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ENERGY TRANSITION OF THE BALTIC STATES: PROBLEMS AND SOLUTIONS

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The importance of the climate change problem is recognised by the governments of the overwhelming majority of the world's countries. To bring additional attention and enable more concrete action, in a number of countries and municipalities the issue has been declared a climate emergency. The need to solve this problem predetermines the task of replacing fossil energy sources with renewable alternatives. The process of the ongoing transformation is called energy transition. It includes transformation of all the energy-intensive sectors of economic activity: power generation, supply and consumption, heat generation and supply, electrification of transport, agriculture and households.

The main goal of the energy transition is obvious – it is necessary to reduce the emissions of carbon dioxide into the atmosphere. The main sources of energy used to achieve this goal in power generation are wind and solar energy. Even though the goal is unambiguously defined and the way to achieve it seems evident, it is already clear that a number of serious problems and obstacles have arisen. They are caused by the emergence of additional objectives that must be achieved and constraints that need to be satisfied in the process of the required transformations. Indeed, the transition should be carried out taking into account power system properties describing techno-economic efficiency, reliability, stability, adequacy, etc. This list can be expanded easily. It should be noted that the additional objectives are not less important than the overarching goal. Along with reducing emissions, it is also necessary to improve energy supply reliability, its availability and affordability for all the segments of the population as well as maintain the security of the energy supply infrastructure and processes.

Keywords: *Energy transitions, FutureProof, INGRIDO, I-POWER, LAGAS, SecureGas, the Baltic States.*

1. INTRODUCTION

The need to simultaneously achieve several goals leads to complex global tasks which can only be solved through the combined efforts of many countries in cooperation with technology developers and manufacturers, research institutions, generation companies, transmission and distribution network operators as well as the energy consumers, i.e., businesses and the general population. An important direction in tackling the problem is the increasing interconnection between various types of energy infrastructures and carriers (i.e., multi-energy systems). However, at the same time, this solution also has the potential to exacerbate the problem by introducing additional issues. The energy supply process can be disrupted by malfunctions in communication systems, water supply, transport infrastructure, etc. Importantly, even short-term power outages can cause huge economic losses arising from the stoppage of economic activity in cities and potentially even whole countries. Moreover, failure of interconnected energy supply infrastructure can lead to tragic consequences to human life, such as the recent failure of the Texas, power system aggravated by a notably rare occurrence of an intensive cold spell. However, such issues can be prevented by planning for the worst-case scenarios, even if their probabilities are very low.

In most of the world, the energy transition process is already in full swing. Dramatic changes have also taken place in the energy systems of the Baltic countries. Some of the most important developments in recent decades are summarised below:

- the operation of major power generation plants has been stopped or severely reduced (i.e., two units of the Elektrėnai Complex have been put in reserve, and the oil-shale power plants in Narva are partly being phased-out);
- new power transmission lines have been built connecting the Baltic States to Finland, Sweden, and Poland;
- the Baltic countries have become part of the Nord Pool electricity market where most of the day-ahead and intraday trade takes place;
- combined cycle thermal power plants of significant capacity have been built or refurbished and put into operation;
- hundreds of renewable energy power plants have been put into operation (small hydroelectric power plants, biomass and biogas plants, wind and solar power plants);
- the operation of electricity and gas networks has been significantly strengthened. The control systems of energy supply infrastructure and facilities have been modernised, taking advantage of the rapid advancements in information and communication technologies.

However, in the process of these changes, the Baltic energy systems have only partially achieved their development goals: emissions are still overall high, and the Baltic energy system as a whole has become acutely deficient. In 2020, only 55 % of the consumed electricity was generated by local power plants. To solve the problem of generation shortage, also taking into account the need to replace the existing fossil power plants, evidently, significant capacities of renewable energy power plants will be required in the near future. This challenge is compounded by the fact that an increase in electricity consumption in transport, households and industry is expected.

Summarising the above, we can say that for the successful future development of energy supply in the Baltic countries, a significant number of problems need to be solved, some of which are addressed in this special issue of the Latvian Journal of Physics and Technical Sciences. A common feature of the articles presented in this issue of the Journal is that this research is partly or in full conducted within a number of projects of the Institute of Power Engineering of Riga Technical University with participation of partners from other scientific institutions and industry. The articles included in this issue show the preliminary or final results of several of the many tasks tackled within the framework of selected projects aimed at energy transition:

1. "Future-Proof Development of the Latvian Power System in an Integrated Europe (**FutureProof**)", project No. VPP-EM-INFRA-2018/1-0005;
2. "Innovative Smart Grid Technologies and their Optimization (**INGRIDO**)", project No. VPP-EM-INFRA-2018/1-0006;
3. "Trends, Challenges and Solutions of Latvian Gas Infrastructure Development (**LAGAS**)", project No. VPP-EM-INFRA-2018/1-0003;
4. "Management and Operation of an Intelligent Power System (**I-POWER**)", project No. lzp-2018/1-0066;
5. European Union's Horizon 2020 research and innovation programme under grant agreement No. 833017, project "**SecureGas**";
6. "**Electrical Grid Design Methods and Tools, Considering Smart Technologies and Market Conditions**" project No. No.1.1.1.2/VIAA/2/18/317.

In the next sections, the aims and main tasks of these projects are summarised, followed by brief introduction of the articles included in this special edition and their contribution to the project tasks.

2. BRIEF DESCRIPTION OF THE PROJECTS

2.1. Future-Proof Development of the Latvian Power System in an Integrated Europe

The main aim of the project is to foster sustainability and competitiveness of a smart and reliable Latvian energy system, promote its conformity to public interests and integration into the European energy system through detailed studies and modelling of the power system infrastructure, markets, risks and future development scenarios. To achieve this aim, a number of diverse tasks are addressed:

- definition and assessment of long-term scenarios for sustainable development of the Latvian power system up to 2050;
- modelling and simulations of electricity markets relevant for Latvia;
- Latvian power system risk assessment and development of recommendations for risk mitigation;
- energy poverty analysis in Latvia;
- preparation of recommendations to policy makers informed by the major project findings and results;
- development of databases, including the characteristics and indicators, historical and forecast time series important for the Latvian power system analysis and its future development scenario assessment.

2.2. Innovative Smart Grid Technologies and their Optimization

The goal of the project is to assess the innovation and optimization potential in the Latvian power system and develop solutions for increased efficiency given the growing use of renewable and distributed energy sources, emergence of prosumers and other market development trends. To complete this project, the following is carried out:

- analysis of the current situation in terms of energy supply in Latvia and the forecast innovation trends up to 2050;
- identification of power system flexibility issues now and in the future, and devising measures to mitigate them, also taking advantage of such development trends as increasing efficiency of the building stock, distributed generation, aggregator operation, demand response, energy accumulation, development of smart grids and the emergence of prosumers;
- encouraging transition towards a smart grid ecosystem by developing optimized control strategies for consumer and prosumer aggregation, and by producing smart adaptive automation and protection methods for the grids of the future;
- development of guidelines for the assessment of energy supply infrastructure efficiency tailored for the Latvian case, and subsequent assessment of infrastructure inefficiencies.

2.3. Trends, Challenges and Solutions of Latvian Gas Infrastructure Development

The aim of the project is to study the infrastructure of gas supply, storage and distribution as well as the market, risks and future development scenarios so as to develop solutions for improving the efficiency and reliability of the gas system operation. The tasks undertaken are related to:

- the Latvian natural gas transmission, distribution and liquefied natural gas production and transportation system development forecasts;
- the modelling of the gas network, ensuring continuity of natural gas supply, the assessment of its reliability;
- the evaluation of extraction technologies depending on resources, energy consumption, costs, flexibility and the potential for their widespread adoption;
- the role of hydrogen in the transportation and storage of energy at present and in the future; assessment is made of hydrogen extraction technologies, including biohydrogen, and their suitability for the conditions in Latvia.

2.4. Management and Operation of an Intelligent Power System

The main aim of the project is to increase the efficiency, reliability and sustainability of the power supply in Latvia. To achieve this aim, the following is performed:

- analysis and selection of small and micro-size energy generation plants and their control technologies: micro-CHPPs, heat pumps of various kinds, solar collectors, wind turbines and heat and electricity storage technologies are reviewed and selected for in-depth analysis along with methods, techniques and algorithms for their control;
- development of models of large, small, and micro-size energy prosumers with the aim of determining short-term and long-term production costs and other economic indicators;

- providing new solutions addressing the need for optimal operation of power plants at market conditions;
- bringing an innovative solution to the market, facing future challenges regarding market development, and spreading the knowledge to as many sectors of the energy industry as possible.

3. GLIMPSE INTO THE ARTICLES

The articles presented in this special issue of the journal reflect the results of the research carried out within the framework of the above projects, showcasing both the outcomes of individual project tasks as well as the fruits of cross-project cooperation, whereby the researchers working in the different areas have identified opportunities for synergetic collaboration. The introductory article describes all the articles in order as they are presented in the journal [1].

"Methodology for Investment Evaluation in Electricity Generation Modules in Accordance with the Requirements of the European Union" by L. Vempere, A. Jasevics, L. Zemīte and G. Vempers [2] illustrates that one of the criteria for whole energy system is a stable electricity supply that meets certain technical parameters. In order to achieve synchronous operation of several energy systems, the Commission of the European Union has adopted Regulation No 2016/631 establishing a network code on the applicable network connection requirements for generators. In 2025, the Baltic States plan to integrate into the Energy Systems Association of Continental Europe and work synchronously with the other European Union countries, disconnected from the current BRELL energy systems. The aim is to develop a model for ensuring the safety of electricity systems, including limiting frequency fluctuations at the level allowed for the system, as well as the development of the electricity and ancillary services market and the development of renewable energy sources. An economic analysis to assess which generators need investment and whether their use will provide economic benefits is performed. As a result, it may be recommended that the state can create a priority list, where generators are divided according to their socioeconomic benefits. In cases where the changes are so large that power plants which do not comply with the requirements of the Regulation, regulation on the modernisation of existing plants may be adopted, which means additional investment.

"**Estimating the Benefit from Independent Aggregation in the Day-Ahead Market**" by K. Baltputnis and Z. Broka [3] provides an assessment of potential benefits from demand response in the day-ahead electricity market if it is offered by independent aggregators. The study is insightful in relation to the development of independent aggregators' regulatory framework in the European countries. The model presented in this study utilises public wholesale market price curve data from the Nord Pool power exchange to simulate market clearing results with introduction of certain amounts of demand response, which, via independent aggregators, compete alongside generation and are able to shift the supply curve. The simulated new market equilibrium point allows estimating the price reduction capability of demand response and the resulting benefits as well as analysing the potential remuneration mechanisms for independent aggregators and implications on their business models. While the results demonstrated a high value from demand response during the peak hour, the overall benefits during average price periods were rather low, thus questioning the business case for independent aggregators in the day-ahead market. The proposed approach can be used for further analysis of different independent aggregator compensation mechanisms considering the system-wide benefits demand response brings to the wholesale market.

“**Modelling the Future of the Baltic Energy Systems: A Green Scenario**” by L. Petrichenko, R. Petrichenko, A. Sauhats, K. Baltputnis and Z. Broka [4] reflects to the task of long-term strategic planning of the Baltic energy system development. The breadth and complexity of this task is due to the following main factors: (*i*) the need to model various technologies of power plants, networks, consumers and an interconnected power system of a wide geographic region; (*ii*) requirement to predict several stochastic processes for many years ahead and (*iii*) objective functions with many constraints and optimization variables.

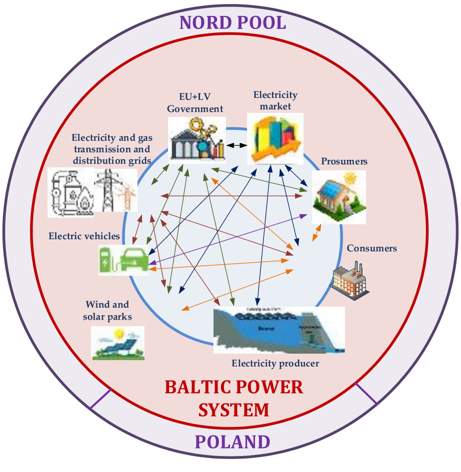

Fig. 1. Overall structure of the power system.

Moreover, there are many participants in the planning and operation of the power system, and their aims often do not coincide. The presence of several agents (decision-makers, see Fig.e 2), leads to further complication of the problem of strategic planning.

Fig. 2. Decision-makers in power system development planning.

The decisions are made at various levels, simulating the operation of the future power system and its elements based on a number of forecasts regarding power production and consumption, costs and other parameters. A description of the overall model structure developed this far is provided in conjunction with preliminary input scenarios and produced output. A case study analysis is performed where the resulting electricity generation mix and trade balance with neighbouring countries is assessed under assumptions of notable advancements in installed renewables capacities in the Baltic States by 2050.

"**Power Plant Cooperation in District Heating Considering Open Electricity Market**" by R. Oleksijs, A. Sauhats and B. Olekshii [5] analyses the possibilities to form a coalition of several electricity and heat suppliers to participate in the district heating market. Cooperation would allow better dispatching the existing energy sources and ensuring a higher total profit for the coalition participants. The objective function for such cooperation is formulated. To optimize the operation of the coalition, mixed integer linear programming is used, considering the constraints of different heat market participants and the need to ensure the heat balance. If any additional profit is made, it is shared among the coalition participants, using the cooperative game theory approach (the Shapley value), which incentivizes the market participants to form a coalition. A numerical case study based on historical prices and consumption is presented.

"**Assessment of PV Integration in the Industrial and Residential Sector under Energy Market Conditions**" by L. Petrichenko, J. Kozadajevs, R. Petrichenko, O. Ozgonenel, D. Boreiko and A. Dolgicers [6] evaluates the integration of solar photovoltaic technology in the aforementioned sectors. The aim is to determine and compare the payback period for the use of photovoltaic technology in the industrial and residential sectors taking into account the application of optimal load scheduling and the level of self-consumption. In addition, self-consumption has a significant benefit due to high network tariffs. The results show that installation and use of photovoltaic technology is most beneficial to users with high self-consumption. It is also most financially attractive to consumers who are able to invest in photovoltaic directly rather than by taking a loan. Furthermore, the greatest benefit from photovoltaic is gained by employing optimal load scheduling.

"**Heat-Pump Optimization Strategies for Participation in Price-Controlled Demand Response in Latvian Electricity Market**" by L.Kurevska [7] presents a case study in which six alternative optimization scenarios are compared on the basis of net financial gains. The case study provides insights for energy policy makers and industry representatives who play a considerable role in the integration of demand response services in the energy market framework. The case study design is based on examples from the research of heating, ventilation and air conditioning optimization algorithms. The scenarios have been developed taking into account the main barriers (complexity) and the main motivators (financial gains) for participation in demand response that were identified in previous research in the energy policy field. The case study compares different proxies for forecasting financial gains from switching off heat pumps for a limited time period. The results show that application of a simple algorithm calculating forecast cost savings provides a reduction in the electricity costs of up to 4 %.

"**Simplified Model for Evaluation of Hydropower Plant Conversion into Pumped Storage Hydropower Plant**" by

S. Kiene and O. Linkevics [8] states that pumped storage hydropower plants currently represent the most mature and widespread storage technology, yet the construction of new facilities is often hampered by the limited choice of suitable sites. An interesting solution is to convert an existing hydropower plant into a pumped storage hydropower plant by building an additional pumping station that pumps water from the lower reservoir during low electricity prices, thus providing additional water for the hydropower units to generate electricity during peak loads. The authors propose a simplified algorithm and a mathematical model to evaluate the operation of hydropower plant based on the historical prices of the Nord Pool market as well as on modelling the possible increase of the daily maximum and minimum electricity price difference in the future. The results show that the difference between the daily maximum and minimum prices at Nord Pool is currently insufficient to ensure recovery of the capital costs of the project. Favourable markets for capital-intensive energy storage projects that use price arbitrage to recover their investments are those with high price volatility. In the future, the increasing share of renewables can bring higher price differences. In addition, results from the simulation of pumped storage hydropower plant operation are then used in the economic model to evaluate feasibility of the proposed conversion.

"Heat Load Numerical Prediction for District Heating System Operational Control" by D. Rusovs, L. Jakovleva, V. Zentins and K. Baltputnis [9] affirms that an advanced control of heat supply for domestic heating needs to be developed, such as the emerging need to plan operation in accordance with an energy market-based environment. To move towards this goal, it is necessary to develop forecasting tools for short- and long-term planning taking into account data about the operation of existing heating systems. This paper considers real-life operational parameters of five different heating networks in Latvia from a period of five years. The application of regression analysis for heating load dependence on outdoor temperature results in the formulation of a normalized slope for the regression curves of the studied systems. The value of this parameter allows describing the performance of particular heating systems. Moreover, a heat load forecasting approach is presented and tested on data from a relatively small district heating system with an average load of 20 MW at an ambient temperature of 0 °C. The deviations of the actual heat load demand from the forecast are evaluated for two testing periods in January 2018. The forecast accuracy is assessed by two parameters – the mean absolute percentage error and the normalized mean bias error.

"**A Linearized Numerical Solution for Steady-State Simulations of Gas Networks**" by I. Zalitis, A. Dolgicers, L. Zemite, S. Ganter, V. Kopustinskas, B. Vamanu, I. Bode and J. Kozadajevs [10] examines risks and resilience analysis and potentially operational planning for different gas transmission systems or other purposes. The changes of gas transmission system brought diversification of gas suppliers, implementation of new interconnections with the European gas transmission system. The developed method combines the linearized hydraulic conductivity approach with a technique derived from linear electrical circuit analysis and an additional pressure change term for modelling of active non-pipeline elements of different gas transmission systems. Operational limits of compressors and pressure regulators and changes of compressibility factor and gas viscosity based on the gas composition, temperature and pressure are also considered in the model. Results obtained from a validation case study performed for the proposed method are presented.

"**CHPP Operation Mode Optimization at Electricity and Gas Market Conditions Using a Genetic Algorithm**" by J. Kozadajevs, A. Dolgicers and D. Boreiko [11] presents an operational planning optimization approach using a genetic algorithm for cogeneration power plants in urban heat supply areas. For efficient production planning in the liberalized power markets, it is paramount is to determine the optimal strategies over a time horizon. Solution of an optimization task of such complexity requires a well-crafted set of tailored modelling, simulation, optimization, and forecasting tools. A number of production units, such as gas turbines, steam turbines, heat-only boilers and thermal storages, reflected in the optimization model, are utilised to increase flexibility of generation.

"**The Natural Gas as a Sustainable Fuel Alternative in Latvia**" by J. Savickis, A. Ansone, L. Zemite, I. Bode, L. Jansons, N. Zeltins, A. Koposovs, L. Vempere and E. Dzelzitis [12] states that compressed natural gas and biomethane as well as liquid natural gas may be more suitable alternatives to conventional fuels for the decarbonisation of the transport sector in cities and other densely populated areas. On the basis of this mobility implementation experience in other European countries, the article provides an analytical insight into three basic development strategies of mobility in Latvia in this decade, with a particular focus on the prospects of simultaneous use of natural gas and biomethane as sources of compressed and liquid natural gas. The compressed natural gas fleet can cover private, business and municipal transport categories, and can be used both in places where natural gas pipeline deliveries are available and where biomethane is produced and supplied on site, at the biogas/biomethane production facilities. Biomethane can perfectly blend with natural gas at any given proportion and thus ensure decarbonisation of the natural gas network and the transport sector simultaneously. Liquefied natural gas can be used for bringing gas to regions where pipeline supply infrastructure is historically absent, limited or underdeveloped. The prospects for the use of liquefied natural gas there in both medium-term and long-term perspective must be carefully evaluated, especially with regard to the emerging bunkering business in the Baltic Sea region.

Comparing the aims of the projects described in Section 2 and the results of the research described in Section 3, evidently, only part of the initially outlined tasks have been presented. Indeed, as the research projects are still ongoing, the remaining tasks are set for completion by 2021. On the other hand, a significant number of journal articles and papers in conference proceedings have been published beforehand, showcasing the prior results of the outlined projects. References to some of these publications can be found in the related articles of this special issue.

"**The Natural Gas Supply of the Latvian Municipality during the Local Energy Crisis**" by L. Zemite, E. Nevercika, L. Jansons, I. Bode, A. Koposovs, N. Kondrahins and A. Jasevics [13] treats the natural gas system as the essential element of the Latvian and the Baltic energy supply. Gas system disruption can seriously impact the national economy and energy security of our country. The article focuses on efficiency of the natural gas supply to the Latvian municipalities, when a local energy crisis is announced. Among other issues, it covers various potential vulnerability factors that may cause the natural gas supply shortages or disruption periods of different length for a wide spectrum of the Latvian natural gas consumers – starting with households and finishing with large industrial consumers and energy producers. A legislative framework analysis along with emergency natural gas supply models has been proposed and reviewed as well, taking into account the actual distribution of the natural gas consumption among urban energy consumers.

"**The Creation of the Integrated Natural Gas Market in the Baltic Region and its Legal Implications**" by L. Zemite, A. Ansone, L. Jansons, I. Bode, E. Dzelzitis, A. Selickis, A. Romanovs and L. Vempere [14] examines natural gas as the cleanest of conventional fossil fuels. In a mid-term perspective, natural gas is considered an important low-carbon energy resource to ensure smooth transition to carbon neutrality both on the national and the regional scale. The main milestones on the way to the creation of a common natural gas market in the Baltic States and Finland, with emphasis on its legislative implications and the possibility of market expansion in the future, are addressed. There are also expectations to expand the common Baltic–Finnish natural gas market westwards after the completion of the natural gas interconnection between Lithuania and Poland. As a result, Poland could join the market platform as a partner and as a crucial route of alternative natural gas deliveries to the Baltic States and Finland. In a long-term perspective, the creation of an integrated regional natural gas market will stimulate the price transparency, strengthen security of the natural gas supply and improve market liquidity in the Baltic region.

"**Analysis of the Role of Latvian Natural Gas Network for the Use of Future Energy Systems: Hydrogen from RES**" by J. Kleperis, D. Boss, A. Mezulis, L. Zemite, P. Lesnicenoks and A. Knoks and I. Dimanta [15] shows that carbon-containing fuels and transfer to carbon-neutral fuel are necessary; therefore, hydrogen may be the answer to achieve the overall European targets. As Latvia has renewable energy sources, it is possible to ensure some production, storage and use of hydrogen. In the article, clear guidelines for Latvia have been investigated. The existing natural gas network may be used for two tasks: large-scale hydrogen transportation and decarbonisation of the natural gas network. To open the natural gas networks for hydrogen, the first evaluations are made and a possible scenario for hydrogen implementation in the network supplying household consumers is analysed to evaluate decarbonisation with the overarching goal of carbon neutrality.

"**A Review: The Energy Poverty Issue in the European Union and Latvia**" by D. Zalostiba and D. Kiselovs [16] is devoted to the analysis of the energy poverty problem. Low level of income, high energy prices/costs and low energy efficiency are the primary factors that characterise energy poverty. The availability and affordability of energy have a direct impact on the quality of life and well-being of society and individuals; the energy sector as a whole as well as areas such as healthcare, consumption and housing sectors are also affected. Although there are no unified definition of energy poverty and no harmonized methodology to assess it, energy poverty has been recognised as a social priority at the European level and embedded in the framework of the "Third Energy Package". To estimate the energy poverty in Latvia, the way energy poverty is currently defined and measured in other countries has been reviewed. Taking into account the available data and information, the analysis of energy poverty has been conducted in three characterising dimensions: low income, high costs of energy services and unsatisfactory housing conditions, by using statistical data as well as the indicators recommended by the European Union Energy Poverty Observatory, and compared with the European Union average values. Since the implementation of policy measures plays a vital role in tackling energy poverty and protecting the most vulnerable social groups, the good practice and measures implemented in individual Member States, including Latvia, have been studied.

4. CONCLUSIONS

The energy transition process is already in full swing. Dramatic changes in recent decades have occurred in the energy systems of the Baltic countries as well: the number, capacity and production of wind farms and solar power plants are growing rapidly; the role of cogeneration plants has increased; the cross-border connections have improved; the energy demand and prices have changed rapidly and significantly. Therefore, it is necessary to understand and predict the functioning and performance of individual components of the power system. It promotes the development of optimization models and analysis tools for the adequacy, security, reliability and stability of the Baltic energy system in the future.

The results of the articles in this special issue show that the energy transition and the use of new technologies should be supported by all the participants in the energy industry value chain: energy generation, transmission, supply, consumption and policy-making. To support the decision-making process, new technologies and new planning and control methods as well as new software products are required. All changes should be focused on reducing the use of fossil fuels and CO_2 emissions while maintaining both economic feasibility and technical security; the upcoming changes should contribute to each country's energy independence and ultimately bring overall societal benefits.

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METHODOLOGY FOR INVESTMENT EVALUATION IN ELECTRICITY GENERATION MODULES ACCORDING TO THE REQUIREMENTS OF THE EUROPEAN UNION

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For a country to be able to survive successfully, one of the criteria is a stable electric power supply that meets certain technical parameters. In the European Union, several countries are working synchronously to ensure the safety of electricity systems. In order to achieve such synchronous operation, the European Union has adopted Regulation No. 2016/631, which sets out the requirements for grid-connected generators. The present article develops a model to assess the compliance of generators with the requirements of the Regulation, as well as conducts economic analysis to assess which generators need investment and whether their use will provide economic benefits. In this way, the state can create a priority list, where generators are divided according to their socio-economic benefits. In 2025, the Baltic States plan to become integrated into the Energy Systems Association of Continental Europe and work synchronously with the other European Union countries, disconnected from the current BRELL energy systems. Therefore, the model developed in the article is applied to the case of Latvia to determine the necessary investments, as a result of which alternatives are considered for improving the current situation.

Keywords: *Cost-benefit analysis, generating sources, investments, power plants, synchronisation.*

1. INTRODUCTION

Electric power supply is a common national infrastructure system whose parameters must be consistent with the overall economic needs and technical characteristics. Any changes in the external environment or system must be avoided in order to ensure the equilibrium of the system. The functioning of several national energy systems in synchronous mode significantly reduces the costs of operating the energy system and improves overall system safety by reducing the potential adverse effects of local accidents on the stability of the energy system as well as simplifying the maintenance of essential performance parameters of the energy system, such as frequency. In order for the system to operate smoothly, it is necessary to ensure a continuous balance of the electricity produced and consumed, including in emergency situations. Deviation from this balance causes the system to be unbalanced. Electricity balance is characterised by electricity frequency.

The Commission of the European Union (EU) has adopted Regulation No. 2016/631, which establishes a network code on the applicable network connection requirements for generators. The purpose of the application of the requirements is the safety of electricity systems in the European Union (continuous consumer energy supply), including limiting frequency fluctuations at the level allowed for the system, as well as the development of the electricity and ancillary services market and the development of renewable energy sources. The legal provisions of the EU Network Connections Code do not apply to existing electrical equipment, but it provides for a mechanism to apply those legal provisions to existing electrical equipment in the event of significant changes in the energy system [1], [2]. In cases when the changes are so large that power plants which do not comply with the requirements of the Regulation cannot meet the objectives set out in the Regulation, regulation on the modernisation of existing plants may be adopted, which means additional investment.

In the event that production plants do not fully or partly comply with the requirements of the system, a study on the feasibility of their application and the amount of investment needed must be carried out. The amount of investment is to be assessed from the point of view of the common system and individual suppliers. On the other hand, from an economic point of view, it is necessary to assess losses arising from non-realisation of investment [3], [4]. Without investment, losses are suffered by society, business, and the economy as a whole, not just regarding the amount of electricity not delivered. As a result, these losses need to be calibrated.

The Baltic power supply system is designed to be closely linked to the energy supply infrastructure of neighbouring countries. Historically, the energy systems of Latvia and the other Baltic States have been designed as part of the former USSR unified energy system, in the so-called BRELL energy systems (the energy systems of Belarus, Russia, Estonia, Latvia, and Lithuania), so the Baltic States also maintained the historical electricity infrastructure connections with Russia and Belarus after the restoration of independence in 1991 [5]–[7]. As the Baltic States joined the European Union (EU) and closer links to the EU's energy bloc were established in 2007, the idea was that the Baltic States could work in sync with the rest of the EU. Exploration work began in 2013 to determine the provisional works and the costs of synchronisation. In 2015, a synchronisation road map was approved, and the Baltic States launched a process of preparations for synchronisation with the EU, scheduled for 2025 [8]. On 27 May 2019, the agreement on connecting the electricity systems of the Baltic States to the continental European grid entered into force. On 20 June 2019, in Brussels, the prime ministers of Lithuania, Estonia, and Poland signed a political road map for connecting the electricity systems of the Baltic States to the continental European grid. At the moment, disconnection from BRELL in the energy circle is taking place. Consequently, in the event of such a cut-off, the continued supply of electricity to consumers is problematic as regards the quality requirements [9]. At present, in the Baltic (2020) normal operating mode, the frequency must be between 49.95 and 50.05 Hz [10]. The energy systems of the Baltic States are facing a major challenge to successfully integrate into the Energy Systems Association of Continental Europe. All transmission system operators within the Energy Systems Association have to jointly ensure electricity balance through frequency adjustment services [11].

Given the need for the EU countries to carry out an analysis of the application of the Regulation for existing modules to assess the overall operation of the system in emergency situations, including frequency provision, the smaller investments are assessed in a situation where existing modules are evaluated as to the requirements of the Regulation when the site is part of a common EU network.

The main goal of this study is to develop a methodology for assessing investment needs in line with the requirements of Regulation EU 2016/631. To achieve this goal, we perform the following actions:

1. Assessment of the adequacy of modules for the requirements of Regulation EU 2016/631;
2. Cost-benefit analysis (CBA) for existing installations;
3. Assessment of the investment needs of modules.

2. METHODOLOGY AND MODELS

A cost-benefit analysis is a process that businesses use to analyse decisions. The business or analyst sums the benefits of a situation or action and then subtracts the costs associated with taking that action. Some consultants or analysts also build models to assign a money value on intangible items, such as the benefits and costs associated with living in a certain town [12].

The economic analysis has been carried out by an additional cost method, comparing the two project implementation scenarios: the situation without the project and the situation with the project and taking into account only the additional costs and benefits associated with the implementation of the project. According to the CBA Regulation, the following performance indicators may be used: net present value; internal rate of profitability; rate of return; investment payback period. The algorithm uses performance indicators and criteria consistent with the Regulation [13] and the CBA guidelines for the EU investment projects [14], [15]:

- Economic net present value (ENPV): this must be greater than zero in a project that is desirable from an economic point of view;
- Economic rate of return (ERR): this

should be higher than the social discount rate;

- Benefit-cost ratio (B/C): this must be greater than one.

The sensitivity analysis is designed to identify the critical variables of the project that are used in drawing up the cash flow of the CBA. According to the guidelines, it is recommended to consider "critical" variables whose changes (positive or negative) by 1 % of the basic value of the net present value are changed by 5 %. The calculation of limit values may reveal useful information, indicating at what percentage changes the net present value (economic or financial) is zero. The sensitivity analysis indicators are as follows: investment cost changes; full off (blackout) one event duration; number of full off (blackout) events per year.

The CBA has to be carried out for the reference period, or for the life cycle of the project, starting with the beginning of the project. The reference period or life cycle is the useful lifetime of the fixed assets created under the project, or the economically valid period of the project, during which it is possible to benefit financially or economically from the funds invested in the project or the assets created. The recommended length of the project life cycle in the energy sector is 25 years [16], [17], the reference period recommended by the European Commission in the energy sector is 15–25 years (Table 1) [18], [19].

Table 1. Input Data

Parameter	Input data
Household losses	Not taken into account, no representative study
Economic benefits	Annual value of avoided blackout
Economic costs	Capacity reservation fee Spare capacity x (calendar number of hours per year) x (Nord Pool Spot minus variable costs)
Discount rate (real)	5 %
Assessment period	15 years

In order to determine the financial effectiveness of applying legal norms to existing electrical equipment, electricity generation modules will be considered as electrical equipment within this study. For each module, a number of points following which the relevant model is assessed should be provided for. In the course of the study, a methodology is developed to assess the conformity of models with the requirements of the Regulation, the necessary investments, and losses.

Two types of modules are distinguished: synchronous and park modules. The synchronous electricity generation module (SEGM) is an indivisible set of equipment capable of producing electricity in such a way that the ratio between the generated voltage frequency, the generator speed and the grid voltage frequency is constant and therefore these indicators are synchronous. An electricity park module (EPM) means an electricity generating unit connected to a network: (1) non-synchronic, (2) by means of an energy electronic (DC) converter, (3) connected to a high-voltage direct current system at a single termination point, (4) in different sets of such units. Each module is broken down to the type concerned, depending on the following active power (P) limits:

- Type A Module: 0.008 MW $\leq$ P $<$ 0.5 MW;
- Type B Module: 0.5 MW $\leq$ P $<$ 5 MW;
- Type C Module: 5 MW $\leq$ P $<$ 15 MW;
- Type D Module: P $\geq$ 15 MW or connection to power mains of 110 kV or a higher voltage.

The assessment is carried out according to the methodology in Fig. 1. For each module, its type is defined as SEGM or EPM, its active power and its conformity with type A, B, C or D have to be evaluated. By module breakdown, the requirements of the Regulation have to be structured and the conformity of each type with these has to be evaluated. As a result, a list of the requirements of the Regulation is drawn up. Each SEGM/EPM type and each A/B/C/D type of module are evaluated according to the applicable requirements (task No. 1). If the model complies with all the requirements of the Regulation, it is not taken into account in the subsequent calculations, this kind of breakdown is applicable as it is possible for their further assessment to be carried out by the CBA (Task No. 2). If the model does not meet a requirement, a technical-financial assessment has to be carried out for each requirement that the model does not meet when determining the required financial contribution (Task No. 3). In order to assess the efficiency of investments, the losses caused to the economy in an emergency situation and the impact on market development and the integration of renewable sources are assessed, depending on a number of safety aspects, namely: frequency, duration, and impact.

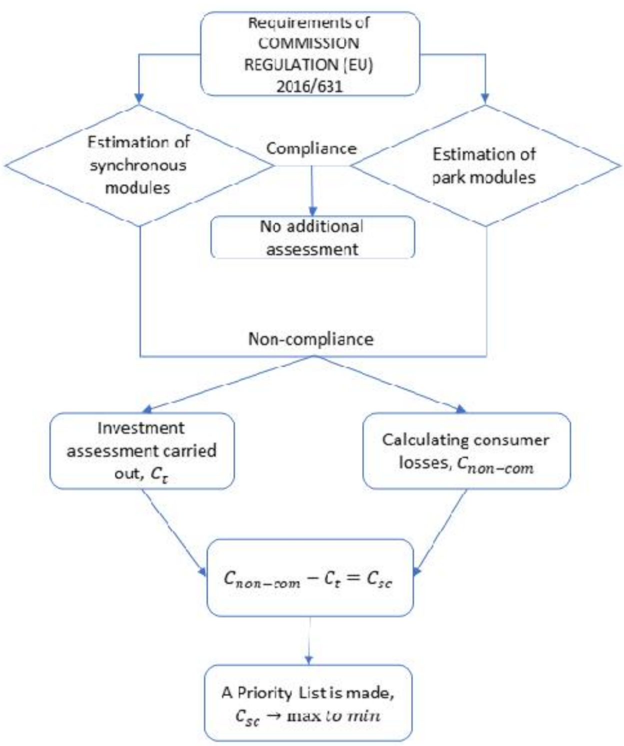

Fig. 1. Structure of the methodology developed.

In order to determine the assessment of the CBA and the investment needs (Figs. 2 and 3), it is necessary to define the objective function – maximising the state costs (Csc).

In order to achieve the objective set in the **first phase**, an investigation into Regulation 2016/631 has to be carried out; each requirement of the Regulation has to be evaluated, and a list of models of types A, B, C and D that must comply with the requirements of the Regulation is drawn up. Two lists are created, for a war-type model, where the SEGM and EPM types are assessed separately. At this stage, the type of each model for each of the requirements of the Regulation has to be assessed as to whether the model complies with the requirement. If the model meets all the requirements of the Regulation, it does not have to be taken into account in the subsequent calculations. If the model fails to meet any one of the requirements, a technical-financial assessment has to be carried out in the second phase.

If the results of the technical analysis of the system demonstrate a mandatory need for the technical development of the installations of the system, the need for investment is inevitable. In such a case, the issue lies in investment financing solutions. Given that electric power supply system members are economic operators, investments inevitably affect the financial performance of their activities. This means that investments must be able to ensure the financial efficiency of the project and the financial viability of the merchant. If the NPV of the project is negative, it is necessary to provide state aid.

On the other hand, if the results of the technical analysis of the system demonstrate alternative possibilities for the technical development of the installations of the system, the need for investment is justified by an economic analysis.

In the **second phase**, a module which does not meet a requirement of the Regulation has to undergo a financial and economic analysis. In accordance with the Regulation, an analysis is carried out, which determines the costs of ensuring compliance of the defined sites with specific requirements of the Connecting Code, the social and economic benefits resulting from the application of these requirements; cost-benefit performance indicators and the sensitivity of the project as a result of hypothetical fluctuations in its potential benefits and costs.

For each of the requirements of the Regulation, an estimate of the amount of investment required has to be made, taking into account the technological design and technical state of the existing electricity generation modules, which have to be determined on the basis of the information provided by their operators and the necessary replacement of existing installations or the setting up of additional new installations, as appropriate. The total required investment estimates for all synchronous and park modules of the type [A, B, C and D] concerned are determined on the basis of the information obtained on their number, capacity and existing technological installations used. On the basis of available information on the costs of the reconstruction of similar types and power plants over the past 10 years and assessing the non-compliance of production modules with the relevant requirements of the Regulation, the necessary investments for the implementation of each individual point are identified.

Many energy companies employ techniques that use the annual costs on the electrical grid:

$$C_t = C_{K,t} + C_{E,t}, \tag{1}$$

where
C_t – annual cost in year t, EUR/y; $C_{K,t}$ – annual capital charge in year t, EUR/y; $C_{E,t}$ – operating costs in year t, EUR/y.

$$C_{K,t} = \frac{i}{100}\sum_{j=1}^{m} K_j, \tag{2}$$

where
$\sum_{j=1}^{m} K_j$ – total capital investments, EUR; i – an interest rate, %; m – the amount of investment from the beginning of the calculation period to year T.

The operating costs consist of two parts:

$$C_{E,t} = C_{Ek,t} + C_{Em,t}, \quad (3)$$

where
$C_{Ek\,t}$ – constant (load-independent) operating costs in year t; $C_{Em,t}$ – annual operating costs of the variable (load-dependent) t, EUR/y; variable (load-dependent) operating costs in year t, EUR/y.

The constant operating costs consist of the depreciation costs of the equipment and the costs of servicing and maintaining (repairing) the equipment:

$$C_{Ek,t} = \sum_{j=1}^{m} K_j * p_a/100 + \sum_{j=1}^{m} K_j * p/100 + C_0, \quad (4)$$

where
p_a – depreciation interest, %; p – interest on servicing and maintenance costs, %; C_0 – rent, taxes, and other constant annual expenses.

The variable (load-dependent) operating costs consist of the cost of power and electric power losses in transformers and lines:

$$C_{Em,t} = C_{\Delta P_L} + C_{\Delta P_{tg}} + C_R, \quad (5)$$

$$C_{Em,t} = \sum \Delta P_L(\tau\beta' + \beta'') + \sum(\Delta P_{tg}(T\beta' + \beta'') + \Delta P_v \left(\frac{S_{maks}}{S_{NT}}\right)^2 * (\tau\beta' + \beta'')) + C_R, \quad (6)$$

where
C_R – costs of reliability of electric power supply, EUR/y, ΔP_L – power losses in the line, β' – electricity loss costs, β'' – power loss costs, ΔP_{tg} – load-independent idling loss, ΔP_v – load-dependent short-circuit losses, T – transformer connection time, h/y; τ – maximum loss hours per year, h/y; S_{maks} – transformer peak load, kVA; S_{NT} – nominal power of transformers, kVA.

The annual costs for selecting project options can be used in two ways:

1. When calculating the net present value for the estimate period:

$$NPV = \sum_{t=1}^{T} C_t * d_t, \quad (7)$$

where
d_t – a discount rate; T – a calculation period in years.

The optimal option is selected at the minimum discounted annual cost (NPV = min).

2. By determining in advance the estimation level (for loads, loss costs, investments, etc.) at which the annual expenditure is calculated. Determining the equivalent level of the θ of the estimated years, it is necessary to take into account changes in load and cost veracity at the time (discounting factor and inflation), and the equivalence of static and dynamic criteria:

$$C_\theta \sum_{t=1}^{T} d_t = \sum_{t=1}^{T} C_t * d_t, \quad (8)$$

where
C_θ – annual cost estimates per year. The optimal option is selected at a minimum annual estimated cost C_θ per year.

The second project option can be selected if no new objects appear during the estimate period. The first project option is more universal, without the limitations that are characteristic of the second project option but it is more labour-intensive, it should be carried out using the relevant computer programs, such as LDM-V and LDM-VZ.

According to the guidelines of the ENTSO-E (European Network of Transmission System Operators for Electricity), the calculation of the benefits is carried out by calculating the total costs of avoiding total regional power outages. The costs are calculated using non-delivered energy, which depends on the average hourly consumption rate, the value of lost loads and the duration of the break [20]:

$$\text{Non}-\text{delivered electricity costs}=\text{VOLL}*\text{consumption}*\text{duration}, \tag{9}$$

where
non-delivered electricity costs are measured in EUR, $VOLL$ – in EUR/MWh; consumption – in MWh/h, duration – in h.

Value of Lost Load. The determination of the VOLL depends on the level of customer differentiation determined by the depth of the study. It should be noted that there is no uniform size for all European countries, it differs significantly from country to country, which is due to a number of factors.

On the basis of the impact assessment criteria, the potential socio-economic benefits of the production module have to be determined for each point of the Regulation for which the model does not correspond (prevention of consumer losses) to $C_{\text{non-com}}$ [EUR/15 years] during the period considered, which has to be determined by the following formula:

$$C_{non-com}=\frac{(N^{a}*M^{b}*S^{c})}{N^{amax}*M^{bmax}*S^{cmax}*10^{3}}*P_N*T_{max}*V*n_a, \tag{10}$$

where
N – the probability factor (assumed at 10). In the case of Latvia, it is 10, in other power systems it may be determined differently depending on the amount of losses caused by the frequency of interruption of power supply; a – the probability level of the effect: low (value 1) – less than once every 10 years; average (value 2) – once a year; high (value 3 (a max)) – more frequently than once a year); M – an impact scale factor (assumed to be 10); b – an impact scale step: local (value 1) – single substations where production is connected module within borders; regional (value 2) – within the limits of one substation and adjacent substations; national (value 3 (b max)) – impact throughout the territory of Latvia; S – an impact factor (assumed to be 10); c – the degree of importance of impact (minor (value 1) – consumers cause interference in the electricity grid but their equipment continues to operate; essential (value 2): consumer operation is disrupted or temporarily terminated, no complete suspension and launch of equipment is required; critical/distinguished (value 3 (c max)): consumer operation is fully suspended and the period of 4 h or more is required for renewal; P_N – nominal active power of the production module, or group of modules, under consideration, MW; T_{max} – the largest number of hours of operation on average in one year, over the past five years; V – the cost of one unit of energy not delivered to consumers, EUR/MWh; n_a – the period considered in years (15 years assumed). The period considered is adopted on the basis of practical data, where every 15 years there is a need for modernisation, reconstruction or other significant changes in activity or investment.

The coefficients M, N and S are assumed to be 10 as the maximum possible coefficient value. The possible value of the factor is between 0 and 10. The ratios are assumed to be 10, as equipment can have a significant impact on the overall functioning of the system as a result of various events. In the assumptions, the ratio 10 is based on the impact of the criterion: 10 – the largest impact, 0 – no impact. The criteria breakdown from 0 to 10 is taken into account on the basis of risk analysis carried out during the modelling process.

In the third phase, after the calculations have been made, for each clause of the Regulation which does not correspond to the model there is a comparison between investment costs (C_{invest}) and non-compliance costs ($C_{non\text{-}com}$) (task No. 3). This results in a value (C_{sc}) that shows how valuable the model is, as well as whether the socio-economic benefits are obtained by reconstructing the model:

$$C_{non-com} - C_{invest} = C_{st}. \tag{11}$$

The evaluation and calculation of all the points of the Regulations for all models have to result in the drawing up of a list of models, starting with the largest Csc models, in order of priority. Such a list is capable of more objectively assessing and identifying which models require investment primarily in order to optimise electricity infrastructure and optimal investment.

3. RESULTS BASED ON THE EXAMPLE OF LATVIA

As part of the study, the use of methodologies for Latvian modules is developed. In accordance with the requirements of the Regulation, all the generating sources installed in Latvia and connected to the power grid, with a capacity exceeding 0.8 kW, are covered within the scope of the study.

The study uses abstract, plant-class-appropriate, standard equipment parameters and economic performance indicators of merchants, as well as available secondary data.

Information on generating sources is obtained both directly from their operators when they receive replies to the information request questionnaires and from the information previously received by the transmission system operator as well as from the publicly available database of the Central Statistical Bureau (CSB).

Given that, by the deadline set for the completion of the study, no information was received from a large number of the producers whereas the total number and capacity of the production plants were known, the output data were extended to all the producers, since the introduction of a requirement of the Regulation would affect all electricity generators and consumers, the related costs and benefits.

Also, taking into account the restrained attitudes of the owners of several production modules towards the provision of output data, for a number of parameters for which no accurate reports or complete questionnaires were received, the output data required within the study were calculated on the basis of similar reporting data from similar power plants as well as the data collected by the Central Statistical Bureau of Latvia and other studies on the techno-economic performance of capacity operations within electricity generation. On the basis of studies [21]– [24], approximate estimates were made for different types of production modules in addition to operating costs resulting from the introduction of the requirements of the Regulation.

The study is based on input data

received for the current situation for 2020, assuming that the Regulation has been applied to all power plants put into service after 31 December 2018 (taking into account the transitional rules laid down in the Regulation).

A summary of information on EGMs (electricity generation modules) based on data received and calculated can be found in Table 2. Since each generation source is considered to be a separate module, it is not detailed in the article in the context of sensitive information.

Table 2. Electricity Generation Modules

Type of module	Number of units, pcs.	Total installed capacity, MW	Total annual electricity output, GWh	Income foregone for electric power unit after implementation of the requirement, EUR/MWh	Additional variable costs assumed for the electric power unit following the implementation of the requirement, EUR/MWh	Fixed additional costs per module after the implementation of the requirement, EUR/module per year
Synchronous modules						
A-type	46	12	68	10.00	0.90	400.00
B-type	119	187	1187	10.00	0.90	600.00
C-type	1	6.3	31	10.00	0.12	900.00
D-type	37	2636.30	5680.35	10.00	0.05	1500.00
Park modules						
A-type	282	50.80	90.60	10.00	1.00	400.00
B-type	20	33.40	58	10.00	1.00	600.00
C-type	1	6.90	10.80	10.00	0.18	900.00
D-type	1	20.7	32.40	10.00	0.15	1500.00

Given that no major new production modules are currently being launched and no plans are in place, if certain low-capacity production modules are introduced, they will play a minor role. In order to ensure stability for the power supply system, it is necessary to apply part of the requirement referred to in the Regulation to the synchronous production modules for Type D production, provided that these requirements do not require inadequate investments (the conversion of primary energy carriers to electric energy and/or the conversion of the power part of generators), provided that these production modules continue to operate long enough after the year 2025 (five and more years). Existing Type D synchronous production modules represent 89 % of the total installed capacity.

On the other hand, the production synchronous modules of types A, B, C and D as well as park modules of types A, B, C and D represent a relatively small part of the power supply system (approximately 11 % of the installed capacity: ~ 320 MW), but their large number (several hundred) poses a risk that their administration might be technically complex and labour intensive, as well as the implementation of the requirements is technically disproportionately complex and therefore the introduction of the requirements of the Regulation for these production modules (existing electrical equipment) is not socio-economically justified. In addition, it should be noted that there is a reduction in capacity in this module segment (closure of modules) due to the government policy of the Republic of Latvia to minimise the production of subsidised electricity (in order to minimise electricity tariffs), particularly in view of the fact that state aid has been fixed for a period of 10 to 20 years and a moratorium on the granting of new rights has been established since 2012 [25].

Consequently, when deciding on the modernisation of existing power plants (rebuilding in line with the requirements of the RfG (Commission Regulation (EU) 2016/631 of 14 April 2016), it should also be taken into account whether improvements are justified for the remainder of plant lifetime.

In addition, it should be noted that a large proportion of these producers work according to the schedules of heat load schedules (combined heat and power plants); available water resources (hydropower plants, 29 MW) or wind (wind power plants, ~ 78 MW), which means that a large part of these production modules are not permanent and their adaptation to the stability of the system is technically difficult.

Although the reporting data show that during the summer months the synchronous and park modules of types A, B and C represent a relatively large proportion of generation, even for a relatively long proportion from the hours of the day, the consumption needs in these periods are mainly met by imported electricity from sources outside Latvia. Consequently, the benefits of applying the RfG requirements to modules of types A, B and C are not relevant during these periods (Table 3).

Table 3. Costs of Existing Electricity Generation Modules and their Socio-Economic Effect over 15 Years, if the Requirements of the Regulation are Introduced

Type of electricity generation modules		Costs of implementing RfG over 15 years, in EUR million	Social benefits of applying the requirements of the RfG over 15 years, in EUR million
Synchronous modules	A-type	3.93	4.82
	B-type	34.37	161.43
	C-type	0.67	15.43
	D-type	106.61	3681.10
Park modules	A-type	22.68	8.44
	B-type	9.88	11.04
	C-type	1.18	4.53
	D-type	2.32	18.66

Comparing the costs of the introduction of the RfG (investment and operational) to existing electricity generation modules (EEGM) over a period of 15 years with the socio-economic benefits of society, the benefits of all EEGM, excluding type A park modules, exceed the costs (Table 4).

Table 4. Investments Needed to Ensure the Eligibility of D-type Modules in EUR (*thousands*)

Number of aggregates (SM)/Modules (PM):	D-type synchronous modules P ≥ 15 MW or 110 kV connection	D-type park modules P ≥ 15 MW or 110 kV connection
Number of aggregates (SM)/Modules (PM)	37	1
Total installed capacity (MW)	2 636.30	20.70
Necessary investments		
F – Frequently defined active power response	12 063.50	461.19
B – Balancing reserves	1 436.26	18.70
Supply of R - jet power:	6 032.20	49.86
P – Overload control	35.50	12.46
a – Protection measures	76 227.19	1 520.81
Category C – other	4 462.30	152.11
Total:	100 256.95	2 215.13

4. DISCUSSION

In theory, there are a number of technical alternatives (Table 5), the implementation of which would ensure stability for the power supply system. Each of these alternatives requires both investment and state funding for their maintenance and there are different risks for both their disposal and operation. These risks are both legal and related to the creation of a partly regulated market with an extremely limited range of competitors, a possible monopoly position with only one supplier participating.

Below follows a list of potential alternatives for solutions which, by applying the Regulation to the limitations and socio-economic benefits of existing electricity generation modules, will ensure that the objectives set out in the Regulation are achieved. In order to ensure the stability of the system, modules are allocated according to capacity and impact on the functioning of the whole system. According to the authors' estimation, the planned capacity demand was calculated on the basis of potential deficit.

Alternative A: Modernisation of Type D synchronous modules ("Big", with a power of 15 MW or with a connection to a network of 110 kV or more); inefficient operation of power plants (irrespective of the timetable for heat load schedules and stock market prices for combined heat and power generation units of 220 MW; 1280 h/year and/or regardless of market prices for hydroelectric power plants); in this case, modernisation would mean the implementation of the requirements of the Regulation, and in addition to ensuring stability for the system, it would be necessary to maintain switched production modules in such modes as to guarantee capacity reserves (primary frequency adjustment (retention) reserves) FCR of +/-10 MW and (automatic frequency renewal reserves) aFRR of +/-30 MW [information from TSOs]. It should be noted that investment is assumed to be implemented in all synchronous modules, but it is likely that these investments may be significantly reduced if one of the existing modules ceases to operate or is fully rebuilt and loses its "existing electrical equipment" status.

In addition, it should be noted that this is the only alternative, which can provide all the necessary technical functions for sound operation of the power supply system.

Alternative B: Construction of a "new" internal combustion engine power plant 12 x 8 MW = 96 MW. Operating 12 MW + 36 MW 1280 h/year regardless of stock market prices; investments of 0.5 MEUR/MW [26]; 96 x 500 = 48 MEUR; fixed operating costs of15 EUR/kW/year and variable costs of 0.5 EUR/kWh [26], which in our case means investment of 48 MEUR and operating costs. This alternative has a number of technical limitations, which do not allow it to be considered as a fully-fledged alternative: (1) a limited operating hour resource of the power plant, which does not permit permanent operation of such a type of power plant; (2) this power plant has to be used as a "cold" reserve, so that it can only provide functions which allow for the supply of additional active power to the electrical power system for five minutes or more within minutes.

Alternative C: Installation of high-capacity batteries; taking into account the permitted discharge levels and reservations of electrochemical batteries, it is estimated that a battery with a capacity of 45 MWh is required for FCR +/-10 MW; an aFRR +/-30 MW battery of 130 MWh is required to provide an aFRR of +/-30 MW. Estimated cost of construction of the above batteries: 14.248 MEUR and 41.924 MEUR, total 56.172 MEUR. The estimated operating costs are related to energy losses and servicing: FCR of 162 767.10 EUR/year and aFRR of 310 400.44 EUR/year. Due to the ageing of battery cells, they should be replaced once in every approximately 2000 full cycles of charge/discharge, which would be every 15 years in the case of FCR and would cost 4.5 MEUR; in the case of aFRR the replacement time would be every 7.5 years and the cost would be 13 MEUR. Nor is this alternative capable of fulfilling all the functions provided by synchronous Type D modules and therefore is not considered to be technically equivalent.

Alternative D: Installation of high-capacity batteries and controlled (harmonised) consumer switching through an aggregate service. As part of this solution, it would be possible to reduce the number of battery charge/discharge cycles per unit of time and thus increase the length of the battery cell replacement interval. As part of this study, it is assumed that such a solution would allow the intervals to be increased twice, respectively, in the case of FCR to 30 years and in case of aFRR to 15 years. This option assumes that half of the charge/discharge energy will be "absorbed" (increased load) and "returned" (reduced load) by consumers. The energy costs would be EUR 80.00/MWh in such a case. There would also be an additional payment for the delegated load of EUR 10.00/MW. The calculations show that this alternative becomes economically competitive when it is possible to "take" and "return" electricity from consumers, at a price close to the average market price of EUR 40.00. This alternative is also incapable of fulfilling all the functions provided by synchronous Type D modules and is therefore not considered to be technically equivalent (Table 5).

Table 5. Technical Alternatives that would Ensure Stability for the Power Supply System

Alternative	Technical solution	Investment costs (million EUR)	Additional operating costs per year (million EUR)	Risks
A.	Modernisation of Type D synchronous modules (with a capacity of 15 MW or connections of 110 kV and above); operation of power plants in inefficient mode (220 MW; 1280 h/year)	100.26	3.04	1. In view of the existence of two such production modules and the need for maintenance on a regular basis, there is a risk that there will be only one production module operating for approximately 720 hours a year, which may participate in frequency adjustment and, in the event of failure, the system may remain without frequency adjustment (n-1 security factor) 2. There is a risk that there will be insufficient competition in the frequency regulating market
B.*	Construction of a "new" internal combustion engine power plant 12 x 8 MW = 96 MW (12 MW + 36 MW, 1280 h)	48.00	2.36	1. There is a risk that there will be insufficient competition in the frequency regulating market, although this will be less than in the case of A 2. A substantial increase in the costs of building a power plant may be possible, which can only be determined more precisely after defining the parameters of the decal and selecting a specific location
C.*	Installation of high-capacity batteries	56.17	2.48 (0.47)*	1. There is a risk that there will be insufficient competition in the frequency regulating market, although this will be less than in the case of A
D.*	Installation of high-capacity batteries and establishment of a demand unit	58.17	3.29 (1.86)**	1. Organisational and legal risks: it may not be possible for a sufficiently large consumer to view and agree on the necessary investments and on a pattern of cooperation within a reasonable period of time 2. Technical risks: a new, relatively large, and complex system must be developed, which has not yet been accredited under the conditions of Latvia

* – Alternatives B, C, and D cannot be considered to be technically equivalent as they cannot technically meet the requirements of Type D synchronous modules set out in the Regulation
** – Costs exclusive of replacement of battery cells 1 x 15 years (FCR) and 1 x 7.5 years (aFRR)
*** – Costs exclusive of replacement of battery cells 1 x 30 years (FCR) and 1 x 7.5 years (aFRR)

In the example of Latvia, it is necessary to carry out a quantitative study on the application of the RfG provisions only for the modernisation of existing Type D synchronous production modules, while also examining alternatives B, C and D as an additional technical means of improving the reliability of power supply. The consideration of alternatives is also desirable given that Type D synchronous modules operate on heat load schedules (combined heat and power plants) or available water resources (hydropower plants), and taking into account the market situation on the electricity exchange (hydropower and combined heat and power generation units in condensation mode or with heat batteries), the continuous operation of these modules involves additional costs or is even technically limited.

Alternatives B, C, D should be used to supplement certain functions to apply the requirements of Type D synchronous production modules for RfG, or additional measures should be included to ensure the stability of the power supply system.

5, CONCLUSIONS

The developed methodology is to help to assess the need for investment in line with the requirements of Regulation (EU) 2016/631. It is assessed by type SEGM or EPM and by type A, B, C or D as regards the active power and its type. This methodology provides the possibility to make the necessary investments in ERM in higher quality and with greater economic benefits, by grouping them according to the effectiveness of the return on investments.

In the case of Latvia, the application of the requirements of the Regulation to Type D synchronous electricity generation modules is socio-economically justified. For other types of production modules, the introduction of the requirements of the Regulation in socio-economic terms is not justified, due to their relatively small impact on the electric power supply system and, in addition, their expected mass decommissioning, which will make the share of these modules even less relevant in the overall producer capacity balance sheet and reduce the expected socio-economic benefits (reducing the efficiency of investments in the RfG). Therefore, in accordance with Article 4 of the Regulation, it is recommended that a thorough and transparent quantitative cost-benefit analysis be carried out in accordance with Articles 38 and 39 of the Regulation for synchronous production modules of Type D.

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ESTIMATING THE BENEFIT FROM INDEPENDENT AGGREGATION IN THE DAY-AHEAD MARKET

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As the EU countries are working on adapting the Electricity Directive to allow independent aggregation (IA) of demand response (DR) in all the electricity markets, this paper provides an assessment of potential benefits from DR in the day-ahead market, which has proven particularly challenging for the IA regulatory framework development. The model devised in this study uses data of the public wholesale market price curve from the Nord Pool power exchange to simulate market clearing results with introduction of certain amounts of DR that, via independent aggregation, competes alongside generation and is able to shift the supply curve. The simulated new market equilibrium point allows estimating price reduction capability of demand response, the total system-wide benefits, as well as analysing the potential remuneration mechanisms for independent aggregators and implications on their business models. While the results demonstrated a high value from DR during the peak hours, the overall benefits during average price periods were rather low, thus exposing the unpredictability of the revenue stream and questioning the business case for IA in the day-ahead market. The proposed approach can be used for further analysis of different IA compensation mechanisms, considering the system-wide benefits it brings to the wholesale market.

Keywords: *Aggregation, compensation, day-ahead market price, demand response, electricity market.*

1. INTRODUCTION

The Directive (EU) 2019/944 on common rules for the internal market for electricity calls for the European Union Member States to "allow final customers, including those offering demand response through aggregation, to participate alongside producers in a non-discriminatory manner in all electricity markets" [1]. Moreover, Articles 13 and 17 of the Directive specify that customers must be able to, without discrimination, establish contractual relations to aggregators who are not affiliated with their electricity suppliers. In essence, this requires setting up the role of an independent aggregator and mandates that such actors must be able to participate in all electricity markets, including balancing and wholesale markets.

While there have been a number of studies dealing with the key issues of independent aggregator participation in balancing markets [2], such as models for independent aggregator (IA) and supplier settlement [3]–[6], baseline calculation for estimating the amount of delivered demand response (DR) energy [7] and even impacts of the rebound effect [8], IA participation in wholesale markets (especially the day-ahead market) alongside energy producers has generally been given less attention in the literature. Some notable exceptions are the studies performed by USEF [5], RAP [9] and SEDC [10]. Nevertheless, this topic is also of utmost importance in the light of implementing the Directive, and the EU Member States are looking for ways to make IA participation in electricity wholesale markets a reality [11]–[13].

Currently, France is a leader in Europe in IA access to markets, being one of the few countries where IAs can also participate in the wholesale market (through the NEBEF mechanism) [14]. However, as pointed out in [15], the assessment on whether the NEBEF mechanism sufficiently enables DR resources to fully participate in the market is mixed, and the rules still need to be adjusted. Moreover, 95 % of the DR sector revenues in France are capacity-related (from ancillary service markets), showing that the energy potential might not be fully exploited in the wholesale market through NEBEF – "while the mechanism is innovative, it does not on its own sustain the aggregators' business models" [15]. One possible adjustment to the mechanism could be a premium paid to IAs reflecting the system-wide benefits brought, sourced from the electricity bills of all consumers. A similar DR-premium approach was already successfully challenged by consumer associations and competition authorities in 2015; however, as argued in [15], provisions set out in the Electricity Directive might reignite the debate.

Nevertheless, in most other parts of Europe, the mechanism for IA participation in wholesale markets has to be built from scratch, including in the Nordic/Baltic region [11], where Nord Pool is the main nominated electricity market operator (NEMO). To establish such a mechanism, information on IA potential impact on the market is necessary. While there are a number of articles studying how DR in general can potentially influence the market price through increased price elasticity of the demand side, to the best of the authors' knowledge, this has not yet been assessed with the independent aggregator role in mind. The key difference here is that the aggregated demand response offered to the market by an integrated aggregator (i.e., retailer) could be expected to affect the demand curve of the market by modifying their demand bids to be more elastic, whereas an independent aggregator who is not its customers' retailer would conceivably participate in the supply side of the market (i.e., by selling 'non-consumption' alongside competing generation). This is a consequence to the way the bids are submitted to the market and afterwards aggregated in the supply and demand curves. The type of the order (buy or sell) is set by the sign of the number representing the bid volume, whereby a negative volume is a sell order and a positive volume is for buy. Consequently, the non-consumption (or consumption reduction) order would have a negatively signed volume and thus would be aggregated to the supply curve.

As a result, the retailer will have purchased some electricity its customers will not consume because of IA-induced DR. To alleviate this issue, a compensation can be envisioned whereby a trade is settled from the retailer to the IA for the DR energy at a certain price. However, if this price is set equal to the corresponding day-ahead price (which would ensure equal treatment of integrated and independent aggregators), this can completely negate any business case for IA participation in the day-ahead market [13]. The Directive, however, does allow for some flexibility in the setup of the compensation system, e.g., by taking into account the socio-economic benefits brought by IA activities [12]. In this study, one such approach has been considered.

The remainder of this paper is structured as follows. Section II outlines the methodology used for the estimation of potential day-ahead price reducing effect from IA participation in the Nord Pool market, making use of actual aggregated supply and demand bid data regularly published by the market operator. In Section III, the results of the assessment are presented, firstly, for a whole study year, and, secondly, for three particular hours discussed as case studies in more detail. Additionally, in this section, the results of a conceivable IA remuneration system are presented. Afterwards, the limitations of this study are summarised and their potential implications outlined. Finally, the conclusions are offered.

2. METHODOLOGY

2.1. Overview

In order to assess the potential impact of independent aggregation on the Nord Pool day-ahead market system price, system price curve data published by the market operator are used in this study. More specifically, the daily market clearing price (MCP) data reports [16] from 2018 have been utilised. These data files contain all price curve points and corresponding volumes, i.e., they do not contain information on individual bids, instead providing the data necessary to construct the demand and supply curves and identify their intersection. Thereby, it is possible to calculate the actual hourly system price, as well as simulate how the MCP would change if the demand or supply curves were modified, e.g., by introducing additional bids in the pool.

In this study, the supply curves for each day-ahead market trading time-step are modified by adding additional supply bids representing IA participation in the wholesale market as direct competitors to electricity generators. The aggregate volume of the additional bids is set equal to a certain percentage of the original market clearing volume for each respective hour, whereas the corresponding bid price is set equal to 0.00 €/MWh to ensure that the bids are accepted (there were no negative system prices recorded in 2018 [17] and a negative bid price for an IA would not be reasonable).

The overall algorithm of the study can be summarised as follows:

1. Download the MCP data report for day number 1.
2. Process the data from the downloaded file to enable its use in simulations. Each daily MCP data report file contains aggregated bid data for 24 hours (except for days with daylight saving time clock changes). Thereby the data need to be separated into hourly categories. Furthermore, the curve points initially only contain single hourly order information; thus, the accepted block order volumes for buy and sell blocks need to be added to the demand and supply curve points. Additionally, the volume for net flows has to be added to the demand curve if it is negative, and to the supply curve if it is positive [18].
3. To check the veracity of the obtained price curves, their intersection point is identified and compared to the known actual system price in the respective hour. Theoretically, these values should match completely or differ only marginally, which could be explained by accumulated rounding errors in the price identification simulation process. More significant differences point to data trustworthiness issues and hours with such deviations ought to be disqualified from further analysis.
   The method used to find the intersection of two curves defined by their points is the Fast and Robust Curve Intersection algorithm as described in [19].
4. If the original system price has been calculated with sufficient accuracy, the system price impacted by a certain amount of aggregated demand response is calculated – firstly, the IA bids are added to the supply curve; and, secondly, the new curve intersection point is found. This is the simulated system price with IA presence. Consequently, the price reduction effect is assessed.
5. The day number is incremented by one and steps 1 to 4 are repeated until day number 365 has been processed. The obtained results are then summarised and assessed.

The analysis of the hourly system prices outlined in these steps is carried out automatically with a dedicated MATLAB code developed for this purpose. Due to the significant volume of data, which need to be read and processed at each time step, the overall time of computation can be quite significant. The calculations for the year 2018 performed for this study took nearly 15 hours on a 2.40 GHz computer with 16.0 GB operating memory utilising task parallelization on eight cores.

2.2. Additional Analysis

From the analysed dataset, three hours have been selected as case study examples for visualization of the price reducing effect, namely: 2018.03.01 8–9 CET (corresponding to the maximum system price of 2018 – 198.27 €/MWh); 2018.06.19 20–21 CET (the average price – 43.99 €/MWh); 2018.10.15 0–1 CET (the minimum price – 2.17 €/MWh).

Moreover, different amounts of the

traded demand response are assessed and a conceivable aggregator compensation system is shown on the basis of these case studies, taking into account the overall reduction in electricity purchase costs, which is a societal benefit IAs can bring by participating in wholesale energy markets. The overall electricity purchase cost reduction is estimated by multiplying the actual and modelled decreased Nord Pool system price with the total energy volume traded at a particular hour in the day-ahead market.

In accordance with the demand response incentivization scheme proposed in [20], in these calculations, the IA does not receive direct remuneration for the non-consumption sold as generation (implicitly, this remuneration is used to compensate the suppliers affected by the IA who have otherwise purchased energy they cannot sell to the intended customers). Instead, the IA is remunerated for the provided DR energy at a price derived from 1/3 of the total system-wide savings resulting from the reduced market price.

3. RESULTS AND DISCUSSION

3.1. Simulation Verification

At this point, the first three steps of the overall algorithm described in Section 2.1 are performed. It is found that from the 8760 hours modelled, for 7740 of them (i.e., 88.36 %), the modelled Nord Pool system price is exactly equal to the actual recorded price. In Table 1, the differences in the remaining hours are summarised.

Table 1. Hours with Errors in the Modelled Year

	Error (€/MWh)					
	> 0.00	**> 0.01**	**> 0.02**	**> 0.05**	**> 0.10**	**> 0.50**
Numb. of hours	1020	439	126	47	38	14
% of hours	11.64 %	5.01 %	1.44 %	0.54 %	0.43 %	0.16 %
Average error (€/MWh)	0.02	0.06	0.20	0.54	0.66	1.75

Evidently, the MCP identification model is overall well suited for calculating the Nord Pool day-ahead market system price using the aggregated demand and supply curves published by the market operator. For 11.64 % of hours, there are deviations from the actual market price, but only for 0.16 % of all the hours these deviations exceed 0.50 €/MWh. The average error is equal to 0.02 €/MWh. Curiously, the largest differences in the modelled prices are observed for 2 January 2018 (maximum error – 3.65 €/MWh and only the first six hours of the day were modelled correctly). The calculation mismatches from this day heavily skew the overall error statistics.

Overall, while the minor differences up to the average error of 0.02 €/MWh could be explained by accumulated rounding issues in the price identification algorithm or the post-processing of the results, larger mistakes in the remaining 126 hours are harder to explain and possibly point to input data quality issues. Unfortunately, the authors do not have information which would allow rectifying these issues, thereby all the hours where the simulation error exceeds 0.02 €/MWh are excluded from the further analysis to maintain integrity of the results. These discarded data-points comprise generally average-level price hours (in the range of about 24–67 €/MWh) and thus their exclusion is not expected to significantly affect the results.

3.2. Demand Response Induced Price Reduction Simulation

In the remaining 8634 hours that have been verified as having sufficiently trustworthy original price curve data, the fourth step of the overall algorithm is carried out by introducing an additional supply bid to the price curve from IA equal to 1 % of the original market clearing volume at each hour and recalculating the resulting reduced Nord Pool system price. It is assumed that the IA bid price is 0.00 €. Consequently, the potential price reduction at each modelled hour can be quantified.

Overall, within the assessed hours, the average price reduction is equal to 0.98 €/MWh with the median being 0.38 €/MWh, whereby the minimum identified reduction is 0.07 €/MWh and maximum – 78.35 €/MWh. As can be discerned from Fig. 1, the price reducing effect is generally quite modest, i.e., in 63.02 % of the hours, it is less than 0.50 €/MWh, and only in 0.47 % of the hours it is equal to or exceeds 4.50 €/MWh.

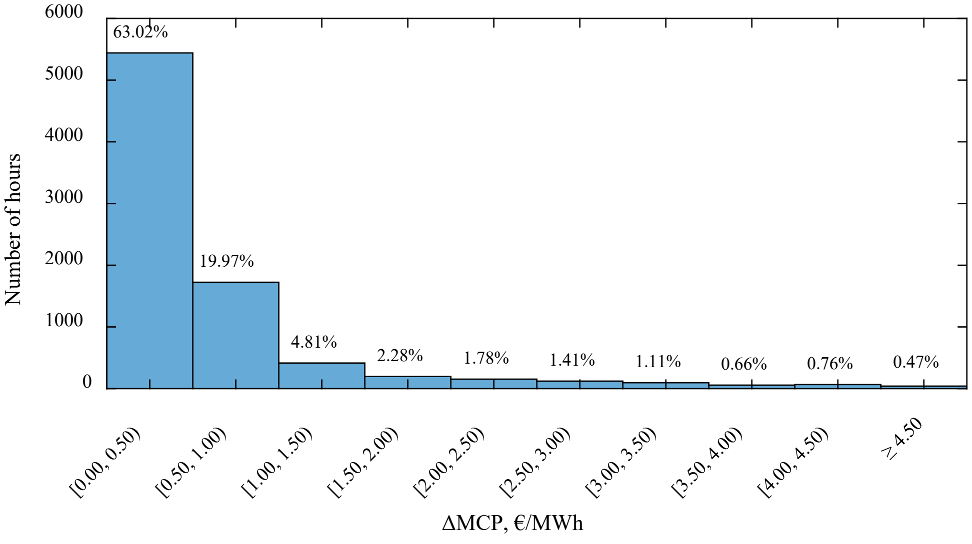

Fig. 1. Histogram of the price reduction effect achieved with 1 % DR.

Figure 2 illustrates the correlation of the price reduction effect to the original Nord Pool system price. As can be seen on the x-axis of the figure, very high system prices are quite exceptional. There are four points which are noticeably distant from the rest of the data, with the yearly price maximum being a clear outlier (at the top-right corner of the chart).

Evidently, the simulated price reduction is higher when the original price itself is high. However, there is another cluster of reductions significantly above the average when the original price is about 20 €/MWh.

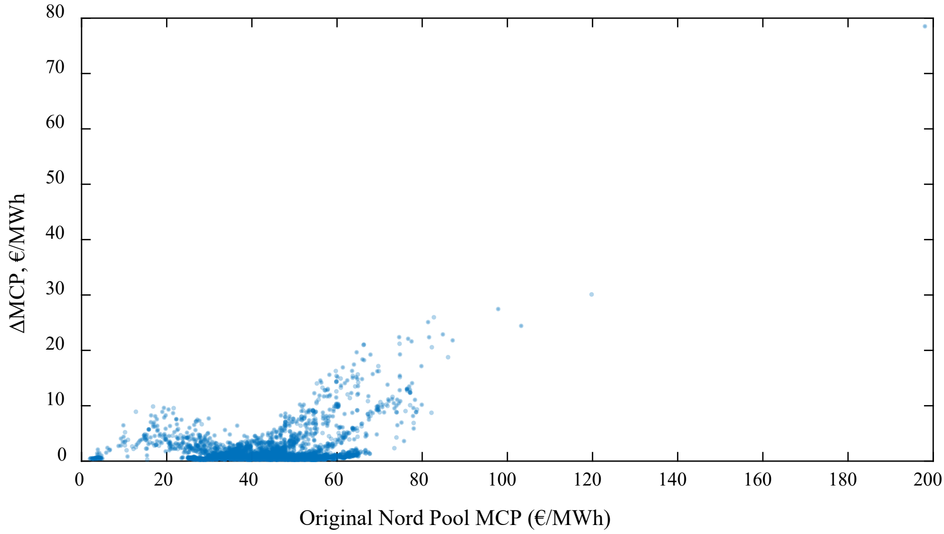

Fig. 2. Price reduction vs original system price (1 % DR).

3.3. Particular Examples

In this subsection, three particular hours from the simulated year 2018 are presented in more detail, also explaining visually the demand response induced wholesale price reduction if IA offers compete with generators on the supply side of the market. In Figs. 3–5, the blue line indicates the demand curve, the orange line indicates the original supply curve, and the yellow line indicates the appended supply curve, which includes the IA offers of aggregated demand response. As expected, as a consequence of the additional offers, the supply curve gets shifted to the right. In the figures, the left charts show the full demand and supply curves, whereas the right charts are zoomed in on the intersection points, which identify the original and the reduced MCP. In these figures, the energy volume of IA offers is set equal to 1 % of the original market clearing volume.

On the other hand, in Tables 2–4, this volume varies from 0.01 % to 5 %. Additionally, in these tables, the price reduction in each case is quantified together with the corresponding hypothetical decrease in the total electricity purchase cost in the Nord Pool.

For the maximum system price case (2018.03.01 8–9 CET), the results are shown in Fig. 3 and Table 2. Evidently, quite significant price reductions can be achieved in this case even with relatively modest amounts of DR energy (e.g., 14.72 €/MWh price reduction with 0.1 % / 62.97 MWh of DR). With a large DR volume (e.g., 5 % / 3.2 GWh), the price can even be reduced to a nearly average level – 49.14 €/MWh in this example.

Table 2. System Price and Total Cost Reduction with Various DR Amounts (at max. price)

DR, % of volume	**0.01 %**	**0.05 %**	**0.10 %**	**0.50 %**	**1.00 %**	**5.00 %**
DR, MWh	6.30	31.48	62.97	314.84	629.68	3148.40
MCP_{new}, €/MWh	198.22	183.55	180.07	177.22	119.92	49.14
ΔMCP, €/MWh	0.05	14.72	18.20	21.05	78.35	149.13
Total cost reduction, €	2 879	926 607	1 145 861	1 325 619	4 933 706	9 390 477

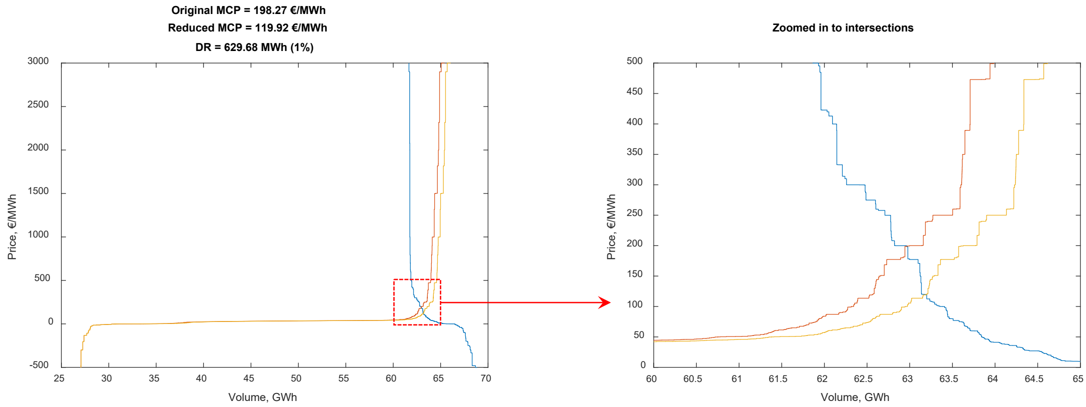

Fig. 3. Modelled market equilibrium at the maximum system price and 1 % DR.

For the average system price case (2018.06.19 20–21 CET), the results are shown in Fig. 4 and Table 3. Here the price reductions are significantly lower, even miniscule (e.g., with a fairly large volume of DR equal to 1 % of the total traded energy, the resulting system price decreases by only 0.15 €/MWh). However, this is well in line with the previously shown results for the whole year. As already concluded from Fig. 1, in the vast majority of hours in the year, the price reduction with 1 % DR is in the range of only 0.00–0.50 €/MWh. Moreover, with relatively low DR volumes (0.01–0.1 %), price reductions are barely attainable at all.

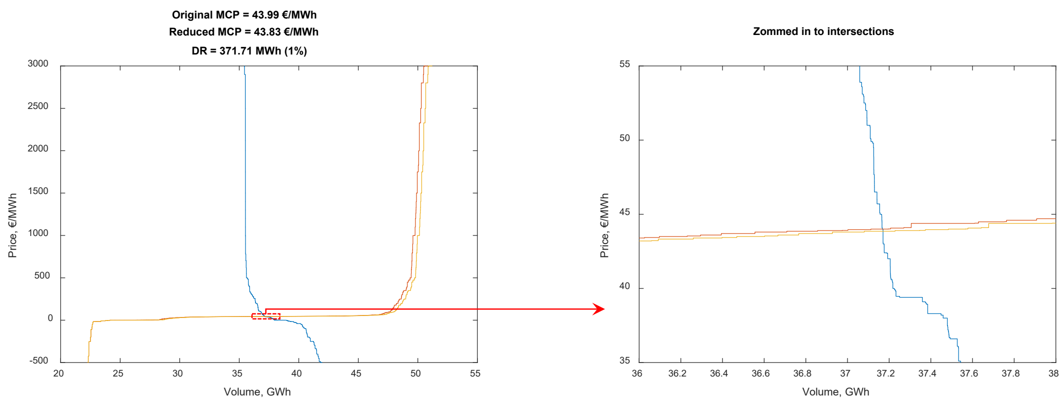

Fig. 4. Modelled market equilibrium at the average system price and 1 % DR.

Table 3. System Price and Total Reduction with Various DR Amounts (at average price)

DR, % of volume	**0.01 %**	**0.05 %**	**0.10 %**	**0.50 %**	**1.00 %**	**5.00 %**
DR, MWh	3.72	18.59	37.18	185.85	371.70	1 858.53
MCP_{new}, €/MWh	43.99	43.98	43.97	43.90	43.83	42.97
ΔMCP, €/MWh	0.00	0.01	0.02	0.08	0.15	1.02
Total cost reduction, €	0	316	632	3 125	5 743	37 807

For the minimum system price case (2018.10.15 0–1 CET), the results are shown in Fig. 5 and Table 4. Counterintuitively, in this case, the price reducing effect is more pronounced than in the average system price case. This can to some extent be explained by the fact that, in this case, the original market equilibrium point happened to be in the vicinity of several major steps in both the demand and supply curve. This can be well seen in the zoomed section of Fig. 5. Nevertheless, a general effect of DR having more notable price reduction capacity when the original system price is low could not be observed and, mostly, the opposite is true as shown in Fig. 2.

Another important point regarding this case study is that, in general, it is quite unrealistic in terms of aggregator willingness to bid at such a low price. However, it does serve well in showing the theoretical effect for comparison purposes.

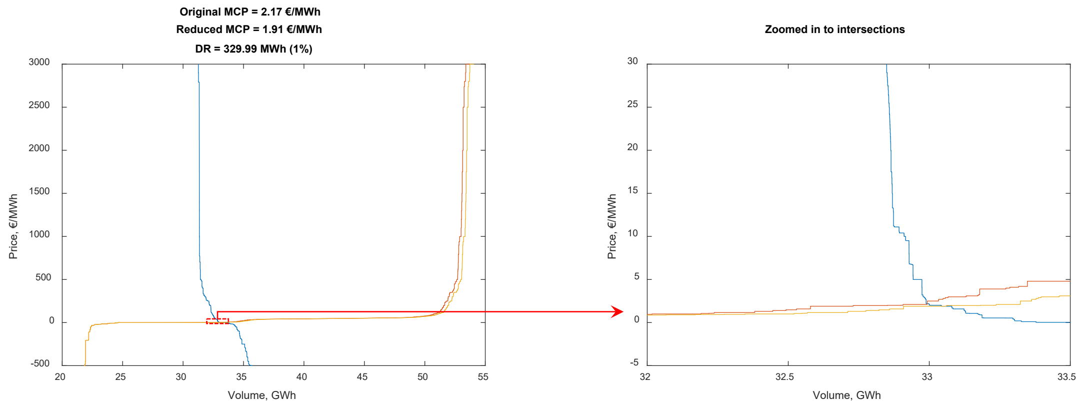

Fig. 5. Modelled market equilibrium at the minimum system price and 1 % DR.

Table 4. System Price and Total Cost Reduction with Various DR Amounts (at min. price)

DR, % of volume	**0.01 %**	**0.05 %**	**0.10 %**	**0.50 %**	**1.00 %**	**5.00 %**
DR, MWh	3.30	16.50	32.00	164.00	329.99	1 649.96
MCP_{new}, €/MWh	2.15	2.10	2.08	1.99	1.91	0.81
ΔMCP, €/MWh	0.02	0.07	0.09	0.18	0.26	1.36
Total cost reduction, €	882	2 587	2 996	6 080	8 652	45 125

It follows from both the whole year analysis and more detailed particular hour case studies that DR direct participation (on the supply side, via independent aggregators) in the Nord Pool market does not significantly affect the system price if it initially (i.e., without IAs) is small or even at about the average price levels. This verifies the conclusion from [21], whereby, using different methodology (multivariate adaptive regression spline), and focusing specifically on the Latvian bidding area of Nord Pool, it was found that for hours with average consumption, costs of energy production changed little with 1 MWh shift in consumption, because the production cost curve was relatively flat in this region.

However, when the initial prices are high, the potential price reducing effect becomes more pronounced. Still, it takes very high amounts of DR to drive the price from maximum to close to average.

The reasons can be well understood by studying a typical electricity wholesale market supply curve (Fig. 6). If the demand curve crosses the supply curve in the region marked by the green dashed line, then, quite obviously, even fairly small shifting of the curves (along the x-axis) can cause notable change in the market equilibrium i.e., the market clearing price. On the other hand, if the curve intersection is within the comparatively flat region marked by the blue dashed line, shift along the x-axis can only cause a considerably smaller price change effect.

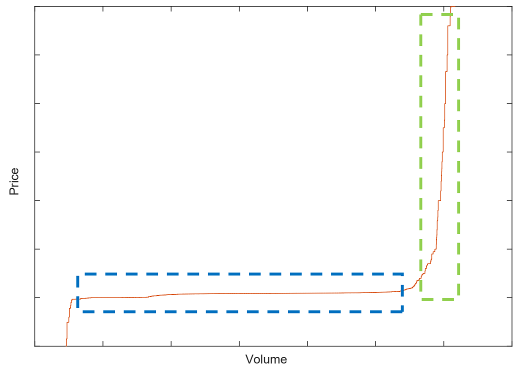

Fig. 6. Typical electricity wholesale market supply curve.

3.4. IA Compensation Based on Socio-Economic Benefit

It follows from the results presented in the previous subsections that the participation of aggregated DR in the electricity wholesale market has some capacity to reduce the market price and consequently the total electricity purchase cost. This would bring direct benefit to all the retailers who procure energy on the wholesale level, as well as to those consumers who have dynamic electricity tariffs (i.e., tied to the hourly day-ahead price). The retailers can be expected, in time, to pass some of this accrued benefit down to also those clients who have fixed price tariffs, thereby disseminating to consumers the overall socio-economic benefit created by IAs in the form of reduced electricity prices.

However, those retailers who have customers in their portfolio engaged with independent aggregators could be placed in unfair position compared to competitors whose clients are not affiliated with any IAs (because of the purchased/forecasted but unserviceable energy). If this issue is alleviated similarly as how has been proposed for IA participation in balancing markets (via compensation set at the day-ahead price) [11], the net position of IAs is equal to zero. Thereby, to not discourage IA participation in the day-ahead market, alternative solutions need to be identified.

Table 5 quantifies the benefit per unit of energy the IAs could be entitled to if a similar remuneration scheme as in [20] were to be applied – by sharing part (1/3) of the total cost savings with the IAs presumably responsible for the overall cost reduction (i.e., taking into account the system price reduction and the total energy traded in the Nord Pool day-ahead market at the respective hour). It is implied that the IAs would have to share this remuneration also with the customers they are aggregating to incentivize their engagement in direct demand response.

The potential remuneration in the average price case is quite small (5–7 €/MWh) and likely insufficient for a viable business case of independent aggregator participation in the Nord Pool day-ahead market. Even though, in the minimum price case, the theoretical compensation is noticeably larger, as discussed previously, DR during low price periods is unlikely. However, in the maximum price case, the remuneration per unit of energy is quite significant, albeit it tends to decrease if the volume of DR energy in the market grows considerably.

Table 5. Potential Remuneration to IAs Participating in the Day-Ahead Market

DR, % of volume	**0.01 %**	**0.05 %**	**0.10 %**	**0.50 %**	**1.00 %**	**5.00 %**
Remuneration to DR providers, €/MWh:						
The maximum price case	152.33	9 811.60	6 065.65	1 403.48	2 611.75	994.21
The average price case	0.00	5.67	5.67	5.60	5.15	6.78
The minimum price case	89.09	52.26	31.21	12.36	8.74	9.12

Overall, the results presented point to the potential value of independent aggregator participation in the day-ahead market specifically as actors aiming to benefit from their ability to reduce exceptionally high market prices. While there are relatively few hours annually when the system price is significantly above average levels (Fig. 2), the very high specific (per unit of DR energy) benefit obtainable in such cases could point to a potentially feasible business model. However, further studies would be necessary to evaluate it, also taking into account the costs associated with independent aggregator operations.

3.5. Study Limitations and Discussion

The results presented in this paper have to be interpreted in conjunction with the limitations inherent in the design and input data of the study. Most importantly, the market clearing simulations and the consequent assessment of potential for price reductions is based solely on the Nord Pool system price. In reality, because of congestions in the interconnections between various bidding zones, the actual market clearing price in the various bidding zones differs from the system price. Unfortunately, the publicly available bidding data published by Nord Pool are aggregated for the whole market and do not distinguish bids based on the bidding zone where they have been placed. Thereby, there is insufficient information to employ these historical bid-based data to perform price identification in specific bidding zones. It could be hypothesised that IA direct participation in the wholesale market might be most valuable in times when due to interconnector congestions there are exceptional price peaks in bidding zones with structural generation shortages.

Another limitation of the price recalculation approach used in this study is that it does not consider the potential impact of demand response on the market flows to and from bidding areas neighbouring the Nord Pool zones. In other words, the net flows to other areas are assumed independent from DR volume. Similarly, potential impacts of block bid peculiarities (e.g., paradoxical rejections) are not considered, since the data available do not allow for that, and neither are any potential impacts on the bidding behaviour of other market participants taken into account, although that can be expected to not be overly pronounced. Moreover, price recalculations were based solely on historical data, disregarding potential future evolution in the production and consumption structure in the region.

Furthermore, the total benefit (in the form of cost reduction) based approach to IA remuneration assessed in Section 3.4 has certain challenges which would need to be overcome for this model to be practically applicable in the Nord Pool areas. Firstly, the entity administering IA settlement and remuneration would need to have the technical capability to calculate (or a regulatory capability to request from market operators) the MCP (i.e., rerun the market clearing algorithm) in a counterfactual case without IA participation, to accurately assess their contribution to price reduction and consequent remuneration. As pointed out by [22], such recalculation can be extremely costly: "it requires definition of the methodology, data collection and analysis, sending the information to stakeholders, sending and paying invoices, all of which will be paid for by consumers". Moreover, DR deployed in one country would inevitably also bring some market price reductions in other countries because of market coupling. Thereby, such a remuneration mechanism would need coordinated and harmonised actions of the responsible authorities of many countries. The solution to this issue could prove even more challenging in a multi-NEMO environment. These issues are not as relevant in situations where the market is run by a centralised entity also responsible for the settlements and without significant market coupling to neighbouring countries, such as the case in Singapore from where the proposed remuneration scheme is sourced [20]. Furthermore, introduction of premiums to DR aggregators formerly proposed in France for residential DR has been heavily criticised as offering unjustifiable subsidies, inviting market manipulation, and aggregator's direct participation in the wholesale market being altogether an inherently flawed business model [22], [23].

Nevertheless, national regulations regarding IA participation in wholesale markets is only part of the overall IA regulatory framework, which needs to be developed in each EU Member State in line with the Clean Energy Package [24], [25]. On the other hand, Article 59 of the Regulation on the internal market for electricity [26] empowers the European Commission to establish network codes in a number of areas, including the rules on aggregation. Such an approach would aid in the creation of harmonised IA frameworks across the EU.

4. CONCLUSIONS

The devised method demonstrated a very good accuracy in simulating the system-wide market clearing price and volume based on the public day-ahead market data available from the Nord Pool power exchange. While in this study the approach was employed for evaluating the potential impact of load-reducing demand response participation in the market, it could also be used for studying other wholesale market operation aspects in the Nordic-Baltic region based on the system curve data.

The impact of DR was simulated for the year 2018, which included both very high and very low prices occasionally. It was assumed that independent aggregation of DR participated in the market alongside generation, offering load-reducing demand response with a volume equal to 0.01–5 % relative to the original market clearing volume. Case studies with 1 % of DR were analysed in more detail. Over the whole year, DR addition of 1 % in most cases (63 %) reduced the price by less than 0.50 €/MWh. The price decrease was larger than 1 €/MWh only in 17 % of the simulated hours.

However, quite significant price reduction was achieved for the maximum system price case, even with modest amounts of DR energy provided: namely, the price reduced by 78.35 €/MWh with 1 % DR, and overall the price decrease varied between 14.72…149.13 €/MWh with 0.05…5 % of DR. These results imply that DR might be particularly useful with extremely high market prices or during generation scarcity when the system-wide benefits from DR participation are the highest.

When studying the potential compensation to the independent DR aggregator based on a model whereby 1/3 of the total system-wide savings is distributed among DR providers, the remuneration per unit of DR energy varied a lot among the different case studies. For the maximum price case, the largest remuneration (9811.60 €/MWh) was achieved with 0.05 % of DR. However, it tended to decrease with larger penetration of DR implying self-cannibalization. For the average system price case, the compensation for DR energy was always less than 7 €/MWh, likely indicating overall insufficient revenue for a viable business case. In contrast, with the lowest system price, the payments for DR were much larger varying between 9…89 €/MWh.

As the EU Member States need to accommodate independent aggregation in all their electricity markets, one of the key issues is a reasonable, fair and non-discriminatory compensation mechanism between independent aggregators and other market participants. To that end, the approach presented in this paper could be useful for assessing the impact of different policies and regulation on the IA business models, considering also the societal benefits brought about by independent aggregation and demand response as suggested by the EU Electricity Directive. One promising direction for the future work is consideration of the social welfare increase as opposed to electricity cost reduction as the main benefit and assessing how various compensation levels could affect that.

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MODELLING THE FUTURE OF THE BALTIC ENERGY SYSTEMS: A GREEN SCENARIO

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The electricity sector in Europe and in the world is undergoing rapid and profound changes. There is a sharp increase in the capacity of renewable energy sources, coal and nuclear power plants are being closed and new technologies are being introduced. Especially rapid changes are taking place in the energy systems of the Baltic States. Under these conditions, there is an emerging need for new planning tools particularly for the analysis of the power system properties in a long-term perspective. The main contribution of this article lies in the formulation and solution of optimization problems that arise when planning the development of power systems in the Baltic States. To solve this problem, it is necessary to use models of various power plants and make a number of assumptions, the justification of which requires the following actions: to briefly review the current situation of the production and demand of energy in the Baltic power systems; to conduct an overview of the Baltic interconnections and their development; to make forecasts of energy prices, water inflow, energy production and demand; to set and solve the problems of optimization of power plant operation modes; to demonstrate the possibility and limitations of the developed tools on the basis of real-life and forecast data. In this paper, a case study is performed using the main components of the overall modelling framework being developed. It focuses on the Baltic power systems in 2050 under the conditions of significant expansion in the installed capacity of renewable energy sources (RESs) and diminished fossil fuel power plant activity. The resulting electricity generation mix and trade balance with neighbouring countries is assessed, showing that even with significant RES expansion, the Baltic countries remain net importers and because of the intermittency of RESs, there are hours within the year when the demand cannot be met.

Keywords: Modelling, power system planning, solar energy, the Baltic States, wind energy.

1. INTRODUCTION

The efforts of the European society towards increasing power supply efficiency and diminishing the impact on climate change (according to the EU Directive 2018/1999) have brought about significant changes in the generation and distribution of energy: rapid changes are observed in the number of renewable energy sources (RESs), their capacity and their share in the amount of energy produced; the role of combined heat and power plants has increased; country-to-country connections have improved [1]; steam-gas technologies have been developed, which form the basis of constructing high-capacity combined heat and power plants; smart grids, smart measurements and Internet technologies with the possibility of two-sided control have been developed, as well as distributed generation, energy accumulation systems. There have been rapid and significant changes in energy demand, prices, and standards.

A considerable increase in the capacities of wind and solar power plants is expected in Europe and worldwide. According to a report by the Global Wind Energy Council [2], the global share of wind energy has increased more than fiftyfold over the recent twenty years. Also, much attention is devoted to solar power, which is testified to by 200 GW of installed capacity in 2019. This is almost twice as much as the total capacity of wind power installations [3]. According to IEA prognosis [4], the total wind and solar capacity will double, expanding by 1 123 GW between 2020 and 2025. Combined wind and solar PV generation is to nearly double to slightly above 4 000 TWh over the forecast period.

Considerable changes are taking place in the power industry of the Baltic States. For example, the power transmission network development plan for the Baltic States till the year 2025 is beginning to be implemented. This plan is mainly concerned with a project for synchronising the Baltic electric power systems with the Continental European Network (CEN) and abandoning synchronisation with the Russian unified electric power system [5]. Thus, this project will ensure greater security of supply to consumers in the Baltic States.

Fundamental changes are planned in the energy supply of transport in industry and households. Its electrification is expected and, accordingly, a sharp increase in electricity consumption is forecast.

A significant factor that characterises the state of the Baltic power system is the planned shutdown of several power plants (PPs). Considering the sustainable development strategy goals of each country, it is planned that most of PPs operating with fossil fuel will be decommissioned by 2030 since they are unable to ensure compliance with the requirements to diminish the emissions of greenhouse gases [6], [7]. The above requirement can be met by reorientation to RESs.

At present, several new RES projects have been implemented in each country [7], [8]. Notwithstanding the rapid increase in the RES capacity and in the amount of electricity produced, the import/export balance of Lithuania and Latvia has been becoming increasingly negative over the recent years [9]. Moreover, it is expected that the consumption of electricity will continue to increase due to the electrification of the transport system, the use of electric power in heat supply, households and the industry [1]. This means that the situation regarding balance may deteriorate even more. In order to ensure future import/export balance in the Baltic States, an acceptable balance between the power supply and power consumption, the required level of reliability, stability and sustainability, diminished emissions into the atmosphere, and accessible energy prices, considerable and rapid further changes in the structure of power systems are to be expected. Considering all of the above factors in the development of the power system of the Baltic States, there is a need for the analysis of power system adequacy for several years to come.

It can be said that the society aims at developing the power systems so that they meet various limitations and are optimal from the point of view of achieving the set goals. The above goal makes it necessary to solve an extremely complicated optimization problem since the operation and development of the power system involves a vast number of participants. Their goals do not always coincide, the decisions of the participants are made for uncertain future conditions; the efficiency of the actions of each participant depends on natural factors and the actions of other participants. The plans of the partners are not always known. To support decision-makers, effective instruments are needed that are capable of the following: 1) forecasting of the impacting processes for years ahead; 2) choosing technologies, their parameters and modes. It is the formation and approbation of a decision support tool (DST) that the present article is devoted to.

A large number of different DSTs and models are used for various power system analysis and planning tasks. Comprehensive reviews of such tools are given in articles [10]–[12]. The most publicly available and commonly used ones are the powerful MARKAL and TIMES modelling tools. These DSTs use an objective function, which is formulated as minimisation of the total cost of all generators and consumers, or in some cases maximisation of social welfare. The above instruments are based on the use of a huge linear programming algorithm, due to which they are able to solve problems containing many thousands of decision variables. This is a major advantage. Unfortunately, the method of setting the objective function makes it necessary to solve large-scale problems that include all participants of the electricity market (generators and consumers of a large geographical region). In this case, there are significant difficulties in collecting the necessary input information. In addition, there are limitations determined by the use of linear programming and a deterministic problem statement. These limitations are overcome by using the tool described in [12], which represents a highly adaptable energy system modelling framework, Backbone, and also minimises the total costs of energy supply.

Summarising the information presented in the publications devoted to decision support tools in modelling the development of power systems, we can conclude that there is a large number of ways and models to solve this problem. However, for the needs of the present study the summation of all costs is considered as not the most suitable solution for modelling the development of the Baltic power system. In real life, everyone is looking for their own benefits. Under the energy market conditions, a more appropriate objective for individual participants is the maximisation of their separate expected profits or minimisation of the expected costs. Based on individual preferences, the operating modes of the equipment are selected and bids for the generation and demand of energy in the day-ahead market are formed. Only after that does the market operator identify the equilibrium point of supply and demand, the price of energy and the operating mode of each player. Therefore, the solution to the problem of determining the state of the market consists of two stages: 1) formation of participants' proposals; 2) determination of the market equilibrium point. The main contribution of this article lies in the use of these two stages in the formulation and solution of optimization problems that arise when planning the development of the power systems of the Baltic States. To solve this problem, it is necessary to use models of various power plants (hydropower, solar, wind, cogeneration, storage plants) and make a number of assumptions, the justification of which requires the following actions: to briefly review the current situation regarding the production and consumption of energy in the energy systems of the Baltic States; to conduct an overview of Baltic interconnections and their development; to make forecasts of energy prices, water inflow, energy production and consumption; to set and solve the problems of optimization of power plant operation modes; to demonstrate the possibility and limitations of the developed tools on the basis of real-life and forecast data.

The rest of the article is organised as follows: Section 2 describes the energy infrastructure of the Baltic States and their neighbours; Section 3 considers the development plans of Baltic and neighbouring countries' energy systems; Section 4 is devoted to the methodology, models, constraints and the forecast process; Section 5 contains a description of the initial data and assumptions, as well as reflects the results of the calculation of energy balance of the Baltic States in 2050; the last sections are devoted to conclusions and discussion.

2. THE ENERGY INFRASTRUCTURE OF THE BALTIC STATES AND THEIR NEIGHBOURING COUNTRIES

The total installed generation capacity of the electric power sources in Latvia is about 3 000 MW, which is made up by the following: the Daugava Cascade hydropower plants (1558 MW); two Riga combined heat and power plants (1025 MW); natural-gas-operated combined heat and PP of small producers (140 MW); RES electric power plants of small producers (270 MW). The amount of electricity produced from RESs has been steadily growing since 2017.

In Lithuania, the share of RESs in the total electricity generation is 64 %. Still the ability to meet the needs with the electricity produced in the country has been very low. In 2019, wind power was the most widely used RES for generating electricity [13]. In order of importance, the next most important RESs are biomass, biogas and solar power. However, notwithstanding the rapid increase in the capacities ensured by RESs, the import/export balance of the Lithuanian electricity trade has been becoming increasingly negative over the recent years [9]. The Lithuanian power transmission system is closely interconnected with the neighbouring power systems. The capacity of the LitPol direct current interconnection between Lithuania and Poland is limited by the capacity of the substation (500 MW). The maximum transmission capacity of the already operating high-voltage direct current NordBalt interconnection with Sweden is 700 MW.

Due to the use of oil shale, Estonia has a high degree of energy self-sufficiency [14]. The structure of electricity generation sources shows that the share of RESs has considerably increased over the past decade. The Estonian electric power transmission system is well interconnected with the power systems of the neighbouring countries. The interconnection with Finland consists of two direct current cables (Estlink 1 and Estlink 2, the total capacity is 1.05 GW). In 2018 and 2019, the import and export amounts of Estonia diminished considerably.

There has been no significant upward trend in consumption in Finland over the past fifteen years. However, the importance of wind energy has grown significantly.

In Sweden, the capacity of hydroelectric and nuclear power plants has been virtually constant for more than twenty years, but the capacity of wind farms has grown rapidly.

As for Poland, the bulk of the installed capacity of its power plants is constituted by bituminous coal and brown coal power plants. The amount of electricity generation exceeds the consumption, although this tends to gradually become less considerable [15].

3. OVERVIEW OF POWER SYSTEM DEVELOPMENT PLANS IN THE BALTIC REGION

When drawing up the future development scenarios of the Latvian power system, it has to be taken into account that RES development, mainly in the form of wind farms, both onshore and offshore, is already actively taking place in the Baltic Sea region. Development of regional wind farms is also on the list of EU priorities. For instance, Estonia and Latvia's planned 1 GW Gulf of Riga offshore wind farm could be Europe's first cross-border project of its kind and pave the way for future co-operation in large-scale offshore renewable capacity. This Estonian-Latvian offshore wind farm will compete with the Lithuanian 700 MW facility planned for 2028 to become the first one built by the Baltics [16]. The Estonian-Latvian offshore wind farm would have a capacity of up to 1 000 MW and it is expected to be completed in 2030 [17]. Latvia and Estonia are actively developing their power transmission networks to make it possible to connect this kind of wind farms to the power transmission grid in the future. For example, it is planned to reconstruct two of the existing Latvian–Estonian interconnections from Valmiera in the territory of Latvia, increasing the transmission capacity of the lines by 500/600 MW. Also, the 3rd Latvia–Estonia interconnection was completed and commissioned at the end of 2020 [18].

There is one more powerful pilot project in Lithuania, namely, an experimental floating PV (FPV) power plant project at Kruonis pumped storage hydropower plant reservoir. According to initial calculations, the synergy of Kruonis and FPV modules would generate enough electricity to supply more than 120 000 households yearly [19].

However, due to environmental requirements, a number of generating units of the Narva PP complex (Estonia) are to be shut down in the nearest years. Thus, by 2023, there is to be a capacity drop by 501 MW and another one of 700 MW – by 2031 [6].

The capacity of the LitPol Lithuania–Poland direct current interconnection is limited by the capacity of the substation (500 MW). It is planned to expand it to 1000 MW and set up one more interconnection with Poland, using an underwater cable in the sea (the Harmony Link project, capacity: 700 MW) [20].

Estonia is planning to achieve RES augmentation not only by developing wind farms and expanding the use of biomass (wood) energy but also by building pumped storage hydropower plants (PSHPPs). At the 500 MW PSHPP planned in Paldiski municipality, the bottom reservoir is to be located deep under the ground. The construction of the plant is to be started in 2022 and it could start operating in 2029 [21].

At the moment, "Eesti Energia" (Estonia) is constructing a number of solar power plants with a total capacity of 7 MW and is planning to increase their capacity by 50 MW by the year 2022 [22]. In the long term (after 2035), Estonia does not rule out the construction of a nuclear power plant so as to replace the capacities lost after shutting down the oil shale power plants. This plant could be located near Narva, which would make it possible to use the existing transmission networks. The capacity under discussion is above 300 MW.

Finland is planning to gradually shut down coal-powered combined heat and power plants by 2030 and provide financial support to those power plant operators who will change over to efficient biomass cogeneration and new heating technologies already by 2025. Upgrade and development of nuclear power generation is planned. It is envisaged to build a power transmission line to Sweden (800 MW) by 2025.

In Sweden, there is one more planned interconnection: a HVDC line connecting the southern part of Sweden with Germany. The planned capacity is 700 MW.

The Polish national energy and climate plan provisions building nuclear power plants in the 2030s, as well as developing wind energy. As regards interconnections, it is important to note the TSOs plan to increase the import/export capacity of the synchronous interconnections with Germany, the Czech Republic and Slovakia by 2000 MW.

Summing up the development plans, let us make the following main conclusions:

1. In the nearest years, a large increase in the capacities of wind and solar power plants is expected. At the same time, a number of power plants in the Baltic States will be shut down so as to diminish the amount of emissions.
2. In most cases, the thermal power plants operate in combined heat and power mode.
3. The Latvian power grid is connected with Lithuania and Estonia and, through them, with the Scandinavian countries, Finland, and Poland; it provides wide but still limited export and import possibilities and operation in the electricity market with a high degree of freedom.
4. For planning and optimising the modes of the power system, forecasts of the impacting processes are needed. The long-term forecasts need to have a time resolution of one hour or finer.
5. Power generation is strongly influenced by weather conditions: outdoor air temperature, precipitation, humidity, water inflow in rivers, wind speed and its direction, solar radiation.
6. The cascade HPPs in Latvia are not suited to seasonal regulation due to the relatively low volume of the water reservoirs. Short-term energy storage is possible at the Daugava HPPs and Kruonis pumped storage power plant.
7. Electrification of transport and households is expected, which is to increase the electricity demand.
8. Sweden, Finland, Poland, Estonia do not rule out the construction of nuclear power plants. These countries are striving to ensure the balance between the generated and consumed energy. No considerable energy exports are expected.

4. METHODOLOGY

A. Solvers of Development Problems and Goals of Problem Solving

In order to be able to choose the best development alternative, it is necessary to mathematically formulate the development planning problem by describing the optimization goals and considering the technical, economic and legal limitations, as well as the available or planned technologies. The formulation of the problem very much depends on the level of the decision-maker and the exact goals. Problems that are characteristic of various decision-makers are shown in Table 1.

Table 1. Solvers of Development Problems and Problem-Solving Goals

Government level	Power system structure? Reliability? Emissions? Import? Export? Revenue? Tax levels? Support amount?
Major producers	Plant profitability? Income/expenses? Reliability? Emissions? Changes in technologies?
Grid	Grid structure? Reliability? Stability? Risks? Losses? Transfer capacities? Import/export? Congestions? Income/expenses?
Prosumers	Technical and economic substantiation for choosing technologies? Income/expenses? Cost of connection? Household electrification?
Electric vehicle owners	Technical and economic substantiation for choosing electric vehicles (EVs)? Income/expenses?
Electric storage equipment owners	Technical and economic substantiation for choosing energy storage equipment? Income/expenses?

Development decision-makers as well as the possible problems vary, yet in most cases it is necessary to evaluate economic indicators, for example, the net present value (NPV) of the cash flow and the income/expenses of any year. This makes it possible to apply a unified approach and similar algorithms to various problems.

B. The Modelled Power System

Below, we will look at a united power system whose participant countries set up the Nord Pool [23] electricity market, which is divided into a number of areas. The market participants, on the one hand, compete with one another and strive for maximum profit. On the other hand, exchange of energy and reserves takes place among countries. In order to ensure coordination of the independent energy producers, energy markets of various types have been set up, by means of which a certain order is brought into the overall activity. Under market conditions, fluctuating energy prices are formed. Producers are forced to adapt their energy generation to the fluctuating prices [23]. The operation of energy companies and its characterising factors, for example, the amount of energy generated and fuel consumed, profit, production costs, and others, are changeable and depend on natural factors and the behaviour of other market participants. When choosing the operation mode and the generator capacities and technologies, it has to be taken into account that the amount of energy generated must be equal to a fluctuating demand and many technical and legal limitations need to be met. The choice problem can only be solved by planning energy generation for a future time period. Depending on the problem formulation, the length of the planning period can be a matter of seconds, minutes, hours or even decades.

The planning should best be done in the form of an optimization problem, which in turn necessitates the formation of production process models and the description of operation conditions, possibly in the form of models, in future periods. A power system is influenced by many factors and processes. One of the tasks of the present study is the choice of the main influencing processes. Then, the process forecasting method has to be chosen. This choice is impacted, on the one hand, by the physical essence of the process, and on the other hand, by the formulation of the optimization problem used. In addition, the solving of the above-mentioned choice tasks strongly depends on the structure and parameters of the power system in question and its producers, as well as the energy market organisation principles. When designing energy facilities or a group of energy facilities, it has to be taken into account that they operate at constantly changing conditions. To perform an analysis of the operation of energy facilities, the following is necessary: mathematical models of impacting processes; power system models; models of the mode control system; models of electricity markets. Below, we will use a modelling platform, a generalised structure of which is provided in Fig. 1.

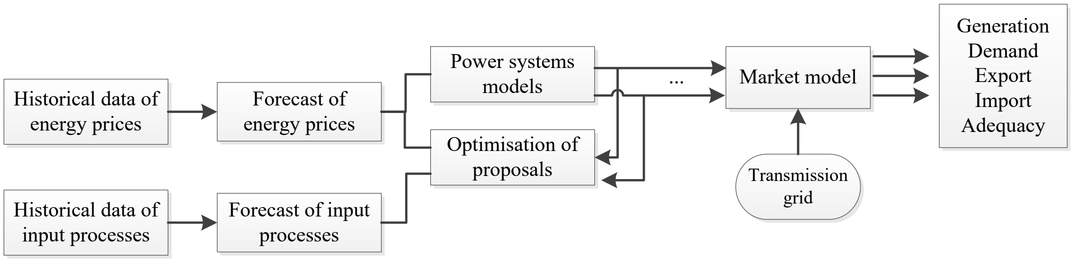

Fig. 1. A generalised structure of the modelling platform.

The power system model forms the core of the structure in question; this core can be embodied in various ways. The exact embodiment determines the requirements regarding the list and description of impacting processes. The structure of the model of the Baltic States power system used in the present study is provided in Fig. 2.

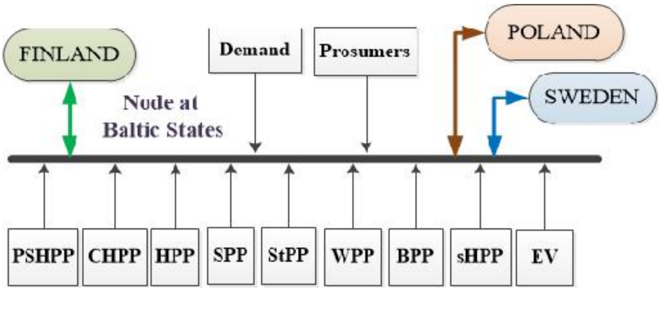

Fig. 2. A diagram of the modelled power system.

The structure depicted in Fig. 2 includes the following main objects, the list of which corresponds to existing and prospective energy sources: pumped storage hydropower plants (PSHPPs), hydropower plants (HPPs), small HPPs (sHPPs), solar power plants (SPPs), wind power plants (WPPs), storage power plants (StPPs); electric vehicles (EVs); prosumers; electricity demand and interconnections between the Baltic States and Finland, Poland, Sweden. We assume that all of the above objects are connected to one Baltic electricity node. We assume that the shareholders of the plants strive to increase their profitability and are forced to follow the technical and legal constraints established by the rules of the Nord Pool day-ahead electricity market, the government and the grids. The discussed model encompasses Finland, Sweden, Poland and the Baltic States. Still only the Baltic States are modelled in detail, considering the peculiarities of the major power plants and consumers/prosumers, heat demand, and similar factors. The other countries of the region are modelled by considering the limitations imposed by the interconnections, as well as the forecast development of electricity prices in the discussed trade regions.

C. Forecasting of Processes

In order to ensure profitability and adequacy of the operation of the power system in the Baltic States, long-term forecasts of the following most influential processes are needed: electricity prices (in all the countries), electricity demand, heat demand, air temperature, water inflow in rivers, solar irradiance, and wind speed. The above processes can be used for simulating the operation of all existing and planned types of power plants. In order to evaluate the profitability of the PPs, recordings of the processes with a resolution of one hour are needed. Considering that the operation is being planned for thirty years ahead and more, it can be said that also the length of the forecast processes needs to be the same. The above-mentioned processes can be divided into two groups:

1. Stationary processes, whose main characterising parameters remain unchanged over time. We will include here all the weather parameters, which means that we do not consider climate change impact.
2. Non-stationary processes, with parameters that change over time (prices, demand, generation capacities).

To simulate processes of the first group, it is possible to use the historical data of process measurements. Simulation of processes from the second group is considerably more complicated. In our study, we have chosen an algorithm based on Fourier transformation, the annual average, the set of harmonics and white noise. A detailed description of this algorithm is provided in one of our earlier publications [24]. When forecasting the future years, the mean component is removed from the historical data and replaced by the mean forecast in the year in question.

The long-term modelling is done with a rolling optimization horizon by using a medium-term optimization sub-model and long-term data sets, i.e., the medium-term calculation (a week or two weeks ahead) is periodically repeated, gradually moving in time towards the future (Fig. 3).

Let us point out that the division of time into weeks is possible in power systems that do not contain long-term energy storage plants. Detailed forecasting algorithms are described in our earlier studies [25], [26].

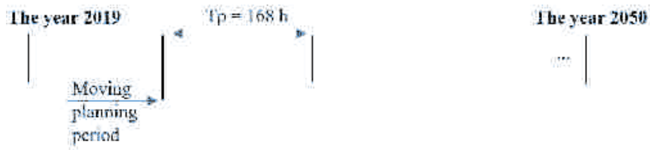

Fig. 3. The temporal structure
of forecasting.

D. Power System Models and Generation/Demand Models

The formation of the power system generation demand/supply for the day-ahead market takes place by formulating and solving the problem of optimization of the expenses/income of all the participants (see Fig. 2). To simplify this task, the following additional postulates have been assumed:

1. The bids of all the market participants to the market are formed by using the assumption that the hourly energy prices are known (in the form of hourly price forecasts).
2. The modes of the Baltic States power system do not influence the electricity prices in the neighbouring countries.
3. The energy prices of the Baltic States may differ from the forecast ones since they are set in accordance with the market conditions, taking into account not only the supply but also the import/export possibilities and limitations, as well as the prices of the neighbouring countries.
4. The internal limitations of the transmission grid in the Baltic States are met in all modes. In this case, the Baltic grid is reduced to one node (see Fig. 3).
5. The power systems of the neighbouring countries are capable of using the interconnections to their full capacity when exporting or importing electricity.

The above postulates make it possible to ensure dramatic simplification of the long-term development planning problem for the following reasons: detailed models of the power systems of the neighbouring countries are not used; the income/expenses of each participant at set future prices depend only on their own actions. The problem of choosing the modes of power plants becomes divided into much simpler subproblems. These can be solved by applying medium-term mode planning models and tools, the substantiation and description of which are addressed in a wide range of scientific literature.

E. The Electricity Market Model

Taking into account the above postulates, the hourly price/capacity bid of the Baltic States area for the market of the following days is formed; to this bid, the hourly energy prices (forecasts) of the neighbouring countries are applied; taking into account the limitations of the interconnections, the equilibrium prices of the Baltic States area are determined. In export, power systems with higher prices are prioritised. Every hour, the model searches through export/import and Baltic States generation and demand alternatives, looking for generation and demand balance and applying market conditions and thus choosing the cheapest energy generation alternative that ensures balance. Such a model is based only on the checking of elementary logic expressions and inequalities, and is thus easy to implement.

F. The Tools to be Used

The structure of the power system model in the Baltic States shown in Fig. 3 encompasses a number of sub-models:

1. Power plants of various types (hydropower plants, among them – the Daugava HPP cascade, combined heat and power plants (based on natural gas, biomass and biogas), thermal power plants, intermittent energy sources – wind and solar);
2. Energy storage plants of various kinds (including pumped storage);
3. Consumption/generation models of energy consumers and prosumers that follow on from the forecasting methodology, taking into account the impact of the environment-related factors;
4. Models of transmission power grids; yet at least in the first iterations, the Baltic States are depicted with one node, which has transmission limitations with the neighbouring countries. Tools for solving optimization problems (the so-called solvers).

The set of the tools to be used includes a number of software products synthesised at Riga Technical University:

- Hydropower plant optimization software *OptiBidus-HES* [27];
- Thermal power plant mode calculation software *OptiBidus-TEC*;
- Generalized energy storage software [28], which is adaptable to technologies of various kinds, as well as the software specifically intended for Kruonis pumped storage hydropower plant [29];
- Forecasting software products, for example, for water inflow [25] and heat load [26], etc.

The mathematical models embedded into the various tools are combined into a united regional power systems model (RPSM). The RPSM is implemented in the MATLAB programming environment, using, among other things, the optimization problem solvers available there. Data input and output are implemented by using *.xlsx* files, which can be edited and read, among others, by the widespread Excel application software. For solving the optimization problems, MATLAB solvers are used, more specifically, the linear programming procedure.

5. CASE STUDY. GREEN SCENARIO

A. Input Data

The approach and methodology described above are used for devising long-term development scenarios for the power industry of the Baltic States, with the aim to evaluate the energy generation/consumption balance and the import/export possibilities. Below, we provide a detailed discussion of only one scenario and only for one point in time, i.e., for the year 2050. This scenario is based on the building of high-capacity wind and solar power plants. At the end of the section, a summary of other scenarios is provided.

The developed scenario for 2050 (as an example) includes the following assumptions:

- The historical data of energy generation by SPPs are taken from a specific facility in Latvia [30];
- The historical data of energy generation by WPPs are taken from the Nord Pool database [23];
- To achieve a specific capacity of the PPs (SPPs and WPPs), the authors calculate and use increase factors;
- The capacity of the LitPol interconnection is 1 GW;
- The capacity of the new interconnection (Harmony Link) between Lithuania and Poland is 700 MW;
- Other described capacities of existing interconnections in Section 2 are taken into account and remain unchanged;
- The capacities of a Lithuanian gas combined cycle PP (455 MW) and two Latvian natural gas PPs (1025 MW) are kept in reserve and launched only in the case of lack of energy generated from RESs. Hereinafter, they are referred to as gas-fired PPs (GFPPs).
- EVs are not considered in the calculation.

The parameters of the generators for the years 2019 and 2050 are presented in Table 2.

Table 2. Installed Capacity of Baltic Generating RES Facilities

SPP, MW	WPP, MW	HPP, MW	PSHPP, MW	BPP, MW	SHPP, MW
The year 2019					
88.4	1092	1558	900	231	67
The year 2050					
1000	5000	1558	1400	231	67

As can be seen from Table 2, it is assumed that by 2050 the increase in the installed capacity of solar energy PP will be 0.91 GW, that of wind energy – up to 3.9 GW, and pumped storage energy – up to 0.5 GW. The rest of the RES capacities remain unchanged.

B. The Forecast for 2050

We assume that long-term trends in processes (electricity demand and energy prices) can be described by changes in annual average parameters. This assumption makes it possible to use forecasts that have been done for estimating the annual average market price and the annual average demand. We use a long-term forecast provided by SKM Market Predictor. They produce the forecast on the basis of using a version of a commercial modelling system called the EFI multi-area power planning model (EMPS model), also known as Samkjøringsmodellen or the Power Market Analyser [31]. EMPS is a stochastic, market-oriented simulation model for large power systems. The model allows simulating large power systems with a relatively high degree of detail, so it is well suited for comprehensive research at the multinational level.

Within the present study, forecasting includes the following steps:

- Initially, the energy price and the electricity demand in each country for 2019 (the base year) are taken from the Nord Pool database;
- Using the Fourier transform, we estimate the constant components and replace them with the predicted average electricity price/demand for 2050 from SKM Market Predictor (Fig. 4).

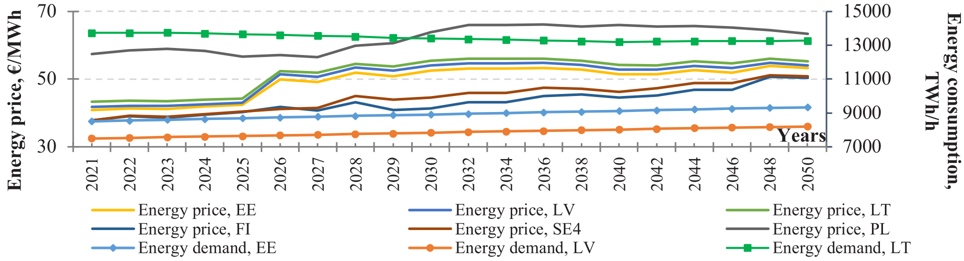

Fig. 4. The annual forecast of energy price and demand by EMPS [31].

Forecast results of the hourly electricity prices of Poland (PL), Sweden (SE4) and Finland (FI), and the electricity demand of the Baltic States for 2050 are shown in Fig. 5.

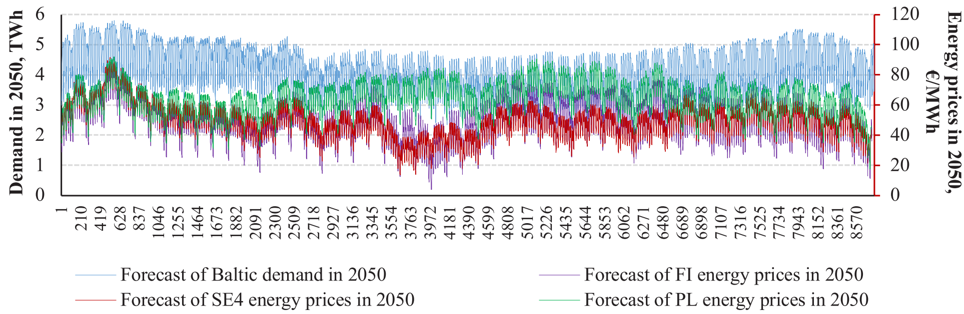

Fig. 5. The forecast of hourly electricity price and electricity demand.

According to Nord Pool data, the total electricity consumption in the Baltic States reached 29.91 TWh/year in 2019. Forecasting and calculating the electricity demand for 2050, this indicator is 36.7 TWh. Over 30 years, the estimated increase is 23 %. From Fig. 5 it is obviously seen that the highest energy price is recorded in PL. The average value in 2050 is 64.6 €/MWh (by 18.72 % more than in 2019). Lower prices are expected in Sweden (the average value is 48.03 €/MWh). In Finland, the average price is expected to rise by 27 % compared to 2019.

C. The Balance of the Baltic States in 2050

Figure 6 presents the results of energy generation modelling at the Baltic renewable energy PPs in 2050.

In 2050, the Baltic States are modelled to generate a total of 21.34 TWh of electricity from RES power plants. This constitutes 72 % of the required amount of electricity. From Fig. 6 it follows that wind energy is the most-used RES for electricity generation, accounting for 67.3 % of the total amount of generated electricity. The next most important types of RESs are PSHPPs (15.23 % of the total electricity generation), SPPs (5.4 %), HPPs (8.9 %), BPPs (2.72 %) and sHPPs (0.4 %).

Despite the large amount of energy produced by RESs, there is not enough energy in the Baltic States to meet the electricity demand (36.7 TWh). As a result, there is a need for electricity import/export, cooperating with neighbouring countries.

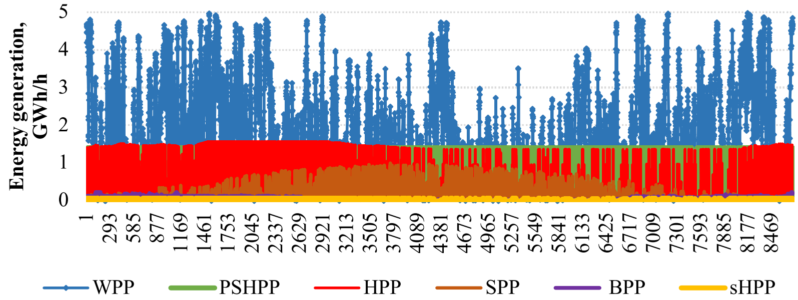

Fig. 6. Energy generation at the Baltic RES PPs.

Figure 7 shows the hourly energy balance (difference between demand and generation) of the Baltic States for 2050.

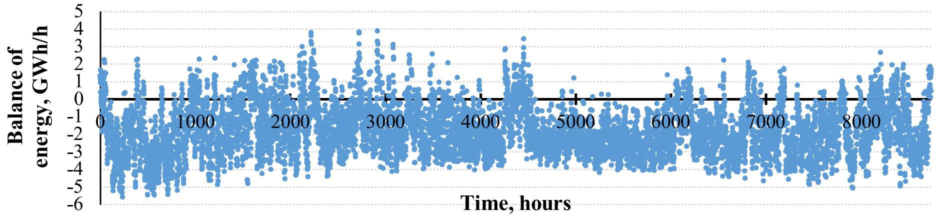

Fig. 7. The energy balance of the Baltic States in 2050.

Analysing Fig. 7, the following conclusions can be drawn: in 1 097 cases there is an excess of electricity in the power system, in 7 639 cases there is an energy deficit. The maximum value of energy surplus is 3 891 MWh, whereas that of energy deficit is −5 574 MWh/h. The average value of balance is −1 776 MWh/h.

Considering the capacities of the interconnections and the forecast of energy prices for 2050, the surplus energy could be sold (Fig. 8) to neighbouring countries (Sweden (SE4), Finland (FI), Poland (PL)).

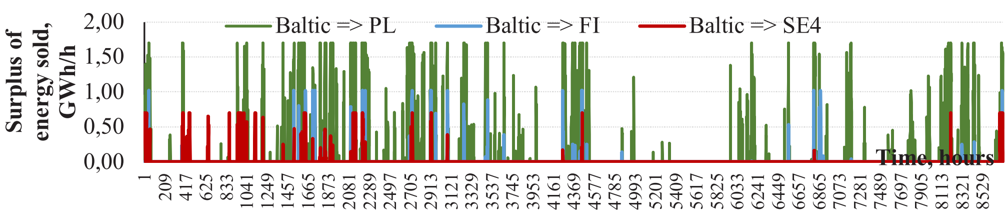

Fig. 8. Surplus of energy sold to FI, SE4, PL.

As shown by the results in Fig. 7, the hourly values of energy surplus or deficit in many cases exceed the capacity of the interconnections between the Baltic States, and one neighbouring country therefore cannot ensure the balance. As a result, hourly export (or import) procedures are carried out between the Baltic States and several countries at the same time, depending on the values of energy prices in the neighbouring countries.

The forecast energy prices are sorted from higher to lower ones. Firstly, the excess energy amount is sold to the country with the highest prices, next, with the second-highest prices and so on. In 107 cases, the excess energy was sold to Sweden, in 106 cases to Finland and in 1 018 to Poland. However, in six cases, the surplus energy was not sold due to line transmission capacity limitations. Among the six cases, the maximum value of excess energy is 474.92 MWh/h and the minimum value – 13.61 MWh/h.

As regards the energy deficit, it could be addressed by buying energy from neighbouring countries, and if there is still not enough energy, the reserve is used (GFPPs). In Fig. 9, the results of purchasing energy from PL, FI, SE4 are presented.

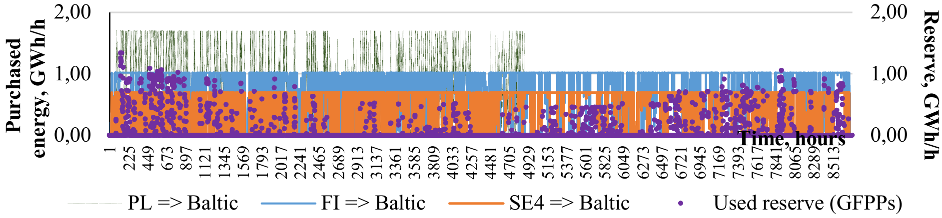

Fig. 9. Energy purchased from FI, SE4, PL (left axis) and GFPP generation (right axis).

The forecast energy prices are sorted from low to high. In 6 718 cases, the necessary energy was bought at a low price from Sweden, in 7 227 cases from Finland and in 5 059 cases from Poland. In 939 cases, the reserve energy from GFPPs was used. However, in 207 cases, the energy deficit was not met. Among 207 cases, the maximum value of deficit energy is 1 242 MWh/h and the minimum value is 0.008 MWh/h.

In Table 3, we present the results of the Baltic energy balance calculations, using different additional scenarios. It should be noted that only the capacities of SPPs and WPPs have been changed.

Table 3. Baltic Energy Balance Results Using Different Scenarios

	Scenarios				
	SPP (1 GW), WPP (4 GW)	**SPP (2 GW), WPP (4 GW)**	**SPP (2 GW), WPP (5 GW)**	**SPP (3 GW), WPP (5 GW)**	**SPP (3 GW), WPP (7 GW)**
Cases of excess energy before export	459	625	1279	1521	2561
Cases of deficit energy before import	8277	8111	7457	7215	6175
Export cases: Baltic => FI Baltic => SE4 Baltic => PL	 37 38 423	 66 50 588	 156 205 1198	 244 243 1440	 788 807 2487
Cases of excess energy after export	0	1	22	40	179
Import cases: FI => Baltic SE4 => Baltic PL => Baltic	 7884 7476 5907	 7650 7267 5561	 6988 6533 4699	 6721 6302 4430	 5630 5266 3447
Cases of using reserve (GFPPs)	1170	1047	829	778	579
Cases of deficit energy after import procedure and after using the reserve	271	234	177	166	129

From Table 3, the following conclusions can be drawn: an increase in the capacity of SPPs and WPPs not only offers advantages (meeting most of the electricity demand) but also creates issues in the operation of the power system such as potential excess and deficit of energy. Before export procedures, excess energy cases range from 5.29 % (in the first scenario) to 29.32 % (in the fifth scenario) of the total possible cases. After selling energy to neighbouring countries, the percentage of cases decreases, from 0 % to 2.04 %. However, in the case of energy shortages, a different situation emerges. Before import procedures, deficit energy cases range from −94.75 % (in the first scenario) to −70.68 % (in the fifth scenario) of the total possible cases. In this situation, the minus sign is used, since we are talking about a lack of energy, thus highlighting this fact. After buying the necessary energy from neighbouring countries and using the reserve from the GFPPs, the percentage of cases increases, and, as a result, energy deficit cases range from −3.10 % (in the first scenario) to −1.47 % (in the fifth scenario).

Despite the improvement in the situation after import/export, in several cases the problem of energy surpluses and deficits remains unresolved. Even though the percentage of such cases is small, the highest values of the amount of insufficient or excess energy are large. For example, the maximum excess values in the 2nd–5th scenarios are 16.8 MWh/h, 1 053 MWh/h, 1 709.7 MWh/h and 3 500 MWh/h, respectively.

6. CONCLUSIONS AND DISCUSSION

1. In the Baltic States, significant changes in energy production and distribution are ongoing: the number, capacity and share of renewable energy sources in the amount of energy produced are growing rapidly; the role of combined heat and power plants has increased; the cross-border connections have improved; steam-gas technologies, distributed generation, and energy storage systems have been developed. The energy demand, prices, and related regulations have changed rapidly and significantly.
2. A significant increase in the capacity of wind farms and solar power plants is expected in the Baltic States. This leads to the need to understand and predict the functioning and performance of individual components of the energy system or the overall behaviour of the system. This motivates the development of optimization models and analysis of the adequacy of the energy system.
3. The choice of the operating mode of a power plant can be made on the basis of the formulation and solution of a complex optimization problem that requires prediction of the processes of price changes, energy generation and demand for a long period and at a high resolution.
4. Long-term electricity price and demand prediction can be implemented based on the use of external predictions of changes in average annual prices and the adoption of a hypothesis about the invariance of seasonal and random components during the planning period.
5. In 2050 modelling results, the Baltic States as a whole experience a shortage of electricity generated from renewable energy sources to meet their electricity needs. In six scenarios, the percentage of electricity generated from electricity demand of the Baltic States varies from 49.56 % to 78.8 %. Even after import/

export, in several cases the problem of energy surpluses and deficits will remain unresolved.

6. Cooperation between neighbouring countries is of great importance. The Baltic States have well-developed interconnections with Finland, Sweden and Poland. Moreover, until 2050, it is planned to increase the capacity of these lines. This makes it possible to increase the volume of electricity export and import.
7. An important aspect of reliability is the serviceability of power lines. In this article, it is assumed that all the lines are working properly and the criteria (n-1) and (n-2) are not taken into account in the calculations. That will be the subject of future work in improving the calculation of the balance of the power system of the Baltic States.
8. The results of calculations show that there are surpluses and deficits of energy in the power system. The import and export of electricity constitute an integral part of the operation of the system. However, even after the sale and purchase of energy, there are hours left when it is necessary to solve the problem of excess and deficit of energy in other ways. In cases of power shortages, the following solutions can be used: using and adjusting demand response programmes, disconnecting less important consumers, using high-capacity storage systems. In cases of excess electricity, it is possible to curtail generation from some of the power plants.
9. The implementation of RESs in the future depends on the decisions taken by the policy-makers and potential investors.

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POWER PLANT COOPERATION IN DISTRICT HEATING CONSIDERING OPEN ELECTRICITY MARKET

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The paper analyses the possibilities to form a coalition of several heat energy providers in order to participate in the district heating market considering the open electricity market. Cooperation would allow the participants to better dispatch the existing energy sources and would ensure higher total profit for the participants. The objective function for such a cooperation is provided. To optimise the operation of the coalition, mixed integer linear programming is used, considering constraints of different heating energy market participants and the need to fulfil heating energy balance. If any additional profit is made, it is shared between coalition participants according to the Shapley value, which grants interest for market participants to form the coalition. Case study based on historical hourly data is provided and numerical results are presented in the paper.

Keywords: *biomass CHP, CCGT, district heating, district heating market, HOB, market participant coalition, wood chip CHP.*

1. INTRODUCTION

According to statistics, 26 % of all energy in the European Union (EU) is used for space heating and 5 % is used for hot water production, which results in total energy consumption of 3985 TWh. 45 % of this energy is produced using natural gas and 12 % – using biomass [1]. Study held in [2] showed that an increase in heat demand would make the district heating market more efficient, i.e., combined heat and power (CHP) plants operating in city district heating zones would need to compete both in electricity and in district heating markets.

Worldwide, heat demand is mainly satisfied by burning wood or fossil fuels, which lead to local pollution and global greenhouse gas emission [3]. District heating systems have been used since the 14th century. In Northern European countries such as Sweden and the Baltic States, district heating is widely used, supplying more than 50 % of total heating energy. Development of district heating systems is reported in various countries. In [4], authors forecast growth of CHP by 2030. Different energy sources could be used for district heating, such as fossil fuels, nuclear power, waste heat, solar power, ground-source heat pumps and biomass [5], [6].

In the past, energy conversion was seen as a direct conversion of energy to electricity and such by-product as heat was usually treated as waste. Efficiency of district heating has increased due to fuel use because it provides a possibility to use a co-generation process, in which both electricity and heating energy are generated and give higher fuel efficiency than single electricity generation. Combined generation also has lower impact on the environment. Combined heat and power plant is a step towards system improvement since previously wasted heat is recovered and used as a valuable product [2], [7], [8].

In the Nordic countries, district heating is common for municipalities; usually heat energy is provided by CHP plants combined with heat only boilers, which are used to cover peak loads. CHPs not only cover heat demand of the city, but also sell electricity in the electricity market [9], [10].

Renewable energy sources are widely used in Europe to reach environmental objectives. Electricity generation from renewable sources is usually fluctuating, which forces classic CHPs operate in a more cyclic mode due to changes in the electricity price in a wide range during the day. Various technologies and solutions are used to increase flexibility of CHP especially in case of highly efficient CCGT power plants [4], [10].

Biomass has become a very promising fuel for electricity generation due to its CO_2 emission reduction potential and its suitability for use in CHP. The European Union continuously aims at reducing greenhouse gas emissions and using more renewable power. The use of biofuel grows in Europe every year [11]. In opposite to wind and solar generation, biomass can be used to provide base load or controllable load. In this context, various technologies such as steam or gas turbines, steam engines, organic Rankine cycle (ORC) or Stirling engines can be used. These technologies mainly differ in their heat supply, whether they require an internal (e.g., gas turbine and engine) or external heating (e.g., ORC, steam and Stirling engines) [12].

Thermodynamic processes requiring internal heating are limited to the application of liquid or gaseous fuels. For solid biomass gasification technologies could be used to make them applicable to internal burning technologies. External fired thermodynamic cycles can be used by the direct combustion of solid fuels and heat decoupling out of the hot flue gas. Thus, external burning technologies have lower electrical efficiency [13].

Modern energy systems are complex and consist of several interacting markets; thus, they are usually considered as individual sub-systems: electricity supply, heating supply, natural gas or hydrogen supply. However, there are a lot of benefits when the energy system is considered an integrated whole. Such benefits are the supply of energy from alternative sources, which grants higher system security; energy efficiency could be raised; energy losses, costs and emission could be minimised because of synergy between various energy vectors; energy flows can be controlled [8], [14].

Good example of an integrated energy system is a district heating system where CHP, heat only boilers, electrical boilers and heat pumps are operating. Such integrated systems can operate more efficiently and be more flexible, which is important due to renewable electricity generation penetration [14].

CHP is a key technology to link electrical and heating power sectors for its high generation efficiency and high distribution in the Northern countries. Integration of renewable energy sources forces CHPs to become more flexible in the electricity market. It becomes even more challenging to operate CHPs as they should participate in electricity and heating energy markets, which are ruled by different operators [15].

In recent years, the concept of energy hub has become very popular, because it considers several energy flows, such as fuel, electricity and heating energy. This approach allows for a simple analysis of couplings and interaction between different infrastructures. Similar to the standard economic dispatch approach for electricity generators, a general optimality condition can be derived for optimal dispatch of multiple energy carriers. Potential application of such an approach includes planning of integrated systems, multi-carrier generation scheduling and security analysis of coupled systems. This approach has great potential for co-generation and trigeneration optimisation [7], [16].

Nowadays it is important to ensure a high comfort level and energy efficiency, which can be reached by adopting different control and management systems. Authors of [17] analyse the district energy system in terms of electricity flow optimization to ensure a comfort level in building and better planning of day-ahead electricity markets to negotiate balancing expenses. Thus, for places with the district heating network such an approach should be modified.

As electricity prices change hour to hour, to gain most income CHP should produce maximum electricity power during hours with high electricity price and avoid operation during hours with low electricity price. However, heat demand should be fulfilled all the time. The study [9] analyses heat storage performance to ensure optimal operation of CHP and to reduce operating hours of heat only boilers.

In [18], authors seek for optimal sources of energy for the city, considering such technologies as remote nuclear power plant, biomass CHPs, natural gas CHPs and ground & air heat pumps. To find an optimal solution, linear programming was used. Thus, an attempt was made to analyse specific needs of one city, without considering the electricity or heat energy market.

Authors of [19] concern about optimal dispatch of large coal fired units, which, according to [1], represent only 9 % of total energy produced for heating. Thus, in some countries this percentage is much higher. Optimization covered operation of CHPs within the electricity market, and the main objectives were to maximise income from electricity sales and minimise production costs of heat energy.

Authors in [20] aim at minimising total costs of the integrated power system considering such sources of electricity as photovoltaic panels, wind turbines, electric boilers, CHP and battery electricity storage systems. Natural gas fired CHPs were considered as a heat energy source. The objective was to minimise daily net operation costs, without any market consideration.

Detailed optimization considering network constraints is provided in [21]. In the study, CHP and non-CHP units were used as a heat and electricity source. The objective was to reduce total production costs.

Authors in [22] developed a model of

the district heating and electricity system considering gas fired CHPs, biomass and gas fired heat only boilers (HOB). The objective was to prove that moving from rule-based production to optimization-based predictive control could result in significant savings.

In [8], authors propose considering natural gas supply in the optimization model as well as electricity and heat energy production of CHP. The proposed approach demonstrated a possibility to optimize power and gas flows.

In [23], authors suggest to consider not only operation optimization of heating energy units of a certain company, but also to evaluate cooperation with other producers. The main aim was to increase income and do not sacrifice interests of society. Results of [23] demonstrated possibilities to gain higher overall profit when wood chip and gas fired CHP operate in coalition. The study also demonstrated how the Shapley value could be applied to fairly split additional income of coalition members. Unfortunately, only average heat production costs for generation units were considered, costs of fuel were taken as fixed costs, which did not represent market relations. Interaction with electricity market was unclear.

In Europe, common types of CHP are natural gas fired or coal fired power plants. Coal fired units usually reach electrical efficiency of 24–28 %, with overall efficiency of around 80 %. Due to environmental aspects, coal fired power plants are shutting down and are not under the scope. Gas fired power plants tend to use a combined cycle gas turbine (CCGT) technology to reach electrical efficiency of 42–47 % and overall efficiency of 80 % [24].

The most popular type of biofuel CHP is an organic Rankine cycle power plant, which can combust wood chip. Analysis of different power plants in the range of 3.7–7.4 MW showed electrical efficiency of 6–13 %, where lower efficiency was reported for smaller CHPs. Total thermal efficiency was in the range of 48–72 %, where the highest efficiency was also reported for bigger CHPs [25]. In [26], electrical efficiency of 16–36 % for the newest ORC power plants is reported, gaining overall efficiency of 85 %.

Results of the reviewed works indicate the need to look at the energy system as a united whole. Optimization of operation considering all markets in which a power plant should participate has numerous advantages. Combined heat and power plants are very suitable for optimization considering electricity and heating energy markets. Different technologies, which are used for CHP, can give additional optimization possibilities.

In the same district heating area, power plants with different technologies can supply heating energy and electricity. Electrical efficiency of ORC power plants is lower than that of CCGT units; therefore, thermal and overall efficiency is better. It means that CCGTs have advantage on the electricity market, but biofuel CHPs – on the heating energy market. As both these technologies allow competing on electricity and heating energy markets, this leads to possible interaction of both biofuel fired and gas fired units to coordinate efforts and optimize operation in order to maximise revenue from participation in the district heating market, considering operation within the open electricity market.

This study aims at optimising different electricity and heat source operation using mixed integer linear programing (MILP). If such optimization leads to additional profit, then profit will be distributed between coopering parties using the Shapley method. Such an approach can result in more efficient use of resources leading to lower costs for the end-user. This study is the first step of the approach; it should indicate whether making coalition in the district heating market could make additional profit for acting parties.

Additional profit due to optimized dispatch could be used in different ways. Usually, market rules ban any type of coalition, but if a regulator can develop clear rules of coalition operation, additional profit could be used to decrease end-user costs of heat energy.

2. METHODOLOGY

Three energy sources are under consideration in the present study: (1) CCGT power plant, which produces both electricity and heat energy, can also operate in a fully condensing mode (electricity production does not depend on heat energy production); (2) wood chip fired CHP, which produces both electricity and heat energy, can operate only in a full cogeneration mode (electricity production fully depends on heat energy production), and (3) gas fired HOB, which produces only heat energy.

Electricity market prices are taken from local electricity market prices of day-ahead spot market, but heat energy prices are calculated according to heat demand and electricity price. It is assumed that operation costs of the mentioned energy sources are limited by fuel costs and efficiency of each technology. Heat energy price is calculated for each energy source considering market electricity price and no additional revenue from heat energy trading. In general, heat energy price for CCGT and CHP is calculated as shown in Eq. (1), but for HOB as shown in Eq. (2). Both these equations consider minimum and maximum electrical and heat power during each hour t of the period p.

Authors in [27] and [28] have concluded that the projected day-ahead heat energy demand might change during the day under different circumstances. This change of demand might lead to additional profit or losses due to the previously set price for heat energy. The re-dispatch during the day, for which electricity and heat prices are already set, might lead to better total profit which later might be shared among market participants granting better economic effect.

$$C_{th.p} = \frac{P_{el.p}\left(\frac{C_{fuel.p}}{\eta_{el}} - C_{el.p}\right)}{P_{th.p}} , \qquad (1)$$

where
$C_{th.p}$ – heating energy price for period p, EUR/MWh; $P_{el.p}$ – electrical energy produced by a power plant in period p, MWh; $C_{fuel.p}$ – fuel average market price for period p, EUR/MWh; $C_{el.p}$ – electricity average market price for period p, EUR/MWh, η_{el} – technology electrical efficiency; $P_{th.p}$ – thermal energy produced by technology in period p, MWh.

$$C_{th.HOB.p} = \frac{\frac{C_{fuel.p}}{\eta_{HOB}}}{P_{th.HOB,p}} , \qquad (2)$$

where
$C_{th.HOB.p}$ – heating energy price for HOB in period p, EUR/MWh; η_{HOB} – HOB efficiency; $P_{th.\ HOB.p}$ – thermal energy produced by HOB in period p, MWh.

For pre-calculation purposes, two heating energy market models were chosen: day-ahead market and week-ahead market. To calculate day-ahead or week-ahead heat prices, it is suggested that every market participant makes its bid at which price it can cover heating energy demand for day or week ahead. The source, which has the lowest heating energy price, produces all demanded heat during a particular hour, if it is not possible, the next cheapest source is started and then third to always cover the whole demand of heat energy at the set day- or week-ahead heating energy market price. Minimal and maximal electrical and thermal power constraints of each energy source are also considered; it is especially essential for CCGT, where heating energy production could be 0, but minimal electrical power is limited, which leads to higher heating energy prices in some cases. It is considered that a provider of the cheapest heating energy for the day or week ahead can adapt their heating energy prices to beat rivals and gain profit. According to the previously mentioned assumption, i.e., all participants set the heating energy price considering no profit, it appears that the second and third cheapest sources will have loss in revenue if they need to operate. The provided objective function assumes very high flexibility of energy sources.

Total profit (E) of the mentioned energy source operation and participation in both markets could be calculated as follows:

$$E = \sum_{t=1}^{T}(P_{el.gas.t}\left(C_{el.t} - \frac{C_{g.t}}{\eta_{el.gas}}\right) + P_{th.gas.t}C_{th.t} + P_{th.HOB.t}\left(C_{th.t} - \frac{C_{g.t}}{\eta_{HOB}}\right) + P_{el.bio.t}\left(C_{el.t} + \frac{C_{th.t}\eta_{th.bio}}{\eta_{el.bio}} - \frac{C_{bio.t}}{\eta_{el.bio}}\right)), \tag{3}$$

where

T – the calculation period in hours (day or week), h; $P_{el.gas.t}$ – electrical energy produced by CCGT at hour t, MWh; $C_{el.t}$ – electricity market price at hour t, EUR/MWh; $C_{g.t}$ – natural gas market price at hour t, EUR/MWh; $\eta_{el.gas}$ – CCGT electrical efficiency; $P_{th.\,gas.t}$ – thermal energy produced by CCGT at hour t, MWh; $C_{th.t}$ – heat energy price at hour t, EUR/MWh; $P_{th.HOB.t}$ – thermal energy produced by gas fired heat only boiler at hour t, MWh; η_{HOB} – HOB efficiency; $P_{el.bio.t}$ – electrical energy produced by wood chip CHP at hour t, MWh; $\eta_{el.bio}$ – electrical efficiency of wood chip CHP; $\eta_{th.bio}$ –thermal efficiency of wood chip CHP; $C_{bio.t}$ – wood chip market price at hour t, EUR/MWh.

Equation (3) can be divided into three parts, CCGT, HOB and biofuel CHP, in accordance with the previously made statements, i.e., heating energy price and total heat consumption will influence possible profit of each technology. District heating market price and electricity market price will have impact on the type of sources which should be operated. The proposed approach is to cover heat demand and use the best energy source combination according to a real day situation in district heating consumption and electricity market to maximise overall profit of all participants.

Mixed integer linear programming can be used to maximise objective function (4) with corresponding constraints, which are represented by inequalities. In the proposed approach, constraints cover fulfilment of heating energy demand, maximum and minimum load of each energy source, CCGT cogeneration heating energy production (operation in a condensing mode or cogeneration), as well as the state of each energy source (operating/ not operating). If some additional profit is made, it should be divided among coalition players considering their input into total result, which is done using the Shapley value (5) [29].

$$E = \sum_{t=1}^{T}(P_{el.gas.t}\left(C_{el.t} - \frac{C_{g.t}}{\eta_{el.gas}}\right) + P_{th.gas.t}C_{th.t} + P_{th.HOB.t}\left(C_{th.t} - \frac{C_{g.t}}{\eta_{HOB}}\right)$$
$$+ P_{el.bio.t}\left(C_{el.t} + \frac{C_{th.t}\eta_{th.bio}}{\eta_{el.bio}} - \frac{C_{bio.t}}{\eta_{el.bio}}\right)) \rightarrow max$$

$$\begin{cases} P_{th.gas} + P_{th.HOB} + \frac{P_{el.bio}\eta_{th.bio}}{\eta_{el.bio}} = P_{th.dem} \\ P_{el.gas} - s_{gas}P_{el.gas.min} \geq 0 \\ P_{el.gas} - s_{gas}P_{el.gas.max} \leq 0 \\ P_{el.bio} - s_{bio}P_{el.bio.min} \geq 0 \\ P_{el.bio} - s_{bio}P_{el.bio.max} \leq 0 \\ P_{th.HOB} - s_{HOB}P_{th.HOB.min} \geq 0 \\ P_{th.HOB} - s_{HOB}P_{th.HOB.max} \leq 0 \\ P_{el.gas}\frac{P_{th.gas.max}}{P_{el.gas.max}} - P_{th.gas} \geq 0 \\ s_{gas} \in \{0,1\} \\ s_{bio} \in \{0,1\} \\ s_{HOB} \in \{0,1\} \end{cases}, \qquad (4)$$

where
$P_{el.gas.min}$ – minimum electrical power of CCGT, MW; $P_{el.gas.max}$ – maximum electrical power of CCGT, MW; $P_{th.HOB.min}$ – minimum thermal power of gas fired HOB, MW; $P_{th.HOB.max}$ – maximum thermal power of gas fired HOB, MW; $P_{el.bio.min}$ – minimum electrical power of wood chip CHP, MW; $P_{el.bio.max}$ – maximum electrical power of wood chip CHP, MW; $P_{th.dem}$ – total heating energy demand during hour *t*, MWh; *s* – the coefficient that indicates CCGT, HOB and bio fired CHP operation state, i.e., 1 is in operation, 0 is shutdown.

Decision variables are $P_{el.gas.t}$, $P_{th.\,gas.t}$, $P_{th.HOB.t}$ and $P_{el.bio.t}$. Additional profit is distributed among coalition players considering their input into total result, which is done using the Shapley value:

$$\Phi_i(\upsilon, N) = \sum_{S \subset N} \frac{(s-1)!(n-s)!}{n!}[\upsilon(S) - \upsilon(S-i)], \qquad (5)$$

where
υ – game; N – any finite carrier of υ, with |N|=n; s – coalition; S – coalitions; i – the number of players.

The proposed approach could be described in four steps:

1. Calculation of heating energy prices for day/weak-ahead market using Eqs. (1) and (2), load distribution among sources, considering the heating energy price for the period and electricity market price;

2. Calculation of profit made by each source from heating energy and electricity trading;
3. Heating load re-dispatch according to objective function (4) as well as re-calculation of profit made from heating energy trading, also overall profit and electricity trading profit are calculated;
4. In case if any additional profit is made, the Shapley value is used to split the reward among players according to their contribution and input to the coalition.

3. CASE STUDY

For the case study, the district heating area of Riga city in the right bank was chosen as a heating energy consumer. The case study is based on historical data for two different years with the historically lowest electricity market price (34.67 EUR/MWh) and year with the historically highest electricity market price (49.89 EUR/MWh). Heat demand was calculated in accordance with data provided in [27] and using real historical hourly ambient temperature data from the mentioned years. Electricity hourly market prices were taken from NordPool spot market data. Natural gas prices were taken from Gaspool data. Wood chip prices were observed from different sources and prices per MWh were calculated using [30]. It is assumed that the cheapest heating energy source for the studied period of day or week sets its price as 0.97 of the second cheapest heating energy source for a particular period.

Table 1. Technical Parameters of Energy Sources

	CCGT	HOB	BIO CHP
Maximum electrical power, MW	534	-	80
Electrical efficiency, p.u.	0.42	-	0.22
Maximum thermal power, MW	394	464	228
Thermal efficiency, p.u.	-	0.91	0.63
Minimum electrical power, MW	160.2	-	48
Minimum thermal power, MW	0	23.2	136.8

Technical parameters of energy sources under consideration are provided in Table 1. These data are based on information from [11] and [24], power ratings of facilities were chosen close to existing capacities of thermal power supply in the district heating area of Riga city in the right bank. As the main aim is to study the possibility of dispatch optimization, data do not represent a real situation in the chosen city [2]. Historically, HOBs in Riga are part of CCGT power plants; therefore, in this study CCGT and HOB are considered to be one player for the Shapley value calculation, the second player is wood chip CHP, which is called BIO CHP in study.

Results of performed calculations before and after optimization for years with different electricity prices are provided in Tables 2 and 3. In this case, heating energy prices were projected for the day-ahead market. Results show that for the year with the lowest average yearly electricity market price, CCGT heat production hours increased by

1.45 %, but for the year with the highest average yearly electricity market price there is seen a reduction by 1.09 %.

For both years under consideration, HOB operating hours and produced heat energy were decreasing; a decrease in operation hours for the year with the lowest average yearly electricity market price was 10.07 %, whereas a decrease in the produced heating energy was 4.63 %. For the year with the highest average yearly electricity market price, a decrease in HOB operation hours was 23.49 % and a decrease in production was 15.96 %.

The results also show that BIO CHP operating hours and produced heat energy increased; an increase in operation hours for the year with the lowest average yearly electricity market price was 7.38 %, and an increase in the produced heat energy was 4.4 %. For the year with the highest average yearly electricity market price, an increase in BIO CHP operation hours was 19.83 %, and an increase in production was 16.19 %.

Numerical results clearly show that the objective function re-dispatches heat generation from CCGT and HOB to a more efficient heating energy production source – BIO CHP. For both studied years, the most significant reduction of operating hours and produced heating energy was for HOB, especially it was important for the year with high average yearly electricity prices, which allowed producing more electricity using cogeneration power plants and gaining higher profit.

For both studied years, CCGT suffered loss in profit for electricity and heating energy trading. Thus, it allowed increasing profit from electricity and heating energy trading for BIO CHP and reducing losses due to HOB operation. Such a situation after optimization granted additional 443 305 EUR profit for the coalition in the year with a low average yearly electricity price and 1 402 593 EUR profit in the year with a high average yearly electricity price for the scenario with day-ahead heating energy prices.

Table 2. Results for the Year with the Lowest Average Yearly Electricity Price and Heating Energy Daily Price Scenario

	Before optimization	After optimization	Deviation, %
CCGT heat production hours, h	4 472	4 537	1.45
HOB operating hours, h	4 230	3 804	-10.07
BIO CHP operating hours, h	5 067	5 441	7.38
Heat produced by CCGT, MWh	844 541	819 964	-2.91
Heat produced by HOB, MWh	533 829	509 096	-4.63
Heat produced by BIO CHP, MWh	1 119 448	1 168 757	4.40
CCGT profit for heating energy, EUR	8 271 941	8 222 098	-0.60
CCGT profit for electricity, EUR	543 077	432 111	-20.43
HOB profit for heating energy, EUR	-2 772 024	-2 471 176	-10.85
BIO CHP profit for heating energy, EUR	16 927 557	17 191 366	1.56
BIO CHP profit for electricity, EUR	-10 895 118	-10 855 661	-0.36
Profit for heating energy, EUR	22 427 474	22 492 288	2.30
Overall profit, EUR	12 075 433	12 518 738	3.67

Table 3. Results for the Year with the Highest Average Yearly Electricity Price and Heating Energy Daily Price Scenario

	Before optimization	After optimization	Deviation, %
CCGT heat production hours, h	6 792	6 718	-1.09
HOB operating hours, h	2 537	1 941	-23.49
BIO CHP operating hours, h	4 166	4 992	19.83
Heat produced by CCGT, MWh	1 288 275	1 183 850	-8.11
Heat produced by HOB, MWh	268 927	226 008	-15.96
Heat produced by BIO CHP, MWh	910 059	1 057 402	16.19
CCGT profit for heating energy, EUR	9 123 715	8 606 193	-5.67
CCGT profit for electricity, EUR	10 144 276	10 110 785	-0.33
HOB profit for heating energy, EUR	-3 133 564	-2 390 136	-23.72
BIO CHP profit for heating energy, EUR	10 272 247	11 037 708	7.45
BIO CHP profit for electricity, EUR	-4 777 407	-4 332 690	-9.31
Profit for heating energy, EUR	16 262 398	17 253 765	6.10
Overall profit, EUR	21 629 267	23 031 860	6.48

Results for week-ahead projected heating energy prices are presented in Tables 4 and 5. The results showed similar tendencies with those demonstrated in Tables 2 and 3. Thus, more significant changes appear in profit for heating energy showing a higher decrease of profit for CCGT, lower decrease of losses for HOB and higher rise in profit for BIO CHP. As a result, the coalition made additional 461 428 EUR profit in the year with the lowest average yearly electricity market price and 1 445 438 EUR profit in the year with the highest average yearly electricity market price, which could be comparable to the day-ahead market scenario and was not enough to compensate overall lower profit. Week-ahead heating energy prices lead to loss of revenue for energy sources due to uncertainties for such a long time span.

Table 4. Results for the Year with the Lowest Average Yearly Electricity Price and Heating Energy Weekly Price Scenario

	Before optimization	After optimization	Deviation, %
CCGT heat production hours, h	4472	4 537	1.45
HOB operating hours, h	4 182	3 756	-10.19
BIO CHP operating hours, h	5019	5 393	7.45
Heat produced by CCGT, MWh	850 453	819 964	-3.59
Heat produced by HOB, MWh	522 917	498 100	-4.75
Heat produced by BIO CHP, MWh	1 105 751	1 157 813	4.71
CCGT profit for heating energy, EUR	8 785 257	8 588 098	-2.24
CCGT profit for electricity, EUR	543 077	432 111	-20.43
HOB profit for heating energy, EUR	-3 616 430	-3 397 972	-6.04
BIO CHP profit for heating energy, EUR	15 514 965	16 026 603	3.30
BIO CHP profit for electricity, EUR	-10 773 503	-10 734 046	-0.37
Profit for heating energy, EUR	20 683 792	21 216 729	2.58
Overall profit, EUR	10 453 366	10 914 794	4.41

Table 5. Results for the Year with the Highest Average Yearly Electricity Price and Heating Energy Weekly Price Scenario

	Before optimization	After optimization	Deviation, %
CCGT heat production hours, h	6 745	6 671	-1.10
HOB operating hours, h	2 537	1 940	-23.53
BIO CHP operating hours, h	4 118	4 944	20.06
Heat produced by CCGT, MWh	1 278 086	1 173 661	-8.17
Heat produced by HOB, MWh	273 717	225 773	-17.52
Heat produced by BIO CHP, MWh	897 517	1 046 458	16.59
CCGT profit for heating energy, EUR	9 038 790	7 923 570	-12.34
CCGT profit for electricity, EUR	10 304 741	10 271 250	-0.33
HOB profit for heating energy, EUR	-3 843 747	-3 116 027	-18.93
BIO CHP profit for heating energy, EUR	8 831 410	10 253 123	16.10
BIO CHP profit for electricity, EUR	-4 743 137	-4 298 421	-9.38
Profit for heating energy, EUR	14 026 453	15 060 666	7.37
Overall profit, EUR	19 588 057	21 033 495	7.38

Graphical results of optimisation are presented in Figs. 1 and 2 for the same day of the year with the highest average yearly electricity market price. During first 7 hours and last 3 hours of the day, electricity prices were below 63 EUR/MWh, the prices during the remaining hours of the day were higher. Heat demand was stable almost all day long. Before optimization, CCGT raised both electrical and thermal power to maximum when electricity price increased. Due to heating energy balance, this led to a decrease in heating power of BIO CHP, which also resulted in reduction of electricity production because of inability to operate in a condensing mode. After optimization, CCGT kept heating energy all day long below 332 MW to allow BIO CHP to operate at its maximum, granting as much as possible electrical energy to raise overall income of the coalition due to very high electricity prices. Before optimization, heating load was covered by the source with the lowest heating energy costs calculated by Eq. (1). After optimization, little loss in income for heating energy was made to gain higher profit during hours with high electricity prices, which led to overall greater income.

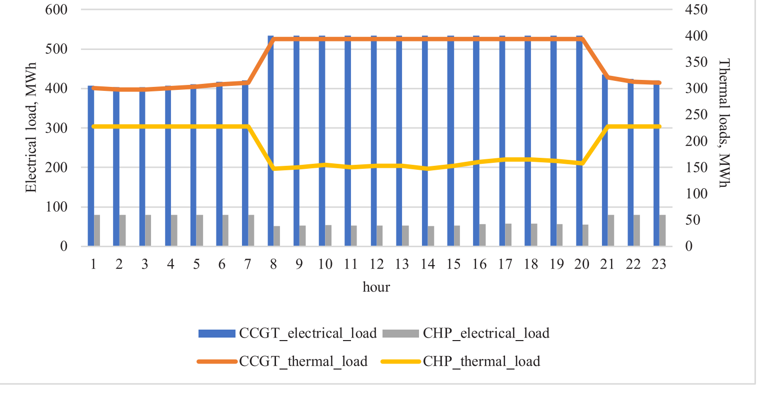

Fig. 1. Dispatch of electrical and heating load, 18 December 2018.

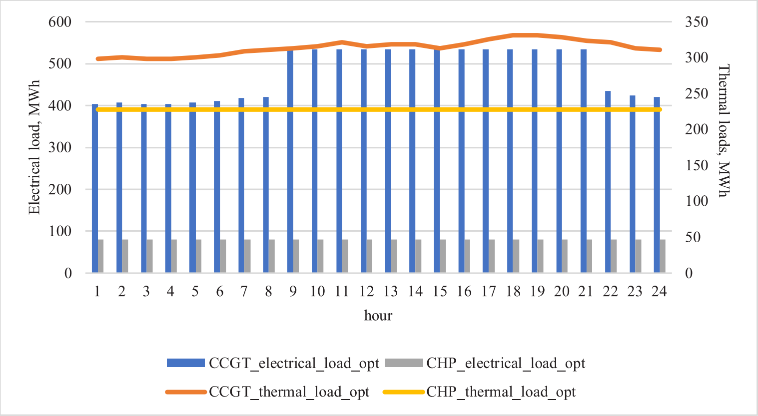

Fig. 2. Dispatch of electrical and heating load after optimization, 18 December 2018.

For both years and heating energy market scenarios, growth in profit was achieved; this additional profit was divided according to the Shapley value between energy sources that formed the coalition. In this case study, CCGT and HOB are considered to be one player. The second player is wood chip CHP. Results of profit split by the Shapley value are presented in Tables 6 and 7; only data for the day-ahead heating energy market are presented. As there are only two players, all additional profit is divided between parties, granting equal additional income. Comparing the results of Tables 2 and 3 to those of Tables 6 and 7, it becomes obvious that the use of the Shapley value is necessary to make players interested in participation in the coalition. Table 3 shows that an overall increase in profit of CCGT and HOB is only 192 415 EUR, but after the use of the Shapley value (Table 7), an increase is 701 296.5 EUR.

Table 6. Shapley Value of the Case Study for Heating Energy Day-Ahead Market in the Year with the Lowest Average Yearly Electricity Price

	CCGT+HOB	BIO CHP
Profit before optimization, EUR	6 042 994	6 032 439
Profit after optimization, EUR	6 183 033	6 335 705
Shapley value, EUR	6 264 646.5	6 254 091.5
Increase in profit for heating energy, EUR	221 652.5	221 652.5

Table 7. Shapley Value of the Case Study for Heating Energy Day-Ahead Market in the Year with the Highest Average Yearly Electricity Price

	CCGT+HOB	BIO CHP
Profit for heating energy before optimization, EUR	16 134 427	5 494 840
Profit for heating energy after optimization, EUR	16 326 842	6 705 018
Shapley value, EUR	16 835 723.5	6 196 136.5
Increase in profit for heating energy, EUR	701 296.5	701 296.5

The case study indicated a problem with the number of start-ups, which was essential in case of CCGT and CHP power plants because of significant costs of start-ups for both gas fired and wood chip fired CHPs [31], [32]. Numerous star-ups can also lead to technical problems of the main equipment [33]. For example, in case of the year with the lowest average yearly electricity market price and day-ahead heating energy market, there were 410 CCGT start-ups before optimization, but after optimization – 426. Both numbers indicate almost 10 times higher than the usual number of start-ups for Latvian CCGTs. For BIO CHP, the number of start-ups before optimization was 246 and after optimization – 215, which showed a 12.6 % decrease, but still it was a very high number of start-ups. To avoid such a significant number of start-ups, objective function (4) should be modified by adding additional costs for start-ups of energy sources, also start-up time should be considered. This additional constraints should be considered in calculations before optimization.

4. CONCLUSIONS

The developed methodology and proposed optimization objective function were tested on historical hourly data and proved to be efficient for dispatching different heating energy and electricity sources in order to gain higher overall profit from the formed coalition, considering participation in both electricity and district heating markets and ensuring heat energy delivery corresponding to the demand. The use of the Shapley value allows rewarding players according to their input in the total coalition profit, thus granting an increase in profit to all involved parties.

The Shapley value allowed splitting additional profit between coalition parties after optimization in such a way that all involved parties increased their profit from electricity and heating energy trading. This additional profit could be used to partly compensate heating energy tariffs for district heating users.

Comparison of two heating energy market price formation models shows that the day-ahead heating energy market can grant higher overall profit to market participants than the week-ahead market price. It could be explained by higher uncertainties for longer time span, but it was not under the scope of this study. Optimization results show an identical increase in profit for both day-ahead and week-ahead markets. In case of the week-ahead market, additional profit is not enough to compensate loses in profit comparing to a scenario with the day-ahead heating energy prices.

Both initial data and optimized data indicate hundreds of start-ups per year for the studied technologies, which in reality are impossible for BIO CHPs and quite harmful for CCGTs. This should be considered in the next study.

To solve objective function (4), a special program solving MILP was developed, and data for optimization could be uploaded in Microsoft Excel format. Total calculation time and generation of resulting file take under 1 minute for one year calculations for three different energy sources. The use of such a program could be very handful because it is based on common computing programs.

5. FURTHER RESEARCH

The proposed optimization objective function should be extended and include start-up costs and time of technologies as well as costs of CO_2 emission footprint. It should also be extended by means of heating energy and electrical energy storage, as well as electrical HOBs.

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ASSESSMENT OF PV INTEGRATION IN THE INDUSTRIAL AND RESIDENTIAL SECTOR UNDER ENERGY MARKET CONDITIONS

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The paper assesses the integration of solar photovoltaic technology in the industrial and residential sectors under energy market conditions. The aim is to determine and compare the payback period for the use of solar photovoltaic technology between the industrial and residential sectors, taking into account the application of optimal load scheduling and level of direct consumption. The industrial sector is represented by a glassware company. Installing PV technologies for a larger area and power is cheaper than installing low-power solar photovoltaic technologies. In addition, direct consumption has significant benefit due to high network service tariffs.

Keywords: *Industrial consumer, load scheduling, payback period, prosumer, PV technology, optimisation.*

1. INTRODUCTION

Renewable energy sources (RESs), such as wind and solar energy, have the potential to reduce dependence on fossil fuels. The share of RESs employed in meeting the global energy demand is expected to grow by one fifth in the next five years and to reach 12.4 % in 2023. In the near future, RESs are forecast to meet more than 70 % of the growth in global electricity generation, led by solar photovoltaic technology (PV) and followed by wind, hydropower and bioenergy [1].

The electricity sector continues to have greatest opportunity for RESs, with an exponential growth in the use of solar PV in recent years. More than 486 GW of installed capacity makes solar energy the third largest RES in the world, with photovoltaic technology being dominant [2]. PV is in high demand in the global solar energy market for both residential and industrial buildings. In addition, the cost of PV has been reducing in recent years [3]. This has encouraged the introduction of feed-in tariff programmes in many countries. However, implementing a net metering policy poses a key challenge. Net metering is important for residential consumers [4] as PV creates a significant amount of surplus power during the middle of the day, when households typically consume less power [5].

A significant volume of research has investigated the opportunities and challenges associated with the wide-spread deployment of PV [6]. An analysis of several publications that have examined the use of PV technology in industry is presented in [7].

Unlike traditional fossil fuel plants and renewable electricity production forms (such as biomass, pumped hydropower and geothermal energy), wind and the sun only provide power when the RES is available. This makes them less predictable. The variability in electricity power generation must be accounted for in order to maximise the penetration of renewable energy into the power system, and ensure a match between electricity supply and demand at all times. To avoid imbalances that jeopardise system stability, action to introduce new energy storage and demand response (DR) technologies will be required.

DR provides an opportunity for consumers to play a significant role in the operation of the electric grid by reducing or shifting their electricity use during peak periods in response to time-based rates or other forms of financial incentives [8], [9]. The electric power industry considers DR programmes to be an increasingly valuable approach to resource management, with capabilities and potential effects being expanded by grid modernisation and smart metering efforts. DR decreases the need for local network investment, as it can shift consumption away from peak periods, with the greatest benefit in regions with a network capacity close to maximum.

To fulfil the energy goals of the European Union and its political promises, the full range of demand-side resources, available at competitive prices, must be engaged, and all consumers must have the ability to benefit from their flexibility [10].

The EU Energy Efficiency Directive encourages energy auditing and the implementation of energy efficiency measures at SMEs (small and medium-sized enterprises) [11]. In response, legislation in Latvia stipulates that enterprises with the high energy consumption have to comply with the energy efficiency standard LVS EN ISO 50001:2012 [12]. However the standard LVS EN ISO 50001:2012 currently lacks coordination between energy efficiency and DR and only refers to using less primary energy.

Much work has been done in recent years to implement industrial demand-side management at energy-intensive enterprises. The focus has been to develop models and optimisation algorithms to provide effective solutions for real-life production scheduling. Scheduling has been receiving considerable attention from the Process Systems Engineering Community, particularly for batch plants. The review paper by Méndez et al. (2006) provides a classification and a conceptual overview of the most important approaches. Research in the past 15 years has focused on continuous-time formulations [13]–[16].

However, the literature on PV and algorithms for optimal load scheduling has not fully considered coordination of load scheduling with PV technology.

The present study compares the payback period (PP) of the use of PV technology between the industrial and residential sector, taking into account the application of optimal load scheduling for industry. The study:

- determines the amount of electricity that can be produced by PV considering typical solar irradiation and the capacity of the PV;
- considers optimisation of load scheduling;
- determines the cost, revenue and savings considering market conditions;
- considers the electricity price policy and optimal load scheduling for the case study of a factory to determine the PP of the PV technology.

The main contributions of the paper are as follows:

- comparison of the PP of PV technologies for an enterprise and for a household;
- analysis of the effectiveness of the proposed approach.

The rest of the article is organised as follows: Section 2 is devoted to the description of the methodology, models, constraints and the rules of the current billing system. Section 3 contains a description of the initial data and assumptions, as well as reflects the calculation results of the NPV of PV technologies. The last section is devoted to conclusions.

2. METHODOLOGY AND MODELS

A. PV Generation

Geographical and weather conditions are inherently important for PV systems. As an example, Latvia has similar potential to use solar energy as Germany and England, where PV technologies have been widely used [17].

The evaluation of PV generation can be performed by using two approaches:

1. A theoretical (statistical) approach, where PV generation is modelled using constant and time-varying parameters. One of the simplified methods for the calculation of hourly PV-generated electricity ($W_{gen.PV,t}$) is as in (1):

$$W_{gen.PV,t} = Rad_t \cdot \eta_{PV} \cdot S_{PV} = Rad_t \cdot \eta_{PV} \cdot 6.4 \cdot W_{PV}, \tag{1}$$

where
t – time step, usually one hour; S_{PV} – the rated area of installed PV technology, m^2; η_{PV} – efficiency of the PV; 6.4 – an area corresponding to 1 kW of installed capacity, m^2/kW [18]; W_{PV} – PV capacity, kW; Rad_t – hourly solar irradiation, kWh/m^2.

Solar irradiation is determined by considering Latvian hourly irradiation data received from the meteorological service [19].

2. An experimental approach, where the generation of the PV is determined from locally measured data.

Figure 1 shows a comparison of the two approaches for a specific plant, which is located in the city of Jelgava. The maximum power for the PV is 5.88 kW.

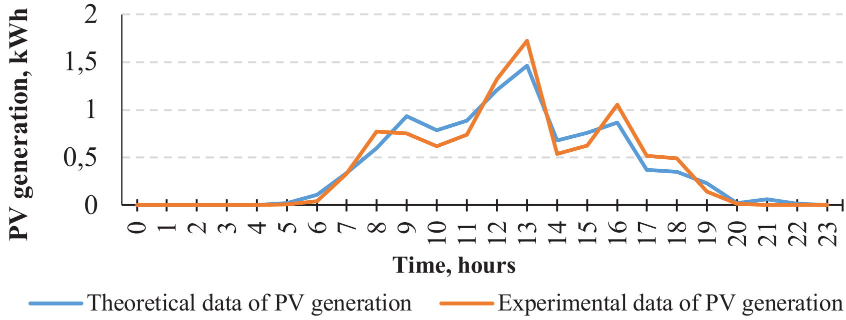

Fig. 1. Fragment of hourly PV generation data of the plant in Jelgava (24/06/2018).

In Fig. 1, we observe that the PV generation by the theoretical approach is similar to the experimental data, with an error of 20% on average. This difference is due to local weather phenomena (cloud cover) or influence of specific sight (trees, buildings, etc.). Many factors affect the accurate determination of PV generation [21]; however, we consider statistical data to be sufficiently accurate for this work, and data are taken from the open access database, *SolarEdge* (country: Latvia) [20].

B. Electricity Billing System and Avoided Cost

We use the Latvian model of electricity billing for electricity tariffs. This consists of five components: the energy price (p); a capacity-based connection fee paid to the distribution system operator ($p_{con.distr}$); an energy-based electricity distribution fee ($p_{en\,distr}$); the mandatory procurement component for the connection ($p_{con.mpc}$); and for the electricity consumed from the grid ($p_{en\,mpc}$).

To determine the economic efficiency of PV, we calculate the avoided cost (AC) for the factory, where AC ($C_{AC\_total,y}$ (€)) is defined as the sum of two terms: the difference between the cost of energy in the case when no PV technology is installed (($C_{base\ y}$) (€)) and the cost of energy when using PV technology ($C_{PV,y}$) (€)); and the difference between the cost of energy in the case when no load scheduling is applied (($C_{base\ y}$) (€)) and the cost of energy when load scheduling is applied ($C_{LS,y}$) (€)). Thus, the total AC for a year, y, is as (2):

$$C_{AC\_total,y} = C_{AC_{PV},y} + C_{AC_{LS},y} = \left(C_{base,y} - C_{PV,y}\right) + \left(C_{base,y} - C_{LS,y}\right), \tag{2}$$

where

y – the discretisation step in the planning period of the cash flow, usually one year; $C_{AC_{PV}\,y}$ – cost avoided that is considered as the difference between the cost of the electricity consumed when PV technology is not installed and optimal load scheduling is not used ($C_{base,y}$), and the cost when it is installed ($C_{PV\ y}$) and load scheduling is used, in year y, €; $C_{AC_{LS}\,y}$ – cost avoided that is considered as the difference between the cost of electricity consumed when PV technology is not installed and optimal load scheduling is not used ($C_{base,y}$), and when only load scheduling is applied ($C_{LS,y}$), in year y, €.

The annual cost (C_y) for the energy consumption of the factory before PV installation and before the use of load scheduling is estimated as (3):

$$C_y = C_{base,y} = p_{con.distr} + p_{con.mpc} + \sum_{d=1}^{365}\sum_{t=1}^{24}\sum_{n=1}^{N} W_{cons,n}^{t,d} \cdot (p^{t,d} + p_{en.distr}^{t,d} + p_{en.mpc}^{t,d}), \tag{3}$$

where

$C_{base,y}$ – the cost of energy consumption before PV installation and before the use of load scheduling in year *y* (the base case), €; *N* – the number of production processes; $W_{cons,n}^{t,d}$ – the energy consumption of the *n*-th manufacturing process in the factory at hour *t* on day *d*, kWh.

The annual cost for the factory after installing PV technology ($C_{PV,y}$) and after the use of load scheduling ($C_{LS,y}$) is as (4):

$$C_{PV,y} = p_{con.distr} + p_{con.mpc} + \left(\sum_{d=1}^{365}\sum_{t=1}^{24}\left(\sum_{n=1}^{N}(W_{cons,n}^{t,d} \cdot (p^{t,d} + p_{en.distr}^{t,d} + p_{en.mpc}^{t,d})\right) - W_{gen.PV}^{t,d} \cdot \left(p^{t,d} + p_{en.distr}^{t,d} + p_{en.mpc}^{t,d}\right)\right), \tag{4}$$

$$C_{LS,y} = p_{con.distr} + p_{con.mpc} + \sum_{d=1}^{365}\sum_{t=1}^{24}\sum_{n=1}^{N} W_{consLS,n}^{t,d} \cdot \left(p^{t,d} + p_{en.distr}^{t,d} + p_{en.mpc}^{t,d}\right), \tag{5}$$

where $W_{consLS,n}^{t,d}$ – the energy consumption of the *n*-th manufacturing process in the factory after load scheduling at hour *t* on day *t*, kWh.

C. Methodology of Feasibility Studies

We investigate and compare the AC that results from the use of PV and load planning. Economic criterion, such as the net present value of the cash flow (NPV), is usually used for analysis; however, the discounted PP (T_{PP}) is also included in this work as it provides a meaningful economic criterion for comparison of PV integration in the industrial and residential sectors. T_{PP} determines the time at which the cumulative savings will exceed the investment cost of the PV technology. It is necessary to notice that, in contrast to the simple PP, the discounted PP takes into account the time value of money [22]. The NPV has been presented in our previous papers [4], [23]. The PP formulation is given in [24], [25]. By using the NPV formulation, the optimisation task can be formulated in the following form:

$$NPV(T_{plan}) = -p_{inv} + \sum_{y=1}^{T_{plan}} \frac{R_y}{(1+i_d)^y}, \rightarrow max, \tag{6}$$

where
T_{plan} – the planning period, years; p_{inv} – initial investment for the PV technology, €; i_d – a discount rate; R_y – a net cash flow, i.e., the difference between inflow and outflow of cash in year y, €.

Forecasts for the parameters are used in this paper. These have been determined from measurements of the parameters under consideration (PV generation ($W_{gen.PV,t}$), electricity consumption ($W_{cons\,t}$), energy price (p_t)) by using a naïve forecasting approach based on the assumption that the values of the parameters remain constant.

3. CASE STUDY

A. The Object under Consideration

The optimisation model was applied to a glass processing company in Latvia, with an annual production of 16,500 m^2 of glass. The glass factory produces several types of glass product.

The finished products, including tempered glass, insulating glass units, laminated glass and structural glazing, undergo six technological processes:

1. Cutting – obtaining semi-finished products for further processing by means of a cutting machine with a capacity of 288 m^2/h;
2. Finishing – providing the glass with a marketable condition and observing the process requirements for further manufacturing processes; for this purpose, three machines with a total capacity of 150 m^2/h can be used;
3. Tempering – providing the glass with special physical properties. If necessary, using it in further manufacturing processes, equipment capacity 144 m^2/h. It should be noted that the energy consumption for glass tempering is continuous. The equipment consumes a significant amount of electricity even in standby mode;
4. Lamination – gluing two or more glass sheets together; a machine with a capacity of 1.33 m^2/h is used;
5. Insulating – producing insulating glass units with a capacity of 50 m^2/h;
6. Painting – a capacity of 50 m^2/h.

The average time and electricity consumption to produce 1 m^2 of finished glass product will depend on the type of finished product. Other factors that affect electricity consumption include the thickness, size, and shape of the glass, which are not considered in this analysis.

The various products involve many different processes. The processes for the most common products are detailed here and shown in Fig. 2:

1. Structural glazing – cutting and finishing;
2. Insulating glass in single-chamber form (two sheets of glass): cutting, finishing and insulating;
3. Tempered glass – cutting, finishing and tempering;
4. Laminated glass – cutting, finishing, tempering and lamination;
5. For insulating glass in two-chamber form (three sheets of glass) – cutting, finishing, tempering and insulating;
6. Insulating glass in single-chamber form (two sheets of glass) with painting and insulating glass in two-chamber form (three sheets of glass) with painting – cutting, finishing, painting, tempering and insulating.

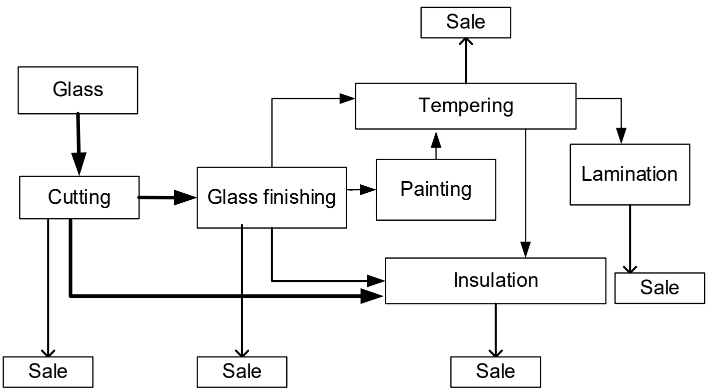

Fig. 2. Production process scheme.

The monthly production data for products and the use of processes are shown in Table 1. The monthly consumption of electricity per unit of production (/m^2) for each process is shown in Table 2.

Table 1. Monthly Production of Goods (m^2)

	m^2	Cutting 1	Finishing 2	Tempering 3	Lamination 4	Insulating 5	Painting 6
Structural glazing	500	500	500				
Insulating glass in single-chamber form (two sheets of glass)	900	1,800	900			900	
Tempered glass	7,600	7,600	7,600	7,600			
Laminated glass	200	400	400	400	200		
Insulating glass in two-chamber form (three sheets of glass)	1,000	3,000	2,000	2,000		1,000	
Insulating glass in single-chamber form (two sheets of glass) with painting	50	100	50	50		50	50
Insulating glass in two-chamber form (three sheets of glass) with painting	150	450	300	150		150	150

Table 2. Monthly Production Data for Goods and Electricity Consumption

	Area of glass, m^2	Electricity consumption, kWh	Specific electricity consumption, kWh/m^2
Cutting	13.85	4,666.60	0.33
Finishing	11.75	4,624.40	0.39
Tempering	10.20	6,4926.30	6.36
Lamination	200	893.01	4.46
Insulating	2.10	5,579.25	2.65
Painting	200	919.81	4.60

The percentage of the electricity consumption for each technological process is shown in Fig. 3. All the processes start with glass cutting. The tempering process takes the greatest amount of electricity and increases the value of the finished product.

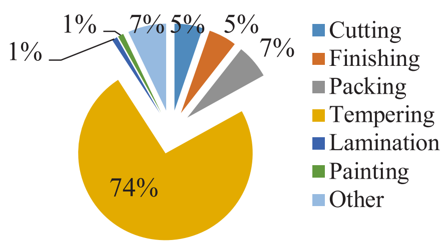

Fig. 3. The percentage share of the production process.

B. The Strategy of Optimal Load Scheduling

In this case study, the production plan is determined by the quantity of glass that has to be processed (m^2). The capacity for each process is given in Table 2, together with the electricity consumption and specific power consumption (kWh/m^2). The sequence of the processes to produce each product is given in Fig. 2, but the time of production can be chosen, taking into account such factors as the electricity price and maximum allowable consumption. Products must be produced as a sequence of processes, but multiple products can be produced at the same time through simultaneous use of the processes: cutting, finishing, packaging, tempering, lamination, and painting.

Load scheduling (production by priority) may be solved by means of linear programming; in this paper, minimising annual cost (C_{base}) for the energy consumption of the factory has been set as the optimisation objective of load scheduling.

Given that production must follow a strict order of process (e.g., cutting, glass finishing, tempering, lamination, insulating and painting), it is important to start with the first process (cutting), followed by any others to produce the finished product (see Table 1).

Allocation of the hourly power for five (out of the six) processes by priority can be achieved by using the following steps. Note that the maximum total energy consumption per hour is constrained. Consideration should also be given to the constraint on the capacity of the first process.

1. Determine the number of hours (NH1) that are required for the first volume process (glass cutting, Fig. 2) for an order.

2. Adjust the timing of the first process so that the total energy consumption remains constant.
3. Determine the number of hours NH2 required for the second process (glass finishing, Fig. 2) for an order. This process should start as soon as possible and run from at least the second hour of the NH1 time period.
4. Determine the number of hours NH3, NH4, NH5 required for any further process steps (glass lamination, insulating and painting, Fig. 2) to complete production that can start at the same time.

The constraints of the task are:

The total hourly consumption of all the processes shall not exceed the maximum permissible consumption for the factory:

$$\sum_{n=1}^{N} W_{cons,n,t} \leq W_{max}, \qquad \forall n \in N, \forall t \in T_{plan}, \tag{9}$$

where

W_{max} – total maximum permitted hourly consumption of the factory, kWh;

The hourly consumption of each process must not exceed its maximum permitted hourly consumption:

$$W_{cons,n,t} \leq W_{\max n}, \qquad \forall n \in N, \forall t \in T_{plan}, \tag{10}$$

where

$W_{\max n}$ – the maximum permitted consumption of the *n*-th process, kWh.

C. Input Data and Assumptions

For the case study, we consider two cases for comparison:

1. The base case, when the factory does not have PV technology and has load scheduling in place.
2. The case when the factory has PV technology and optimal load scheduling is used.

The following conditions are taken into account in the simulation:

a. A fixed fee for connection is applied in accordance with the pricing policy [26].
b. The mandatory procurement component fee is applied in accordance with the pricing policy of 11 July 2018 [27].
c. The charges for system services or distribution and transmission services are applied in accordance with the existing pricing policy. The basic tariff is used [26].
d. The company operates one shift. The shift starts at 8:00 and ends at 17:00. Consequently, the optimisation period for load scheduling is 9 hours.
e. Data for electricity consumption of the factory from 2018 are used.

f. The Nord Pool [28] day-ahead electricity price records from 2018 are used.
g. Energy production data by PV are taken from a specific facility in Latvia [20]. PV installed power is 33 kW.
h. Data for electricity price, PV generation and factory consumption from 2018 are assumed to have remained constant for the analysis period.
i. PV generation is used to provide power supply of the glass tempering line, which works continuously.
j. The distribution fee for energy consumption is divided into three periods according to the S8 tariffs: day zone (7:00 to 8:00, 10:00 to 17:00, and 20:00 to 23:00), peak hour zone (8:00 to 10:00, 17:00 to 20:00) and night zone (23:00 to 7:00).
k. Each process is assigned power consumption per square meter of production of glass (w) as in Table 3.
l. The total maximum hourly permissible consumption (W_{max}) is 550 kWh/h.
m. The maximum permissible consumption for each process is given in Table 4.
n. The optimal load distribution is determined using linear programming.
o. Subsidies are not applied.

Table 3. Specific Consumption Process (kWh/m^2)

Cutting	Finishing	Packaging	Painting	Lamination
w_1	w_2	w_3	w_4	w_5
0.34	0.4	2.65	4.40	4.65

Table 4. Maximum Permitted Consumption (kWh/h)

Cutting	Finishing	Packaging	Painting	Lamination
W_{max1}	W_{max2}	W_{max3}	W_{max4}	W_{max5}
35	35	50	15	15

The NPV is calculated for four alternatives:

1. Alternative 1 – taking a loan and considering the total avoided costs from the PV installation and load scheduling (C_{AC_total}):

$$NPV\left(T_{plan}\right) = -p_{inv} + \sum_{y=1}^{T_{plan}} \frac{C_{AC\_total,y} - \left(\frac{p_{inv}}{T_{plan}} + p_{loan,y} \cdot i\right)}{(1+i_d)^y} , \tag{11}$$

where
$C_{AC\_total,y}$ – total avoided cost (AC) of the consumer in year y, €; – remaining amount of the loan in year y, €; $p_{loan,y}$ – the credit rate, %.

2. Alternative 2 – taking a loan and considering the total avoided costs from the PV installation ($C_{AC_{PV}}$):

$$NPV\left(T_{plan}\right) = -p_{inv} + \sum_{y=1}^{T_{plan}} \frac{C_{AC_{PV},y} - \left(\frac{p_{inv}}{T_{plan}} + p_{loan,y} \cdot i\right)}{(1+i_d)^y} . \tag{12}$$

3. Alternative 3 – without taking a loan and considering the total avoided costs from the PV installation and load scheduling (C_{AC_total}). If the consumer does not take a loan, the second term in the numerator in (11), ($\frac{p_{inv}}{T_{plan}} + p_{loan,y} \cdot i$) is equal to zero.

4. Alternative 4 – without taking a loan and considering the total avoided costs from the PV installation ($C_{AC_{PV}}$) without load scheduling. If the consumer does not take a loan, the second term in the numerator in (12), ($\frac{p_{inv}}{T_{plan}} + p_{loan,y} \cdot i$) is equal to zero.

The economic and technical assumptions are summarised in Table 5

Table 5. Key Assumptions

Name of Parameter; Measuring Unit	Value*
Rated maximum allowable current of the factory, A	909
Electricity distribution tariff	S-8
Mandatory procurement component, €/kWh	0.0178
Electricity distribution fee, €/kWh:	
- day zone	0.039
- peak hour zone	0.055
- night zone/weekend	0.0306
Mandatory procurement component for the connection, €/A/year	8.71
Capacity-based connection fee to the distribution system operator, €/A/year	13.96
Loan interest rate [29], %	2.6
Discount rate, %	2.0
Planning time, years	25
Capacity of PV technology, kW	33
Investment in PV technology, €/kW	1,242.0
Efficiency of PV technology, %	18

*Data for 2019

For this study, we assume that the cost of purchasing and installing the PV system for a 33 kW PV technology is approximately 41,000 € [30]. However, it is expected that in the near future the prices of PV will decrease, which serves as evidence of the real prices for powerful solar stations. For example, in Pärnu, Estonia, the price per kW of a new 3.96 MW solar power plant is 883.83 € [31].

D. Results

The results of energy produced and the AC ($C_{AC_{PV},y}$) from the PV installation in Latvia by month are given in Fig. 4.

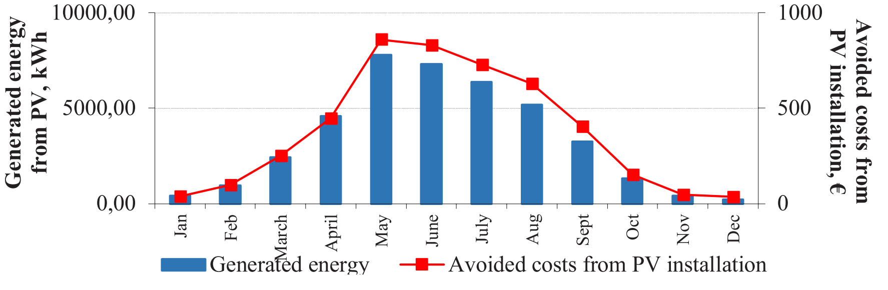

Fig. 4. Energy produced and the AC from PV technology by month.

Figure 4 shows how generation varies by season, with the spring/summer period providing the greatest output.

The annual energy produced by a 33 kW PV technology is 40,015 kWh. We assume all the generated electricity is consumed by the factory in place of electricity taken from the grid. Figure 5 shows an example of the consumption of one process and the energy generated by the PV in May.

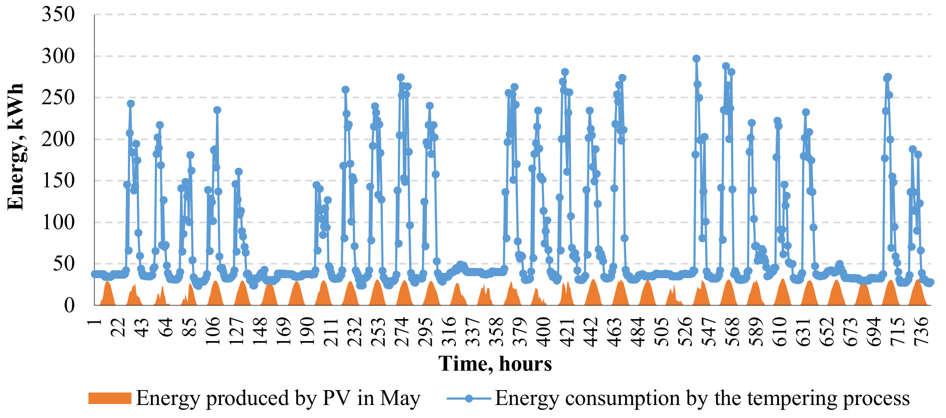

Fig. 5. Energy produced by the PV and the energy consumption by the tempering process in May.

Given all generated electricity is consumed, a net metering system (NMS) [31] is not be required. Information on an NMS can be found in our previous work [32]. Residential PV generation differs in this respect, as it will export to and consume from the grid. Information about the net metering system can be found in our previous work [33].

Figure 6 shows an example of optimal load distribution, with the load distribution before and after optimisation for the glass cutting process.

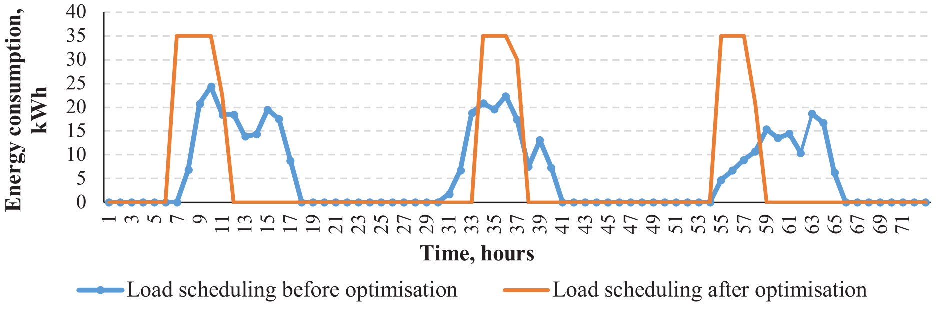

Fig. 6. Fragment of load scheduling before and after optimisation for the glass cutting process (01/01/2018–03/01/2018).

Figure shows that the entire load should be concentrated in the hours when the price is lowest, thereby reducing the energy cost. Figure 7 shows the change in the NPV over time for the four alternatives.

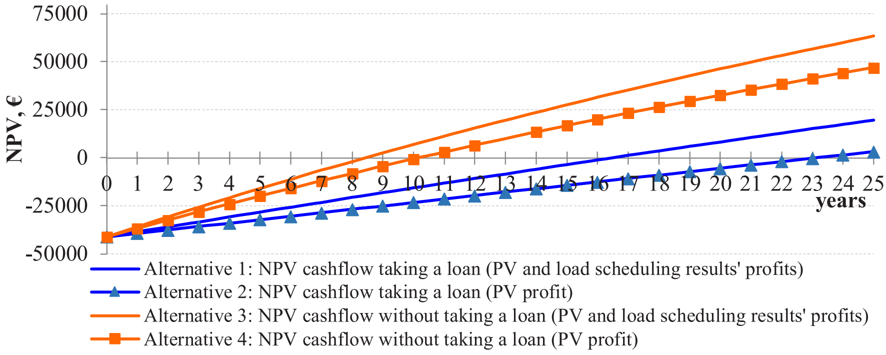

Fig. 7. NPV cash flow.

The annual income to the factory from the utilisation of PV is 4,509 € (Fig. 4), assuming the utilisation of energy is adapted to take full advantage of its generation. The estimated NPV for PV is shown to have a positive tendency. Figure 7 demonstrates that Alternative 3 is the most profitable (no loan with load scheduling); PP is eight years and the total NPV is 63,430 €. Alternative 2 is the least profitable (loan and no load scheduling); PP is twenty-three years and the NPV is 3,346€. For Alternative 1, the PP is sixteen years and for Alternative 4 the PP is ten years.

We use Alternative 2 and Alternative 4 and data from [32] to compare the PP between industrial and residential use of PV technology.

In accordance with the study "Evaluation of the Net Metering System and Suggestions for System Improvements" [33], we would like to emphasise the following input data and conclusions:

- NMS was applied to residential PP. Energy surplus is exported.
- Average Residential PV capacity is assumed to be 5.5 kW.
- Two scenarios of NMS were considered:
  - Case A: it is assumed that there is complete (100 %) direct consumption (DirC) of all generated electricity. In the case of a no-loan situation, the PP is 11 years. In the case of a loan, the PP is 25 years.
  - Case B: export and consumption vary but there is an overall balance in annual electricity use. In the case of a no-loan situation, the PP is 26 years. With a loan, the PP is more than 28 years.

The comparison between the PP of industrial and residential is summarised in Table 6.

Table 6. Payback Period Comparison

Initial data and circumstances	Type of consumer	
	Industrial	Household
Capacity of PV technology, kW	33	5.5
Investments in PV technology, €	40 990	6 000
Payback period, years:		
Without loan	8 (Alternative 3) 10 (Alternative 4)	26 (if DirC is 20 %) 11 (if DirC is 100 %)
With loan	16 (Alternative 1) 23 (Alternative 2)	> 28 (if DirC is 20 %) 21 (if DirC is 100 %)

Table 6 indicates that PV is more profitable for industrial installation (large enterprises) than for residential (small users). This arises from the lower cost of installation for a large power PV than low-power PV and the difference in tariff costs. In addition, direct consumption has a significant impact on the economic benefits of using the PV technology, i.e., the higher the direct consumption, the lower the total cost of electricity. In the case of a factory, the direct consumption is 100 %, whereas typical EU residential direct consumption is between 20 and 30 % [33].

4. CONCLUSIONS

The increase in energy consumption and climate change contribute to a wider use of renewable energy resources. The paper has investigated the economic incentives for use of PV technologies.

Installation and use of PV technology are most beneficial to users with high direct consumption. It is also most financially attractive to users who are able to invest in the PV rather than as a loan. The greatest benefit from PV comes by combining the use of PV and applying optimal load scheduling.

For industrial enterprises, the average PP of the PV technology is 23 years if a loan is taken, compared to 10 years if no loan is taken. For residential users with NMS, the PP is 26 years. Such a PP is too long to incentivise the use of RES technologies.

In all analyses, the prevailing tariffs will affect the PP.

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HEAT PUMP OPTIMIZATION STRATEGIES FOR PARTICIPATION IN PRICE-CONTROLLED DEMAND RESPONSE IN THE LATVIAN ELECTRICITY MARKET

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Improved end-user engagement is considered to be a key factor in decarbonization efforts towards climate neutral energy systems. While first adopters are already actively seeking ways how to optimize their energy consumption, a true shift in consumer behaviour can only be achieved if the financial benefits are well established and presented.

The study aims at estimating the economic performance of end-user engagement in provision of demand response services using air-to-air heat pumps as the underlying technology. The results of the paper help evaluate in a real data setting whether the existing market framework provides sufficient incentives to facilitate end-user participation in the demand response service.

Keywords: *Demand response, electricity price, electricity markets, heat pumps.*

1. INTRODUCTION

Traditionally, the balance between demand and supply in a power system is maintained by adjusting centrally controlled supply to largely inelastic demand. The increase in intermittent and distributed generation [1] as well as a continuous increase in demand for electricity not only promotes volatility of electricity prices, but also creates new challenges for the power system infrastructure. An aspect of this is illustrated by the case of South Queensland (Australia) where during the period of 2009–2014 the total installed capacity of solar panels increased from 187 MW to 4092 MW [2] and percentage of residential consumers with rooftop solar panels reached 25 %. Such a shift reduced electricity volumes consumed through a distribution system but did not have considerable impact on the costs of the system, the volume-based distribution system tariffs increased by 112 % [3].

With the emerging preference for electric transportation and heating, the demand for electricity has even more tendency to cluster in high and low demand periods, which may result in peak load demands increasing faster than the total annual consumption and adding additional price pressures to the electricity and power system alike. On the other hand, technologies enabling demand response offer an opportunity to mitigate the volatility of energy consumption patterns, which could help the power system adjust to the emerging and in some cases already established market requirements. The consideration that improving system flexibility is a key factor in reducing the costs of integrating intermittent generation has also been reinforced by recent studies [4]–[6]. For this reason, encouraging consumer engagement in demand response activities has become an increasingly important energy policy topic [4], [7]–[9]. While there might be a discussion on whether facilitation of consumer engagement in the electricity market is necessary, how to achieve that is a challenge with a less clear solution. The objective of this paper is to compare easy-to-use cost optimization scenarios for an air-to-air heat pump based heating system. The rest of the paper is organised as followed: Section 2 presents market background and legal framework for the Latvian electricity market. Section 3 is devoted to the examination of contributing factors and barriers for consumer participation in demand response. This review serves as the basis for the case study design, which is described in Section 4. In the last section of the paper, the results of the case study and conclusions are presented.

2. BACKGROUND AND LEGAL FRAMEWORK

The EU energy policy foresees increased importance and integration of demand response, facilitated by smart meter rollouts, supportive legal framework and active consumer education. The recital of Council Directive 2019/944/EU (2019) foresees that "[..]Consumers should have the possibility of participating in all forms of demand response. They should therefore have the possibility of benefiting from the full deployment of smart metering systems and, where such deployment has been negatively assessed, of choosing to have a smart metering system and a dynamic electricity price contract. This should allow them to adjust their consumption according to real-time price signals that reflect the value and cost of electricity or transportation in different time periods, while Member States should ensure the reasonable exposure of consumers to wholesale price risk. Consumers should be informed about benefits and potential price risks of dynamic electricity price contracts […]". In its turn, Article 11 stipulates that "Member States shall ensure that the national regulatory framework enables suppliers to offer dynamic electricity price contracts. Member States shall ensure that final customers who have a smart meter installed can request to conclude a dynamic electricity price contract with at least one supplier and with every supplier that has more than 200 000 final customers" [10]. According to CEER in 2018, 21 out of 27 Member States offered some type of variable price contracts and only in 15 out of 27 Member States spot-price tied contracts were available to residential users [11].

Electricity market liberalization started in Latvia in 2007 when the option to freely choose an electricity supplier was offered to business consumers with high consumption. Furthermore, such an opportunity was offered to business consumers with medium consumption on 1 April 2012 and to all other business consumers on 1 November 2012. The market was opened to residential consumers on 1 January 2015. While the electricity suppliers in Latvia are required to offer a "universal product" to residential consumers, the Latvian legal framework does not require electricity suppliers to offer dynamic electricity price contracts. According to the data published by the Public Utilities Commission of Latvia, 12.5 % (a three-fold increase from the end of 2017) of residential consumers and 42.8 % of business consumers (~30 % increase from the end of 2017) chose a dynamic pricing type of contract (Figs. 1 and 2) [12]. Currently, most of electricity suppliers provide some type of dynamic price contracts (either time-of-use [13] or spot-price tied [14]) to both business and residential consumers.

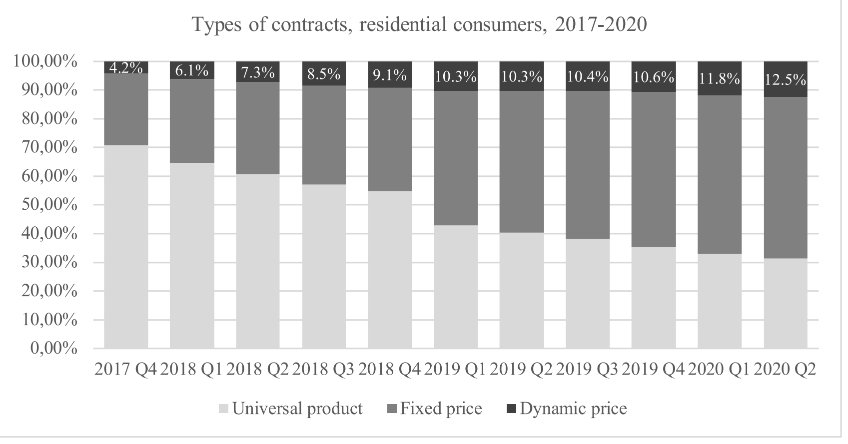

Fig. 1. Contract type structures for residential consumers in Latvia, 2017–2020. Data source: [11].

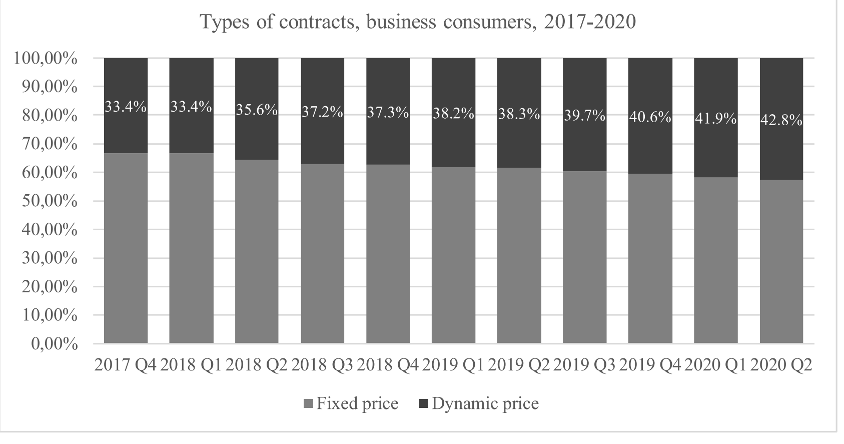

Fig. 2. Contract type structures for business consumers in Latvia, 2017–2020. Data source: [11].

To look at overall consumption pattern trends in Latvia, the year 2020 is excluded due to a considerable, but not easily measurable impact of pandemic. By comparing day-ahead market volumes for 2017 and 2019, it can be observed that while the overall volumes increased the volatility of the volumes bought decreased (see Table 1) [15]. Despite a positive trend, more research should be conducted to explore the drivers behind it. The data also show high variations between peak and off-peak demand and a potential for an implicit demand response to facilitate it.

Table 1. Comparative Descriptive Statistics for Energy Volumes Sold on NordPool Day-Ahead Market in 2017 and 2019 [14]

Parameter	2017	2019	Deviation
Sum	7.2 TWh	7.3 TWh	+0.7 %
Mean	828 MWh	834 MWh	+0.7 %
Standard deviation	177 MWh	167 MWh	-5.9 %
Range	828 MWh	742 MWh	-10.4 %
Minimum volume	444 MWh	479 MWh	+7.9 %
Maximum volume	1 272 MWh	1 222 MWh	-4.0 %

3. BARRIERS FOR CONSUMER ENGAGEMENT IN DEMAND RESPONSE

Residential consumer engagement (or lack of it) can be divided into stages, each characterised with different preconditions. EPRI (2012) proposes the following three-step structure: participation (being enrolled in demand response), performance (responding in the desired way) and persistence of effects over time (Fig. 3) [4], [16].

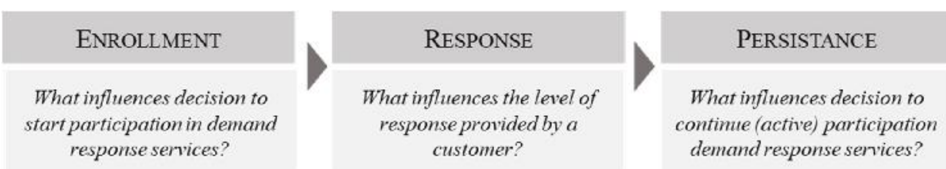

Fig. 3. Three stages of consumer engagement in demand response. Adapted from [3].

Understanding the barriers and drivers of long-term active participation in demand response can allow policy makers and market actors to identify and foster consumer engagement in a more cost-effective way and assess the potential for demand side response participation in a more precise manner.

Parrish et al. (2020) identified the following types of motivators: financial, environmental and social. Based on multiple studies, the financial incentives are the most important [4], [17]–[23]. Financial incentives include reduced monthly bill, rewards for specific consumption patterns, free or reduced cost technology [4]. Environmental motivators are less studied and seem to play a less important role as participation in demand response does not necessarily decrease the overall consumption [4], [24]. Social motivators include increased perceived control over energy consumption

[17], [24], finding the experience novel and entertaining [17] or taking pride in being socially responsible or supportive to the energy system [4], [25], [26].

These benefits or motivators are usually weighed against effort, time, convenience, and comfort [4], [27]–[29]. Based on the systemic review by [4], real financial benefits serve as a necessary precondition for meaningful participation in implicit demand response activities.

4. CASE STUDY DESIGN

Heating, ventilation, and air conditioning (HVAC) systems have a tendency in developed countries to become more prevalent over time [30]. For example, in Latvia, 6 % of residential buildings had electricity-based heating and ~2 % of residential buildings had air conditioning in 2015 [31]. It should be noted that HVAC tends to be one of the most energy intensive residential types of electric appliances. The exact estimation for the proportion of electricity consumption for which HVAC is responsible is hard to come by as these estimates will differ on climate, building and other appliances. On average, it is considered that heating is responsible for up to 50 % of the monthly electricity consumption during a peak demand period [32].

By reviewing the existing literature on HVAC control system testing and designing, it can be observed that while there are different energy efficiency objectives or particular challenges of multi-building or multi-zonal systems, a general approach to introducing deterministically controlled HVAC system is fairly simple and requires data collection, algorithm and load controller device [32]–[35]. The objective of this study is to evaluate in a real data setting the most appropriate algorithm for implementing automatic and cost-efficient HVAC system management that relays on publicly available data. To achieve the objective for the set period of time (in December 2020 and January 2021), four HVAC systems were monitored. Afterwards, alternative optimization approaches were tested. The best performing algorithm is further intended to be used for HVAC management. Table 2 and 3 present the case study environment and describe the data used, respectively.

Table 2. Description of the Case Study Environment

HVAC systems used	One Toshiba Premium air-air type of heat pumps (RAS-25PAVPG-ND), with heating capacity of 0.7–6.70 kW and three Toshiba Optimum (RAS-25PKVSG-ND) heat pumps 1.00–6.50 kW were chosen
Area	Two isolated rooms of 26 m^2 (set indoor temperature of 17 °C) and 23 m^2 (set indoor temperature of 17 °C) and a large hall of 70 m^2 (set indoor temperature of 19° C with some HVAC unrelated temperature fluctuations due to ventilation or use of other devices)
Period	24 days, December 2020–January 2021

Table 3. Description of the Data Used in the Case Study

Outside temperature	Factual hourly data from metrological data from the Latvian Environment, Geology and Meteorology Centre (°C) [35]
Day-ahead prices	Factual hourly data from NordPool exchange (EUR/MWh) [15]
Heat pump load	Measured every minute (MW)

In the context of this study, the following assumptions (simplifications) were made – firstly, the load was only shifted and there was no reduction of total consumption (rebound effect expected to be 100 %). The consumption from the hour when the system is turned off is shifted to the next two hours. The determination of the exact nature of the rebound effects in different conditions is outside the scope of this study and is left for further research. This assumption prescribes that switching off may not occur more often than once every two hours (the condition is also observed during the date change).

The following optimization scenarios were devised (Table 4).

Table 4. Optimization Scenarios Used in the Case Study

Scenario	Conditions	Objective
Selecting two hours in every given day, when the HVAC is switched off, is based on the following criteria:		
2-1	The lowest temperature	Representation of the highest expected consumption [36]
2-2	The highest day-ahead price	Representation of the highest cost per MWh
2-3	The highest projected cost savings from load shifting	Representation of the highest total gains from shifted consumption
Selecting three hours in every given day, when the HVAC is switched off, is based on the following criteria:		
3-1	The lowest temperature	Representation of the highest expected consumption
3-2	The highest day-ahead price	Representation of the highest cost per MWh
3-3	The highest projected cost savings from load shifting	Representation of the highest total gains from shifted consumption

The highest projected costs savings (C_{H0}) from load shifting were calculated as follows:

$$C_{H0} = E_{H0} \times P_{H0} - E_{H0} \times \frac{P_{H1}+P_{H2}}{2}, \qquad (1)$$

where
C_{H0} – expected costs savings from load shifting (EUR);
E_{H0} – energy volume shifted from hour H_0 to hour H_1 and H_2 (MWh);
P_{H0}, P_{H1}, P_{H2} – day-ahead price for hour H_0, hour H_1, hour H_2, respectively (EUR/MWh).

The expected energy volume E_{H0} shift was calculated based on the empirically obtained relationship for a particular HVAC system:

$$E_{H0} = 0.001288 - 0.00015\ T_{H0}, \qquad (2)$$

where
T_{H0} – expected temperature at hour H_0 (°C).

The empirical equitation (Fig. 4) was obtained by applying linear regression to the empirical consumption and factual temperature data from the case study.

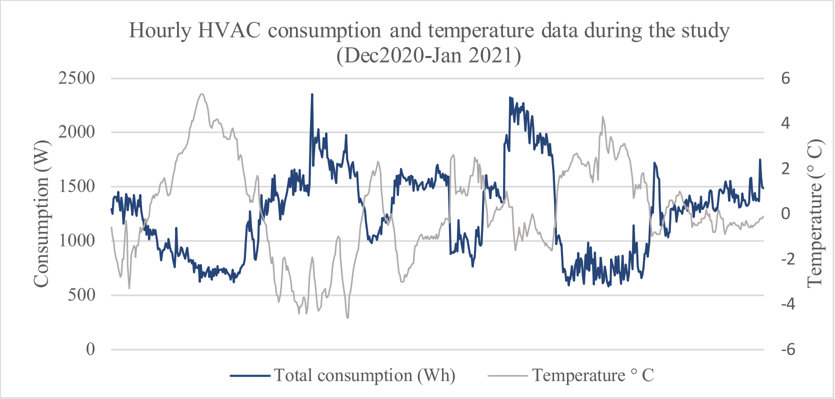

Fig. 4. Hourly HVAC consumption and temperature data during the study. Temperature data source [34].

The optimization algorithm selects the best fit based on the conditions described above. In case the best fit violates the condition that HVAC may only be switched off no more often than once every three hours, the next best fit is selected.

5. RESULTS AND CONCLUSIONS

During the observation period the following data were collected in regard to outdoor temperature, day-ahead price and actual HVAC consumption (Table 5).

Table 5. Descriptive Statistics of Temperature, Electricity Price and HVAC Consumption during the Case Study. Data sources – temperature [34], electricity prices [14]

Parameter	Temperature (°C)	Day-ahead price (EUR/MWh)	HVAC actual consumption (kWh)
Mean	0.1	43.89	1.26
Range	9.9	197.21	1.77
Minimum	-4.6	2.75	0.58
Maximum	5.3	199.96	2.36

The scenarios previously described provide the following outcomes (Table 6).

Table 6. Optimization Scenario Output Comparison

Scenario	# of hours selected per day	Total consumption (kWh)	Total cons. shifted (kWh)	Percentage of cons. shifted	Total cost of electricity (EUR)	Cost difference from base scenario
Base	0h	748.42	-	-	33.58	-
2-1	2h	748.42	70.94	9.5 %	33.58	0.01 %
2-2	2h	748.42	65.37	8.7 %	32.94	-1.90 %
2-3	2h	748.42	67.42	9.0 %	32.18	-4.18 %
3-1	3h	748.42	104.64	14.0 %	33.54	-0.13 %
3-2	3h	748.42	97.36	13.0 %	32.68	-2.69 %
3-3	3h	748.42	99.43	13.3 %	31.97	-4.81 %

The relative performance of the scenarios was similar in both two-hour and three-hour scenario groups. The highest load shift was observed in a scenario where the load was shifted away from the coldest hours (in a two-hour scenario – 9.5 % of total load was selected, while in a three-hour scenario 14.0 % of load was shifted). However, neither scenario 2-1 nor 3-1 resulted in noticeably different total costs regarding the base case scenario. This might be related to the following: the coldest hours are typically during the night when the electricity price dynamic is less pronounced. Scenarios 2-2 and 3-2 in both two-hour and three-hour groups demonstrated similar relative performance in their scenario groups; however, the best performing scenario was 2-3 and 3-3 that considered both the expected difference in price and the expected loads. The improved economic performance over scenario 2-2 and 2-3 is considerably higher than the increased load shift. This indicates that a sub-optimal choice is considering day-ahead prices and not taking into account the expected consumption level.

Overall, results of the case study suggest that the immediate benefits from load-shifting are modest. Taking this into account, if the energy policy maker considers and identifies that active engagement of residential consumers in implicit demand response activities is pivotal for better integration of intermittent and distributed generation as well as power system optimization, additional incentives reflecting overall system benefits from more moderate peak and off-peak loads might be considered.

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SIMPLIFIED MODEL FOR EVALUATION OF HYDROPOWER PLANT CONVERSION INTO PUMPED STORAGE HYDROPOWER PLANT

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Increasing capacity of intermittent generation brings new challenges to balance demand and supply in power systems. With retirement of conventional fossil generation, the role of energy storage is increasing. One of the most competitive storage technologies is pumped storage hydropower plant (PSHP). Usually, such PSHPs are constructed as green field solutions, but in some cases conversion of a hydropower plant into a pump storage hydropower plant by building a pump station is possible. To evaluate the feasibility of such modernisation it is necessary to estimate the benefits of PSHP operation. The simplified model was developed for simulation of charging and discharging cycles of PSHP in Latvian power system and trading electricity in Nord Pool power exchange. The nature of this task is stochastic as the price volatility has a trend to increase with expansion of wind and solar power plant capacity. Results of PSHP operation simulation were then used in the economic model to evaluate the feasibility of the proposed conversion.

Keywords: *Feasibility of conversion, price volatility, pump station, pumped storage hydropower plant (PSHP), simulation of storage operation.*

1. INTRODUCTION

Among other targets, the European Green Deal provides the plan for decarbonisation of energy sector, where the major role is given to renewable energy sources [1]. Without any doubt, it is the right strategy to combat the climate change, but to implement this policy, the industry is facing some technical challenges. One of the most complicated tasks is ensuring the security of electricity supply in the situation of growing capacity of intermittent generation, such as wind and solar. In power system with a high share of wind and solar, there are periods with high output of wind and solar when its capacity may exceed the demand, resulting in electricity prices close to zero or even negative. The opposite situation, which the German Energy Community calls “Dunkelflaute”, is the case with low wind and solar and, respectively, with high electricity prices [2]. Decommissioning of existing conventional fossil fuel-based power plant fleet is making the situation even worse, by creating the deficit of back-up capacity. In the future energy systems, we are going to see more volatile electricity prices with high peaks and very low or even negative off-peak prices. This creates a very good basis for investments in energy storage solutions, such as a pumped storage hydropower plant (PSHP).

The situation described above is very well illustrated when analysing the correlation between electricity spot prices in Danish price area 1 (DK1) and wind generation output in the Nordic power systems. In Fig. 1, the trend analysis (fifth-degree polynomial) shows that the price is decreasing from about 50 EUR/MWh in no wind situation to almost zero in maximum wind output [3].

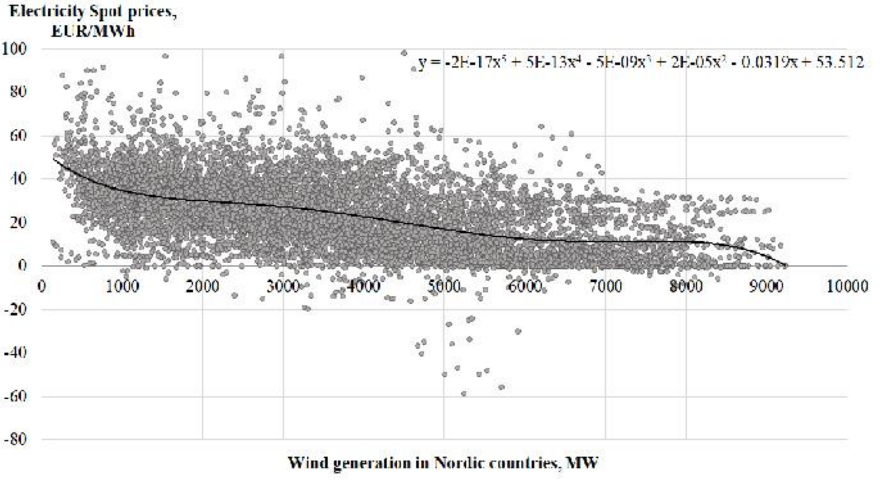

Fig. 1. Electricity prices in Denmark price area DK1 as the function of wind generation output in the Nordic power systems.

Therefore, energy storage has an increasing role to provide a significant integration of the growing share of renewable energy sources and ensure system flexibility and security of supply.

Great contribution to the development of storage optimization models was made by researchers of the Faculty of Electric and

Environmental Engineering of Riga Technical University. Mathematical model for optimization of Kruonis PSHP scheduling was described and verified in the case study in [4]. An algorithm for storage plant scheduling optimization with a particular focus on market situation in the Latvian bidding area was considered in [5]. The paper [6] presents a stochastic approach to solving a combined optimization problem for short-term scheduling and long-term investment planning of storage power plants for a 30-year long planning horizon. In [7], the stochastic optimization algorithm to solve the complex task of planning the operation of three hydroelectric power plants was proposed based on time average revenue maximisation and considering the random nature of the electricity prices and river water inflows.

2. PLAVINAS HYDROPOWER PLANT

Electricity generation of the Latvian hydropower plants provide a large share of renewable energy sources among other European countries [8]. Plavinas hydropower plant (HPP) with its ten hydroelectric units (HG) of Francis type and the installed capacity of 907.5 MW is the largest hydropower plant in the Baltic States and one of the largest in the European Union [9]. Plavinas HPP along with Kegums HPP and Riga HPP is located on the Daugava River, forming the Daugava HPP cascade. Thus, the upper reservoir of Kegums HPP is at the same time the lower reservoir of Plavinas HPP. The first hydroelectric set of Plavinas HPP was launched in 1966, whereas the whole plant was put into full operation in 1968. During the period from 1992 to 2014, the gradual reconstruction of all ten hydroelectric units of Plavinas HPP was performed. At Plavinas HPP, close attention is paid to safety of hydraulic structures. The modernisation of safety monitoring and control equipment has been performed, implementing a computerised system for observation, data collection and processing [10].

There is an urgent need to build an emergency spillway at Plavinas HPP, the necessity of which was emphasised already in 1994. The main objective would be to increase the dam safety level. Necessity of it is explained by stricter EU regulation on probable maximum flood (PMF) values during extreme floods compared to an old USSR regulation being in force at the moment of designing and constructing the Plavinas HPP. Plavinas HPP discharge capacity at the upstream level is not sufficient to discharge the PMF. Therefore, there is a need for additional discharge capacity [10], [11].

The concept of establishing the Plavinas pumped storage hydropower plant envisages the possibility to convert the existing hydropower plant into a PSHP by building a pump station integrated into emergency spillways of Plavinas HPP for pumping water from Kegums HPP reservoir to Plavinas HPP reservoir during off-peak periods with low electricity demand, high surplus of electric capacity and low prices. The accumulated water would then be discharged through the existing Plavinas HPP hydro turbines during high electricity demand and high electricity prices.

One of the factors for successful conversion of Plavinas HPP into a PSHP is that the installed capacity of the existing hydro units (10 units with flow capacity in the range from 260 to 280 m^3/s each) is too high compared with the normal Daugava inflow, and for this reason there is an additional reserve for draining the amount of water through the units, which can be provided by the construction of a pumping station.

3. PSHP MODELLING

The parameters of Plavinas and Kegums HPP reservoirs used in the calculations of the PSHP operating mode are given in Table 1. Permissible levels in reservoirs are an important factor in modelling the possibilities of hydro storage. It should also be considered that the hydropower plant operates at peak loads and free water flow in the downstream reservoir is not provided.

Table 1. Data of Plavinas HPP Reservoir and Hydraulic Structures [10]

Rated electrical power, MW	907
Number of hydro units	10
Average perennial electricity generation, GWh	1 586
Average annual inflow, m^3/s	576
Normal water level of upper reservoir (NUL), m	72.0
Minimal water level of upper reservoir, m	67.0
Average water level of upper reservoir, m	69.0
Water head at NUL, m	40
Upper reservoir 1-meter volume AB, mln. m^3	28.78
Lower reservoir 1-meter volume LB, mln. m^3	23.44
Minimum water level of lower reservoir, m	30.4

The operational condition of hydroelectric power plants mainly depends on water inflow in the Daugava River, which has a distinctly seasonal character – the lower inflow is in summer and winter periods, while during spring floods it is the highest. Water supply is very uneven, both over several years and over one year. The unevenness of this inflow must be taken into account when modelling the operation of the pumping station, as there may not be available hydroelectric units for additional electricity generation in high water inflow periods, while during low-water periods there may not be enough water for pumping.

According to the information of Latvenergo JSC, in 2004 the suitability of Kegums HPP and Plavinas HPP reservoirs for hydro accumulation was assessed. Within the framework of the Plavinas HPP emergency spillway study, the possibility of integrating a pumping station into the reserve spillway was assessed. From an economic point of view, a pumping flow of 80 m^3/s provided by two pumping units is the most technically advantageous option. Fluctuations in reservoir levels caused by pumping are not significant in either Plavinas HPP or Kegums HPP reservoir. Neither dam structures nor gates or any other element of the system are subject to significant loads that may result from pumped storage operation [10].

Thus, a pumping station built into an emergency spillway has an advantage in terms of the investment that would be required to accomplish a green field project. A large part of the investments (such as acquisition of land from owners, mobilisation of the project, most of the construction works, transfer of works) that are attributable to the preparation of construction site should not be attributed to the construction project of Plavinas HPP pumping station. However, the existing infrastructure needs to be considered – the capacity of the pumping station is limited by the permissible levels of reservoirs.

According to the technical estimates, the pumping station with a pumping flow of 80 m^3/s, provided by two units, has an electrical load of 36 MW (2x18 MW) and a total efficiency of 84.6 %. If one specific hydro unit with a capacity of 90 MW is selected for generation, then the technical parameters of the possible Plavinas PSHP are given in Table 2.

Table 2. Plavinas PSHP Technical Parameters [10]

Parameters	Pumping	Generation
Water head, m	39	35
Water consumption, m^3/s	80	284
Water consumption in 1 hour, thousand m^3	288	1022
Installed electrical power (input/output), MW	36	90
Efficiency, %	84.6	92.6

Considering the technical parameters of the hydroelectric units, the pumping station should operate for at least 3.5 hours to provide water for the operation of the HG with a nominal capacity for one hour. Thus, the total PSHP efficiency can be calculated as:

$$\eta_{HPSP} = P_{g\,nom} / \left(\frac{Q_{gen}}{Q_{pump}} \cdot P_{pump} \right), \qquad (1)$$

where

$P_{g\,nom}$, P_{pump} – the rated electrical power of the selected hydroelectric unit and pump station, respectively, MW; Q_{gen}, Q_{pump} – water consumption of the hydroelectric unit of HPP and pumps of pumping station, respectively, m^3/s (from Table 2).

4. ELECTRICITY PRICE ANALYSIS: FACTS AND FORECAST

Pumped storage hydroelectric power plants are mainly used for peak load shaving or the so-called energy arbitrage. This means buying low-cost electricity for pumping when demand is low and selling electricity at a higher price during peak demand.

Electricity prices in the Latvian price area of the Nord Pool Spot power market have been analysed for the past 3 years [3]. The respective price duration curves are shown in Fig. 2. In 2020, negative prices appeared in the Latvian price zone for the first time. However, in general the price duration curve was flatter than in previous years – prices above 50 EUR/MWh appeared 944 hours, while in 2019 and 2018 – 3255 hours and 3846 hours, respectively. The maximum price peaks reached 200 EUR/MWh similarly as in 2019, while the maximum price in 2018 reached 255 EUR/MWh. In 2020, prices below 35 EUR/MWh appeared around 4900 hours, in 2019 – around 1800 hours and in 2018 – 1177 hours. In 2020, the average electricity price was the lowest – 33 EUR/MWh, which could be explained by lower electricity demand due to Covid-19. However, in the future, with the changing growth of wind and solar power plants in the Baltic region, greater price fluctuations are expected, which may have a positive impact on the economic and payback performance of PSHP [6], [11].

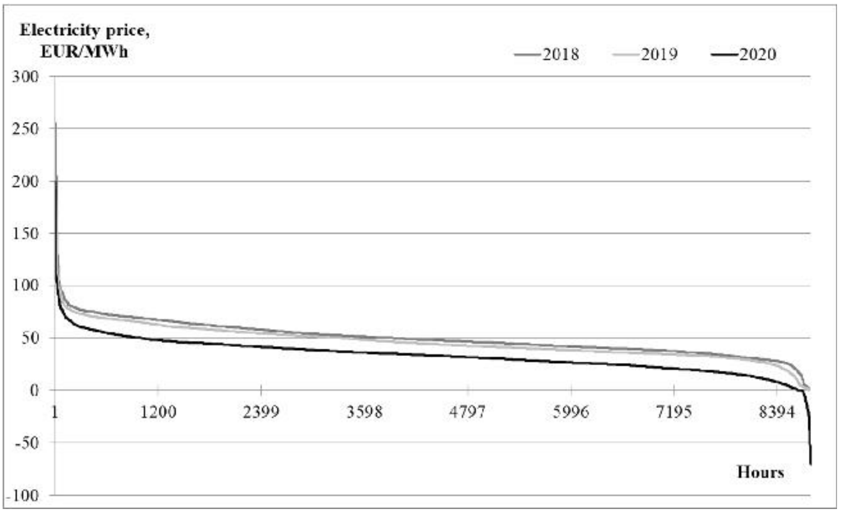

Fig. 2. Nord Pool Spot electricity price duration curves in the Latvian price area.

In order to make the forecast of electricity prices in the Baltic States, we shall simulate the effect of increasing wind capacity from existing 924 MW (EE: 320 MW, LV: 66 MW, LT: 548 MW) to 2500–5500 MW in 2030 [12]–[14]. The projected increase of wind capacity will result in higher price fluctuation. For the purposes of our analysis, we modified electricity price profiles. The principle of this modification is illustrated in Fig. 3. We reduced the lowest daily electricity prices to widen the difference between high and low prices.

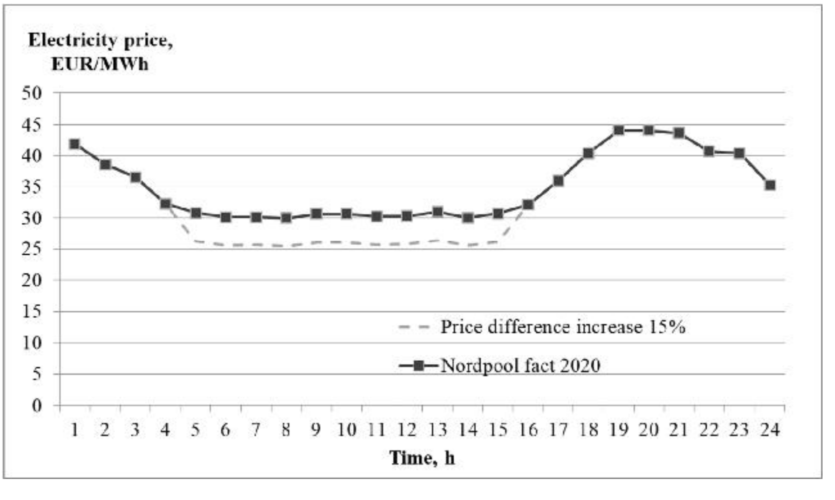

Fig. 3. Modification of electricity price profiles to take higher intermittent generation capacities.

Taking into account all the above data, as well as using historical data on the actual operation of hydroelectric units, reservoir downstream and upstream levels, and electricity prices on the Nord Pool Spot, we simulated the combined operation of the pumping station and existing hydroelectric units of Plavinas HPP. A simplified modelling algorithm for the determination of PHSP operating condition is shown in Fig. 4.

Based on the hourly electricity price data, the daily maximum price is determined and the price ratio N is calculated as:

$$N = C(t)/C_{max}, \tag{2}$$

where
C(t) – the actual price at time t (t = 1 h).

The efficiency of the PSHP calculated according to Eq. (1) is 70 %, which determines the price ratio at which it would be useful to buy electricity for pumping and selling electricity on the exchange. At the price ratio N < 70 % pumping is provided, while during the daily peak load at high prices N ≥ 95–100 % generation is provided.

Before starting the operation of the pump, the permissible upper (AB) and lower (LB) reservoir levels, as well as the actual operation of the generators at Plavinas HPP ($\sum P_{gen} = 0$) are checked. This means that the pumping station can only be operated when the hydroelectric units are still. If the permissible values are not exceeded, the pump with the rated electric power P_{pump} is operated.

The amount of water W_{pump} obtained during pumping is:

$$W_{pump}(t) = Q_{pump} \cdot t. \tag{3}$$

Plavinas HPP hydroelectric units have a technically permissible range within which they can operate. In this case, the minimum electrical power $P_{gen\,min}$ of the generator is 65 MW, which corresponds to the water consumption of the turbine $Q_{gen\,min}$ (m^3/s) determined according to Eq. (4):

$$P_{gen\,min} = 9.81 \cdot h \cdot Q_{gen\,min} \cdot \eta_{gen} , \tag{4}$$

where
9.81 – gravitational acceleration, m/s^2; h – water head of Plavinas HPP, m; η_{gen} – efficiency of HG, % (see Table 2).

The pumped water volume is compared with the minimum water volume required for the operation of the hydraulic unit:

$$W_{pump}(t) \geq Q_{gen\,min} \cdot t. \tag{5}$$

The operation of the hydraulic unit is activated depending on the available water volume $W_{pump}(t)$ at the price ratio N ≥ 99 %, which corresponds to the daily maximum price:

$$P_{gen}(t) = \begin{cases} P_{gen\,min}, \mathrm{W}_{pump}(\mathrm{t}) \ = \ W_{gen\,min} \\ 9.81 \cdot h \cdot \frac{W_{pump}}{t} \cdot \eta_{gen}, W_{gen\,min} \leq W_{pump}(t) \leq W_{gen} \\ P_{g\,nom}, W_{pump}(t) > W_{gen} \end{cases}, \tag{6}$$

where
$W_{gen} = Q_{gen} \cdot t$ – water volume required for one-hour operation of the hydroelectric unit at rated capacity, m^3.

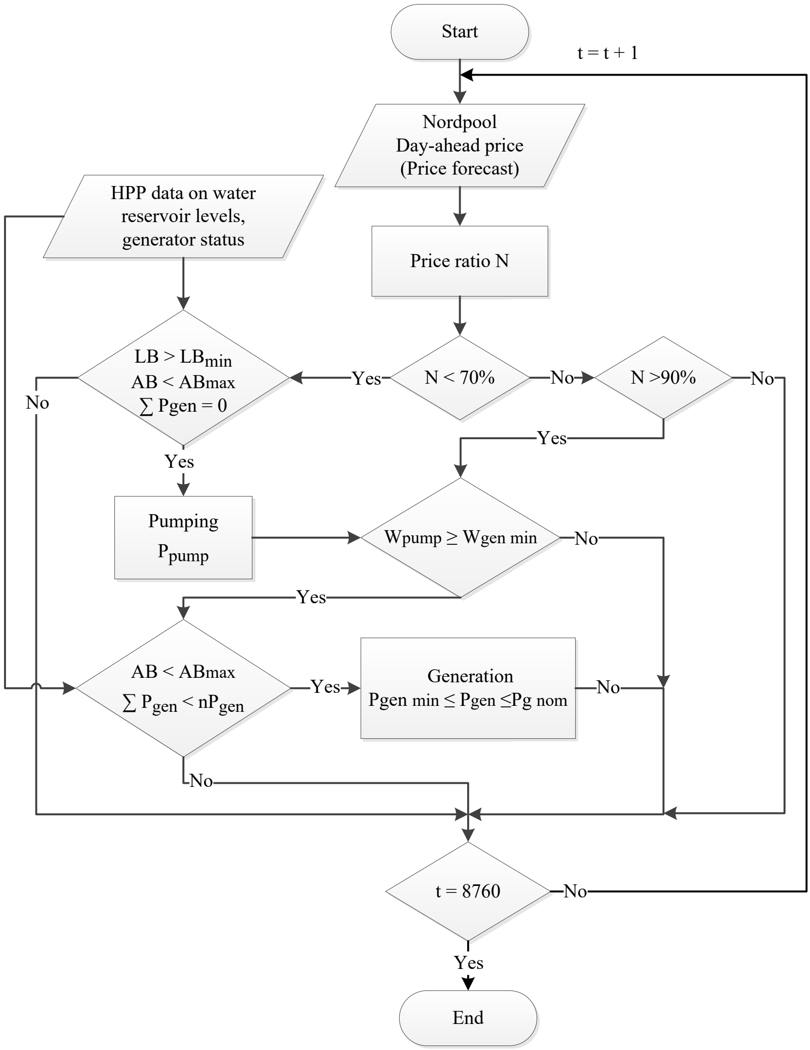

Fig. 4. Simplified algorithm for calculation of PSHP operating regime.

As in case of pumping, the limitations of the water level of upper reservoir and the availability of hydroelectric units for generation are taken into account before operating the HG. In cases when the price peak is highly expressed, the algorithm predicts the operation of several generators simultaneously $n \cdot P_{gen}$, where n is the number of hydroelectric units operated simultaneously:

$$n = W_{pump}(t)/W_{gen}. \tag{7}$$

During the modelling, the permissible levels of reservoirs are observed, the change of which is calculated as:

$$\Delta AB(t) = W_{pump}(t)/W_{HPP\ AB},$$
$$\Delta LB(t) = W_{pump}(t)/W_{HPP\ LB}, \tag{8}$$

where
ΔAB and ΔLB – changes in upstream and downstream water levels of Plavinas HPP, respectively, m; $W_{HPP\ AB}$ and $W_{HPP\ LB}$ – water volume of 1 meter at upstream and downstream reservoirs of Plavinas HPP, respectively, m^3 (see Table 1).

6. RESULTS AND DISCUSSION

Performing simulation according to the developed algorithm and historical electricity price data of Nord Pool Spot for 2020, PSHP daily operating modes were obtained. The daily operating mode of Plavinas HPP on the example of 28 January is shown in Fig. 5. In this example, the PSHP operated in pumping mode for 5 hours at a relatively low price and consumed 180 MWh of electricity, providing water for the operation of the generator during peak load. In this particular example, the hydro unit could operate for two hours generating 180 MWh of electrical energy. It can be seen that electricity prices remained high in the coming hours, so pumping stopped. In this example, the daily income of Plavinas HPP would be around 3100 EUR.

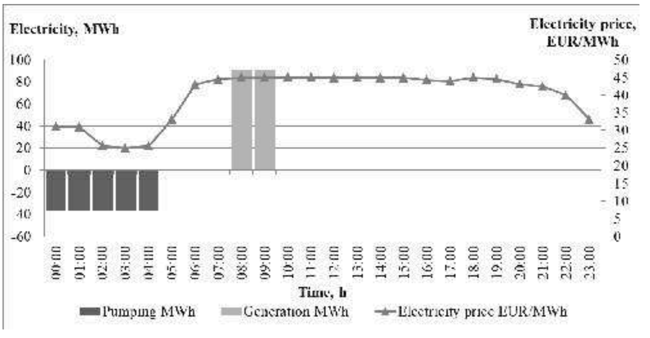

Fig. 5. Plavinas PSHP daily operation mode (28 January).

The operating modes of PSHP during the year are shown in Fig. 6. It can be seen here that no pumping takes place during the flood period (March to April). The water inflow into the Daugava exceeds 1000 m^3/s and at night it provides a sufficient amount of water for the operation of all Plavinas HPP hydroelectric units during peak hours.

According to the simulation data, on average there were 2 hydroelectric units used for generation daily. The average daily additional peak capacity gain is 180 MW. In total, during the year about 60 GWh of electricity was generated in addition to the existing operation of Plavinas HPP, while consuming approximately 80 GWh of electricity in the pumping mode.

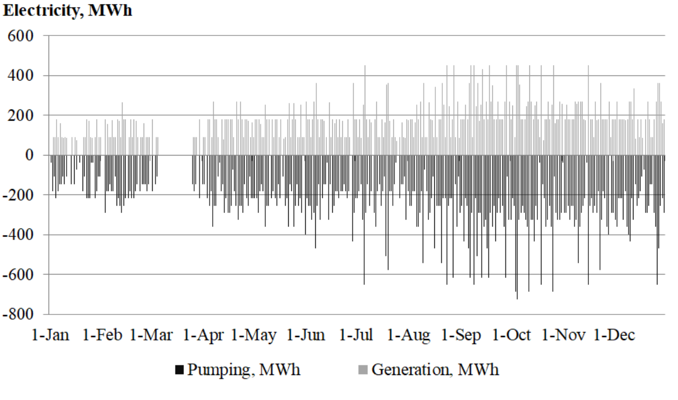

Fig. 6. Annual operation of Plavinas PSHP.

As a result of operation of the pumping station, the maximum change of the water level is +0.300 m in Plavinas HPP reservoir and -0.369 m in Kegums HPP reservoir. The permissible levels of the upper and lower reservoirs were not exceeded. Changes in the upper water reservoir levels during the pump operation are shown in Fig. 7. There were 28 hours/year when the operation of the pumping station had to be limited due to the maximum allowable water level in the upstream reservoir. It should be considered that with the pumping of water from the lower reservoir of Plavinas HPP, the amount of water available for the operation of Kegums HPP is reduced. In some cases of low water inflow, the operation of Kegums HPP may be affected. In this case, the operation of the pumping station should be limited, which would reduce the potential profit of the PSHP.

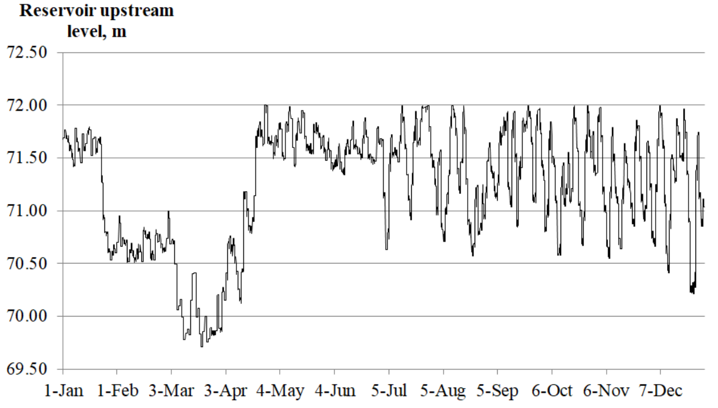

Fig. 7. Plavinas HPP upper reservoir water level fluctuations.

7. ECONOMIC ASSESSMENT

In 2004, the capital costs of the pumping station were estimated as additional costs for the Plavinas HPP emergency spillway in the amount of approximately 21 million EUR [10], [11]. Considering the construction cost growth index available at the Central Statistical Bureau [15], the costs of the pumping station today could amount to around 43 million EUR (specific capital costs around 1200 EUR/kW). Operating costs are assumed to be 1.75 % of capital costs, amounting to approximately 760 thousand EUR/year. The discount rate is assumed to be 5 %.

Economic calculations showed that the daily price difference on the Nord Pool Spot market, which was around 30 % on average over the last three years, is not sufficient to ensure the capital investment return on the Plavinas HPP project. The possible profit from the operation of PSHP is about 800 thousand EUR.

In order to simulate possible future situation with high price fluctuations, we used the modified price curve with an increased price difference between the daily maximum and minimum prices. By increasing price difference up to 40 %, we observed significant improvement of the economic indicators of PSHP. Table 3 shows various values of price differences and the corresponding income, as well as the co-financing required to pay off the project over 30 years.

Table 3. Some of the PSHP Economic Indicators at Various Price Differences

Average price difference, %	37 %	39%	40 %
Income, million EUR	1.2	1.4	1.5
Subsidy, %	85 %	75 %	70 %

As we can see, at average price difference of 40% the annual profit increased to 1.5 million EUR, which can be returned in 30 years if 70 % of investment is subsidised.

It should be noted that the main limitation of PSHP projects is the uncertainty about their future income. However, in addition to peak load balancing, storage can provide a number of other functions that do not currently have a revenue stream but have an economic value. First, the performance of thermal power plants is optimised by reducing the need for changes in their capacity or start-up and shut-down times [16], [17]. The cost savings in this case are not considered in the PSHP economy. Second, the non-revenue benefit of PSHP is the delivery of the necessary additional benefits to the network, which currently does not have a market price, such as fast and ultra-fast ramp rates in capacity. It is very important for PSHP project developers to find a way to gain the income of these last two benefits.

8. CONCLUSIONS

The authors have come to the following conclusions:

1. Further improvement of the proposed algorithm for calculation of PSHP operating regime is possible to ensure variable pumping and generation capacity of PSHP.
2. The algorithm for optimisation of PSHP operation has been implemented using MS Excel software and integrated with economic model. To improve the proposed calculation method, it is supposed to reproduce the model in more advanced software, for example MatLab.
3. Plavinas PSHP with the pumping capacity of 80 m^3/s can provide the amount of stored electricity around 60 GWh per year, while consuming approximately 80 GWh of electricity in pumping mode. The availability of electrical capacity to cover peak loads is increased by an average of 180 MW.
4. The difference in historical hourly electricity prices of Nord Pool Spot has not been sufficient to ensure the recovery of the capital costs of PSHP development.
5. A favourable market for the high economic efficiency of PSHPs is the one with large hourly price differences between low price and high price. In the future, with the increasing share of renewable energy sources, higher price differences are expected.
6. The economic benefits of PSHPs should be assessed appropriately in terms of the additional value they could bring to the energy system.
7. Pumping of water from the lower reservoir of Plavinas HPP in particular low-water periods may disturb the operation of Kegums HPP by limiting the amount of available water. It would be necessary to additionally assess whether restrictions on the operation of Kegums HPP are being created.

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HEAT LOAD NUMERICAL PREDICTION FOR DISTRICT HEATING SYSTEM OPERATIONAL CONTROL

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To develop an advanced control of thermal energy supply for domestic heating, a number of new challenges need to be solved, such as the emerging need to plan operation in accordance with an energy market-based environment. However, to move towards this goal, it is necessary to develop forecasting tools for short- and long-term planning, taking into account data about the operation of existing heating systems. The paper considers the real operational parameters of five different heating networks in Latvia over a period of five years. The application of regression analysis for heating load dependency on ambient temperature results in the formulation of normalized slope for the regression curves of the studied systems. The value of this parameter, the normalized slope, allows describing the performance of particular heating systems. Moreover, a heat load forecasting approach is presented by an application of multiple regression methods. This short-term (day-ahead) forecasting tool is tested on data from a relatively small district heating system with an average load of 20 MW at ambient temperature of 0 °C. The deviations of the actual heat load demand from the one forecasted with various training data set sizes and polynomial orders are evaluated for two testing periods in January of 2018. Forecast accuracy is assessed by two parameters – mean absolute percentage error and normalized mean bias error.

Keywords: *Forecasting, heating demand, heating curve slope, multiple regression.*

1. INTRODUCTION

In line with the recently proposed European Climate Law, energy consumption and greenhouse gas (GHG) emissions should be dramatically reduced in order to achieve the European Union's long-term climate neutrality objective [1]. Energy production for district heating system (DHS) operation makes up to 14 % of the total energy balance in Latvia [2].

Recent energy market liberalization for heat and electrical energy supply creates additional challenges for DHS, especially in case of integrated operation with combined heat and power plants (CHPPs). The requirement for competition between different energy producers in heat and electrical energy markets calls for the creation and utilization of accurate forecasting tools for various important parameters (e.g., electricity market price, heating demand etc.) necessary for operational planning and the optimization of bidding in the energy markets.

In Latvia, the introduction of Climate Finance became an important support for significant improvements in DHS efficiency. During the last few years, at least three heat energy storage sites integrated with CHPPs were constructed in Latvia, summarised in Table 1.

Table 1. The Largest Heat Storage Sites in Latvia

Heat storage site	Tank volume, m^3	Heat storage capacity, MWh	Max. charge/discharge capacity, MW/h
Riga CHPP-2, Latvenergo [3]	18000	550	150
Salaspils Siltums [4]	8000	418	15/25
Jelgava, Fortum Latvia [5]	5000	170	15

The application of heat storage tanks and utilization of the thermal inertia of consumers (i.e., buildings) can cover disbalance between heat demand in DHS and the request for electrical energy produced by CHPPs from the perspective of the electricity wholesale market [6]–[8]. DHS renovation together with the already ongoing pre-insulated network pipe exchange and building thermal insulation improvements will enhance the overall operational efficiency. For instance, the heat losses from DHS network can be reduced by 40 % if old pipes are replaced by new pre-insulated pipes as estimated for a particular case in Tallinn DHS [9]. In another study [10], ranking of the DHS based on efficiency and relative losses from networks is offered. For the overall technical evaluation of network performance, a factor is suggested, which depends on the heat transfer coefficient of the pipes. Another way to decrease losses in DHS networks is forward temperature reduction in the supply lines [11]. Moreover, the heat load can be modelled by controlling the forward temperature in the network and the indoor temperature in housing [12]. However, ultimately, all these steps will ensure the best performance only if the smart operation of DHS is also supported by accurate heat load prediction.

Furthermore, the simulation of DHS performance requires the application and modelling of heat demand profiles, forward and return temperature in the supply line, as well as the estimation of pressure losses in the network. Therefore, forecasting of heat load is an important part of the overall DHS planning process [13]. The planning of the electricity generation schedule of CHPPs for participation in the electricity wholesale market requires day-ahead hourly forecast of the heat load for DHS to be supplied by the particular CHPPs [14]. Overall, there are several approaches to heat demand forecasting in the literature. For instance, the forecasting of heat demand for the case of Riga by an application of artificial neural networks, linear regression and a combined method ensured the daily mean average percentage error in the range of 4.76–5.83 % for the particular data set studied [14].

While currently, in some DHS networks, the prediction of load is carried out for daily volumes, the need to adapt a more market-oriented operational and planning model in line with the highly volatile electrical energy prices in trading platforms (such as Nord Pool) requires shifting the forecast resolution to at least hourly basis. Therefore, our research is devoted to day-ahead forecasting of hourly heating load. The overarching goal thereby is to devise and successfully validate a short-term forecasting approach able to provide satisfactory accuracy on any DHS, at the same time maintaining simplicity of implementation, so that such an approach could be applied by any CHPP operator aiming to improve their heat and power production planning co-optimization.

Consequently, the heating load forecasting algorithm initially described in [14] and more thoroughly elaborated in [15] is used in this study with the aim to validate its accuracy in DHS load forecasting in a particular system during different periods of the heating season and with varied model parameters. Up until now, this forecasting approach has been tested on only one DHS, which, furthermore, could be characterised as a generally very large system. Thereby, this paper envisions to add to prior research by validating the short-term forecasting approach on a significantly different DHS, e.g., notably smaller in terms of average consumption.

Moreover, the obtained forecast deviations from the actual consumption values are to be analysed by the implementation of the mean average percentage error (MAPE) and normalized mean bias error (NBIAS). When applied together, these metrics allow drawing more complete conclusions on the performance of a forecasting model.

The other major goal of this study is to introduce and apply a novel parameter for DHS performance characterisation – heating load curve normalized slope, which, to the best of the authors' knowledge, has not previously been considered in the literature and, consequently, its definition offers additional novelty. The extensive datasets collected for this research allow for the calculation of this parameter for a number of different DHSs.

2. METHODOLOGY

2.1. Simple Linear Regression and Normalized Slope

For this study, the data about hourly DHS parameters (hourly heat load in MW and mean hourly ambient temperature in °C) were collected for five distinctly different DHSs from 2015 to 2019 in various parts of Latvia.

The studied DHS networks supply heat energy for two main purposes: space heating and domestic hot water supply. Heat consumption for air heating in ventilation systems is insignificant in the scope of the collected data. The value of heat load depends on many factors, such as the season of the year, ambient temperature, desired inside temperature, air humidity, solar radiation, wind speed and direction etc. The size of the heating area and building insulation parameters as well as the number of inhabitants and their activities also affect the resulting heat demand. Therefore, heat load modelling is a very complicated process and certain simplifications need to be made. Most importantly, these simplifications are based on the available data.

A novel parameter characterising DHS performance is proposed – normalized slope. To obtain it, it is first necessary to perform a linear regression analysis on the data sets of various DHSs, using heat load as a dependent variable and mean hourly ambient temperature as an independent variable. From the regression analysis, a linear equation is obtained in the form of

$$Q = aT + Q_0, \tag{1}$$

where

Q – the dependent variable (heat load); T – the independent variable (ambient temperature); a – the slope; Q_0 – the intercept term (equal to the average heat load at ambient temperature of 0 °C).

The coefficients a and Q_0 from Eq. (1) are found for each DHS by minimising the sum of least-squares, which is a mathematical approach to calculate the dispersion of experimental data. The goal of the analysis is to get the smallest possible sum of squares and draw a line according to the linear regression equation, which best matches the collected DHS performance data.

Goodness of fit of the obtained load curve can be assessed by evaluating the coefficient of determination (R^2) for each studied system. It shows the deviations of the measured DHS load from the one calculated by the regression line. The value of R^2 is the sum of the squared deviations of the DHS load from the average value. It is common to consider that the obtained regression models are strong if R^2 is close to 1.

After the regression analysis, the DHS load curve normalized slope can be calculated as the ratio of the temperature multiplier (slope) in the linear regression equation (1) vs the average load (intercept) from the same equation (i.e., a/Q_0). This coefficient shows the DHS load change relative to the average load when the temperature changes by one degree.

To perform this analysis, only the heating season is considered (i.e., when DHS heating load consists of both space heating and hot water supply). Thereby data about the heating load of various DHS networks during December–March period of the year are used. We eliminated from consideration the data for October–November and April, when the heating load is not stable.

For clarity, it should be noted that a simple linear regression model described here, the results of which are summarised in Section 3.2, is not used as a forecasting approach, but rather as a tool to obtain DHS characteristics necessary to calculate the heating load curve normalized slope (i.e., a DHS performance assessment approach). Though, in principle, it can be used as a forecasting method; it would generally be applicable as such more likely to long-term planning (e.g., preparing for the next heating season), as opposed to short-term forecasting and planning. The key difference in short-term planning, which is necessary for effective participation in established and emerging energy markets, is the need to more dynamically adapt to changes in heating consumption patterns occurring during the season. Such a forecasting approach specifically suitable for short-term operational planning is offered in the next section.

2.2. Heat Load Short-Term Forecasting Approach

There are various data-driven approaches for generating linear and multilinear regression models with different influencing parameters for heat load prediction. For instance, in [16], the forward selection method is used to identify the most important influencing parameters for the forecasting of daily heat energy consumption. There it is found that for a particular DHS studied, high coefficient $R^2 = 0.9369$ can be achieved when only daily mean ambient temperature is taken into account. In comparison, this coefficient grows to 0.9663 when input variables also include the heating consumption of the previous day, maximum daily temperature, wind data, humidity and month of the year [16]. Nevertheless, the selection of influencing parameters also heavily depends on data availability.

For this case study, the heating demand short-term (day-ahead) forecasting methodology from [15] has been adapted for the use on one of the DHS described in this paper. The forecasting model is based on multiple linear regression with the forecast of the day-ahead hourly ambient temperature being the main predictor. However, for the purposes of this study, to not include temperature forecast inaccuracy in the heating demand forecasting and only isolate the effects of the model itself, the actual historical temperature data will be used as input. The additional effects temperature forecast inaccuracy can cause in heat demand prediction have previously been discussed in [17].

Overall, the forecasting algorithm used in this study can be summarised as follows:

1. Select forecasting model parameters – the look-back horizon (training data set) in days *b* and the order of the polynomial to be constructed with multiple linear regression *k*.
2. Select the number of days the forecast has to be performed for, *h*.
3. Start with the day number $d = 1$.
4. Read the hourly temperature and heat load data from previous days (*d–b* to *d–1*).
5. Perform multiple linear regression on the dataset (obtained in step 4) in the form of

$$Q_i = a_0 + \sum_{n=1}^{k} a_n \cdot T_i^n + \varepsilon_i, \tag{2}$$

where Q_i – the dependent variable at point i; T_i – independent variable at point i; n – power of each term; k – power of the last term (i.e., order of the polynomial); ε_i – the error term at point i; a_0 – the intercept term; a_n – the coefficient for the corresponding function of the independent variable.

Using the least-squares method, this allows identifying the model parameters – a_n coefficients.

6. The error terms for each point *i* are then averaged over the training dataset based on the hour of the day, thereby obtaining a 24-hour profile of the training model residuals.
7. Read the hourly temperature for the next day *d*+1.
8. Input the day-ahead temperature in the model obtained by the linear regression and output the initial 24-hour day-ahead heating load forecast.
9. Subtract from the initial forecast the 24-hour error profile and output the final heating demand forecast for day *d+1*. Save the result.
10. Increment day number *d* by one and repeat steps 4 to 10 until the day number *d* exceeds the preselected number of days for the forecasting experiment *h*.

Afterwards, the results can be assessed. The forecasting model performance is evaluated using the mean absolute percentage error and normalized mean bias error.

$$MAPE = \frac{1}{m}\sum_{i=1}^{m}\left|\frac{Q_i - \widehat{Q}_i}{Q_i}\right| \cdot 100\%, \quad (3)$$

$$NBIAS = \frac{1}{m}\sum_{i=1}^{m}\frac{(Q_i - \widehat{Q}_i)}{Q_{max} - Q_{min}} \cdot 100\%, \quad (4)$$

where

Q_i – the actual heat load at point i; $\widehat{Q}_i$ – forecasted heat load at point i; m – the total number of points in the forecast; Q_{max} – maximal value of heat load in the actual observation series; Q_{min} – minimal value of heat load in the actual observation series.

These two error measures have distinctly different applications and, consequently, they can be used in parallel, as each of them describes the accuracy of the tested forecasting approach from a different angle. MAPE shows the average error disregarding the bias of it. This allows drawing conclusions on the overall accuracy of the model. On the other hand, NBIAS specifically focusses on the sign of the errors, allowing for the identification of systemic inaccuracies, i.e., a tendency of the model to over- or underestimate.

3. RESULTS

3.1. Example of the Case Study Data

Figure 1 shows an example of the duration curve for hourly ambient temperature and the corresponding DHS heat load for a relatively small DHS with the average heating power of about 8 MW during 2016. Figure 2 demonstrates for the same system the seasonal profile of average temperature and DHS heat load during 2016 and 2017. The yearly profile can be classified into two parts – the heating season, when the ambient temperature is lower than 8 °C, and the off-season. The duration of the heating season in Latvia is usually about 200 days or 4800 hours per year. In the second part of the yearly profile (the off-season), the DHS heating load is mostly for hot water supply.

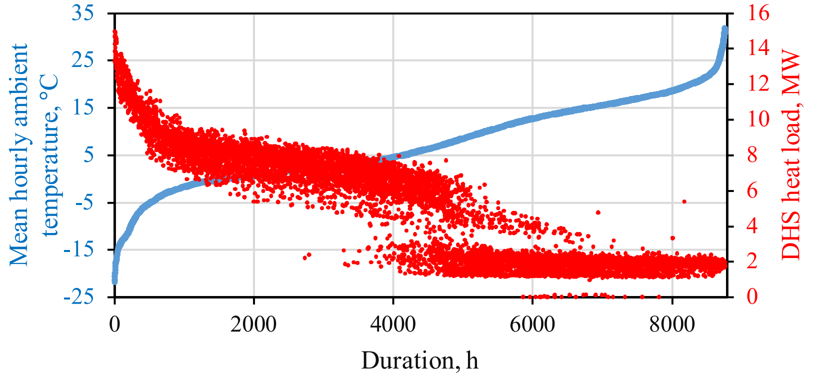


Fig. 1. Ambient temperature duration curve and the corresponding heat load in a small DHS in 2016.

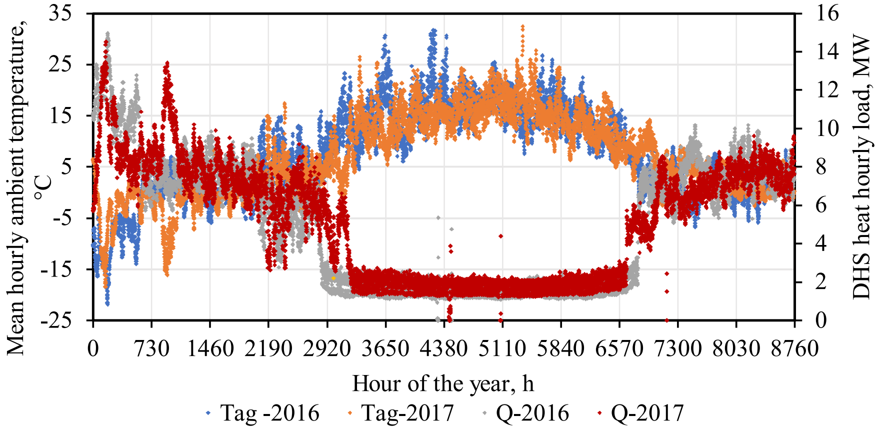


Fig. 2. Ambient temperature and DHS heat load annual profile during 2016 and 2017.

It can already be seen from Figs. 1 and 2 that there is a profound impact of the ambient temperature on the heating load in the DHS during the heating season. Since the average temperature during a heating season is about 0 °C, we introduce the definition of rated power (RP) of DHS as the average heating load (MW) when the ambient temperature is equal to the average. The RP values of the various DHS networks studied in this paper are summarised in Table 2, whereby data regarding the regression analysis of heating load dependency on the ambient temperature on an hourly basis are also shown, explained in more detail in the next section.

3.2. Simple Linear Regression Models of DHS Heat Load

Table 2 presents the analysis of a considerable volume of statistical data of hourly heat load, which allows performing linear regression for DHS heat load curves. Data were extracted from a five-year period (2015–2019) for five different DHSs with rated power (i.e., average consumption) ranging from 8 to 453 MW. In Table 2 and in the following figures, the RP value is used to distinguish and identify various DHS networks considered, since that is a parameter which varies greatly among the studied systems.

The regression analyses presented in Figs. 3–7 demonstrate how the DHS load variable changes when the independent variable represented by ambient temperature varies.

Table 2. Data of DHS Case Studies for Different RP and Time Periods

DHS RP/ figure number	Heating season	Average load Q_0, MWh/h	Minimum/ maximum load, MWh	Linear regression equation ($Q = aT+Q_0$)	R^2	Normalized slope, a/Q_0
RP8/ Fig. 3	2016–2018	8.04	3.8…15	$Q = -0.3229T + 8.0426$	0.8600	–0.040
RP10/ Fig. 4	2018	9.66	3.8…18.2	$Q = -0.4199T + 9.664$	0.8894	–0.044
RP20/ Fig. 5	2017–2018	18.56	14…38	$Q = -0.7972T + 18.563$	0.8770	–0.043
RP40/ Fig. 6	2017	42.41	22…80	$Q = -1.8123T + 42.407$	0.8579	–0.043
RP40	2018	40.94	12…75	$Q = -1.8357T + 40.937$	0.8977	–0.045
RP40	2019	41.95	22…62	$Q = -1.6395T + 41.946$	0.8039	–0.039
RP460/ Fig. 7	2015	457.48	210…1100	$Q = -22.877T + 457.48$	0.9400	–0.050

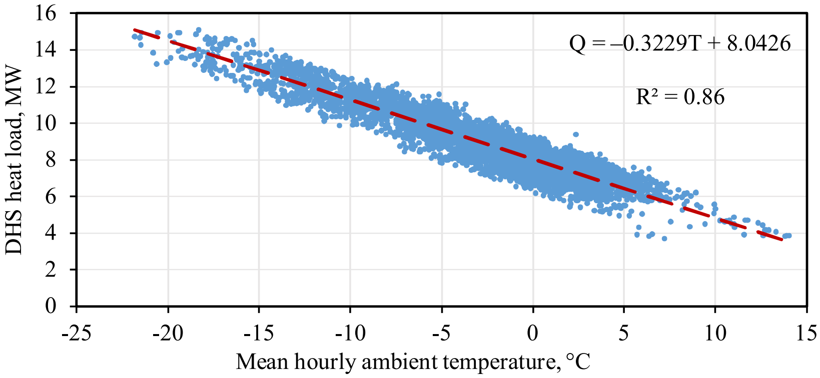


Fig. 3. DHS (RP=8 MW) heat load dependency on ambient temperature (2016–2018).

Fig. 3 demonstrates the performance of a DHS with RP of 8 MW during three heating seasons of 2016–2018. The obtained linear regression equation represented in Table 2 describes the average performance during these three seasons.

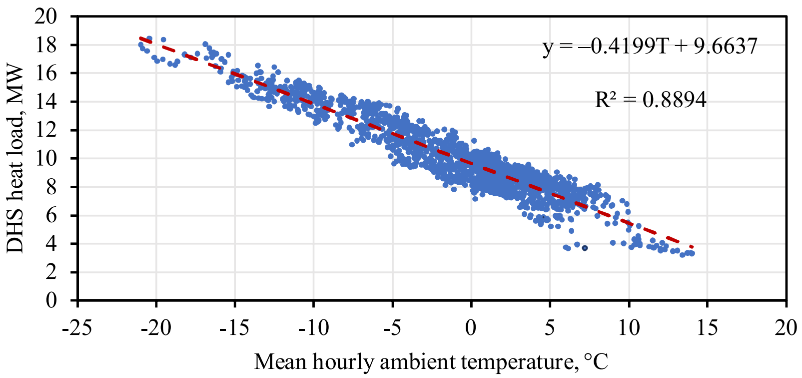


Fig. 4. DHS (RP=10 MW) dependency on ambient temperature in 2016.

In contrast, Fig. 4 represents data for a DHS with RP of 10 MW during only part of the 2016 season (January–March).

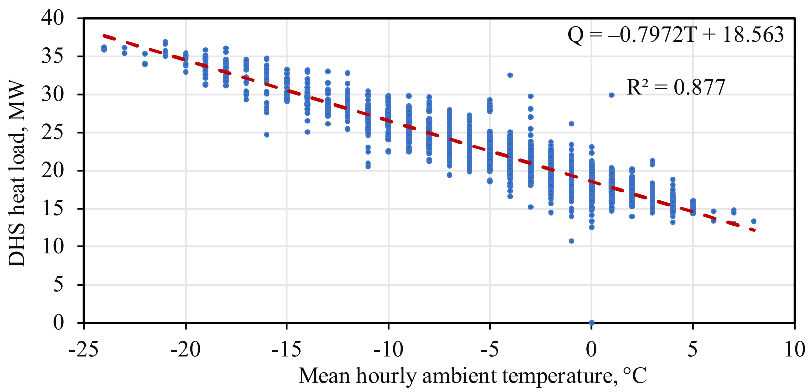


Fig. 5. DHS (RP=20 MW) dependency on ambient temperature (2017–2018).

For DHS with RP of 20 MW presented in Fig. 5, the data extracted during December of 2017 and January–March of 2018 were used. Note that for this DHS, the ambient temperature data were only available in integer values, hence the peculiarity of Fig. 5 compared to the other figures.

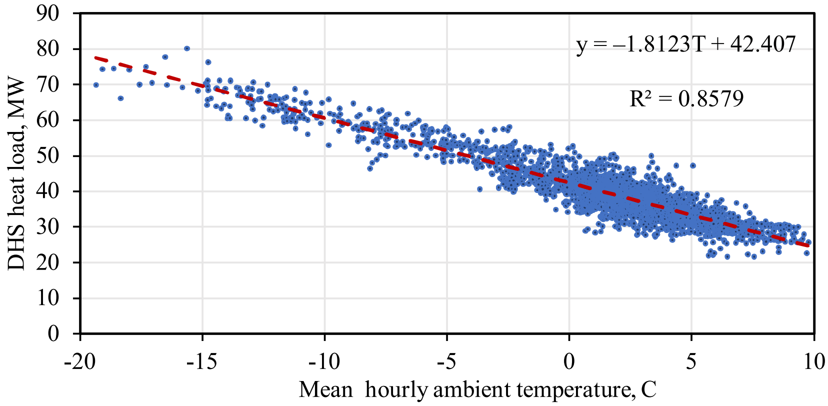


Fig. 6. DHS (RP=40 MW) dependency on ambient temperature in 2017.

Every single heating season had its own set of parameters (like ambient temperature profile) and therefore linear regression equation could be different for the same system. To exemplify this situation, data of a DHS with RP of 40 MW were compared during three distinct heating seasons (2017, 2018, 2019) and the results were consequently presented in Table 2 and Fig. 6.

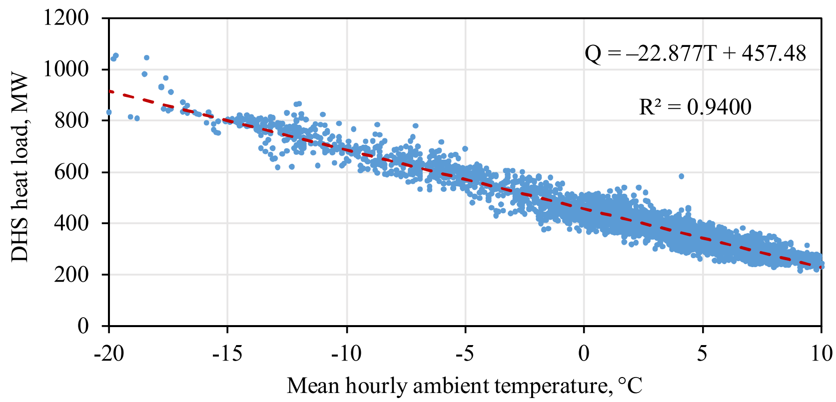


Fig. 7. DHS (RP=457 MW) dependency on ambient temperature during 2015 and 2016.

Finally, the last row in Table 2 describes the performance of a large DHS with RP of 460 MW during the heating season of 2015–2016. These data are visualised in Fig. 7.

As explained before, the simple linear regression equations presented in Table 2 represent the dependency of the recorded heating demand on the ambient temperature. Additionally, Table 2 contains the coefficients of determination (R^2) for each case study. For example, in the case of RP460 in Fig. 7, the value of R^2 is 0.94, which is sufficiently close to 1. However, in the other case studies the coefficient is noticeably smaller. Nevertheless, overall, the results presented do confirm a general dependency of the heating load on the ambient temperature in the studied systems and, consequently, this is a promising direction in the further development of regression-based forecasting tools applicable to these particular DHSs.

Interestingly, linear regression of heating demand versus ambient temperature generally shows good correlation if studied from the whole system perspective, as in this paper; however, when performing the analysis on a smaller scale (i.e., residential building level) the correlation is noticeably weaker. For instance, the authors of [18] found that for a particular large residential building in Latvia the R^2 of the daily heat consumption versus the ambient temperature was only 0.5459. This signifies that while for an individual consumer linear regression against solely the ambient temperature is not well suited for heating demand estimation, on a larger scale, the individual consumer deviations seem to some extent cancel out, and the regression results for the whole system are markedly better.

Furthermore, in other studies, the ambient temperature has been proven to be a major impacting variable also on other important DHS characteristics. For instance, the second-degree polynomial equations developed for DHS return temperature in [19] had determination coefficient of 0.9 for function of ambient temperature.

Nevertheless, the fact that for most of the case studies presented in this paper the coefficient of determination for linear regression is below 0.9, and therefore shows a bigger gap between the obtained equation and the collected data, needs to be addressed. The R^2 value for four of the studied DHS networks is from 0.9 to 0.8 or, in other words, 10 to 20 % of the calculated DHS load data cannot be predicted by the selected independent variable – ambient temperature.

The observed deviations of real DHS heat load from the values obtained by the linear regression equations could be explained by the impact of factors other than ambient temperature. For example, in some of the studied DHS networks, the heating energy for hot water consumption can be equal to about 10–20% of the RP and this consumption, evidently, does not depend on ambient temperature, as can be seen in the off-season part in Fig. 2. If the presented linear equations were used for DHS load operational forecasting (e.g., during the following heating seasons), the obtained results could provide insufficient accuracy because only one parameter (ambient temperature) was taken as argument in the linear model and, more so, because of the fact that various DHS characteristics could change both during and in-between heating seasons. This latter argument is well supported by the results in Table 2, particularly, the significantly changing parameters of the RP40 DHS in the three seasons considered.

In devising and testing a short-term DHS heat load forecasting approach described in Section 2.2, this second shortcoming is alleviated by incorporating an adaptive data set, i.e., using only the most recent data of a certain time period for each new forecasting operation.

However, before addressing the results of the short-term forecasting approach, we should also consider the last column of Table 2, which shows the DHS load curve normalized slope represented by a ratio of the temperature multiplier (slope) in the linear regression equation vs the average load (intercept) from the same equation (i.e., a/Q_0). This dimensionless coefficient shows the DHS load change relative to the average load when the temperature changes by one degree. To the best of the authors' knowledge, this is the first time when the normalized slope parameter has been used to characterise district heating systems.

In our opinion, the value of the normalized slope describes the performance of DHS (including energy losses in the buildings and the distribution networks). The lesser the value, the better system resistance to ambient temperature drops. In other words, statistical data analysis, also including the calculation of the heating curve normalized slope, can be used to evaluate the total performance of a DHS.

3.3. Testing of DHS Heat Load Forecasting

For validation of the multiple regression model, historical data from a DHS with RP = 20 MW (Table 2) were used. The dataset contains heat load and ambient temperature records from 1 September 2017 to 31 May 2018. The forecasting simulation experiments were run for two time periods from 30 December 2017 to 7 January 2018 (9 days; the first period) and from 23 January 2018 to 26 January 2018 (4 days; the second period). Both periods are in the middle of the heating season. The recorded temperatures were used as predictors as they were considered to be the most important predictor in heating load forecasting. Multiple regression with polynomials up to the 3rd order and for two training data set sizes (29 and 60 days) was tested.

An example of the actual and forecasted heating demand is provided for both periods with a case of 29-day training set size in Figs. 8 and 9. Note that for better readability of the illustrations and to emphasise the differences between the lines, the y-axis in both figures does not start from zero, i.e., the charts are zoomed in.

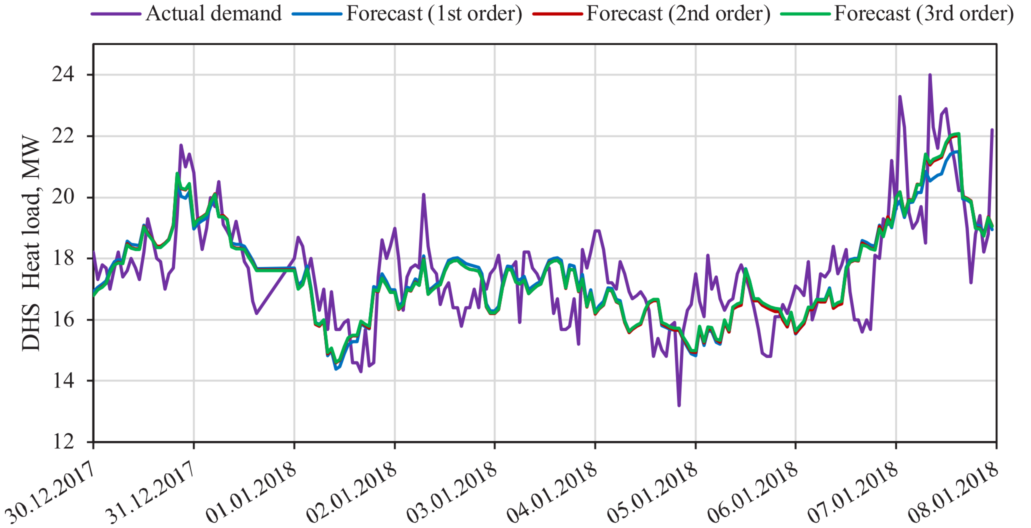
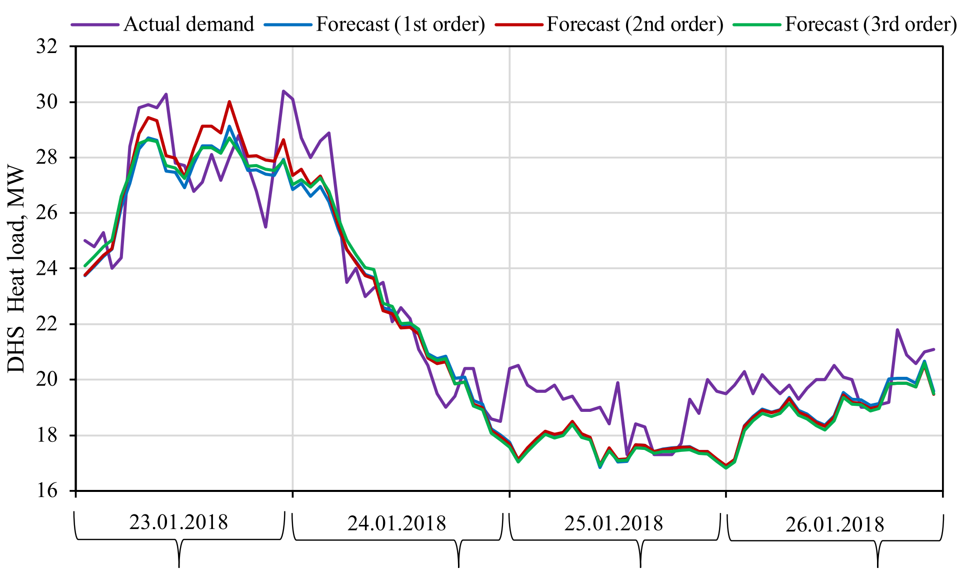


Fig. 8. Actual and forecasted demand in the 1st period with 29-day training data (RP20).

For the forecasting example from the second period, some additional information is provided in Fig. 9. Namely, the dynamically changing forecasting equations have been extracted from the rolling-horizon experiment as displayed in the figure for each day and for each polynomial order. The term $\overline{\varepsilon_t}$ in each of these equations denotes the mean model residual (from the training dataset) averaged over the hour-of-day, i.e., this term is different for each hour within the day. To obtain the final forecasted values, this term has to be subtracted from the initial forecast evaluated with the polynomial. These equations do not have any intrinsic value on their own; however, displaying them in the figure allows seeing their change over time. In the short horizon (four days shown), this change is moderate, since only one of the 29 days in the training set gets exchanged at each step. Nevertheless, in a longer horizon they can be expected to evolve more noticeably. This can be particularly well understood when comparing these equations to the simple linear regression equation for RP20 from Table 2, which is considerably different. The linear regression model from Table 2 is based on all the data from the stable part of the heating season, including data which are not known by the rolling-horizon forecasting model in this section, as, from its perspective, part of the data is in the future.

Table 3 summarises the performance of each of the three polynomial models tested depending on the training set size (29 or 60 days).



$Q_{1,(1)} = -0.8252T + 18.7174 - \bar{\varepsilon}_t$

$Q_{1,(2)} = -0.7908T + 0.0045T^2 + 18.7047 - \bar{\varepsilon}_t$

$Q_{1,(3)} = -0.8045T + 0.0260T^2 + 0.0021T^3 + 18.5254 - \bar{\varepsilon}_t$

$Q_{2,(1)} = -0.8219T + 18.7334 - \bar{\varepsilon}_t$

$Q_{2,(2)} = -0.7932T + 0.0036T^2 + 18.7345 - \bar{\varepsilon}_t$

$Q_{2,(3)} = -0.8048T + 0.0274T^2 + 0.0023T^3 + 18.5351 - \bar{\varepsilon}_t$

$Q_{3,(1)} = -0.8240T + 18.7133 - \bar{\varepsilon}_t$

$Q_{3,(2)} = -0.7951T + 0.0034T^2 + 18.7236 - \bar{\varepsilon}_t$

$Q_{3,(3)} = -0.8018T + 0.0263T^2 + 0.0022T^3 + 18.5385 - \bar{\varepsilon}_t$

$Q_{4,(1)} = -0.8268T + 18.7001 - \bar{\varepsilon}_t$

$Q_{4,(2)} = -0.8031T + 0.0026T^2 + 18.7251 - \bar{\varepsilon}_t$

$Q_{4,(3)} = -0.8051T + 0.0241T^2 + 0.0020T^3 + 18.5571 - \bar{\varepsilon}_t$

Fig. 9. Actual and forecasted demand in the 2nd period with 29-day training data (RP20).

Table 3. DHS Heat Load Prediction Accuracy

	The first period				The second period			
	Training set 29 days		Training set 60 days		Training set 29 days		Training set 60 days	
	MAPE	NBIAS	MAPE	NBIAS	MAPE	NBIAS	MAPE	NBIAS
1st order polynomial	5.76 %	–0.40 %	5.77 %	1.30 %	4.31 %	3.84 %	5.10 %	5.45 %
2nd order polynomial	5.56 %	–1.13 %	5.74 %	1.32 %	4.19 %	3.48 %	5.06 %	4.65 %
3rd order polynomial	5.60 %	–1.08 %	5.70 %	1.17 %	4.55 %	4.50 %	5.24 %	5.50 %

For the first period, the 2nd order polynomial with training set of 29 days provided the best accuracy with a MAPE of 5.56 %, while the 3rd order polynomial was close behind with 5.60 % and the same training set size. In regard with NBIAS, an overall tendency to have a negative bias with a 29-day training set and a positive bias with a 60-day set can be observed. If calculated for the whole forecast set, NBIAS ranges from –1.13 % to 1.32 %, with 1st order polynomial with a 29-day training set providing the best results (–0.40 %). However, when calculating NBIAS for individual days, there is more variety and the daily errors range from –12.93 % to 8.25 %.

For the second period, similar results were received. The 2nd order polynomial with a training set size of 29 days provided the best (lowest) MAPE value – 4.19 % and is followed by the 1st order polynomial with the MAPE equal to 4.31 % and training set of 29 days. The NBIAS values also show that the accuracy of the forecast is higher for the training set of 29 days and for the 2nd order polynomial. Evidently, for the particular DHS studied, larger training set size introduces additional risk of overfitting the regression model. This effect was especially pronounced in the second evaluated period. The reason could potentially be discerned from Fig. 9 – in the second period the actual heating demand was subject to sharp changes, presumably induced by similarly sharp deviations in the ambient temperature. A larger training set might have not allowed the forecasting model to adequately react to these changes, if a significant portion of the dataset contained records from more stable periods.

Moreover, in regard with NBIAS for the second period of the case study, there is a strong tendency for a positive bias. If calculated for the whole forecast set, NBIAS ranges from 3.48 % to 5.50 %. However, when calculating this error measure for individual days, it varies from –1.70 % to 36.55 %, but in only one of the days it is negative. Evidently, in certain instances, the forecasting approach tested can accrue bias. This likely is also connected to the notable ambient temperature change in the second period, especially since by the other metric, which disregards bias (MAPE), the second period of the case study actually has better results. Thereby, in future work, the approach should be improved to identify and eliminate bias.

4. CONCLUSIONS

The historical data statistical analysis presented in this paper demonstrates that simple linear regression for the description of different DHS heat load from a single parameter (ambient temperature) has coefficient of determination for DHS load in the range of 0.8 to 0.94 for five distinct and different DHSs in Latvia. Evidently, the heat load dependency on the ambient temperature is peculiar to particular systems. Moreover, as demonstrated in the case of one of these DHSs, this dependency can also vary notably from season to season.

A major contribution of this paper is the introduction of a descriptive parameter for DHS – a dimensionless heating curve normalized slope, calculated as the ratio of the temperature coefficient in linear regression equation (i.e., the slope) to the average DHS heat load or RP (the intercept in the regression equation). This parameter demonstrates how the heat load will change relative to its average value when the ambient temperature changes. It can be used for the evaluation of DHS performance and it can be especially useful when comparing different systems. The heating curve normalized slope can be recommended for application as a system descriptive metric also in other countries for a wide range of DHSs.

The accuracy of the linear regression models for heat load obtained in this study is to some extent insufficient as the models do not consider the ambient temperature-independent component of heating demand – hot water consumption. To overcome this problem, in devising a heat load short-term forecasting approach with satisfying accuracy, we test in this paper the application of a regression-based forecasting method that takes into account the testing model residuals averaged over the hour of the day, which presumably may contain implicit information pertaining to hot water consumption. The aim of the testing was to prove the stability of prediction accuracy for different data set sizes in different periods within the heating season.

For the selected system (RP = 20), the forecasting inaccuracy expressed by MAPE ranged in value from 4.19 % to 5.76 % and by NBIAS, from –1.13 % to 5.45 %, depending on the forecasting model parameters. Evidently, the forecasting approach is generally suitable for heat load day-ahead forecasting also in small DHSs and provides an overall satisfying accuracy; however, further improvements are necessary, especially to improve forecasting performance in periods that contain sharp changes in ambient temperature.

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A LINEARIZED NUMERICAL SOLUTION FOR STEADY-STATE SIMULATIONS OF GAS NETWORKS

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Considering the changes of gas transmission system (hereinafter – GTS) brought about by diversification of gas suppliers, new interconnections with European GTS and implementation of an open electricity market and then an open gas market, a steady-state GTS modelling tool has been developed for future implementation in the risk and resilience analysis and potentially operational planning for different GTS or other purposes. The developed method combines the linearized hydraulic conductivity approach with a technique, derived from a linear electrical circuit analysis and an additional pressure change term for modelling of active non-pipeline elements of GTS. This method also takes into consideration operational limits of compressors and pressure regulators and changes in compressibility factor and gas viscosity based on the gas composition, temperature and pressure. The paper includes part of the results obtained from a validation case study performed for the presented method.

Keywords: *Modelling, natural gas, steady state, transmission system.*

1. INTRODUCTION

While the European Union (hereinafter – the EU) moves towards its clean energy 2030 and 2050 targets [1]–[3], the EU remains heavily dependent on the natural gas as a primary energy source constituting approximately 22 % of European energy consumption in 2018 [4]. Given its limited and decreasing reserves of natural gas, the EU is a net importer of gas. The increasing dependency on natural gas imports [4] has posed challenges and increased the risks to security of supply.

The Baltic GTS is becoming more integrated into the European GTS and it faces similar dependence on gas imports. However, for a long time the Baltic countries had only one major gas supplier (Gazprom) resulting in heavy reliance on this source. This issue is being addressed by building of new interconnections (Estonia–Finland, Lithuania–Poland, Poland–Denmark), [5] LNG terminals (Klaipeda, other potential terminals under consideration) and implementing an open gas market [6].

In Latvia, electricity and heat generation from gas-fired power plants makes up approximately 60 % of the total gas consumption [6]. These existing power plants are now being challenged by low-priced electricity imports after joining the Nord Pool electricity market and increase of interconnectedness of electric grids with the Nordic region. The resulting competition requires more flexibility from the existing gas-fired power plants [7], which automatically affect a large portion of total gas demand in the country. The necessity of flexibility provided by new interconnections between GTS, local gas storage and LNG terminals will only increase after the desynchronisation of the Baltic electric power grid from BRELL [6]. Considering the aforementioned issues, it is clear that the increased complexity of the GTS operation requires new approaches and analysis tools not only for operational planning but also for risk, resilience analysis and reliability assessment.

As a foundation for such an analysis, it is usefull to have a modelling tool allowing for evaluation of the physical operation of GTS, which is often implemented as a single-phase, one-dimensional, isothermal steady-state model (hereinafter – SSM) of a compressible gas flow [8]–[12]. Typically SSM equations are composed using the 1st or 2nd Kirchof's law and nonlinear flow equations linking GTS element flow rate to its inlet and outlet pressures. Depending on the Kirchof's law used, the Newton-nodal or Newton-loop or Newton loop-node method may be used for formulation and solution of SSM equations [10], [12], [13]. Similar to the Hardy Cross method pre-dating these methods, the Newton-Raphson method variations are known to have poor convergence and strong reliance upon having a good initial guess [8], [9], [11]–[13]. While there are some globaly convergent strategies that may be used to alleviate this issue, the risk of divergence still remains [8]. As can be seen from [12], the main differences of many published SSM versions are the type of flow equation used and GTS aspects (node elavation, possibility to model non-pipeline elements). In this regard, the SSM variant given in [14] is unusual as it combines the Newton-Raphson method with a recalculation of the gas specific gravity to analyse the impact of injection of different gases into the GTS.

Another group of methods applies linearization for their SSM implementation. One method applied for GasGrid software is the Linear Theory method. Here a set of aproximate linearized SSM equations are obtained by changing the difference of pressure squares to pressure drop and average pressure product and flow rate square to flow rate and its previous iteration flow rate product [11]. However, it can also have convergence issues due to numerical oscilations [8]. There is a method, which separates the linear equations obtained using Kirchof's laws and the nonlinear flow equations applying linearisation to the nonlinear part of the SSM [12]. Accurate results are presented with fast convergence but only for particular pipeline networks, but recently another paper has added an approach for modelling of non-pipeline elements [15]. A different method adapts the hydraulic conductivity of GTS elements so that the flow rate value remains the same, but it is a function directly of presure drop or drive power in case of compressors [8], [9]. Such an approach is not the easiest one for implementation of compressor constrains, and it can lead to compressor operation outside the permittable operation region. However, this method provided comperatively close results to measurement data from a real pipeline network, which combined with the robust convergence was also integrated in the developed method.

There are also methods for modelling of GTS transients [16], [17], including for a multi-phase flow [18]. While more accurate from the physical prespective, the use of transient simulations for risk and resilience analysis might result in overly large computational burden when considering real-life GTS models that are large and/or detailed.

The main contribution of this paper is the GTS steady-state modelling method that combines the linear hydraulic conductivity analogue approach with derivatives from a linear electrical circuit analysis not only for compilation of SSM equation system, but also for a different, "electrical" approach to modelling of active non-pipeline elements (mainly compressors, pressure regulators). At the same time, the presented method updates gas parameters (compressibility factor, dynamic viscosity) based on gas pressure, temperature and gas composition and takes into consideration operational limitations of pressure regulators and compressors ensuring correct account for transported media and equipment physical parameters. Since the method presented reduces the core task to the solution of system of linear equations, it is highly suitable for modern multicore computing systems. This paper also presents two different flow equations and results from a validation case study using both equations.

2. THE THEORETICAL BACKGROUND

Similar to other GTS steady-state modelling methods, the purpose of the developed method is to obtain steady-state node pressures and branch (edge) volumetric flow rates. Considering the challenges of the Latvian GTS described above, this method has to be robust and fast as it will have to operate with a large number of scenarios with varying degrees of difficulty to convergence of the SSM solver. Additionally, this method has to be capable of considering at least some of the main aspects defining the operation of modern GTS:

- complex network topologies;
- potential presence of compressors and pressure regulators;
- existence of several gas suppliers;
- effect of the terrain elevation.

Based on these requirements, it was decided to use a combination of the pipeline hydraulic conductivity linearization approach [8], [9] and an analogy of the mathematical modelling of linear electrical circuits [19], [20].

First, the general form of the equivalent circuit branch used for the developed method to represent elements of GTS will be presented (Fig. 1).

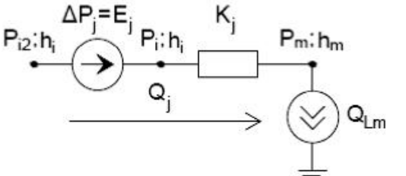

Fig. 1. Model of a GTS element as a branch with a constant volumetric load at the output node.

Here the typical pipeline model with input pressure P_i and elevation h_i, output pressure P_m and elevation h_m, hydraulic resistance coefficient considering elevation change K_j and volumetric flow rate Q_j is extended with an additional pressure change or pressure "source" $\Delta P_j = E_j$, which can be viewed as an electromotive force source in electrical terms, and constant volumetric flow load Q_{Lm}, which is represented as an electrical current source here. The electrical ground in the figure represents atmospheric pressure, which will serve as a base node for "equivalent circuits" of the GTS. The pressure source E_j (that can be either constant or controlled in the loop of the numerical solution process) is added for representation of different non-pipeline elements such as actual network sources with or without their regulators; compressors; pressure regulators etc. The constant flow injections or loads represented with the current source are mainly added for representation of gas consumers and sources, which only provide a fixed amount of gas.

The extended branch model allows creating equivalent circuits for GTS, but in order to calculate the steady-state parameters (node pressures and branch flow rates) a corresponding equation system has to be compiled. As the pipeline steady-state flow equations are nonlinear [10], [21], in order to apply the approach used for linear electrical circuits modified versions of the pipeline hydraulic conductivities corresponding to linear flow equation have to be obtained. Later this transformation will be described in more detail. When these "linearized" conductivities are introduced, one can use the analogy of the Ohm's law and Kirchhoff's first law to compile a linear equation system in the matrix form, in the same manner as the nodal potential or admittance method in electrical circuits is derived [19], [20]:

$$YP = Q_{\mathrm{L}} - MLE + Y_{\mathrm{B}} P_{\mathrm{B}}, \tag{1}$$

$$Y = MLM^{\mathrm{T}}, \tag{2}$$

where P – the vector of absolute pressures of an equivalent circuit nodes except for the base node, Pa; P_{B} – the absolute pressure of the base node, Pa; Q_{L} – the vector of constant volumetric node demands or injections, m^3/s; Y – the matrix of nodal linearized hydraulic conductivities (admittances); Y_{B} – the base node linearized hydraulic conductivity vector; M – the first-incidence matrix of the network topology graph; M^{T} – transpose of matrix M; L – the diagonal matrix of linearized branch conductivities; E – the vector of pressure sources, Pa.

The input matrices for (1) and (2) are composed according to the equivalent circuit of the GTS based on the following rules:

- an element M_{ij} of matrix M assumes value –1 if the flow of branch j flows into the node i, value 1 if the current of the branch j flows out of the node i and value 0 if the branch j is not connected to the node i;
- an element $Q_{\mathrm{L}i}$ of the vector of Q_{L} assumes value Q if a flow injection source of Q m^3/s is connected to and directed towards the node i, value –Q if it is connected to and directed away from the node i (representation of loads) and value 0 m^3/s in other cases;
- an element E_j of the vector E assumes value E1 if an additional pressure increase of E1 Pa is intended along the assumed flow direction of the branch j, value –E1 if the pressure decrease of E1 Pa is intended along the branch j and value 0 Pa in other cases;
- a diagonal element L_{jj} of the matrix L assumes values of corresponding linearized conductivity of the branch j, while all non-diagonal elements are zeros;

- an element Y_{Bi} of the vector Y_B assumes a value of the total linearized conductance of the branches connecting the base node and the node i, and value 0 if the node i is not connected to the base node.

In order to obtain the unknown node pressures, one must then solve the linear equation system (2), which can be done in multiple ways [22]. When the node pressures have been obtained, the branch flow rates can be determined using Ohm's law analogy in matrix form:

$$Q = L\big(E + M^T(P - P_{\mathrm{B2}})\big), \quad (3)$$

where Q – a vector of branch flow rates, m^3/s; P_{B2} – a vector of the absolute pressure of the base node sized the same as P, Pa.

Before addressing the linearization of the hydraulic conductivities of the pipelines, at least two often used forms of pipeline flow equations considering elevation described in literature should be presented [9], [10], [21], [23]:

$$P_{\mathrm{i}}^2 - P_{\mathrm{m}}^2 = K_{1j}(P_{\mathrm{i}} + P_{\mathrm{m}})^2 + K_{2j}Q_j^2, \quad (4)$$

$$P_{\mathrm{i}}^2 - e^{s_j}P_{\mathrm{m}}^2 = K_{3j}Q_j^2, \quad (5)$$

where P_{i}, P_{m} – absolute pressures at the pipeline input and output, Pa; Q_j – volumetric flow rates of the pipeline, m^3/s; K_{1j} – flow invariant coefficient of elevation caused pressure change; K_{2j} – elevation invariant hydraulic resistance coefficient of the pipeline; K_{3j} – hydraulic resistance coefficient of the pipeline that considers also pipeline elevation; s_j – elevation adjustment parameter.

Both (4) and (5) are nonlinear, as mentioned before. Therefore, to apply the analogy with linear electrical circuits, the developed method will adopt the approach of the linearized pipeline hydraulic conductivity analogue, which transforms real pipeline conductivities to ones that result in the same flow rate not due to square root of the difference of pressure squares [8], [9]:

$$Q_j = C_j\sqrt{P_{\mathrm{i}}^2 - e^{s_j}P_{\mathrm{m}}^2},\ C_j = \sqrt{1/K_{3j}}, \quad (6)$$

but directly due to the pressure drop:

$$Q_j = L_j(P_{\mathrm{i}} - P_{\mathrm{m}}), \quad (7)$$

where C_j – the actual pipeline hydraulic conductivity; L_j – the linear analogue of the pipeline hydraulic conductivity.

The value of linear analogue L_j is obtained using a transformation coefficient T_j. When using Eq. (5) or (6) T_j is equal to [8], [9]:

$$T_j = L_j/C_j = \sqrt{\big(r_j^2 - e^{s_j}\big)/\big(r_j - 1\big)^2}, \quad (8)$$

where r_j – a ratio of the pipeline input and output pressure ($r_j = P_{\mathrm{i}} / P_{\mathrm{m}}$).

If the term is relocated in the flow equation [24], [25] the transformation coefficient is

$$T_j = \sqrt{\big(r_j^2 e^{-s_j} - 1\big)/\big(r_j - 1\big)^2}. \quad (9)$$

In case Eq. (4) is used, this coefficient is

$$T_j = \sqrt{\Big(r_j^2 - 1 - K_{1j}\big(r_j + 1\big)^2\Big)/\big(r_j - 1\big)^2}, \quad (10)$$

Equations (8)–(10) show that the function $T_j = f(r_j)$ has a break point when $r_j = 1$ p.u. In order to avoid risk of an infinite L_j value, the developed method will change any $1 \le r_j < 1.0001$ p.u. to $r_j = 1.0001$ p.u. Additionally, if $r_j < 1$ p.u. (actual flow is opposite to the assumed branch direction) T_j will be an imaginary number. Thus, in such cases the value of pressure ratio r_j will inversed to adapt to the actual flow direction. The derived equations (8)–(10) may be used with the GTS element model (Fig. 1), but the pressure ratio must be calculated as follows:

$$r_j = (P_{i2} + E_j)/P_m, \quad (11)$$

where P_{i2} – the absolute pressure of the extended GTS element branch model input, Pa.

This modification is especially important for modelling of active or pressure changing non-pipeline elements, for which the conductivity transformation must apply only on the small equivalent pipeline section representing the connecting piping right after this GTS element.

In order to model the pipelines or their sections, two different pipeline flow equations were considered and tested during the development of the proposed method. The first pipeline flow equation form is (4) with coefficients K_{1j} and K_{2j} derived from [23]:

$$K_{1j} = g(h_\mathrm{m} - h_\mathrm{i})/(2Z_\mathrm{avg}R_\mathrm{gas}T_\mathrm{avg}), \quad (12)$$

$$K_{2j} = \left(\frac{4P_\mathrm{st}}{\pi Z_\mathrm{st}T_\mathrm{st}}\right)^2 \left(\frac{fLZ_\mathrm{avg}T_\mathrm{avg}}{D^5R_\mathrm{gas}E_\mathrm{p}^2}\right), \quad (13)$$

where g – gravitational acceleration, m/s^2; h_i, h_m – elevation of the pipeline beginning and end, m; Z_avg – average gas compressibility factor along the pipeline; T_avg – average gas temperature along the pipeline, K; R_gas – specific gas constant, J/(kg·K); L – length of the pipeline, m; D – inner diameter of the pipeline, m; f – the Darcy friction factor; E_p – the hydraulic efficiency of the pipeline, p.u.; P_st – gas pressure at the standard conditions, Pa; T_st – gas temperature at the standard conditions, K; Z_st – gas compressibility factor at the standard conditions.

The second form considered is (5) with resistance coefficient K_{3j} [24], [25]:

$$K_{3j} = \frac{4.323\cdot10^{-2} f \rho_\mathrm{st\,gas} L Z_\mathrm{avg} T_\mathrm{avg}(1-e^{-s_j})}{D^5E_\mathrm{p}^2 s_j}, \quad (14)$$

$$s_j = 2g(h_\mathrm{m} - h_\mathrm{i})/(Z_\mathrm{avg}T_\mathrm{avg}R_\mathrm{gas}), \quad (15)$$

where ρ_st – gas density at the standard conditions, kg/m^3.

The flow equation (5) used with (14), (15) links pressures in MPa and flows in m^3/h and for (14) D has to be given in mm. The gas parameters R_gas and ρ_st can be determined either from the specific gravity (relative density) or the molecular weight of the gas [10], [11], [21], [23], [26]–[28]. In order to calculate the compressibility factor, the average pressure along the pipeline based on calculated or initially assumed node pressures is required:

$$P_\mathrm{avg} = \frac{2}{3}\left(P_\mathrm{i2} + E_j + P_\mathrm{m} - \frac{(P_\mathrm{i2}+E_j)P_\mathrm{m}}{P_\mathrm{i2}+E_j+P_\mathrm{m}}\right), \quad (16)$$

where P_{avg} – the average pressure along the pipeline, Pa.

The compressibility factor and dynamic viscosity are determined according to [25], [26], [29].

The two tested flow equations each use different friction factor estimation approaches. However, both of them require calculation of the Reynolds number [25], [30]:

$$Re = 10\rho_\mathrm{st\,gas}|Q_j|/(9\pi D\mu), \quad (17)$$

where Re – the Reynolds number; μ – dynamic viscosity, $\cdot10^{-6}$ Pa·s.

For a laminar flow ($Re \leq 2000$) both approaches use the same friction factor formula [21], [23]:

$$f = 64/Re. \tag{18}$$

Differences start when the flow is critical, partially turbulent or turbulent. The first approach used in combination with (13) also requires the calculation of the critical Reynolds number [23]:

$$Re_{\mathrm{cr}} = 35.235(\varepsilon_{\mathrm{r}}/D)^{-1.1039}, \tag{19}$$

where Re_{cr} – the critical Reynolds number; ε_{r} – the equivalent absolute roughness of the pipeline inner wall, m or mm (same as D).

Approximate values of ε_{r} for different pipe types are given in [18], [21], [31]. Based on the value of Reynolds number, one of two friction factor formulas is used [23]:

1) if $2000 < Re < Re_{\mathrm{cr}}$ the Prandtl-Von Karman equation for partially turbulent is applied:

$$1/\sqrt{f} = -2\log_{10}\left(2.825/\left(Re\sqrt{f}\right)\right); \tag{20}$$

2) if $Re \geq Re_{\mathrm{cr}}$ the Nikuradse equation for fully turbulent flow is utilised:

$$1/\sqrt{f} = -2\log_{10}((\varepsilon_{\mathrm{r}}/D)/3.7). \tag{21}$$

When the flow is partially turbulent, a numerical approach similar to one used for the modified Colebrook-White equation can be utilised to determine the friction factor value [21]. Here this process is repeated until difference ($\Delta f = f - f_0 / f_0$) falls below 1 % and the initial guess used is $f_0 = 0.1$. The second approach used with (14) determines the friction factor based both on Reynolds number and the hydraulic roughness of the pipeline inner wall [30], [32]:

1) if $2000 < Re \leq 4000$ a formula for critical flow is applied:

$$f = 0.0025\sqrt[3]{Re}; \tag{22}$$

2) if $Re > 4000$ and $((Re \cdot \varepsilon_{\mathrm{r}}) / D) \geq 23$ a formula for fully turbulent flow in hydraulically rough pipeline is used:

$$f = 0.11\sqrt[4]{(\varepsilon_{\mathrm{r}}/D) + (68/Re)}; \tag{23}$$

3) if $4000 < Re \leq 10^5$ and $((Re \cdot \varepsilon_{\mathrm{r}}) / D) < 23$ an equation for a partially turbulent flow in a hydraulically smooth pipeline is utilised:

$$f = 0.3164/\sqrt[4]{Re}; \tag{24}$$

4) if $Re > 10^5$ and $((Re \cdot \varepsilon_r) / D) < 23$ a formula for a fully turbulent flow in a hydraulically smooth pipeline is used:

$$f = 1/(1.82\log_{10}(Re) - 1.64)^2. \tag{25}$$

In order to model pressure changing non-pipeline elements such as compressors and pressure regulators, the value of the pressure source in the extended GTS element model is determined based on one of the two control strategies. The first one is a constant output pressure strategy, which enforces the pressure at the output (end) node of the branch ($P_{\mathrm{out}} = P_{\mathrm{set}} = \mathrm{const.}$), and the second one is a constant compression ratio strategy, which enforces a set value of ratio between the output and input nodes ($r_{\mathrm{j}} = P_{\mathrm{out}} / P_{\mathrm{in}} = r_{\mathrm{set}} = \mathrm{const.}$). When the constant output pressure strategy is applied ($P_{\mathrm{set}} \neq 0$ Pa, $r_{\mathrm{set}} = 1$ p.u.), the pressure source value is calculated as follows:

$$E_j = \begin{cases} P_{\mathrm{set}} - P_{\mathrm{i2}}, \text{if } P_{\mathrm{set}} > 0. \\ -(|P_{\mathrm{set}}| - P_{\mathrm{m}}), \text{if } P_{\mathrm{set}} < 0. \end{cases} \tag{26}$$

When the constant pressure ratio strategy is applied ($r_{\mathrm{set}} \neq 1$ p.u., $P_{\mathrm{set}} = 0$ Pa), the pressure source value is determined as follows:

$$E_j = \begin{cases} E_j = P_{i2}(r_{set} - 1), \text{if } r_{set} > 0. \\ E_j = -P_m(|r_{set}| - 1), \text{if } r_{set} < 0. \end{cases} \quad (27)$$

In case of pipelines and other pasive GTS elements, settings P_{set} = 0 Pa, r_{set} = 1 p.u. are used to indicate that for their branches E_j = 0 Pa.

The pressure regulators here are modelled only with the pressure source determined based on a constant output pressure strategy, which directly reflects their actual control mechanism, and a small equivalent pipeline section representing the connecting piping. As most modern pressure regulators are pilot-operated ones with the droop (pressure difference from the setting) in the range of 1–3 % or lower [33], it will be assumed that they are capable to ensure the set pressure at their output. If the inlet pressure of a regulator is to fall below the outlet pressure setting, it is assumed that the regulator will either fully open or go into a bypass mode to retain gas supply to customers as long as possible.

The compressor representation in the equivalent circuits is the same as for pressure regulators. However, for compressors potentially either constant output pressure or pressure ratio strategy may be used, they can have gas self-consumption and their operational limits are more complicated than for pressure regulators. The current version of the developed SSM solver adds the gas self-consumption of a compressor as a percentage of the flow rate through the compressor branch computed in previous iterations. An important aspect for modelling of the compressor steady-state operation is their limits, many of which have been outlined in [10]:

- compression ratio limit: $(P_{out} / P_{in}) \leq r_{max}$;
- flow rate limit: $Q_{CS} \leq Q_{max}$;
- compressor: drive power limit $KW_{CS} \leq KW_{CSmax}$;
- out manifold pressure limit $P_{out} \leq P_{out\,max}$.

After additional literature review, the limit of gas pressure at gas turbine intake $P_T \geq P_{CSmin}$ was added [34]–[36]. From all the aforementioned limits, the maximum flow rate, outlet pressure and minimum gas pressure for gas turbine driven compressors are implemented as “hard limits” breaching of which will result in compressor shutdown and operation in bypass mode. The other limits are implemented as “soft limits” that essentially change the r_{set} or P_{set} values for the corresponding branch. For implementation of the soft limits, different versions of the drive power formula from [21] are used. This compressor representation can also be used for modelling of multi-directional compressor stations either by implementing a valve bridge in the equivalent circuit with one compressor branch or by creating a star connection from branches representing all of the directions of potential pressure increase. In the last case, one must consider that if the limits are exceeded for any of these branches they are breached for the whole compressor station.

The constant P_{out} strategy is also applied for large balancing sources that can supply large quantities of gas while sustaining pressure at their connection point. At least one of the sources for this method has to be represented with a branch that is connected to the base node and has a corresponding constant output pressure setting.

The developed method has been implemented in an algorithm that has an inner cycle, which first calculates the actual and linearized branch conductivities, then solves (1), obtains branch flow rates using (3), recalculates the hydraulic resistance coefficients with (12)–(15), pressure source values according to (26), (27) and self-consumption of compressors. The inner cycle ends with testing of convergence criteria. In order to exit the inner cycle, one of two criterion groups CRITERION 1 or CRITE-

RION 2 has to be satisfied. CRITERION 1 requires determination of three parameters:

$$EPS_1 = \max\left(\left|P^k - P^{k-1}\right|\right), \tag{28}$$

$$EPS_2 = \max(|Q_{\mathrm{imb}}|), \tag{29}$$

$$EPS_3 = \max(|d_{\mathrm{set}}|), \tag{30}$$

where P^k, P^{k-1} – vectors of absolute node pressures of inner cycle steps k and $k-1$, Pa; Q_{imb} – vector of volumetric node imbalance flows, m^3/s; d_{set} – vector of relative differences between calculated pressures, pressure ratios and corresponding settings P_{set} and r_{set}, p.u.

Elements of d_{set} are calculated according to the pressure source control strategy for each branch of an active GTS element:

$$d_{\mathrm{set}\,i} = \begin{cases} \left|\frac{(P_{\mathrm{out}\,i} - P_{\mathrm{set}\,i})}{P_{\mathrm{set}\,i}}\right|, \text{if } r_{\mathrm{set}\,i} = 1 \text{ p.u.} \\ \left|\frac{(r_i - r_{\mathrm{set}\,i})}{r_{\mathrm{set}\,i}}\right| \text{ if } P_{\mathrm{set}\,i} = 0 \text{ Pa.} \end{cases} \tag{31}$$

The CRITERION 1 is satisfied if EPS_1; EPS_2; EPS_3 are below user defined threshold values $maxEPS_1$; $maxEPS_2$; $maxEPS_3$. CRITERION 2 includes the same test for parameter EPS_1 but it is compared with a larger threshold $maxEPS_4$ to allow for the determination of GTS steady-state parameters even in case of small numerical oscillations that exceed $maxEPS_1$. The second parameter used by CRITERION 2 is the number of stagnating steps N_{stag}, which have to exceed a user defined amount of permissible stagnations $maxN_{\mathrm{stag}}$. The inner cycle step is considered stagnating if neither the EPS_1 nor EPS_3 is lower than their minimum values in the previous step and if there is any improvement in either of the two parameters this counter is reset to 0. If either CRITERION 1 or CRITERION 2 is satisfied within user chosen number of permissible calculation steps N_{max} the algorithm proceeds to the outer cycle, which checks operational limits of compressors and pressure regulators and if necessary changes the P_{set} or r_{set} values accordingly. When there are no compressors and pressure regulators or their parameters are within limits the whole process is finished, but if any of the limits are exceeded the inner cycle will be repeated after the adjustment of P_{set} or r_{set} values.

3. THE VALIDATION CASE STUDY

A validation case study has been carried out to test the developed method with both flow equations and a method described in [15] and some of the results will be presented here. The settings for the convergence criteria were $maxEPS_1$ = 5 kPA (0.05 bar); $maxEPS_2$ = 0.01 m^3/s; $maxEPS_3$ = 0.001 p.u;$maxEPS_4$ = 20 kPa (0.2 bar). Additionally, the molar fractions of carbon dioxide x_{CO2} (with x_{H2S} included) and nitrogen x_{N2} (with x_{O2} included) were assumed to be 0.041 p.u. and 0.04 p.u., respectively, based on composition of natural gas supplied to Latvia [37]–[39].

The first network used for comparison is one given by Leong [8], [9] and includes elevation changes, a compressor and two sources (Fig. 2). Leong assumed that the relative density S_g = 0.69 p.u.; E_p = 1 p.u.; T_{avg} ≈ 297.04 K; T_{st} ≈ 288.71 K; ε_r ≈ 0.046 mm; Z_{avg} = 0.9 p.u. for all pipelines in this network. The pipelines represented with flows Q1–Q3 and Q8 are NPS 6 Sch 40 and pipelines represented by branch flows Q4–Q7 and Q9–Q13 are NPS 4 Sch 40. The lengths of the pipelines represented by Q6 and Q7 are approximately 24.14 km and for pipelines Q1–Q5, Q8–Q13 approximately 48.28 km [8], [9].

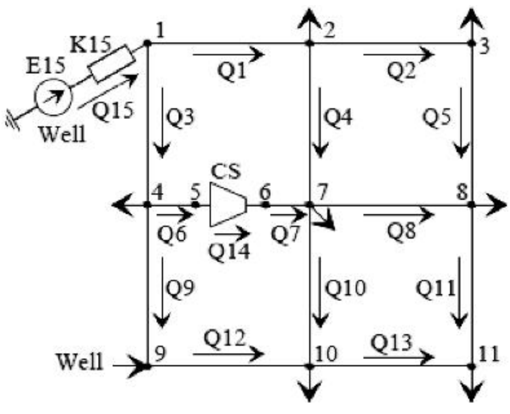

Fig.2. Network diagram for the first example.

For the compressor it was assumed that the inlet side temperature was 297.04 K and compressibility factor 0.9 p.u. Additionally, the polytrophic coefficient was assumed $n_p = 1.4$. The overall compression efficiency was given as $\eta_p \cdot \eta_{CS} = 0.9$ p.u. and the compression ratio setting as $r_{set} = 2.5$ p.u. [8], [9]. For his calculations, Leong used a version of the linearized pipeline hydraulic conductivity method with the AGA-fully turbulent flow equation. The node elevations and gas consumption rates were taken the same as in [8], [9]. An additional branch Q14 was added to model the compressor and the largest of the two gas wells supplying the network was assumed as a balancing source represented with branch Q15 with the output pressure setting the same as pressure calculated by Leong for node 1 (3.511 MPa). The lengths of these artificial pipeline section branches were assumed 1 m and pipeline diameters were assumed 500 mm.

The node pressure results obtained by the proposed method with flow equation (4) (labelled as "Developed method 1" in graphs) and with modified equation (5) (labelled as "Developed method 2" in graphs), ones obtained by Leong as well as ones calculated using a method developed by Sebastian Ganter [15] are presented in Fig. 3. The calculated flow rates are given below in Fig. 4. When comparing the values of the calculated pressures with ones given by Leong, it was determined that they were within 5 % margin for nodes close to the sources. However, for nodes 3, 8 and 11 the obtained pressures differed from Leong's results by 7.6 %; 11.3 % and 14.4 % for Ganter's results; 2.3 %, 3.6 % and 6.6 % for developed method 1; 8 %, 12.2 % and 17.2 % for developed method 2. This is largely due to pressure values for these nodes being only 40.0 %; 31.2 % and 25.5 % of the source pressure. On the other hand, if the pressure differences were compared to the average network pressure level of 2.236 MPa the deviations of neither the developed method versions nor Ganter's method exceeded 7 %. Therefore, one can also see in Fig. 3 that all of the methods obtained practically the same pressure distributions. The multiple correlation coefficient R^2 values (the closer to 1 the stronger the correlation) calculated according to [40] were 0.9951; 0.9992 and 0.9937 for the Ganter's and developed method 1 and 2, respectively. Similar to Fig. 3, these values also indicate strong correlation between the pressure results. It should be stated that while such a comparison of results is used and close results are a good indicator that the developed methods are on par with already tested ones, an ideal match of results cannot be expected without adjustments of pipeline hydraulic efficiency to account for differences in flow equations and solution methods used for the SSM.

The calculated flow rates for the three methods are mostly within 2 % of ones provided by Leong with the exceptions of Q5 and Q10, which are the two smallest flow rates resulting in seemingly large deviations. When these deviations are compared to the average absolute flow rate of the network (1.276 m³/s), one can see that overall none of the deviations exceeds 2.5 %. The overall match between the results can also be seen in Fig. 3 and from the values of the multiple correlation coefficient R^2 (0.9999, 0.9999 and 1.0000 for the Ganter's and developed method 1 and 2, respectively). The flow rate results show that the difference is significantly smaller, which is to be expected as the flow rates are more predefined than node pressures due to the fixed demand flow rates of the network nodes.

Leong also provided his estimate of the power required by the compressor of 201.81 HP (150.49 kW) [8]. Applying the same assumptions, information on the compressor as used by Leong, the gas compressibility factor values (calculated separately) for the compressor inlet and outlet sides of 0.9609 and 0.9083, it was possible to calculate the required power as 155.59 kW according to formula from [21] adopted also by this method. The difference with Leong's result is 3.4 %, which indicates that the estimated power necessary for compressor operation is at least similar to one determined with an existing method and could be used for other purposes in the future.

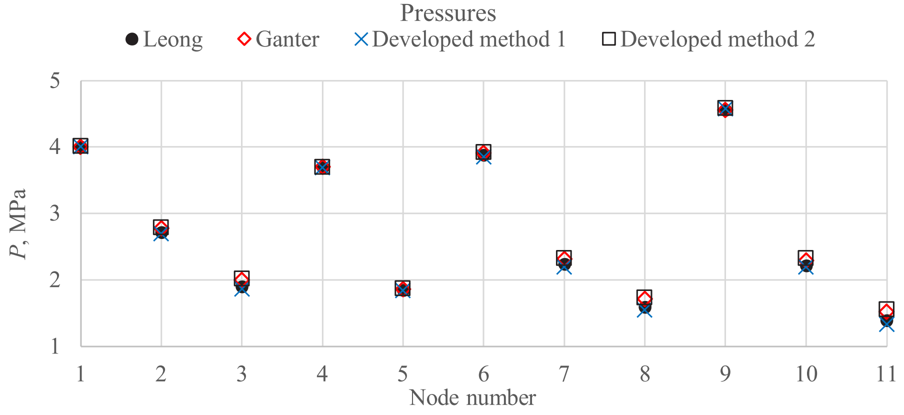

Fig. 3. Graph of the calculated node pressures for the first example.

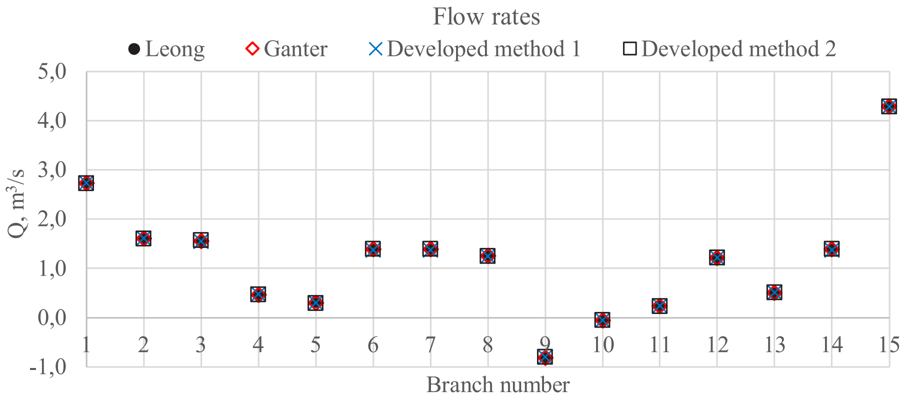

Fig. 4. Graph of the calculated branch flows for the first example.

The second example that will be presented here is a steady-state simulation of a larger pipeline network (Fig. 5). This network was chosen as it represented a real network in the Mexico valley with the pressure values reported as measurement data [8], [11], [15], [41]. The following assumptions used by the other authors [8], [11], [15], [41] were adopted: $S_g = 0.65$ p.u.; $T_{avg} \approx 191.67$ K; $E_p = 0.95$ p.u.; $T_{st} \approx 288.71$ K; $Z_{avg} = 0.98$ p.u. for all of the pipelines in this network. The pipeline lengths and diameters were taken from [8], [9] and the values of pipeline inner wall roughness ε_r were obtained from [11]. The demand flow rates were taken from Leong's work [8], [9] as ones given in [11] seemed too miniscule to result in the reported pressure drops. The assumptions about the gas composition remain the same as in the first example. The node elevations were unknown or disregarded by the other authors so they were not considered here as well.

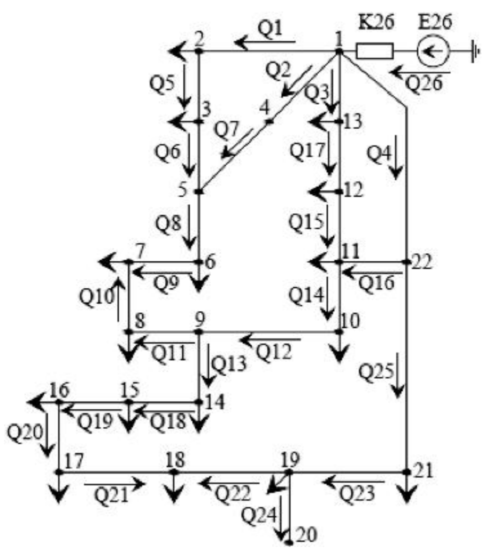

Fig.5. Network diagram for the second example.

The pressure results by Martinez were obtained using the Panhandle-B flow equation and the Newton-Raphson method. He also applied the conjugated gradient method to improve the convergence of the solution of a linear equation system that provided the node pressure correction vector for the Newton-Raphson method [41]. In order to apply the proposed method, a branch represented with the flow Q26 was added to serve as a pressure source with P_{set} the same as reported node 1 pressure of 2.461 MPa. The length of this artificial pipeline section branch was assumed 1 m and pipeline diameter was assumed 1000 mm.

The node pressures including the reported measurement values [8], [9], ones calculated by Martinez [41] as well as ones obtained using the two versions of the developed method and Ganter's method are given in Fig. 6. The calculated branch flow rate results for comparison were available only from a graph given by Leong [8], [9]. Thus, in Fig. 7 the results of the two versions of the developed method and Ganter's method were compared only to Leong's results. Considering the assumptions made and potential measurement errors, all four modelling methods obtained pressures close to measurement data (largest deviations being 4.41 %, 5.22 %, 4.97 % and 5.18 % for Martinez's method, Ganter's method, developed method 1 and developed method 2, respectively). Figure 6 also shows how well all of the methods captured the significant pressure drop for nodes 15–20 caused by choke points (small diameter pipelines Q18 and Q23). The almost constant pressure value difference for nodes 2–8 seem to indicate that the hydraulic efficiency of pipelines represented with Q1 and Q2 were lower than reported or assumed by other authors. The multiple correlation coefficient R^2 values (determined using the measurements as reference) for this example were 0.9987; 0.9980; 0.9986 and 0.9981 for the Martinez's method; Ganter's method and developed method 1 and 2, respectively, which also indicated that all of the methods replicated the pressure distribution well. One can also notice that the measured pressures were lower than those obtained by modelling methods (including Leong's method [8], which had similar results to ones presented by Martinez). To some extent, this is an expected result as it shows than in fact the real pressure drops are slightly higher, but the difference can and is intended to be accounted for with small changes in the hydraulic efficiency values as described in theory [10], [21].

The calculated flow rates in most cases are within 6 % of ones obtained by Leong [8], [9] with exceptions of Q5; Q6; Q10; Q11; Q21, the value of which are 35 % or less of the average absolute flow rate of the network of 14.659 m^3/s. When compared to this average flow rate, neither of the deviations of branch flow results reach 6 %. The overall match of estimated flow rates to ones reported by Leong is also indicated by Fig. 7 and values of the multiple correlation coefficient R^2 (0.9995, 0.9997 and 0.9995 for the Ganter's method and developed method 1 and 2, respectively).

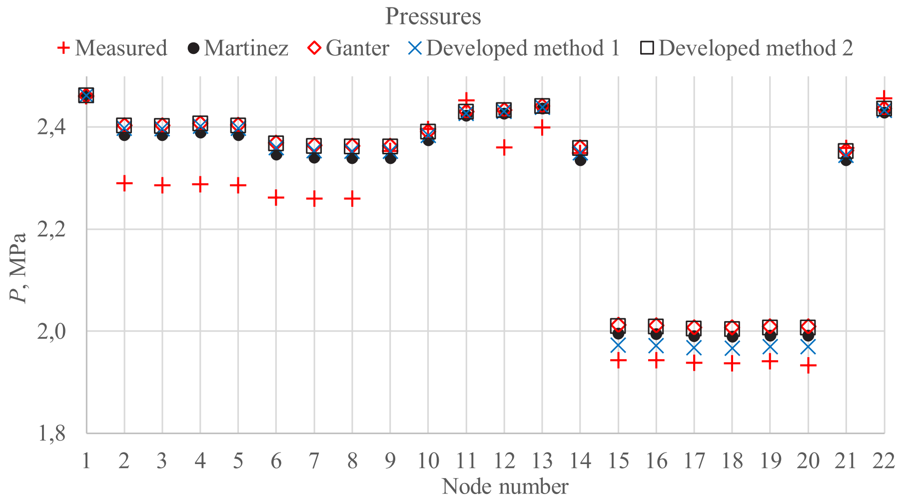

Fig. 6. Graph of the measured and calculated node pressures for the second example.

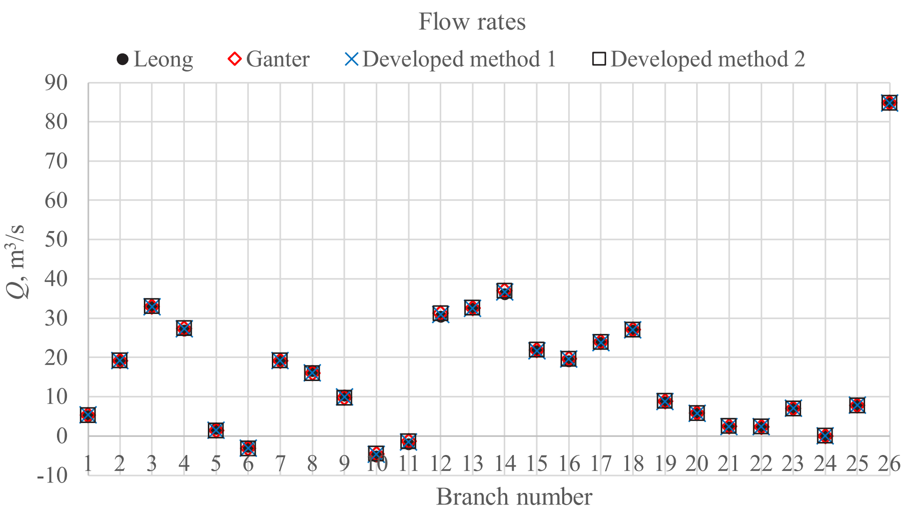

Fig. 7. Graph of the calculated branch flow rates for the second example.

4. CONCLUSIONS

1. The combination of analogy of graph based steady-state modelling of linear electrical circuits with linearized hydraulic conductivity analogue can be implemented in GTS SSM solver that is straightforward in terms of use and robust due to the linear nature of the main equation system.
2. Use of an additional pressure change term in the steady-state flow equation and determination of its value according to either constant output pressure or constant pressure ratio control strategy provides a flexible and easy-to-use approach for modelling of the main active non-pipeline elements of GTS (compressors, pressure regulators, etc.).
3. The applied pressure change control strategies with their settings can be utilised to implement operational limits of pressure regulators and compressors both by adjusting these settings and representing the bypass mode.
4. The validation case study showed that the flow rates estimated with the developed method and Ganter's method in most cases were well within 5 % of the reported ones or at least the average flow rate value and their general match to reported results were further confirmed by values of the multiple correlation coefficient.
5. The obtained node pressure values in most cases were within 6 % of the ones reported for validation study examples except the cases where the reported pressure value was already relatively small, but the differences were always within 7 % of the average pressure level of the network nodes.
6. Due to diverse flow equations and mathematical solution methods used for the SSM as well as potential deviations between assumptions made and the actual network parameters, some differences between the obtained and previously reported results were to be expected and, therefore, the main goal during this validation process was to obtain a similar flow rate and pressure distributions with limited (say up to 5–10 %) differences that could be accounted for by small changes in the hydraulic efficiency of the pipelines.
7. Considering the aforementioned aspects and the relatively good match between the obtained results and the results reported for both a theoretical and a real GTS network case, it can be concluded that both the developed method and Ganter's method were validated.

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CHPP OPERATION MODE OPTIMIZATION UNDER ELECTRICITY AND GAS MARKET CONDITIONS USING A GENETIC ALGORITHM

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The article presents an operation planning optimisation approach using a genetic algorithm for CHPPs in an urban heat supply zone. Changes in market environment will result in a significant change in energy system planning and operation. For efficient production planning in the liberalized power markets, it is paramount to determine the optimal strategies over a time horizon. Solution of an optimization task of such complexity requires a well-crafted set of tailored modelling, simulation, optimization, and forecasting tools. A well-designed solution is unthinkable without a great number of production units, such as gas turbines, steam turbines, heat-only boilers, and thermal storages, reflected by the optimization model.

Keywords: CHPP operation, electricity market, gas market, genetic algorithm, optimization.

1. INTRODUCTION

Combined heat and power plants (CHPPs) simultaneously generate electricity and heat on the basis of cogeneration. CHPPs are widespread in the Nordic countries, where domestic heat consumption is high, especially in winter, and district heating as a thermal load for CHPPs is typical of cities and towns [1]. Historically, CHPPs are built in places with heat demand, and the combined operating mode is the main one for CHPPs during the heating season when operation takes place according to the heat schedule, i.e., the production of electricity depends on the production of heat, the latter being a priority.

However, nowadays CHPP operation becomes more complicated when power market conditions change the game. Liberalization of the power markets – development of the electricity market, primary energy source markets and potential development of the heat energy market – becomes an integral part of energy policy planning.

New markets will result in a significant change in energy system planning and operation. Production planning in the liberalized power markets is to determine the optimal strategies over a time horizon (a day, a week, a month or a year) so that the overall net profit can be maximised subject to production constraints. CHPP operation planning optimization for a time horizon is a very complicated task. The interdependence between heat and power generation imposes a great challenge in operation optimization. It must be done in coordination between heat and power, taking into account the non-uniform equipment fleet [2].

Moreover, the liberalized power and gas market introduces more uncertainties than before, operation optimization should cover not only the operation of a single CHP plant, but the operation of all CHPPs in a heat supply zone (Fig. 1). This means that a great number of production units, such as gas turbines, steam turbines, heat-only boilers, and thermal storages should be added to the optimization model.

The solution of an optimization task of such complexity requires a well-crafted set of tailored modelling, simulation, optimization, and forecasting tools.

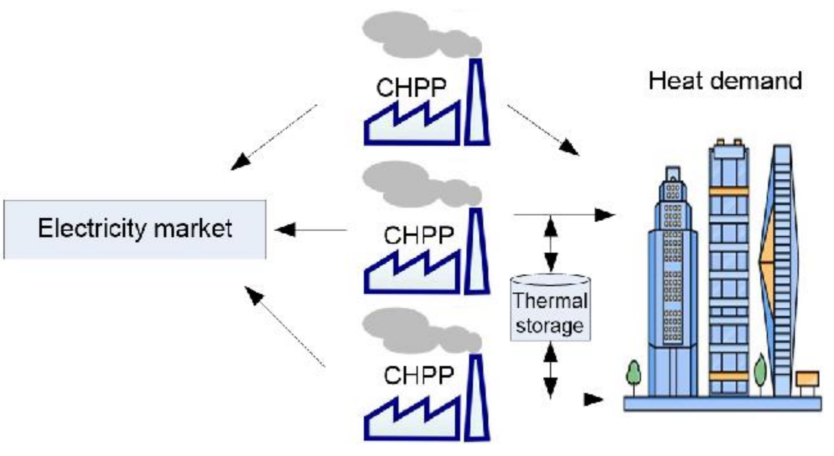

Fig. 1. The supply of CHPPs.

The great challenge for operation planning optimization is the choice of the optimization method. First of all, a CHPP optimization problem is not linear, it has a large number of decision variables, and note should be taken of the exponential growth of the array of variables when the planning time span increases. The timed nature of operation and the limitations imposed by launch and stop operations add more complexity to the task (for example, gradient-type mathematical solvers are unfit for such a type of task).

A lot of work has been done during the recent years to improve CHPP operation optimization [3]–[11]. The major focus in most papers is on discovering what type of models and optimization algorithms to use to render effective solutions for CHPP operation planning optimization for a time period, and the longer the period, the better.

Over the recent years, the Genetic Algorithm (GA) has become one of the most popular mathematical solvers for such a type of problems [3]–[11]. A genetic algorithm is a type of numerical algorithms, suitable for nonlinear tasks, including interrupted function tasks. However, GA is not the best performer when it needs to deal with larger sets of decision variables.

Upon summarising the results of the publications devoted to CHPP operation planning optimization, we can conclude that the non-uniform CHPP operation planning optimization task for a heating zone under power market conditions (an electricity market and a developing gas market) has not yet been considered widely enough for the time being.

The overall objective of our study is to develop an operation planning optimization model for the CHPPs of the city of Riga, using a genetic algorithm for operation planning optimization, electricity market and gas market models for power market simulation, Riga CHPP 1, Riga CHPP 2.1 and Riga CHPP 2.1 models for the simulation of heat and power production. The objective function for the optimization task is to **maximise the net profit** for the operation of the CHPPs.

Riga CHPPs and production units are described in the next section of this paper. It should be noted that several reconstruction projects have been implemented at Riga CHPPs to improve their operation flexibility under market conditions: reconstruction of the heat-only boilers to meet the maximum heat load during the coldest days and to meet the heat load during CHPP maintenance; thermal storage installation to shift the heat load chart away from electricity production. In this paper, the operation planning optimization time period is 24 hours.

For future work, it is planned to increase the planning period and to use forecasting for power market prices and heat loads.

The main contributions of this paper are summarised as follows:

- A genetic algorithm is successfully applied for planning the operation of the CHPPs of the city of Riga for a time period of 24 hours with an objective to maximise their net profit;
- The effectiveness of the proposed approach is analysed on the basis of the operation planning optimization results.

The rest of the article is organised as follows: Section 2 is devoted to the description of the production units of Riga CHPPs, the description of the Nord Pool power market model and the description of the model of the developing gas market. Section 3 contains a description of the optimization model based on the genetic algorithm. Section 4 contains optimization results and result analysis.

2. METHODOLOGY AND MODELS

A. Riga CHPPs

Riga CHPP No. 1, Riga CHPP No. 2.1 and Riga CHPP No. 2.2 meet 69 % of the heat needs of the city of Riga.

The production units of CHPP No. 1 are as follows: a gas-steam combined cycle (CCGT) twin unit with an installed thermal power capacity of 145 MW_{th} and an installed electrical power capacity of 144 MW_{el}, also heat-only boilers (HOBs) with an installed capacity of 348 MW_{th}. The total thermal power capacity of CHPP No. 1 is 493 MW_{th}. Natural gas is used as the primary energy source. In case of a gas supply outage, diesel fuel could be used as a backup fuel for the heat-only boilers.

Table 1. Riga CHPP No. 1

Riga CHPP 1	**No.**	**Pe, MW**	**Pq, MW_{th}**	**Pq total**
Cogeneration	1	144	145	145
Heat-only boilers	3	-	116	348
Total	-	144	-	493

CHPP No. 1 operation modes:

1. Cogeneration:
1.1. 2 GTs + ST (Pq – heat load; Pq > 45 MW up to Pq < 145 MW);
1.2. 1 GT + ST (Pq > 45 up to 66 MW).
2. Cogeneration with heat-only boilers:
2.1. 2 GTs + ST +HOB (Pq > 145 MW, up to a total of 493 MW_{th});
2.2. 1 GT + ST and HOB (Pq > 66 MW, up to a total of 414 MW_{th}).
3. HOB – 12 MW_{th} up to 348 MW_{th},
where GT is a gas turbine and ST is the steam turbine, and HOB is the heat-only boiler.

CHPP 2.1 power unit's total electrical power in cogeneration mode is 413 MW_{el} and 442 MW_{el} in condensing mode, respectively, and the total thermal power in cogeneration mode is 274 MW_{th}. CHPP 2.2 power unit's total electrical power in cogeneration mode is 419 MW_{el} and 439 MW_{el} in condensing mode, respectively, and the total thermal power in cogeneration mode is 270 MW_{th}. Heat-only boilers – No. 1, 2, 3, 4, 5 with a total thermal power of 580 MW_{th}.

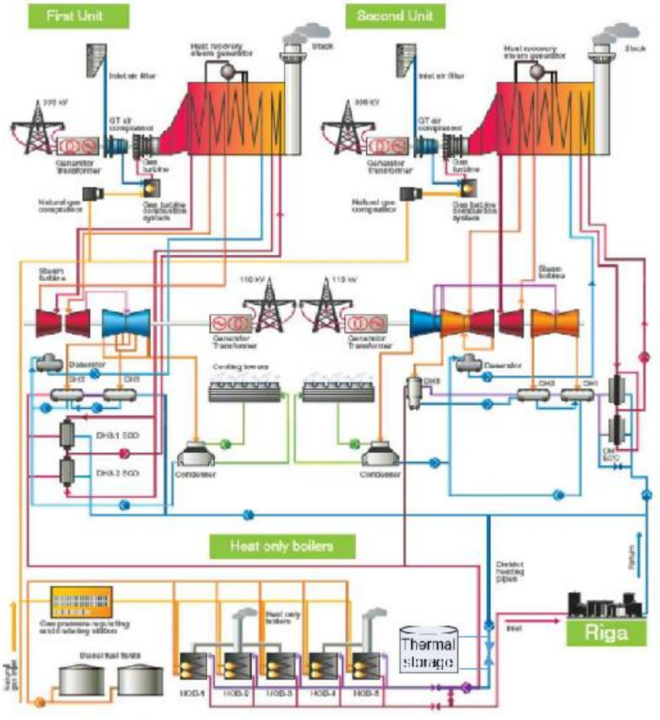

Fig. 2. Illustration of Riga CHPP 2.1 and CHPP 2.2.

In case of a gas supply outage, diesel fuel could be used as a backup fuel for the heat-only boilers. In the year 2020, a thermal storage was installed for CHPP 2.1 and CHPP 2.2 with a total capacity of 550 MWh and a charge/discharge capacity of 150 MW per hour.

Table 2. Riga CHPP 2

Riga CHPP 2	**No.**	**Pe, MW**	**Pq, MWth**	**Pq total**
Cogeneration unit CHPP 2.1	1	413	274	274
Condensing unit CHPP 2.1	1	442	0	0
Cogeneration unit CHPP 2.2	1	419	270	270
Condensing unit CHPP 2.2	1	439	0	0
Heat-only boilers	5	-	116	580
Total cogeneration at CHPP 2	-	832	-	1124
Total condensing at CHPP 2	-	871	-	-

The equipment set of CHPP 2.1 and CHPP 2.2 allows for several main operation modes.

1. Cogeneration mode:

1.1. CHPP 2.1 (Pq from 180 MW_{th} up to 274 MW_{th} and electrical power from 190 MW_{el} up to 413 MW_{el});
1.2. CHPP 2.2 (Pq from 160 MW_{th} up to 270 MW_{th} with electrical capacity from 185 MWel up to 419 MW_{el});
1.3. CHPP 2.2 Opflex mode (Pq from 145 MW_{th} up to 160 MW_{th} and electrical power from 148 MW_{el} up to 175 MW_{el});
1.4 CHPP 2.1 and CHPP 2.2.

2. Condensing mode:

2.1. CHPP 2.1 electrical power from 190 MW_{el} up to 442 MW_{el};
2.2. CHPP 2.2 electrical power from 180 MW_{el} up to 439 MW_{el};
2.3. CHPP 2.1 and CHPP 2.2.

3. Mixed operation mode:

3.1. CHPP 2.1 power unit: Pq from 60 MW_{th} up to < 180 MW_{th} and electrical power from 190 MW_{el} up to 413 MW_{el};
3.2. CHPP 2.2 power unit: Pq from 20 MW_{th} up to < 160 MW_{th} and electrical capacity from 180 MW_{el} up to 419 MW_{el}.

4. CHPP power unit and heat-only boilers.

5. CHPP power unit and heat-only boiler with thermal power from 12 MW_{th} up to 580 MW_{th},

where electrical power – *P* is a function of thermal power – *Q,* and is represented with a 2nd degree polynomial (1). CHPP fuel/natural gas consumption *F* is a function of electrical power (2). For every CHPP and every production unit and mode, functions *P=f(Q)* and *F=f(P)* are different.

$$P = a * Q^2 + b * Q + C \quad (1)$$
$$F = q * P^2 + w * P + r \quad (2)$$

B. The Nord Pool Market

Nord Pool runs the leading power market in Europe and offers day-ahead and intraday markets to spot customers. The day-ahead market is the main arena for power trading, and the intraday market supplements the day-ahead market and helps secure balance between supply and demand.

The Nordic and Baltic areas are divided into bidding areas by the relevant transmission system operator in order to handle congestions in the electricity grid. Bidding areas can have a balance, deficit or surplus of electricity. Electricity will flow from areas where the price offered is lower towards areas where the demand is high and the price offered is higher.

If the transmission capacity between bidding areas is not sufficient to reach full price convergence across the areas, congestions will lead to bidding areas having different prices.

If the flow of power between bidding areas is within the capacity limits set by the transmission system operators, the area prices in these different bidding areas will be identical.

All the producers are paid according to the calculated area price, and similarly all the consumers pay the same price [12].

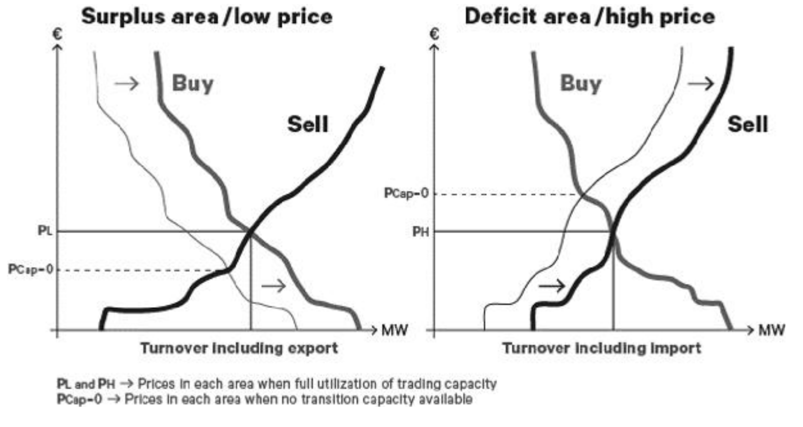

Fig. 3. Electricity pricing.

For our task in this article, the Nord Pool market model is represented by Latvian area electricity prices for 24 hours, with a time step of one hour.

C. Gas Market

The European Union began a liberalization process during the last decade in order to create an internal market for gas by breaking up vertically integrated national companies, allowing for entry on the supply side and consumer-switching on the demand side. The opportunity to purchase gas from different suppliers does not eliminate possible constraints in gas delivery (gas transmission capacity limits), gas storage (storage capacity limits, storage charge/discharge limits) and so on. In this case, the gas market model for our optimization task is represented by several gas suppliers, each of them offering a specific volume at a specific price [17].

3. MATERIALS AND METHODOLOGY

A. Methodology

The objective function for the optimization task is to maximise the net profit for the operation of Riga CHPP 1, CHPP 2.1, and CHPP2.2, the thermal storage and the heat-only boilers for a time period of 24 hours.

$$F = \sum_{i=1}^{24} C_{p\_i} \left(P_{CHPP1i} + P_{CHPP2.1i} + P_{CHPP2.1i}\right) - \\ - \sum_{i=1}^{24} \left(V_{gCHPP1i} + V_{gCHPP2.1i} + V_{gCHPP2.1i} + V_{gHB}\right) C_g - \\ - penalty_{CHPP1+CHPP2.1+CHPP2.2} \rightarrow max \quad (3)$$

where

C_{p_i} – an hourly electricity price from Nord Pool spot exchange, €/MWh; the penalty is every CHPP unit's start/stop cost, €.

$P_{CHPP1i}, P_{CHPP2\ 1i}, P_{CHPP2\ 1i}$ represent the electricity sold/output by CHPP 1, CHPP 2.1, CHPP 2.2 every hour, MWh during hour *i*; further sold/output electricity is a function of produced electricity:

$$P_{CHPP1i} = f\left(P_{CHPP1pi}\right) \quad (4)$$
$$P_{CHPP2.1i} = f\left(P_{CHPP2.1pi}\right) \quad (5)$$
$$P_{CHPP2.1i} = f\left(P_{CHPP2.1pi}\right) \quad (6)$$

where

$P_{CHPP1pi}, P_{CHPP2.1pi}, P_{CHPP2.1pi}$ – the electricity produced by CHPP 1, CHPP 2.1, CHPP 2.2, MWh, during hour *i*.

Further electricity produced by every CHPP is a function of produced heat energy, MWh, during hour *i*:

$$P_{CHPP1pi} = f(Q_{CHHP1pi}) \quad (7)$$
$$P_{CHPP2.1pi} = f(Q_{CHHP2.1pi}) \quad (8)$$
$$P_{CHPP2.2pi} = f(Q_{CHHP2.2pi}) \quad (9)$$

where

$f(Q_{CHHPpi})$ is the heat energy produced by the CHPP without heat-only boilers; $f(Q_{CHHPpi})$ is represented in Eq. (1); Q_{CHHPpi} is the heat energy produced by every CHPP for every hour, in total 72 variables are decision variables for the optimization problem.

Further, the total natural gas consumption of CHPPs is represented as a function of the heat energy produced. It should be mentioned that the condensing operation mode is also taken into account.

$$V_{gCHPP1i} = f\left(Q_{CHHP1pi}\right) \quad (10)$$
$$V_{gCHPP2.1i} = f\left(Q_{CHHP2.1pi}\right) \quad (11)$$
$$V_{gCHPP2.1i} = f\left(Q_{CHHP2.2pi}\right) \quad (12)$$

where

V_{gCHPPi} is the gas consumption in MW for electricity and heat production;

further C_g is the natural gas price as a function of natural gas volume. This function is described in the gas market section:

$$C_g = f(\textstyle\sum_{i=1}^{24}(V_{gCHPP1i} + V_{gCHPP2.1i} + V_{gCHPP2.1i} + V_{gHBi}) \quad (13)$$

where

V_{gHB} is the gas consumption (MWh) for heat production by the heat-only boilers every hour.

Constraints:

$$Q_{CHPP1p\_min} \leq Q_{CHPP1pi} \leq Q_{CHPP1p\_max} \tag{14}$$

$$Q_{CHPP2.1p\_min} \leq Q_{CHPP2.1pi} \leq Q_{CHPP2.1p\_max} \tag{15}$$

$$Q_{CHPP2.2p\_min} \leq Q_{CHPP2.2pi} \leq Q_{CHPP2.2p\_max} \tag{16}$$

where
Q_{CHPPp_min} and Q_{CHPPp_max} are technical (design) constraints for heat production for every CHPP (without the heat-only boilers).

$$P_{CHPP1p\_min} \leq P_{CHPP1pi} \leq P_{CHPP1p\_max} \tag{17}$$

$$P_{CHPP2.1p\_min} \leq P_{CHPP2.1pi} \leq P_{CHPP2.1p\_max} \tag{18}$$

$$P_{CHPP2.2p\_min} \leq P_{CHPP2.2pi} \leq P_{CHPP2.2p\_max} \tag{19}$$

where
P_{CHPPp_min} and P_{CHPPp_max} are technical constraints for electrical energy production for every CHPP.

$$Q_{HBmin} \leq Q_{HB} \leq Q_{HBmax} \tag{20}$$

where
Q_{HBmin} and Q_{HBmax} are technical constraints for heat production by the heat-only boilers.

$$0 \leq Q_{storageuse\_i} \leq Q_{storageuse\_max} \tag{21}$$

where
$Q_{storageuse\_i}$ is the use of heat from the heat energy storage in every hour.

$$0 \leq Q_{storage\_i} \leq Q_{storage\_max} \tag{22}$$

where
$Q_{storage\_i}$ is the heat stored in the heat energy storage for every hour.

$$Q_{CHPP1p_i} + Q_{CHPP2.1p_i} + Q_{CHPP2.2pi} + Q_{storageuse} + Q_{HB} \geq Q_d \tag{23}$$

where
Q_d is a function of outdoor temperature $Q_d = f(T)$ and represents the heat demand. The production amount of all the units must meet the heat demand.

As shown in this section, CHPP optimization problem is a nonlinear one, with a large number of decision variables. The timed character of operation and the limitations imposed by the launch and stop operations add more complexity to the task. All of the above makes the choice of a genetic algorithm for the optimization problem the most preferable option.

B. Genetic Algorithm

The genetic algorithm has been inspired by the process of natural selection where the fittest individuals are selected for reproduction in order to produce offspring in the next generation. The process of natural selection starts with the selection of the fittest individuals from a population. They produce offspring that inherit the characteristics of the parents and will be added to the next generation. If parents have better fitness, their offspring will be better than their parents and have a better chance at surviving. This process keeps on iterating and at the end, the population will consist of the fittest individuals or, in other words, the best values of decision variables will be found [13].

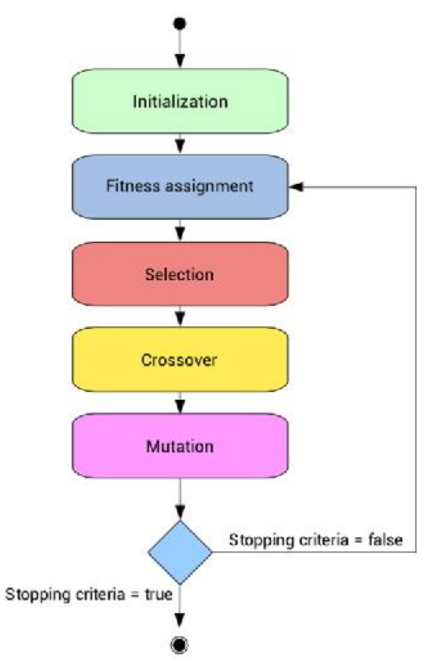

Fig. 4. The structure of a genetic algorithm.

The present paper does not focus on the details and arrangement of genetic algorithms. However, some important aspects of GA application in our task should be mentioned. These aspects will be discussed in the next section. Optimization algorithms – and the genetic algorithm is not an exception – sometimes converge towards a local minimum, a point where the function value is smaller than at nearby points but not the smallest one in the whole search space. The genetic algorithm can sometimes overcome this deficiency with the right settings.

Now let us discuss genetic algorithms in general. Five main phases are considered in a genetic algorithm: Initial Population, Fitness Function, Selection, Crossover and Mutation.

The optimization process begins with a set of individuals called a Population. Each individual is a solution to the problem we want to solve. The closer the initial population values to the optimum, the better.

The idea of the Selection phase is to select the fittest individuals and let them pass their genes on to the next generation. Two pairs of individuals (parents) are selected based on their fitness scores. Individuals with a high fitness are selected for reproduction.

Crossover is the most significant phase in a genetic algorithm. For each pair of parents to be mated, a crossover point is chosen at random from within the genes.

In Mutation, some of the genes can be subjected to a mutation with a random probability [15].

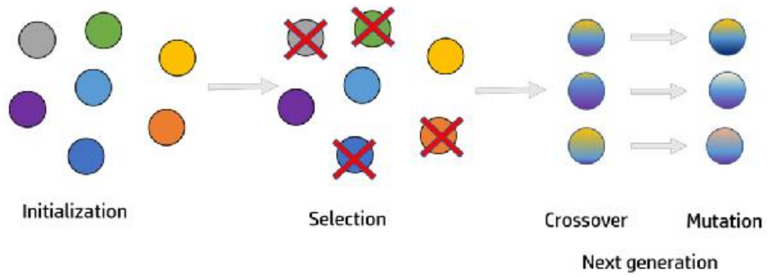

Fig. 5. Genetic algorithm.

C. Genetic Algorithm Implementation

One of the factors of our problem is the redundancy of each of the CHPP units. What is more, each CHPP unit can be turned off for the entire planning period. This type of operation introduces certain difficulties for the use of the genetic algorithm. This is a type of the so-called local minimum problem. To overcome this deficiency, the choice of the initial population for the genetic algorithm is very important. A special subprogram is developed for the genetic algorithm input (Fig. 6). The idea of this subprogram is to choose the best combination of the three CHPP units (the start-up set) for GA input. The criterion for the best combination is the objective function – Eq. (3) – and fulfilment of constraints. However, only three operation modes are possible for the initial population: (1) the power plant unit is off, (2) minimum power and (3) maximum power for every hour of the planning period. This means that we do not conduct any optimization, just enumeration with the choice of the best decision.

The next important step is the choice of the decision variable range. It is more practical to reserve the whole range from 0 up to $Q_{CHPPp\,max}$ but if the value is less than $Q_{CHPPp\,min}$, it means that the CHPP unit is off. The turning on/off of the CHPP units is represented in the objective function with a penalty, Eq. (3).

The next operation is the choice of the number of individuals for the elite, crossover and mutation. Practice shows that the number for the elite should be quite high for tasks with a great number of decision variables, up to 25 % from the population. The mutation can be conducted after the crossover; however, the mutation should be with strong random and the number of individuals for the mutation should not exceed 20 % of all the individuals. Mutation can make individuals unfit/unsuitable for constraints; on the other hand, strong mutation is vital to overcome local minima.

The gas costs are calculated based on the total gas consumption and the available gas supply volumes and the gas prices on the market. The CO_2 emission costs are added to the calculated gas costs.

It should be mentioned that for operation planning optimization the initial state of every CHPP unit and heat storage must be defined. This approach makes it possible to use optimization in a rolling way, i.e., the end of a planning period is the start of the next planning period. This way of optimization for a longer period has its disadvantages; however, heat demand forecasting and electricity price forecasting are not accurate either for a time period longer than 24 hours, and all kinds of such planning can be used only for informational purposes.

The proposed optimization approach is implemented in MATLAB, using the custom genetic algorithm.

To reduce the number of decision variables, the method of decomposition, in other words, division of the problem into two separate optimization layers, is used. At the top layer, the population forms a heat production task for each CHPP unit (described in detail above). At the bottom layer, this task is distributed among the CHPP assemblies with a check for the possibility of such a mode, including inheritance from the previous hour mode.

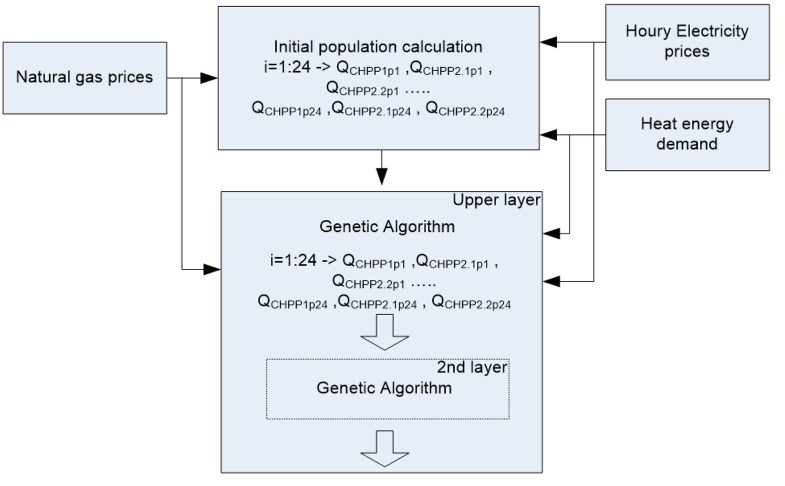

Fig. 6. The method of decomposition.

4. RESULTS

In this section we present optimization results for different days with different heat demand and with gas price and electricity price fluctuation. The heat demand and the electricity prices are taken from a historical database. Figures 7 and 8 present an easy scenario of a cold winter day with a high heat demand and a very low gas price of 5 €/MWh (plus 6.67 €/MWh as CO_2 emission expenses). It should be mentioned that HOB (Figs.7–10) represents total thermal power production by CHPP1 and CHPP2 HOBs. For a starting point, all units are in cogeneration mode. The value of the objective function is 96 019 €. The profit is so low because we are not taking into account the income from the heat sold. The value of the heat sold is equal to the heat demand, and the heat price is constant, so it can be excluded from the objective function. If we change the gas price from 5 € up to 20 € (one supplier with a fixed price), all the CHPP units will be disconnected (Fig. 9). For this scenario, the heat-only boilers can meet the whole heat demand. The value of the objective function is −562 161 € (a negative value).

Here we can see a strong interdependence between the price of gas (and emissions) and the electricity price for optimal operation planning.

Now let us consider a natural gas price of 18 €/MWh. The operation planning results are shown in Figs. 10 and 11. One can see that CHPP 1 is not active for the whole operation planning period. CHPP 1 has a low maximum electrical power output and high maximum heat power. This

CHPP was designed to meet the whole heat demand when the heating season was over. When the electricity price is high and the heat demand is not sufficient for the operation of all the CHPP units, the operation of CHPP 2.1 and CHPP 2.2 is a priority because they can produce more electricity with the same heat production. This situation is shown in Figs. 10 and 11. (CHPP1 Start/Stop expenses makes more feasible to run HOB to cover the remaining heat load).

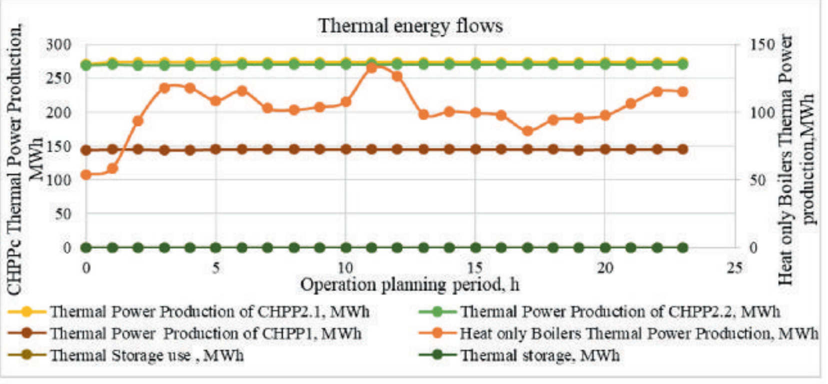

Fig. 7. Heat energy flows; the natural gas price is 5 €/MWh.

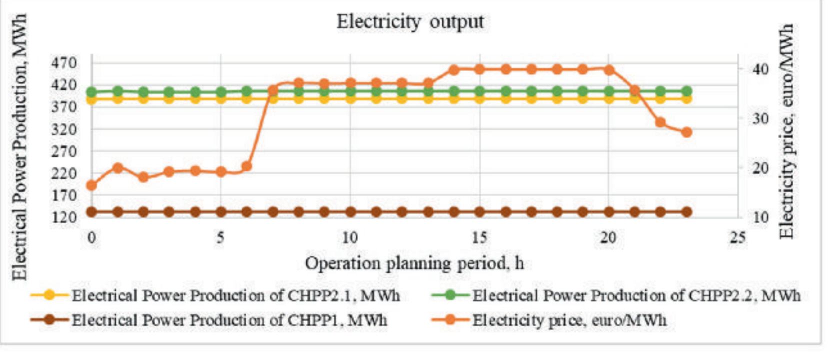

Fig. 8. Electricity output; the natural gas price is 5 €/MWh.

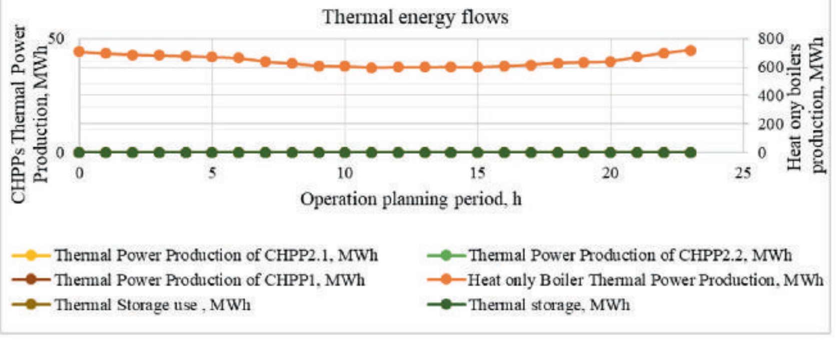

Fig. 9. Heat energy flows. Heat only boilers (from CHPP1 and CHPP2) are in operation; the natural gas price is 20 €/MWh.

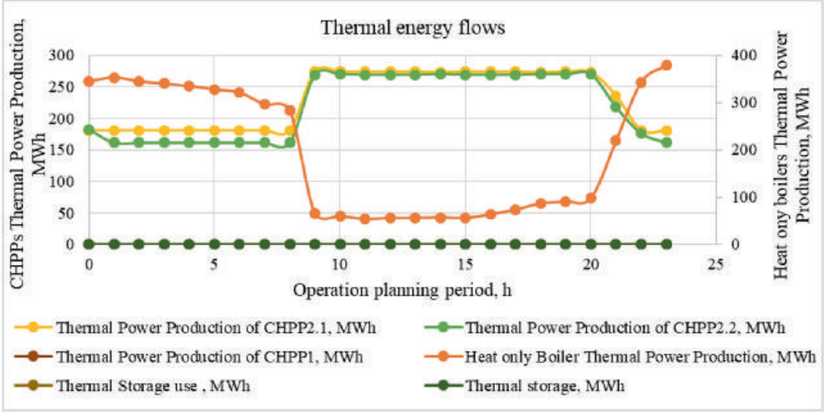

Fig. 10. Heat energy flows at a natural gas price of 18 €/MWh.

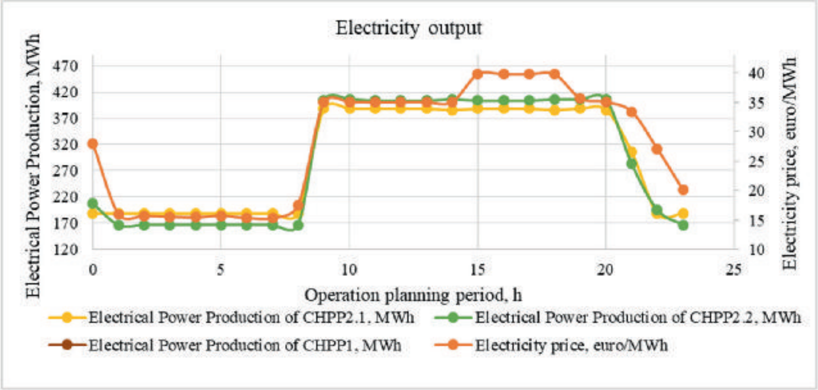

Fig. 11. Electricity output at a natural gas price of 18 €/MWh.

5. CONCLUSIONS

The application of the proposed GA-based optimization technique to the set of possible states of a hybrid system allows selecting a subset of states that:

a. provides the greatest possible profit;
b. guarantees the feasibility of the operation mode and provides consumers with the necessary heat throughout the entire planning interval;
c. does not create unacceptable operating modes for the equipment.

Decomposition of the problem into two mutually related layers makes it possible to create an optimal objective function for the implementation of the available computational resources, reduce the number of decision variables and significantly speed up the process of finding the optimum. Part of the calculations at the lower layer can be performed only once and then they have to be replaced by interpolation of the calculated table. The application of the proposed method in a sliding window manner allows solving the optimization problem for any planning period.

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THE NATURAL GAS AS A SUSTAINABLE FUEL ATLERNATIVE IN LATVIA

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Despite various benefits that the natural gas mobility can provide, CNG (hereinafter – compressed natural gas) and LNG (hereinafter – liquified natural gas) filling infrastructure both in Latvia and the Baltic States as a whole is still at the stage of active development. As a result, the natural gas fuelled vehicle fleet comprises less than 1 % of all registered road vehicles in the Baltics, but, with regards to transport and climate policies of the European Union (hereinafter – the EU), it has a significant potential for further growth.

In order to estimate the perspectives of mobility of natural gas, including bioCNG and liquified biomethane (hereinafter – LBM), CNG has been chosen and analysed as a possible alternative fuel in Latvia with its environmental and economic benefits and payback distance for CNG vehicles compared to petrol and diesel cars. The review of various types of CNG filling stations is also presented, along with information on operating tax rates and currently registered vehicles divided by types of fuel in Latvia.

It was established that with the Latvian fuel price reference of the late 2020, exploitation of CNG-powered vehicle was by 24 % cheaper per kilometre in comparison with diesel and by 66 % cheaper in comparison with petrol vehicles. CNG vehicles have smaller operational taxes, since they are based on carbon dioxide (hereinafter – CO_2) emissions, which are lower for CNG-powered vehicles. Calculation results also indicate that CNG vehicle payback time may fall within the warrant period, if at least 57650 kilometres as an alternative to a petrol vehicle or 71 531 kilometres as an alternative to a diesel vehicle are driven by it.

Keywords: *Alternative fuels, CNG, filling stations, Latvia, LNG, transport decarbonisation, transport infrastructure.*

1. INTRODUCTION

The transport, and particularly road transport, is one of the most significant fossil fuel dependent segments of the national economies across Europe. Oil dependency of all segments of the transport sector makes it the single biggest source of greenhouse gas emissions (hereinafter – GHG) in the EU as well. Road transport is responsible for about 73 % of total transport GHG emissions, as more than 308.3 million road vehicles in Europe are over 90 % reliant on conventional types of oil-based fuels (diesel, petrol etc.) [1]–[3].

At the same time, if viewed from the sustainability standpoint, there are viable alternatives to traditional oil-based fuels, which can be used effectively already today. Among them, natural gas in a form of CNG and LNG, along with admixtures of various renewables gases (hereinafter – RG) should be pointed out as one of the most promising option. Natural gas emits approximately 6 % to 11 % less GHGs than petrol throughout the fuel life cycle. The GHG emissions impacting the CNG and LNG life cycle are predominately the result of production-phase fuel leakage. When comparing the life cycle emissions of the two types of the natural gas – CNG and LNG, a reasonable statement could be made that they are nearly identical. However, production of CNG uses less petroleum and emits slightly fewer GHGs than LNG because compressing natural gas requires less energy than liquefying it [4].

The main driver for more active and widespread use of natural gas as a transport fuel is its chemical properties. Natural gas has a high calorific value, with significantly less GHG than conventional fuels. Natural gas used in road transport is the same as used for electricity production, heating or cooking. The main component of natural gas is methane – the simplest hydrocarbon [5]. Methane has a high-octane rating (130), which is a standard measure of the performance of an engine or aviation gasoline, and a low boiling point (-161.5 °C), making it a usable fuel for spark ignition internal combustion engines [6]. Similar to petrol and diesel, natural gas has a low ignition limit, or 4.3–15.2 % by volume in the air, which reduces the risk of accidental ignition. At the same time, high-octane rating allows for a higher degree of compression in the engines, thus providing more engine power. The combustion properties of natural gas differ significantly from diesel and petrol, and it burns cleaner.

Another significant property of natural gas is its relative density: 0.55–0.70 kg/m^3 [7]. Due to the fact that natural gas is lighter than air, it quickly disperses into the atmosphere in case of leakage. Diesel and petrol, on the other hand, are liquid substances and, if they leak, there is an increased risk of fire or even long-term environmental pollution.

Price advantage of natural gas, including CNG, over conventional fuels should also be pointed out. In most countries, natural gas is much cheaper than the equivalent amount of conventional fuel, even after the cost of transportation and treatment – liquefaction or compressing, is added to the price of natural gas itself. Petrol and diesel have to undergo a complex refining process until they reach filling stations, while natural gas has to be treated less. The price of natural gas is also less subjected to price fluctuations, and the resource itself is more evenly distributed throughout the world [8].

Although natural gas as a primary energy resource has been rather cheap in a past decade, installation of transport and distribution infrastructure and filling stations still remains costly. Therefore, in almost all countries where CNG and LNG filling infrastructure is developed, investors are offered various development promotion programmes: loans, subsidies, tax rebates, exemptions from import duties on machinery and equipment. Support mechanisms are needed at the early stages of development to stimulate investor interest. In Canada, for example, reducing investment in CNG filling infrastructure has led to the collapse of the industry as a whole [9].

The cost of setting up a CNG infrastructure can vary considerably depending on a size of a filling station, its capacity and the type of CNG filling. Costs can be significantly reduced by setting up a combined CNG and LNG (hereinafter – L-CNG) filling station, especially in regions where such a decision is economically viable, or adding CNG filling option to existing service station [8].

2. THE MAIN TYPES OF THE NATURAL GAS FUELING STATIONS

In general, there are several types of CNG filling systems: buffer, cascade direct and portable (mobile) filling. In buffer type filling stations, CNG is stored in one high-pressure tank. In cascade-type filling stations, CNG is mainly stored in three tanks. These are called low, medium and high-pressure tanks [10]. Direct filling CNG stations are refuelled directly by means of a compressor, while portable filling stations can be connected to and disconnected from the natural gas grid relocated without problems.

2.1. Buffer-Type Filling System

Buffer-type CNG filling systems are usually known as "slow filling", while cascade-type CNG filling systems – "fast filling". Slow filling systems are mostly used in households or small businesses with small CNG vehicle fleet, where filling speed is not critically important. Slow filling systems are suitable for a night time use, as they switch off automatically when the filling cycle is complete. Fast filling stations, on the other hand, are suitable for more "traditional fuel like" CNG filling, thus increasing customer convenience. For fast CNG filling systems, vehicle filling time is about the same as for filling of petrol or diesel cars [11].

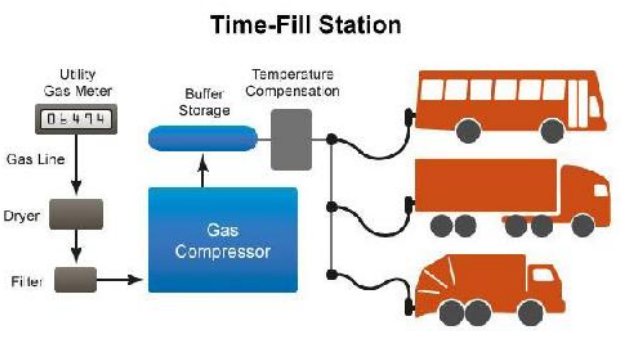

Fig. 1. Buffer-type filling system.
Source: *afdc.energy.gov*

Natural gas for CNG filling is usually taken from the medium pressure distribution gas system, where pressure is lower than 4 bar. The CNG storage system at the filling station consists of several tanks, the size of which can vary from 50 to 100 litres or more. The storage system maintains more pressure than the car system to allow gas to flow to it. The buffer-type CNG filling stations operate in the range of 20.5–25 MPa, while pressure in cars on-board cylinder is 20 MPa. In this type of storage, all reservoir cylinders are connected, and pressure in them are held equally high among them.

2.2. Cascade-Type Filling System

In cascade-type filling systems, the natural gas storage is divided into three tanks: low, medium and high pressure. Each of these tanks consists of several storage cylinders. In this storage system, the tank cylinders are installed in ascending order.

During fast filling, the CNG cylinder of the vehicle is initially connected to the low-pressure tank of the filling station. As the pressure in the tank drops and it rises in the car cylinder, the gas flow decreases. As the gas flow rate decreases to a previously stated value, the system automatically switches to a medium pressure tank, then to a high-pressure tank to complete the vehicle refill. Switching from one tank to another is provided by a microprocessor algorithm, as well as sensors for measuring the mass flow from all three tanks. The microprocessor controls the electronic sequence valves [12].

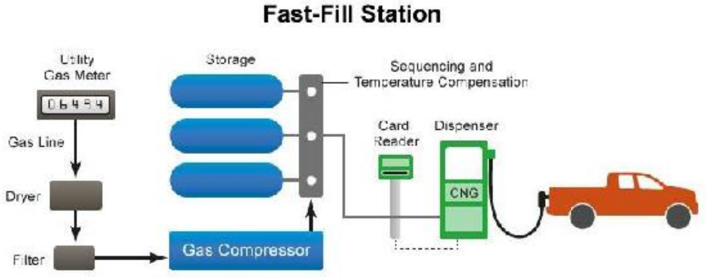

Fig. 2. Cascade-type filling system.
Source: *afdc.energy.gov*

The cascade-type filling systems provides a "more complete" filling compared to buffer-type systems. In addition, when the compressor is automatically switched on to fill the tanks, it first fills the high-pressure tank, then switches to the medium-pressure tank and then to the low-pressure tank. This ensures that the high-pressure tank is maintained at maximum pressure at all times, ensuring that vehicles will always be filled with the maximum amount of the natural gas available. Proper specification of compressor capacity and cascade storage volume is necessary to ensure that a CNG filling station can fill certain types of vehicles, such as buses, trucks, etc. [10].

2.3. Combined-Type Filling System

Combined-type filling systems can be used for both fast and slow filling. For example, the slow-filling option allows vehicles to be left to fill overnight, but, at the same time, fast-filling options can also be used, making fleet filling more flexible. Combined-type CNG filling stations are usually more expensive than the types of filling stations mentioned above.

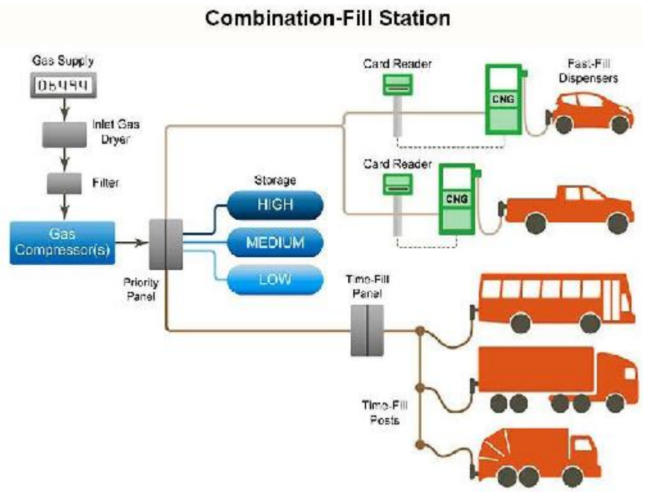

Fig. 3. Combined-type filling system.
Source: *afdc.energy.gov*

Although such filling stations can also be a source of additional income, as service provider's own fleet can be connected to a slow filling system and left there overnight, with fast-filling system made available to all in need of fast and convenient CNG filling at all times [13].

2.4 Local (Household) CNG Filling Installations

In order to avoid building of large filling stations, it is also possible to install a small local filling station in households and small businesses as well. The installation of such a filling station is rather simple, it is compact without taking up much space and it is easy to use. Unfortunately, such small filling stations are only designed for slow filling option. They usually have a filling rate of 2 m^3/h to 5 m^3/h, and a maximum rate of 20 m^3/ h. Like other filling stations, it has a small tank of about 0.5 m^3 to reduce compressor load fluctuations [14].

2.5 Portable CNG Filling Stations

There are also portable CNG filling station solutions available on a market. Such stations can be used for both temporary and permanent filling, and contain all the same elements as stationary filling stations. Depending on the station configuration, both CNG and LNG can be used for filling. The main advantage of mobile stations is their mobility and wide range of applications, for example, they can replace stationary stations during their maintenance or repair. The filling station can be used on construction sites to fill vehicles. Often, mobile filling stations are powered by natural gas engines; as a result, they do not require an external energy source [14].

2.6 LNG and L-CNG Filling Stations

In the Eastern Baltic, the percentage of alternatively fuelled road vehicles remain rather low, with the natural gas-powered road vehicle fleet in Latvia being equal to about a few hundred. Currently, there are only two LNG filling stations in the Baltic

States, both located in Estonia, and 9 filling stations located in Finland. It is important to mention that most of these filling stations can serve both CNG and LNG fuelled vehicles. L-CNG filling stations allow filling CNG for light and LNG for heavy-duty vehicles. Such filling stations have lower capital and operating costs than separate LNG and CNG filling stations of similar capacity [15].

A typical LNG filling station consist of the following components and systems: cryogenic storage tank for LNG, with typical volume of 60–70m³, acryogenic submerged centrifugal pump skid, weights and measures certified dispensers for LNG, connected to a payment system, LNG cooling system using patented equipment to deliver cold LNG and eliminate the risk of natural gas being released to atmosphere, the natural gas and leak detection equipment, and a complete PLC control system supporting remote access.

In L-CNG filling stations, the following technical elements must be present: a cryogenic storage tank for LNG, cryogenic reciprocating pumps, vaporizers for delivery of gaseous natural gas, odorizing unit – a safety feature that makes it possible to detect leakage, dispensers for CNG, and a complete PLC control system supporting remote access.

LNG is used as a raw material in L-CNG filling stations. LNG is stored at a very low temperature, about -163 °C, at a pressure of 1 bar. 1 litre of LNG at a pressure of 1 bar contains approximately 600 litres of the natural gas.

In a nutshell, L-CNG filling stations are advantageous for several reasons. They increase a number of existing and future CNG filling stations, and allow setting up CNG filling stations in places, where the natural gas connection is not available, or its construction is expensive. L-CNG filling stations sell high-quality CNG due to the stability of the natural gas properties and efficient filling of CNG fuel tanks due to lower temperature normally provided by the L-CNG system. The lower the inlet gas temperature, the lower the storage temperature of the final product and the correspondingly larger amount of CNG can be stored at the same pressure [15], [16].

3. USAGE OF NATURAL GAS AS TRANSPORT FUEL IN LATVIA

The EU has set ambitious targets not only for energy, but also for transport sector decarbonisation, and quite a few directives and regulations have been adopted to promote it. One of the most important ones – Directive 2014/94/EU requires the EU Member States to ensure, through their national policy frameworks, that an adequate number of publicly available CNG filling stations are established by 31 December 2020 to allow CNG-powered vehicles to circulate in urban / suburban agglomerations and other densely populated areas, and, where appropriate, in networks designated by the Member States. It is also necessary to provide a policy framework for the establishment of an adequate number of publicly available CNG filling stations by 31 December 2025, at least on the existing TEN-T core network, in order to ensure that CNG-powered mechanical vehicles can circulate throughout the EU. The same regulatory principle is applied to LNG filling availability as well [17].

Despite modern and robust natural gas transportation and distribution infrastructure, which allows establishing CNG filling stations in more than a half of the territory of Latvia [18], the current stage of the natural gas mobility in our country is not well established yet. In order to fulfil requirements outlined in Directive 2014/94/EU, CNG filling stations should be opened in almost all major cities and towns of Latvia, where the natural gas network is available. These locations include but are not limited to Riga, Liepaja, Jelgava, Valmiera, Bauska, Rezekne, Jekabpils and Daugavpils.

The Latvian state industry standard LV NS GS 06-2006/A1: 2009 "Natural Gas Filling Stations and Filling Equipment" distinguishes two types of filling: the natural gas filling station and car filling equipment. The natural gas filling station is intended for fast (commercial) filling into cylinders that are directly connected to the vehicle. The car refuelling equipment is intended for slow (non-commercial) refuelling of vehicles without supervision. It has no storage pressure vessel and under standard conditions the flow rate does not exceed 20 m^3/h, with a maximum gas capacity of 0.5 cm^3 and a maximum gas outlet pressure of 26 MPa [19].

The construction of the natural gas filling stations is subject to strict norms, for example, when installing a natural gas filling station with a total volume of assembled gas above 500 m^3, the minimum distance to buildings and structures that cannot be considered as part of the filling station must be at least 50 m [19].

For CNG filling, the relevant factor is the timing, which depends on inlet gas pressure, buffer tank volume, filling column permeability and compressor capacity. The filling time is reduced, if the vehicle is filled from the buffer tank. It is also reduced by using a suitable filling device connection cable with the appropriate diameter: natural gas vehicle 1 (diameter 8 mm) for cars and minibuses, and natural gas vehicle 2 (diameter 12 mm) for trucks and buses. Also, filling time can be reduced by the number of filling modules in the filling station and their efficient use, as insufficient buffer tank volume increases the filling time [15], [16].

In order to promote decarbonisation of the transport sector and reduce the negative environmental impact of its GHG emissions, as well as to transpose the requirements of Directive 2014/94/EU in Latvia, "The Development Plan for Alternative Fuels 2017–2020" (hereafter – Plan) was adopted. Its aim was to identify the necessary trends of research and analysis that would lead to the development of further policies on the introduction of alternative fuels in certain transport sectors to ensure their sustainability. The task of the Plan was to identify the current situation in the field of alternative fuels and to determine further steps for the introduction and promotion of alternative fuels in Latvia [20], [21]. The Plan, among other, requires, for example, that by 31 December 2020, at least five publicly available CNG filling stations be established in Latvia, and by 31 December 2019, a review of tax policy, including the level of excise duty on natural gas as transport fuel, be performed. The first requirement, however, was fulfilled only in early 2021.

The history of CNG filling infrastructure in Latvia is still a short one, as the first CNG filling station in Latvia was opened in Jekabpils in 2019. Such a location of the filling station was chosen by the fuel retailer JSC "Virši-A" due to a fact that Jekabpils public transportation company obtained public buses that used CNG as fuel. Consequently, Jekabpils was the first municipality in Latvia to use CNG in passenger transport. Currently, its bus fleet includes 7 CNG-powered buses. The buses were purchased within the framework of the EU support project "Development of Environmentally Friendly Public Transport (Buses)" of the priority axis “Transition to a Low-Carbon Economy in All Sectors” of the programme “Growth and Employment”. The total amount of funding provided was EUR 1 792 053, EUR 1 398 250 of which was co-funded from the EU sources [22]. Currently, the procedure is under way in order to acquire 35 CNG fuelled buses for public transportation company in one of the largest Latvian municipalities – Daugavpils [23].

In spring of 2021, there were 6 public CNG filling stations in operation in Latvia: Riga, Babite, Jekabpils, Rezekne, Olaine and Broceni, all owned and operated by JSC “Virši-A” [24]. During the same period, more than 20 CNG filling stations were in operation in Estonia, and close to 10 – in Lithuania.

4. CNG AND LNG DEVELOPMENT POTENTIAL IN LATVIA

Electric mobility has long been considered the energy of the future for transport, but its use in road transport still has its drawbacks. Given the availability of the natural gas technologies and the good prospects for achieving transport decarbonisation targets, they are often preferred, for example, in transport in large cities of several European countries (Germany, Italy, Switzerland) and the United States. Thanks to positive environmental performance, including GHG savings, they are also entering maritime transport, opening up new global markets for the wider and more intensive use of the natural gas resources worldwide [25], [26].

According to the requirements of Directive 2014/94/EU, in 2025 CNG filling stations on motorways must be located every 150 kilometres. This means that in Latvia it is necessary to build such filling stations in all major cities where natural gas is available.

Additional incentives for the use of CNG as a transport fuel can be given by vehicle operating tax rates. In Latvia, for vehicles registered for the first time after 31 December 2008, the operating tax rate is applied depending on the amount of CO_2 emitted per kilometre (Table 1).

Table 1. Operating Tax Rates per Year from 1 January 2019 [27]

For vehicles with an engine capacity not exceeding 3500 cm^3 (inclusive)		For vehicles with an engine capacity exceeding 3500 cm^3	
CO_2 emissions (g) per km	Rate (EUR)	CO_2 emissions (g) per km	Rate (EUR)
Up to 50	0	Up to 50	300
51–95	12	51-95	312
96–115	48	96-115	348
116–130	84	116-130	384
131–155	120	131-155	420
156–175	144	156-175	444
176–200	168	176-200	468
201–250	264	201-250	564
251–300	408	251-300	708
301–350	552	301-350	852
351 and more	756	351 and more	1056

CNG is not only cheaper as a fuel, but the owner of such a vehicle would also have to pay a lower operating tax compared to the same car model with diesel or petrol engine.

The construction of an LNG terminal in Latvia could also contribute to the faster development of both LNG and CNG filling station networks. The LNG terminal would open the possibility to build L-CNG type filling stations as well.

In 2019, as a result of negotiations between industry and policy makers, the Cabinet of Ministers of the Republic of Latvia drafted an order "Amendments to Cabinet Order No. 202 of 25 April 2017 "On Alternative Fuels Development Plan 2017–2020"", which, *inter alia*, provides an assessment of possible solutions to ensure the application of a reduction in excise duty on natural gas used as fuel in transport, if biomethane is added [21]. In the most optimistic case of the alternative fuel development in Latvia reflected in the plan, CNG and LNG combined would account for more than any other transport fuel in fleet, including diesel and gasoline, by 2050, but for fulfilment of such a high ambition much stronger and politically coordinated support to RG industry, first and foremost domestic biomethane production and its end use both locally and by means of natural gas grid, must be provided.

Table 2. Possible Alternative Fuel Development in the Latvian Transport Sector (2025–2050, %)

Fuel	Year			
	2025	2030	2040	2050
Diesel	67.2	64	34.4	23.1
Gasoline	20.4	12.1	12.8	10.6
LPG	7.1	13.9	7	6.4
LNG	0.5	0.7	2	2.1
CNG	2.5	4.5	19.9	30.2
Biodiesel	0.2	0.2	10.4	12.9
Bioethanol	0.7	0.4	0.5	0.4
Biomethane	0	1	1.9	0
Hydrogen	0	0	0	0
Electric cars	1	2.5	10.2	13.2
Electric public transport	0.5	0.6	0.9	1

Latvia admits that the absence of a national policy plan has jeopardised the use of natural gas in transport. It has established targets for the deployment of CNG refuelling points accessible to the public. The targeted number of CNG refuelling points could support a significant increase in CNG vehicles. As indicated in the national policy framework, Latvia also has no plans for the deployment of LNG refuelling points in its ports [21].

However, at the moment Latvia lacks any elements of the LNG import infrastructure, although several propositions to build a terminal in different locations were presented over the course of the last decade. The first proposition is related to Kundzinsala Southern Project. According to information of the Freeport of Riga, LNG terminal with an area of 34 hectares was planned to be built on the island of Kundzinsala, which is mainly used as a maritime trade related industrial area. Instead of planning connection to the natural gas transmission network, developers of Kundzinsala LNG terminal made a decision in favour of connection to the natural gas distribution grid. Project team requested and received technical regulations from the Latvian natural gas distribution system operator to make a connection to the natural gas distribution system in Riga. In order to make a connection, the LNG terminal operator was obligated to build the following elements of infrastructure and technical equipment: supply pipeline from the terminal to the distribution system, a gas connection point and a metering station with a gas chromatograph [28]. The expected business areas of the terminal were outlined as follows: bunkering, trade of LNG, including deliveries to road transport filling stations and alternative distribution networks, and injection of regasified natural gas into the Latvian natural gas distribution network [26].

As an alternative, a proposal to construct LNG terminal in Skulte, the Northwestern part of Riga Gulf, emerged. Skulte project was presented as a floating regasification unit without LNG storage tanks, but with a direct pipeline connection to the Incukalns underground gas storage (hereinafter – Incukalns UGS) facility. Unfortunately, this type of LNG terminal is not designed to supply unregasified LNG, which could be transported further by trucks, for example, to L-CNG filling stations. The Skulte project developers state that the project has unique geographic, economic and technological advantages over any other LNG import terminal proposal of comparable capacity. A fact that LNG cold storage facility, which usually takes up to 70–80 % of LNG import terminal building expenses, is not needed was presented as its obvious strong point. Instead, the developers made an assumption that Incukalns UGS will serve as a permanent storage for all delivered natural gas resources, and direct high-pressure pipeline connection between the storage and the LNG terminal will be built. Despite the fact that preliminary costs of the project are not yet known, the developers announced that total estimated investments would be at least 3 times less than for any other LNG terminal type of comparable capacity with LNG cold storage option [29], [26].

In addition, biogas can be used to reduce CNG and LNG CO_2 emissions further. A positive factor for the use of biogas in internal combustion engines is lower toxicity of exhaust gases. Emissions of carbon monoxide, hydrocarbons and nitrogen oxides are much lower than for diesel or petrol [30], [31]. To use biogas in car engines, it must first be cleaned of excess ballast CO_2 and hydrogen sulphide, which causes metal to rust. Excess CO_2 in biogas also reduces engine power. About 2 m^3 of biogas is equivalent to 1 litre of liquid motor fuel. If biogas is upgraded to biomethane level and compressed, bioCNG provides clean fuel for all types of road vehicles.

The statistics show that the dynamics of the biomethane production with its subsequent conversion into LBM has demonstrated a significant upward pattern in the EU between 2018 and 2020. In this period, a number of biomethane plants have increased by 51 %, from 483 in 2018 to 729 in 2020. There are currently eighteen countries producing biomethane in Europe, with Germany having the highest share of biomethane production plants (232), followed by France (131) and the UK (80) [32].

In the Baltic States, upgrading of the biogas to biomethane level with subsequent injection into the natural gas transportation or distribution grids has not been developed yet. However, at least Latvia with 59 existing biogas plants and 17 of them being located 10 or less km away from the natural gas distribution grids could benefit both from biomethane production and local sales (where CNG filling stations and/or small-scale biomethane liquifying facilities are installed onsite) and injection of the biomethane into the natural gas networks [33].

Moreover, in this decade the EU production of LBM is set to increase by factor of ten. The EU LNG heavy-duty transport is expected to reach 280.000 units in the same period. Using a 40 % LBM mix with LNG will help reduce the CO_2 emissions from those trucks by 55 %. In the shipping sector, 50 % of large container vessel orders today are LNG fuelled or ready for conversion to LNG. 20 % of LBM mix in maritime transport would reduce CO_2 emissions by up to 34 %.

5. METHODOLOGY FOR EVALUATION OF CNG AS TRANSPORT FUEL IN LATVIA

5.1 Natural Gas in the Latvian Transport Fuel Mix

In Latvia, approximately 94 % of all vehicles use petrol and diesel as fuel [34], and Table 3 shows the most commonly used transport fuel types in our country. It does not include data on rarely used fuels such as gas generator, diesel combined with natural gas, etc. Thus, it indicates that only around 0.04 % of all road transport vehicles in Latvia use natural gas as primary or secondary fuel.

Table 3. Number of Registered Vehicles as of 1 October 2020 [34]

Fuel type	Heavy duty		Vehicle		Buses		Total	
	Quantity	%	Quantity	%	Quantity	%	Quantity	%
Petrol	2761	3.0	227639	30.7	21	0.5	230421	27.47
Diesel	88850	95.3	465694	62.8	4270	99.0	558814	66.62
Electricity	18	0.0	1031	0.1	8	0.2	1057	0.13
Petrol and gas	868	0.9	25115	3.4	4	0.1	25987	3.10
Petrol and LPG	593	0.6	21294	2.9	2	0.0	21889	2.61
Petrol and natural gas	15	0.0	183	0.0	0	0.0	198	0.02
Natural gas	62	0.1	81	0.0	7	0.2	150	0.02
Natural gas and LPG	15	0.0	14	0.0	0	0.0	29	0.00
Total	93229	100.0%	741292	100.0%	4312	100.0%	838833	100.0%

Such a low indicator signals that there is significant potential for CNG use in all segments of the Latvian transport sector. By increasing the number of vehicles using natural gas, it would also be possible to reduce the total consumption of oil-based fuels.

5.2 Methodology for Evaluation of CNG Effectiveness

In order to estimate the economic performance of CNG in comparison to traditional fuels – diesel and petrol, calculations were made to determine the cost per kilometre, as well as the time period in which the purchase of a private CNG-powered vehicle would pay off.

As part of this study, three SEAT passenger cars were used as a practical reference. The empirical evaluation took into account investment costs and fuel costs, but maintenance costs were not evaluated due to the similarities of all chosen models. Three chosen models were equipped with different engine types: the first – with a compressed natural gas-petrol engine, the second – with a petrol engine and the third – with a diesel engine. The main characteristics of the three models are summarised in Table 4.

Table 4. The Main Technical Parameters and Prices (December, 2020) [35]

Model	Power, kW	Fuel type	Fuel consumption, l/100km	Price, EUR
SEAT LEON 1.5 TGI MAN-6	96	Petrol/CNG	3.8	18 700
SEAT LEON 1.5 TSI MAN-6	96	Petrol	5.0	17 400
SEAT LEON 1.6 TDI MAN-5	85	Diesel	4.2	18 100

The calculation takes into account the limiting factor, which in this case is a warranty period of the vehicle (5 years), during which no more than 100,000 km may be driven. This means that a vehicle that uses CNG as a primary fuel must demonstrate, within the specified limitations, that it is more cost-effective than the use of two conventional fuel alternatives.

This part of the calculation does not consider the case, when CNG fuelling takes place in a private filling point – it relates only to publicly available filling stations. Prices for CNG and conventional fuels were taken from the specific fuel retailer – "Virši-A", as it is the only fuel trader in Latvia currently selling CNG along with traditional oil-based fuels. Fuel price comparison for the three engine types is shown in Table 5.

Table 5. Fuel Prices in Latvia (December, 2020)

Fuel type	Price for one-unit kg or l (EUR)
CNG	0.90
Diesel	1.014
Petrol E95	1.135

In order to perform calculation, it is necessary to determine the cost per kilometre using different types of fuel. Equation (1) is used for the calculations:

$$C_{km}=0.01 \cdot F \cdot P, \tag{1}$$

where
C_{km} – cost per kilometre, EUR/km;
F – fuel consumption, l/100 km;
P – fuel price, EUR/l.

Then, using Eq. (2), is possible to calculate by how much CNG is cheaper per kilometre, comparing to diesel and petrol:

$$P_{dif}=(C_{CNGkm}-C_{Fkm})C_{CNGkm}) \cdot 100, \tag{2}$$

where
P_{dif} – difference on how much other fuels are more expensive than CNG, %;
C_{CNGkm} – cost per kilometre for a specific fuel type (diesel or petrol), EUR/km;
C_{Fkm} – cost per kilometre for a specific fuel type (diesel or petrol), EUR/km.

Equation (3) helps calculate the mileage by fuelling for the same amount of money – EUR 10:

$$M=10P \cdot 100F, \tag{3}$$

where
M – mileage, km;
P – fuel price, EUR/l;
F – fuel consumption, l/km.

In addition, the payback period of vehicles is to be calculated using Eq. (4):

$$T_{pb}=P_{CNG}-P_{fuel}C_{fuel}-C_{CNG}, \quad (4)$$

where
T_{pb} – payback time, km;
P_{CNG} – CNG car price, EUR;
P_{fuel} – the price of a petrol or diesel car, EUR;
C_{fuel} – the cost of one kilometre when driving with petrol or diesel, EUR;
C_{CNG} – the cost of one kilometre when driving with CNG, EUR.

6. RESULTS

By using Eq. (1) and data from Tables 1 and 3, the cost per kilometre for different fuels was calculated (see Fig. 4).

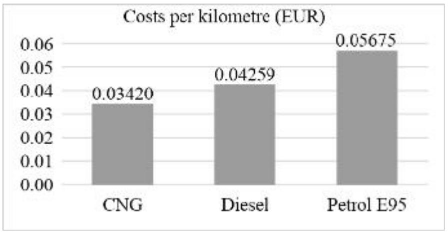

Fig 4. Costs per kilometre by using various types of fuels.

The acquired data demonstrate that the highest price for driving one kilometre is attributed to petrol (0.06 EUR/km), while diesel is cheaper (0.04 EUR/km), but CNG is the cheapest of the three types (0.03 EUR/km). According to Eq. (2), driving the CNG-powered vehicle is by 24 % cheaper per kilometre comparing to diesel and by 66 % cheaper to petrol-powered car.

Based on Eq. (3) and data from Tables 1 and 3, a possible mileage for EUR 10 equivalent of fuel was calculated (see Fig. 5).

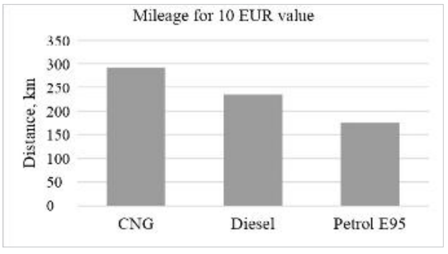

Fig. 5. Possible driving distance for 10 EUR for various types of fuels.

Results indicate that, from the perspective of fuel choice, the best value for money is ensured by CNG, which provides by far the longest driven distance of 292 kilometres. At the same time, with diesel it is possible to drive 235 kilometres and with petrol – only 176 kilometres. This again proves clear benefits of CNG usage at a described situation of price differences.

By using Eq. (4), the payback distance was calculated, to recover the difference in vehicle purchase prices between CNG and petrol-powered vehicles or between CNG and diesel-powered vehicles (Fig. 6).

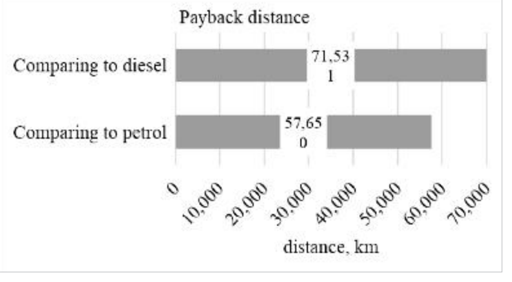

Fig. 6. Payback distance comparing price of CNG car to a petrol or diesel car.

According to the obtained result, it can be concluded that a purchase of a CNG-powered vehicle starts to pay off after 57650 kilometres comparing to a petrol-powered vehicle or after 71 531 kilometres comparing to a diesel-powered vehicle. It has previously been mentioned that there are limitations to a CNG vehicle dealer's warranty that should be included. Warranty works for 5 years or mileage limit – 100000 kilometres. The results of calculations in both cases show that a CNG-powered vehicle pays back during the warrant period, if at least 57650 kilometres as an alternative of a petrol-powered vehicle or 71 531 kilometres as an alternative of a diesel-powered vehicle are driven during this time.

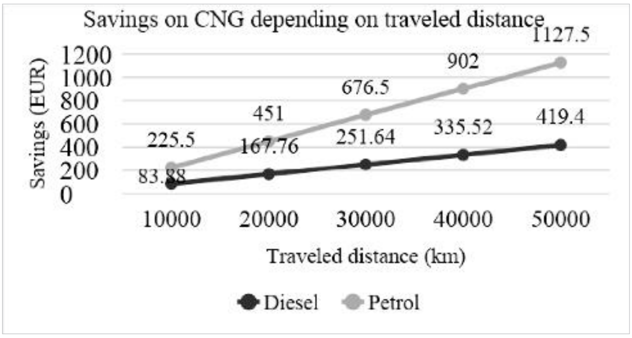

Fig. 7. Savings by using CNG as fuel, depending on distance.

Figure 7, in turn, shows savings, comparing a CNG-powered vehicle with petrol and diesel-powered vehicles, which outline the main trend – the more one drives, the larger the savings and economic benefits a CNG-powered vehicle can bring. By using a CNG-powered vehicle to drive 30000 km, it is possible to save EUR 676.5, comparing to expenses that would occur in case of driving a petrol-powered vehicle. But at 50000 km even more than EUR 1000 may be saved by using a CNG-powered vehicle instead of a petrol-powered one.

All four calculations show clear economic benefits of a CNG-powered vehicle, if a fuel cost difference is used as the sole economic performance comparison benchmark.

7. CONCLUSIONS

Although the most attention has been focused on low emissions of CNG-powered vehicles, especially in densely populated areas, one of the main advantages of CNG as the road transport fuel remains the price. The calculations presented above clearly indicate the economic benefits of a CNG-powered vehicle, if a fuel cost difference is used as the sole economic performance comparison benchmark.

With fuel prices of a certain retailer, as presented at the end of 2020, the exploitation of CNG-powered vehicle was by 24 % cheaper per kilometre comparing to diesel and by 66 % cheaper comparing to a petrol-powered vehicle. In addition, CNG-powered vehicles have smaller operational taxes, since an operation tax is applied based on CO_2 emissions, which are lower for CNG vehicles. The calculation results also indicate that a CNG-powered vehicle pays back during the warranty period, if at least 57 650 kilometres as an alternative of a petrol-powered vehicle or 71 531 kilometres as an alternative of a diesel-powered vehicle are driven during this time, so this should be taken into account when choosing the best vehicle option for specific customers' needs.

Since currently CNG vehicles comprise less than 1 % of all road transport registered in Latvia and taking into account the EU transport and climate policies, CNG price and possible development of CNG and L-CNG filling stations, there is a significant potential for the natural gas and RG mobility development in Latvia.

ACKNOWLEDGEMENTS

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THE NATURAL GAS SUPPLY OF THE LATVIAN MUNICIPALITY DURING THE LOCAL ENERGY CRISIS

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Natural gas is an essential element of the Latvian and the Baltic energy portfolio, so its supply disruption can seriously affect the national economy and energy security of our country.

The article focuses on a basic case study of the natural gas supply to one of the Latvian municipalities, when the energy crisis is announced. It also marks potential vulnerabilities factors that may cause the natural gas supply shortages or disruption periods of different length for a wide spectrum of the Latvian natural gas consumers – starting with households and finishing with large industrial consumers and energy producers.

A legal framework analysis along with an emergency natural gas supply review has been proposed as well, taking into account the actual distribution of the natural gas consumption among the urban energy users, which can be compared with references included into the Cabinet of Ministers Regulation No. 312 "Procedures for the Supply of Energy Users and Sale of Heating Fuel during Declared Energy Crisis and in Case of Endangerment to the State" (hereinafter – Regulation 312).

Keywords: *Definition, energy crisis, Latvian municipality, natural gas, user groups.*

1. INTRODUCTION

Natural gas is regarded not only as one of the most notable energy resources worldwide – the cleanest of conventional fossil fuels, but also as an essential element of the Latvian and the Baltic energy portfolio. Since the mid-twentieth century, it has always played an important role in the energy supply of the Baltic region, including Latvia. Its disruption can seriously affect the national economy and energy security of our country. The Latvian natural gas market comprises approximately 35 % of the natural gas market in the Baltic States [1], and in a midterm perspective natural gas is considered to be an important low carbon energy resource to ensure smooth transition to carbon neutrality both on the national and regional scale [2], [3].

Natural gas as transitional fuel might benefit significantly to more active introduction of both the renewable gases and "green" hydrogen to the EU primary energy sector [4]. The natural gas consumption has been rather stable in the EU, with import amount equalling 300–400 billion cubic meters (hereinafter – BCM) a year. However, the EU natural gas consumption in 2020 fell by 3 % in comparison with 2019 to 394 BCM due to the COVID-19 pandemic, but the imports throughout 2020 reached 326 BCM, down from 358 BCM in 2019 [5].

The stability of positions of natural gas as a future transitional fuel is a reason why awareness in the European Union (hereinafter – the EU) must be risen on the natural gas security of supply issues in order to prevent situations, when access to natural gas resources is limited, disrupted or terminated. The concept of energy crisis normally applies to the whole energy sector or one or several neighbouring countries, when all the energy supply chain is affected, but practically the cause of such a crisis almost always lies in problems related to one particular segment of energy sector, which can have a stronger or weaker impact on functionality of others. The energy crisis inevitably brings the disruption to the rest of the national economy as well [6].

In order to minimise the predictable national economy impact of the natural gas related energy crisis, models should be developed and studies initiated in order to understand, whether existing legislation frameworks for the natural gas supply reductions to different groups of users are set up correctly, or need some improvements. The current research presents calculations based on real natural gas consumption data of one Latvian municipality – dubbed "town A", in high and low natural gas consumption points of 2018 – months of February and July. The calculations are done in order to verify, whether the national regulation on limitation of the natural gas supply in Latvia correlates with real consumption fluctuation date of the "virtual" local energy crisis.

2. THE CONCEPT OF ENERGY CRISIS AND ITS DEFINITION IN LATVIA

An energy crisis is a reduction of the amount of available energy at national or local level that adversely affects the normal functioning of consumers and can have social, political and economic consequences [7]. The energy crisis might affect the whole energy sector, or only part of it. Serious and continues natural gas supply disruptions, shortages or terminations also directly relate to appearance of energy crisis or situations, when one or several groups of the natural gas consumers (users) might be limited in their actual access to the said energy resource. In all, the security of the natural gas supply currently plays one of the crucial roles in the EU energy sector, and is one of the pillars of its stability and sustainability [8]. In addition, it is regarded as one of the bridging fuels that will ensure and support smooth energy transition in the EU Member States, with predictable reaching of continental-scale carbon neutrality by the mid-21st century [9]–[11].

Regulation 2017/1938 of the European Parliament and of the Council concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010 [12] clarifies the established levels of the energy crisis, which are divided into three categories:

- early warning category (early warning): if specific, serious and credible information is available that a situation is likely to arise which could lead to a significant deterioration of the natural gas supply and is likely to lead to an alert or emergency; the early warning level can be activated by an early warning mechanism;
- alert level category (alert) occurs in the event of the natural gas supply disruption or extreme demand for natural gas that significantly worsens the natural gas supply situation, but the market is still able to cope with the disruption or demand without the need for non-market measures;
- emergency level category (emergency) is declared when there is an exceptional demand for natural gas or there is a major natural gas supply disruption or a significant deterioration in the natural gas supply situation, and if all relevant market measures have already been implemented, but the natural gas supply is insufficient to meet the remaining demand for the gas resources. Therefore, additional non-market measures should be introduced to ensure the supply of natural gas to protect the customers [12].

At the same time, the Latvian legislation, in accordance with Chapter II, Section 4 of the Civil Protection and Disaster Management Law, identifies several scale-related variations of the energy crisis:

- local disasters – the scale of damage caused by a disaster does not exceed the borders of the administrative territory of one local government;
- regional disasters – the scale of damage caused by a disaster exceeds the borders of the administrative territory of one local government;
- state disasters – the scale of damage caused by a disaster affects the entire territory of the state or a significant part thereof [13].

Regulation 312 prescribes how supply of the users should be carried out during an announced state or local energy crisis. It also sets up procedures, by which energy supply merchants, as well as merchants who provide security reserve services, and merchants to whom licenses for fuel business have been issued in accordance with the procedures specified in regulatory enactments, sell the fuel at the request of the state or local government's energy crisis centre.

In accordance with Clause 9 of Regulation 312, the Latvian natural gas distribution system operator (hereinafter – DSO)

JSC "Gaso" is authorised to put restrictions on the amount of supplied natural gas, when the energy crisis is declared in the country.

During the energy crisis, if the supply of natural gas is disrupted, all the natural gas users should be divided into four groups: the priority users, the first group energy users, the second group energy users and the third group energy users.

The priority group consists of households, schools, pre-school educational institutions, hospitals, state and municipal long-term social care and social rehabilitation institutions, crisis centres, social rehabilitation institutions for persons addicted to narcotic, toxic or other intoxicating substances, emergency services, telecommunications units, emergency medical service, state fire and rescue service, the national armed forces, police, state border guard, state security institutions, water supply and sewerage works, penitentiaries, mobilized civil defence formations.

The first group of energy users is made of administrative institutions, energy generation objects (power plants), railways, airports, bus stations (if distance of bus routes (trips) in one direction exceeds 50 km), ports, the Latvian Environment, Geology and Meteorology Centre, responsible state custodians of the material reserves (in the places of storage of state material reserve resources).

The second group comprises ambulatory health care facilities, food and agricultural production plants, local public transport (all types of public transport in cities and municipal territories, if the distance of the transport route (trip) in one direction does not exceed 50 km), food supply transport, industrial facilities, state and local government institutions not included in the first group.

The third group, however, is much less defined, and it includes those not included in the first three groups [14].

If the energy crisis is declared, Clause 2 of Regulation 312 stipulates that the following restriction to the natural gas supply can be applied by the DSO to its users in Latvia:

- in case of the first level energy crisis – the possibility to ensure energy supply decreases by 7]–12% of daily (average) energy consumption;
- in case of the second level energy crisis – the possibility to ensure energy supply decreases by 12–17 % of daily (average) energy consumption;
- in case of the third level energy crisis – the possibility to ensure energy supply decreases by more than 17 % of daily (average) energy consumption [14].

On 8 May 2018, the Cabinet of Ministers of the Republic of Latvia approved amendments to Chapter IV, Paragraph 12^1 of Regulation 312, by adding this information: "In order to ensure the daily capacity of the natural gas withdrawal from Incukalns underground gas storage (hereinafter – UGS) facility during the energy crisis, the unified natural gas storage and transmission system operator must guarantee that in the period from the end of the natural gas injection season of the specific storage cycle to March 1 of the following year the amount of active gas intended to ensure the supply of natural gas to Latvia does not fall below 3160 thousand MWh (300 million m^3) [15]. It means that the strategic reserve of natural gas is formed to be kept in Incuklans UGS facility, so the Latvian consumers must be guaranteed to receive less severe impact of the possible natural gas related energy crisis, at least for a certain period of time.

3. MODELLING FRAMEWORK FOR THREE LEVELS OF ENERGY CRISIS

Regulation 312 clearly states that a certain percentual energy supply restriction is set for each consumer group depending on the level of the energy crisis (Table 1).

Table 1. Energy Cuts Required According to Regulation 312 (%)

Distribution of the users*	Priority group	The first group	The second group	The third group
The natural gas delivery cuts (%), the 1st level energy crisis	0	0	20	20
The natural gas delivery cuts (%), the 2nd level energy crisis	0	20	40	100
The natural gas delivery cuts (%), the 3rd level energy crisis	0	40	80	100

Formulas (3.1) and (3.2) were developed and applied to calculate the energy reduction (cuts) in the "town A", where energy crisis was announced. Using Formula (3.1), the total energy cuts in "town A" (m^3/day) are calculated depending on the level of the declared energy crisis:

$$Q_{nodr} + Q_{pirm} + Q_{otr} + Q_{tr} = Q._{n.līm.}, \tag{3.1}$$

where
Q_{nodr} – energy cuts to the priority users, m^3/day;
Q_{pirm} – energy cuts to the first group users, m^3/day;
Q_{otr} – energy cuts to the second group users, m^3/day;
Q_{tr} – energy cuts to the third group users, m^3/day;
$Q_{n.līm}$ – total energy cuts depending on the declared energy crisis level, m^3/day.

Formula (3.2) calculates the above-mentioned total energy cuts in the "town A" depending on the level of the announced energy crisis percentwise in order to compare the obtained results with those specified by Regulation 312.

$$\frac{Q_{n.līm.}}{Q} * 100 = Y_{n.līm}, \tag{3.2}$$

where
Q – the total amount of the energy consumed in the "town A", m^3/day;
$Y_{n.līm.}$ – the energy reduction during the energy crisis, %/day.

By modelling the energy crisis scenarios for the "town A", energy consumption throughout the reference year 2018 was taken into account. Depending on the weather, the amount of natural gas used can fluctuate significantly during the winter and summer seasons, so the calculations are based on the natural gas consumption results of two reference months – February, when maximal amount of the natural gas is most frequently consumed in Latvia due to long-term low outdoor temperatures, and July, when the natural gas consumption drops to a minimum.

3.1. Level 1 Energy Crisis Modelling

The priority group users:

X_{n1} = 0 – in accordance with 0 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{nodr} = 67912.74*0 = 0 m^3/day;
$Q_{nodr.min}$ = 50 709.38*0 = 0 m^3/day;
$Q_{nodr.max}$ = 90 837.06*0 = 0 m^3/day;

July 2018:

Q_{nodr} = 5449.96*0 = 0 m^3/day;
$Q_{nodr.min}$ = 4,040.64*0 = 0 m^3/day;
$Q_{nodr.max}$ = 6 241.22*0 = 0 m^3/day.

The first group users:

X_{p1} = 0 – in accordance with 0 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{pirm} = 293908.51*0 = 0 m^3/day;
$Q_{pirm.min}$ = 219 456.87*0 = 0 m^3/day;
$Q_{pirm.max}$ = 393 118.96*0 = 0 m^3/day;

July 2018:

Q_{pirm} = 69005.68*0 = 0 m^3/day;
$Q_{pirm.min}$ = 51 161.37*0 = 0 m^3/day;
$Q_{pirm.max}$ = 79 024.45*0 = 0 m^3/day.

The second group users:

X_{o1} = 0.2 – in accordance with 20 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{otr} = 30907.86*0.2 = 6181.57 m^3/day;
$Q_{otr.min}$ = 23 078.41*0.2 = 4 615.68 m^3/day;
$Q_{otr.max}$ = 41 340.97*0.2 = 8 268.19m^3/day;

July 2018:

Q_{otr} = 37517.45*0.2 = 7503.49 m^3/day;
$Q_{otr.min}$ = 27 815.74*0.2 = 5 563.15 m^3/day;
$Q_{otr.max}$ = 42 964.51*0.2 = 8 592.90m^3/day.

The third group users:

X_{t1} = 0.2 – in accordance with 20 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{tr} = 22911.35*0.2 = 4582.27 m^3/day;
$Q_{tr.min}$ = 17 107.54*0.2 = 3 421.51 m^3/day;
$Q_{tr.max}$ = 30,645.20*0.2 = 6,129.04 m^3/day;

July 2018:

Q_{tr} = 5761.95*0.2 = 1152.39 m^3/day;
$Q_{tr.min}$ = 4 271.96*0.2 = 854.39 m^3/day;
$Q_{tr.max}$ = 6 598.52*0.2 = 1 319.70 m^3/day.

The actual total energy cuts during the announcement of the 1st level energy crisis were as follows:

February 2018:

$Q._{1.līm.}$ = 0 + 0 + 6181.57 + 4582.27 = 10763.84 m^3/day;

$$Y_{1.līm} = \frac{10763.84}{415640.46} * 100 = 2.59\ \%$$

$Q._{1.līm.min}$ = 0 + 0 + 4 615.68 + 3 421.51 = 8 037.19 m^3/day;

$$Y_{1.līm.min} = \frac{8037.19}{310352.2} * 100 = 2.59\ \%$$

$Q._{1.līm.max}$ = 0 + 0 + 8 268.19 + 6 129.04 = 14 397.24 m^3/day;

$$Y_{1.līm.max} = \frac{14397.24}{555942.2} * 100 = 2.59\ \%$$

July 2018:

$Q_{1.līm}$ = 0 + 0 + 7503.49 + 1152.39 = 8655.88 m^3/day;

$$Y_{1.l\bar{\imath}m} = \frac{88655.88}{117735.04} * 100 = 7.35\ \%$$

$Q_{1.līm.min}$ = 0 + 0 + 5 563.15 + 854.39 = 6 417.54 m^3/day;

$$Y_{1.l\bar{\imath}m} = \frac{88655.88}{117735.04} * 100 = 7.35\ \%$$

$Q_{1.līm.max}$ = 0 + 0 + 8 592.9 + 1 319.7 = 9 912.61 m^3/day;

$$Y_{1.l\bar{\imath}m.max} = \frac{9912.61}{134828.7} * 100 = 7.35\ \%$$

Evaluating the obtained results, it has been established that according to the results of February 2018, $Y_{1.l\bar{\imath}m}$ did not fit into the recommended percentual span from 7 % to 12 %, while in July the reduction of the natural gas did – it was satisfactory.

3.2. Level 2 Energy Crisis Modelling

The priority users:

X_{n2} = 0 – in accordance with 0 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{nodr} = 67 912.74*0 = 0 m^3/day;
$Q_{nodr.min}$ = 50 709.38*0 = 0 m^3/day;
$Q_{nodr.max}$ = 90 837.06*0 = 0 m^3/day;

July 2018:

Q_{nodr} = 5 449.96*0 = 0 m^3/day;
$Q_{nodr.min}$ = 4,040.64*0 = 0 m^3/day;
$Q_{nodr.max}$ = 6 241.22*0 = 0 m^3/day.

The first group users:

X_{p2} = 0.2 – in accordance with 20 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{pirm} = 293908.51*0.2 = 58781.70 m^3/day;
$Q_{pirm.min}$ = 219 456.87*0.2 = 78 623.79 m^3/day;
$Q_{pirm.max}$ = 393 118.96*0.2 = 43 891.37 m^3/day;

July 2018:

Q_{pirm} = 69005.68*0.2 = 13801.14 m^3/day;
$Q_{pirm.min}$ = 51 161.37*0.2 = 10 232.27 m^3/day;
$Q_{pirm.max}$ = 79 024.45*0.2 = 15 804.89 m^3/day.

The second group users:

X_{o2} = 0.4 – in accordance with 40 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{otr} = 30907.86*0.4 = 12363.14 m^3/day;
$Q_{otr.min}$ = 23 078.41*0.4 = 9 231.36 m^3/day;
$Q_{otr.max}$ = 41 340.97*0.4 = 16 536.39 m^3/day;

July 2018:

Q_{otr} = 37 517.45*0.4 = 15 006.98 m^3/day;
$Q_{otr.min}$ = 27 815.74*0.4 = 11 126.29 m^3/day;
$Q_{otr.max}$ = 42,964.51*0.4 = 17,185.81 m^3/day.

The third group users:

X_{t2} = 1 – in accordance with 100 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{tr} = 22911.35*1 = 22911.35 m^3/day;
$Q_{tr.min}$ = 17 107.54*1 = 17 107.54 m^3/day;
$Q_{tr.max}$ = 30 645.20*1 = 30 645.20 m^3/day;

July 2018:

Q_{tr} = 5 761.95*1 = 5 761.95 m^3/day;
$Q_{tr.min}$ = 4 271.96*1 = 4 271.96 m^3/day;
$Q_{tr.max}$ = 6 598.52*1 = 6 598.52 m^3/day.

The actual total energy cuts during the announcement of the 2[st] level energy crisis were as follows:

February 2018:

$Q_{2.līm}=0+58781.70+12363.14+22911.35=$ 94056.19 m^3/day;

$$Y_{2.līm} = \frac{94056.19}{415640.46} * 100 = 22.63\ \%$$

$Q_{2.līm.min}=0+43891.37+9231.36+17107.54=$ 70 230.28 m^3/day;

$$Y_{2.līm.min} = \frac{70230.28}{310352.2} * 100 = 22.63\ \%$$

$Q_{2.līm.max}=0+78623.79+16536.39+30645.2=$ 125 805.38 m^3/day;

$$Y_{2.līm.max} = \frac{125805.38}{555942.2} * 100 = 22.63\ \%$$

July 2018:

$Q_{2.līm} = 0 + 13801.14 + 15006.98 + 5761.95 =$ 34 570.07 m^3/day;

$$Y_{2.līm} = \frac{34570.07}{117735.04} * 100 = 29.36\ \%$$

$Q_{2.līm.min}=0+10232.27+11126.29+4271.96=$ 25 630.53 m^3/day;

$$Y_{2.līm.min} = \frac{25630.53}{87289.7} * 100 = 29.36\ \%$$

$Q_{2.līm.max}=0+15804.89+17185.81+6598.52=$ 39 589.21 m^3/day;

$$Y_{2.līm.max} = \frac{39589.21}{134828.7} * 100 = 29.36\ \%$$

Evaluating the obtained results, it has been established that according to the results of February and July 2018, $Y_{2.lim}$ was higher than the set level of energy reduction – from 12 % to 17 %.

3.3. Level 3 Energy Crisis Modelling

The priority group users:

$X_{n3} = 0$ – in accordance with 0 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{nodr} = 67 912.74*0 = 0 m^3/day;
$Q_{nodr.min}$ = 50 709.38*0 = 0 m^3/day;
$Q_{nodr.max}$ = 90 837.06*0 = 0 m^3/day;

July 2018:

Q_{nodr} = 5 449.96*0 = 0 m^3/day;
$Q_{nodr.min}$ = 4,040.64*0 = 0 m^3/day;
$Q_{nodr.max}$ = 6 241.22*0 = 0 m^3/day.

The first group users:

$X_{p3} = 0.4$ – in accordance with 40 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{pirm} = 293908.51*0.4 = 117563.40 m^3/day;
$Q_{pirm.min}$ = 219 456.87*0.4 = 87 782.75 m^3/day;
$Q_{pirm.max}$ = 393 118.96*0.4 = 157 247.58 m^3/day;

July 2018:

Q_{pirm} = 69005.68*0.4 = 27602.27 m^3/day;
$Q_{pirm.min}$ = 51 161.37*0.4 = 20 464.55 m^3/day;
$Q_{pirm.max}$ = 79 024.45*0.4 = 31 609.78 m^3/day.

The second group users:

$X_{o3} = 0.8$ – in accordance with 80 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{otr} = 30907.86*0.8 = 24726.29 m^3/day;
$Q_{otr.min}$ = 23 078.41*0.8 = 18 462.75 m^3/day;
$Q_{otr.max}$ = 41 340.97*0.8 = 33 072.78 m^3/day;

July 2018:

Q_{otr} = 37517.45*0.8 = 30013.96 m^3/day;
$Q_{otr.min}$ = 27 815.74*0.8 = 22 22.59 m^3/day;
$Q_{otr.max}$ = 42 964.51*0.8 = 34 371.61 m^3/day.

The third group users:

X_{t3} = 1 – in accordance with 100 % of the natural gas consumption cuts for this group of users;

February 2018:

Q_{tr} = 22 911.35*1 = 22 911.35 m^3/day;
$Q_{tr.min}$ = 17 107.54*1 = 17 107.54 m^3/day;
$Q_{tr.max}$ = 30 645.20*1 = 30 645.20 m^3/day;

July 2018:

Q_{tr} = 5 761.95*1 = 5 761.95 m^3/day;
$Q_{tr.min}$ = 4 271.96*1 = 4 271.96 m^3/day;
$Q_{tr.max}$ = 6 598.52*1 = 6 598.52 m^3/day.

The actual total energy cuts during the announcement of the 3rd level energy crisis were as follows:

February 2018:

$Q_{3.l\bar{\imath}m}$=0+117563.40+24726.29+22911.35= 165 201.04 m^3/day;

$$Y_{3.l\bar{\imath}m} = \frac{165201.04}{415640.46} * 100 = 39.75\ \%$$

$Q_{3.level.min}$ = 0 + 87 782.75 + 18 462.73 + 17 107.54 = 123 353.02 m^3/day;

$$Y_{3.l\bar{\imath}m.min} = \frac{123353.02}{310352.20} * 100 = 39.75\ \%$$

$Q_{3.l.max}$ = 0 + 157 247.58 + 33 072.78 + 30 645.20 = 220 965.57 m^3/day;

$$Y_{3.l\bar{\imath}m.max} = \frac{220965.57}{555942.2} * 100 = 39.75\ \%$$

July 2018:

$Q_{3.l\bar{\imath}m}$=0+27602.27+30013.96+5 761.95= 63 378.18 m^3/day;

$$Y_{3.l\bar{\imath}m} = \frac{63378.18}{117735.04} * 100 = 53.83\ \%$$

$Q_{3.level.min}$ = 0 + 20 464.55 + 22 252.59 + 4 271.96 = 46 989.09 m^3/day;

$$Y_{3.l\bar{\imath}m.min} = \frac{46989.09}{87289.7} * 100 = 53.83\ \%$$

$Q_{3.l\bar{\imath}m}$=0+31 609.78+34 371.61+6 598.52= 72 579.91 m^3/day;

$$Y_{3.l\bar{\imath}m.max} = \frac{72579.91}{134828.70} * 100 = 53.83\ \%$$

During level 3 energy crisis, the total natural gas cuts of all groups ultimately resulted in more than 39 % in February and almost 54 % in July despite the fact that the expected cut level should be within 17 %–18 % limit.

3. RESULTS AND DISCUSSION

The above-mentioned modelling provided data that helped track changes in the average consumption of natural gas in each of the four user groups. It was established that the natural gas consumption of the first group, during the announcement of the energy crisis, many times exceeded the three other groups, which meant that also the main share in energy savings was taken by this group – state and municipal administration institutions, energy supply companies, railways, airports, long-distance bus terminals, ports etc.

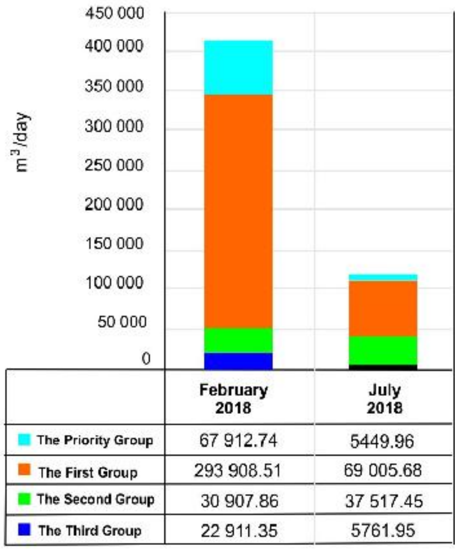

Fig. 1. Average monthly natural gas consumption changes, 2018, in m^3/day.

Examining the consumption figures by season, it was found that the energy consumption of the four groups differed a lot in winter and summer, which was related to the need to spend more natural gas for heating in winter, while demand for it sharply decreased in summer. Figure 2 shows that the decline in the demand for the natural gas users of the priority group was 89 % in July. As it was stated above, this specific group consisted mainly of households, schools, hospitals, crisis centres, emergency services, telecommunications units etc. In case of all four groups, the year 2017 is shown in Fig. 2 along with the year 2018 for comparative purposes.

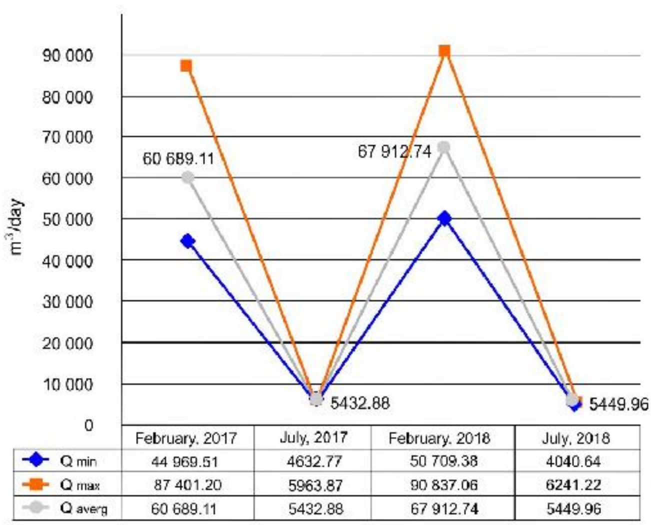

Fig. 2. Fluctuations of the natural gas consumption in the priority group (2017–2018, m^3/day).

The results of the first group (see Fig. 3), which includes energy supply companies, play an important role in overall energy security of supply. The amount of natural gas consumed by this group during the heating season falls by 25 % in summer. Thus, the difference between winter and summer consumption is much less pronounced than in case of the priority group.

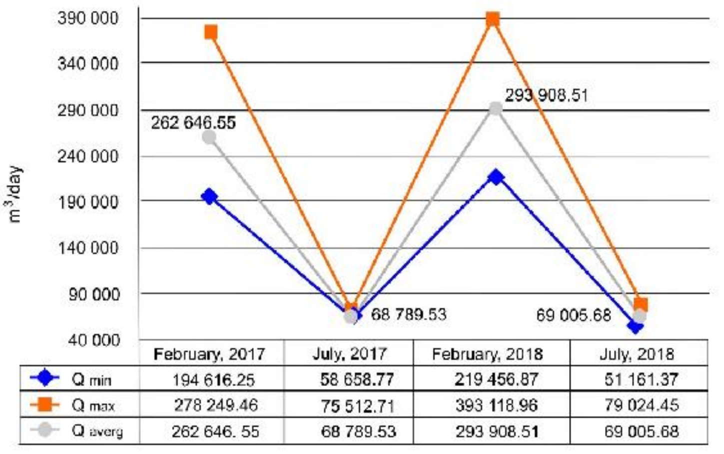

Fig. 3. Fluctuations of the natural gas consumption in the 1st group (2017–2018, m^3/day).

The results of the second group (see Fig. 4), however, show, that the amount of consumed energy during the heating season is by almost 25 % lower, if compared to the summer time. This can be explained by the fact that the second group users include grain processing facilities, which consume the most of its energy – both in form of primary energy resources like natural gas and the secondary energy resources – electricity, during harvesting months in summer and early autumn.

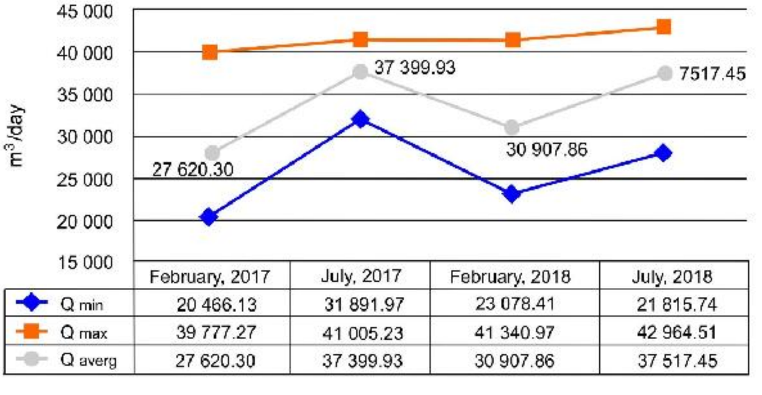

Fig. 4. Fluctuations of natural gas consumption in the 2nd group (2017–2018, m^3/day).

The consumption of natural gas in the 3rd group is shown in Fig. 5, which demonstrates the identical seasonally determined trend as in the priority group and the 1st group.

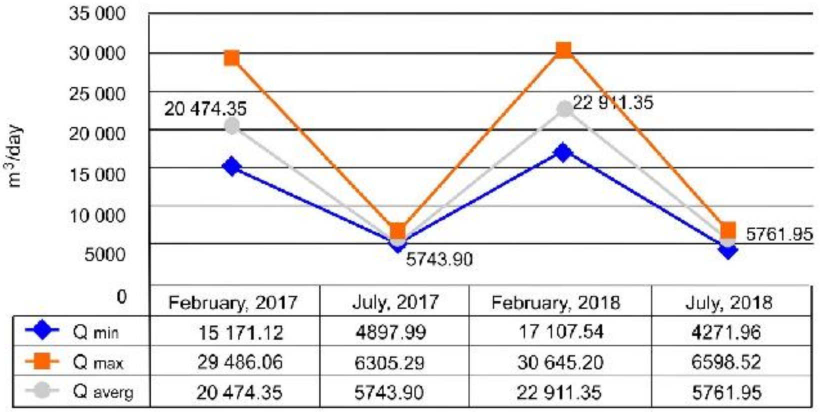

Fig. 5. Fluctuations of the natural gas consumption in the 3rd group (2017–2018, m^3/day).

Thus, it can be concluded that the consumption of natural gas in all groups may vary significantly during the heating and non-heating seasons, but it cannot be forgotten that natural gas is also used in electricity generation, demand of which is increasing every year.

During the generalized evaluation of the results of energy crisis modelling in the "town A", shortcomings in the reduction intervals offered by Regulation 312 were established. The results of the calculation are presented in Table 2, which shows that only in July $Y_{1.līm}$ falls into the necessary interval. In real life, the month of February plays the biggest role, because during the winter, consumption increases for all users, due to the fact that natural gas is used for both local and district heating purposes.

Table 2. Total Energy Reduction as Percentage by Energy Crisis Levels

	February 2018, %	July 2018, %
$Y_{1.līm}$	2.59*	7.35
$Y_{2.līm}$	22.,63*	29.36*
$Y_{3.līm}$	39.75	53.83

* - does not meet the conditions of MK 312, because the obtained results do not fit into the energy reduction intervals offered in the regulations,

where:

$7\ \% < Y_{1.līm.} < 12\%$

$12\ \% < Y_{2.līm.<} 17\ \%$

$17\ \% < Y_{3.līm.}$

According to the amendments of Regulation 312, the Incukalns UGS facility must have at least 3160 thousand MWh (300 million m^3) of the active gas, which is intended to ensure the supply of natural gas in Latvia during the energy crisis. However, if the energy crisis occurs both locally and nationally, the specified storage capacity might be exhausted rather quickly. The amendments of Regulation 312 show that after the opening of the natural gas market in Latvia the risk of announcing the energy crisis has increased; therefore, it has been decided to ensure the minimum amount of the natural gas reserves in order to provide Latvian users at least for some period of time.

Results of $Y_{3.\bar{l}\bar{\imath}m}$ in general agree with the energy reduction offered by Regulation 312, which must be greater than 17 %. In February, the estimated reduction of natural gas was 39.75 % per day and 53.83 % in July. However, such a decrease is unlikely to be beneficial and could have an adverse effect on local production, the economy and society as a whole.

To make the energy crisis provisions of the national scale, more calculations and the actual annual or semi-annual natural gas consumption analysis of as many Latvian municipalities as possible should be performed in order to find out the average preferable percentage of the energy cuts that should be specified in Regulation 312. At the same time, the results obtained within the "town A" research could be critically compared with the results obtained in other Latvian municipalities, so the identification of deviation factor could also be possible. The deviation factor cannot be identified, if only one municipality case study is performed.

Percentual energy cuts according to the natural gas user groups and levels of the energy crisis as proposed in the amendments of Regulation 312, based on the results of the "town A" case study, are shown in Table 3.

Table 3. Energy Cuts as Proposed in the Amendments of Regulation 312, Based on the Results of the "Town A" Case Study (%)

Distribution of the users	Priority group	The first group	The second group	The third group
The natural gas delivery cuts (%), the 1st level energy crisis	0	10	15	20
The natural gas delivery cuts (%), the 2nd level energy crisis	0	15	20	30
The natural gas delivery cuts (%), the 3rd level energy crisis	0	20	35	40

4. CONCLUSION

Disruption of the natural gas supply in Latvia – both at the local and regional scale, can be detrimental to the economy, energy production and the society as a whole. For adequate provision and improvement of the security of the natural gas supply in a context of the energy crisis, the following proposals could me made:

- the comparative studies should be performed in several largest or all largest gasified municipalities in Latvia in order to determine variations of the natural gas consumption fluctuation during the local or/and state energy crisis;
- then, the results obtained during the "town A" case study can be critically compared with the results of other Latvian municipalities, and the identification of deviation factor could also be done;
- in regards to provisions of Regulation 312:
  - natural gas consumers' distribution by energy user groups should be more carefully reviewed;
  - setting up more reality related natural gas consumption limits for certain energy user groups, based on

the actual distribution of the natural gas consumption among energy user groups;
- measures to restrict or interrupt the supply of natural gas shall be taken by the DSO in the area of operation of its license;
- currently the natural gas user during the energy crisis is not entitled to consume more energy than DSO has decided. In case, if the natural gas user consumes more natural gas than that, the DSO is entitled to terminate natural gas supply to the user until the end of the energy crisis. This measure should be specified.

ACKNOWLEDGEMENTS

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THE CREATION OF THE INTEGRATED NATURAL GAS MARKET IN THE BALTIC REGION AND ITS LEGAL IMPLICATIONS

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A common natural gas market in the Baltic region, which is in operation since 1 January 2020, means a single entry–exit tariff system for the natural gas transmission among Finland, Estonia, Latvia, and a common Latvian–Estonian balancing zone. Finland joined the market with a separate balancing zone, certain rules, contracts, invoices and billing, with a decision for full integration to be taken not earlier than in 2022. Lithuania is not currently the common market participant, because it is not ready to join it with such revenue splitting conditions as Finland, Estonia and Latvia. But still common entry–exit tariff zone countries are actively working to find a viable solution for market expansion. Lithuania and other neighbouring Member States of the European Union (hereinafter – the EU), first and foremost, Poland, are welcome to join.

The creation of an integrated regional natural gas market in the Baltics in the long term will stimulate the interest of traders in the region, strengthen security of supply and improve market liquidity. Increased market competition, predictable prices in the long term, transparent tariffs, digital communication and customer-oriented business strategies are just a small part of benefits that will inevitably develop with time.

Keywords: *BEMIP, Finland, legal implications, natural gas market, RGMCG, the Baltic region.*

1. INTRODUCTION

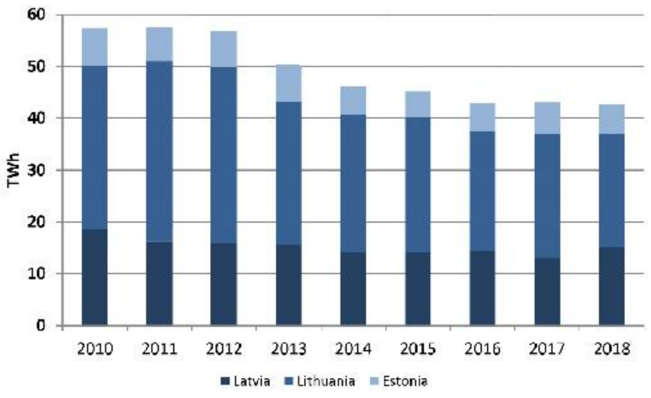
Natural gas is one of the most widely used energy resources in the world, as it is considered to be the cleanest one of conventional fossil fuels. Historically, since its introduction in the early 1960s, it has always played an important role in the energy supply of the Baltic region, including Latvia. The Latvian natural gas market comprises approximately 35 % of the natural gas market in the three Baltic States [1], and in a mid-term perspective natural gas is considered to be an important low carbon energy resource to ensure smooth transition to carbon neutrality both on the national and regional scale [2].

The EU takes a strong position in the global fight against climate change by setting ambitious targets on reduction of greenhouse gas (hereinafter – GHG) emissions. A binding target is to reduce those emissions by at least 40 % below 1990 levels till 2030, which would help make Europe the first climate neutral continent by the mid-21st century. Consequently, the expected 2050 GHG emission reduction target for the EU is 80 %–90% below 1990 levels [3]. This could be achieved by turning climate and environmental challenges into opportunities across all policy areas and making the energy transition just and inclusive for all. Despite contradictive status and clear fossil nature of the natural gas, its sustainable use can still be a key factor in the EU gradual and cost-effective transition to carbon neutrality [4], [5].

The European Commission''s (hereinafter – the EC) Strategy for Energy System Integration, published in July 2020, states that the natural gas will still account for about 20 % of gaseous fuels used in the EU by 2050, as a true percentage of biogas, biomethane, hydrogen or synthetic gases in its primary energy mix by that time is hard to predict precisely [6]. However, with the EC's hoping for greater electrification in the region, it anticipates that overall natural gas demand will fall to below 630 terawatt-hours (hereinafter – TWh) by 2050 in comparison with 5222TWh in 2019. The strategy identifies carbon capture and storage as one of the ways for natural gas to fit into the European ambitious climate-neutrality objectives, and sets a clear path for natural gas as a bridge fuel to more intensive use of the renewable gases [6], [7].

Despite the fact that overall regressive trend in the natural gas consumption has been dominant in the Baltic region over the past two decades, the share of natural gas in total primary energy consumption of Latvia has never reached a level below 21 %. According to the data of the Central Statistical Bureau of the Republic of Latvia (hereinafter – the CSB), in 2010 31.5 % and in 2019 24.3 % of the total primary energy consumption came from natural gas [8].

The drop of about 6 % was due to an increasing share of switch to alternative fuels in centralised heat production and growing political support of the renewable energy sources. However, as CSB data also indicate, in almost ten years (2010–2018) a decline of the natural gas consumption in Latvia has not been significantly sharp. However, at the same time, the total decrease in the natural gas consumption in the three Baltic States between 2010 and 2018 reached about 25 %, of which the biggest share was attributable to Lithuania [1].



Source: Central Statistical Bureau of Latvia, ENTSOG, Amber Grid

Fig. 1. Natural gas demand in the Baltic States, TWh (2010–2018).

In a wider regional scale, a role of the natural gas as a transitional fuel would rise, as many EU Member States, including Finland, are airing plans for coal phase-out in energy production in the upcoming decade. On 19 March 2020, the Finnish Government issued a decree on investment aid for projects accelerating the replacement of coal in energy production. The aid is intended to promote voluntary phase-out of coal use by the end of 2025. At the same time, the ban of coal-based power and heat generation will take effect in the country from 1 May 1 2029 [9].

Such a decision is important for both rising Finland's level of energy efficiency and sustainability, and further development of the regional natural gas market, with obvious potential for an increase in the natural gas consumption in at least mid-term perspective.

2. TOWARDS LIBERALIZATION OF THE BALTIC NATURAL GAS MARKET

In 2015, the EC adopted the Energy Union Strategy based on five key targets, which incorporate market objectives as well as put in place the guidelines of the common EU energy policy [10]. The Energy Security Strategy addresses measures both for short-term security, mainly focusing on resilience to energy supply disruptions, and for long-term security – diversification of energy supply and finally reduction of energy dependency on external energy supplies. The aims of the common energy policy include ensuring the functioning energy market and security of energy supply by diversification of energy sources and promoting interconnection of all Member States' energy networks [11].

Even before the Energy Union Strategy was launched, the EU energy market liberalization packages, adopted in 1998, 2003 and 2009, have been at the centre of the common gas market creation in the EU. With the adoption of relevant directives and regulations, the EC set a goal to finalize (with a few exceptions) the internal energy market by 2014, notably, by enforcing the unbundling of networks away from the competitive parts of the electricity and gas businesses. The EU Third Energy Package mandated the EU Member States to unbundle the natural gas and electricity distribution networks: transmission should be separated from supply and distribution. This should done to reduce the monopoly power possession risks of single or several energy market actors [12].

To achieve this goal, the EU Third Energy Package provided three options for unbundling: ownership unbundling, establishment of the Independent System Operator or creation of the Independent Transmission System Operator. Lithuania was among the first countries that implemented the Third Energy Package and adopted the strictest option – ownership unbundling [13]. Following Lithuania's decision, Estonia implemented its unbundling legislation. Latvia, on the other hand, postponed the implementation until April 2017. Even after unbundling finalization in Latvia, in Finland fully state-owned natural gas company "Gasum Oy" remained a vertically integrated company and the major market player in the Finnish natural gas industry. The company thus continued to perform various market roles: it was the only market participant importing natural gas to Finland, acted as the natural gas transmission operator (hereinafter –TSO), whilst also operating in the segments of the natural gas transport and trade, complemented by its subsidiary "Kaasupörssi Oy".

The work and achievements of regional cooperation in the energy sector in the Baltic Sea region has been conducted within the framework of the Baltic Energy Market Interconnection Plan (hereinafter – BEMIP) initiative, which was launched in 2009. The main goal of the BEMIP initiative, within the context of the EU's 20-20-20 objectives and beyond, was full integration of the three Baltic States – Lithuania, Latvia and Estonia – into the European energy market, through the strengthening of interconnections with their EU neighbouring countries [14]. The BEMIP initiative was further reinforced through reforms launched by the EC at the BEMIP High Level Group (hereinafter – HLG) meeting on 31 October 2014 and the Declaration on Energy Security of Supply (hereinafter – Declaration) signed on 15 January 2015 by the energy ministers of the Baltic States [15].

The BEMIP has been successful, since Estonia, Latvia, and Lithuania have developed electricity interconnections both between themselves and to other parts of the EU [11].

Another part of the BEMIP concerned plans to build pipelines between Poland and Lithuania, and Finland and Estonia to interconnect the natural gas systems and integrate the natural gas markets of these countries. This task is partially fulfilled – the natural gas interconnector between Estonia and Finland – *Balticonnector*, has been in operation since 1 January 2020 – the same day, when the common Baltic and Finnish natural gas market platform was launched [16]. In turn, the Lithuanian–Polish natural gas interconnector GIPL is expected to be ready for exploitation in 2022.

Source: *entsog.eu*

Fig. 2. Routes of *Balticconnector* (left), and GIPL (right).

As for December of 2020, in Lithuania, more than 50 % of the pipeline construction works were finalized. In summer of last year, the interconnecting pipeline was laid down under the two widest rivers in Lithuania, using the environmentally-friendly horizontal directional drilling technology. After testing the pipeline at maximum pressure and installing the starting point of the pipeline, the first part of GIPL was connected to the operating gas transmission system and filled with natural gas. In Poland, the construction of the pipeline is divided into two sections (northern and southern) and works are ongoing to build the northern section, which is approximately 185 km long. In addition, the two TSOs launched a non-binding survey procedure for development of services for new transmission capacity in GIPL in November 2020 [17].

3. THE NATURAL GAS MARKET INTEGRATION TRENDS AND THE REGIONAL GAS MARKET COORDINATION GROUP

The Baltic States have always been dependent on one dominant natural gas supplier and have also been isolated from the European natural gas networks in terms of the natural gas transmission infrastructure. In order to prevent rising energy dependency of the EU as a whole and further physical isolation of certain segments of the energy sector of particular Member States, the EC decided to gradually liberalize the natural gas markets.

The First Energy Package was adopted more than 20 years ago in 1998, with the Second Package following soon after – in 2003. Further liberalization of the natural gas markets came in April 2009, when the Third Energy Package was adopted, providing the basis for the completion of the internal energy markets and ending of monopoly state. The Third Energy Package consisted of several documents, two of which: Directive 2009/73/EC of the European Parliament and of the Council concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (hereinafter – Directive 2009/73/EC) [18] and Regulation (EC) No. 715/2009 of the European Parliament and of the Council on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (hereinafter – Regulation 715/2009) [19], concern the natural gas markets.

Considering the support from the EC and national agreement within the Baltic Sea region, in October 2008, the EC set up HLG, including representatives of Denmark, Germany, Estonia, Latvia, Lithuania, Poland, Finland and Sweden [20]. Norway participated in the group as an observer.

In June 2009, this group came up with the BEMIP, which embraced certain tasks in order to achieve both national and regional goals: namely, integration of the regional electricity and natural gas markets, and thus ending the isolation of the Baltic electricity and natural gas sectors from the rest of Europe.

At the end of 2014, the Prime Ministers of the Baltic States met in Tallinn, Estonia, and jointly agreed that it was essential to ensure implementation of the Third Energy Package. As the consequence of this decision, in January 2015, the Declaration was signed by the Baltic Energy Ministers. In this document, the signing parties committed themselves to develop a transparent, competitive and fully functioning regional natural gas and electricity market through the implementation of the Third Energy

Package. Among others, this included the establishment of a Regional Gas Market Coordination Group (hereinafter – the RGMCG) and the decision to invite Finland to participate in the market [15].

The RGMCG was established to promote the opening of the national natural gas markets, to develop an action plan for the development of a regional natural gas market, to promote an efficient functioning common regional natural gas market in the Baltic States, and to develop measures to ensure the Baltic natural gas market physical connection with Finland.

It was agreed that the common natural gas market platform would deliver a number of benefits, such as efficiently transported and stable natural gas flows, the most economically advantageous natural gas price offers, greater market liquidity, where previously contractual congestion would otherwise limit gas flows in certain market areas and improve security of supply. Also, economic consultants from the United Kingdom's *Frontier Economics* found in its 2016 study that, *inter alia*, a single market area would bring benefits and overall prosperity to the region compared to isolated, small areas [21].

Regular cooperation within the RGMCG was ensured with participation of responsible ministries, national regulatory authorities and the natural gas transmission system operators (hereinafter – TSOs) of the three Baltic States and Finland. The main objective of this group was to create a common and fully functional Finnish–Baltic natural gas market by outlining attractive market conditions for existing and new market players, ensuring free access to the advantages of the region's largest natural gas infrastructure and to strengthen security of the natural gas supply.

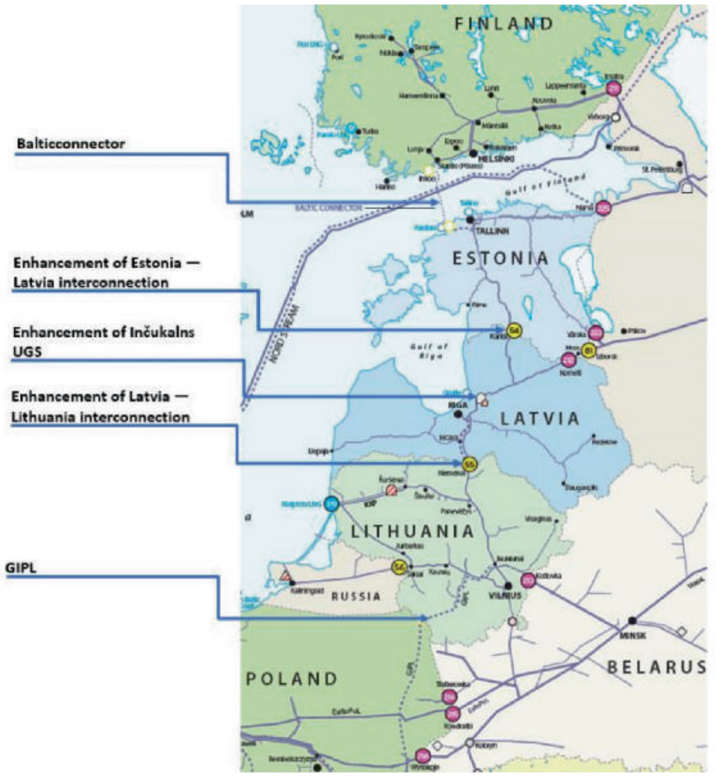
RGMCG meetings were held several times a year to monitor progress, provide support and solutions to problems encountered, and to guide further processes towards the goal of establishing a common gas market. Meetings were held on a rotating basis each year, mainly in the ministries of the Baltic States. In 2019, Latvia was the leading country organising RGMCG meetings, but in 2020 meetings were planned to be held in Estonia.

To ensure that actions of RGMCG are coordinated and target oriented, in June 2015 the RGMCG approved short-term and medium-term action plan that included measures to:

- develop non-discriminatory, transparent and flexible access rules for gas transmission systems and storage within the regulatory framework;
- harmonise requirements related to the natural gas quality;
- discuss issues regarding financing of *Projects of Common Interest* (hereinafter – PCI);
- harmonise energy measuring units and other parameters.

The involvement of Finland in the implementation of the plans was voluntary and not mandatory, taking into account derogation based on Directive 2009/73/EC and Regulation 715/2009. Finland was equally active and involved in common market development as the Baltic States, expressing its readiness to be part of the common gas market.

Well-developed infrastructure plays a key role in creation of a strong and truly integrated market. GIPL, *Balticconnector* and the development of interconnectivity capacities within the Baltic States themselves are the main natural gas infrastructure projects important for the establishment and proper functionality of the common gas market and the implementation of the BEMIP.



Source: The Latvian Public Utilities Commission

Fig. 2. PCI in the Baltic Region.

Since creation of the RGMCG, progress has been made in all aspects to develop a common natural gas market. Regulatory authorities of the Baltic States, together with TSOs and responsible ministries, have continued to harmonise and develop a transparent and non-discriminatory variety of rules and processes, including the adoption of common principles for the use of the natural gas transmission system. Discussing progress on short-term and medium-term goals and taking into account the main tasks, in 2016 the RGMCG presented the Regional Gas Market Action Plan with the main tasks to be accomplished by 2020. Accordingly, on December 2016, the Baltic prime ministers signed a Declaration on the Development of the Regional Gas Market, welcoming the Regional Gas Market Action Plan and inviting Finland to continue its successful cooperation in the process of establishing the market.

4. RULES OF OPERATION OF A COMMON NATURAL GAS MARKET

In October 2018, the natural gas TSOs of Finland, Estonia and Latvia signed a common Memorandum of Understanding (hereinafter – MoU), stating their preparedness to do anything that is necessary to create a common gas market by 2020. Unfortunately, Lithuania did not sign the MoU and was not ready to agree to join with the same conditions as Finland, Estonia and Latvia (hereinafter – FINESTLAT). Lithuania wanted to apply for exceptions in relation to GIPL and Klaipeda liquefied natural gas (hereinafter – LNG) terminal, while having trouble accepting Inter TSO Compensation Mechanism that was agreed by other involved parties.

In February 2019, FINESTLAT TSOs singed Inter TSO Compensation (hereinafter – ITC) agreement, which enabled the functioning of a single gas transmission tariff zone for Finland, Estonia and Latvia from the beginning of 2020. ITC mechanism intended to combine revenues from entry points and share them by the national natural gas consumption after deducting TSO variable costs related to facilitation of regional flows.

Taking into account contributions made by all countries to the market development, from 1 January 2020 Finland, Estonia and Latvia have a single entry–exit tariff area and Estonia – Latvia – common balancing zone. As for now, Finland has a separate balancing zone with separate terms, contracts, bills and settlements, but after 2022 it will face the next big energy market decision on whether to fully join the Estonian–Latvian balancing zone or not. As Estonia and Latvia also have a common balancing area with common network rules, it means that by signing an agreement with either Latvian or Estonian natural gas TSO, system user has automatic access to the transmission infrastructure of both countries.

New unified system balancing rules developed for a common natural gas market were submitted to the Latvian Public Utilities Commission and the Estonian Competition Council on 29 May 2019 for taking a coordinated decision [22].

Also, the development of tailor-made solutions for the natural gas trading was intended to contribute to increased liquidity, competitiveness and transparency of wholesale gas markets in the Eastern Baltic region. “GET Baltic” market platform operates as a licensed natural gas market operator with the status of Registered Reporting Mechanism provided by the European Union Agency for the Cooperation of Energy Regulators. It administrates the electronic trading system for trading spot and forward natural gas products with physical delivery in the market areas located in Lithuania, Latvia, Estonia and Finland [23].

5. A COMMON NATURAL GAS MARKET AND THE NATIONAL LEGAL FRAMEWORK

The creation of a regional natural gas market was related to and directly influenced by national energy legislations of both the Baltic States and Finland. One of the most important tasks for the responsible ministries within the RGMCG Action Plan was to amend the legislation and prepare grounds for common natural gas market inauguration in the early 2020.

5.1. Finland

Finland’s processes were different from the rest of the Baltic States, since Finland was preparing not only for becoming part of a common entry–exit tariff zone with Estonia and Latvia, but also it needed to make major legislation changes to ensure smooth and timely natural gas market liberalization. The access rules to the transmission system and the internal market rules came into force, by which "Gasum Oy" gas transmission function was separated from the natural gas sales.

Already in January 2018, the new Finnish Natural Gas Market Act (hereinafter – the Act) came into force, and, as of March of 2019, the Finnish Government called for the need of its amendments, which were directly related to the establishment of a common natural gas market. Among others, amendments included new rules allowing for transmission tariff flexibility to ensure end of Finland's energy isolation and to allow Finland to be part of common entry–exit tariff system, which included two or more EU Member States. The reform of the natural gas market in the long term plans a number of specific legislative changes to facilitate the development of the single natural gas market by extending the powers of both the Finnish natural gas TSO and the national regulatory authority regarding regional tariff agreements and regional entry–exit tariff system. Consequently, Finland's readiness to carry out such a significant reform of the natural gas sector, which concerns both market liberalization and the unbundling of the transmission system operator, as well as support and readiness to engage in regional market creation processes through appropriate preparation of the national regulatory framework, was highly valued by market participants, other countries and the EC.

The purpose of the Act was to ensure the conditions for a national and regional natural gas market that would function efficiently, securely and environmentally sustainably as well as for the EU's internal natural gas market. The aim is to ensure good security of supply of natural gas and access to natural gas that is competitively priced and sufficiently high in quality. The primary means for creating a functioning natural gas market are safeguarding healthy and effective economic competition in the supply and storage of the natural gas, and maintaining reasonable and fair service principles in the functioning of natural gas networks and LNG processing facilities. The tasks of enterprises in the natural gas sector include ensuring the provision of services relating to their customers' natural gas procurement and promoting in their own and their customers' activities the efficient and economic use of natural gas. The Act applies to the import, export, transmission, distribution, delivery and storage of natural gas and LNG. In addition, the provisions of the Act cover the gases from renewable energy sources and other gases that can be technically and safely injected into the natural gas network and transmitted and distributed within it [24].

Currently, the Finnish natural gas system is run by "Gasgrid Finland Oy", a new company unbundled from "Gasum Oy" [25]. The natural gas transmission system operations were ownership unbundled from electricity and natural gas generation and supply. A new natural gas TSO "Gasgrid Finland Oy" was unbundled through a partial demerger from "Gasum Oy" that entered into force on 1 January 2020. Furthermore, on the same date, the ownership of transmission system operation was transferred to the Ministry of Finance of Finland. "Gasgrid Finland Oy" submitted its application for the certification of the TSO to the Finnish Energy Authority in January 2020, with subsequent positive decision made by the Authority in May 2020. Then it was submitted to the EC for the final approval. On 2 July 2020, the approval was received and the certification of "Gasgrid Finland Oy" was finalized [26].

5.2. Estonia

In Estonia, establishment of a common natural gas market was made by single amendment in the Estonian Natural Gas Act [27]. It was done in Paragraph 9, Section 2 of the Act, which was related to a pricing of the natural gas. The Act was amended in a manner that the entry tariff might be included in the natural gas pricing. These legislative changes were drafted by the Ministry of Economic Affairs and Communications of Estonia, in cooperation with the national regulatory authority, TSO and natural gas traders. No objection was raised by any of the parties involved and the legislative changes were made very easily by adding them to other amendments already in the first reading.

In all, the Estonian Natural Gas Act has always been relatively flexible, without creating restrictions on new market processes. Within the Estonian legal framework, the Competition Authority cannot influence the import and/or supply prices, which are formed on a contractual basis. However, the Authority can verify whether the seller of natural gas follows law and sells natural gas to all consumers on equal conditions and does not abuse its position in the market [28].

5.3. Lithuania

In Lithuania, the year 2018 ended with quite extensive amendments to the Law on Natural Gas of Lithuania [29]. In several aspects, these amendments were related to the development of a common natural gas market, despite the fact that Lithuania had not been part of the common market area yet. These amendments gave mandate to the Lithuanian Government to make a decision to join a common natural gas market after evaluating conclusions on economic benefits for consumers made by the Ministry of Energy of the Republic of Lithuania and the National Commission for Energy Control and Prices (hereinafter – the NCECP). Therefore, when there is a common decision made, it will be possible for Lithuania to join the market immediately. At the same time, TSO was given a mandate to review the transfer of balancing function to a common regional natural gas market operator – a new legal entity jointly created by common gas market TSOs and acting as a "one-stop shop" for balancing services in the entire region. The NCECP received power to approve the inter-operator agreement mechanism, if submitted by TSOs as well.

Both the Lithuanian natural gas TSO AB "Amber Grid" and the national regulatory authority participated in the development of appropriate amendments. There were no objections to the purpose of these amendments, and the Lithuanian Parliament gave them almost unanimous support. For a few legal aspects, for example, uncertainty about how the market will be regulated and supervised in a common entry–exit tariff zone, the parties and responsible ministry and regulatory authority held intensive discussions with government lawyers, so that these amendments would be accepted [29].

5.4. Latvia

In Latvia, on 23 February 2016, amendments to the Energy Law (hereinafter – the EL) concerning opening of the natural gas market and division conditions of JSC Latvijas Gāze were approved by the Parliament. The amendment of the EL provided that by 3 April 3 2017, JSC Latvijas Gāze would haveto be divided, and a distinction had to be made between the natural gas transportation and storage, and distribution and trading functions. On 22 December 2016, common natural transportation and storage operator JSC Conexus Baltic Grid was established [30]. The creation of single natural gas distribution system operator JSC Gaso followed on 22 November 2017 [31].

To ensure full functionality of a common natural gas market, on 1 January, 2020 it was essential to amend the national Energy Law. Amendments were needed for all parties to have clear definitions, responsibilities and obligations in the new market situation. Also, there was a need to empower the Latvian National Regulatory Authority – the Public Utilities Commission (hereinafter – the PUC), to approve new gas transmission tariffs for the whole new market area.

In October 2020, amendments to the Energy Law, removing obstacles to the development of a common natural gas market with Estonia and Finland, came into force. According to the mandate given, the PUC was now able to approve the network and balancing rules, as well as transmission tariffs, and make decisions that had cross-border effects.

6. CONCLUSION

When assessing the creation of a common natural gas market in the Baltic States and Finland, it can be concluded that the integration processes both from technical, regulatory, political and legal viewpoints were managed and carried out successfully.

In particular, during all the managerial stages of integration, the RGMCG has proven itself as an efficient cooperation platform, which has brought the professionals, politicians and lawyers of the natural gas sector together to discuss and solve the problems. The creation of a common gas market in the Eastern Baltic showed that its impact on the national legislation depended on a complexity of existing natural gas related regulations, but in general it did not cause any significant burden for the national legislations of the involved parties.

The integration of the Baltic–Finnish natural gas market brought novelties to the natural gas exchange platform “GET Baltic” as well. On 1 January 2020, it successfully launched a new market area in Finland becoming a single regional trading platform for the Baltic–Finnish natural gas market. Due to the merger of the Latvian and Estonian natural gas markets, the market areas were also merged on the natural gas exchange into one common market area. Finally, together with expanding its activities, continuous trading opportunities were ensured: trading on “GET Baltic” takes place around-the-clock. These and many other changes implemented during 2020 led to grown market interest and activity on the natural gas exchange and the Baltic–Finnish common natural gas market as a whole [23].

Close cooperation for addressing major challenges on the way to creation a common natural gas market united all involved parties and led to a unique and beneficial result – the creation of the EU’s first truly transnational natural gas market platform. For the future, it is planned to expand common entry–exit tariff zone and balancing zone in the neighbouring countries, with other significant tasks including increasing sustainability of the natural gas infrastructure being on their way.

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ANALYSIS OF THE ROLE OF THE LATVIAN NATURAL GAS NETWORK FOR THE USE OF FUTURE ENERGY SYSTEMS: HYDROGEN FROM RES

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As EU is steadily moving in the direction of emission reduction, each country must develop plans to decarbonise the transport and energy sectors. In Latvia, transport sector is one of the biggest emission sources. The heating applications come next. Both require carbon containing fuels and a transfer to carbon neutral fuel is necessary; therefore, hydrogen may be the answer to achieve the overall EU targets. As Latvia has renewable energy sources, some production, storage and use of hydrogen are possible. Currently clear guidelines for Latvia have been investigated. The existing natural gas network may be used for two tasks: large-scale hydrogen transportation and decarbonisation of natural gas network. To open the natural gas networks for hydrogen, the first evaluations are made and a possible scenario for hydrogen implementation in network supplying consumers in the household sector is analysed to evaluate decarbonisation with an overarching goal of carbon neutrality.

Keywords: *Decarbonisation, HCNG blending, hydrogen, natural gas, NG networks.*

1. INTRODUCTION

The existing EU natural gas (NG) network provides large capacity to integrate renewable (bio-methane, hydrogen) and low-carbon gases (synthetic methane, hydrogen/compressed natural gas (HCNG) blends); therefore, transformation of the gas network for hydrogen applications may provide a cost-efficient solution [1].

Today, hydrogen contributes less than 2 % of Europe's energy consumption [2] and is almost exclusively produced from fossil fuels and used in industry. Nevertheless, hydrogen has a significant role to play in emission reduction in hard-to-decarbonise sectors, in particular, as a fuel in certain transport applications and as a fuel or feedstock in certain industrial processes (steel, refining or chemical industries – including the production of 'green fertilisers' for agriculture) [1], [2]. Carbon dioxide in reaction with hydrogen can also be further processed into synthetic fuels, such as synthetic kerosene in aviation. In addition, hydrogen brings other environmental co-benefits when used as fuel, such as the lack of air pollutant emissions.

The priority for the EU is to develop hydrogen production from renewable electricity, which is the cleanest solution [2]. In other words, the aim is to develop green hydrogen production in the EU. However, in transitional phase other forms of low-carbon hydrogen, for example, HCNG, are needed to replace the existing NG and kick-start an economy of scale.

The gas networks may use hydrogen blend of 5–20% by volume and be tolerated by most systems without the need for major infrastructure upgrades or end-use appliance retrofits or replacements [3]. The transmission of existing natural gas networks to hydrogen network is one of the main aspects to achieve the hydrogen availability and in the meantime large-scale transportation. The promotion of hydrogen network as the EU backbone is gaining momentum in Central Europe, and the development of a hydrogen backbone activity is ongoing [4].

To decarbonise the NG grids, the threshold of hydrogen allowance in the existing grid systems must be increased. Considering that the assessment of hydrogen injection in the Latvian gas grid will be developed in 2021, the first initial analysis can already be made, and experience gained from other countries can be replicable. To create a consistent and long-lasting plan, the current energy sector players must participate in the development of this strategy, as actors in the field have command of currently used facilities and technologies.

Analysis of hydrogen introduction into the Latvian energy sector is performed in this article. The blending of green hydrogen produced by renewable sources in the NG network at a limited percentage is a key element to enable hydrogen production in a preliminary and transitional phase (2020–2030). The present article deals with the evaluation of (i) the potential of green hydrogen blending at low percentage (up to 20%) in the Latvian gas network and (ii) the maximum power-to-gas (P2G) capacity compatible with low percentage blending. The paper aims to provide preliminary assessment of the green hydrogen blending potential into the Latvian natural gas network as a tool for policy makers, grid and network managers, as well as energy planners.

2. EVALUATION METHODOLOGY

2.1. The Main Aspects from Experience of Other EU Countries

Preliminary assessments and tests in the EU countries [3], [5]–[7] show that it is urgent to evaluate at the same time (i) the potential of green hydrogen blending at low percentage (up to 10%) and (ii) the maximum of available P2H capacity compatible with low percentage blending. If the first estimates purely theoretically calculate the maximum possible amounts of hydrogen gas that can be filled into the existing national NG networks at low impurity concentrations [5], [6], then real experiments are performed in separate network sections, e.g., in Germany and Denmark with "windgas", France (Dunkerque), the UK (Keele, Leeds), Italy (Salerno).

The work carried out by French operators [5] shows that it is possible to integrate a significant volume of hydrogen into the gas mix by 2050, with limited infrastructure adaptation costs. In the short term, hydrogen can be blended in the most networks up to 6 % (volume) without any additional installations on the customer's premises. The first task will be to determine suitable areas for injection project owners. These areas will be extended gradually to align with the results of R&D and equipment replacement actions. By 2030, operators recommend setting a target capacity for integrating hydrogen/NG blends into the networks of 10 % and 20 % thereafter. The goal is to anticipate the need to adapt equipment for downstream users at a distribution level. The work carried out for this report shows additional areas of relevance for the three injection routes by 2050: blending, methanation and 100 % hydrogen clusters.

In Italy, two different networks are operated [6]: the transportation and the distribution networks. More than 90 % of natural gas is imported from foreign countries through 7 points. The Italian distribution system is responsible for natural gas supply to final customers. Almost 30 GSm^3 of natural gas, equivalent to almost 300 TWh, is annually supplied by more than 200 Distribution System Operators (DSO) to more than 23 million final Italian customers. More than 500 connection points between distribution and transmission networks are present and each of them would become a hydrogen blending point. A very complex coordination among DSOs would be therefore required to not exceed the hydrogen concentration threshold. Therefore, hydrogen blending is assumed only in the Italian transmission gas system, which is considered an option for location of P2H plants. Even if the Italian regulation allows for hydrogen concentration for blending only up to 1.0 % [6], as defined for biomethane injection, experimental activities have been already performed in existing networks: 5 % blending has been already tested in a small closed network near the southern city of Salerno (see references in [6]). Up to 8100 ton/year of green hydrogen blending, i.e., 715,000 Sm^3/year can be injected right now in the existing Italian NG network with a proper location and sizing of P2H plants with an installed capacity of about 78 MW of electrolyzers and about 488 MEUR of investment.

As mentioned prior, also in UK ativities to evaluate hydrogen blending into NG grid are ongoing. HyDeploy [7] is H2020 project in the UK. ITM Power (the energy storage and clean fuel company) has announced that the UK's first pilot project HyDeploy to inject zero carbon hydrogen into a gas network to heat homes and businesses is now fully operational. In 2018, the HSE granted the HyDeploy consortium an exemption to the current limit of 0.1 % hydrogen in the UK gas network. The exemption to 20 % hydrogen for the project at Keele was awarded after the project gathered extensive evidence, which was scrutinised by the HSE, to demonstrate the hydrogen blend would be 'as safe as natural gas'. The UK's first live pilot to inject zero carbon hydrogen into the gas network to heat homes and businesses is now fully operational. The HyDeploy demonstration is injecting up to 20 % (by volume) of hydrogen into Keele University's existing NG network, feeding 100 homes and 30 faculty buildings. The 20 % hydrogen blend is the highest in Europe. If a 20 % hydrogen blend were rolled out across the UK, it could save around 6 million tonnes of carbon dioxide emissions every year, the equivalent of taking 2.5 million cars off the road [7].

2.2. The Latvian Gas Grid

The Latvian emission reduction strategy states that the main factor for GHG emission reduction is to increase the overall energy efficiency and to substitute fossil energy resources with bio-gas or other renewables [8].

The modern NG transmission system, which is part of the Conexus Baltic JSC company structure, is 1188 km long and it directly connects the Latvian natural gas market with Lithuania, Estonia and Russia [9]. The Latvian transmission system is not directly connected with the European gas network. Since the liquid natural gas terminal is in operation in Lithuania, there is an option to use not only the natural gas from Russia but also from other countries.

The oldest operating tubes were manufactured in 1967; thus, the renewal of existing infrastructure is ongoing. The Latvian transmission NG grid is connected with transmission systems of neighbouring countries – Estonia, Russia and Lithuania. The cross-country connections with Estonia allow securing the natural gas flow only in one direction. The connections with Lithuania and Russia ensure the flow in both directions [10].

Within the heating period, the main source of natural gas is the Incukalns underground gas storage (UGS) facility. It is one of the most significant infrastructures of the Latvian NG grid network. Incukalna UGS facility is the only functional storage in the Baltic countries with an overall capacity of 4.47 bil. m^3 of natural gas [11]. Incukalns UGS is in operation because in the depths of the Latvian soil there is a layer of porous sandstone, which has good storage properties and which is coated with gas-tight rock layers. These geological structures are also placed at the optimal depth level of 700–800 meters, allowing for safe and cost-efficient storage of gas [9], [12]. The main technical gap with HCNG blends into Incukalna UGS is the identification of potential chemical reactions in underground water. It could lead to microorganisms consuming dissolved hydrogen, to the production of hydrogen sulphide, and to the development of biofilms near wells (risk of corrosion) [1]. Specific research of Incukalns UGS must be conducted where material compatibility with gaseous hydrogen is tested and evaluated. Analogical evaluation is ongoing within the RINGS project that is performed by the University of Pau and Pays de l'Adour (UPPA) and Teréga (France). Within the project, laboratory experiments of reproduction of reservoir conditions using samples of rock, micro-organisms aquifer water and variable gas composition will be done [13]. The interim results will be available in 2021 and could be useful as a starting point for Incukalns UGS evaluation [14].

What tactics to use when choosing hydrogen entry points in the Latvian natural gas network? This issue cannot be solved in this article. The assessment of potential injection locations must be done in close cooperation with the network operators (CONEXUS, GASO). In order not to affect the supply of clean natural gas to Estonia and Lithuania from the Incukalns UGS facility, experiments with the storage facility and distribution branches to Estonia and Lithuania should not be exercised in the original hydrogen blending plan. This is due to the fact that hydrogen impact on Incukalns UGS materials is not known and should be tested and evaluated prior larger pilots or activities. Thus, for the first evaluations smaller branches should be used, such as Daugavpils, Liepaja.

2.3. Pipelines and Characterisation of H_2/NG Blends

If hydrogen mixture is increased in the natural gas systems, the first assessment of existing pipeline system must be made. Gaseous hydrogen can be stored and transported in pipelines. Evaluations to use the existing natural gas pipeline network are ongoing and the first aspects are already outlined, such as the usage of polymer pipes or specific coating of existing pipelines.

The need for modification varies from the intended concentration of hydrogen in the pipelines. Pipelines themselves need little modification, and new stretches of dedicated hydrogen pipeline do not differ a lot from NG pipelines either. However, depending on the capacity at which the pipeline is operated, major modifications on the compressor stations may be needed. Hydrogen has lower energy density per volume than natural gas: at the same pressure, a cubic meter of hydrogen only contains 1/3 of the energy density of a cubic meter of natural gas. However, this does not mean that three times as many pipelines are required to transport the same amount of energy. The volume flow of hydrogen can be higher than for natural gas, bringing the maximum energy capacity of hydrogen pipeline to a value of up to 80 % of the energy capacity it has when transporting natural gas [4].

As one of the solutions to transform the gas network pipes suitable for hydrogen transportation is to use an inner coating. The inner coating would chemically protect the steel layer and reduce the hydrogen diffusion into the metal. This aspect might allow increasing the overall pressure in the tubes. Initial hydrogen conversion projects in Germany and the Netherlands have shown that existing pipelines in those regions do not require internal coating; studies in France show that re-coating can be a viable part of the optimisation solution by enabling pipes to be operated at pressures closer to the pressure of natural gas [4].

In order to inject the green hydrogen in NG network, it must be produced. Currently, different options for green hydrogen production are available and suitable for the Latvian situation.

3. RESULTS AND DISCUSSION

3.1. Evaluation of Available RES and Hydrogen from them

In 2018, Latvia had the third highest share of RES (40.3 %) in the energy consumption in the European Union (EU) after Sweden (54.6 %) and Finland (41.2 %), while the EU average indicator constituted 18.0 % [15]. In order to maintain its place, the Latvian operator directs all the energy produced by RES to its own consumption, and only surplus energy that is left at any given time can be allocated to hydrogen production. Table 1 provides information on electricity produced from renewable energy resources in Latvia in 2018 [5], [19] and the estimated amount of hydrogen produced.

Table 1. Electricity Produced from Renewable Energy Resources in Latvia in 2018 (GWh) and the Estimated Amount of Hydrogen (Tonnes) Produced [15], [19]

Resources	Electricity produced GWh/annually	Hydrogen produced, tonnes/annually
Hydroelectric power plants together	2431	44200
Average annual surplus from spring floods	280	5090
Wind power plants	122	2218
Biomass cogeneration plants and power plants	570	10364
Total biogas cogeneration plants	374	6800
Solar microgenerators and power plants	1	18

To ensure constant hydrogen pressure within the selected gas grid system at the same time sustaining high fraction of renewable hydrogen, it should be produced locally in Latvia from surplus electricity generated in RES. Even though, there are many possible hydrogen production technological solutions, at this moment for Latvia the best option is conventional alkali-based electrolysis (PEM electrolysers for large-scale applications are developing quickly [4]). That will require certain amount of electricity (55 kWh/kg H_2 [4]) and there are four main renewable energy sources that are meaningful to use under current conditions: hydro, wind, solar and biogas energy. Small- to medium-scale plants can participate and create a buffer for a steady hydrogen flow in the gas grid.

Hydroelectric power plants. Latvia has many potential places for small-scale hydro power plants that could utilize seasonal floods for hydrogen production creating H_2 buffer, but high peak production is expected only 1–2 months a year (March, April). Is it enough for a steady buffer level? The net electricity consumption in Latvia totalled 7 410 215 MWh in 2018, local generation covered 87.7 % of national consumption [15]. However, if we look at the volumes of electricity produced and consumed in Latvia in 2018 by month (Fig. 1), it can be observed that in the first four months of the year more electricity is produced than consumed. The reason is the spring floods and a high water level in the largest river of Latvia, the Daugava, on which three of Latvia's largest hydroelectric power plants are located. This amount of surplus electricity changes year by year, and an average value for last 5 years was 280 GWh//annually (2020 – 45, 2019 – 35, 2018 – 5440, 2017 – 817, 2016 – 242) [15]. About 5090 tonnes of hydrogen can be produced from such amount of electricity (Table 1). In order to assess the capacity of the electrolyser to be installed at the Daugava hydroelectric power plant for processing the remaining electricity into hydrogen, the maximum observed amount of excess electricity per month must be taken. In the reporting period (2016–2020) it was 303 GWh in March 2017, which corresponded to 421 MW of electrolysis equipment (about two times lower if hydrogen compressing, storage and transportation energies are accounted).

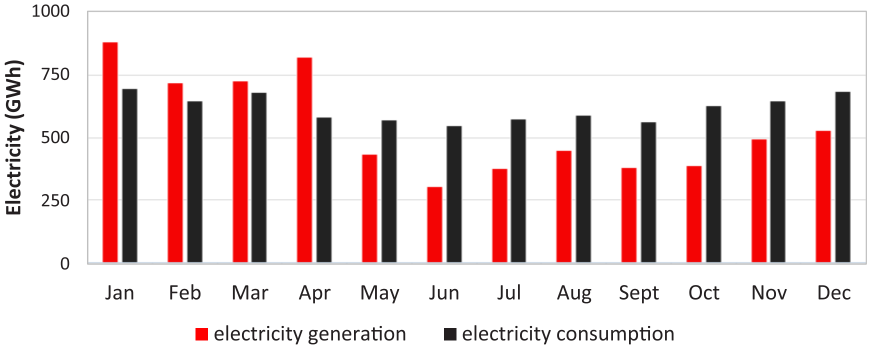

Fig. 1. Total net balance of the Latvian electricity generation & consumption in 2018 [15].

At present, surplus electricity generated by hydropower plants is sold in neighbouring countries, but there are at least two scenarios for using it as an energy carrier themselves:

1. Reversible power-to-gas process (P2G®G2P) – use surplus electricity to produce hydrogen in the electrolysis process, store hydrogen in compressed form in large cylinders or empty underground gas pipes and convert it back into electricity with powerful fuel cell plants in months when less power is produced in hydroelectric power plants to cover consumption deficits;
2. Simple P2G process – use surplus electricity to produce hydrogen in the electrolysis process, store hydrogen in compressed form in cylinders for the gradual injection into the natural gas network with the aim of improving the natural gas combustion process for the end user – to reduce nitrogen oxide and CO_2 emissions.

Solar PV plants. Despite assumption, solar energy can be harvested in Latvia throughout the year, as it was clearly shown by Telicko et al. who investigated the type and orientation influence on the production capacity from an experimental set up. They concluded that orientation losses did not exceed 20 % and currently monocrystalline panels provided more power [16]. This was elaborated empirically by "Saules Darzs" with net capacity of 40kW and initially planned production of 58 MWh. In the first running year, it produced 45 MWh, with average production of 0.477 MWh in winter months and 6.83 MWh in late spring and summer months [17]. As the solar and wind (as well as aforementioned hydro) energy sources are seasonal (in span of days, weeks, months, and years depending on the source), localized hydrogen production and storage systems must be implemented to ensure a steady state hydrogen flow in the gas system. The same conclusion was reached with regard to the evaluation of solar energy use for central heating due to specificity of solar production in Latvia [18].

Wind power plants. Regarding wind energy utilisation in Latvia, firstly, we have to consider availability of this resource. As it has been extensively shown, the highest wind velocities and power are recorded in the western part of Latvia. Winds reach over 7.5 m/s along the Baltic Sea coastline. If we consider 2018 and compare the produced electricity from hydro, wind, cogeneration and solar, we see (as shown in Table 1) that solar and wind energy sources are still not optimum for diverting some amount of electricity for production of hydrogen. Thus, new plants should be built in places where a potential of electricity generation is hight and the produced hydrogen would be available for injection into a gas grid.

Biogas cogeneration plants. In 2018, there were 59 biogas plants with installed capacity of 63 MW in operation in Latvia, used mostly for the production of electricity – 374 GWh in 2018 [14], [17]. This electricity, at least partly can be used for production of hydrogen to participate in biogas upgrading in biomethane through bio-fermentation of local CO_2. Production of biomethane with its subsequent injection into the natural gas grids would be a more cost-effective option in terms of economy and sustainable transformation of the natural gas sector [14].

The distance between the gas networks and the main RES. When considering hydrogen production in Latvia, it is necessary to assess the distance from the local production sites till the gas grid. If the potential hydrogen production facility is located away from the gas grid, the hydrogen is needed to be transported to the injection point.

The main gas grid net stretches throughout Latvia; if we combine possible power sources as wind distribution [20] and available major hydro-powerplants on the map (Fig. 2), we can estimate whether the additional transportation is necessary. It is noteworthy that generally solar production has not major hot spots, as the average solar irradiance can produce 2.72 kWh/m$^2\cdot$ day; on the other hand, the maximum amount is 2.92 kWh/m$^2\cdot$ day, which overlaps with the wind distribution map. In Fig. 2, we see that the main NG network branch Riga-Daugavpils is in very close proximity to larger hydro-power plant Plavinas in the middle of the city of Aizkraukle; therefore, further evaluations should be made in order to assess the potential of direct pipeline connection. The closest point is just beside Plavinas HPP territory – the Gas Regulation Station (GRS) "Aizkraukle" in Jaunberzini, Aizkraukle parish, Aizkraukle district.

As for the wind power, it is not so clear. The main locations of wind farms only partially overlap with Iecava-Liepaja branch. Therefore, if hydrogen is produced from the wind energy in Latvia, the injection in the natural gas grid could be established in Iecava-Liepaja branch. The distance does not exceed 100 km; thus, the most cost-effective and efficient solution for power transportation should be evaluated, which is out of the scope of the present study.

The proximity of biogas plants to the NG grids is shown in [14] – the fourteen biogas plants from 59 can relatively easily be connected to grids (five of them are located less than 1 km, nine are located less than 5 km) [14].

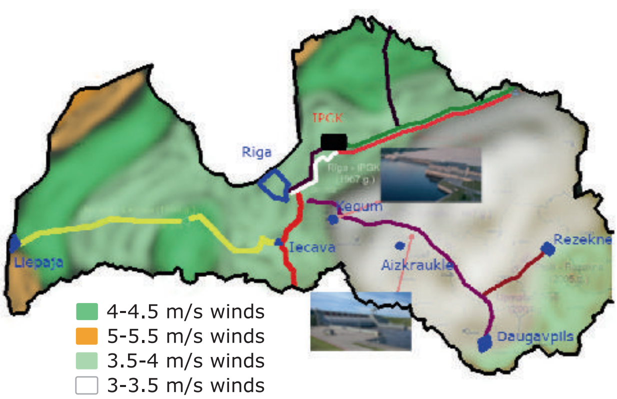

Fig. 2. Wind velocity map overlay and the Latvian gas grid, locations of major cities.

Evaluation of power to produce hydrogen for blending NG networks. It is possible to calculate the necessary hydrogen amount and power consumption of H_2 blending into NG for the needs of the Latvian economy sectors. We chose as an example the total consumption of natural gas in Latvia in 2018 by sector [19], not taking into account the transferred amount across the borders: industry and construction – 139; households – 146; services (commercial and public sector) – 129; agriculture, forestry and fisheries – 8; all together 422 million m^3. Assuming low losses and more than 55 % efficiency of alkaline electrolyzer, results are depicted in Fig. 3. In order to reach the desired blends, substantial amount of power has to be produced that, at this moment, exceeds production availability. Wind power production increases every year, reaching 24 GWh in January 2020 alone. Similar trend can be seen for solar power [15]. However, local power production in Latvia is not zero-sum, as it is not simple to input produced excess power into the national grid. On the other hand, excess power could be converted into hydrogen and injected into NG or stored for later use as backup in combination with fuel cell in some centralised underground storage facilities, which are identified in Zemgale and Kurzeme regions, but that is not within the scope of this paper.

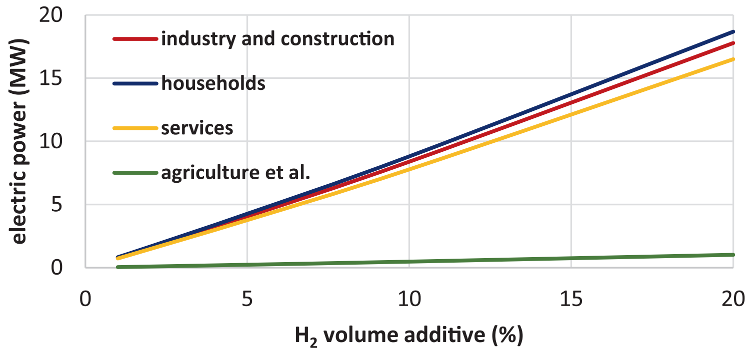

Fig. 3. Hydrogen production power requirements for the Latvian economy sectors considering various possible blends from 1 % to 20 % by volume.

3.2. Evaluations of H_2/NG Blends and Saved CO_2 Emission Amounts

To define the acceptable hydrogen level for each network subzone, it is therefore necessary to establish which of its equipment is most sensitive to hydrogen. Both the tests carried out in European projects (Naturalhy, Ameland) and those in GRHYD show that residential customers' equipment can operate at a hydrogen level of 20 % (or even 30 %), with no loss of production performance and with a reduction in nitrogen oxides and carbon monoxide emissions [12]. As the lower heating value (LHV) of hydrogen is 10.8 MJ/Sm^3 that is less than that of natural gas (35.8 MJ/Sm^3), by adding an amount of hydrogen to the NG the overall flow rate must be slightly increased to keep an initial combustion heat value. It can be easily calculated by summing up the volume fractions. To convert the saved flow of NG to the CO_2 emission amount, we base on the widely used stoichiometric considerations that 1 Nm^3 of NG results in 1.92 kg of CO_2 at complete combustion (Fig. 4).

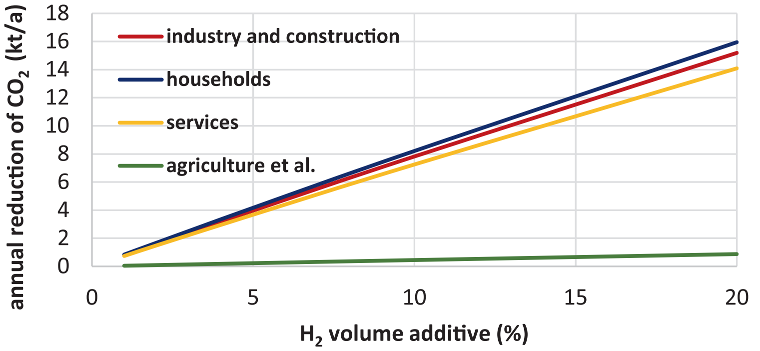

Fig. 4. Annual reduction of carbon dioxide emissions from the Latvian economy sectors using NG in dependence of blending hydrogen amount.

It is a significant amount of CO_2 reduction that can be reached by increasing the potential hydrogen mix in the natural gas system (see total final consumption of natural gas and final consumption by sector in Latvia, million m^3, and savings of CO_2 emissions for end-users – Fig. 4). Thus, to use the HCNG in the distribution system the equipment of end users must be hydrogen proof if concentration exceeds 20 vol% [4], [7].

As one of the options is to only use NG system for hydrogen transportation. A set pipeline system should be used while it is possible to separate the hydrogen from the NG system. This means that separation equipment must be installed prior distribution system network to separate the hydrogen from the NG mix. Solutions currently exist but must mature before they become available at reasonable costs. Separation could also eventually be used to recover pure hydrogen to supply dedicated uses [12]. This means that separated hydrogen could be used for transport applications if it is purified to the 99.999 %. The possibility for hydrogen transportation would allow a potential hydrogen refueling station infrastructure holder to deploy hydrogen refueling stations close to the existing transmission natural gas network and install separation and purifying equipment. Note that the hydrogen transportation using the NG system does not decarbonise the system itself. To decarbonise the natural gas system, the HCNG must be used in end-user applications.

3.3. Operational Aspects and the Allowed Hydrogen Content

One of the aspects that must be considered is the overall gas quality characteristics. The gas quality of the NG distribution system is set in legislative acts. The Regulation Regarding the Trade and Use of Natural Gas includes the overall natural gas quality characteristics and states that the hydrogen allowance in the natural gas mix is ≤ 0.1 mol% [21]. The set amount of hydrogen allowance in the NG mix in the distribution system allows for the end-users to be sure that the installed technological units such as turbines, heating boilers etc. do not have to be "hydrogen-capable" as the overall amount of hydrogen in the mix will not affect the equipment operation.

The usage of NG tubes for hydrogen transportation is already under evaluation in various parts of Europe. In the case of Latvia, the Cabinet regulation "Requirements for the Injection and Transportation of Biomethane and Gaseous Liquefied Natural Gas in the Natural Gas Transmission and Distribution System" sets the overall allowed gas mixture that can be injected in the natural gas system. Note that the allowed hydrogen content in the mix is the previously mentioned ≤ 0.1 mol%. To use hydrogen for natural gas grid decarbonisation, the amendment of the previously mentioned legislative act should be made.

The regulation "Requirements for the Injection and Transportation of Biomethane and Gaseous Liquefied Natural Gas in the Natural Gas Transmission and Distribution System" sets definitions of "base gas", "substitution gas" and "additive gas" [22]:

- "Base gas" is natural gas obtained from natural deposits to be transported in the natural gas transmission and distribution system;
- "Substitution gas" is biomethane and liquefied natural gas converted to a gaseous state which, at the same pressure, temperature and unchanged regulation of the gas appliance, has identical combustion characteristics to the base gas. Substitution gas may be used instead of base gas;
- "Additive gas" is bio-methane the quality characteristics of which differ from the basic gas. When mixing with base gas the required quality can be obtained or mixing with conditioning gas it is possible to get substitution gas.

Firstly, in order to allow the use of hydrogen in the NG networks in Latvia, the determined thresholds of hydrogen should be increased from 0.1 to 20 vol% as it is evaluated in this study. The current allowance does not open the path for NG network decarbonisation. Currently, hydrogen is not set under one of the previously mentioned definitions.

Amendment wise, hydrogen cannot be included in the "substitution gas" as the hydrogen combustion characteristics differ from the base gas. The option is that hydrogen should be included as "additive gas" with reference that "additive gas is biomethane or hydrogen (…)". The amendment is necessary as also with HCNG blend it is possible to reach the quality characteristics.

Thus, in order to make the amendments, different operational aspects must be considered to increase the hydrogen mix in the NG system. This includes the risk of leaks, integrity risks (a problem similar to that of pipes), and malfunctions.

4. CONCLUSIONS

Our evaluation of the current energy grid has put forward the following aspects that need to be addressed. Firstly, introduction of hydrogen into natural gas consumption via blending can lower carbon dioxide emissions. By increasing the hydrogen fraction from 0.1 % to 20 % in the natural gas and hydrogen blend, the carbon dioxide emissions decrease accordingly due to the reduced natural gas fraction from 100 % to 80 %. In the considered household sector, the total annual reduction reaches 52 kilotonnes of CO_2. Secondly, Latvia has an extensive central NG transportation grid connected to neighbouring countries, enabling additional H_2 transportation within Latvia and potentially exporting it. But there are legislative and technical obstacles to the introduction of H_2 at this moment.

The first obstacle – to enable the hydrogen allowance in the NG networks in Latvia, the allowed threshold of hydrogen should be increased from 0.1 to 20 vol%. It would allow using the gas transmission network for H_2 transportation. As the experience of some European countries shows, even without separating hydrogen from natural gas, there would be no impact on end-users and gas infrastructure.

The second obstacle is the inappropriate section of the current NG network for hydrogen transportation (oldest pipes from 1967). These sections must be updated.

The ability of hydrogen injection into NG network as a central storage facility should be further investigated. As the local green hydrogen production stakeholders are slowly gaining momentum, also the natural caves should be evaluated as a potential hydrogen storage facility in Latvia.

About 5090 tonnes of hydrogen annually can be produced from surplus electricity, about 280 GWh annually from the spring floods in the largest river of Latvia, the Daugava, on which three of Latvia's largest hydroelectric power plants are located.

Combination of H_2 production with excess power, introduction in NG network for transportation would allow a potential hydrogen refuelling station infrastructure holder to deploy hydrogen refuelling stations close to the existing transmission natural gas network and install hydrogen separation and purifying equipment, and therefore the produced hydrogen could enable to decarbonise the transport sector.

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A REVIEW: THE ENERGY POVERTY ISSUE IN THE EUROPEAN UNION AND LATVIA

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Energy poverty is a growing concern in the European Union. Following energy market liberalization, the problem of energy affordability has entered the political discussion, making it necessary to estimate its dimensions, develop and implement a policy and means for its mitigation. To evaluate the situation in Latvia, the paper reviews the way energy poverty is currently defined and measured, investigating the advantages and shortcomings of various definitions and approaches. It then provides a brief analysis of energy poverty in three characterising dimensions: low income, high costs of energy services and unsatisfactory housing conditions (primarily related to energy efficiency aspects), using available statistical data. The characterising indicators of energy poverty are compared with the EU average values. Finally, this paper highlights individual policy measures for diminishing energy poverty.

Keywords: *Energy access, energy communities, energy poverty, fuel poverty, renewables.*

1. INTRODUCTION

The availability and utilization of energy have a direct impact on the well-being of society and enable a dignified standard of living as well as full-fledged participation in the life of society. The increase in the prices of energy resources and the impact of the 2007–2010 global financial crisis have affected many people, increasingly exacerbating the issue of energy poverty[1] and protection of the most vulnerable social groups.

Energy poverty is often characterised as

[1] On the whole, the issues related to energy poverty are defined and described by using a number of terms, including the following: fuel poverty, energy insecurity, energy precariousness, energy affordability etc. Still, all of these refer to the inability to obtain energy or meet a certain level of energy needs. The present publication uses the terms “fuel poverty” and “energy poverty” interchangeably.

a situation in which a household or an individual is unable to meet their local energy needs. As a result, there is an adverse impact on the quality-of-life indicators characterising the welfare of the household or the individual and on the energy sector as a whole, as well as such areas as the healthcare, consumption and housing sectors. Reduction of energy poverty is topical not only in developing countries but it has also become a social priority at the EU level.

When looking at the Energy Union Strategy [1], which is based on five mutually complemented and closely interconnected dimensions, namely, (1) energy security, solidarity and trust; (2) a fully integrated European energy market; (3) energy efficiency contributing to moderation of demand; (4) decarbonising the economy, and (5) research, innovation and competitiveness, it can be seen that much attention is devoted to issues related to the reduction of energy poverty and the protection of vulnerable energy users. EU Directive 2019/944 stipulates that *"energy services are fundamental to safeguarding the well-being of the Union citizens. Adequate warmth, cooling and lighting, and energy to power appliances are essential services to guarantee a decent standard of living and citizens' health. Furthermore, access to those energy services enables Union citizens to fulfil their potential and enhances social inclusion. Energy poor households are unable to afford those energy services due to a combination of low income, high expenditure on energy and poor energy efficiency of their homes."* The EU member states have been assigned with the task to estimate the scale of energy poverty, develop and implement policy tools for its reduction.

In the recent years, new smart technologies and methods have been developed and introduced to the market for improving energy efficiency and energy saving, changing the way of energy consumption, providing flexibility to the grid and economic benefits to the energy market players. The potential and impact of the employment of such technologies are also studied in Latvia, e.g., in [2]–[5]. As noted in [6], citizens engaging in the energy community support energy transition and boost social innovation, positively impacting the mitigation of energy poverty and lowering the barriers that stop vulnerable groups from participating in, and gaining benefits from, the energy market.

To evaluate the situation in Latvia, a study was made, which focused on the definition of energy poverty, assessment of energy poverty evaluation approaches and the characterising indicators, as well as the analysis of good practices and policies. The paper is arranged in four sections. The next section provides a background of theoretical studies on the definition of energy poverty, evaluation approaches and the related issues. The subsequent section provides an analysis of energy poverty and the policies and measures to reduce energy poverty are described. The concluding section discusses the importance of energy poverty assessment and energy poverty mitigation instruments, focusing attention on energy communities.

2. THEORETICAL STUDY

2.1. Definition of Energy Poverty

After the 1973 oil crisis and the sharp fluctuations of fuel prices, concerns increased regarding the impact of the availability of energy services, especially the availability of heat and its impact on public health. At that time, the statistical data regarding mortality showed the highest number of deaths in the winter months, which was supposedly due to poor housing in the United Kingdom, which increased the heating bills. During the late 1970s and the early 1980s, the understanding of fuel poverty was developed, defining the concept of fuel poverty [7], [8].

In 1991, Brenda Boardman in her publication provided the first quantitative fuel poverty definition, namely, “the inability to afford adequate warmth because of the inefficiency of the home”, setting a limiting value of 10 % of the household’s income as allotted to energy. This led to the acceptance of a nationwide definition in the United Kingdom: “A household is in fuel poverty if, in order to maintain a satisfactory heating regime, it would be required to spend more than 10 % of its income (including Housing Benefit or Income Support or Mortgage Interest) on all household fuel use” [7]–[9].

In 2013, the definition in England was transformed, using the Low Income, High Cost (LIHC) approach proposed in [10], [11] and a corresponding indicator: a household is considered energy poor if its required fuel costs are higher than the nationwide median value and if meeting these costs results in the household falling below the official poverty line.

As pointed out by [12], [9], the United Kingdom has had a considerable impact on the discussions about energy poverty, influencing both research and policies; this results in focusing on heat comfort, heating being regarded as the most important service while other energy services are discussed less frequently. Yet the lack of other energy services, for example, air conditioning, lighting, transport etc., may have as dramatic effects as those that arise due to lack of heating. It has to be pointed out that the situation has been changing lately and in the discussion of energy poverty, much attention is devoted to energy services overall.

Moore (2012) [13] draws attention to the need to develop the definition further, since it is closely linked to and influences formulation of policies, determination of the scale and nature of the problem, mapping out of the strategy and progress observation. In addition, it is suggested that the definitions of energy poverty be differentiated into ones that are needed for forming national or regional policies and ones that are needed for identifying energy poor households locally.

The research [14] points out that Thomson, upon investigating the use of the terms “fuel poverty” and “energy poverty”, by analysing more than 187 official EU policy documents over the recent thirteen years, finds that preference has been given to the term “energy poverty” (in more than 70 % of the cases). Still, these terms are also used interchangeably in the same contexts. The Directive on the Internal Market for Electricity, which assigns the member states with the task to define more vulnerable consumers, uses the term “energy poverty”, and, according to [14], Thomson concludes that since there are no directions at the EU level, the member states are not sure as to how to act. Up to now, there has been a lack of suitable tools for evaluating the scale of the problem. Moreover, the definition of energy poverty often has a narrower meaning in legal acts (referring only to electricity and gas).

In another study [15], which investigates how energy poverty is understood in Europe and discusses various indicators of energy poverty, this concept is defined as the inability of a household (or difficulty experienced by it) to access the energy it needs to ensure a dignified standard of living at an acceptable price in terms of its income. To introduce such a definition, it is necessary to have a unanimous understanding as to what constitutes a dignified standard of living, adequate heating levels and costs at an acceptable price, and it is possible that this understanding will differ in different member states, although the consequences are the same (energy use ceases, energy bills are not paid, etc.).

Over the recent years, studies [16], [17] have been focusing on developing and implementing a globally applicable definition of energy poverty as "the inability to attain a socially and materially necessitated level of domestic energy services" (the meaning of "socially necessitated" is usually understood as such a standard of energy services that enables a person to fully participate in society whereas the material aspect has to do with effects on health, mental health and well-being). In parallel, the authors of [18] have initiated a detailed discussion regarding the need to consider and evaluate a wider range of [energy] services, looking at how and for what reasons vulnerable households may suffer from energy poverty, using energy for other purposes than heating, how household electronic appliances (for meeting primary needs) influence energy consumption, how that influences the quality of life in various dimensions, as well as revisiting the grouping of protected customers, for example, adding the groups of students or young adults.

The authors of [19] also support a unified EU definition. This study argues that such a definition has an important role and that its introduction would impact three directions: political acknowledgement (better political visibility), fine-tuning (elimination of terminological unclarity) and synergy of policies (links with other spheres), especially at a time when the energy prices are increasing, the wages remain unchanged and concerns are growing as regards energy security and climate change. Likewise, the European Economic and Social Committee (EESC) recommends in its opinion that the European Commission should use a unified term.

Contrary to the arguments in [19], [20] holds that a common EU definition of energy poverty would be problematic and that democratically elected national governments would benefit from choosing their own definitions of energy poverty and policies in this field since there are considerable differences in energy availability. The study [20] points out that before the definition and evaluation criteria of energy poverty are incorporated into policy formation and policy assessment processes, a thorough assessment is needed. As a result of political pressure, policymakers may support the introduction of such policies that ensure greater improvements in official indicators rather than greater improvements in well-being.

A number of studies show that different indicators and the corresponding concepts may be suitable for different tasks in the context of evaluating energy poverty, for example, [21] suggests dividing the policy-making regarding energy poverty into three independent steps: definition of policy goals (this pertains to the choice of the target group, the political feasibility of such a choice and its economic costs), determination of energy poor homes (this pertains to the choice of the household identification process, the choice of identification criteria and the actual identification of the poor households) and implementation of policies (for example, choosing the most appropriate policy measures; direct interaction with the household; an evaluation of the acceptance level regarding the measures, etc.).

It has to be pointed out that in developed countries, energy poverty usually has to do with a lack of energy affordability; it is constituted by a number of issues that preclude consumers from achieving the level of energy services or the level of thermal comfort needed to ensure a normal way of life, which is often regarded as the basic necessary level [7], [9], [22], [23]. On the other hand, in developing countries, energy poverty is usually related to the unavailability of energy and lack of access; the phenomenon has been subjected to a more multi-disciplinary approach, concentrating on the issues of energy availability or unavailability, equitability and investments into sociotechnical systems[17], [22]–[25].

In addition, some groups of authors [18], [19], [26] suggest using the term "energy poverty" in order to discuss problems related to insufficient access to energy services in developing countries and the term "fuel poverty" in order to characterise problems when households suffer from insufficient financial resources to pay for their basic needs in energy services.

The close link between energy poverty and a general lack of income or poverty has made researchers to investigate the "independence" of energy poverty, comparing the basic indicators of poverty with those indicators that pertain to energy poverty.

Addressing such research issues as whether fuel poverty differs from a low standard of living in general, as defined by the modified version of the national basic freedom indicator, or whether the risk factors of fuel poverty differ from the overall risk factors of household poverty, the authors of [27] have found out that the same factors are related to poverty in general and energy poverty. The link between problems in the quality of housing and material deprivation is as strong regarding poverty in general as it is regarding energy poverty. The results of numerical simulation show that the primary cause of a lack of fuel is a lack of resources rather than the housing problem. Energy poverty as measured by the self-evaluation indicator is not primarily related to the energy efficiency of the home but rather to the household's ability to afford an adequate standard of living. The authors conclude that the efforts in solving the fuel problem should focus on factors that cause poverty in general, for example, the ability to gain sufficient income (for example, a low level of education, a lower level of skills, the history of employment or unemployment and such limitations of workforce supply as the need to care for disabled adults or for children).

Contrary to the above, a number of studies point out and show empirically that energy poverty is a problem that is different from poverty in general since the former is sensitive to changes in energy prices and there is a large proportion of capital that is linked to the home and the energy efficiency of its equipment [8], [17], [25], [28]. In addition, the authors acknowledge that energy poverty is a multid-imensional phenomenon, and it is inadequate to judge it only based on low income, supporting the idea that energy poverty means not only a low level of income but inability to meet some kind of elementary basic needs. Still, the definition of these elementary needs is not an easy task [28] and attempts to define them provoking a discussion as to whether these needs mean the provision of a basic level of heating or a relative level of energy that is needed to ensure a healthy life in a certain society.

Summarising the energy poverty definitions of different countries (mainly EU member states) [9], [29], [30], [31], [32], it can be concluded that most studies link this phenomenon to an inability to adequately heat one's home or ensure adequate electric power supply, although in some cases, a wider concept, "energy services", is used. Still, it also has to be considered that disproportionate expenditure in relation to energy exposes the household to the risk of poverty in general. Energy poverty itself is related to low household income, high energy prices/expenditure and a low level of energy efficiency as well as to the way in which the energy is used. This means that energy poverty does not completely overlap with income poverty, although many households with a low level of income are energy poor as well. It has to be pointed out that a number of definitions encompass the concept of energy costs, yet the approaches to determining them are different. In addition, recent research emphasises the need to discuss and evaluate energy poverty not only from the point of view of energy consumption but also by assessing the sufficiency and usefulness of energy.

An equally important issue in relation to the definition of energy poverty concerns the population group that can be regarded as energy poor or vulnerable. In [33], it is pointed out that policymakers prefer energy poverty to be regarded as linked to groups with low income (the way it is reflected in the definitions used in Belgium, the United Kingdom, Austria, and France).

2.2. The Causes of Energy Poverty and its Definition

Although there is no unified definition or methodology, a number of projects and studies have attempted to evaluate the spread of energy poverty in the whole of Europe. As shown before – confirmed by several studies [14], [15], [34]–[36] –, the primary factors or causes that contribute to energy poverty are: a low level of income, high energy prices/costs and a low level of energy efficiency (especially in buildings). As can be seen in Fig. 1, the overlapping areas outline the spheres where there are indicators for measuring these aspects of energy poverty. For example, the type of the heating system as well as the fuel used influences energy consumption and energy efficiency; a high level of energy consumption results in larger energy bills, which has an adverse effect on households with a lower level of income. The energy poverty level of a household depends on the number and dimension of the factors that influence the household.

As can be seen, evaluation of energy poverty is a multi-dimensional problem and requires a combination of a number of indicators in order to obtain a detailed picture of the situation. This is also confirmed by[14], [21], [33]. Likewise, [37] concludes that the determination of energy poverty is a complicated task, although there are indicators (based on statistical data) that could be used for this purpose, such as the inability to maintain an adequate temperature at one's home, the percentage of population that have debts due to arrears on bills, or the number of homes where there are leaking roofs, cracks or other defects that influence the condition of the building.

As indicated in [38], the choice of the evaluation method also depends on whether the fact of energy poverty has to be determined at the European, national or regional level for the purposes of supervision and comparative evaluation, or there is a need for a more precise set of data so as to determine energy poor households or protected consumers for implementing a local policy. Equally important is the issue regarding the availability of the required data and resources to conduct additional empirical calculations as well as policy priorities regarding the determination of those social groups that need support. It has to be added, though, that there are discrepancies between the European-level and national statistical data.

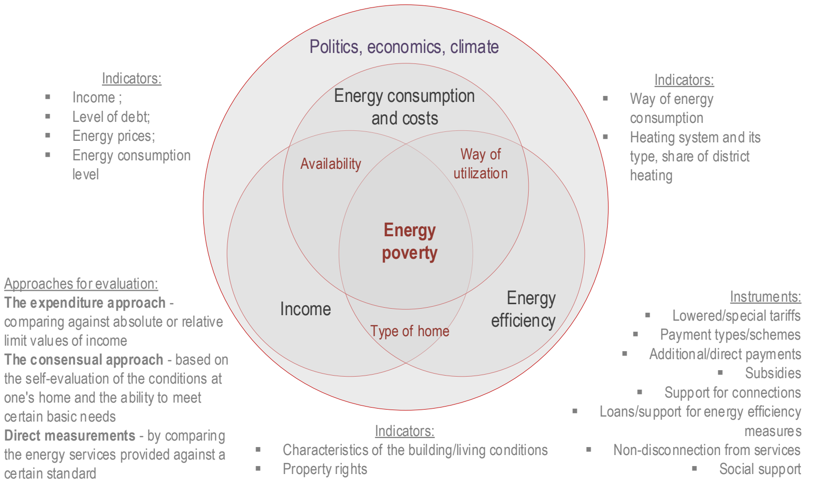


Fig. 1. The causes and indicators of energy poverty (interpretation by the authors, using the results of the Insight_E project [39]).

2.3. Approaches and Measurement Methods for Evaluating Energy Poverty

Three main approaches to the evaluation of energy poverty can be named [9], [38]:

- The expenditure approach: analysis/comparison of how the energy expenditure of different households differs in relation to preset absolute and relative values;
- The consensual approach: collecting the subjective impressions of households regarding the level of energy services achieved at their homes, or collecting the data of self-evaluation regarding the conditions at the homes, which can be used to make indirect judgements about the local degree of lack of energy;
- The direct measurement approach: checking the level of energy services (heating, lighting, cooling, etc.) at the home by conducting direct measurements, and comparing the values obtained with a certain standard.

The Expenditure Approach

This is one of the most widely used approaches. It is based on determining the relation between the energy expenditure of a household and its income. There are the following main methods/indicators to the expenditure approach [40], [41]:

- The Ten-Percent Rule (Boardman 1991, 2009);
- The Double Median or Mean Indicator (Boardman 1991, Hills 2012);
- Low Income, High Cost (LIHC) (Hills 2012);
- Minimal-Standard Indicator (MIS) (Moore 2012).

Some of the main reasons for the popularity of the expenditure approach are its objectiveness and its numerically definable nature, still it also receives a lot of criticism [38]:

- (Faulty) interpretation in other countries has suggested that the methodology is complicated and not easily transferable; the threshold value has to be individually determinable and justified (taking into account the specific conditions in each country) [42], [43];

- The formula-based fixed model for determining the required amount of heating may produce a misleading picture regarding the needs of the household [44]. In [45], it is pointed out that the narrowing of the scope of the causes of energy poverty to low income, insufficient conditions at dwellings and high energy prices fail to account for the significance of energy needs and sociodemographic conditions at the household scale. This particularly concerns people with special needs since, according to the research, they may have increased needs for energy services [11], [46]. Further, in [47] it has been found that some home owners prefer lower temperatures because of reasons other than financial limitations;
- It is difficult to apply this approach on the European scale and the specific contexts of different countries have to be taken into account. For example, in [48] it is proved that special attention has to be paid to the features of district heating systems that are widespread in countries of Central and Eastern Europe, like not allowing individual homes to regulate temperature or time settings.

The Consensual Approach

The consensual approach is based on the relative poverty approach and investigation of the self-evaluation of poverty [49]–[51]. It evaluates the inability of a household to "afford goods that the majority of society regards as basic needs in life". Usually, surveys contain questions about the following: the ability to adequately heat one's home; the ability to pay the utility bills; the presence of corresponding heating equipment; dampness in walls and/or floors; the availability of district heating; rotten window frames etc.

The consensual approach has a number of advantages [38]:

- In this method, it is less complicated to collect data as compared to the expenditure approach (especially for modelling needs); the method is suitable as a temporary measure for evaluating energy poverty in countries where there has been no comprehensive investigation regarding the condition of houses;
- At the European level, there are no standardised microdata regarding the energy costs of households or the condition of houses; thus, by using the coordinated indicators obtained in the EU-SILC investigation, the energy poverty in the EU can be evaluated in quantitative terms;
- This method makes it possible to reach wider elements of energy poverty than those used in determining social exclusion and material insecurity; it is possible to evaluate a person's experience regarding energy poverty and the burden brought about by it; the respondents themselves make their evaluations as to what constitutes adequate heat and comfort levels.

Among the limitations, the subjectivity of indicators can be mentioned; the method is also criticized due to the exclusion error [21], [38], since a household may refuse to acknowledge itself as energy poor, although, if other indicators were used, the household would be in the risk group. In addition, "adequately warm or cool" is a subjective and culturally specific indicator [52], which means that a house that is usually regarded as well-lit and warm in one geographical context may fail to receive this assessment in a different one. Another cause for concern is the level of coincidence between self-evaluation indicators and actual expense indicators, for example, the authors of [53] found out that one-third of the households who stated that they could not keep their living space warm in winter had average or above-average income. This means that if the self-evaluation is erroneous, the person may look poor due to insufficient comfort rather than due to a lack of resources [54].

Usually, this approach is applied (by using the data of the EU-SILC survey) to evaluate energy poverty at the European level, still in some countries, it is also used for investigating energy poverty at a national level.

The Direct Measurement Approach

The direct measurement approach evaluates whether a sufficient level of energy services (heating, lighting, cooling etc.) is ensured at a house, by conducting direct measurements and comparing the values obtained with a certain standard. Additional difficulties lie in the determination of appropriate standards of energy services, which are partly culture-specific.

According to [38], the direct measurement approach is not widely used in the European Union due to technical, practical and ethical issues. As explained in [55], even the temperature measurement approach, which theoretically seems simple, is fraught with problems due to several reasons, mainly because the data regarding temperatures at households are insufficient and are not plausible; also, irregular population density may distort the results if this approach is used. It is also important as to what threshold should be used to signify an adequate heat level, as well as the above considerations regarding people with special needs. Moreover, in those countries where a large number of dwellings are serviced by district heating systems which do not allow individuals to control their heat consumption, for example, in Central and Eastern Europe, temperature is not a good indicator of a lack of energy since the indoor temperatures are "typically adequate, or in cases even too high" [48].

Still, the movement towards smart homes and the introduction of smart meters over the whole of the EU show a future potential of wider use of the direct measurement approach. Besides, the implementation of the Smart Energy City concept establishes favourable conditions for employment of smart technologies and unites the needs of citizens in a sustainable and secure way [56], [57].

3. RESULTS AND DISCUSSION

3.1 An Analysis of Energy Poverty in the EU

Definition of energy poverty and the criteria characterising it are complicated and multi-dimensional; an equally complicated task is to evaluate both the current level of energy poverty in European municipalities and its impact on the life of residents as well as to propose policy instruments to improve the situation.

Evaluating energy poverty according to the data of the Eurostat EU-SILC survey (see Table 1), it was found that in 2019, 7.0 % of all the residents in the EU member states could not keep their dwellings adequately warm, whereas 13.1 % reported problems regarding leaking roofs, dampness in walls, ceilings and foundations or rot in window frames, doors and floors; 6.1 % of the residents had arrears on utility bills. In turn, the proportion of residents whose income was below the poverty line and who were financially unable to keep their dwellings adequately warm was 2.5 times higher (17.8 %) than the total proportion of all the residents with this problem (7.0 %) in the EU countries. A similar situation was observed among the residents (below the poverty line) who had arrears on utility bills: a 2.4 times larger proportion. In turn, one-fifth of the residents below the poverty line live at dwellings with dampness and rot problems. As a positive feature, it should be pointed out that since 2015, all the indicators have been gradually diminishing.

Table 1. Indicators Characterising Energy Poverty (2017–2019) [Eurostat: EU-SILC]

Population share (%)	**EU**	**EU (below poverty line)**	**LV**	**LV (below poverty line)**
Inability to keep home adequately warm – EU-SILC survey [ilc_mdes01]				
2015	9.4	22.7	14.5	29.1
2016	8.7	21.0	10.6	22.7
2017	7.8	18.4	9.7	20.3
2018	7.3	17.9	7.5	15.4
2019	7.0	17.8	8.0	15.9
Living in a dwelling with a leaking roof, damp walls, floors or foundation, or rot in window frames or floor — EU-SILC survey [ilc_mdho01]				
2015	15.2	24.0	24.4	38.7
2016	15.4	24.6	21.9	37.2
2017	13.3	21.1	22.8	35.5
2018	13.9	21.9	23.5	36.5
2019	13.1	20.4	19.3	30.0
Arrears on utility bills – EU-SILC survey [ilc_mdes07]				
2015	9.1	21.0	16.7	30.4
2016	8.1	18.5	13.2	23.3
2017	7.0	16.7	11.9	19.5
2018	6.6	15.7	11.6	19.4
2019	6.1	14.6	8.7	12.2

Upon comparing the indicators in Latvia with the EU average values, it can be concluded that residents in Latvia are more affected by problems regarding dampness or rot at dwellings as well as regarding the ability to pay utility arrears. On the other hand, their ability to keep their dwellings adequately warm is close to the EU average level; among the residents whose income is below the poverty line, the indicator is even better than the EU average.

According to statistics, these problems are most outspoken regarding elderly people, single people over 65 years of age, the unemployed, people who depend on social benefits, etc. The results may be of various kinds: insufficient heating affects hygiene, health (people have to choose whether to eat or live in warmth etc.), mobility limitations affect the employment situation, inability to heat the home or using inadequate heating systems results in an increased level of mortality, excessive debt, social and geographical isolation. Likewise, the author of [8] reports that the most vulnerable groups who are prone to poverty are elderly people, people with disabilities, young children, single parents and people with low income. The problem of a lack of fuel is more widespread in households with low income, who probably cannot afford to heat their dwellings to an adequate degree, especially if the energy prices are high and are increasing and when the dwelling is poorly insulated, thus causing a low fuel consumption efficiency level and, consequently, higher energy costs. As indicated in [8], this is due to a number of reasons: firstly, many low-income households rent their houses and, being tenants, they have no stimulus to invest into the energy efficiency of the houses; secondly, households with low income have more limited access to loans (for example, for the purpose of improving the heat insulation of the house); thirdly, households with low income do not invest into heat insulation improvements because of lacking information about energy efficiency possibilities and schemes and their use. Still, recent research regarding Ireland shows [58] that the relationships between the variable quantities of houses (including the type of dwelling, the age of the dwelling and housing quality problems) and the lack of fuel do not significantly differ from the relationship between the variable quantities of houses and basic deprivation. The results showed that energy poverty was mainly a problem of inadequate resources rather than housing quality, and it was found out that individuals in detached houses (who pay more for heat) were less poor than those who lived in semi-detached or terraced houses. The authors conclude that the prime mover of a lack of fuel is the exceeding number of resources (i.e., income and savings) rather than heating or energy effectiveness costs.

Likewise, mobility is a heavy burden for the budgets of those households who live far from city centres and for whom transport is a precondition for being employed. According to [59], in the EU there are 10,000,000 people who have to walk for more than thirty minutes to reach public transport.

Notwithstanding the absence of a unified definition on the EU level, in some countries various indicators of energy poverty are in place and are used, as well as special rules have been developed regarding the protection of socially vulnerable consumers and support to them, for example, subsidized tariffs, free-of-charge tools (meters that operate on prepayment cards, supply guarantees), paying for the arrears on the utility bills, protection against disconnection of energy services, etc. Because of the large amount of attention devoted to this issue, a considerable academic and political knowledge base has been formed, along with an understanding about energy poverty as a wider inability to ensure a socially and materially necessary end-consumption energy level in a household [52].

3.2. An Analysis of Energy Poverty in Latvia

Up to now, the problems of energy poverty have not received detailed analysis in Latvia, although there are individual policy instruments for diminishing energy poverty. Within a study of the State Research Programme, an analysis of energy poverty along with an evaluation of the situation in Latvia has been made. Taking into account the above considerations and the available data, the analysis was performed using statistical data as well as the indicators recommended by the EU Energy Poverty Observatory (EPOV).

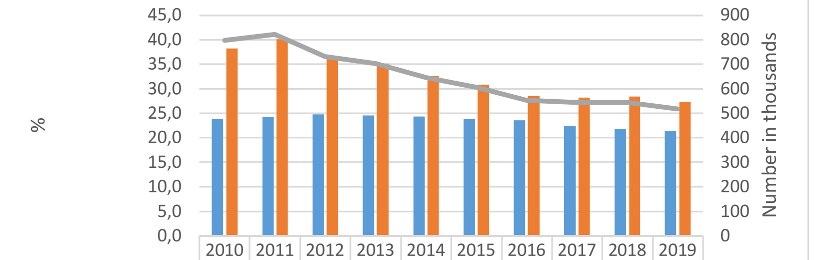
Energy poverty in Latvia has been addressed in three characterising dimensions: low income, high costs of energy services and unsatisfactory housing conditions (primarily related to energy efficiency aspects).

It has to be pointed out that since 2015, Latvia has a completely liberalized electricity market and application of administratively regulated electricity prices in electricity sales to households has been discontinued. In order to mitigate the potential adverse impact of price increases and the additional financial burden on the socially most vulnerable part of society, it was necessary to devise a tool for protecting these users. For this purpose, the concept of a "protected user" was introduced and a compensatory mechanism was formed. The protected user support mechanism defined in the Law on the Electricity Market only applies to support for electricity payments. Therefore, similar support mechanisms should be defined for all energy services. Likewise, a unified system and a compensatory mechanism for diminishing energy poverty should be developed. When defining the group of protected users on the basis of sociodemographic features, an additional criterion should be set, i.e., the income limit, which may differ from category to category, considering their needs.

The Income of Households and Residents

Income is one of the main indicators when analysing energy poverty, as well as an important indicator when evaluating the risk of poverty or social exclusion. Since energy poverty is considered a variety of poverty, it is important to evaluate which groups of people are the most threatened ones in the context of low income.

In Latvia, there is a very high proportion of population (in 2019[2] – 27.3 % or 518,000 people, Fig. 2) who are exposed to the risk of poverty or social exclusion, as well as the proportion of such residents (in 2019 – 22.9 % or 434,000 people) whose disposable income is under the poverty risk line. The most widespread problem is low income as well as uneven distribution of income.



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EU, %	23,8	24,3	24,8	24,6	24,4	23,8	23,5	22,4	21,8	21,4
LV, %	38,2	40,1	36,2	35,1	32,7	30,9	28,5	28,2	28,4	27,3
LV, thousands	798	821	731	702	645	606	554	544	543	518

Fig. 2. People at risk of poverty or social exclusion, number in thousands and their proportion from the whole population (2010–2019); [Eurostat: ilc_peps01].

The groups with the most people exposed to the risk of poverty were the unemployed and retired people, followed by single-parent families with children and lonely persons below the age of 64 as well as multiple children families.

Disposable income is gradually increasing, yet this process is not even, nor equal in all the groups of quintiles of the income. There is a positive diminishing tendency regarding the change in the number and proportion of poor and deprived people.

[2] A difference in data registration: The Eurostat data correspond to the preceding year's data of the Central Statistical Bureau of Latvia

Households' Housing Expenditure

According to the data of the Central Statistical Bureau of Latvia (see Fig. 3), the housing maintenance expenditure has risen by 9.2 % since 2017 and was equal to an average of 150.74 EUR per month in 2019; households spent an average of 12.2 % of their disposable income for these needs. Although there has been an increase in expenditure since 2011 (except for the years 2016 to 2017), its proportion from disposable income is gradually diminishing. The households who spent most for housing maintenance were couples with two children (250 EUR/month or 11.7 % of the disposable income) and multiple children families – 226 EUR/month or 11.5 % of the disposable income. Households consisting of one person spent the least amount of all but the proportion from disposable income was larger (18.7 % – 22.2 %).

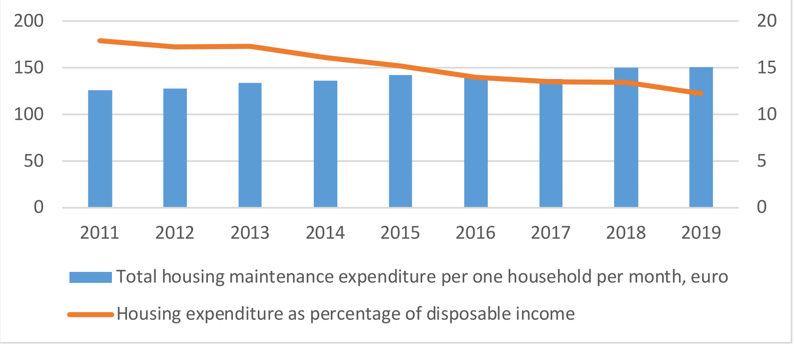


Fig. 3. Housing maintenance expenditure per household monthly and housing expenditure as percentage of disposable income [CSP: MTG050].

The experts interviewed in [60] point out that in the case of Latvia, difficulties may arise from the moment when housing expenditure amounts to as much as 20 % of the household's total income, which is substantiated by the size of the remaining part of the income.

Upon evaluating the indicators of deprivation and housing expenditure, it was found out that on the whole, the deprivation index and the economic stress indicators were falling, still the economic stress indicator was relatively high in the 1st and 2nd groups of quintiles.

As indicated by [60], when determining the proportion of housing expenditure that does not cause financial difficulties for the household, it is important to take into account the average income of the residents of the country in question.

The Ability to Pay for Utility Bills

One of the indicators that characterise energy poverty is the amount of residents' arrears on utility bills. Looking at the Eurostat data regarding residents' arrears on utility bills, it is possible to identify the proportion of households who have had such arrears due to lacking finances. Since 2015 (see Table 1), the proportion of households who have arrears on utility bills due to lacking finances has diminished almost twofold (to 8.7 % in 2019). The decrease has been the largest among households where there is a single adult with children (15.5 %) or an adult under 65 years of age (13.3 %). As can be seen from Fig. 4, among households whose income is below the poverty line, the arrears on the utility bills are highest in the cases of households consisting of two adults and two children (25 %) or an adult under 65 years of age (20.3 %).

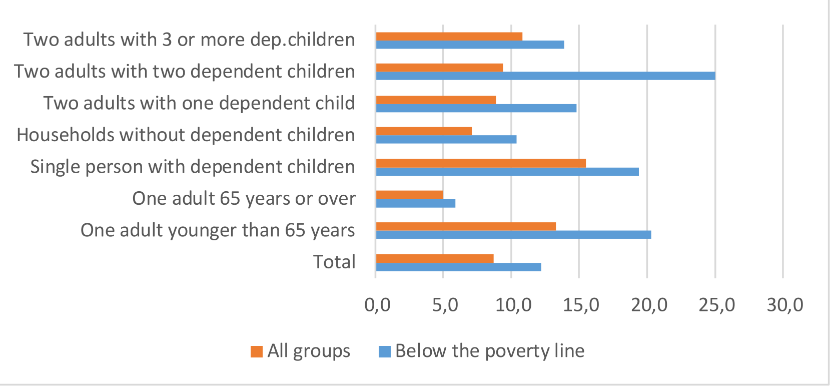


Fig. 4. Arrears on utility bills, % (2018); [Eurostat: ilc_mdes07].

Although housing expenditure is a heavy burden for households consisting of one old-age person, still these households are mostly capable of paying for their utility bills, including those households whose income is below the poverty line.

According to the results of the survey of experts published in [60], looking from the point of view of inequality as regards affordability of housing, the experts pointed out that "one important problem consists in the housing costs for those population groups for whom they make up more than 20–30 % of the total income of the household".

The Financial Ability to Maintain the Home Adequately Warm

The financial ability to maintain one's home warm is one of the criteria that characterise energy poverty. This indicator can be discussed both from the point of view of residents and from the point of view of dwellings. In addition, special attention has to be paid to analysing the housing resources and conditions.

The statistical data in Table 1 show that since 2015, the proportion of the residents who have difficulty in keeping their homes warm has decreased 1.8 times, falling to 8 % in 2019, which is close to the EU average (7.0 %). The tendency is similar among residents whose income is under the poverty line: an almost twofold drop since 2015, reaching 15.9 % in 2019.

As shown in Fig. 5, the households most affected by this problem are those consisting of one adult above 65 years of age (17.2 %), one person with a child (14.1 %) and one person up to 64 years of age (11.8 %). The proportion of the single persons aged over 65 whose income is below the poverty line and who are financially unable to keep their homes adequately warm is almost twice as high (17.2 %) as the overall proportion of households (9.7 %) with this problem.

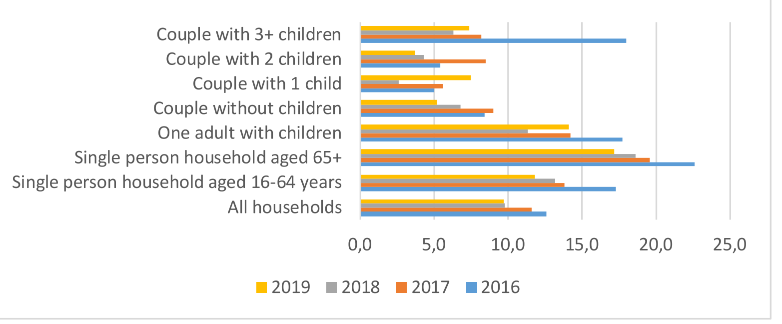


Fig. 5. The proportion of households that could not afford to meet certain expenses to keep their homes adequately warm due to the lack of finances (%) [CSP: MNG010].

Unsatisfactory Housing Conditions

Problems related to leaking roofs, dampness or rot have a direct impact on energy efficiency and thus also influence the energy poverty situation. According to the data of the Central Statistical Bureau of Latvia, the proportion of residents whose households have unsatisfactory housing conditions is gradually diminishing. An analysis from the point of view of households (see Fig. 6) shows that in 2019, this problem was most frequent in households consisting of one adult with a child (27.4 %), as well as those consisting of one adult (19.7 and 18.6 %). This problem especially affects households with lower income.

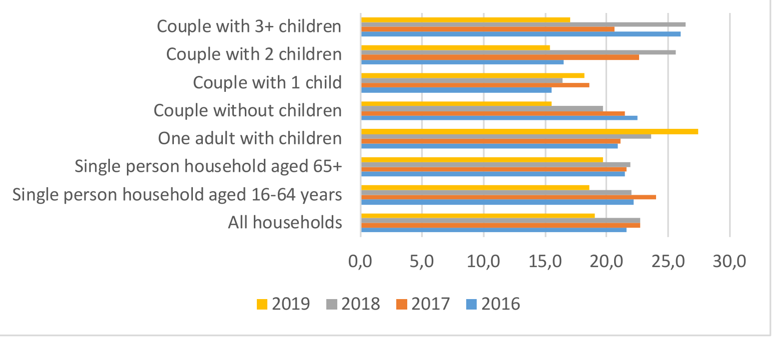


Fig. 6. The proportion of households that reported a leaking roof, damp walls/floors/foundation, or rot in window frames or floor, % [CSP: MNG050].

In order to develop measures for improving the energy efficiency of dwellings and thus fighting energy poverty, it is important to evaluate the conditions of the housing resources and houses. As has been indicated in the 2018 annotation to the initial impact evaluation report for the draft law "Amendments to the Law on Assistance in Solving Housing Issues", which is based on data from the State Cadastre Information System, the current housing resources are considerably outdated, which increases the maintenance costs and, if the income of households does not increase, shifts the renewal prospects to a more distant future. 45 % of multi-flat houses in Latvia were built until the year 1941 and 53% of the housing resources were built from 1961 to

1992. From 1993 to 2014, the proportion of new multi-flat houses was only 2 %. The renewal of the multi-flat housing resources is very slow in Latvia; only 0.2 % of the flats are built annually.

According to the data of the Central Statistical Bureau [MTG030; MTG020], the bulk of the households in Latvia (62.8 %) live in multi-flat houses with ten or more flats; 26.6 % live in a detached house or in an individual farmstead. In 2019, the average area of one dwelling was 69.7 m^2, with an average of 2.7 rooms, 1.2 rooms per household member.

3.3. Policies and Good Practices for Diminishing Energy Poverty

Defining energy poverty and its characterising criteria is a complicated and multi-dimensional task; an equally complicated task is to evaluate both the current level of energy poverty in European municipalities and its impact on people's lives, and to offer policy instruments for improving the situation.

According to [61], one of the departure points of the energy poverty exposedness approach is the understanding of the fact that those households that are, at a certain time moment, characterised as "poor from the point of view of energy services" may cease to be such if some conditions change; on the other hand, energy poverty may affect households that are not characterised as energy poor at the moment of their discussion. In order to help households to get out of energy poverty, different policy tools, measures and support mechanisms are developed and implemented. As indicated by the EESC, the main goal of such measures is to make the exposed consumers active solvers of their energy issues so that their consumption should diminish yet become more effective since that would improve the quality of their lives. In those cases when it is economically useful and technically feasible, decentralised energy production from renewable sources is supported. Information, instruction and education may help households to become aware of the problems encountered and to take correct action (to switch off equipment that is in standby mode; to choose energy-efficient equipment; to provide the necessary repairs, etc.).

As mentioned above, the problem of evaluating and diminishing energy poverty is complicated and multi-dimensional and it affects a number of different spheres. This has aroused wide discussions at the EU level, contributed to transfer of knowledge and development of various tools for addressing energy poverty. The main measures are shown in Table 2.

Table 2. Good Practice Instruments and Measures for Diminishing Energy Poverty

Financial measures	**Consumer protection**	**Orientation towards market**	**Energy efficiency of buildings**
Earmarked grants General social support Subsidized tariffs set	Safety measures against disconnection Consumers' complaints Awareness-raising campaigns and dissemination of information Direct supplier	Objective and proved price comparison tools Codes of ethics Modernized subsidies, loans or tax relief	Energy efficiency standards Support from energy companies for the energy efficiency of low-income residents Subsidies for appliances

Notwithstanding the fact that it was only in 2020 that the concept of energy poverty was officially defined in Latvia and there was no methodology for its calculation. Individual measures have been defined and incorporated into normative acts that are directly or indirectly aimed also at diminishing energy poverty and protecting vulnerable users: support for electricity payments; support for setting up connections to the electricity grid; housing benefits; an energy efficiency programme; a guaranteed minimum income level; an energy efficiency obligation scheme; the Elektrum energy efficiency centre and the Dzīvo Siltāk (*Live Warmer*) activity.

It should be noted that recently (in 2021), changes regarding energy poverty have been implemented in the Energy Law in Latvia. According to it, a household is considered energy poor if:

1. It has been pronounced a low-income or poor household and receives material support for meeting the expenses related to the use of the housing;
2. It is renting housing or a public welfare flat owned by the municipality or rented by it, according to the law "On Help in Housing Issues" or the law "On Public Welfare Flats and Public Welfare Houses".

The official statistics of the Ministry of Welfare regarding social services and social welfare support show that the number of recipients of housing support gradually dropped from 113 018 persons in 2015 (5.7 % of the total population) to 70 954 persons in 2019 (3.7 % of the total population). Overall, the number of housing support recipients has dropped by 37 % whereas the amount of financial means used for the housing support has diminished by 25 % (from EUR 18 390 069 to EUR 13 769 163), and the average size of housing support has increased by 19 % (to EUR 194.06 in 2019).

In Latvia, housing support can be received by poor or low-income persons; the size, type and granting criteria of this support are determined by the municipalities. As a result, different municipalities use different criteria for determining an income level that corresponds to the status of a low-income person; moreover, the procedure for estimating these levels is unclear. This problem is also highlighted by [60]: "the lack of unified criteria leads to a situation when persons in similar financial and social conditions are entitled to different levels of support both on the municipal level and on the national level". Such differences can even be present across the same region, for example, a person with an average monthly income of 350 EUR (in 2018) was entitled to support in Jekabpils, whereas a person living in Daugavpils or Rezekne (in the same Latgale region) with the same size of income could not receive this support since the 2018 average income limit for granting low-income status was 344 EUR in Daugavpils and 272 EUR in Rezekne. To address this issue, the further changes of laws and regulations are planned.

3.4. Energy Communities and their Role in Diminishing Energy Poverty

In order to reach the 2030 and 2050 energy and climate change mitigation goals, the central role has been appointed to the use of renewable energy sources. In addition, the market liberalization, departing from the traditional monopoly, has contributed to the inclusion of more competitive and innovative participants into the energy market. Energy communities represent one type of such new participants. The Clean Energy Package defines citizen energy communities (Internal Electricity Market Directive (EU) 2019/944) and renewable energy communities (Renewable Energy Directive (EU) 2018/2001).

As indicated in [6], the introduction of the initiative of energy communities contributes to the start of new energy services and activities, from renewable generation to investments into electromobility services. Energy communities may use a variety of legal forms. They can both engage in traditional activities and implement new entrepreneurship models. Usually, they are small resident-led initiatives in the form of a cooperative, connected with renewable energy generation activities. Yet, as pointed out in [6], more and more energy communities have taken on new functions of energy service providers: generation (collectively using or owning generation assets); supply (the sale and resale of electricity and gas; engagement in aggregation activities, etc.); consumption and sharing (individual and collective self-consumption; local sharing of energy within a community); distribution (ownership and/or management of community-run distribution networks); energy services (energy efficiency or energy savings; flexibility, energy storage and smart grid integration; energy monitoring and energy management; financial services); electromobility (car sharing, car-pooling and/or operation and management of charging stations, or provision of e-cards for members and cooperatives); and other activities (consultation services, information and awareness-raising campaigns, or fuel poverty measures). In this way, energy communities can help implement local sustainability projects, contributing to energy independence, diminishing carbon emisisons and energy poverty, as well as boosting local economies.

As shown in [6], energy communities diminish energy poverty, increasing the energy efficiency on the household level, reducing consumption and supply tariffs, for example, by supporting solidarity foundations and donating certain amounts from every consumed kilowatt-hour; by donating the overproduced energy amount, jointly meeting the energy service costs of the vulnerable users or diverting part of their profits to poverty mitigation.

4. CONCLUSIONS

Energy poverty is a new social priority. To define it, several characterising criteria need to be used: low income, large expenditure for energy services and housing quality in terms of energy efficiency. The definition of energy poverty is especially important for policy formulation; it impacts the scale and nature of the problem, as well as constant supervision and mitigation solutions.

Most good practices and measures implemented in individual EU member states concentrate on causes, for example, energy prices (for example, the "subsidized tariffs"), the quality of buildings (for example, improvement of energy efficiency in state-owned and private housing), low income (for example, financial support). Similarly, in some member states there have been corrective measures for mitigating the effects of energy poverty, for example, by forbidding disconnection of power supply services to more vulnerable families at critical moments.

To analyse and compare energy poverty in the European Union and Latvia, the following main indicators of the Eurostat EU-SILC survey have been used: inability to keep home adequately warm; living in a dwelling with a leaking roof, damp walls, floors or foundation, or rot in window frames or floor; arrears on utility bills. Since 2015, the proportion of the residents who have any of the mentioned difficulties has decreased both in the EU and Latvia. The tendency is similar among residents whose income is under the poverty line. However, in 2019 residents in Latvia were more affected by problems regarding dampness or rot at dwellings, this indicator (19.3 %, LV) was higher than the EU average (13.1 %) and almost equal to the EU level below the poverty line (20.4 %), households with lower income (30.0 %) were especially affected. On the other hand, the ability to keep homes adequately warm is close to the EU average level (7 % in the EU, 8 % in LV); among the residents whose income is below the poverty line, the indicator is even better than the EU average (17.8 % in EU, 15.9 % in LV). A similar situation was observed among the residents (below the poverty line), who had arrears on utility bills (14.6 % in the EU, 12.2 % in LV).

According to statistics, the most affected groups are elderly people, single people over 65 years of age, the unemployed, people who depend on social benefits, etc., resulting in an increasing level of inability to heat the home or using inadequate heating systems, health issues, unemployment, excessive debt and even mortality.

One of the main measures to diminish energy poverty in Latvia is housing support (for poor or low-income persons). In 2019, the number of recipients of housing support was 70 954 persons (3.7 % of the total population), whereas the amount of financial means used for the housing support was EUR 13 769 163 (an average of EUR 194.06 per person).

The initiative of energy communities fosters both technological and social innovation, as well as the introduction of socially more equitable energy prosumership models, thus diminishing energy poverty.

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