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Dmitrii Bogdanov

TRANSITION TOWARDS OPTIMAL RENEWABLE ENERGY SYSTEMS FOR SUSTAINABLE DEVELOPMENT

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Abstract

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The world is in transition from current fossil fuel-based decoupled energy sectors, towards defossilised and integrated energy systems. Debates on such a transition, initially inspired by fossil fuel scarcity concerns, intensified at the end of the 20th century due to growing evidence of anthropogenic climate change. Finally, a consensus has been reached that energy systems have to reach net-zero greenhouse gas emissions by the middle of this century. However, the current growth rates of sustainable energy technologies cannot yet fully cover the energy demand growth and greenhouse gas emissions still increase. Another concern is a lack of agreement on the main tools of the transition: despite the fast maturing of renewable energy generation and energy storage technologies, technologies of questionable long-term sustainability are still discussed as pillars of future energy systems. This study aims to investigate the technical feasibility and economic viability of a fast transition towards fully sustainable renewable energy-based systems by mid-century and to provide knowledge about the possible pathways of such a transition, the role of different technologies, consequences of regional climate conditions and current system structures, and the impact of system sector integration.

Using the right modelling tool to answer these questions has the highest importance. Due to the variable nature of modern renewable energy resources (mainly solar and wind) the temporal, spatial and technological resolution of the model plays the most important role. To fulfil these requirements to the highest extent and make possible the simulation of integrated energy systems, the LUT Energy System Transition model has been developed and expanded for this dissertation. This optimisation model with myopic foresight allows simulation of an energy system's operation, including the entire energy system or individual sectors, in full hourly resolution. The model defines optimal energy transition pathways considering power, heat, transport and industry sectors. The development process of the model is presented alongside the main findings.

The results show that renewable-based energy systems are feasible, 100% renewable energy supply can be reached in all energy sectors and all regions in the world. Every region in the world can satisfy its growing energy demand with local renewable resources, mostly solar and wind. In addition, energy demand and supply can be balanced for each hour using existing renewable electricity generation, energy storage and bridging technologies, while geothermal, hydropower and bioenergy, with limited potentials and partly negative impacts on the environment, play minor roles. The power sector and electricity as an energy carrier will become the backbone of integrated energy systems.

Sector coupling can bring additional complexity to the transition, but at the same time it provides benefits: additional sources of flexibility, decreasing the electricity cost, accelerating the transition and leading to a substantial increase in energy system efficiency. Direct electrification must be pursued wherever possible to avoid the use of costly e-fuels and decrease the overall cost of energy. The cost of electricity supply in renewable energy-based systems will be lower than that of fossil CCS or nuclear alternatives, and lower than levels of today. Thus, according to all criteria listed in the dissertation, renewable-based systems are better or similar to alternatives, making the direct transition towards renewable-based systems a Pareto optimal solution.

Keywords: energy transition, renewable energy, transition modelling, sustainability

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Dmitrii Bogdanov
May 2021
Lappeenranta, Finland.

For the family:
Roots, which define and give strength to raise,
Love, that supports no matter what and sees no obstacles,
Our children, who will be better than us and will live in a better future we build.

Contents

Abstract

Acknowledgements

Contents

Publications

List of publications

This dissertation is based on the following publications. The rights have been granted by the publishers to include the articles in the dissertation.

I. Bogdanov D., Breyer C. (2016). North-East Asian Super Grid for 100% Renewable Energy supply: Optimal mix of energy technologies for electricity, gas and heat supply options. *Energy Conversion and Management*, 112, pp. 176-190, DOI 10.1016/j.enconman.2016.01.019.

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IV. Bogdanov D., Farfan J., Sadovskaia K., Aghahosseini A., Child M., Gulagi A., Oyewo A.S., de Souza Noel Simas Barbosa L., and Breyer C. (2019). Radical transformation pathway towards sustainable electricity via evolutionary steps. *Nature Communications*, 10, 1077, DOI 10.1038/s41467-019-08855-1.

V. Bogdanov D., Toktarova A., Breyer C. (2019). Transition towards 100% renewable power and heat supply for energy intensive economies and severe continental climate conditions: Case for Kazakhstan. *Applied Energy*, 253, 113606, DOI 10.1016/j.apenergy.2019.113606.

VI. Bogdanov D., Gulagi A., Fasihi M., and Breyer C. (2021). Full energy sector transition towards 100% renewable energy supply: Integrating power, heat, transport and industry sectors including desalination. *Applied Energy*, 283, 116273, DOI 10.1016/j.apenergy.2020.116273.

VII. Bogdanov D., Ram M., Aghahosseini A., Gulagi A., Oyewo A.S., Child M., Caldera U., Sadovskaia K., Farfan J., de Souza Noel Simas Barbosa L., Fasihi M., Siavash K., Traber T., and Breyer C. (2021). Low-cost renewable electricity as the key driver of the global energy transition towards sustainability. *Energy*, 227, 120467, DOI 10.1016/j.energy.2021.120467.

Author's contribution

Dmitrii Bogdanov is the first author in **Publications I** and **III – VII**. In **Publications I** and **III-VII** Dmitrii Bogdanov developed methods and models for the studies, performed the investigation, ran the simulations, analysed and interpreted the results, lead or aided in conceptualisation of the research.

In **Publication II** Olga Weiss was the principal author and investigator, developed the agent-based market model and wrote the paper, Dmitrii Bogdanov simulated the initial optimal renewable energy (RE) based system structure, provided the financial and technical cost assumptions for the generation and storage technologies, and contributed to the main model preparation and paper writing.

In **Publication III** Javier Farfan investigated the current generation fleet, Kristina Sadovskaia investigated the grids structures and estimated transmission and distribution losses in the regional grids, Mahdi Fasihi investigated financial and technical parameters of the power-to-X technologies.

In **Publication IV** Javier Farfan investigated the current generation fleet, Kristina Sadovskaia investigated the grid structures and estimated transmission and distribution losses in the regional grids. Arman Aghahosseini, Michael Child, Ashish Gulagi, Ayobami Solomon Oyewo, and Larissa de Souza Noel Simas Barbosa investigated the RE potential and future power demand for regions in North America and Middle East and Northern Africa (MENA), Europe, Southeast Asia and South Asian Association for Regional Cooperation (SAARC) regions, sub-Saharan Africa, and South America, respectively.

In **Publication V** Alla Toktarova aided in the investigation of the trends in the power and heat sectors of Kazakhstan.

In **Publication VI** Ashish Gulagi investigated the material and energy demand in the industry sector, Mahdi Fasihi investigated the technical and financial parameters of the power-to-X technologies.

In **Publication VII** Manish Ram contributed the analysis of results and the writing of the paper. Arman Aghahosseini, Michael Child, Ashish Gulagi, Ayobami Solomon Oyewo, and Larissa de Souza Noel Simas Barbosa investigated the RE potential and future power and heat demand for regions in North America and MENA, Europe, Southeast Asia and SAARC regions, sub-Saharan Africa, and South America, respectively. Upeksha Caldera investigated the demand and the technical and financial parameters for seawater desalination. Javier Farfan investigated the current generation fleet, Kristina Sadovskaia investigated the grid structures and estimated transmission and distribution losses in the regional grids. Mahdi Fasihi investigated the technical and financial parameters of the power-to-X technologies. Siavash Khalili investigated transport sector technical parameters and demand. Thure Traber supported the results analysis.

The author has also participated in the following papers closely related to the subject of this publication or using the LUT model, or variations of the LUT model for seawater desalination or e-fuels and e-chemicals synthesis modelling:

1. Breyer Ch., Bogdanov D., Komoto K., Ehara T., Song J., Enebish N. (2015). North-East Asian super grid: renewable energy mix and economics. *Japanese Journal of Applied Physics*, 54, 08KJ01.

2. Caldera U., Bogdanov D., Breyer Ch. (2016). Local cost of seawater RO desalination based on solar PV and wind energy: A global estimate. *Desalination*, 385, pp. 207-216.

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Nomenclature

Abbreviations

a	Annum/year	
AC	Alternating Current	
A-CAES	Adiabatic Compressed Air Energy Storage	
b	Billion	10^9
BECCS	Bioenergy Carbon Capture and Storage	
BEV	Battery Electric Vehicle	
Capex	Capital Expenditures	
CCGT	Combined Cycle Gas Turbine	
CCS	Carbon Capture and Storage	
CCU	Carbon Capture and Utilisation	
CDR	Carbon Dioxide Removal	
CF	Capacity Factor	
CHP	Combined Heat and Power	
CIS	Commonwealth of Independent States	
COP	Conference of the Parties	
CoP	Coefficient of Performance	
crf	Capital Recovery Factor	
CSP	Concentrating Solar Power	
DAC	CO_2 Direct Air Capture	
DH	District Heat	
E	Exa	10^{18}
EROI	Energy Return on Investment	
FCEV	Fuel Cell Electric Vehicle	
FIT	Feed-In Tarif	
FLh	Full Load hours	
FT	Fischer-Tropsch	
G	Giga	10^9
G20	The Group of Twenty, major advanced and emerging economies	
GHG	Greenhouse Gases	
GT	Gas Turbine	
h	Hour	
HDV	Heavy Duty Vehicle	
HVAC	High Voltage Alternating Current	
HVDC	High Voltage Direct Current	
ICE	International Combustion Engine	
IEA	International Energy Agency	
IPCC	Intergovernmental Panel on Climate Change	
J	Joule	
k	kilo	10^3
LCOE	Levelised Cost of Electricity	

LDV	Light Duty Vehicle	
LH2	Liquified hydrogen	
Li	Lithium	
LNG	Liquified Natural Gas	
LOLE	Loss of Load Expectation	
LULUCF	Land Use, Land Use Change and Forestry	
M	Mega	10^6
MDV	Medium Duty Vehicle	
MED	Multi Effect Distillation	
MENA	Middle East and Northern Africa	
MSF	Multi Stage Flash	
NDC	Nationally Determined Contribution	
NETs	Negative Emissions Technologies	
Opex	Operational Expenditures	
OECD	Organisation for Economic Co-operation and Development	
P	Peta	10^{15}
PHEV	Plug-In Hybrid Electric Vehicle	
PM	Particulate Matter	
PtG	Power-to-Gas	
PtX	Power-to-X	
PV	Photovoltaic	
PP	Power Plant	
ppm	Parts per million	
PPP	Purchasing Power Parity	
RE	Renewable Energy	
RED	Renewable Energy Directive	
t	tonne	
T	Tera	10^{12}
TPED	Total Primary Energy Demand	
TFC	Total Final Consumption	
SAARC	South Asian Association for Regional Cooperation	
SDGs	Sustainable Development Goals	
SNG	Synthetic Natural Gas	
SoC	State of Charge	
SWRO	Seawater Reverse Osmosis	
UN	United Nations	
USD	United States Dollar	
V2G	Vehicle-to-Grid	
VRE	Variable Renewable Energy	
W	Watt	
WACC	Weighted Average Cost of Capital	

1 Introduction

1.1 Structure of the existing energy system

The structure of each energy system is historically developed based on specific regional conditions such as resources availability, climate conditions, interregional cooperation options, and influence of political and social factors. Every regional energy system in the world is unique, but most of the regional energy systems and the global energy system are based on fossil fuel use. According to the International Energy Agency (IEA) (IEA, 2020a), in 2015 more than 77% of electricity and 95% of heat were produced from fossil fuels, which also dominate in transport sector energy supply. This structure has remained quite stable: in 1990, which is the base year for the Kyoto protocol inventory, the share of fossil generation was 80% of electricity and about 99% of heat generation, only slightly more than now. In the power and heat sectors coal and gas fuels play the most important roles, in total these fuels contribute to 62% of electricity generation and 85% of heat production. In transportation oil-based fuels play a dominant role with the share exceeding 92%.

In the last 20 years, power, heat and transport sector energy consumption was constantly growing. However, the structure of the energy supply has not changed significantly. Coal, the fuel with the generally highest greenhouse gas (GHG) emissions, is the main energy source in the power and heat sectors. Its share in electricity supply was constantly growing in the last decades, mainly due to newly installed generation capacities in developing countries. Coal consumption reached its peak in 2013 and has steadily decreased since. Gas fuel, as the fuel with lower GHG emissions as long as leakage is assumed to be almost negligible, also increased its share in electricity generation. However, the latest studies show that the natural gas supply chain emissions are significantly higher than the inventory estimates (Alvarez et al., 2018), which leads to an underestimation of natural gas related emissions (Howarth & Jacobson, 2021). In the heat sector the share of coal increased even more significantly, partially displacing gas fuels. Nuclear and oil-based generation of power and heat have constantly decreased in their shares, even though some new nuclear capacities have been built, the total capacity and generation of nuclear energy constantly declined in the last 20 years (Schneider, 2020).

The share of renewables in electricity and heat generation increased by 3% since 1990. In the heat sector this growth was reached mostly by modern bioenergy and waste. In the power sector, modern renewables, namely solar and wind energy, emerged from almost zero to 4.4% of electricity generation in 2015, 6.9% in 2018 and 7.8% in 2020. Together with the growth of the modern bioenergy utilisation, they compensated for a drop in the hydropower generation share, and lead to increase of the RE share in electricity generation from 20% in 1990 to 29% in 2020. Hydropower generation is dominant in a limited number of countries, such as Norway, Albania, Tajikistan, Kyrgyzstan, Nepal, Bhutan, Democratic Republic of Congo, Namibia, Central African Republic, Ethiopia, Paraguay. In these countries hydropower covers more than 90% of the electricity production. The hydropower potential was mostly developed in the 20th century and it cannot contribute much more to the growing energy demand. The global hydropower potential could be doubled (Gernaat et al., 2017), but at the cost of further negative impacts on river ecosystems. The share of biomass in power generation increased in the last decades, though further growth will be constrained by the limited potential of sustainable biomass (all recyclable wastes and energy crops are excluded). Another constraint is the negative impact of biomass incineration on the environment and health. If transportation related emissions are excluded, biomass can be considered carbon neutral in the very long-term; however, biomass combustion still leads to NO_x, PM and SO_2 emissions and consequent negative impacts on human health. At the same time, the modern renewable potential, namely solar photovoltaics (PV) and wind, is much higher, these technologies have reached maturity and show the possibility of a fast integration in energy systems. The full representation of the power and heat sectors from a fuel shares perspective is given in Table 1. Data for 1990 and 2020 is based on IEA Statistics (IEA, 2020a) and electricity shares on the data from IEA's Net Zero by 2050 report (IEA, 2021). Similar values for the heat sector in 2019 and 2020 were not available at the moment of compiling this dissertation.

Table 1. Fuel shares in electricity and heat generation in 1990, 2015, 2018 (IEA, 2020a) and shares in electricity generation in 2019-2020 (IEA, 2021) .

Production from:	1990		2015		2018		2019	2020
	Electricity	Heat	Electricity	Heat	Electricity	Heat	Electricity	Electricity
	%	%	%	%	%	%	%	%
Coal	37.2	30.4	39.2	42.5	38	42.8	36.5	35.2
Oil	11.1	16	4	4.4	2.9	3.7	3.0	2.8
Gas	14.7	51	22.8	42.3	23	41.8	23.5	23.2
Biomass	0.9	1.1	1.7	3.9	1.9	4.3	2.5	2.7
Waste	0.2	0.5	0.4	3.1	0.4	3.2		
Nuclear	16.9	0.3	10.5	0.2	10.1	0.2	10.4	10.1
Hydropower	18.4	0	16.4	0	16.2	0	15.9	16.5
Geothermal	0.3	0.1	0.3	0.3	0.3	0.3	0.3	0.4
Solar PV	0	0	1	0	2.1	0	2.5	3.1
Solar thermal	0	0	0	0	0	0	0.1	0.1
Wind	0	0	3.4	0	4.8	0	5.3	5.9
Tides	0	0	0	0	0.	0	0.0	0.0
Other sources	0.2	0.6	0.1	3.4	0.1	3.7	0.1	0.1

The world electricity generation capacity structure is generally close to the electricity generation shares: coal and gas generation capacities play the most important roles in the current electricity sector. The renewable energy (RE) capacities share combines to approximately 28% of total generation capacity as in the beginning of 2015. The structure of total cumulated installed capacity by technology active at the beginning of 2015 is presented in Figure 1.

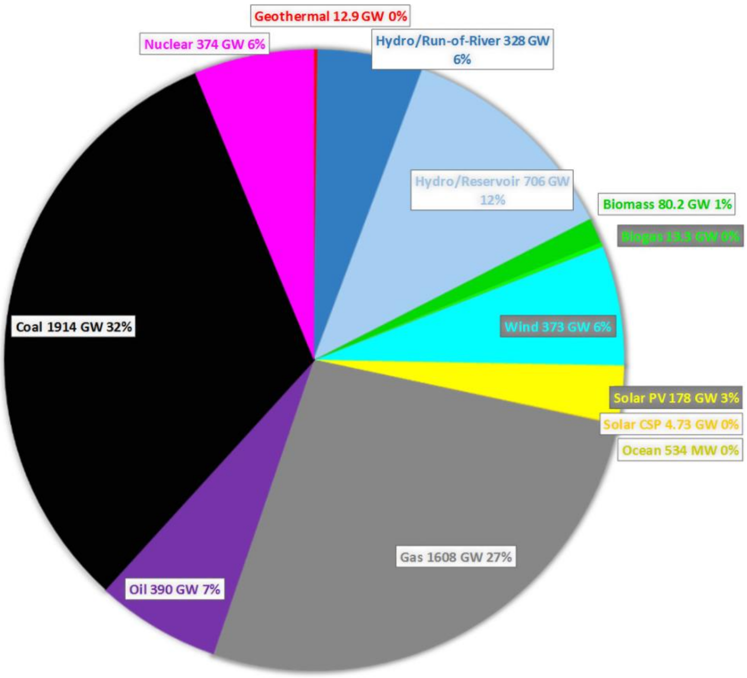

Figure 1. Total cumulated installed capacity by technology active at the end of 2014 (Farfan & Breyer, 2017).

The last two decades have been a period of a fast energy demand growth in developing countries, led by China and India. The fast-growing energy demand has been mostly satisfied by the installation of massive capacities of coal power plants. Most of the RE capacity growth was reached in the last decade. In the period starting from 2007, more than 45% of newly installed generation capacities were based on RE technologies, from which 29% were wind generation capacities and 17% solar PV capacities, while the share of RE in newly added capacities reached the historic highest value of 77% in 2019 (Frankfurt School-UNEP Centre/BNEF, 2020). Most of this growth concentrated in the developed countries of Europe and China, which already faced the negative effects of coal-based energy supply, namely decreasing air quality (You & Xu, 2010), which can even affect other countries (Hien et al., 2011), and induce a water deficit (Lohrmann et al., 2019). These effects were amongst reasons for changes in the trends in energy supply of China and fast growth of modern RE installations. However, significant capacities of coal power generation are still installed even in the countries with strong RE policies; in China alone the power generation from coal increased by 663 TWh in 2015-2018, and by 86 TWh in 2018-2019. At the same time, some countries continuously phase out coal and even decommission rather new coal power plants (Le Quéré et al., 2019). Overall, the net global power generation from coal increased by 608 TWh in 2015-2018, and the newly installed coal capacities may stay in the system for a long period of time and will influence the system development. The structure of global yearly active capacity installations until the end of 2014 is presented in Figure 2.

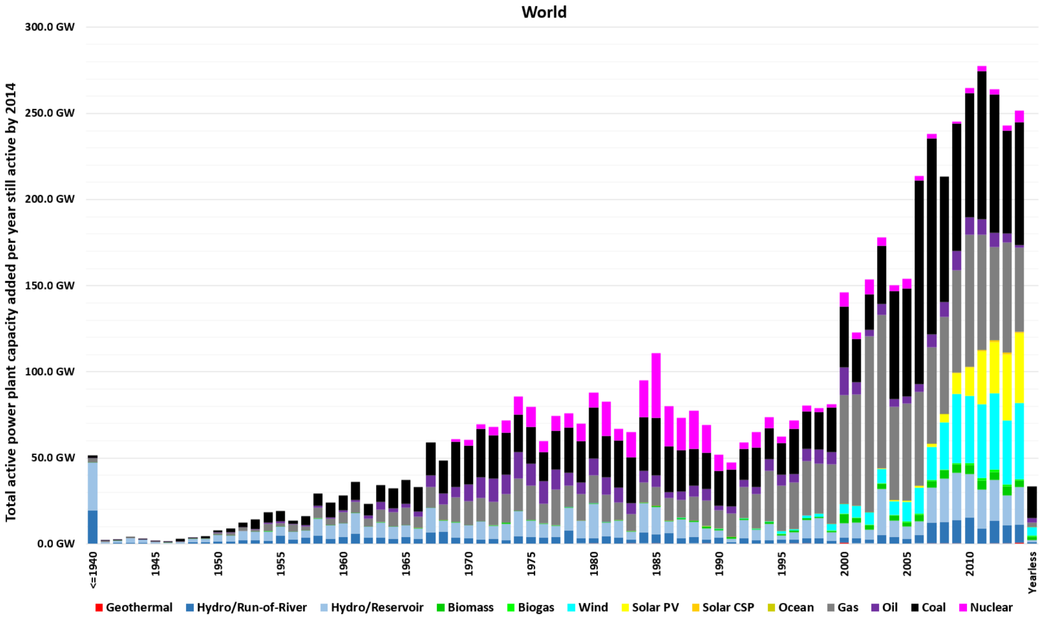

Figure 2. Global yearly active capacity installations to the end of 2014 (Farfan & Breyer, 2017).

The current global energy system remains massively dependent on fossil fuels. The role of renewables has increased in the last decades and especially recently, as the share of RE in newly added capacities reached the historic highest value of 77% in 2019. Though, the growth is not as fast as is needed to change the structure significantly and decrease GHG emissions, despite the vocal initiatives as United Nations Framework Convention on Climate Change, Kyoto protocol and its amendments. Massive capacities of coal generation are installed in both the power and heat sectors, which are expected to stay in the system for decades.

At the same time, existing power and heat capacities are aging – about half of power generation capacities were installed before 1990 and will reach their technical lifetime soon. These capacities need to be repowered in the coming decades, which will demand investments to extend the lifetime with slight improvements in efficiency and ecological standards or to fully decommission these conventional power plants and substitute them with modern non-polluting technologies.

1.2 Major trends in the conventional energy systems

Putting aside the growing concerns of the impact of conventional energy system emissions (Coady et al., 2016), current conventional systems have to adapt to emerging changes in the supply and consumption of energy. The IEA names ‘declines in the costs of major low-carbon technologies’ and ‘increasing importance of electricity’ as large-scale shifts happening in global energy (IEA, 2017).

Declining costs of renewables, namely solar and wind energy, result in a growing share of variable renewables energy (VRE) in energy systems. In countries like Denmark or Germany the shares of solar and wind generation can already exceed the electricity demand for some hours in some days (Ministry of Foreign Affairs of Denmark, 2020). Due to negligible operational costs, renewables are first in the energy market merit order, and the growing generation of RE pushes the high cost generation away from the market (Fraunhofer ISE, 2020). At the same time, RE generation fluctuations increase the ramping of conventional power plants, which has a negative impact on their efficiency and energy output cost. That puts two inconsistent demands to conventional power plants: investments in flexibility options on one hand and a decrease of marginal cost on the other hand.

The importance of electricity in global energy use is growing due to fast electrification of heat supply and transportation services. Emerging affordable heat pumps and battery electrical vehicles (BEV) make electricity the least cost fuel for heat and transport technologies in many regions and result in an accelerated growth of electricity demand. At the same time, this increases the share of distributed and more variable power consumption, which can have a negative impact on conventional energy systems due to high variability and lower predictability of the demand.

Conventional energy systems already have a number of issues, but adding the climate change perspective, they have to move towards higher efficiency and lower emissions (and ultimately net zero emissions by 2050 and net-negative emissions afterwards), which hardly can be reached with conventional generation technologies at the same time with following flexibility and cost constraints.

1.3 Energy system sustainability criteria

Energy systems have to adopt to the ongoing changes and new challenges while taking into account not only the climate mitigation perspective, but also fulfilling the general sustainability criteria extended into social, environmental, and economic spheres. The environmental perspective naturally includes climate change mitigation, but also extends to other elements, such as prevention of air pollution, ozone depletion, ocean acidification, freshwater source pollution and depletion, and support of biodiversity. Sustainability of the environmental sphere is the basis for a sustainable society and economy as suggested in Child et al. (2018). Thus, the environmental sustainability criteria and preservation of natural capital (Ekins et al., 2003) must have the highest priority; we cannot tolerate an irreversible destruction of natural capital (Pelenc & Ballet, 2015), since this capital cannot be substituted (Ekins et al., 2003).

At the same time, energy system development should not violate long-term social and economic sustainability criteria, including minimisation of negative health impact, resource-based conflicts, security of energy access and its affordability, inclusion of the public to the decision-making, resources efficiency increase and general prosperity growth.

At the moment, most of the sustainability criteria applicable to energy systems are violated to some extent; planetary resources are overexploited and consumed at higher rates than they are renewed (Meadows et al., 2004; Steffen et al., 2015). Overall, the ability of the biosphere to adapt to the impact of anthropogenic changes is exceeded, which results in overstressed nitrogen and phosphorus cycles (Steffen et al., 2015; Rockström et al., 2009), various dangerous and unpredictable effects in the climate system as claimed by the Intergovernmental Panel on Climate Change (IPCC) (2014b), ozone layer weakening, ocean acidification and coral reef destruction, land erosion and desertification, chemical pollution, and aerosol loading (Steffen et al., 2015), and an increased rate of biodiversity loss. Impacts of human activities on the planetary processes became the main driver of all these changes, thus the current geological era is now called the “Anthropocene” (Child et al., 2018; Waters et al., 2016).

The awareness of these negative effects of human activities has been growing for centuries: water and air pollution due to fuel incineration were visible even before the Industrial Revolution and significantly increased after. Famous smog events like photochemical smog in Los Angeles, the Great smog of London and similar occurrences in other cities led to the first changes in legislation measures to reduce air pollution, including UK’s Clean Air Act of 1956. Rachel Carson’s “Silent Spring” (Carson, 1962) highlighted that the effect of human activities expanded much further than visible air or water quality by describing the negative impact of the chemical industry and precisely the results of the irresponsible use of pesticides. Finally, the Club of Rome and “The limits to growth” presented a global view of the planetary ecosystem, resources and the limits of “business as usual” growth (Meadows et al., 1972). It has become impossible to ignore these challenges given the magnitude of evidence, and society is increasingly focused on sustainability and climate change mitigation in particular.

1.4 Recent policy changes: Paris Agreement and UN’s SDGs.

The Paris Agreement and United Nations’ (UN’s) Sustainable Development Goals (SDGs) are the major guidelines for the world development in the twenty first century. Long-term sustainability must become the main measure in the decision-making. Both documents directly influence energy systems, and both promote climate actions.

The main aim of the UN’s Sustainable Development Goals program is to achieve a better and sustainable future for all humans on the planet. The main goals are the elimination of inequality, poverty and hunger, improvement of healthcare and education levels, access to clean water and affordable clean energy, and nature preservation. In total, the UN's Sustainable Development program states 17 goals, and clean energy and climate actions are tied directly or indirectly to at least five of them:

- Goal 6, Water and sanitation: improvement of water quality by reducing pollution and increasing water-use efficiency across all sectors, which will demand limits to water cooled thermal power plant generation.
- Goal 7, Energy: ensure universal access to affordable, reliable and modern energy services, increase the share of renewable energy in the total consumption, which directly recognises the importance of renewable energy utilisation.
- Goal 8, Economic growth: progressive growth of resource utilisation efficiency and decoupling of economic growth from environmental degradation, which will limit use of fossil fuels and thermal power plants in some regions.
- Goal 11, Cities: reduce the adverse per capita environmental impact of cities, including paying special attention to air quality and municipal and other waste management, adopt and implement integrated policies and plans towards inclusion, resource efficiency, mitigation and adaptation to climate change.
- Goal 13, Climate Change: highlights the negative effect of affecting countries on every continent and summarises the importance of a transition towards cleaner, more resilient economies.

While the SDGs highlight the urge to strengthen the global response to the threat of climate change in a wider context of sustainable development, the Paris Agreement, adopted at the 21st Conference of the Parties (COP21) in Paris, is focussed directly on climate actions in the energy sector, but also industry and land-use.

The main motivation of the Paris Agreement was a commitment to strengthen the global response to climate change, and limit the global temperature increase to a level well below 2°C while pursuing efforts to keep the temperature growth below 1.5°C. Recognising that climate change represents an urgent and potentially irreversible threat to human societies and the planetary ecosystem, the agreement does not specify the exact date of the global GHG emissions peaking, but recognises the urgency of deep reductions in global emissions and the fact that the peak has to happen as fast as possible. The agreement takes into account the complexity of the process and the many aspects of the actions which must be taken including financial support and technological transfer towards the least developed countries, actions for better adaptation, enhancing stability and reduction of vulnerability to climate change, climate change education, training, and enhancement of public awareness. The Paris Agreement recognises the importance of the conservation and enhancement of sinks and reservoirs of the greenhouse gases which will be needed for carbon capture and storage (CCS) and negative CO_2 emission technologies in the future. However, mitigation actions are mostly voluntary and nationally determined contributions (NDCs) for countries are not defined. The Paris Agreement emphasises the importance of data transparency of NDC communication and that each next NDC shall represent a progression beyond the previous one and reflect the highest possible ambition, but there is no authority which will set the NDCs for countries or check if the target requirements are fulfilled. The Paris Agreement acknowledges that the transition will be more challenging for developing countries, which can progress in accordance to different national circumstances. However, developed countries shall progress faster and undertake absolute economy-wide reduction targets.

1.5 Overview on the G20 countries’ energy sector trends and policies

It is most important how the Paris Agreement and SDGs are applied in practice. The application of these guidelines in the countries representing the major part of the global economy and responsible for most of the emissions will define the speed and the pathway of the transition. The Group of Twenty countries (G20) account for around 85% of the global economy (World Bank, 2020b), about 75% of world trade (OECD, 2019), 60% of the global population (UNPD, 2020) and about 80% of global energy consumption (IEA, 2020a). While the energy system structures in G20 countries vary significantly, most G20 member economies currently mostly rely on a high share of fossil fuels in their total primary energy demand (TPED). As a result, G20 economies account for 82% of energy related GHG emissions. Policies applied in these 20 countries will define the transition in the coming decades.

Coal remains the main energy source for the power sector, while oil products dominate the G20 total energy consumption and natural gas has grown in importance in recent decades. Though the role of coal has declined significantly in recent years, especially in Western Europe and the United States, coal still satisfies most of the power generation growth demand in fast developing regions like China and India and plays a major role in the energy systems of South Africa and Australia.

At the same time, G20 countries are leaders in the cleaner energy system development, holding an 81% share of the global renewable power capacity (IEA, 2018b). Energy transitions in G20 economies have an important influence on the global energy markets and RE technology development. The decisions made in G20 countries have a major impact on the GHG emission pathway and influence sustainable development policies worldwide. Several G20 economies are in the lead of the energy transition; the decarbonisation and RE introduction support policies started in these countries, and did not simply support the energy transition in these countries, but enabled the fast decline of RE technology costs worldwide and made low-carbon technology utilisation feasible in other regions (Nemet, 2019). Of course, the national economies and energy systems of the G20 countries significantly differ and approaches to energy system development also differ to better match the respective economic development.

In 2016 the total worldwide energy investments are estimated at just over USD 1.7 trillion (12% below the previous year) (IEA, 2018b). In that year the electricity sector became the largest recipient of energy investments, ahead of oil and gas, mainly driven by investments in energy efficiency and clean energy: renewable energy generation, and other low-carbon generation technologies. At the same time, the amount of planned investments in other low-carbon projects such as nuclear and CCS continues to decline. Similar trends can be observed in the G20 countries. China, the main destination for energy investments and accounting to 21% of global energy investments in 2016, shows a significant decline in new coal power plants investments and constant growth in low-carbon and renewable energy supply, networks and energy efficiency action investments. Indian energy investments grew in the last years due to a strong push to modernise and expand India's power system in order to enlarge practical access to electricity (increasing both access to grids and reliability of power supply for consumers) and facilitate economic growth. These two countries together with the US are the three largest energy investors in the world and are responsible for most of the new power capacity installations, while EU28 may have been the second largest next to China.

During the years 2010 to 2016, China was leading in RE capacity installations, followed by the European Union, the United States and India. In total China installed about 40% of the G20 renewable capacity growth (318 GW in 2010-2016). The European Union countries accounted for 22% (160 GW) of the RE capacity growth, followed by the United States (12% of the total, and 86 GW) and India (5% of the total, and 35 GW). The RE capacity growth was mostly driven by policy support in these countries, represented by various feed-in tariffs (FITs) and other measures. This could at least partly balance the enormous subsidies for fossil fuels due to a lack of allocating the cost of air pollution and GHG emissions in a fair polluter-pays rule (Coady et al., 2016), but also supported by falling costs of the RE technologies. Most of the installed capacities in the years 2010-2016 were wind turbines (276 GW), almost on par with solar PV (247 GW) and followed by hydropower (171 GW). The role of all other RE technologies was much lower, at about 40 GW (IEA, 2018b). The installation rates of RE technologies are growing year to year and in 2020 global annual installation rate was about 100 GW of wind and 130 GW of solar PV.

The IEA forecasts the further expansion of the renewable generation capacity in G20 countries, about 825 GW to be installed over 2017-22, which will represent 90% of global growth. Considering the limited hydropower potential, wind and solar will be in the focus of the RE expansion in these years, representing 86% of G20 growth in these five years. Solar PV is also expected to surpass wind to lead capacity growth. In total, 90% of all G20 solar PV additions are expected to be installed in China, the United States, India, the European Union, Japan and Mexico. Total solar PV additions in G20 countries was expected to be about 410 GW over 2017-22 (IEA, 2018b), representing 90% of global growth, while in reality this ambitious target has already been surpassed, with about 451 GW of PV installed globally in 2017-2020, showing the rather limited forecasting quality of IEA. The quality of IEA's forecasting of RE leads to constant and substantial underestimation of the RE and especially PV capacity in IEA's reports and forecasts as shown by Breyer & Jefferson (2020).

Renewable heat supplies 9% of G20 heat demand on average. The European Union and the United States are the largest consumers of renewable heat, which meets 19% of EU and 11% of US heat demand (IEA, 2018b). At the same time, in Russia renewable heat accounted for only 2% of the country's substantial heat consumption; the RE heat share in Japan is also low at 4%. In total renewable heat consumption increased by 13% between 2010 and 2015, and the fastest growth could be seen in China, where renewable heat consumption has doubled during this period. Most of this growth was driven by ambitious solar thermal and geothermal energy introduction targets applied in China for this Five-Year Plan period (IEA, 2018b). In the European Union, the renewable heat introduction was supported by the Renewable Energy Directive (RED) (EC, 2009), which included a range of policy measures such as installation grants, renewable heat obligations and building codes. The targets were further increased in the revised Renewable Energy Directive (REDII) (EC, 2018). Despite solar thermal and geothermal technology growth, bioenergy still dominates heat consumption and is being used for both space heating and industrial heat. Ongoing heat sector electrification, mostly based on energy efficient heat pump technology and previously described growth of RE generation in G20 countries, also contributes to the heat sector transition towards renewables, though this is not adequately represented in the statistics.

Despite the EV industry development, biofuels are the principal form of renewable energy in the transport sector. In 2016, biofuels represented over 96% of all renewable energy consumed in road transport, and the remaining 4% related to electricity consumption in EVs. In total, biofuels met around 3% of transport energy demand, and most biofuel consumption is currently in road transport (mainly passenger light-duty vehicles). In future biofuels can also play a more significant role in aviation, while currently it is negligible. In 2017, global crop-based conventional biofuel production increased by 2% and reached around 2.4 mb/d (140 billion litres). Brazil and the United States account for around 70% of global output (by volume) in 2017. (IEA, 2018b) However, current biofuel production based on food crops or competing with food crops cannot be seen sustainable.

In general, G20 countries show a strong commitment to the Paris Agreement and SDGs, and are truly the drivers of the transition towards higher shares of renewables. This commitment also has a strong economic rational, RE already is the cheapest option in many of the G20 counties even if external CO_2 related cost are not considered (Ram et al., 2018). Current policies have driven higher efficiency and lower energy intensity in most of the G20 economies. However, energy consumption is growing due to economic growth: between 2005 and 2015, total final consumption (TFC) of energy grew by 17% across G20 countries, with the largest proportionate increases in Saudi Arabia (74%), India (61%) and China (60%). Consequently, the overall primary energy demand is still growing, though it is partially compensated by improved efficiency and changes in the energy mix. Consequently, the annual G20 primary energy demand growth has been reduced, from 2.6% annually between 2000 and 2005 to around 1% between 2010 and 2015 (IEA, 2018b), and further slows down after 2015 as can be seen from G20 countries statistics (IEA, 2020a). Latest statistics on countries level shows the same trend (not taking into account 2020, which is exceptional due to COVID-19 lockdowns). Despite all the progress, the RE growth rates still could not cover this demand increase in these years and the demand increase still led to rising or stagnating GHG emissions.

1.6 Motivation and objectives

The current structure of the global energy system is based on extensive fossil resource exploitation, and energy consumption growth leads to a constant increase of fossil fuel utilisation and related GHG emissions. Despite the growing concerns of climate change, a consensus on the anthropogenic nature of this process, the highlighted numerous agreements signed in the last decades such as the Kyoto Protocol and the Paris Agreement, and promising global initiatives such as UN SDGs, the structure of energy supply still has not change significantly. The role of modern RE generation has not improved substantially, as all the progress seen in the last decade is not sufficient since newly installed capacities were not sufficient to cover energy demand growth and energy generation from fossil sources and respectively GHG emissions kept rising. Though, recent years show the change of this trend. In 2019, the last pre-COVID-19 year, renewables contributed 77% of all newly added capacities in the power sector (Frankfurt School-UNEP Centre/BNEF, 2020) and the global energy-related CO_2 emissions flattened at around 33 Gt, following two years of increases (IEA, 2020b).

GHG emissions and the induced climate change mitigation is not the only threat for the fossil-based economy. Fossil fuel utilisation related air pollution also creates additional pressure due to additional social costs (Coady et al., 2016) including premature deaths (Jacobson et al., 2018), which, similarly to climate change, can be exterritorial and affect not only the country relying on fossil fuels, but also neighbouring regions (Hien et al., 2011). Unlike climate change, air pollution issues are much harder to ignore and the regions which face the extreme air pollution tend to accelerate defossilisation in the affected regions (O'Meara, 2020). Another massive threat is ongoing change in energy systems due to the growing share of VRE in power supply, which puts additional pressure on the conventional fossil-based technology, by reducing the total energy system electricity generation costs and inducing the implied additional flexibility requirements. The current energy system violates numerous sustainability criteria, leading to an overall overexploitation of planetary resources. The switch to carbon neutral technologies such as nuclear and fossil fuels plus CCS, as is discussed in some high level studies (Johansson et al., 2012), could partially decrease the GHG emissions; however, this would still violate other sustainability criteria and create additional complications concerning the final storage of nuclear waste and CO_2 deposition, as well as the target of achieving an affordable energy system.

Many countries in the world already claim their commitments to build a carbon neutral energy system based on high shares of renewables in order to fulfil the Paris Agreement conditions (UNFCCC, 2019). However, the transition from current energy systems towards renewables and reducing of fossil fuel utilisation (defossilisation) and emissions to zero, is a challenging aim, especially taking into account the extremely ambitious timeline. In order to fulfil the Paris Agreement targets, the global GHG emissions should decline rapidly in the coming years. Otherwise, the remaining GHG emission budget for 1.5C 66% (420 $GtCO_2$ accordingly to IPCC's SR15 (IPCC, 2018) may be exploited faster than expected due to additional GHG emissions from permafrost melting (Rogelj et al., 2019), which, if taken into account, significantly decreases the available carbon budget. In the worst case, and considering the total annual anthropogenic carbon emissions at a level of about 40 Gt_{CO2} (Friedlingstein et al., 2020), the carbon budget can be exploited in about 5 years from now. Moreover, each energy system sector has its specifics; even if electrification and defossilisation of the power and heat sectors can be accomplished based on currently available and economically competitive technologies, transport and industry sector defossilisation is expected to be more challenging.

Given the time constraints and the required capital expenditures of such a transition, all countries should have detailed transition roadmaps to build an optimal RE-based energy system by 2050. Every country has its own historical structure of the energy system, region specific energy demand pattern and a specific availability of RE energy resources. Thus, every country should have its own unique transition pathway, developed in accordance to the availability of local RE resources, climate conditions, demand patterns, historical structure of the existing energy system, the possibility of cooperation with neighbouring countries and other factors.

Many research groups and think tanks are working to support the energy transition. Numerous studies are published in an attempt to describe a possible structure of an RE-based system or entire transition pathways for various countries using different models. The first ever study on a 100% RE system was published back in 1975 by Sørensen (1975), which discussed a 100% RE-based system for Denmark, followed in 1996 by the first global study (Sorensen, 1996). The number of transition studies grew in the 2000s supported by growing attention to the climate change problem, and improved computational capacities enabled more sophisticated approaches in energy transition modelling. However, the next global energy system study was published only in 2011 (Jacobson & Delucchi, 2011) and became a major breakthrough in the field. It is still the most influential publication with the highest number of citations.

Many global energy scenarios have tried to project the future transition of energy systems based on a wide ranging set of assumptions, methods and targets from a national as well as global perspective (Koskinen & Breyer, 2016). Most of the global energy transition studies present pathways that result in net CO_2 emissions even in 2050, which are not compatible with the goals of the Paris Agreement (as is the case with practically all IEA global scenarios except the NZE2050 (IEA, 2021). They are also dependent on the role of technologies with a questionable level of sustainability (fossil CCS and nuclear) as in the Global Energy Assessment of the International Institute for System Analysis (IIASA) (Global Energy Assessment Writing Team, 2012). Some later studies, such as Grubler et al. (2018), consider a decline of final energy demand by 2050, despite increasing population, income and activity.

The Centre for Alternative Technology (CAT, 2018) outlines scenarios on global, regional, national and sub-national scales that illustrate how the Paris Agreement targets could be realised. Most of the studies lay out pathways to phase out non-sustainable technologies, while integrating sustainable renewable energy options to satisfy the increasing energy demands of the future global society. Several studies on the global level with different models and assumptions show that such a transition can be achieved by 2050. Pursiheimo et al. (2019), using the TIMES-VTT model, Löffler et al. (2017) with GENeSYS-MOD, Jacobson et al. (2018) and Teske (2019) have different regional structures, technology portfolios, technical and financial assumptions, but all prove that an RE-based system is cost competitive compared to a conventional system. Jacobson et al. (2019) and Teske (2019) also show that benefits of an RE system are not limited to radical declines in GHG emissions and low energy system costs, but also lead to lower social costs and additional jobs.

Hansen et al. (2019) provide an overview on 100% RE system studies and highlight the importance of multi-sector analyses, hourly temporal resolution, sector coupling and Power-to-X technologies. Any model has its limitation and, as a result, all global energy scenarios fail to acknowledge some aspects of the transition. Some energy system transition models have even failed to acknowledge the role of storage technologies in future energy systems (Koskinen & Breyer, 2016), the impact of sector coupling Power-to-X technologies, namely Power-to-Heat and e-fuels production and the possible impact of emerging technologies like reverse osmosis water desalination and purification. Deeper sector integration is seen as one of the most important approaches to increase the overall energy system efficiency and decrease the cost of a transition towards a carbon neutral economy (Mathiesen et al., 2015).

Temporal resolution is another important aspect, as most of the models used for global energy system studies normally use the time-slices approach (MESSAGE, MARKAL/TIMES, GENeSYS-MOD). These often add sophistication to the estimation of the impact of RE generation variability on the system and the role of mid-term and long-term storage.

Energy prosumerism is an emerging factor in energy system transitions, though it is also not covered in most of the energy system studies. While prosumer PV capacity has already reached significant levels in many developed countries, in most studies prosumer PV is neglected, or mixed in generic PV assumptions despite a different decision making behaviour of prosumers and impacts on distribution grids.

Some studies, like Teske (2019), assume relatively high shares of bioenergy in the total energy supply, which may be in conflict with sustainable bioenergy availability. In order to reach full sustainability, the use of biofuels should be strictly limited to unavoidable residues, and food crop-based fuel production must be substituted by e-fuel synthesis, which does not compete with food production. The emerging issue of water scarcity has to be taken into account, considering the additional energy demand of water desalination, purification and transportation in order to enable universal access to clean water for residential, agricultural and industrial use (Wada et al., 2014).

Overall, the objective of this dissertation was to develop a model and conduct studies which combine the best practices from other existing studies and models, but also adequately acknowledge the role of energy prosumerism in the future energy system, the role of storage technologies in future energy systems, the impact of sector coupling Power-to-X technologies, namely Power-to-Heat and e-fuel production, and the possible impact of emerging technologies, both on local and global levels. That demanded the development of a technology-rich, multi-nodal energy system model, operating in full hourly resolution. Due to the attention to emerging technologies and close coupling of energy sectors with bridging technologies, the LUT Energy System Transition Model takes into account the specific evolution of each energy sector: power, heat, transport and industry, and the synergy effect of the integration of these sectors. In the studies discussed in this dissertation all sectors are assumed to reach carbon neutrality by 2050. However, due to different levels of technological maturity, cost of decarbonisation, and technological lifecycles, the speed and trajectories of each sector's transition can be different and thus was partly modelled individually. At the same time, the model allows estimation of the synergy effects of integration on the system efficiency and costs, as different levels of sector integration can be observed, from overnight or greenfield studies for individual sectors, to the transition of a fully integrated energy system.

As scenarios should not violate sustainability criteria and follow the current trends in energy system development (discussed in section 2), it is important to:

- avoid investments in technologies of questionable sustainability (nuclear and CCS),
- limit the use of biomass to sustainable residues and not recyclable wastes,
- aim for the highest possible energy system electrification in order to limit fuel combustion,
- acknowledge the role of sustainable e-fuels in the segments where direct electrification is not yet feasible (technically or economically).

The publications presented in this dissertation use the LUT Energy System Transition Model to test the possibility of building carbon neutral energy systems using currently available generation, storage and bridging technologies in various regions of the world without negative CO_2 emission technologies. They also prove the feasibility of 100% renewable energy systems inregions with all kinds of present climate conditions. In the next section, the major trends are defined for energy systems along with possible pathways of energy system development in the future. For each region the specific energy transition pathway is designed and analysed. The impacts of different climate conditions, starting energy system structure, energy demand and the sectors considered in energy systems are further studied and discussed to define the main dependencies in energy system transitions. These objectives were achieved in the publications included in this dissertation:

1. The first research question is about the technical feasibility of a 100% RE power sector and its cost competitiveness. It is also necessary to check if the RE resources are sufficient to cover the electricity demand even in the fast-developing regions with energy intensive economies like Northeast Asia. A RE-based system can be vulnerable in case of long-term extreme climate anomalies and a related RE generation deficit, and the options to secure an RE-based energy system without the use of fossil CCS or nuclear have to be discussed. Another research question is if RE-based systems can be self-sufficient on a regional level or whether a regional integration is necessary; and what the benefit would be of a regional integration if the regions can be technically self-sufficient. Other research questions are the possibility and the impact of the sector integration. These research questions are examined in **Publication I**.
2. The next group of research questions addresses whether the RE system is technically feasible and cost competitive and if it can it operate in the current market environment. Will it be possible to pay back the investments in RE technologies with zero marginal costs or what are the changes in the market design to make this possible? These research questions are discussed in **Publication II**.
3. The transition from the current fossil fuel-based power sector towards an RE based system has to be accomplished in the next 30 years to reach a carbon neutral power system by 2050. This transition has to be well planned to avoid stranded investments and guarantee reliability of power supply at every stage of the transition. Such planning requires accurate modelling of the transition pathways, taking into account regional conditions (most importantly RE potential and power demand projections) and projections of the generation, storage and transmission technologies in the future, as well as their cost and those of the fuels. The methods for such a modelling and the example of such a transition for the dynamically developing region of Northeast Asia are described in **Publication III**.
4. The transition pathway and the structure of the final power sector strongly depend on the specific regional conditions, including the RE potential, energy intensity of the economy, climate conditions, influencing both RE supply and energy demand seasonality, and the structure of the current energy system. The possibility of the transition towards a RE-based power system has to be examined for all regions in the world and for all regions the optimal transition pathway has to be investigated. The possibility to build a RE-based power system in all regions of the world and the specific regional pathways are described in **Publication IV**.
5. The power sector is the most important part of the energy system, though to reach Paris Agreement targets all energy sectors have to be fully defossilised. The sector transitions have to go in parallel with sector integration to transform the current mostly fossil fuel-based isolated energy sectors to a closely integrated, electrified

and RE-based energy system. This transition and integration can create additional challenges, but also create additional opportunities. This is examined in detail in **Publications V and VI**, which investigate the options and the impact of different sector integration on the example of a country with an energy intensive economy and high seasonality of energy supply and demand.

6. Finally, energy systems have to be defossilised by 2050 in each region of the world. The transition has to start fast to sharply reduce GHG emissions in all energy sectors: power, heat and transport, in order to comply with the 1.5°C target of the Paris Agreement. The possibility of such a transition is examined in **Publication VII**, which also describes the potential 1.5°C scenario compatible pathways for all regions of the world.

1.7 Outline of the work

The first part of this dissertation represents the background of the existing energy system: its structure, current challenges, recent global initiatives and the impact which is already seen on the example of the G20 countries – the group of countries representing the lion share of global energy demand, to show the importance of the transition and insufficiency of current measures. The second chapter describes the most important pathways or trends in energy system development, which are widely discussed to be the keys to build truly sustainable energy systems to show that only RE technologies can be considered fully sustainable in the long-term perspective. The third chapter discusses the modelling tools needed for sustainable energy system simulations and transition research, and discusses the major features of the LUT Energy System Transition model in comparison to other existing energy system models. The fourth chapter represents the key results of the chosen publications, showing the flow of the research development and highlighting most important aspects of the transition towards sustainable energy systems. The fifth chapter discusses these results and defines the limitations of the current research and the expected impact on conclusions. References and the previously mentioned publications are included at the end of the dissertation.

2 Main requirements of the sustainable development of energy systems

Current energy systems are at the beginning of a radical transformation towards long-term sustainability. In order to reach such a transformation, systems have to change in many different aspects to reach sustainability in three dimensions (UN, 2020): society (energy supply for quality of life), economy (energy affordability, reliability and security) and environment, which will also demand significant technical advances in the energy industry. The main aspects of this transition are: equal access to energy on regional and global levels, decentralisation of energy systems, energy system electrification, energy efficiency improvements, energy system decarbonisation and defossilisation. Most of these aspects are correlated and one aspect can follow from another; therefore, it is also hard to define to which dimension each of these main aspects primarily belong to.

2.1 Equal access to energy

Equal access to energy is the core element of the SDG 7: affordable and clean energy. Significant progress in this aspect can be observed in recent years: the percent of people with access to electricity increased from 78% to 87% in the period from 2000 to 2016 (UNDP, 2020b) and is continuously growing (World Bank, 2020a). Still, in some regions of the world, such as Haiti and Rwanda, less than 40% of the population have access to electricity (UNDP, 2020a; World Bank, 2020a). Access to energy is vital in the 21st century and can be considered as one of the basic human rights (Bradbrook & Gardam, 2006). Consequently, the ultimate target of an energy system transition is to provide equal access to energy and electricity to all people. This demands significant investments in the energy infrastructure, especially in developing regions. However, these investments pay off through accelerated economic growth, social development and overall life quality improvement. Renewable energy systems can be seen as an optimal solution for the case of developed countries. Scalable RE systems allow provision of energy in remote areas with limited infrastructure at low cost (Bertheau et al., 2017; Cader et al., 2016). There is evidence of how access to electricity supply or to simple electrical lighting changes the life of communities by expanding the economic activity period during the day, accelerating local businesses and allowing self-education (Da Silveira Bezerra et al., 2017; World Bank, 2018).

At the global level, countries have to target a truly circular economy, which cannot be reached with the current fossil fuel-based energy systems. Inequality in access to energy resources often defines the role of a country in the international division of labour (Fengru & Guitang, 2019). Therefore, the countries with fossil fuel reserves have a competitive advantage in energy intensive industries and can be successful in both downstream manufacturing and more sophisticated upstream manufacturing. Meanwhile, countries importing energy carriers can compete only on sophisticated upstream manufacturing under the condition of significant technological advancement. Transformation towards the circular economy paradigm will demand more even access to energy resources on a global level. RE resources are distributed much more evenly compared to fossil fuel reserves and the transition towards RE-based energy supply will diminish existing inequality and allow building mostly self-sustainable circular economies.

2.2 Energy efficiency

Energy efficiency is another aspect of SDG 7. One of the key indicators is to double the global rate of improvement in energy efficiency by 2030 and reach a significant decrease in the energy intensity of the global economy in terms of primary energy and GDP. Energy efficiency improvements have a great potential to decrease the cost of energy supply, boost economic growth and in parallel decrease GHG emissions.

The IEA views energy efficiency as the “first fuel” of all energy transitions (IEA, 2019a), which could enable GHG emissions to peak before 2020 (IEA, 2018a). Energy efficiency improvements do not directly speed up the transition towards renewables, though they can simplify the transition by reducing the RE capacity needed to satisfy the energy demand. The Efficient World Strategy of IEA’s report ‘Energy Efficiency 2018’ (IEA, 2018a) have shown an existing potential to expand the global actions in energy efficiency and to reach significant improvements in all end use sectors to reach substantial benefits for economy, society and environment. According to IEA’s Efficient World Strategy scenario the size of the global economy could double between 2018 and 2040 with only a marginal increase in energy demand in case of substantial progress in energy efficiency measures. Despite the existing potential and undoubted benefits of energy efficiency improvements, the process of the efficiency growth slows down on a global level. Energy efficiency is still growing, but the growth rate of primary energy intensity improvement, the main indicator of how much energy is used by the global economy, is decreasing. In 2016-2017 the primary energy intensity decreased by 1.7% from 5.1 MJ/USD (2011 Purchasing Power Parity (PPP)) to 5.0 MJ/USD (2011 PPP), showing a second consequent year of slowing improvements (IEA, 2020c). In 2018, the primary energy intensity improved by just 1.2%, the slowest rate since 2010. The peak value of 2.9% was reached in 2015 and the improvement rate has decreases since, while a 3% level is needed to reach the Efficient World Strategy scenario, as described by IEA (IEA, 2019a).

Energy efficiency improvements reduce the amount of energy required to provide a service. Efficiency improvements on the energy consumption side lead to a decrease of final energy demand, while energy efficiency improvements on the supply side lead to a reduction of primary energy demand. The amount of primary energy saved in major economies in 2017 as a result of efficiency gains since 2000 is estimated to exceed 50 EJ (13.9 PWh) (IEA, 2019b). Most of the savings, 37 EJ (10.2 PWh), were due to improvements on the consumption side and respective avoided final energy use. Only 13 EJ (3.6 PWh) are related to avoided primary energy supply due to a decrease in electricity demand and efficiency gains in the power sector. Most of the savings were realised in the industrial sector, as this sector’s final energy consumption decreased by 19 EJ, while the energy consumption within buildings decreased by 14 EJ, and the remaining 4 EJ were saved due to improvements in the transport sector.

The overall slowdown in efficiency improvements in the later years can be partially explained by specific weather conditions: cold winters and warmer summers in the US, and accelerated growth of the energy intensive industry (IEA, 2019a). However, long-term structural factors also have a strong effect on efficiency improvements; while energy efficiency in industry, buildings, transportation improves, the structural changes in consumption are dampening the impact of the technical efficiency improvements. These changes are known as the rebound effect (Stern, 2020), as improved specific efficiency is often compensated by demand growth, such as growing building floor area use per person, changes in transport modes including growth of aviation travel, a switch to more private vehicles, and bigger vehicles. These structural changes cannot be limited or reverted since it would violate equity requirements and devaluate the idea of sustainable development. Instead, more efforts should be concentrated on energy supply side efficiency. Reduction of fossil fuel-based energy utilisation in current centralised power generation, and a transition towards more evenly distributed RE-based power generation will improve efficiency on three levels: avoiding thermal losses in power generation, energy consumption for energy carrier transportation, and power losses in centralised power grids. Direct electrification of industrial processes and electrical transport, wherever this is technologically possible, will also lead to advanced efficiency improvements and enable overcoming the rebound effect.

2.3 Electrification

Electrification of all energy sectors can be the main measure for energy system efficiency improvement (Brown et al., 2018). Electricity-based energy processes in industry and electrical mobility have a much higher efficiency compared to similar fossil fuel-based processes or internal combustion engine (ICE) vehicles. For example, the e-Golf 2019 car from Volkswagen would consume 15.9 kWh_{el}/100km while the similar ICE vehicle Golf from the same manufacturer would consume 5.3 l/100km – about 51 kWh_{th}/100km. Similar cases can be shown for industrial processes: standard steel making demands about 6650 kWh (considering electricity, steam and coal energy) to produce one tonne of steel (World Steel Association, 2008), while the improved hydrogen-based direct reduced iron (H_2 DRI) process demands about 5700 kWh_{th} per tonne of steel (considering electricity, steam and hydrogen) (Otto et al., 2017), and the electro winning process based on direct electrical reduction demands only about 3700 kWh_{el} and 300 kWh_{th} per tonne of steel output (Yuan et al., 2009). Direct electrification of low temperature heat supply with heat pumps also results in a significant efficiency gain. The coefficient of performance (CoP) of heat turbines reaches in standard conditions 3 – 4.5 depending on the heat source type, though the real CoP can be much lower due to seasonal performance factors (EC, 2014). Though in case of heat pumps the efficiency gain depends on the primary energy demand definition, if environmental heat is included in primary energy supply calculations, overall efficiency will be on a level comparable with direct electric heating; however, the required electricity is only unity divide by CoP for the delivered heat.

Direct electrification of medium and high temperature heat with direct electrical heating may not bring a significant efficiency improvement due to the similar efficiency of modern furnaces and electrical heating; however, switching to electricity allows to simplify the logistics and decrease the energy consumption for the last mile of transportation.

However, in some processes direct electrification is currently not possible nor economically feasible with current technologies, such as long-haul aviation, long distance shipping, or seasonal energy storage. In these cases indirect electrification via e-fuels can be the solution (Ramirez et al., 2020). However, e-fuel utilisation will result in a primary demand growth and overall efficiency drop due to additional losses in the e-fuel synthesis. Consequently, the cost of e-fuels will be significantly higher than the cost of electricity in the system, which will make any indirect electrification only feasible in case of very low electricity cost and high carbon pricing or in other words fossil fuel prices reflecting the economic truth of harmful emissions causing climate change and air pollution (Coady et al., 2016).

Finally, an overall energy system electrification cannot be simply a measure to raise energy efficiency, but the main driver for these improvements, ultimately driven by reducing the cost for the aimed energy services. Transitioning to RE-based electricity enables affordable electricity supply, being universally available. The transition towards electricity-based processes in heat, transport and industry sectors creates multiple benefits, in particular also beyond the efficiency improvement narrative.

2.4 Decentralisation and prosumerism

Decentralisation is an ongoing process in many aspects of human life. Development of IT technologies and broad digitalisation have allowed to develop peer-to-peer networks in various fields of human activities starting from information, where social networks and open encyclopaedias allow unlimited free exchange of information, to real economy where services such Airbnb and Uber allow individuals to provide housing and transport services. There is no centralised service provider except the exchange platform, only the common medium in which individual consumers can reach individual service providers. In most of the cases the same individual can be consumer or producer of the service depending on the situation, which is described with the term prosumerism (Ritzer & Jurgenson, 2010). Obviously, prosumerism and decentralised services always existed in some form, but have never been as widespread and open as today; this is why prosumerism can be seen as an old form of capitalism, a result of evolution and a new one at the same time (Ritzer, 2014).

In the field of energy, the spread of prosumerism can be seen in the growing number of domiciles with their own power generation capacity while at the same time connected to the grid, and a growing share of individual heating in countries with previously developed district heating systems. Prosumerism is already developing fast in regions like Europe and may develop further in the future (Child et al., 2019). Similar to other fields, energy prosumerism was enabled by digitalisation, which simplified the control of individual energy systems, but even more impactful was the development of RE, energy storage and electric heating technologies, namely PV and heat pumps. As a result of the continuous decline of PV costs and increase of retail electricity prices, PV reached grid-parity in many regions of the world making own generation profitable (Breyer & Gerlach, 2013). A similar trend is seen for heat pumps; in many cases heat supply from one's own heat pump is cheaper than heat from an existing district heat (DH) system especially in case of sparse systems (Reidhav & Werner, 2008), even considering increasing retail prices of electricity. Both technologies benefit from decentralisation; the coefficient of performance for small-scale household applications is normally higher than for large-scale DH heat pumps (Connolly, 2010; EC, 2014) due to heat transfer limitations, while PV requires significant rooftop area, which is not available in the context of dense apartment block housing.

This decentralisation is beneficial for all VRE technologies, namely PV and wind. These technologies are characterised by rather low capacity densities and in many cases have to be installed further from consumption centres, in locations with specific conditions to reach maximum energy output. The geographical distribution also decreases the impact of short-term weather effects and increases the RE generation reliability (Brown et al., 2018).

2.5 Decarbonisation and defossilisation

The severe negative impacts of climate change around the world cannot be disregarded; growing evidence like temperature anomalies and droughts (NOAA, 2017; Schellnhuber et al., 2016), collapsing sea (Hughes et al., 2018) and land ecosystems (Hughes et al., 2018; IPCC, 2014a), irregular monsoons, etc. push society to react and reduce the anthropogenic pressure on the environment. Otherwise, without immediate actions the climate change process is expected to accelerate in the future leading to more severe and frequent climatic deviation (Steffen et al., 2018) getting even worse beyond a temperature rise of 1.5°C above pre-industrial levels (IPCC, 2018). Some models show that even an immediate stop of carbon emissions may be not enough to stop climate change processes (Randers & Goluke, 2020). At the same time, limiting warming to 1.5°C by mid-century could reduce the exposure to both climate-related risks and the corresponding susceptibility to economic burdens.

Rapid and fundamental change is required across all economy sectors. While in many cases most of the attention is applied to CO_2 emissions, other GHG emissions also need to be drastically reduced: each molecule of methane or halogen gases have a much higher impact on global warming then a CO_2 molecule. Despite much lower ppt values, methane and halogens are responsible for 12% and 9% of the total global warming through 2018 (before cooling subtracted), respectively (Jacobson, 2020). However, carbon emissions (CO_2, black and brown carbon) contribute to the lion share of emissions. Energy systems, including power, heat, transport and industrial sectors, are responsible for about 75% of the GHG emissions with the remaining 25% coming from land use, land use change and forestry (LULUCF) and agriculture (IPCC, 2014). Reduction of GHG emissions is the key of UN SDG 13 ‘Climate actions’, and in terms of energy goes in line with SDG 7 ‘Affordable and Clean energy’. While the demand to drastically reduce carbon emissions in energy systems and other sectors is undoubted, different views on the possible approaches are seen.

Some researchers and institutions see the development of nuclear power generation as the response to the climate change challenges (Knapp et al., 2010). In case of a media-wise described nuclear renaissance, which is not based on market facts, nuclear power generation is supposed to become the backbone of energy systems, providing energy for electrified heat, power and industrial sectors. While nuclear power-based energy systems can reach carbon neutrality, they have a substantial number of severe drawbacks. The most important issue is the severe risks of major nuclear accidents as have been already seen in case of Three Mile Island, Chernobyl, or Fukushima disasters. These can lead to physical health threatening radiation exposure of power plant personnel and the population of nearby areas, long-term radiation contamination of the areas around the plant, and radiation spread to distant areas by atmospheric transfer of radioactive material as in case of Chernobyl (Chernobyl Forum Expert Group “Enviroment,” 2006) or by oceanic currents as in case of Fukushima (Smith et al., 2015). These security issues have led to significant social resistance to nuclear energy development in many countries, which first emerged after the Three Mile Island disaster, further escalated by Chernobyl and after decline in the 2000s arose again due to the Fukushima disaster. The second issue is storing of the long-term radioactive waste from normal operation of the nuclear power plants. The half-life for some isotopes reaches 24 000 years, and for the whole time the storage security must be guaranteed, which is by at least one order higher longer than the entire period of civilisation. The nuclear cycle also creates hundreds of thousands of tonnes of low radioactive waste, including ore processing and uranium enrichment tails, contaminated and embrittled construction materials. The third issue is limited potential of fission materials used in the traditional uranium cycle: even considering the current share of nuclear in the primary energy supply, present measured resources of uranium (6.1 Mt) are sufficient to supply today’s nuclear power plants fleet (about 400 GW_{el}) for 90 years (World Nuclear Association, 2020), but will not be enough to cover the current energy demand even for 5 years (IEA, 2020a). The resource issue could be partially resolved by introduction of a closed nuclear cycle with breeder reactors and the introduction of a thorium cycle, but these technologies are still at low technical maturity stages, though at higher level than for fusion reactor technology, which still struggles with overcoming fundamental technical barriers. Utilisation of a closed nuclear cycle has a number of issues. One is the necessity to use highly enriched uranium to run fast-neutron reactors, which limits the list of countries able to deploy due to the Treaty on the Non-Proliferation of Nuclear Weapons. Additionally, a closed nuclear cycle is only possible in a short list of countries which possess the full knowledge of nuclear technology and industrial capacities for isotopes refining. Otherwise, an export of full cycle technology will further endanger the Non-Proliferation Treaty, giving access to technologies for production of weapons grade uranium and plutonium. A closed cycle with refining of the used fuel in other countries is no solution because it leads to constant international flows of highly radioactive materials. In any case, even the closed nuclear cycle will produce nuclear wastes both from operation and fission material (uranium or thorium) mining. Finally, the main issue is the growing cost of nuclear power plants construction and continuous delays of their commissioning, finally making nuclear energy too expensive (Brown et al., 2018; Wealer et al., 2021). Overall, the upscaling of nuclear generation will have a number of issues making nuclear-based energy systems implausible (Abbott, 2011; Wealer et al., 2021).

Some researchers and institutions promote the utilisation of conventional fossil-based technologies with carbon capture units, with further permanent storage of the captured CO_2 (CCS) or captured CO_2 utilisation (CCU) for e-fuels production and other purposes.

While it is claimed that the main purpose of the CCS technology is to create additional sinks for the emitted CO_2 and ultimately reach a carbon neutral energy system, this technology is often seen as a way to support the business as usual for fossil fuel producing companies (Spreng et al., 2007). At the same time the concept of CCS remains unproven by long term profitable operation of the test sites (Zegart, 2017). The concept of CCS itself has three major flows. First of all, fossil CCS cannot reach carbon neutrality as not all CO_2 emissions can be captured from the exhaust gases at point sources. Efficiency of carbon capture units is well below 100% (Fasihi et al., 2019) and additional carbon emissions occur at every step of the fossil fuel lifecycle: in mining, refining and transport. Negative emission technologies have to be established to reach carbon neutrality in CCS-based systems, while the options are rather limited. The second issue is the possibility of the CO_2 return to the atmosphere in case of long-term storage leakage. Thirdly, CCS would result in higher fossil fuel consumption due to lower overall efficiency of power or heat plants with CCS, leading to eventually higher total emissions. Overall, even with additional emission compensation with DAC to reach carbon neutrality, the fossil CCS utilisation will result in unnecessary fossil fuel extraction and increased air pollution compared to the case that the same financial resources are invested in renewable electricity and heat generation capacities in order to replace existing fossil-based capacity (Jacobson, 2019). Additionally, CCS introduction will incur administrative difficulties, demanding accurate monitoring of the fuels and captured carbon flows from numerous final consumers in order to avoid releasing flue gases to the atmosphere. Bioenergy CCS (BECCS) at the same time can be a viable negative emission technology, if a reliable long-term carbon sink is utilised; however, the sustainably available amount of bioenergy is severely limited to 27.8 PWh_{th} (100 EJ) (Creutzig et al., 2015), which equals 16.6% of present primary energy demand and thus is not a scalable option. Another issue is that CCS is not applicable well to the transport sector and thus electrification of transport will be unavoidable in CCS-based energy systems, which will lead to further growth of electricity demand, fossil fuel consumption and emissions. Finally, due to a number of previously described flaws CCS cannot be the basis of a carbon-neutral energy system.

Similarly, fossil CCU cannot be part of carbon neutral systems since carbon is simply reused and ultimately emitted to the atmosphere (SAPEA, 2018). The Bioenergy CCU (BECCU) route can be an important source of CO_2 for hydrocarbon synthesis (Breyer et al., 2019). However, the bio-CO_2 sources have to be sustainable: either sustainable residue-based biomass used for power and heat production as in the Audi e-gas facility in Werlte (Audi MediaCenter, 2016), or a side product of industrial processes as in the recently published vision by LUT, ST1 and Wärtsilä (Laaksonen et al., 2020). According to this vision of the future, renewables will play significant roles in future energy systems, substituting fossil fuels both as an energy source and a raw material source for industry.

2.6 Renewable energy

Historically RE played an important role in energy supply, but due to limited resources of traditional RE sources, hydro and biomass, the share of RE in the total primary energy supply constantly declines through the twentieth century. Development of novel RE generation technologies, wind turbines, solar thermal and solar PV power plants, provided a new impulse to renewable energy. Historically, renewables, mainly traditional biomass and muscle power, but also wind energy, were the main source of energy for humanity. Only after the industrial revolution did the role of fossil fuels start a fast growth supporting an explosive increase of the energy demand. At the beginning of the 20th century fossil fuels became the major energy source for the system (Johansson et al., 2012). The 20th century was an age of fossil fuels, but in the recent decades energy generation from RE sources has rapidly increased around the world and modern RE technologies already play important roles in energy supply in many regions with various climate conditions. Initially climate change concerns were the main motive for the introduction of renewables in energy systems and the process was massively supported by governments. This support allowed further development and maturing of the technology leading to cost declines, especially for solar PV technology (Nemet, 2019). Similar learning curve effects are observed for wind (Ibenholt, 2002) and battery storage technologies (Schmidt et al., 2017), which are necessary elements of RE-based energy systems. Finally, in recent years RE generation became cost competitive towards conventional generation technologies in some regions of the world, and the number of these regions is growing with further development of technology and cost declines (REN21, 2020). In 2019, RE contributed to 77% of all newly installed capacity (Frankfurt School-UNEP Centre/BNEF, 2020) and IEA has accepted PV as the least cost source of electricity. The RE generation has emerged to become a quite competitive option worldwide in the solar resources rich Sun Belt regions (Gulagi et al., 2017), wind resource rich coastal regions (Child et al., 2019), and even in high latitude regions like Finland (Haukkala, 2015; Vartiainen et al., 2020). The final confirmation of outstanding solar PV competitiveness has been provided by IEA (IEA, 2020d, p. 13) in stating that “Solar becomes the new king of electricity […] with solar at the centre of this new constellation of electricity generation. […] With sharp cost reductions over the past decade, solar PV is consistently cheaper than new coal- or gas-fired power plants in most countries, and solar projects now offer some of the lowest cost electricity ever seen.”

Growth of RE fulfils all the prior energy system transformation requirements. A shift to RE allows to effectively decarbonise the energy system on a fully sustainable basis, avoiding security risks of the artificial long-term carbon sinks as in the case of fossil CCS and the problems and risks related to the long-term nuclear waste disposal and the nuclear power plants operation itself. Though RE generation in general does not lead to direct carbon emissions (with the exception of some technologies as direct flash steam geothermal in limestone or other carbonate minerals), RE generation capacity still has a carbon footprint if fossil fuel-based energy is used for manufacturing (White & Kramer, 2019), but the carbon footprint will constantly decrease if RE growth rate exceeds energy demand growth. RE technology equipment, as with any other technology equipment, will demand recycling after the end of its technical lifetime, and is practiced as documented for the case of solar PV (Heath et al., 2020). Further technological development will be needed to increase the recycling rate and decrease its cost for RE technologies, in particular for batteries (Greim et al., 2020).

RE technologies like PV and wind benefit from decentralisation of energy systems and solar PV technology made possible the emergence of energy prosumerism. The possibility of decentralisation and automation of energy supply with RE makes this the key technology to provide universal access to energy and electricity. Pico PV and micro grid systems open access to energy for new communities or substitute small-scale diesel generation (GOGLA, 2020; Power Africa, 2019), leading to consequent overall life quality improvement and economic growth by elongating the active economical day time for studying and business. Substitution of inefficient small-scale diesel generation also reduces carbon emissions and fuel costs, while it reduces overall cost (Cader et al., 2016). Although the cost of PV based generation is lower than diesel generation cost in Sun Belt countries, the cost of a diesel generator is still lower than the cost of similar PV systems, creating a financial trap- while saving on the capital cost of the system, people lose much more in the running costs. Additional financial initiatives are needed to promote renewables in these regions to avoid this trap and satisfy fast growing energy demand on RE basis.

The modern RE resource potential is sufficient and far exceeds the requirements of the global economy today and in future (Perez & Perez, 2009), and is not limited by peak-oil, peak-coal, peak-uranium, or concerns on conventional and nuclear energy sources. However, some concerns appear considering the material availability for large-scale RE-based system implementation, especially in part of the materials for battery storage like cobalt and lithium (Greim et al., 2020; Junne et al., 2020). Fortunately, a wide range of technologies exist nearly in each segment, with different materials requirements. Thus, different technologies can step ahead in case of some material scarcity at the cost of slightly lower efficiency or slightly higher cost. Various battery technologies already exist, including cobalt-free lithium-ion batteries, (though with lower capacity per unit mass, or higher self-discharge, or higher cost) and new promising technologies as sodium-ion arise to partially substitute Li-ion technologies, rare materials dependent PM generators in wind turbines can be substituted by asynchronous (induction) generators at the cost of an additional gearbox and more complicated control, copper can be substituted by aluminium in most of appliances at the cost of slightly higher losses etc. Finally, it should be possible to overcome most of currently discussed material limitations, which could be an obstacle to the transition towards RE-based energy system.

Overall, the future energy system has to be RE-based in order to satisfy all the sustainability criteria. Though the installation rates of RE capacities are growing, systems are just at the beginning of the transition and energy systems have to go through a radical transformation until 2050 to reach carbon neutrality and further support sustainable development. This transition will require substantial investments and consequently accurate planning to minimise the chance of stranded investments and guarantee reliable energy supply at minimum possible cost. The transition pathway planning will demand accurate estimation of the RE potential and accurate modelling of the RE technology specifics, especially the operation of VRE sources such as PV and wind, operation of energy storage technologies and other flexibility options which will become integral parts of systems.

3 Methods

Any definition of energy system transition pathways will demand accurate pathway planning to minimise the cost of the system transformation and avoid stranded investments. At the same time the reliable operation of a system has to be guaranteed at each step of the transition. Giving the complexity of energy systems and the necessity to consider the operation of energy systems with high shares of RE, this applies additional requirements to the modelling approach. To properly address all the requirements and model energy system transitions in detail and considering the role of RE in this transition, the new LUT Energy System Transition Model was developed during this dissertation.

3.1 Overview of energy systems modelling

Given the complexity of energy systems and the uncertainty of their future development, modelling becomes an excellent tool to provide a better understanding of the processes in energy systems, energy system optimal structure, possible pathways of energy system transitions and the impacts of different parameters and technologies on future energy system structures and development pathways.

According to Grubb et al. (1993), all models share three unavoidable limitations:

1. Any model is always a simplified representation of reality, and each researcher defines the most important aspects that should be reflected in high detail, and less important aspects that can be simplified to keep the overall model complexity at a level compatible with the available computational capacity. No model can capture the operation of the system in full.
2. Energy system models are still rather complex and include vast amounts of data, parameters and assumptions. Estimation of these numbers is a research task on its own, and inaccuracy of the used data can be another major source of the uncertainty of results. To simplify data collection, the list of inputs can be limited, which may result in the increase of the model complexity. On the contrary, more parameters can be exogenous, which can simplify the model, but may increase the complexity of the scenario definition. In any case, sensitivity analyses have to be adequately performed to examine the impact of the input data uncertainty on the model results.
3. Timescales have an inevitable impact on the energy system, on different levels.

In the past decades dozens of models have been created to catch the most important aspects of energy systems according to different research group perceptions, with different approaches to system representations, different approaches to input data structures and different timescales (Connolly et al., 2010; Lopion et al., 2018; Prina et al., 2020). The task of classifying energy system models becomes more and more complex with the increasing number of models that sometimes have only slight differences.

Different approaches to the classification have been discussed in the scientific literature. Grubb et al. (1993) proposes six main dimensions, based on the model structure:

1. ‘Top-down’ and ‘Bottom-up’ models
2. Time horizon: ‘Short-term’ vs ‘Long-term’
3. Sectoral coverage: Energy vs general economy
4. Optimisation vs Simulation
5. Level of Aggregation
6. Geographic coverage

Jebarai and Iniyan (2006) reviewed a number of papers published in the period from the 1970s to the early 2000s and classified them into six categories mostly based on their application:

1. Energy planning models
2. Energy supply demand models
3. Forecasting
    - 3.1. Commercial energy models
    - 3.2. Renewable energy models (solar, wind and biomass sub-categories)
4. Optimisation
5. Energy models based on neural networks
6. Emission reduction models

Jacobson (2020) discusses three common types of energy system models:

1. Power flow/load flow models
2. Optimisation models
3. Trial-and-error simulation models.

Hiremath et al. (2007) combined the previous classification approaches and proposed a classification based on nine dimensions:

1. General and specific purposes of energy models
2. The model structure: internal assumptions and external assumptions
3. The analytical approach: top-down vs. bottom-up
4. The underlying methodology
5. The mathematical approach
6. Geographical coverage: global, regional, national, local or project
7. Sectoral coverage
8. The time horizon: short, medium, and long term
9. Data requirements.

Muller et al. (2018) provided an overview of the previously mentioned and some other classification methods and came to the interesting conclusion that a classification approach which would fit all models does not exist, and that the models' classification, similarly to the models, should be tailored according to the target audience and the aim of the study. For the case of this dissertation parameters will be discussed which at the highest extent differentiate the most used energy system models. Current computational power still does not allow describing energy system transitions in as full detail as power flow/load flow models. Consequently, these and other similar models are not considered in this overview. Top-down models are in opposition and do not describe the system in high enough detail to capture the specifics of RE introduction. Thus, in this review only bottom-up models are considered, which represent a compromise between the high detail and complexity (as with power flow/load flow models) and an oversimplified view on the energy system as with top-down models. The mathematical approach and underlying methodology are closely coupled terms and can be merged into one. Data requirements are the outcome of all other model parameters and thus can be omitted. In case of studying energy systems with high shares of RE, one aspect becomes especially important; temporal resolution of the model plays a decisive role in the modelling of highly variable solar and wind energy resources (Brown et al., 2018). For the purpose of this study, five main dimensions will be observed:

1. The underlying methodology: Optimisation vs simulation
2. Temporal resolution
3. Geographical coverage
4. Sectoral coverage
5. The time horizon: short, medium, and long term

Dozens of models can be used for RE-based system analyses, and the most popular models are EnergyPLAN, the LUT Energy System Transition Model (as described in this chapter), TIMES, HOMER, REMix, AU model, PyPSA, LOADMATCH, NEMO, ISA model, H_2RES, GENeSYS-MOD, and MESAP/PlaNet. Almost 400 energy system modelling related articles were analysed and the results of this analysis is presented in Lopez et al. (2021). At the moment of the analysis (May 2020) by far the most used models for highly renewable energy system studies with a RE share of at least 95% were EnergyPLAN and the LUT Energy System Transition Model, somewhat remotely followed by TIMES and HOMER. Full statistics are described in Table 2.

Table 2. Leading Energy System Models (ESMs) for highly renewable energy system analyses 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 (Lopez et al., 2021).

		citations		model used for 100% RE	
Model	articles	total	2019	earliest	latest
EnergyPLAN	55	4259	822	2006	2020
LUT Model	50	795	377	2015	2020
TIMES	14	341	108	2011	2020
HOMER	14	652	146	2007	2020
REMix	9	252	97	2016	2018

AU model	16	989	187	2010	2018
PyPSA	11	142	87	2017	2020
LOADMATCH	7	519	212	2015	2019
NEMO	7	428	78	2012	2017
ISA model	7	41	18	2016	2020
H_2RES	6	595	53	2004	2011
GENeSYS-MOD	6	36	24	2017	2019
MESAP/PlaNet	5	134	43	2009	2018
others	187	6311	1390		
total	389	15494	3642		

EnergyPLAN (Aalborg University, 2020) is an energy system simulation model developed at Aalborg University, Department of Development and Planning. Currently, EnergyPLAN is the most popular and most cited model with more than 50 studies published in journals and more than 4000 citations since 2006, when this model was first used for 100% RE studies. The model is publicly available and can be downloaded for free, and it has a user-friendly interface and well-developed documentation. EnergyPLAN is a simulation model, which demands the researcher to manually specify an energy system structure, while the model checks whether such a system is feasible and if so, it reports energy and mass flows in the system. This results in challenges to find the cost optimal energy system structure in the case of a system with a realistic set of competing technologies. It can demand from the researcher many attempts to define some feasible and close to optimal solutions, while never knowing how close the solution is to the optimal system structure. However, on the other hand, each simulation is completed very fast. EnergyPLAN operates in full hourly resolution and enables simulation of a system with several nodes. The model includes the power, heat, transport sectors and to some extent the industrial sector, allowing coverage of all energy related emissions. The system has a short time horizon – energy systems can be simulated for a given year and transition modelling capabilities are not yet built in the model.

TIMES (The Integrated MARKAL-EFOM System) was developed as a part of the IEA-ETSAP (Energy Technology Systems Analysis Program) in 2005 (IEA-ETSAP, 2021) and currently is the third most popular model for highly renewable energy system analyses, with 14 publications since 2011. The model has many sub-versions for specific projects and regions. TIMES is an optimisation model and the model defines the optimal system structure and operation. However, to decrease computational complexity the model does not operate in full hourly resolution, the year is represented by a limited number of time-slices which are supposed to represent conditions during different seasons. Though the TIMES framework can operate with any number of intra-annual time-slices (Kannan & Turton, 2013), according to a review by Prina et al. (2020), the typical number of time-slices applied is in between 12 (4 seasonal and 3 diurnal: day, night, peak) and 32 (4 seasonal, 2 weekly and 4 diurnal) as in TIMES-DK (Balyk et al., 2019). However, with such an approach it is not possible to guarantee that the simulated system will be able to work stably through the whole year and that the defined generation and storage capacity will be sufficient to cover energy demand at every hour and at the same time such a system will not be oversized (Kotzur et al., 2018). The main version of TIMES does not allow simulations of multi-node systems; however, the model allows sectoral integration modelling and covers the power, heat, transport and industrial sectors. TIMES is a perfect foresight (clairvoyant) model and allows transition studies.

HOMER (Hybrid Optimisation of Multiple Energy Resources) is a micropower optimisation model developed in 1992 by the National Renewable Energy Laboratory (NREL) (HOMER Energy, 2021). HOMER is an optimisation model and operates in high temporal resolution, up to 1 minute. The model is mostly applied to microgrid simulations rather than to full energy system simulations. The model includes the power and heat sectors, elements of transport and industry (in terms of hydrogen production and consumption). The standard model simulates one year, but additional modules allow simulations of changes in the project through the lifetime of the project.

Prina et al. (2020) review energy system models and integrated assessment models and analyse model transparency and resolution in terms of time, space, techno-economic detail and sector coupling. According to these metrics, the LUT Energy System Transition Model shows the best performance due to high time, space and sector coupling resolution, and satisfactory techno-economic detail and transparency. After analysing and comparing these and other models to the LUT Energy System Transition Model, Lopez et al. (2021) conclude that at the moment this is the only energy system model combining all the key features for comprehensive energy system analyses: cost-wise optimisation, full hourly resolution, multi-node approach, multi-sector integration, technology-rich description of each of the sectors, and transition modelling.

3.2 LUT Energy System Transition Model structure

The LUT Energy System Transition Model optimises energy system transition pathways including the power, heat, transport, and industrial sectors, considering additional emerging technologies such as e-fuel production, seawater desalination, and CO_2 removal. The optimisation is performed in full hourly resolution for all hours of a year in single-year steps, where the starting conditions of the simulation depend on the time step assumptions and the previous time step results. At each step of transition, the model defines the optimal structure of an energy system and simulates an optimal operation for each hour to guarantee balance of energy and other services, supply and demand, and the least cost of the system operation. The most advanced version of the model is described in **Publication VI** (Bogdanov et al., 2021).

The model development started in 2014 based on the MRESOM model (Pleßmann et al., 2014) designed at the Reiner Lemoine Institut (RLI) by Guido Pleßmann and Prof. Christian Breyer for the optimisation of decentralised hybrid power systems using a state-of-the-art linear optimisation approach. The hybrid power system included PV, wind and

CSP as power supplies, battery storage, thermal energy storage (charged from CSP, electric heating or fuel-based burners and used to produce power via steam turbines) and the gas storage (including PtG technology and gas turbines to produce power from synthetic gas). Based on that starting point, the model development was conceptualised and designed under the supervision of Christian Breyer. The concept of the model was augmented to introduce a multi-nodal operation with modelling of the operation and losses of grids, hydropower and pumped hydro energy storage, and the model was reorganised to enable the simulation of regional energy systems, which led to the first version of the LUT Energy Model used in **Publication I**.

Further expansion of the power generation and energy storage technologies portfolio, including fossil and nuclear generation technologies, and the introduction of energy transition functionality led to the version of the LUT Energy System Transition Model presented in **Publication III**. Integration of heat, transport, and industry sectors, and emerging technologies, with a respective expansion of the portfolio of technologies, led to **Publications IV-VII**. The model is in the process of constant development and the publications discussed in this dissertation do not include some of the latest modifications, and studies based on the latest versions of the model are currently in preparation. At the moment, the description of the most advanced model version is provided in **Publication VI**.

Most of the model code (more than 90%) is written by the author of the dissertation. However, the model code still shares some functions with the ancestor model MRESOM, written by Guido Pleßmann. Though the model development was performed by the author of the dissertation, the detailed investigation of specific elements and sectors to provide the inputs for the model were often performed by other researchers. Ahe description of the researcher’s contributions is presented in the Author's contribution section. The model uses a third party solver for linear optimisation. In most casesc, the MOSEK optimiser (Mosek, 2021) is used. However, the model can also use the Gurobi optimiser (Gurobi Optimization, 2021) or, after modification, any other high performance linear optimisation tool.

3.2.1 Purpose of the model

The purpose of the LUT Energy System Transition Model is to assess different possible pathways of energy system development and assist global, national, and regional energy strategy planning. Simulations allow investigation of the impact of different policies on the system structure, cost, emissions and the process of development. The model also tests the benefits of energy sector integration (also called sector coupling), including the power, heat, transport and industrial sectors (including emerging industrial segments: industrial fuels production, desalination and CO_2 removal), as well as evaluates the possibility of additional flexible demand integration and its impact on the system. The model can be used for:

Technical analyses - *Simulation of the system operation with given system structure, resource, technical and financial assumptions.*

Such simulations can be utilised for energy system robustness assessment to evaluate the range of conditions for which the system can satisfy the demand.

Feasibility studies - *Energy system structure and operation optimisation mode for given technical and financial constraints.*

There is an overnight simulation approach (also called short-term), which provides information on optimal greenfield energy system structures for given financial and technical assumptions. This is applied in **Publications I-II**.

Energy system transition studies - *Simulation of the energy system transition from the current structure towards an optimised energy system.*

In case of a transition study (also called long-term), the simulation is performed for several time steps with specific financial and technical assumptions. The simulation starts from the existing energy system structure and the initial conditions of each time step are based on the system structure formed in previous steps. The results provide information on an optimised system structure and operation mode for each step, data on system cost, costs of all the products and elements, and GHG emissions of the system. This is applied in **Publications III-VII**.

3.2.2 Modelling procedure

The first step of the energy system modelling is **Data preparation**, defining the financial and technical assumptions.

The second step is the **Scenario specification and simulation**, available options are a transition scenario or overnight scenario. For each type of scenario, the power, heat, transport, and industrial (including industrial fuel production, desalination, and CO_2 removal) sectors can be enabled. For the power sector, the simulation can be performed for a centralised system excluding or including the presence of power prosumers. For each type of simulation, three levels of regional integration can be applied (introduced in **Publication I**):

- Regional: all regions (nodes) of the energy system are isolated;
- Country-wide: energy systems are integrated by transmission infrastructure, such as power grids, inside the same country;
- Area-wide: countries are integrated by transmission infrastructure for the selected area, typically a major region, such as Europe.

The third step is **Results preparation**. After the end of the simulation, the tool collects the optimised results for all model elements in data files and summarises the main data in a results Excel file. The overall structure of the modelling procedure is given in Figure 3.

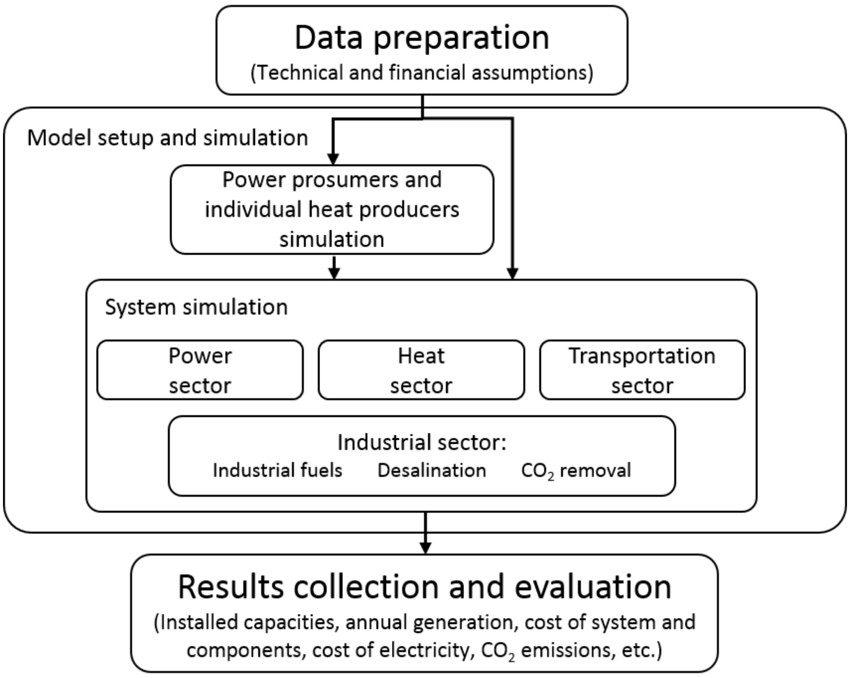

Figure 3. The overall structure of the modelling procedure.

3.2.3 Energy systems operation: Power sector

The power sector is divided into a centralised energy system and a power prosumers sub-segment. The share of electricity demand related to prosumers can be specified from 0 to 99% of the total. The power sector, represented as a combination of a centralised power system and prosumers, has been introduced in **Publication I**.

Centralised power system

In the centralized power system, all consumption goes through the local alternating current (AC) grid to which the RE generation capacities (PV, wind, hydropower, solar thermal electric, geothermal, biomass power plants), fossil and nuclear power plants, and fossil and biomass-based combined heat and power (CHP) plants are connected. At the same time, the local AC grid is connected to storage capacities and interregional high-voltage direct (HVDC) and high-voltage alternating current (HVAC) grids.

Power prosumers sub-segment

PV prosumers represent three types: residential, commercial, and industrial. For each prosumer type, the share of total electricity demand (where the sum of residential, commercial, and industrial is equal to the full power sector), grid electricity price and financial assumptions for PV systems and batteries can be specified. Prosumers have the option to install their own PV generation capacities, install Li-ion battery storage, sell excess electricity to the centralised power system for a specified feed-in price, or buy electricity from the centralised power system at a specified electricity cost. In the standard scenario, the share of consumers willing to install their own PV generation capacities increases accordingly to a logistic function in steps of 3%, 6%, 9%, 15%, 18%, and 20% of the respective electricity demand segment (if grid electricity is cheaper than that from PV generated, the share for the next step remains unchanged). If power prosumers use individual heating, generated power can also be used for electrical heating (heating rods and heat pumps).

The simplified diagram of the power sector is presented in Figure 4.

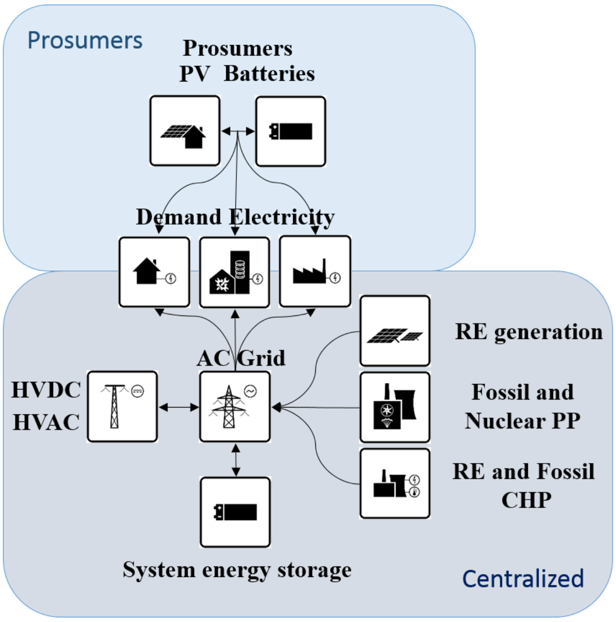

Figure 4. Power sector structure.

3.2.4 Energy systems operation: Heat sector

The heat sector was first introduced in **Publication V**. The heat sector consists of six main segments: Industrial high (> 1150 ºC), medium (100 – 1150 ºC), and low (< 100ºC) temperature heat demand, domestic water heating, space heating, and cooking biomass demand. All heat shall be generated inside the region. The heat sector is also divided into centralised and individual heating systems.

All industrial heat must be covered by the centralised heat system. Shares of centralised water and heating demand must be specified, and this must reflect the share of district heating specifics for each region. All biomass cooking, and the rest of water and heating demands are generated with individual heating systems. The heat can be generated by CHP plants, solar thermal collectors, individual or centralised fuel-based boilers, electrical heaters, and heat pumps. Industrial high temperature heat demand can be satisfied only by fuel-based heat plants. Medium temperature heat can be also provided by electrical heating. Low temperature heat can also be satisfied by heat pumps, heating rods, solar thermal collectors and recovered heat loss from thermal power plants. Generated heat can be stored in medium or low temperature heat storage. The simplified diagram of the heat sector is presented in Figure 5.

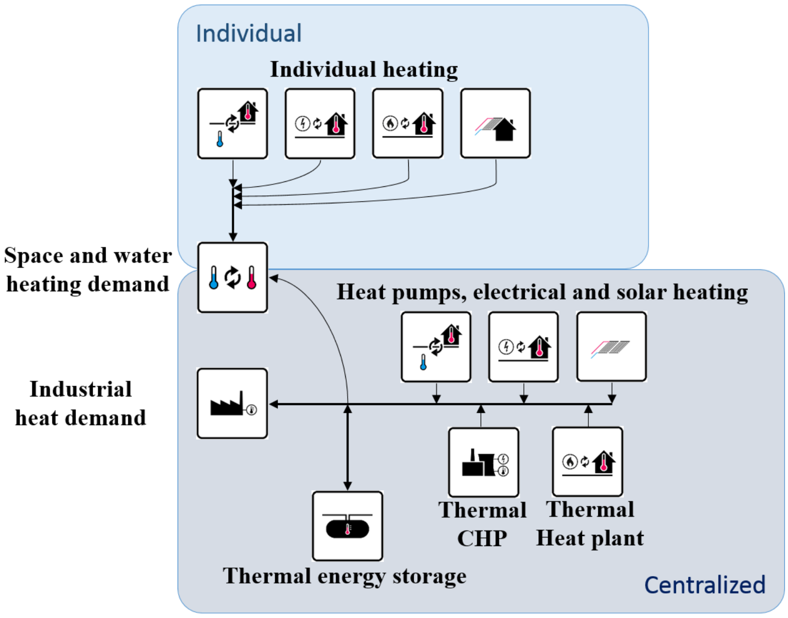

Figure 5. Heat sector structure.

3.2.5 Energy systems operation: Transport sector

The transport sector was first introduced in **Publication VI**. The transport sector is structured into the segments: Road, Rail, Marine, and Aviation.

Within the Road segment, a separation is done for light duty vehicles (LDV), mainly cars; medium duty vehicles (MDV), such as delivery trucks; heavy duty vehicles (HDV); and buses. For the four road segments, the following powertrains are available: internal combustion engine (ICE), battery electric vehicle (BEV), plug-in hybrid electric vehicle (PHEV) and hydrogen-based fuel cell electric vehicles (FCEV). The share of each type should be specified, as the choice of the vehicle is not always cost-driven and thus cannot be optimised in a cost-driven optimisation model. BEVs and PHEVs are charged from the grid by ‘dump charge’ – equally at every hour. Later model adjustments for ‘smart charge’ and ‘vehicle-to-grid (V2G)’ are planned.

Within the Rail segment, two fuel types are available: liquid hydrocarbon fuel (diesel), which can be fossil fuel, biofuel or renewable electricity-based Fischer-Tropsch (FT) liquid fuel, and electricity. The shares of the fuels shall be selected according to respective projections.

Within the Marine segment, four fuel types are available: liquid hydrocarbon fuel (diesel), which can be fossil fuel, biofuel or renewable electricity-based FT-fuel; liquefied methane gas (LNG), which can be liquefied fossil natural gas, biomethane or renewable electricity-based methane (SNG); liquefied hydrogen (LH2), which is only foreseen as renewable electricity-based hydrogen, and electricity for shorter distance domestic shipping.

Within the Aviation segment, three fuel types are available: liquid hydrocarbon fuel (kerosene), which can be fossil kerosene, biofuel or renewable electricity-based FT-kerosene; hydrogen, which is only foreseen as renewable electricity-based hydrogen; and electricity for shorter distance flights.

The simplified diagram of the transport sector is presented in Figure 6.

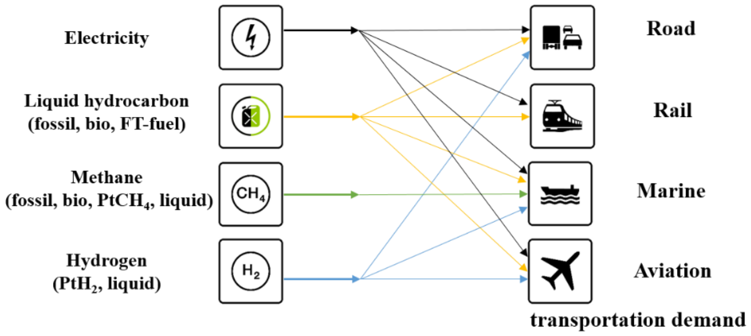

Figure 6. Transport sector structure.

3.2.6 Energy systems operation: Industry sector

The current model version includes the following industry segments: cement, steel, chemical industry, aluminium production, pulp and paper, and emerging segments such as industrial synthetic e-fuel production, desalination, and CO_2 removal. The inclusion of further industry sectors is planned for the future. The industry sector in its current form was first introduced in **Publication VI**, though parts were introduced earlier (for example synthetic methane for industry in **Publication I**).

Industrial fuel production

The energy system can use fossil fuels, as long as it is allowed or affordable, convert biomass to biofuels, and produce renewable electricity-based synthetic e-fuels in the power, heat, or transport sectors.

Currently, hydrogen, methane, and liquid hydrocarbon production units are integrated in the model. Methane can be produced from biogas after its purification/upgrading. Then, this biomethane can be used in the gas system. The share of biogas which can be upgraded is limited by the urbanisation level of the region, but cannot exceed 70% even if the urbanisation level is higher. A second option is synthetic natural gas (SNG) – methane produced with methanation reactors from hydrogen and carbon dioxide. The whole Power-to-Gas (PtG) system includes water electrolysis reactors (assumptions are based on alkaline technology) producing hydrogen from water, CO_2 direct air capturing (DAC) units collecting CO_2 and water from ambient air, and methanation units. Water electrolysers and DAC units consume power from the system in order to produce H_2 and CO_2, and then methanation units convert them to synthetic CH_4.

Liquid hydrocarbons can be produced from biomass by biorefineries, or can be synthesised from H_2 and CO_2 using the Fischer-Tropsch (FT) process. PtG with gas storage and gas turbines can be part of storage for the power sector. Fossil fuel refineries are not directly included in the model, and existing capacities of refineries are assumed sufficient to satisfy local consumption of fossil fuels, but the refining cost is included in the refined oil product cost.

The simplified diagram of the industrial fuel production sector is presented in Figure 7.

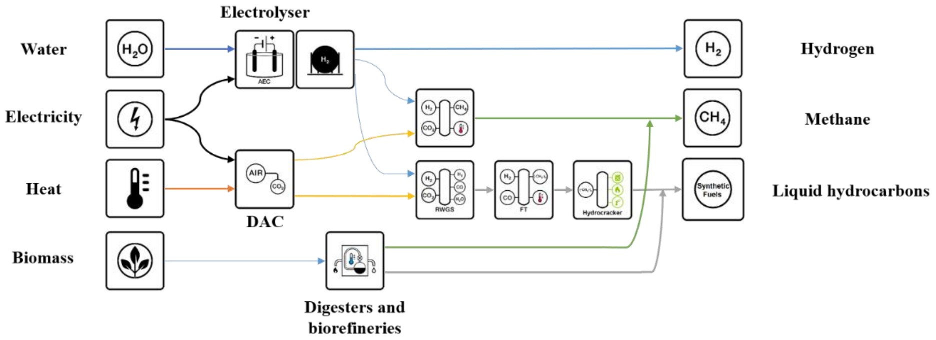

Figure 7. Industrial fuels production sector structure.

Desalination sector

Water demand in the region can be covered with Seawater Reverse Osmosis (SWRO) desalination, Multi Stage Flash (MSF) and Multi Effect Distillation (MED) technologies. The water is delivered to consumers by distributed piping systems with a respective energy demand, dependent on the distance and altitude from the coast. The water is stored at the production site, which may provide additional flexibility to the desalination system, and can optimise production in order to minimise total system cost.

The simplified structure of the desalination sector is presented in Figure 8.

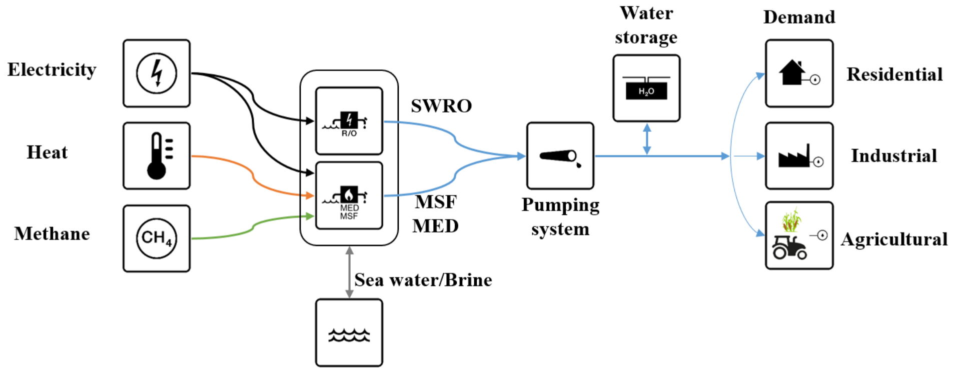

Figure 8. Desalination sector structure.

CO_2 removal sector

CO_2 removal demand can be specified for each region in tons of CO_2 per year. This amount of CO_2 will be captured from the atmosphere by DAC units in addition to CO_2 captured for synthetic e-fuel production. Heat and electricity needed for the DAC operation will be taken from the heat and power sectors, respectively.

The simplified structure of the CO_2 removal sector is presented in Figure 9.

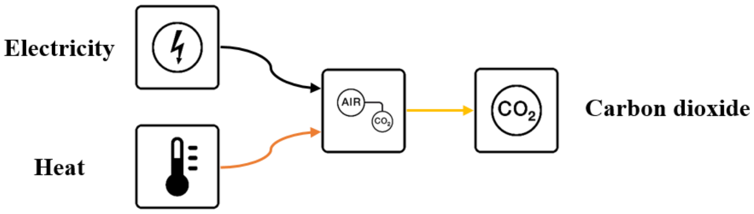

Figure 9. CO_2 removal sector structure.

3.2.7 Energy systems operation: Integrated system

Every sector can be modelled individually or as several integrated sectors. Technologies such as PtG, electrical heating (heating rod, heat pumps), steam turbines, SWRO desalination, and FT-fuel production can operate as 'bridging technologies' binding different sectors. Flexible power demand from the heat, transport, industrial fuel production, desalination, and CO_2 removal sectors, together with better energy management due to bridging technologies can lead to a significant increase in the integrated system efficiency and drop in the total system cost. The impact of sector integration is described in detail in **Publication VI**.

3.3 LUT Energy System Transition Model description

The energy system optimisation model is based on a linear optimisation of the system parameters under a set of applied constraints with the assumption of perfect foresight of RE power generation and power demand. A multi-node approach enables the description of any desired configuration of sub-regions and power transmission interconnections. The main constraints for the optimisation are the matching of all types of generation and demand values for every hour of the applied year, and the optimisation criteria is the minimisation of the total annual cost of the integrated system (or a sector if only one sector is optimised). The hourly resolution of the model significantly increases the required computation time; however, it guarantees that for every hour of the year, the total supply within a sub-region covers the local demand and enables a more precise system description including synergy effects of different system components or sectors (sector coupling).

The optimisation is performed in a third-party solver. At the moment, the main option is MOSEK ver. 8 (Mosek, 2021), but other solvers (e.g. Gurobi (Gurobi Optimization, 2021), CPLEX (IBM, 2021), etc.) can also be used. The model is compiled in the Matlab environment in the LP file format, so that the model can be read by most of the available solvers. After the optimisation results are parsed back to the Matlab data structure and can be post-processed for analyses and diagram preparation.

Simulation time depends on the modelling setup and the hardware used. The time increases with the growth of nodes and technologies considered in the modelling (due to an increase of the number of variables and model size) and with the number of node interconnections (model matrix becomes more 'dense'). The impact is nonlinear and depends on the researched case and the step of transition (influenced by the assumptions and applied constraints). At a workstation with 40 physical cores at 2.4 GHz and 380 GB of operating memory, the simulation of one node for one sector (power) for one year in hourly resolution can be finished in 2 hours.

3.3.1 Target function

The target of the system optimisation is the minimisation of the total annual cost of the integrated system (or a sector if only one sector is optimised), calculated as the sum of the annual costs of installed capacities of the different technologies, costs of energy and product generation, and production ramping. This target function includes annual costs of the power, heat, transport, and industrial (industrial fuels production, desalination, and CO_2 removal) sectors. The target function of the applied energy model for minimising annual costs is presented in Eq. (1) and comprises all hours of a year using the abbreviations: sub-regions (*r*, *reg*), generation, storage, and transmission technologies (*t*, *tech*), capital expenditures (Capex) for technology *t* ($CAPEX_t$), capital recovery factor (crf) for technology *t* (crf_t), fixed operational expenditures (Opex) for technology *t* ($OPEXfix_t$), variable operational expenditures for technology *t* ($OPEXvar_t$), installed capacity in the region *r* of technology *t* ($instCap_{t,r}$), annual energy generation by technology *t* in region *r* ($E_{gen,t,r}$), cost of ramping of technology *t* ($rampCost_t$), and sum of power ramping values during the year for technology *t* in the region *r* ($totRamp_{t,r}$).

$$\min\left(\sum_{r=1}^{reg}\sum_{t=1}^{tech}(CAPEX_t\cdot crf_t+OPEXfix_t)\cdot instCap_{t,r}+OPEXvar_t\cdot E_{gen,t,r}\right.$$
$$\left.+\,rampCost_t\cdot totRamp_{t,r}\right)\qquad(1)$$

The power prosumers and individual heating user system is realised in an independent sub-model with a slightly different target function. The prosumer system is optimised for each sub-region independently, even if the sub-region is connected to neighbours inside the area. The target function includes annual costs of the prosumer power generation and storage, heating equipment, the cost of electricity required from the distribution grid and the cost of fuels required for boilers. Income of electricity feed-in to the distribution grid is deducted from the total annual cost.

The target function of the applied energy model for minimising annual costs is presented in Eq. (2) and comprises all hours of a year using the abbreviations: generation and storage 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 for technology *t* ($OPEXvar_t$), installed capacity of technology *t* ($instCap_t$), annual generation by technology *t* ($E_{gen,t}$), retail price of electricity (*elCost*), feed-in price of electricity (*elFeedIn*), annual amount of electricity required from the grid (E_{grid}), annual amount of electricity fed-in to the grid (E_{excess}).

$$\min\left(\sum_{t=1}^{tech}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot instCap_t + OPEXvar_t \cdot E_{gen,t} + elCost \cdot E_{grid} + elFeedIn \cdot E_{excess}\right) \quad (2)$$

3.3.2 Energy balance constraints

The main constraint for the power sector optimisation is the matching of the power generation and demand for every hour of the applied year as shown in Eq. (3). For every hour of the year the total generation within a sub-region and electricity import must cover the local electricity demand.

$$\forall h \in [1{,}8760] \sum_{t}^{tech} E_{gen,t} + \sum_{r}^{reg} E_{imp,r} + \sum_{t}^{stor} E_{stor,disch} = E_{demand} + \sum_{r}^{reg} E_{exp,r} + \sum_{t}^{stor} E_{stor,ch} + E_{curt} + E_{other} \quad (3)$$

Eq. (3) describes constraints for the energy flows of a sub-region. Abbreviations: 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 fuel production, CO_2 removal) (E_{other}), curtailed excess energy (E_{curt}). The energy loss in the high voltage direct current (HVDC) and alternating current (HVAC) transmission grids and energy storage technologies are considered in storage discharge and grid import value calculations.

The heat sector energy balance is defined by three equations: for industrial high temperature heat demand, for industrial high and medium temperature heat demand, and all centralised heat demand. High temperature heat can only be generated by fuel-based boilers Eq. (4). Medium temperature heat can also be generated by electrical heating and can be stored in high temperature heat storage and used to produce electricity with steam turbines Eq. (5). Low temperature heat can also be provided by heat pumps, electric heating rods and waste heat from other technologies Eq. (6).

$$\forall \mathrm{h} \in [1{,}8760] \sum_{t}^{techHH} E_{gen,t} \geq E_{demandHH} \quad (4)$$

$$\begin{aligned}\forall \mathrm{h} \in [1{,}8760] \sum_{t}^{techHH} E_{gen,t} + \sum_{t}^{techMH} E_{gen,t} + E_{HHstor,disch} \\ \geq E_{demandHH} + E_{demandMH} + E_{HHstor,ch} + E_{curt} + E_{other}\end{aligned} \quad (5)$$

$$\begin{aligned}\forall \mathrm{h} \in [1{,}8760] \sum_{t}^{tech} E_{gen,t} + \sum_{t}^{stor} E_{stor,disch} \\ = E_{demand} + \sum_{t}^{stor} E_{stor,ch} + E_{curt} + E_{other}\end{aligned} \quad (6)$$

Abbreviations: hours (*h*), technology (*t*), high temperature heat generation technologies ($techHH$), medium temperature heat generation technologies ($techMH$), all heat generation technologies ($tech$), industrial high temperature heat demand ($E_{demandHH}$), industrial medium temperature heat demand ($E_{demandMH}$), total centralised heat demand, including industrial, and space heating and water heating demand (E_{demand}), heat generated (E_{gen}), storage technologies (*stor*) including high temperature heat storage (*HHstor*) heat from discharging storage ($E_{stor,disch}$), heat for charging storage ($E_{stor,ch}$), heat consumed by steam turbines to produce electricity (E_{other}), excess heat (E_{curt}).

Power and heat sector constraints for prosumers have some minor differences. Prosumers can buy electricity from electricity distribution companies (Eq. 7). Heating of prosumers based on individual heaters includes fuel, RE and electricity-based heaters, but there is no individual heat storage option (Eq. 8).

$$\begin{aligned}\forall \mathrm{h} \in [1{,}8760] \sum_{t}^{tech} E_{gen,t} + \sum_{t}^{stor} E_{stor,disch} \\ = E_{demand} - E_{grid} + \sum_{t}^{stor} E_{stor,ch} + E_{curt} + E_{other}\end{aligned} \quad (7)$$

$$\forall \mathrm{h} \in [1{,}8760] \sum_{t}^{tech} E_{gen,t} = E_{demand} + E_{curt} \quad (8)$$

Abbreviations: hours (*h*), technology (*t*), all modelled power generation technologies (*tech*), energy generated (E_{gen}), storage technologies (*stor*), energy from discharging storage ($E_{stor,disch}$), energy demand (E_{demand}), electricity energy for charging storage ($E_{stor,ch}$), electricity consumed by heating (E_{other}), and excess energy (E_{curt}).

The power and heat demand of the centralised system and prosumers are assumed to be inflexible. Though demand response could be easily modelled (similarly to storage) the decision was to avoid using demand response to highlight the fact that RE can satisfy the energy demand at every hour and the balance of demand and supply in a VRE-based system can be reached with other flexibility options, without forcing demand response. Emerging technologies, such as e-fuel production, CO_2 removal, and desalination, are fully optimised by the model and thus the energy demand of these technologies can be flexible. If a technology's CAPEX is low enough and the benefit from a reduced energy cost pays off the negative effect of the reduction of FLH, such a technology will reduce the output production and energy consumption in energy deficit periods.

3.3.3 Power and heat generation

Renewable-based power and heat generation is defined by historical capacity factors for this technology and the optimal installed capacity of this technology Eq. (9).

$$\forall \mathrm{h} \in [1,8760]\ E_{genRE,h} = CF_{genRE,h} \cdot instCap_{genRE} \tag{9}$$

Abbreviations: hour (*h*), renewable-based generation technology (*genRE*), energy generated by renewable-based generation technology (E_{genRE}), installed capacity in the region of the technology ($instCap_{genRE}$), hourly capacity factor (CF) of the RE technology ($CF_{genre,h}$).

The hourly capacity factor represents the ratio of the net electricity generated in the given hour to the electricity that could have been generated if the unit would work at full capacity. This definition allows application of the concept of CF, widely used for conventional thermal and nuclear power plants, to properly model specific performance of VRE technologies. For solar PV and CSP, the hourly capacity factors are calculated based on the solar irradiation data, temperature and wind speed, and geographical location. For given wind turbines, they are based on the wind speed data, surface roughness and turbine parameters. The hourly capacity factors for hydropower plants represent the water flow through the hydropower plants and potential power output possible at this flow. For the case of hydropower dams, the energy can be stored in the reservoir and used to produce the electricity when necessary for the system. The hydropower dam operation is defined by equations similar to energy storage (section 3.3.4. Eqs. 14-17), though the charging of the reservoir is defined by assumed hourly capacity factors and the model optimises the installed capacity of dammed hydropower plants. Fuel-based power and heat generation is defined by the optimal installed capacity for this technology Eq. (10), availability factor for this technology Eq. (11), fuel availability for this technology Eq. (12), and efficiency of the technology Eq. (13).

$$\forall \mathrm{h} \in [1{,}8760]\ E_{genFU,h} <= instCap_{genFU} \tag{10}$$

$$\sum_{h}^{8760} E_{genFU,h} \leq\ 8760 \cdot AF_{genFU} \cdot instCap_{genFU} \tag{11}$$

$$\sum_{h}^{8760} FU_{genFU,h} \leq\ \ totalFU_{genFU} \tag{12}$$

$$\forall \mathrm{h} \in [1{,}8760]\ E_{genFU,h} =\ FU_{genFU,h} \cdot eff_{genFU} \tag{13}$$

Abbreviations: hour (*h*), fuel-based generation technology *(genFU*), energy generated by fuel-based generation technology (E_{genFU}), installed capacity in the region of the technology ($instCap_{genFU}$), availability factor of the technology (AF_{genFU}), fuel consumption for the hour h ($FU_{genFU,h}$), annual fuel consumption for the hour h ($totalFU_{genFU,h}$), energy conversion efficiency for the technology (eff_{genFU}).

For all technologies, capacity is calculated in output units. For cogeneration, the capacity is given in electrical units. For some types of fuel (municipal solid waste, industrial biomass waste, biogas), all available fuel must be consumed for sustainability reasons. Biogas inflow in the system is constant and biogas can be stored only for 48 hours.

3.3.4 **Power and heat storage**

Storage technologies are described as energy storage capacity and storage interface capacity. Energy storage capacity limits the maximum state of charge (SoC) of the storage technology and the amount of energy stored Eq. (14), while the storage interface capacity limits the maximum power of charge and discharge Eq. (15), (16). The energy balance constraint for storage technologies is given in Eq. (17).

$$\forall \mathrm{h} \in [1{,}8760]\ SoC_{stor,h} <= instCapEn_{stor} \tag{14}$$

$$\forall \mathrm{h} \in [1{,}8760]\ E_{stor,ch,h} <= instCapInt_{stor} \tag{15}$$

$$\forall \mathrm{h} \in [1{,}8760]\ E_{stor,disch,h} <= instCapInt_{stor} \tag{16}$$

$$\begin{aligned}\forall \mathrm{h} \in [1{,}8760]\ & SoC_{stor,h} \\ &= SoC_{stor,h-1} \cdot selfDisch_{stor} + E_{stor,ch,h} \cdot eff_{stor,ch} \\ &- E_{stor,disch,h}/eff_{stor,disch}\end{aligned} \tag{17}$$

Abbreviations: hour (*h*), storage technology *(stor*), storage state of charge for an hour *h* ($SoC_{stor,h}$), installed energy capacity of the storage ($instCapEn_{stor}$), installed power capacity of the storage ($instCapInt_{stor}$), charging energy of the storage for an hour *h* ($E_{stor,ch,h}$), discharging energy of the storage for an hour *h* ($E_{stor,disch,h}$), hourly self-discharge of the storage ($selfDisch_{stor}$), charge efficiency ($eff_{stor,ch}$), discharge efficiency ($eff_{stor,disch}$).

3.3.5 Power transmission

Power transmission is represented by HVDC and HVAC grids. Each line of the grid is bidirectional, but represented in the model as two unidirectional lines: import and export. Capacities of import and export lines are equal to the total power capacity of the interconnection, as shown in Eq. (18). Hourly export/import energy for a sub-region is calculated as the sum of all import lines multiplied by this line transmission efficiency minus the sum of all export line energy flows, as shown in Eq. (19). The efficiency of energy transmission by HVDC lines depends on the distance and AC/DC converter pair efficiency, as shown in Eq. (20). The efficiency of energy transmission by HVAC line depends only on distance, as shown in Eq. (21). For both HVDC and HVAC, the distance related losses are calculated in a simplified way.

$$\forall \mathrm{h} \in [1{,}8760]\ line_{import,h} \leq instCap_{line}\ ; \quad line_{export,h} <= instCap_{line} \tag{18}$$

$$\forall \mathrm{h} \in [1{,}8760]\ E_{exp/imp,h} = \sum_{l}^{lines} line_{import,l,h} \cdot eff_l - \sum_{l}^{lines} line_{export,l,h} \tag{19}$$

$$eff_l = eff_{CS} \cdot (1 - distance \cdot EffLoss) \tag{20}$$

$$eff_l = 1 - distance \cdot EffLoss \tag{21}$$

Abbreviations: hour (*h*), line (*l*), energy flow through the power line *(line*), installed capacity of the power line ($instCap_{line}$), exported/imported energy for the region for an hour *h* ($E_{exp/imp,h}$), total energy import efficiency (eff_l), converter pair efficiency (eff_{CS}), charge length of the line (*distance*), energy loss in the line (*EffLoss)*.

3.3.6 Transportation

Transportation demand is expressed in in (metric) ton kilometres (t-km) and passenger kilometres (p-km). Power and fuel consumption for a given mix of transportation means is included in the power, heat, and gas (H_2, CH_4) balance equations on the demand side.

3.3.7 Industrial sector

Fuel production

The energy system can produce GHG neutral methane for the needs of the power, heat, transport, and industry sectors. The first option is upgrading the available biogas to biomethane. The amount of upgraded biogas cannot be more than the urbanisation level of the region, but not more than 70% of all biogas. Biomethane can be stored in the gas storage. The second option is power-to-gas. Hydrogen produced with water electrolysis and CO_2 from DAC units are used as raw materials for the methanation units. It is planned to expand the model for point source CO_2 capture for further utilisation, such as from cement mills, waste incinerators, and pulp and paper plants. Produced SNG can be also stored in the gas storage.

Desalination

In case that desalinated water demand exists in the region, the system has to provide the demanded amount of water every hour. Water storage on the supply side provides flexibility to the system. Desalination units are located on the seashore and they can optimise work in order to decrease the total system cost. The water demand and water storage balance are described in Eqs. (22-23).

Water desalination units produce water and store it in water storage. Desalinated water production is limited by optimal capacities of enabled desalination plants and storage technologies, Eqs. (24-25). Power, heat, and gas consumption for desalination unit operation as shown in Eqs. (24-26) are included in the power, heat, and gas balance equations on the demand side. The water pumping electricity demand according to Eq. (27) and cost are calculated based on the pumping capacity of the system, hourly water demand, weighted average length, and head of the piping system.

$$\forall \mathrm{h} \in [1{,}8760] \sum_{t}^{tech} W_{des,t,h} + W_{stor,disch,h} - W_{stor,ch,h} = W_{demand,h} \tag{22}$$

$$\forall \mathrm{h} \in [1{,}8760]\ SoC_{stor,h} = SoC_{stor,h-1} + W_{stor,ch,h} - W_{stor,disch,h} \tag{23}$$

$$\forall \mathrm{h} \in [1{,}8760]\ W_{des,t,h} \leq instCapDes_{t} \tag{24}$$

$$\forall \mathrm{h} \in [1{,}8760]\ SoC_{stor,h} \leq instCapStor \tag{25}$$

$$\forall \mathrm{h} \in [1{,}8760]\ E_{heat,h} = \sum_{t}^{tech} W_{des,t,h} \cdot heatCons_{t} \tag{24}$$

$$\forall \mathrm{h} \in [1,8760]\; E_{el,h} = \sum_{t}^{tech} W_{des,t,h} \cdot elCons_t - \sum_{t}^{tech} W_{des,t,h} \cdot elProd_t \tag{25}$$

$$\forall \mathrm{h} \in [1,8760]\; E_{gas,h} = \sum_{t}^{tech} W_{des,t,h} \cdot gasCons_t \tag{26}$$

$$\forall \mathrm{h} \in [1,8760]\; E_{elPump,h} = \sum_{t}^{tech} W_{des,t,h} \times (elCons_{vPump} \cdot alt + elCons_{hPump} \cdot dist) \tag{27}$$

Abbreviations: hour (*h*), desalination technology (*t*), desalinated water (W_{des}), water storage discharge ($W_{stor,disch}$), water storage charge ($W_{stor,ch}$), water demand (W_{demand}), installed desalination technology capacity (*instCapDes*), desalination heat demand (E_{heat}), desalination electricity demand (E_{el}), desalination gas demand (E_{gas}), desalination heat consumption (*heatCons*), desalination electricity consumption (*elCons*), desalination electricity production (*elProd*), desalination gas consumption (*gasCons*), water pumping electricity demand (E_{elPump}), horizontal water pumping electricity consumption ($elCons_{hPump}$), vertical water pumping electricity consumption ($elCons_{vPump}$), pumping distance (*dist*), pumping altitude difference (*alt*), water storage state of charge *h* (SoC_{stor}), installed capacity of the water storage (*instCapStor*).

CO_2 removal

The energy system can capture additional amounts of CO_2 from the atmosphere for permanent storage. The CO_2 captured by DAC is stored in CO_2 buffer storage. The system will balance hourly DAC and CO_2 buffer operation in order to balance hourly CO_2 removal demand.

3.3.8 Results preparation and cost calculations

All optimisation results are collected and converted from the solver output form to the Matlab structure. This structure contains all information about the system: installed capacities of all system elements, operation modes, energy, fuel and other product flows.

Data on the structure and operation of the energy system in combination with financial and technical assumptions give the full description of the system. Based on these numbers, it is possible to calculate annual costs of each component and the whole system, allocate costs to specific sectors, calculate costs of products (electricity, heat, e-fuels, e-chemicals, water) and different components of these costs (primary generation, storage, transmission, curtailment components of electricity prices etc.).

The total annualised cost of the system is calculated as the sum of all sectors costs, Eq. (28), which includes annualised capital cost and operational costs of all system elements, Eq. (29):

$$\begin{aligned} totalCost_{sys} = {} & elSysCost + elProsCost + heatSysCost + heatIndCost \\ & + transpSysCost + industrSysCost \end{aligned} \tag{28}$$

$$totalCost_{sys} = \sum_{t=1}^{tech} (CAPEX_t \cdot crf_t + OPEXfix_t) \cdot Cap_t + OPEXvar_t \cdot E_{gen,t} \tag{29}$$

$$crf_t = \frac{WACC \cdot (1 + WACC)^{N_t}}{(1 + WACC)^{N_t} - 1} \tag{30}$$

Abbreviations: total annualised cost of the system ($totalCost_{sys}$), annualised cost of the centralised Power sector (*elSysCost*), annualised cost of the electricity prosumer sector (*elProsCost*), annualised cost of the centralised heat sector (*heatSysCost*), annualised cost of the individual heat sector (*heatIndCost*), annualized cost of the transportation sector (*transpSysCost*), annualised cost of the industrial sector (*industrSysCost*), all technologies (*tech*), technology (*t*), capital expenditures (*CAPEX*), capital recovery factor for technology *t* (crf_t) Eq. (30), annual fixed operational expenditures (*OPEXfix*), variable operational expenditures (*OPEXvar*), installed capacity of technology *t* (Cap_t), annual output of technology *t* ($E_{gen,t}$), weighted average cost of capital (*WACC*), lifetime for technology *t* (N_t).

The WACC is set on the same level for all technologies and does not consider the social impacts of projects based on different technologies. For coal and nuclear technology projects, the WACC is set at a higher level to reflect the higher risk of stranded investments and partially the negative social impact. The total cost reflects only the costs for the energy system including carbon pricing, though it does not consider the full cost of climate change and other social costs.

Total levelised cost of electricity in the system (*LCOEtotal*) is calculated as the electricity demand weighted average of the centralised power system LCOE (*LCOEsys*) and prosumer sector LCOE (*LCOEpros*); the formula is presented in Eq. (31). Centralised power system LCOE is comprised of the levelised cost of consumed electricity (*LCOEprim*), levelised cost of storage (*LCOS*), levelised cost of curtailed electricity (*LCOC*), levelised cost of electricity transition (*LCOT*) and levelised cost of prosumer feed-in reimbursement (*LCOFS*), Eq. (32). For the prosumer sector, the total LCOE is comprised of the levelised cost of consumed electricity (*LCOEprim*), levelised cost of storage (*LCOS*), and levelised cost of prosumer feed-in reimbursement (*LCOFS*), Eq.

(33). Levelised cost of generated electricity is calculated as the total annualised cost of the electricity generation system divided by total annual generation, Eq. (34). In this calculation, the operational costs include the costs of fuel and GHG emission costs per unit of generated electricity. The electricity generation systems also include part of the fuel production facilities, which are used for fuel production for power system generators. Levelised cost of consumed electricity is calculated based on the cost of the generated electricity ($LCOEgen$), excluding electricity lost due to curtailment, storage, and transmission system losses, Eq. (35). Levelised cost of storage is calculated as the annualised cost of storage system equipment and annual cost of electricity losses divided by total electricity consumption, Eq. (36). Storage systems also include part of the fuel production facilities, which are used for fuel production for the storage system generators (e.g. for Power-to-Gas – Gas-to-Power). Levelised cost of curtailment is calculated as the annual cost of curtailed electricity divided by total electricity consumption, Eq. (37). Levelised cost of transmission is the calculated area total annualised cost of power grid equipment and annual cost of electricity losses divided by total electricity consumption, and multiplied by regional grid utilisation weights, Eq. (38), where regional grid utilisation weights are the average of regional shares of total export and import of energy, Eq. (39).

$$LCOEtotal_r = (LCOEsys_r \cdot El_{consSys_r} + LCOEpros_r \cdot El_{consPros_r})/(El_{consSys_r} + El_{consPros_r}) \tag{31}$$

$$LCOEsys_r = LCOEprim_r + LCOS_r + LCOC_r + LCOT_r + LCOFS_r \tag{32}$$

$$LCOEpros_r = LCOEprim_r + LCOS_r - LCOFS_r \tag{33}$$

$$LCOEgen_r = \frac{\sum_{t=1}^{Gen}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot Cap_{t,r} + OPEXvar_t \cdot El_{gen,t,r}}{El_{gen,r}} \tag{34}$$

$$LCOEprim_r = \frac{LCOEgen_r \cdot (El_{gen,r} - El_{curt,r} - El_{storLoss,r} - El_{transLoss,r})}{El_{cons,r}} \tag{35}$$

$$LCOS_r = (\sum_{t=1}^{Stor}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot Cap_{t,r} + OPEXvar_t \cdot E_{out,t,r} + LCOEgen_r \cdot El_{storLoss,r})/El_{cons,r} \tag{36}$$

$$LCOC_r = \frac{LCOEgen_r \cdot El_{curt,r}}{El_{cons,r}} \tag{37}$$

$$LCOT_r = RegShare\ _r \cdot (\sum_{r}^{Reg}\sum_{t=1}^{trans}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot Cap_{t,r} + OPEXvar_t \cdot El_{out,t,r} + LCOEgen_r \cdot El_{transLoss,r})/El_{cons,r} \tag{38}$$

$$RegShare\ _r = 0.5 \cdot \frac{Import_r}{\sum_r Import_r} + 0.5 \cdot \frac{Export_r}{\sum_r Export_r} \tag{39}$$

$$LCOFS_r = \frac{feedInTarif_r \cdot El_{prosTogrid,r}}{El_{cons,r}} \tag{40}$$

Abbreviations: region (*r*), total levelised cost of electricity in the system (*LCOEtotal*), centralised system levelised cost of electricity (*LCOEsys*), prosumer sector levelized cost of electricity (*LCOEpros*), centralised system electricity consumption ($El_{consSys}$), prosumer sector electricity consumption ($El_{consPros}$), consumed electricity LCOE (*LCOEprim*), levelised cost of stored electricity (*LCOS*), levelised cost of curtailed electricity (*LCOC*), levelised cost of prosumer feed-in reimbursement (*LCOFS*), generated electricity LCOE (*LCOEgen*), power generation technologies (*Gen*), storage technologies (*Stor*), power transmission technologies (*trans*), technology (*t*), capital expenditures (*CAPEX*), capital recovery factor for technology *t* (crf_t) , annual fixed operational expenditures (*OPEXfix*), variable operational expenditures (*OPEXvar*), installed capacity of the technology *t* (Cap_t), annual output for the technology *t* ($El_{gen,t}$), annual electricity generation (El_{gen}), annual electricity curtailment (El_{curt}), annual storage loss ($El_{storLoss}$), annual grid loss ($El_{transLoss}$), annual electricity consumption (El_{cons}), annual output of storage *t* ($E_{out,t}$), annual export of grid technology *t* ($El_{out,t}$), electricity exported by region r (*Export*), electricity imported by region *r* (*Import*), feed-in reimbursement (*feedInTarif*), electricity sold by prosumers to the grid ($EL_{prosTogrid}$).

The levelised cost of heat (LCOH) is calculated as the weighted average of the centralised and individual system LCOH, Eq. (41). The centralised heat system LCOH (LCOHsys) and individual heat system LCOH (LCOHind) are calculated as the annualised cost of heat system equipment and annual cost of electricity consumption by heating equipment divided by total heat consumption, Eqs. (42,43). In both formulas, operational expenditures include the cost of fuel and GHG emissions per unit of generated heat. The heat systems also include part of the fuel production facilities, which are used for fuel production for heat generators. Cogeneration plant costs are only included in the power system.

Levelised cost of transportation (LCOM) is calculated as the sum of the annualised cost of the entire transport fleet, cost of consumed fuel and electricity, GHG emission cost, divided by transportation demand Eq. (44).

Levelised cost of the industrial sector products (LCOP) are: levelised cost of Gas (LCOG), liquid fuel (LCOF), water (LCOW), and CO_2 direct air capture (LCOD). These are calculated as the sum of the annualised costs of the equipment and costs of annually consumed heat and electricity, divided by total annual consumption of the product, Eq. (45).

$$LCOHtotal_r = (LCOHsys_r \cdot He_{consSys_r} + LCOHind_r \cdot He_{consInd_r})/(He_{consSys_r} + He_{consInd_r}) \tag{41}$$

$$LCOHsys_r = (\sum_{t=1}^{heat} (CAPEX_t \cdot crf_t + OPEXfix_t) \cdot Cap_{t,r} + OPEXvar_t \cdot He_{out,t,r} + \ LCOEsys_r \cdot El_{demSysHeat,r})/He_{consSys,r} \tag{42}$$

$$LCOHind_r = (\sum_{t=1}^{heat} (CAPEX_t \cdot crf_t + OPEXfix_t) \cdot Cap_{t,r} + OPEXvar_t \cdot He_{out,t,r} + \ ElPrice_r \cdot El_{demIndHeat,r})/He_{consInd,r} \tag{43}$$

$$LCOM_r = \frac{\sum_{t=1}^{Mob}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot Cap_{t,r} + \; FuPrice_{t,r} \cdot FuCons_{t,r}}{TR_{dem,r}} \quad (44)$$

$$LCOP_r = (\sum_{t=1}^{tech}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot Cap_{t,r} + OPEXvar_t \cdot Pr_{out,t,r} + \; LCOEsys_r \cdot El_{cons,t,r} + \; LCOHsys_r \cdot He_{cons,t,r})/Pr_{cons,r} \quad (45)$$

Abbreviations: region (*r*), total levelised cost of heat in the system (*LCOHtotal*), centralised system levelised cost of heat (*LCOEsys*), individual heat sector levelised cost of heat (*LCOHind*), centralised system heat consumption ($He_{consSys}$), individual heat sector heat consumption ($He_{consPros}$), heat generation technologies (*heat*), transportation technologies (*Mob*), industrial sector production technologies (*tech*), technology (*t*), capital expenditures (*CAPEX*), capital recovery factor for technology *t* (crf_t) , annual fixed operational expenditures (*OPEXfix*), variable operational expenditures (*OPEXvar*), installed capacity of the technology *t* (Cap_t), annual output for the technology *t* ($He_{out,t}$), centralised system levelised cost of electricity (*LCOEsys*), retail price of electricity (*ElPrice*), electricity consumed by centralised heat system heaters ($El_{demSysHeat}$), electricity consumed by individual heat system heaters ($El_{demIndHeat}$), fuel price for transportation technology *t* ($FuPrice_t$), fuel consumption for transportation technology *t* ($FuCons_t$), transportation demand (TR_{dem}), annual product production (Pr_{out}), electricity consumption for the production (El_{cons}), annual heat consumption for the production (He_{cons}), annual product consumption (Pr_{cons}).

3.3.9 Data inputs

Accurate simulation of the energy system requires the definition of numerous assumptions and data inputs to be fed to the model in accordance to the model design. The list and classification of the model inputs are presented in Table 3.

Table 3. List and classification of the LUT Energy System Transition Model inputs.

Data group	Input data	Unit	Additional information
Financial assumptions	Capex for technology	[€/kW] or [€/kWh] for storage capacity	Reference values for all technologies for all years from 1960 in 5-year intervals
	Opex fixed for technology	[€/kW] or [€/kWh] for storage capacity	Reference values for all technologies for all years from 1960 in 5-year intervals

Data group	Input data	Unit	Additional information
	Opex variable for technology	[€/kWh]	Reference values for all technologies and fuels for all years from 1960 in 5-year intervals
	Capex factor for regions	unitless	Factors for each of the regions, applied to reference values to reflect regional differences
	Opex fixed factor for regions	unitless	Factors for each of the regions, applied to reference values to reflect regional differences
	Opex variable factor for regions	unitless	Factors for each of the regions, applied to reference values to reflect regional differences
	Ramping cost for energy conversion technologies	[€/kW]	Reference values for all technologies, the same for all regions and years.
	CO_2 pricing	[€/t_{CO2eq}]	CO_2 emissions pricing for transition years
	Hydropower plants refurbishment cost	[€/kW] or [€/kWh] for PHES capacity	Cost of rehabilitation for hydropower capacities (run-of-river, dams, PHES)
	WACC for different groups of technologies	[%]	Values for Residential, Commercial, Industrial Prosumers, High risk technologies (coal and nuclear) and for the rest of the system. The same values for all regions and all steps of the transition
	Retail electricity prices	[€/kWh]	Retail electricity prices for Residential, Commercial, Industrial consumers for all transition years and all regions
	Feed-in tariff for prosumers	[€/kWh]	The excess electricity production by prosumers can be sold to the centralised grid. Individual numbers for regions, but constant over the transition.
	Premium on fuel cost for individual consumers	[%]	Fossil and bio fuel costs increase compared to the fuel price for utility-scale consumers. Individual numbers for regions, but constant over the transition.
Technical assumptions	Technical lifetime for technology	[years]	Values for all technologies for all years from 1960 in 5-year intervals
	Efficiency for technology and used-fuel type	[%]	Values for all energy conversion technologies for all years from 1960 in 5-year intervals

Data group	Input data	Unit	Additional information
	Charge efficiency of storage by technology	[%]	Values for all storage technologies for all years from 1960 in 5-year intervals
	Discharge efficiency of storage by technology	[%]	Values for all storage technologies for all years from 1960 in 5-year intervals
	Self-discharge of storage by technology	[%/h]	Values for all storage technologies for all years from 1960 in 5-year intervals
	Set-up efficiency for RE technologies	[%]	Efficiency decrease for utility-scale power plants compared to individual installation (mainly to represent wind shading effects on wind farms)
	Power loss in transmission lines	[%/km]	Values for HVAC and HVDC technologies for all years from 1960 in 5-year intervals
	Power loss in AC/DC converters	[%/pair]	Values for all years from 1960 in 5-year intervals
	Power loss in local T&D grids	[%]	Values for each region and all years from 1960 in 5-year intervals
	Energy consumption of industrial and PtX processes	[kWh/output]	Electricity and heat consumption of industrial processes, desalination, CO_2 DAC etc. for all years from 1960 in 5-year intervals
	Raw materials consumption of industrial processes	[tonnes/output]	Values for all years from 1960 in 5-year intervals
	Energy consumption by transport types	[kWh/km], [kWh/p-km], [kWh/t-km]	Fuel or electricity consumption of transport means for all years from 1960 in 5-year intervals
	Emission factors of fossil fuels	[kg_{CO2}/kWh]	Values for all years from 1960 in 5-year intervals
	Non-energy related emission factors for industrial processes	[kg_{CO2}/output]	Values for all years from 1960 in 5-year intervals
RE resources	Hourly capacity factors profiles	unitless	Profiles for solar PV, solar thermal, wind and hydro technologies for each of the regions
	Biomass potential	[kWh]	Annual feedstock of biomass and MSW for each region

Data group	Input data	Unit	Additional information
	Geothermal potential	[kW]	Maximum sustainable geothermal heat extraction
	Maximum capacity for RE technologies	[kW]	Maximum capacity potential for solar PV, solar thermal, wind and hydro
	Hydropower dam reservoir capacity	[h]	Constant
	Urbanisation level	[%]	Urbanisation level for each region. Defined share of biogas which can be converted to biomethane and fed to gas network
Installed capacity	Historical installed capacities for technologies	[kW] or [kWh] for storage capacity	Active installed capacities for all technologies for all regions and all years from 1960 in 5-year intervals
	Lower limit on installed capacities for technologies	[kW] or [kWh] for storage capacity	Used in overnight mode. Defined capacity which has to be installed for all technologies for all regions
	Upper limit on installed capacities for technologies	[kW] or [kWh] for storage capacity	Defined maximum capacity which can be installed for all technologies for all regions
Demand	Annual electricity demand	[kWh]	Annual electricity demand for all regions and all years of the transition in 5-year intervals
	Prosumers share in electricity demand	[%]	Maximum share of prosumers of total demand. Consequent steps of possible share increase defined individually for Residential, Commercial and Industrial segments for all regions
	Residential, Commercial and Industrial segments shares in electricity demand	[%]	Value defined for all regions, constant over the transition
	Annual space heating demand	[kWh]	Annual space heating demand for all regions and all years of the transition in 5-year intervals
	Annual domestic hot water heating demand	[kWh]	Annual domestic hot water heating demand for all regions and all years of the transition in 5-year intervals

Data group	Input data	Unit	Additional information
	District heating share in space and domestic hot water heating	[%]	Value defined for all regions and all years of the transition
	Residential and Commercial segments shares in individual heating demand	[%]	Value defined for all regions, constant over the transition
	District heating system losses	[%]	Value defined for all regions and all years of the transition
	Annual biomass for cooking demand	[kWh]	Annual biomass for cooking demand for all regions and all years of the transition in 5-year intervals
	Annual industrial heat demand	[kWh]	Annual industrial heat demand for all regions and all years of the transition in 5-year intervals
	High, medium and low temperature heat shares in total industrial heat demand	[%]	Value defined for all regions, constant over the transition
	Industrial production demand	[kWh] or [tonnes]	Annual output of industry, fuel and chemical production in [kWh], other goods in [tonnes]
	Freight transportation demand	[mil t-km]	Annual freight transportation demand for road, rail, aviation, and marine transport for all regions and all years of the transition in 5-year intervals
	Passenger transportation demand	[mil p-km]	Annual freight transportation demand for road, rail, aviation, and marine transport for all regions and all years of the transition in 5-year intervals
	Negative emissions demand	[kgCO_2]	Annual demand of CO_2 sequestration for all regions and all years of the transition in 5-year intervals
Grid structure	Distances between interconnected regions' consumption centres	[km]	Represents all interconnections, including HVAC and HVDC
	Existing power capacity of HVAC interconnections	[kW]	

Data group	Input data	Unit	Additional information
	Existing power capacity of HVDC interconnections	[kW]	
	Maximum allowed power capacity of HVAC interconnections	[kW]	
	Maximum allowed power capacity of HVDC interconnections	[kW]	
Other	Shares of different modes in road passenger transportation demand	[%]	Values for LDV, buses and 2-3 wheeled transport shares for all regions and all years of the transition in 5-year intervals
	Shares of different modes in road freight transportation demand	[%]	Values for MDV and HDV for all regions shares and all years of the transition in 5-year intervals
	Annual milage for road transport modes	[km/vehicle]	Values for LDV, buses and 2-3 wheeled transport, MDV and HDV for all regions and all years of the transition in 5-year intervals
	Annual load for road transport modes	[pass/vehicle] or [tonnes/vehicle]	Values for LDV, buses and 2-3 wheeled transport, MDV and HDV for all regions and all years of the transition in 5-year intervals
	Shares of newly sold road vehicles by the engine types	[%]	Values for ICE, PHEV, FCEV and BEV vehicles
	Shares of newly sold rail vehicles by the engine types	[%]	Values for electric and diesel trains
	Shares of newly sold ships by the engine types	[%]	Values for oil, LNG, LH2 engines and electrical motors driven ships
	Shares of newly sold airplanes by the engine types	[%]	Values for jet fuel, LH2 engines and electric motor driven planes
	Smart Charing share	[%]	Share of BEV and PHEV with enabled Smart charging
	Vehicle-to-grid share	[%]	Share of BEV and PHEV with enabled Vehicle-to-grid

Data group	Input data	Unit	Additional information
	Capacity for Vehicle-to-grid	[%]	Share of BEV and PHEV battery capacity used for Vehicle-to-grid

The inputs are presented for the latest version of the LUT Energy System Transition Model used for transition and overnight studies for 2015, 2020 to 2050 with 5-year intervals, though the model can be modified to operate for different time intervals.

3.4 Limitations of the LUT Model and planned improvements

By definition any model is just a simplified representation of reality, and thus will always have a number of limitations. The LUT Energy System Transition Model is no exception, and several aspects could be improved.

3.4.1 Sensitivity studies

Due to the model complexity, each simulation takes a significant amount of time even with the most modern and high performing hardware. This decreases capabilities to conduct studies with numerous parameter sensitivity analyses. Normally, the study presents the scenario for the given set of assumptions, but the impact of each of these assumptions on the total is not analysed. At least in the model mode of overnight scenarios, more variations can be calculated, but not numerous fine tuned variations. For example, grid cost assumption variations can lead to different roles of grids and storage in the future energy system as these technologies both provide flexibility, and significantly reduce the grid capacity compared to values seen in the presented studies. However, in the RE-based system it would also lead to changes in the electricity generation structure. At least the impact of various combinations of energy resources can be noticed in comparing energy system solutions across different climates in the world, while technical and financial assumptions are kept equal. Without sensitivity analyses, the input data uncertainty applies additional limitations to the results’ applicability and describes only the case of a certain combination of financial and technical assumptions.

3.4.2 Grids and energy trading modelling

The model allows multi-node configurations of the energy system with nodes representing energy systems of individual regions. The regional energy systems are connected with interregional HVAC or HVDC power grids, the cost of these grids is part of the optimisation target function and thus is considered in the optimisation process. However, the cost of the local transmission and distribution grid development is not considered, similarly to the actual losses in each line of the real transmission and distribution grids, which leads to an underestimation of the total cost of energy system transition and can lead to overestimation of the electrification benefit.

The e-fuel and e-chemical trading between regions is not yet integrated in the model, but it seems to be very important for the integrated energy system transition due to observed differences in e-fuel production costs between the regions.

3.4.3 Energy system element degradation

Many of the energy system elements face a degradation during the operational lifetime. For some technologies like electrolysers the degradation process effect is partially taken into account with additional opex costs for exchange of degradation elements. The impact of PV and battery degradation is partially reflected in cost assumptions or yield. However, the impact of the active peak capacity is not yet included in the model and will be considered in next versions of the model.

3.4.4 Renewable electricity generation forecasting horizon

The LUT Energy System Transition Model is a myopic optimisation model that operates with a perfect forecast of the RE capacity factors and energy demands for each hour of the year in each step of the transition simulation. But it has no information concerning the financial and technical assumptions for the next transition steps and the RE generation and energy demand the following years. That results in perfect optimisation of the generation and storage capacities and optimal operation of storage capacities for the given year. In the LUT Energy System Transition Model, additional reserve generation capacity and storage can be specified as an exogenous parameter for scenarios, as a capacity margin for flexible power generation and a minimum level of long-term storage charge (as in **Publication I**) to ensure the system robustness and possibility to operate according to real conditions. However, introduction of shorter forecast horizons and stochastic long-term estimations of RE generation and energy demand would further improve the model, allowing estimation of the capacity and storage margins based on indigenous parameters of the system, and less on exogenous, sometimes redundant, margins.

At a transition simulation level, the myopic approach allows reduction of the computational complexity due to decoupled simulation steps. At the same time, the myopic approach can result in stranded investments in energy transition optimisation studies. Without the information about financial assumptions in the following periods, the system can invest in technologies which will not be competitive in the following periods (such as coal power plants) in case of fast declining RE generation costs and increasing levels of carbon pricing). Currently, this issue is resolved with additional constraints limiting the investments in the technologies losing economic competitiveness (coal and nuclear PPs).

3.4.5 Energy return on energy invested (EROI)

Energy return on energy invested in the energy system is an important topic which also needs to be directly addressed in energy system transition modelling. Production of new energy generation and storage capacities, equipment for emerging industry sectors like e-fuel production, seawater desalination, CO_2 capture and sequestration will demand significant amounts of energy. Energy demand for the energy generation and storage operation is included in the energy demand statistics and thus is indirectly considered in the simulation. However, accurate tracing of energy demand for the generation and storage capacities will improve the quality of the transition modelling by considering the energy demand related limiting factors.

Adding energy consumption for energy related equipment as an endogenous parameter will be important to prove the possibility of the energy system transition, considering existing scepticism related to RE technologies EROI (Diesendorf & Wiedmann, 2020; White & Kramer, 2019), which can be lower than the EROI of conventional generation technologies.

3.4.6 Input data limitations

Though the model itself can be operated in different time resolutions (with minimum modifications of input data structures), the modelling in full hourly resolution applies additional requirements on a proper estimation of current and future demand profiles for power, heat, transport utilisation, and industrial energy demand. The estimation of future energy demand profiles has a significant impact on the role of storage requirements and other flexibility sources to balance supply and demand in VRE-based systems.

Simulations of the system in higher temporal resolution are technically possible, but limited by a lack of demand data in high resolution and availability of weather data in high temporal and spatial resolution for VRE profile estimation.

The financial and technical assumptions applied in the scenario have a decisive impact on the structure of the optimal energy system and the transition pathway.

Overall, as in any other model, input data quality has a decisive impact on the results of simulations. The combination of even a flawless model and faulty input data would still deliver wrong results.

4 Results

This section represents the main steps of the research and main findings at each of these steps, which are summarised in the publications presented in turn in the following subsections.

4.1 Publication I: Feasibility of the defossilised power system

Publication I describes the optimal structure and operation of a 100% RE-based power system for 2030 in Northeast Asia, including China, Japan, Republic of Korea, Democratic People's Republic of Korea and Mongolia.

In **Publication I,** Dmitrii Bogdanov developed the methods and the model for the study, performed the investigation, data collection and the simulations, analysed and interpreted the results, and aided in the conceptualisation of the research.

Aims

Despite the fact that the defossilisation process is ongoing in many regions of the word and RE generation shares reached significant levels in power systems of many countries, almost all significant power systems are based on fossil and nuclear-based generation, or in some cases on flexible RE, namely hydropower. The aim of this study was to check if 100% RE-based power systems are feasible: that they can be built using currently available generation and storage technologies and that they can guarantee reliable operation for all hours of a year without using fossil fuels, even as a cold reserve. It was important to check the feasibility for the case of dynamically developing regions with a fast-growing economy and respective power demand, to show that the RE resources are sufficient to cover not only the current power demand, but also to satisfy a higher power demand in the future. Another aim was to see the impact of a regional integration on the energy system and see the effect of the proposed Northeast Asian super grid concept on the 100% RE-based power system structure and the cost of electricity in such a system. Fossil CCS and nuclear power generation technologies are not considered in the scenarios as these technologies do not fulfil the applied sustainability criteria, and thus should not be part of a future sustainable energy system.

Methods

The LUT Energy System Model was developed and applied first for this study. The set of applied technologies was limited to RE generation technologies including optimally tilted (fixed tilt) PV, single-axis tracking PV (in north-south axis orientation), onshore wind turbines, run-of-river and dammed hydropower plants, solar thermal power plants (including heat storage) and biomass power plants including solid biomass, biogas power plants and gas turbines running on bio- or synthetic methane; storage technologies: short to mid-term storage technologies – pumped hydro energy storage and battery storage and long term synthetic methane storage. Bordering regions could be also interconnected with

HVDC grids. Conventional and nuclear power plants were not considered since the main aim was to simulate an optimal 100% sustainable energy system operation and the greenfield overnight approach was applied. The simplified structure of the power system is presented in Figure 10.

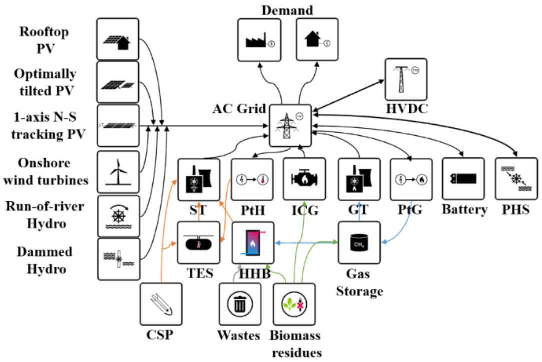

Figure 10. Power system structure.

The model has been applied to the case of the dynamically developing Northeast Asia region including China, Japan, Republic of Korea, Democratic People’s Republic of Korea and Mongolia. Countries of the region have energy intensive economies with large and fast growing electricity consumption, reaching one-third of the global consumption as of 2017 (IEA, 2020a). Another benefit was the variety of the conditions in the countries of the region. Northeast Asia includes densely populated regions in Japan, Republic of Korea, South and Eastern provinces of China and less populated regions in the West and North of China, and Mongolia. Climate and RE conditions also vary a lot across the region. To better capture regional specifics inside the countries, Japan was divided in two sub-regions, a Western and Eastern part as technically separated by the 50/60Hz grids border and China was divided into eight sub-regions based on the Chinese power grid structure.

To see the impact of the grid integration in the region with heterogenous climate and RE conditions, three scenarios were applied: a region-wide energy system, with isolated sub-regional power systems, a country-wide energy system, with isolated national power systems, but sub-regions integrated inside the countries, and an area-wide energy system scenario with the whole Northeast Asian power system integrated.

Two additional scenarios were added: an area-wide extra secure energy system with additional gas turbine (GT) capacities and synthetic gas reserves to guarantee two months of GT-based generation, and an area-wide energy system with additional gas demand – in this scenario the gas demand from the chemical industry is covered by additional synthetic methane production.

Results

Existing RE generation and storage technologies are enough to build and operate a 100% RE-based power system. The solar and wind potentials of Northeast Asia are sufficient to cover the future power demand of this dynamically developing region, and each sub-region can cover the demand based only on the local resources, though the country-wide and area-wide grid integration of sub-regional power systems will be beneficial, leading to higher system efficiency and lower cost of electricity supply. The total LCOE for 2030 cost assumption has been found to be in the range of 69-81 €/kWh for different area integration scenarios, competitive to conventional power generation options, even though the RE technology cost assumptions which had been used back in 2016 are considerably overestimated: 2030 PV capex was set to 550 €/kWp – higher than the cost level reached already in 2020 (IEA-PVPS, 2020; Vartiainen et al., 2020).

PV and wind generation provide most of the electricity in the system, with an increased role of grid integration of wind and exported wind power from wind rich regions like Tibet or Inner Mongolia in China to densely populated regions in South and East China, Republic of Korea, and Japan. The super grid concept will be especially beneficial for Japan and Korea, allowing a significant decrease in the cost of electricity supply. Prosumer PV plays an important role in all regions, suppling about 17.5% of the total power demand.

The grid integration also increases the system flexibility and allows reduction of the storage requirements of the RE-based system. Overall, the grids complement the wind generation technology and substitute as a mid-term energy storage, while short-term battery storage mostly complements PV generation with its daily cycles. Long-term gas storage based on Power-to-Gas technology is the highest cost energy balancing option and is used only for seasonal supply and demand variation compensation and for peak shaving in some cases. Both grid and storage technologies provide flexibility to the system and the role of storage and grids depends on the applied financial and technical assumptions. With higher financial assumptions applied to grids, one would see less grid development and higher capacities of storage technologies, together with a slight change of the generation capacity structure, though a sensitivity analysis for grid and storage financial assumptions has not been performed.

Although the system can reliably operate in normal conditions, additional capacity and a PtG-based storage margin can be needed to overcome major energy system failures in case of an exceptional long-term weather anomaly leading to reduction of the RE generation. The calculations show that the margin allowing operation of the system for two months without RE energy supply and the system oversizing to produce and accumulate necessary synthetic gas just in two years will result in 23% higher LCOE compared to the base area-wide integrated system.

Integration of additional sectors, for example the chemical industry, can result in a significant reduction of the LCOE and much lower energy storage requirements. If the cost of product synthesis and storage is lower than the cost of the energy equivalent storage, then integration of the sectors provides additional flexibility to the system. In this case synthesis units operate as flexible demand, operating in periods when the power system faces an energy excess and decreasing methane production during power generation deficit periods, since the required methane can be produced flexibly and stored for low cost to cover the continued demand. This effectively reduces curtailing of electricity generation potential and substitutes long-term energy storage.

4.2 Publication II: Feasibility of the RE-based system under different market design options

Publication II studies the possibility to operate a 100% RE-based power system under different market structures for the case of Israel.

In **Publication II,** Dmitrii Bogdanov, performed the investigation, data collection and the initial simulation to define the optimal structure of a 100% RE-based power system for Israel, aided in the software development for the agent-based model and the conceptualisation of the research.

Aims

The LUT Energy System Model is an optimisation model, which simulates the operation of the integrated system, or one regulator which owns and operates all generation, storage and transmission capacities. Though this approach has its benefits, it falls short of describing the actual behaviour of existing electricity markets. As shown in **Publication I,** a 100% RE-based system can be feasible and balance electricity demand and supply for every hour of the year. Whether the feasibility of such a system can be utilised under existing market designs conditions is not known. The aim of this publication was to check if a RE system can sustainably operate and develop under different market design options and which modifications may be needed to enhance the market design to better fit RE-based system requirements.

Methods

The method is based on soft-linking of two models: an optimisation model (LUT Energy System Model) to define the optimal RE-based power system, and a multi-agent behavioural simulation model developed specifically for this study. The multi-agent model simulates the system with six competing generation companies, each of these companies owns certain technology capacities: solar PV, wind turbines, biomass and biogas power plants, waste incinerating CHPs and battery storage. Each of the companies makes its hourly bidding and investment decisions individually. The model considers both electricity and capacity markets. Based on the revenue from electricity and capacity markets the companies make long-term investment decisions, considering future profit estimation. The principle structure of the multi-agent behavioural simulation model is presented in Figure 11.

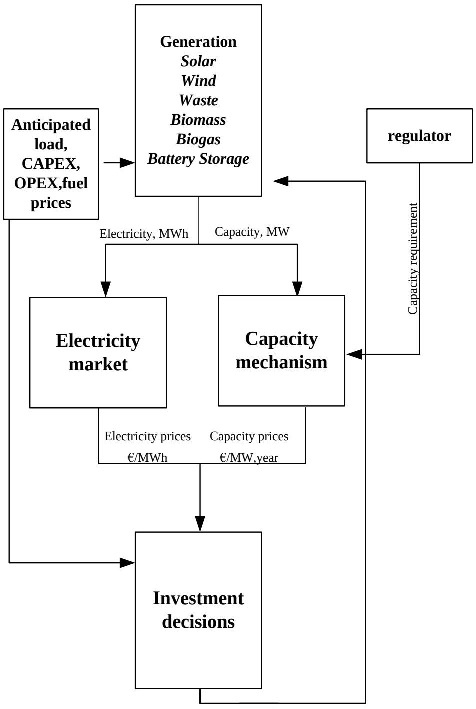

Figure 11. Principle structure of the multi-agent behavioural simulation model.

Three different market design options were assessed: electricity market, electricity market with capacity renumeration mechanisms, electricity market with strategic reserve requirements.

The initial optimal 100% RE-based system structure was defined with the LUT Energy System Model and further operation and development of this system was simulated with the agent-based behavioural simulation model.

Due to the limited number of the technologies considered (due to complexity of agent-based modelling, the number of agents had to be limited) the simulation was performed for the case of Israel – a country with excellent RE resources, low seasonality of RE supply and electricity demand and an isolated power system, which made an energy island approach acceptable in this case.

Results

The results show that the optimal 100% RE-based power system defined by the optimisation model (LUT Energy System Model) can also operate in an electricity market environment for the conditions of Israel. The RE-based system was feasible under all three suggested market design structures; the power system was satisfying demand and the agents were receiving enough profit to invest in the system development. Though, solar generation still had to be supported by feed-in tariffs, otherwise solar PV agents would not receive enough revenue from the electricity market because the PV generation periods are normally characterised by the lowest market prices. In the study the biomass and biogas generation capacity were playing the most important role in the electricity market, to a high extend defining the electricity cost in the market as the technologies with fuel costs. Without biomass, battery storage would play the key role as it is possible to define the marginal cost of the storage based on the storage technology's annualised cost and lifetime in charge/discharge cycles.

Though the system was able to operate under standard electricity market conditions, the capacity market or strategic reserve requirements are beneficial, decreasing the chances of high risk strategic bidding, leading to a lower reliability of the system and a higher loss of load expectation (LOLE) value, and in this study also leading to lower consumer prices compared to a solely electricity market case.

4.3 Publication III: Power system transition modelling

Publication III describes the transition from the current mostly fossil fuel-based power system as of 2015 towards an optimal 100% RE-based power system by 2050 in Northeast Asia, including China, Japan, Republic of Korea, Democratic People's Republic of Korea and Mongolia.

In **Publication III,** Dmitrii Bogdanov developed methods and the model for the study, performed the investigation, data collection and the simulations, analysed and interpreted the results, and aided in the conceptualisation of the research.

Aims

A 100% RE-based power system can be feasible and reliably operate covering the electricity demand even in a highly industrialised and dynamically developing region like Northeast Asia. Though the transition pathway from the current mostly fossil fuel-based power system towards a mostly renewable or 100% RE-based power system has to be accurately planned. That will allow to avoid too sharp changes in the system structure, requiring unrealistically high rates of installations of new technologies, minimise the unnecessary stranded investments in old technologies, and finally guarantee a low-cost energy system transition and least cost of electricity supply at every step of the transition. The aim was to describe such a transition pathway and analyse how it changes the structure of the energy system through this transition, investigate the speed of the cost driven transition, and observe the cost of electricity supply in the system at different stages of defossilisation.

Methods

The LUT Energy System model was modified and expanded to simulate the operation of the conventional fossil fuel-based and nuclear power generation and to optimise the mixed energy system structure in the transition towards higher shares of RE. Additionally, other important RE generation options were added, including offshore wind and geothermal PP. The mid-term adiabatic compressed air energy storage (A-CAES) was added to the existing storage options and HVAC grids as another grid integration option. The simplified structure of the power system is presented in Figure 12.

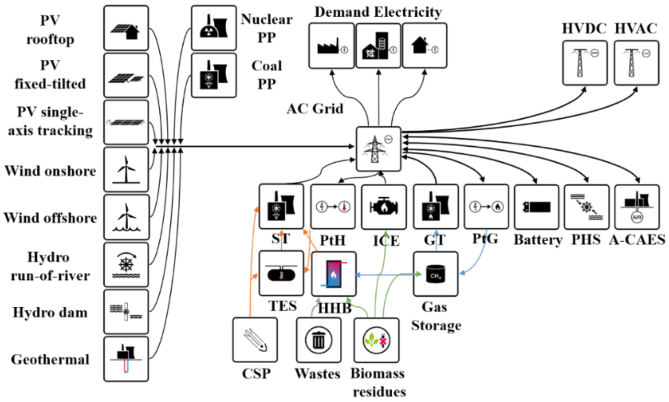

Figure 12. Block diagram of the LUT Energy System Transition model. (Bogdanov et al., 2018). Copyright (2018) The Japan Society of Applied Physics

The model was also modified to describe the transition process: it tracks all the technological capacity ages and decommissions capacities after reaching the end of their technical lifetime. At every step of the transition modelling, the model takes the energy system structure from the previous step as an initial condition of the system and defines capacities to be decommissioned, and the remaining still active capacity defines the available existing capacity for the model, so that it optimises the system by adding capacity to balance electricity supply and demand at minimum annualised cost.

To avoid an unrealistically fast integration of the RE technologies in the system, the growth speed of the RE capacity share in the total power capacity mix was limited to 4% a year – the highest growth rate observed in the past (Farfan & Breyer, 2017). For instance, if the cumulated RE capacity at the end of a year represented 10% of the total capacity, it cannot exceed 14% at the end of the next year.

At each step of the transition, all fuel flows are traced and, based on the annual fossil fuel consumption and emission factors, annual GHG emissions are calculated at each step, allowing an estimation of the carbon budget development of the transition. The GHG emission costs are also included in the target function of the model, representing market-based measures to support defossilisation or measures to decrease indirect subsidies to the fossil fuel industry.

The study was made for the same region examined in **Publication I**, Northeast Asia, which represents a variety of climate and RE availability conditions, regions with high and low population density and different energy intensity and overall a dynamically developing region with an energy intensive economy. Historical generation capacity data is based on GlobalData and other databases (Farfan & Breyer, 2017). In the applied scenario the installation of new coal, fossil CCS and nuclear technologies is blocked as these technologies do not fulfil the sustainability criteria as discussed in chapter 2 of the dissertation. The existing nuclear capacity is allowed to operate till the end of its technical lifetime.

Results

The results show that a transition towards a 100% RE-based system is possible and it can be fully cost-driven. Without any additional support, the RE generation technologies quickly become the main electricity suppliers, providing more than 50% of electricity as early as 2025. Step by step, the RE capacity substitutes decommissioned fossil fuel-based generation, and, with ongoing cost decline of RE technologies, it starts to substitute still active fossil generation, demoting it to a cold reserve status. In the first steps of the transition, wind energy is the most dynamically developing RE technology, mostly due to excellent resources in Tibet and Inner Mongolian regions of China. Later, due to the ongoing cost decline of PV generation and battery storage, PV starts to play a more and more important role, while wind becomes uncompetitive towards PV and new wind installations mostly stop. In total, PV reaches parity with wind in terms of power generation by 2030 (both technologies provide around 35% of total generation), and provides 71% of total electricity generation in 2050, with wind generation contributing a comparably low share of about 18%.

Each country in the region can cover its power demand with the available RE resources for low cost. In all the regions, the calculated LCOE in 2050 is found to be significantly lower than the LCOE calculated for the current power system structure. Overall LCOE in the Northeast Asia region decreases from 74 €/MWh in 2015 to about 55 €/MWh in 2050. The least cost energy supply can be reached in the RE rich regions like Tibet, Central, North and Northeast China, and Mongolia, while in densely populated regions with moderate RE potential like East China, South Korea, and Japan, the electricity cost in the RE system is found to be slightly higher, but still lower than in the fossil fuel-based system.

Fast RE integration leads to a sharp drop of GHG emissions in the power system: by 2035 GHG emissions decreased by 95% from the 2015 level and by 99% by 2045. The defossilisation of Northeast Asia demands substantial PV and wind capacities; in 2050 wind capacity reached 920 GW and PV capacity reached 7400 GW, supporting claims of a terawatt-scale PV future (Haegel et al., 2019).

4.4 Publication IV: Global assessment of the power sector transition

Publication IV describes the transition from the current mostly fossil fuel-based power system as of 2015 towards an optimal 100% RE-based power system by 2050 globally for 145 regions of the world.

In **Publication IV,** Dmitrii Bogdanov developed methods and the model for the study, performed the investigation and data collection for Eurasia and Northeast Asia, supervised the data collection for other regions, performed the simulations, analysed and interpreted the results, and aided in the conceptualisation of the research.

Aims

In **Publication III,** the possibility of a transition towards a 100% RE-based system was investigated for Northeast Asia. The main aim of **Publication IV** was to check the possibility of a cost-driven defossilisation of the power sector globally, taking into account various climate conditions, the current energy system structure and demand projections until 2050 for the regions around the world, and analyse the impact of differences of transition trajectories. The global power sector transition pathway simulation will also allow a definition of the cumulative GHG emissions by 2050 and the remaining carbon budget for other energy sectors.

Methods

For this study, some smaller countries were merged, such as Belgium, the Netherlands and Luxemburg aggregated to one BeNeLux region, while bigger countries like Russia, India, China, Canada, USA, Brazil, and some others were split in several regions each to better represent the local climate and demand differences while keeping regions on a comparable level in terms of area and power demand. In total, the world is represented by 145 regions. Regional power systems are considered to be independent, except regions belonging to bigger countries - these regions are interconnected by HVAC and HVDC grids inside the country borders. Considering this structuring, the world was split into 92 independent power systems, and the transition of each of these power systems was modelled by the LUT Energy System Transition Model developed for **Publication III**.

Results

The transition modelling results show that carbon neutral RE-based power systems can be built in all parts of the world without respect to local climate conditions, current system structures, and power demand growth projections. Similarly, to the case of the Northeast Asian power system (**Publication III**), it can be found around the world that a fast RE growth leads to a rather fast defossilisation, resulting in quickly declining GHG emissions. By 2035, the global GHG emissions can decrease by 90% form the 2015 level, while the LCOE also declines, thus showing true CO_2 reduction benefits. The defossilisation of the system is fully cost-driven since additional requirements to install

RE generation are included in the model, only the ban of new coal capacities, a carbon price mechanism and a fossil fuel use ban in 2050 limit fossil fuels in the system. At the same time, coal generation becomes uncompetitive against RE already in the 2030s in most of the regions in the world, and the coal installation ban saves the system from massive stranded investments.

The process of the system transition massively depends on local RE resources. In most of the regions, wind dominates in new RE installations only in the first steps of the transition, and later PV becomes the least cost source of electricity in the system and represents major parts of new installed capacity. Globally, PV becomes the main source of electricity already after 2030. However, in some regions with very high wind or hydropower potentials, PV still plays the secondary role as shown in Figure 13. Solar PV plays the most important role in the Sun Belt countries. For the high latitude countries, more affected to seasonal variations of the power demand and the RE generation potential, diversified systems based on a mix of technologies are more beneficial and provide a lower cost power generation mix throughout the year.

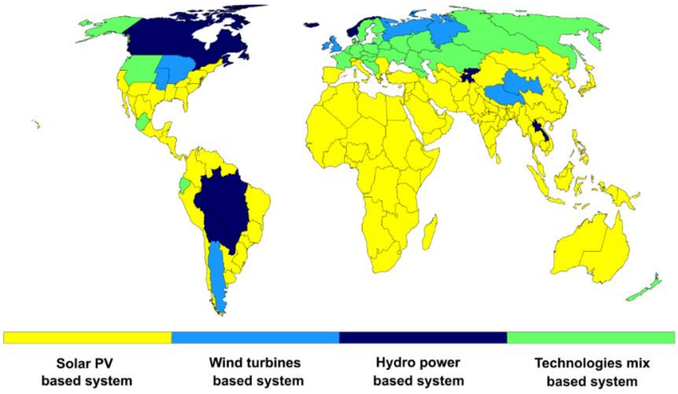

Figure 13. Main types of 100% renewable electricity systems. Four main types of RE-based power systems are identified based on their main source of electricity (more than 50% share of electricity generation). If none of the technologies achieves a share exceeding 50%, then the type is defined as a “Technologies mix-based system”.

Another important factor influencing the transition is the structure of the current energy system. The transition is most complicated in countries suffering from an aging power generation structure like Commonwealth of Independent States (CIS) countries, where massive power generation capacities are soon to reach the end of their technical lifetimes. In these regions, decommissioned fossil capacities have to be substituted by RE in the first steps of the transition, while the cost of RE technologies is still moderate, which finally leads to slightly higher LCOE in the system in later steps of the transition. However, reinvesting in fossil generation, specifically coal, would lead to massive stranded investments and consequently higher levels of LCOE in later steps of the transition as well. The second category is represented by developed countries with a rather stable power demand. In this case, the fossil fuel capacity substitution process is more stretched over time and thus more stable. The last category is formed by fast developing countries with most of the fossil fuel capacity installed in recent years. In these countries, the RE capacities are mostly introduced to cover the power demand growth, while the fossil fuel capacity decommissioning is rather slow and most of the existing coal capacities stop operation after 2035, before their end of lifetime because coal-based generation is no longer competitive.

Another factor influencing the relative defossilisation speed is the assumption about power demand growth. The impressive power system defossilisation rate is partially the result of the applied assumption of the fast power demand growth, as the system had to install RE to satisfy the growing power demand and the fossil fuel generation share was dissolved fast. With lower power demand growth rates, the fossil fuel generation would play a more significant role for longer in relative terms.

A further important parameter influencing the transition is the change of generation, storage, and transmission technology costs, fuel costs, and carbon pricing during the transition. This effect was not fully analysed in the study due to calculation complexity limitations. Though the calculations with a 12% uncertainty range show that even for the case of 6% higher RE costs, the RE-based system LCOE will be lower than in the current fossil fuel-based system.

Though the scenarios with installation of new nuclear capacity were not performed due to the fact that such technology does not comply with sustainability criteria, the results of the transition towards a 100% RE-based system show that new nuclear would not be cost-competitive. The LCOE of new nuclear plant, even assuming the 95% capacity factor, would be higher than the LCOE in the complete power system (including interregional transmission, electricity storage and curtailment).

By 2050, the power system will go through a radical transformation, which will demand substantial investments. Total capital investments will reach about 22.5 trillion euros by 2050 (uncertainty range 19-25.5 trillion). However, this study shows a pathway for how this radical transformation can be realised in a set of evolutionary steps from 2015 to 2050, while this is most likely one of the least cost options among all realistic pathway options, considering the limited perception of the future at each of the transition steps.

4.5 Publication V: Impact of the heat sector integration and feasibility in a harsh continental climate

Publication V describes the transition from the current mostly fossil fuel-based power and heat sectors towards an optimal 100% RE-based power and heat supply by 2050 for the case of the harsh climate conditions of Kazakhstan.

In **Publication V,** Dmitrii Bogdanov developed methods and the model for the study, performed the investigation and data collection, analysed and interpreted the results, and lead in the conceptualisation of the research.

Aims

The power sector transition is feasible in all regions of the world, as found in **Publication IV**. The RE resources are substantial enough to cover the current and growing demand of the future. Also, currently existing technologies are sufficient to balance the supply and demand for all regions of the world, even in case of high seasonality of VRE generation and power demand. However, the power sector represents only a fraction of the total energy demand and total energy related GHG emissions. Other energy sectors, in particular heat and transport have to be taken into account.

In **Publication V,** the aim was to assess the impact of the heat sector integration and overall electrification on the energy transition trajectory. Another aim was to check the feasibility of a 100% RE-based power and heat system for harsh continental climate conditions and a country with an energy intensive economy. The harsh continental climate results in higher energy demand for heating in winter periods, while the seasonality of the PV generation profile (the main energy source in most regions as found in **Publications I-IV**) is also high, but peak generation is reached in the spring-summer period.

Methods

The LUT Energy System Model was modified and expanded to model the operation of the current fossil fuel-based heating system and simulate the transition towards electricity and RE-based heating. The fossil fuel, biomass, and electricity-based individual and large-scale heating technologies were added to the list of technologies, the fossil fuel and biomass-fired power plants were divided into condensing fossil fuel and biomass power plants and CHP plants. Additional low-temperature district heat storage was added, while the high heat thermal energy storage already existed as a part of the Heat-to-Power route established for concentrating solar thermal power (CSP) plants. The simplified structure of the power and heat system is presented in Figure 14.

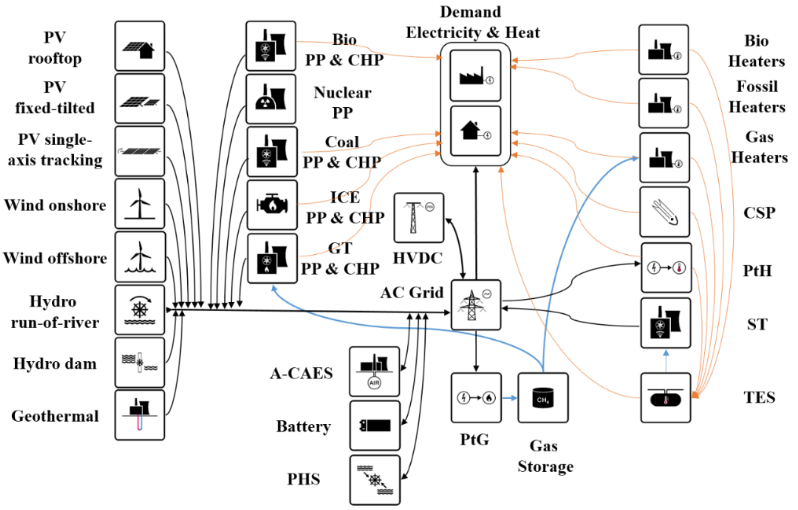

Figure 14. Block diagram of the LUT Energy System Transition model including power and heat generation technologies, storage and power transmission.

The model was applied to the case of Kazakhstan, a country with aging energy infrastructure, which can create additional difficulties during the transition as discussed in **Publication IV**: a harsh continental climate and an energy intensive economy. Though the RE potential is sufficient to cover the energy demand of the power and heat sectors of Kazakhstan, balancing of the energy demand of these sectors and energy supply from the VRE sources can be challenging. To see the impact of the heat sector integration, two scenarios were simulated: transitions of the isolated power sector and the integrated power and heat sectors.

Results

The resources of Kazakhstan are sufficient to cover the energy demand of the integrated power and heat sectors, and the LCOE in 2050 for the integrated system was projected to be lower than in the current fossil fuel-based system. However, the cost of electricity was found to be still higher than in case of the power only system transition. The addition of the heat sector increased the demand seasonality and thus the seasonal mismatch between the energy demand and electricity generation. This implies additional storage requirements and results in additional cost for the system. Additionally, the generation mix also changes. Due to the energy demand growth, the share of dispatchable RE (dammed hydropower and biomass) decreases; at the same time, the role of wind energy increases. Though the wind generation cost is higher than for PV, the wind electricity generation is higher in the wintertime and better matches the demand, decreasing the storage requirements and thus the overall energy system cost.

On the other hand, sector integration provides additional flexibility options, such as flexible operation of heat pumps and electrolysers, which allowed less curtailment at times of high VRE availability and discharged storage facilities at times of energy deficits, reducing the total electricity storage requirements. Nevertheless, these technology impacts cannot overcome the burden of the heat demand seasonality. In some periods, batteries also operate to increase electrolyser full load hours (FLh) and to maximise the efficiency of the system.

The aging energy infrastructure of Kazakhstan creates additional difficulties for the transition, as a significant share of the generation capacities reaches the end of lifetime around 2025, which provokes an unrealistically sharp phasing out of the old capacities and phasing in of new RE capacities. This is a substantial burden to follow an optimal transition pathway in reality and may lead to additional costs.

4.6 Publication VI: Sectors integration impact on the system flexibility

Publication VI describes the transition from the current mostly fossil fuel-based energy system sectors towards an optimal 100% RE-based energy system (including power, heat, transport and industry sectors, and emerging technologies such as desalination) by 2050 for the case of the harsh climate conditions of Kazakhstan.

In **Publication VI,** Dmitrii Bogdanov developed methods and the model for the study, performed the investigation and data collection, analysed and interpreted the results, and aided in the conceptualisation of the research.

Aims

The main aim of **Publication VI** was to examine in detail the effects of sector integration including all energy sectors and considering emerging technologies. The impact of the heat sector was examined in **Publication V**, while the transport sector impact was not yet studied. In **Publication V,** power and heat demand was assumed to be inelastic, though the industrial heat and power demand can provide additional flexibility to the system as it happens today and was shown for the case of the upcoming chemical industry based on synthetic e-chemicals as investigated in **Publication I** for the case of methane. Other emerging technologies, namely seawater desalination can also have a significant effect on RE-based energy systems.

Methods

Several modifications were applied to the LUT Energy System Transition Model. The transport sector service demand in passenger-km and tonne-km, as well as shares of different transport modes are predefined outside of the model and thus the transport sector transition is only partly optimised, as the demand is predefined, while the supply remains optimised. The main reasons are difficulties with the mobility cost estimations for the future and the fact that the cost is not the only influencing factor in road transportation, and similarly for the other transport modes rail, marine, and aviation. Nevertheless, the model optimises the energy flows to satisfy the energy demand of the transport sector. To properly simulate the industrial energy demand and its flexibility potential, the industrial sector was represented as a set of segments: cement, steel, chemical, alumina, aluminium, and pulp & paper industries. For the industry sector, the model traces the electricity, heat, fuel and raw material consumption, and the excess heat generation in case of some technologies. Seawater desalination had been introduced in the model earlier, but has not been used in the discussed publications. A special version of the model was created for desalination studies (Caldera et al., 2016). The model defines the desalination energy demand and the energy demand for the desalinated water delivery to the demand centres. The desalinated water demand is an exogenous parameter, but the model defines the least cost technology for seawater desalination and the optimal operation profiles of water desalination technologies, water storage and the water pumping system. The simplified structure of the energy system is presented in Figure 15.

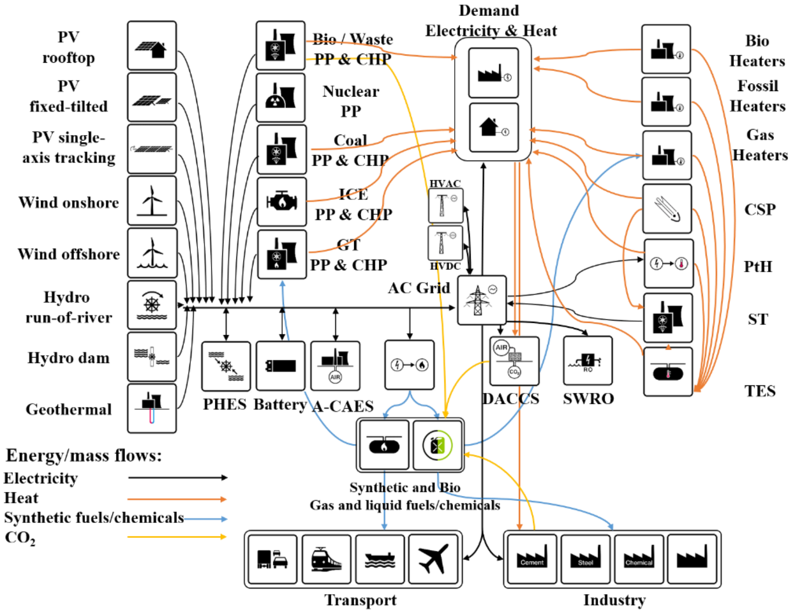

Figure 15. Block diagram of the LUT Energy System Transition model including power, heat, transport, industry sectors, and desalination.

To study the impact of the sector integration, the power only sector transition was taken as a reference and then the heat, transport, industry sectors and desalination were added to the system, leading to five simulated scenarios in total:

- BPS-1: power sector;
- BPS-2: power and heat sectors integrated;
- BPS-3: power, heat and transport sectors integrated;

- BPS-4: power, heat, transport and industry integrated sectors, excluding desalination;
- BPS-5: power, heat, transport and industry including desalination integrated sectors, as the full energy system.

Similar to **Publication V**, the study was performed for the case of Kazakhstan due to its specific climate conditions and industry-based energy intensive economy.

Results

The sector integration has a significant impact on the system structure in terms of generation mix, storage structure, role of technologies, and finally the cost of energy in the system. In most of the scenarios, the power sector benefits from the sector integration due to access to additional flexibility, except for the case of heat sector integration as previously discussed in **Publication V**. For the case of Kazakhstan, the negative effect of the heat sector's demand seasonality overcomes the positive impact of flexibility from power-to heat and electrolysers. Regarding the other sectors, transport and industry have mostly a positive impact, providing additional flexibility and reducing overall seasonality of the demand. Unlike space heating demand, industrial heat demand is rather stable during the year. Though desalination does not provide flexibility to the system due to high capital expenditures of the seawater desalination and water pumping systems, it tends to operate at high full load hours. Thus, the introduction of desalination further decreases demand seasonality and due to fast growth of electricity demand for desalination in the last steps of the transition, it also leads to lower cost of primary electricity generation.

Overall, sector integration and electrification facilitates the transition and decreases the cost by resolving many of the discussed technological challenges during the transition, including the necessity to integrate large capacities of energy storage and related storage costs, resulting in higher cost of electricity, heat and e-fuel supply. Considering different transition speeds, the energy sectors complement each other during the transition, allowing an increase in each sector's efficiency, while reducing total system costs.

4.7 Publication VII: Global assessment of the energy system transition

Publication VII describes the transition from the current mostly fossil fuel-based energy system sectors towards an optimal 100% RE-based energy system (including power, heat and transport sectors, and emerging technologies such as desalination) by 2050 globally for 145 regions.

In **Publication VII** Dmitrii Bogdanov developed methods and the model for the study, performed the investigation and data collection for Eurasia and Northeast Asia, supervised the data collection for other regions, analysed and interpreted the results, and aided in the conceptualisation of the research.

Aims

As shown in **Publication VI,** RE resources can cover the energy system demand even in regions with extreme climate conditions and an energy intensive economy, such as in Kazakhstan. However, Kazakhstan benefits from excellent solar and wind conditions and a low population density. In other regions the RE potential can become a limiting factor. The main aim of **Publication VII** was to check the possibility of a cost driven defossilisation of energy systems globally, considering the specific climate conditions of the regions, the current energy system structures and energy demand projections, similarly to **Publication IV**, but for the full energy system, and to investigate the impact of regional characteristics on the transition trajectory. The global energy system transition simulation also allows a calculation of the total GHG emissions through the transition of the energy sectors and a check whether the cost driven transition can be a 1.5°C compatible scenario.

Methods

The applied model in this study was similar to the one described in **Publication VI**. The transition was simulated for the integrated power and heat sectors, transport sector and seawater desalination. Power and heat sectors were simulated similarly to **Publication V**, without accurate tracing of industry sector energy flows, while the industry sector power and heat demand is included in the power and heat sector demands, respectively. Similar to **Publication IV**, smaller countries were merged, some bigger countries were split in several regions each to better represent climate and demand differences and keep regions on a comparable level in terms of area and energy demand. In total the world is represented by 145 regions, while the regional energy systems are considered to be independent, except regions comprising bigger countries. These regions are interconnected by HVAC and HVDC grids inside the country borders, and FT fuels can be also exchanged between regions inside a country, but the heat systems of the regions are isolated. After the simulation of the power and heat sectors, the transport sector and seawater desalination, the total integrated system parameters are calculated.

Results

The transition towards fully defossilised RE-based energy systems is feasible in all regions of the world. Both the RE potentials and existing technologies are sufficient to satisfy the energy demand in each region and for every hour. This transition will result in substantial growth of energy system efficiency, as the shift from conventional low-efficient combustion of fossil fuels towards almost pure exergy, i.e. electricity, the global primary energy savings were calculated to reach about 150 000 TWh per annum for the year 2050. Overall, despite a continuous growth of the final energy demand, the 2050 TPED can be still at the same level as of today.The efficiency gain will depend on climate conditions and thus the structure of the energy system in 2050, but overall the primary energy savings were projected to be in the range of 40-60% depending on the region, with a global average value of 49%. In most of the regions PV will be the main source of energy, though in high latitude regions wind electricity generation will play a more significant role as shown in Figure 16, similar to the results obtained in **Publication IV** and **Publication V**. The role of hydropower and biomass will be reduced compared to the power system transition, as discussed in **Publication IV** due to a negligible additional resource potential compared to the energy demand of the integrated energy system. In total, more than 60 TW of PV capacity will be needed by 2050, which represents a challenging, but achievable target (Haegel et al., 2019; Verlinden, 2020).

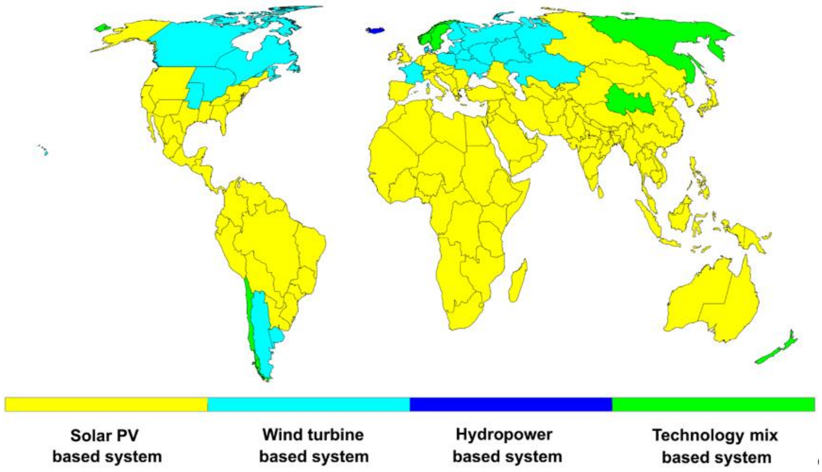

Figure 16. Main types of 100% renewable electricity systems. Four main types of RE-based energy systems are identified based on their main source of electricity (more than 50% share of electricity generation). If none of the technologies have a share exceeding 50%, then the type is defined as “Technology mix based system”.

The cost-driven transition discussed in this study will result in a fast reduction of GHG emissions and will fulfil the ambitious 1.5°C climate target requirements (with 66% probability the carbon budget is about 550 $GtCO_2$ from 2018 onwards) without carbon dioxide removal technology (CDR) utilisation or final energy consumption limitations.

This transition will directly accomplish four major Sustainable Development Goals. First, it will decrease the probability of significant climate change by reducing GHG emissions without applying additional limits on energy consumption growth in the future. Second, it will provide equal access to low-cost energy supply in all regions across the world. Third, it will enable sustainable growth in standards of living across developing countries of the Global South. Fourth, it will enable universal access to clean water and decrease water stress. Indirectly, it will also help accomplish a number of other Sustainable Development Goals, leading to an overall sustainable future.

5 Discussion

The main findings of the dissertation can be summarised in seven main points:

1) RE technologies can satisfy the energy demand in every region of the world even considering the growth of final energy demand (FED). The energy transition does not require a limit on consumption and does not demand a change in human lifestyle (as described in **Publication VII**).
2) In every region of the world a fully sustainable VRE-based system can satisfy energy demand at every hour of the year, at a cost comparable to or lower than the energy cost today (as described in **Publication VII**). The energy transition towards VRE-based systems does not reduce the reliability of the system and variability of RE sources can be compensated without limiting the final consumption of residential and commercial consumers. The RE generation deficit during exceptional long-term weather anomalies can be satisfied using e-fuel-based long-term storage and capacity margins, without use of fossil CCS or nuclear options (as described in **Publication I**).
3) Energy system electrification and sector integration are the most important elements of the transition, though the impact is region dependent. Depending on the energy sector and regional specifics, the integration can bring benefits (increased system flexibility due to low-cost energy storage in form of the final product: heat for the heat sector and e-fuels in case of transport and chemical industry), or make the transition more sophisticated as for heat sector electrification in case of countries with high seasonality of heat demand (as described in **Publication VI**).
4) Overall, the transition towards RE-based systems and electrification results in a substantial growth of the total system energy efficiency. In the case of transition towards 100% RE, sector electrification and integration, TPED (as described in **Publication VII**) can be more than 50% lower than the TPED in the case of the current energy system structure.
5) Further, direct electrification in transport and industry has to be perceived as a way to foster system efficiency and reduce energy cost.
6) While VRE-based power systems would require significant long-term energy storage to compensate the VRE generation seasonality, a 100% RE-based integrated energy system does not require such long-term energy storage to compensate the seasonality of the VRE power generation. In most of the cases, the seasonality can be resolved with long-term product storage like synthetic hydrogen for the chemical industry or any other product of a flexible technology with low CAPEX (allowing operation at lower FLh) and cheap final product

storage. Instead of using e-fuels to produce the power at specific periods of RE generation deficit, the system decreases the e-fuel and some other product production, while existing generation and short-term storage cover the inflexible energy demand. This allows avoidance of considerable energy losses due to the low roundtrip efficiency of e-fuel-based energy storage (Power-to-Fuel and Fuel-to Power) and negative effects of fuel combustion.

7) The existing computational capacities and the LUT Energy System Transition Model allow simulation of the energy system transition with vast technology portfolios (more than 100 technologies), with all sectors fully coupled, in full hourly resolution and with a technically unlimited number of nodes taken in consideration. This allows detailed studies of the energy system transition pathways, taking into account regional details and adequately considering the impact of RE variability as well as the roles of prosumers, bridging and emerging technologies.

Broader discussion of the results is presented in the following sections.

5.1 General discussion of presented results

RE-based power systems feasibility and cost

The global energy system is already in the process of defossilisation. Though the share of renewables in TPED is still too low and energy related GHG emissions are growing, the share of RE in power generation and its growth rate are constantly increasing (IEA, 2020a). In some countries modern RE has already reached a significant share: in 2019 renewables generated about 79% of all electricity in Denmark, 98% in Uruguay, 40% in Germany, and 20% in Australia (IEA, 2020a). Finally, in 2019 the energy related emissions flattened at a level of 33 Gt_{CO2} (IEA, 2020b), probably showing the breaking of the trend. The results of **Publications I** show that the full defossilisation of the power sector can be achieved, as the RE potential is substantial enough to cover the current and future power sector demand even in fast developing regions with energy intensive economies; and currently existing technologies are sufficient to balance supply and demand for all hours of a year. Furthermore, **Publication II** shows that such a 100% RE system can operate and reinvest in the market conditions very similar to today’s market structure, though some modifications such as a capacity market or strategic reserve requirements are beneficial, allowing to reach more reliable electricity supply. Simulation of a cost driven transition in **Publication III** shows that the RE technologies are cost competitive and in 2050 RE-based generation is lower in cost than fossil fuel-based alternatives. Defossilisation leads to a reduction of electricity cost in the system: LCOE reached in 2050 for nearly 100% RE systems (some nuclear PPs still have not reached the end of their technical lifetime, but the share in the generation is negligible) is 25% lower than the average LCOE calculated for 2015. For the case of an extreme long term RE generation deficit lasting for several months, the system can be secured with capacity reserve on the basis of carbon neutral technologies, mostly Power-to-X (PtX) and GTs running on synthetic bio and e-fuels as discussed in **Publication I**, without dependence on unsustainable fossil CCS or nuclear options. The results of **Publication I** show that even with already outdated cost assumptions for PV systems (the cost applied for 2030 in **Publication I** was 27% higher than the levels reached in 2020 (Vartiainen et al., 2020), an RE-based power system can provide the electricity on a highly competitive level of 70 €/MWh$_{el}$, lower than the nuclear and fossil CCS options. Considering the fact that a RE-based energy system better complies with all the long-term sustainability requirements, the transition towards RE-based systems can be considered as the ultimate solution of the climate change problem and the role of nuclear and fossil CCS options must be limited wherever it is possible, and finally will be limited in case of cost driven decision-making.

Transition towards RE-based systems by 2050

A transition towards RE-based energy supply by 2030 is technically possible and the RE-based power supply will be lower in cost than fossil fuel-based or nuclear options. Radical changes would have to be made and enormous investments will be needed, but the primary obstacles are a lack of political will and resistance of fossil industry beneficiaries (Jacobson & Delucchi, 2009). However, the energy transition has to be accomplished by the latest 2050 in order to reach targets claimed in the Paris Agreement. **Publication III** shows a possible pathway for a transition from a current fossil-based energy system towards a defossilised and carbon neutral RE-based power system in 2050. For the case of the Northeast Asian region such a transition results in an LCOE for 2050 on a level of 55 €/MWh including power generation, storage, interregional transmission and power transmission and distribution losses costs, which is 25% lower than the LCOE calculated for 2015 using the same methodology. The LCOE of the RE-based system significantly decreased compared to **Publication I** due to several reasons. First, updated cost assumptions were made, most importantly for PV and battery storage technologies. A decline of the capital and operational expenditures for the core technologies of the RE-based system inevitably lead to a reduction of the system's LCOE. Second, a different reference year was used, as the transition must be finished by 2050 instead of 2030, when the costs of RE generation and energy storage technologies are expected to be significantly lower. Changes in the model also had a significant impact on LCOE. On the one side, the addition of new generation and storage technologies results in lower LCOE due to a higher number of flexibility options. On the other side, the transition approach leads to higher LCOE compared to the overnight system simulation. These improvements have also led to a different energy system structure. Despite similar RE potential assumptions, the share of PV in the total generation mix of RE significantly increased compared to **Publication I** due to lower PV cost assumptions, although with the overnight simulation approach the share of PV would be even higher. As with the overnight approach the optimal structure would be defined based on the target year's financial and technical assumptions, while in the transition simulation the optimal solution is strongly affected by the legacy system, thus based on previous step solutions. In the transition simulation most of the wind capacities are installed in the first steps of the transition when wind electricity is highly cost competitive towards PV due to PV and battery storage cost.

Another benefit of the transition simulation is considering the effect of the existing energy system structure and age of existing capacities. In case of financial and climate conditions equally favourable for PV and wind-based generation, the starting conditions, like existing grid structure or fossil generation decommissioning schedules, may define the final energy system structure.

With the current cost decline of RE generation technologies and assumed carbon pricing levels, fossil generation capacities get less competitive towards renewables and in the 2030s the coal PP full load hours reduce to 2000-3000 h, when the carbon pricing is in the range of 61-68 €/tCO_2, and to 1000-1500 h in the 2040s, when the carbon pricing is in the range of 75-100 €/tCO_2, beckoning that the running cost of existing coal generation exceeds the cost of the RE-based generation (as for the case of Kazakhstan in **Publication VI**).

The possibility to build the RE-based energy system globally has been also discussed and proven in studies by Teske (2019) and publications Jacobson et al. (2017, 2018, 2019). Recently, even IEA presented the first scenario with net zero emissions by 2050, NZE2050 (IEA, 2020d). Unfortunately, the details of the transition scenario are only disclosed till 2030 and the energy supply structure in 2050 is not clear. Previously most of the global energy system transition studies by IEA were much less progressive, assuming much lower rates of defossilisation and slower RE growth. Even the latest NZE2050 scenario assumes the average annual PV capacity additions in 2020-2030 at a level of 300 GWp/year, while a much higher rate of 900 GWp/year is necessary to archive the 1.5°C target as shown in **Publication VII**. Over global studies, as GEA reports (Johansson et al., 2012), and as other studies based on IAM models (like MESSAGE used in GEA report and other studies by IIASA) tend to emphasise, there is a role of fossil CCS and nuclear energy in the transition towards renewables. However, these do not respond to the sustainability requirements as discussed earlier in section 2 and highlighted in the publications by Jacobson et al. (2017). Another problem is the costs of fossil CCS and nuclear technologies, which are already higher than the costs of RE generation and show a negative learning curve – the costs tend to grow over time, while RE costs decline. In later publications, such as Grubler et al. (2018), fossil CCS is explicitly excluded and nuclear is part of the system but plays minor role. However, the study assumes a 40% decline of final energy demand by 2050 despite increasing population, income and activity. The MESSAGE model, due to its complexity, has to operate in a reduced temporal resolution. Similar to the TIMES model, it uses a time-slice approach, though the models with time slices can be applied to energy transition studies with very high shares of renewables as was also shown by Pursiheimo et al. (2019). The authors recognise that the time-slice approach can be a limiting factor in RE-based system modelling and “analysing effects of high renewable share on energy system based on hourly data […] needed studying close to 100% renewable future scenarios” (Pursiheimo et al., 2019). Finally, to reach the highest quality of energy system models (ESMs), integrated assessment models (IAMs) have to aim for high resolution in three fields: time, space, techno-economic detail; and consider sector coupling (Prina et al., 2020).

According to a review by Prina et al. (2020), the LUT Energy System Transition Model responds to these requirements to a high extend.

RE system individuality and parameters defining the power supply structure

Current fossil fuel-based energy systems are typically built based on a quite similar design principle: hydropower generation if available, baseload generation based on coal (or nuclear in some countries), gas turbines mostly play a balancing role (though some large-scale, heavy-duty, combined cycle gas turbine (CCGT) plants are not that flexible and tend to operate as baseload) and oil generation is mostly used to satisfy peak demand (or more baseload demand in some hydrocarbon exporting countries). The shares can vary due to local resource availability or access to technologies, but they are similarly driven by prices on international fuel markets. As shown in **Publication IV,** RE power systems are characterised by a variability of possible power system structures. Depending on local conditions, power systems will be based mainly on solar PV, wind or, in cases of exceptionally good resources, also on hydropower. High latitude regions with higher seasonality of electricity demand (like regions of Russia, Canada, and Scandinavian countries) and RE generation tend to have diversified energy systems with balanced shares of PV and wind generation as shown in Figure 13. Similar to findings in **Publications V-VII**, PV is still the least cost energy source in 2050 in most regions, including high latitude areas, though wind generation is vital to balance the demand and supply in the winter months in regions with strong seasonality of energy demand and RE generation. Otherwise, systems would need to invest more in long-term energy storage and total system costs would be higher. Finally, the major energy source in these optimal RE-based systems is not necessarily the least cost source of energy, which is the case for some technology mix options, based on hydropower or wind turbines. However, even inside each of these four classes of energy systems, each regional energy system has its own specifics, different generation technologies shares, different storage system structures and roles in the power system, to individually tailor the power system to specific regional conditions.

The available RE resources are not the only parameters defining power system structures, as the current structures of the power system also have a significant impact on future system structures. Countries with developed power grid interconnections between regions tend to have higher shares of wind generation in the system because the grids allow balancing of the regional variability of the wind generation, while countries with more self-sufficient regional power systems tend to rely more on PV generation balanced with local storage systems. The age of the existing capacities also has a significant impact, as systems with an aging existing fleet require re-investments earlier and thus tend to have a higher share of wind generation in the mix, while the power systems with a more stable age structure of capacities and in particular a strong demand growth tend to rely more on PV. This is because more investments in the fleet renewal and overall capacity increase occur in later periods of the transition, when the ongoing PV and battery cost decline makes wind-based systems less competitive. Even in these major classes of PV-based, wind-based, hydropower-based, and mixed power systems, each regional system is unique due to different storage system structures, different roles of biomass, and different roles of grids in the balancing of supply and demand. Another important parameter is the retail electricity price levels, as countries with high retail electricity prices face a fast growth of energy prosumerism and prosumer PV systems represent a significant part of the generation and have an impact on the overall system structure: reducing the centralised system power load, peak generation capacity and grid interconnection capacity as shown for the example of Europe by Child et al. (2019). Otherwise, in countries with subsidised or cross-subsidised retail electricity prices, prosumerism is less attractive and prosumer PV does not play that important role in the overall power supply. Finally, the optimal structure of RE-based power systems depends on a longer list of sometimes interlinked key parameters, and each country will require an individual and accurate planning of the power system transition considering local energy demand.

Energy systems decentralisation

The rise of prosumerism and overall transition towards RE-based systems open the possibility to build more decentralised energy systems. **Publications IV** and **VII** show that the currently integrated power systems of Europe can be stably operated in an isolated mode relying only on local RE resources (though some regions were merged to reduce computational complexity of the modelling). **Publication I** discussed in detail the benefits of regional grid integration or cost of autarky. In the case of Northeast Asia and assumptions used in **Publication I,** regional integration would reduce the LCOE by 15% at the cost of higher dependence on neighbouring countries. The same effect has been observed for the case of Europe in Child et al. (2019). Though the regions of Europe can be self-sustainable in terms of energy, regional integration results in energy supply cost decline.

Another level is decentralisation inside a region. Though the methods applied in **Publications I-VII** do not allow analysis of capacity placement inside a region and the regional transmission and distribution grid structure, PV may become the main driver for the energy system decentralisation independently of the role of prosumers. Unlike fossil fuels, hydropower or to a lesser extent wind resources, solar resources are more evenly distributed, which opens the possibility to build decentralised grids inside regions, where the electricity will be produced and consumed at the same locations, and the grids will play only a balancing role. An optimal design of such systems will demand more detailed modelling of the generation and storage capacity placement, taking into account the spatial distribution of power demand and PV potential, as well as the cost of grid construction under the given conditions.

PV as a central pillar of the RE-based energy system

Solar PV plays the main role in the global energy system as described in **Publications IV** and **VII**. The share of PV in total power generation increases with integration and electrification of energy system sectors. In **Publications IV** solar PV provides around 70% of the energy consumed by the global power system, while in case of the integrated energy system described in **Publication VII,** solar PV provides more than 75% of all produced electricity, or about 68.5% of the TPED. The share of solar CSP is minor, about 2% of TPED. Overall, solar PV benefits from increasing flexibility of the system as discussed in **Publication VI** and also the role of PV increases with energy demand growth in case of regions with limited wind resources, as seen in the results of **Publications IV** for the example of South Korea. Other studies also see solar energy as the major source of energy in future energy systems. In Teske (2019) solar energy is the major source of energy, providing about 30% of TPED, in Jacobson et al. (2018) the share of solar energy is even higher, at about 44%, though wind is the main source of energy with a slightly higher share of 49%. Both Teske and Jacobson et al. project that solar CSP may play a significant role in the energy supply, unlike the results of **Publications IV** and **VII**. In Pursiheimo et al. (2019), which discussed less progressive scenarios without a fully carbon neutral energy system by 2050, the share of solar PV in TPED reaches 39–44% depending on the scenario, and the share of CSP is significantly lower, at about 5%.

Intuitively, the cost assumptions applied to technologies, and specifically PV cost assumptions, define the role of PV in the results of studies to a high extent, which explains significant uncertainty in defining the role of PV in the mentioned studies and IPCC reports. However, as found by Jaxa-Rozen & Trutnevyte (2021), a “large portion of the uncertainty in the global scenarios is associated with general features such as the type of organisation, energy model and policy assumptions”. Victoria et al. (2021) show that the limited role of PV in most IAM-based scenarios is the result of underestimation of PV cost decline and grid integration limitation.

The modelling method described in this dissertation does not favour any technology and the modelling approach is admitted as one of most advanced in some model reviews (Prina et al., 2020). The major role of PV in the results of **Publications I-VII** is explained solely by the utilised resources and cost assumptions, which make PV the least cost source of energy in most of regions. The cost assumptions for PV are based on trustworthy sources (Vartiainen et al., 2020), and the results are recognised in leading publications on solar PV perspectives in the future energy system (Haegel et al., 2019; Victoria et al., 2021).

Sector coupling effects on the energy system transition

Sector coupling adds additional dimensions to optimal energy system definition problems, applying additional constraints but also providing benefits from sector bridging technologies. Integration and electrification of additional sectors can lead to an increase in the electricity demand seasonality, as in the case of heat sector integration due to higher electricity demand for heating in the winter months as shown for the example of heat sector integration in Kazakhstan in **Publications V** and **VI**. Further, a higher seasonality of demand induces additional storage requirements, which in turn increase the share of the energy sources with higher cost. But, higher generation during energy demand peak seasons thus results in additional energy cost compared to a power only case. However, as it is seen in **Publication VI,** integration and electrification of the sectors with constant load, like industry, transport, and new technologies like water desalination, help to reduce the electricity demand seasonality and consequently decrease the demand in long-term energy storage.

Furthermore, in most of the cases sector integrations provide additional flexibility to the system, decreasing RE electricity curtailment and storage requirements and consequently increasing the overall efficiency of a system. The potential benefit of sector integration was highlighted in studies by Connolly, Mathiesen and Lund (Connolly et al., 2016; Mathiesen et al., 2015), which show the additional sources of flexibility in the integrated 'Smart energy systems'. Brown et al. (2018) also show for the case of Europe that both sectoral and regional coupling of energy systems result in comparable cost benefits, which can be partially combined. The impact of the heat, transport and industry sector integration on system flexibility, plus the effects of the emerging technologies like desalination, is discussed in detail in **Publication VI**. In general, the impact of the sector integration depends on the set of parameters. First, the cost of storing the sector's main product must be cheaper then storing the electricity needed to produce this product. Second, the capital expenditures of the equipment or the share of capital costs in the final cost of the main sector's product has a very strong impact, as the technologies with high CAPEX and a high share of capital costs in the final product cost tend to operate at high full load hours, thus the flexibility of these technologies is limited. An example of the latter is seawater desalination, where the cost of freshwater storage is low, but the high capital costs of the water desalination equipment and water distribution pumping system result in low flexibility of this technology. Third, another limit is induced by technological limitations, i.e. technologies where the current equipment does not allow fast ramping of production (as for methane and hydrogen liquefaction), thus they have to be operated at baseload and cannot provide flexibility to the system.

Electrification and the power sector as the backbone of future energy systems

In any case, as a result of sector coupling the power sector becomes the backbone of future energy systems. Direct electrification provides benefits to all sectors, improving the energy system efficiency and in most of the cases leading to lower energy supply cost compared to fossil fuel-based options. The cost driven electrification of the energy sectors leads to a fast rise of electricity demand, as shown in **Publication VII.** Electricity generation can exceed 135,000 TWh in 2050, while current global electricity generation is at a level of 26,730 TWh (as in 2018) (IEA, 2020a). That demands substantial growth in RE generation capacities, especially PV, which can exceed 63 TW by 2050 (**Publication VII**), compared to about 22 TW for the case of a power sector transition (**Publication IV**). Wind capacity also increases, reaching 8 TW for the entire energy system compared to 3 TW in the power only system transition. The relative role of other RE sources decreases due to a limited resource potential.

The power sector is the main beneficiary of sector coupling. As shown, sector integration leads to a significant reduction in the LCOE in RE-based systems. The first reason is the impact of additional low-cost flexibility options allowing a reduction of long-term energy storage requirements of the power sector and mostly substitute long-term electricity storage by seasonal demand response of other energy sectors. Another reason is the growing electricity demand. As discussed for the example of **Publication III,** the demand growth during the transition has a substantial impact on the energy system structure and the energy cost in the RE-based system. Due to the ongoing cost decline of RE generation and electricity storage technologies, faster growth of electricity demand in the later steps of transition increases the share of the low-cost generation technologies in the total capacity mix and thus leads to lower average electricity generation costs. A similar effect can be observed for electricity storage cost. Thus, even the integration of technologies with inflexible electricity demand can lead to a LCOE decline in RE-based energy systems, as shown in **Publication VI**.

Power-to-X as a costly alternative to the direct electrification

However, some sectors cannot be fully directly electrified using currently existing technologies. In industry and transport there will be segments where direct electrification will not be possible by 2050, or despite the technical possibility of the direct electrification, old fuel-based equipment will be still in operation. The segments which can be directly electrified will be transformed first, but to fully defossilise these segments by 2050, a new e-fuel industry has to emerge in the 2030s with a strong absolute growth in the 2040s at the latest. The e-fuel production, namely hydrogen, synthetic methane and FT-liquids, will substitute the remaining fossil fuels in transport, heat and industry, while FT-based naphtha, synthetic methanol and ammonia will substitute fossil fuel feedstock of the chemical industry, as modelled in **Publication VI**, which is currently the most detailed description of PtX pathways in the known literature, with five different PtX fuels and chemicals.

As discussed in **Publications VI-VII,** the e-fuel generation will provide additional flexibility to the system, which also leads to a LCOE decline. However, in some regions the cost of synthetic hydrocarbons will be higher than the current fossil fuel cost, which may lead to higher overall levelised cost of energy compared to the current levelised cost of energy, as shown in **Publication VII**. Additionally, it needs to be noted that this is largely a consequence of high subsidies for fossil fuels and not accounting for the very high cost of climate change and air pollution. Having that factored in, all countries may switch to e-fuels quite fast. Though some regions possess excellent RE resources and, with the financial assumptions of **Publication VII** by 2050, they could produce synthetic hydrocarbons at a cost comparable with current fossil fuels, even ignoring the very high societal costs of climate change and air pollution. That opens the possibility of international e-fuel trade similar to the current oil and gas market. The international e-fuel trade would allow a decrease in the negative impact of the indirect electrification and would significantly decrease the levelised cost of energy in many regions, especially the cost of energy for industry and transport (Ram et al., 2020). Though on top of the cost the use of e-fuels has another significant flaw. Combustion of carbon neutral e-fuels still leads to NO_x emissions.

Biofuels can also contribute to the transition towards a fully RE system, substituting fossil fuels in the early steps of the transition and e-fuels in later steps of the transition. However, the use of unsustainable biomass endangering remaining ecosystems or energy crops competing with food crops has to be avoided. The total amount of sustainable biomass representing agricultural, forestry and farming residues together with unrecyclable wastes is considered in **Publication VII,** at a level of 9250 TWh_{th} globally, from which about 8800 TWh_{th} is consumed by the energy system in 2050, representing about 6% of TPED. Bioenergy is no necessary element of an energy system, as Jacobson et al. (2017, 2018, 2019) show how a RE-based energy system can operate without combustion of biofuels or bioenergy use in any of the energy system sectors. While Teske (2019) in opposition, projects a more significant role of bioenergy, which covers about 20% of TPED in the proposed scenario. Though, as discussed previously, in all these scenarios solar PV is regarded as a main source of energy in the RE-based systems.

Efficiency of the RE-based energy system

Publication VII shows the decisive impacts of sector integration, electrification and defossilisation on overall energy system efficiency. Altogether, these measures result in more than a halving of TPED compared to the case of the mostly decoupled, fossil fuel-based sectors as in the current energy system. The energy efficiency of the global RE-based energy system described is higher than the values assumed in Teske (2019) and Jacobson et al. (2018). At the same time, **Publication VII** assumes a much higher final energy demand compared to Teske and Jacobson et al. and represents a more complicated case of the energy transition, which does not compromise further growing final energy consumption and growing standards of living around the planet. The results of **Publication VII** show that the assumed growth in power, heat and transportation services leads to a less than 40% increase of final energy demand due to significant efficiency improvements from direct electrification of the road transport segment and results in a 20% growth in TPED, even considering additional energy losses in e-fuel production routes.

Though the TPED can be defined differently in RE studies. There is still no consensus on the methods of TPED/TPES calculations in case of RE and novel technologies such as heat pumps. In the **Publications** used for this dissertation the TPED/TPES was calculated accordingly to IEA’s Physical Energy Content Method (PECM), whereby TPED of non-combustible technologies is set to the electricity or heat output (as for wind, solar PV, geothermal heat), but in case the technology produces heat at an intermediate step (like geothermal power, solar thermal power) TPED is set to the amount of heat consumed. This method is widely used by IEA, OECD, Eurostat and is the International Recommendations of Energy Statistics (Kraan et al., 2019). Other methods of calculations exist in parallel, like the Direct Equivalent Method (DEM), often used by the United Nations Statistical Bureau and in IPCC reports (Kraan et al., 2019); the Incident Energy Method (IEM); and the Partial Substitution Method (PSM), used by EIA, WEC, IIASA, BP (Kraan et al., 2019). All methods lead to different results, whereas the DEM leads to the lowest TPED values in RE systems, and the PSM to highest values. The PECM, the most widely used and also applied in this dissertation, ranges in the middle (Kraan et al., 2019). Thus, the method of TPED calculations should be always directly mentioned in study method descriptions and overall TPED values should be treated carefully in the analysis.

RE-based energy systems are feasible

The studies show that RE-based power systems and energy systems on the whole are technically feasible and can satisfy the energy system demands of each sector for every hour of the year on a cost competitive basis. However, the possibility of such systems to operate and develop within current power market conditions is questionable, and the possible market modifications need to be improved so that the operation of the system with high shares of RE is enabled. **Publication II** shows that a 100% RE-based system can operate in current power only, and power and capacity market conditions, while it had been found that RE, especially PV, still needs support to guaranty the cost recovery and reinvestments in capacities with zero marginal costs, at least as long as the true costs of fossil fuels are not factored in. Capacity renumeration mechanisms are especially important to ensure the necessary capacity of flexible generation will meet capacity margin requirements and reliability standards. **Publication II** provides an optimistic result of the technical feasibility of 100% RE systems in existing market conditions. Though, further studies with more diversified technology portfolios and a more limited biomass role need to be conducted.

5.2 Policy implication

The most important outcomes of the previously discussed **Publications I-VII** are the technical feasibility and economic viability of RE-based energy systems and 100% renewable energy systems in all regions of the world, and that these energy systems can supply the economy with electricity and energy at a cost competitive level, with LCOE lower than all other carbon neutral alternatives. These results support the claim that the integration of renewables and VRE-based electrification must be the main aim of any energy system decarbonisation and defossilisation. In some countries decision makers still consider nuclear and fossil CCS as temporary solutions for a transition period, though the imminent very high risk of stranded investments has to be considered, as both options do not belong to a cost-optimised solutions. The subsidies for nuclear and fossil CCS have to be limited and retraced into RE generation, energy storage and sector bridging technologies, since these technologies will form future energy system structures and define energy costs.

As shown in **Publication II**, some additional changes may be needed to adjust the market mechanisms to better acknowledge the specifics of RE technologies with zero marginal costs and allow the RE capacities to pay off without additional support mechanisms, such as feed-in tariffs.

The sectoral and regional integration of energy systems has to be supported as a major measure to increase system efficiency and reduce the cost of energy. **Publication VI** shows the significant impact of energy sector integration on energy costs and the potential impact of emerging technologies like desalination, which also have to be acknowledged in energy system planning. **Publication I** shows the significant cost reduction potential from regional integration, though it also shows that in RE systems energy autarky is also reachable, even for the case of Europe. This is also shown in **Publication VII**.

The speed of the energy transition has to be accelerated. The progressive transition scenario described in **Publication VII** is just at the edge of the remaining carbon budget for a 1.5°C increase with 66% probability scenario. Any delay in the transition acceleration will result in carbon budget overruns and a necessity to introduce carbon dioxide removal (CDR), or negative emission technologies (NETs), which will induce additional costs and possible risks related to long-term CO_2 storage reliability.

Considering the current cost development of RE generation technologies, a ban on new coal capacity commissioning should be considered not only as a measure to limit fossil carbon emissions, but also as a way to avoid stranded investments in the 2030s and 2040s, when the existing conventional baseload capacities will lose any competitiveness to RE generation technologies. Some countries like Germany and Chile have already committed to phase out coal generation by 2038 and 2040, respectively, as have some states in the USA (REN21, 2020). The Philippines have recently declared a moratorium on new coal power plant projects (IEA Clean Coal Centre, 2020). In countries like China, India, the United States and parts of the European Union, the LCOE of new solar PV or wind is already lower than running costs of existing coal power plants (REN21, 2020). Another motivation for accelerating coal generation decommissioning is air pollution. This motivation was highlighted by Jacobson et al. (2017). Resolving the air pollution problem would save annually 4-7 million human lives and would help to avoid millions more getting ill.

Initial attention has to be applied to an accelerated power sector defossilisation in the coming decade. In later steps, the renewable electricity supply from this sector will be the basis for the direct and indirect electrification and defossilisation of all other sectors. The direct electrification of the transport, heat and industry sectors is the primary target due to higher efficiency and consequently lower energy supply cost, thus direct electrification has to be persisted wherever possible. The addition of e-fuel production will play an important role in the final steps of the transition, substituting fossil fuels in segments where fuel use is hard to abate, though the introduction and ramping have to be started much earlier, in the middle of the transition.

The massive RE growth, as described in **Publications IV** and **VII**, will demand significant land areas to be allocated for PV power plants and wind farms. On a global level the area occupied by RE will not exceed 1%, but in some regions like Switzerland, Benelux, Java in Indonesia it could exceed 6% of the total area, and can peak at the level of 11-12% in densely populated regions with intensive economies, like South Korea, or regions with beneficial solar PV conditions, like Bahrain and Qatar, as found in **Publication VII**. To support an accelerated RE growth, land use codes in many countries will be needed to be adjusted to simplify the land use changes and allow mixed land use, such as Agri-PV (Schindele et al., 2020) or wind turbines on agricultural land and in forests. The RE integration considering the distributed nature of RE resources will demand grid infrastructure reinforcements, especially in wind-based systems, which can also create additional issues considering land requirements and social acceptance. Additional support can be needed to avoid problems with the social acceptance of accelerated RE growth and grid expansion.

Prosumer PV can play an important role in the system especially in the countries with liberalised retail electricity prices for residential and commercial consumers. In some countries the codes have to be adjusted to allow power prosumerism and promote rooftop PV system installations via fair feed-in tariffs, net-metering, or other adequate measures which guarantee a maximum utilisation of the zero impact rooftop area. In doing so, ground mounted area occupation can be limited as much as possible, which will also benefit the system decentralisation and will allow a decrease in the role and cost of grid infrastructure in the future.

Publication IV and **VII** show how a radical transition of energy systems can be managed by 2050 in a set of evolutionary steps. That will demand significant investments, although such a transition is cost driven and RE systems will be lower in cost than fossil CCS or nuclear options. The transition will also bring numerous other benefits, such as decreasing the number of premature deaths due to air pollution (Jacobson et al., 2017) and avoided costs related to air pollution from fossil fuel combustion at a level of 2,650 billion USD per year (Coady et al., 2019). The structure of energy systems will change and will become more decentralised and self-sufficient, reducing the costs of energy imports. Further, the transition may result in additional jobs. There could be about 10 million additional direct jobs within the EU, accordingly to Connolly et al. (2016), and 24 million additional jobs globally, according to Jacobson et al. (2017). Overall, the transition towards a RE-based system will lead to sustainable, reliable and low-cost energy supply in all regions of the planet. It will directly or indirectly complement the accomplishment of most of the SDGs and finally it will support further sustainable growth in standards of living across the globe, especially in developing countries.

5.3 Limitations of the current research

The main limitation of this research is that only one set of financial and technical assumptions, derived from the existing scientific and technical literature, has been used in the studies. Sensitivity analyses have not been applied in these studies due to the computational complexity of the model and the time requirements to conduct one full transition run for the considered technology-rich system structure and full hourly resolution. Thus, the results describe an optimal transition pathway for the given scenario design, but it is not possible to judge how the transition pathway and the final energy system structure would change in case the applied assumptions are too conservative or too optimistic. Another element is the universally weighted average cost of capital, which was assumed to be at a level of 7% for all the regions in the world. Although a 7% WACC is often used in studies, the actual WACC can vary from country to country from a 1-2% level to two-digit values in the least stable countries. This has a significant effect on the energy system mix and a strong impact on any CAPEX intensive technologies, as they benefit most from lower WACC values. Even current WACC values for countries cannot be directly acquired and are a result of estimation. Even worse, proper methods for future WACC projections are not yet available. In the least stable countries, projects with significant investment requirements are very often based on financing from international development banks, whose interest rates are not always related to internal banking rates (Bogdanov et al., 2019). Though it had been decided to apply the standard WACC for all countries to be able to compare RE system feasibility in the long term, the real RE costs can substantially differ. WACC can be significantly lower in stable countries like Switzerland, Germany and Japan, and much higher in countries which currently see major disruptions, like Somalia, South Sudan, or Iraq.

Due to computational complexity limitations the studies were performed for isolated countries (**Publications II-VII**) or isolated region cases (**Publication I**) without considering benefits of global power and synthetic hydrocarbons trade. Despite findings that long power grid interconnections (more than 1000 km) did not prove feasible for the case of East Asia (Gulagi et al., 2017) and Americas (Aghahosseini et al., 2019), in other cases power grid integration could have a positive impact, like in the case of the European power system integration (Child et al., 2019), where the average grid distances are in the order of some hundreds of kilometres. Though an integrated global power system has not been simulated yet in proper detail, and the existing study (Breyer et al., 2020) suffers from too low spatial resolution and consequent effects on the results, the improved methods for such a study allowing avoidance of a “cooper plate” effect and the model modification for this have been already developed. A global synthetic hydrocarbon trade would possibly have an even higher impact on an energy system transition considering the wide range of regional costs of hydrocarbon synthesis in the 2030s to 2050.

Technologies like smart charging of BEVs and V2G can be major sources of flexibility for the energy system in the mid- to long-term steps of the transition, when BEVs may represent a significant share of the road vehicle fleet (Child et al., 2018). Though these technologies are already integrated in the model, these technologies as model features have not been considered in the publications discussed in this dissertation.

Publications I-VII do not consider negative CO_2 emission options as a part of a carbon neutral energy system or as a measure to avoid overriding the carbon budget. The introduction of CDR can be lower in cost than e-fuel production, though a large-scale CDR phase-in will induce the risk of problems with long-term stability and CO_2 leaking to the atmosphere. The NET functionality is already included in the LUT Energy System Transition Model and the possible impact of CDR introduction will be further studied in future publications, though the competitiveness of CDR technologies will depend on respective cost assumptions, projected fossil fuel costs and availability, and the long-term CO_2 sink reliability.

Another limitation is the considered perfect foresight of the RE conditions for the whole simulated year. With the applied myopic forecast approach, the model optimises the system for the given year conditions, though without considering effects of later periods, which is seen to be the more realistic approach compared to a perfect foresight for the whole transition period. The perfect foresight for the given simulation year results in an optimal energy system structure for the given conditions and constraints of this system, while the operation in case of deviations from the given forecast may be challenging. This problem can be resolved by applying additional capacity margin and storage reserve assumptions, though integration of a shorter perfect foresight and stochastic longer term forecast could improve the quality of the simulation.

6 Conclusions

The results of this dissertation confirm that carbon neutral energy systems can be built by 2050 based solely on RE technologies. Such a transition will demand radical transformations in all energy sectors: power, heat, transport and industry, though the proposed pathways show that this transformation can be realised in the next 30 years in a set of evolutionary steps.

Such a transition will be technically feasible and can be cost driven considering current trends in RE generation and energy storage cost development, which is further supported by a consensus in major countries about the negative impact of fossil carbon emissions and the requirement of respective carbon pricing. The transition will lead to lower LCOE in most regions, though the levelised cost of energy can increase in some regions especially for the segments where direct electrification is not possible and a substantial amount of e-fuels is required. Significant differences in the regional production cost of synthetic hydrocarbons will open the possibility for an e-fuels market and will allow a decrease in the cost of energy in some regions. Additionally, it should be taken into account that the current levelised cost of energy does not consider a climate change cost-based level of carbon emission pricing for fossil fuels, which would require levels far beyond 100 €/tCO_2.

The utilisation of alternative carbon neutral technologies like fossil CCS and nuclear is not necessary for the system defossilisation and would result in additional costs because the LCOE in a 100% RE system is lower than the LCOE of systems including these higher risk alternatives.

The proposed global energy system transition trajectory was found to result in about 567 Gt$CO_{2\text{-eq}}$ of emissions and thus is compatible with the ambitious 1.5°C target of the Paris Agreement (66% probability in case of 550 GtCO_2 emissions from 2018 onwards). To keep the emissions within this carbon budget, the accelerated defossilisation of the power sector has to start immediately, accompanied by electrification of the heat and transport sectors.

Electrification will become the key for the transition, making the power sector and electricity generation the backbone of energy systems and providing energy for all other sectors. To satisfy the energy demand for power, heat, and transport sectors, electricity generation will need to nearly double in each decade to exceed 135 000 TWh_{el} by 2050. To reach this, PV will become the main energy source in energy systems, complemented by wind energy and supported by hydropower. The global capacity of PV systems will exceed 63 TW, which will be challenging but manageable.

Despite the complexity of the process and sharp growth of electricity generation, sector integration will facilitate the system transition by providing additional system flexibility and lead to higher system efficiency and lower energy costs. Although indirect electrification via e-fuel utilisation will result in additional losses in the e-fuel synthesis step, this is more than compensated by very high efficiency gains in direct electrification. Overall, the transition towards RE-based electricity generation and system electrification can lead to efficiency savings of about 150 000 TWh, which equals to an approximately 49% efficiency gain compared to the continuation of current practices with low shares of electrification and a strongly fossil fuel-based power and system while the final energy demand continues to grow.

In order to build cost optimal energy systems, the energy transition requires an accurate planning of individual pathways for each region in the world, which considers the impact of local RE resources, the existing system structure and energy demand growth trends. The LUT Energy System Transition Model developed during this dissertation can be used for further studies in this field to simulate regional energy system transitions in detail, considering specific national legislation and governmental plans and checking the impact of different policies on the transition in order to support decision-making.

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North-East Asian Super Grid for 100% Renewable Energy supply: Optimal mix of energy technologies for electricity, gas and heat supply options

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North-East Asian Super Grid for 100% renewable energy supply: Optimal mix of energy technologies for electricity, gas and heat supply options

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ABSTRACT

In order to define a cost optimal 100% renewable energy system, an hourly resolved model has been created based on linear optimization of energy system parameters under given constrains. The model is comprised of five scenarios for 100% renewable energy power systems in North-East Asia with different high voltage direct current transmission grid development levels, including industrial gas demand and additional energy security. Renewables can supply enough energy to cover the estimated electricity and gas demands of the area in the year 2030 and deliver more than 2000 TW h_{th} of heat on a cost competitive level of 84 €/MW h_{el} for electricity. Further, this can be accomplished for a synthetic natural gas price at the 2013 Japanese liquefied natural gas import price level and at no additional generation costs for the available heat. The total area system cost could reach 69.4 €/MW h_{el}, if only the electricity sector is taken into account. In this system about 20% of the energy is exchanged between the 13 regions, reflecting a rather decentralized character which is supplied 27% by stored energy. The major storage technologies are batteries for daily storage and power-to-gas for seasonal storage. Prosumers are likely to play a significant role due to favourable economics. A highly resilient energy system with very high energy security standards would increase the electricity cost by 23% to 85.6 €/MW h_{el}. The results clearly show that a 100% renewable energy based system is feasible and lower in cost than nuclear energy and fossil carbon capture and storage alternatives.

1. Introduction

Fast economic growth in the North-East Asian region provoked an extensive rise in electricity demand, based mainly on fossil fuel utilization, in the last decades [1]. Increasing ecological and social problems are caused by the fossil fuel based energy system, including increased anthropogenic pressure on nature in general [2] and an ongoing destruction of ecosystems all around the world [3]. This anthropogenic pressure leads in particular to climate change [4], which will have a dramatic negative impact on the economy on a global scale, as concluded by Stern [5]. Harmful and costly consequences of coal-based air pollution [6] have to be further taken into account for the full societal cost of energy supply. These issues drive the idea for a renewable energy (RE) based system development up to 100% RE [7] and the discussion of its competitiveness on a global scale [8] and in a rather distributed manner [9]. It is feasible that RE based systems can decrease the anthropological footprint [10] in particular since the most important RE technologies show a continued strong growth and the large majority of countries in the world have introduced respective policies [11].

Scenarios of energy systems based on very high shares of RE had been already discussed for several countries and regions. Connolly and Mathiesen [12] showed for the case of Ireland in an hourly modeling that 100% RE is technically feasible and economic affordable. Henning and Palzer [13] discussed that a 100% RE system for the sectors electricity and heat is technically doable and the cost are comparable to the current energy system, also based on hourly resolution. Thellufsen and Lund [14] pointed out that energy efficiency measures in the electricity and heat sector can even generate positive synergies for 100% RE for the example of Denmark. Critz et al. [15] emphasized that demand response measures help to integrate a high penetration of renewables into the existing system and that it can reduce the overall cost for the case of Hawaii. Huber et al. [16] found on the case of the ASEAN region that a well balanced mix of renewable resources and a geographic integration of a larger region is required for balancing high shares of RE.

Komoto et al. [17] proposed very large scale solar photovoltaic power plants for North-East Asia pointing out that excellent renewable resources of a large unpopulated region, such as the Gobi desert, can be utilized for a very large region by applying a

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Nomenclature

Capex	capital expenditures
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CHP	combined heat and power
crf	capital recovery factor
CSP	concentrating solar thermal power
GT	gas turbine
HHB	hot heat burner
HVDC	high voltage direct current
ICE	internal combustion engine
LCOC	levelized cost of curtailment
LCOE	levelized cost of electricity
LCOS	levelized cost of storage
LCOT	levelized cost of transmission
OCGT	open cycle gas turbine
Opex	operational expenditures
PHS	pumped hydro storage
PtG	power-to-gas
PtH	power-to-heat
PV	photovoltaic
rampCost	ramping cost
RE	renewable energy
RoR	run-of-river
SNG	synthetic natural gas
ST	steam turbine
TES	thermal energy storage
totRamp	total ramping
URBS	a linear optimization model for distributed energy systems by TUM
WACC	weighted average cost of capital

Subscripts

ell	electric units
fix	fixed
gas	gas units
th	thermal units
reg	region
p	peak or nominal capacity
var	variable

Super Grid approach. The availability of various types of RE resources in Asian regions, including solar, wind and hydro resources, enables that very promising vision of building a Super Grid connecting different regional energy resources to reach synergy effects and realise a 100% RE electricity supply [18]. The idea of a global Super Grid for power supply was already discussed some years ago [19], and attracted new attention by the RE-based Gobitec [20], the Gobi Super Grid project initiating a deeper cooperation of North-East Asian countries [21] and the North-East Asian Super Grid initiative as highlighted from the Korean perspective [22] influenced by the EU-MENA sustainable energy system analyses [23] and the Desertec Foundation vision of utilizing RE sources in North Africa and Middle East for the region, but also for exports to Europe [24]. However, an economical assessment and energy system optimization of the North-East Asian Super Grid have never been done before, and the economic and technical feasibility of such a project was questionable. An RE-based electrical supply system can become a major step toward a 100% renewable energy supply. Bridging technologies such as power-to-heat and heat storage [25] will convert electricity generation losses and electricity curtailment into valuable heat for residential and industrial needs. Power-to-Gas (PtG) technology based on water electrolysis, CO_2 from air, and methanation reactors will provide renewable synthetic natural gas supply for a 100% renewable energy system as introduced in the field of energy system analyses by Sterner [26], finally also used for chemicals, fertilizers, other industries, transportation and other non-power sectors [27]. However, as discussed earlier, a cost competitive 100% RE system can only be reached in case of an optimal design and wise utilization of all available RE resources in order to reach a maximum synergy between various resources, in particular for the key pillars solar photovoltaic and wind energy [28], but also in combination with the major energy storage technologies [9] and in interconnecting different regions. In this work the design of a centralized regional energy system is discussed, where each sub-regional system is optimized to match regional RE conditions, electricity and gas demand with regards to other regional parameters. Grid interconnections reduce regional independence, however that dependence is limited in its impact by accounting for respective grid losses and grid costs. Finally, an optimized energy system is the result of balancing regional conditions and energy demands, impacts of prosumers, and other configurations such as electricity exchange with neighbouring regions. This work is based on results obtained earlier [29] but presents a more comprehensive model, taking into account more technologies, a broader energy demand and the impact of prosumers.

2. Materials and methods

The model for optimizing the energy system structure is composed of a set of power generation and storage technologies, respective installed capacities and different operation modes of these technologies. Energy system models can be divided into market and regulatory models. An example of an agent based market model can be found in [30]. In such an approach the final structure of the system and the operation modes depend on the market rules applied to the agents. However, the resulting system may not be optimal and its configuration strongly depends on the applied set of rules. Regulatory models do not take short-term market mechanisms into account and provide an optimal long-term energy system structure. Such models can utilize different optimization methods. Tahani et al. [31] perform an optimization of the Tehran energy system using a nonlinear annealing algorithm. However, nonlinear methods are very computational time-consuming and can hardly be applied for a multi-nodal simulation of a full power system. Linear optimization models such as the URBS-model [16] can perform more sophisticated and integrated energy systems. However, the URBS-model performs hourly resolved simulations not for the whole year but only for 12 representative weeks, and cannot guarantee system sustainability for the whole year. The energy system model applied in this research is designed to overcome this limitation and is described in the following section.

2.1. Model overview

The energy system optimization model is based on a linear optimization of the system parameters under a set of applied constraints with the assumption of a perfect foresight of RE power generation and power demand. A multi-node approach enables the description of any desired configuration of sub-regions and power transmission interconnections, i.e., not all the sub-regions have to be interconnected, but a grid configuration can be defined in scenario assumptions or can be chosen close to an existing grid configuration. The main constraint for the optimization is the matching of the power generation and demand for every hour of the applied year. The hourly resolution of the model significantly increases the computation time. However, it guarantees that for every hour of the year the total generation within a sub-region and electricity import cover the local electricity demand and enable a more precise system description including synergy effects of different system components as shown in Eq. (1) for the power system balance.

$$\forall h \in [1,8760] \sum_{t}^{tech} E_{gen,t} + \sum_{r}^{reg} E_{imp,r} + \sum_{t}^{stor} E_{stor,disch} = E_{demand} + \sum_{r}^{reg} E_{exp,r} + \sum_{t}^{stor} E_{stor,ch} + E_{curt} \quad (1)$$

Eq. (1) describes constraints for the energy flows of a sub-region. Abbreviations: hours (h), technology (t), all modeled 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 ($E_{stor,ch}$), curtailed excess energy (E_{curt}). The energy loss in the high voltage direct current (HVDC) transmission grid and energy storage technologies are considered in storage discharge and grid import value calculations.

The target of the system optimization is the minimization of the total annual energy system cost, calculated as the sum of the annual costs of installed capacities of the different technologies, costs of energy generation and generation ramping. The system also includes distributed generation and self-consumption of residential, commercial and industrial electricity consumers (prosumers) by installing respective capacities of rooftop PV systems and batteries. For these prosumers the target function is minimal cost of consumed energy calculated as a sum of self-generation, annual cost and cost of electricity consumed from the grid, minus the benefits of selling excess energy. The target function of the applied energy model for minimizing annual costs is presented in Eq.(2) using the abbreviations: sub-regions (r, reg), energy 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 for technology t ($OPEXvar_t$), installed capacity in the region r of technology t ($instCap_{t,r}$), annual electricity generation by technology t in region r ($E_{gen,t,r}$), 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 ($totRamp_{t,r}$).

$$\min \left(\sum_{r=1}^{reg} \sum_{t=1}^{tech} (CAPEX_t \cdot crf_t + OPEXfix_t) \cdot instCap_{t,r} + OPEX\,var_t \cdot E_{gen,t,r} + rampCost_t \cdot totRamp_{t,r} \right) \quad (2)$$

For the gas generation scenario, an additional hourly gas demand is introduced in the model.

2.2. Input data

The model uses several types of input datasets and constraints:

- historical weather data for direct and diffuse solar irradiation, wind speed and precipitation amounts,
- synthetic load data for every sub-region,
- technical characteristics of used energy generation, storage and transmission technologies, such as power yield, energy conversion efficiency, power losses in transmission lines and storage round trip efficiency,
- capital expenditures, operational expenditures and ramping costs for all technologies,
- electricity costs for residential, commercial and industrial consumers,
- limits for minimum and maximum installed capacity for all energy technologies,
- configuration of regions and interconnections.

The datasets for solar irradiation components, wind speed and precipitation are taken from NASA databases [32,33] and partly reprocessed by the German Aerospace Center [34]. The spatial resolution of the data is 0.45° × 0.45°. The time resolution is hourly for wind speed and solar irradiation, and monthly for precipitation. The feed-in time series for fixed, optimally tilted solar photovoltaic (PV) systems is computed in accordance to Gerlach et al. [28], based on Huld et al. [35] and for 1-axis, north–south oriented continuous horizontal tracking as described in Duffie and Beckmann [36]. The feed-in time series for wind power plants is computed in accordance to Gerlach et al. [28] for standard 3 MW wind turbines (E-101 [37]) for hub height conditions of 150 m. The synthetic load data are based on publically available hourly load data at a national level, e.g. for Japan but also European countries, and takes into account local data such as gross domestic product, population, temperature and power plant structure.

2.3. Applied technologies

The technologies applied in the North-East Asian energy system optimization can be grouped into three main categories: conversion of RE resources into electricity, energy storage, and electricity transmission.

The technologies for converting RE resources into electricity applied in the model are solar photovoltaic (PV) ground-mounted (optimally tilted and single-axis north–south oriented horizontal continuous tracking) and PV rooftop systems, concentrating solar thermal power (CSP) plants, wind onshore, hydro power (run-of-river and dams), biomass plants (solid biomass and biogas) and waste-to-energy power plants.

The energy storage technologies used in the model are battery storage, pumped hydro storage (PHS), thermal energy storage (TES) and power-to-gas (PtG) technology. PtG includes synthetic natural gas (SNG) synthesis technologies: water electrolysis, methanation, CO_2 scrubbing from air, gas storage, and both combined and open cycle gas turbines (CCGT, OCGT). SNG synthesis process technologies have to be operated in synchronization because of the absence of hydrogen and CO_2 storage. Additionally, there is a 48-h biogas buffer storage and a part of the biogas can be upgraded to biomethane and injected into the gas storage.

The electricity transmission technologies are represented on two levels: power distribution and transmission within the sub-regions are assumed to be based on standard alternating current (AC) grids, and inter-regional transmission grids are modeled on HVDC technology. Power losses in the HVDC grids consist of two major components: length dependent electricity losses of the power lines and losses in the converter stations at the interconnection with the AC grid.

The full model block diagram and operation sequence flowchart are presented in Fig. 1.

3. Scenario assumptions

3.1. Region subdivision and grid structure

The North-East Asian region is divided into 13 sub-regions: Mongolia, East and West Japan (with respect to 50/60 Hz AC grids

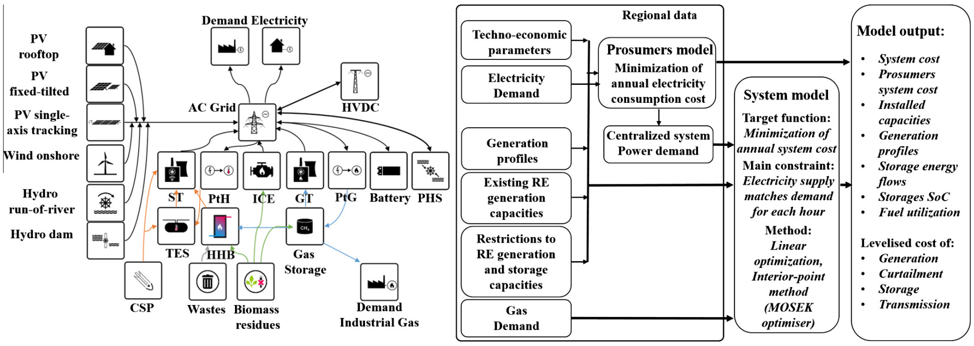

Fig. 1. Block diagram of the energy system model elements (left) and the model flowchart (right).

utilization), South Korea, North Korea, China divided into eight sub-regions by State Grid Corporation of China [38]: Northeast, North, East, Central, South, Northwest China, Tibet and Uygur regions.

In this paper, five scenarios of energy system development options are discussed:

- region-wide energy systems, in which all the regions are independent (no HVDC grid interconnections) and the electricity demand has to be covered by the respective region's own generation;
- country-wide energy system, in which the regional energy systems are interconnected by HVDC grids within the borders of nations;
- area-wide energy system, in which the country-based energy systems are interconnected;
- area-wide energy system with gas generation, in which the PtG technology is used not only as a storage option within the system, but also to cover industrial, residential and transportation gas demands;
- area-wide extra secure energy system, in which an additional system robustness is provided by additional gas turbine capacities and gas reserves in the storage. In this scenario, installed capacities of gas turbines are sufficient to cover the peak demand in every region in case of a grid system failure and the gas reserves can guarantee two months of sole GT generation. Half of these gas reserves will be recharged annually using increased PtG capacities. In the normal operation mode the additional GT capacities take the role of an active reserve and compensate for effects of RE uncertainty and forecasting errors.

The North-East Asian region's subdivision and grid configuration are presented in Fig. 2, and HVDC interconnections for energy systems of the countries are shown by dashed lines. The Chinese HVDC grid configuration is based on the existing Chinese grid operated by State Grid Corporation of China and its development plans. SNG capacities are assumed to be situated in West Japan, where most of the Japanese LNG terminals are built, South Korea, North, East, South and Central China, based on fast development of gas transportation and storage infrastructure in these Chinese regions [39]. The most recent findings of State Grid Corporation of China indicate an economic rationale for a Super Grid not only for China or North-East Asia but also on a global level [40], similar to earlier findings of Komoto et al. [19].

3.2. Financial and technical assumptions

The model optimization is carried out on an assumed cost basis and technological status for the year 2030 and the overnight building approach. The investment cost (capex) and operation and

Fig. 2. North-East Asian area subdivision and HVDC grid configuration.

maintenance (opex) numbers refer in general to a kW of electrical power, in case of water electrolysis to a kW of hydrogen thermal combustion energy, and for CO_2 scrubbing, methanation and gas storage to a kW of methane thermal combustion energy. Efficiencies of water electrolysis, CO_2 scrubbing and methanation refer to the lower heating value of hydrogen and methane, respectively. The financial assumptions for the energy system components including HVDC transmission lines for the 2030 reference year are presented in Table 1. The financial assumptions for storage systems refer to a kW h of electricity, and gas storage refers to a thermal kW h of methane at the lower heating value. Financial numbers for HVDC transmission lines and converter stations are given for the net transmission capacity (NTC). Assumptions are mainly taken from Pleßmann et al. [9] but also other sources: Li-ion batteries [41–43], silicon based PV cost development [44,45], biomass and biogas technologies [46], alkaline electrolyzers [27], HVDC grids [23], PHS [43], hydro power [43] and waste-to-energy [43]. Urbanization level numbers used for biogas potential evaluation are taken from the UN [47]. The lifetime for PV systems is based on lifecycle assessment research [48] and PV aging research findings [49]. The technical assumptions concerning power to energy ratios for storage technologies, efficiency numbers for generation and storage technologies and power losses in HVDC power lines and converters are presented in Tables 2–4, respectively.

Biomass and waste resource potentials are mainly taken from the German Biomass Research Center [50]. All biowaste is divided in three components: solid waste, solid biomass and biogas sources. Solid waste is comprised of municipal and industrial used wood; solid biomass includes straw, wood and coconut residues; biogas sources are excrement, municipal bio-waste and bagasse. Costs for biomass are calculated using data from IEA [51] and IPCC [52]. For solid fuels a 50 €/ton gate fee for the waste incineration is

Table 2
Efficiencies and energy to power ratio of storage technologies.

Technology	Efficiency (%)	Energy/power ratio (h)	Self-discharge (%/h)
Battery	90	6	0
TES	90	8	0.002
PHS	85	8	0
Gas storage	100	80 ∗ 24	0

Table 3
Efficiency assumptions for energy system components for the 2020 and 2030 reference years.

	η_{el} (%)	η_{th} (%)
CSP (solar field)		51
Steam turbine	42	
Hot heat burner		95
Heating rod		99
Water electrolysis		84
Methanation		77
CO_2 scrubbing		78
CCGT	58	
OCGT	43	
Biomass CHP	40	45
Biogas CHP	42	43
Waste incinerator	34	
Biogas upgrade		98

Table 4
Efficiency assumptions for HVDC transmission [23].

	Power losses
HVDC line	1.6%/1000 km
HVDC converter pair	1.4%

Table 1
Financial assumptions for energy system components.

Technology	Capex (€/kW)	Opex fix (€/kW)	Opex var (€/kW h)	Lifetime (a)
PV optimally tilted	550	8	0	35
PV single-axis tracking	620	9	0	35
PV rooftop	813	12	0	35
Wind onshore	1000	20	0	25
CSP (solar field)	528	11	0	25
Hydro run-of-river	2560	115.2	0.005	60
Hydro dam	1650	66	0.003	60
Water electrolysis	380	13	0.0012	30
Methanation	234	5	0.0015	30
CO_2 scrubbing	356	14	0.0013	30
CCGT	775	19.4	0.001	30
OCGT	475	14.25	0.001	30
Steam turbine	600	12	0	30
Hot heat burner	100	2	0	30
Heating rod	20	0.4	0.001	30
Biomass CHP	2500	175	0.001	30
Biogas CHP	370	14.8	0.001	30
Waste incinerator	5240	235.8	0.007	20
Biogas digester	680	27.2	0	20
Biogas upgrade	250	20	0	20
	Capex (€/kW h)	Opex fix (€/kW h)	Opex var (€/kW h)	Lifetime (a)
Battery	150	10	0.0002	10
PHS	70	11	0.0002	50
TES	24	2	0	20
Gas storage	0.05	0.001	0	50
	Capex (€/(kW_{NTC} km))	Opex fix (€/(kW_{NTC} km))	Opex var (€/kW h_{NTC})	Lifetime (a)
HVDC line on ground	0.612	0.0075	0	50
HVDC line submarine	0.992	0.0010	0	50
	Capex (€/kW_{NTC})	Opex fix (€/kW_{NTC})	Opex var (€/kW h_{NTC})	Lifetime (a)
HVDC converter pair	180	1.8	0	50

assumed. Calculated solid biomass, biogas and solid wasted potentials are presented in Table 5. Prices for biomass fuels are presented in Table 6. Price differences between countries are explained by various waste and residue component shares.

Electricity prices for residential, commercial and industrial consumers in Japan and China for the year 2030 are taken from Gerlach et al. [53]. Mongolian and North Korean prices are assumed to be close to Chinese prices, and South Korean to Japanese ones. Prices are presented in Table 7.

Table 5
Regional biomass potentials.

Region	Biomass potential (TW h/a)		
	Solid waste	Solid biomass	Biogas sources
Total area	105.4	805.0	174.8
East Japan	11.03	9.66	7.69
West Japan	10.89	9.54	7.59
South Korea	13.28	4.62	2.27
North Korea	1.00	5.62	2.80
Northeast China	5.65	63.39	12.62
North China	13.44	150.84	30.03
East China	13.03	146.14	29.09
Central China	19.13	214.60	42.72
South China	12.73	142.83	28.43
Tibet	0.15	1.74	0.35
Northwest China	3.85	43.24	8.61
Uygur	1.13	12.63	2.51
Mongolia	0.11	0.13	0.09

Table 6
Regional biomass costs.

Region	Biomass costs (€/MW h)		
	Solid waste	Solid biomass	Biogas sources
Total area	−9.94	8.29	1.79
Japan	−9.87	11.62	0.28
South Korea	−9.80	5.26	0.00
North Korea	−10.17	5.26	0.00
China	−9.99	8.25	2.00
Mongolia	−10.17	5.26	0.00

Table 7
Regional grid electricity costs.

Region	Electricity costs (€/MW h)		
	Residential	Commercial	Industrial
Total area	154	144.9	144
Japan	260	225	190
South Korea	160	130	110
North Korea	140	135	140
China	140	135	140
Mongolia	140	135	140

Excess generation, which cannot be self-consumed by the prosumers, is assumed to be fed into the grid for a transfer price of 2 €cent/kW h.

3.3. Feed-in for solar and wind energy

The feed-in profiles for solar CSP, optimally tilted and 1-axis tracking PV, and wind energy were calculated based on NASA data [32,33] for direct and diffuse solar irradiation, wind speed, temperature and surface roughness for the year 2005 reprocessed by the German Aerospace Center [34]. The assumed wind power plants consist of 3 MW wind turbines at 150 m hub height. The dataset is used in a $0.45^\circ \times 0.45^\circ$ spatial and hourly temporal resolution for the real weather conditions of the year 2005. Feed-in full load hours (FLH) for sub-regions are computed on the basis of the $0.45^\circ \times 0.45^\circ$ spatially resolved single sub-area data using a weighted average formula. The sub-regions' numbers are calculated using the rule: 0–10% best sub-areas of a region are weighted by 0.3, 10–20% best sub-areas of a region are weighted by 0.3, 20–30% best sub-areas of a region are weighted by 0.2, 30–40% best sub-areas of a region are weighted by 0.1 and 40–50% best sub-areas of a region are weighted by 0.1. The computed average full load hours for CSP, optimally tilted and 1-axis tracking PV systems, and wind power plants are presented in Table 8. The LCOE numbers are calculated by applying cost numbers in Table 1 and applying Eq. 4. The numbers for population and electricity demand are also tabulated for indicative reasons.

The aggregated profiles of solar PV generation (optimally tilted and single-axis tracking), CSP solar field, and wind energy power generation normalized to maximum capacity averaged for North-East Asia are presented in Fig. 3.

The feed-in values for hydro power are computed based on the monthly resolved precipitation data for the year 2005 as a normalized sum of precipitation in the regions. Such an estimate leads to a good approximation of the annual generation of hydro power plants (deviation of computed data for all North-East Asian regions to public data is less than 5%).

3.4. Upper and lower limitations on installed capacities

Lower and upper limits are applied to renewable energy sources (optimally tilted PV, wind turbines, and hydro power) and pumped hydro storage. For CSP, biomass, biogas, waste power plants, gas turbines, battery and gas storage, and units of the power-to-gas process, the lower limit is set to zero. For lower limitations of opti-

Table 8
Average full load hours and LCOE for CSP, optimally tilted and 1-axis tracking PV systems, and wind power plants in North-East Asian regions.

Region	Pop. (mio. Pop)	Electr. demand (TW h)	CSP FLH	PV 0-axis FLH	PV 1-axis FLH	Wind FLH	CSP LCOE (€/MW h)	PV 0-axis LCOE (€/MW h)	PV 1-axis LCOE (€/MW h)	Wind LCOE (€/MW h)
Total area	1548	9878	1763	1592	2008	3279	69.7	32.1	29.0	34.0
East Japan	64	516	1230	1316	1536	3362	95.2	38.4	37.0	31.5
West Japan	64	510	1288	1365	1604	3204	90.9	37.0	35.5	33.0
South Korea	50	543	1486	1467	1733	2946	78.8	34.4	32.8	35.9
North Korea	25	33	1495	1469	1749	2890	78.3	34.4	32.5	36.6
NE China	110	676	1706	1457	1832	3519	68.7	34.7	31.0	30.1
North China	261	1609	1844	1592	2011	3541	63.5	31.7	28.3	29.9
East China	253	1558	1228	1340	1549	2083	95.4	37.7	36.7	50.8
Central China	371	2289	1284	1471	1726	2608	91.2	34.3	33.0	40.6
South China	247	1523	1208	1435	1678	2310	97.0	35.2	33.9	45.8
Tibet	3	19	2417	1983	2719	5208	48.4	25.5	20.9	20.3
NW China	75	461	1963	1739	2221	3703	59.7	29.0	25.6	28.6
Uygur	22	135	1957	1666	2124	2724	59.9	30.3	26.8	38.8
Mongolia	3	6	1975	1572	2062	3288	59.3	32.1	27.6	32.2

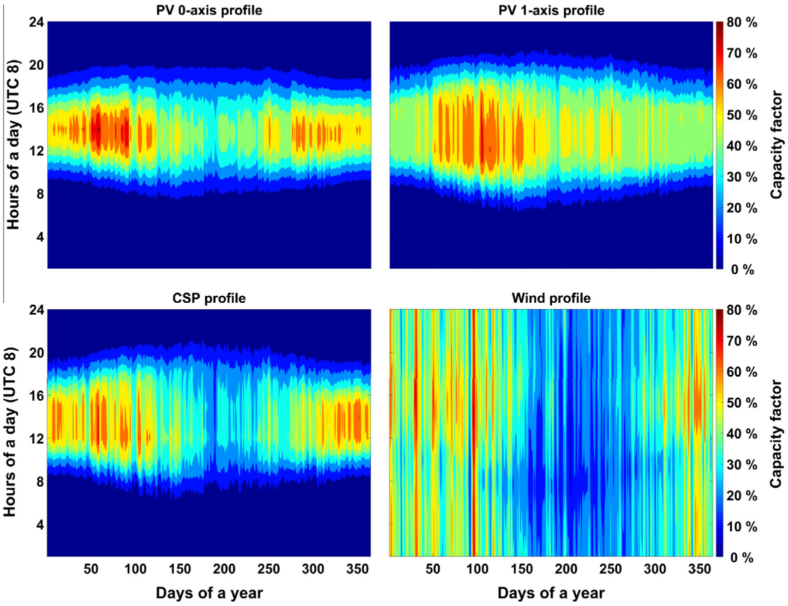

Fig. 3. Aggregated feed-in profiles for optimally tilted (top left) and single-axis tracking PV (top right), CSP solar field (bottom left), and wind power plants (bottom right) in North-East Asia.

mally tilted PV systems, wind power plants, hydropower plants and PHS storage systems, data of existing installed capacities in North-East Asian sub-regions have been taken from the Platts database [54]. Lower limits on already installed capacities in North-East Asian sub-regions are summarized in Table 9.

Upper limits for CSP, optimally tilted and single-axis tracking PV systems, and wind power plants are based on land use limitations and the density of capacity. The maximum area covered by solar systems is set to 6% of the total sub-regions' territory and for wind power plants to 4%, respectively. The capacity densities are for the CSP solar field 225 MW_{th}/km^2, for optimally tilted and single-axis tracking PV systems 75 MW/km^2, and for onshore wind power plants 8.4 MW/km^2. Maximum installable capacities are computed by applying Eq. (3.1), with the rotor diameter (d_{rot}), dimensionless distance constants (d_1, d_2) set to $d_1 = 5$ and $d_2 = 7$, according to the recommendations based on practical experiences by Heier [55], Gasch and Twele [56] and Hau [57]

$$Cap_{wind} = area_{total} \cdot limit_{wind} \cdot \frac{P}{\left(d_1 \cdot d_2 \cdot d_{rot}^2\right)} \tag{3.1}$$

$$Cap_{solar} = area_{total} \cdot limit_{solar} \cdot (\eta_{solar} \cdot GCR \cdot I_{STC}) \tag{3.2}$$

For hydro power plants and PHS storage, upper limits are set to 150% and 200% of already installed capacities by the end of 2013 (Table 9). For North Korea the PHS upper limit is set equal to South Korea because of no currently installed PHS capacity and obviously high potential in North Korea. All upper limits of installable capacities in North-East Asian sub-regions are summarized in Table 10.

For all other technologies, upper limits are not specified. However, for biomass residues, biogas and waste-to-energy plants it is assumed, due to energy efficiency reasons, that the available and specified amount of the fuel (Table 5) is used during the year.

Table 9
Lower limits of installed capacities in North-East Asian regions.

Region	Installed capacity by Platts [54] (MW)			
	Solar PV	Wind	Hydro RoR and dams	PHS
Total area	1029	17,984	215,541	48,197
East Japan	50	990	9470	9364
West Japan	47	560	10,640	15,762
South Korea	116	357	1569	4390
North Korea	0	0	6354	0
Northeast China	0	4031	6762	600
North China	43	2245	32,195	3216
East China	117	1709	9911	6064
Central China	6	607	68,552	3840
South China	23	1273	51,234	4848
Tibet	122	0	201	113
Northwest China	425	5564	17,014	0
Uygur	81	649	1638	0
Mongolia	0	0	0	0

3.5. Load

The demand profiles for sub-regions are computed as a fraction of the total country demand based on synthetic load data weighted by the sub-regions' population. Fig. 4 represents the area-aggregated demand of all sub-regions in North-East Asia. Electricity demand increase by year 2030 is estimated using IEA data [1], electricity growth for China is estimated to be about 70%, for Japan and South Korea 19% and for Mongolia and North Korea load is adjusted according to the Chinese assumptions.

Table 10
Upper limits on installable capacities in North-East Asian regions in units of GW_{th} for CSP and GW_{el} for all other technologies.

Region	Area (1000 km^2)	Solar CSP	Solar PV	Limits (GW)			
				Wind	Hydro RoR	Hydro dams	PHS
Total area	11,499	286,081	111,287	8314	162	162	105
East Japan	195	1946	876	65	7.1	7.1	19
West Japan	179	1794	807	60	8.0	8.0	32
South Korea	99	986	444	33	1.2	1.2	8.8
North Korea	116	1165	524	39	4.8	4.8	8.8
Northeast China	1308	32,706	14,718	1100	5.1	5.1	1.2
North China	1154	28,842	12,979	970	24	24	6.4
East China	479	1917	863	64	7.4	7.4	12
Central China	1279	31,981	14,391	1075	51	51	7.7
South China	1013	4052	1824	136	38	38	10
Tibet	1127	28,183	12,682	948	0.2	0.2	0.2
Northwest China	1380	34,507	15,528	1160	13	13	0
Uygur	1618	40,449	18,202	1360	1.2	1.2	0
Mongolia	1551	38,776	17,449	1304	0	0	0

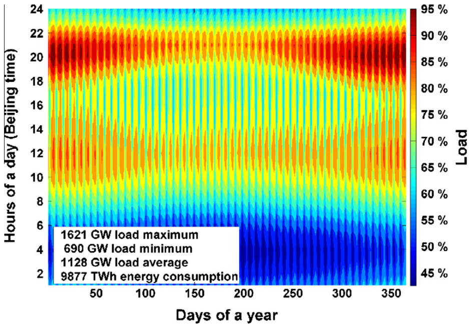

Fig. 4. Aggregated load curve for North-East Asia for the year 2030.

Industrial gas demand values (gas demand excluding electricity generation and residential sectors) for China, Japan and South Korea are presented in Table 11, values are based on National Bureau of Statistics of China [58] and IEA data [59].

3.6. Metrics used for the analysis

For analysing the cost structure of the different scenarios a set of fundamental parameters are computed according to Eq. 4: levelized cost of electricity (LCOE, Eq. (4.2)), levelized cost of electricity for primary generation ($LCOE_{prim}$, Eq. (4.3)), levelized cost of curtailment (LCOC, Eq. (4.4)), levelized cost of storage (LCOS, Eq. (4.5)), levelized cost of transmission (LCOT, Eq. (4.6)), total annual system cost ($totalCost_{sys}$, Eq. (4.1)), total capital expenditures ($CAPEX_{tot}$, Eq. (4.10)).

$$totalCost_{sys} = \sum_{r}^{reg} LCOE_r \cdot E_{demand,r} \tag{4.1}$$

$$LCOE_r = LCOE_{prim,r} + LCOC_r + LCOS_r + LCOT_r \tag{4.2}$$

$$LCOE_{prim_r} = \frac{\sum_{t=1}^{REtech}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot Cap_{t,r} + OPEXvar_t \cdot E_{gen,t,r}}{E_{demand,r} + E_{exp,r} - E_{imp,r}} \tag{4.3}$$

$$LCOC_r = LCOE_{prim_r} \cdot \frac{E_{curt,r}}{E_{demand,r} + E_{exp,r} - E_{imp,r}} \tag{4.4}$$

Table 11
Industrial gas demand.

	Bcm	TW h_{th}
Japan	41.9	439.1
South Korea	15.7	164.1
China	95.6	1000.6

$$LCOS_r = \frac{\sum_{t=1}^{Storagetech}(CAPEXcrf_t + OPEXfix_t) \cdot Cap_{t,r} + OPEX\,var_t \cdot E_{storage,disch,t,r}}{E_{demand,r} + E_{exp,r} - E_{imp,r}} \tag{4.5}$$

$$LCOT_r = \frac{totalCost_{TR} \cdot share_r}{E_{demand,r} + E_{exp,r} - E_{imp,r}} \tag{4.6}$$

$$crf_t = \frac{WACC \cdot (1 + WACC)^{N_t}}{(1 + WACC)^{N_t} - 1} \tag{4.7}$$

$$\begin{aligned} totalCost_{TR} = \sum_{l=1}^{lines} \big[& (CAPEX_{TL} \cdot crf_{TL} + OPEXfix_{TL}) \cdot Cap_{TL,l} \cdot dl_{TL} \\ & + OPEX\,var_{TL} \cdot E_{transm,t,l} + (CAPEX_{CS} \cdot crf_{CS} + OPEXfix_{CS}) \\ & \cdot Cap_{CS,l} + OPEX\,var_{CS} \cdot E_{transm,t,l} \big] \end{aligned} \tag{4.8}$$

$$share_r = 0.5 \cdot E_{exp,r} \Big/ \sum_{r}^{reg} E_{exp,r} + 0.5 \cdot E_{imp,r} \Big/ \sum_{r}^{reg} E_{imp,r} \tag{4.9}$$

$$CAPEX_{tot} = \sum_{r}^{reg} \sum_{t}^{tech} CAPEX_t \cdot Cap_{t,r} \tag{4.10}$$

Eq. 4: Levelized cost of electricity (LCOE) and total cost of sub-regions and total area. Abbreviations: sub-region (*r*), technology (*t*), primary (*prim*), all sub-regions summarized (*tot*), transmission lines (*TL*), converter substation (*CS*), RE technologies (*REtech*), such as PV, wind onshore, hydro RoR, hydro dams, storage technologies (*Storagetech*), such as batteries, PHS, power-to-gas, all modeled technologies (*tech*), all sub-regions (*reg*), levelized cost of curtailment (*LCOC*), levelized cost of storage (*LCOS*), levelized cost of transmission (*LCOT*), capital expenditures (*CAPEX*), capital recovery factor (*crf*), weighted average cost of capital (*WACC*), lifetime (*N*), fixed operational expenditures (*OPEXfix*), variable operational expenditures (*OPEXvar*), installed capacity (*Cap*), annual electricity generation (E_{gen}), annually curtailed excess energy (E_{curt}) and share of region in grid utilization (*share*).

4. Results

4.1. Main findings on the optimized energy system structure and costs

For all scenarios optimized electrical energy system configurations are derived and characterized by optimized installed capacities of RE electricity generation, storage and transmission for every modeled technology, leading to respective hourly electricity generation, storage charging and discharging, electricity export, import and curtailment. In Table 12 the average financial results of the different scenarios according to Eq. 4 are presented for the total system (including PV self-consumption and the centralized system) levelized cost of electricity (LCOE), levelized cost of electricity for primary generation (LCOE primary), levelized cost of curtailment (LCOC), levelized cost of storage (LCOS), levelized cost of transmission (LCOT), total annualized cost, total capital expenditures, total renewables capacity and total primary generation. Weighted average cost of capital (WACC) is set to 7% for all scenarios, only for residential PV self-consumption WACC is set to 4%.

From Table 12 it can be easily seen that the installation of HVDC transmission lines has a positive impact on the electricity cost and annual expenditures of the system: electricity cost of the entire system in the case of area-wide open trade power transmission decreases 1% and 17% compared to the country-wide and region-wide scenarios. Grid utilization decreases the primary energy conversion capacities and generation by 4% and 17% in terms of installed capacities and by 2% and 5% in terms of generated electricity in reference to country-wide and region-wide scenarios, respectively. Grid utilization leads to a significant decrease of storage utilization, whereas cost of transmission is relatively small in comparison to the decrease in primary generation and storage costs. Curtailment costs do not decrease in case of broader grid utilization. However, the impact of energy excess on total cost is rather low. The rather small difference between area-wide and country-wide scenarios can be explained by the dominant share of China in the total electricity demand. Whereas the total installed capacity of RE decreases with grid utilization increase, the installed capacity of wind turbines increases, as can be seen in Table 13. For North-East Asia wind is a least cost RE source, thus wind energy imports displace a part of the higher cost of inland solar PV generation. Optimally tilted PV share is close to zero in almost all regions, only in South Korea for the region-wide and country-wide scenarios the installed capacity of optimally tilted PV is 30% of all system PV capacities in the region due to the less favourable solar irradiation conditions which decrease the benefits of the 1-axis tracking PV technology. Obviously, transmission lines decrease the need for energy storage options: installed capacities of batteries, PHS, heat storage, Power-to-Gas and gas turbines decrease with the grid expansion.

At the same time the area-wide gas scenario shows a substantial increase in the annual system cost, installed capacities and generation. An increased electricity demand from the gas synthesis sector leads to an increased RE generation and therefore higher primary energy cost. However, this increase is about 6%. Curtailment, storage and transmission cost increased 250%, 51%, and 209%, respectively, in reference to the area-wide scenario. The reason for this increase can be found in the shift of electricity generation toward low cost energy producing regions like Tibet or North China and increased energy transmission. At the same time the gas producing regions (Northeast, East, Central, South China, West Japan and South Korea) tend to install more electrolysis, CO_2 from air and methanation units, as well as new energy storage capacities to flatten the electricity demand and generation to guarantee high enough FLH of the methanation sector. In the same way, the

Table 12
Financial results for the four scenarios applied in North-East Asia regions.

2030 Scenarios	Total LCOE (€/MW h)	LCOE primary (€/MW h)	LCOC (€/MW h)	LCOS (€/MW h)	LCOT (€/MW h)	Total ann. cost (b€)	Total CAPEX (b€)	RE capacities (GW)	Generated electricity (TW h)
Region-wide	80.9	42.0	3.0	35.8	0.0	799	6745	6559	12,246
Country-wide	71.5	41.7	3.0	23.9	2.8	705	6253	5890	11,965
Area-wide	69.4	41.8	3.1	20.9	3.6	683	6127	5639	11,721
Area-gas	91.3	44.3	7.7	31.6	7.6	905	8212	7340	15,705
Area-secure	85.6	41.3	2.0	38.3	4.0	876	9329	9504	16,474

Table 13
Overview on installed RE technologies and storage capacities for the five scenarios.

		Region-wide	Country-wide	Area-wide	Area-gas	Area-secure
PV self-consumption	(GW)	1484	1484	1484	1484	1484
PV optimally tilted	(GW)	113	113	1	623	1
PV single-axis tracking	(GW)	2451	1349	1091	1984	2555
CSP	(GW)	64	0	0	0	0
Wind onshore	(GW)	1555	2104	2263	2639	2975
Biomass power	(GW)	74	60	60	143	45
Waste-to-energy incinerator	(GW)	5	4	4	7	4
Biogas power	(GW)	77	99	107	95	116
Hydro RoR	(GW)	115	113	110	110	110
Hydro dams	(GW)	160	160	162	156	162
Battery PV self-consumption	(GW h)	1938	1938	1938	1938	1938
Battery	(GW h)	4225	1936	1511	2186	2278
PHS	(GW h)	98	98	105	98	105
Heat storage	(GW h)	1360	585	0	749	163
PtG electrolyzers	(GW_{el})	328	212	185	452	513
CCGT	(GW)	347	265	245	25	147
OCGT	(GW)	188	195	187	45	2001
Steam Turbine	(GW)	35	19	0	35	6.8

installed capacities of gas turbines dramatically decrease for the area-wide gas scenario: SNG is used to smooth the seasonal variations and the need for long-term storage decreases considerably.

The area-secure scenario shows that additional energy system security mainly increases energy storage cost and both primary generation and curtailment costs are decreased in comparison to the area-wide scenario. The primary LCOE is decreased due to a lower share of costly hydro RoR in the total energy mix. An interesting effect can be observed for the area-gas and area-secure scenarios: both scenarios show additional gas generation, but in the area-gas case the generation of a comparable amount of synthetic gas results in a significant increase of primary LCOE and LCOT. The reason for such a difference is the different distribution of the SNG demand: in the case of the area-secure scenario the demand is evenly distributed across other regions, but in the area-gas scenario the demand is concentrated in several industrially developed and sometimes energy deficit regions such as South Korea and West Japan. This causes a utilization of high cost energy sources and increases the LCOT.

In the case of the region-wide open trade scenario, all sub-regions of North-East Asia need to match their demand using only their own renewable energy resources. In the case of the country-wide and area-wide open trade scenarios, a division of regions into net exporters and net importers can be observed. Net exporters are sub-regions with the best renewable resources and net importers are sub-regions with moderate ones. Annual import and export diagrams for the area-wide scenario is presented in Fig. 5. Differences in generation and demand are mainly due to export and import, but in a minor quantity also due to storage losses. For the area-wide gas scenario, differences are also due to energy consumption for SNG production.

Fig. 5 reveals the net exporter regions: Tibet, Central, North, Northwest and Northeast China, and North Korea. Net importers are East and South China, South Korea and Japan. Electricity export from Mongolia is negligible, which can be explained by the fact that the wind potential in Chinese Inner Mongolia is higher, and North China's generation is slightly lower in cost (Table 8). In the case of the country-wide open trade scenario, generation in Japan and South Korea exceeds demand because of wide utilization of storage, and energy losses during charge and discharge. For the area-wide gas scenario a drastically increased electricity demand of the SNG producing sector changes the picture dramatically, SNG producing regions tend to increase the inner regional electricity generation to fulfill the increased demand. At the same time the energy import from low cost RE regions also increases. Thus, almost all the regions (except East China having access to less favourable RE resources) become net exporters (electricity transferred to other regions or to SNG production).

An overview on installed capacities for the sub-regional energy system structures is presented for three different scenarios (region-wide, area-wide and area-wide gas) in Fig. 6.

From Fig. 6 we can see that in the case of region-wide open trade in the sub-regions of Japan, South Korea, East and South China, the solar PV capacities exceed 75% of all installed power capacities despite the fact that wind power FLH in these regions are better or comparable to PV FLH. That happens due to the upper limit of installable wind power capacity being much lower than the upper limit of PV capacity because of the lower area limit and considerably lower power density of wind technology. Due to reaching the maximum capacity of the least cost component (wind power plants), the second least cost energy component (PV systems) is installed to cover the demand. The interconnected HVDC transmission grid significantly decreases total installed capacities (Fig. 6 and Table 13) and especially solar PV capacities, whereas installed capacities are increased in wind resource rich regions, such as Tibet and North China.

For the area-wide gas scenario the installed capacities of PV increase again because of a higher electricity demand. However, in some regions, e.g., Northeast China, the installed capacities decrease because this region stands along the transmission line to Korea and Japan, and ergo can balance its demand using grid electricity. Additional demand in case of RE base energy system can change the entire system structure because of shifting optimal cost structure parameters and areas being confronted with their upper resource limits.

The structure of HVDC power lines and utilized RE resources strongly influences the total storage capacity needed, but also interferes with the composition of different storage technologies for the energy system in the same area. Data of storage system discharge capacities, annual energy throughput and full cycles per year are summarized in the Appendix A (Table 1). The decrease of the PV generation fraction goes hand in hand with the decrease

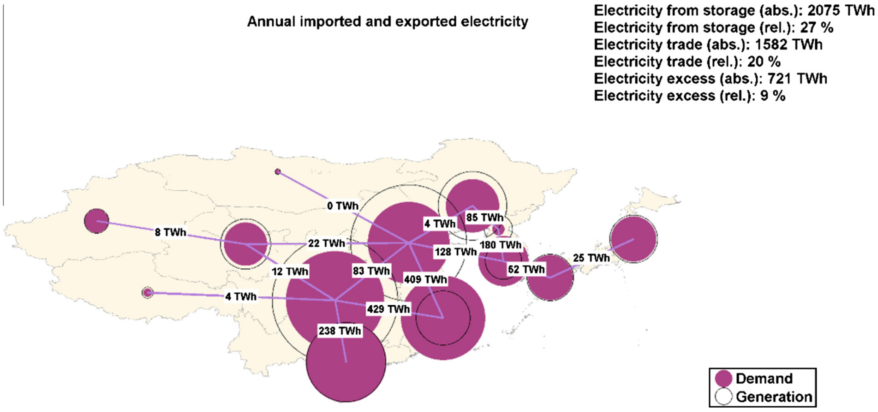

Fig. 5. Annual generation and demand diagram for the area-wide open trade scenario for North-East Asia.

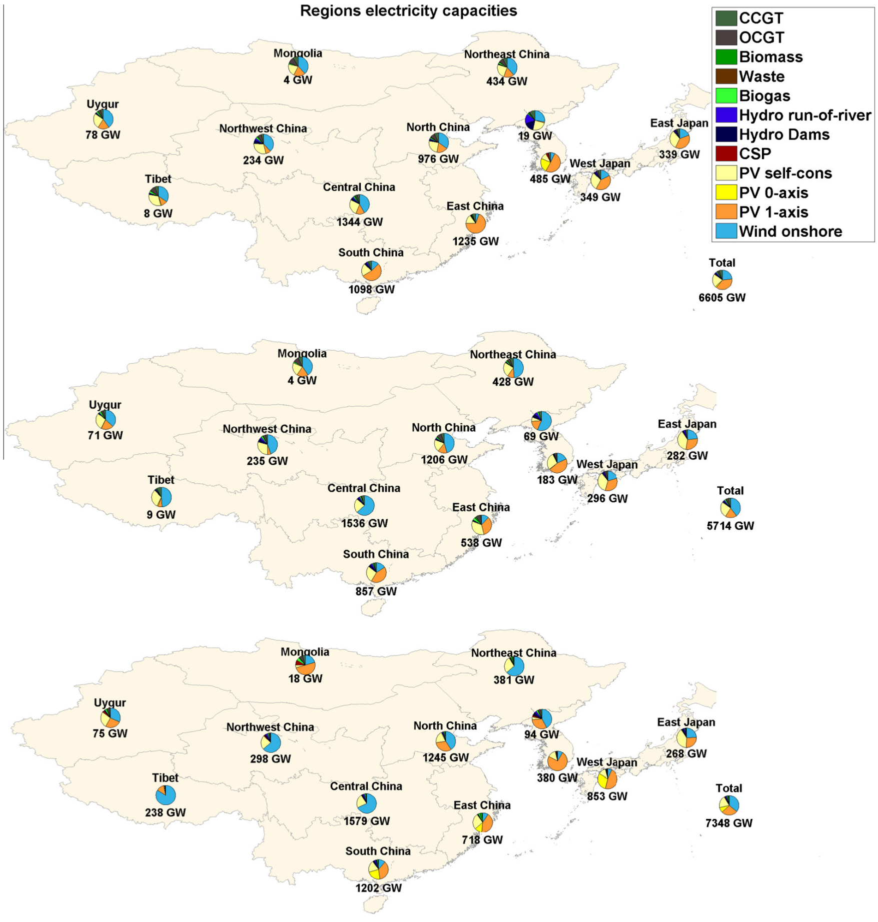

Fig. 6. Installed capacities for region-wide (top), area-wide (center) and area-wide gas (bottom) open trade scenario for North-East Asia.

of short-term storage (batteries and PHS). At the same time the increase of the wind generation fraction leads to an increase of long-term storage (gas storage). Consequently, power transmission and decrease of PV generation share leads to a reduced share of battery and PHS storage (in Japanese sub-regions and Korea, PHS installed capacities reached the lower limits and cannot be decreased further). Finally, it can be stated that interconnected HVDC power lines substitute in particular short-term storage, i.e., transfer of energy in time (storage) is substituted by transfer of energy in space (transmission) by reducing overall generation and storage capacities and increasing transmission capacities to reach a lower total energy system cost.

Increased SNG production and RE generation capacities decreases the need for long-term storage since water electrolysis and CO_2 units provide more flexibility to cover the seasonal variability in RE generation, and gas turbines are utilized mainly for peak shaving. At the same time short-term storage capacities are increased to cover short variations in RE generation and guarantee high FLH for the high cost PtG sector.

These structural changes lead to a shift in total energy system cost and in the structure of LCOE. Diagrams of LCOE components are presented in Fig. 7 and the numeric values for LCOE components and the import/export share in all regions and scenarios are summarized in the Appendix A (Table 2). The share of export is defined as the ratio of net exported electricity to the generated primary electricity of a sub-region and the share of import is defined as the ratio of imported electricity to the electricity demand. The area average is composed of sub-regions' values weighted by the electricity demand.

The findings of this section can be summarized for the aggregated area in an energy flow diagram comprised of the primary RE resources converters, energy storage and the HVDC transmission grid. The difference of primary power generation and final electricity demand is subdivided into potentially usable heat and

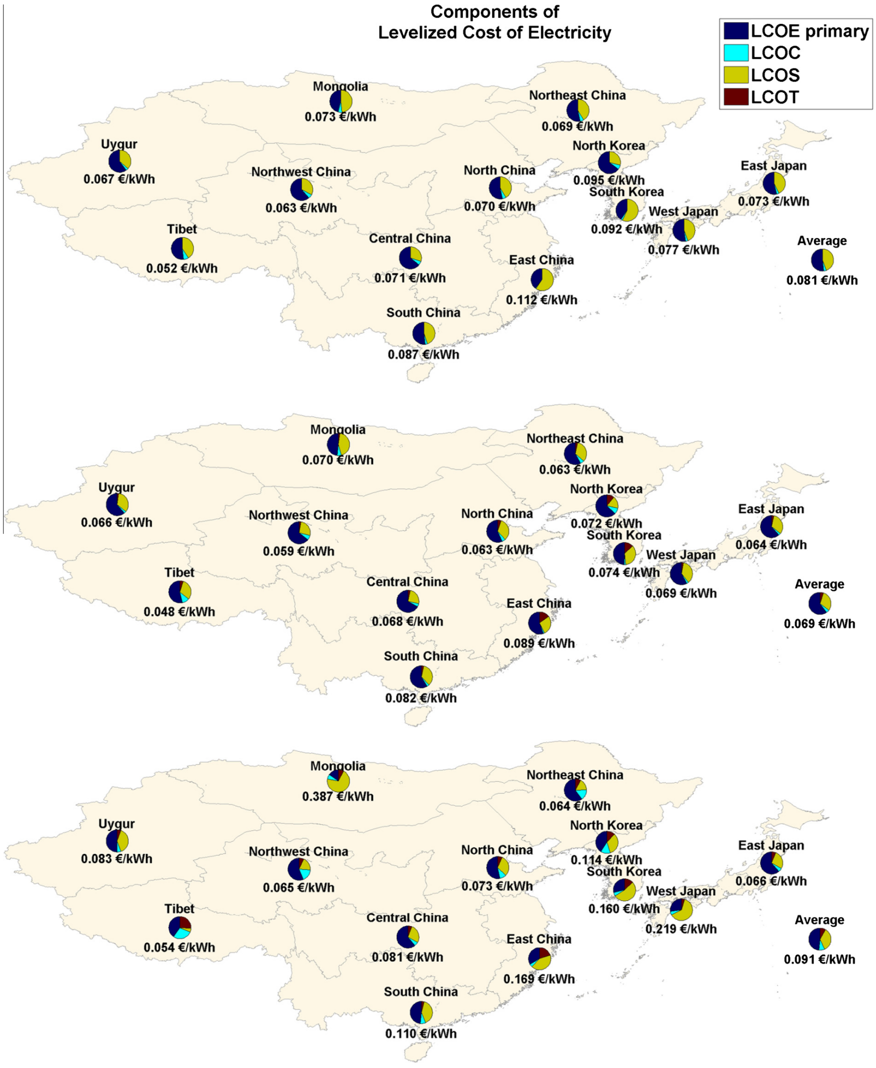

Fig. 7. LCOE components for region-wide (top), area-wide (center) and area-wide gas (bottom) open trade scenarios for North-East Asia and reference year 2030.

the ultimate system loss. Both are comprised of curtailed electricity, heat produced by biomass, biogas and waste power plants, heat of transforming power-to-hydrogen in the electrolyzers, hydrogen-to-methane in methanation and methane-to-power in the gas turbines, and the efficiency loss in PHS, battery storage, as well as by the HVDC transmission grid. This energy flow for the area-wide scenario is visualized in Fig. 8.

For all modeled scenarios the usable heat share is around 10%. This heat could be used for district heating or industrial heating in case of temporal and spatial match of demand and supply. The most fruitful may be the utilization of power-to-heat technology in synergy with hot heat storages, since it will help to decrease energy losses due to curtailment by using this energy for serving the heat demand. The usable heat amount varies from 1246 TW h_{th}

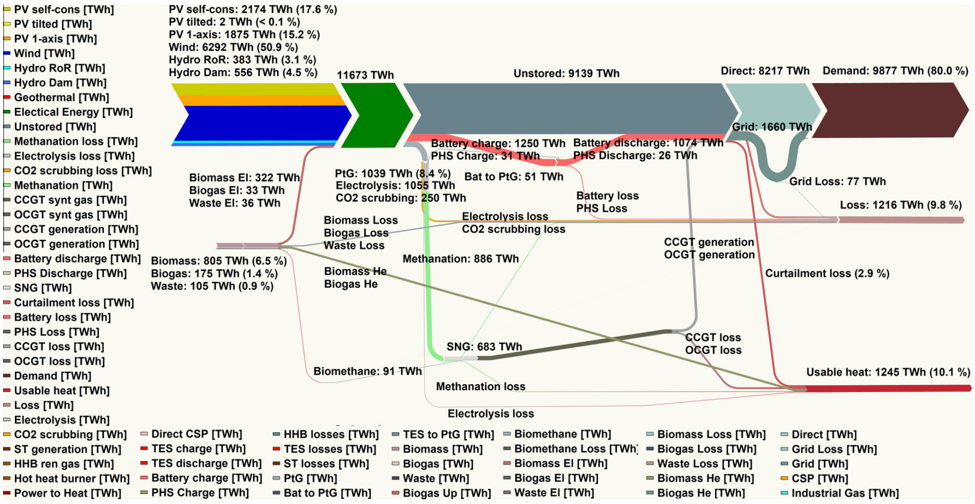

Fig. 8. Energy flow of the system for the area-wide open trade scenario.

per year for the area-wide open trade scenario up to 2000 TW h_{th} for the area-wide gas open trade scenario.

5. Discussion

The installation of a HVDC transmission grid enables a significant decrease in cost of electricity in the RE-based system. The total levelized cost of electricity in the region decreased from 80.9 €/MW h for the region-wide open trade scenario to 71.5 €/MW h for the country-wide open trade scenario and 69.4 €/MW h for the area-wide open trade scenario. The total annualized cost of the system decreased from 799 b€ to 683 b€. The difference in total region electricity prices between country-wide and area-wide open trade scenarios is not so substantial due to the fact that the Chinese demand is expected to represent about 83% of the whole North-East Asian electricity consumption, and the installation of an internal Chinese Super Grid leads to a major cost decrease. However, an international grid installation leads to 20% LCOE decrease in South Korea, and 8–9% decrease in Japan. In parallel the capex requirements are reduced from 6745 b€ for the region-wide open trade to 6253 b€ and 6127 b€ for the country-wide and area-wide open trade scenarios, respectively. Additional costs of HVDC transmission lines (annual cost 25 b€, capex 373 b€) are compensated by a substantial decrease in generation and storage capacities enabled by lower losses and costs of energy transmission compared to energy storage, and access to low cost electricity generation in other regions. In addition, the HVDC transmission grid enables additional benefits due to the large spatial east–west dimension of the North-East Asian region.

PV self-consumption influences the power sector in an interesting way. The region-wide, country-wide and area-wide open trade scenarios were also calculated without PV self-consumption and the total demand is assumed to be covered by a more centralized system. The annualized costs for the more centralized 100% RE system is 1.9% higher for the region-wide scenario (814 b€ against 799 b€ base scenario), but for the country-wide and area-wide open trade scenarios the more centralized system is found to be 4.9% and 5.4% lower in cost. For the region-wide scenario the benefits of decentralized generation can be explained by a RE resources deficit in regions, such as South Korea and East China, which can be solved by additional installation surfaces on private rooftops and the system gaining access to cheaper battery capacities (for residential consumers WACC is assumed to be 4%). For the country-wide and area-wide scenarios the PV self-consumption provokes additional costs because of a different target function of prosumers. Prosumers tend to reach their minimum annual cost of electricity consumption. The LCOE of PV self-consumption then must be lower than the grid electricity selling price, but can be higher than the total system LCOE. Additionally to higher generation cost, prosumers' electricity generation provokes a distortion in the system demand profile, i.e., the system reacts by installing more flexibility granting capacities, such as low cost RE or further storage capacities, which increases the system costs as well.

The fourth scenario, focusing an area-wide additional SNG generation, represents the possibility to cover current natural gas demand (except the gas demand for power generation) by SNG generation. The availability of RE in North-East Asia is sufficient to cover additional electricity demand for producing 1604 TW h_{th} (153.2 bcm) of SNG. However, that growth in electricity demand provokes an increase in electricity cost due to uneven distribution and profiles of RE generation. Adding 3180 TW h_{el} for gas synthesis induces an additional installation of RE generation capacities of 1515 GW of PV and about 375 GW of wind energy. As well, former long-term gas storage is partly substituted by short-term battery and heat storage, in total of about 1424 TW h. Next, there is a rather moderate increase in electrolyzer units of about 270 GW and substantially reduced gas turbines capacities of about 330 GW. The annual system cost rises to 905 b€ from 683 b€ for the electricity only system. For synthetic natural gas sold on the gas market at a price at 13.7 €/MBtu (16.2 $/MBtu) representing the LNG import price in Japan in the year 2013 [60], the electricity system price would be 84 €/MW h_{el}. For the integration of the electricity generation system and the SNG generation sector, we can observe a synergy effect: the SNG generation sector flattens seasonal resource fluctuations, resulting in a reduction in long-term storage capacities. Exactly this effect has been already described in a recent study [27]. However, this synergy effect does not compensate for the increased system price due to higher energy demand requiring a utilization of more expensive energy sources.

Furthermore, the system generates excess heat as a byproduct of biogas and biomass CHP plants, waste-to-energy incinerators, and gas turbines, as well as excess electrical energy which can be curtailed or converted to heat and stored in heat storage. The usable heat amount varies from 1245 TW h_{th} per year for the area-wide scenario up to 1650 TW h_{th} for the region-wide scenario. The waste heat from biomass and gas power plants is evenly distributed over the year: At the same time excess electricity is generated mainly during the period from October to April, when heat is most valuable. Cooling demand is included in electricity demand numbers and does therefore not generate an additional demand. For the area-wide gas generation scenario the amount of usable heat is even higher, at 2027 TW h_{th}, due to higher curtailment, whereas the heat profile distribution is mainly the same.

The findings for the North-East Asian 100% renewable resource-based energy system can be compared to recent insights in Europe about non-renewable options, such as nuclear energy, natural gas and coal carbon capture and storage (CCS) alternatives [61]. These alternatives could also lead to a low carbon energy system, which is of highest relevance for a climate change mitigation strategy. The LCOE of the alternatives are as follows [61]: 112 €/MW h for new nuclear (assumed for 2023 in the UK and Czech Republic), 112 €/MW h for gas CCS (assumed for 2019 in the UK) and 126 €/MW h for coal CCS (assumed for 2019 in the UK). However, a report published by the European Commission [62] concludes that CCS technology is not likely to be commercially available before the year 2030. The findings for Europe are assumed to be also valid for North-East Asia in the mid-term. The 100% renewable resource-based energy system options for North-East Asia presented in this work are considerably lower in cost (about 20–45%) than the higher risk options, which have still further disadvantages. These include nuclear melt-down risk, nuclear terrorism risk, unsolved nuclear waste disposal, remaining CO_2 emissions of power plants with CCS technology, diminishing conventional energy resource base and high health cost due to heavy metal emissions of coal fired power plants.

More research is needed for a better understanding of a fully optimized renewable energy system in North-East Asia. However, this research work clearly indicates that a 100% renewable resources-based energy system is a real policy option.

6. Conclusion

Existing RE technologies can generate enough energy to cover all electricity demand for the year 2030 on a significantly lower price level of 69.4 €/MW h_{el}, compared to non-renewable options. A further improved energy system robustness increases the cost by 23% to 85.6 €/MW h_{el}, still lower in cost then non-renewable options. It is also possible to cover the gas demand of the industrial and transportation sectors with PtG technology, although for a gas price which is substantially higher than today. Heat generated as a byproduct of electricity, synthetic natural gas generation and curtailed electricity conversion can cover up to 2000 TW h_{th} of heat demand. The HVDC transmission grid plays a key role since the established Super Grid enables a significant cost decrease within the renewable resource-based energy system. The utilization of a HVDC transmission grid leads to a cut-off of storage utilization and significantly reduced primary generation capacities. At the same time, PV self-consumption induces a moderate increase of total electricity prices of 4–5%, because consumers tend to utilize solar energy on a higher cost level and the electricity excess from prosumer generation provokes additional disturbances in the system and thus increases the system need for flexibility.

For the area-wide gas scenario a very interesting effect has been found, since increased SNG generation substitutes SNG storage as seasonal storage for the electricity sector. Instead of gas turbine utilization in case of an energy deficit, the system curtails SNG generation in that system set-up as a major source of flexibility to the system.

More research is needed for a better understanding of a fully-integrated renewable energy system in North-East Asia. However, this research work clearly indicates that a 100% renewable resources-based energy system is a real policy option.

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Appendix A. Supplementary material

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.enconman.2016.01.019.

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Publication II

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Market designs for a 100% renewable energy system: Case isolated power system of Israel

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Market designs for a 100% renewable energy system: Case isolated power system of Israel

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ABSTRACT

This paper examines market design options for a 100% renewable energy system taking a behavioral simulation approach. Various market models are tested to understand whether the current energy only market design is suitable to provide investment incentives and operate the 100% RES reliably and economically, or whether an additional capacity remunerative mechanism might be needed. Markets are analyzed with respect to the short-term operation of the technologies and the long-term development of the generation mixes in the 100% RES, and compared in terms of reliability and costs for the consumers. The results indicate that with the energy only market design, it is possible to solve the cost recovery and investment incentive problem in the 100% RES if market prices take account of the opportunity costs of flexible resources. A capacity mechanism may be needed to reduce the risk of underinvestment in flexible resources. The 100% RES system will require markets to accommodate the operational specifics of renewable energy generation. Therefore, the feasibility of radical market designs should be considered when analyzing the market design options for 100% RES systems.

1. Introduction

Mitigation of climate change is increasingly pushing energy systems towards decarbonization. Often, this is achieved by increasing the proportion of renewable energy production (wind, photovoltaics, biomass, and biogas) in the system. Transformation into a 100% renewable electricity system (RES) will require markets to accommodate the operational specifics of renewable energy generation. Numerous studies have shown the potential and technical feasibility of 100% RES in different regions. These studies apply an optimization model and provide a vision of a cost-minimum 100% RES, yet do not specify a transition path to it. Models on country-specific renewable systems of various degrees have been made for Australia [1], Denmark [2], Finland [3,4], Germany [5], Ireland [6], Portugal [7], and even on a global scale [8]. However, as long as most of the electricity markets are deregulated, the question remains: what kind of a market design is feasible in the fully renewable system?

The existing deregulated electricity markets can mainly be classified as energy only markets or energy plus capacity markets. Energy only markets trade electricity (€/MWh) and, without market imperfections, are believed to provide adequate cost recovery [9]. However, there are many discussions on whether the short-term operation in energy only markets could provide sufficient incentives for long-term investments [10–12]. Binding price caps and other regulatory failures may create a risk of "missing money" in energy only markets leading to a shortfall in revenues to provide adequate investment incentives. Recently, the "missing money" problem has been aggravated by the growing proportion of variable renewable generation. Renewable production technologies have typically a low marginal cost and a high volatility, which reduces the price level and raises concern over capacity adequacy. A high proportion of variable renewable energy production needs complementary flexible capacity in order to maintain power balance. In addition to dispatchable generation such as biomass plants, demand-side management [13], energy storages [14,15], and enhanced use of transmission connections [16] are often assumed to be the main sources of flexibility. If energy only markets fail to attract sufficient capacity to meet certain reliability standards, regulatory mechanisms for ensuring the security of supply such as capacity mechanisms could be introduced. The purpose of capacity mechanisms is to ensure the profitability of the existing power plants and to guarantee or at least support investments [17]. There are different forms of capacity remunerative mechanisms ranging

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from capacity auctions and capacity payments to strategic reserves (SR) [18]. To the authors' knowledge, the literature fails to acknowledge simulations on fully renewable markets to understand if the current energy only market or the energy plus capacity markets are suitable to provide investment incentives and operate 100% RES reliably and economically. Some studies focus on analyzing the possible effect of renewables on the wholesale prices [19–21], yet do not contribute to the question of the preferred market design. In Ref. [22], potential electricity market designs for neo-carbon society scenarios are investigated by taking an approach that relies on theoretical and social studies; nevertheless, a quantitative analysis of the viability of the market designs in 100% RES receives only limited attention in the paper [23]. provides qualitative analysis of market design options for the 100% RES and concludes that the current energy only model may be suitable for a fully renewable system by adopting certain market rules. The study also discusses more radical market design options such as compensating generators by the average production or long-term marginal costs while maintaining the marginal-cost-based dispatch or introducing long-term feed-in tariffs or technology-specific auctions with an obligation to supply power. However, with the long asset lives of the electricity industry, the viability of different market options has to be carefully evaluated quantitatively. This paper fills the research gap and tackles the question about the market designs that provide cost recovery and continuous investments in the 100% RES. The European policy discussions seem to focus on developing energy only markets instead of the more radical design options [24,25]; therefore, we rather focus on testing the feasibility of existing market design models in the 100% RES. By applying the methodology of soft-linking of optimization and simulation models, numerous existing market designs are tested numerically and analyzed with respect to the short-term operation of the technologies and the long-term development of the generation mixes in the 100% RES, and compared in terms of reliability and costs for the consumers. The paper is structured as follows. Section 2 details the modeling approach we have used to test the market design options numerically. Section 3 presents the input data. The results are given in Section 4, while Section 5 provides a conclusion and policy implications.

2. Methodology

Electricity market models can be divided into optimization, equilibrium, and simulation models [26]. Optimization models maximize or minimize a specific objective function, that is, the profit function of a single firm. Equilibrium models are able to address several market participants' profit maximization simultaneously. A comprehensive review on the optimization and equilibrium modeling tools used for energy system analysis is presented in Ref. [27]. Among these tools, there are models with more than 1000 users, such as RETScreen, HOMER, LEAP, BCHP Screening Tool, and energyPro, while Homer and EnergyPlan optimization tools are used to model the 100% RES for different regions ([2] [3] [6]). Yet, optimization and equilibrium approaches are largely static and present limitations to assess transitional stages or systems away from equilibrium. Considering simulation models, an example could be agent-based models, which usually take a behavioral simulation approach, and the final structure of the system depends on the market rules applied to the agents and their corresponding behavior [28]. Opposite of equilibrium and optimization models, simulation models allow observation of the dynamic evolution of the system under different policies and scenarios, and are able to integrate such aspects of electricity markets as imperfect competition, asymmetric information, players' individual behavior, and strategic interactions in a more realistic way. Thus, simulation models reflect realistic market conditions and close to real-world short-term operating and long-term investment decision-making processes, which is highly important due to challenges arising in the integration of variable renewable generation into electricity markets [29]. Extensive discussion on the application of agent-based simulation models in electricity markets can be found for instance in literature review studies in Refs. [30–32]. A detailed overview of the existing multi-agent energy system simulation tools is provided in Ref. [33]. These tools include EMCAS (The Electricity Market Complex Adaptive System), AMES (Agent-based Modeling of Electricity Systems), MASCEM (Multi-agent Simulator for Competitive Electricity Markets), MAN-REM (Multi-Agent Negotiation and Risk Management in Electricity Markets), and many others. The simulation models have been applied to address various electricity market research questions, for instance the impact of energy and environmental policies and market designs on the long-term evolution of power systems [30,34,35].

The following sections present the description of the model applied in this paper to numerically test the market design options in the 100% RES. At this stage, we are not proposing radical changes in the market design as described in Ref. [23]. We rather focus on testing the feasibility of the present market design models in the 100% RES. Table 1 provides an overview of the market design options considered in the paper.

2.1. Model description

To analyze the impact of market design rules and policies on the short-term operation and long-term development of the 100% RES, we apply the methodology of soft-linking of two separate models: optimization and simulation. Firstly, we use a static optimization approach to obtain an initial cost-minimum 100% RES for the reference year 2030. The initial system is a result of an energy system optimization model with an objective of minimizing the total costs of a renewable energy system from the perspective of a central planner or regulator. For more details of the model, see Ref. [36]. We do not specify how the 100% RES would be achieved by 2030; it is outside the scope of the paper to model a roadmap and market policies for the purpose. Rather, we are interested in analyzing which market designs will advance this scenario, that is, provide incentives for further investments and enable reliable operation of the 100% RES at the lowest possible costs for consumers. In other words, we want to simulate the possible market dynamics of the 100% RES showing possible and realistic short-term and long-term behavior of market players, market prices, and evolution of generation mixes over years depending on the market rules applied. For this purpose, we apply a simulation

Table 1
Market design options.

	Market design	Electricity market	Capacity mechanisms
EO	“Energy only” market	Pool with marginal pricing	No
EO-CA	“Energy-plus-capacity” market	Pool with marginal pricing	Pay-as-bid capacity auction
EO-SR	“Energy-plus-strategic reserve” market	Pool with marginal pricing	Strategic reserve

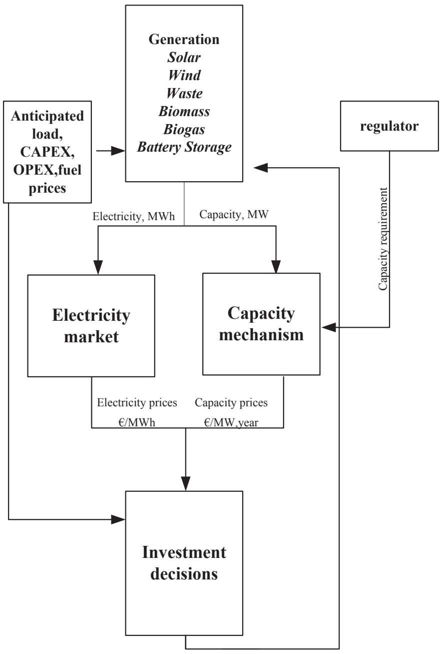

Fig. 1. Principle of the model.

model where the cost-minimum 100% RES resulting from the optimization model serves as an initial generation mix.

The main principle of the behavioral simulation model is given in Fig. 1. The model was developed by the lead author in Matlab R2013b. The model comprises several modules: an electricity market model, a capacity market module, and an investments module. The sections below provide further details about the modules. We assume that there are six independent generating companies competing with each other in the market. Each particular renewable energy technology (solar, wind, biomass, biogas, waste, and battery storage) represents one generating company. The financial and technical characteristics of the technologies, the demand patterns, the fuel prices, and the capacity factors of wind and solar are given exogenously. Generating companies make their decisions individually and independent from each other's short-term (hourly) operating and long-term (annual) investment decisions. Thus, the model has hourly and yearly resolution. In electricity markets, generating companies sell their hourly energy production (MWh) and decide upon their electricity sell volumes and prices. On the annual basis, generating companies sell their availability or capacity (MW) in capacity markets and make their long-term investments decisions, while assessing the profitability of new investments. The regulator is responsible for defining the total required capacity to be procured from the generating companies in the capacity market in order to ensure the desired level of system reliability.

2.1.1. Electricity market

Electric energy is traded in pool-based electricity markets, where generators offer their hourly production at a bid price.

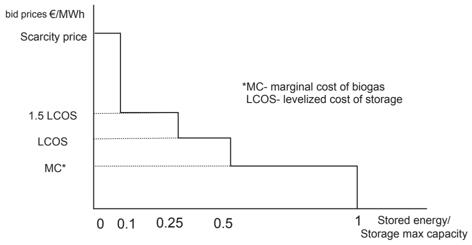

Fig. 2. Bidding prices of a battery storage depending on the level of stored energy.

Renewable energy technologies are divided according to their market behavior into two groups: undispatchable (wind, solar) and dispatchable (waste, biomass, biogas, battery storages). Undispatchable technologies offer energy irrespective of market prices; in the case of excess generation, solar and wind production is curtailed. All technologies, except battery storage, are assumed to bid at their marginal costs. The model does not consider minimum start-up/shut down and ramping rates, which is a reasonable assumption because of the absence of large thermal power plants such as coal and nuclear. The marginal costs of wind and solar are assumed zero. We assume that feed-in tariffs will be provided on top of the marker price for solar producers. The marginal costs of biomass and biogas are defined by the costs of the corresponding biofuel. The battery storage is considered either a consumer or a producer depending on the demand/supply situations. The battery storage buys electricity at a low price when there is excess generation and sells it at a higher price in tight supply and demand situations. During the hours of excess generation, that is, when production of solar and wind exceeds demand, the battery storage acts as an electricity consumer buying electricity from the market, and thus, submitting buy bids. During the hours of low solar and wind production, the storage acts as a producer and sells stored electricity to the market. The offer prices of the battery storage depend on the stored energy available against the technical storage capacity, reflecting the willingness to sell at the highest possible market prices when the stored energy is low (see Fig. 2). It allows the storage to produce whenever it is most profitable, thus saving the energy for periods of tight supply. To ensure its dispatch in periods of high availability of stored energy, the bidding prices of the storage are slightly below the marginal cost of the most expensive peak power plant in the system, that is, the biogas peak power plant in our model. With a decrease in stored energy, bidding prices account for the leveled cost of storage (LCOS), estimated as the sum of annual investment, operating, and charging costs divided by the forecasted annual storage production. When the availability of storage energy is below ten percent, the storage is willing to bid at the highest possible market price (scarcity price).

Based on the bid curves of producers and consumers, the market operator runs the market clearing algorithm, that is, combines the supply- and demand-side bids to obtain market clearing prices. Consumers are assumed to be completely inelastic, thus bidding at the highest possible market price or price cap. The market prices are set by the marginal cost of the most expensive producer that clears demand and supply. In the case of supply scarcity, demand is curtailed to meet the supply, and the market price is set at the value of lost load (*VOLL*)[1] or price cap.

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[1] The value of lost load (*VOLL*) serves as a measure for the marginal willingness to pay for electricity consumption.

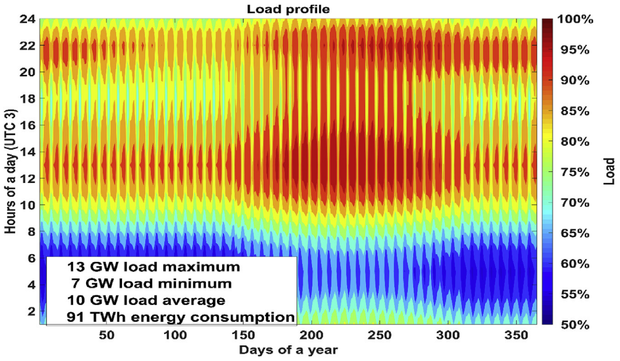

Fig. 3. Synthetic load profile for the year 2030.

2.1.2. *Capacity remunerative mechanisms*

The energy plus capacity markets are separated between electricity and capacity trading: electricity markets are used for trading electric energy production (€/MWh) and to cover the variable cost of power production while capacity mechanisms are used to trade availability (€/MW) and provide additional revenue stream required to cover fixed costs. There are different types of capacity mechanisms ranging from strategic reserves, capacity payments, and capacity auctions. This paper focuses only on capacity auction and strategic reserve.

2.1.2.1. Capacity auction. For a capacity market, we assume that capacity auction is held only for new capacity. On the demand side, the regulator determines the required new capacity by taking the given peak demand plus the reserve margin and subtracting capacity of the existing power plants. The reserve margin is set by the regulator as required capacity that is needed on top of the expected peak demand to ensure generation adequacy. Producers sell their capacity certificates to the common capacity market pool. Capacity certification of new and existing power plants is performed by the regulator. By multiplying the normative capacity factors by the nominal capacities (installed capacities) of power plants, it defines their available capacity during peak hours. For dispatchable resources such as biomass, waste, and biogas power plants, normative capacity factors are equal to one minus the forced outage rate. The normative capacity factors of wind and solar are assumed zero. We assume that the regulator certifies the maximum discharge capacity of the battery storage for sale in the capacity auction.

On the supply side, the regulator collects all certified bids and subsequently, all bids are put in an ascending order to generate the supply curve that is matched with the capacity demand. Capacity auction is a pay as bid auction, where every accepted capacity receives the price of its capacity bid. We assume that investors bid the annuity of the profitability gap. In other words, a capacity price of each project equals an annual payment necessary to increase the negative net present value (NPV) to zero. The capacity market ensures a payment at the level of the auction price over multiple years.

2.1.2.2. Strategic reserve. The goal of a strategic reserve is to ensure that a certain amount of reserve capacity is available to safeguard the security of supply. While the main part of the market remains energy only, a strategic reserve is contracted in addition to the market capacity and is withheld from the spot market in favor of a central dispatch. The strategic reserve (SR) dispatched at the dispatch price is defined exogenously by the regulator. Setting the proper dispatch price is an essential element in designing the strategic reserve. For our analysis, we set the dispatch price at a price slightly higher than the marginal cost of the most expensive unit in the system in order not to decentivize market capacity from producing in the electricity markets. The required volume of strategic reserve is tendered by the regulator, which is typically the transmission system operator (TSO). The generators in the strategic reserve are provided with fixed capacity payments, which are collected from the end-users through transmission tariffs. We assume that the SR consists mainly of battery storages. The battery storages of SR buy and store energy when there is an excess of solar and wind generation and sell it back at the dispatch price when there is no market capacity available to meet the demand. The target volume of SR for the next year is defined as the expected peak demand increased by the required reserve margin minus the existing market capacity multiplied by the normative capacity factors. The revenue mismatches resulting from selling electricity at the dispatch price in the electricity market and the total costs (annualized fixed costs plus costs of buying electricity) are compensated for by collecting capacity payments from consumers.

2.1.3. *Investment decisions*

In the investment decision block, each agent assesses the profitability of new investments by estimating the net present value (NPV) of a new investment over the entire economic lifetime. For a new investment with the size ranging from the number of power blocks with nominal capacities from one to the maximum (technically possible to install because of the limited fuel availability in the region or other technical limitation) each agent runs forecast dispatches for the whole lifetime of new investments to obtain electricity prices and estimates the expected revenues from selling electric energy to the market. Among all possible investments, the agent selects the number of blocks that give a positive and the highest NPV. At the second step, the investment is added to the installed capacities of the previous step with the construction time lag. We do not model mothballing decisions of existing power plants in the case of intermediate negative profitability. In the case of an energy plus capacity market, the agent calculates the NPV in

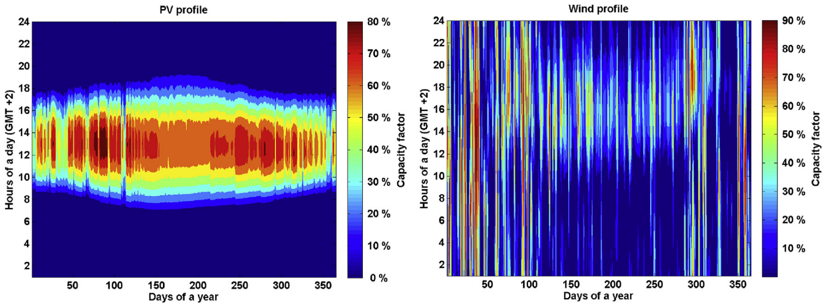

Fig. 4. Aggregated capacity factors for optimally tilted PV (left) and wind power plants (right).

order to estimate the profitability gap of the energy market, based on which it estimates the capacity bid prices for a new investment.

3. Input data

We used the power system data of Israel to generate an initial baseline 100% renewable generation mix in 2030 and simulate market designs. The perfect solar resources of the eastern Mediterranean make the idea of the 100% RES in Israel very promising. Moreover, as we do not model interconnectors, Israel with its quite isolated power market is a suitable case to perform the analysis. The input data used in the model can be divided into three categories:

- hourly profiles for electricity demand and capacity factors for wind turbines and solar PV
- technical characteristics assumptions for power generation and energy storage technologies included in the system
- capital expenditures, operational expenditures for all technologies included in the system

3.1. Power demand, wind and solar capacity factor profiles

The demand profile is based on the synthetic generated load data, calculated using historical temperature profiles, and data of work weeks and public holidays. This demand profile is upscaled to fit the annual electricity consumption of Israel [37,38]. An example of the load profile for Israel is presented in Fig. 3.

The capacity factors for optimally tilted PV and wind turbines are calculated based on the data for direct and diffuse solar irradiation, wind speed, temperature, and surface roughness for the year 2005, provided by NASA [39,40], and reprocessed by the German Aerospace Center [41]. The wind turbine capacity factors are calculated for a 3 MW wind turbine at a hub height of 150 m. The capacity factors are calculated in a 0.45°×0.45° spatial and hourly temporal resolution for the actual weather conditions of the year 2005. The aggregated profiles of the solar PV and wind energy power generation normalized to the maximum capacity averaged for Israel are presented in Fig. 4.

3.2. Financial and technical assumptions for power generation and energy storage technologies

The financial assumptions for the energy system components for the 2030 reference year are presented in Table 2 (the investment cost (capex) and operation and maintenance (opex) values refer, in general, to a kW of electrical power output). The financial assumptions for storage systems refer to a kWh of electricity storage capacity. The assumptions are mainly taken from Ref. [42] but also from other sources: Li-ion batteries [43–45], silicon-based PV cost development [46,47], biomass and biogas technologies [48], and waste-to-energy [49]. The technical assumptions concerning power to energy ratios for storage technologies and the efficiency numbers for generation are presented in Table 3.

Biomass and waste resource potentials are taken from the

Table 2
Financial assumptions for energy system components.

Technology	Capex [€/kW]	Opex [€/kW]	MC [€/kWh]	Lifetime [a]
PV	550	8	0	30
Wind onshore	1000	20	0	25
Biomass CHP	2500	175	0.065	30
Biogas CHP	370	14.8	0.085	30
Waste incinerator	5240	235.8	−0.015	20
	Capex [€/kWh]	Opex [€/kWh]	MC [€/kWh]	Lifetime [a]
Battery	150	10	–	10

Table 3
Efficiencies and energy to power ratio of the storage technologies.

Technology	Efficiency charge [%]	Efficiency discharge [%]	Energy/power ratio [h]
Battery	85	85	6

Table 4
Optimal baseline generation mix for the year 2030.

Technology	Baseline generation mix [MW]
PV	32997
Wind onshore	6978
Biomass	5222
Biogas	1512
Waste	28
Battery	10368

German Biomass Research Center [49]. All biowaste is divided into three components: solid waste, solid biomass, and biogas sources. Solid waste is comprised of municipal and industrial used wood; solid biomass includes straw, wood, and coconut residues; biogas sources are excrement, municipal biowaste, and bagasse.

3.3. Baseline generation mix

For the preparation of the baseline generation mix, the energy system optimization model was applied. The model was optimized to reach a minimum annual energy system cost for the given constraints: demand and capacity factor constraints and the financial and technical assumptions. The result gives the mix of installed capacities and operation profiles for the optimal technologies, which provides the minimum cost of guarantee energy supply for every hour of the year. The optimal baseline generation mix for the year 2030 is given in Table 4.

4. Results and discussion

For all scenarios, the model generates hourly supply-demand profiles, storage charging and discharging, spot market prices, and wind, solar and demand curtailments. On the annual basis, the model provides installed capacities, annual production by technologies, reliability, and economic indicators such as consumer bill, capacity margins, and the number of lost load occasions. We report results for a 20 year time frame (2030–2050). A policy analysis, comparing all three market design scenarios in terms of reliability and affordability, is presented in Section 4.3.

4.1. Operating profiles

Figs. 5 and 6 illustrate example summer and winter supply–demand profiles and hourly market prices for EO scenario. The summer and winter profiles illustrate how different technologies operate at an hourly level to accommodate the variability of demand, solar and wind.

The simulation provides a number of insights into the opportunity of constructing and operating a 100% renewable energy system in regions with high solar resources. In the 100% RES, where almost 70% of inflexible generation (wind and solar) has no fuel costs, the market prices are often set to zero if the variable generation is sufficient to meet the demand. Only flexible generation is able to contribute to positive hourly market prices: biomass and biogas power plants by fuel costs, and storage plants bidding opportunity costs.

In summer, the high correlation of the solar availability with the daily peak demand (between 6:00 and 16:00) and the high generation from PV (10 h of sunshine) allow meeting the peak demand only with solar generation at almost zero prices. During these periods, the storage is actively buying excess zero-cost PV generation for charging. During some hours in summer, because of the limited charge capacity of the storage and high PV generation, the excess PV and wind generation has to be curtailed to meet the demand. This occurs in particular when the wind and solar availability correlate highly. We can see the cutbacks in PV production during some hours in Fig. 5. Instead, in times of an empty battery storage and insufficient production of biomass and biogas to meet the demand, there might be power shortfalls and the load would be curtailed to match the supply. In this case, the power market price will rise to the value of the lost load. The evening reduction in PV generation is managed by flexible technologies. For this purpose, biomass provides effective baseload power. Battery storage discharging and sale of the stored energy becomes profitable during the evening peak demand. Owing to the most expensive fuel costs, biogas is mainly used when no stored energy is available or when the storage capacity is low and the storage bids an opportunity cost (higher than the marginal costs of biogas).

In winter, because of the lower solar availability and intensity than in summer (8 h of sunshine instead of ten), and the poor wind conditions of the region, the production of PV and wind is not sufficient to charge the storage at full. For this reason, to maintain the desired level of stored energy to be able to provide energy during evening peaks, apart from PV, the storage has to buy energy from biomass. In this case, the market prices are set by the marginal cost of biomass. Other than zero, the power market prices during daily peak demand produce inframarginal rents, which benefit solar producers and help to recover their fixed costs. Sometimes, high wind production occurring before the daily peak of PV generation as well as a bounded rationality of the battery storage regarding the availability of solar and wind may produce quite high solar curtailments, which can be observed in the two last days of the winter profile in Fig. 6. Thus, efficient operation of flexible resources, particularly storages and demand-side resources together with accurate forecasts of production of inflexible resources, will continue to play a key role in the operation of the 100% RES economically and reliably. In this paper, we consider only one type of storages. However, a combination of different types of storages from short-term to long-term ones and demand-side resources will help to balance the system better with less energy losses.

4.2. Generation mixes

Fig. 7 provides the evolution of installed capacities of different technologies under the EO market design in the years 2030–2050.

At present, there is around 12 GW of capacity in Israel, mostly composed of gas, coal, and oil generation. This capacity meets a demand that varies from 6 GW to 11 GW. The 100% RES has far more installed capacity (almost 55 GW while the peak demand is 13.5 GW in 2030), with almost 70% of that being wind and solar PV. However, the 100% RES system maintains only 15.5 GW of firm technologies (biomass, biogas, waste, and storage maximum discharge capacity). The amount of firm capacity is sufficient to meet the peak demand even when no solar or wind is available.

Fig. 7 shows that the EO market design provides continuous investments in all technologies following the demand growth, indicating that the market prices are sufficient to cover the costs of producers. Thus, we can conclude that EO market design based on marginal pricing is able to ensure profitable operation of the 100% RES. However, further provision of subsidies to zero marginal cost generation might be required, particularly to solar generation, which is dominating in the generation mix under study. Furthermore, investments in capital-intensive storage technologies become viable only if it is allowed to price energy at opportunity costs rather than at marginal costs. On the other hand, this might initiate strategic behavior among producers, which would pose a risk of high costs to consumers. Therefore, attracting enough flexible resources to the market, that is, different types of storages and demand-side resources, and ensuring appropriate competition

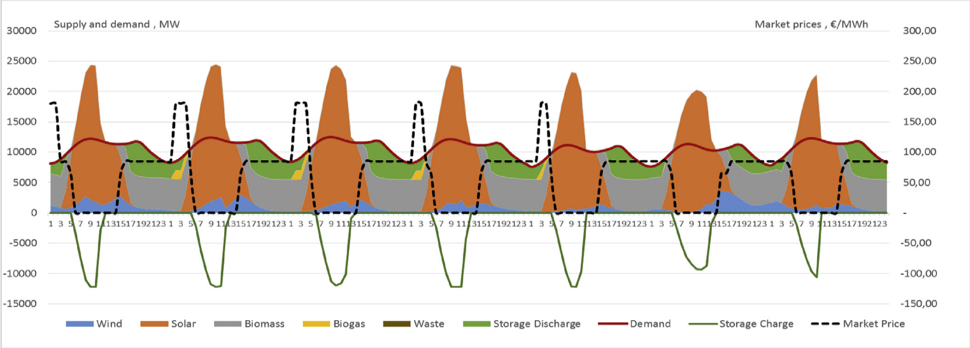

Fig. 5. Summer supply–demand profile and hourly market prices.

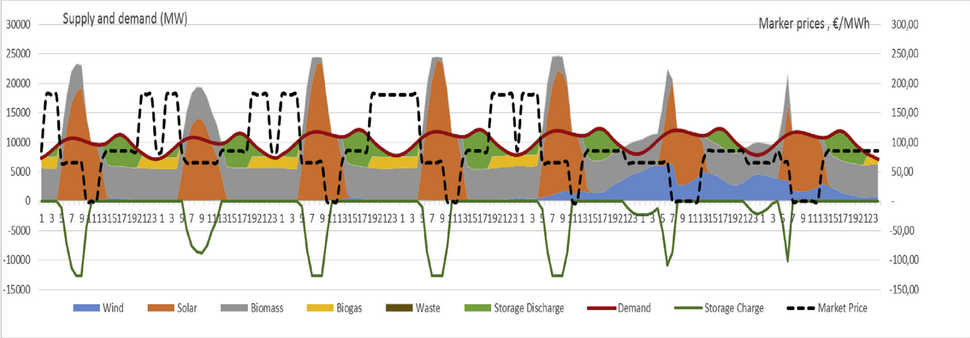

Fig. 6. Winter supply–demand profile and hourly market prices.

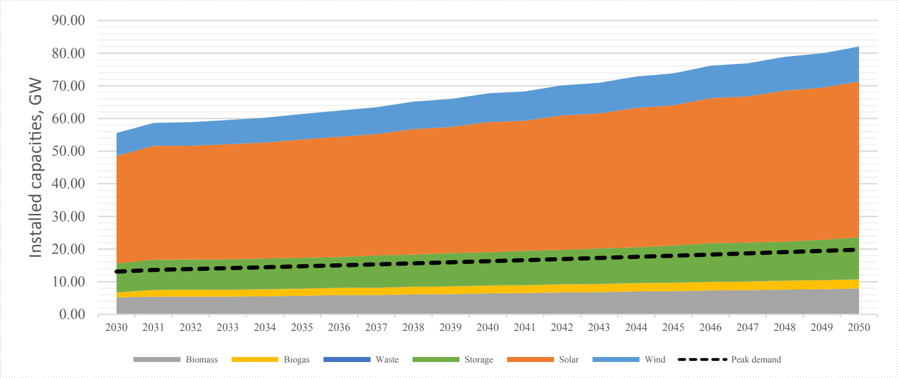

Fig. 7. Evolution of installed capacities 2030–2050 under EO market design.

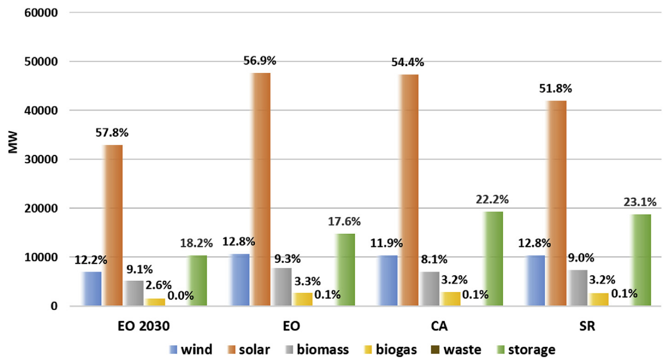

Fig. 8. Installed capacity (MW, in percent of total) by technologies under three different market designs (year 2050).

among them will play a vital role in the efficient functioning of the 100% RES markets. Another way of attracting sufficient investments in flexible resources is introduction of different forms of capacity remuneration mechanisms that provide stable and predictable revenue streams based on availability.

Next, we will illustrate how investments and generation mixes develop under three market designs. Fig. 8 provides the installed capacities MW and the proportions of different technologies in percent of the final generation mix by the end of the simulation period (year 2050) while Fig. 9 illustrates the annual generation in TWh and the proportions of annual production in percent of the total production for the year 2050.

One important observation is that the proportion of technologies in the final mix in the EO design by 2050 is almost the same as in the optimal baseline generation mix 2030. The simulation shows that investments in flexible generation increase with the EO-CA and EO-SR designs compared with the EO design because of the provision of stable capacity payments to flexible resources guaranteeing capacity that can be used to meet the peak demand. On the other hand, the lower scarcity prices resulting from the lower price cap and the higher reserve margins in the capacity-based markets make investments in inflexible generation such as wind and solar, which are not getting any capacity payments, less attractive than in the case of the EO design. In the EO-SR there are less investments in biomass and biogas than in the EO design. The dispatch price of the strategic reserve is capping scarcity prices, and thus, decreases the revenues and investment incentives for other technologies, particularly in other flexible technologies such as biogas and biomass. Despite the increased production of biogas and biomass, owing to the strategic reserve that is being dispatched only when no other generation is available in the market, biomass and biogas are getting less inframarginal rents required to cover their fixed costs than in the EO design, which makes their investments less attractive. Thus, to maintain the required amount of flexible resources in the market, decreased investments in biomass and biogas have to be compensated for by increasing the size of the strategic reserve, that is, storage. However, the production of the storage is lowest among all market design scenarios. Again, the possible reason is its last dispatch, leading to the decreased production and also decreased production of inflexible resources as a result of the storage buying less solar and wind production. In the EO-CA market, the losses of inframarginal rents of biogas resulting from reduced scarcity prices are compensated by capacity payments. Thus, we see more investments in biogas in the EO-CA design than in the EO-SR.

4.3. Affordability and reliability

We compare the three market designs (EO, EO-CA, EO-SR) in terms of affordability and reliability using several metrics presented in Figs. 10–12. Figs. 10 and 11 present the dynamic development of average wholesale electricity prices and capacity margins under three market designs over the simulation years. The capacity margin is estimated taking into account only the availability of firm capacity in the market, that is, biomass, biogas, waste, and storage maximum discharge capacity in the market. In addition, Fig. 12 presents a summary of the results. Firstly, it represents the average values over the whole simulation years of the loss of load expectations LOLE,[2] solar and wind curtailments, and electricity and capacity prices. Secondly, it illustrates the consumer bill consisting of energy component, capacity component, and solar surcharge. The energy component corresponds to the annual costs of consumers, and it originates from energy procurement in the spot market, while the capacity component corresponds to the annual costs of consumers, and originates from capacity procurement in the capacity markets. Solar surcharge represents the total financial support from outside the electricity market paid through feed-in tariffs by consumers to solar producers.

In terms of reliability, capacity markets have a positive effect on the market. In Fig. 10, this can be seen from the higher and less volatile capacity margins in the EO-CA and EO-SR scenarios than in the EO market design scenario. The number of the loss of load occasions is lower (5.75 h against 0 in the CA and EO-SR scenarios) as a result of the larger amount of flexible capacity installed in the capacity markets. The capacity margins are estimated taking into account the 100% availability of flexible resources during peak demand. In practice, the availability of flexible technologies, especially storage, is lower.

The average prices vary between 60 and 85 €/MWh depending on the market design. Because of the considerable proportion of flexible resources bidding non-zero prices to the market, the average wholesale prices will not decrease (which is a current concern in the energy only markets), yet they will be double the

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[2] LOLE represents the number of hours per annum in which supply will not meet demand.

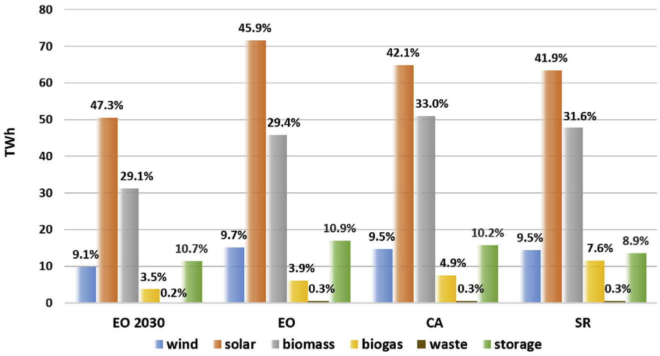

Fig. 9. Annual generation (TWh, in percent of total) by technologies under three different market designs (year 2050).

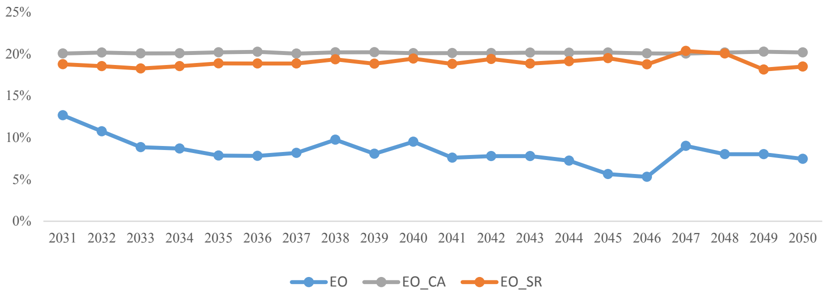

Fig. 10. Capacity margin of the system (%) over years.

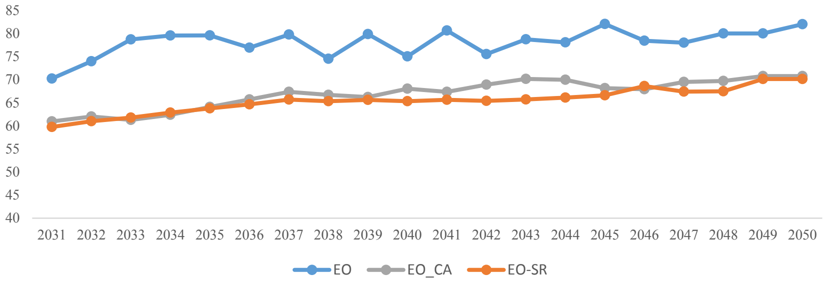

Fig. 11. Average wholesale electricity prices (€/MWh) over years.

current average EU-28 market prices. The average market prices and the energy component in the consumer bill are highest in the EO design among all scenarios. Firstly, this can be explained by the more frequent occurrence of the lost load occasions as the investors are providing less flexible capacity. Secondly, a higher price cap provides more incentives for the storage to exercise strategic behavior and bid scarcity prices up to price cap in tight demand-supply situations. With capacity markets there is always less potential to exercise strategic bidding because of the sufficient capacity and a lower price cap. Moreover, prices are less volatile in the capacity market designs, because the regulator ensures a steady amount of flexible firm capacity in the market, which is not the case in the EO design, where the installed capacities have a more fluctuating development. The average market prices and consequently, the energy component in the consumer bill are lowest in the case of the EO-SR design. As long as the storage belongs to the TSO and

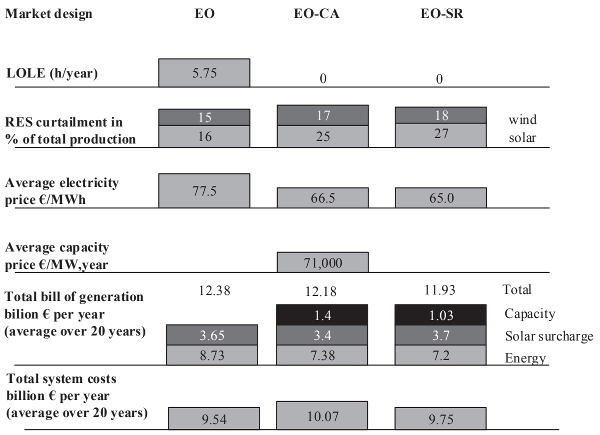

Fig. 12. Summary of the results.

receives guaranteed compensation in the form of capacity payments to cover its total costs, it has no incentives to exercise strategic bidding in the energy market. The storage operates as a last resort resource and is dispatched only in the case of scarcity at constant dispatch prices, thereby flattening power prices and reducing the energy component in the consumer bill. However, it is emphasized that withholding the storage from the market makes the competition tighter and increases the possibility for the market flexible capacity to exercise strategic bidding, which could lead to higher prices and consequently, a higher consumer bill than the ones we presented above. The same concerns the assumptions regarding the capacity auction. We assumed perfectly a competitive auction, where generators restore exactly the missing-money from the energy market. If we accounted strategic bidding in capacity auctions, it would lead to higher capacity costs for consumers, and thereby, a higher average consumer bill. To conclude, the assumptions we made with regard to the behavioral assumption of producers and investment decisions may lead to an overestimation of the consumer bill in the case of the EO market design and on the other hand, underestimation in the case of the capacity markets.

Solar curtailments are highest in the capacity market scenarios. In the EO-SR market design, nonmarket-based operation of the storage leads to distortions in the dispatch of other technologies and thereby to high energy losses of cheap wind and solar generation. Another reason for high solar curtailments in the capacity market scenarios is the willingness of the storage to maintain the required amount of storage capacity to ensure its availability during peak demand in order to be eligible to receive capacity payments, thus making it to buy biomass production in order to reduce its risk of being unfilled in the case of low solar availability.

Another important question is to define whether the markets are able to ensure the cost recovery of the system. Using the capital, O&M, fuel and financing costs, we estimated the annualized system costs of the 100% RES given in Fig. 12. The system costs depend on the total installed capacity in the market. By comparing the system costs under three different scenarios, we can observe that the EO market design provides the least-cost mix of technologies compared with other market designs under consideration. In the case of the EO-CA design, we have the highest system costs because of the largest proportion of total installed capacity compared with the other market designs. By comparing the system costs with the total consumer bill, we can see that all market designs are able to provide sufficient revenues to recover the producers' costs. However, the markets generate different surpluses, that is, the difference between the revenues and the costs of producers. Thus, the EO market benefits the producers most. Again, some assumptions we made with regard to the strategic bidding in the EO market or capacity auctions may lead to the over- or underestimation of the producers' benefits.

5. Conclusions and policy implications

This paper tackled the question about the market designs that will provide cost recovery and continuous investments to incentivize investments in the 100% RES. Various energy only and energy plus capacity market models were tested numerically taking a behavioral simulation approach. The market designs were analyzed with respect to the short-term operation of technologies and the long-term development of generation mixes, and compared in terms of reliability and costs for consumers. The objective was to examine whether the current energy only market design is suitable to provide investment incentives and operate the 100% RES reliably and economically, or whether an additional capacity remunerative mechanism might be needed as long as the investment problem remains one of the most important issue in the 100% RES.

Our results indicate that with the energy only market design, it is possible to solve the cost recovery and investment incentive problem in the 100% RES if applying certain rules. Cost recovery for variable power plants with zero marginal costs (particularly solar) only from market prices is challenging because of the low market prices at times of their production. Thus, subsidies to intermittent power plants will most likely be kept in the future energy only markets. Note that we did not consider the opportunity of inflexible generation to bid at prices above their marginal costs and leave this question for further research. Moreover, market prices should take account of the value of flexibility of flexible resources, particularly storage or demand-side resources, to enable recovering their capital and operating costs. However, this might involve a high risk of strategic bidding obviously not benefiting consumers. Uncertainties in price developments and the high price volatility in the energy only market make investments in dispatchable generation highly risky, thereby increasing the risk of underinvestment and threatening the security of supply. Thus, capacity remunerative mechanisms might be required to mitigate the risk of insufficient investments.

Our study demonstrates that capacity remuneration mechanisms ensure the required proportion of flexible resources in the 100% RES to meet the reliability standards. This is manifested by the reduced number of lost load occasions and a less volatile and higher capacity margin than in the case of energy only market. Moreover, our study shows that assuming strategic bidding in the energy only market, introduction of capacity markets leads to a decrease in the consumer bill. However, this holds only when assuming prevention of strategic bidding in the capacity markets. Many studies argue that capacity markets improve the reliability of the system at the expense of consumers. However, we found that this is not always the case because of the interlinkage of capacity and energy markets, where a decrease of revenues in one market is compensated in another.

Finally, we want to note that the quantitative results presented above may be limited because of the several assumptions we had to make to keep the model tractable, in particular, with regard to the behavioral assumption of producers and investment decisions. However, we are confident that our main findings on market design options for the 100% RES will hold because the change in assumptions affects all scenarios alike, driving the final results in one direction.

In our future research, we would like to extend our analysis to market designs for the 100% RES by incorporating more flexible resources such as power-to-gas technology and demand response in the model. Further, the study should include the changing demand structure resulting from the growing number of electric vehicles entering the market. Moreover, the feasibility of radical market designs should be considered. Finally, the riskiness of investments depending on market designs should be considered when analyzing the market design options. In addition, it is possible to model a roadmap and market policies designed to achieve the 100% RES with the model presented in the paper.

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Publication III

Bogdanov D., Farfan J., Sadovskaia K., Fasihi M., Child M., and Breyer C.
Arising role of photovoltaic and wind energy in the power sector and beyond: Changing the Northeast Asian power landscape

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Arising role of photovoltaic and wind energy in the power sector and beyond: Changing the Northeast Asian power landscape

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Accordingly to the COP21 Paris Agreement a net zero greenhouse gas emission energy system must be built no later than 2050. Such a fast power system transition will be very challenging for the conditions of Northeast Asia, a region with a large and fast growing power demand. Power system transition modelling was performed in order to check the technical feasibility of such a transition. The results of the simulation show that the transition can be accomplished and a 100% renewable energy system is both technically feasible and economically viable in Northeast Asia with average electricity generation cost of around 55 €/MWh. Solar photovoltaic (PV) will become the major energy source in Northeast Asia with a generation share of more than 70%; wind energy will contribute to 18% of the generation. Decarbonisation of the system can be achieved quite fast: by 2035 CO_{2eq} emissions in the power sector will decrease by 95 and 99% by 2045, respectively.

1. Introduction

Current global energy demand far exceeds the boundaries of Earth.[1] Constantly growing consumption of fossil fuels leads to depletion of conventional energy sources, and at the same time to irreversible changes in the environment. Climate change is its most critical indicator.[2] This led countries to unite and formulate the COP21 Paris Agreement,[3] which already entered into force only one year later in November 2016. The set target is a net zero emission society around the middle of the 21st century. This will almost certainly demand a net zero emission energy system, and in particular power system, to be built no later than 2050. From these facts emerged additional attention related to the possibility of power system transformation towards 100% renewable energy (RE) sources — the only sustainable way to build a net zero emission system. Such a transition should be possible from both a technical point of view — all technologies needed to build such a system are already available,[4] and a resources point of view — renewable energy sources are sufficient to provide all energy needed globaly.[5] Many studies focused on optimal energy systems with high shares of renewables were published in recent years, including studies concentrated on the Northeast Asian region.[6] Jacobson et al.[7] generated a major impact and attracted lots of attention to RE integration perspectives on a global scale. However, the process of the transition from the current fossil-based systems towards renewable based systems still needs to be studied in better detail.

This research has been formulated on the background of the growing awareness of the consequences of a "business as usual" continuation and the requirement to build net zero emission energy systems. The key question discussed in this paper is the contribution of variable renewable electricity, i.e., solar photovoltaics (PV) and wind energy, in a "best policies scenario" (BPS) to achieve a net zero emission power sector by 2050 in Northeast Asia, and the process of the transformation of the regional energy systems.

2. Materials and methods

2.1 Model overview

The regional power systems were modelled with the LUT Energy System Transition modelling tool.[6,8] The LUT Energy System Transition modelling tool simulates an energy system development under specific given conditions. For every time step the model defines a cost optimal energy system structure and operation mode for the given set of constraints: power demand, available generation and storage technologies, financial and technical parameters, and limits on installed capacity for all available technologies. The modelling is based on linear optimisation and performed in hourly resolution for an entire year, which ensures precision and reliability of results for the area of the studied regions. The optimal system is defined as the system with the lowest annual cost, where cost of the system is calculated as the sum of the annual capital and operational expenditures (including ramping costs) for all available technologie [Eq. (1)]. The transition simulation was performed for the period from 2015 to 2050 in 5-year time steps.

$$\min\left(\sum_{r=1}^{reg}\sum_{t=1}^{tech}(CAPEX_t\cdot crf_t + OPEXfix_t)\cdot instCap_{t,r} + OPEXvar_t\cdot E_{\mathrm{gen},t,r} + rampCost_t\cdot Ramp_{t,r}\right) \qquad (1)$$

Equation (1) describes the target function of the LUT Energy System Transition modelling tool for minimising annual costs. 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 ($E_{\mathrm{gen},t,r}$), 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 ($Ramp_{t,r}$).

The distributed generation and self-consumption of residential, commercial and industrial prosumers are included in the energy system analysis and defined by a special model describing the PV prosumer capacity development. The prosumers can install their own rooftop PV systems, lithium ion batteries, buy power from the grid in order to fulfill their demand, and sell electricity surplus. The target function for

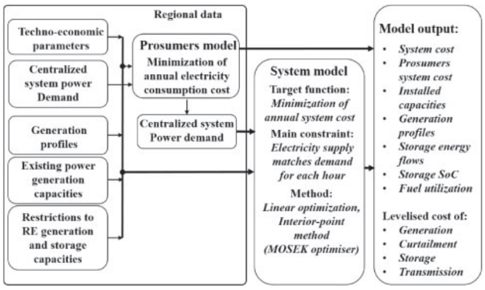


Fig. 1. Main inputs and outputs of the LUT Energy System Transition modelling tool.

prosumers is the minimisation of the cost of consumed electricity, calculated as a sum of self-generation annual cost and the cost of electricity consumed from the grid, minus the cost of electricity sold to the grid [Eq. (2)].

$$\min\left(\sum_{t=1}^{tech}(CAPEX_t \cdot crf_t + OPEXfix_t) \cdot instCap_t + OPEXvar_t \cdot E_{\mathrm{gen},t} + elCost \cdot E_{\mathrm{grid}} - elFeedIn \cdot E_{\mathrm{curt}}\right) \tag{2}$$

Abbreviations: generation and storage 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 of technology t ($instCap_t$), annual generation by technology t ($E_{\mathrm{gen},t}$), retail price of electricity ($elCost$), feed-in price of electricity ($elFeedIn$), annual amount of electricity bought from the grid (E_{grid}), annual amount of electricity sold to the grid (E_{curt}).

The share of consumers which are expected to be interested in their own generation gradually increases from 3% in 2015 to 20% in 2050. The flow diagram of the LUT Energy System Transition modelling tool from inputs to outputs can be found in Fig. 1. The full set of all technical and financial assumptions used in the modelling of the Northeast Asian energy transition is provided in the online supplementary data at http://stacks.iop.org/JJAP/57/08RJ01/mmedia (Tables S1–S7).

The energy system transition modelling for Northeast Asia was built with three important constraints:

- No new nuclear, coal, or oil-based power plants could be installed after 2015.
- RE capacity share cannot increase more than by 4% per year, 3% between 2015 and 2020.
- Hydro dam, run of river, and pumped hydro storage (PHS) capacities are refurbished every 35 years and never decommissioned.

Gas turbines can be installed after 2015 due to lower carbon emissions and the possibility to accommodate synthetic natural gas or bio-methane into the system.[9]

2.2 Applied technologies

The model has integrated all crucial aspects for the electricity system. For Northeast Asia, technologies introduced to the model can be classified into four main categories:

- Renewable Energy technologies based electricity generation
- Fossil and nuclear technologies based electricity generation
- Energy storage
- Electricity transmission

Fossil generation technologies are coal, oil based internal combustion engines (ICE), open cycle (OCGT) and combined cycle gas turbines (CCGT). RE technologies are solar PV (optimally fixed-tilted, single-axis north-south tracking, and rooftop PV), wind turbines, concentrating solar thermal (CSP), hydro power (run-of-river and dam), geothermal and bioenergy (solid biomass, biogas and waste-to-energy power plants). Storage technologies can be divided in three main category: short-term storage — Li-ion batteries and PHS, medium-term storage — adiabatic compressed air energy storage (A-CAES) and thermal energy storage (TES), and long-term gas storage including power-to-gas technology, which enables synthetic methane production for system use. The energy transition simulation takes into account the existing AC power grid of Northeast Asian regions, its development and impact on overall electricity transmission and distribution losses. Every country is modelled as an energy island — no power connections to other countries are possible. High voltage direct current (HVDC) and alternating current (HVAC) power lines are used to interconnect the regions only inside the countries, all country demand is covered by power generation of the respective country.

Figure 2 presents the block diagram of the energy system model and all technologies available for the energy transition in Northeast Asia.

2.3 Financial and technical assumptions

The financial and technical assumptions for applied technologies are generally taken from Pleßmann et al.,[10] European Commission,[11] and from other sources.[12–28] The financial and technical assumptions with references to data sources for all the energy system components are presented in the online supplementary data at http://stacks.iop.org/JJAP/57/08RJ01/mmedia (Tables S1–S4). Assumptions are made in 5-year time steps from the year 2015 to 2050. Weighted average cost of capital (WACC) is set to 7%, but for residential PV prosumers WACC is set to 4% due to lower financial return requirements. Electricity prices for residential, commercial and industrial consumers were derived according to Gerlach et al.,[29] and extended to 2050, and annual electricity generation demand (consumption plus power loss in local transmission and distribution grids) are presented in the online supplementary data at http://stacks.iop.org/JJAP/57/08RJ01/mmedia (Table S5). Excess electricity generated by prosumers is fed into the national grid and is assumed to be sold for a transfer price of 0.02 €/kWh. The model ensures that prosumers satisfy their own demand for electricity before feeding it to the grid.

2.4 Resource potential for renewable technologies

The Northeast Asian region is divided into 13 sub-regions: Mongolia, East and West Japan (with respect to 50/60 Hz AC grids utilisation), South Korea, North Korea, China divided into eight sub-regions: Northeast, North, East, Central, South, Northwest China, Tibet, and Uygur regions.

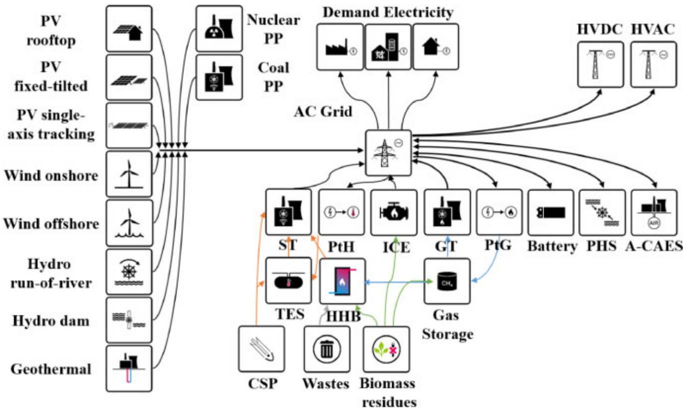


Fig. 2. (Color online) Block diagram of the LUT Energy System Transition modelling tool. This is composed of renewable energy sources, transmission options, storage technologies and demand sectors.

For each of these regions the model is based on defined capacity factors in hourly profiles for wind turbines, solar PV and hydro power plants, and data is structured for available biomass and geothermal resources.

The generation profiles for single-axis tracking, optimally tilted PV, solar CSP and wind energy were calculated according to Bogdanov and Breyer.[6] The hydro power feed-in profiles are computed based on the monthly resolved precipitation data for the year 2005 as a normalised sum of precipitation in the regions. The potentials for biomass and waste resources were taken from the DBFZ[30] and classified into three main categories: solid wastes, solid residues and biogas. The costs for biomass are calculated using data from the IEA[31] and Intergovernmental Panel on Climate Change (IPCC).[32] For solid waste a 50 €/ton gate fee was assumed for 2015, raising to 100 €/ton in 2050. Geothermal energy potential was calculated according to the method described in Gulagi et al.[33] Full load hours (FLh) for wind turbines, solar PV and hydro plants, as well as potentials of bio and geothermal energy are provided in the online supplementary data at http://stacks.iop.org/JJAP/57/08RJ01/mmedia (Table S6). A synthetic electricity demand profile till 2050 was created based on data from IEA.[34]

3. Results and discussion

3.1 Northeast Asian power system transition modelling

In just 35 years the power system of Northeast Asia can be transformed from the current, mostly fossil based system, to a 100% renewable energy system. The transition starts from the year 2015 and can be accomplished in evolutionary 5-years steps till the year 2050. Each of these steps results in a gradual change in the system, and all together in a radical transformation of the system from the 2015 state to a 100% RE based system. The regional electricity generation of 7,400 TWh in the year 2015 is composed of 58.6% coal, 14.3% fossil gas, 2.2% oil, 4.0% nuclear energy, 14.0% hydro power, 4.6% wind energy, 1.6% solar PV, 0.6% bioenergy, and 0.1% others (e.g., geothermal, CSP). In the year 2050 the generation demand will increase to 15,000 TWh, which will be comprised of 8.1% hydro power, 18.0% wind energy, 71.3% solar PV, 1.5% bioenergy, 0.3% others (e.g., geothermal, CSP), and 0.8% nuclear generation, which is assumed to be used till the end of the individual technical lifetime of existing nuclear power plants. An earlier phase-out of nuclear energy would be technically and economically possible based on respective political decision making, but had not been taken into account in this research. Figure 3 represents the evolutionary development of the electricity generation from 2015 to 2050 in 5-years intervals. In 2050, PV will be the major energy source in Northeast Asia on the whole and in most of the sub-regions. Total installed capacity of utility-scale PV and decentralised prosumers PV will reach 7400 GW. However, in the regions with outstandingly good wind conditions: Tibet and Northwest China regions, wind will be the most important energy source, providing more than half of all electricity produced. In total wind turbines will be the second major energy source with 920 GW capacity. The maps of PV and wind generation shares in Northeast Asia regions are presented in Fig. 4.

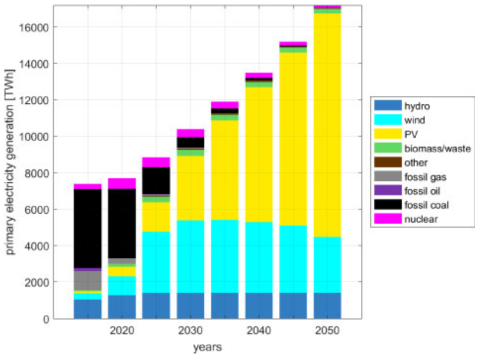


Fig. 3. (Color online) Evolutionary development of the electricity generation in Northeast Asia from 2015 to 2050 in 5-years intervals.

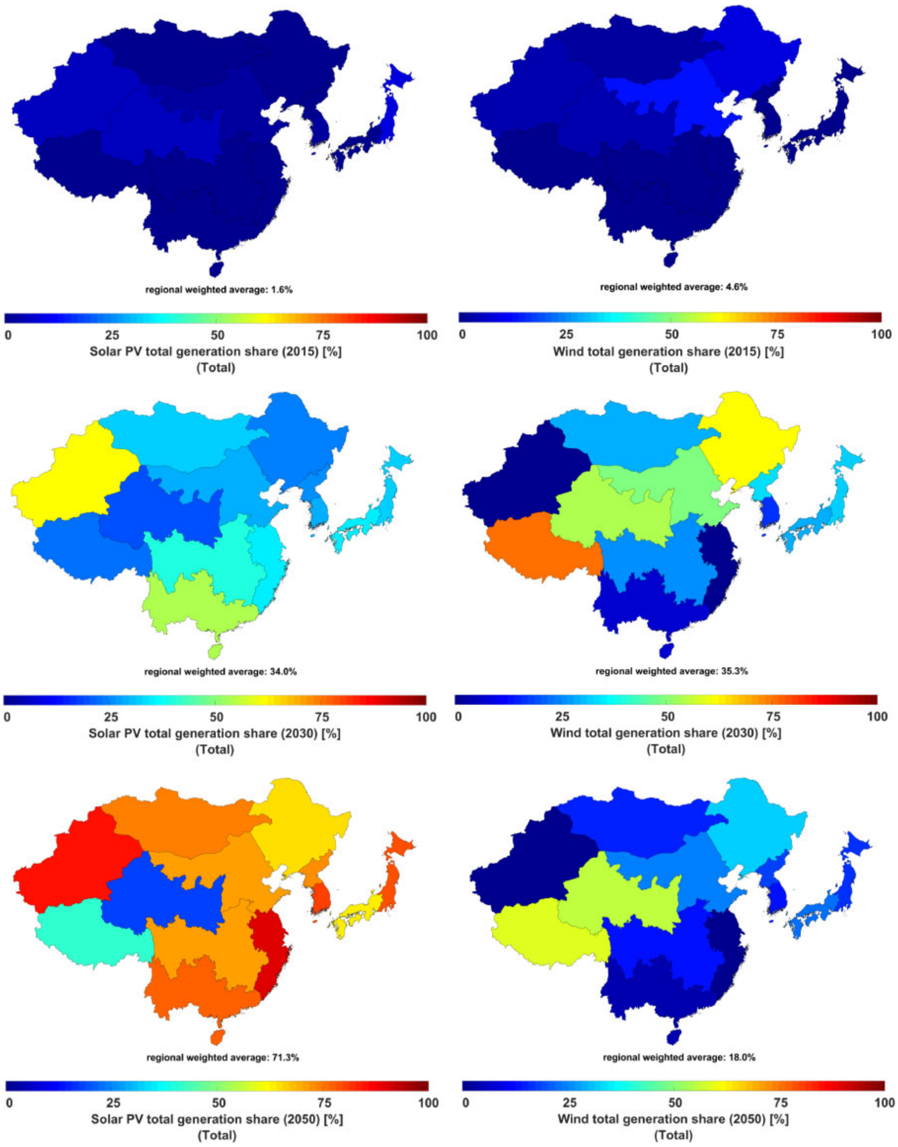


Fig. 4. (Color online) PV (left) and wind (right) generation shares in Northeast Asian regions in 2015 (top), in 2030 (center), and in 2050 (bottom).

The transformation of the power system will not lead to a higher cost of electricity in the system; actually the calculated cost of electricity production will decrease, from about 74 €/MWh in 2015 to 55 €/MWh in 2050. With the transformation towards a 100% RE system, electricity curtailment and storage costs will increase significantly; however, it will be compensated by much lower primary generation costs and eliminated fuel and CO_2 emission costs. The levelised cost of electricity over the transition process and its breakdown into primary energy generation cost, curtailment cost, storage cost and power transmission cost and into technologies are presented in Fig. 5.

All regions of Northeast Asia will benefit from the transition, but the cost of the electricity during the transition will strongly depend on the regional RE resources and the starting conditions of the system. The LCOE for all countries of Northeast Asia over the transition period are summarised in Table I. In almost all countries, after the small decrease of

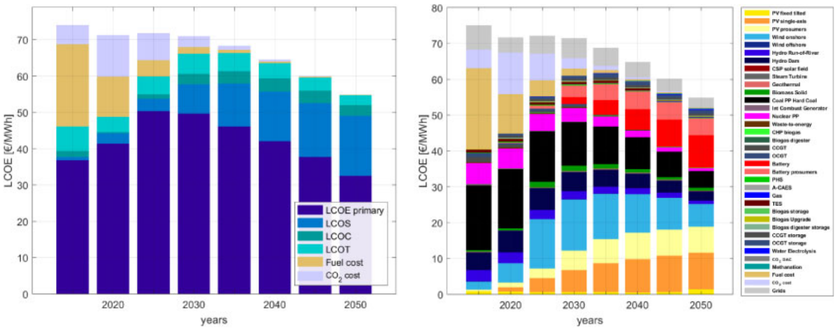


Fig. 5. (Color online) Levelised cost of electricity over the transition process from 2015 to 2050 in 5-years intervals for cost structure elements (left) and in technological resolution (right).

Table I. Country average LCOE (in €/MWh).

	2015	2020	2025	2030	2035	2040	2045	2050
Total	74.0	71.3	71.8	71.0	68.3	64.6	60.0	54.8
China	70.5	72.4	71.5	70.8	68.1	64.3	59.5	54.0
Japan	94.1	67.9	73.0	72.5	70.5	66.3	63.3	59.5
S. Korea	71.7	66.7	73.4	70.8	68.9	67.0	63.6	61.9
N. Korea	59.6	61.0	71.5	67.4	63.8	62.0	59.6	57.0
Mongolia	78.1	77.5	80.3	73.6	59.8	57.7	55.6	53.6

LCOE in 2020 mainly related to increased efficiency and decommissioning of extra old fossil capacity, in 2025 LCOE increases marginally due to massive investments to substitute decommissioned old fossil power plants. After 2025 electricity costs in all countries of the region constantly decrease. This decrease is explained by the continuous process of the RE technology development, that leads to cost decrease and efficiency improvement in all variable RE (VRE) technologies. Moreover, this is most importantly due to PV and battery technologies. After 2050 the LCOE is expected to continue to decline due to reinvestment of previously installed RE capacities.

China is the country that benefits the most from the energy transition. However, the transition of each sub-regional power system will be specific and will result in different levelised cost of locally produced electricity. The regional LCOE distribution for Northeast Asian sub-regions for the year 2050 is presented in Fig. 6. The highest electricity generation costs are observed in the regions with limited resources. Within China, the regions with moderate resources (East China and Uygur regions) have the possibility to import lower cost electricity from neighbouring regions with better RE conditions. Such regional energy systems will have higher shares of flexible generation and storage to balance imports and consumption profiles. That increases local generation LCOE, but leads to lower total cost of electricity consumed.

The power system structure transformation process will be evolutionary, but the optimal pathway will not be constant over the whole period. Due to a change of financial and technical parameters during the transition process, an optimal energy system development strategy will be different in every step. The process of the power system transition is shown in Fig. 7, which presents the cumulative and newly installed power generation capacities over the transition period. Initially the fossil and nuclear capacities represent almost 75% of total installed capacity, and the share of VRE — wind and solar generation capacities — is limited to 10%. The share of RE starts to grow fast after 2015, new RE capacities are built to both substitute aging fossil capacities and satisfy the growing energy demand of the region. During 2020 to 2025 most of the newly installed capacities are wind turbines, but after 2035 wind capacities do not grow anymore, and the share of wind energy in the mix starts to decrease after its maximum in 2030, when wind generation covers 35% of the regional electricity demand. PV capacities grow over the whole transition period and the share of PV reaches its maximum in 2050. Both utility-scale PV systems and decentralised prosumers PV are competitive options for Northeast Asia; however, the capacity of fixed-tilted PV power plants is limited and installations occurs only in 2045 to 2050. For the other periods single-axis tracking PV power plants are more competitive. Growth of RE based generation increases storage demand in the system. Before 2030, the impact of storage is limited, but later, when the share of

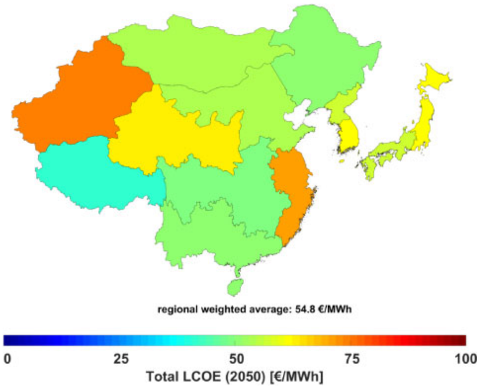


Fig. 6. (Color online) Levelised cost of electricity for Northeast Asian sub-regions for the year 2050.

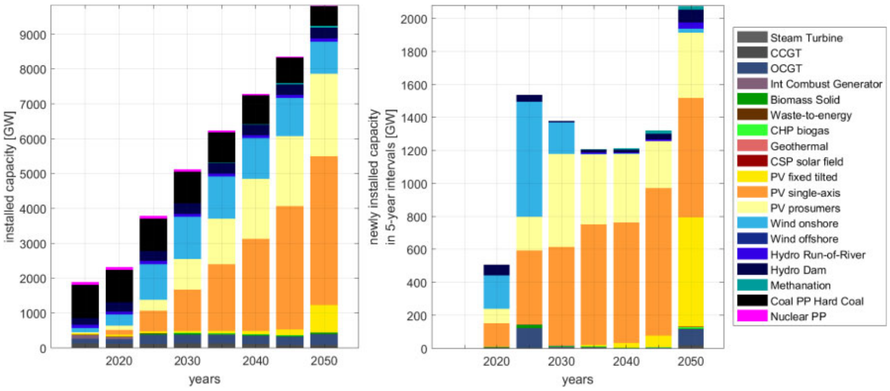
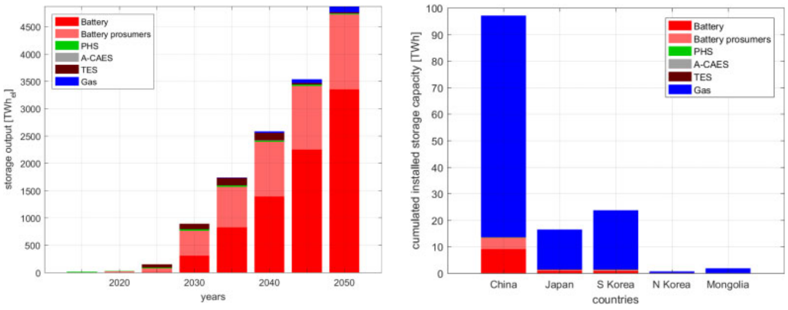


Fig. 7. (Color online) Cumulative (left) and newly (right) installed power generation capacities for Northeast Asia from 2015 to 2050 in 5-years intervals.



(a) (b)

Fig. 8. (Color online) Storage technology throughput from 2015 to 2050 in 5-years intervals (a) and cumulative energy storage capacity for 2050 by countries (b).

VRE sources exceeds 50% of the capacities mix, storage installation and utilisation starts to continuously grow. From an annual throughput point of view, diurnal battery storage dominates the system. Throughput of the gas storage is much smaller, however enough to compensate seasonal resource and demand variations. Nonetheless, from an energy storage capacity point of view, needed gas storage capacity far exceeds all other energy storage capacities, which is explained by different operation modes–seasonal gas storage has only one full cycle over the year. The storage technology throughput breakdown for different storage technologies over the transition process and the countries' storage capacities for the year 2050 are presented in Fig. 8.

The transition process in every country of Northeast Asia has its own specifics, related to local RE resources availability, demand growth during the transition, and the initial power system structure. The cumulative and newly installed power generation capacities over the transition period for China, Japan, South Korea, North Korea, and Mongolia are presented in Figs. 9–13. The Chinese power system transition is very similar to the process observed for the whole region (Fig. 9): fast growth of wind and solar capacities between 2020 and 2035, and an increasing role of PV after 2035. In Japan very significant capacities of wind turbines are installed in the years 2020 to 2030 (Fig. 10), and most prosumer PV is installed in the same period of time. In South Korea massive RE capacity installations are shifted to later periods of time — most of new capacities are installed only after 2030 (Fig. 11). Most of the installed PV capacities after 2040 are fixed-tilted PV power plants. In North Korea the transition process starts from substituting old coal generation capacities mainly with gas turbines and biomass power plants. Later the transition trajectory is similar to China: wind investments in the first decade and a focus on solar PV after 2030 (Fig. 12). In Mongolia the transition starts with utility-scale PV investments, and only during 2025 to 2030 significant capacities of wind energy are installed (Fig. 13). Full data on installed cumulative capacities and net electricity generation by various power sources; installed capacities and net output of various storage sources during the energy transition from 2015 to 2050 for China, Japan, South Korea, North Korea, and Mongolia are presented in the online supplementary data at http://stacks.iop.org/JJAP/57/08RJ01/mmedia (Tables S7–S11).

An optimal mix of the power system capacities guarantees that for every hour of the year the electricity demand will be

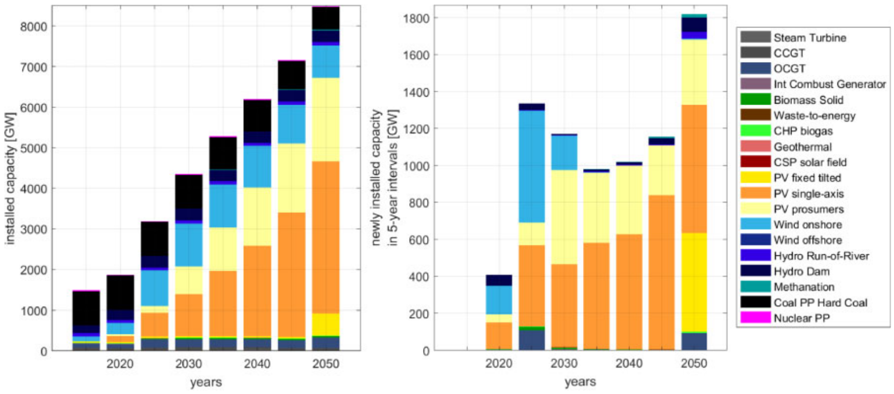


Fig. 9. (Color online) Cumulative (left) and newly (right) installed power generation capacities for China from 2015 to 2050 in 5-years intervals.

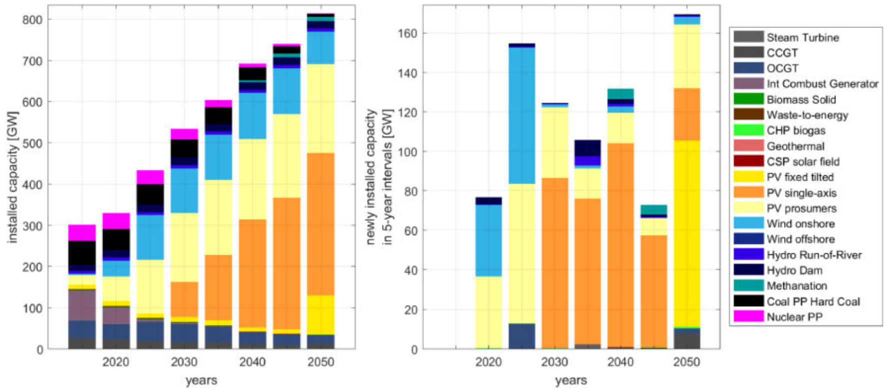


Fig. 10. (Color online) Cumulative (left) and newly (right) installed power generation capacities for Japan from 2015 to 2050 in 5-years intervals.

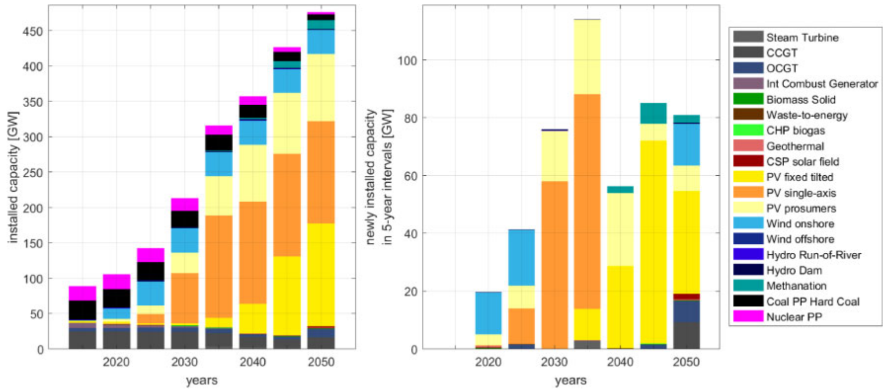


Fig. 11. (Color online) Cumulative (left) and newly (right) installed power generation capacities for South Korea from 2015 to 2050 in 5-years intervals.

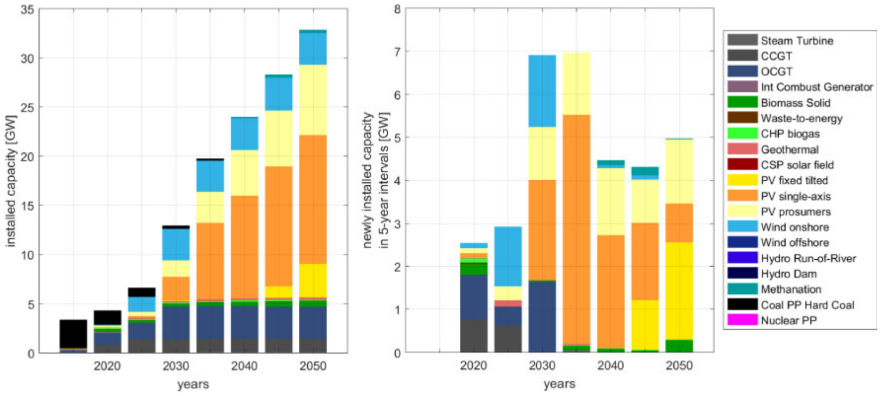


Fig. 12. (Color online) Cumulative (left) and newly (right) installed power generation capacities for North Korea from 2015 to 2050 in 5-years intervals.

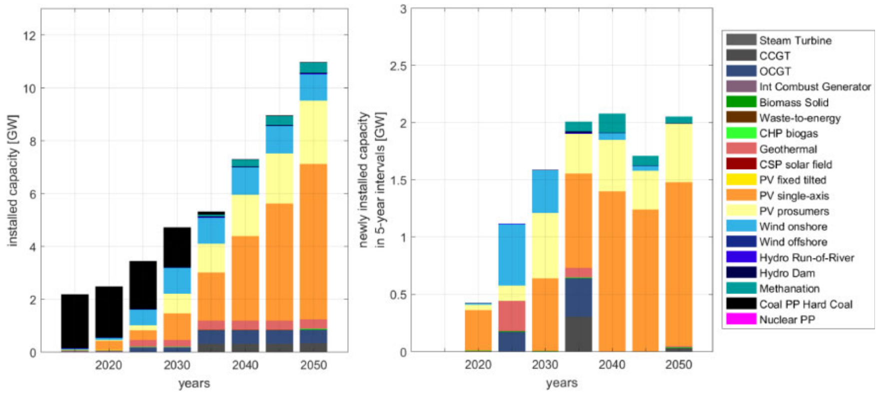


Fig. 13. (Color online) Cumulative (left) and newly (right) installed power generation capacities for Mongolia from 2015 to 2050 in 5-years intervals.

covered with the least cost electricity supply. In the future energy system all the system elements must work in an optimally dispatched way to reach a maximum synergy. Solar PV and wind will become the backbone of the system, but the role of all other elements will be extremely important. Flexible RE generation such as hydro reservoirs, biomass power plants and storage discharge will support the system during periods of VRE deficit. During VRE surplus, energy will be used for storage charging or sent to neighbouring regions. Hourly stability of the system will demand synchronous operation of all system elements. An example of hourly operation for a 100% RE system in Northeast Asia, built for 2030 assumptions,[6] can be investigated on the Internet of Energy website.[35]

The power system transition will demand high investments in new generation, storage and power transmission capacities. The peak of investments will be reached in the 2020s — the time that significant amounts of old fossil capacities will reach their end of lifetime and must be decommissioned. Later on, the amount of investments in new generation capacity will decrease; however, the demand in new storage capacities will result in additional capital expenditures. Between 2035 and 2045 investments stabilise at a level of around 160 b€/a. In 2050 investments will increase due to necessary reinvestment capacities built in the 2010s and 2020s. In the nearly 100% RE systems (as one can see for 2045 to 2050) half of investments should go to primary generation and half to storage technologies. Capital expenditure requirements during the transition and a breakdown into technologies are presented in Fig. 14.

As a result of the transition process, the Northeast Asian power system is transformed to a nearly 100% RE based system (the generation share of nuclear energy at a level of 0.8% is negligible and neither technically nor economically necessary, but a simple consequence of the applied technical lifetimes). That leads to a complete decarbonisation of the power system. However, most of the decarbonisation happens in the first 15 years: CO_{2eq} emissions per unit of electricity consumption decreases by 92% from 544 $kgCO_{2eq}/MWh$ in 2015 to 43.5 $kgCO_{2eq}/MWh$ in 2030. At the same time absolute emissions decrease only by 90%, from 4007 $MtCO_{2eq}$ to 451 $MtCO_{2eq}$ in 2030. Both absolute and

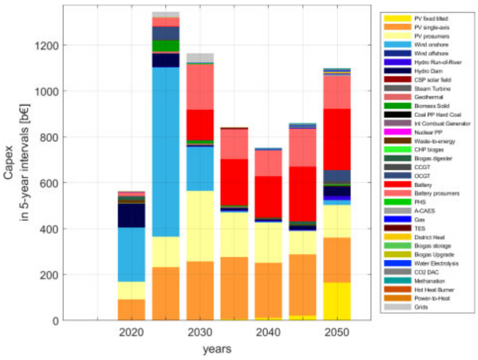


Fig. 14. (Color online) Capital expenditures including reinvestments for Northeast Asia from 2015 to 2050 in 5-years intervals.

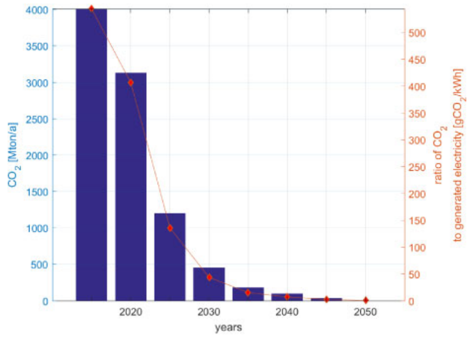


Fig. 15. (Color online) Absolute and relative CO_{2eq} emissions from 2015 to 2050 in 5-years intervals.

relative CO_{2eq} emissions decrease by 99% by 2045. The absolute and relative CO_{2eq} emission results during the transition process are presented in Fig. 15.

The future power sector will be the central element of the entire future energy system. Electricity will emerge as the integrating energy platform for the whole energy system, bridging mobility, heating/cooling, industrial and desalination sectors. The power sector will provide electricity for charging vehicles, production of synthetic fuels and chemicals. In addition, many industrial processes can be electrified, which will lead to an additional decrease of greenhouse gas emissions. The decarbonisation of the power sector will be the driver for the decarbonisation of all other sectors and the main step towards a carbon neutral and sustainable energy system.

3.2 Impact of initial conditions on the countries power systems transition

The transition strategies in all countries of Northeast Asia follow the same pattern: steady growth of the RE generation capacities, with an initially high role of wind energy in 2020 to 2030 and dominance of PV later on. In all countries, PV becomes the major energy source. However, the power system transition process has its specifics in each country, and each of the key parameters: RE resources availability, demand growth over the transition period and initial system structure has its impact.

The availability of RE resources influence both the trajectory and the result of the transition. Obviously, regions with great wind conditions will rely on wind generation to a greater extend, as it can be seen in Tibet. Regions with better solar conditions will have a higher share of PV generation. At the same time, limits on the maximum installation capacity can also influence the system structure. In South Korea wind turbine generation is the least cost solution; however, due to high population density and lack of enough area, the upper limit of wind turbine installation is reached in 2025, and later mainly PV is installed to compensate for both fossil capacities decommissioning and growing power demand. In all regions, wind capacities are growing fast before 2030, while wind generation cost is comparable to PV in all countries. Later, with continued cost decrease of PV and battery storage capacity, PV becomes the least cost solution in most of the regions and gains a predominant share in newly installed capacities beyond 2030. In 2050 in China wind energy capacities even decrease, because decommissioned turbines are substituted with PV capacities.

That shows the impact of the initial system structure. Countries with a high share of ageing capacities tend to install high amount of new wind turbines in the first years of the transition, while PV is less competitive. In the countries with a more modern capacity mix, reinvestment happens more steadily at later periods of time, when PV becomes more competitive.

Other aspects to consider are the grid structure and the country size. As presented in Table I, China benefits from the transformation the most: the electricity cost decreases by 25% from 2020 to 2050, and reaches 54 €/MWh in 2050, at the same level as Mongolia, the country which has access to both the excellent solar and wind resources of the Gobi desert. The availability of wind and solar resources across China is very diverse: the Inner Mongolia region has access to both excellent solar and wind resources, excellent wind conditions are available in Central China. However, in the major consumption centres of East and South China, both wind and solar resources are comparably moderate. This is mostly compensated by grid integration of Chinese regions, and such integration is beneficial for all regions. While some regions get access to lower cost imported electricity, others get demand for their electricity generation surplus, and overall system efficiency increases. A study of the integration benefits for a 100% RE system for Northeast Asia showed that the whole region will benefit from even more integration, and integration will lead to an additional power system cost decrease.[6)]

Countries with fast electricity consumption growth also benefit from the power system transition. Continuous development of RE and storage technologies leads to a significant cost decrease during the transition period. Growing demand motivates the system to install new capacities with lower primary generation cost and the levelised cost of generated electricity decreases.

4. Conclusions

The transformation of the Northeast Asian power system towards 100% RE generation is technically feasible and economically viable. The full transformation can be achieved by 2050 at a low electricity generation cost level of about 55 €/MWh, which will be 25% lower than the average electricity generation cost calculated for 2015. In 2050 every country in the region can satisfy the projected local power demand with local RE resources. However, LCOE in every country of the region will be different due to region specific conditions: around 54 €/MWh in China and Mongolia, 60 €/MWh in Japan, 62 €/MWh in South Korea and 57 €/MWh in North Korea. The lowest LCOE can be achieved in countries with access to excellent solar, wind and hydro resources. Power grid integration and constantly growing power demand are factors which also lead to a decrease of the total cost of the power system.

For every country the transition trajectory and results of the power system structure transformation will be specific and will strongly depend on available RE resources and initial system structure, but in every country PV will become the major energy source, providing more than 70% of all generated electricity. The total capacity of PV, comprised of utility-scale PV power plants and decentralised prosumer PV capacities, will reach 7400 GW, almost 100 times higher than in 2015. Wind energy will be the second major energy source with a generation share of about 18% and a capacity of 920 GW.

The results clearly show that a very deep decarbonisation of the power sector can be accomplished before 2050, 90% of CO_{2eq} emissions can be avoided after 2030 and 95% after 2040, respectively. Decarbonisation of the power sector is not only possible from technical, economic and societal points of view, but also results in the least cost energy system.

Acknowledgments

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Publication IV

Bogdanov D., Farfan J., Sadovskaia K., Aghahosseini A., Child M., Gulagi A., Oyewo A.S., de Souza Noel Simas Barbosa L., and Breyer C.

Radical transformation pathway towards sustainable electricity via evolutionary steps

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Radical transformation pathway towards sustainable electricity via evolutionary steps

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A transition towards long-term sustainability in global energy systems based on renewable energy resources can mitigate several growing threats to human society simultaneously: greenhouse gas emissions, human-induced climate deviations, and the exceeding of critical planetary boundaries. However, the optimal structure of future systems and potential transition pathways are still open questions. This research describes a global, 100% renewable electricity system, which can be achieved by 2050, and the steps required to enable a realistic transition that prevents societal disruption. Modelling results show that a carbon neutral electricity system can be built in all regions of the world in an economically feasible manner. This radical transformation will require steady but evolutionary changes for the next 35 years, and will lead to sustainable and affordable power supply globally.

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Several milestones have recently been reached that are indicative of growing environment risk: average global temperature[1], greenhouse gas (GHG) concentrations, and GHG emission levels[2] have all hit highs for the industrial era. Further, there are increasing reports of climate deviations around the globe[3], and coral reefs represent the first major planetary ecosystem under threat of major collapse[4–6]. It has become impossible to ignore the challenge of climate change given the magnitude of evidence, and society is more focused on climate change mitigation. The Paris Agreement[7] was an important first step towards united energy policy[4]. Fossil fuel-related GHG emissions were recognized as a major cause of global warming, a key characteristic of the Anthropocene era[8] and a major threat to the future of civilization. Global society and its leaders recognize the need for a transition towards sustainable energy systems in order to limit climate change and guarantee future development[9]. This awareness has resulted in increased interest in and focus on renewable energy (RE), further accelerated by the latest IPCC SR1.5 report[10]. And increasing numbers of energy scenarios consider RE as a major part of the energy system in the decades to come[11–21]. While the International Energy Agency (IEA) shows vision inertia and constantly underestimates the role of RE in its World Energy Outlook (WEO) scenarios[10], as discussed in Creutzig et al.[15]. Other organizations are more visionary. Greenpeace shows much higher reliance on RE in its Advanced [r]evolution scenario[12,13]. Based on the historical impact of decreasing costs and rapidly increasing installations, Haegel et al.[14], Creutzig et al.[15] and Pursiheimo et al.[16] expect solar photovoltaics (PV) to emerge as a main source of electricity in the future with terawatt (TW) scale installed capacities[17], and others ponder the role of RE in their scenarios[4]. Lastly, 100% RE-based energy systems are discussed as a feasible solution in different regions of the world and globally, as listed by Brown et al.[18]. Further, Jacobson et al.[19] reported the possibility of satisfying global energy demand with only renewable energy, while Breyer et al.[20] showed in hourly resolution that electricity supply based fully on RE is possible, for attractive cost, and for all regions globally for 2030 assumptions. The International Renewable Energy Agency is the first international governmental institution which confirms that electricity supply very close to 100% RE can be expected for major countries and economic rims in 2050, in particular China, EU, and India[22].

Thus, currently available generation and storage technologies are sufficient for nearly 100% power system operation. Available RE energy resources are adequate to satisfy current and future power sector demand in every region of the world[20]. The remaining challenges are the stability of an energy system with a low share of rotating generation machinery and the societal acceptance of the RE technologies. An RE-based system will have lower physical inertia and will not be able to mitigate a short-term imbalance of generation and demand. However, a lack of physical inertia in a system with a high RE share can be overcome with the integration of synthetic inertia, essentially improved algorithms of power converters of RE generation and storage capacities[23]. A recent synthetic inertia investigation for a 100% renewable power system for sub-Saharan Africa confirmed the attractiveness of this approach[24]. Raw material scarcities can be limiting factors for some technologies in the future, as lithium for lithium batteries, or dysprosium and neodymium for wind turbines with permanent magnet drives. However, in all these fields alternative technologies exist, using alternative raw materials (i.e. non-lithium ion batteries[25], electrically excited synchronous generators and others in wind turbines[26]). For silicon-based PV, representing more than 95% of the annually added solar PV capacity, the main raw materials from a mass content point of view are silicon (for glass and semiconductor material) and aluminum, two of most abundant elements in the Earth's crust. Mass content of doping materials is negligible. Silicon solar cells often use silver, but this is not mandatory, as documented by the high-efficiency PV cells of SunPower. In total, there is no material limitation known to produce these capacities of PV.

Societal acceptance is a more uncertain aspect. In our work we assume that up to 6% of regional area can be used for PV system installations, 4% of area can be used for wind farm installations, hydro generation capacities can be increased at most by 50%. The latter is mainly related to the commissioning of under construction capacities and repowering of old hydropower plants. Social acceptance of technologies varies over time and cannot be derived or estimated by techno-economic analysis. All major concerns about the technical feasibility and economic viability of 100% renewable systems, which still persist, are summarized by Brown et al.[18].

The aforementioned scenarios are fully or partly limited in temporal resolution, spatial resolution, speed of defossilization, energy transition pathway description, cost efficiency, and technological scope. Therefore, a new methodology was needed that overcomes these limitations.

Accordingly, a simulation is carried out on a global scale using the LUT Energy System Transition model. The world is structured into nine major regions: Europe, Eurasia, Middle East and North Africa (MENA), sub-Saharan Africa (SSA), South Asian Association for Regional Cooperation (SAARC), Northeast Asia, Southeast Asia and the Pacific Rim, North America, and South America. In total, the world is divided into 145 subregions (Supplementary Table 1), balanced to represent comparable shares of global power demand, population and land area. Both hourly resolution and the regional structure are considered to avoid underestimating RE source variability.

The modeled transition starts from the existing power system structure as of 2015, and existing capacities are decommissioned only after reaching their technical lifetimes[27]. The speed of RE capacity deployment is limited to avoid an unrealistically fast transition and is based on empirical data[27]. For each transition step, linear optimization of the power system is performed, with a target of minimum annualized system cost under given constraints. The annual cost includes annualized capital expenditures (capex), operational expenditures, ramping costs for each technology, fuel costs, and GHG emission costs. The final step of the transition process is to reach a 100% sustainable and carbon neutral energy system, independent of fossil and nuclear fuel supply. Nuclear energy is not considered as sustainable energy in this analysis due to high societal risk, unsolved radioactive waste problems, and substantial economic issues[28,29]. However, existing plants are operated until the end of their technical lifetimes. Contrary to other scenarios[30], it is shown that nuclear energy is unnecessary for effective climate change mitigation.

Results

Existing power sector and RE potential. Fossil fuels are the backbone of the present global energy system, contributing to 65% of all electricity generated[11]. Most existing RE is generated by hydropower (16%), while solar PV (1.2%) and wind energy (4%) contribute less[11]. However, solar PV and wind energy show high compound annual capacity growth rates of 48% and 21% for the period 2006−2016, and 33% and 12.5% in 2016[31], respectively, and their high technical potentials of 87.5–2770 $\mathrm{PWh_{el}}$ (solar PV) and 23.6–161 $\mathrm{PWh_{el}}$ (wind energy)[32] are distributed over the planet much more evenly than hydropower or fossil resources. Still, some regions have better wind conditions, some excellent solar irradiation, and some benefit from available hydropower potential or substantial biomass resources. Every region has unique climatic conditions and RE potentials, which will lead to specific optimal structures of respective 100% RE systems.

The energy transition will depend not only on RE resource conditions, but also on how various RE sources complement each other in different regions. Some regions, like MENA, have an excellent and stable solar resource, which will lead to high shares of solar PV, likewise for all Sun Belt countries. Eurasia has a harsh continental climate with cold winters, during which electricity demand strongly increases while PV generation decreases. Meanwhile, wide plains of Eurasia are ideal for wind energy generation; high wind speeds lead to low generation cost, while low population density enables the installation of large-scale capacities. Europe, despite its small size, includes highly different regions: windy Britain, Norway with abundant hydropower potential, the sunny Iberian Peninsula and Balkans, and most other countries with a mix of these extremes. Regional descriptions, data on RE resources potentials applied in this research, installed capacity limits for RE and the projected power demand for all 145 regions are presented in Supplementary Tables 1–4, respectively.

Existing capacity structures also vary globally. Some regions rely mostly on coal capacities (e.g. Poland, Kazakhstan, India, Mongolia), which lead to very high GHG emissions. Others mainly rely on gas generation (e.g. Argentina, Belarus, Egypt, Algeria). Some countries have already integrated significant capacities of PV and wind into their power systems (e.g. Italy, Spain, Germany, Denmark, Uruguay), and some have built substantial hydropower capacities (e.g. Norway, Iceland, Myanmar, Laos). By the age structure of installed capacities, regions can be divided into two: first, regions with growing installation rates of new power generation capacity, and second, regions where maximum installation rates have already been surpassed. In Europe and Eurasia, the peak of capacity growth has already passed, and the share of gas-based electricity generation is high. On the other hand, Northeast Asia and the SAARC region have coal-based power supply with fast growing capacities. Recently, RE capacity shares have grown rapidly[27,31]. However, huge coal capacities installed in recent decades will burden the transition process.

The transition process will depend on many parameters, such as regional economic situations, social acceptance of fossil fuels, nuclear energy and renewables, and political concerns[33], but most importantly on future electricity generation costs. Financial and technical assumptions for all applied technologies and data sources are presented in Supplementary Tables 5–8 in the Supplementary Material. The cost assumptions of RE technologies consider major trends in learning curves and increasing adoption rates that have a huge impact on future scenarios. The falling costs of renewable electricity generation and supporting storage technologies will be the driving force of the energy transition: solar PV has already become the least cost energy source in many regions of the world[30], and this decline is expected to continue[14]. Continued storage cost decrease[34,35] will make 100% renewable electricity systems highly cost competitive.

The modeling was performed using the LUT Energy System Transition model. Future electricity consumption assumptions are based on IEA estimations[36] and represent the development of the existing power sector without consideration of possible additional electricity demand due to massive electrification of heat and transport sectors, as discussed for the case of Europe[37]. Solar and wind resource assumptions are based on a NASA database and recalculated for the case of currently widely available RE generation technologies (PV with 15% efficiency and Enercon E-101 turbines). Further details on available RE resources, power demand, technical and financial assumptions, for all observed technologies, are represented in Supplementary Tables 2–8.

Future uncertainty. All the parameters influencing the future system development and energy cost are uncertain including political will, societal acceptance, and the cost of energy system elements. With the techno-economic approach, we assume that political and societal will follow the common good: low-cost and sustainable energy supply. Cost assumptions for the technologies are based on a set of reliable sources, as presented in the Supplementary Material. However, we also apply a ±10% cost range for the most important generation technologies: solar PV and wind power plants, since the cost development for these is well studied. For most important storage technologies: battery storage and power-to-gas system elements (electrolyzers, CO_2 direct air capture and methanation units), we assume a wider range of ±30%, since these technologies have not yet reached technical maturity.

Other aspects are unforeseen costs and cost overruns. Sovacool et al.[38] show that hydropower plants and nuclear reactors have the highest probability and magnitude of cost overruns (71% and 117% cost increase, respectively), much higher than for thermal power plants (13%). Cost overruns for modern renewables are much lower: 8% for wind power plants and 1% for solar PV power plants. For power storage technologies, such statistics are unavailable so we assume 10% cost escalation for power storage projects. In total, cost overruns of the system can reach 6% in 2050, weighted according to the mix of technologies.

A major factor of uncertainty can be the cost of capital, which is set for this research to a uniform weighted average cost of capital of 7%. This can deviate to higher values reflecting higher risk, but also to lower values. The latter has been recently observed for the case of solar PV and wind power plant investments in Germany, which have been reported for weighted average cost of capital of 2.5% and 2.75%[39], respectively, assuming a standard 30% equity and 70% debt financing.

For simplicity, cost diagrams are given for the median costs of technologies presented in the Supplementary Material and without additional unforeseeable costs.

Transformation towards 100% renewable electricity. Modeling results show that a 100% carbon neutral RE-based electricity system is possible by 2050. Such an energy system is economically feasible, at a levelized cost of electricity (LCOE) of 52 €/MWh (uncertainty range 45–58 €/MWh), less than the present 70 €/MWh. Solar PV will be the main source of electricity, generating almost 70% of all electricity, and wind nearly 18%. Diverse RE resource availability and starting system configurations will result in different system transitions. Modeled regional energy systems are classified into four groups (see global overview in Fig. 1). Shares of solar PV, wind turbines and power plants in total electricity generation during transition is shown in Supplementary Figs. 1–3. Each of the 145 systems is unique, even the systems of the same type still have substantial differences. For instance, India and Saudi Arabia are both located in the Sun Belt and have PV-based energy systems; however, Indian monsoons will increase the mid-term share of wind and storage technologies[40] compared to Saudi Arabia, which has a more stable solar resource[41].

Results show the global generation capacities in 2050 will exceed 28 TW, of which 22.0 TW will be solar PV and 3.2 TW will be wind turbines, representing about 39,130 TWh and 10,160 TWh of solar PV and wind electricity generation. Accordingly, solar PV capacity increases by about 100 times compared to 2015, and wind energy capacity by about 8 times. Achieving this will be challenging but manageable[14]. In 2030, the global generation capacities for solar PV will be around 7 TW, which is within the expectation of Haegel et al.[14] and consistent with recent actual installation growth rates, whereas the solar PV generation in 2050 is very close to the results of Creutzig et al.[15], who consider the full energy system. Hydropower capacities will not grow that significantly, only about 25%, which mostly represents commissioning of current under construction capacities (18%) and repowering and modernization of existing hydropower plants, mainly due to the limited potential of unexploited hydro resources, negative impacts of large-scale hydropower projects[28,42] and decreasing competitiveness to solar PV and wind energy. Contributions of other generation technologies, bioenergy and geothermal generation may be not significant on a global scale, but still important for some regions.

The other major structural change in the system is the role of storage, which becomes an inevitable element of the power system, supplying 31% of total electricity demand. The most important role will be played by battery storage, which complements the major energy source, solar PV. Diurnal Li-ion battery storage will be most important both from throughput and power capacity perspectives. Battery storage will reach about 8 TW power capacity and 48 $\mathrm{TWh_{cap}}$ of energy storage capacity, but seasonal gas storage will be the largest from a storage capacity perspective. About 1000 $\mathrm{TWh_{cap}}$ of gas storage capacity will be needed to compensate seasonal demand and generation fluctuations in high latitudes, which is comparable to the current gas storage capacity in Europe. On average, gas storage is used equally for storing biomethane from biomass sources and synthetic methane produced by power-to-gas units[43].

The range of LCOE for countries will be 27–70 €/MWh around a global average of 52 €/MWh (uncertainty range 45–58 €/MWh) for 2050. The lowest LCOE is reached in Iceland, a country with excellent geothermal energy and hydropower potential. The highest LCOE is recorded for Belarus, a country with moderate solar irradiation, moderate wind resources and limited hydropower potential. The global average cost of electricity generation in 2050 will be about 25% lower than for 2015. Moreover, after 2050 the cost will continue to decline a further 20% due to reinvestments in RE capacities, which saw cost declines during the transition. A global overview of LCOE by country is depicted in Fig. 2.

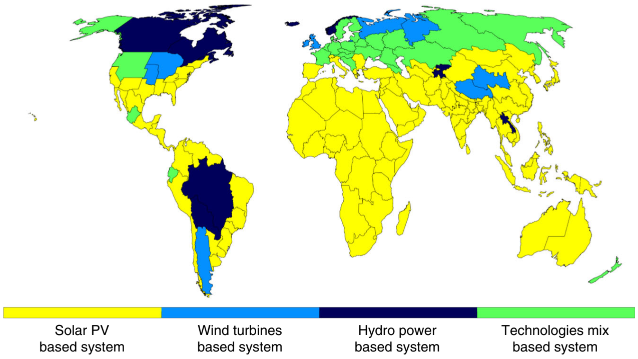

Fig. 1 Main types of 100% renewable electricity systems. Four main types of RE-based power systems are identified based on their main source of electricity (more than 50% share of electricity generation). If none of the technologies have a share exceeding 50%, then the type is defined as "Technology mix-based system"

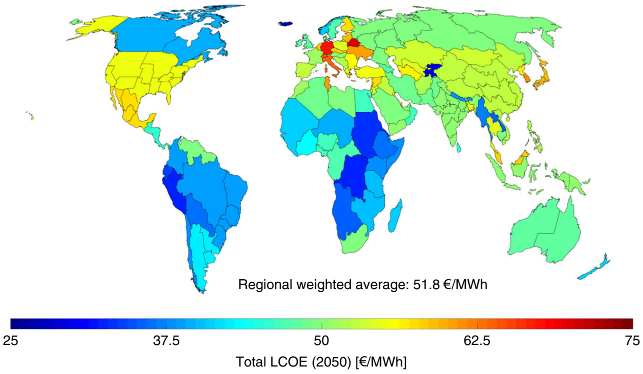

Fig. 2 Levelized cost of electricity for 100% renewable electricity systems in 2050. Country average numbers are presented. Numbers are calculated based on the generation mix for 2050 and financial and technical assumptions for all electricity system components. For countries divided in several regions, levelized cost of electricity is calculated as weighted average

The countries with dominance of dispatchable RE generation, like Iceland with hydropower and geothermal generation, or Tajikistan and Kyrgyzstan with high shares of hydro reservoirs, will have the lowest electricity generation cost globally. However, this does not mean dispatchable RE generation is a condition to have low LCOE in an RE-based system. For the year 2050, LCOE is very low in Brazil and equatorial countries with energy systems based on a mix of various energy sources. In these countries, the power system must include a well-developed transmission and distribution grid to provide access to the mix of resources distributed throughout the countries. Very low-cost levels for 100% renewable electricity can be reached in completely different conditions. Kenya, Uganda, Somalia, and Djibouti have limited access to dispatchable RE resources, and would have power systems based on variable RE sources, mostly solar PV. However, the total LCOE is low, at 35 €/MWh (uncertainty range 30–40 €/MWh). Climate conditions in such countries complement solar-based systems. Low seasonal demand fluctuation and an optimal diurnal solar cycle result in low long-term storage demand, so electricity can be supplied by mainly solar PV and limited battery storage.

Some developed countries, such as Germany, Italy, Switzerland, Japan, and Korea, have significantly higher LCOE than their neighbors. One of the reasons is the high activity of PV prosumers in these regions. PV prosumers generate electricity at higher cost, but it is still cheaper than buying electricity from distribution companies. At the same time, PV prosumers hardly buy electricity during peak production, which increases demand for storage and finally storage costs of the system. For Korea and Japan, high cost is also driven by very high population density, which limits deployment of area intensive wind energy. Very high electricity demand and limited area result in an energy resource mix that leads to higher cost of electricity compared to areas with lower population density. These issues may be solved with additional, progressive regulations of the prosumers in the first case, and higher social acceptance of renewables, in particular wind energy, in the future. This will enable decreasing electricity cost in some regions.

Radical transition in evolutionary steps. The transition towards a 100% renewable electricity system will demand radical changes in system structure. Technology and generation mixes will change drastically, while a new storage sector will emerge. At first, wind energy and solar PV capacities grow at similar rates. In most energy-intensive regions wind generation is the cheapest source of electricity for the first 5-year steps of the transition, while expensive storage limits PV integration. The ongoing cost decline of PV systems and battery storage makes PV substantially more competitive than wind energy in many regions. Particularly in the Sun Belt, this leads to growth stagnation of wind capacities beyond 2030 and most new capacities installed are PV.

Biomass and biogas are very valuable resources for the system through the whole transition period; however, their impacts are rather small because of limited sustainable biomass resources and the rather high cost of solid biomass resources[44,45]. We assume these to be on the level of about 1900 TWh for biogas and 6400 TWh for solid biomass residues and wastes. During the first steps of transition, biomass and biogas are used for baseload electricity generation. Later, as the growing share of RE generation results in an increased need for system flexibility, biomass capacities start to play a regulatory role, and biogas is converted to biomethane and stored in gas storage. Finally, biomethane and solid biomass show their highest value as dispatchable renewable energy sources. In 2050 all biogas is used for electricity generation, while only one-third of available solid biomass is used globally, mostly in the regions with high seasonality of RE resources and electricity demand.

Storage technologies emerge from very low levels to provide more than 15,000 $\mathrm{TWh}_{,\mathrm{el}}$ in 2050. Gas storage operates as seasonal storage and emerges quite early to store biomethane for gas turbines. At later transition stages SNG is also stored in the same storage due to the same chemical identity. Gas storage is highly important for countries with strong seasonal variations in generation and demand. For other countries, in particular in the Sun Belt, diurnal battery storage is far more important as it supports the PV-based system. Battery storage emerges around 2030, when the PV capacity share reaches 50%. Beyond 2030, battery capacity steadily grows with PV generation. Shares of batteries in the total power supply trough the transition are presented in Supplementary Fig. 4. The total electricity throughput of battery storage, however, is much higher than for gas storage, since batteries are operated daily, leading to around 300 full charge cycles per year, instead of less than two for gas storage due to seasonal discharge. The structure of the power capacities, generation, storage capacities and storage throughput for each 5-year step are presented in Fig. 3. Installed capacities and generation structure through the transition for the world and all major regions are presented in Supplementary Figs. 5–13 and numerically in Supplementary Tables 9–28.

The very high share of solar PV of about 70% in total electricity generation in the year 2050 implies a consideration in potential limitations. The solar resource is not limited since only a small fraction of total available solar resources are used. As well, only a relatively small amount of land is needed, thereof a considerable amount in zero impact areas, such as rooftops. Energetic sustainability is given since the energy payback time for newly installed systems is about 1 year in global average resource conditions[46] and expected to further decline, in particular due to the energetic learning curve for solar PV systems[47]. Fundamental material limitations are not known, since the major input materials are SiO_2 for glass and silicon, and aluminum and hydrocarbons for foils. Silver is used for charge carrier extraction in some PV technologies, but could be substituted by copper-based solutions. The industrial manufacturing capacities can be ramped up more quickly as markets grow[48], which is a major reason for the continued steep cost decline, and industrial proof that fast growing markets can be served.

The most challenging period of the transition is the 2020s. As very large fossil capacities are decommissioned, they are substituted by renewables. However, in Eurasia existing capacities are very old, since most were built before 1990, and complete substitution of these capacities with renewables so quickly is unlikely. In such regions, additional capacities of gas turbines are installed to balance supply and demand. Later these gas turbines become part of seasonal storage and use carbon neutral biomethane or SNG as fuel, providing 2% of global demand in 2050. The 2030s and 2040s see a more gradual transition, since decommissioned fossil capacities are substituted by new RE capacities, and the first large-scale RE reinvestments happen. Most defossilization happens before 2030, while the assumed GHG emissions price is low and should not have significant impact on the cost. Until then, old and inefficient coal capacities are retired, substituted by RE generation, and the fossil capacity role changes from more baseload power generation to auxiliary generation. Later GHG emissions price increases and the role of fossil-based generation proceeds to decline. By 2035, GHG emissions can shrink by 90% compared to 2015. Beyond 2035, the system evolves to cover the growing electricity demand in developing and emerging countries and reach even higher defossilisation levels. The final 5-year step to a sustainable and carbon neutral system is demanding, as the last amounts of fossil

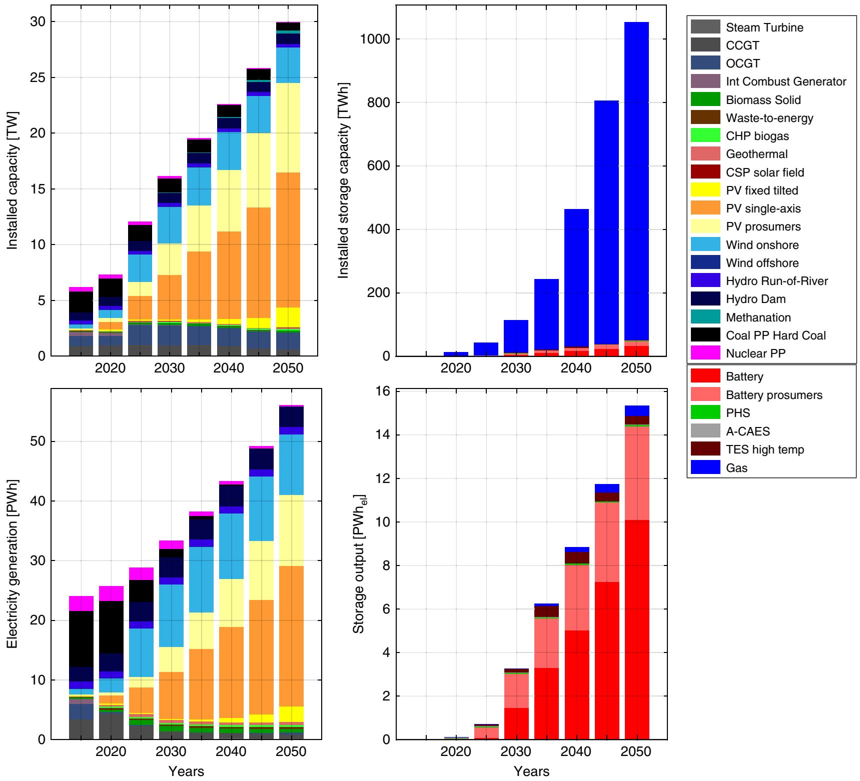

Fig. 3 Power and storage capacities, power generation and storage throughput from 2015 to 2050. During the first steps of the transition most of new installed capacities are represented by wind turbines, as the least cost source of electricity during this time in most regions. Later with cost decline of PV and battery storage technologies, and utilization of most efficient wind generation sites, the share of PV in new installed capacities becomes dominant. Some wind turbine capacities are reinstalled in the later periods of the transition to substitute decommissioned old turbines. Overall growth of cumulated installed capacities is initiated by both growth of the power demand and the generally lower FLh of RE sources. Substantial growth of storage technologies capacities starts after 2030, when the VRE generation share exceeds 50% in most of the regions. PV photovoltaics, RE renewable energy

fuels are the most challenging to substitute. The global GHG emissions for each 5-year step are presented in Fig. 4. GHG emissions for all major regions are presented in Supplementary Figs. 14–22 and Supplementary Table 29. The total LCOE decreases with growth in the RE share, which implies that storage extra cost is well compensated by the very low cost of renewable electricity generation. After a small increase in LCOE in the years 2025–2030 related to the integration of RE capacities, total LCOE decreases due to continued development of RE technologies and related RE capital expenditure reduction. This trend is observed globally. Significant decrease of transmission and distribution grid losses expected in developing countries[49] also lead to LCOE decrease. The global LCOE breakdown for each 5-year step is presented in Fig. 5.

During the transition, the electricity cost structure changes drastically. Initially, half of the system LCOE refers to capex of the generation (LCOE primary), one-third to fuel cost and the rest to interregional power transmission (LCOT), curtailment losses (LCOC) and to lower levels of GHG emission cost. The share of fuel cost decreases and becomes negligible after 2035, while the storage cost (LCOS) share grows due to increasing storage. At the same time, the share of capital and fixed operational expenditures in LCOE increases with the integration of higher shares of RE generation technologies, which have almost no fuel cost in comparison to traditional fossil-based generation. Major regions' LCOE breakdown for each 5-year step is presented in Supplementary Figs. 23–41.

Investments during the transition. The transition of the power sector will demand high capital expenditures (capex) of around 22.5 trillion € (uncertainty range 19–25.5 trillion €), or on average about 650 b€ per year. This is comparable to current investments in power generation, power transmission and fossil fuels for use in the power sector. In addition, it is significantly lower than the total energy system investment of 1308 b€ and global electricity investments of 552 b€ in 2016[51]. Capex in the power sector for all major regions for each 5-year step is presented in Table 1. The 2020s are the most challenging period due to a peak in old power capacity decommissioning. Lifetime extensions of old and inefficient fossil generation would seriously violate GHG emission limits and must not be allowed. All these capacities will be substituted by RE capacities or, in most extreme cases for a short intermediate period, by gas-fueled gas turbines. Capital expenditures breakdown by technologies for all major regions are presented in Supplementary Figs. 42–51.

During the 2020s capex spikes to about 900 b€ a year, and later stabilizes at about 600 b€ per year. However, the situation widely depends on the region and past energy policy. Additional costs due to cost overruns at the system average level of about 6% may have to be also considered. Regional transmission and distribution grid reinforcements may increase total capital expenditures by 10–15% dependent on the grid structure and level of demand centralization[17]. Regions with high shares of pre-1990, fossil-based capacities face the biggest challenges. Investment demand spikes in Eurasia and North America, with the highest share of lifetime extended capacities, while in Europe or South America the transition can be more balanced. Moreover, the consequences of past policy failures persist in the system even after 2030, as very large capacities installed in 2020 must be reinvested in 2050 and these waves of reinvestments remain for long periods. So, a late start of the energy transition and extension of business as usual policies will result in continued challenges in future. The transition would need to be even faster, and demand extra investments while conventional assets will most likely become stranded. The distorted investment cycle will remain longer. The system transition must be accomplished in the most optimal way, which will allow a fast but gradual evolution towards 100% renewables without major disruptions.

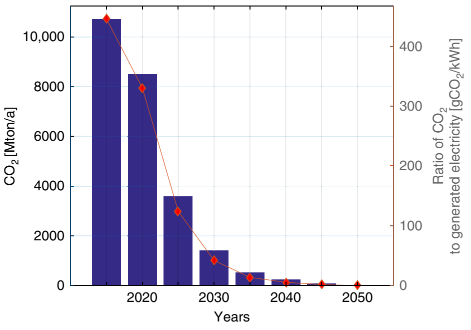

Fig. 4 Global GHG emissions for the transition period 2015−2050. According to the existing trends in energy system development[50], the possible decrease of GHG emissions by 2020 will not be reached, global emissions may increase in comparison to the 2015 value. GHG greenhouse gas

Energy system models towards higher share of renewables. Jacobson et al.[19], Sgouridis et al.[21], Löffler et al.[52], Pursiheimo et al.[16] and Teske et al.[12,13] also confirm that the global transformation towards RE-based systems is possible and affordable in economic and energetic terms. Different modeling approaches result in different shares of generation technologies in the global mix and GHG emission reduction trends, but they commonly recognize solar, wind and hydro as the most important energy sources. However, hourly resolution, latest cost trends, and an explicit focus on energy storage technologies, applied in this research, led to a much lower share of concentrating solar thermal power (CSP) plants and a higher relevance of solar PV. Integration of an electrified transport sector, electrical heating and cooling demand, and demand side management would help the system to accommodate even higher shares of PV[14]. This is confirmed by Pursiheimo et al.[16], who found an even higher solar PV share than in this study. However, due to the limited temporal resolution of the model used, they suggest carrying out detailed studies in higher temporal resolution to reduce uncertainties, which is the methodological core of this research. Jacobson et al.[19] show that 100% RE systems will positively impact society with several co-benefits: defossilization resulting in lower GHG emissions, heavy metal emissions and mortality rates. Furthermore, lower energy consumption results in no fossil fuel mining and transportation demands, and more jobs will be created than will be lost during defossilization. All aforementioned global energy transition studies leading to very high shares of RE or 100% RE are based on energy system models. However, these are

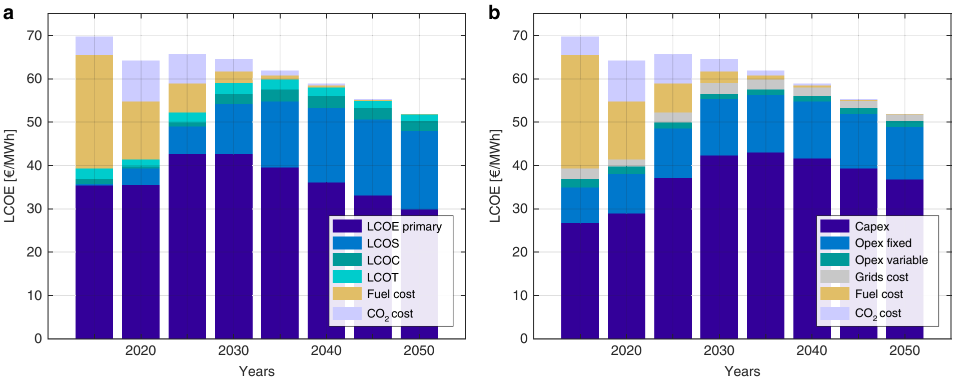

Fig. 5 Globally averaged electricity system LCOE for the transition period from 2015 to 2050. LCOE primary levelized cost of electricity generation, LCOS levelized cost of storage, LCOC levelized cost of curtailment, LCOT levelized cost of transmission. **a** Breakdown by system components. **b** Breakdown by cost components. The energy transition leads to lower cost electricity supply. Applied financial and technical assumptions do not consider any breakthrough in efficiency or cost development, only evolutionary improvements and extending existing trends (see Supplementary Material for assumptions and results for all major regions)

Table 1 Capital expenditures in the power sector for the transition from 2015 to 2050

Major region	Unit	Year						
		2015–2020	2020–2025	2025–2030	2030–2035	2035–2040	2040–2045	2045–2050
Europe	[b€]	374–436	520–649	381–491	360–465	330–444	308–393	267–338
Eurasia	[b€]	89–95	266–302	76–92	65–78	48–62	48–62	75–96
MENA	[b€]	120–130	318–364	273–372	208–303	134–197	134–190	159–216
SSA	[b€]	50–55	133–156	125–175	119–168	119–169	161–232	205–287
SAARC	[b€]	150–163	342–415	545–771	362–514	341–493	404–581	438–623
Northeast Asia	[b€]	517–608	1223–1466	988–1340	693–988	619–885	693–1026	917–1278
Southeast Asia	[b€]	121–134	274–330	336–477	281–397	183–262	241–345	307–413
North America	[b€]	344–386	1126–1345	598–802	379–512	277–405	250–368	205–288
South America	[b€]	166–188	111–141	94–132	73–96	92–127	109–146	115–155
Total	[b€]	1920–2182	4307–5162	3415–4649	2538–3518	2140–3040	2347–3340	2679–3683

Including power generation, storage and interregional transmission. Capex numbers are given for 5-year periods including the uncertainty range, i.e. annual numbers would be roughly one fifth
MENA Middle East and North Africa, *SSA* sub-Saharan Africa, *SAARC* South Asian Association for Regional Cooperation

not yet in full hourly resolution and also limited in their spatial resolution. Integrated Assessment Models (IAMs) are very strong in linking the energy system to physical systems of Earth, and require more reduction in complexity in the energy system. IAM results in the IPCC AR5[3] showed low levels of RE, which has been criticized and at least partly traced back to very conservative cost assumptions, in particular for solar PV[20]. Recent results of IAMs have taken this criticism into account, in particular the too conservative solar PV cost assumptions. As a result, they now confirm very high shares of renewables[15]. However, there is not yet a 100% RE study carried out with IAMs. The IPCC SR1.5[10] provides an excellent overview of the latest results of ambitious pathway analyses towards the 1.5 °C target of the Paris Agreement and high RE shares are about 78% in the median, whereas the maximum share reaches 97%. Assumptions of pathways towards 1.5 °C for these IAMs do not vary widely compared to this research. However, IAMs still lack insights for storage needs, grid demand, demand response and VRE resource complementarity, since these models are typically operated using annual energy balancing, i.e. no temporal resolution. This research can answer some of these questions due to the full hourly resolution, in particular for storage and resource complementarity. Another criticism of IAMs and energy system models is that such models would be too normative[53] and not arbitrary in assumptions and results. A common weakness of techno-economic energy models is a lack of proper description of social dynamics and technology diffusion.

Discussion

A global transition needs effort and investment, but each step can realistically lead to gradual, evolutionary change. A sustainable and carbon neutral electricity system based on 100% RE is technically feasible and economically viable globally by 2050 due to the reasonable total system LCOE (26–72 €/MWh) with a global average of 52 €/MWh (uncertainty range 45–58 €/MWh). Ongoing RE and storage cost decreases will position renewable electricity as the least cost source globally, and displace fossil fuel-based electricity, even with market mechanisms, unless the system is distorted by subsidies[54]. However, each regional energy transition will proceed rather uniquely. Each country will have a specific optimal electricity supply mix, but solar PV will become the dominating source of electricity globally. Beyond 2040, PV will generate more than half of global electricity demand, and almost 70% in 2050. The 2020s will be most challenging due to the substitution of very high capacities of newly retired fossil fuel and nuclear capacities, and high capex. The transition will require a capex of around 22.5 trillion € (uncertainty range 19–25.5 trillion €), which is comparable to current power sector-related investments. Lifetime extensions of old fossil capacities and investments in new ones would result in additional challenges that complicate system development. For decades the RE share has grown slightly. However, despite discussions about defossilization and decarbonization of the energy system, GHG emissions keep on growing. In order to fulfill the Paris Agreement requirements as well as the United Nation's Sustainable Development Goals, a greatly accelerated transition should be started soon.

Methods

Modeling tool. The transition modeling was performed with the LUT Energy System Transition model, which optimizes an energy system for given constraints. The simulation is applied for 5-year time periods for the years 2015−2050. For each period, the model defines a cost optimal energy system structure and operation mode for the given set of constraints: power demand, available generation and storage technologies, financial and technical assumptions, and limits on installed capacity for all applied technologies. The model is based on linear optimization and performed in an hourly resolution for an entire year (further details on the workings of the model along with the respective mathematical representation of the target functions can be found in Model section of Methods). The model ensures high precision computation and reliable results. The costs of the entire system are calculated as a sum of the annualized capital expenditures including the weighted average cost of capital (WACC), operational expenditures (including ramping costs), fuel costs and the cost of GHG emissions for all available technologies. The current model version is 2.0.

The LUT Energy System Transition modeling tool simulates and optimizes energy systems including the Power, Heat, and Transportation sectors, and additional Industry sectors, such as Industrial fuels production, Desalination and CO_2 removal. The simulation is performed in full hourly resolution for all hours of a year in single-year steps, where the starting conditions of the simulation depend on the time step assumptions and the previous time step results.

The purpose of the LUT Energy System Transition modeling tool is to assess different possible pathways of energy system development and assist global, national and regional energy strategy planning. Simulations allow investigation of the impact of different policies on the system structure, cost, emissions and the process of development. The model also tests the benefits of energy sectors integration (also called sector coupling), including the Power, Heat, Transportation and Industry sectors (for Industrial fuels production, Desalination and CO_2 removal), as well as evaluates the possibility of additional flexible demand option integration and its impact on the system. The model can be used for:

First, energy system development studies—simulation of the energy system transition from the current structure towards an optimized energy system: In such case, the simulation is performed for several time steps with specific financial and technical assumptions. The simulation starts from the existing energy system structure and the initial conditions of each time step are based on the system structure formed in previous steps. The results provide information on an optimized system structure and operation mode for each step, data on system cost, costs of all the products and elements, and GHG emissions of the system.

Second, feasibility studies—simulation of an optimized energy system structure and operation mode for the given technical and financial constraints: Instead of an energy transition, it is also possible to select an overnight approach, which can provide information on how a newly optimized energy system would look, built under given constraints.

Third, technical analysis—simulation of the system operation with given system structure, resource, technical and financial assumptions: Such simulations can be utilized for energy system robustness assessment to evaluate the range of conditions for which the system can satisfy the demand.

Modeling procedure. The first step of the energy system modeling is data preparation: defining the financial and technical assumptions. The structure of input data is described in the Input data section.

The second step is the scenario specification and simulation: available options are a transition scenario or overnight scenario. For each type of scenario, power, heat, transportation, and industry (industrial fuels production, desalination and CO_2 removal) sectors can be enabled. For the power sector, the simulation can be performed for a centralized system only or with the presence of power prosumers. For each type of simulation, three levels of regional integration can be applied: regional, country-wide, and area-wide. Regional: all regions (nodes) of the energy system are isolated. Country-wide: energy systems are integrated by transmission infrastructure, such as power grids, inside the same country. Area-wide: countries are integrated by transmission infrastructure for the selected area, typically a major region.

The third step is results preparation. After the end of the simulation, the tool collects the optimized results for all model elements in data files and summarizes the main data in a results Excel file. The description of the procedure and the structure of results file are given in the Results preparation section. The overall structure of the modeling procedure is given in Supplementary Fig. 52.

Energy systems operation. The model includes four energy sectors, each of which can also be simulated independently.

Energy systems operation—Power sector. The power sector is divided into a centralized energy system and a power prosumers subsegment. The share of electricity demand related to prosumers can be specified from 0 to 99% of total.

Centralized power system: In the centralized power system all consumption goes through the local AC grid to which the RE generation capacities (PV, wind, hydro, solar thermal electric, geothermal, biomass power plants), fossil and nuclear power plants, and fossil and biomass-based CHP plants are connected. At the same time, the local AC grid is connected to the storage capacities and interregional high voltage direct current (HVDC) and high voltage alternating current (HVAC) grids.

Power prosumers subsegment: PV prosumers represent three types: residential, commercial, and industrial. For each prosumer type, the share of total electricity demand (where the sum of residential, commercial and industrial is equal to the full power sector), grid electricity price, and financial assumptions for PV systems and batteries can be specified. Prosumers have the option to install their own PV generation capacities, Li-ion battery storage sell excess electricity to the centralized power system for a specified feed-in price or buy electricity from the centralized power system at a specified electricity cost. In the standard scenario the share of consumers willing to install their own PV generation capacities increases accordingly to a logistic function in steps of 3, 6, 9, 15, 18, and 20% of the respective segment electricity demand (if grid electricity is cheaper than that from PV generated, the share for the next step remains unchanged). If the power prosumer uses individual heating, generated power can also be used for electrical heating (heating rods and heat pumps). The simplified diagram of the power sector is presented in Supplementary Fig. 53.

Energy systems operation—Heat sector. The heat sector consists of six main segments: industrial high (>1150 °C), medium (100–1150 °C), and low (<100 °C) temperature heat demand, domestic water heating, space heating and cooking biomass demand. All heat shall be generated inside the region. The heat sector is also divided into centralized and individual heating systems.

All industrial heat must be covered by the centralized heat system, shares of centralized water and heating demand must be specified, and this must reflect the share of district heating specific for each region.

All biomass cooking, and the rest of water and heating demands are generated with individual heating systems.

The heat can be generated with CHP plants, solar thermal collectors, individual or centralized fuel-based boilers, electrical heaters, and heat pumps. Industrial high temperature heat demand can be satisfied only with fuel-based heat plants. Medium temperature heat can be also provided by electrical heating. Low temperature heat can also be satisfied by heat pumps, heating rods, solar thermal collectors and recovered heat loss from thermal power plants. Generated heat can be stored in medium or low temperature heat storage. The simplified diagram of the heat sector is presented in Supplementary Fig. 54.

Energy systems operation—transportation sector. The transportation sector is structured into the segments: road, rail, marine and aviation.

Within the road segment a separation is done for light duty vehicles, mainly cars; medium duty vehicles, such as delivery trucks; heavy duty vehicles; and buses. For the four road segments, the following powertrains are available: internal combustion engine, battery electric vehicle (BEV), hybrid plug-in vehicle (PHEV), and hydrogen-based fuel cell vehicles. The share of each type should be specified. BEVs and PHEVs are charged from the grid with “dump charge”—equally at every hour. Later model adjustments for “smart charge” and “vehicle-to-grid (V2G)” are planned.

Within the rail segment two fuel types are available: liquid hydrocarbon fuel (diesel), which can be fossil fuel, biofuel or renewable electricity-based Fischer-Tropsch (FT)-liquid fuel, and electricity. The shares of the fuels shall be selected according to respective projections.

Within the marine segment four fuel types are available: liquid hydrocarbon fuel (diesel), which can be fossil fuel, biofuel or renewable electricity-based FT-fuel; liquefied methane gas, which can be liquefied fossil natural gas, biomethane or renewable electricity-based methane (SNG); liquefied hydrogen (LH2), which is only foreseen as renewable electricity-based hydrogen, and electricity for shorter-distance domestic shipping.

Within the aviation segment three fuel types are available: liquid hydrocarbon fuel (kerosene), which can be fossil-based kerosene, biofuel or renewable electricity-based FT-kerosene; hydrogen, which is only foreseen as renewable electricity-based hydrogen; and electricity for shorter-distance flights.

The simplified diagram of the transportation sector is presented in Supplementary Fig. 55.

Energy systems operation—industry sector. The current model version includes the following industry sectors: industrial fuels production, desalination, and CO_2 removal. The inclusion of further industry sectors, such as cement, steel, chemical industry, metal refining and remaining industrial sectors, is planned for the future.

Industrial fuels production: The energy system can use fossil fuels, as long as it is allowed or affordable, convert biomass to biofuels, and produce renewable electricity-based synthetic fuels in the power, heat or transportation sectors. Currently hydrogen, methane and liquid hydrocarbons production units are integrated in the model.

Methane can be produced from biogas after its purification/upgrading. Then this biomethane can be used in the gas system. The share of biogas which can be upgraded is limited by the urbanization level of the region, but cannot exceed 70% even if the urbanization level is higher. A second option is synthetic natural gas (SNG)—methane produced with methanation reactors from hydrogen and carbon dioxide. The whole power-to-gas (PtG) system includes water electrolysis reactors (assumptions are based on alkaline technology) producing hydrogen from water, CO_2 direct air capturing (DAC) units collecting CO_2 and water from ambient air, and methanation units. Water electrolyzers and DAC units consume power from the system in order to produce H_2 and CO_2, and then methanation units convert them to synthetic CH_4.

Liquid hydrocarbons can be produced from biomass by biorefineries, or can be synthesized from H_2 and CO_2 using the FT process. PtG with gas storage and gas turbines can be part of storage for the power sector.

Fossil fuel refineries are not included in the model, and existing capacities of refineries are assumed sufficient to satisfy local consumption of fossil fuels.

The simplified diagram of the industrial fuels production sector is presented in Supplementary Fig. 56.

Desalination sector: Water demand in the region can be covered with Seawater Reverse Osmosis (SWRO) desalination, Multi-Stage Flash (MSF) and Multi-Effect Distillation (MED) technologies. The water is delivered to consumers by distributed piping systems with a respective energy demand, dependent on the distance and altitude from the coast. The water is stored at the production site, which may provide additional flexibility to the desalination system, and can optimize production in order to minimize total system cost. The simplified structure of the desalination sector is presented in Supplementary Fig. 57.

CO_2 removal sector: CO_2 removal demand can be specified for each region in tons of CO_2 per year. This amount of CO_2 will be captured from the atmosphere by DAC units in addition to CO_2 captured for synthetic fuels production. Heat and electricity needed for the DAC operation will be taken from the heat and power sectors, respectively. The simplified structure of the CO_2 removal sector is presented in Supplementary Fig. 58.

Integrated system: Every sector can be modeled individually or as several integrated sectors. Technologies such as PtG, electrical heating (heating rod, heat pumps), steam turbines, SWRO desalination, and FT-fuel production can operate as “bridging technologies” binding different sectors. Flexible power demand from the heat, transportation, industrial fuel production, desalination and

CO_2 removal sectors together with better energy management due to bridging technologies can lead to a significant increase in the integrated system efficiency and drop in the total system cost.

Energy system elements. All generation technologies are categorized into renewable-based, biomass-based, fossil-based power generation, renewable-based, biomass-based, fossil-based heat generation and fuel production technologies. Information on renewable-based power generation is summarized in Table 2. Information on biomass-based power generation is summarized in Table 3. Information on fossil-based power generation is summarized in Table 4. Information on renewable-based heat generation is summarized in Table 5. Information on biomass-based heat generation is summarized in Table 6. Information on fossil-based heat generation is summarized in Table 7. Information on fuel production technologies is summarized in Table 8.

All storage options can be divided into three main categories based on the typical energy-to-power ratio: diurnal (E/P ratio less than 24 h), mid-term storage (E/P ratio around 72 h), and long-term storage. Main information about storage technologies included in the model is summarized in Table 9.

Information on interregional power transmission technologies is summarized in Table 10. Information on water desalination and supply is summarized in Table 11.

Model. The energy system optimization model is based on a linear optimization of the system parameters under a set of applied constraints with the assumption of a perfect foresight of RE power generation and power demand. A multinode approach enables the description of any desired configuration of subregions and power transmission interconnections. The main constraints for the optimization are the matching of all types of generation and demand values for every hour of

Table 2 Renewable-based power generation

Technology	Name	Abbr.	Inputs	Output	Additional
Solar PV	Utility-scale optimally tilted	RPVO	Min and max capacity limits	Optimal installed capacity	
	Utility-scale single-axis tracking (North-South)	RPVA	Capacity factors profile	Power generation profile	
	PV prosumers Residential	RPVR			
	PV prosumers Commercial	RPVC			
	PV prosumers Industrial	RPVI			
Wind turbines	Onshore Modern	RWIN	Min and max capacity limits	Optimal installed capacity	
	Onshore Old[a]	RWIO	Capacity factors profile	Power generation profile	
	Offshore Modern	ROWI			
Hydro	Run-of-river	RRRI	Min and max capacity limits	Optimal installed capacity	
	Reservoir (Dam)	HDAM	Capacity factors profile	Power generation profile	Average size of reservoir in days
Geothermal	Utility-scale power	TGEO	Min and max capacity limits	Optimal installed capacity	
			Hourly geothermal heat influx	Power generation profile	
Solar thermal	Utility-scale power	TSTU	Min and max capacity limits	Optimal installed capacity	
			Hourly CSP heat production	Power generation profile	

[a] Modern onshore wind turbines have higher efficiency and respective higher capacity factors than old onshore wind turbines. All onshore wind turbines installed before 2015 are considered RWIO in order to avoid overestimation of existing turbine generation

Table 3 Biomass-based power generation

Technology	Type	Abbr.	Fuel	Inputs	Output
Biomass	Power	TBPP	Biomass residues	Min and max capacity limits	Optimal installed capacity
			Biomass waste	Energy conversion efficiency	Power and/or heat generation profile
	CHP	TCBP	Biomass residues	Available amount of fuel	
			Biomass waste		
Waste incinerator	CHP	TMSW	Municipal waste		
Biogas CHP	CHP	TCHP	Biogas		

Table 4 Fossil-fuel-based power generation

Technology	Type	Abbr.	Fuel	Inputs	Output
Gas	CCGT	TCCG	Natural Gas	Min and max capacity limits	Optimal installed capacity
	OCGT	TOCG	Biomethane	Energy conversion efficiency	Power and/or Heat generation profile
	CHP	TCNG	SNG	Available amount of fuel	
Coal	Power	THPP	Coal		
	CHP	TCCO			
Liquid hydrocarbons	Power	TICG	Fossil liquids		
	CHP	TCOI	biofuel		
			FT-synfuel		
Nuclear	Power	TNUC	Uranium		

Table 5 Renewables/power-based heat generation

Technology	Type	Abbr.	Inputs	Output	Additional
Solar thermal	Utility-scale CSP	RCSP	Min and max capacity limits DNI profile in [kWh/m^2]	Optimal installed capacity Heat generation profile	
	Residential heat collector	RRSH	Min and max capacity limits Capacity factors profile		
Electrical heating	District heat	TDHR	Min and max capacity limits	Optimal installed capacity	
	Indiv. heat	THHR	Energy conversion efficiency	Heat generation profile	
Heat pump	District heat	TDHP	Min and max capacity limits	Optimal installed capacity	
	Indiv. heat	THHP	Energy conversion efficiency	Heat generation profile	

Table 6 Biomass-based heat generation

Technology	Type	Abbr.	Fuel	Inputs	Output
Biomass heat	District heat	TDBP	Biomass residues Biomass waste	Min and max capacity limits Energy conversion efficiency	Optimal installed capacity Heat generation profile
Biomass heat	Indiv. heat	THBP	Biomass residues Biomass waste	Available amount of fuel	
Biogas heat	Indiv. heat	THBG	Biogas		

Table 7 Fossil-based heat generation

Technology	Type	Abbr.	Fuel	Inputs	Output
Gas	District heat Indiv. heat	TDNG THNG	Natural Gas Biomethane SNG	Min and max capacity limits Energy conversion efficiency Available amount of fuel	Optimal installed capacity Heat generation profile
Coal	District heat Indiv. heat	TDCO THCO	Coal		
Liquid hydrocarbons	District heat Indiv. heat	TDOI THOI	Fossil liquids biofuel FT-synfuel		

Table 8 Fuel production

Name	Abbr.	Inflow	Outflow	Inputs	Output
Water electrolysis	TWEL	Power	Hydrogen	Min and max capacity limits Energy conversion efficiency	Optimal installed capacity Hydrogen generation profile
CO_2 DAC	TCOS	Power	Carbon dioxide	Min and max capacity limits Energy demand for CO_2 production	Optimal installed capacity CO_2 generation profile
Methanation reactor	TMET	Hydrogen Carbon dioxide	Synthetic methane (SNG)	Min and max capacity limits Feedstock demand for methane production	Optimal installed capacity SNG generation profile
FT-reactor	TFTR	Hydrogen Carbon dioxide	Liquid hydrocarbons Naphtha	Min and max capacity limits Feedstock demand for fuel production	Optimal installed capacity FT fuel generation profile
Biorefinery	TBFR	Biomass Power	Bio Liquid hydrocarbons	Min and max capacity limits Feedstock demand for fuel production	Optimal installed capacity Bio fuel generation profile
Biogas separator	TBGU	Biogas	Biomethane	Min and max capacity limits Energy conversion efficiency	Optimal installed capacity Biomethane inflow profile
Biogas digester	TBGD	biomass	Biogas	Min and max capacity limits	Optimal installed capacity Biogas inflow profile

the applied year, and the optimization criteria is the minimization of the total annual cost of the integrated system (or a sector if only a sector is optimized). The hourly resolution of the model significantly increases the required computation time; however, it guarantees that for every hour of the year the total supply within a subregion covers the local demand and enables a more precise system description including synergy effects of different system components or sectors (sector coupling).

The optimization is performed in a third-party solver. At the moment, the main option is MOSEK ver. 8, but other solvers (e.g. Gurobi, CPLEX, etc.) can also be used. The model is compiled in the Matlab environment in the LP file format, so that the model can be read by most of the available solvers. After the simulation results are parsed back to the Matlab data structure and can be postprocessed for analyses and diagram preparation.

Model—target function. The target of the system optimization is the minimization of the total annual cost of the integrated system (or a sector if only a sector is optimized), calculated as the sum of the annual costs of installed

Table 9 Storage technologies

Name	Abbr.	Type	Inputs	Output
Utility-scale batteries	SBAT	Diurnal	Min and max capacity limits	Optimal installed capacity
Prosumer batteries (Residential)	SBAR	Diurnal	Charge and discharge Energy-to-power ratio	Charge and discharge profiles
Prosumer batteries (Commercial)	SBAC	Diurnal	Charge and discharge efficiency	
Prosumer batteries (Industrial)	SBAI	Diurnal	Self-discharge per hour	
Pumped hydro storage	SPHS	Diurnal		
Hot heat storage	SHOT	Diurnal		
Hydrogen storage	SHYD	Diurnal		
District heat storage	SDHS	Mid-term		
Biogas	SBGA	Mid-term		
Adiabatic compressed air storage	SACA	Mid-term		
Gas storage	SGAS	Seasonal		
Liquid hydrocarbons	SLIQ	Seasonal		

Table 10 Power transmission technologies

Name	Abbr.	Inputs	Output
HVAC Line	THAO[a]	Grid connections map	Optimal installed capacity of lines
HVDC Line	TRTL[a]	Min and max line capacity limits for connections	Energy flows profiles in both directions for lines
HVDC Converters station	TRCS	Efficiency	Power import exports profiles for regions

HVDC high voltage direct current, *HVAC* high voltage alternating current

[a] HVAC and HVDC line financial assumptions should be calculated for the expected structure of the regional grid with average shares of underground cables and above-ground lines

capacities of the different technologies, costs of energy and product generation, and production ramping. This target function includes annual costs of the power, heat, transportation, and industrial (industrial fuels production, desalination and CO_2 removal) sectors. The target function of the applied energy model for minimizing annual costs is presented in Eq. (1) and comprises all hours of a year using 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 ($\mathrm{OPEXfix}_t$), variable operational expenditures technology t ($\mathrm{OPEXvar}_t$), installed capacity in the region r of technology t ($\mathrm{instCap}_{t,r}$), annual generation by technology t in region r ($E_{\mathrm{gen}\ t,r}$), cost of ramping of technology t ($\mathrm{rampCost}_t$) and sum of power ramping values during the year for the technology t in the region r ($\mathrm{totRamp}_{t,r}$).

$$\min\left(\sum_{r=1}^{\mathbf{reg}}\sum_{t=1}^{\mathbf{tech}}(\mathrm{CAPEX}_t\cdot crf_t+\mathrm{OPEXfix}_t)\cdot\mathrm{instCap}_{t,r}+\mathrm{OPEXvar}_t\cdot E_{\mathrm{gen}\,t,r}\right.$$
$$\left.+\mathrm{rampCost}_t\cdot\mathrm{totRamp}_{t,r}\right). \tag{1}$$

The power prosumers and individual heating users system are realized in an independent submodel with a slightly different target function. The prosumer system is optimized for each subregion independently, even if the subregion is connected to neighbors inside the area. The target function includes annual costs of the prosumer power generation and storage, heating equipment, the cost of electricity required from the distribution grid and the cost of fuels required for boilers. Income of electricity feed-in to the distribution grid is deducted from the total annual cost.

The target function of the applied energy model for minimizing annual costs is presented in Eq. (2) and comprises all hours of a year using the abbreviations: generation and storage technologies (t, **tech**), capital expenditures for technology t (CAPEX_t), capital recovery factor for technology t (crf_t), fixed operational expenditures for technology t ($\mathrm{OPEXfix}_t$), variable operational expenditures technology t ($\mathrm{OPEXvar}_t$), installed capacity of technology t ($\mathrm{instCap}_t$), annual generation by technology t ($E_{\mathrm{gen}\ t}$), retail price of electricity (elCost), feed-in price of electricity (elFeedIn), annual amount of electricity required from the grid (E_{grid}), annual amount of electricity fed-in to the grid (E_{curt}).

$$\min\left(\sum_{t=1}^{\mathbf{tech}}(\mathrm{CAPEX}_t\cdot\mathrm{crf}_t+\mathrm{OPEXfix}_t)\cdot\mathrm{instCap}_t+\mathrm{OPEXvar}_t\cdot E_{\mathrm{gen}\,t}\right.$$
$$\left.+\mathrm{elCost}\cdot E_{\mathrm{grid}}+\mathrm{elFeedIn}\cdot E_{\mathrm{curt}}\right). \tag{2}$$

Model—energy balance constraints. The main constraint for the power sector optimization is the matching of the power generation and demand for every hour of the applied year as shown in Eq. (3). For every hour of the year the total generation within a subregion and electricity import cover the local electricity demand.

$$\begin{aligned}\forall h\in[1,8760]\quad&\sum_{t}^{\mathbf{tech}}E_{\mathrm{gen}\,t}+\sum_{r}^{\mathbf{reg}}E_{\mathrm{imp}\,r}+\sum_{t}^{\mathbf{stor}}E_{\mathrm{stordisch}\,t}\\&=E_{\mathrm{demand}}+\sum_{r}^{\mathbf{reg}}E_{\mathrm{exp}\,r}+\sum_{t}^{\mathbf{stor}}E_{\mathrm{storch}\,t}+E_{\mathrm{curt}}+E_{\mathrm{other}}\end{aligned} \tag{3}$$

Eq. (3) describes constraints for the energy flows of a subregion. Abbreviations: hours (h), technology (t), all modeled power generation technologies (**tech**), subregion (r), all subregions (**reg**), electricity generation (E_{gen}), electricity import (E_{imp}), storage technologies (**stor**), electricity from discharging storage ($E_{\mathrm{stordisch}}$), electricity demand (E_{demand}), electricity exported (E_{exp}), electricity for charging storage (E_{storch}), electricity consumed by other sectors (heat, transport, desalination, industrial fuels production, CO_2 removal) (E_{other}), curtailed excess energy (E_{curt}). The energy loss in the HVDC and HVAC transmission grids and energy storage technologies are considered in storage discharge and grid import value calculations.

The heat sector energy balance is defined by three equations: for industrial high temperature heat demand, for industrial high and medium temperature heat demand, and all centralized heat demand. High temperature heat can only be generated by fuel-based boilers (Eq. (4)). Medium temperature heat can also be generated by electrical heating and can be stored in high temperature heat storage and used to produce electricity with steam turbines (Eq. (5)). Low temperature heat can also be provided by heat pumps, electric heating rods and waste heat from other technologies (Eq. (6)).

$$\forall h\in[1,8760]\sum_{t}^{\mathbf{techHH}}E_{\mathrm{gen}\,t}\geq E_{\mathrm{demandHH}}, \tag{4}$$

$$\begin{aligned}\forall h\in[1,8760]\quad&\sum_{t}^{\mathbf{techHH}}E_{\mathrm{gen}\,t}+\sum_{t}^{\mathbf{techMH}}E_{\mathrm{gen}\,t}+E_{\mathrm{stordisch}}\\&\geq E_{\mathrm{demandHH}}+E_{\mathrm{demandMH}}+E_{\mathrm{storch}}+E_{\mathrm{other}}\end{aligned}, \tag{5}$$

$$\forall h\in[1,8760]\sum_{t}^{\mathbf{tech}}E_{\mathrm{gen}\,t}+\sum_{t}^{\mathbf{stor}}E_{\mathrm{stordisch}}=E_{\mathrm{demand}}+\sum_{t}^{\mathrm{stor}}E_{\mathrm{storch}}+E_{\mathrm{curt}}+E_{\mathrm{other}}. \tag{6}$$

Abbreviations: hours (h), technology (t), high temperature heat generation technologies (**techHH**), medium temperature heat generation technologies (**techMH**), all heat generation technologies (**tech**), industrial high temperature heat demand (E_{demandHH}), industrial medium temperature heat demand (E_{demandMH}), total centralized heat demand, including industrial, and space heating and water heating demand (E_{demand}).

Power and heat sector constraints for prosumers have some minor differences. Prosumers can buy electricity from electricity distribution companies

Table 11 Water desalination and supply technologies

Name	Abbr.	Inflow	Outflow	Inputs	Output
Reverse Osmosis Seawater Desalination	WROD	Power	Water	Min and max capacity limits Desalination efficiency Water demand profile	Optimal installed capacity Water desalination profile
Multi-Stage Flash Stand alone	WMSS	Power Heat	Water	Min and max capacity limits Desalination efficiency Water demand profile	Optimal installed capacity Water desalination profile
Multi-Stage Flash Cogeneration	WMSC	Gas	Water Power	Min and max capacity limits Desalination efficiency Water demand profile	Optimal installed capacity Water desalination profile
Multi-Effect Distillation Stand alone	WMDS	Power Heat	Water	Min and max capacity limits Desalination efficiency Water demand profile	Optimal installed capacity Water desalination profile Power
Multi-Effect Distillation Cogeneration	WMDC	Gas	Water Power	Min and max capacity limits Desalination efficiency Water demand profile	Optimal installed capacity Water desalination profile
Water storage	SWAT	Water	Water	Min and max capacity limits Water demand profile	Optimal installed capacity Charge and discharge profiles
Horizontal pumping	WHPU	Power		Water demand profile	Optimal installed capacity Pumping power demand profiles
Vertical pumping	WVPU	Power		Water demand profile	Optimal installed capacity Pumping power demand profiles

(Eq. (7)). Heating of prosumers based on individual heaters includes fuel, RE and electricity-based heaters, but there is no individual heat storage option (Eq. (8)).

$$\forall h \in [1,8760] \sum_{t}^{\mathbf{tech}} E_{\mathrm{gen}\,t} + \sum_{t}^{\mathbf{stor}} E_{\mathrm{stordisch}} = E_{\mathrm{demand}} - E_{\mathrm{grid}} + \sum_{t}^{\mathbf{stor}} E_{\mathrm{storch}} + E_{\mathrm{curt}} + E_{\mathrm{other}}, \tag{7}$$

$$\forall h \in [1,8760] \sum_{t}^{\mathbf{tech}} E_{\mathrm{gen}\,t} = E_{\mathrm{demand}} + E_{\mathrm{curt}}. \tag{8}$$

Abbreviations: hours (h), technology (t), all modeled power generation technologies (**tech**), energy generated (E_{gen}), storage technologies (**stor**), energy from discharging storage ($E_{\mathrm{stordisch}}$), energy demand (E_{demand}), electricity energy for charging storage (E_{storch}), electricity consumed by heating (E_{other}), excess energy (E_{curt}).

Model—power and heat generation. The renewable-based power and heat generation is defined by historical capacity factors for this technology and the optimal installed capacity of this technology (Eq. (9)).

$$\forall h \in [1,8760]\, E_{\mathrm{genRE}\,h} = \mathrm{CF}_{\mathrm{genRE}\,h} \cdot \mathrm{instCap}_{\mathrm{genRE}}. \tag{9}$$

Abbreviations: hour (h), energy generated by renewable-based generation technology (E_{genRE}), capacity factor of the technology ($\mathrm{CF}_{\mathrm{genRE}}$), installed capacity in the region of the technology ($\mathrm{instCap}_{\mathrm{genRE}}$).

The fuel-based power and heat generation defined by the optimal installed capacity for this technology (Eq. (10)), availability factor for this technology (Eq. (11)), this technology used fuel available (Eq. (12)), and efficiency of the technology (Eq. (13)).

$$\forall \mathrm{h} \in [1,8760] E_{\mathrm{genFU}\,h} \leq \mathrm{instCap}_{\mathrm{genFU}}, \tag{10}$$

$$\sum_{h}^{8760} E_{\mathrm{genFU}\,h} \leq 8760 \cdot \mathrm{AF}_{\mathrm{genFU}\,h} \cdot \mathrm{instCap}_{\mathrm{genFU}}, \tag{11}$$

$$\sum_{h}^{8760} \mathrm{FU}_{\mathrm{genFU}\,h} \leq \mathrm{totalFU}_{\mathrm{genFU}}, \tag{12}$$

$$\forall h \in [1,8760] E_{\mathrm{genFU}\,h} = \mathrm{FU}_{\mathrm{genFU}\,h} \cdot \mathrm{eff}_{\mathrm{genFU}}. \tag{13}$$

Abbreviations: hour (h), energy generated by fuel-based generation technology (E_{genFU}), installed capacity in the region of the technology ($\mathrm{instCap}_{\mathrm{genFU}}$), availability factor of the technology ($\mathrm{AF}_{\mathrm{genFU}}$), fuel consumption for the hour h ($\mathrm{FU}_{\mathrm{genFU}\ h}$), annual fuel consumption for the hour h ($\mathrm{totalFU}_{\mathrm{genFU}\ h}$), energy conversion efficiency for technology ($\mathrm{eff}_{\mathrm{genFU}}$).

For all technologies, capacity is calculated in output units. For cogeneration the capacity is given in electrical units. For some types of fuel (municipal wastes, industrial biomass wastes, biogas) all available fuel must be consumed for sustainability reasons. Biogas inflow in the system is constant and biogas can be stored only for 48 h.

Model—power and heat storage. Storage technologies are described as energy storage capacity and storage interface capacity. Energy storage capacity limits the maximum state of charge (SoC) of the storage technology and the amount of energy stored (Eq. (14)), while the storage interface capacity limits the maximum power of charge and discharge (Eqs. (15) and (16)). The energy balance constraint for storage technologies is given in Eq. (17).

$$\forall h \in [1,8760] \mathrm{SoC}_{\mathrm{stor}\,h} \leq \mathrm{instCapEn}_{\mathrm{stor}}, \tag{14}$$

$$\forall h \in [1,8760]\, E_{\mathrm{storch}\,h} \leq \mathrm{instCapInt}_{\mathrm{stor}}, \tag{15}$$

$$\forall h \in [1,8760] E_{\mathrm{stordisch}\,h} \leq \mathrm{instCapInt}_{\mathrm{stor}}, \tag{16}$$

$$\forall h \in [1,8760] \mathrm{SoC}_{\mathrm{stor}\,h} = \mathrm{SoC}_{\mathrm{stor}\,h-1} \cdot \mathrm{selfDisch}_{\mathrm{stor}} + E_{\mathrm{storch}\,h} \cdot \mathrm{eff}_{\mathrm{storch}} - E_{\mathrm{stordisch}\,h} / \mathrm{eff}_{\mathrm{stordisch}}. \tag{17}$$

Abbreviations: hour (h), storage state of charge for an hour h ($\mathrm{SoC}_{\mathrm{stor}\ h}$), installed energy capacity of the storage ($\mathrm{instCapEn}_{\mathrm{stor}}$), installed power capacity of the storage ($\mathrm{instCapInt}_{\mathrm{stor}}$), charging energy of the storage for an hour h ($E_{\mathrm{storch}\ h}$), discharging energy of the storage for an hour h ($E_{\mathrm{stordisch}\ h}$), hourly self discharge of the storage ($\mathrm{selfDisch}_{\mathrm{stor}}$), charge efficiency ($\mathrm{eff}_{\mathrm{storch}}$), discharge efficiency ($\mathrm{eff}_{\mathrm{stordisch}}$).

Model—power transmission. Power transmission is represented by HVDC and HVAC grids. Each line of the grid is bidirectional, but represented in the model as two unidirectional lines: import and export. Capacities of import and export lines are equal to the total power capacity of the interconnection, as shown in Eq. (18). Hourly export/import energy for a subregion is calculated as the sum of all import lines multiplied by this line transmission efficiency minus the sum of all export line energy flows, as shown in Eq. (19). The efficiency of energy transmission by HVDC lines depends on the distance and AC/DC converter pair efficiency, as shown in Eq. (20). The efficiency of energy transmission by HVAC line depends only on distance, as shown in Eq. (21). For both HVDC and HVAC the distance-related losses are calculated in a simplified way.

$$\forall h \in [1,8760]\mathrm{line}_{\mathrm{import}\,h} \leq \mathrm{instCap}_{\mathrm{line}};\ \mathrm{line}_{\mathrm{export}\,h} \leq \mathrm{instCap}_{\mathrm{line}}, \tag{18}$$

$$\forall h\ \in\ [1,8760]E_{\mathrm{exp/imp}\,h} = \sum_{l}^{\mathbf{lines}} \mathrm{line}_{\mathrm{import},l,h} \cdot \mathrm{eff}_l - \sum_{l}^{\mathbf{lines}} \mathrm{line}_{\mathrm{export},l,h}, \tag{19}$$

$$\mathrm{eff}_l = \mathrm{eff}_{\mathrm{CS}} \cdot (1 - \mathrm{distance} \cdot \mathrm{EffLoss}), \tag{20}$$

$$\mathrm{eff}_l = 1 - \mathrm{distance} \cdot \mathrm{EffLoss}. \tag{21}$$

Abbreviations: hour (h), line (l), energy flow through the power line (line), installed capacity of the power line ($\mathrm{instCap}_{\mathrm{line}}$), exported/imported energy for the region for an hour h ($E_{\mathrm{exp/imp},h}$), total energy import efficiency (eff_l), converter pair efficiency ($\mathrm{eff}_{\mathrm{CS}}$), charge length of the line (distance), energy loss in the line (EffLoss).

Model—transportation. Transportation demand is expressed in (metric) ton kilometers (t-km) and passenger kilometers (p-km). Power and fuel consumption for a given mix of transportation means is included in the power, heat and gas (H_2, CH_4) balance equations on the demand side.

Model—industrial sector. Fuel production: The energy system can produce GHG neutral methane for the needs of the power, heat, transportation and industry sectors. The first option is upgrading the available biogas to biomethane. The amount of upgraded biogas cannot be more than the urbanization level of the region, but not more than 70% of all biogas. Biomethane can be stored in the gas storage. The second option is power-to-gas. Hydrogen produced with water electrolysis and CO_2 from DAC units are used as raw materials for the methanation units. Produced SNG can be also stored in the gas storage.

Desalination: In case that desalinated water demand exists in the region, the system has to provide the demanded amount of water every hour. Water storage on the supply side provides flexibility to the system. Desalination units are located on the seashore and they can optimize work in order to decrease the total system cost. The water demand and water storage balance are described in Eqs. (22)–(23).

Water desalination units produce water and store it in water storage. Desalinated water production is limited by optimal capacities of enabled desalination plants and storage technologies (Eqs. (24)–(25)). Power, heat and gas consumption for desalination unit operation as shown in Eqs. (26)–(28) are included in the power, heat and gas balance equations on the demand side. The water pumping electricity demand according to Eq. (29) and cost is calculated based on the pumping capacity of the system, hourly water demand, weighted average length and head of the piping system.

$$\forall h \in [1,8760] \sum_{t}^{\mathbf{tech}} W_{\mathrm{des}\,t,h} + W_{\mathrm{stordisch}\,h} - W_{\mathrm{storch}\,h} = W_{\mathrm{demand}\,h}, \tag{22}$$

$$\forall h\ \in\ [1,8760]\mathrm{SoC}_{\mathrm{stor}\,h} = \mathrm{SoC}_{\mathrm{stor}\,h-1} + W_{\mathrm{storch}\,h} - W_{\mathrm{stordisch}\,h}, \tag{23}$$

$$\forall h\ \in\ [1,8760] W_{\mathrm{des}\,t,h} \leq \mathrm{instCapDes}_t, \tag{24}$$

$$\forall h\ \in\ [1,8760]\mathrm{SoC}_{\mathrm{stor}\,h} \leq \mathrm{instCapStor}, \tag{25}$$

$$\forall h\ \in\ [1,8760]E_{\mathrm{heat}\,h} = \sum_{t}^{\mathbf{tech}} W_{\mathrm{des}\,t,h} \cdot \mathrm{heatCons}_t, \tag{26}$$

$$\forall h\ \in\ [1,8760]E_{\mathrm{el}\,h} = \sum_{t}^{\mathbf{tech}} W_{\mathrm{des}\,t,h} \cdot \mathrm{elCons}_t - \sum_{t}^{\mathbf{tech}} W_{\mathrm{des}\,t,h} \cdot \mathrm{elProd}_t, \tag{27}$$

$$\forall h\ \in\ [1,8760]E_{\mathrm{gas}\,h} = \sum_{t}^{\mathbf{tech}} W_{\mathrm{des}\,t,h} \cdot \mathrm{gasCons}_t, \tag{28}$$

$$\forall h\ \in\ [1,8760]E_{\mathrm{elPump}\,h} = \sum_{t}^{\mathbf{tech}} W_{\mathrm{des}\,t,h} \times \left(\mathrm{elCons}_{\mathrm{VPump}} \cdot \mathrm{alt} + \mathrm{elCons}_{\mathrm{HPump}} \cdot \mathrm{dist}\right). \tag{29}$$

Abbreviations: hour (h), desalination technology (t), desalinated water (W_{des}), water storage discharge ($W_{\mathrm{stordisch}}$), water storage charge (W_{storch}), water demand (W_{demand}), installed desalination technology capacity (instCapDes), desalination heat demand (E_{heat}), desalination electricity demand (E_{el}), desalination gas demand (E_{gas}), desalination heat consumption (heatCons), desalination electricity consumption (elCons), desalination electricity production (elProd), desalination gas consumption (gasCons), water pumping electricity demand (E_{elPump}), horizontal water pumping electricity consumption ($\mathrm{elCons}_{\mathrm{HPump}}$), vertical water pumping electricity consumption ($\mathrm{elCons}_{\mathrm{VPump}}$), pumping distance (dist), pumping altitude difference (alt), water storage state of charge h ($\mathrm{SoC}_{\mathrm{stor}}$), installed capacity of the water storage (instCapStor).

CO_2 removal: The energy system can capture additional amounts of CO_2 from the atmosphere for permanent storage. The CO_2 captured by DAC is stored in CO_2 buffer storage. The system will balance hourly DAC and CO_2 buffer operation in order to balance hourly CO_2 removal demand.

Results preparation and cost calculations. All optimization results are collected and converted from the solver output form to the Matlab structure. This structure contains all information about the system: installed capacities of all system elements, its operation modes, energy, fuel and other product flows.

Data on the structure and operation of the energy system in combination with financial and technical assumptions give the full description of the system. Based on these numbers, it is possible to calculate annual costs of each component and the whole system, allocate costs to specific sectors, calculate costs of products (electricity, heat, synthetic fuels, water) and different components of this costs (primary generation, storage, transmission, curtailment components of electricity prices etc.).

The total annualized cost of the system is calculated as the sum of all sectors costs (Eq. (30)), which includes annualized capital cost and operational costs of all system elements (Eq. (31)):

$$\begin{aligned}\mathrm{totalCost}_{\mathrm{sys}} = {} & \mathrm{elSysCost} + \mathrm{elProsCost} + \mathrm{heatSysCost} + \mathrm{heatIndCost} \\ & + \mathrm{transpSysCost} + \mathrm{industrSysCost},\end{aligned} \tag{30}$$

$$\mathrm{totalCost}_{\mathrm{sys}} = \sum_{t=1}^{\mathbf{tech}} (\mathrm{CAPEX}_t \cdot \mathrm{crf}_t + \mathrm{OPEXfix}_t) \cdot \mathrm{Cap}_t + \mathrm{OPEXvar}_t \cdot E_{\mathrm{gen}\,t}, \tag{31}$$

$$\mathrm{crf}_t = \frac{\mathrm{WACC} \cdot (1 + \mathrm{WACC})^{N_t}}{(1 + \mathrm{WACC})^{N_t} - 1}. \tag{32}$$

Abbreviations: total annualized cost of the system ($\mathrm{totalCost}_{\mathrm{sys}}$), annualized cost of the centralized Power sector (elSysCost), annualized cost of the electricity prosumers sector (elProsCost), annualized cost of the centralized heat sector (heatSysCost), annualized cost of the individual heat sector (heatIndCost), annualized cost of the transportation sector (transpSysCost), annualized cost of the industrial sector (industrSysCost), all technologies (**tech**), technology (t), capital expenditures (CAPEX), capital recovery factor for technology t (crf_t) Eq. (32), annual fixed operational expenditures (OPEXfix), variable operational expenditures (OPEXvar), installed capacity of the technology t (Cap_t), annual output for the technology t ($E_{\mathrm{gen}\ t}$), weighted average cost of capital (WACC), lifetime for technology t (N_t).

Total levelized cost of electricity in the system (LCOEtotal) is calculated as the electricity demand weighted average of the centralized power system LCOE (LCOEsys) and prosumers sector LCOE (LCOEpros); the formula is presented in Eq. (33). Centralized power system LCOE is comprised of levelized cost of consumed electricity (LCOEprim), levelized cost of storage (LCOS), levelized cost of curtailed electricity (LCOC), levelized cost of electricity transition (LCOT) and levelized cost of prosumer feed-in reimbursement (LCOFS), Eq. (34). For the prosumer sector, total LCOE is comprised of the levelized cost of consumed electricity (LCOEprim), levelized cost of storage (LCOS), and levelized cost of prosumer feed-in reimbursement (LCOFS), Eq. (35). Levelized cost of generated electricity is calculated as the total annualized cost of the electricity generation system divided by total annual generation (Eq. (36)). In these calculations, operational costs include costs of fuel and GHG emissions cost per unit of generated electricity. The electricity generation systems also include part of the fuel production facilities, which are used for fuel production for power system generators. Levelized cost of consumed electricity is calculated based on the cost of the generated electricity (LCOEgen), excluding electricity lost due to curtailment, storage and transmission system losses (Eq. (37)). Levelized cost of storage is calculated as the annualized cost of storage system equipment and annual cost of electricity losses divided by total electricity consumption (Eq. (38)). Storage systems also include part of the fuel production facilities, which are used for fuel production for the storage system generators (e.g. for power-to-gas—gas-to-power). Levelized cost of curtailment is calculated as the annual cost of curtailed electricity divided by total electricity consumption (Eq. (39)). Levelized cost of transmission is the calculated area total annualized cost of power grid equipment and annual cost of electricity losses divided by total electricity consumption, and multiplied by regional grid utilization weights (Eq. (40)), where regional grid utilization weights are the average of regional shares of total export and import of energy (Eq. (41)).

$$\mathrm{LCOEtotal}_r = (\mathrm{LCOEsys}_r \cdot \mathrm{El}_{\mathrm{consSys}_r} + \mathrm{LCOEpros}_r \cdot \mathrm{El}_{\mathrm{consPros}_r})/ (\mathrm{El}_{\mathrm{consSys}_r} + \mathrm{El}_{\mathrm{consPros}_r}), \tag{33}$$

$$\mathrm{LCOEsys}_r = \mathrm{LCOEprim}_r + \mathrm{LCOS}_r + \mathrm{LCOC}_r + \mathrm{LCOT}_r + \mathrm{LCOFS}_r, \tag{34}$$

$$\mathrm{LCOEpros}_r = \mathrm{LCOEprim}_r + \mathrm{LCOS}_r - \mathrm{LCOFS}_r, \tag{35}$$

$$\mathrm{LCOEgen}_r = \frac{\sum_{t=1}^{\mathbf{Gen}} (\mathrm{CAPEX}_t \cdot \mathrm{crf}_t + \mathrm{OPEXfix}_t) \cdot \mathrm{Cap}_{t,r} + \mathrm{OPEXvar}_t \cdot \mathrm{El}_{\mathrm{gen,t,r}}}{\mathrm{El}_{\mathrm{gen,r}}} \tag{36}$$

$$\mathrm{LCOEprim}_r = \frac{\mathrm{LCOEgen}_r \cdot (\mathrm{El}_{\mathrm{gen},r} - \mathrm{El}_{\mathrm{curt},r} - \mathrm{El}_{\mathrm{storLoss},r} - \mathrm{El}_{\mathrm{transLoss},r})}{\mathrm{El}_{\mathrm{cons},r}}, \tag{37}$$

$$\mathrm{LCOS}_r = \left(\sum_{t=1}^{\mathbf{Stor}} (\mathrm{CAPEX}_t \cdot \mathrm{crf}_t + \mathrm{OPEXfix}_t) \cdot \mathrm{Cap}_{t,r} + \mathrm{OPEXvar}_t \cdot E_{\mathrm{out}\,t,r} + \mathrm{LCOEgen}_r \cdot \mathrm{El}_{\mathrm{storLoss}\,r}\right) / \mathrm{El}_{\mathrm{cons}\,r}, \tag{38}$$

$$\mathrm{LCOC}_r = \frac{\mathrm{LCOEgen}_r \cdot \mathrm{El}_{\mathrm{curt}\,r}}{\mathrm{El}_{\mathrm{cons}\,r}}, \tag{39}$$

$$\mathrm{LCOT}_r = \mathrm{RegShare}_r \cdot \left(\sum_r^{\mathbf{Reg}} \sum_{t=1}^{\mathbf{trans}} (\mathrm{CAPEX}_t \cdot \mathrm{crf}_t + \mathrm{OPEXfix}_t) \cdot \mathrm{Cap}_{t,r} + \mathrm{OPEXvar}_t \cdot \mathrm{El}_{\mathrm{out}\,t,r} + \mathrm{LCOEgen}_r \cdot \mathrm{El}_{\mathrm{transLoss}\,r}\right) / \mathrm{El}_{\mathrm{cons}\,r}, \tag{40}$$

$$\mathrm{RegShare}_r = 0.5 \cdot \frac{\mathrm{Import}_r}{\sum_r \mathrm{Import}_r} + 0.5 \cdot \frac{\mathrm{Export}_r}{\sum_r \mathrm{Export}_r}, \tag{41}$$

$$\mathrm{LCOFS}_r = \frac{\mathrm{feedInTarif}_r \cdot \mathrm{El}_{\mathrm{prosTogrid}\,r}}{\mathrm{El}_{\mathrm{cons}\,r}}. \tag{42}$$

Abbreviations: region (r), total levelized cost of electricity in the system (LCOEtotal), centralized system levelized cost of electricity (LCOEsys), prosumer sector levelized cost of electricity (LCOEpros), centralized system electricity consumption ($\mathrm{El}_{\mathrm{consSys}}$), prosumer sector electricity consumption ($\mathrm{El}_{\mathrm{consPros}}$), consumed electricity LCOE (LCOEprim), levelized cost of stored electricity (LCOS), levelized cost of curtailed electricity (LCOC), levelized cost of prosumer feed-in reimbursement (LCOFS), generated electricity LCOE (LCOEgen), power generation technologies (Gen), storage technologies (Stor), power transmission technologies (trans), technology (t), capital expenditures (CAPEX), capital recovery factor for technology t (crf_t), annual fixed operational expenditures (OPEXfix), variable operational expenditures (OPEXvar), installed capacity of the technology t (Cap_t), annual output for the technology t ($\mathrm{El}_{\mathrm{gen}\ t}$), annual electricity generation ($\mathrm{El}_{\mathrm{gen}}$), annual electricity curtailment ($\mathrm{El}_{\mathrm{curt}}$), annual storage loss ($\mathrm{El}_{\mathrm{storLoss}}$), annual grid loss ($\mathrm{El}_{\mathrm{transLoss}}$), annual electricity consumption ($\mathrm{El}_{\mathrm{cons}}$), annual output of storage t ($E_{\mathrm{out}\ t}$), annual export of grid technology t ($\mathrm{El}_{\mathrm{out}\ t}$), electricity exported by region r (Export), electricity imported by region r (Import), feed-in reimbursement (feedInTarif), electricity sold by prosumers to the grid ($\mathrm{El}_{\mathrm{prosTogrid}}$).

The levelized cost of heat (LCOH) is calculated as the weighted average of the centralized and individual system LCOH (Eq. (43)). The centralized heat system LCOH (LCOHsys) and individual heat system LCOH (LCOHind) are calculated as the annualized cost of heat system equipment and annual cost of electricity consumption by heating equipment divided by total heat consumption (Eq. (44,45)). In both formulas, operational expenditures include the cost of fuel and GHG emissions per unit of generated heat. The heat systems also include part of the fuel production facilities, which are used for fuel production for heat generators. Cogeneration plants costs are only included in the power system.

Levelized cost of transportation (LCOM) is calculated as sum of the annualized cost of the entire transport fleet, cost of consumed fuel and electricity, GHG emission cost, divided by transportation demand (Eq. (46)).

Levelized cost of the industrial sector products (LCOP) are: levelized cost of gas (LCOG), liquid fuel (LCOF), water (LCOW), and CO_2 direct air capture (LCOD). These are calculated as the sum of annualized cost of the equipment and cost of annually consumed heat and electricity, divided by total annual consumption of the product (Eq. (47)).

$$\mathrm{LCOHtotal}_r = (\mathrm{LCOHsys}_r \cdot \mathrm{He}_{\mathrm{consSys}_r} + \mathrm{LCOHind}_r \cdot \mathrm{He}_{\mathrm{consInd}_r})/ (\mathrm{He}_{\mathrm{consSys}_r} + \mathrm{He}_{\mathrm{consInd}_r}), \tag{43}$$

$$\mathrm{LCOHsys}_r = \left(\sum_{t=1}^{\mathbf{heat}} (\mathrm{CAPEX}_t \cdot \mathrm{crf}_t + \mathrm{OPEXfix}_t) \cdot \mathrm{Cap}_{t,r} + \mathrm{OPEXvar}_t \cdot \mathrm{He}_{\mathrm{out}\,t,r} + \mathrm{LCOEsys}_r \cdot \mathrm{El}_{\mathrm{demSysHeat}\,r}\right) / \mathrm{He}_{\mathrm{consSys}\,r}, \tag{44}$$

$$\mathrm{LCOHind}_r = \left(\sum_{t=1}^{\mathbf{heat}} (\mathrm{CAPEX}_t \cdot \mathrm{crf}_t + \mathrm{OPEXfix}_t) \cdot \mathrm{Cap}_{t,r} + \mathrm{OPEXvar}_t \cdot \mathrm{He}_{\mathrm{out}\,t,r} + \mathrm{ElPrice}_r \cdot \mathrm{El}_{\mathrm{demIndHeat}\,r}\right) / \mathrm{He}_{\mathrm{consInd}\,r}, \tag{45}$$

$$\mathrm{LCOM}_r = \frac{\sum_{t=1}^{\mathbf{Mob}} (\mathrm{CAPEX}_t \cdot \mathrm{crf}_t + \mathrm{OPEXfix}_t) \cdot \mathrm{Cap}_{t,r} + \mathrm{FuPrice}_{t,r} \cdot \mathrm{FuCons}_{t,r}}{\mathrm{TR}_{\mathrm{dem}\,r}}, \tag{46}$$

$$\mathrm{LCOP}_r = \left(\sum_{t=1}^{\mathbf{tech}} (\mathrm{CAPEX}_t \cdot \mathrm{crf}_t + \mathrm{OPEXfix}_t) \cdot \mathrm{Cap}_{t,r} + \mathrm{OPEXvar}_t \cdot \mathrm{Pr}_{\mathrm{out}\,t,r} + \mathrm{LCOEsys}_r \cdot \mathrm{El}_{\mathrm{cons}\,t,r} + \mathrm{LCOHsys}_r \cdot \mathrm{He}_{\mathrm{cons}\,t,r}\right) / \mathrm{Pr}_{\mathrm{cons}\,r}. \tag{47}$$

Abbreviations: region (r), total levelized cost of heat in the system (LCOHtotal), centralized system levelized cost of heat (LCOEsys), individual heat sector levelized cost of heat (LCOHind), centralized system heat consumption ($\mathrm{He}_{\mathrm{consSys}}$), individual heat sector heat consumption ($\mathrm{He}_{\mathrm{consPros}}$), heat generation technologies (**heat**), transportation technologies (**Mob**), industrial sector production technologies (tech), technology (t), capital expenditures (CAPEX), capital recovery factor for technology t (crf_t), annual fixed operational expenditures (OPEXfix), variable operational expenditures (OPEXvar), installed capacity of the technology t (Cap_t), annual output for the technology t ($\mathrm{He}_{\mathrm{out}\ t}$), centralized system levelized cost of electricity (LCOEsys), retail price of electricity (ElPrice), electricity consumed by centralized heat system heaters ($\mathrm{El}_{\mathrm{demSysHeat}}$), electricity consumed by individual heat system heaters ($\mathrm{El}_{\mathrm{demIndHeat}}$), fuel price for transportation technology t ($\mathrm{FuPrice}_t$), fuel consumption for transportation technology t (FuCons_t), transportation demand ($\mathrm{TR}_{\mathrm{dem}}$), annual product production ($\mathrm{Pr}_{\mathrm{out}}$), electricity consumption for the production ($\mathrm{El}_{\mathrm{cons}}$), annual heat consumption for the production ($\mathrm{He}_{\mathrm{cons}}$), annual product consumption ($\mathrm{Pr}_{\mathrm{cons}}$).

Data availability

The data that support the findings of this study are available from the authors on reasonable request. The main model code is available from the authors on reasonable request.

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Author contributions

D.B. was responsible for model and methodology development, simulation, results analysis, writing, and collected data for Eurasia and Northeast Asia major regions. J.F. collected the data on existing power capacities for all regions. K.S. collected data on transmission and distribution grid loss for all regions and estimated the values of future losses. A.A. collected data for MENA, North and South America major region, and was responsible for the preparation of diagrams, M.C. collected data for Europe major region, and gave support for paper writing, A.G. collected data for Southeast Asia and SAARC major regions, A.S.O. collected data for Sub-Saharan Africa major region, L.d.S.N.S.B. took part in South America data collection, C.B. analyzed the results, supervised, contributed to writing and coordinated the work.

Additional information

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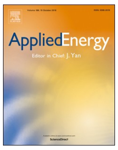

Transition towards 100% renewable power and heat supply for energy intensive economies and severe continental climate conditions: Case for Kazakhstan

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HIGHLIGHTS

- 100% RE can supply an energy intensive economy under harsh climate conditions.
- Substantial storage capacities are needed to compensate seasonality of heat demand.
- Electrical heating becomes the main source of heat.
- 100% RE can provide energy at a cost of 45 €/MWh for heat and 56 €/MWh for power.

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ABSTRACT

Transition towards 100% renewable energy supply is a challenging aim for many regions in the world. Even in regions with excellent availability of wind and solar resources, such factors as limited availability of flexible renewable energy resources, low flexibility of demand, and high seasonality of energy supply and demand can impede the transition. All these factors can be found for the case of Kazakhstan, a mostly steppe country with harsh continental climate conditions and an energy intensive economy dominated by fossil fuels. Results of the simulation using the LUT Energy System Transition modelling tool show that even under these conditions, the power and heat supply system of Kazakhstan can transition towards 100% renewable energy by 2050. A renewable-based electricity only system will be lower in cost than the existing fossil-based system, with levelised cost of electricity of 54 €/MWh in 2050. The heat system transition requires installation of substantial storage capacities to compensate for seasonal heat demand variations. Electrical heating will become the main source of heat for both district and individual heating sectors with heat cost of about 45 €/MWh and electricity cost of around 56 €/MWh for integrated sectors in 2050. According to these results, transition towards a 100% renewable power and heat supply system is technically feasible and economically viable even in countries with harsh climatic conditions.

1. Introduction

Located in the heart of Eurasia, Kazakhstan is an excellent representative of the entire Eurasian region with energy intensive industries, an energy sector based economy, low population density, aging energy infrastructure and excellent availability of renewable energy (RE) resources. Eurasia is one of the major energy exporting regions in the world, with significant oil, gas and coal reserves and a large export market share. Most of the energy system infrastructure was inherited from the Soviet era and needs to be modernised in the decades to come. Existing power and heat generation capacities use locally available fossil resources and the share of modern renewables in the total mix is very small. In Kazakhstan, most of the electricity and heat are generated from coal. Kazakhstan is a country richly endowed with fossil fuels resources, such as coal, oil, gas and uranium [1]. Rapid economic growth in the past decades was mostly supported by growth of the fossil fuel based energy sector [2,3] leading to fast growth of emissions. Between 1999 and 2014, CO_2 emissions of Kazakhstan increased from 111 Mt_{CO2} to 260 Mt_{CO2} [3]. The CO_2 emissions per capita in the country were 1.3 times higher than the average value of OECD

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Nomenclature

A-CAES	adiabatic compressed air energy storage
CAGR	compound annual growth rate
Capex	capital expenditures
CF	capacity factor
CHP	combined heat and power
CCGT	combined cycle gas turbines
CSP	concentrating solar power
DAC	CO_2 direct air capture
FLh	full load hours
GHG	greenhouse gases
HVAC	high voltage alternating current
HVDC	high voltage direct current
ICE	internal combustion engine
Opex	Operational expenditures
OCGT	open cycle gas turbines
PHES	pumped hydro energy storage
PtG	power-to-gas
PV	photovoltaic
RE	renewable energy
SNG	synthetic natural gas
TES	thermal energy storage
WACC	weighted average cost of capital

countries [4]. However, aging existing infrastructure and the need to modernise the energy sector [5] presents a great opportunity for the whole region to build a new, sustainable and renewable based energy system. Kazakhstan could become the trailblazer for the entire Eurasia and similar regions, showing feasibility of RE systems under conditions of harsh continental climate, energy intensive economy. Energy transition towards higher shares of RE is on the agenda of the Kazakh government since 2011 [6]. Since the last decade, the share of modern RE is growing fast and this growth will continue after the integration of RE auction mechanism in 2018. In total, Kazakhstan has a great potential to build a sustainable and RE-based system with excellent solar, wind, hydro and biomass potentials.

Perspectives of transitioning towards energy systems with higher shares of renewables and 100% RE based systems, the only fully sustainable way to build a zero emission system, attract attention in many regions of the world [7]. The transformation towards RE based systems should be technically feasible and economically viable [8]. From the technical point of view, technologies necessary for RE based system's operation, generation, storage and bridging are available [8]. Further, cost to of RE generation and power storage options proceed to decline due to the technical development [9] and industrial scaling. However, issues such as, inertia in systems without rotating masses of synchronous generators, or stability in isolated RE-based micro-grids raises doubt for a fully sustainable energy systems. But, synchronous generators' inertia can be substituted by integration of synthetic inertia, as shown for a 100% RE system in Sub-Saharan Africa [10], and by the use of optimisation of generation and storage power converters operation algorithms [11]. RE-based micro-grids stability can be significantly improved by an agile system control design, implementing load sharing strategies for distributed generators [12], enabling improved frequency control for islanded micro-grids [13] and optimisation of distributed storage utilisation [14].

Various studies show that available RE resources are sufficient to satisfy power demand in all regions in the world, including Kazakhstan [15]. Further, some studies show that RE resources can satisfy annual energy demand of the integrated energy system on global scale [16,17]. Studies on the structure of RE-based systems are presented for different regions on different levels. RE-based energy systems are discussed as the backbone of electricity supply systems of archipelagos [18], where each island currently represents an isolated energy system and centralised or decentralised supply options should be considered for the system development [19]. Possibilities to satisfy the electricity demand in the industrially developed country of Japan with RE sources is discussed in Esteban et al. [20]. Many articles describe the possible future RE systems modelled using EnergyPlan, an energy system simulation tool, results show the possibility to satisfy the energy demand for every hour of the year for the Ireland [21], Finland [22], Åland island [23], and whole Southeast Europe [24]. Another widely used tool, JRC-EU-TIMES also allows to automatically optimise the energy system structure, generation and storage capacity mix, for the year represented in a set of representative time slices. This tool was used in the Heat Roadmap Europe project and in numerous studies concerning European energy systems [25]. However, perspectives of energy system transition in countries with severe climatic conditions, including a high variation of seasons, and high daily and yearly temperature differences, is not widely discussed in the literature. The transition in these countries will be complicated due to additional flexibility and storage demand to compensate extra energy requirement in the winter time, when RE generation may be limited. Assembayeva et al. [26] discuss the perspectives of RE integration in the power sector of Kazakhstan and the impact of storage in such a system. This study shows that an energy system with a high share of RE in the power supply is feasible, however an option of a 100% RE system is not tested. The heat sector, for which energy demand is considerably high in countries with harsh climatic conditions, is not included in the study and its impact on the system is not discussed. At the same time, transition pathways from the current energy system structure towards the potential high RE systems are not discussed in the studies mentioned earlier, however an optimal transition pathway is an important concern, especially for the countries heavily dependent on aging fossil fuel based infrastructure.

Testing the feasibility of RE-based power and heat sectors for countries with harsh climatic conditions is most important due to the high variability in seasons, where power and heat requirements compared to a more stable industrial and transportation energy demands. Additionally, feasibility should be tested in full hourly resolution to guarantee the stability of the RE-based system and the proper estimation of the energy storage requirements considering the nexus between the RE share, storage requirements, and curtailment [27]. Feasibility of 100% RE systems in such worse case conditions can prove the feasibility of RE systems in general. Kazakhstan's energy system represents such a case and can be used as a model for such class of countries. At the same time, an energy intensive economy with an aging inflexible coal-based generation represents the worse case starting condition for an energy transition, since high shares of modern VRE have to be integrated on early stages of the transition when flexibility options are on high cost level. Transition modelling for these climates, energy demands, and existing system structure conditions will show most important challenges and provide valuable solutions for most complicated transformation cases.

This research suggests a transition pathway for Kazakhstan to reach an optimal and sustainable energy system by 2050. This pathway can be an example for countries with harsh climate conditions and energy intensive economies. Kazakhstan is a case country for all other countries of the Eurasian region, experiencing the same problems: aging of power capacities, high shares of inefficient fossil-based generation and high GHG emissions. Background information on the case country Kazakhstan is provided in the Supplementary Materials. Such a transition can result not only in lower GHG emissions and higher overall sustainability of the energy system, but also to higher energy efficiency due to better integration of energy sectors as it is discussed for Smart Energy Systems [28,29]. However, in this study we do not directly consider the transport sector and demand for non-energetic industrial feedstock. The optimisation model simulates a transition towards 100% RE power and heat supply systems for Kazakhstan by 2050, with consideration of the fast growing energy demand.

2. Materials and methods

Kazakhstan's power system was modelled with the LUT Energy System Transition modelling tool [30,15]. The LUT model simulates an energy system development under specific given conditions. For every time step the model defines a cost optimal energy system structure and operation mode for the given set of constraints: power demand, heat demand for industry, space and domestic water heating, available generation and storage technologies, financial and technical parameters, limits on installed capacity for all available technologies. The model is based on linear optimisation and performed on an hourly resolution for each year, which increases reliability of the results in comparison to time slices or annual energy balancing approaches. The target of the optimisation is minimisation of the total system cost. Costs of the system are calculated as the sum of the annual capital and operational expenditures (including ramping costs) for all available technologies. The transition simulation was performed for the period from 2015 to 2050 with 5-year time steps.

The distributed generation and self-consumption of residential, commercial and industrial prosumers are included in the energy system analysis and defined with a special model describing the development of the individual power and heat generation capacities. The prosumers can install their own rooftop PV systems, lithium ion batteries, buy power from the grid or sell surplus electricity in order to fulfil their demand, at the same time prosumers can install individual heaters for space and water heating. The target function for prosumers is minimisation of the cost of consumed electricity and heat, calculated as a sum of self-generation equipment annual cost, cost of fuels and cost of electricity consumed from the grid. The share of consumers who are expected to be interested in own generation gradually increases from 3% in 2015 to 15% in 2050, not reaching the in-built limit of 20%. The flow diagram of the LUT model from various input data to output results can be found in Fig. 1. The Supplementary Material in the Appendix A provides the consistent description of the model and the full set of all technical and financial assumptions used in the modelling of the energy transition in Kazakhstan (Tables A1 and A2).

2.1. Applied technologies

The model has integrated all crucial aspects of an energy system. For Kazakhstan, technologies introduced to the model can be classified into five main categories:

- Electricity generation: fossil, nuclear and RE technologies
- Heat generation: fossil and RE technologies
- Energy storage
- Energy sector bridging
- Electricity transmission

Fossil electricity generation technologies are coal power plants, combined heat and power (CHP), oil based internal combustion engine (ICE) and CHP, open cycle (OCGT) and combined cycle gas turbines (CCGT), gas based CHP. RE electricity generation technologies are solar PV (optimally fixed-tilted, single-axis north-south tracking and rooftop), wind turbines, hydro power (run-of-river and reservoir), geothermal and bio energy (solid biomass, biogas and waste-to-energy power plants and CHP). Fossil heat generation technologies are coal-based district heating, oil-based district and individual scale boilers, gas-based district and individual scale boilers. RE heat generation technologies are concentrating solar power (CSP) parabolic fields, individual solar thermal water heaters, geothermal district heaters and bio energy (solid biomass, biogas district heat and individual boilers).

Storage technologies can be divided in 3 main categories: short-term storage – Li-ion batteries and pumped hydro energy storage (PHES); medium-term storage – adiabatic compressed air energy storage (A-CAES), high and medium temperature thermal energy storage (TES) technologies; long-term gas storage including power-to-gas (PtG) technology, which allows to produce synthetic methane for the system use.

Bridging technologies are power-to-gas, steam turbines, electrical heaters, district and individual scale heat pumps and direct electrical heaters. These technologies convert energy of one sector into valuable products for another sector in order to increase total system flexibility, efficiency and decrease overall costs.

The energy transition simulation takes into account the existing AC power grid of Kazakhstan, its development trends and projected overall electricity transmission and distribution losses [31].

Fig. 2 presents the block diagram of the energy system model and all

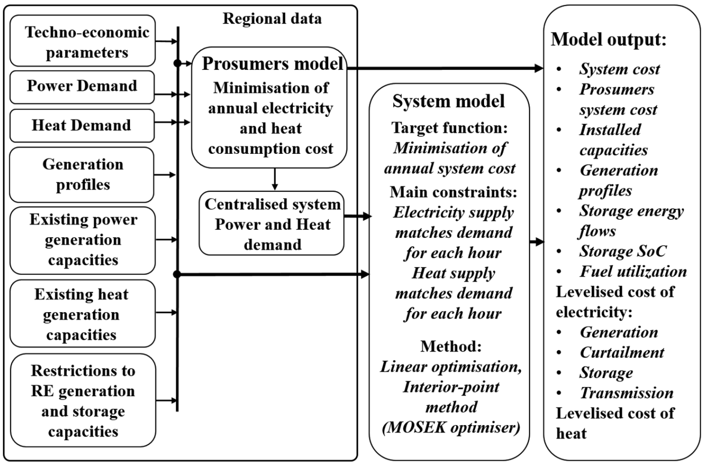

Fig. 1. Main inputs and outputs of the LUT Energy System model.

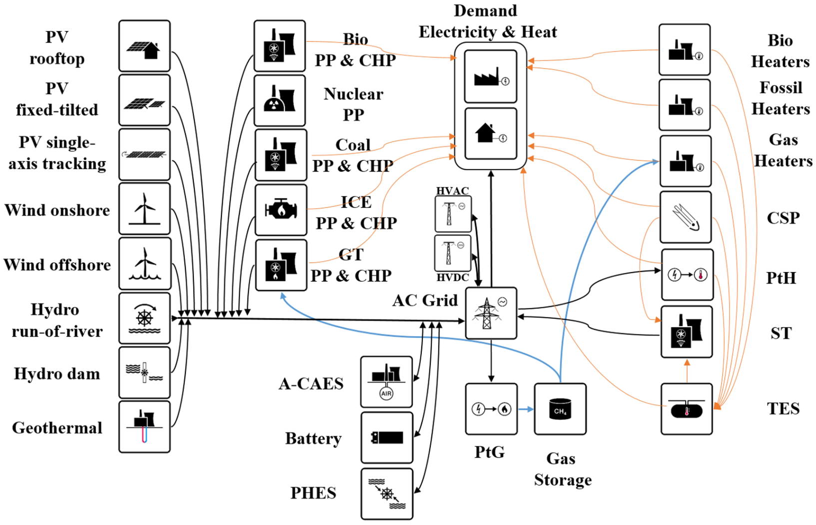

Fig. 2. Block diagram of the LUT Energy System Transition model. This is composed of energy converters for power and heat, storage technologies, transmission options and demand sectors.

technologies available for the energy transition in Kazakhstan.

2.2. Applied scenarios

In this paper, two main scenarios were studied for the energy transition of Kazakhstan: power sector and integrated power and heat sector transition. These scenarios focus on achieving a 100% RE system by 2050, so no fossil coal, gas, oil or uranium can be used in the system in 2050. The power scenario focuses on the power sector – for every 5-year time step of the transition, the system has to satisfy the electricity and heat demand of residential, commercial and industrial sectors for every hour of a year. Power and heat integration scenario also takes into account industrial heat demand, space and domestic water heating.

Availability of RE is calculated using weather data from NASA [32,33], and German Aerospace Centre [34], the calculations method is described in the section 2.3 and respective input and constraints are provided in the Appendix A (Tables A5–A6 and Figs. A1, A2, A4).

The energy system transition modelling for Kazakhstan was designed with four important constraints:

- No new nuclear, coal or oil-based power plants or combined heat and power (CHP) plants could be installed after 2015
- No new coal or oil-based district heating boilers could be installed after 2015
- Run-of-river, reservoir (dam) hydropower plants and pumped hydro storage are refurbished every 35 years and never decommissioned, based on empiric observation [35].
- RE capacity shares cannot increase more than by 4% per year, 3% between 2015 and 2020, based on empiric observation [35].

Gas based power plants, CHP and boilers can be installed after 2015 due to lower GHG emissions and the possibility to accommodate synthetic natural gas (SNG) or bio-methane into the system [36].

2.3. Financial and technical assumptions

The financial and technical assumptions are mostly taken from the European Commission [8], but also from other sources [37–50]. The financial and technical assumptions for all power and heat generation capacities, storage, transmission and bringing technologies and fuels with respective references are presented in the Appendix A (Tables A1 and A2). Assumptions are made in 5-year time steps from the year 2015 to 2050. For all scenarios, weighted average cost of capital (WACC) is set to 7%, but for residential PV prosumers WACC is set to 4% due to lower financial return requirements. Electricity prices for residential, commercial and industrial consumers were derived according to [51], and extended to 2050, and can be found in the Appendix A (Table A3). Excess electricity generated by prosumers is fed into the national grid and is assumed to be sold for a transfer price of 0.02 €/kWh. The model ensures that prosumers satisfy their own demand for electricity before feeding it into the grid. District heating efficiency increases from the Eurasian region's average estimate of 85% to 92% in 2050 [52] and the district heating share in space and domestic water heating continuously decreases from 70% in 2015 [53,54] to 50% in 2050.

2.4. Demand and resource potential for renewable technologies

Electricity demand assumptions are based on IEA data. Actual electricity consumption for year 2015 is taken from IEA statistics [53], and future consumption values are calculated based on annual growth rates for the Eurasian region from IEA WEO 2017 [55]. The annual electricity demand is converted into hourly profiles according to the method presented in Toktarova et al. [56]. Profiles for industrial heat demand, space and water heating demand are taken from Barbosa et al. [57]. Power and heat demand assumptions for each step of the transition are provided in the Appendix A (Table A4 and Fig. A3).

The generation profiles for single-axis tracking, optimally fixed tilted PV, solar CSP and wind energy were calculated according to [30] using global weather data for the year 2005 from NASA [32,33] and German Aerospace Centre [34]. The hydropower feed-in profiles are computed based on the monthly resolved precipitation data for the year 2005 as a normalised sum of precipitation in the regions based on [58]. Hourly capacity factor profiles for single-axis tracking PV and wind turbines are presented in the Appendix A (Fig. A5). The potentials for biomass and waste resources were taken from [59] and classified into four main categories: forestry industry wastes, solid wastes, solid residues and biogas. The costs for biomass are calculated using data from the IEA [60] and Intergovernmental Panel on Climate Change (IPCC) data [61]. For solid waste a 50 €/ton gate fee was assumed for 2015, rising to 100 €/ton in 2050. Geothermal energy potential was calculated according to the method described in [62]. FLh for wind turbines, solar PV and hydro plants, potentials of bio and geothermal energy are provided in the Appendix A (Table A5). The lower and upper limits of renewables and fossil fuels are provided in the Appendix A (Table A6). The A-CAES storage potential is based on a global A-CAES resource assessment [63].

3. Results and discussion

3.1. Transition scenario for the power sector

Possibility and strategy of the energy sector transition towards a 100% RE-based system in Kazakhstan and the whole Eurasian region is the main focus area of this research. Currently, energy system of the region mostly relies on fossil-based generation technologies, predominantly coal and gas in Kazakhstan. Most of these capacities were built more than 25 years ago (95% of all coal power plants were built before 1990) and have to be decommissioned very soon. These decommissioned capacities can be substituted by sustainable RE generation technologies. The results of the simulation show that the transition of the power sector is possible and a 100% RE system can be reached by 2050. Fig. 3 presents the structure of the energy system for every 5-year time step for the transition period.

Fig. 3 depicts that for the initial years of the transition, coal generation capacities are dominant in the system, but in 2020 to 2030 most of these old capacities are decommissioned due to aging and are substituted mostly by new wind and CCGT generation. This period shows the most significant change of the system structure – after 2025 RE represents more than half of the system capacity. In the following periods, the share of RE sources gradually increases. Significant capacities of wind generation are installed in 2025 and 2030, but in later periods, wind capacities stay the same and after 2045 they are partially substituted by single-axis tracking PV. After 2030, solar PV is the fastest growing technology in the system, in 2040 total PV capacity exceeds the capacities of all other technologies. By 2050, PV forms around 50% of the total system capacity, however, the share of fixed-tilted PV is not relevant, since 13% (about 8 GW) of the generation capacities are contributed by PV prosumers and 42% (more than 25 GW) are single-axis tracking PV power plants – the least cost energy source in the system. In total, solar PV contributes to more than 52% (about 58 TWh) of total electricity generation, wind energy to less than 30% (30 TWh) and hydropower to about 10% (11 TWh). Biogas, biomass and waste incinerator power plant generation stays stable over the years on the level about 9 TWh, contributing to 7% of total electricity generation. Biomass utilisation is mostly limited by sustainably available resources of biomass. However, the capacities of biomass-based power plants gradually increase over time to increase the flexibility of the system and decrease the storage requirements. Gas turbine capacity stays constant after fast growth in 2025, gas based power generation gradually decreases – with increase of gas and CO_2 emission costs, gas generation becomes more expensive for the system. In 2050, fossil methane is banned in the system, gas turbines use only bio-methane and synthetic methane from Power-to-Gas (PtG). Due to relatively low electricity distribution prices, before 2030, prosumer PV is not installed, but later it becomes cost competitive for commercial and industrial prosumers.

As a consequence of the growth of the RE shares, one can observe a growing demand in storage capacities. Throughput of storage increases from zero in 2015 and 2 TWh in 2020 to 24.5 TWh in 2050, as it can be seen in Fig. 4.

For 2020, thermal energy storage is the only economically feasible solution, with the growth of RE shares in the system and cost decrease of storage technologies other types of storage appear. The most important role is played by short-term Li-ion battery storage, which is very important for systems with high PV generation shares [64]. Prosumer batteries never appear in the system because of the comparably low retail electricity prices, thus the expected electricity distribution price is too low for PV prosumers to invest in their own energy storage systems. Mid-term adiabatic compressed air energy storage also plays an important role in the system and generally complements wind generation, as also described in more detail by Gulagi et al. [65]. Gas storage appears in the system only during the last step of the transition, long-term SNG storage is needed to compensate seasonal demand fluctuations in the harsh climatic conditions of Kazakhstan. Gas storage installed capacity reaches 3 TWh in 2050, however the share in total electricity demand is limited to 10% of all stored electricity.

The power system transition results in a 100% RE system by 2050, and no electricity is generated with fossil fuel utilisation. Furthermore, the energy transition leads to lower costs of electricity generation compared to the current system, as it can be seen from Fig. 5.

Fig. 5 shows that levelised cost of electricity (LCOE) decreases from 74 €/MWh in 2015 to 54 €/MWh in 2050. For the first decade, the system is still based on fossil generation, thus the share of fuel and CO_2 emission costs in total LCOE is significant. With the integration of new RE capacities, the share of fuel costs decreases and capital costs become

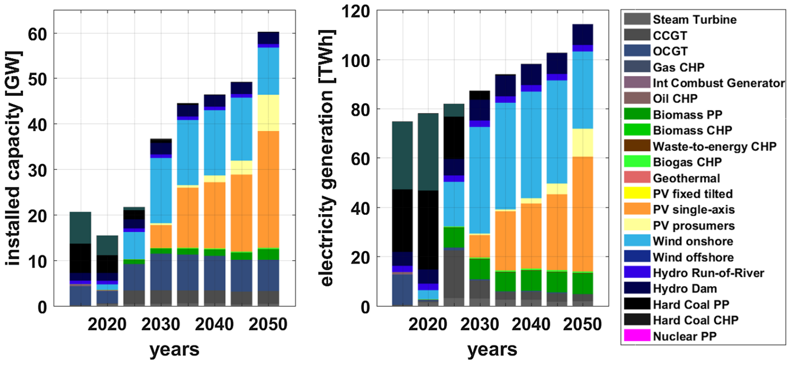

Fig. 3. Installed capacities of different technologies (left) and power generation (right) for the power system transition scenario.

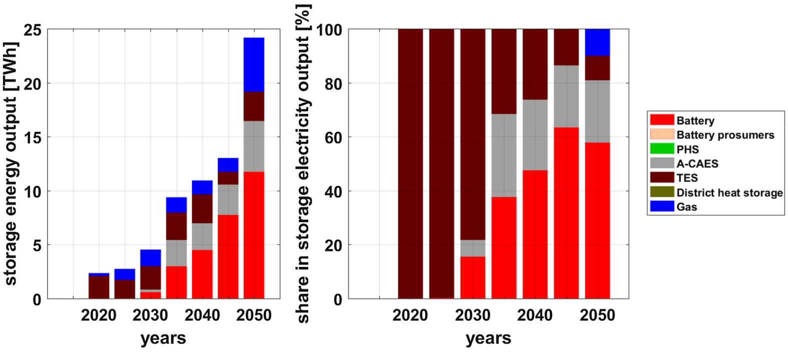

Fig. 4. Storage output for the power system transition scenario.

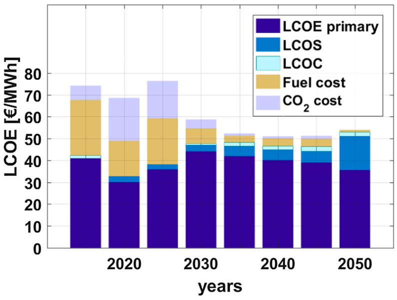

Fig. 5. LCOE components for the power system transition scenario.

the main components of the LCOE. At the same time, some energy is curtailed due to inflexibility of RE sources. This effect leads to an increasing levelised cost of storage (LCOS) and levelised cost of curtailment (LCOC) components. The period of the year 2025 is different and breaks the trend of gradual decrease in LCOE, this is due to sharp decommissioning of aged coal generation capacities, which can be interpreted as a shock for the system. As a result, huge new capacities of RE and gas turbines need to be installed. As the resulting capital costs increase sharply, while fuel and CO_2 costs stay almost the same. Finally, one can see the very high LCOE for this decisive transition step. The last step of the transition also shows some challenges, due to seasonality of the continental climate of Eurasia. Power demand during winter significantly increases and long-term storage needs to be installed in order to compensate the demand and supply fluctuations. Power-to-Gas based gas storage significantly increases the cost of the system and results in slightly higher LCOE in comparison to 2045. If all capacities of the year 2050 were built for the financial and technical assumptions of the year 2050, then the total LCOE would be 16% lower at 44 €/MWh, a cost level which can be expected for the periods after 2050.

3.2. Transition scenarios for power and heat integrated system

Integration of different sectors can be very valuable for the system as it was seen for other regions [30,66], but at the same time it can provoke additional problems, such as resource limitations, mainly due to increased generation demand. Fig. 6 presents the power system structure and generation for the power and heat integrated system scenario. Fig. 7 presents the heat generation capacities structure and the heat generation for the power and heat integrated system scenario.

The power sector structure of the integrated system is comparable to the one of the power only system, however power generation and capacities grow faster in order to satisfy rising demand from an electrified heat generation sector. The transition process follows the same pattern as in the case of the power only sector: wind capacities grow significantly during 2020 to 2030 and later stagnate, while solar PV

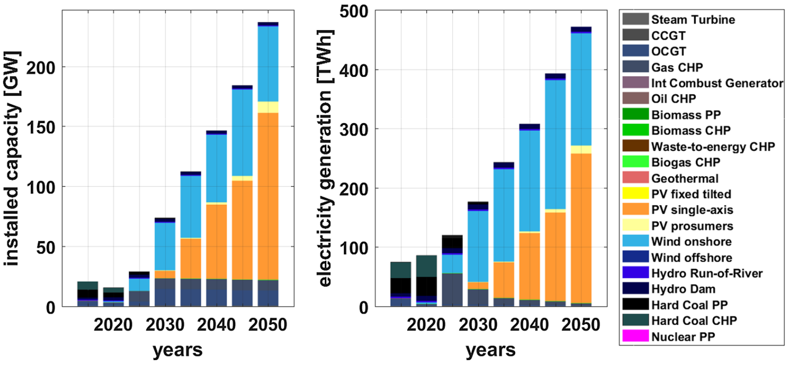

Fig. 6. Installed capacities of different power generating technologies (left) and annual power generation (right).

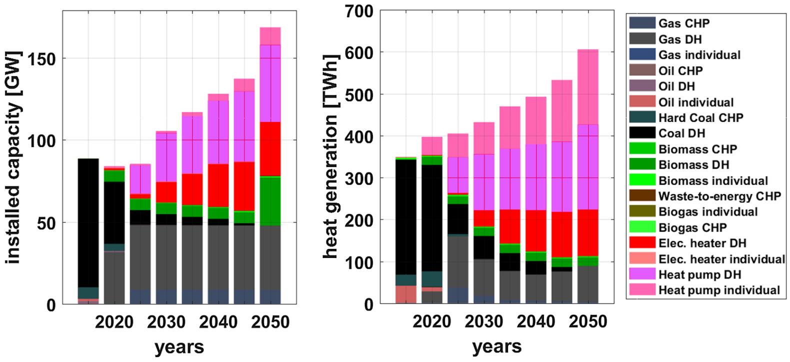

Fig. 7. Installed capacities of different heat generating technologies (left) and annual heat generation (right).

consistently grows after 2030. Wind and solar are the main power sources starting from 2035, shares of other RE sources are limited by their maximum potential. In 2050, solar PV provides more than 50% (about 270 TWh) of the consumed electricity, the wind share is about 40% (about 165 TWh), which is higher than the case for power only scenario. Rest of electricity is generated by hydropower plants (about 11 TWh) and biomass plants (less than 1 TWh). The system chooses to install more wind turbines which are an expensive energy source in 2050, as the wind availability is more stable throughout the year and other resources such as hydropower and biomass reach their resource limits.

The heating sector of Kazakhstan transitions from the current, mostly dependent on coal-based district heating, to a mostly electricity-based heating system by 2050. During the transition, the system substitutes coal capacities first by gas and biomass sources and later by electrical heating, mainly through electric heat pumps and direct electric heaters. At the end of the transition, most of the heat is produced by heat pumps and gas, which is stored seasonally. While biomass heat is used mainly to satisfy high temperature heat demand of industry, additional electrical heaters provide medium temperature heat for industry. The individual heating shares gradually increases from 15% in 2015 to 25% in 2050. The individual heating sector is electrified much faster: in 2020, 78% of heat is produced by heat pumps; later this share steadily grows and reaches 99% in 2050. Finally, in 2050, heat pumps are the main source of energy for space and water heating, providing 49% of this heat demand, whereas electrical heaters are used to satisfy medium temperature industrial heat demand, and biomass and renewable electricity based SNG are used for high temperature heat demand in industry.

Energy demand of the heating sector in Kazakhstan is more than 4 times higher than the power demand accounted in final energy units, at the same time it is highly influenced by the harsh continental climatic conditions. This results in much higher storage system requirements of the power and heat integrated system. In 2050, 57% of all produced electricity and 24% of all produced heat have to be stored. Most of the energy is stored in short-term battery storage in order to guarantee the base load operation of PtG units and to satisfy energy requirement during winter times. The throughput of storage technologies and their shares in total electricity and heat output are presented in Fig. 8.

For the power system, battery storage plays the most important role, balancing daily generation variability. Only in later years gas storage starts to operate in order to balance seasonal variability of generation and temporal mismatch to demand. In the last year of transition, mid-term A-CAES storage emerges in the system to balance weekly variability and mismatch. However, even in 2050 battery storage plays the leading role by providing 80% of all stored electricity.

In the initial years of the transition, post the integration of district heating heat pumps, district heating heat storage is installed in order to maximise the efficiency of the space and water district heating system. Later, with the integration of electrical heating for industry, thermal energy storage is also installed. In later years of the transition, with decommissioning of coal-based heat and overall high GHG emission costs, gas storage starts to provide SNG for industrial high temperature processes.

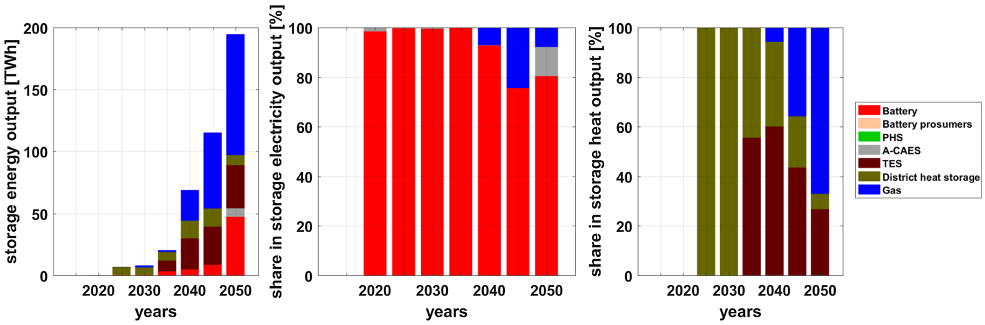

Fig. 8. Throughput of storage technologies (left) and technologies shares in electricity (centre) and heat (right) output.

With integration of the heating sector, heat storage is not used anymore for electricity generation, the heat becomes more valuable as a final product, which is quite a remarkable inversion of the value of heat at the beginning of the transition. At the same time, with the heat electrification, power sector demand becomes relatively much smaller than power generation and all reasons to produce power from heat disappear, which is also driven by the larger power generation.

Further integration of energy sectors will lead to even higher efficiency of the system: excess electricity and excess heat produced in the system with higher share of RE power and heat generation will become valuable energy source for industrial feedstock and transport sectors leading to lower energy cost, at the same time storage and distribution grids are used more effectively which also decreases the overall system cost [67,68]. Another example for higher energy system efficiency of a Smart Energy System is CO_2 direct air capture [69], which is important for power-to-fuels and power-to-chemicals, since a major share of the required energy is thermal energy of about 70–100 °C which can be at least partly sourced from excess and waste heat thus improving the overall energy system efficiency [70].

RE resources of Kazakhstan are sufficient to build a 100% RE power and heat system, even in the prevailing harsh climatic conditions. Even with much higher storage requirements due to seasonal heat demand variations, such a system can be economically feasible with power LCOE around 56 €/MWh and heat LCOH around 45 €/MWh in 2050. Fig. 7 shows the LCOE and LCOH development during the transition for the power and heat integrated system scenario.

From Fig. 9, it can be seen that the LCOE development during the transition, as well as the LCOE components structure are similar to the power sector transition case. However, there are some variations. In particular, a higher cost increase in 2025 can be observed due to a faster growth of electricity demand along with the massive old power plants decommissioning. Another major deviation is due to slightly higher LCOE in 2050, power and heat sectors integration results in total LCOE of around 56 €/MWh in 2050, 2 €/MWh higher than in the power only scenario. The main reason is a higher share of more expensive wind power in the generation mix, which is needed for a better support of electricity-based heat supply during the winter seasons. At the same time, heat related storage costs are allocated to LCOH because most of the system balancing is made for the heat sector and that decreases the respective LCOS component of the power sector. Substantial PtG capacities are built in 2040 to 2050 that increase the total cost of the system and this results in slightly higher values for both LCOE and LCOH in 2050. LCOH is almost constant in 2015 and 2020 on the level around 25 €/MWh, due to low GHG emission costs and presence of fossil-based CHP plants, but later, with the decommissioning of CHP and a continuous increase of the GHG emission costs the LCOH slightly increases to reach 45 €/MWh in 2050. Despite the fact that in the 100% RE system heat becomes the product of electricity conversion, heat costs are still remarkably low because of the vast heat pumps utilisation. After 2050, LCOE and LCOH are expected to decline because of continuing cost decrease of RE and storage technologies. For the financial and technical assumptions of the year 2050 the LCOE would decline in the following periods by about 17% to about 46 €/MWh, the LCOH would decline by about 10% to about 40 €/MWh.

4. Conclusion

Results clearly show that the ambitious target to build a 100% renewable energy system in Kazakhstan is achievable. A 100% RE power and heat system can be built by 2050, substantially exceeding the country's «green concept» goal of 50% RE in the same time frame. That means, a 100% RE system will be most likely also feasible in any other region of Eurasia and other regions with similar climate conditions, since the case of Kazakhstan exhibits the harshest climatic conditions in Eurasia. However, the example of Kazakhstan shows that a transition towards 100% RE system can face some issues. Decommissioning of aging coal power plant capacities, induce challenges for a quick replacements. Most of these capacities were built in the pre-1990 era and reach the end of their lifetime around 2025, which can provoke a system shock due to fast fossil capacities phasing out and phasing in of the new RE capacities. This sharp change of the system structure may provoke a short-term spike in electricity costs due to an increased share of capital costs in the total levelised cost of electricity. Nevertheless, for the power only and integrated scenarios' electricity cost shows the trend to decrease while increasing the RE shares: from 74 €/MWh in 2015 to 54 €/MWh in 2050 for the power scenario and 56 €/MWh in 2050 for the integrated scenario. For both scenarios solar PV will become the main energy source, generating more than 50% of energy in the system (52% for power only and 56% for power and heat scenario), the wind energy share will be on the level of 30% for power only and 40% for the integrated scenario. Remaining energy will be provided by hydropower and biomass plants.

With an increase of the RE shares in the system, the demand for storage grows. The variability of RE sources and the continental climate of Kazakhstan implies a high storage throughput – in 2050 around 20% of all electricity demand is cycled through storage facilities. For power and heat sector coupling, integrated storage becomes even more important, as more than 50% of electricity and 24% of heat have to be stored to compensate heat demand variability under harsh continental climatic conditions. Most of the stored electricity is later on converted to heat, in particular seasonally. More batteries are used for increasing the electrolyser full load hours in the summer months via shifting solar PV electricity into the night hours and respective seasonal storage via power-to-gas and for increasing the FLh of heat pumps during the winter; both reduces the total energy system costs. From the storage capacity point of view, gas storage is the biggest storage in the system,

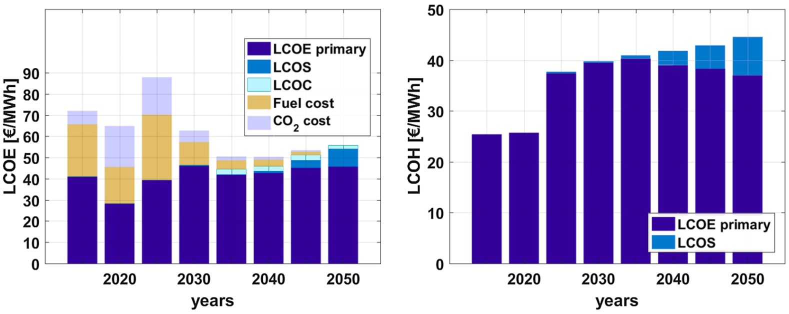

Fig. 9. LCOE components (left) and LCOH (right) during transition.

however, throughput of battery storage is much higher, comprising 58% and 80% of total storage electricity output in the power sector scenario and integrated scenario, respectively. Further integration of transport and industrial feedstock sectors can lead to even higher system efficiency and thus lower overall energy cost.

Other regions of Eurasia have comparable solar and wind resources, and also significant hydropower and biomass potentials. The climatic conditions in most of the regions are more balanced than in Kazakhstan. All these factors position Kazakhstan to be a very good proof of possibility to realise a 100% renewable and sustainable energy system in Eurasia. These regions will face the same inherited problems: aging of existing capacities, huge storage requirements due to climate conditions, which will provoke some problems for the energy transition process. But, all the issues can be solved and a sustainable 100% renewable and low cost energy system can be created even in the near future.

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Appendix A. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2019.113606.

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Publication VI

Bogdanov D., Gulagi A., Fasihi M., and Breyer C.

Full energy sector transition towards 100% renewable energy supply: Integrating power, heat, transport and industry sectors including desalination

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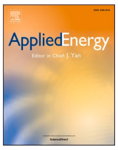

Full energy sector transition towards 100% renewable energy supply: Integrating power, heat, transport and industry sectors including desalination

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HIGHLIGHTS

- Sector coupling leads to lower cost of energy supply in a RE-based system.
- Power sector becomes the backbone of the entire energy system.
- Integration impact depends on demand profiles, flexibility and storage cost.
- Electrolysers are an important source of flexibility in an integrated system.
- All sector defossilisation is achieved even for severe conditions as of Kazakhstan.

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ABSTRACT

Transition towards long-term sustainable energy systems is one of the biggest challenges faced by the global society. By 2050, not only greenhouse gas emissions have to be eliminated in all energy sectors: power, heat, transport and industry but also these sectors should be closely coupled allowing maximum synergy effects and efficiency. A tool allowing modelling of complex energy system transition for power, heat, transport and industry sectors, responsible for over 75% of the CO_{2eq} emissions, in full hourly resolution, is presented in this research and tested for the case of Kazakhstan. The results show that transition towards a 100% sustainable and renewable energy based system by 2050 is possible even for the case of severe climate conditions and an energy intensive industry, observed in Kazakhstan. The power sector becomes backbone of the entire energy system, due to more intense electrification induced sector coupling. The results show that electrification and integration of sectors enables additional flexibility, leading to more efficient systems and lower energy supply cost, even though integration effect varies from sector to sector. The levelised cost of electricity can be reduced from 62 €/MWh in 2015 to 46 €/MWh in 2050 in a fully integrated system, while the cost of heat stays on a comparable level within the range of 30–35 €/MWh, leading to an energy system cost on a level of 40–45 €/MWh. Transition towards 100% renewable energy supply shrinks CO_{2eq} emissions from these sectors to zero in 2050 with 90% of the reduction achieved by 2040.

1. Introduction

Ongoing growth in anthropogenic greenhouse gas (GHG) emissions is one of the greatest threats to civilization. Despite the consensus that GHG emissions should be eliminated by 2050 in order to fulfil the Paris Agreement and limit global temperature rise to the well below 2 °C level [1], consumption of fossil fuels is growing in all energy sectors [2]. To complicate matters even further, major countries are falling short of their GHG reduction commitments, raising concerns that even a 2 °C target may be out of reach [3]. Growing number of evidence from significant climate change effects like temperature deviations from a long term climatic norm for an area [4,5], collapsing sea [6] and land ecosystems [7], and irregular monsoons are common occurrences in different parts of the world, while this process is projected to accelerate in the future [8] without immediate and adequate actions [9]. As a response, society and general public are showing renewed interest in climate change mitigation questions: particularly, increasing number of

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Nomenclature

A-CAES.	adiabatic compressed air energy storage
BAU	business as usual
BEV	battery-electric vehicle
BF-BOF	blast furnace-basic oxygen furnace
BPS	Best Policy Scenario
CAGR	compound annual growth rate
Capex	capital expenditures
CF	capacity factor
CHP	combined heat and power
CCGT	combined cycle gas turbines
CSP	concentrating solar power
DAC	CO_2 direct air capture
EAF	electric arc furnace
EWIN	electrowinning of iron
EV	electric vehicle
FCEV	fuel cell electric vehicle
FLh	full load hours
GDP	gross domestic product
GHG	greenhouse gases
H-DRI	hydrogen-based direct reduced iron
HDV	heavy duty transport
HtP	heat-to-power
HVAC	high voltage alternating current
HVDC	high voltage direct current
ICE	internal combustion engine
LCOE	levelised cost of electricity
LCOH	levelised cost of heat
LDV	light duty vehicle
LNG	liquefied methane
MDV	medium duty vehicle
OCGT	open cycle gas turbines
OECD	Organisation for Economic Co-operation and Development
Opex	operational expenditures
PHES	pumped hydro energy storage
PHEV	plug-in electric vehicle
PtG	power-to-gas
PtH	power-to-heat
PP	power plant
PV	photovoltaic
RE	renewable energy
SNG	synthetic natural gas
SWRO	seawater reverse osmosis
TES	thermal energy storage
WACC	weighted average cost of capital
2/3W	2–3 wheeled transport

companies [10], cities and regions [11] and countries [12] aim to defossilise and limit further growth in GHG emissions or completely transform specific energy sectors towards 100% renewable energy supply in the coming decades. However, more coherent efforts are needed from all the countries to achieve the common goal, while scientific evidence is very strong on the technical feasibility [13] and economic viability of the target [14].

The power, heat, transport and industry sectors are the major sources of GHG emissions, responsible for about 76% of all GHG emissions, while the remaining 24% emissions are from agriculture and land-use [15]. While, equal attention is required to defossilise each sector, power sector decarbonisation seems to be the easiest and would also have a significant impact on other energy sectors [16]. Together with electrification and close sector coupling, a decarbonised power sector will provide sustainable energy for the heat and transport sectors [17].

The overall electrification leads to significant efficiency gains in the majority of processes, due to high efficiencies of electricity based processes and synergy effect from optimal operation of an integrated energy system [17], even though, indirect electrification leads to additional losses in PtX processes. Therefore, direct electrification should be utilised wherever possible. While, an increase in overall electrification of the energy system, sectors integration and transition towards higher share of RE could be beneficial, varying structures of energy sectors, climatic conditions and resource availability makes the design of such an optimal sustainable energy system a challenging task. Even though from a technical point of view technologies do exist for a renewable based energy system operation, generation, storage and bridging [13], the transition will demand significant investments over a few decades.

At the same time, transition of different sectors should proceed in an optimal order, in a way that different sectors support each other for the best possible outcome in fast reduction of cost and GHG emissions. The energy system transition demands careful planning of the entire transition process for all the sectors, closely coupled to avoid stranded investments and guarantee optimal system operation during each step of the transition. In addition, proper modelling of renewable energy systems, storage operation and coupling of different sectors demands simulation in high temporal resolution [13]. A shift towards 100% renewable energy supply will not only solve the sustainability issue and lower the GHG emissions but also relieve the overall pressure on the environment.

Various studies have shown the technical and economic feasibility of RE-based energy systems in different regions of the world, proving that RE resources are adequate to satisfy energy demand from power, heat, and transport sectors [14]. The majority of studies still focus on decarbonisation of only the power sector [14]. Studies describing decarbonisation of individual islands [18], Åland [19], Philippines archipelagos [20], countries [21–25] and *trans*-national regions, like South East Europe [26], Europe [27,28] or Americas [29], show that the power sector can be decarbonised for a substantial less effort in comparison to other sectors using existing RE electricity generation and energy storage technologies. The results highlight that a significant variety of optimal energy system structures are observed for different regions, massively dependent on local climate conditions and RE resources availability [14]. While in Sun Belt countries, solar photovoltaics (PV) plays a major role in power supply [30], wind power generation plays a prominent role in high latitude countries like Kazakhstan [21] and Finland [31]. While, a number of studies considering integration of other sectors has grown, however, some of these studies neglect effects of sector coupling. Major attention regarding defossilisation is on the sectors power, heat [32] and transport [33], but very few articles consider the integration of the industry sector, responsible for almost a quarter of global GHG emissions [34]. Three of the very few exceptions in highly renewable energy systems research to include industry are Aboumahboub et al. [35], Pursiheimo et al. [36] and Teske et al. [37], however, the latter two do not offer solutions how to eliminate GHG emissions in the industry sector, while all other sectors phase out fossil fuels. The key aim of this research is to overcome this limitation in methods and simulate the transition of an entire energy system: integrated power, heat, transport and industry including emerging energy demand from seawater desalination.

A large number of studies use EnergyPlan [38], one of the most used tools for an integrated system modelling, which is applied for a wide list of countries and regions from Croatia [18], Jordan [22] to Finland [24] and Ireland [25], and Europe as a whole [27] representing a comprehensive view on possible energy system structures for regions with completely different climate conditions. Another energy system modelling tool is TIMES, which models the entire energy system, and was used along with EnergyPlan in the Heat Roadmap Europe project [39] and in numerous studies concerning European regions [28]. However, EnergyPlan is a simulation model, where the user must specify installed capacities manually and thus optimal energy system solutions can hardly be reached. The TIMES model allows to optimise the system automatically, however the time slices approach leave doubts on the accuracy of system operation and stability especially for very high shares in RE generation and energy storage requirements [40], for which full hourly resolution seems to be the optimal solution [13].

The global view on the energy system transition is presented by Jacobson et al. [41], Pursiheimo et al. [36], Teske [42], and Creutzig et al. [43], presenting not only the structure of a sustainable energy system, but also the transition pathway which allows to reach this challenging aim. However, the approach used in Jacobson et al. and Creutzig et al. does not allow to fully integrate the effects of RE resources variability and thus the storage demand in the system. In order to define an optimal pathway for the energy system transition, the model should be able to simulate a fully coupled energy system, including power, heat, transport and industry sectors in full hourly resolution, to capture the effects of the RE sources variability, storage demand and possible synergy effects of the system integration. Such a model must cover not only energy use, but also industrial processes feedstock as fossil chemicals in chemical industry, limestone in cement and alumina etc., which are also responsible for significant GHG emissions. Finally, the model should define the transition steps from the current energy system to a fully RE based system, not simply the final structure of a future defossilised system.

The model presented in this article is a result of further development of the LUT Energy System Transition model which allows to simulate power [16], power and heat systems [17] in full hourly resolution for centralised systems, or with high shares of prosumers, for isolated energy systems or regional integration scenarios. The tool was expanded in order to model the integration of power, heat, transport and industry sectors, which allows to trace most of the energy related GHG emissions and better evaluate options and barriers on the pathway towards RE-based systems. All sectors are closely coupled and simulated simultaneously to obtain a full synergy effect and efficiency gains in case of an optimal system operation. The model is tested for the case of Kazakhstan – a country with an energy intensive economy and harsh continental climate.

This country was previously studied for the case of a coupled power and heat sector transition [44] and shows one of the most complicated cases for the transition towards high shares of RE due to high per capita energy demand for space heating as a consequence of harsh climate conditions, high energy demand for industry, while all these factors are augmented by high seasonality or energy demand (with maximum in winter months) and RE generation (with maximum in summer months). Mismatch of energy demand and RE generation demand implies the requirement of additional flexibility options to enable the balancing of supply and demand. The transition modelling of the entire energy system will further examine options for renewable based energy systems in the given class of countries with harsh climate conditions and an energy intensive industry sector. Currently, Kazakhstan is one of the major GHG emitters in the region with fast growing emissions from 113 $\mathrm{Mt_{CO2}}$ in 1999 to 236 $\mathrm{Mt_{CO2}}$ in 2014 and 266 $\mathrm{Mt_{CO2}}$ in 2019 [45]. The CO_2 emissions per capita in the country were 1.3 times higher than the average value for the OECD countries [46]. At the same time, transition towards higher shares of RE in the total energy demand is on the agenda in Kazakhstan since 2011 [47], as the existing aging infrastructure and the need to modernise the energy sector [48] presents a great opportunity to build a new, sustainable and renewable based energy system. Kazakhstan can become an example for the whole region of Central Asia and Eurasia experiencing the same challenges: harsh climate conditions and aging infrastructure.

This article presents a transition model for the power, heat, transport and industry sectors, operating in full hourly resolution and allowing to simulate the energy system transition towards high shares of RE considering close coupling of all energy sectors. The research primarily focusses on the following research question: What are the sector coupling benefits of a stable and cost-optimal energy system which is consistent with the Paris Agreement?

2. Methods and data

This section describes the methods of this study: LUT Energy System Transition model (section 2.1), technologies enabled for the case of Kazakhstan (section 2.2), and the scenarios applied (section 2.3), followed by the description of financial and technical assumptions.

2.1. Model description

The energy system of Kazakhstan was modelled with the LUT Energy System Transition modelling tool described in Bogdanov et al. [16], which simulates transition of the power, heat, transport and industry sectors under given specific conditions. For each time step the model defines an optimal structure of an integrated energy system and operation modes of every system's element to reach a least cost optimum of the entire energy system. The LUT Energy System Transition modelling tool is a linear optimisation model and performs on an hourly resolution for each time step, which increases the reliability of the results in comparison to annual energy demand balancing or time-slices based approaches. The target of the optimisation is minimisation of the total integrated energy system cost. Costs of the system are calculated as the sum of the annual capital and operational expenditures, including ramping costs, for all considered technologies. The energy system transition was performed for the period from 2015 to 2050 with 5-year time steps. The reference year was chosen as 2015 because for 2020 the energy data was not available at the time when this study was conducted.

The model describes transition of power, heat, transport and industry sectors and covers most of the energy demand and anthropogenic GHG emissions. It also defines the structure and operation of the energy system in order to satisfy the given hourly profiles of power demand, space and domestic water heating demand, energy demand of the transport sector and industrial demand (cement, steel, chemicals, aluminium, pulp and paper and desalination). Bridging technologies provide means for a stronger coupling of all these sectors during the transition. The main technologies enabling integration of these sectors are electrification of heat, transport and industrial processes in general, and specifically various Power-to-X variations, such as Power-to-Heat (PtH), Power-to-Mobility, in particular for electric vehicles (EV), Power-to-Fuels, synthetic fuels such as hydrogen, methane and Fischer-Tropsch fuels, Power-to-Chemicals, which comprises mainly hydrogen-based ammonia and methanol, Power-to-CO_2 which enables CO_2 direct air capture, and Power-to-Water for seawater reverse osmosis desalination. Some processes can be inverted, such as Heat-to-Power (HtP), Fuels-to-Power, or Vehicle-to-Grid, so that highly efficient sector coupling routes can be combined.

The industry sector is modelled from the current state of the art processes to improved technologies expected in future, while also considering options of feedstock switching, if possible. For the chemical industry, the fossil fuel feedstock is replaced by renewable electricity, water and air during the transition to produce the required chemicals [49,50]. In the steel industry, more emphasis is given to the recycling of used steel and steel products and where recycling is not possible, direct electricity and hydrogen as a feedstock replacing coal is used in steel making as described in Otto et al. [51]. In the electricity intensive aluminium industry, processes are not changed, but more emphasis is placed on recycling of aluminium, which will drastically reduce the electricity demand during the transition. The pulp and paper industry, which utilises biomass as feedstock, has low process related fossil GHG emissions, while the electricity and heat demand is covered by increasing levels of renewable electricity, similar to the aluminium industry. All the important raw material streams, waste heat and by-products are captured for each of the transition years for producing the end use products within the respective industries.

A separate model describes the distributed electricity, heat generation and self-consumption of residential, commercial and industrial prosumers. The prosumers can install their own electricity generation (rooftop PV systems) and storage (lithium ion batteries), purchase from or sell surplus electricity to the distribution grid in order to fulfil their power demand. Heat prosumers can install individual heating technologies for space and water heating based on fuels or electricity. Part of prosumers combine both features, electricity and heat self-consumption and can install additional power capacities to run electricity-based heating. The target function for prosumers is minimisation of the cost of consumed electricity and heat, calculated as a sum of power, heat and storage capacities annual cost, cost of fuels, cost of electricity consumed from the grid minus benefit from selling excess electricity to the grid. The share of consumers who are expected to invest in their own electricity generation can progressively increase from 3% in 2015 to 20% in 2050, if profitable. The flow diagram of the LUT model from various input data to output results can be found in Fig. 1 and the simplified scheme of the integrated system is shown in Fig. 2.

The Supplementary Material in the Appendix A provides the detailed description of the model including the model formulation and the routines for cost of energy calculations (section 3. Methods and 4. Results preparation and cost calculations) and the full set of all technical and financial assumptions used in the modelling of the energy transition in Kazakhstan (Tables A1-A3).

2.2. *Applied technologies*

To represent the transition of the current power, heat, transport and industry sectors based on fossil fuels towards an energy system based on high shares of RE, the model considers technologies which can be classified into seven main categories:

- Electricity generation: RE, fossil and nuclear technologies;
- Heat generation: RE and fossil technologies;
- Transportation: road, rail, marine and aviation;
- Industrial processes: cement, steel, chemicals, aluminium, pulp and paper, desalination and water transport technologies;
- Energy storage: electricity, heat and fuels;
- Energy sector bridging technologies;
- Electricity transmission.

Renewable energy, fossil and nuclear generation sources provide electricity to satisfy consumers demand and additional demand from electrical heating, electricity-based industrial processes, electrical transportation and synthetic fuels production.

Fossil based power generation technologies are coal-based condensing and combined heat and power (CHP) plants, oil-based internal combustion engine (ICE) and CHP plants, open cycle (OCGT) and combined cycle gas turbines (CCGT), gas-based CHP and fission based nuclear power plants. Renewable electricity generation includes solar PV technologies (optimally fixed-tilted, single-axis north–south tracking and rooftop PV for residential, commercial and industrial segments), wind turbines (onshore, offshore), hydropower (run-of-river and reservoir), geothermal energy and bioenergy (solid biomass, biogas and waste-to-energy power plants and CHP).

Renewable energy and fossil fuels based heat generation technologies satisfy space heating, domestic heating demands, industrial heat demand and additional heat demand from synthetic fuels production. RE heat generation technologies are concentrating solar power (CSP) parabolic fields, individual solar thermal water heaters, geothermal district heaters and bioenergy (solid biomass and biogas district heat and individual boilers). Fossil heat generation technologies are divided into individual and district heating. Both these categories can use coal, oil and gas as fuels.

The transport sector is divided into four categories: road, rail, marine and aviation. Road passenger transport is divided into light duty vehicles (LDV), buses and 2–3 wheelers (2/3W). Road freight transport is divided into medium-duty vehicles (MDV) and heavy-duty vehicles (HDV). For all road transport vehicles, the model considers four powertrain types: conventional internal combustion engine vehicles (ICE), plug-in hybrid electric vehicles (PHEV), battery-electric vehicles (BEV) and hydrogen-based fuel cell vehicles (FCEV). Rail passenger and freight transport is composed by electrical engine and ICE trains. Marine passenger and freight transport are represented by electrical motor, liquefied methane (LNG) and liquid fuels ICE propelled vessels. Aviation passenger and freight transport are represented by electricity, hydrogen and liquid fuels based aviation.

Industrial processes describe the energy and raw materials demand for cement, steel, chemicals, aluminium, pulp and paper and desalination. Considered technologies include conventional and improved technology for cement production; conventional (coal-based blast

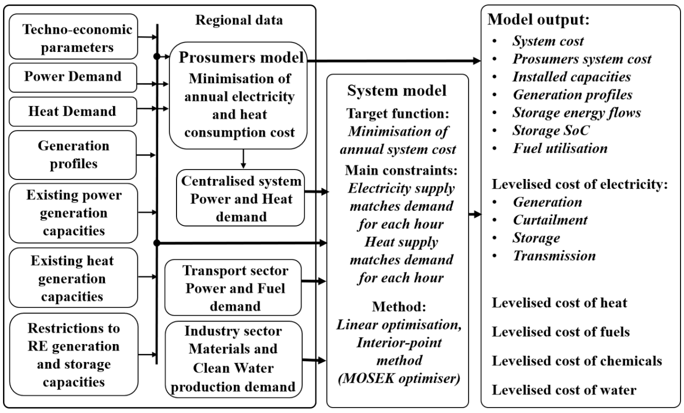

Fig. 1. Main inputs and outputs of the LUT Energy System Transition model.

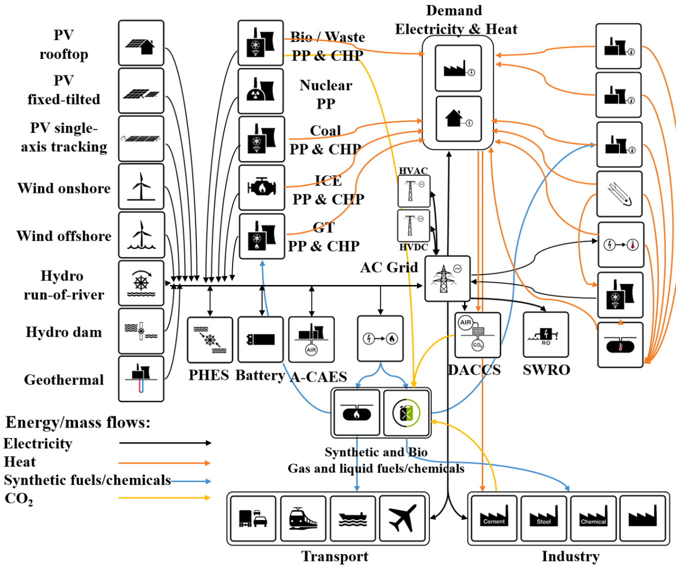

Fig. 2. Integrated system structure scheme.

furnace), hydrogen-based direct reduced iron (H-DRI) with electric arc furnace (EAF) and electrowinning of iron (EWIN), steel scrap recycling using EAF for secondary steel production; ammonia, methanol and naphtha production for the chemical industry; alumina and aluminium production, aluminium recycling for secondary aluminium production; pulp and paper mills for paper production; seawater reverse osmosis (SWRO) desalination and water transport system for clean water supply.

Storage technologies store energy for power, heat and transport sectors in the form of electricity, heat or fuels and can be divided in three main categories: short-term storage composed by Li-ion batteries and pumped hydro energy storage (PHES); medium-term storage composed by adiabatic compressed air energy storage (A-CAES), high and medium temperature thermal energy storage (TES) technologies; long-term gas storage including power-to-gas (PtG) technology, which produces synthetic methane, which can be used in the system.

Bridging technologies are electrolysers, H_2-to-X synthesis, steam turbines, electrical heaters, district and individual scale heat pumps and direct electric heaters, seawater desalination, water storage and pumping technologies. These technologies convert energy from one sector into valuable products for another sector in order to increase total system flexibility, efficiency and decrease overall costs.

The energy transition simulation considers the existing AC power grid of the region, its development trends and projected overall electricity transmission and distribution losses [52].

2.3. Applied scenarios

Transition towards the integrated RE-based energy system is studied for five Best Policy Scenarios:

- BPS-1: power sector;
- BPS-2: power and heat sectors integrated;
- BPS-3: power, heat and transport sectors integrated;
- BPS-4: power, heat, transport and industry integrated sectors, excluding desalination;
- BPS-5: power, heat, transport and industry including desalination integrated sectors, as the full energy system.

For all the scenarios, the energy system must reach zero energy related GHG emissions by 2050, so no fossil coal, gas, oil, or uranium can be used in the system in 2050. The transition modelling is performed in 5-year time steps from 2015 to 2050. For every step the system must satisfy hourly electricity, heat and electrical charging demand, while for synthetic fuels, industrial feedstock materials and desalinated water production it should satisfy an annual demand.

The energy system transition modelling for Kazakhstan was designed with six important constraints similar to the ones applied in Bogdanov et al. [44] for the power and heat energy transition case:

- no new nuclear, coal or oil-based condensing power plants or CHP plants can be commissioned after 2015;
- no new coal or oil-based district heating boilers can be commissioned after 2015;
- oil-based individual boilers can be commissioned after 2015;
- old capacities are decommissioned accordingly to respective technical lifetimes, except 2020 when only half of aging capacity is decommissioned to reflect existing trend to overextend the power plants operation;
- hydropower run-of-river and reservoir (dam) plants and PHES are refurbished every 35 years and not decommissioned, based on empiric observation [53];
- RE capacity share cannot grow more than by 4% per year and 3% for the first step, based on empiric observation [53].

Gas-based power plants, CHP and boilers can be installed after 2015 due to lower GHG emissions and the possibility to switch to bio-methane and synthetic natural gas (SNG) utilisation [54].

2.4. Financial and technical assumptions

The financial and technical assumptions are mostly taken from the European Commission [55], but also from other sources [56–65]. The financial and technical assumptions for all power and heat generation capacities, storage, transmission and bringing technologies and fuels with their respective references are presented in the Appendix A (Tables A1-A3). Assumptions are made in 5-year time steps for the years 2015 to 2050. For all scenarios, weighted average cost of capital (WACC) is set to 7%, but for residential PV prosumers WACC is set to 4% due to lower expectation of financial returns. Electricity prices for residential, commercial and industrial consumers were derived according to Gerlach et al. [66], and extended to 2050 according to Breyer et al. [67], and can be found in the Appendix A (Table A3). Excess electricity generated by prosumers is fed into the national grid and is assumed to be sold for a transfer price of 0.02 €/kWh. The model ensures that prosumers satisfy their own demand for electricity before feeding excess into the grid. District heating distribution grid efficiency increases from the Eurasian region's average estimate of 85% to 92% in 2050 [68] and the district heating share in space and domestic water heating continuously decreases from 70% in 2015 [69] to 50% in 2050, extrapolating the present trends of the heat system decentralisation in Kazakhstan and similar systems in post-Soviet countries, which already have well developed DH systems, but aging infrastructure.

2.5. Demand and resource potential for renewable technologies

Electricity demand assumptions are mostly based on International Energy Agency statistics. Historical electricity consumption for the year 2015 is taken from IEA statistics [70], future consumption is estimated using annual growth rates for the Eurasian region from IEA [71]. Hourly profiles for power demand are calculated according to Toktarova et al. [72]. Profiles for space and water heating demand are taken from Barbosa et al. [73]. Transportation demand for the different transport modes is taken from Khalili et al. [74]. Industrial feedstock and energy demand is calculated based on various sources: cement production [75], steel production [51,76], chemical feedstock demand [50], alumina production [77], aluminium production [77], pulp and paper production [78,79], and seawater desalination demand [80]. Power, heat, transport, and industry demand assumptions for each step of the transition are provided in the Appendix A (Table A4).

The capacity factor profiles for optimally fixed tilted PV, solar CSP and wind energy are calculated according to Bogdanov et al. [81] using global weather data for the year 2005 from NASA [82,83] and reproduced by German Aerospace Centre [84], and single-axis tracking PV according to Afanasyeva et al. [85]. The hydropower feed-in profiles are computed based on the monthly resolved river flow data for the year 2005 [86] as a normalised weighed average flow in locations of existing hydropower plants. Full load hours for fixed tilted PV, single-axis tracking PV and wind turbines in Kazakhstan are presented in the Appendix A (Figures A1-A3).

The potentials for sustainable biomass and waste resources were taken from Bunzel et al. [87] and classified into four main categories: forest and paper industry wastes (black liquor, bark, sawdust), solid wastes (non-recyclable municipal wastes and used wood), solid residues (agriculture and forestry residues) and biogas feedstock (municipal biowastes, manure, sludge). The costs for biomass are calculated using data from the IEA [88] and Intergovernmental Panel on Climate Change (IPCC) data [89]. For solid waste a 50 €/ton gate fee was assumed for 2015, rising to 100 €/ton in 2050. Unsustainable biomass and recyclable wastes cannot be used in the energy system.

Geothermal energy potential was calculated according to the method described in Aghahosseini et al. [90]. Full load hours for wind turbines, solar PV and hydropower plants, potentials of bioenergy and geothermal energy, and upper limits for ground-mounted PV, wind energy and hydropower are provided in the Appendix A (Table A5). The A-CAES storage potential is based on a global A-CAES resource assessment [91].

2.6. Demand, technical and financial assumptions for industry sector

The industry sector is added for the first time to the LUT Energy System Transition model in full detail. The industries traced in detail are cement, iron and steel, chemicals, alumina and aluminium, pulp and paper and desalination. All mentioned industries contribute to the energy demand, whereas chemicals and desalination are also traced for their product cost.

The cement industry transition is assumed for a phase-out of the business-as-usual (BAU) cement process and the phase-in of an improved process, according to transition shares as listed in Table 1. The electricity demand for a ton output of cement, is 106 kWh_{el}/t_{output} and 88 kWh_{el}/t_{output} for BAU and improved process, respectively, while the heat demand is 919 kWh_{th}/t_{output} and 813 kWh_{th}/t_{output} for BAU and improved process, respectively, for an equal temperature level of 1400–1500 °C, according to Farfan et al. [75]. Cement demand for Kazakhstan is taken from Farfan et al. [75].

The steel industry transition assumes a phase-out of the standard oxygen blast furnace (BF-BOF) by 2050, while a consequent increase in steel recycling via the electric arc furnace (EAF) route, and the phase-in of hydrogen direct reduced iron (H-DRI) with a subsequent EAF process step and a later phase-in of an electrowinning process (EWIN). The assumed relative shares are listed in Table 1. The following energy demand data are taken from Otto et al. [51] for H-DRI technology [76], Yuan et al. for EWIN technology and World Steel Association [92] in general. Electricity demand is assumed to be 128 kWh_{el}/t_{output}, 703 kWh_{el}/t_{output}, 929 kWh_{el}/t_{output}, and 3703 kWh_{el}/t_{output} for BF-BOF, EAF, H-DRI + EAF, and EWIN, respectively. The heat demand is assumed to be 320 kWh_{th}/t_{output}, 217 kWh_{th}/t_{output}, 1561 kWh_{th}/t_{output}, and 217 kWh_{th}/t_{output} for BF-BOF, EAF, H-DRI + EAF, and EWIN, respectively, for an equal temperature level of 1200–1300 °C. The BF + BOF route requires 6072 kWh_{th}/t_{output} of high quality anthracite coal, while the EAF, H-DRI + EAF and EWIN processes require 284 kWh_{th}/t_{output} of biochar coal for a high quality steel and a sustainable process. The H-DRI process step requires an additional 2290 $kWh_{th,H2}/t_{output}$.

The chemical industry is structured around three important chemicals: ammonia, methanol and naphtha, as the entire industry can be built on these feedstock chemicals [49]. Naphtha is a valuable by-product from Fischer-Tropsch synthesis and represents about 20% of the total output [93] and is re-allocated within the LUT model from the transport sector to the industry sector. Electricity demand is assumed to be 0.123 $kWh_{el}/kWh_{th,NH3}$ and 0.034 $kWh_{el}/kWh_{th,MeOH}$, and hydrogen demand is assumed to be 1.131 $kWh_{th,H2}/kWh_{th,NH3}$ and 1.246 $kWh_{th,H2}/kWh_{th,MeOH}$, and 0.230 $kg_{CO2}/kWh_{th,MeOH}$. The financial and technical assumptions can be found in Appendix A (Tables A1-A3). The assumptions for ammonia are taken from Fasihi et al. [94] and for methanol from Fasihi and Breyer [95]. The total chemicals demand is projected according to Fasihi et al. [50], thereof the ammonia demand projection is used from Fasihi et al. [94], and the naphtha by-product from FT synthesis is used first, while the remaining chemicals demand is supplied by methanol, as the fundamental chemical feedstock. The global chemicals demand is distributed on a country level according to the relative gross domestic product (GDP) share of a country in the global value, based on the GDP data as used in Toktarova et al. [72]. The BAU chemicals phase-out shares and the RE-based chemicals ammonia and methanol phase-in assumptions are listed in Table 1. The fossil feedstock for the chemical industry for the starting period is taken from the IEA database [70].

The aluminium industry does not require a specific transition pathway, as the industry itself is based on electricity, so transition towards sustainability is possible as soon as the source of input electricity is based on renewable sources. However, the alumina input for aluminium requires heat for the conversion of bauxite, which needs to be also sustainably sourced. For modelling the electricity demand of the

Table 1
Industry processes applied in the LUT Energy System Transition model and respective transition trajectories.

	Unit	2015	2020	2025	2030	2035	2040	2045	2050
Cement									
BAU	%	100	98	92	74	41	15	4	0%
Improved	%	0	2	8	26	59	85	96	100
Steel									
BF-BOF	%	65	58	52	44	32	21	8	0
EAF (recycling)	%	35	41	43	46	50	55	64	73
H-DRI + EAF	%	0	1	5	10	17	20	19	13
EWIN	%	0	0	0	0	1	4	9	14
Chemicals									
BAU	%	100	98	92	74	41	15	4	0
RE-Chemicals	%	0	2	8	26	59	85	96	100
Aluminium									
primary	%	68.4	67.5	65.4	62.6	59.4	56.7	53.9	50.9
secondary	%	31.6	32.5	34.6	37.4	40.6	43.3	46.1	49.1

aluminium industry, the recycling rate is of high importance due to significantly less electricity demand for secondary aluminium. Primary aluminium production is modelled in a two-step approach. First, bauxite to alumina, and second, alumina to aluminium. For the first step, primary aluminium production requires heat input of 4055 $\mathrm{kWh_{th}/t_{output}}$ at 150–200 °C according to the Bayer process [77], while for the second step electricity input of 14,800 $\mathrm{kWh_{el}/t_{output}}$ is required [77]. Secondary aluminium production requires an electricity input of 124 $\mathrm{kWh_{el}/t_{output}}$ and heat input of 1063 $\mathrm{kWh_{th}/t_{output}}$ at 700–800 °C [96,97]. The global aluminium market is expected to grow annually by 2.1% from 56.4 million metric tons in 2015 [98], while the aluminium recycling rate is taken from the International Aluminium Institute statistics [99] and is listed in Table 1. The aluminium demand is based on the capacity per country with additional growth according to the world market development, distributed to countries accounting to the GDP share in global GDP using the projection of Toktarova et al. [72].

The pulp and paper industry is modelled according to the data from the European Commission [78]. The required electricity and heat demand are assumed to be 1200 $\mathrm{kWh_{el}/t_{output}}$ and 6111 $\mathrm{kWh_{th}/t_{output}}$, respectively. About 92% of the heat required is low temperature heat (120–200 °C) and the remaining is high temperature heat (850–1000 °C). The global pulp demand is considered according to Kuparinen et al. [100]. It is assumed that the pulp process does not undergo substantial changes in the future. Currently, there is no pulp production in Kazakhstan, and it is assumed no change will occur in future due to the climatic conditions.

The methanol and ammonia production units are assumed to be fully flexible and that output can be changed from 0 to 100% within 1 h. The operation profiles are optimised by the model. For the cement, steel, aluminium and pulp & paper technologies minimum FLh are set to 4000 h.

Desalination is allocated to the industry sector. The desalination demand, technical and financial assumptions are taken from Caldera and Breyer [80]. Kazakhstan is a landlocked country and factually the Caspian Sea is a saltwater lake. In this study, we assume that the Black Sea is the source of water for desalination, as the closest ocean connected basin. That implies additional costs due to transportation, and additional energy demand for desalination due to slightly higher salinity level. However, due to this approach questions arise on the sustainability of the Caspian Sea water desalination, especially in the context of the Aral Sea crisis.

3. Results and discussion

This section is structured as a brief overview of the key insights of broadening the sectoral scope (section 3.1) and is followed by an energy system perspective of a steadily enlarged energy system for the sectors power, heat, transport, industry excluding and including desalination.

3.1. *Overview on fundamental trends towards carbon neutrality in the energy system*

The five scenarios are analysed in a sequence from BPS-1 to BPS-5, so that the impact of sector coupling can be studied as a consequence of adding different energy sectors. Table 2 summarises the key energy system metrics for a 100% RE system, achieved in the year 2050.

A clear trend can be observed, that an increasing level of energy system integration leads to a lower LCOE and curtailment, and a more efficient use of storage components. While the energy system flexibility is positively influenced by electrolysers, the solar PV share is increasing, despite the low resource availability in the winter half year. The LCOE is steadily decreasing from 62 €/MWh (BPS-2) to 42.5 €/MWh (BPS-5), even though the overall electricity demand is increasing. The LCOH is decreasing from 37 €/MWh (BPS-2) to 34.5 €/MWh (BPS-5). The curtailment is decreasing from 12.8% (BPS-2) to 9.6% (BPS-4), while it increases again to 12.0% (BPS-5), due to very low flexibility for energy system integration offered by the expensive SWRO desalination capacities, forcing an operation mode close to baseload [101,102]. Remarkable is the continuously increasing electricity generation share from solar PV despite strong seasonality observed in Kazakhstan, indicating a strong impact of very low PV LCOE in conjunction with high PtX flexibility [103]. The specific battery capacity, expressed in units of $\mathrm{GWh_{cap}/GW_{PV}}$ is slightly declining from 1.68 $\mathrm{GWh_{cap}/GW_{PV}}$ (BPS-2) to 1.56 $\mathrm{GWh_{cap}/GW_{PV}}$ (BPS-5), while the specific gas storage is strongly decreasing from 185 $\mathrm{GWh_{cap}/TWh_{el}}$ (BPS-2) to 60 $\mathrm{GWh_{cap}/TWh_{el}}$ (BPS-4), but slightly increasing to 73 $\mathrm{GWh_{cap}/TWh_{el}}$ (BPS-5), which is driven by the inflexible operation requirement of the desalination units due to economic reasons. Electrolysers can be identified as key drivers for flexibility, LCOE and curtailment reduction, as observed from increasing specific electrolyser capacities in ratio to total electricity generation from 11.4 $\mathrm{MW_{el}/TWh_{el}}$ (BPS-1) to 70.6 $\mathrm{MW_{el}/TWh_{el}}$ (BPS-4).

Detailed results for all five scenarios are provided in the Appendix A (Tables A6-A20 and Figures A4-A21).

3.2. *Transition for the power sector*

Transitioning of an isolated power sector towards 100% RE supply seems to be the least challenging part: no new capacity needs to be built in the initial years of the transition due to existing overcapacities. The existing fossil fuel based generation capacity can be used until the end of its technical lifetime and gradually substituted by RE generation while oldest fossil generation units are decommissioned at the end of their technical lifetime. Due to the lower FLh of RE generation technologies, total capacity of the system will increase in the process of defossilisation, and the expected growth in general electricity demand will also lead to growing generation capacities. Fig. 3 describes the power generation capacity and generation mix through the transition.

By 2030, most of the existing coal-based capacities will reach end of

Table 2
Key energy system metrics for the five scenarios. Levelised cost of energy is defined by total annualised energy system cost divided by total final energy demand.

Scenario	LCOE	LCOH	LCO Energy	electricity generation	curtailment	PV share of generation	battery specific	electrolyser specific	gas storage specific
units	€/MWh$_{el}$	€/MWh$_{th}$	€/MWh	TWh	%	%	GWh$_{cap}$/GW$_{PV}$	MW$_{el}$/TWh$_{el}$	GWh$_{cap}$/TWh$_{el}$
BPS-1	55	–	55	114	11.9	45	1.14	11.4	51
BPS-2	62	37	46.8	262	12.8	67	1.68	57.9	185
BPS-3	55	35	48	336	11.6	73	1.69	68.8	125
BPS-4	46	35	49.5	402	9.6	78	1.60	70.6	60
BPS-5	42.5	34.5	46.7	737	12.0	80.5	1.56	59.7	73

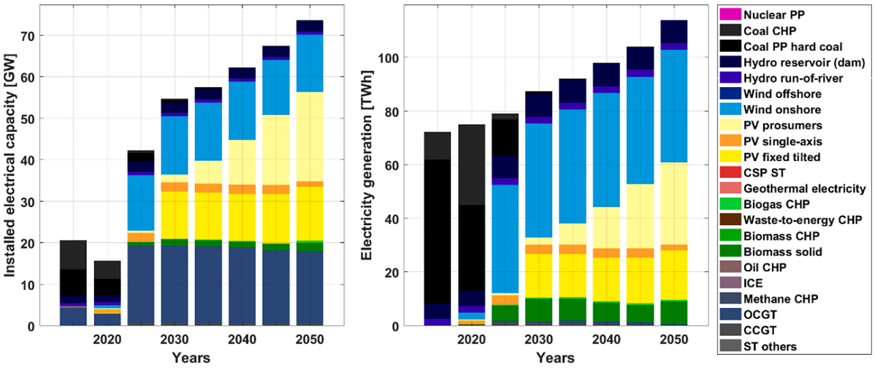

Fig. 3. Installed capacities of electricity generation technologies (left) and electricity generation (right) for the power sector transition scenario (BPS-1).

their technical lifetime and can be substituted by modern RE and gas-based generation. During the initial steps of the transition, wind turbines and hydropower generation are economically feasible, due to more stable generation profiles, however later solar PV generation becomes the least cost source of energy, due to projected cost reduction of PV and battery storage technologies. Similarly to findings of Praliyev et al. [104] fixed tilted PV is beneficial for the system compared to tracking PV, while the systems are quite close and a coexistence may be likely.

Biomass utilisation in power generation significantly increases after 2020, providing 5 TWh$_{el}$ in 2025 and 8 TWh$_{el}$ in 2030, partially substituting coal generation. However, the use of biomass is limited by the sustainable biomass potential, in the frame of this study only sustainable types of biomass, in particular residues and unrecyclable wastes, can be used for energy supply.

Storage becomes more important with growth in RE generation share, so massive installations of storage technologies start in the 2030 s the same time as most of the fossil generation leaves the system (see Fig. 4). The gas storage has the highest capacity of available storage options through the transition. During the initial steps of the transition, gas storage acts as a buffer storage for biomethane, but later it increasingly plays the role of seasonal storage and compensates the seasonality of RE supply and power demand. However, from energy output perspective the role of seasonal gas storage is minor, as only 1.25 TWh of electricity is generated from synthetic methane in 2050 (1.3% of total demand), while the throughput of short-term battery storage

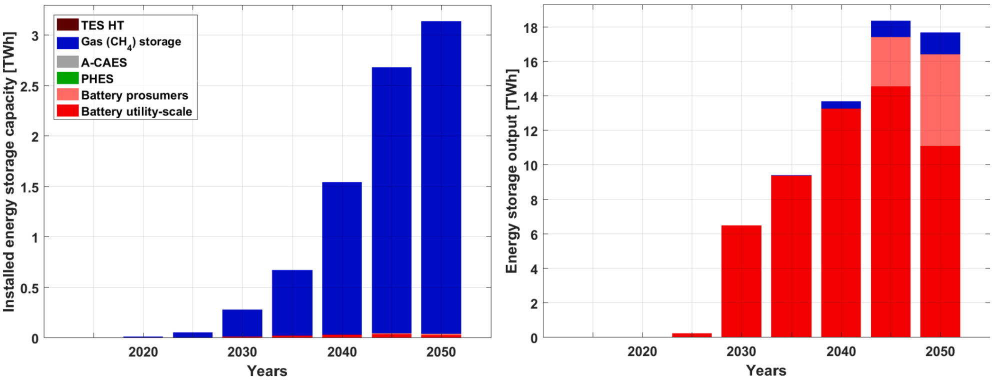

Fig. 4. Installed capacities (left) and electricity output (right) of energy storage technologies for the power sector transition scenario (BPS-1).

exceeds 16 TWh. Overall, electricity cost in the system significantly decreases from about 65 €/MWh in 2015 to 55 €/MWh in 2050 (see Fig. 5), additional costs for the energy storage are compensated by cost decrease in RE-based generation through the transition.

3.3. Transition of the power and heat sectors

The transition of integrated power and heat sectors will demand a fast growth in RE generation capacity to substitute the existing aging electricity generation infrastructure and satisfy the additional electricity demand from electrical heating. Fig. 6 presents the structure of the energy system for every 5-year time step for the transition period.

During the later years of the transition, PV becomes a dominating technology, representing more than half of the total power generation capacity, while absolute capacity and generation of wind turbines decreases after 2045 due to decommissioning of old wind farms and its partial substitution by new PV plants. In 2050, the optimal share of wind-based generation decreases to 28% of the total electricity generation, while the share of solar PV increases to 67%.

The share of hydropower and biomass in the power generation is limited. For hydropower dams it reaches the technical potential, while hydropower run-of-river plants cannot compete on cost basis with other variable RE sources. Biomass is effectively utilised in the heating sector.

The heat sector becomes one of the main electricity consumers with consumption comparable to the power sector. Starting with district heating using a fossil fuels based structure, dominated by coal, the heat sector transforms towards utilising higher shares of individual heating systems, electricity and sustainable biomass-based heating. Installed capacities for heat supply and heat generation during the transition are presented in Fig. 7.

In 2015, most of the heat was generated from coal by CHP and district heating plants. In 2050, more than 80% is generated from electricity, mostly by heat pumps and the rest from sustainable biomass. Even though the heating sector is nearly carbon neutral by 2045, defossilisation speed is much slower compared to that observed in the power sector. Heat demand peak during winter time, when RE generation is limited, and high efficiency of fuels to heat conversion make fuels based heating more competitive. Due to the same reasons most of the biomass is used for heat production, specifically, providing additional heat during the winter months.

The LCOE of the integrated power and heat system decreases through the transition, similarly to the power sector case (BPS-1). However, the LCOE in 2050 is slightly higher and some increase occurs in 2045–2050 as seen in Fig. 8. The main reason is the increased seasonality of the system and the need to store more energy in the form of synthetic hydrocarbons. Similar tendency is observed for levelised cost of heat (LCOH). After an initial drop in 2020 due to the model's decision to reduce expensive oil-based heating, in 2025 heat cost increases due to system modernisation and after that steadily decreases. For most of the transition the LCOH stays around 37 €/MWh, starting from 38 €/MWh in 2015 to 37 €/MWh in 2050.

From 2015 until 2025, cost of electricity generation is increasing, which is mainly attributed to the assumed GHG emission cost increase during the period, making generation from existing coal capacities more expensive. From 2025, fuel related costs start decreasing, and at the same time capital expenditures increase due to substitution of the aging fossil fuels based capacities with RE capacities. After 2025, the LCOE consistently decreases, due to decline in fossil fuels use and reduction of the costs related to the installation of new RE capacities, after 2030 significant storage capacity is needed to balance mostly RE-based generation, but even additional storage related costs cannot change the general trend of cost decline. In 2050, LCOE slightly increases, due to complicated and costly substitution of remaining fossil generation.

3.4. Transition for power, heat and transport sectors

The transport sector integration leads to further growth of power generation capacities. Additional solar PV and wind energy capacities are added to cover the electricity demand, additional demand for electrification of the transport sector and synthetic fuels production. Part of the low temperature heat demand for district heating systems is covered by excess heat from synthetic fuels production, which is a positive effect due to coupling of the sectors heat and transport. At the same time heat generation systems can provide heat to CO_2 direct air capture units, which are part of the synthetic fuels synthesis system, all based on electricity, which demonstrates a further positive sector coupling effect.

Transport sector defossilisation demands direct and indirect electrification of road, rail, marine (not present in Kazakhstan as it is a landlocked country) and aviation transport modes. Starting from a nearly 100% fossil fuel based, the transport sector transitions to a mostly electricity-based sector. Within the transport modes, where direct electrification is not possible, fossil fuels are substituted by hydrogen, sustainable biofuels and Fisher-Tropsch synthetic fuels. Direct and indirect electrification leads to 31 TWh of additional electricity demand for direct electrification and 46 TWh of electricity and 5.5 TWh of heat for synthetic fuels production. At the same time, overall electrification leads to drastic decrease in final energy demand for the transport sector, despite the assumed growth in passenger transportation by about one third and freight transportation growth by about 50%. The structure of energy demand through the transition for the transport sector is

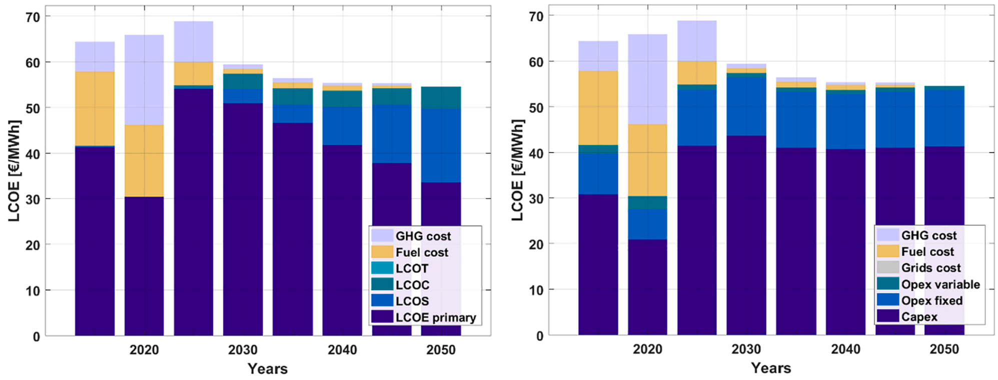

Fig. 5. LCOE components by function (left) and category (right) during the transition period for the power sector scenario (BPS-1).

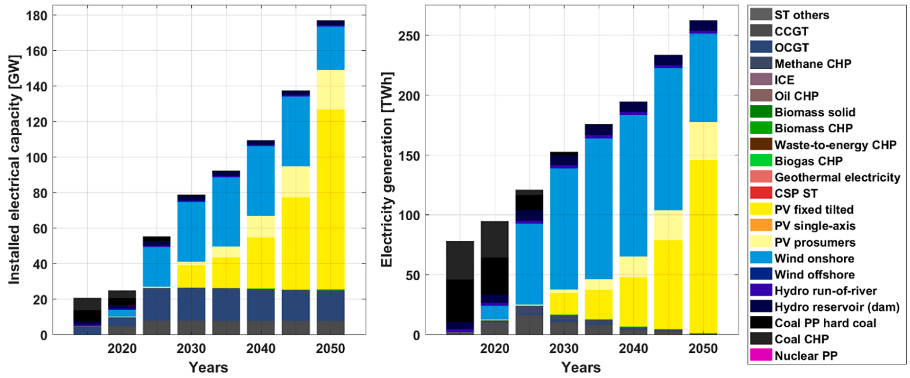

Fig. 6. Installed capacities of electricity generation technologies (left) and electricity generation (right) for the power and heat sectors transition scenario (BPS-2).

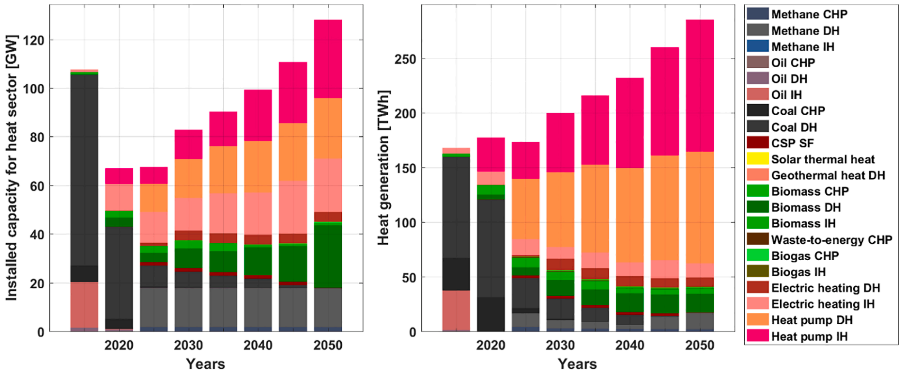

Fig. 7. Installed capacities of heat generation technologies (left) and annual heat generation (right) in the power and heat sectors transition scenario (BPS-2).

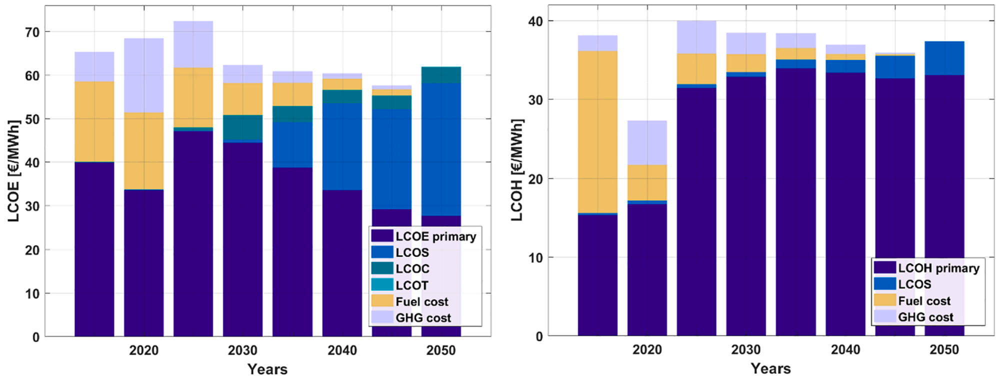

Fig. 8. LCOE components by function (left) and LCOH (right) during the transition period for the power and heat sector scenario (BPS-2).

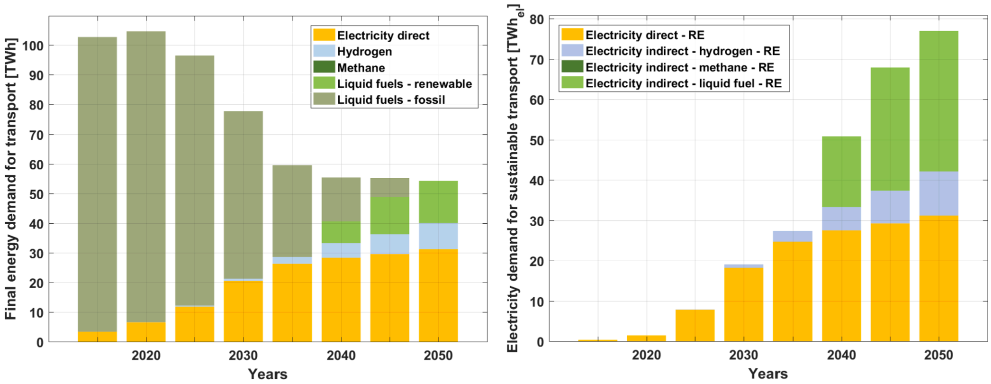

Fig. 9. Final energy demand (left) and electricity demand for the transport sector (right) during the transition period in the BPS-3.

presented in Fig. 9.

Synthesis of Fisher-Tropsch fuels, methane and hydrogen, the liquefaction units have limited flexibility and have to operate in baseload through the year, which creates some additional demand during periods of energy deficit. However, most of the energy demand comes from highly flexible water electrolysers, where CO_2 DAC units prefer very high full load hours, for economic reasons, similar to SWRO desalination units. In total, fuel synthesis provides additional flexibility to the energy system via demand response of electrolysers. Direct electrification could also provide additional flexibility in case of smart charging and V2G integration, which is not modelled in this study.

The transition of the integrated power, heat and transport sectors (BPS-3) leads to a decrease in RE supply cost, compared to the power and heat sector scenario (BPS-2). Additional flexibility from the transport sector, mainly provided by electrolysers, compensates the growth of VRE resources share while the share of storage throughput in total energy demand stays the same. Finally, LCOE and LCOH of the system decreases, due to growing electricity demand from the transport sector, and availability of 'free' heat recovered from PtX processes losses. The system installs more RE capacity at later steps, leading to a higher relative share of new capacities, while the cost of RE generation and storage technologies is expected to decrease. The LCOE for the transition period is presented in the Fig. 10.

3.5. *Transition of the power, heat, transport and industry sectors*

The transition trajectory of the integrated power, heat, transport and industry sectors is similar to the one seen for the case of power, heat and transport sectors. For the defossilisation and electrification of the industry sector demand, additional electricity and heat generation during the later steps of the transition provides additional flexibility to the power and heat sectors. However, this leads to, not only a proportional growth of the electricity generation capacities, but also changes in the electricity generation structure. The share of PV in the total capacity and generation slightly increases from nearly 73% of the total generation for power, heat and transport to 78% in case of all energy sectors integrated. The share of hydropower and biomass decreases due to reaching the maximum technical potential limit and growing electricity demand. The share of wind energy in the optimal mix decreases even though the technical potential is not reached, but as a consequence of excellent solar PV competitiveness and additional flexibility provided by the electrolysers. The structure of the power generation capacities and power generation through the transition is shown in Fig. 11.

Overall, the industry sector coupling is beneficial for the total system. Flexibility provided by the industrial energy demand allows the system to balance the total energy demand and increase the use of the least cost PV generation, while in the power and heat system (BPS-2) due to stronger seasonality of demand, the share of wind energy would be

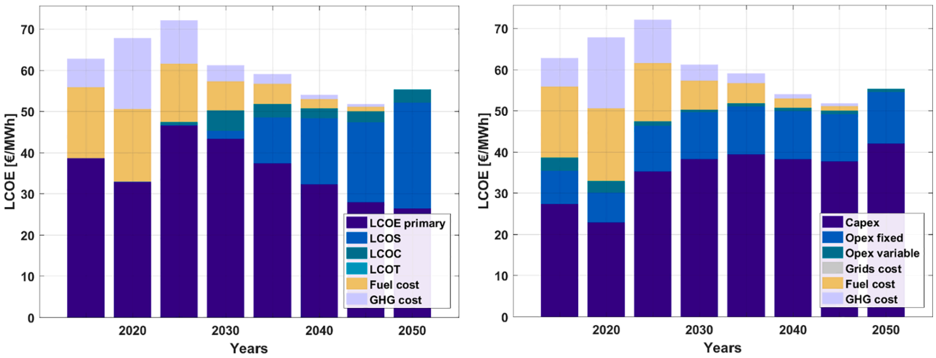

Fig. 10. LCOE components by function (left) and category (right) during the transition period for the power, heat and transport sector scenario (BPS-3).

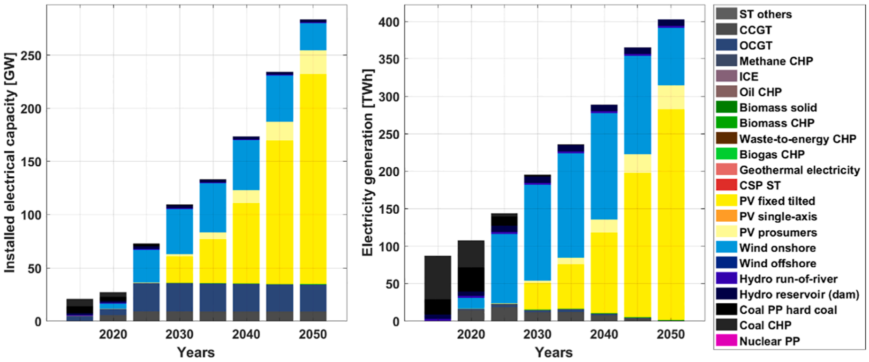

Fig. 11. Installed capacities of electricity generation technologies (left) and electricity generation (right) for the power, heat, transport and industry sectors transition scenario (BPS-4).

much higher to balance the higher demand during the winter time. At the same time, additional electricity demand from the industry sector also speeds up the relative defossilisation of the power sector, since more RE capacities are installed to cover the demand and the share of old fossil generation erodes faster. However, a similar effect is not observed from the heat sector perspective. Additional heat demand for industry leads to higher capacity and generation of utility-scale heat pumps and direct electrical heating. Therefore, the share of old fossil heating in the capacity mix decreases, but the share of fossil fuels in total generation even increases during some periods. The reason is higher demand of high temperature heat, which cannot be provided with direct electrical heating or heat pumps, while the potential of carbon–neutral biofuels is limited and synthetic fuels cost is not competitive during the early and middle stages of the transition, even considering GHG emission cost. The structure of heat generation installed capacities and annual heat generation is shown in Fig. 12.

In total, the additional industry sector coupling leads to 59 TWh_{el} and 32.5 TWh_{th} of additional electricity and heat demand for industrial processes, 21% and 10% of total electricity and heat demand, respectively. Electricity generation capacity increases by 23%, with a relatively higher share of PV in the capacity mix and lower PV FLh compared to wind turbines. Heat generation capacity increases by only 2%, since it is mostly defined by peak space heating demand. The industry sector's products demand and energy consumption are shown in Fig. 13.

From the total 56 TWh_{el} of electricity demand for the industrial processes, 44 TWh_{el} is consumed by water electrolysers to produce hydrogen for steel making and chemical industry. These electrolysers provide most of the additional flexibility in the system, changing the flexibility of the industrial processes. Decreasing the minimum FLh of the cement, steel and aluminium plants to as low as 1000 FLh had no significant impact on the system structure and the energy costs, compared to the default minimum of 4000 FLh. The LCOE structure through the transition is shown in Fig. 14.

During the initial transition phase, LCOE of a fully integrated energy system (BPS-4) is similar to the one for power, heat and transport (BPS-3). But, with the electrification of the industry sector, LCOE decreases faster than observed for BPS-3. This is because of additional electricity demand growth and higher share of additional low cost RE capacities. In 2050, LCOE reaches 46 €/MWh, 20% lower than for the case of the integrated power, heat and transport system (BPS-3). Additional flexibility from the industry sector also leads to lower shares of storage and curtailment in the total LCOE.

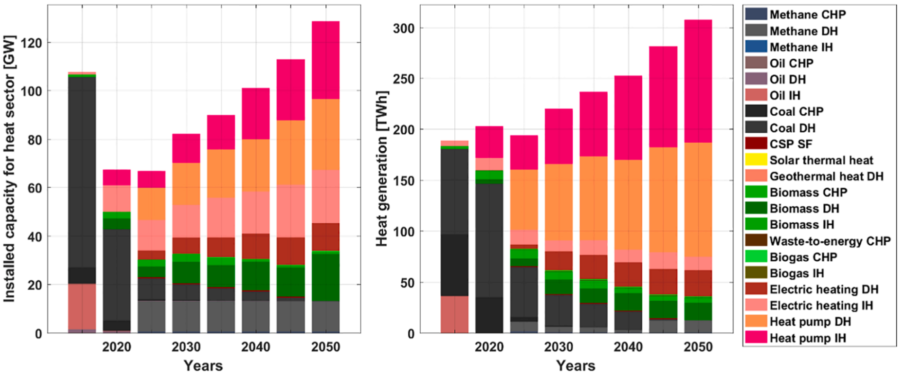

Fig. 12. Installed capacities of heat generation technologies (left) and annual heat generation (right) in the power, heat, transport and industry sectors transition scenario (BPS-4).

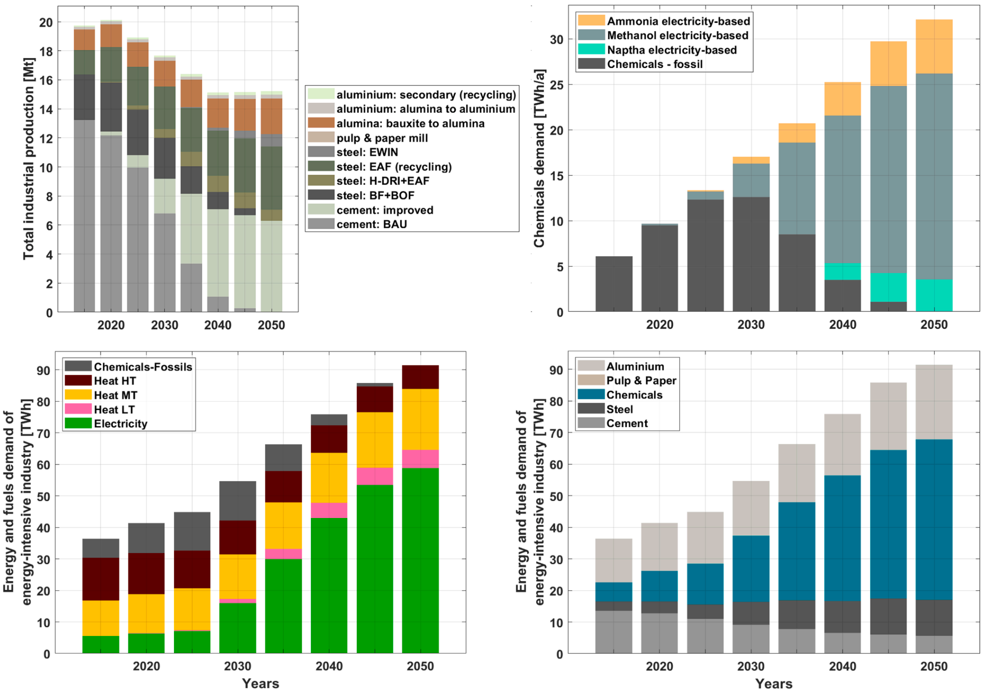

Fig. 13. Industry sector non-chemical products demand (top left), chemical product demand (top right), energy demand for industrial processes by energy type (bottom left) and by industry (bottom right) during the transition period for the power, heat, transport and industry sector scenario (BPS-4).

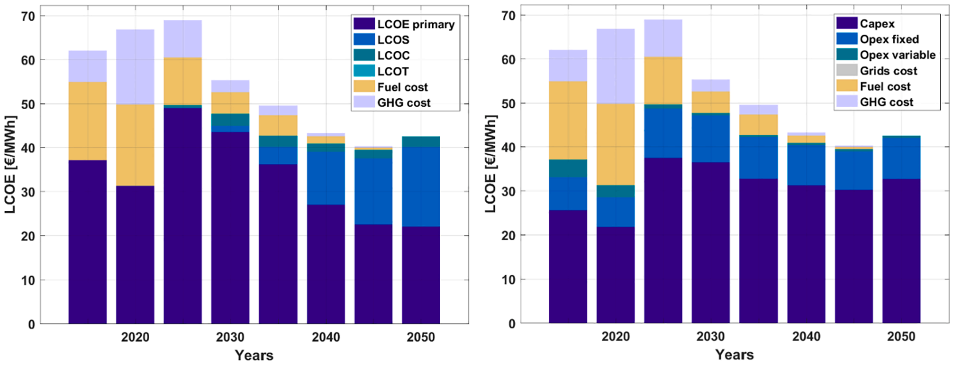

Fig. 14. LCOE components by function (left) and category (right) during the transition period for the power, heat, transport and industry sector scenario (BPS-4).

3.6. *Transition of the power, heat, transport and industry sectors with seawater desalination*

The need for seawater desalination may arise in near future for Kazakhstan, so that this industry sub-sector will provide clean water to satisfy the agricultural, industrial and residential water demand while the traditional water sources are exhausted. Many regions already face freshwater deficit, and considering limited aquifers capacity, seawater desalination is seen as a sustainable solution. The seawater desalination demand projections from Caldera and Breyer [80] and the cost of desalinated water at demand site are shown in Fig. 15.

Since Kazakhstan is a landlocked country which is densely populated and agricultural regions are very distant from the sea, sustainable freshwater supply will demand a significant amount of energy, from which the lion's share will be used for water pumping and a minor share for seawater desalination itself. Consequently, for the specific case of

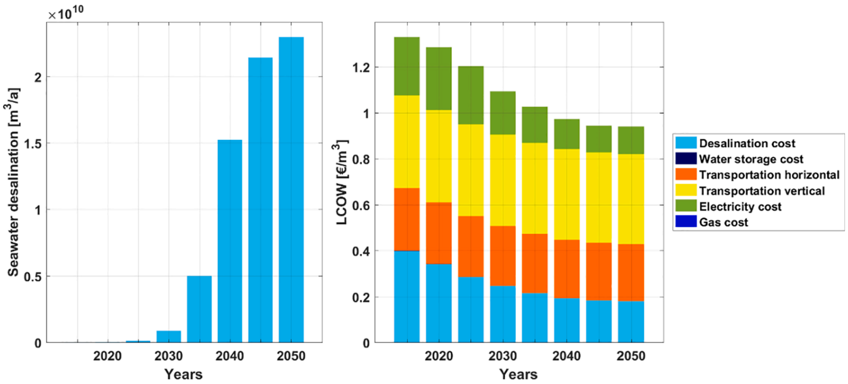

Fig. 15. Water desalination demand projections (left) and the final cost of desalinated water at demand site (right) for the power, heat, transport, industry and desalination sectors transition scenario (BPS-5).

Kazakhstan water transportation costs also form most of the final desalinated water cost. Considering the desalinated water demand projections from Caldera and Breyer [80], additional electricity demand for freshwater supply may double the total electricity generation capacity, which may reach 500 GW for an integrated system (BPS-5). Most of the desalination related electricity demand growth occurs in later years of the transition, further increasing the PV share in the total generation mix and speeding the defossilisation of the electricity generation as it is shown in Fig. 16.

Due to high capital expenditures of the desalination and water supply system, seawater desalination tends to work on baseload and does not provide significant flexibility to the system [101,102], even though technically it can be rather flexible. Although additional energy demand for desalination is stable over the year and decreases, relative seasonality of total electricity demand profile, consequently leading to lower system reliance on long term storage.

Since the dominant desalination technology, reverse osmosis, is electricity-based, desalination sector integration has no impact on the heat system and the heat generation structure does not change compared to the integrated power, heat, transport and industry scenario (BPS-4). The LCOE in the integrated system further decreases to 43 €/MWh, the lowest value observed across all scenarios, mainly due to lower primary electricity generation costs, while curtailment related cost slightly increases.

3.7. Sector coupling impacts on the energy system

The results show that the impact of different sector coupling on the system severely depends on the characteristics of the integrated system: the demand profiles, its flexibility, and cost of the final product storage. If the RE production profiles do not complement the demand profile, demand is not flexible and the possibility of the long term storage of the final product is limited, as it is the case for the heat sector, the integration can make the transition towards 100% RE more complicated. Adding heat demand in the case of Kazakhstan increased the seasonality of the energy demand and the mismatch between energy supply and demand profiles, while heat storage itself is rather cheap, options to store heat for long periods in a cold climate is limited due to high losses. That increased the need to use PtX based long term energy storage and led to higher system cost. Integration of sectors with more flexible demand and low-cost final product storage cost led to the opposite observation. For the case of transport and industry sectors, the flexibility of electrolysers and low-cost hydrogen storage allow the system to decrease the use of other more costly storage options, and switch to

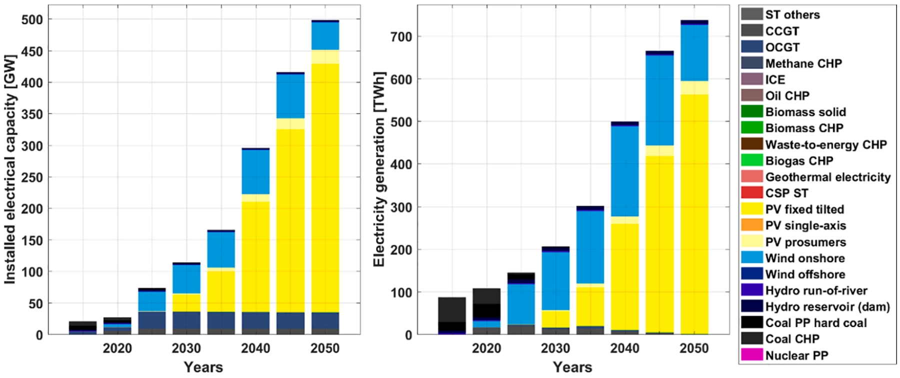

Fig. 16. Installed capacities of electricity generation technologies (left) and electricity generation (right) for the power, heat, transport, industry and desalination sectors transition scenario (BPS-5).

lower cost PV electricity supply and decrease curtailment, leading to an overall more efficient system with lower cost energy supply. Even inflexible demand can be beneficial for the system, if it allows to decrease the overall energy supply and demand mismatch, as found for the case of industry, transport and most importantly for the economically inflexible seawater desalination system.

Similar results have been reported on the example of Europe [105]: integration of power, heat and transport sectors and additional flexibility options in the integrated system led to 28% lower system cost, and exceeded the parallel benefit from regional integration. Smart energy system studies for Europe [27,106] further highlight synergy effects from integrating power, heat and transport sectors. This effect is not only limited to the northern hemisphere with cases of Europe and Kazakhstan, since in Brazil, a region with significantly lower heat demand and different climate conditions, sectors integration also resulted in higher system flexibility and allowed to integrate high shares of PV and CSP based generation at low cost [107]. These studies applied the overnight system simulation method and thus could not catch the impact of power demand growth on the electricity generation cost.

Sectors integration and electrification allows to speed up the defossilisation of energy supply, since the role of existing fossil capacities is eroded by fast growing RE generation, and most importantly allows to decrease the electricity supply cost, since the share of the RE capacity built in later steps of the transition increases. In integrated energy systems, where electricity generation becomes the backbone of the entire system, it leads to overall lower energy and products cost.

Integration of additional flexibility technologies like smart charging of battery electric vehicles (BEV), BEV battery utilisation for system balancing in vehicle-to-grid applications (V2G) and regional integration of energy systems can provide additional flexibility [108]. Integration of additional technologies like CO_2 direct air capture with carbon storage (DACCS) or carbon capture and utilisation (CCU) for sustainable and unavoidable CO_2 point sources [109], and additional energy demand from these technologies can also lead to higher flexibility in the system, if capex of these technologies will be low enough.

4. Conclusions

Transition towards a 100% RE-based energy system was modelled for five scenarios considering different energy system structures, from a limited power sector consideration to a full energy system for power, heat, transport, industry with desalination sectors. The modelling results show that a 100% RE based system is achievable for the applied case of Kazakhstan even considering all energy sectors' demand and additional demand for international transport, chemical industry feedstock and desalination, which are typically not included in sustainable energy transition studies utilising high shares of renewables. The feasibility of a 100% RE system for the case of Kazakhstan, a country with one of the harshest climate conditions and a highly energy-intensive economy, can exhibit the possibility of such a transition in other regions with similar climates, economic and geographic conditions.

Integration of additional sectors has a significant impact on the system structure, including the optimal generation mix, storage use and finally on the levelised cost of energy of the system. Due to different sectors defossilisation and massive electrification, the power sector becomes the backbone of the integrated energy system, providing a lion's share of primary energy demand. At the same time, defossilisation of the power sector increases reliance on the variable RE sources, mainly wind and solar, and consequently demand of costly electricity storage increases. Integration of additional sectors enables access to low-cost flexibility, allowing to substitute electricity storage options by low-cost product storage options, like power-to-heat and heat storage in case of heat sector integration; hydrogen, gas and liquid fuels storage in case of transport sector integration; hydrogen and synthetic chemicals in case of industry sector coupling. Water electrolysers provide the most valuable flexibility for the entire energy system, in particular in combination with low-cost solar PV electricity. Integration of sectors which do not provide flexibility, but demand baseload electricity, can also result in the system efficiency growth for some specific cases. For the applied case of much higher electricity and heat demand during winter time, additional baseload demand allows to decrease the seasonal mismatch of final energy demand and variable RE supply, and thus decrease reliance on high cost long-term electricity storage. Modelling considering integration of different sectors also changes the relative speed of the defossilisation, the age and capacity structure of the power sector due to different final electricity demand trajectories. Considering all sectors integration and electrification more capacities must be installed, especially in the later years when RE costs are expected to be significantly lower, that erodes the fossil fuels based generation share and consequently decreases the average system cost. Since solar PV becomes more cost competitive towards wind turbines, additional demand growth in the latest steps also leads to higher shares of PV in the optimal generation mix.

Overall, sectors integration and electrification facilitates the transition and decreases the cost by resolving many of the discussed technological difficulties on the way of transition, such as high energy storage demand, high cost of electricity, heat and synthetic fuels supply. Considering different transition speeds, the energy sectors complement each other during the transition, allowing to increase each of the sectors efficiency while reducing total system costs. A fast decarbonisation of the power sector at a first step of the transition compliments direct electrification of the heat and transport sectors and allows to shrink overall greenhouse gas emissions. Indirect electrification of the heat, transport and industry energy demands at a later step offers additional flexibility to the power sector and eases the transition towards a 100% RE-based energy supply. Considering this, simulation of individual sectors transition cannot provide a balanced view on the possible transition pathway options as most valuable sector coupling effects are ignored, and a sector separated view underestimates complexity and overestimates the cost of the transition. An integrated energy system transition simulation, placing full sector coupling into the heart of considerations, enables fundamental insights on an optimal energy system transition pathway.

CRediT authorship contribution statement

Dmitrii Bogdanov: Conceptualization, Methodology, Software, Investigation, Data curation, Writing - original draft. **Ashish Gulagi:** Investigation, Writing - review & editing. **Mahdi Fasihi:** Investigation. **Christian Breyer:** Investigation, Writing - review & editing, Funding acquisition.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2020.116273.

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Publication VII

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Low-cost renewable electricity as the key driver of the global energy transition towards sustainability

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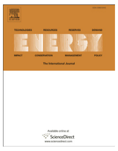

Low-cost renewable electricity as the key driver of the global energy transition towards sustainability

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ABSTRACT

Climate change threats and the necessity to achieve global Sustainable Development Goals demand unprecedented economic and social shifts around the world, including a fundamental transformation of the global energy system. An energy transition is underway in most regions, predominantly in the power sector. This research highlights the technical feasibility and economic viability of 100% renewable energy systems including the power, heat, transport and desalination sectors. It presents a technology-rich, multi-sectoral, multi-regional and cost-optimal global energy transition pathway for 145 regional energy systems sectionalised into nine major regions of the world. This 1.5 °C target compatible scenario with rapid direct and indirect electrification via Power-to-X processes and massive defossilisation indicates substantial benefits: 50% energy savings, universal access to fresh water and low-cost energy supply. It also provides an energy transition pathway that could lead from the current fossil-based system to an affordable, efficient, sustainable and secure energy future for the world.

1. Introduction

The Sustainable Development Goals (SDGs) report [1] highlights risks posed by the impact of climate change in eroding and reversing decades of progress on inequality, food security and other SDGs. In this context, a transition of the global energy system is of utmost relevance as energy use is responsible for the majority of global greenhouse gas (GHG) emissions [2]. Transition towards higher shares of renewable energy (RE) will simplify achieving universal access to clean and affordable energy, reducing GHG emissions and decreasing water scarcity by eliminating freshwater usage in thermal power plants [3]. This transition has already started with renewables providing more than 27% of the global electricity generation by end of 2019 [4], including about 11% generated by new renewable energy technologies, mainly wind turbines and solar photovoltaics (PV). Driven by cost reductions, renewable electricity is increasingly cost-competitive with conventional thermal power plants: in some regions RE cost is lower than running costs of existing fossil and nuclear power plants [5], and solar PV has emerged as the least costing source of electricity production in the history of mankind [6]. A similar trend is observed in the heat sector: about 10.1% of the heat used worldwide in 2019 was produced from sustainable sources, including renewable electricity [4]. The transport sector is still lagging in adopting sustainable solutions: despite the rapid development of electrification, hybrids and synthetic fuels, oil and petroleum products contribute the vast majority of energy demand.

Many global energy scenarios have tried to project the future transition of energy systems based on a wide ranging set of assumptions, methods and targets from a national as well as global perspective [7]. Most of the global energy transition studies present pathways that result in CO_2 emissions even in 2050, which are not

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compatible with the goals of the Paris Agreement (as is with most IEA global scenarios except the NZE2050 in the recent WEO 2020 [6]) and are dependent on the role of technologies with questionable sustainability (fossil CCS and nuclear) as in the Global Energy Assessment of the International Institute for System Analysis (IIASA) [8], while later studies such as Grubler et al. [9] consider decline of final energy demand by 2050, despite increasing population, income and activity. The Centre for Alternative Technology [10] outlines scenarios on global, regional, national and subnational scales that illustrate how the Paris Agreement targets could be realised. Most of the studies lay out pathways to phase out non-sustainable technologies, while integrating sustainable renewable energy options to satisfy the increasing energy demands of the future global society. Several studies on the global level with different models and assumptions show that such a transition can be achieved by 2050: Pursiheimo et al. [11] using the TIMES-VTT model, Löffler et al. [12] with GENeSYS-MOD, Jacobson et al. [13] and Teske [14] have different regional structures, technology portfolios, technical and financial assumptions, but all prove that a renewable energy based system is highly cost competitive compared to the conventional system. Jacobson et al. [15] and Teske et al. [14] also show that benefits of a renewable energy system are not limited to radical declines in GHG emissions and low energy system costs, but also lead to lower social costs, and additional jobs. However, limitations in different methods of global energy scenarios lead to some of them failing to acknowledge the role of storage technologies in future energy systems [7] and the impact of sector coupling Power-to-X technologies, namely Power-to-Heat and synthetic fuels production. Hansen et al. [16] provide an overview on 100% renewable energy system studies and highlight the importance of multi-sector analyses, hourly temporal resolution, sector coupling and Power-to-X technologies. In order to reach full sustainability, the use of biofuels should be limited to unavoidable residues and synthetic fuels have to play a more significant role, so that fuel production does not compete with food crops. Emerging issue of water scarcity has to be taken into account, considering the additional energy demand for water desalination, purification and transportation in order to enable universal access to clean water for residential, agricultural and industrial use [17].

While the global energy system and the factors that influence it are far more complex than what any scenario or narrative can capture, this research presents a possible cost-driven energy system transition from the present structure (2015) towards a fully sustainable 100% renewable system in 2050, in high regional and hourly temporal resolution across the power, heat, transport sectors, and seawater desalination. This scenario presents a possible global pathway for the defossilisation of the current energy system to fulfill the IPCC's 1.5 °C scenario requirements in a cost-effective manner.

2. Methods

The LUT Energy System Transition model initially applied across the power sector [18], is further expanded to involve collating all relevant energy data across power, heat, transport and desalination into 145 sub-regions of the world. This novel approach enables a more decentralised, cost-driven energy transition optimisation across 145 sub-regions of the world that can satisfy their energy demands through resources available within the corresponding sub-regions. Lastly, a post-processing of the results involving analyses and visualisation from the 145 sub-regions produces compiled results for nine major regions, Europe, Eurasia, Middle East Northern Africa (MENA), sub-Saharan Africa (SSA), South Asia (SAARC), Northeast Asia, Southeast Asia, North America and South America, which are further aggregated into global results. The high temporal and geospatial resolutions allow to avoid a cooper plate effect by evaluating the impact of VRE integration in greater detail and assesses the role of storage, flexibility options and regional grid interconnections in balancing energy systems with high shares of RE.

2.1. Model description

The energy transition modelling was performed with the LUT Energy System Transition model [18], which optimises an energy system under certain constraints for a comprehensive set of energy, generation, storage, and transformation technologies. Unlike most other models used for global energy systems studies that normally use the time-slices approach (MESSAGE, MARKAL, TIMES, GENeSYS-MOD), the LUT model optimises the energy system in full hourly resolution. This allows for consideration of the variability effects of RE on energy systems in greater detail, thereby ensuring the balance of energy demand and supply for all hours of the year. The model uses myopic foresight, in this study simulation is applied for five-year intervals from 2015 to 2050, comprising the coupled power and heat sectors, transport sector, and energy demand for desalination. A multi-node approach enables the description of any desired configuration of sub-regions and power transmission interconnections. The main constraint for the optimisation is the matching of the energy supply and the energy demand for every hour of the applied year and the optimisation target is the minimum of the total annual cost of the system. Energy supply is modelled for electricity, heat of three temperature levels, and transport fuels: hydrogen (gaseous, liquid), methane (gaseous, liquid), and liquid hydrocarbons, comprised of gasoline, diesel, marine fuel oil and jet fuel. The full hourly resolution of the model significantly increases the computation time. However, it guarantees that for every hour of the year the total supply within a sub-region covers the local demand and enables a more precise system description including synergy effects of different system components. The model is based on linear optimisation and performed on an hourly resolution for an entire year in two stages. First, a prosumers simulation based on annual energy cost in relation to own generation and local retail energy prices is conducted to determine the least cost energy options for prosumers in the sub-regions. The next stage involves an overall energy system simulation across the different sectors to derive cost optimal energy mixes form 2015 to 2050 for the corresponding sub-regions. The model ensures high precision computation and reliable results. The costs of the entire system are calculated as a sum of the annualised capital expenditures including the weighted average cost of capital, operational expenditures (including ramping costs), fuel costs and cost for GHG emissions for all available technologies. The detailed description of the LUT Energy System Transition model is provided in the Supplementary Material in Appendix A (section 1. Model description). Prina et al. [19] compared models for highly renewable energy systems in the main categories: resolution in time, in space, in techno-economic detail, in sector coupling and for transparency. Amongst all long-term energy transition models, the LUT model received the highest scoring, which further validates the efficacy of these findings.

2.2. Applied technologies

To describe the transition of power, heat and transports sectors towards RE-based energy supply the wide list of technologies was considered in the modelling, in total the technologies can be classified into six main categories.

- Electricity generation: RE, fossil and nuclear technologies;
- Heat generation: RE and fossil technologies;
- Transportation: road, rail, marine and aviation;
- Energy storage: electricity, heat and fuels;
- Energy sector coupling technologies;
- Electricity transmission technologies.

Fossil fuels based power generation technologies include condensing coal power plants, oil-based internal combustion engines (ICE), open cycle (OCGT) and combined cycle gas turbines (CCGT), fission based nuclear power plants and coal, gas and oil-based combined heat and power (CHP) plants. Renewable electricity generation includes solar PV technologies (optimally fixed-tilted, single-axis north-south tracking and rooftop PV for residential, commercial and industrial segments), wind turbines (onshore, offshore), hydropower (run-of-river and reservoir), geothermal energy and bioenergy (solid biomass power plants and CHP, biogas and waste-to-energy CHPs).

Heating technologies are subdivided in district heat or utility-scale heating technologies including fossil fuel boilers (coal, gas and oil fuelled), direct electric heating and utility-scale heat pumps, concentrating solar thermal power (CSP) parabolic fields, geothermal and solid biomass district heat plants. Individual heating technologies include small scale fossil fuel boilers (gas and oil fuelled), direct electric heaters and heat pumps, solid biomass and biogas boilers.

The transport sector is divided into four categories: road, rail, marine and aviation. Road passenger transport is divided into light duty vehicles (LDV), buses and 2−3 wheelers (2/3W). Road freight transport is divided into medium-duty vehicles (MDV) and heavy-duty vehicles (HDV). For all road transport vehicles, the model considers four powertrain types: conventional internal combustion engine vehicles (ICE), plug-in hybrid electric vehicles (PHEV), battery-electric vehicles (BEV) and hydrogen-based fuel cell vehicles (FCEV). Rail passenger and freight transport is composed by electrical engine and ICE trains. Marine passenger and freight transport are represented by electrical motor, liquefied methane (LNG) and liquid fuels ICE propelled vessels. Aviation passenger and freight transport are represented by electricity, hydrogen and liquid fuels based aviation.

Storage technologies can be divided in three main categories. Short-term storage: battery and pumped hydro energy storage (PHES). Medium-term storage technologies are adiabatic compressed air energy storage (A-CAES), high and medium temperature thermal energy storage (TES) technologies. Long-term gas storage including power-to-gas (PtG) technology.

Sector coupling technologies include fuel synthesis technologies: electrolysers, and further H_2-to-X synthesis technologies; Power-to-Heat (direct electrical heaters, district and individual scale heat pumps) and Heat-to-Power (steam turbines) technologies; and other: seawater desalination, water storage and pumping technologies. These technologies allow to convert energy or products from one sector into valuable services or energy for another sector increasing the overall efficiency of the system and providing additional flexibility for the system.

Electricity transmission technologies include high voltage AC (HVAC) and DC (HVDC) power lines and AC/DC converters which allow to interconnect AC power grids of regions inside the countries, thought countries power grids are not interconnected. The structure of the regional AC power grids of the regions is not modelled, however regional grids development trends are considered in overall electricity transmission and distribution losses [20].

2.3. Financial and technical assumptions

The financial and technical assumptions are mostly taken from the European Commission [21], but also from various other referenced sources [22−50]. The financial and technical assumptions for all power and heat generation capacities, storage, transmission and sector coupling technologies and fuels with their respective references are presented in Appendix A (Tables A1-A4). Assumptions are made in 5-year time steps for the years 2015−2050. For all scenarios, weighted average cost of capital (WACC) is set to 7%, but for residential PV prosumers WACC is set to 4% due to lower expectation of financial returns. Application of region specific WACC levels would result in more accurate results, however there is limited research with regard to the development of WACC in the long term capturing country-specific variations [51]. Electricity prices for residential, commercial and industrial consumers were derived for every region according to Gerlach et al. [52], and extended to 2050 according to Breyer et al. [53]. Excess electricity generated by prosumers is fed into the national grid and is assumed to be sold for a transfer price of 0.02 €/kWh. The model ensures that prosumers satisfy their own demand for electricity before feeding excess into the grid.

2.4. Demand and resource potential for renewable technologies

Power demand is mostly based on electricity consumption growth data from IEA [45] and local sources, as described in Bogdanov et al. [18], and projections for transmission and distribution grid losses are taken from Sadovskaia et al. [20]. Heat demand is based on a report by Barbosa [54]. Desalination demand is taken from Caldera and Breyer [55]. Transportation demand is taken from Khalili et al. [56]. Power, heat, transport, and desalination demand assumptions for each step of the transition are provided in Appendix A (Table A5).

The capacity factor profiles for optimally fixed tilted PV, CSP and wind energy are calculated according to Bogdanov et al. [57] using global weather data for the year 2005 from NASA [58,59] and reproduced by German Aerospace Centre [60], single-axis tracking PV capacity factors profiles are calculated according to Afanasyeva et al. [61]. The hydropower feed-in profiles are computed based on the monthly resolved river flow data for the year 2005 [62] as a normalised weighed average flow in locations of existing hydropower plants.

The potentials for sustainable biomass and waste resources are based on Bunzel et al. [63] and classified into three main categories: solid wastes (non-recyclable municipal wastes and used wood), solid agriculture and forestry residues and biogas feedstock (municipal biowastes, manure, sludge). The assumptions consider high recycling rates for plastic, cardboard and paper, limiting feedstock for waste incinerators, and high collection rates of biogas feedstock, which increases valuable biogas influx and limits the leakage of landfill gases as emissions. The costs for biomass are calculated using data from the IEA [64] and Intergovernmental Panel on Climate Change (IPCC) data [65]. The gate fee in 2015 is assumed to be in the range 50−100 €/tonne, rising to 100 €/tonne in all regions by 2050. The region specific solid agriculture and forestry residues, biogas and solid wastes, and corresponding cost assumptions are presented in Appendix A (Table A6).

Geothermal energy potential was calculated according to the method described in Aghahosseini et al. [66]. The A-CAES storage potential is based on a global A-CAES resource assessment [67].

3. Results and discussion

3.1. High electrification scenario

The development of the energy sector comprised of power, heat, transport and desalination sectors is characterised by a dynamically growing electricity demand driven by electrification of the energy system and continuous growth in final energy demand across developing and emerging countries. A global compound annual growth rate (CAGR) of final energy demand is about 1%, but the growth rates are much higher for developing countries.

Powertrain assumptions capture the transition from a fossil fuels based transport sector towards one with high levels of direct electrification and adoption of synthetic fuels, based on indirect electrification [56]. Other sectors also face comprehensive electrification due to the overall decline in costs of electricity as well as electricity-based heating and desalination technologies. In the frame of this high electrification scenario, electricity is expected to become the dominant energy carrier with a TPED share of about 89% by 2050, while the utilisation of fossil fuels declines to zero, indicating a fundamental change in terms of energy consumption around the world. Direct and indirect electrification together with the growth of the renewable electricity generation share in the power sector lead to a substantial increase of overall energy efficiency. This defossilisation and electrification induced efficiency gains result in decoupling of final and primary energy growth rates during the transition process, as highlighted in Fig. 1. Despite the growth in energy services and final energy demand, total primary energy demand (TPED) decreases from about 125,000 TWh in 2015 for the mentioned energy sectors to around 105,000 TWh by 2035 and increases to 150,000 TWh by 2050, which results in a CAGR of 0.5%. In comparison, a progression of current practices with low shares of electrification and a majorly fossil fuels based energy system would result in a TPED of nearly 300,000 TWh by 2050, which implies a CAGR of 2.5%. This effect on the energy system is one of the most fundamental results of this research, since it results in efficiency savings of nearly 150,000 TWh (approximately 49%) compared to the continuation of current practices with low shares of electrification, while energy services can be steadily expanded. Moreover, this varies substantially across the different regions of the world, regions with existing high renewable electrification gain less, for instance Norway [68], whereas regions with least efficient energy systems gain most, e.g. oil-rich Libya and Saudi Arabia. Solar-rich Africa, which is yet to develop most of its energy infrastructure, can leapfrog into a highly electrified energy system of the future [69] (see Fig. 1). The TPED is calculated based on IEA's Physical Energy Content Method (PECM), while other methods result in different TPEDs, i.e. the Partial substitution Method (PSM) would lead to higher TPED, while the Direct Equivalent Method would lead to lower TPED [70]. The PECM defines primary energy as the physically obtained energy at the first extraction from nature and equates all fuels and technologies fairly on this fundamental basis of initial human action.

Despite the projected per capita consumption growth of energy services, the average per capita primary energy demand decreases from around 17 MWh/capita in 2015 to around 15 MWh/capita by 2050. Only the projected population growth from 7.2 to 9.7 billion by 2050 [71] leads to absolute TPED growth.

Another metric for renewable energy system efficiency is curtailment of electricity generation. Despite the variability in renewable electricity based generation, the curtailment in the system is rather low at about 3.5% of total electricity generation in 2050. This low curtailment results from the combination of flexibility options, mainly battery storage balancing diurnal PV generation and flexible demand response from synthetic fuel production, particularly electrolysers.

3.2. Evolutionary transition leaps

To support the energy system transition, global electricity generation undergoes a rapidly evolving transition from predominantly fossil fuels in 2015 to 98% renewables in 2040, and entirely zero GHG emissions by 2050. The driving force is the cost of electricity generation technologies, wherein solar PV emerges as the major electricity supply source in a cost optimal energy transition, increasing from a mere 1% in 2015 to around 32% by 2030 and further increases to 76% by 2050 (see Fig. 2). This exponential growth in solar PV electricity supply is also attributed to the excellent resource distribution across the world. Wind energy is the major source of renewables during the early part of the transition, with a share in electricity supply increasing up to 42% by 2030. Thereafter, as solar PV becomes more cost effective the share of wind energy steadily declines to about 20% until 2050, while still growing in absolute terms until 2045. Hydropower, geothermal and bioenergy have some shares in the global electricity mix by 2050, with complementary roles through the transition due to limited resource availability. While, they do contribute substantially in some regions across the world, with major shares in energy supply through the transition. The value of reservoir-based hydropower and bioenergy is high due to their dispatchability. On the other hand, the shares of fossil fuels and nuclear in the electricity generation mix are observed to decline completely through the

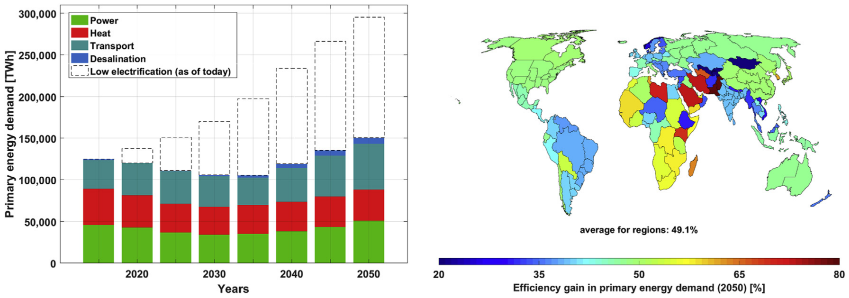

Fig. 1. Global primary energy demand sector-wise (left) including efficiency gains in primary energy demand as indicated by dashed lines for lack of efficiency improvements, and primary energy demand per capita (right) during the energy transition from 2015 to 2050.

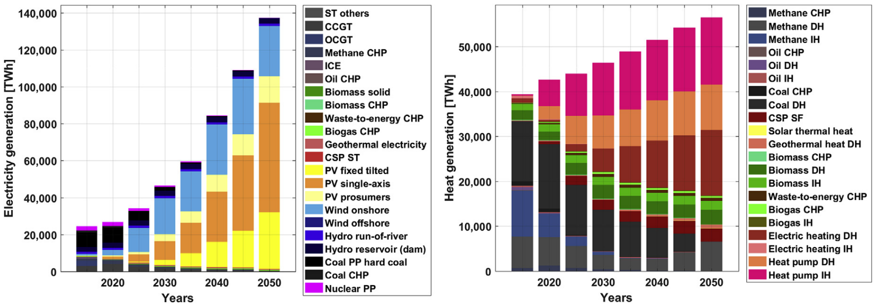

Fig. 2. Global — Technology-wise electricity generation (left) and technology-wise heat generation (right) during the energy transition from 2015 to 2050.

transition period, as they become uneconomical compared to renewables (see Fig. 2). Overall electricity supply increases from nearly 24 PWh in 2015, to 137 PWh in 2050, the main driving force is the fast growth of electricity demand from electrified heat, transport and desalination sectors, while the electricity demand from the power sector (excluding heat, transport and desalination) increase to just around 41 TWh by 2050. In addition, the share of electricity for the power sector declines from over 83% in 2015 to just about 30% in 2050, this highlights the significant rise of electricity demand from the other sectors. The rate of electricity supply growth is even higher in developing regions, where electrification is driven by the overall growth in energy consumption per capita, with efforts to close the gap in energy access between developed and developing countries.

Similarly, global heat generation transitions from high shares of fossil fuels based heat in 2015 to electric and renewable based heat in 2050. Heat pumps and electrical heating in general play a significant role in the heat sector with a share of over 40% of heat generation by 2050 on district heating (DH) and individual heating (IH) levels, as shown in Fig. 2. Additionally, some shares of non-fossil gas and biomass-based heating contribute to satisfying industrial process heat demand. Whereas the shares of coal-based heating along with fossil oil and gas based heating decrease through the transition, from more than 75% in 2015 to zero by 2050.

Electrification of the heat and transport sectors along with the additional electricity demand for desalination, strongly influence the defossilisation of the power and heat sectors. Direct electrification of transportation leads to additional electricity demand of 13,000 TWh$_{\mathrm{el}}$ in 2050 compared to 477 TWh$_{\mathrm{el}}$ in 2015, whereas indirect electrification results in further additional electricity demand of 39,000 TWh$_{\mathrm{el}}$ to produce synthetic fuels in 2050: hydrogen, methane, LH$_2$, LNG and Fischer-Tropsch (FT) fuels. Projected water desalination demand in most water stressed regions will reach 1100 bm^3 in 2050, which will lead to additional electricity demand of 5900 TWh$_{\mathrm{el}}$ to run seawater reverse osmosis units and water transport systems. Rapid growth of electricity demand during the transition increases demand for new power generation capacities and consequently results in diminishing shares of fossil fuels based electricity in the generation mix. Without a high level of sector coupling and additional electricity demand from heat, transport and desalination, electricity generation in 2050 would be approximately 40,000 TWh and fossil generation capacities would play a more significant role through the transition.

3.3. Critical role of solar PV — utility-scale and prosumers

Solar PV is expected to become the prime energy supply technology, similar to the conclusion of Creutzig et al. [72]. The largest share of solar PV in the total generation mix is reached mostly in the Sun Belt and developed countries. In the Sun Belt countries, perfect solar conditions make large-scale solar PV unrivalled, while in developed countries PV prosumers form a significant share of the capacity mix due to high electricity retail prices and respective attractive economics. This can be noticed with the stark difference in the shares of PV prosumer electricity in most European countries with high shares. Whereas, Russia and adjoining countries, which currently have low retail electricity prices (that are heavily subsidised), have much lower shares of electricity from PV prosumers (see Fig. 3).

3.4. Local resource driven energy systems

The regional structure of power and heat supply is strongly dependent on local resource availability and its match with energy consumption profiles. Solar PV capacities are well distributed across the different regions of the world and achieve a total installed capacity base of 63,380 GW in 2050. Whereas wind energy capacities achieve a total installed capacity base of 8130 GW in 2050 and are predominantly from latitudes of 45º N and higher, which show a strong energy consumption and renewable electricity generation seasonality effect, i.e. parts of North America, Europe and Eurasia have higher wind energy capacities (see Fig. 4).

In a system that is massively dependent on variable renewable energy sources, such as solar PV and wind energy electricity, storage plays a vital role in matching supply and demand. Utility-scale and prosumer batteries contribute a major share of electricity storage capacities, with some shares of pumped hydro energy storage (PHES) and compressed air energy storage (A-CAES) by 2050, as shown in Fig. 4. Batteries, both prosumers and utility-scale, deliver the largest shares of output by 2050, as shown in Fig. 4. The share of output from prosumer batteries is relatively higher in the most developed regions with high PV prosumer capacities, especially Europe and North America, whereas utility-scale batteries deliver higher outputs in the southern regions of MENA, SAARC and Northeast Asia. PHES and A-CAES contribute complementary shares of electricity storage output through the transition across the different regions of world. As far as heat is concerned, gas storage is installed across all regions primarily as a buffer storage

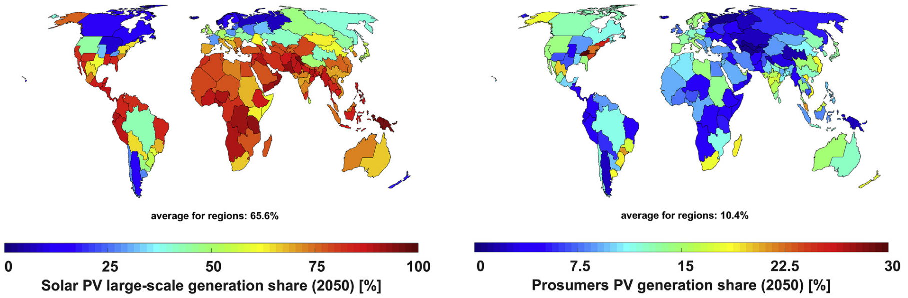

Fig. 3. Regional variation of the share of electricity generation from large-scale solar PV (left) and PV prosumers (right) on a global scale in 2050.

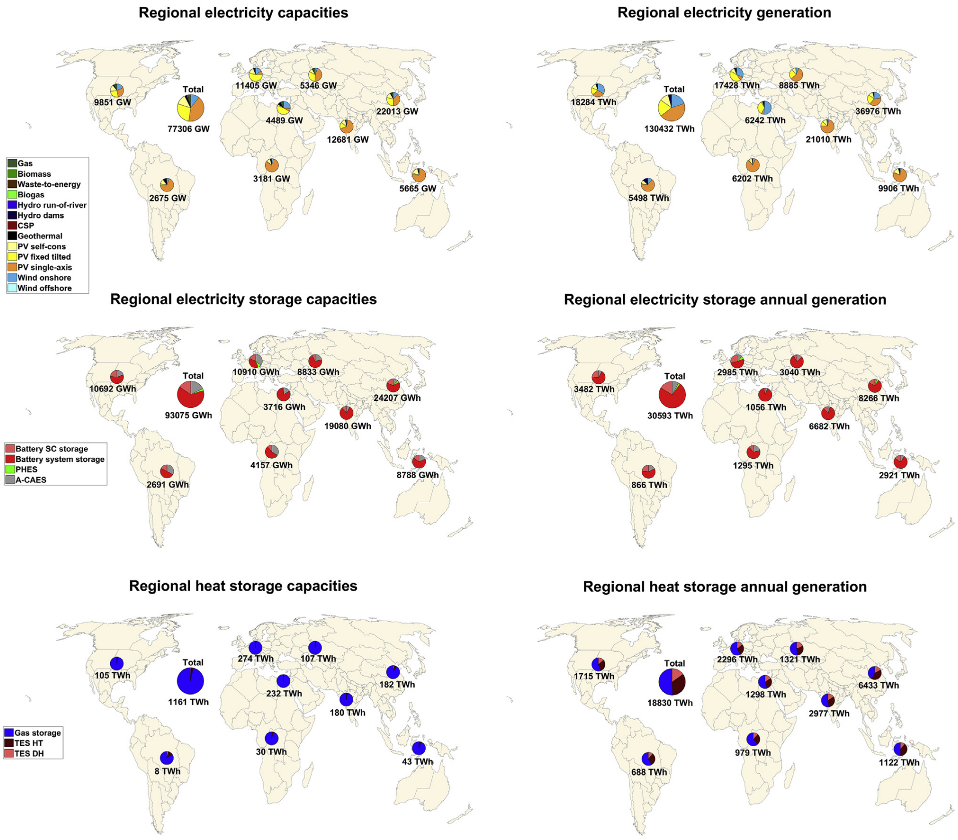

Fig. 4. Regional distribution of electricity generation capacities (top left), electricity generation (top right), electricity storage capacities (centre left), electricity storage output (centre right), heat storage capacities (bottom left) and heat storage output (bottom right) in 2050.

for biomethane and synthetic natural gas production and seasonal storage. On a global level, biomethane and synthetic natural gas contribute 0.29% and 0.14%, respectively, of the total electricity supply, while hydrogen is not considered as a seasonal storage for electricity in this research. However, their role is more significant in high latitude regions where long-term storage is necessary for seasonal balancing. A well-balanced and optimised 100% renewable energy system does not require much seasonal balancing in the form of stored gaseous compounds. High temperature and district heating thermal energy storage (TES) contribute ample shares of output, since they operate to balance short to mid-term heat demand variations.

3.5. *Cost optimal energy transition pathway*

Renewable energy generation along with electricity and heat storage technologies evolve as the fundamental pillars of the global energy supply system in the first half of the 21st century, changing the system while its levelised cost of energy remains stable through the transition. Levelised cost of energy is defined as the annualised energy system cost per unit of final energy demand. Investments needed to make this transition happen are presented in Fig. 5.

Investments, which are capital expenditures for installed capacities of energy technologies that occur in the 5-year time periods, are well spread across a range of technologies. Majority of the investments are allocated in the power sector, which becomes the backbone of the whole energy system: solar PV, wind energy and batteries are installed to substitute fossil fuels based generation and satisfy the growing electricity demand of all energy sectors. Heat pumps and synthetic fuel production technology capacities are mostly built in the later periods of the transition, when direct and indirect electrification of heat and transport sectors accelerates. Investments increase substantially on an annual basis from over 900 b€ in 2020 to around 2800 b€ by 2050, enabling fossil fuels substitution by RE-based electricity in all energy sectors. Moreover, the cumulative capital expenditures are about 67,200 b€ through the energy transition, with a majority in the later part from 2040 onwards, when a massive defossilisation of the transport sector is projected, in particular for marine and aviation. However, levelised cost of energy remains around 50–57 €/MWh through the transition because increased capital expenditures are well compensated by phasing out fossil fuel costs in the long term, as shown in Fig. 5. However, this does pose a challenge in the short term for developing countries with recent and new investments into fossil fuel assets, which are soon to face economic challenges from declining costs of renewables. Innovative policy and fiscal mechanisms will be needed to effectively plan phase-outs and divestments, at the same time taking on opportunities to leapfrog into a sustainable energy system. Shifting fossil fuel subsidies and additional financial support by development institutions could drive developing and emerging countries towards rapid adoption of sustainable energy. The total system wide levelised cost of energy in 2050 is slightly less than in 2015. This corroborates that an energy transition towards 100% renewable energy is an economically attractive proposition, since the transition in the energy system is projected to be cost-neutral in practical terms.

On a regional level, the levelised cost of energy for a 100% renewable energy system remains in an affordable range of 40–80 €/MWh, with the global average cost of 53.8 €/MWh across the different regions of the world in 2050, as indicated in Fig. 6. Moreover, a vast majority of the regions have levelised cost of energy in the range of 45–55 €/MWh.

Fischer-Tropsch fuels, hydrogen and liquefied gases (methane and hydrogen) are viable alternatives to fossil fuels and are expected to play a vital role in replacing fossil fuels in hard-to-abate applications [73–75]. The regional variation of production costs of these fuels has been factored into the cost optimal energy transition pathway. As indicated in Fig. 6, production costs for FT-fuels vary significantly across the different regions of the world with a global average cost of nearly 86 €/MWh in 2050. FT-fuel costs in Europe and central Asian regions are higher due to a decentralised and localised approach to the production of FT-fuels, whereas an integrated production and trading of FT-fuels will most likely reduce the costs [76]. For most parts of the world the costs range from 75 to 85 €/MWh. In addition, costs are extremely low (60–65 €/MWh) in South America (driven by low-cost wind in Patagonia and low-cost PV in Atacama Desert) and China, which could become future hubs for FT-fuel production (see Fig. 6), if the attractive cost in the Horn of Africa and the very south of the Arabian Peninsula may not be accessible due to political disorder, at least in the short-to mid-term.

3.6. *Regionally diverse energy systems*

In a highly digitalised future with strong global climate policies, electrification of energy services are expected to be pervasive [77]. Primarily, fossil and nuclear fuels used in the power sector are substituted by technologies directly extracting electricity from the

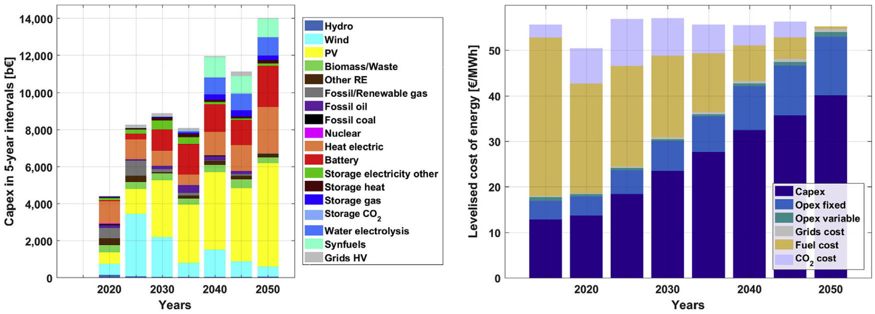

Fig. 5. Capital expenditures for five-year intervals (left) and levelised cost of energy (right) of the entire energy system during the energy transition from 2015 to 2050. Levelised cost of energy is increasingly dominated by capital costs as fuel costs lose importance through the transition period, which implies increased levels of energy security for countries around the world.

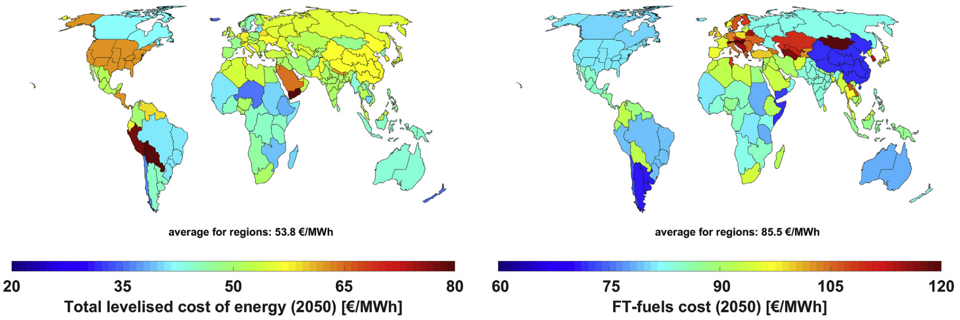

Fig. 6. Regional levelised costs of energy (left) and Fischer-Tropsch (FT) fuels costs (right) in 2050.

environment, in particular solar PV and wind energy. Power-to-X technologies will play a central role in linking low-cost variable renewable electricity and demand across all energy sectors. Electric vehicles will largely replace fossil-fuelled 2-wheelers, 3-wheelers, cars and trucks [56,78]. Meanwhile, heat pumps and electric heating substitute oil and gas furnaces in buildings and industries [79,80]. In addition, renewable electricity is used to produce hydrogen and other synthetic fuels for applications where direct electrification is uneconomical or technically challenging [81,82]. The advantages of widespread electrification are clear and compelling [9].

Another critical aspect of this research is capturing the regional variation in energy systems across the world through the transition period. Renewable energy resources are well distributed around the world, but different resources are available in different proportions, across the different regions. Therefore, the results of this research enable energy transition pathways that maximise utilisation of locally available renewable resources in a cost optimal manner, as indicated in Fig. 7.

The results provide regional insights into energy systems from a global perspective. Likewise, the high latitude countries utilise relatively higher shares of wind energy as compared to Sun Belt and moderate climate countries, where solar PV is rather predominant. Eurasia along with some regions in Europe and North America utilise higher shares of onshore wind energy across the northern regions. Hence, regions in Eurasia are wind dominated (see Fig. 7). Additionally, Canada and some parts of the USA are dominated by wind energy. Meanwhile, just the Patagonian region of Argentina is dominated by wind energy in the Southern hemisphere. In most regions and countries around the world, low-cost solar PV, as highlighted in Fig. 7, will dominate energy systems. By 2050, the highest generation share of solar PV among regions is in SAARC [83] with more than 95% in its cost optimal generation mix, whereas sub-Saharan Africa [69] utilises 82% of all electricity generation from single-axis tracking solar PV in its cost optimal generation mix. Meanwhile, only Iceland is dominated by hydropower in 2050 due to limited hydropower potential in other regions [84]. Notably, some regions, such as New Zealand, Chile, Northeast China, Nordic

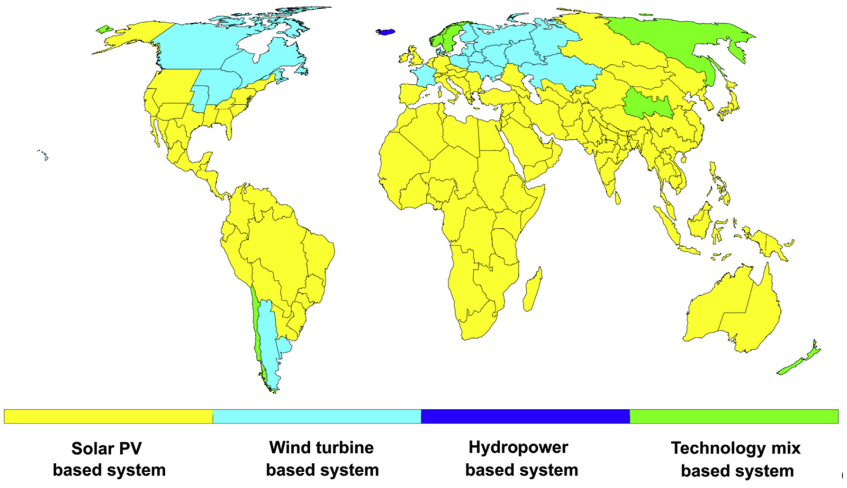

Fig. 7. Regional energy mix for power, heat, transport and desalination sectors in 2050.

region and Russian Far East have an energy system based on an even mix of renewable energy technologies with solar PV, wind energy and hydropower playing substantial roles (see Fig. 7). Similarly, from a heat supply perspective Eurasia has the most attractive techno-economic conditions for the application of heat pumps in the heat sector, providing about 60% of heating demand by this technology from 2030 through 2050. Other regions that cover a large part of the heating demand with heat pumps by 2050 are Europe with 51%, North America with 50%, Northeast Asia and sub-Saharan Africa both with 45%, respectively.

3.7. Climate compliant energy transition pathway

The results of the global transition towards a 100% renewable energy system indicate a steady decline in global GHG emissions to zero until 2050, as shown in Fig. 8. Global Tank-to-Wheel (TTW) GHG emissions from the power sector decline through the transition from over 11,000 $MtCO_{2eq}/a$ in 2015 to zero by 2050. Similarly, GHG emissions from the heat sector decline through the transition from over 9300 $MtCO_{2eq}/a$ in 2015 to zero by 2050. Global GHG emissions from the transport sector decline through the transition from over 9000 $MtCO_{2eq}/a$ in 2015 to zero by 2050. During the initial periods, GHG emissions of the transport sector increases, whereas a rapid electrification of the road transport mode and parallel rise in renewable electricity leads to a massive GHG emissions reduction from the 2020s onwards. The power sector undergoes a deep defossilisation by 2030, whereas for the heat and transport sectors this occurs mostly between 2030 and 2050. The remaining cumulative energy related GHG emissions taken into account in this study comprise around 422 $GtCO_{2eq}$ from 2018 to 2050 as shown in Fig. 8.

The IPCC SR1.5 report [2] recommends that cumulative CO_2 emissions should be kept within a budget by reducing global annual GHG emissions to net-zero and further suggests a remaining budget for limiting warming to 1.5 °C with a 66% chance of about 550 $GtCO_2$, and of about 750 $GtCO_2$ for a 50% chance, accounting GHG emissions from 2018 onwards. In this context, this research shows that cumulative GHG emissions can be limited to 422 $GtCO_2$ from 2018 to 2050 across the power, heat, transport and desalination sectors globally. CO_2 emissions from remaining sectors have not been factored, in particular from non-energetic industrial feedstock and processes, land use, agriculture and waste. The non-energetic industrial feedstock demand is mainly represented by the chemical industry, which can be also transitioned to zero GHG emissions with renewable electricity based bulk chemicals, in particular ammonia and methanol [85,86]. Comparing the GHG emissions of this research to the second half of the previous decade with global anthropogenic CO_2 emissions of about 40 $GtCO_2$ per year [87] shows that this research covers about 75% of all CO_2 emissions, while about 85% of all CO_2 emissions originating from fossil fuels use and the remaining 15% are land use related. Assuming that all anthropogenic CO_2 emissions would be reduced in the same pace as the traced emissions in this research, then the total remaining CO_2 emissions would equate to about 567 $GtCO_2$. Consequently, the ambitious energy transition pathway described in this research could be categorised as limiting peak warming to about 1.5 °C with 66% probability by mid-21st century, as the total pathway emissions are quite close to the 550 $GtCO_2$ limit. Even more aggressive actions could be needed for a more safer temperature level [88], including a rapid transition and carbon dioxide removal (CDR) [89], which may be realised mainly by the highly scalable direct air captured carbon and storage (DACCS) [90], as indicated by Realmonte et al. [91]. Grubler et al. [9] demonstrated a 1.5 °C scenario without CDR, but with the compromise of 40% less final energy demand in 2050 compared to the present level. Whereas, this research shows a 1.5 °C scenario without CDR, along with a final energy demand growth of 43% from 2015 to 2050, and in a cost-optimal manner, which is enabled by massive direct and indirect electrification of the entire energy system and the consequent use of low-cost renewable electricity.

4. Conclusions

The fundamental structure of the global energy system can shift from conventional, low-efficient burning of extracted fuels towards almost pure exergy, which is electricity, generated from low-cost solar, wind and other natural energy resources. This transition will result in substantial growth of the system efficiency and enable rapid reduction of GHG emissions to fulfil a 1.5 °C scenario without CDR utilisation or limitations on final energy consumption. The broad electrification of end-use sectors like transport and heat makes electricity the growing backbone of the world's energy supply [92].

A 1.5 °C compatible transition scenario requires rapid defossilisation coupled with accelerated electrification of the different energy sectors, starting with the power sector already in the 2020s. Global levelised cost of energy of the whole system stays rather constant through the transition, even with the levelised cost of electricity declining significantly, as this new sustainable energy system includes storage technologies, increased flexibility and production of synthetic fuels. This in turn, demands massive capital investments, which not only enable a sustainable energy system but also increase socio economic welfare [93]. From an investment perspective, reduced fuel costs in the long term could benefit

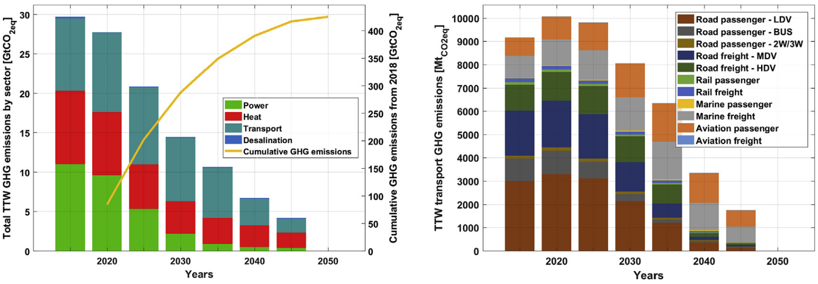

Fig. 8. Global sector-wise and cumulative GHG emissions (left) and GHG emissions in the transport sector from different categories (right) during the energy transition from 2015 to 2050. Tank-to-Wheel (TTW) considers GHG emissions from readily available fuels and does not consider GHG emissions from the upstream production and delivery of fuels.

various countries, but significant capital investments in the short term can pose a challenge for economies around the world. However, findings from BNP Paribas [94] indicate that the net energetic yield per invested unit of capital in renewable electricity solutions far exceeds the one in upstream fossil fuels, which are neglected in most energy system analyses. As energy policy has been evolving around the world to drive growth in renewable electricity uptake, these efforts must be scaled up and diversified across the other sectors.

Economics and markets continue to shape energy choices around the world, but policymakers will play the central role in transforming the global energy sector, as highlighted by Daszkiewicz [95]. Various energy strategies, targets and policies aiming at decreasing capital investment costs can be used to trigger the deployment of renewables across the sectors of power, heat, and transport. Moreover, from a developing countries perspective, as Relva et al. [96] point out, in addition to higher shares of renewable energy resources, this process also requires complementary innovations such as energy storage, smart grids, demand response, network expansion, new business models and market arrangements. Moving forward, energy policies will continue to shape the energy transition, continuously evolving and adapting to individual country requirements and dynamic market conditions.

Solar PV transpires to become the main energy source in the system, similar to the findings of Creutzig et al. [72] and Haegel et al. [97] with installed capacities in the range of dozens of TW. The solar PV industry is capable of providing all required capacities, as shown by Verlinden [98], since 70 TW of PV capacities can be ramped up by 2050, which is about 10% more than 63.38 TW found in this research. At the same time, increasing adoption of variable renewable energy and drastic reduction of the supply of inflexible baseload generation, is made possible by promoting of Power-to-X, dispatchable renewables, grids, storage technologies and overall sector coupling [99] forming a flexible energy system [4]. The combination of high shares of variable renewable energy and Power-to-X has been identified as a major gap in Integrated Assessment Models, mainly used by the IPCC [100], which is a consequence of unreasonably high solar PV cost assumptions, as documented in Krey et al. [101] and concluded in Jaxa-Rozen and Trutnevyte [102]. This is further amplified by methodological short comings in Power-to-X modelling and lack of hourly resolution [100]. The results of this research indicate that RE resources are sufficient to satisfy the growing global energy demand even with high rates of electrification and moreover, increase in energy access across developing countries, thereby bridging the gap between developing and developed countries in terms of energy supply per capita.

A global energy transition towards 100% renewable energy has the potential to lift the standards of living for people all around the world due to phasing out emissions and giving equal access to energy and water, especially in the Global South, which has excellent solar conditions throughout the year and tremendous potential for adopting solar PV as indicated by the results of this research and others [72]. Introduction of desalination will resolve the water scarcity issue providing 3 billion m^3 of clean water per day. As most of the development across the regions is yet to take shape, shifting them towards sustainable energy infrastructure development presents the opportunity to leapfrog developed countries into a sustainable future. In consequence, global energy resource based conflicts can be mitigated and a pathway towards peace and increased welfare can be attained.

Such a transition will directly accomplish four major Sustainable Development Goals. First, it decreases the probability of significant climate change threatening civilisation, by reducing GHG emissions without limiting growth of energy consumption in the future. Second, it provides equal access to low-cost energy supply in all regions across the world. Third, it enables sustainable growth in standards of living across developing countries of the Global South. Fourth, it enables universal access to clean water and decreases water stress. Indirectly, it will also help accomplish several other Sustainable Development Goals leading to an overall sustainable future.

Credit author statement

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Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

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