	years	25	25	25	25	25	25	25	
	Consumption	kWh_{el}/m^3	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
Water Storage	Capex	€/m^3	64.59	64.59	64.59	64.59	64.59	64.59	64.59	[8]
	Opex fix	€/m^3	1.29	1.29	1.29	1.29	1.29	1.29	1.29	
	Opex var	€/m^3	0	0	0	0	0	0	0	
	Lifetime	years	50	50	50	50	50	50	50	

Table AII2. Conversion of LUT input to EnergyPLAN input for Synfuels.

Parameter		Unit	HHV	LHV
PtG (incl. DAC)	Efficiency	%	63.8	57.4
PtL (incl. DAC)	Efficiency	%	52.6	49.0
GtL	Efficiency	%	82.4	85.3
PtG (incl. DAC)	Capex	€/kW_{FTL}	993	1067
Extra CO_2 needed	Capex	€/kW_{FTL}	119	128
GtL	Capex	€/kW_{FTL}	615	660
PtGtL total	Capex	€/kW_{FTL}	733	788
	Capex	€/kW_{SNG}	605	672

Table AII3: Energy to power ratio and self-discharge rates of storage technologies. Energy/Power ratios values by 2050 are individually optimised.

Technology	Efficiency [%] input	Energy/Power Ratio [h]	Self-Discharge [%/h] input	Sources

		BPS-MHT; BPS-MNT; BPS-S; BPS-ET; BPS-EP result		
Battery prosumers	95	7.54; 7.53; 7.98; 7.53; 8.97	1	[33]
Battery system	95	5.73;6.13; 6.14; 5.44; 8.97		[33]
PHES	85	9.89; 9.19; 0; 8.6; 0	1	[6]
A-CAES	70	8.29; 11.97; 16.34; 12.61; 0	0.9999	[6]
Hot Heat TES	90	3.38; 1.92; 1.66; 2.77; 0	0.9999	[33]
District Heat TES	90	1.45; 1.1; 1.04; 1.22; 8.44	0.9999	[33]

Table AII4: Installed capacity – BPS-ET.

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
PV prosumers RES	[GW]	0.03	0.15	0.39	0.82	1.69	2.43	3.23
PV prosumers COM	[GW]	0.03	0.12	0.28	0.61	1.06	1.48	1.89
PV prosumers IND	[GW]	0.00	0.16	0.39	0.71	1.44	2.09	2.82
PV fixed tilted system	[GW]	0.07	0.07	0.07	0.07	1.30	3.84	4.74
PV single-axis system	[GW]	0.00	0.47	6.23	20.67	51.64	69.28	89.61
CSP	[GW]	0.00	4.28	4.29	4.29	4.29	4.29	0.73
Wind onshore	[GW]	0.03	0.31	0.31	0.31	0.31	0.29	0.00
Hydro run-of-river	[GW]	0.42	0.96	0.96	0.96	0.96	0.96	0.96
Hydro reservoir (dam)	[GW]	0.26	0.31	0.31	0.31	0.31	0.31	0.31
Geothermal	[GW]	0.00	0.37	0.37	0.37	0.37	0.37	0.37
CCGT	[GW]	1.59	1.55	1.53	1.40	1.40	1.34	1.04
OCGT	[GW]	0.90	2.60	5.57	8.42	8.40	8.26	7.87
ST others	[GW]	0.03	0.03	0.03	0.01	0.00	0.00	0.00
Biomass PP	[GW]	0.10	0.10	0.10	0.10	0.02	0.00	0.00
Biogas dig	[GW]	0.00	0.28	0.57	0.86	0.86	0.86	0.86
Biogas Upgrade	[GW]	0.00	0.17	0.34	0.52	0.52	0.51	0.52
ICE	[GW]	0.14	0.11	0.09	0.08	0.06	0.01	0.00
Methane CHP	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Waste CHP	[GW]	0.00	0.28	0.55	0.84	0.84	0.84	0.84
Biomass CHP	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biogas CHP	[GW]	0.00	0.02	0.06	0.13	0.16	0.17	0.17
El heater DH	[GW]	0.00	0.00	4.29	11.92	17.18	22.20	27.46
Heat pump DH	[GW]	0.00	0.48	0.70	0.79	0.79	0.80	1.81

Methane DH	[GW]	4.59	5.78	5.61	5.17	5.16	5.49	6.61
Oil DH	[GW]	0.64	0.61	0.54	0.46	0.43	0.38	0.15
Coal DH	[GW]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass DH	[GW]	3.61	3.26	2.64	2.27	2.23	1.94	1.14
El heater IH	[GW]	0.03	0.05	0.08	0.32	0.74	0.87	1.04
Heat pump IH	[GW]	0.00	0.91	1.13	1.52	2.04	2.61	3.29
Methane IH	[GW]	2.09	1.66	1.46	0.54	0.00	0.00	0.00
Oil IH	[GW]	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Biomass IH	[GW]	1.16	0.84	0.71	0.32	0.20	0.23	0.24
Biogas IH	[GW]	0.00	0.07	0.07	0.07	0.08	0.08	0.08
Battery RES	[GWh]	0.00	0.29	0.71	1.35	2.62	3.79	5.07
Battery RES	[GWh]	0.00	0.22	0.44	0.87	1.42	1.99	2.54
Battery IND	[GWh]	0.00	0.23	0.56	1.03	2.10	3.06	4.15
Battery System	[GWh]	0.00	0.04	0.39	0.39	0.39	4.38	23.24
PHES storage	[GWh]	0.00	0.01	0.01	12.23	40.56	49.03	49.03
TES HT	[GWh]	0.00	0.01	2.72	49.73	70.10	88.76	111.24
TES DH	[GWh]	0.00	11.92	10.18	11.06	26.80	34.21	34.22
A-CAES	[GWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas (CH_4) storage	[GWh]	0.00	0.21	1.72	19.74	1555	2511	3152
Electrolyser	[GW_{el}]	0.00	0.00	0.00	2.03	15.97	22.65	28.24
Electrolyser	[GW_{H2}]	0.00	0.00	0.00	1.42	11.19	15.88	19.80
Steam methane reforming	[GW_{H2}]	0.00	0.02	0.27	0.27	0.27	0.27	0.27
CO_2 DAC	[$MtCO_2$/a]	0.00	0.00	0.43	0.87	7.09	10.16	12.78
Methanation	[GW_{CH4}]	0.00	0.00	0.00	0.00	3.22	4.77	6.22
Fischer-Tropsch	[GW_{liq}]	0.00	0.00	0.16	0.33	0.60	0.74	0.78

Table AII5: Installed capacity 2050 – Overnight Scenarios.

Technology	Unit	BPS-EP	BPS-S	BPS-MNT	BPS-MHT
PV prosumers RES	[GW]	2.33	2.95	3.22	3.23
PV prosumers COM	[GW]	2.33	1.71	1.89	1.89
PV prosumers IND	[GW]	2.33	2.69	2.82	2.82
PV fixed tilted system	[GW]	3.00	0.01	36.89	5.71
PV single-axis system	[GW]	104.25	106.29	76.83	92.84

CSP	[GW]	0.00	0.004	0.00	0.00
Wind onshore	[GW]	0.00	0.00	0.05	0.05
Hydro run-of-river	[GW]	0.75	0.42	0.42	0.42
Hydro reservoir (dam)	[GW]	0.31	0.065	0.26	0.26
Geothermal	[GW]	0.00	0.00	0.00	0.00
CCGT	[GW]	0.00	0.00	0.00	0.00
OCGT	[GW]	0.00	0.00	0.00	0.00
ST others	[GW]	0.00	0.00	0.00	0.00
Biomass PP	[GW]	0.00	0.00	0.00	0.00
Biogas dig	[GW]	0.49	0.86	0.86	0.86
Biogas Upgrade	[GW]	0.48	0.57	0.51	0.52
ICE	[GW]	0.00	0.00	0.00	0.00
Methane CHP	[GW]	0.74	0.00	0.00	0.00
Waste CHP	[GW]	0.80	0.84	0.84	0.84
Biomass CHP	[GW]	0.00	0.00	0.00	0.00
Biogas CHP	[GW]	0.06	1.51	0.34	0.18
El heater DH	[GW]	10.4	24.29	28.83	27.05
Heat pump DH	[GW]	10.50	1.59	2.13	1.89
Methane DH	[GW]	22.04	7.23	6.65	6.60
Oil DH	[GW]	0.00	0.00	0.00	0.00
Coal DH	[GW]	0.00	0.00	0.00	0.00
Biomass DH	[GW]	0.19	0.56	1.12	0.51
El heater IH	[GW]	0.00	1.07	1.04	1.04
Heat pump IH	[GW]	4.45	3.20	3.31	3.29
Methane IH	[GW]	0.00	0.00	0	0.00
Oil IH	[GW]	0.00	0.00	0	0.00
Biomass IH	[GW]	0.19	0.31	0.23	0.24
Biogas IH	[GW]	0.00	0.08	0.08	0.08
Battery RES	[GWh]	6.92	5.04	5.04	5.07
Battery COM	[GWh]	6.92	2.56	2.55	2.54
Battery IND	[GWh]	6.92	4.01	4.15	4.15
Battery System	[GWh]	62.25	116.15	77.39	77.60
PHES storage	[GWh]	0.00	0.00	0.00	0.00
TES HT	[GWh]	0.00	105.20	118.45	111.44

TES DH	[GWh]	45.00	30.10	32.89	34.22
A-CAES	[GWh]	0.00	0.00	0.00	0.00
Gas (CH_4) storage	[GWh]	4960	3731.08	2425.27	2741.92
Electrolyser	[GW_{el}]	52.25	27.18	30.87	28.60
Electrolyser	[GW_{H2}]	37.1	19.05	21.64	20.05
Steam methane reforming	[GW_{H2}]	0.00	0.00	0.00	0.00
CO_2 DAC	[$MtCO_2$/a]	-	13.96	12.64	12.57
Methanation	[GW_{CH4}]	30.1	6.91	6.12	6.10
Fischer-Tropsch / Chemical Synthesis	[GW_{liq}]	0.56	0.78	0.80	0.78

Table AII6: Electricity generation – BPS-ET.

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
PV prosumers RES	[GWh]	50	267	677	1415	2873	4117	5469
PV prosumers COM	[GWh]	43	206	485	1056	1790	2490	3156
PV prosumers IND	[GWh]	0	291	716	1301	2619	3812	5133
PV fixed-tilted system	[GWh]	146	146	146	146	1946	5658	6925
PV single-axis system	[GWh]	0	1154	15384	50498	125720	166656	213030
Wind onshore	[GWh]	56	976	976	976	970	920	0
Hydro run-of-river	[GWh]	2088	5336	5336	5336	5336	5336	5336
Hydro reservoir (dam)	[GWh]	1368	1642	1642	1642	1642	1642	1642
Geothermal	[GWh]	0	3117	3117	3117	1695	1695	1695
CCGT	[GWh]	5399	1396	762	698	0	4	14
OCGT	[GWh]	2671	1300	2780	4203	24	18	6
ST others	[GWh]	9	0	0	5	0	0	0
Biomass PP	[GWh]	532	0	0	0	0	0	0
ICE	[GWh]	383	0	0	0	0	0	0
Methane CHP	[GWh]	0	1	0	0	0	0	0
Waste CHP	[GWh]	0	2305	4609	6984	6984	6984	6984
Biomass CHP	[GWh]	0	0	0	0	0	0	0
Biogas CHP	[GWh]	0	123	435	817	871	879	870

Table AII7: Electricity storage output – BPS-ET.

Technology	**Unit**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**

Battery	[TWh]	0.00	0.27	0.84	1.21	2.24	4.65	13.15
PHES storage	[TWh]	0.00	0.00	0.00	3.32	13.14	15.94	15.86
A-CAES	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TES HT	[TWh]	0.01	0.00	0.00	0.01	0.00	0.00	0.00
Gas (CH_4) storage	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.01

Table AII8: Heat generation – BPS-ET.

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
Methane CHP	[GWh]	0	1	0	0	0	0	0
Waste CHP	[GWh]	0	6264	11119	15567	16392	16912	18009
Biomass CHP	[GWh]	0	0	0	0	0	0	0
Biogas CHP	[GWh]	0	149	512	931	990	1026	1065
CSP	[GWh]	0	9334	9351	9352	9352	9352	1776
Geothermal DH	[GWh]	0	13044	13044	13044	7093	7093	7093
El heater DH	[GWh]	0	0	13932	39555	50048	63101	79151
Heat pump DH	[GWh]	0	2480	3351	4213	2953	4383	12699
Methane DH	[GWh]	23460	42016	38073	28271	29477	38029	48435
Oil DH	[GWh]	3206	1	0	0	11	0	0
Coal DH	[GWh]	0	0	0	0	0	0	0
Biomass DH	[GWh]	17411	558	558	533	529	524	524
El heater IH	[GWh]	43	3	6	23	52	53	58
Heat pump IH	[GWh]	0	7415	9003	11016	13602	16463	20321
Methane IH	[GWh]	2656	177	167	68	0	0	0
Oil IH	[GWh]	0	0	0	1	0	0	0
Biomass IH	[GWh]	3846	372	374	427	444	450	453
Biogas IH	[GWh]	0	557	594	611	628	634	635

Table AII9: Heat storage output – BPS-ET.

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
TES HT	[TWh]	0.00	0.00	1.03	17.33	23.92	30.18	37.84
TES DH	[TWh]	0.00	3.99	4.61	5.15	14.74	16.20	16.65
Gas (CH_4) storage	[TWh]	0.00	0.00	0.00	0.00	14.39	29.57	44.28

Table AII10: Sustainable fuel production (output) – BPS-ET.

Technology	Unit	2020	2025	2030	2035	2040	2045	2050
Electrolyser	[TWh]	0.00	0.00	0.01	4.30	38.18	54.80	69.20
Methanation	[TWh]	0.00	0.00	0.00	0.00	23.42	34.98	45.68
FT	[TWh]	0.00	0.00	1.33	2.71	4.96	6.16	6.51
FT kerosene	[TWh]	0.00	0.00	0.27	0.54	1.34	2.19	2.10
FT diesel	[TWh]	0.00	0.00	0.80	1.63	2.63	2.74	3.11
FT naphtha	[TWh]	0.00	0.00	0.27	0.54	0.99	1.23	1.30
LNG	[TWh]	0.00	0.00	0.00	0.00	0.00	0.00	0.01
LH2	[TWh]	0.00	0.00	0.00	0.05	0.22	0.56	1.12

Table AII11: Electricity generation – Overnight Scenarios.

Technology	Unit	BPS-EP	BPS-S	BPS-MNT	BPS-MHT
PV prosumers RES	[GWh]	4296	5520	5456	5469
PV prosumers COM	[GWh]	4296	3200	3156	3156
PV prosumers IND	[GWh]	4296	5022	5133	5133
PV fixed-tilted system	[GWh]	5523	10	54859	8886
PV single-axis system	[GWh]	237500	232036	168321	213099
Wind onshore	[GWh]	0	0	124	124
Hydro run-of-river	[GWh]	3370	2123	2088	2088
Hydro reservoir (dam)	[GWh]	1640	331	1368	1368
Geothermal	[GWh]	0	0	0	1
CCGT	[GWh]	0	0	0	0
OCGT	[GWh]	0	0	0	0
ST others	[GWh]	0	0	0	0
Biomass PP	[GWh]	0	0	0	0
ICE	[GWh]	0	0	0	0
Methane CHP	[GWh]	3570	0	0	0
Waste CHP	[GWh]	6980	6984	6984	6984
Biomass CHP	[GWh]	0	0	0	0
Biogas CHP	[GWh]	29	702	933	915

Table AII12: Electricity storage output – Overnight scenarios.

Technology	Unit	BPS-EP	BPS-S	BPS-MNT	BPS-MHT
Battery	[TWh]	1.09	49.12	33.74	34.48
PHES storage	[TWh]	7.81	0.00	0.00	0.00
A-CAES	[TWh]	0.00	0.00	0.00	0.00
TES HT	[TWh]	0.00	0.00	0.00	0.00
Gas (CH_4) storage	[TWh]	3.56	0.00	0.00	0.00

Table AII13: Heat generation – Overnight scenarios.

Technology	Unit	BPS-EP	BPS-S	BPS-MNT	BPS-MHT
Methane CHP	[GWh]	2549	0	0	0
Waste CHP	[GWh]	19070	19066	17969	18466
Biomass CHP	[GWh]	0	0	0	0
Biogas CHP	[GWh]	21	879	1148	1123
CSP	[GWh]	0	9	0	0
Geothermal DH	[GWh]	0	0	0	0
El heater DH	[GWh]	17880	78845	78932	78681
Heat pump DH	[GWh]	51520	9642	14657	13558
Methane DH	[GWh]	87177	54039	48528	48295
Oil DH	[GWh]	0	0	0	0
Coal DH	[GWh]	0	0	0	0
Biomass DH	[GWh]	703	464	524	524
El heater IH	[GWh]	0	61	58	58
Heat pump IH	[GWh]	22900	19488	20341	20321
Methane IH	[GWh]	0	0	0	0
Oil IH	[GWh]	0	0	0	0
Biomass IH	[GWh]	1000	540	470	453
Biogas IH	[GWh]	0	681	635	635

Table AII14: Heat storage output – Overnight scenarios.

Technology	Unit	BPS-EP	BPS-S	BPS-MNT	BPS-MHT
TES HT	[TWh]	0	32.62	37.36	36.93
TES DH	[TWh]	13.25	10.77	16.78	16.00

Gas (CH_4) storage	[TWh]	56.86	49.44	44.39	44.11

Table AII15: Sustainable fuel production (output) – Overnight scenarios.

Technology	Unit	BPS-EP	BPS-S	BPS-MNT	BPS-MHT
Electrolyser	[TWh]	122.28	75.62	69.48	68.96
Methanation	[TWh]	97.07	50.97	45.76	45.48
FT / Chemical Synthesis	[TWh]	4.20	6.48	6.63	6.51
FT kerosene	[TWh]	2.10	2.10	2.19	2.10
FT diesel	[TWh]	2.10	3.09	3.11	3.11
FT naphtha	[TWh]	0	1.30	1.33	1.30
LNG	[TWh]	0.01	0.01	0.01	0.01
LH2	[TWh]	1.12	1.12	1.12	1.12

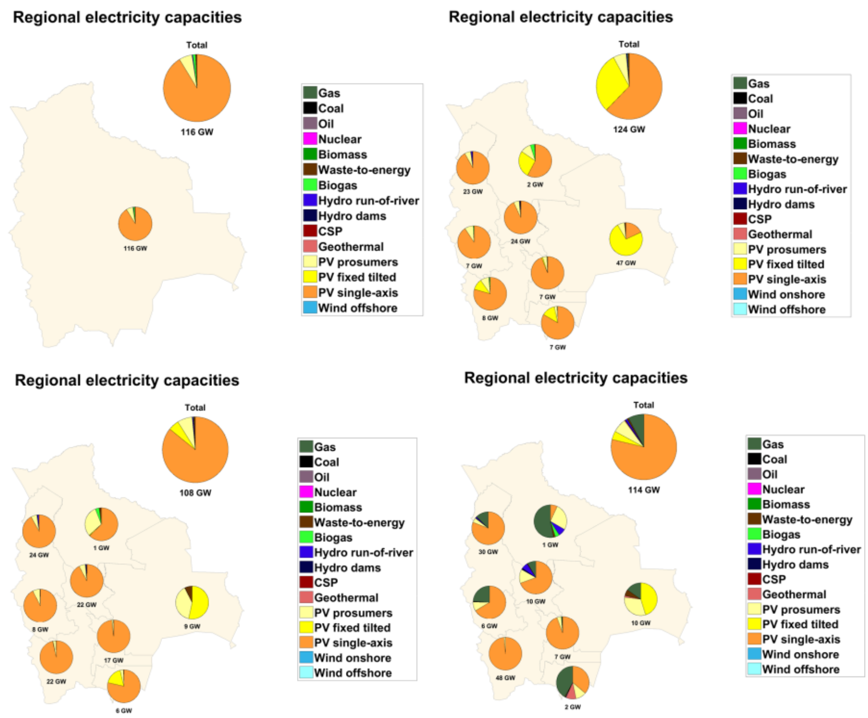

Figure AII1. Regional electricity capacities in 2050 for BPS-S (top left), BPS-MNT (top right), BPS-MHT (bottom left), and BPS-ET (bottom right).

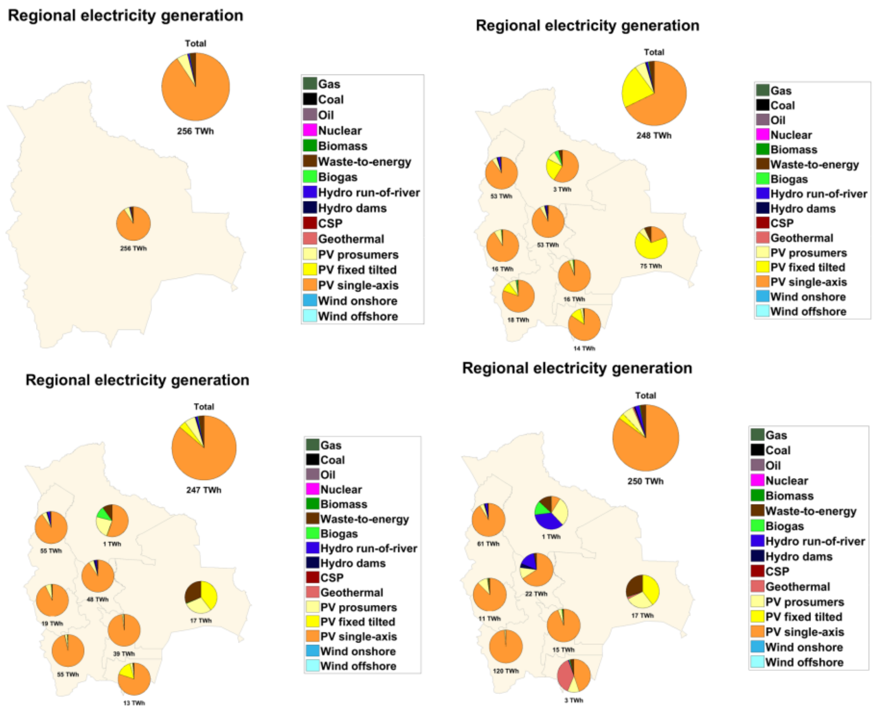

Figure AII2. Regional electricity generation in 2050 for BPS-S (top left), BPS-MNT (top right), BPS-MHT (bottom left), and BPS-ET (bottom right).

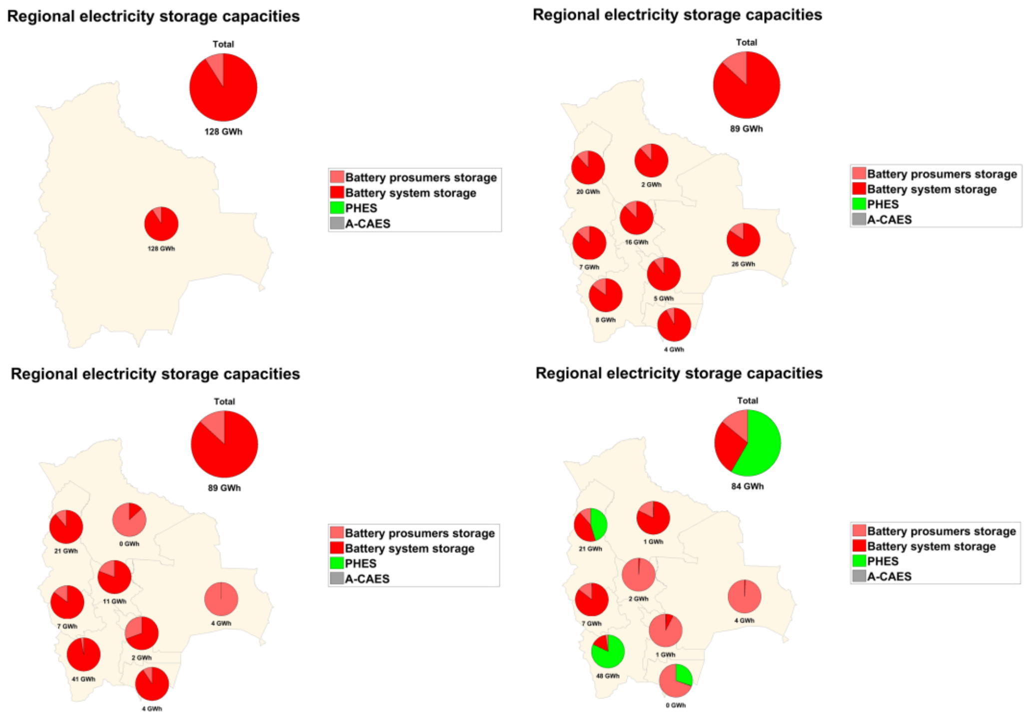

Figure AII3. Regional electricity storage capacities in 2050 for BPS-S (top left), BPS-MNT (top right), BPS-MHT (bottom left), and BPS-ET (bottom right).

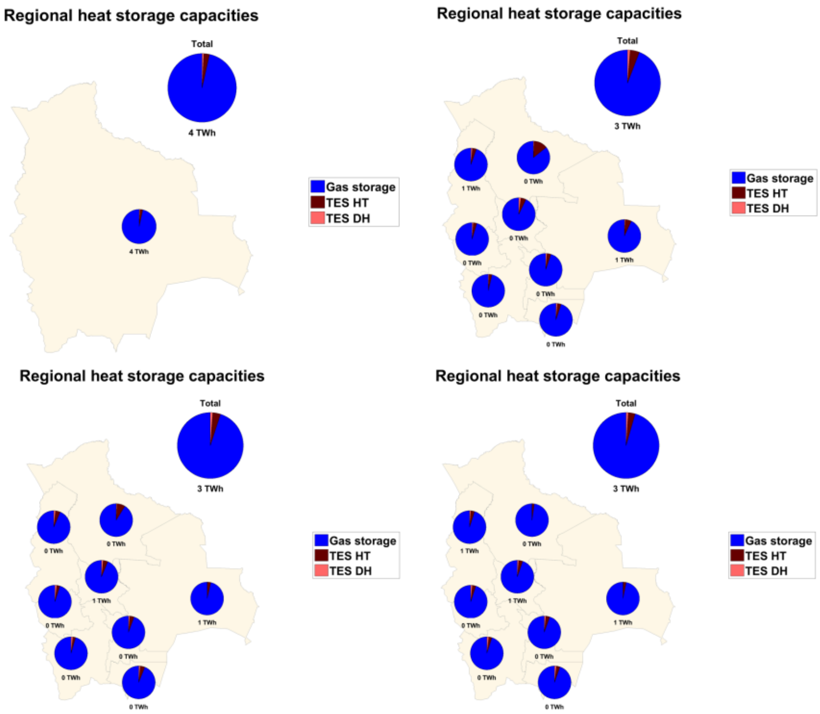

Figure AII4. Regional heat storage capacities in 2050 for BPS-S (top left), BPS-MNT (top right), BPS-MHT (bottom left), and BPS-ET (bottom right).

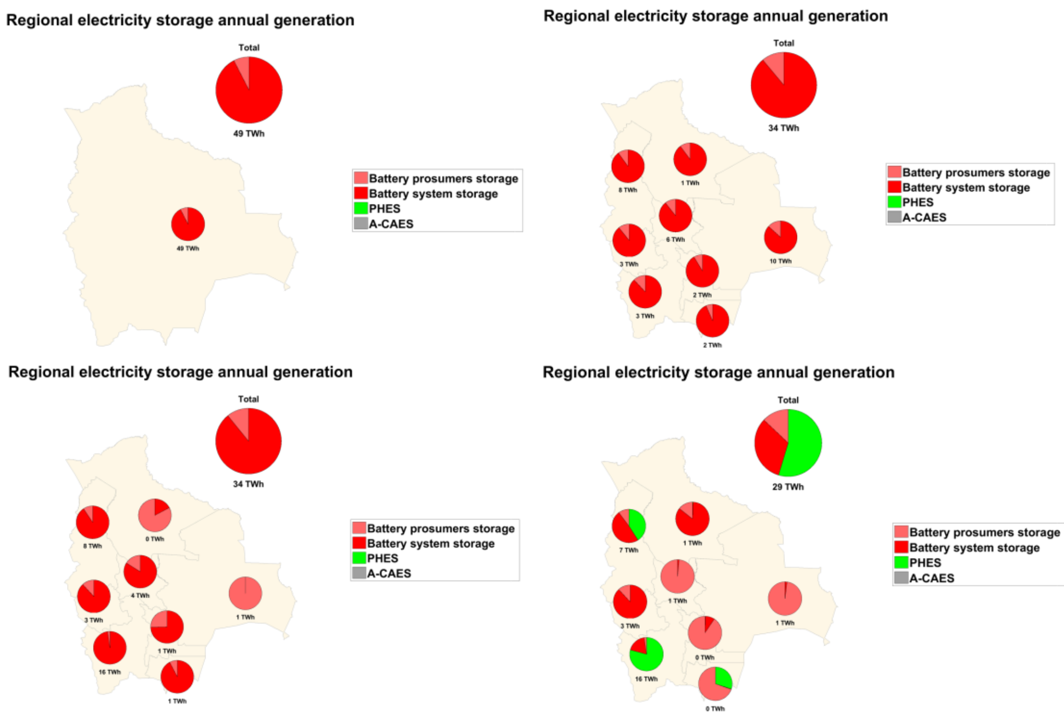

Figure AII5. Regional electricity storage annual generation in 2050 for BPS-S (top left), BPS-MNT (top right), BPS-MHT (bottom left), and BPS-ET (bottom right).

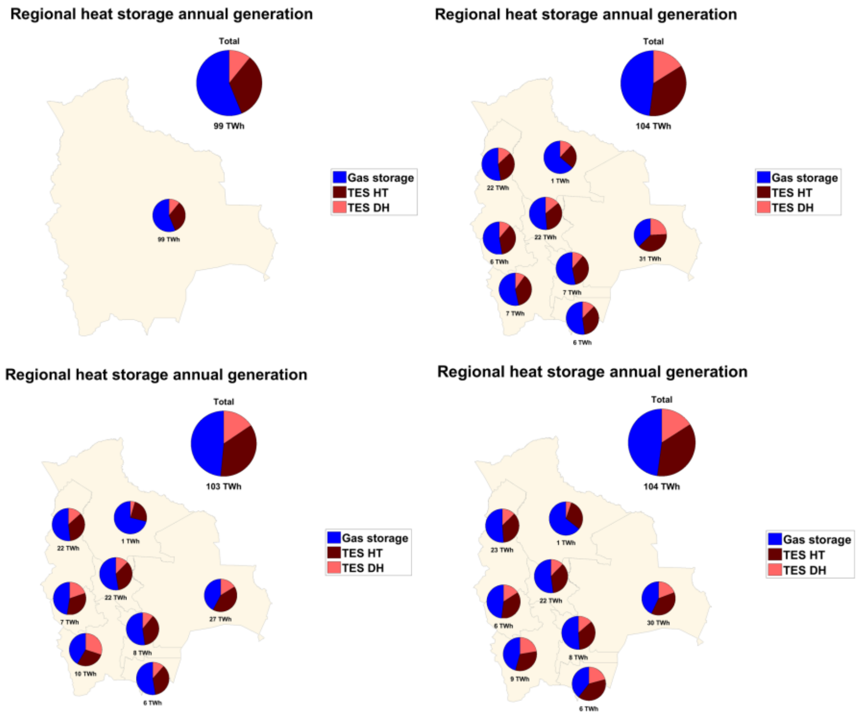

Figure AII6. Regional heat storage annual generation in 2050 for BPS-S (top left), BPS-MNT (top right), BPS-MHT (bottom left), and BPS-ET (bottom right).

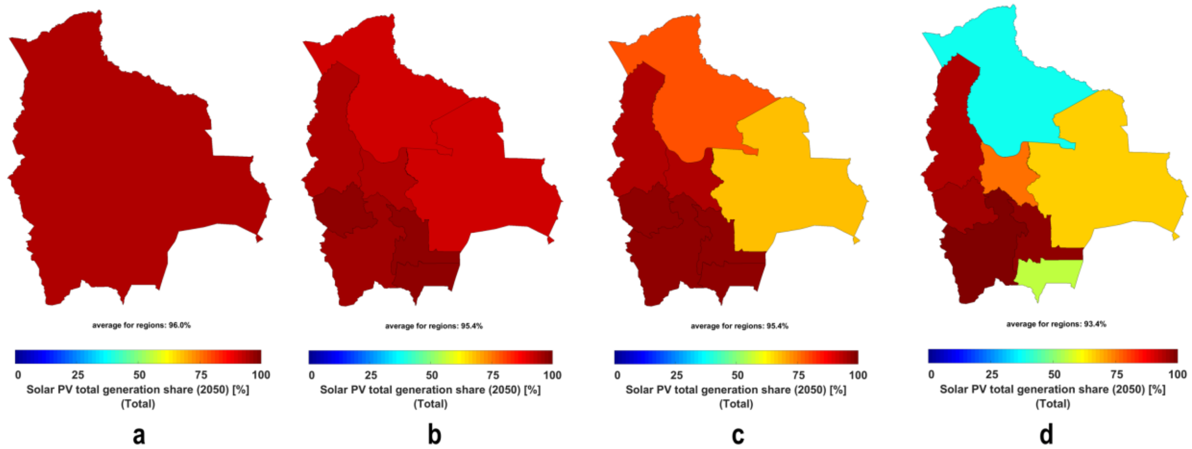

Figure AII7. Regional solar PV generation shares in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

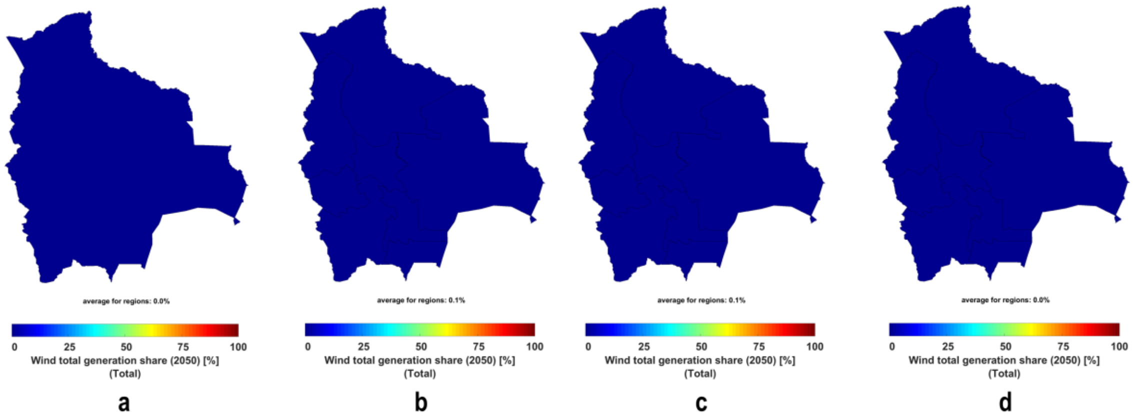

Figure AII8. Regional wind total generation share in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

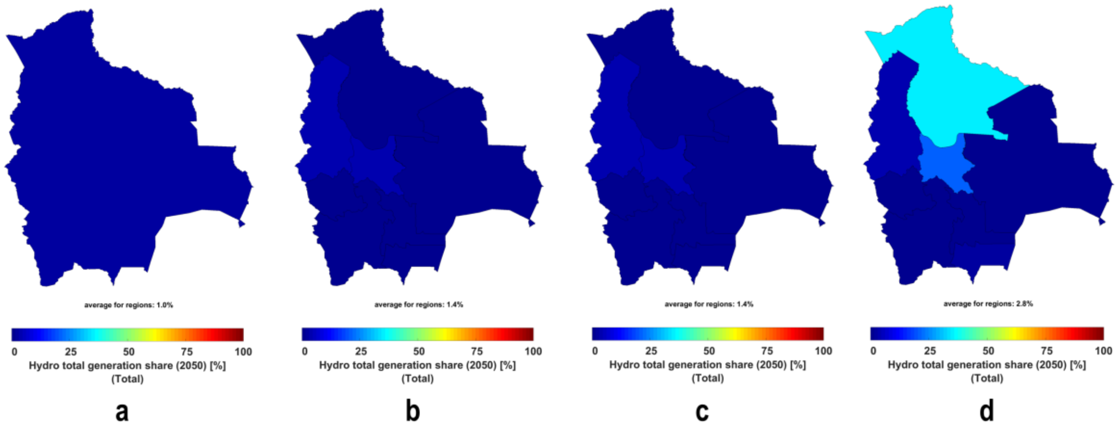

Figure AII9. Regional hydropower total generation share in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

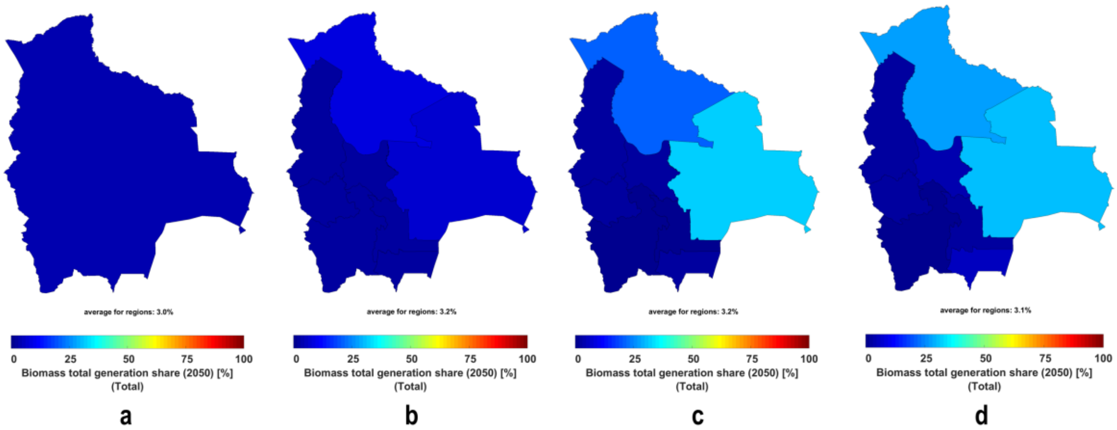

Figure AII10. Regional biomass total generation share in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

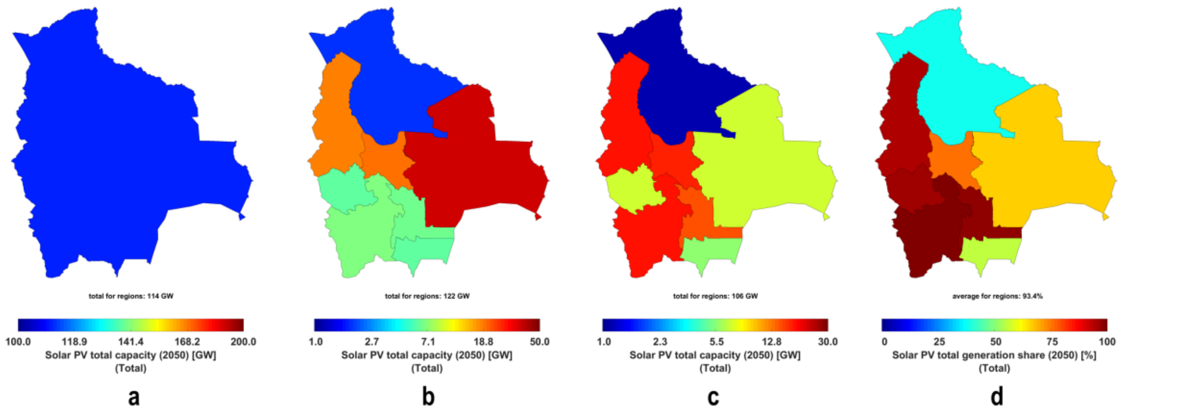

Figure AII11. Regional solar PV capacities in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

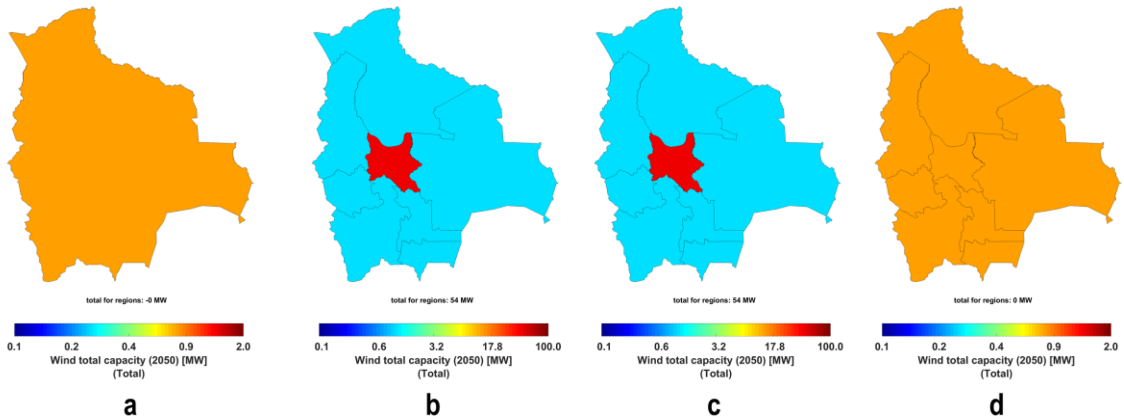

Figure AII12. Regional wind capacities in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

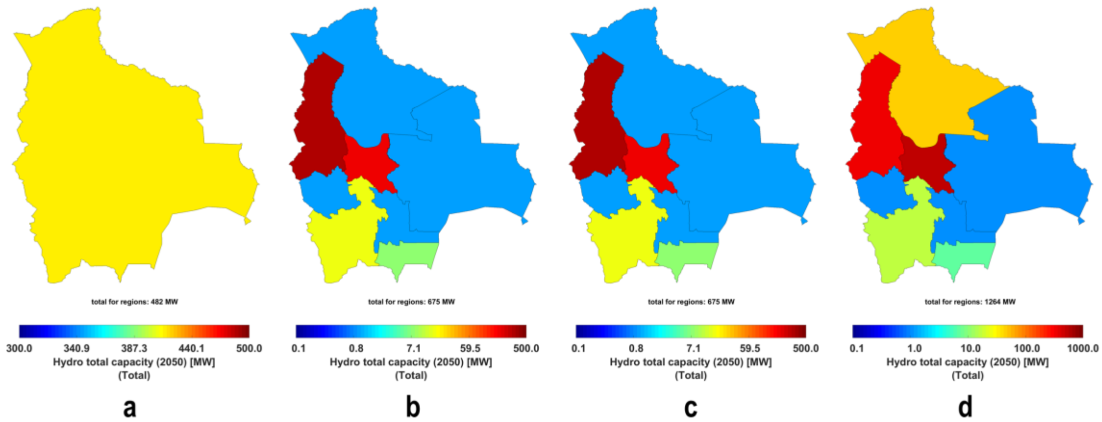

Figure AII13. Regional hydropower capacities in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

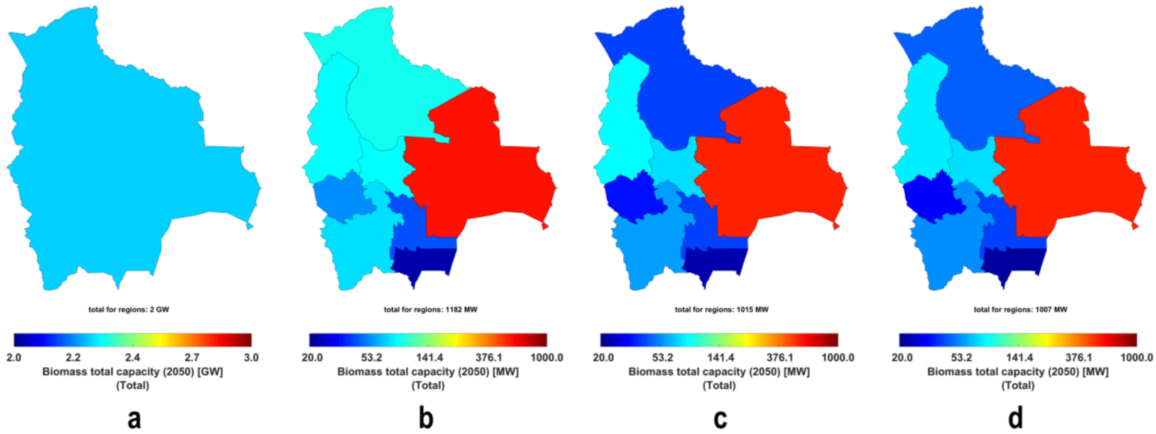

Figure AII14. Regional biomass capacities in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

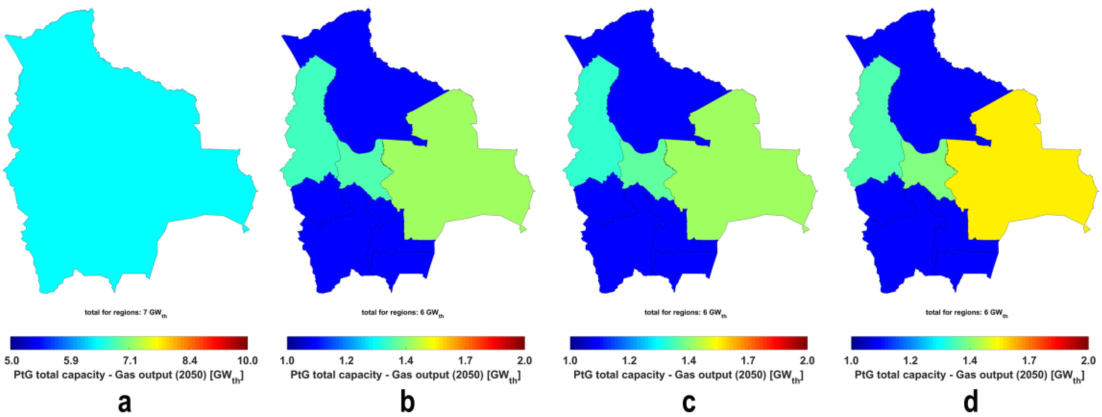

Figure AII15. Regional PtG capacities in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

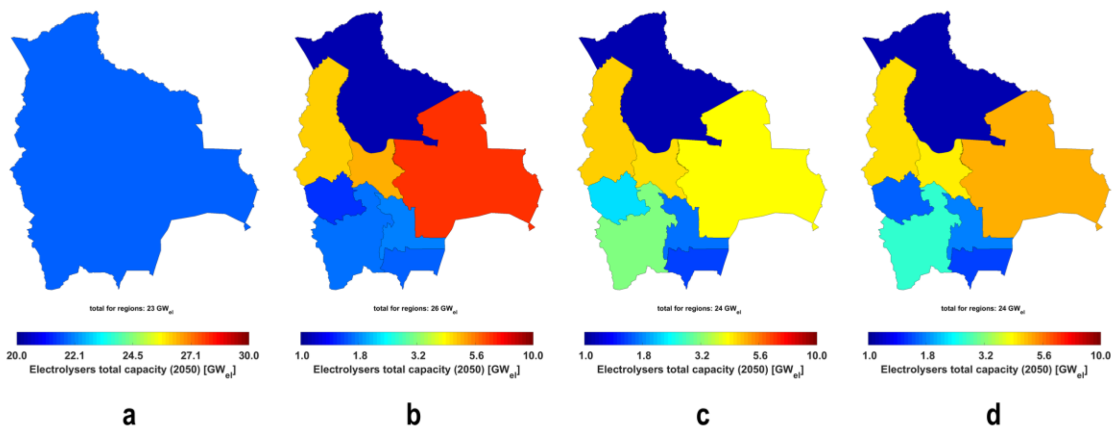

Figure AII16. Regional electrolyser capacities in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

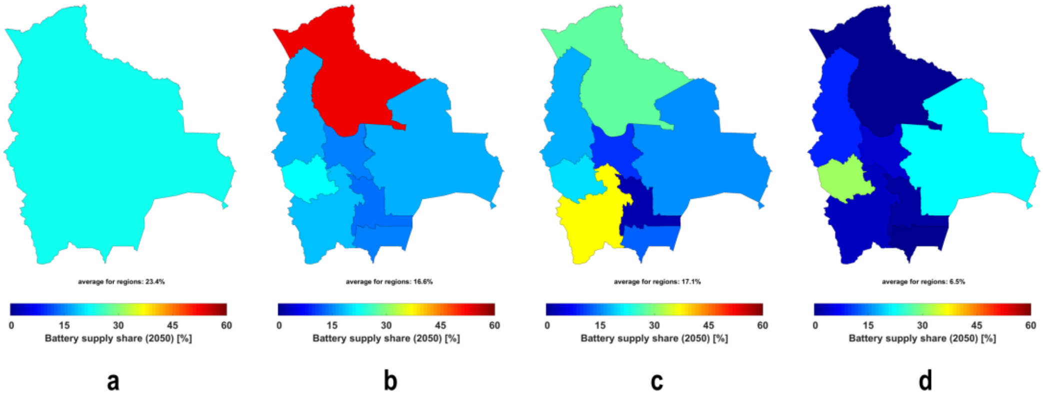

Figure AII17. Regional battery supply shares in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

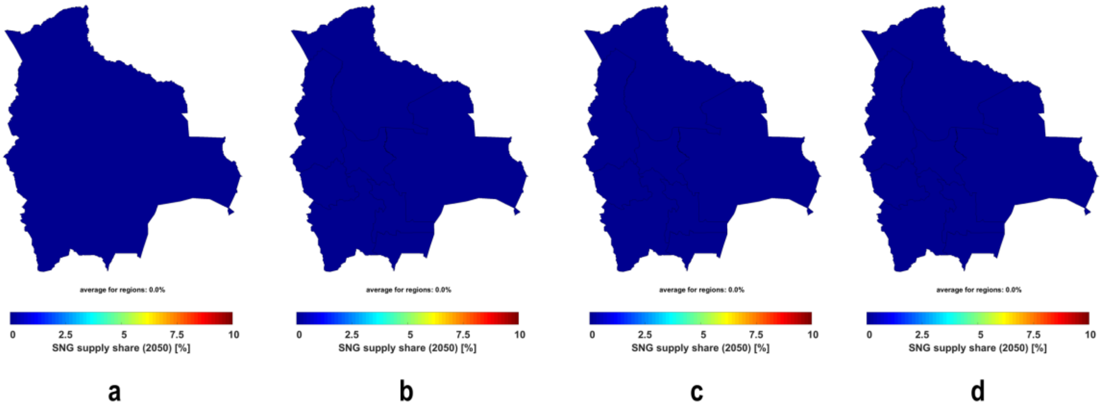

Figure AII18. Regional SNG supply shares in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

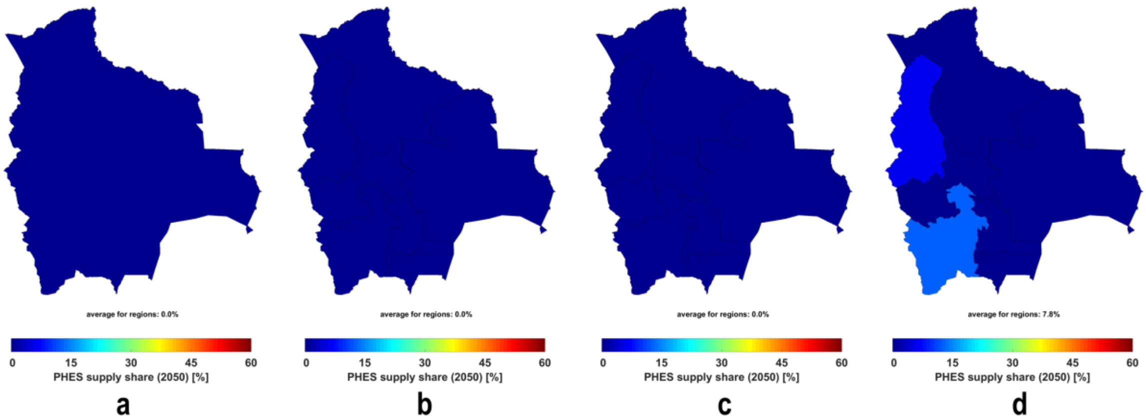

Figure AII19. Regional PHES supply shares in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

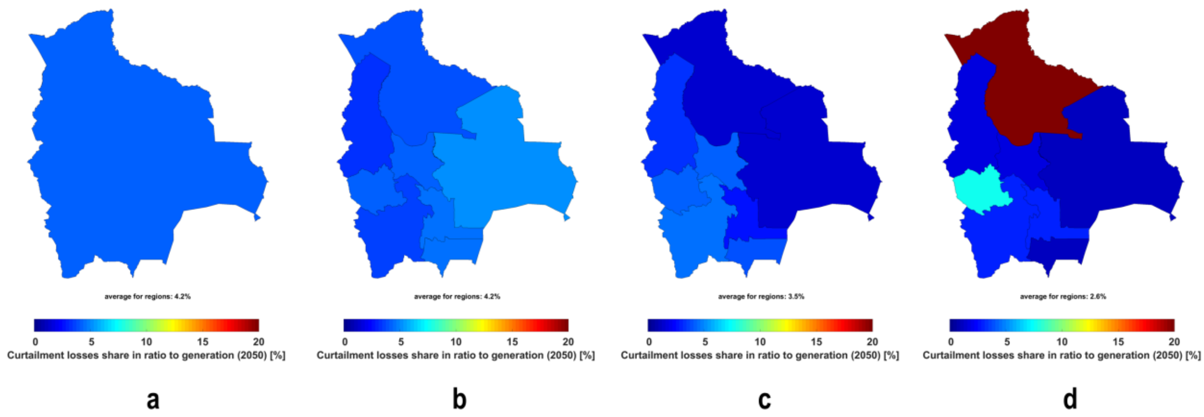

Figure AII20. Regional curtailment losses in ratio to generation in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

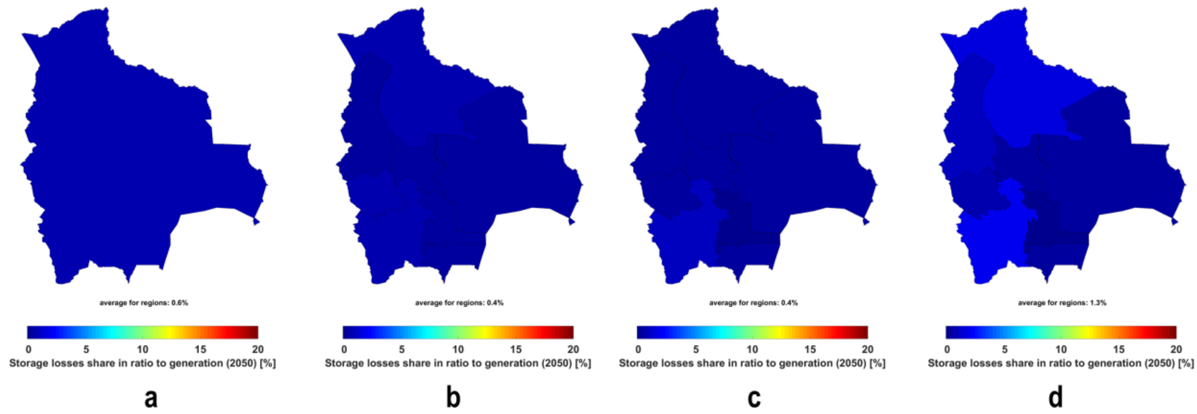

Figure AII21. Regional storage losses in ratio to generation in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

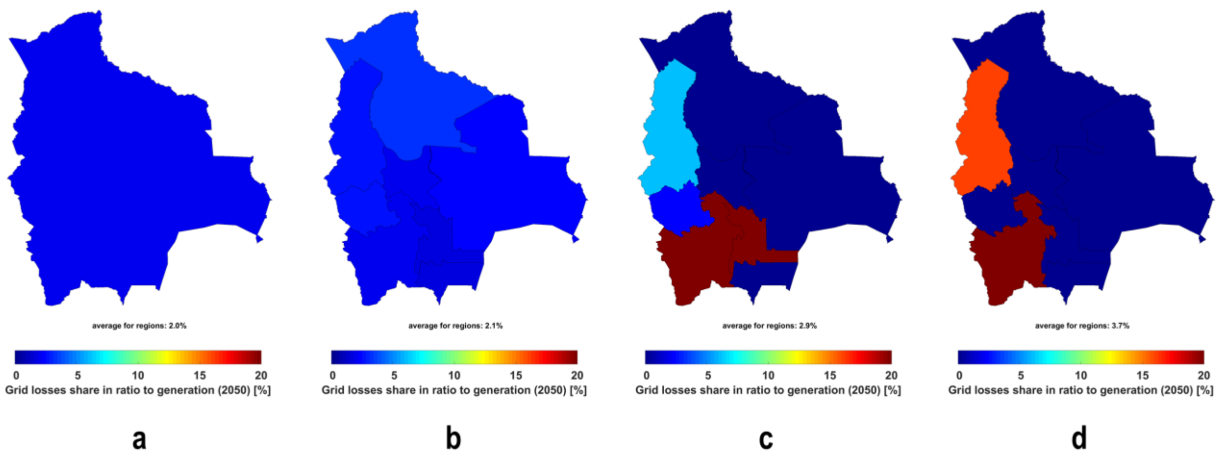

Figure AII22. Regional grid losses in ratio to generation in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

Table AII16: Electricity costs for BPS-ET.

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOE – Generation	[€/MWh_{el}]	32.19	57.76	43.94	30.79	18.22	15.06	13.79

GHG emissions cost	[€/MWh]	9.49	3.78	2.99	2.12	0.00	0.00	0.00
Fuel costs	[€/MWh]	34.08	8.87	6.41	4.47	-0.17	-0.15	-0.15
LCOC – Curtailment	[€/MWh]	0.75	0.00	0.00	0.15	0.44	0.49	0.47
LCOS – Storage	[€/MWh]	0.00	1.30	1.40	2.11	4.29	4.72	4.94
LCOT – Transmission	[€/MWh]	28.23	16.22	8.62	4.72	3.43	2.71	2.29
Total LCOE	[€/MWh]	104.73	87.94	63.36	44.35	26.20	22.83	21.34

Table AII17: Heat costs for BPS-ET.

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOH – Generation	[€/MWh_{th}]	26.37	37.42	47.68	52.67	33.25	23.42	21.17
LCOH – Storage	[€/MWh_{th}]	0.00	0.63	0.83	1.90	8.43	9.43	9.29
Total LCOH	[€/MWh_{th}]	26.37	38.05	48.51	54.57	40.22	31.49	29.54

Table AII18: Sustainable fuel and water costs for BPS-ET.

	Unit	2020	2025	2030	2035	2040	2045	2050
LCOE – Generation	[€/MWh]	32.19	57.76	43.94	30.79	18.22	15.06	13.79
Hydrogen	[€/MWh]	0.00	58.80	66.34	131.53	107.58	79.64	72.95
LH2	[€/MWh]	0.00	0.00	72.61	136.31	119.28	94.09	87.86
SNG	[€/MWh]	0.00	0.00	0.00	0.00	104.52	84.07	79.60
LNG	[€/MWh]	31.66	34.96	36.72	32.42	66.05	61.20	56.34
Fischer-Tropsch	[€/MWh]	0.00	0.00	128.42	228.53	187.64	129.40	114.29
LCOW	[€/m^3]	1.62	1.38	1.37	1.40	1.61	1.57	1.57

Table AII19: Electricity costs for BPS-S, BPS-MNT and BPS-MHT.

	Unit	BPS-S	BPS-MNT	BPS-MHT
LCOE – Generation	[€/MWh_{el}]	10.79	11.35	10.62
GHG emissions cost	[€/MWh]	0.00	0.00	0.00
Fuel costs	[€/MWh]	-0.16	-0.15	-0.15
LCOC – Curtailment	[€/MWh]	0.47	0.52	0.34
LCOS – Storage	[€/MWh]	4.68	3.46	3.36
LCOT – Transmission	[€/MWh]	0.00	0.00	0.83
Total LCOE	[€/MWh]	15.77	15.17	14.99

Table AII20: Heat costs for BPS-S, BPS-MNT and BPS-MHT.

	Unit	BPS-S	BPS-MNT	BPS-MHT
LCOH – Generation	[€/MWh_{th}]	11.11	12.65	15.30
LCOH – Storage	[€/MWh_{th}]	10.08	9.13	8.62
Total LCOH	[€/MWh_{th}]	20.83	21.29	23.29

Table AII21: Sustainable fuel and water costs for BPS-S, BPS-MNT and BPS-MHT.

	Unit	BPS-S	BPS-MNT	BPS-MHT
LCOE – Generation	[€/MWh]	10.79	11.35	10.62
Hydrogen	[€/MWh]	34.33	38.24	48.11
LH2	[€/MWh]	37.27	43.37	56.29
SNG	[€/MWh]	47.88	49.36	56.78
LNG	[€/MWh]	53.51	37.99	44.37
Fischer-Tropsch	[€/MWh]	71.12	77.50	70.57
LCOW	[€/m^3]	1.63	1.62	1.64

Table AII22: Annualised costs for BPS-EP by technology.

	Unit	Total investment costs	Annualised investment cost	Fixed O&M
Solar thermal	[m€]	768.00	62	1.00
Small CHP units	[m€]	0.00	0	0.00
Heat Pump gr. 2	[m€]	5572.00	478	21.00
Heat Storage CHP	[m€]	135.00	13	1.00
Large CHP units	[m€]	656.00	53	56.00
Heat Pump gr. 3	[m€]	0.00	0	0.00
Heat Storage Solar	[m€]	0.00	0	0.00
Boilers gr. 2 and 3	[m€]	1390.00	107	51.00
Large Power Plants	[m€]	0.00	0	0.00
Wind	[m€]	0.00	0	0.00
Wind offshore	[m€]	0.00	0	0.00
Photo Voltaic	[m€]	22951.00	1722	560.00
Wave power	[m€]	0.00	0	0.00
River of hydro	[m€]	1805.00	131	54.00
Hydro Power	[m€]	505.00	37	15.00
Hydro Storage	[m€]	0.00	0	0.00
Hydro Pump	[m€]	0.00	0	0.00
Nuclear	[m€]	0.00	0	0.00
Geothermal Electr.	[m€]	0.00	0	0.00
Electrolyser	[m€]	10659.00	859	373.00
Hydrogen Storage	[m€]	2.00	0	0.00
Pump	[m€]	0.00	0	0.00
Turbine	[m€]	320.00	30	9.00
Pump Storage	[m€]	5852.00	552	157.00
Indv. boilers	[m€]	0.00	0	0.00
Indv. CHP	[m€]	0.00	0	0.00
Indv. Heat Pump	[m€]	0.00	0	0.00
Indv. Electric heat	[m€]	0.00	0	0.00
Indv. Solar thermal	[m€]	0.00	0	0.00

BioGas Upgrade	[m€]	95.00	9	8.00
Gasification Upgrade	[m€]	0.00	0	0.00
DHP Boiler group 1	[m€]	932.00	72	34.00
Waste CHP	[m€]	3787.00	357	170.00
Absorp. HP (Waste)	[m€]	0.00	0	0.00
Biogas Plant	[m€]	335.00	29	13.00
Gasification Plant	[m€]	0.00	0	0.00
BioDiesel Plant	[m€]	0.00	0	0.00
BioPetrol Plant	[m€]	0.00	0	0.00
BioJPPlant	[m€]	0.00	0	0.00
Tidal Power	[m€]	0.00	0	0.00
CSP Solar Power	[m€]	0.00	0	0.00
CO2Hydrogenation	[m€]	16703.00	1346	702.00
Synthetic Gas Plant	[m€]	0.00	0	0.00
Chemical Synthesis	[m€]	377.00	30	11.00
Desalination Plant	[m€]	5.00	0	0.00
Water storage	[m€]	15.00	1	3.00
Gas Storage	[m€]	249.00	18	5.00
Oil Storage	[m€]	0.00	0	0.00
Methanol Storage	[m€]	0.00	0	0.00
Interconnection	[m€]	0.00	0	0.00
Geothermal Heat	[m€]	0.00	0	0.00
Indust. Excess Heat	[m€]	0.00	0	0.00
Indust. CHP Electr.	[m€]	0.00	0	0.00
Indust. CHP Heat	[m€]	0.00	0	0.00
Electr Boiler Gr 2+3	[m€]	780.00	60	15.00
Individual Gas	[m€]	0.00	0.00	0.00
Individual biomass	[m€]	146.00	14	1.00
Individual direct electricity	[m€]	0.00	0	0.00
Individual heat pumps	[m€]	3017.00	285	30.00
Fuel cost[1]	[m€]	-	24.00	-
Marginal operation cost[1]	[m€]	-	240	-

[1] Cost considered only in annualised cost structure

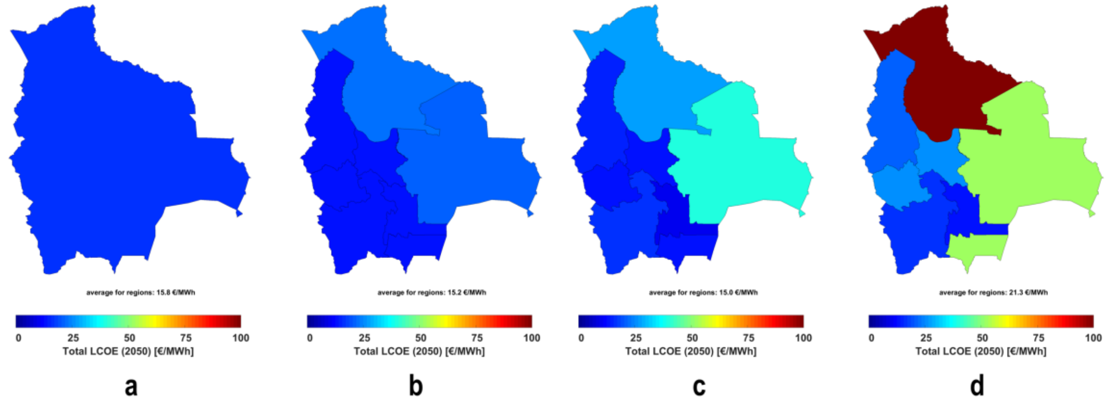

Figure AII23. Regional LCOE in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

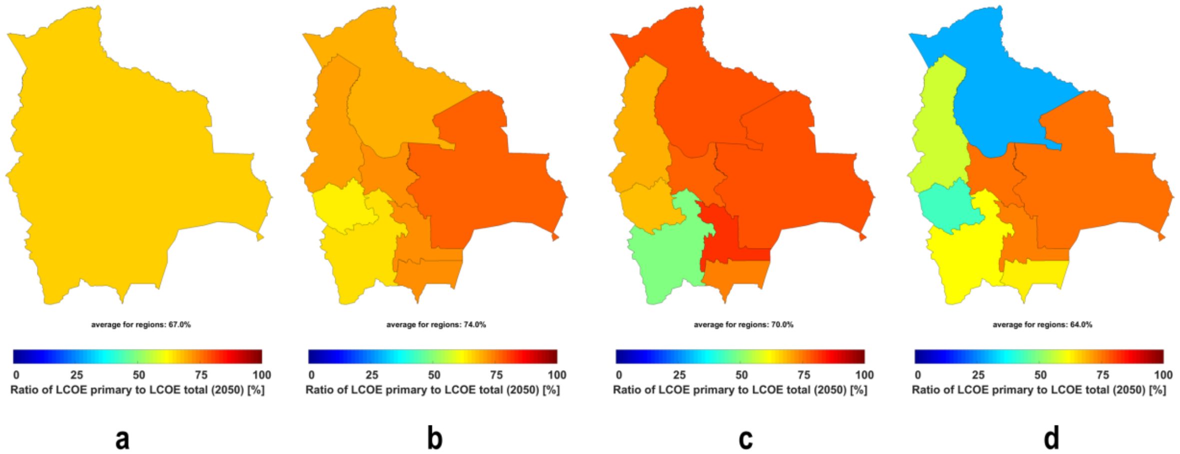

Figure AII24. Regional ratio of LCOE primary to total LCOE in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

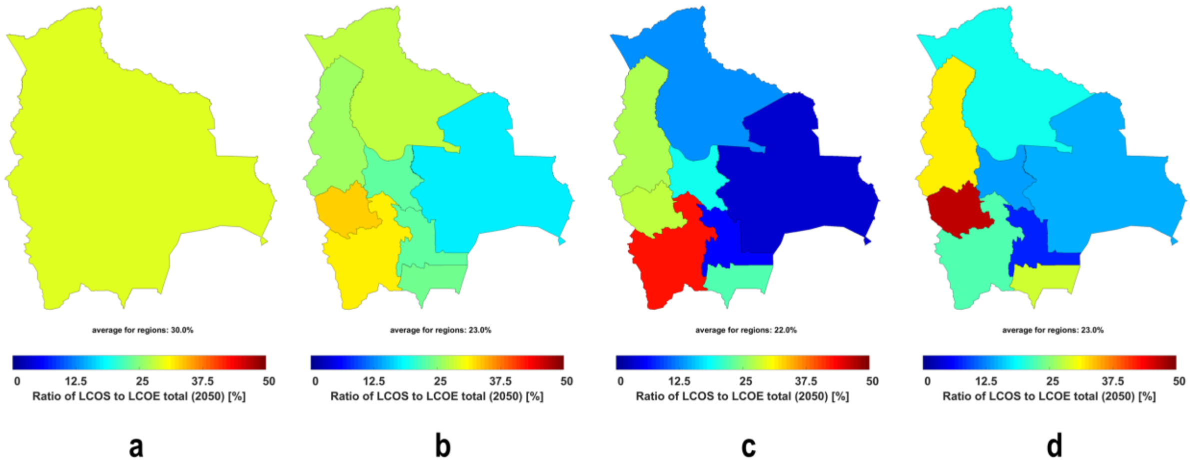

Figure AII25. Regional ratio of LCOS to total LCOE in 2050 for BPS-S (a), BPS-MNT (b), BPS-MHT (c), and BPS-ET (d).

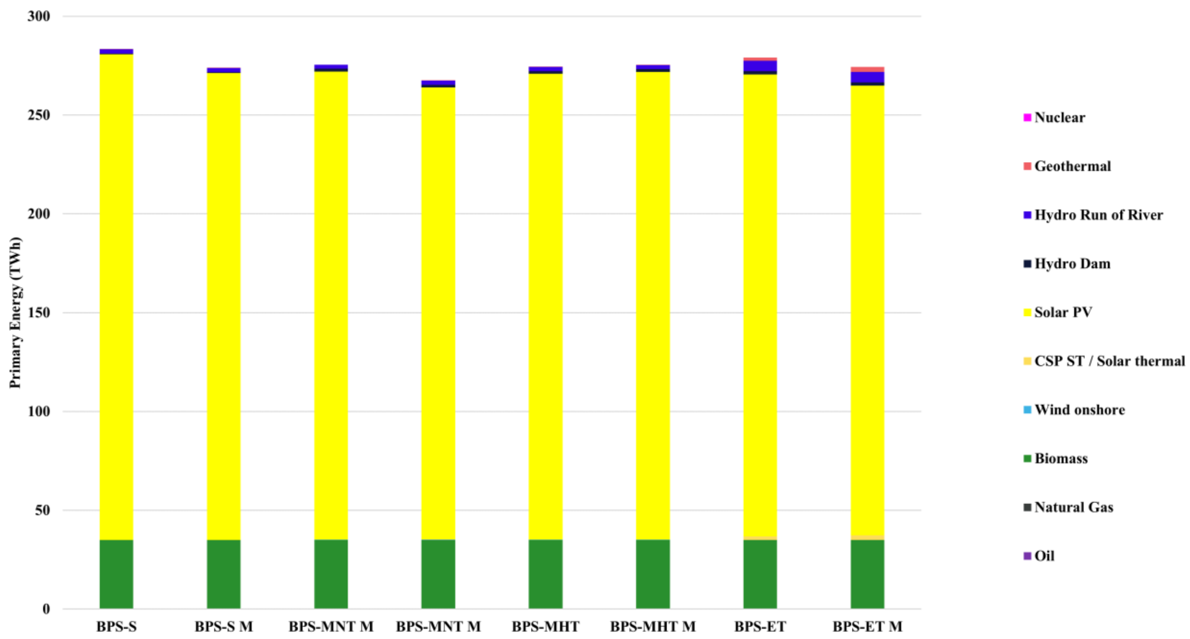

Figure AII26. Primary energy across LUT scenarios for LHV and mixed HHV/LHV results.

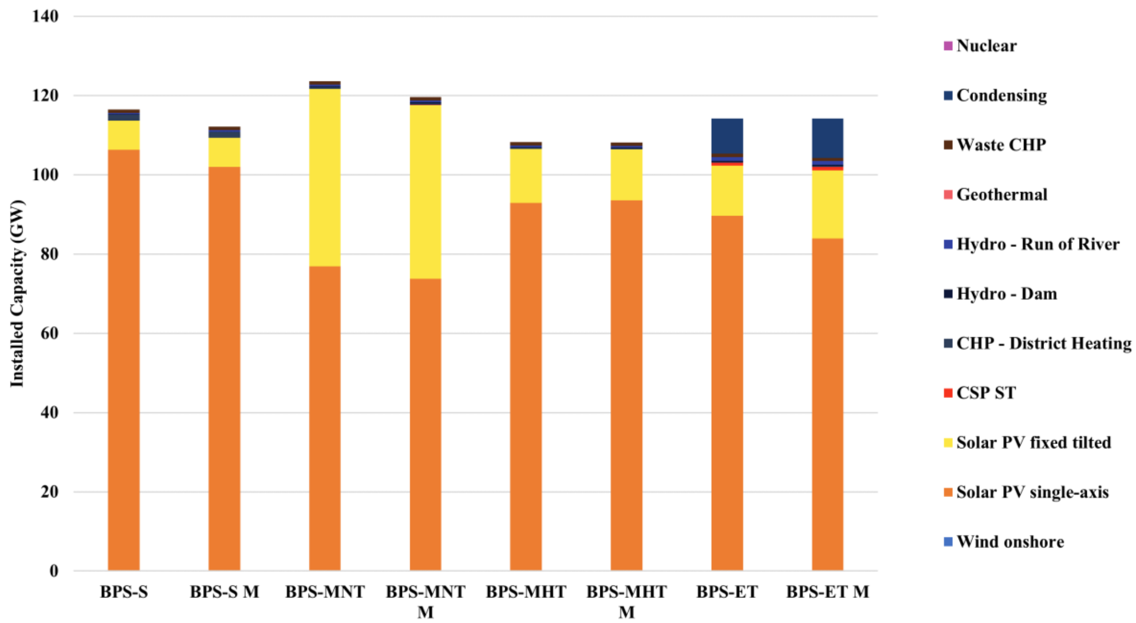

Figure AII27. Installed electric capacity for LUT scenarios for LHV and mixed HHV/LHV results.

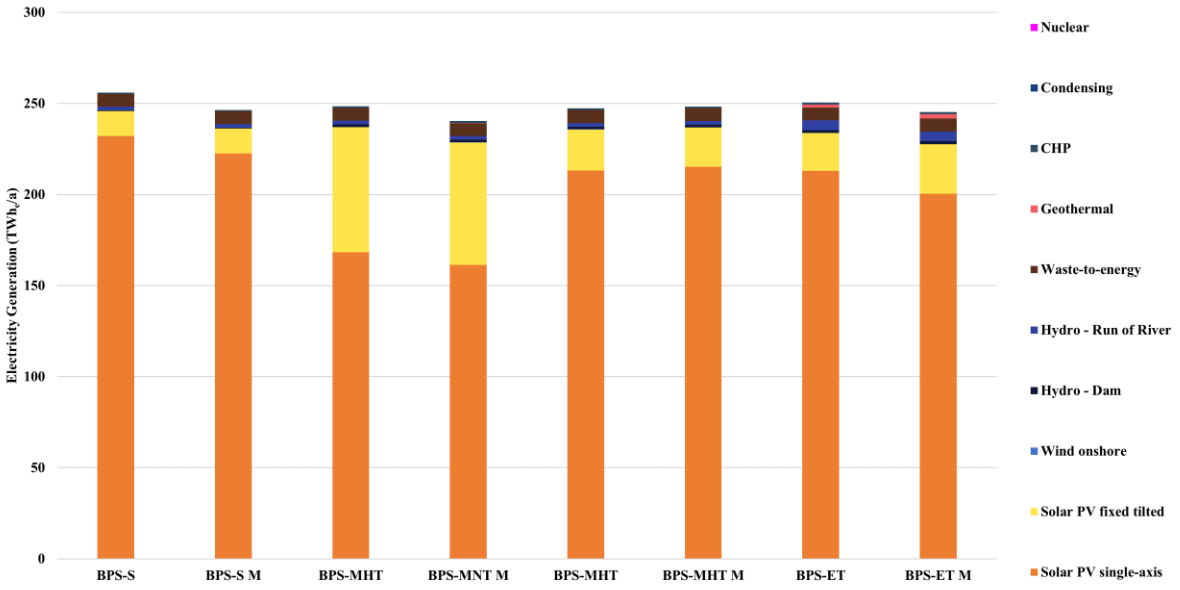

Figure AII28. Electricity generation across LUT scenarios for LHV and mixed HHV/LHV results.

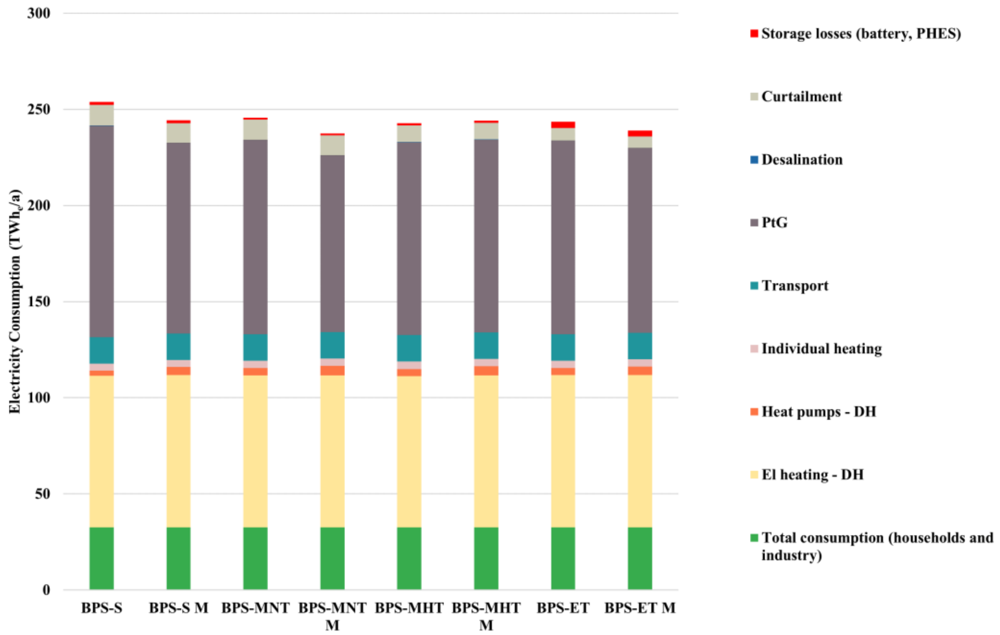

Figure AII29. Electricity consumption for LUT scenarios for LHV and mixed HHV/LHV results.

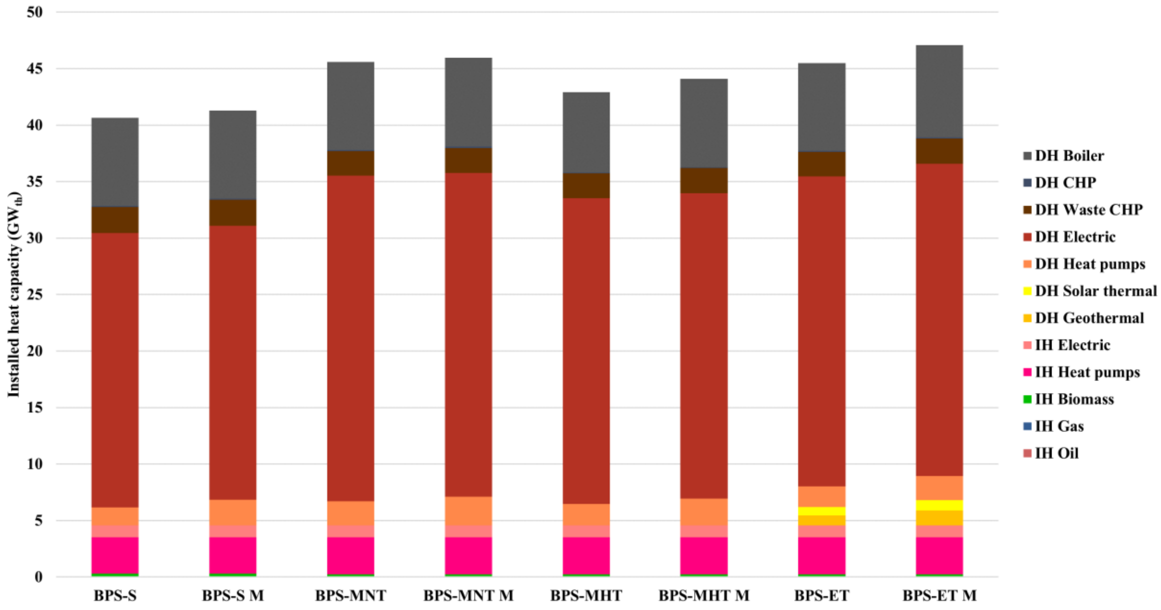

Figure AII30. Installed heat capacity for LUT model scenarios for LHV and mixed HHV/LHV results.

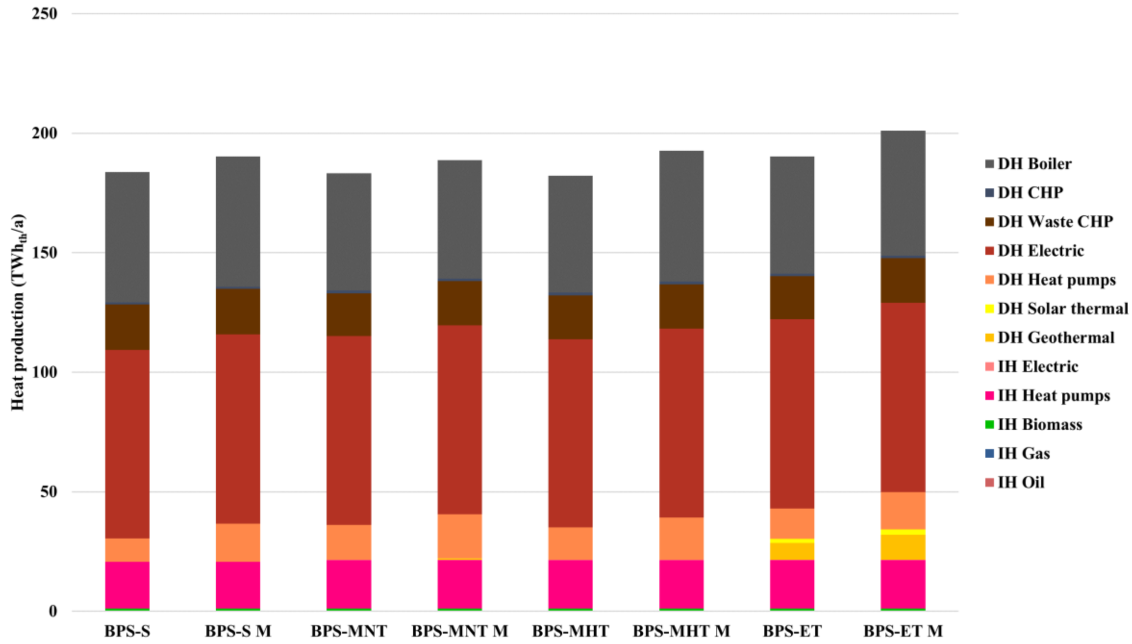

Figure AII31. Heat production across LUT model scenarios for LHV and mixed HHV/LHV results.

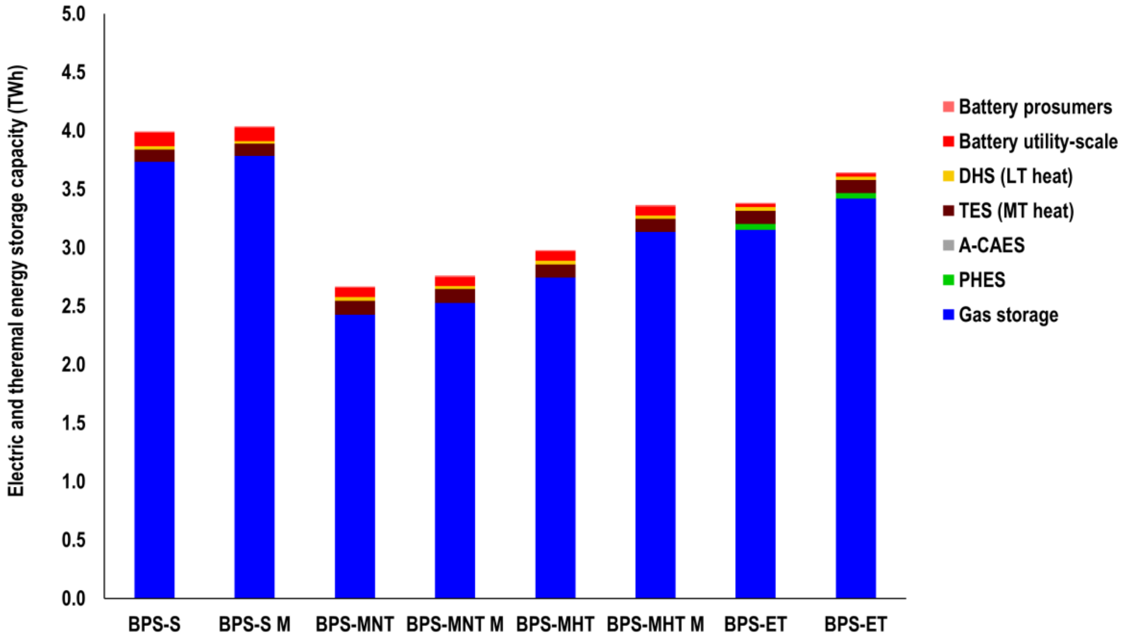

Figure AII32. Electric and thermal energy storage capacities across LUT model scenarios for LHV and mixed HHV/LHV results.

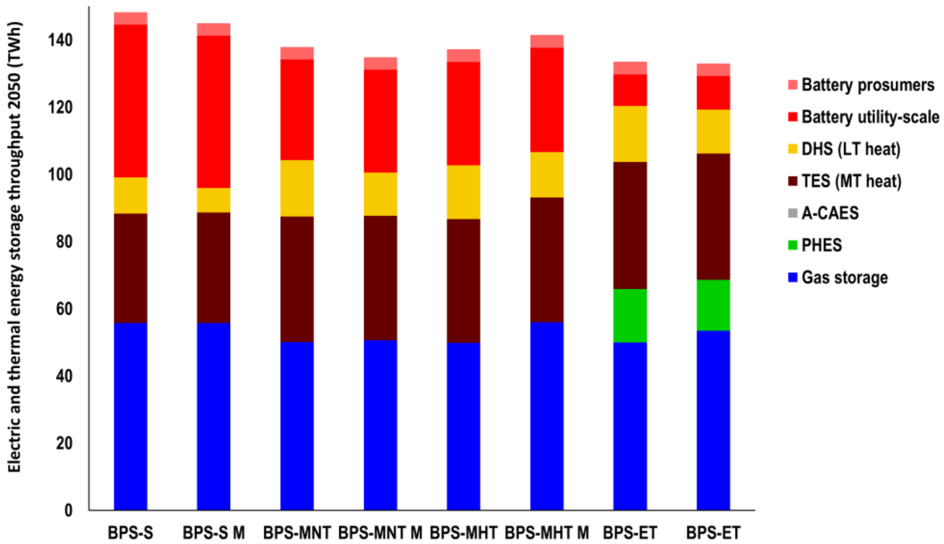

Figure AII33. Electric and thermal energy storage throughput across LUT model scenarios for LHV and mixed HHV/LHV results.

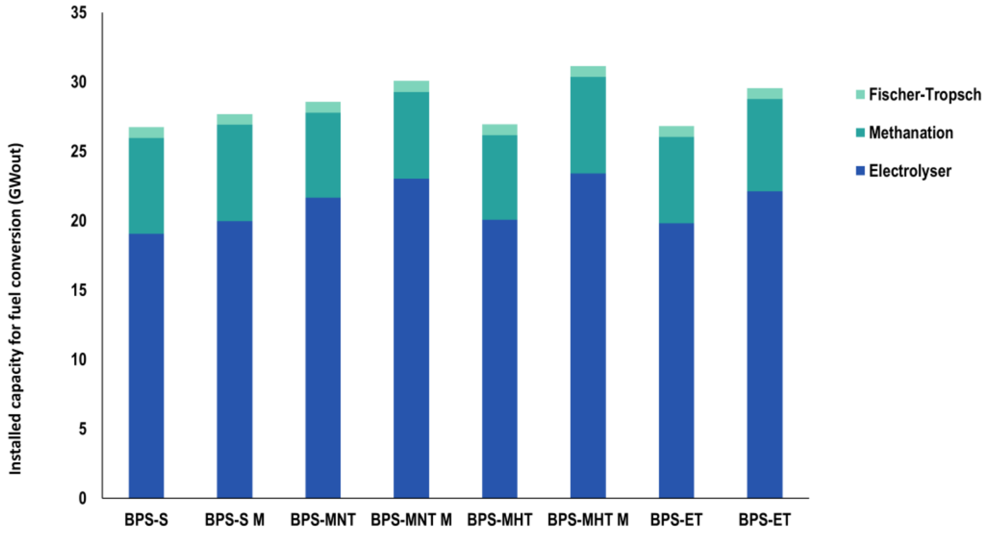

Figure AII34. Installed fuel conversion capacities for all LUT model scenarios for LHV and mixed HHV/LHV results.

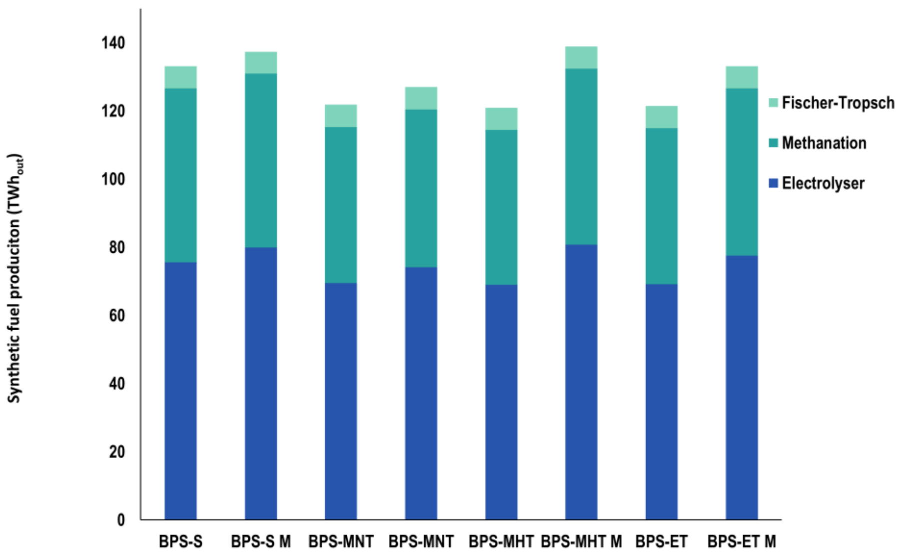

Figure AII35. Synthetic fuel production by technology across LUT model scenarios for LHV and mixed HHV/LHV results.

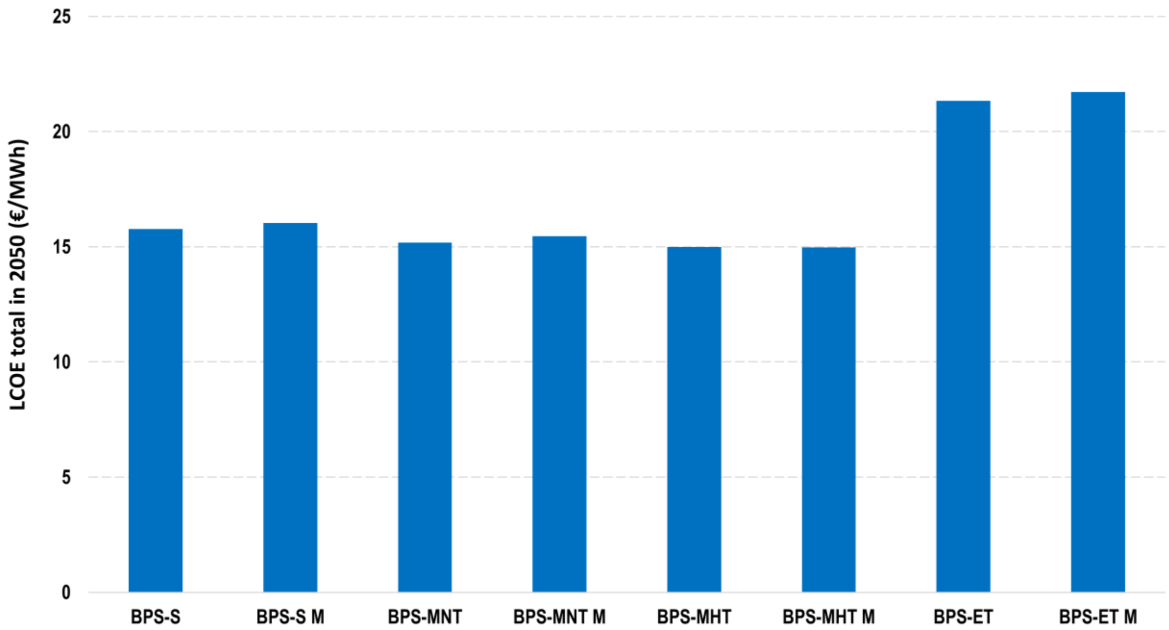

Figure AII36. Total LCOE across LUT model scenarios as well as overnight and historical LCOE for BPS-ET for LHV and mixed HHV/LHV results.

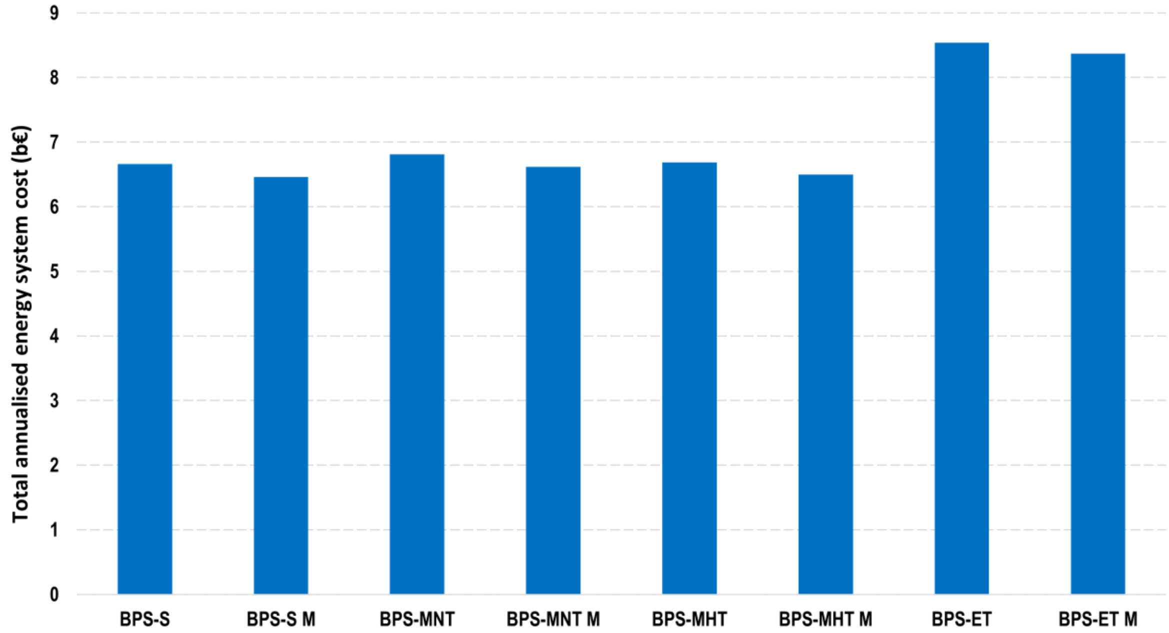

Figure AII37. Total annualised energy system costs for all LUT model scenarios for LHV and mixed HHV/LHV results.

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