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OPERATIONAL MODELLING OF REGIONAL ENERGY SYSTEM WITH HIGH SHARE OF WIND POWER, PHOTOVOLTAICS AND LARGE HEAT PUMPS

Case study in the Baltic countries towards 2030

Master's Thesis
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ABSTRACT

Nelli Putkonen: Operational Modelling of Regional Energy System with High Share of Wind Power, Photovoltaics and Large Heat Pumps — Case Study in the Baltic Countries Towards 2030
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European energy systems are in a rapid transition driven by emission reduction targets and development in renewable energy and electrification technologies. Variable wind and solar generation, and electrification are expected to expand fast already within the next decade. Transition from dispatchable power and heat generation towards intermittent and unpredictable generation demands new solutions in flexibility and sector integration. Planning and operation of future energy systems require increasingly sophisticated computational modelling, able consider sufficient operational limitations, temporal resolution and sectoral co-operation. The Baltic countries — Estonia, Latvia and Lithuania — have ambitious targets in achieving emission reductions, increasing renewable generation and renewing their energy system already by 2030.

This thesis studies the features of energy system modelling and research — especially in terms of wind and solar power and large heat pumps integration — and investigates the near-term future of the Baltic system using Backbone modelling software. First, an introduction to general trends in energy systems research as well as the operational characteristics of variable generation and heat pumps is given. Then, the special features of the Baltic system, as well as state-of-the-art solutions in computational modelling of energy systems are addressed. Finally, the case study models the hourly operation of the Baltic regional system in 2030 (including power, heat, transport and building sectors) based on realization of the national energy and climate plans. The operation and indicators of the scenario year 2030 are compared with a historical model year of 2017. Additionally, the sensitivity of the 2030 system operation towards different capacities of wind power, photovoltaics and large heat pumps is investigated in a comparative analysis. Results are analysed in terms of operational decisions as well as economic, environmental and energy security indicators.

The case study modelling indicates a drastic transition in system operation, especially in Estonia, as oil shale based generation is substituted with renewables, and in Lithuania, ending up with a very ambitious share of variable generation. The modelled transition achieves substantial emission reductions, and increases renewable and domestic generation. The model maintains hourly system balance with active use of existing storages and interconnectors. However, possible energy security concerns are observed regarding Estonian balancing capacity, Latvian natural gas cogeneration plants and Lithuanian very high wind integration and simultaneous grid renovations. Additionally, the modelled power and heat system costs increase compared with 2017 in all three Baltic countries, and the model does not achieve targets in EU effort sharing sector emissions, due to increase in traffic demand and slow progress in end-use electrification.

Deployment of wind power, especially onshore wind, seems to reduce emissions and increase domestic and renewable power generation shares in the Baltics inexpensively. The economic indicator results support the nationally planned wind power investment levels. Megawatt-scale photovoltaics competes with offshore installations in price, and can offer support for complementing wind variability, although full-load hours of solar generation in the Baltic region remain low. Large heat pumps show promise in feasibility in supplying district heat in Tallinn, Riga and Vilnius, especially when combined with large heat storages. In addition to improving energy efficiency and emission reductions, heat pumps can offer flexibility to complement variable generation, and support investments and domestic generation by increasing value of electricity.

Keywords: energy system, energy modelling, Baltic countries, wind power, variable renewable generation

TIIVISTELMÄ

Nelli Putkonen: Alueellisen energiajärjestelmän operaation mallinnus korkeilla tuuli- ja aurinkovoiman sekä suurten lämpöpumppujen osuuksilla — Case study Baltiassa kohti vuotta 2030
Diplomityö
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Eurooppalaiset energiajärjestelmät ovat nopeassa murroksessa päästövähennystavoitteiden ja uusiutuvan energian sekä sähköistymisen esiinmarssin ajamina. Vaihtelevan tuuli- ja aurinkotuotannon määrän sekä sähköistymisasteen ennustetaan kasvavan nopeasti jo seuraavan vuosikymmenen aikana. Siirtymä ohjattavasta sähkön- ja lämmöntuotannosta epäsäännölliseen ja vaikeasti ennustettavaan tuotantoon vaatii järjestelmältä joustavuutta ja kytkeytyneitä ratkaisuja. Tulevaisuuden energiajärjestelmien suunnittelu ja operointi vaativat yhä kehittyneempää tietokonemallinnusta, joka pystyy huomioimaan riittävät operaatiorajoitukset, aikatarkkuuden ja sektorien yhteistoiminnan. Baltian mailla — Virolla, Latvialla ja Liettualla — on kunnianhimoiset tavoitteet päästövähennyksien saavuttamisessa, uusiutuvien energiantuotantomuotojen lisäämisessä ja energiajärjestelmän uudistamisessa jo vuoteen 2030 mennessä.

Tässä diplomityössä tutkitaan yleisellä tasolla tulevaisuuden energiajärjestelmien mallinnuksen ja tutkimuksen piirteitä — erityisesti tuuli- ja aurinkovoiman sekä suurten lämpöpumppujen lisäämisen näkökulmasta — sekä syvennytään Baltian järjestelmän lähitulevaisuuteen Backbone-mallinnusohjelmiston avulla. Työ alkaa johdatuksella energiajärjestelmien tutkimuksen kehitysnäkymiin sekä tuuli- ja aurinkovoiman että lämpöpumppujen ominaisuuksiin järjestelmän suunnittelussa ja operoinnissa. Teoriaosa jatkuu tutustumalla Baltian energiajärjestelmän erityispiirteisiin sekä tietokoneperusteisen energiamallinnuksen ratkaisuihin ja uusimpiin kehityssuuntiin. Käytännön osuudessa mallinnetaan tunneittain kansallisten energia- ja ilmastosuunnitelmien mukainen Baltian alueellinen sähkö-, lämpö-, liikenne-, ja rakennusjärjestelmä skenaariovuonna 2030, ja verrataan järjestelmän toimintaa ja indikaattoreita historialliseen mallivuoteen 2017. Lisäksi suoritetaan herkkyystarkastelu vertailemalla erilaisia tuulivoiman, aurinkovoiman ja suurten lämpöpumppujen kapasiteettitasoja vuoden 2030 mallissa. Tuloksia käsitellään järjestelmän toimintapäätösten sekä talous-, ympäristö- ja energiaturvallisuusindikaattoreiden avulla.

Keskeisenä tuloksena huomataan järjestelmän toiminnan voimakas murros erityisesti Virossa siirryttäessä palavasta kivestä uusiutuviin tuotantomuotoihin sekä Liettuassa päädyttäessä erittäin kunnianhimoisiin tuuli- ja aurinkovoiman osuuksiin. Samalla saavutetaan tavoitteiden mukaiset merkittävät päästövähennykset sekä uusiutuvan ja kotimaisen tuotannon kasvu. Malli ylläpitää järjestelmän tuntitason balanssia aktiivisella olemassa olevien varastojen ja siirtoyhteyksien käytöllä. Mahdollisia energiaturvallisuushavaintoja tehdään kuitenkin Viron joustavuuskapasiteetin, Latvian maakaasuyhteistuotantolaitosten sekä Liettuan erittäin suuren tuulituotannon ja verkkomuutosten suhteen. Lisäksi järjestelmän mallinnetut kustannukset kasvavat vuoteen 2017 verrattuna kaikissa maissa, ja malli ei saavuta tavoitteita EU:n taakanjakosektorin päästöissä, johtuen liikennemäärien kasvusta ja hitaasti etenevästä loppukäytön sähköistymisestä.

Investoinnit tuulivoimaan, erityisesti maatuulivoimaan, näyttävät vähentävän päästöjä ja lisäävän kotimaisen ja uusiutuvan sähköntuotannon osuutta Baltiassa edullisin kustannuksin. Kansallisten suunnitelmien mukainen taso näyttäisi mallinnustulosten mukaan kustannustehokkaimmalta. Erityisesti keskitetty megawattiluokan aurinkovoima pärjää kustannusindikaattoreilla jopa merituulivoimaa paremmin ja voi tukea tuulivoiman tuntivaihtelua, vaikkakin kapasiteettiin suhteutettu vuosituotanto jää alhaiseksi. Suuret lämpöpumput näyttävät mahdollisesti kannattavilta kaukolämmön tuottajina pääkaupungeissa Tallinnassa, Riiassa ja Vilnassa, erityisesti yhdistettynä suuriin lämpövarastoihin. Energiatehokkuuden parantumisen ja päästövähennysten lisäksi lämpöpumput voivat tarjota joustavuutta vaihtelevalle tuotannolle ja tukea investointeja ja tuotantoa nostamalla sähkön arvoa.

Avainsanat: energiajärjestelmä, energiamallinnus, Baltia, tuulivoima, vaihteleva tuotanto

PREFACE

This thesis was conducted as a part of FasTen (Fast, flexible and secure decarbonisation of the Baltic states — possible progress in the next Ten years) and Amber (Impacts of ambitious energy policy pathways) research projects for VTT Technical Research Centre of Finland. The projects have received funding from Nordic Energy Research (NER), and executed in participation with VTT, Riga Technical University (RTU), Lithuanian Energy Institute (LEI) and Tallinn Technical University (TalTech) between 2020 and 2022. I wish to thank the wonderful instructors of the thesis, Senior Scientist Tomi J. Lindroos at VTT, and University Lecturer Henrik Tolvanen and Project Manager Yrjö Majanne at Tampere University for sharing their expertise and time. A special thanks to my lovely aunt Dr. Marjo Vuorikoski, and my friends Heta Norblad, Taimi Vesterinen and Sara-Leena Kamppuri for proofreading and emotional support.

This thesis concludes my nearly seven-year journey and change of careers from marketing and communications to a Master of Science in energy engineering and what I hope to turn out as a beginning of a successful career in energy system research and modelling. Everything that I am and everything that I achieve, I owe to the people around me. So, I wish to thank all my friends, relatives, and colleagues for accepting and appreciating me and showing me ways forward. A special thanks goes out to the boards, employees and guild councils of Student Union of TUT 2016–2018, my fellow students in YKI, and finally and most of all, to my forever supportive husband Santtu, and my two amazing children Iina and Aarni.

Enjoy the thesis. It was made with a lot of love and a hint of sweat and tears (for added flavor).

Tampere, 20 March 2022

Nelli Putkonen

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LIST OF SYMBOLS AND ABBREVIATIONS

AC	Alternating current
BOE	Barrel of oil equivalent
BRELL	Belarus, Russia, Estonia, Latvia and Lithuania
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
CMD	Command
CO_2/tCO_2/$MtCO_2$	Carbon dioxide / ton / megaton — subscript $_e$ stands for carbon dioxide equivalent
COP	Coefficient of performance
DC	Direct current
DE	Germany
DH	District heat
DK	Denmark
DP	Dynamic programming
EE/EST	Estonia
ERCOT	Electric Reliability Council of Texas
ETIP	European Technology & Innovation Platform
EU	European Union
EU ESR	European Union Effort Sharing Regulation
EU ETS	European Union Emission Trading System
EU-27	27 European Union countries after the UK left the EU
EV	Electric vehicle
FasTen	Fast, flexible and secure decarbonisation of the Baltic states — possible progress in the next Ten years
FI	Finland
FLH	Full load hours
FOM	Fixed operation and maintenance costs
GAMS	General Algebraic Modeling System
GDP	Gross Domestic Product
GHG	Greenhouse Gas
HP	Heat pump
IAM	Integrated assessment model
IEA	International Energy Agency
IPS/UPS	Integrated Power System / Unified Power System
IRENA	International Renewable Energy Agency
kW/MW/GW	kilowatt/megawatt/gigawatt — subscript $_e$ stands for electricity and $_h$ for heat
LCOE	Levelized cost of energy
LNG	Liquefied natural gas
LOLE	Loss of load expectation
LP	Linear programming
LT/LTU	Lithuania
LULUCF	Land use, land-use change and forestry
LV/LVA	Latvia
MILP	Mixed-integer linear programming
MINLP	Mixed-integer nonlinear programming
MWh/GWh/TWh	megawatthour/gigawatthour/terawatthour — subscript $_e$ stands for electricity and $_h$ for heat
NATO	North Atlantic Treaty Organization
NECP	National Energy and Climate Plan
NPP	Nuclear power plant

OPEX	Operating expences
PHES	Pumped hydroelectric energy storage
PHEV	Plug-in hybrid electric vehicle
PV	Photovoltaics
ref	Reference
RES-E/RES-H	Renewable share of electricity / Renewable share of (district) heat
SE	Sweden
SMR	Small modular reactor
SP	Scenario planning
St. Dev. (p.u.)	Standard deviation (per unit)
TSO	Transmission system operator
UC/UCED	Unit commitment / Unit commitment and economic dispatch
UK	United Kingdom
US/USA	United States (of America)
VOM	Variable operation and maintenance costs
VRE	Variable renewable energy

1. INTRODUCTION

For several decades, energy system fundamentals have remained familiar: Power and heat generation in large centralized thermal power plants fired by fossil fuels, and passive consumption by end-users in industry, transport and buildings. The International Renewable Energy Agency (IRENA) and the International Energy Agency (IEA) among many others, envision the 2050 global energy system as completely transformed — highly powered by variable renewable energy (VRE), highly electrified, highly flexible and highly integrated [1], [2]. The change towards a new equilibrium is driven by both political pressure and technological development. The Paris Agreement [3], the European Union (EU) 2050 carbon-neutrality target, a recent increase of the 2030 EU greenhouse gas (GHG) emission reduction targets and instruments like the EU Emissions Trading System (EU ETS) [4] compel European countries to rethink their fossil-based economy. Rapid technological and price development of both renewable electricity production and end-use electrification technologies offer appealing solutions. For instance, globally the cost of electricity generated by photovoltaics (PV) has reduced by 82% and by onshore wind by 40% over the last decade alone [5]. The desired speed of transition is breathtaking: Target scenario by the European Commission foresees over doubling of wind generation, almost tripling of PV generation and nearly quadrupling of electricity use for heat generation in the EU between 2020 and 2030 [6].

This thesis evaluates the energy transition, and deployment of wind and solar power, and large heat pumps, from three distinct perspectives: *Impacts on energy system operation*; *unique impacts on the Baltic energy system*; and *modelling of energy system operations*. The theoretical background of the thesis (Chapters 2–4) aims to describe the state-of-the-art in literature from each of the three perspectives by answering the following research questions:

1) What kind of challenges and opportunities wind power, PV and large heat pumps bring to energy system operation?
2) What are the unique features of the Baltic energy transition?
3) How the operation of energy systems with high shares of renewables should be modelled?

Firstly, wind and solar power have several operational characteristics that both challenge the traditional energy system operation and offer new opportunities. Especially, when considering high shares of intermittent capacity, novel operational challenges in timing, adequacy and grid design arise from variability, forecasting and decentralized generation. However, wind and solar power offer opportunities for expanding electrification by supply of low-cost electricity. [7] Target-level deployment of wind and solar will require improved sources of flexibility in end-use, power grid, and coupling with other energy sectors. These solutions include demand-response, interconnectors, electricity storages, liquid or gas electricity derivatives (power-to-X) and sector coupling with heat, transport and potentially other sectors. [8] While the VRE generation in the Nordic conditions will likely remain dominated by wind power, PV deployment may offer benefits in supporting wind generation curve and reducing costs [8], [9]. Electrification of heating — using green electricity for industrial, public and domestic heating via heat pumps — can lower GHG emissions and improve energy efficiency, but also offer flexibility by coupling power and heat sectors [10].

Secondly, the Baltic countries — Estonia, Latvia and Lithuania — each have unique challenges and opportunities in an effort to reach EU emission requirements and maintain energy security. Within the next ten years, Estonia is planning a substantial shift in power generation from oil shale to renewables, Latvia aims to make only moderate changes, and Lithuania is planning to deploy very high amounts of wind and solar to improve energy self-sufficiency [11]–[13]. Simultaneously, the countries are planning to disconnect from Russian synchronous grid and strengthen interconnections towards Poland [14]. Several modelling studies in the Baltic region have been conducted (e.g. [6], [15]–[18]), and key results address the themes of energy security, changes by the fast transition of transition, and ways of taking down policy barriers.

Finally, computational modelling of energy systems has taken huge leaps forward with the development of modelling techniques to capture increased complexity of the modelled systems. Increase in computational capacity has allowed the intake of high temporal and spatial resolution and scope. The speed of system change and tightening of emission reduction targets have increased the demand for modelling scenarios in order to support public and private decision-making [19]. When modelling systems with high variable generation shares, the importance of operational detail and novel model characteristics like stochastic programming, forecasting, capacity adequacy and grid stability is increased [20]. The core method of optimizing operational decisions considered in this thesis is solving the unit commitment and economic dispatch problem over each time step of the simulated year [21].

The Baltic modelling case study (presented in Chapters 5–6) uses the methods established in literature in order to model the Baltic regional energy system in 2030 with hourly time resolution. The model compares the 2017 system with the 2030 scenario based on National Energy and Climate Plans (NECPs) of the Baltic countries, and estimates the techno-economic feasibility of the three technologies in focus. The research questions are:

4) If the national plans are followed, what kind of operational challenges and opportunities the modelling indicates for the Baltic energy system for 2030?

5) What kind of challenges and opportunities emerge in the Baltic energy system operation in 2030 with different levels of wind power, PV and large heat pumps?

The case study is conducted using an established Backbone modelling framework for optimizing energy system planning and operation [22]. The Backbone framework is selected, because it allows several important features in studying the impacts of high variable shares in the Baltic setting, like co-optimization of multiple energy sectors, full year unit commitment decisions, and flexible spatial resolution to represent the whole Baltic region, yet study i.e. capital regions in detail. The framework allows later expansion of the model to include stochastic impacts, larger European region, or longer study timeframe. Both the *Backbone framework* and the Baltic model created for it (called *Baltic Backbone*) are fully open source, contributing to open science.

In literature, there are fewer modelling studies in the Baltic energy system than for many Nordic and Central European regions. Previous modelling studies focusing on the Baltic region have used representative days or weeks [15], [17] [23], or annual generation only [16]. Therefore a key improvement of Baltic Backbone is to include full-year hourly resolution for co-optimization of multiple energy sectors. The Baltic Backbone model is created in a research project *FasTen (Fast, flexible and secure decarbonisation of the Baltic states — possible progress in the next Ten years*) in cooperation by the author and other project partners [24]. This thesis is conducted as a part of the project. The Baltic Backbone model and FasTen project results are presented also in a conference article [25], and a clear distinction between the contributions of the thesis and the FasTen project is given when presenting results.

The aim of the theory chapters is to first establish the major trends in energy system research, and then deepen the analysis to the case study technologies, the Baltic region and finally energy system modelling. With this theoretical background in mind, the case study in Chapter 5 presents a Baltic energy system model that is suitable for addressing the systemic trends, while remaining relevant to the operational characteristics of the studied technologies, the energy political stance of the Baltic region, and advances in energy system modelling. Finally, results in Chapter 6 offer techno-economical findings in system operation between 2017 and 2030 if the Baltic national energy and climate plans are followed. Furthermore, the feasibility of three prominent technologies — wind power, solar PV and large heat pumps — is evaluated in the Baltic 2030 setting.

2. REGIONAL ENERGY SYSTEMS WITH HIGH SHARE OF RENEWABLES

This chapter describes the opportunities and challenges of future energy systems with high shares of variable renewable generation — namely wind and solar PV — and increasing electrification of heat production. Regional energy systems are analyzed in terms of power and heat generation, distribution and trade, end-use, and acquisition of primary energy sources. The focus is on the operational impacts induced by the distinctive features of generation technologies, and their implementation in a North and Central European setting. The modelling solutions of studying the operational impacts are investigated in Chapter 4.

First, Figure 1 describes the components of a *regional energy system*, as it is understood in the scope of the thesis. Primary energy sources are used directly by end-users in transport, industries and residential, commercial and public buildings, or combusted for centralized power and heat generation. Heat is distributed in localized district heating grids, while power is transmitted over large geographical areas with connections to neighboring countries. Renewable sources for power generation, large heat pumps to electrify district heating, energy storages and end-use flexibility are novel components in a system built to supply energy securely and affordably under market conditions and political regulation for societal needs. The studied region can cover anything from a city to a continent, but typically national-level energy systems are considered.

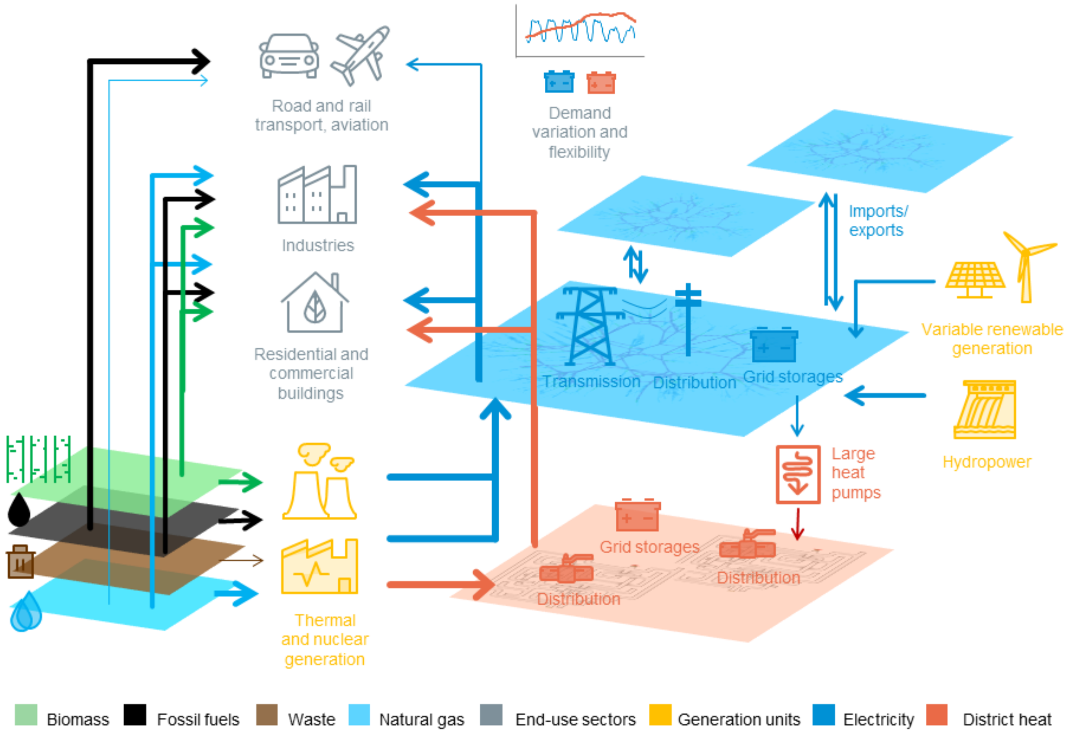


Figure 1. *Components of a regional energy system and the interactions between supply and demand.*

Key operation of the energy system relates to balancing supply and demand at each time instant. This requires cost-optimal dispatch decision of generation units, optimal use of storages and power interconnectors and possible demand response under the technical, market and regulatory restrictions. Planning of the energy system seeks optimal investments under uncertain future conditions. As the system grows increasingly complex, simultaneous consideration of many energy sectors becomes necessary.

Next subchapter describes the factors shaping future energy systems and their study. After that, operational characteristics of wind, solar and heat pump from regional energy system perspective are addressed.

2.1 Trends in future energy systems

While discussion on the most important factors or technologies shaping the future of energy systems is ongoing, recurring trends can be identified in literature. Understanding these trends is essential in building models and scenarios to study the future of energy systems.

1) *Climate targets will increasingly impact energy systems.* The Paris Agreement is a legally binding global agreement signed by 196 participants in 2015, aiming to limit global warning to well below 2 ºC, preferably to 1.5 ºC [3]. The energy sector is the largest contributor to global GHG emissions [26], and there is a wide consensus that climate change mitigation requires a fundamental transformation of the energy system [27]. In the European Union, the practical impact is felt via green transition targets, most importantly a binding target to reach climate neutrality by 2050, and a new set of proposals 'Fit for 55' to tighten the intermediary target of 2030 to 55% GHG reductions from 1990 levels [28]. Emission trading system, member states' emission reduction targets and a set of legislative, market and tax regulation are shifting the most cost-efficient energy options from fossil to carbon-neutral.
2) *Lowering technology costs and increasing EU emission trade prices are making new VRE generation a cheaper source of electricity than existing fossil capacity.* Global weighted-average levelized cost of electricity (LCOE) from new onshore wind installations decreased by 13% solely between 2019 and 2020. The LCOE from offshore wind reduced by 9% and from utility-scale PV by 7%. [5] Together with significant development in e.g. battery, electric vehicle and heat pump technology, VRE deployment and electrification is becoming increasingly market-driven.
3) *Power generation will be among the first sectors to decarbonize, followed by end-use in transport, buildings and industries.* For example, in IRENA's projections to reach the Paris Agreement targets, European renewable energy share in power generation should reach 86% and end-use electrification 49% by 2050 [2]. European Technology & Innovation Platform on Wind Energy (ETIP) foresees a 50% wind share of European electricity demand by 2050 [29].
4) *Decarbonization requires increasing integration and sector coupling.* Mathiesen et al. [30] introduce the term "smart energy system" and state that focusing only on smart power grid reduces the potential for VRE deployment. For instance Kunze & Schreiber [31] remind of the need to consider increasing integration and sector coupling also in energy system modelling efforts.
5) *Full decarbonization requires end-use electrification, flexibility, conventional renewable sources, green hydrogen, and innovation.* IRENA has named these "the five technology pillars for the future of energy" [2]. Similarly, Nordic Clean Energy

Scenarios [32] found that in all decarbonization scenarios for the Nordic countries, direct electrification was the main pathway. Complementary solution tracks were carbon capture and storage (CCS and bioenergy-CCS), bioenergy, power-to-X and behavioral change.

6) *Decentralized generation will substitute and complement centralized generation.* For example, high-renewable future scenarios by EU research project REXLEX [33] compared two pathways, one with large-scale offshore and onshore wind power at prime locations, integrated grid infrastructure, and centralized heat production and hydrogen electrolysis; and another with decentralized rooftop PV, onshore wind at all possible locations, small-scale biomass heat plants, and residential heating by heat pumps, solar and batteries.

On the other hand, *the largest differences* in global energy scenarios by different organizations, according to IRENA [34], include the role of energy efficiency, the significance of carbon capture and storage (CCS), the future of natural gas, the penetration of hydrogen and its derivatives, feasibility of small nuclear reactors (SMR), and speed of scale-up for disruptive technologies.

2.2 Status and trends in deployment of wind power, solar power and large heat pumps

In the European energy transition, wind power and solar PV have already become mainstream. Fast deployment of VRE also plays a significant role in European green transition plans [28]. On the other hand, introduction of large heat pumps to support district heating is an emerging solution, driven by sector integration benefits [35]. The installed capacity of onshore wind in Europe in 2020 was 183 GW, while the capacity of offshore wind was 22 GW [36]. The installed solar PV capacity in Europe in 2021 was 165 GW [37]. In 2019, the share of district heat generated by heat pumps was only 0.8% [38]. Figure 2 shows the different levels of wind generation share in European Union countries [39].

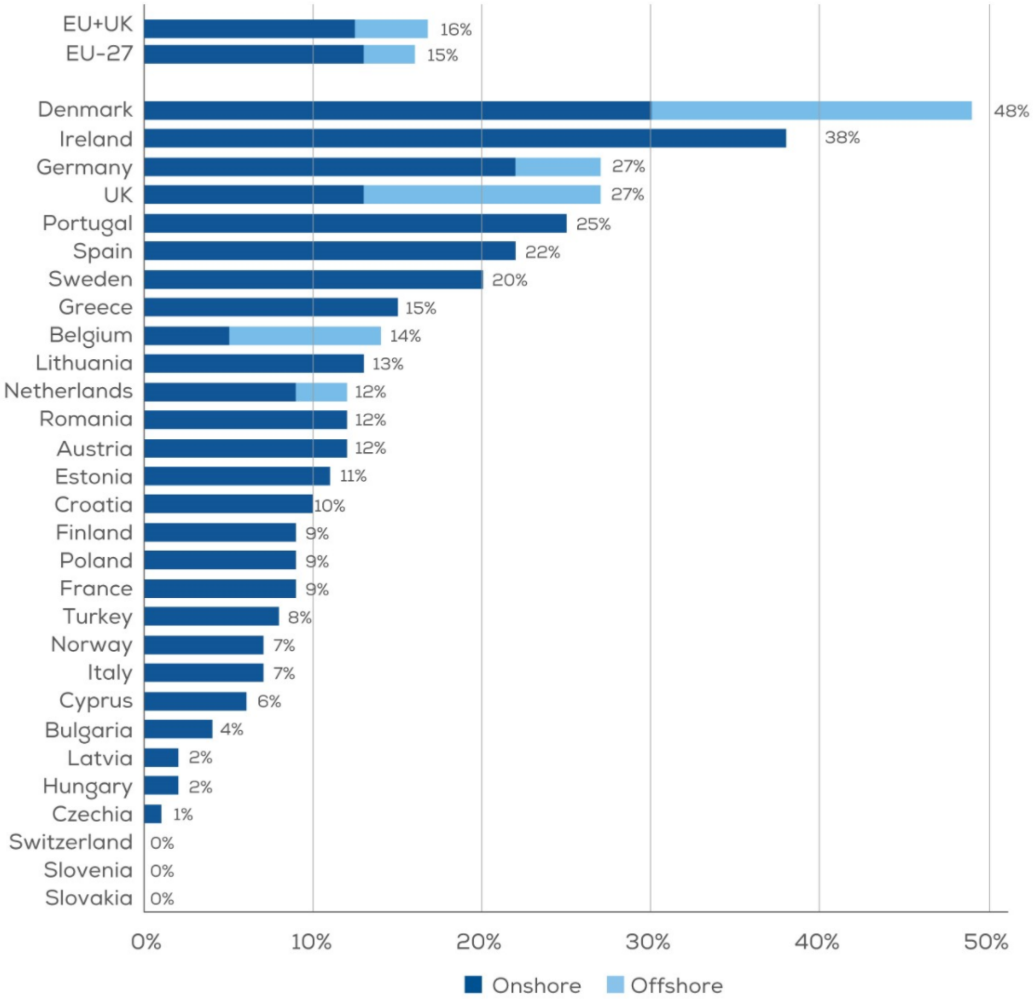


Figure 2. *Electricity generation share by wind power by country in Europe in 2020 [39].*

The largest country specific shares are found in Denmark (48%), while the Baltic countries' shares (2–13%) are below EU average of 15% [39]. The countries with the most wind capacity include Germany (54 GW), France (17 GW), and the UK (14 GW) [36]. In total, 16% of Europe's electricity demand was generated by wind power [39].

EU's 'Fit for 55' scenario [6] proposes the total wind power capacity in the EU to increase from current 183 to 427 GW by 2030 (including 361 GW onshore and 66 GW offshore wind). This would increase the total EU electricity generation share by wind from 15% to 34%. For the Baltic countries, the modelled scenario to achieve new targets would increase onshore wind from current 316 to 546 MW in Estonia, from 100 to 458 MW in Latvia, and from 573 to 2358 MW in Lithuania by 2030. In addition, Estonia would build 725 MW and Latvia 300 MW offshore wind in the next decade. Currently the Baltic countries have no installed offshore capacity.

Prices of wind installations are expected to continue declining, primarily due to increase of turbine sizes, improvement in capacity factors and advances in installing and operation. ETIP [29] anticipates the LCOE generated by onshore wind to decrease from 41–50 €/MWh in 2020 to 27–40 €/MWh by 2030 and to 21–32 €/MWh by 2050. Similarly the LCOE by offshore wind would drop from 78–94 €/MWh in 2020 to 37–60 €/MWh by 2030 and 29–48 €/MWh by 2050.

In 2021, 26 GW of new solar PV capacity was connected to the grid in Europe. With current fleet of 165 GW this results in 16% growth in a single year. [37] EU 'Fit for 55' [6] modelling suggests an increase in electricity generation in the EU by solar PV from current 5% to 14% by 2030. The European PV market is dominated by Germany and Italy with 60 GW and 22 GW of installations respectively. The installed capacity in Estonia is 546 MW, in Latvia only 19 MW and Lithuania 220 MW. Surprisingly, Estonia is in 7th place per capita installations in the EU. [37] Estonia is already exceeding its PV capacity target of 358 MW in EU modelling. Latvia's target is modest with only 78 MW, but Lithuania's ambitious 2111 MW. [6]

Similar to wind installations, PV capacity feasibility continues to develop, but with an even faster speed. Solar Power Europe [37] forecasts that LCOE by utility-scale PV (100 MW) in Finland would decrease from 25–50 €/MWh in 2020 to 18–35 €/MWh by 2030 and 12–20€/MWh by 2050.

While global share of heat pumps has increased by 10% over the last 5 years, and IEA's "Net Zero Emissions by 2050" scenario suggests that the installed heat pump fleet reaches 600 million from current 180 million by 2030 [40], large heat pumps for district heating are still marginal. In 2015, district heating was responsible for 12% of heating market in the 14 most heat-intensive EU countries, while nearly 50% in Finland and Sweden [41]. Majority (60%) of all district heating in Europe is generated by fossil fuels, and the current share of heat pumps is only 0.8% [38].

The benefits of large heat pumps increase as energy systems become increasingly integrated. Heat Roadmap Europe [41] states that "In the vast majority of urban areas, district energy is technically and economically more viable than other network and individual based solutions, and can be 100% decarbonised through the use of renewables, large heat pumps, excess heat, and cogeneration." In their scenarios up to half of heating demand could be cost-effectively supplied by district heating, of which 20–30% by large heat pumps. The expansion of district heating is, however, not a confirmed trend, and many studies predict only small or negligible increase in district heating shares (for example [42]).

Heat pump systems compete with conventional decarbonization options like biomass, but they can be beneficial especially if there are excess heat sources available (e.g. data centers) or suitable water ways. David et al. [10] identify four defining aspects in European deployment potential: 1) availability of heat sources, 2) available and allowed refrigerants, 3) operating temperatures and 4) type of operation (see Chapter 2.5). Examples of current installations seem to exist only where there is a pronounced benefit, like inexpensive electricity supply (like in Norway), or constraints in local supply of biomass (like in Helsinki, Finland) [35]. In the future, a combination of heat pumps and heat storages may be successfully coupled with highly variable electricity availability and prices [10].

2.3 Wind integration

Study in the field of wind and solar integration has merged into studying both at the same time with VRE shares up to 50% and more. The two main focus areas are *long-term planning* issues including grid planning and capacity adequacy; and *short-term operational* impacts and balancing related issues, including reliability, stability, reserves, and maximizing the value of wind in operational timescales. [43]

From operational energy system perspective, two of the most important wind power characteristics are *variability* and ability to forecast variation, i.e. *uncertainty*. Wind speed varies at all time intervals, from seconds to years, but from the power system point-of-view variation is strongest and most significant in the hourly scale [7]. However, variation of a single turbine is much greater than the aggregated output of a larger area, as demonstrated by Figure 3. This phenomenon is called *geographical smoothing.* Figure 3 displays the hourly variation in wind power generation capacity with different levels of aggregation during consecutive hours and sorted by frequency. [7], [44]

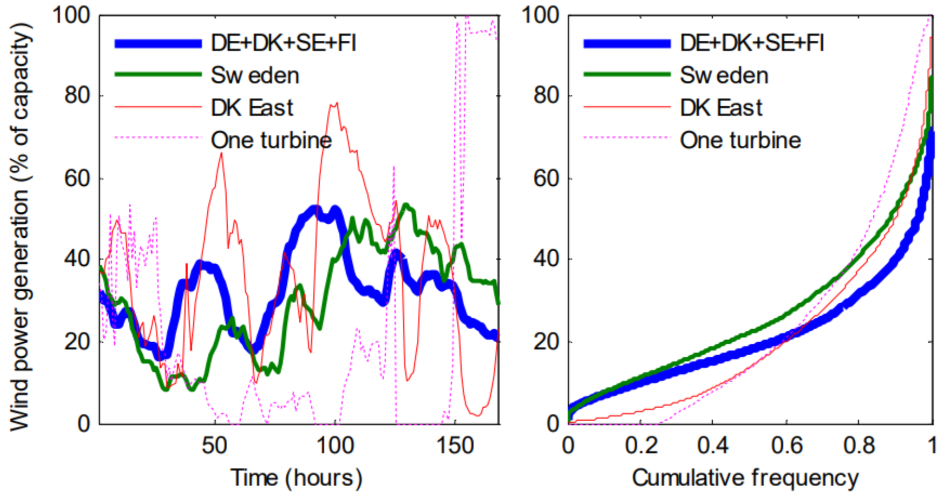


Figure 3. *Hourly variation of wind power generation at different levels of geographical aggregation during a week in 2010 (left) and annual 2010-11 sorted data (right) [44].*

As shown by the left figure, geographical smoothing decreases hourly variation as the level of aggregation is increased (from one turbine to area level, country level and finally to an aggregate of four countries). Similarly, a single turbine experiences frequent hours with no output or full output, while the output of a large aggregated area is never 0% nor 100%. This is shown by the right figure with cumulative frequencies of generation share percentages. Number of wind plants, and geographical and capacity dispersion impact smoothing effect. [7], [44]

While hourly variation and forecasting is the most important timescale from operational point of view, annual and seasonal variation impacts planning. Hourly wind variations are stochastic, but annual and seasonal variations follow more distinctive patterns [45]. Figure 4 displays the weekly variation of a single wind power plant in Sweden [7].

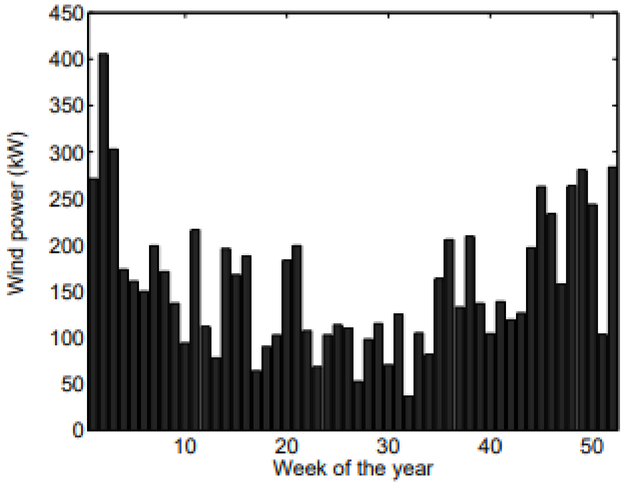


Figure 4. *Weekly variations of a single turbine in Sweden over three-year period [7].*

While week-to-week variations are unpredictable, a seasonal pattern typical to the location is shown. A ten-year comparison in annual generation of single wind power plant in US locations showed an annual standard deviation of 7–14% from average annual generation, with minimum year at 82% of average and maximum at 113%. [45] It is noteworthy that wind conditions have a connection to precipitation and therefore hydropower conditions [7].

From long-term planning perspective, wind power production variation can be estimated using probability distribution and density functions, typically Weibull distribution. The Weibull distribution indicates the wind speed distribution with given expected wind value and shape factor. [7] However, from operational perspective forecasting wind generation in the next hours and days is relatively inaccurate, and forecast error increases rapidly as forecast horizon extends. The quality of forecasts decrease significantly already on time scales of 1–4 hours, and continue to decline over the next 24–36 hours. Large forecast errors increase operation costs of the system as other units or reserves need to be redispatched. [44]

In wind integration studies, the term *capacity value* is used to describe the fraction of capacity rated firm, i.e. ability to reliably meet demand. In the case of wind power, the capacity value is dependent on the coincidence of wind flow with demand and decreases as wind deployment grows. Furthermore, the term *capacity credit* is used to estimate the capacity of conventional generation that can be replaced with wind power. [7] *Capacity factor*, on the other hand, represents expected energy production as a share of available capacity of nominal capacity [8]. Capacity factor time series is a useful tool in describing the hourly expected generation over a whole year.

In addition to operational characteristics mentioned here, the decentralized nature of wind installations calls for substantial grid development in both transmission and distribution levels [8]. As a recent example, Bloomberg [46] reports that Sweden has been limiting electricity exports in 2021 because of grid difficulties at least partly associated with wind deployment in the north and decommissioning of nuclear plants in the south. Grid development has also reported to lag behind wind deployment in China and Germany [8]. When wind power is added to a system with inadequate flexibility, wind power must be *curtailed*, limiting its value. Figure 5 shows that the level of curtailment varies from system to system [8].

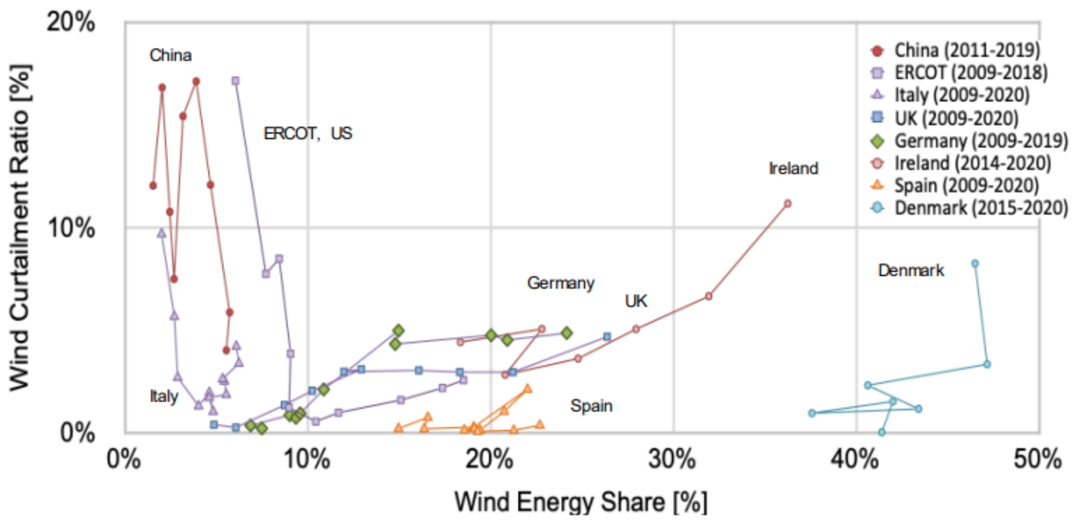


Figure 5. *Wind curtailment ratio against wind energy share in selected locations in Europe, China and ERCOT (Texas) [8].*

As indicated by the figure, wind curtailment is a significant problem in some regions. Reasons for high curtailment include weak interconnections, inflexible grid or market, and regulatory constraints [8]. The high curtailment ratio in China even with low wind generation shares serves as an example of inadequate wind integration. In the case of Ireland, increase of wind power share strongly correlates with wind curtailment ratio. This is typical for an island system, where large geographical area and AC interconnectors cannot be used to balance wind variation and grid stability.

As of today, limited real life examples on extremely high wind systems exist. Denmark, with nearly 50% of wind power generation share is among the best examples. The first time the system operated without any large power plants online was reported in 2015 and the situation has been recurring more frequently since [8]. Skytte and Grohnheit [47] reported in 2018 that the current market and infrastructure in Denmark have been able to handle wind power variations and forecast challenges, most importantly using international interconnectors, and hydropower and combined heat and power (CHP) systems with heat storages in the Nordic power market region.

2.4 Solar integration and complementarity

In the Nordic conditions, the practical approach to solar integration studies is to focus on the complementarity of solar and wind power. The seasonal and daily cycle of solar resources is a barrier to reliable PV-dominated systems everywhere, and systems require storages and complementary wind to meet demand [9]. Additionally, in the Nordic region, solar generation is most abundantly available in the summer when the demand is lowest.

Like wind, operational issues in solar integration include variability and forecasting. The unpredictability is due to changes in cloudiness, and can cause fast variation to solar generation on sub-hour timescales. Movement of the sun in the sky causes 10–13% ramp rates to PV generation on a 15-minute timescale. Clouds, on the other hand, can cause 60% change in generation to a point source in a matter of seconds. Like in the case of wind power, geographical smoothing reduces variability, and the impact is seen even within a single PV plant. [48] On an hourly level, the distinctively different wind and solar generation curves have the opportunity to complement each other like shown in the example from France in Figure 6 [8].

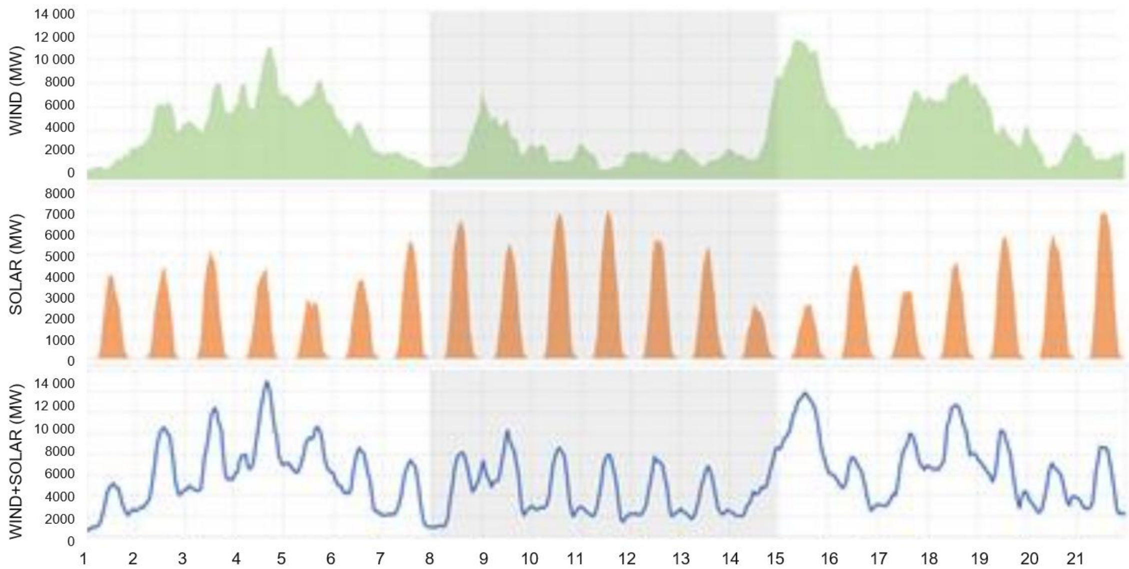


Figure 6. *Comparison and combination (bottom) of the hourly generation curves of wind (top) and solar power (middle) in a three-week period in France 2020 [8].*

The combined generation curve (in the bottom) shows reduced variability compared to wind or solar generation individually (above) [8]. The regional degree of complementarity can be estimated with Kendall correlation coefficient. Global coefficient values range from -0.83 to -0.91 (the best value is -1). Northern regions have amongst the best values, indicating an overall high level of complementarity in the Nordic and Baltic countries. [9] The complementarity is also linked to the optimal mix between wind and solar generation. According Tong et al. [9], the most reliable generation mix between wind and solar power consist of 65% to 85% of wind power, depending on location. For northern systems the best mix is even more wind oriented: between 75% and 85%.

2.5 Integration of large heat pumps for district heating

Unlike wind and solar, large heat pump integration is not to be considered as mitigation to inevitable future conditions, but rather a key opportunity to decarbonizing heat generation while balancing the impacts of variable generation. Decarbonizing centralized heat is a more complex challenge than simply substituting current generation with renewable sources, and it requires cooperation of many solutions. Heat pumps reduce district heating emissions by improving energy efficiency, offering possibility to utilize low temperature excess heat and store excess electricity from variable sources in thermal storages. Additionally, in the search of a systemic solution to variable generation, hopes are that heat is one of the sectors that will help mitigate problems in the power sector by offering flexibility. [10], [41], [42]

Heat Roadmap Europe [41] suggests a 2050 system where district heat supplies at least half of heat demand, and is generated 20–30% by large heat pumps, at least 25% by excess heat, and 25–35% by CHP generation. In their modelling this strategically decarbonized heating and cooling system was able to absorb 30% more of variable electricity generation than conventionally decarbonized system due to enhanced flexibility [10]. Heat pumps can also help in maximizing value of wind power and reduce curtailment [8].

Operational benefits of large heat pumps in future energy systems include balancing variable power generation by using heat pumps when renewable energy is available, and charging thermal storages when demand is low. One sector coupled solution with heat pumps, CHP plants and heat storages steered according to variable generation is exemplified in Figure 7 [10].

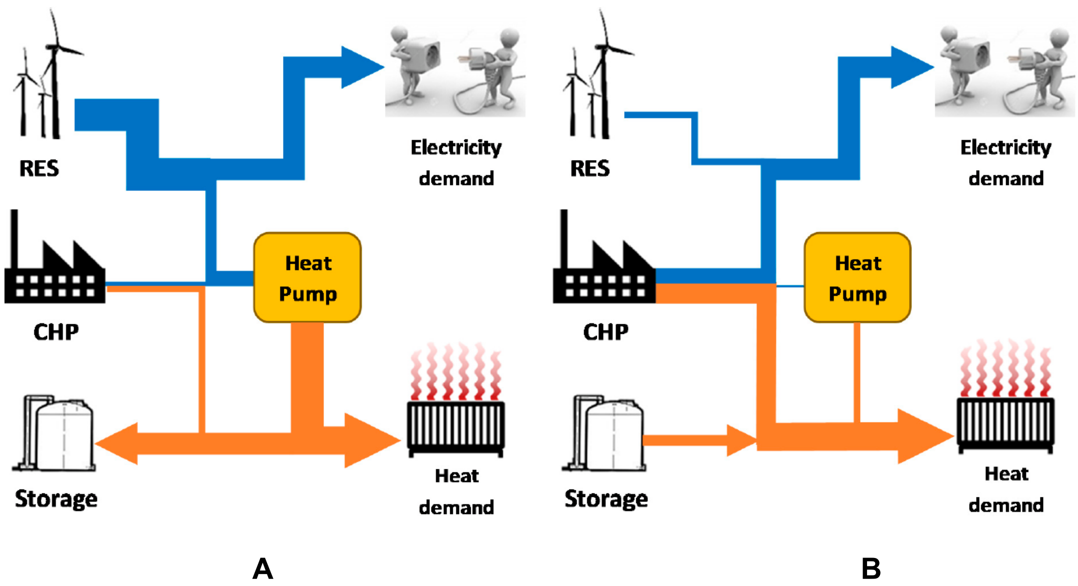


Figure 7. *Sector coupled large heat pump operation driven by availability of renewable electricity. (A) in the case of high renewable generation, and (B) in the case of low [10].*

In this example, heat pumps are operated whenever renewable electricity is available, and heat is stored if heat demand on that instant is low. Also the operation of cogeneration units is optimized according to variable power generation in order to maximize the value of intermittent capacity and provide system flexibility. However, there is controversy whether large heat pumps are suitable for continuous startups and shutdowns required by this type of operation. Most current installations operate on high full load hours (FLH), but large heat pumps in Heat Roadmap scenarios operate on average 33% annual FLHs. Firstly, this would require overbuild of capacity, and secondly, redesigning heat pumps to better sustain regulation use. [10] Additionally, heat storages have a limited capacity to balance supply and demand due to seasonal nature of district heating demand, especially in temperature dependent residential-dominated systems.

3. BALTIC ENERGY SYSTEM TRANSITION

The Baltic countries — Estonia, Latvia and Lithuania — are facing the energy system trends from a unique situation. This chapter presents the current state of these energy systems, identifying the position of each country in light of recent literature and National Energy and Climate Plans (NECPs) [11]–[13]. Major transformations in Baltic operating conditions and recurring themes in literature are identified and linked to systemic trends described in Chapter 2. Finally, operation and integration of existing renewable resources in the Baltic system are presented as prelude to the case study in modelling and operational analysis of the future system.

The current Baltic energy system is shaped by geopolitical status, existing oil shale generation in Estonia, hydropower and gas-fired production in Latvia and modest domestic capacity of Lithuania. Strong interconnectors, underground natural gas storage and pumped hydro storage are Baltic system's existing strengths. The future system development relies on the national plans and goals, the EU requirements and changes in operating environment. Gathered from national strategies, literature and conversations with Baltic stakeholders in the FasTen project, the major energy related changes the Baltic counties are facing include:

1) The 2021 updated EU legislation [28] tightens emission reduction targets for all member countries.
2) The planned disconnection from Russian synchronous grid in 2025 [49] will likely limit the net transfer capacity of the Baltic region.
3) The planned phase-out of significant amount of existing fossil generation and deploying new renewable, especially wind generation, [11]–[13] is rapidly transforming the power generation infrastructure.
4) Changes in the operating conditions, like global fuel prices, EU ETS prices and development in the Nordic countries and continental Europe, will have a substantial impact on the small, import dependent Baltic countries [14], [15], [23].

The future development of the Baltic energy system has been evaluated in recent literature with various approaches. The ones using modelling offer concrete results for comparison, while others offer viewpoints on what may be the major challenges or opportunities for the Baltic states. Recurring themes include *energy security*; *challenges and opportunities of fast transition from fossil to renewable power and heat production*; and *taking down policy barriers to reach the targets*. The most important reference study for the case study of the thesis is Baltic Energy Technology Scenarios [15] by Lindroos et al. in 2018. The results of the case study are later compared to their modelling work conducted in Balmorel energy system framework (see Appendix A). Other important references include the modelling study conducted as part of EU 'Fit for 55' package [6] for all EU member countries in 2020, and modelling studies by Blumberga et al., Lund et al. and Petrichenko et al. [16]–[18].

3.1 History and current status

A crucial factor influencing the Estonian, Latvian and Lithuanian energy systems is their shared history: All three countries were under the Soviet Union rule from 1940 until Soviet Union dissolution and regained independence in 1991. In 2004, the countries joined the European Union and military alliance NATO. [50]–[52] This is evident in current technical status as well as political goals. For example, the Baltic countries are technically part of Russian electricity grid (Integrated Power System / Unified Power System (IPS/UPS)), but they are looking to synchronize with the continental European grid by the end of 2025 with large investments to transmission connections [49]. Their political interest emphasizes energy security and energy independence from Russia.

The Baltic states are small countries with a total population of 5.9 million people: Estonia 1.3 million, Latvia 1.9 million and Lithuania 2.7 million. The population has also been in decline since 1990, when there were a total of 8.0 million Balts. [53]–[55]. The 2020 Baltic per capita gross domestic product (GDP) of 12–15 k€ is clearly below EU-27 average of 26 k€ [56]. The countries are geographically small with no major renewable natural resources.

Estonia's most distinct feature is extensive oil shale use. Oil shale is an organic-rich sedimentary rock containing kerogen, and can be burned for energy production. Deposits of oil shale occur around the world, USA having largest resources. Oil shale can be refined as shale oil used as an alternative for crude oil. It was quite widely exploited until 1960s, however, only few nation continue today to rely on oil shale for fuel, namely Estonia, China and Brazil. [57] Estonia is the only shale oil producer in the EU. Oil shale industry in Estonia is larger than what is used for domestic energy — in the early 2010s, approximately 80% of shale oil was exported. Oil shale refining and combustion have many environmental and climate issues, but also many benefits to the Estonian industry, employment and economy. [58]

Latvia's major sources of electricity include three large hydro power stations in cascade on Daugava river — Plavinas (884 MW), Riga (402 MW) and Kegums (264 MW) —

providing 30–60% of national consumption depending on the annual precipitation [59], [60]. The remaining share is produced primarily by natural gas cogeneration, supplemented with electricity imports. Natural gas is mainly imported from Russia. Inčukalns underground gas storage facility with 2.3 Gm^3 capacity (1.5 times the annual Latvian demand) stabilizes the supply of natural gas to Latvia and Estonia: gas is injected during cheap summer months and used during heating season. [15]

Until 2009, Lithuania used to supply around 70% of domestic electricity demand by Ignalina nuclear power plant. However, the similar-to-Chernobyl plant was decommissioned as a part of accession agreement to the EU, leaving Lithuania heavily import dependent. Lithuania has a 900 MW pumped-hydro storage plant Kruonis used for short term grid balancing. [15], [61] After closing the Ingalina nuclear power plant (NPP), a new regional NPP venture in Visaginas, Lithuania was planned. Latest public records are from 2016 when a former energy minister announced the project planning preparations have stopped. [62] The development of annual electricity generation in Estonia, Latvia and Lithuania 1990–2020 in Figures 8–10 shows the unique situation of each country [60], [61], [63].

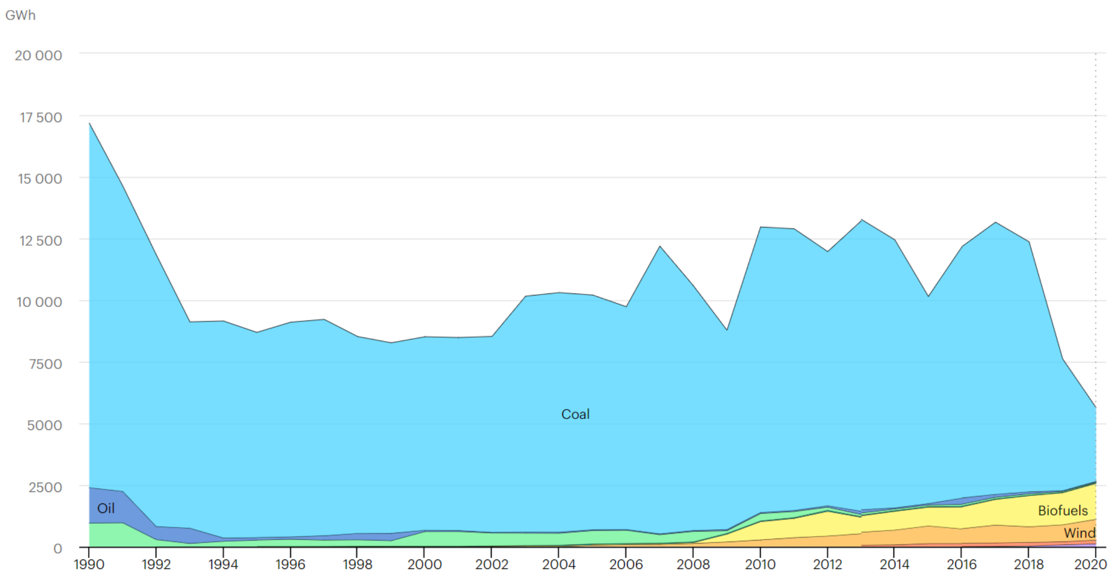


Figure 8. *Annual electricity generation in Estonia 1990–2020 [63].*

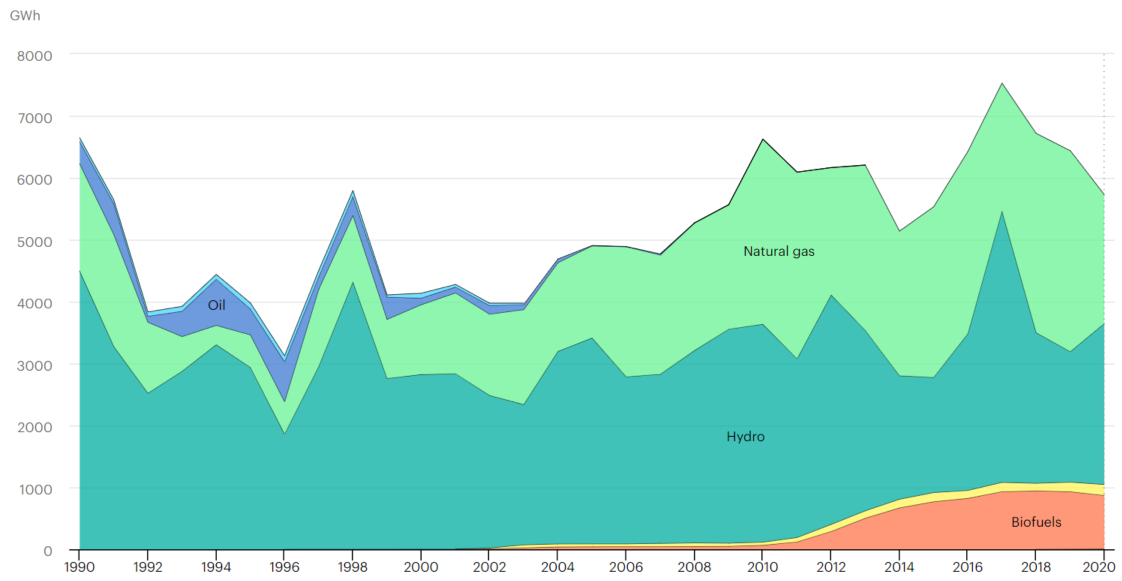


***Figure 9.** Annual electricity generation in Latvia 1990–2020 [60].*

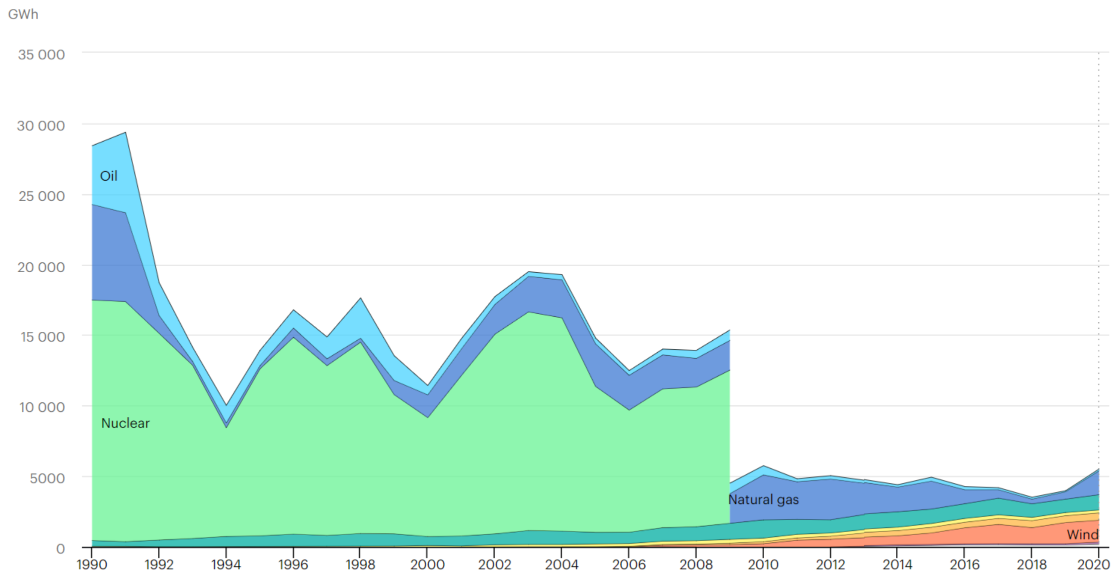


***Figure 10.** Annual electricity generation in Lithuania 1990–2020 [61].*

As shown in Figure 8, Estonia is dominated by oil shale (coal in statistics) with some biofuels and wind power introduced in the last decade. The statistics show a significant reduction in oil shale use in the past two years. For Latvia in Figure 9, reservoir hydro power and natural gas form are the basis of power production, with some new biofuel production. In Figure 10, the decommissioning of the Ingalina nuclear plant in Lithuania in 2009 is evident, leaving the country with a small own-production-share generated by hydro power, biofuels, natural gas and wind power. Noteworthy is the decrease in total generation amount of all the Baltic countries in the beginning of 1990s associated with the dissolution of the Soviet Union.

3.2 Reaching emission targets

As identified in Chapter 2.1, one major trend in political steering of energy systems is the role of emission reduction targets. The Baltic countries are no exception. EU Climate legislation is the driver behind the national Estonian, Latvian and Lithuanian emission targets. The effective EU GHG reduction target is -40% by 2030 compared to 1990. In July 2021, EU released a ‘Fit for 55’ legislation package [28] in order to support and further tighten reduction targets to reach -55% by 2030 in line of becoming the first climate-neutral continent in 2050.

According to the legislation [64], each EU member state must also prepare and submit a National Energy and Climate Plan (NECP) to the EU commission every ten years. The latest plans are from 2018–19. In the Baltic NECPs, Estonia seeks to reduce GHG emissions by 70% by 2030 from 1990 level (from 40.4 to 12.1 $MtCO_{2e}$) [11]. Latvia’s reduction target is 55% (from 25.4 to 11.4 $MtCO_{2e}$). Additionally, the Latvian NECP mentions a reduction target of 43% from 2005 level — which would mean a remainder of only 6.5 $MtCO_{2e}$. [12] Lithuania’s NECP is committed to EU-level target of 40% (from 45.2 to 27.1 $MtCO_{2e}$) [13].

The emission reduction targets in EU regulation are divided between Emission Trading Scheme (ETS), Effort Sharing Regulation (ESR) and Land use, Land-Use Change and Forestry (LULUCF). EU ETS covers large energy producers and consumers in power and heat and industry sectors. From emission perspective, the main EU ESR sectors include transport, buildings, agriculture and small industrial use. [65]

The new ‘Fit for 55’ package [65] proposes new strengthened emission reduction targets especially for EU ESR sectors. The proposal includes widening of the emission trade scheme to cover also road transport and buildings (currently under effort sharing regulation), and updated EU ESR targets for member countries. The current national NECP targets in reductions in EU ESR sectors between 2005 and 2030 are 13% in Estonia, 6% in Latvia, and 9% in Lithuania [11]–[13]. The new proposed targets would increase to 24% for Estonia, 17% for Latvia, and 21% for Lithuania. The additional needed measures would be in the order of magnitude of 2 $MtCO_{2e}$ for Estonia, 1 $MtCO_{2e}$ for Latvia and 15 $MtCO_{2e}$ for Lithuania. [65] The 2018 situation of released GHG emissions by sector in the Baltic countries is presented in Figure 11 [26].

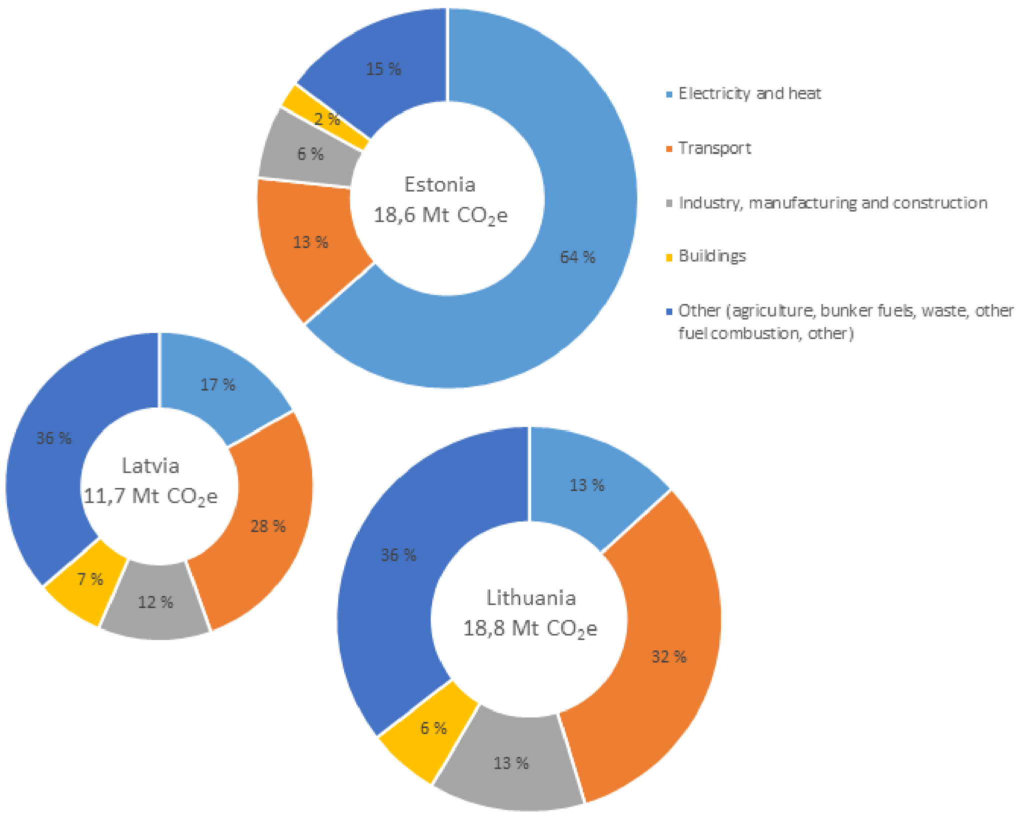


Figure 11. *Total GHG emissions in selected sectors in Estonia, Latvia and Lithuania 2018 [26].*

Estonia's emissions are primarily related to power and heat generation (EU ETS emissions) whereas the majority of the Latvian and Lithuanian emissions come from EU ESR sectors like transport and agriculture. The historical development of emissions in recent years is quite steady. However, the Baltic countries experienced a massive drop in GHG emissions in the early 1990s with the Soviet Union dissolution: the Baltic total dropping from 110 to 66 $MtCO_{2e}$ between 1990 and 1993 alone. In 2020, the total GHG emissions of the Baltic countries were 65% smaller than in 1990. [26] This partially helps the Baltic countries in reaching EU goals, but does not answer nearly all EU demands, especially in EU ESR sectors.

The countries' NECPs list main policies to achieve emission reduction targets as:

1) Increasing the share of renewable energy in electricity, transport and heating by building new capacity, especially wind and PV, supporting reduction of oil use in transport and heating, and widening of biomass use while maintaining LULUCF carbon sinks;

2) Improving energy efficiency, by reducing primary and final energy use by, for example, energy renevations;
3) Support for development of markets, innovation and competitiveness [11]–[13].

The modelling studies by Lindroos et al. [15] and Lund et al. [17] concur that the likely decarbonization pathway in the Baltics is similar to global trend: GHG reductions are led by power and heat sector, and followed by transport, buildings and others. Several studies (e.g. [14], [66], [67]) worry that while plans are in place, policies to support them don't exist or are poorly planned. Experts agree that while targets exist, building them into realizable direction, pathways and strategies will be a challenge.

3.3 Ensuring energy security

An additional dimension in the Baltic energy policy is the emphasis on security, driven by their historical situation. According to the NECPs, the Baltic countries are aiming to reduce imports of electricity and natural gas, increase interconnectivity and flexibility, and ensure both long- and short-term capacity adequacy [11]–[13]. These goals are impacted most profoundly by two future plans: disconnection from Russian electricity grid and fast transition in power and heat generation mix.

On the market side, the Baltic countries belong to the European power market Nord Pool, but technically remain a part of the Soviet-era (Belarus, Russia, Estonia, Latvia, Lithuania) BRELL energy ring and the Integrated Power System / Unified Power System (IPS/UPS) of Russia. This means that the Russian grid has the power to control frequency, physical and commercial flows in the area. For political reasons, mainly security of supply, the Baltic countries have long fostered a plan to de-synchronize with the Russian grid and join the frequency area of Continental Europe. The Political Roadmap for Synchronization agreement was signed by the Baltic countries, Poland and the EU in 2018. With EU support, the transition is planned to be finished by 2025. Figure 12 summarizes the planned changes in interconnections and grid reinforcements to and from as well as inside the Baltic countries. [49]

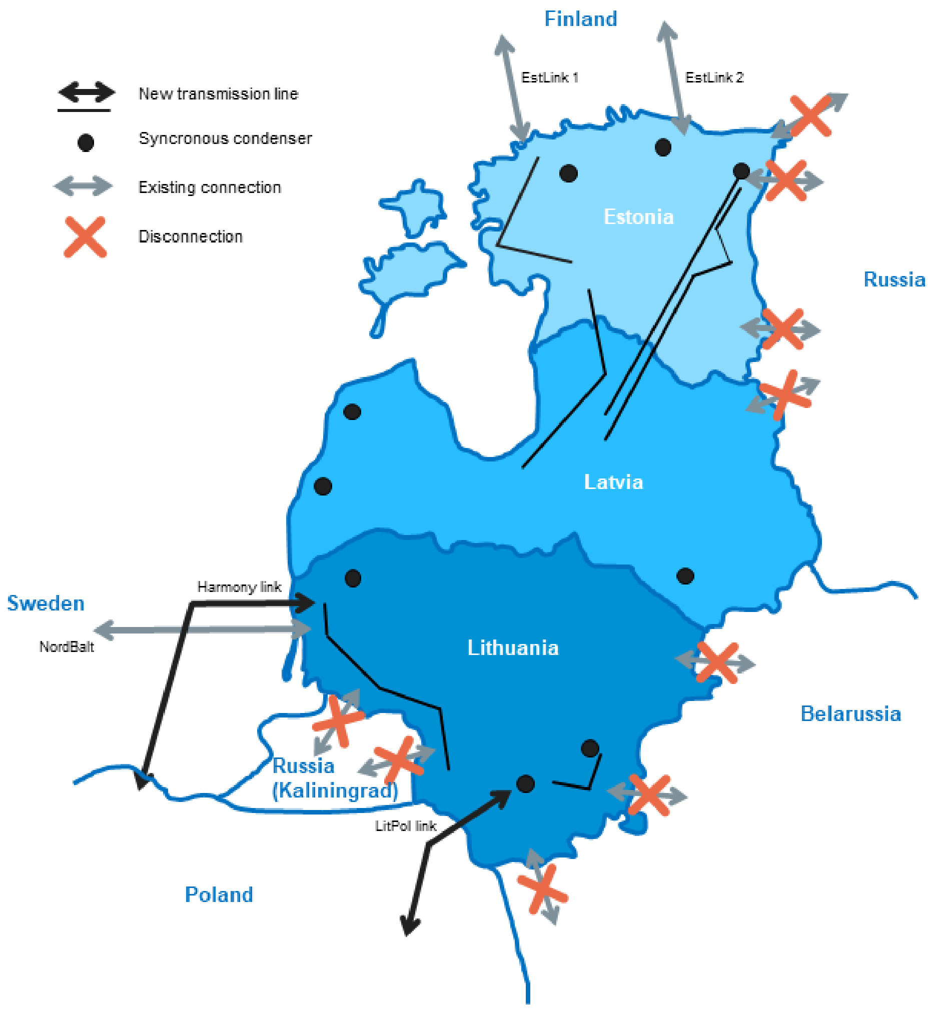


Figure 12. *Baltic synchronization plans with the Continental European grid in 2025 with planned decommissioning, new interconnectors and planned and implemented grid reinforcements [49].*

The current DC connection between Lithuania and Poland (LitPol) would be upgraded to an AC interconnection, and a new sub-sea DC cable (Harmony link) would be constructed. At the same time, the AC interconnections to Russia, including Kaliningrad region, would be disconnected. This requires several steps in reinforcing the power system inside the Baltic countries, including installation of several synchronous condensers and new transmission lines. [49] The existing import capacity from Russia to the Baltic countries totals to 3.4 GW [68], while the planned new connections to Poland add up to 1.7 GW [69]. However, the exact impact on transfer capacity is hard to estimate as, for example, the rated capacities can be only partially available for commercial operation while the remainder is reserved for reserve trade.

While in general, the synchronization plan is seen to improve the security of electricity supply, literature also raises concerns, for example, on peak load capacity adequacy, electricity self-sufficiency and electricity market and network development. Spiridonovs and Bogdanova [14] name integration with Continental Europe electricity grid as one of the two major challenges for Baltic medium- to long-term policy visions. Their research was published a year before signing the Political Roadmap for Synchronization agreement, but their findings on political options and need for Baltic cooperation in planning, market integration and investments are not outdated. They analyze the results of six studies on the topic carried out since 1998, and conclude that while the plan is technically possible, it is politically sensitive and has several implementation options. Critical voices have been raised especially in Estonia, furthest away from the balancing area [70].

In addition to measures to reduce Russian electricity dependency, plans to reduce Russian natural gas dependency are also a key energy security issue in the Baltic countries. The existing Inčukalns natural gas storage facility in Latvia helps balance seasonal variation in demand and prices, and increase self-sufficiency. In order to additionally diversify supply options, Lithuania has established a LNG station in Klaipeda, and new gas connectors are planned between Poland and Lithuania, and Finland and Estonia. [15]

The historical development in electricity generation shows the increasing share of wind and biomass and the decrease in fossil-based generation (08–Figure 100). According to both the NECPs and literature, the rate of change is accelerating, and as identified in Chapter 2.1, the change is becoming increasingly market driven. Many studies agree on the dominant role of wind power in the Baltic future system [15]–[17], as investments in renewable capacity seem to be the feasible way to boost domestic generation [15], [16]. Lund et al. [17] state that most of the investments to reach zero emissions in 2050 would have to take place before 2030. According to the NECPs [11]–[13] and reports by the national transmission system operators (TSOs) [69], [71] the Baltic countries are planning to invest in 3220 MW of wind power capacity, and 1435 MW of PV capacity by 2030. Additionally, Estonia is planning to decommission a total of 1680 MW of oil shale capacity in Narva by 2030 [71]. While the change in power and heat generation mix will increase domestic share and help reduce electricity and natural gas imports, it will also have impacts on capacity adequacy and flexibility requirements.

ENTSO-E Midterm Adequacy Forecast [72] estimates the power system resource adequacy and risk of loss of load in the next ten years for 42 European countries. While the situation of the Baltic countries is not worst in Europe, the region is among the worst performing in terms of loss of load expectation (LOLE) in 2025 and especially in 2030. The Estonian LOLE values for 2030 derived by different tools are between 0.2 and 1.8 h/year, Latvian between 0.0 and 5.5 h/year, and Lithuanian as high as between 2.5 and 13.1 h/year.

3.4 Adapting to changes in operating environment

In the small systems of the Baltic countries, individual policy measures can have a profound impact. For example, Lithuania lost over 70% of domestic power generation with the decommissioning of a single nuclear power plant in 2009 [61], and Estonia will lose up to 80% when shutting down Narva plants by 2030 [63]. Similarly, deployment of a single pumped hydro plant balances the operation of the entire Lithuanian system (see Chapter 3.5), or the success of one joint offshore wind project is crucial in reaching renewable targets [11], [12]. This means that the system is agile, but sensitive to changes inside and outside the region. As a region, the Baltic has strong power interconnections and is dependent on electricity imports (see Chapters 3.3 and 3.5), both amplifying the sensitivity to outside operational changes and improving power system resilience (see Chapter 2.3).

The operating environment in the neighboring countries, EU and globally impacts the Baltic countries via *direct generation cost impacts* and *indirect availability and price impacts.* The direct impacts include changes in fuel and emission prices, and indirect impacts involve availability of inexpensive electricity, natural gas and biomass from neighboring countries. If energy use electrifies as projected, electricity market will be an increasingly important operating ecosystem. For example, Norvaisa and Galinis [23] estimate that electricity prices and their development by policies in neighboring regions will significantly influence the development of the Lithuanian system. According to their study, Lithuania may even end up in a situation where low investment and high imports would be the most economical option, even though not fulfilling the energy security targets.

Spiridonovs and Bogdanova [14] have named the most influential factors in availability and prices of electricity in the Baltic countries as:

1) Interconnection projects (see Chapter 3.3)
2) Olkiluoto and Hanhikivi NPPs in Finland;
3) decommissioning of four Swedish NPPs;
4) renewable generation capacity development;
5) changes in international fuel costs;
6) and changes of emission prices.

The impact of added renewable and nuclear capacity on electricity prices are not straightforward, as the final impact depends on electricity demand, and on what and how much other capacity is replaced. However, increase in capacity of sources with low operational costs is likely to lower average electricity prices, especially if demand increase remains moderate [73]. Furthermore, as nuclear plants are typically operated as baseload (non-dispatchable) and wind generation varies, the combined effect may increase price volatility and value of flexibility. In the short term, high fossil fuel and emission prices can increase energy prices, but in a long run, they help to further accelerate the renewable transition in the Baltic region and neighbors.

Olkiluoto 3 unit will increase Finland's power capacity by 1.6 GW in 2022 [73], and if Hanhikivi 1 project is successful, its 1.2 GW of capacity is estimated to begin operation in 2029 [74]. Simultaneously, Sweden has decommissioned four nuclear plants between 2016 and 2020 with the combined capacity of 2.8 GW [75]. According to the EU 'Fit for 55' modelling, European neighbors of the Baltic countries (Poland, Sweden and Finland) would install 26 GW of wind power and 21 GW of solar power by 2030 if they were to reach the suggested emission reduction targets. The combined gross electricity generation in these three countries by renewables would increase by 102 TWh (74% of increase by wind power, 19% by solar power, and remainder 7% mostly by biomass and waste) and by nuclear by 17 TWh between 2020 and 2030. [6] Naturally, electricity prices are impacted by investments, interconnectors and conditions in the entire Nordpool area of 15 countries.

Long-term international fuel price estimates used in EU modelling [65] from mid-2020 predict doubling of fossil fuel prices by 2030: oil from 36 to 72 $€_{2015}$/boe, natural gas from 18 to 36 $€_{2015}$/boe, and coal from 8 to 16 $€_{2015}$/boe. EU ETS prices are estimated to rise from approximately 25 €/tCO_2 in 2020 to 30–50 $€_{2015}$/tCO_2 in 2030. However, this prediction already seems outdated since EU ETS prices reached 50 €/tCO_2 in spring 2021 and have since gone up to 70–90 €/tCO_2 [76]. Energy crisis in late 2021 and early 2022 has also increased international fossil fuel prices, but not to unprecedented heights. It remains hard to estimate the permanence of these recent trends.

3.5 Operation of resources in current system

In order to later analyze the possible operational changes with the quite drastic changes in generation capacity, hourly operation of current combined Baltic power generation and consumption is presented in Figure 13. The ENTSO-E data [59] is selected from four weeks of 2020 in January, April, July and September.

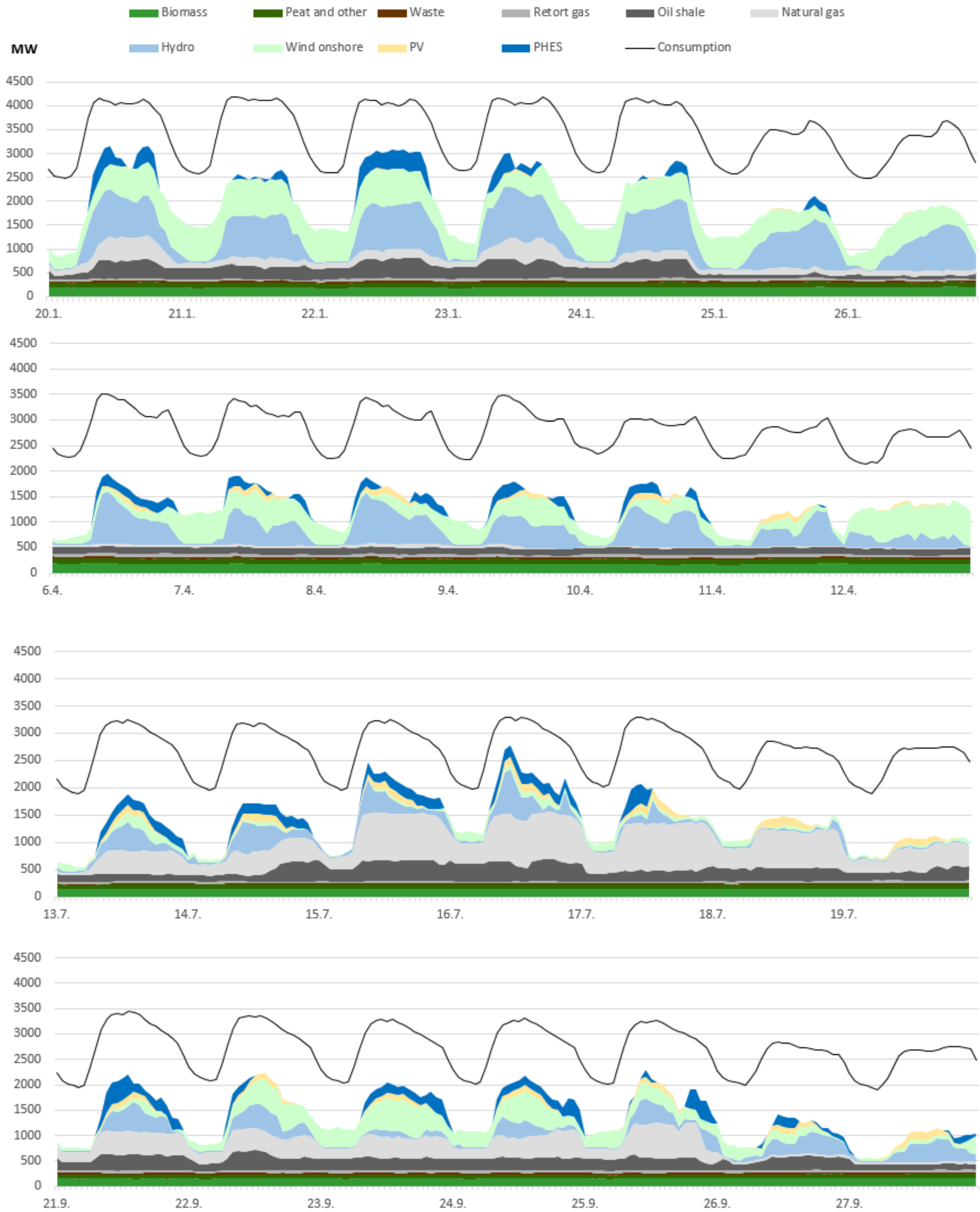


Figure 13. *Combined hourly operation of Baltic electricity demand and supply by source in four weeks in 2020 (data from [59]).*

Biomass, peat, waste, retort gas and oil shale seem to act as baseload in all the four example weeks. Natural gas seems to be operated when wind and hydro are scarcely available. Hydropower, as dispatchable capacity, is operated according to consumption and mostly available at springtime. The variability of wind is evident on week and day scale. PV share is visible in the summertime. Pumped hydro storage in Lithuania is following demand and most likely import prices. Demand is larger than generation in all example hours, and the remainder is imported.

It is important to remember that the Baltic countries have a relatively high share of district heating and many thermal units are CHP units operated according to heat demand. In 2017, around 40% of Baltic households were district heated [77]. The district heating demand curve calculated based on industrial base load and temperature variability in FasTen project for 2017 (Figure 14) shows the seasonal variance and sensitivity to cold periods in wintertime.

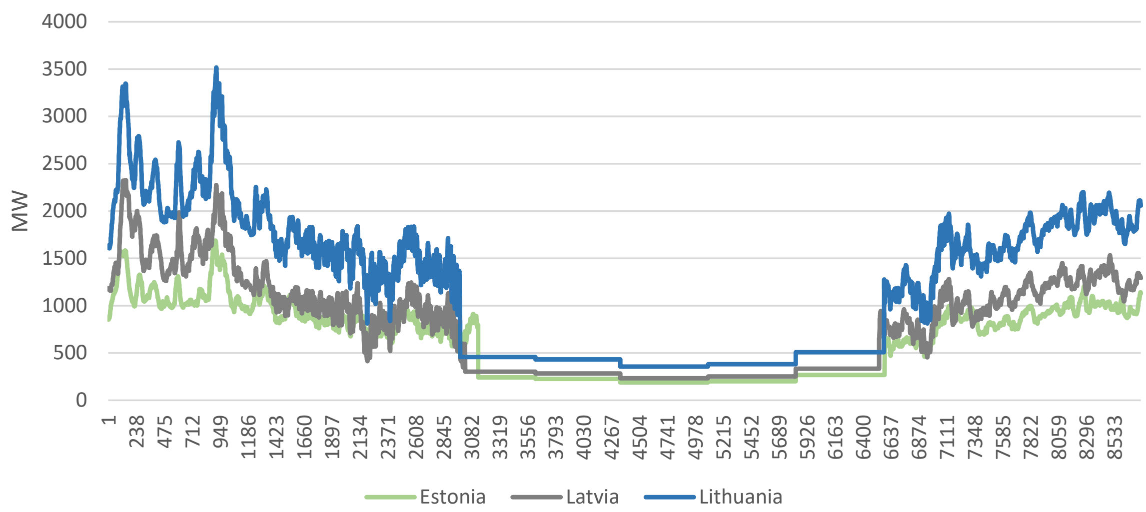


Figure 14. *District heating demand curve in Estonia, Latvia and Lithuania used in FasTen project for 2017.*

Based on literature (see Chapters 2.3 and 2.4), the planned large wind and solar investments will likely increase the variability in hourly prices, and increase the use of balancing capacity and interconnectors. In the Baltic system, large share of wind would diversify the weeks further in terms of import–export balance, but in general, varying, cheap and non-dispatchable generation would substitute imports and natural gas capacity. PV generation would be highest in the summer and coincide with demand variation. Hydropower, pumped hydro storage and interconnectors would be operated to balance wind variation, but additional flexible capacity may be needed. The need for smart grid control, storages, flexibility and sufficient reserves is highlighted in several studies (e.g. [17], [78]). The changes in operation are studied more closely in the case study and reported in Chapter 6.

4. ENERGY SYSTEM MODELLING

Energy system modelling is key in both understanding the energy transition and decision-making under it. Directions in modelling arise from energy system trends (described in Chapter 2.1), the development of modelling techniques and increase in computational capacity. Two major trends in energy system modelling are identified. Firstly towards *increased role for modelling in energy research,* because the planning and secure operation of energy systems grows increasingly challenging, and also the pressure to transform the energy sector in order to reach climate targets continuously increases. The second trend leads towards *increased complexity in models* as modelling methods develop to better capture the challenges of trends like intermittent generation and sector coupling. [19], [20], [79], [80] This chapter aims to classify the various approaches of energy system modelling and name the most influential trends, especially in terms of wind integration studies. The chapter advances from a wide understanding of energy modelling towards the approaches used in the case study of the thesis.

Firstly, the term *energy system model* can be used for many types of modelling and simulation to study system operations, engineering designs and energy policies. In this thesis, energy system model refers to *computational modelling of energy sector level operational, tactical and strategic decisions.* The left section of Figure 15 categorizes energy system models by levels of aggregation and highlights the approach used in the thesis [79], [80].

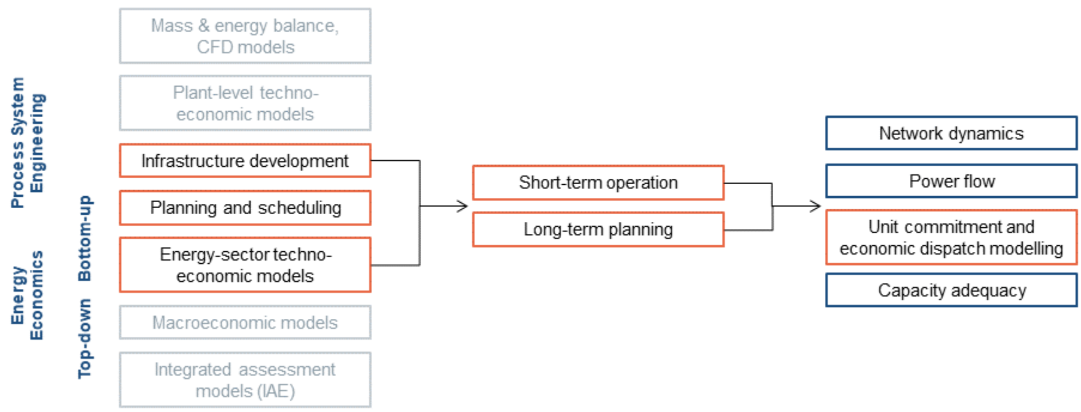


Figure 15. *Classification of energy system models according to level of aggregation and discipline (left) [79], [80], and categorization of modelling approaches in wind and solar integration (middle and right) [8], [43]. The approaches relevant to the case study are highlighted in orange.*

In comparison to *infrastructure development*, *planning and scheduling* and *energy-sector techno-economic models*, both smaller- and larger-scale energy models exist: From *building and process specific energy models*, to *macroeconomic* and *integrated assessment models (IAM)* [80]. The division between representing the energy sector with high technical detail, but neglecting macroeconomic impact of energy policies is also called a *bottom-up* approach, while the opposite, expressing the energy-economy as a part of macro-economy is known as *top-down* [79]. Similar, but a slightly different division can be made between *Process System Engineering* and *Energy Economics models* [80].

The middle and right section of Figure 15 indicate the division of modelling challenges according to Holttinen et al. [8] and IEA Wind [43] when addressing systems with high amounts of variable generation. A division is made between *long-term planning* and *short-term operational* analysis. Planning includes transmission planning and ensuring long-term reliability, while operational issues include reliability, stability, operating reserves and balancing. [8] The recommended practices in wind and solar integration [43] further categorize study focuses as *capacity adequacy, economic dispatch, power flow* and *dynamics*. Unit commitment and economic dispatch (UCED), the most central approach to the case study, is highlighted.

4.1 Status and trends in energy system modelling

Before moving closer to the chosen approach of schedule modelling, some general trends in operation and planning models are addressed. There are at least dozens of commercial and open-source models in the market. The practical choice of model scope and resolution depends on the research focus. Pfenninger et al. [19] have made a division to four focuses: 1) energy system optimization models, 2) energy system simulation models, 3) electricity market and power system models, and 4) qualitative and mixed-method scenarios. Another division is made by Kriechbaum et al. [79] into optimization, simulation, partial equilibrium, and newer approaches of agent-based and co-simulation modelling. Additionally, models vary in terms of sectoral, temporal and spatial scope, level of detail, stochastic approach and mathematical formulation [19], [79], [80]. Table 1 categorizes modelling approaches according to main scopes, and represents the case study position [19], [20], [79], [80].

Table 1. *Types of operational and planning energy system models by scope and approach [19], [20], [79], [80]. The case study modelling framework (Backbone) capabilities are highlighted in orange, and used model approach indicated in underlined bold.*

Method	**Optimization**	Simulation	Agent-based, Co-simulation
Sectors	Power system only	**Multiple energy sectors (heat, power-to-X)**	Additional sectors (behavior, policy, economy)
Temporal and spatial resolution	Annual	Representative days/Time slices	**Full year (hourly resolution or less)**
	"Copper plate"	**Power transport**	AC/DC power flow
Stochastic approach	Deterministic	**Scenarios**	Probabilistic
Programming	**Linear programming (LP)**	Mixed-integer linear programming (MILP)	Mixed-integer non-linear programming (MINLP), dynamic programming (DP)
Pathway approach	**Snapshot**		Pathway

While the approach is chosen based on research objectives and scope, emerging modelling challenges impact the development of the field. Pfenninger et al. [19] have named four emerging challenges in development of energy system models as:

1) *Resolving time and space.* Traditional models use spatial aggregation with annual or time slice temporal resolution. In the case of renewables, location impacts economic potential and intermittency cannot be represented without full-year consideration.

2) *Uncertainty and transparency*. Approach to increasing uncertainty can be addressed with deterministic solutions (like Monte Carlo method with varying input data), or stochastic programming. Lack of transparency of inner composition of modelling tools is a challenge for scientific validation and reproducibility.

3) *Growing complexity*. Decentralization, diversifying energy mix, increased interconnections and flexibility needs increase energy system complexity. Missing important aspects can lead to inaccurate conclusions and increase the risk of system vulnerability. Complexity can be addressed, for instance, by increasing the spatial and sectoral scope of the model, integrating different resolution scales, or agent-based modelling.

4) *Human dimension*. Energy system models focus on technical and economic factors, and often neglect behavioral, indirect costs, and socio-political and non-financial barriers of technology deployment. Integrating diverse approaches remains a challenge in modelling.

4.2 Energy system modelling with high shares of renewables

Recently, inclusion of large shares of variable generation has led to an increase of operational (dispatch) details and better temporal resolution also to planning (investment) studies. In turn, this leads to a trend in models towards better interplay of operational and investment functionalities. Novel focus areas include considering capacity value of alternative supplies, power system stability like impacts of low inertia, ramping capability, reserve procurement, demand response and storage behavior. Table 2 gathers operational and planning trends in light of high VRE integration challenges. [20] Like presented in the table, most of these advanced features are not included in the case study model while applicable in the used modelling framework (see Chapter 5).

Table 2. *Modelling challenges in energy systems with high shares of variable generation [20]. The case study modelling framework (Backbone) capabilities are highlighted in orange, and used model approach indicated in underlined bold.*

Level of complexity			
Planning/operation approach	**Planning or operational model only**	Link between planning and operational models	Co-optimization of planning and operational models
Forecasting	**Perfect foresight**		Myopic Recursive dynamic
Variability	**Deterministic**		Stochastic Day-ahead
Unit operation	**Unit commitment**		Special UC constraints
Balancing and stability	None	Balancing market **Operating reserves**	Special constraints
Capacity adequacy	**None**	Capacity value of alternative sources Capacity adequacy constraint	LOLE calculation or similar
Long-term variability	**None**	Interannual variations	Uncertainty in demand, fuel prices etc.

IEA Wind [43] has made recommendations regarding the modelling quality in terms of methodology and data in wind and PV integration studies. These data and methodological recommendations will be considered as the basis for building the case study approach, and case study methodology will be critically addressed in light of them in Chapter 5.8.

The *methodological recommendations* for production cost simulations include:

- Modelling of flexibility options and constraints
- Modelling of flexibility potential from neighboring regions by modelling systems, or as a secondary option using fixed flows or market prices.
- Capturing network limitations like congestion and N-1 security criterion (ability to sustain secure operation in all single component outages) directly within UCED

or as constraints. Stability constraints may be necessary with very high VRE shares.

- Assessing the flexibility needs, and addressing existing flexibility and potential new sources of flexibility. [43]

The *recommendations for input data* for unit commitment and economic dispatch studies include:

- 5 min to hourly full-year spatially smoothed wind and PV generation, and load time series over the studied area;
- Forecast time series or forecast error distribution for wind, PV and load;
- Transmission line capacity between neighboring areas and/or passive parameters in circuit;
- For other power plants minimum and maximum online capacity, start-up and shut-down times and costs, ramp rates, minimum up or down times, efficiency curve and fuel prices. [43]

4.3 Approaches to energy scenarios

High-quality modelling is built on credible scenarios, taking into account key assumptions, key uncertainties and their interaction. Scenario planning and formulation is used for exploration of different options in uncertain future conditions, and typically different scenarios are compared against each other or against a baseline or reference scenario. It is noteworthy that building and communicating scenarios has a close link to decision-making and policy analysis. Different approaches to scenario building can be categorized between qualitative and quantitative methods [19], [81] or between explorative, predictive and normative approaches [82], [83].

According to Pfenninger et al. [19] a key challenge in scenario building is the combining technical quantitative detail with qualitative sciences of policy, public acceptance and behavior, while maintaining reasonable level of complexity to be transparent enough to suit policy analysis. For example, technical aggregations are usually easy to quantify, but cost and behavior of the future are not. There is no single solution for this problem, but rather qualitative and mixed-methods are used to complement quantitative model scenarios. Witt et al. [81] present ways to combine scenario planning with energy system analysis using a structured Scenario Planning (SP) approach. SP is a systematic approach to identify alternatives and external uncertainties, and determine influenceable and non-influenceable factors and their interactions. This approach aims at forming internally consistent scenarios, and avoiding the key challenge of studying assumptions for uncertain parameters that are not consistent with the scenario. However, they also conclude that there is no systematic way of converting qualitative storylines to quantitative models, and therefore quantitative assumptions should be clearly stated when presenting results.

World Energy Council [83] and Ghasemian et al. [82] differentiate three common approaches to energy scenario planning based on analysis of existing global energy scenarios: *exploratory, predictive* and *normative*. Table 3 presents key features and differences of each approach and provides some examples on the references used in the thesis.

Table 3. *Categorization of energy scenario approaches [82], [83].*

Scenario approach	**Explorative (plausible)**	**Predictive (Outlooks)**	**Normative**
Key question	What might happen?	What future we expect?	What future we want?
Quantitative-qualitative approach	Qualitative-based, narrative-led	Quantitative-led	Specific goal aligned to a vision
Perspective	Societal and political elements included	Techno-economic	Value and identity based
Relation to decision-making	Framework to engage with uncertainty	Sensitivity and cost-benefit analysis for new policies	Identifying pathways
Typical composition	Plausible future / Plausible future / Plausible future	“Best case” / Baseline / “Worst case”	Preferable future / ←gap→ / “Business-as-usual”
Examples	Nordic Clean Energy Scenarios [32]	EU: Reference [6]	IEA: Net Zero by 2050 [1] IRENA: Global Renewables Outlook Energy Transformation 2050 [2] EU: Fit for 55 [6]

Forming exploratory scenarios builds on identifying pre-determined factors (constants) and key uncertainties (variables), and building storylines on combinations of uncertainties. Predictive scenarios are typically built on a projection of “business-as-usual” development, whereas normative scenarios fix the target as a constant and back-cast the pathway in order to reach the target. As shown by the table, both the scope and relation to decision-making differ by approach. Some approaches are more value-neutral, focusing on studying development or finding feasible solutions under established conditions, while others are visionary or agenda-driven, aimed at reaching a shared target. [82], [83] The limits of scenario approaches are not distinct, but the case study scenarios are closest to the predictive approach.

4.4 Unit commitment problem and operational modelling in Backbone

Like described above, the chosen approach in the thesis for regional energy system modelling is unit commitment based system optimization with full-year hourly time resolution. This approach allows studying the cost-optimal operational decisions with different technologies, energy vectors and degrees of sector coupling. In the heart of this modelling approach lies the unit commitment (UC) problem and set of equations to minimize system costs with given constraints. The UC problem is used to optimally commit generation units in order to minimize operating costs while meeting energy balance and technical and security constraints. In a simple form the UC problem is formulated to *minimize the sum of operating costs* (fixed and variable, start-up and shut-down costs) *with the given generation units and time horizon, while meeting logical constraints, power bounds, ramping limits, power balance and security constraints*. It is a mixed-integer linear (MILP) programming problem. The UC problem solution yields the optimal (integer) commitment status and (linear) power output of each unit at each time interval. [21]

The case study model is built for Backbone modelling framework (see Chapter 5), that enables both unit commitment (operational) and planning features. Backbone uses a slightly more complex formulation of the UC problem, additionally taking into account the probability of forecasts in the forecast horizon, value of state of storage and investment cost in units and transmission lines. The function to minimize is:

$$v^{obj} = \sum_{\{f,t\}\in FT} p_{f,t}^{probability} \times v_{f,t}^{vomCost} + v^{stateValue} + v^{fomCost} + v^{unitInvestCost} + v^{lineInvestCost} \quad (1)$$

The variable operating cost in the equation includes startup, shutdown and ramp costs, possible penalties, and fuel and emission costs. The formulation is general for all energy vectors, but certain constraints, like reserve requirements and inertial constraints, are based on power system operations. [22] In regard to the Baltic system modelled in the case study, the solution for the objective function over the full-year run will yield the optimal hourly scheduled operation of the system's units, transfer connections and storages. The lowest cost by the objective function at each time interval represents the *marginal cost* (market balance point). In addition to time series results, several annual results such as the total costs, emissions, average marginal prices and share of domestic generation can be derived from this data.

5. METHODOLOGY AND MATERIALS

In this chapter, the Baltic energy system model to study the energy transition of the Baltic countries, is presented. The modelling work is used to answer two of the research questions directly linked to the Baltic system (questions 4–5, see Figure 16). Figure 16 shows the role of each model component (*2017 statistical analysis*, *2017 energy system model*, *2030 reference model* and *2030 scenario analysis)* in light of the questions. As the thesis was completed as part of FasTen research project [24], the diagram also clarifies which parts of the model were completed in the project prior to the thesis and which tasks were included in thesis work.

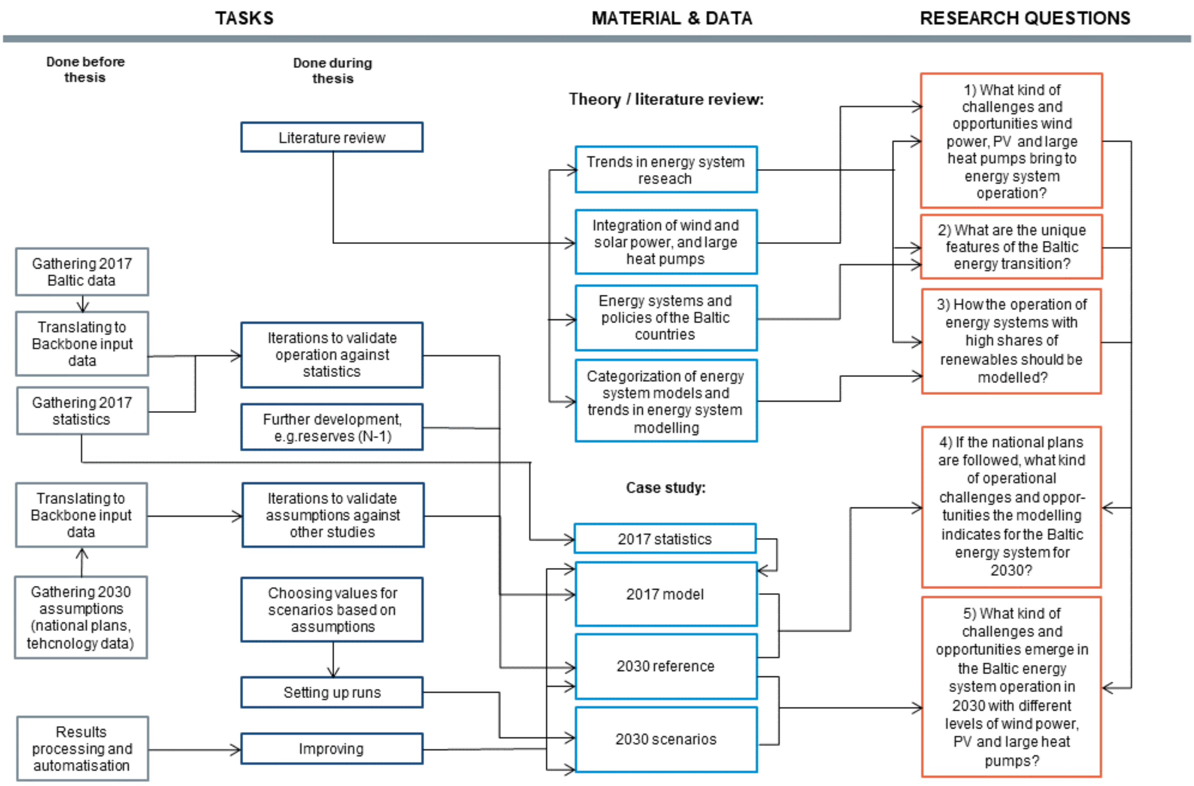


Figure 16. *Diagram of materials and methods used in the thesis and their connection to research questions.*

The Baltic Backbone model was published in autumn 2021 as a conference article by the author and co-authors [25]. Later, the updated article was submitted to a journal, but as of the submission of the thesis, the paper has not yet been published. The article [25] presents the model, modelling assumptions, and analyses preliminary results from 2030 reference scenario using national plans. The thesis describes the technical implementation of the model in more detail and builds on the published results. Already published modelling assumptions are not repeated.

5.1 Baltic model in Backbone

Backbone modelling framework [22] is an established, highly-flexible energy system modelling tool using mixed-integer optimization, that can be used for dispatch or investment modelling. The mathematical formulation consists of an objective function with constraints related to energy balance, unit properties and other system operations. The objective function to be minimized includes the sum of all operational costs, possible investment costs and value of state change (such as change in stored energy). The flexibility of Backbone is due to its general formulation to allow user-defined energy vectors and simultaneous optimization of multiple energy sectors.

Backbone is implemented in GAMS (General Algebraic Modeling System) and it uses solvers linked to GAMS to solve the optimization problem. Backbone source code is fully open-source and under active development [84]. Backbone has been validated and used in several peer-reviewed modelling studies (e.g. [85], [86]). The framework is comprehensively described by Helistö et al. [22].

Backbone modelling framework allows building Backbone models that represent actual energy systems. Figure 17 clarifies the process and differentiates the Backbone model (*Baltic Backbone model*) and the established Backbone optimization tool (*Backbone modelling framework*).

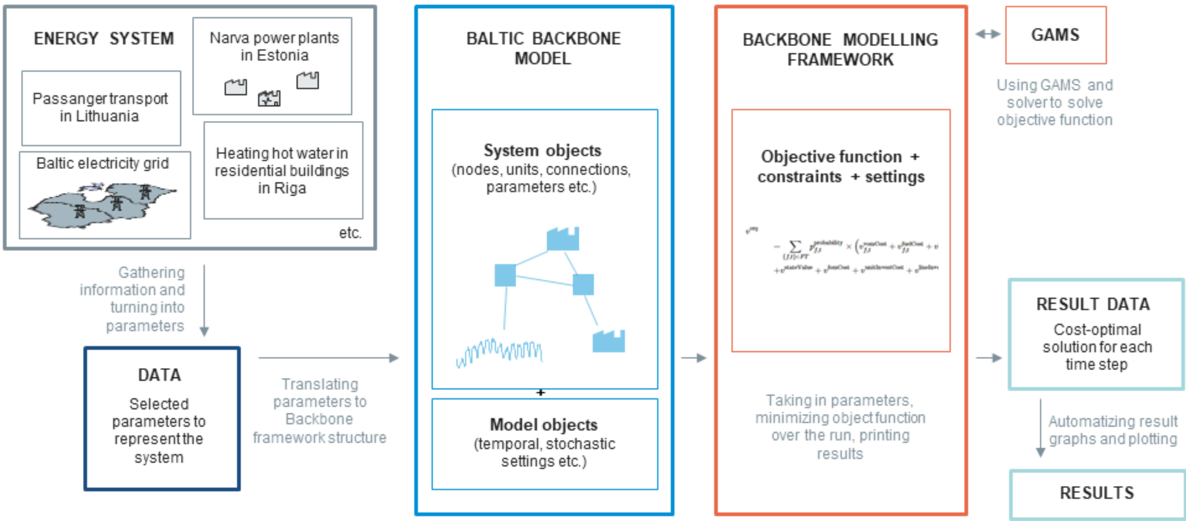


Figure 17. *Diagram of components of Baltic Backbone model and Backbone modelling framework.*

The actual Baltic energy system is represented as selected data parameters (data). The model presented in this work (Baltic Backbone model) includes the system data (system objects) alongside model objects translated to a Backbone compatible structure. Backbone modelling framework is the optimization tool used. Finally, result data is processed. The Baltic Backbone model, input data and results tool created in the FasTen project are presented in [25].

5.2 System and model objects in Backbone

The Baltic Backbone model describes the Baltic energy system in terms of grids, nodes and units — a structure of *system objects* (see Figure 17) defined by Backbone framework.

Grids describe different energy carriers like electricity, district heat, transport and fuels, and are essentially groups of nodes. In the Baltic model, grids include electricity, district heat, hydro reservoirs, space heating, water heating, transport and a selection of fuels. Modelled fuels include biomass, biogas, waste, natural gas, oil, coal, oil shale and retort gas for power and heat production; biomass, coal, oil and natural gas for building heating; and gasoline, ethanol, diesel and biodiesel for transport. Additionally, electricity trade is modelled as a fuel commodity. Fuels and other grids differ in maintaining energy balance: whereas other grids must balance inputs and outputs at each node and time step, fuels are infinitely available for a certain (variable) price.

Nodes are the most important part of the model. They represent locations on a grid and enforce energy balance, and can also have properties like state and connections to other nodes and units. In addition to geographical locations, they are also used to describe energy storages and sometimes to model functionalities (e.g. separate generation and consumption nodes in order to add transmission costs in between). Transmission lines can be used to connect nodes on the same grid.

Units are needed to transform energy between grids. Units include generation units (like power plants), aggregated car stocks and heating equipment, and ancillary units used for example for charging and discharging storages or converting international trade into electricity. Units are linked to nodes with input and output capacity, or may be connected to a free flow with time series (in the case of wind power, PV and run-of-river hydro units). Unit parameters include variable and fixed operational costs, starting costs, efficiency defined in at least two operating points, efficiency calculation method, and possible operational constraints for extraction type CHP units (able to offer flexibility by choosing an power-heat operating point within certain constraints). Units or nodes can be grouped to give system operations additional constraints.

Additionally, *emission* contents of commodities, and *reserve requirements* are defined. Reserve modelling includes primary upward reserve for each Baltic country equal to the largest generation unit or interconnector (N-1 condition).

In addition to system objects, *model objects* (see Figure 17) are needed to specify selection between dispatch and investment run, temporal settings and stochastic settings. The *temporal settings* include time resolution and number of time steps and settings for rolling (receding) horizon: The Baltic model uses hourly time resolution with one-year run calculated in one-day time steps. *Stochastic settings* allow building forecasts with different probabilities. There is a possibility to use samples of time periods with certain probabilities, utilized primarily with investment modelling. In the case study, only deterministic dispatch run (operational model) is used, but the model is suitable for investment and stochastic studies to be included later.

5.3 Structure of Baltic Backbone model

The Baltic Backbone model is divided into three modules: system (A), buildings (B) and transport (C). Simplified diagram of the model structure is shown in Figure 18. The modular approach allows using system module individually, or optimizing all three modules simultaneously. Information sources and input data values are described in detail in [25] and full documentation is available at GitLab [87] — only a brief summary of the model contents and data sources is provided here.

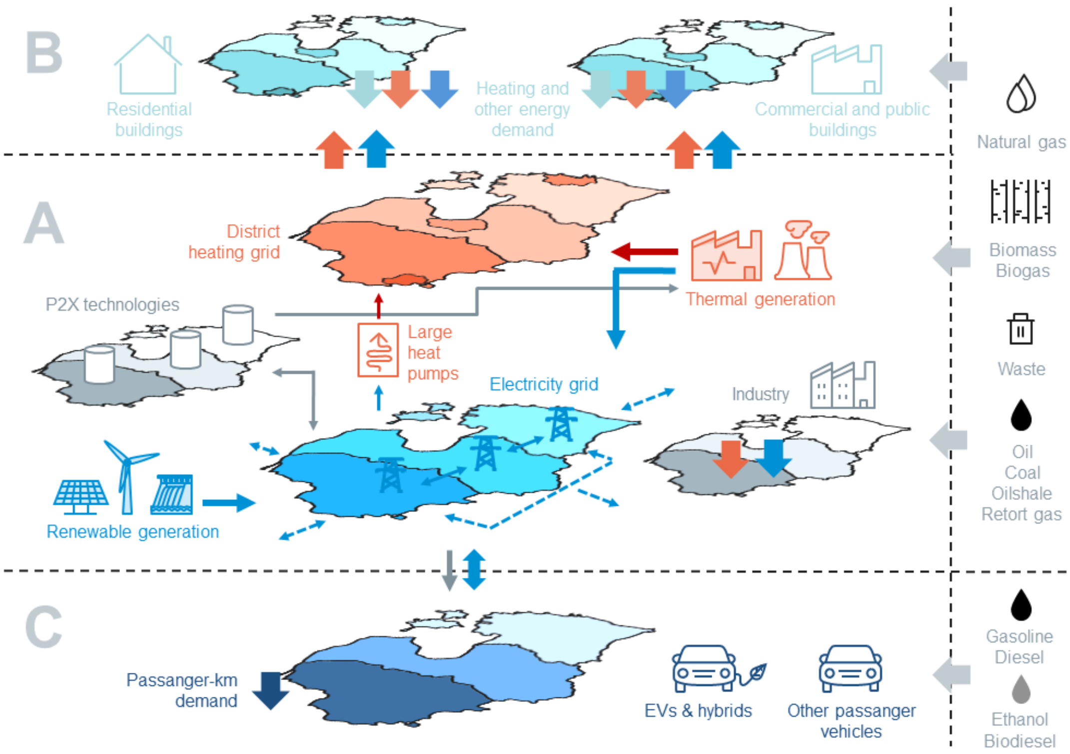


Figure 18. *Simplified diagram of the Baltic Backbone model. Module A (system) includes electricity grid, district heating grid and energy conversions; Module B (buildings) covers residential and commercial energy-use; and Module C (transport) contains personal vehicles.*

In Module A, electricity grid is modelled on a national level with transfer connections to Finland, Sweden, Poland, Russia and Belarus. District heating grid divides each country into two areas: the capital and the aggregate of other areas. Additionally, the system module includes generation units, demands, reserves, storages and structure for adding energy conversions such as power-to-X technologies and large heat pumps.

Estonian power generation is modelled as 24, Latvian as 29 and Lithuanian as 28 units. Altogether, the data consist of 31 CHP units, 6 condensing units, 18 boiler units and 19 units using free flow time series. National data [88]–[90], previous studies [15] and typical technology parameters [91] were used for unit parameters. Transmission connections to neighboring systems are given as capacity limits with hourly price for import and export electricity, based on ENTSO-E [59] and Nord Pool [92] data. Demand data is given for industry and other sectors as hourly time series while transport and building demands are modelled as actual passenger-kilometer or heating demand. Flows for hydro, wind and solar are given as deterministic hourly capacity factor time series based on MERRA-2 [93] and technology data [91]. Fuel prices are estimated based on Heat Roadmap Europe [94] values. Taxes for fuel use in heat production are added to unit operational costs and transmission and distribution costs to electricity end-use from national sources.

Emission trade prices are added for fuel use in the power and heat sector. Additionally, Module A includes reserve modelling according to N-1 condition.

Module B includes the space and hot water heating demand of the building stock of each Baltic capital region and aggregate of other regions (altogether six regions). The stock is divided between residential, and commercial and public buildings. Heating is provided with fixed shares of biomass, oil, natural gas, heat pumps, district heat and direct electricity according to Eurostat data [95].

Module C describes the personal transport of each country as passenger-kilometer demand supplied by aggregated EV, hybrid, gasoline and diesel vehicle stocks [96], [97]. In addition to electricity, gasoline and diesel, fuel options include ethanol and biodiesel blends. EV storages, charging patterns and availability of flexible charging are included.

5.4 Model workflow

In addition to the model, a workflow process automation was created for model and scenario running, and results handling. The workflow for running the model consists of input data on Excel sheets, GDXXRW mapping tool, and a series of CMD, GAMS files and file extensions. Each module, year and scenario of the model is constructed on a separate Excel workbook, covering all *system objects*. The data is converted into GAMS native input format GDX using GDXXRW. *Model objects* are defined in GAMS code. Running and scenario selection is done with file extensions controlled by CMD-files.

In an input data Excel, first sheet contains indexing between sheets and GAMS elements, sets and parameters. All basic elements (like grids, nodes and units) are given as sets with unique names on respective sheets, and parameters linking to these sets are given on parameter sheets. When multiple input data files are used, each new set is added to list of sets, and parameters are overwritten.

Running the model requires the project files described above and Backbone source code. As the project is documented and available in git, the project files can be cloned and Backbone files retrieved via submodule to a local repository. To run GAMS and solve the optimization algorithm, GAMS IDE software and linked CPLEX solvers are used. With a standard laptop, the solve time for running the model is 30–60 minutes.

Results are printed in GDX with several result tables defined in Backbone code. A CMD file converts parts of the GDX to Excel format for automatic import and calculation constructed in Visual Basic and Excel functions.

5.5 Model validation

The operation of historical model year of 2017 was validated against statistical information [88]–[90] in terms of power and heat generation, and import and export quantities by connector. The full validation comparison is presented in [25]. Overall, the model performs well and differences to statistical data are small. Figure 19 compares the annual statistical and modelled power generation in 2017.

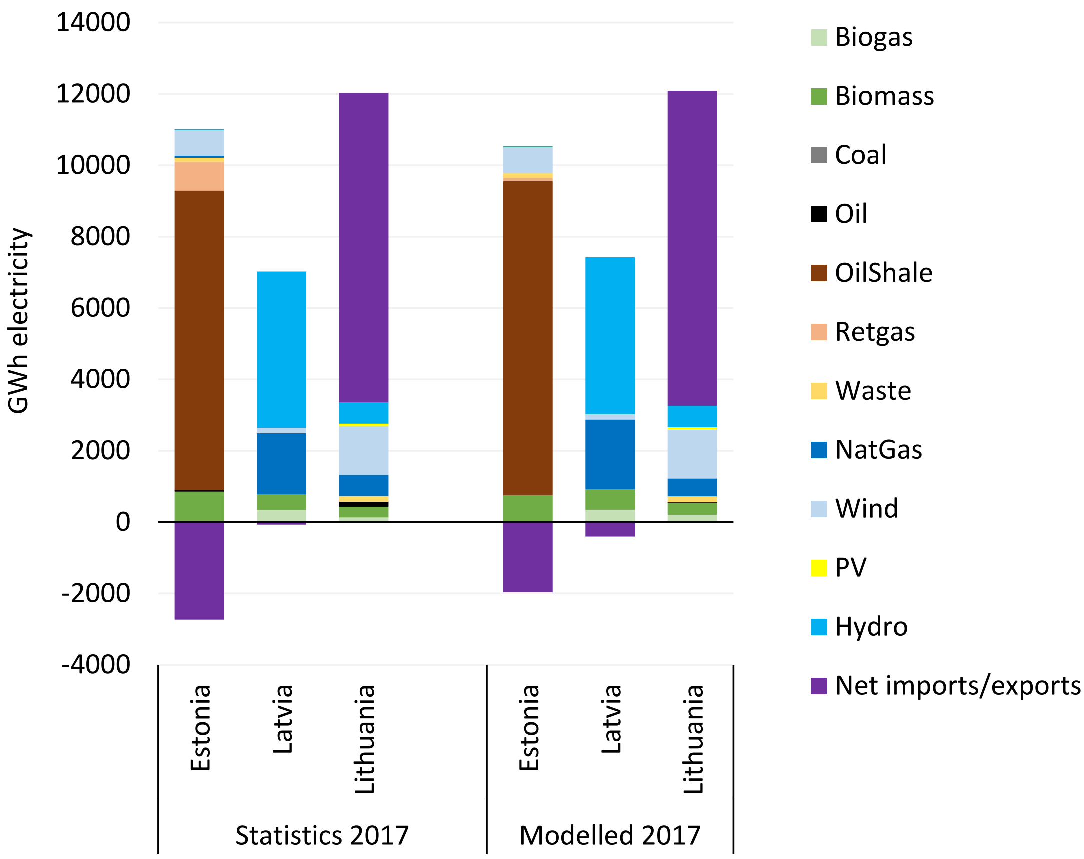
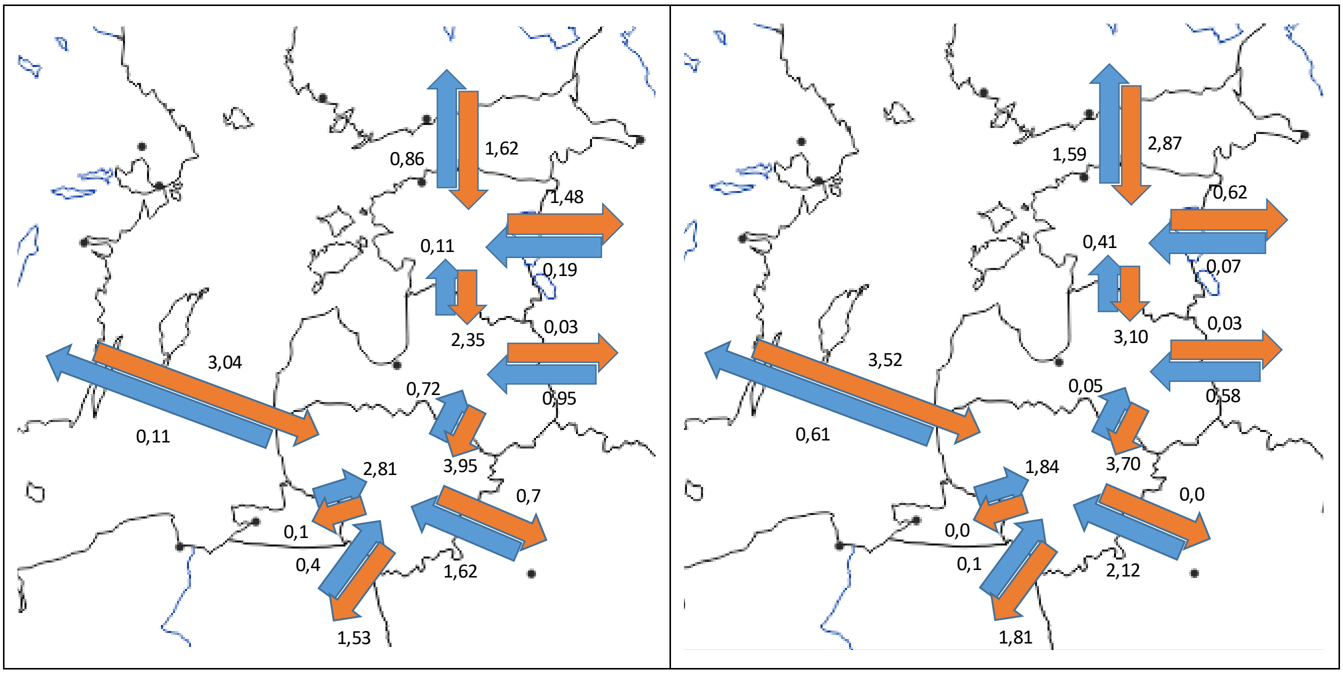


Figure 19. *Statistical and modelled electricity supply by source and by country in 2017 [25]*

Largest differences are observed in Estonian net exports (2.7 TWh in statistics versus 2.0 TWh in model), Estonian oil shale and retort gas (9.2 TWh vs. 8.9 TWh), and Latvian natural gas (1.7 TWh vs. 2.0 TWh), other differences are small or negligible. The differences in district heat generation are slightly larger, yet not significantly. Lithuanian modelled generation corresponds closely to statistics, while in Latvia the model uses biomass a somewhat more than in historical data (4.2 TWh vs. historical 3.3 TWh). The share of natural gas in heating is consequently smaller in model than in statistics. In Estonia, the difference is to the opposite direction and model shows slightly too much generation for natural gas (1.1 TWh vs. statistical 0.7 TWh) and oil shale (1.5 TWh vs. 1.1 TWh), and too little for biomass (1.8 TWh vs. 2.5 TWh). The total generation amounts are in correspondence with statistics. Also the total net imports and exports are close to statistical data, but power flows between countries differ from statistical data to some extent as shown by Figure 20.



(a) Statistics 2017 (b) Modelled 2017

Figure 20. *Statistical and modelled electricity imports and exports in 2017 (TWh) [25]*

The differences in power flows are due to modelling electricity trade constrained only by hourly prices and interconnector capacity, and not accounting for the demand or generation in neighboring countries. Also, as a part of BRELL circle, there are some transit flows via Baltic countries and Belarus between Moscow and St. Petersburg regions that are not accounted for in modelling. The transport and building sectors are modelled without allowing operational decisions between energy carriers. The conclusion in [25] is that the model is sufficiently well calibrated to build credible future operational scenarios.

5.6 Modelled years and scenarios

The scenario analysis is based on 2030 reference scenario, describing national plans in unit investments, decommissioning, transfer capacity, demand development and deployment of electrification in end-use sectors. By category, it is an *outlook* type of scenario (see Chapter 4.3), only assessing a pre-determined outlook (fulfillment of national plans) and not considering a how easy or hard it is to reach, or what factors or storyline realization depends upon. The unit and transfer capacities in reference scenario is described in detail in [25]. Sensitivity scenarios together with reference scenario results aim to answer research questions 4 and 5 on operational changes the Baltic system can anticipate if national plans are followed or different levels of wind, PV or heat pumps deployed.

Scenario analysis seeks to identify the individual impacts of technologies: onshore and offshore wind power; decentralized and utility-scale PV; and large heat pumps for district heating. The analysis on each technology is done by running several scenarios, varying only technology capacity. This will help isolate changes and detect possible linear correlation with system impact in indicators. As the impacts of transport and buildings with '2030 reference' assumptions is negligible, to save run time the analysis is performed running only Module A for power and heat.

Wind power scenario analysis is done by varying the total Baltic installed wind capacity while maintaining constant shares between countries. The capacities for wind scenarios are listed in Table 4. The '2030 reference' scenario's 1701 MW of added onshore wind capacity from 2017 is divided between 23% in Estonia, 19% in Latvia and 58% in Lithuania. The 1596 MW of offshore capacity is divided between 31% in Estonia, 25% in Latvia and 44% in Lithuania.

Table 4. *Total capacities (MW) of onshore and offshore installations in wind scenarios.*

	2017 wind capacity	+0.8 GW	+1.6 GW	+2.5 GW	2030 refe-rence	+4.1 GW	+5.0 GW	+6 GW
Onshore (Baltic total)	0	425	851	1276	1701	2126	2552	2977
Offshore (Baltic total)	0	399	798	1197	1596	1995	2394	2793

PV scenario analysis similarly follows the proportional increase and decrease of each countries planned level in '2030 reference'. 31% of the 1335 MW's of PV capacity increase in '2030 reference' is planned for Estonia, only 8% for Latvia and up to 61% for Lithuania. Additionally, as the planned level in '2030 reference' is presumed as decentralized PV, a comparison between building-level and MW-scale installations is also included. The capacity levels of PV scenarios are listed in Table 5.

Table 5. Total capacities (MW) of decentralized and centralized installations in PV scenarios.

	2017 PV capacity	+0.7 GW	2030 reference	+1.3 GW centralized PV	+2.6 GW de-centralized PV	+2.6 GW centralized PV
Decentralized (Baltic total)	0	653	1305	30	2610	30
Centralized (Baltic total)	0	15	30	1305	30	2610

Scenario analysis for large heat pumps for district heating cannot be divided according to plans, because only Latvia is planning large heat pump investments in '2030 reference'. Therefore, the total capacity is divided between district heat demand in each region. For comparison, a 'Reference +' scenario is created, representing similar levels as in Latvia for all regions. Regional capacities are presented in Table 6.

Table 6. Regional capacities (MW) of district heating heat pumps in DH HP scenarios.

	No DH HPs	2030 refe-rence	Reference + (300 MW DH HP)	600 MW DH HP	+900 MW DH HP
Tallinn	0	0.1	26	53	79
Estonian other regions	0	0.1	34	68	102
Riga	0	65	65	113	169
Latvian other regions	0	50	50	90	135
Vilnius	0	0.1	31	62	93
Lithuanian other regions	0	0.1	107	214	321

5.7 Result indicators

To study operational impacts, four topics are investigated: impacts on annual and hourly generation; impacts on annual emissions; impacts on share of domestic and renewable generation; and impacts on economic indicators — marginal price, levelized cost of energy (LCOE) and total annualized costs. Results are analyzed and key results are presented in Chapter 6.

Generation is presented in annual energy by source and analyzing the hourly generation of each country between minimum, reference and maximum scenarios**.** *Annual emissions* are calculated from CO_2 content of fuel consumed. Non-CO_2 GHG-emissions are not accounted for. *Share of domestic generation* is shown as percentage share of net electricity generation of total demand, including losses. *Share of renewable electricity* (RES-E) expresses net power generation by renewables and waste of total net generation, and *share of renewable heat* (RES-H) net district heat generation by renewables and waste of total net generation.

Marginal price describes the marginal (additional) cost if of one more MWh of electricity or district heat were needed, produced either by generation or import. *Total annual costs* include generation costs (including fuel costs, start-up costs and fixed and variable operational and maintenance costs (FOM & VOM)), net import costs (remainder of import costs and export profits) and annualized investment costs. All indicators other than annualized investment costs and LCOE are calculated in GAMS or in result calculation workflow described in Chapter 5.4.

Annualization of investment cost (A) is calculated using

$$A = N * \frac{(1+p)^n * p)}{(1+p)^n - 1} \quad , \tag{2}$$

where N is investment cost, p is interest rate in decimals and n is economical lifetime. In calculation, p = 0.05 and n = 20 years is used. Investment costs are according to Danish Energy Agency's technology library [91]. Prices are selected for 2025 or average of 2020 and 2030. Offshore turbines are estimated as near-shore turbines, decentralized PV as small residential PV (typical size 6 kW) and centralized PV as large-scale utility systems (typical size 8 MW). The LCOE analysis for DH-HPs is done for three technologies with different investment costs: air, excess heat and seawater sourced compressor heat pumps between 10–20 MW all using a constant COP of 3.

For LCOE calculation, a simplified formula is used:

$$LCOE = \frac{annualized\ investment\ cost + FOM\ costs}{full\ load\ hours} + fuel\ costs + VOM\ costs. \tag{3}$$

5.8 Methodological benefits and limitations, and summary of the model composition

The central improvement of the Baltic Backbone model compared to previous modelling in the Baltic countries relates to running the full year hour-by-hour and simultaneously optimizing many sectors. While several other studies have pointed to similar annual capacity and generation results (see Appendix A), only a full-year hourly model is able to confirm the feasible operation throughout the year. The inclusion of other sectors has a very limited impact on 2030 results, as the planned electrification of transport and buildings is low (see [25]). However, to later study the transition towards a fully decarbonized system, the inclusion of other sectors becomes vital.

Another benefit relates to the selected scenario analysis approach. Comparing the historical year 2017 with the scenario year of 2030 according to national plans allows a policy relevant perspective to techno-economic modelling. Additionally, in comparing different levels of wind power, PV and heat pump deployment, linear addition of one technology at a time and study by indicators allows technology-specific analysis and the comparison of feasible and unfeasible technologies alike. It allows digging deeper into each technology than the common approach of model-optimized investment levels.

The key drawbacks of the Baltic Backbone model include 1) the representation of neighboring regions as simple price time series; 2) only presenting regional system-optimized results; 3) relaxing MILP model for linear solving; 4) and not accounting for short-term (forecasts) or long term (weather years) variability. The first will be seen in results as too inexpensive prices for high import situations and too costly for low import. It also allows full availability of electricity at all hours. With better representation of neighboring countries the capacity development and unit commitment decisions could be taken into account. The second and third drawback can result in unrealistic behavior as the benefits for single countries (or actual agents in the country) are not accounted for, and units can avoid costly shutdowns and starts when they do not have to choose between on and off, but can choose to operate e.g. with 0.1 capacity. Finally, not accounting for short-term variability eases model decisions and reduces costs as no redispatching of reserves or thermal units is required. Studying only a single weather year (without knowing if it is normal, challenging or optimal) can lead from small to moderate impacts in modelling results, system operation and especially energy security observations linking to capacity adequacy. Finally, Table 7 summarizes the composition and settings of the Baltic Backbone model used.

Table 7. Summary of Baltic Backbone model and scenario analysis composition.

Modelled regions	Estonia, Latvia and Lithuania
Modelled sectors	Electricity, district heat, buildings, personal transport
Optimization model and settings	Backbone system optimization model, linear composition, dispatch run
Time resolution	Hourly, full year run 8760 h
Spatial resolution	Heating by capital & other aggregated regions, others by country
Temporal settings	24 h rolling horizon, deterministic
Modelled years	2017 historical year, 2030 reference year (according to realization of national plans), and 16 sensitivity scenarios for 2030
Validation	2017 historical results against statistics
Modelled scenarios	Wind power x 7, photovoltaics x 5, large heat pumps x 4. Total 16 scenarios.
Analysis indicators	Operational — annual and hourly generation Environmental — emissions and share of renewable generation Energy security — share of domestic generation Economic — marginal price, levelized cost of energy (LCOE) and total annualized costs

6. RESULTS AND ANALYSIS

This chapter presents key modelling results in the operational changes in the Baltic countries between historical year of 2017 and scenario year of 2030, based on National Energy and Climate Plans of the Baltic countries. Further, it analyzes the impacts of additional wind, PV and district heating heat pump capacity. The full result analysis consists of studying operational, environmental, security and economic indicators (see Chapter 5.7) for the '2030 reference' scenario and for each additional technology. Only selected results offering interesting insights are presented.

In light of the research questions, Chapter 6 seeks to answers questions 4 and 5 — *If national plans are followed, what kind of operational challenges and opportunities the modelling indicates for the Baltic energy system for 2030?;* and *What kind of challenges and opportunities emerge in Baltic energy system operation in 2030 with different levels of wind power, PV and large heat pumps?* Results in Chapter 6.1. and 0 from '2030 reference' are presented also in [25]. Results and analysis in Chapters 6.3–6.6 are new results created for the thesis.

6.1 2030 reference: Fast transition of power generation

Firstly, it is evident that if national plans are followed, the power generation in the Baltic region will undergo a fast transition from fossil to renewable generation during the next decade. The optimized annual operation by fuel of power and district heat generation is presented in Figure 21.

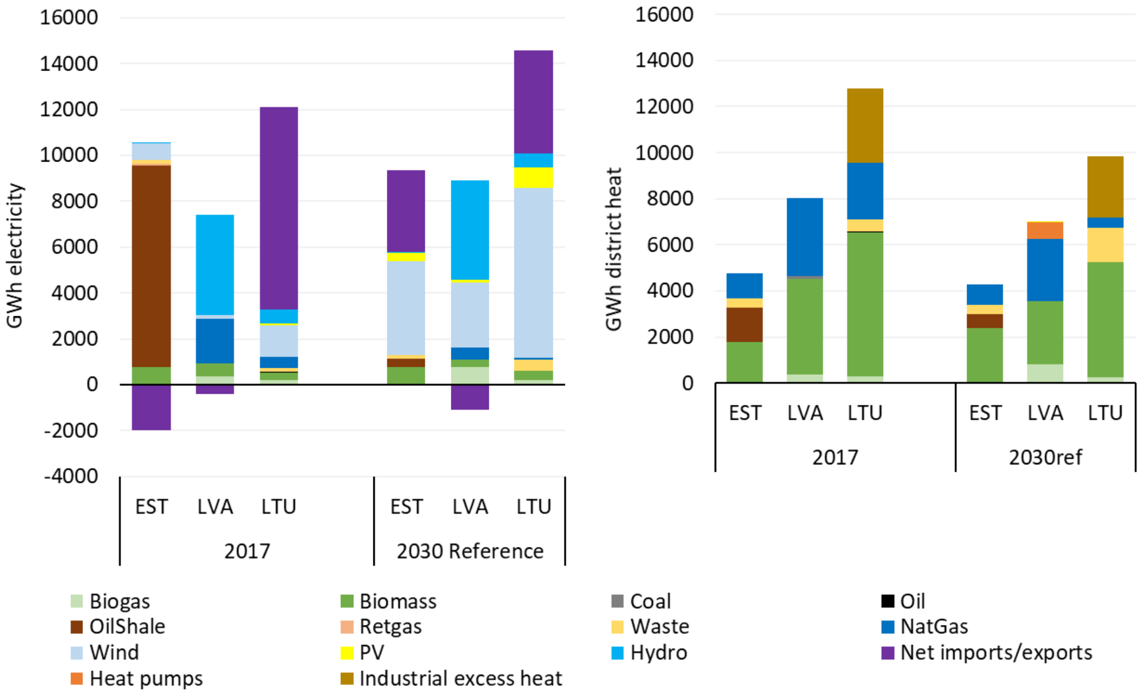


Figure 21. *Annual electricity (left) and district heat generation (right) by source and by country in 2017 and '2030 reference' scenario.*

Fossil-based domestic power generation decreases from 56% to 6% with simultaneous VRE share increase from 11% to 64% between modelled years 2017 and 2030. In Estonia, total domestic generation share decreases as oil shale units are either decommissioned or become unfeasible due to EU ETS price increase. Domestic generation in Latvia and Lithuania increases with wind and solar investments. However, as a region, the Baltic remains import dependent.

The modelling results are in line with previous Baltic studies in literature [6], [15], [16]. Overall, modelling according to capacities in national plans leads to an even more rapid transition than in comparative studies, especially for Estonian oil shale and Latvian and Lithuanian natural gas based generation. The country specific comparison to reference studies is presented in Appendix A. As shown on the right in Figure 21, changes in district heat generation between 2017 and 2030 remain moderate. Next, Figure 22 gathers modelling results from annual CO_2 emissions, and shares of renewable electricity and renewable district heat.

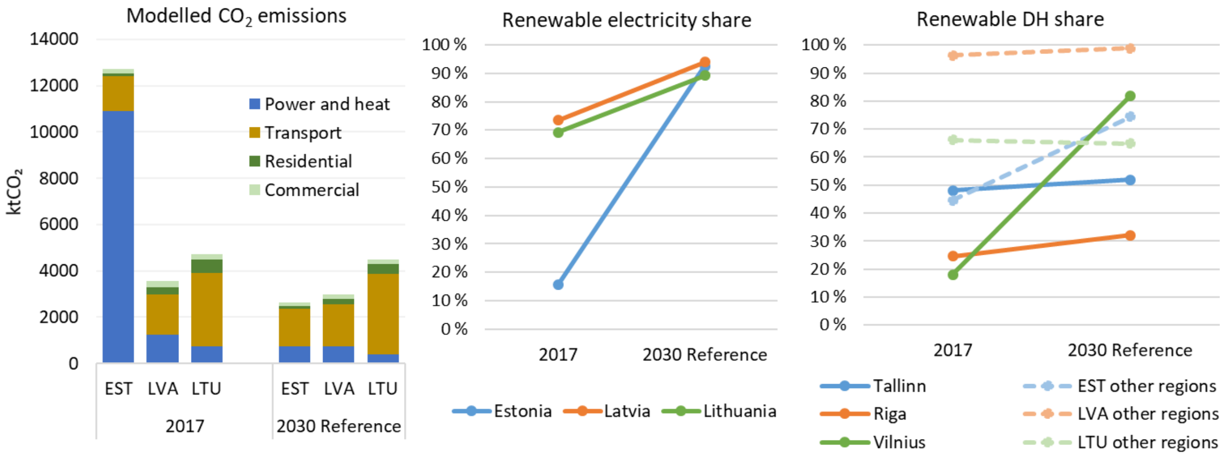


Figure 22. *Annual modelled CO_2 emissions by sector (left), renewable electricity share (including waste) (middle), and renewable district heat share (including heat pumps) (right) by region in 2017 and '2030 reference' scenario.*

The presented changes in power generation structure lead to a significant drop in power and heat sector (included in EU ETS) emissions (from 12.9 to 1.8 $MtCO_2$) as shown on the left. Total modelled CO_2 emissions drop from 21.0 to 10.1 $MtCO_2$ despite small increase in transport emissions (due to increased transport volumes). As shown in the middle, renewable electricity share increases to approximately 90% in all three countries, with largest change recorded in Estonia. On the right, changes in renewable district heat shares are small, with the exception of Vilnius where the introduction of new waste-CHP units increase renewable share.

The planned changes increase modelled costs in all three countries. The combined modelled costs for power and heat generation, imports and exports and annualized investments are shown in Figure 23.

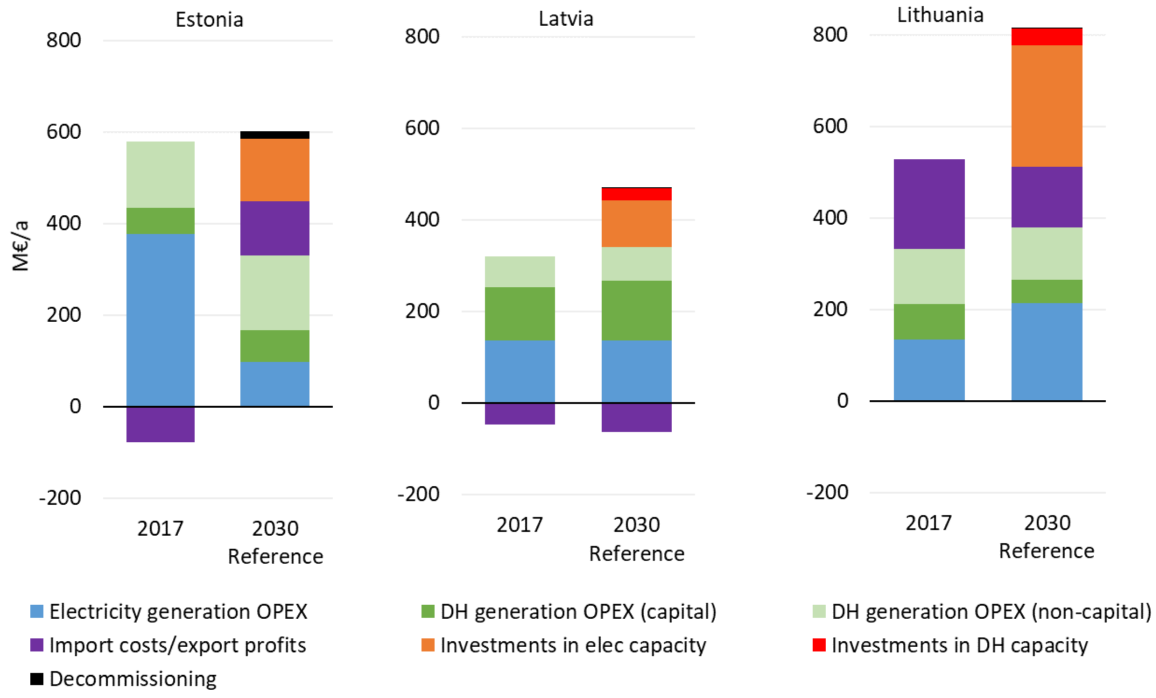


Figure 23. *Annual combined costs for power and heat sector in 2017 and 2030 reference in Estonia (left), Latvia (middle) and Lithuania (right).*

The combined annual costs in the power and heat sector increase from 501 to 602 M€/a in Estonia, from 275 to 407 M€/a in Latvia, and from 529 to 814 M€/a in Lithuania. Without the impact of investments, the operational and import costs slightly decrease in Estonia and remain stable in Latvia and Lithuania. Estonia's operational costs are decreased with reduction in thermal power generation, while import costs are increased. Latvia's power generation costs remain at the same level, but would be increased without planned investments in wind. Lithuania's costs are impacted by the large increase in domestic capacity, mostly wind and PV. Import costs are reduced, but not enough to substitute the increase in operational and investment costs.

The results indicate that if national plans are followed, while overall emission and renewable targets are reached, and domestic share is increased, the risks include falling behind EU ESR targets and increase in system costs. Furthermore, fast energy transition causes operational changes that may impact maintaining energy security, as considered next.

6.2 2030 reference: Operational results linking to energy security

Power generation turnaround, no matter how positive, should never risk maintaining cost-effective and secure operation of the power system. The modelling results point to three operational changes that require security consideration. Firstly, Estonia phases out such a large proportion of oil shale capacity that without additional investments in balancing capacity, the model experiences frequent price peaks. Secondly, in Latvia, the planned deployment of wind power reduces usage of large CHP units to such degree that commercial operation is threatened. Finally, Lithuania plans to reduce import capacity while the VRE share in power generation reaches up to 80%.

As Estonia is planning to decommission 1680 MW_e of oil shale capacity by 2030 [71], and no mention of new balancing capacity plans is found [11], the first version of '2030 reference' scenario was based on this information. The result analysis on marginal prices revealed frequent price peaks over the run, indicating there was not enough dispatchable domestic capacity to balance the system against normal import electricity price fluctuations. Consequently, an analysis was conducted outside the scope of the thesis to compare different balancing options (considered options included batteries, biomass-CHP, transfer capacity, gas turbines and oil shale backup). As a result, 200 MW_e (with storage capacity of 200 MWh_e) was added to Estonian system in updated 2030 reference to balance the operation. (All results in the thesis are using the updated results.) While batteries offered best economic results, also biomass-CHP and oil shale backup may offer benefits.

In Latvia, a significant change in the operating hours of natural gas CHP units was observed when comparing the daily electricity generation with and without wind capacity additions in 2030. A comparison of daily model operation without any additional wind capacity ('2017 wind capacity') and the reference scenario in Figure 24 demonstrates the clear difference in operation. '2017 wind capacity' is otherwise identical to '2030 reference', but no new wind investments are done after 2017.

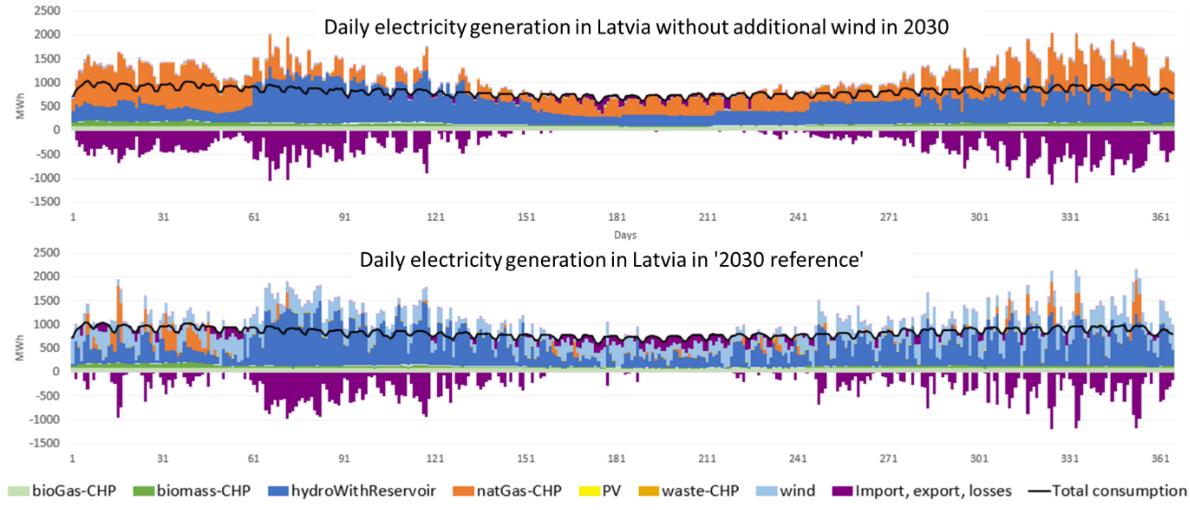


Figure 24. *Comparison of daily electricity generation in Latvia between '2030 reference' (below) and '2017 wind capacity' (above).*

The natural gas CHP generation shown in orange reduces significantly between the above and below scenarios as wind is added. Plotting the online hours of thermal units in different wind scenarios shows that the operation hours of five large Latvian gas CHP units (including Riga CCGT's) drop below 1000 h/year after 350–700 MW of Latvian wind investments (700 MW is the investment level in '2030 reference'). The substitution is purely economic: Electricity generation by wind combined with district heat generation by natural gas boilers results in a slightly lower combined operating cost compared to operating cost of the CHP units. The situation is different in more import dependent Estonia and Lithuania where wind generation is mainly substituting imports. Reducing operating hours may endanger commercial operation especially during warm weather years.

Lithuanian ambitious investment plans in wind and PV, combined with cost increase of natural gas generation, lead to very high share of generation by non-dispatchable, variable sources. In '2030 reference', Lithuanian VRE share reaches 82% of power generation and 57% of power demand. Simultaneously, a significant net decrease of import capacity is planned related to de-synchronization from BRELL. Transmission grid will be significantly impacted by these changes, requiring both careful planning and rapid investments. While the Backbone model used did not encounter security issues during the operation of a normal weather year, except some high ramp rates in interconnectors, variations in wind and temperature should be investigated with more detail to ensure system stability in all conditions.

6.3 Wind power scenarios: Support for planned deployment

As expected based on previous studies [6], [15]–[17], large deployment of onshore and offshore wind seems to be a feasible solution to increase domestic and renewable share and decrease emissions in the Baltic region. Cost-optimal capacity level will depend on development in operational environment and technology cost, but overall, addition of even high shares of wind does not seem to have a large impact on system costs. The wind analysis compares eight different levels of wind power deployment from only existing wind parks ('2017 wind capacity' scenario) up to almost 3 GW of onshore and 3 GW of offshore ('+6 GW' scenario). Planned investments in '2030 reference' have 1.7 GW of onshore and 1.6 GW of offshore capacity.

Figure 25 summarizes the impacts of different levels of wind capacity deployment on the shares of renewable and domestic electricity generation, CO_2 emissions, and combined system costs. In the figure, renewable electricity generation includes renewables and waste, modelled emissions include power and heat sector CO_2 emissions, and combined system costs include electricity generation, import and annualized wind power investment costs.

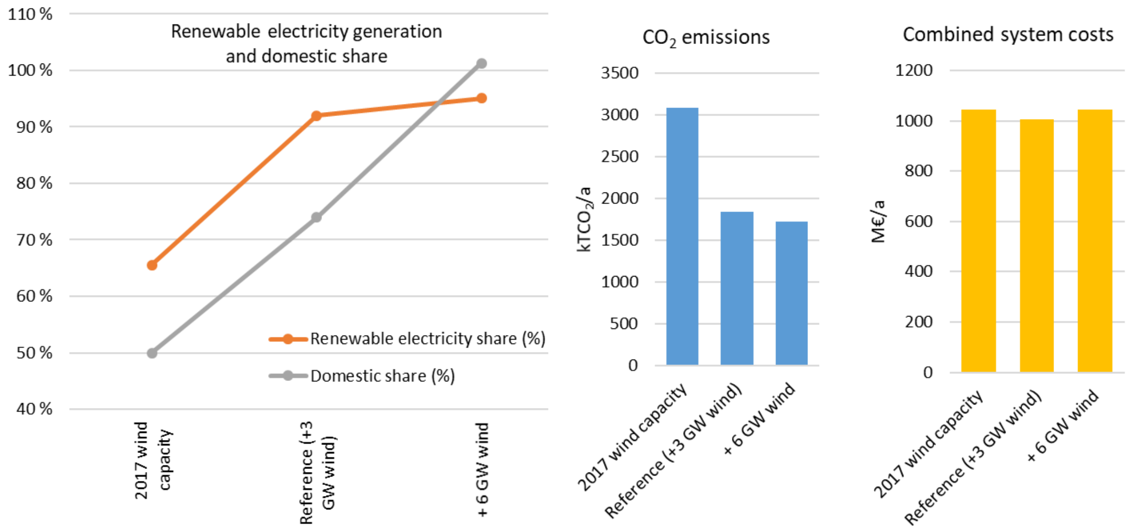


Figure 25. *Baltic renewable and domestic electricity generation share (left), modelled CO_2 emissions (middle) and power and heat sector's combined system costs (right) in lowest, reference and highest wind scenario.*

Increasing onshore and offshore wind capacity in the Baltic model reduces CO_2 emissions, increases the share of renewable electricity, and advances domestic generation share without significant impact on combined system costs. The EU ETS CO_2 emissions reduce from 3.1 $MtCO_2$ in '2017 wind capacity' to 1.8 $MtCO_2$ in '2030 reference' and further to1.7 $MtCO_2$ in '+6 GW wind' scenario. The share of renewable electricity increases from 66% in '2017 wind capacity' to 92% in reference scenario, and further to

95% in the highest scenario. The impact on emissions and renewable share is strongest with capacity increase until reference, and weaker beyond. Domestic generation share on the other hand increases nearly linearly: from 50% in '2017 wind capacity' to 74% in '2030 reference' and 101% in '+6 GW wind' scenario. Therefore, beyond reference scenario, the primary benefit of additional deployment in wind seems to be increase in domestic share.

Country-specific analysis on system costs reveals that while in general, wind addition seems to increase investment costs and decrease import, the countries are impacted differently. The annual power and heat sector costs by country are shown in Figure 26.

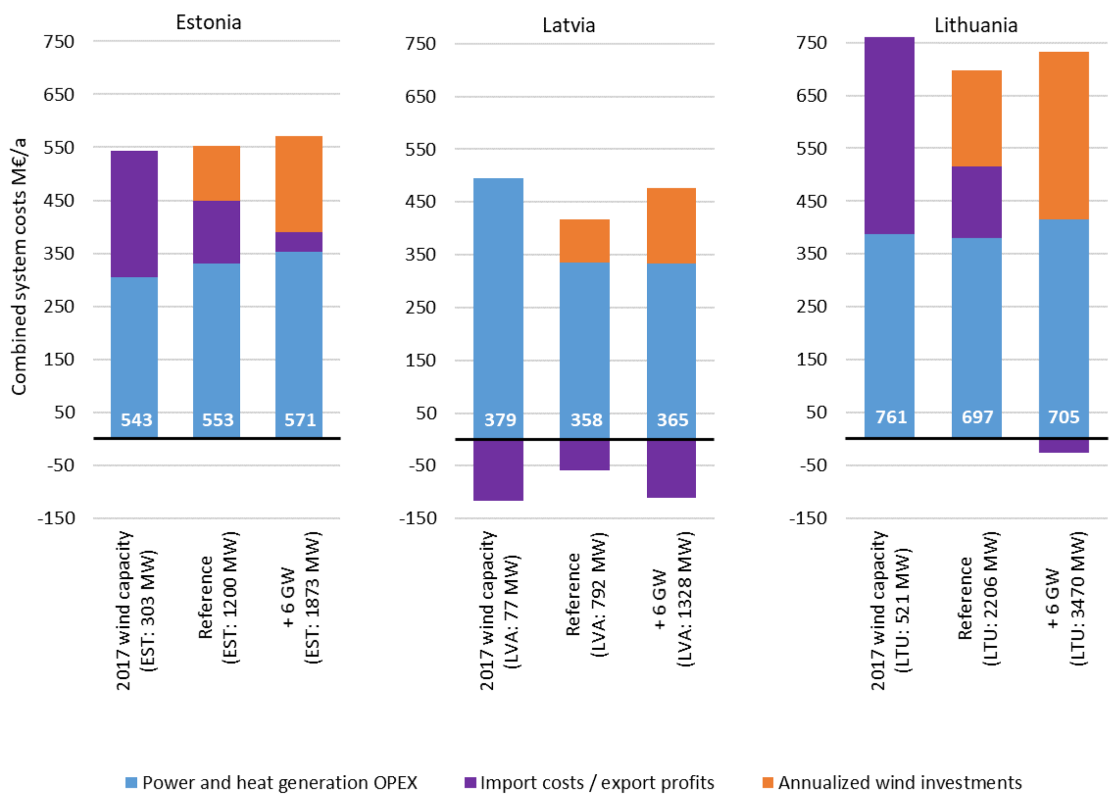


Figure 26. *Annual power and heat sector costs in lowest, reference and highest wind scenario in Estonia (left), Latvia (middle) and Lithuania (right).*

The cost minimum in the wind power scenarios for Latvia and Lithuania is found in the '2030 reference' scenario. For Estonia, the cost minimum is with low deployment ('+0.8 GW' scenario). The cost minimum for the combined Baltic system is found in '2030 reference' and '+2.5 GW scenario' (with slightly lower wind deployment than reference). However, the result is sensitive for import electricity price assumptions, and is somewhat distorted with simplifications in electricity trade. With current modelling import price remains constant regardless of volumes, while in reality, prices would rise with volume increase. Also, the annualized wind investment costs only include the installations themselves and do not describe the possible investments in transmission networks. Therefore, the cost results should be interpreted as suggestive.

Overall, the modelling results for 2030 support the anticipated benefits of adding a significant capacity of wind power as presented in the Baltic national plans. Wind power seems a cost-effective solution to increase domestic and renewable share and decrease emissions. Findings are consistent with previous studies [6], [15]–[17]. Finally, to concretize the demands of the execution of the national wind power plans in '2030 reference' for the Baltic region, a 1.8 billion euro investment in onshore and a 2.7 billion euro investment in offshore wind is required before 2030 (with construction time of 1.5–2.5 years for each installation) [91].

6.4 Solar power scenarios: Increasing feasibility of utility-scale PV

In comparison to wind power, the benefits of additional solar power investments seem substantially smaller, yet not necessarily unfeasible. Globally, the costs for electricity generation by residential (decentralized) PV have fell 40–80%, and utility-scale (centralized) PV as much as 85% in the last ten year [5]. This is making especially the lower-cost utility-scale PV a lucrative option even with the typical Baltic full-load hours of less than 1000 h/year.

The '2030 reference' scenario has 1.3 GW planned investments in decentralized PV. The PV capacity analysis compared six different deployment levels from '2017 PV capacity', to as high as 2.6 GW of solar PV ('+2.6 GW' scenarios). Investments in decentralized (residential) and centralized (utility-scale) PV are studied separately. It is noteworthy that as the wind power investment level in '2030 reference' (and therefore in all PV scenarios) is quite high, PV investments are studied as further, not as alternative, VRE investments. Figure 27 compares scenarios for low, reference, high decentralized and high centralized PV investments in terms of the shares of renewable and domestic electricity, annual CO_2 emissions and combined system costs.

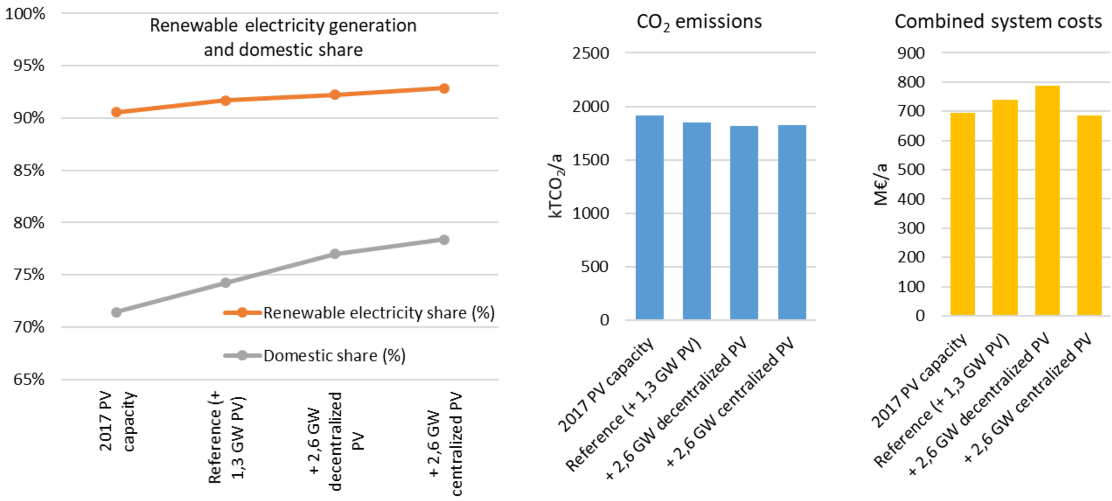


Figure 27. *Baltic renewable and domestic electricity generation share (left), modelled CO_2 emissions (middle) and power and heat sector's combined system costs (right) in different PV scenarios.*

On the left, the benefits of additional PV capacity on the share of renewable generation is relatively small, from 91% to 93% between the minimum and maximum scenarios. The impact on the domestic share is slightly better, from 71% to 78% — but modest compared to impacts of wind capacity expansion. In the middle, the impact on CO_2 emissions is also limited, only from 1.9 to 1.8 $MtCO_2$ between the minimum and maximum scenarios. On the right, the impact on system costs seems unbeneficial in the case of decentralized PV expansion, but beneficial in the case of centralized.

Country-specific system cost analysis reveals similar changes with wind, only on a smaller scale. Figure 28 compares the annual power and heat sector costs by country between minimum, reference, and high-decentralized and high-centralized scenario.

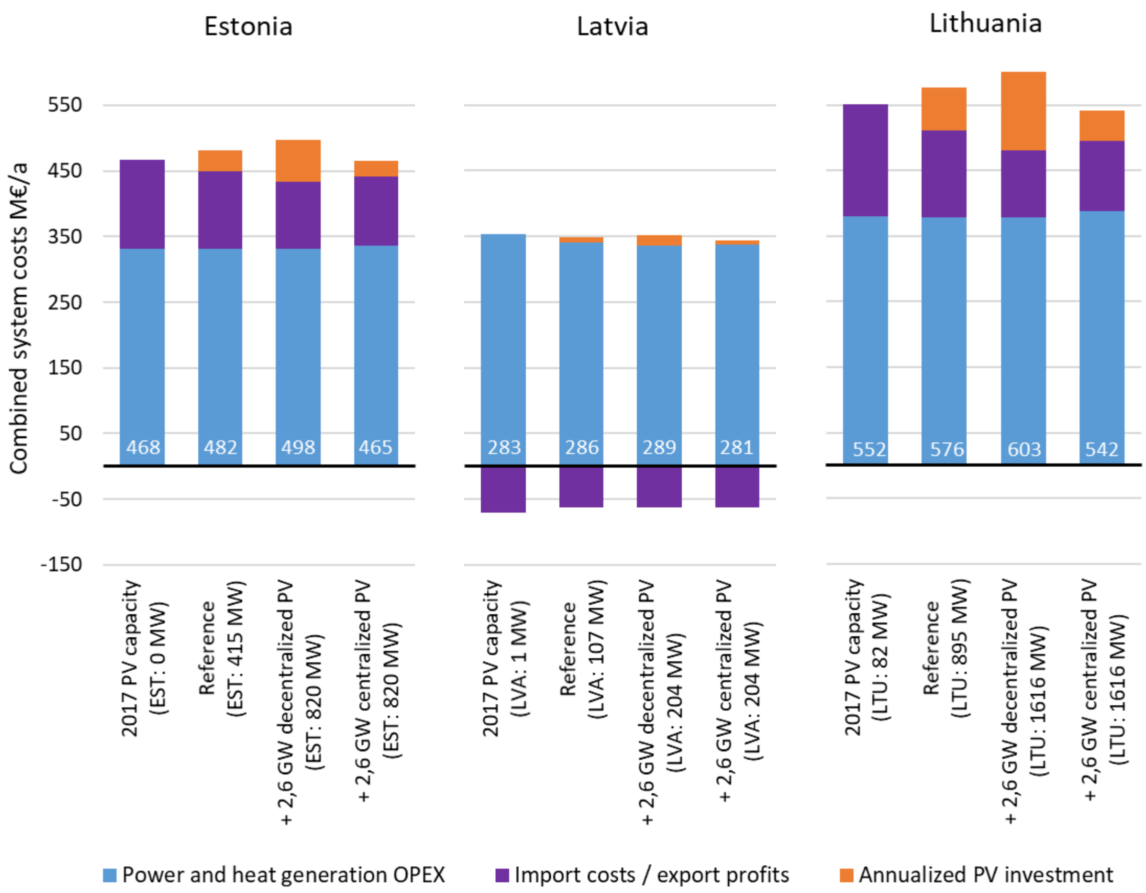


Figure 28. *Annual system costs in the Baltic countries with different PV deployment levels.*

For Estonia and Latvia, the minimum and high-centralized scenario result in nearly identical costs. The cost minimum for Lithuania is found in the highest '+2.6 GW centralized PV' scenario. This is also the cost minimum for the combined Baltic region. A clear difference in combined costs is shown between centralized and decentralized PV, in the favor of centralized (megawatt-scale) installations. Therefore, if the technology prices of PV installations decrease with predicted rates, introduction of further solar investments — especially utility-scale — seems increasingly feasible in the Baltic countries. In the case of PV, the execution of national plans for 2030 would mean total investments of 1.3 billion euros in decentralized PV in the Baltic countries [91]. For comparison, the sum is 29% of planned wind investments.

6.5 Wind and solar power scenarios: Operational impacts

Analyzing the changes in hourly operation with different levels of VRE, the link between import and wind share is evident. Especially in import-dominated Estonia and Lithuania increase of wind share is substituting imports. The impact of additional PV is similar to wind, only smaller in magnitude. In Latvia, VRE is substituting more expensive thermal generation. The changes in dispatch order are clearly seen in marginal prices of electricity in Figure 29.

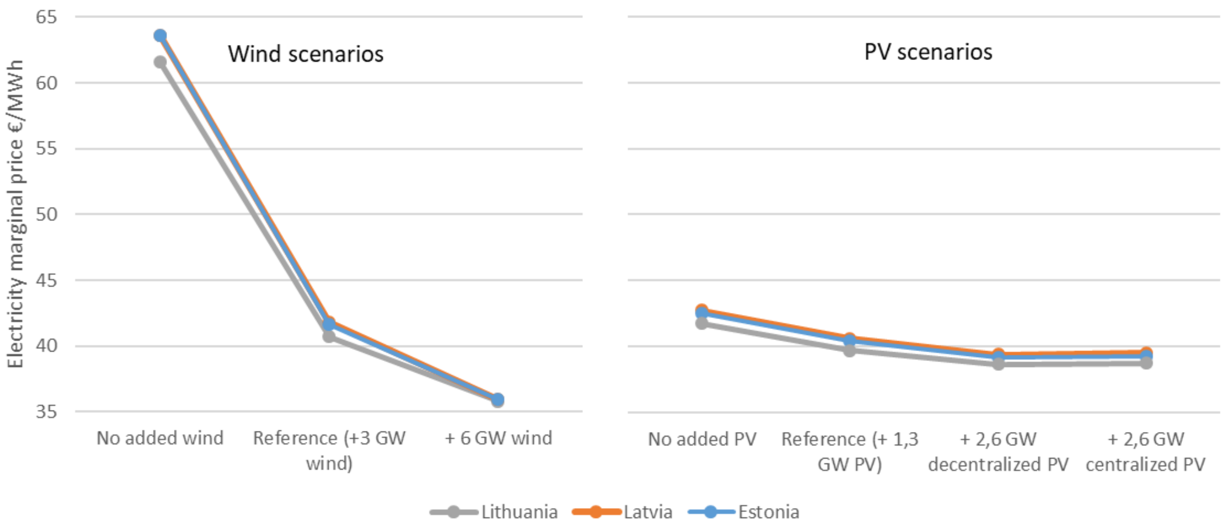


Figure 29. *Average marginal prices for electricity by country in different wind scenarios (left) and PV scenarios (right).*

The reduction in marginal price between minimum and maximum wind scenario is 27.7 €/MWh in Estonia and Latvia, and 25.8 €/MWh in Lithuania. For PV scenarios, the average marginal prices are reduced by 4.8 €/MWh in Estonia, 4.9 €/MWh in Latvia and 4.4 €/MWh in Lithuania between minimum and maximum scenarios. This indicates that while power and heat sector costs are increased in all countries in '2030 reference' compared to 2017, not investing in VRE capacity would likely lead to increased electricity prices.

The decrease in marginal price also highlights the different magnitude of impacts of wind and PV generation: Addition of 1 GW of capacity reduces marginal prices by 1.6–2.0 €/MWh in the case of wind and only 0.3–0.4 €/MWh in the case of PV. This can be traced back to difference in capacity factors: Full load hours (FLH) for onshore wind have an average of 3000, for offshore wind 4000, for PV less than 1000.

To compare the costs and operation of different VRE technologies with significant differences in operating hours and generation curves, levelized cost of energy (LCOE) is calculated, and hourly generation patterns are investigated. The prices of electricity generation by onshore and offshore wind power, and by centralized and decentralized PV are compared to average marginal prices and average import prices in Figure 30.

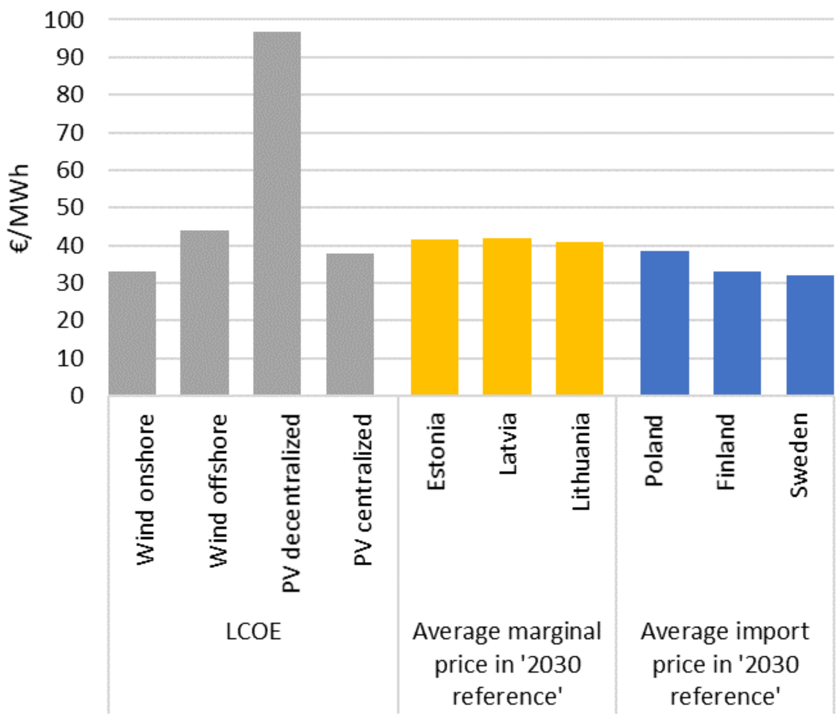


Figure 30. *Levelized cost of energy (LCOE) for wind and PV technologies and comparison to average electricity marginal price and import price.*

The LCOE analysis indicates that onshore wind is most cost-efficient with LCOE of approximately 33 €/MWh, and is followed by centralized PV at 37–38 €/MWh. Offshore wind results at 44 €/MWh and decentralized PV at 94–98 €/MWh. In comparison to average marginal electricity prices of 41 €/MWh and average import prices of 32–39 €/MWh, onshore wind, centralized PV and offshore wind can all be categorized as economic investments. The indicated competitiveness in surprisingly good for centralized PV.

In further investigation of hourly operation of wind and PV mix, the '+2.6 GW centralized PV' scenario in Lithuania is studied as an example. This scenario serves as an example of a nearly 100% renewable system, where 1506 MW of onshore wind, 700 MW of offshore wind, 1606 MW centralized and 10 MW decentralized PV is supported by pumped hydro storage (900 MW / 10800 MWh). Four generation combinations are observed highlighted in Figure 31.

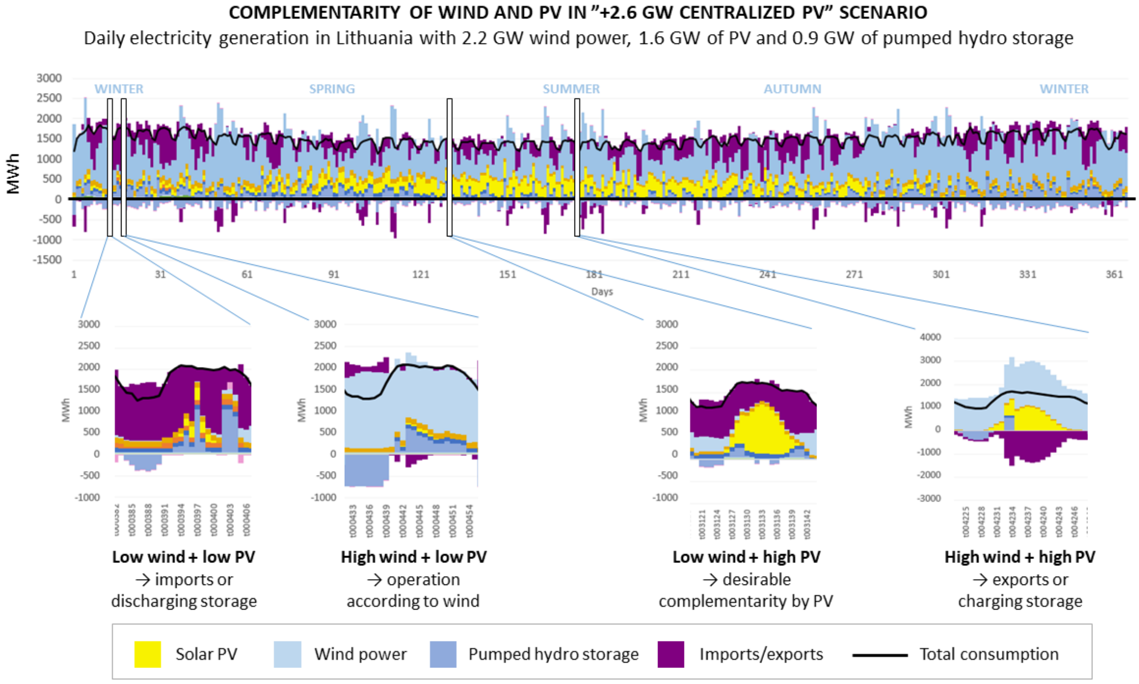


Figure 31. *Daily electricity generation in Lithuania in '+2.6 GW centralized PV' scenario as an example to estimate hourly system behavior with high wind and high PV. Examples of four different combinations are highlighted.*

The observed wind and solar power complementarity situations include:

1) *High wind coincides with low PV*. System is operated according to wind availability.

2) *Low wind coincides with low PV*. This is a test for capacity adequacy, especially since peak loads often take place during heating season. Though the situation is typical during winter, it occurs also in summer months. In normal operation the system optimizes between imports and use of storages based on current and past import prices levels and past VRE availability.

3) *Low wind is compensated with high PV*. This is a desirable situation, where PV is supporting wind.

4) *High wind and high PV coincide*. At these moments, the model can choose between loading storages and exports. The model seems to prefer exports, but in reality, demand of export electricity may limit this.

In total, 29% hours of the year (2500 h) are 'low wind hours' (wind generation below 30% of average demand). On the contrast, 77% of annual hours (6800 h) are 'low PV hours' (PV generation below 20% of average demand). Combined 'low wind and low PV hours' add up to 19% (1700 h). It seems that nearly half of high PV hours coincide with low wind hours, helping to balance wind variations. While the analysis is done with only a single year's generation curves, the findings are not surprising in light of literature [8], [9].

To summarize the operational changes by VRE, electricity generation costs will lower and net imports likely reduce. However, simultaneously dependency on interconnectors for system balancing will increase. The reflection of reduced generation costs on consumer prices cannot be determined based on these results, as it is also impacted by network improvement costs and taxation. Definite results on operation of international trade requires further modelling. No direct operational challenges are observed in maintaining the hourly power balance, however addition of wind power may compromise feasibility of some existing thermal units, especially Latvian natural gas CHP. As the PV prices continue to drop and PV time series seems to have the ability to reduce low VRE generation hours, the best VRE-mix between wind and PV in terms of operation and cost calls for further investigation.

6.6 Large heat pump scenarios: Opportunities in capital regions

Moving from power to heat generation, the results for large heat pump installations to electrify district heating show promising results, especially for the capital regions. With additional VRE power generation, electrifying district heating can cost effectively increase the renewable share of capital district heating networks, reduce CO_2 emissions and lower average production prices of heat.

The heat pump analysis compared five investment options from none (‘No DH HPs’) up to 900 MW’s of installations. Unlike the electricity grid, the district heating grid in the model is split between capital and aggregate of other regions in each country, altogether six areas. In ‘2030 reference’ there are only heat pumps in Riga and other Latvian regions — therefore ‘Reference +’ scenario with similar level added to all regions is presented as comparison in this subchapter. For wind and PV scenarios, the capacity division between regions is based on national plans, but as no plans exist for large heat pump deployment, the level of installations in each region corresponds to district heating demand. Firstly, Figure 32 presents the share of renewable heat generation, annual CO2 emissions and combined system costs in minimum, reference and maximum heat pump scenarios. In the chart, generation by heat pumps and waste are included in the renewable heat generation share.

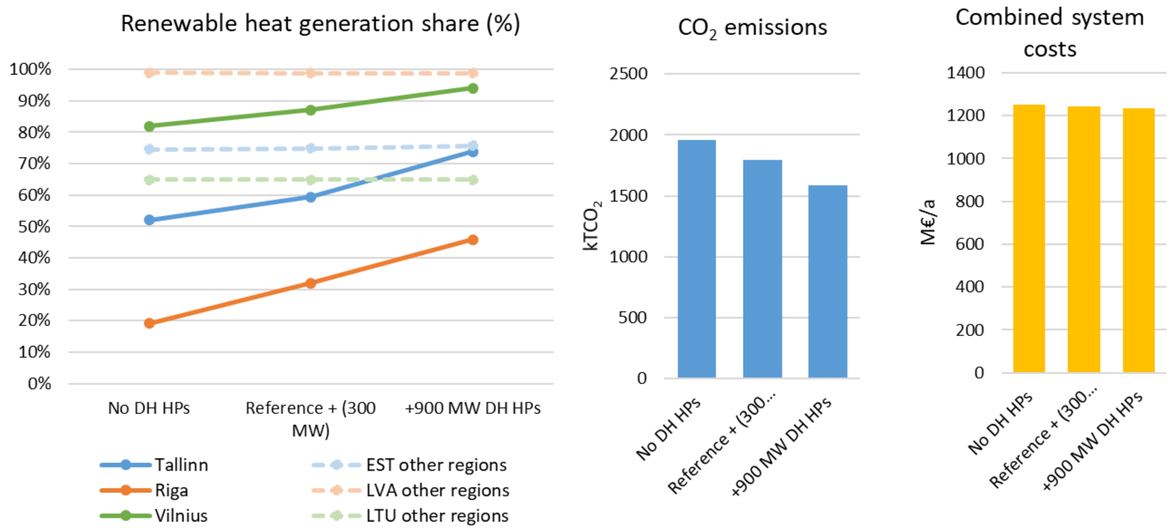


Figure 32. *Renewable district heat generation share by region (left), and Baltic modelled CO_2 emissions (middle) and power and heat sector's combined system costs (right), over large heat pump scenarios.*

On the left, the increase in renewable share is substantial in Riga (from 19% to 46% between minimum and maximum scenarios), in Tallinn (from 52% to 74%) and Vilnius (from 82% to 94%), but negligible in other areas. In the capital regions, large heat pumps substitute heat generation by natural gas boilers, whereas in the other areas, the heat pumps are mainly substituting biomass boilers. As shown in the middle, total modelled CO_2 emissions drop from 2.0 $MtCO_2$ to 1.6 $MtCO_2$ between minimum and maximum scenarios. Noteworthy, this is lower than emission level in highest wind and PV deployment scenarios (1.7–1.8 $MtCO_2$). On the right, the combined costs to the combined Baltic power and heat sector are slightly reduced.

The country-specific analysis on cost and operational impacts reveals that overall, heat pumps lower heat generation costs, but increase electricity import costs. The country-specific annual costs are shown in Figure 33. The investment costs in the analysis are based on heat pumps using excess heat (air-sourced heat pumps would be more and seawater-sourced less expensive) [91].

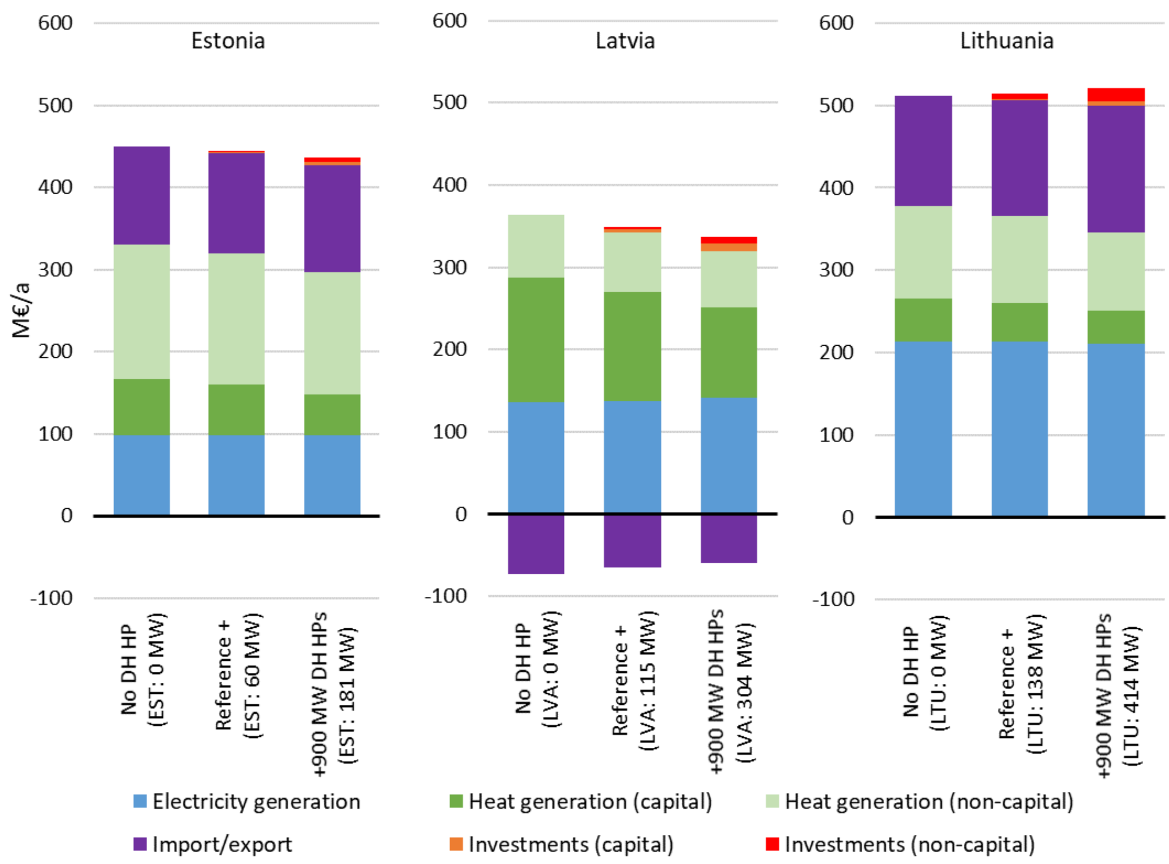


Figure 33. *Annual power and heat sector costs over large heat pump scenarios in Estonia (left), Latvia (middle) and Lithuania (right).*

The results indicate that large heat pump deployment reduces combined power and heat system costs in Estonia and Latvia, and increases them in Lithuania. However, regional differences are significant. The reduction in heat generation costs is largest in the capitals, whereas electricity import costs are increased most in Estonia and Lithuania. Regionally, the total costs reduce in Riga, remain the same in Tallinn and 'Estonian other regions', and increase in Vilnius, and 'Latvian and Lithuanian other regions'. With the deployment of large heat pumps in Latvia, an additional positive impact in supporting domestic generation by CHP units is observed. Also, it is noteworthy, that in Riga the operation of heat pumps is supported by planned investment in district heating storages, allowing improved utilization of cheap electricity hours.

Next, the regional marginal price impacts for district heating and electricity are presented, and the levelized costs of energy (LCOE) for different technologies and operational hours calculated and compared to average district heating marginal prices. Both charts are shown in Figure 34, with marginal prices above, and the results of the LCOE calculations below.

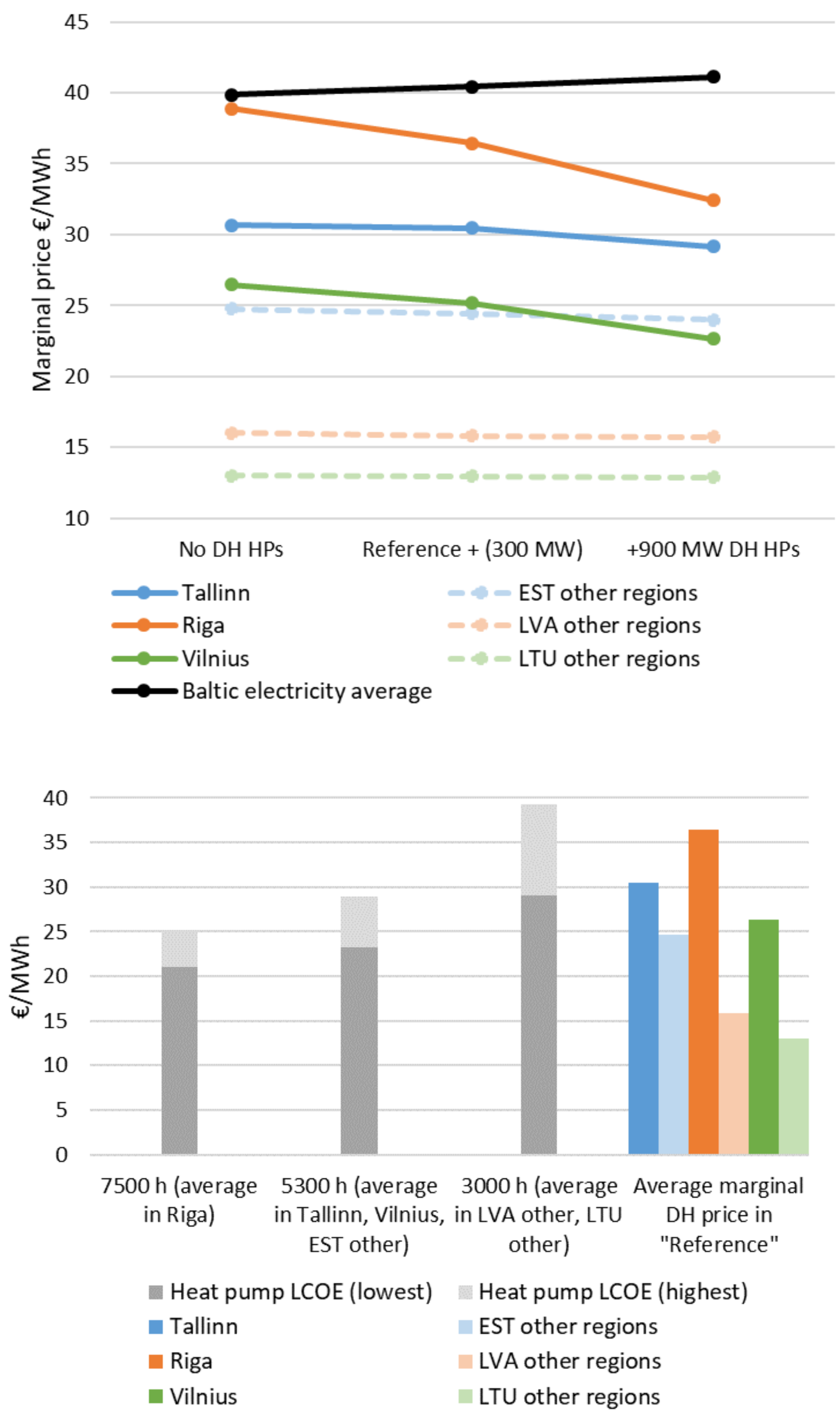


Figure 34. *Average marginal prices for district heat in different regions and for electricity average in the Baltics (above), and levelized cost of energy compared with average regional marginal heat prices (below).*

In the chart above, the largest reductions in marginal costs of district heat associated with large heat pump deployment, are found in Riga (-6.5 €/MWh between minimum and maximum scenarios), Vilnius (-3.8 €/MWh) and Tallinn (-1.5 €/MWh). The impacts on marginal prices are small in the other regions. The findings are consistent with the earlier results on regional differences. The increase in electricity demand associated with large heat pump generation causes an increase of +1.3 €/MWh in the average Baltic electricity marginal price.

In the figure below, the LCOE of heat generation by large heat pumps ranges from 21 to 39 €/MWh_h, depending on the technology and operational hours. In the scenarios, heat pumps are operated approximately 7500 hours in Riga, 5300 hours in other capitals and 'Estonian other regions' and as low as 3000 hours in 'Latvian and Lithuanian other regions'. The investment costs in technology are lowest for seawater-sourced heat pumps, in the middle for excess heat -sourced, and highest for air-sourced heat pumps [91]. The average marginal prices of district heat vary between 13 and 36 €/MWh in different regions. The comparison of LCOE costs with average marginal prices shown on the right again show best potential feasibility for the Riga region, followed by Tallinn and Vilnius.

As a conclusion, investments in large heat pumps perform surprisingly well in comparison to estimates found in literature [15], [85]. It seems that the somewhat faster transition of power generation towards variable generation than in comparative studies (see Appendix A) supports electrification technologies in general. While the district heating grid in the model is coarsely aggregated and cannot fully describe actual networks, results do suggest closer studies for Riga, Tallinn and Vilnius regions to chart potential heat sources, and to investigate the co-optimized impacts of large heat pumps and district heat storages.

7. DISCUSSION

In summary, the most important results and contributions of this thesis are found in the techno-economic analysis of different technologies in light of the Baltic national plans. They include 1) *support for national plans in wind and solar power deployment with high temporal resolution modelling*; 2) *identifying increasingly feasible technologies in future setting*; and 3) *pointing out potential concerns in system operation with high shares of variable generation.* In categorizing contributions, a differentiation must be made between the outputs of *the thesis alone*, and *the thesis as a part of FasTen project*. Further, the contributions listed above are *societal* in nature, offering policy evaluation rather than scientific advances. Also *interpretative* and *scientific* contributions are identified. Table 8 categorizes the outputs, and highlights the primary contributions in bold.

Table 8. *Categorization of contributions of the thesis on its own, and as a part of FasTen research project.*

Thesis		**FasTen project**
Interpretative	**Societal**	**Scientific**
1. Categorization of energy modelling approaches and trends	**1. High-resolution modelling support for national plans in wind and PV deployment**	1. Full-year hourly multisector regional Baltic model
2. Literature analysis on unique features of the Baltic energy system	**2. Identification of promising technologies (large heat pumps in capitals, utility-scale PV)**	2. Open access model and Baltic data
3. Summary of energy system trends and operation of VRE resources	**3. Observing potential concerns in energy security (Estonian flexible capacity, Latvian gas-CHP, Lithuanian very high VRE-share)**	3. Methodologic improvements on Backbone modelling structure

The reliability of the three highlighted contributions is impacted by a range of factors, such as uncertainties in assumptions, methodological simplifications and impacts from outside modelling scope. The two latter, methodological benefits and limitations as well as model scope is already assessed in Chapter 5 (especially Chapter 5.8), with the key finding that the overall modelling approach is reliable, and even able to enhance modelling accuracy compared to “industry standard”. Simplifications in modelling neighboring regions, relaxing MILP formulation, and not accounting for short- and long-term stochasticity will likely produce slightly too optimistic final results, i.e. modelled system operation costs are likely lower than actual costs. Also, many of the associated costs, like grid enforcements needed to integrate new wind and solar investments, are outside the model scope. This should be observed when interpreting the results.

Crucial uncertainties in the assumptions on *benefits of wind and solar power installations* include fuel, electricity, emission and technology prices as well as development of demand. The unpredicted events from 2020 onwards (including the COVID-19 pandemic, the European energy crisis in winter 2021–2022, and Russian attack on Ukraine in early 2022) have further decreased the predictability of price development. The modelled fossil fuel price development was based on the Heat Roadmap estimate in 2017, the electricity trade prices were estimated to remain stable between 2017 and 2030, and EU emission trade system prices were estimated to rise from 5 €/tCO_2 in 2017 to 50 €/tCO_2 in 2030. The recorded development so far has shown an underestimation of all three of these costs.

The promising results for utility-scale PV and large heat pumps depend on estimated technology price reductions. The numbers by Danish Energy Agency (updated between 2016 and 2020) expect very optimistic development in prices and efficiencies, and additionally, do not account for regional cost factors. Yet, recent historical wind and PV deployment as well as price development have exceeded expectations. Some simplifications in heat pump modelling, such as assuming a constant COP of 3 without assessing available heat sources, and not constraining the ramp rates or number of start-ups and shut-downs of heat pumps, increases heat pump feasibility in results. However, lack of co-optimized large heat storages and unlimited supply of biomass impact results to the opposite direction.

Potential energy security concerns are named “potential” as no actual capacity adequacy analysis or loss of load expectation (LOLE) calculation is applied. Similarly, assessing the stability of the Lithuanian very high planned variable share would require more detailed grid modelling and power flow analysis. Here, the lack of public data increases the risk of false conclusions, for example the online hours of Latvian CHP units versus boiler units are sensitive to non-public values like variable and fixed operating costs. Further, the Estonian flexible capacity included in the original ‘2030 reference’ may not have included all national plans due to i.e. language barrier.

8. CONCLUSIONS

There is a wide consensus in literature that European energy systems are in rapid transition, and that significant deployment of wind power, photovoltaics and electrification are key technological solutions in the green transition. Ability to model scenarios of different energy futures is crucial in mitigation strategies and investment planning. Simultaneously, considering the operational features of variable generation becomes increasingly important in modelling efforts. Overall, scenario modelling in literature support the premise that highly renewable systems can be both operationally functional and not overly expensive. This requires, however, systemic solutions to increase system flexibility including storages and interconnectors, but also demand-side flexibility, sector coupling and smart grid operation and planning.

For the Baltic countries, the planned transition translates to significant investments in renewable generation and grid infrastructure. The national plans also include supporting renewable fuel-use in end-use, and improving energy efficiency, but these factors are less prominent in the system-level operational modelling results. The main overall modelling result is that the planned high shares of VRE and also additional large heat pumps in centralized heating can support the national targets in emission reductions and increasing renewable and domestic shares with moderate costs. The hourly operation of the modelled system remains balanced with active use of storages and interconnectors. The operational environment such as interconnectors to neighboring regions, has a significant impact on successful VRE integration. As the Baltic region has significant electricity interconnector capacity, and belongs to a large synchronous area (currently BRELL and Continental Europe in the future), the geographical conditions support high shares of variables. However, some changes in operation and uncertainties in modelling alert caution, and encourage focus on ensuring energy security, offering flexibility and shifting focus from supporting renewable generation towards electrification.

The thesis sought answers to a total of five research questions, three of which were addressed by a literary review and two by a modelling case study. First, the state-of-the-art in operation of future energy systems was addressed in Chapter 2. Then, the features and special challenges and opportunities of the Baltic system were analyzed in Chapter 3. Finally, Chapter 4 presented leading approaches to energy system modelling. Deriving from literature, the case study modelled the regional system of Estonia, Latvia and Lithuania, and compared the operation of current Baltic system to a 2030 scenario based on realization of national energy and climate plans. A Baltic model using the Backbone modelling framework was used to optimize the full-year hourly operation of power, heat, transport and building sectors of the region for a historical year of 2017 and the scenario year of 2030. The comparison yielded general results in power and heat generation, costs, emissions and shares of renewable and domestic generation. Additionally, an informal analysis was performed to discover potential energy security risks and other system behavior of interest. Finally, different capacity amounts for the studied technologies (wind power, PV and large heat pumps) were compared in order to assess system sensitivity to different deployment levels, and compare costs, environmental and energy security indicators.

The Baltic Backbone modelling according to the national plans indicated a significant change in system operation especially for Estonia and Lithuania between 2017 and 2030. Several positive impacts were reported as total Baltic CO_2 emissions were significantly reduced, renewable power generation as well as EU ETS targets reached, and domestic generation increased. The model was able to maintain operational balance by actively using existing and planned interconnectors and storages in Latvia and Lithuania, but indicated a need for additional flexibility in Estonia. Implementation of the plans increased modelled annual power and heat sector costs moderately in all three countries.

Concerns caused by the results included falling behind on EU ESR emission reduction targets, and reduced commercial feasibility of cogeneration plants as a result of wind deployment. Also, closer analysis of the hourly results revealed frequent price peaks in marginal costs of power in Estonia indicating a need for more dispatchable capacity, and high ramp rates in Lithuanian interconnectors possibly indicating overly relying on neighboring regions to balance system operation. However, final conclusions on these observations are partially outside the modelled scope, and they therefore only indicate the need for additional study.

In closer comparison of the impacts of different levels of onshore and offshore wind power, centralized and decentralized PV, and large heat pumps, there was no surprise that wind power — especially onshore wind — performed best in terms of improving environmental and self-sufficiency indicators with the lowest cost impacts. The cost-optimal wind deployment level seemed to be close to planned level. Wind capacity had a strong correlation to the online hours of some thermal plants, displacing especially generation by large Latvian natural gas CHP units, and shifting heat generation to existing boilers. Substitution of thermal generation is expected, but impact on strategically important cogeneration units may risk capacity adequacy or result in need to subsidize fossil-based generation. While both the planned level and average full-load hours of PV in the Baltic setting are low compared to wind power, rapidly falling prices of especially utility-scale PV installations and ability to complement wind generation make PV an increasingly important consideration in the renewable generation mix.

Large scale heat pumps performed surprisingly well in Baltic capital regions compared to literature assessments, even when combined benefits of heat pumps with large heat storages was not fully accounted for. For an import dependent region, this is somewhat counter-intuitive, but as the modelling assumed somewhat higher VRE shares than in comparative studies, the ability to offer flexibility and increase the value of electricity (supporting both feasibility of thermal units and value of wind power) have added value. If assumptions on heat pump price development and reaching planned VRE levels apply, and suitable heat sources are available, further studies in large heat pump feasibility in Riga, Tallinn and Vilnius is encouraged.

Combining the lessons from Baltic literature and the case study results, a strong policy focus on supporting decarbonized energy generation and interconnector projects is indicated. However, if deployment of electrification and flexibility is not simultaneously supported, there is a risk of ‘high-VRE, low-electrification and low-flexibility’ period, where the energy security risks of variable generation are increased. Further support and policy measures in end-use electrification may help the Baltic countries to avoid some of the economic and environmental risks of rapid energy transition, as deployment of electrification technologies can support the price of electricity, attract market driven VRE investments, increase system flexibility and support cogeneration feasibility. End-use electrification can also help in emission reductions in EU ESR sectors, where they are furthest behind targets.

Overall, wind and solar investments are becoming more and more market driven, and the Baltic countries are highly impacted by increasingly uncertain development in surrounding environment. The uncertain conditions and growing complexity suggest a holistic, cautious and reactive policy approach. As policy measures will have a declining impact on energy sector investments in an increasingly market driven transition, policy focus should consider shifting to factors outside market participants’ scope — ensuring energy security, capacity adequacy and grid balancing. Finally, high-quality modelling combined with continuous iteration of energy policy plans with high awareness of systemic trends, neighboring regions and technology development are essential in averting major risks in Baltic long-term energy system planning.

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APPENDIX A: COMPARISON OF 'REFERENCE 2030' SCENARIO RESULTS TO LITERATURE

Tables 9–11 summarize the electricity generation results of Baltic Backbone '2030 reference' scenario and comparison with Baltic modelling in literature: Baltic energy technology scenarios ('BENTE') from 2018 [15], EU modelling attached with the EU 'Fit for 55' package ('EU reference' and tighter 'EU fit-for-55') from 2020 [6], and system dynamics modelling by Blumberga et al. from 2016 [16].

Table 9. *Estonian electricity generation by source in 2030. Baltic Backbone model '2030 reference' results compared to modelling results in literature.*

ESTONIA	2030 reference	EU reference	EU fit-for-55	BENTE	Blum-berga et al.
Consumption [GWh]	**9334**	8990	9153	8500	
Generation [GWh]	**5786**	9351	7918	8300	
Shares of total consumption [%]					
..Wind (onshore & offshore)	**44 %**	39 %	47 %	44 %	25 %
..PV	**4 %**	3 %	4 %	0 %	0 %
..Biomass & biogas	**8 %**	12 %	14 %	8 %	5 %
..Oil shale	**4 %**	44 %	15 %	45 %	65 %
..Natural gas	**0 %**	6 %	6 %	0 %	0 %
..Hydro	**0 %**	0 %	1 %	0 %	1 %
..Waste	**2 %**	0 %	0 %	1 %	0 %
..Imports (+) / exports (-)	**38 %**	-4 %	13 %	2 %	4 %

Table 10. *Latvian electricity generation by source in 2030. Baltic Backbone model ‘2030 reference’ results compared to modelling results in literature.*

LATVIA	2030 reference	EU reference	EU fit-for-55	BENTE	Blum-berga et al.
Consumption [GWh]	**7803**	7524	7501	7800	
Generation [GWh]	**8911**	9497	10027	4000	
Shares of total consumption [%]					
..Wind (onshore & offshore)	**36 %**	31 %	32 %	3 %	26 %
..PV	**1 %**	0 %	1 %	0 %	11 %
..Biomass and biogas	**14 %**	15 %	17 %	5 %	6 %
..Natural gas	**7 %**	40 %	43 %	0 %	30 %
..Hydro	**56 %**	41 %	41 %	44 %	21 %
..Waste	**0 %**	0 %	0 %	0 %	0 %
..Imports (+) / exports (-)	**-14 %**	-26 %	-34 %	49 %	6 %

Table 11. *Lithuanian electricity generation by source in 2030. Baltic Backbone model ‘2030 reference’ results compared to modelling results in literature.*

LITHUANIA	2030 reference	EU reference	EU fit-for-55	BENTE	Blum-berga et al.
Consumption [GWh]	**14553**	10234	10548	11900	
Generation [GWh]	**10062**	7715	13444	6400	
Shares of total consumption [%]					
..Wind (onshore & offshore)	**51 %**	40 %	55 %	27 %	55 %
..PV	**6 %**	8 %	20 %	12 %	15 %
..Biomass and biogas	**4 %**	17 %	19 %	6 %	10 %
..Natural gas	**0 %**	4 %	29 %	0 %	5 %
..Hydro	**4 %**	6 %	6 %	5 %	15 %
..Waste	**3 %**	0 %	0 %	3 %	0 %
..Imports (+) / exports (-)	**31 %**	25 %	-27 %	46 %	0 %