RIGA TECHNICAL UNIVERSITY

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DESIGNING REGULATORY FRAMEWORK FOR DEMAND RESPONSE SERVICE INTEGRATION IN BALTIC ELECTRICITY MARKETS

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DECLARATION OF ACADEMIC INTEGRITY

I hereby declare that the Doctoral Thesis submitted for the review to Riga Technical University for the promotion to the scientific degree of Doctor of Science (Ph. D.) is my own. I confirm that this Doctoral Thesis had not been submitted to any other university for the promotion to a scientific degree.

Līga Kurevska ……………………………. (signature)
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The Doctoral Thesis has been written in English. It consists of an Introduction; 4 Chapters; Conclusion; 28 figures; 19 tables; 10 appendices; the total number of pages is 132, including appendices. The Bibliography contains 101 titles.

ABSTRACT

Mitigating climate change is professed to be one our generation’s greatest challenges, however, similarly to many public goods where benefits are enjoyed by many while the costs are born by few, finding a balance between the pace of the change and cost borne by society is not an easy task. The energy strategy initiatives proposed by both EU and other supranational policy makers are determined to lead the world towards stronger reliance on renewable energy sources and improved energy efficiency. The new requirements, objectives, and investment opportunities has created a space for emergence of new technologies and increased availability of previously prohibitively expensive ones. On top of the sheer pace of new technology uptake and the resulting dynamic changes in the industry, the policy makers also must evaluate the least cost to ensure naturally conflicting objectives – technical system reliability, uptake of new, climate-neutral technology and low energy costs.

The objective of this thesis is to develop and assess appropriate proposal for the main components of regulatory framework to facilitate demand response service development and promote non-disruptive end-user engagement in energy transition. The research includes developed taxonomy and decision-making algorithm based on which a policy maker can evaluate the best set for market participant roles and responsibilities within given market conditions as well as proposal for Baltic electricity markets. Furthermore, comparative analysis of alternative consumption baseline data using real electricity consumption data as well as a proposal on transposing metering data from hourly to 15-minute time resolution. The research also examines potential impact demand response services might have on the electricity price as well as financial benefits demand response asset holder might have from participation in either implicit or explicit demand response services. The tools developed during the research as well as the findings can support policy maker in developing market regulation and decide on necessity for additional stimulus to accelerate the pace of demand response service participation in electricity markets.

ANOTĀCIJA

Klimata pārmaiņu mazināšana tiek uzskatīta par vienu no mūsu paaudzes lielākajiem izaicinājumiem un tā pārvarēšanā būtiski atrast līdzsvaru starp globālu pārmaiņu ieviešanas tempu un izmaksām, kas jāsedz sabiedrībai. Enerģētikas stratēģijas iniciatīvas, ko ierosinājušas gan Eiropas Savienības, gan citu starptautisku organizāciju politikas veidotāji, ir skaidri iezīmējušas mērķi palielināt atjaunojamo enerģijas avotu īpatsvaru un uzlabot energoefektivitāti. Jaunās prasības, mērķi un atbalsta finansējuma iespējas ir radījušas iespēju jaunu tehnoloģiju attīstībai un veicinājuši šo tehnoloģiju pieejamību. Papildus jauno tehnoloģiju apguvei un no tās izrietošajām dinamiskajām izmaiņām nozarē politikas veidotājiem arī jārod veids, kā sabalansēt sistēmas tehnisko drošību, jaunu, klimatneitrālu tehnoloģiju ieviešanas veicināšanu un zemas enerģijas izmaksas.

Šīs disertācijas mērķis ir izstrādāt priekšlikumu atbilstoša nozares regulējuma galvenajām komponentēm, kuras veicinātu pieprasījuma reakcijas pakalpojumu attīstību un veicinātu galalietotāju iesaistīšanos klimatnetralitātes mērķu sasniegšanā. Pētījums ietver tirgus darbības modeļu taksonomiju un algoritmu, pēc kura vadoties politikas veidotājs var noteikt optimālu tirgus dalībnieku lomu un pienākumu kopumu konkrētajiem tirgus apstākļiem, kā arī priekšlikumu tirgus darbības modelim Baltijas elektroenerģijas tirgos. Papildus pētījumā ietverta alternatīvu patēriņa bāzes aprēķinu modeļu salīdzinošā analīze, izmantojot faktiskus elektroenerģijas patēriņa datus, kā arī priekšlikums par patēriņa uzskaites datu pārnešanu no stundas uz 15 minūšu laika izšķirtspēju. Pētījumā arī aplūkota pieprasījuma reaģēšanas pakalpojumu iespējamā ietekme uz elektroenerģijas vairumtirgus cenu, kā arī finansiālie ieguvumi, ko pieprasījuma reakcijas pakalpojuma sniedzējs var iegūt sniedzot tiešus vai netiešus pieprasījuma reakcijas pakalpojumus. Pētījuma laikā izstrādātie rīki, kā arī gūtie secinājumi var palīdzēt politikas veidotājam izstrādāt tirgus regulējumu un kā arī izvērtēt nepieciešamību ieviest papildu stimulus pieprasījuma reakcijas pakalpojumu attīstības tempa veicināšanai.

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INTRODUCTION

Background and relevance of the research

Mitigating climate change is professed to be one our generation's greatest challenges; however, similarly to many public goods where benefits are enjoyed by many while the costs are born by few, finding a balance between the pace of the change and cost borne by society is not an easy task. The Paris Agreement under the United Nations Framework Convention on Climate Change, which as of April 2017, has been ratified by 145 countries (including the Baltics) [1] and European Commission's "Clean Energy Package" published on 30 November 2016 [2] have already shown that the global policy makers are determined to lead the world towards stronger reliance on renewable energy sources and improved energy efficiency. This global trend is cemented even more within the newest set of European Commission policy initiatives under the umbrella of The European Green Deal which aims to make Europe climate neutral by 2050.

The objectives of The European Green Deal effectively cover wide range of economic activity starting from waste reduction, reforestation, transportation, and sustainable farming. However, energy sector is at the center of it. It is estimated by the policy makers that the energy sector is responsible for approximately 75 % of greenhouse gas emissions. The new requirements, objectives, and investment opportunities have created a space for emergence of new technologies and increased availability of previously prohibitively expensive ones.

The combination of the aforementioned conditions causes a fundamental paradigm shift in global legal framework, the energy sector experiences emergence of new products and services. Firstly, the continuous increase of energy system decentralization and higher reliance on less-controllable/ predictable intermittent generation requires redefinition of the roles and interdependencies of the energy system actors. Secondly, considerable increase in active energy users (prosumers) creates the demand for secondary services (technical, operational, financial support services). Thirdly, the rapid change in the fabric of the industry creates new challenges to system operators regarding technical, operational and pricing (tariff) aspects.

On top of the sheer pace of new technology uptake and the resulting dynamic changes in the industry, the policy makers also have to evaluate the least cost to ensure naturally conflicting objectives – technical system reliability, uptake of new, climate-neutral technology, and low energy costs.

Technical system reliability

The reliability of electric power system operation depends on the balance between power production and consumption [3]. To achieve this balance, every grid connection point needs to be accounted for [4]. Traditionally, this is managed by dividing the system in multiple imbalance areas each having a market participant, which is financially responsible for ensuring that all energy generated within the area is sold and all energy consumed within the imbalance areas is bought. These market participants are called balance responsible parties (BRPs). BRPs ensure the balance by forecasting demand and supply of energy within their imbalance areas and ensuring according energy trades via day-ahead and intraday markets.

When BRPs fail to forecast demand and supply accurately, it can result in excess/deficit energy in the power system. Forecasting errors are corrected in real time by transmission system operators (TSOs) via balancing market. Ensuring sufficient balancing energy reserves is pivotal to TSOs, as without them the power system balance cannot be maintained, which, depending on the interconnections to other power systems, can result in costly procurement of balancing energy from other control areas or in adverse system frequency fluctuations.

The costs of power system balancing are covered by the imbalance payments from those BRPs whose actual consumption/generation deviate from the forecast. Accordingly, the costlier balancing energy is, the more expensive penalty payments for forecasting errors are and consequently the costlier energy in retail markets becomes. The main driver for high balancing prices is balancing resource scarcity. Currently, in the Baltics, only electricity producers provide balancing resources. Furthermore, since the opening of the Common Baltic Balancing market and subsequent increased reliance on national balancing resources (instead of balancing energy resources from Russian TSO), we can observe preliminary indications of balancing resource scarcity [5].

Furthermore, according to the Baltic generation adequacy report, it is expected that during the next 10–15 years the capacity required for balancing reserves will increase due to rising intermittent generation and the planned Baltic power system desynchronization from UPS/ISP. At the same time, the generation from some of the sources typically used for balancing purposes in the Baltic states (thermal power plants in Estonia) will reduce by up to 50 % due to lost competitiveness of oil-shale power plants caused by the increasing costs of SO_2 and NO_2 emissions [5].

This gives clearly indicates that additional sources for balancing reserves are needed. Demand response (DR) is a promising source of balancing energy to consider. DR integration in balancing energy markets can provide significant financial savings for grid operators and market participants and promote optimal resource allocation [6]. Some large consumers in the Baltic states have already expressed preliminary interest in providing services to the TSOs. However, to facilitate DR participation in power system balancing, the service must provide economic gains for both the existing market participants and DR service providers. From the policy makers' point of view, the reliability of the power system is pivotal for functioning economy and must not be jeopardized or experimented with.

Facilitating uptake of climate neutral solutions

While availability of technology is a necessary precondition for behavioral changes in society, the opportunity itself is not sufficient for overall societal change. Based on the research, most rational market actors choose to engage in new initiatives based on three main considerations – the weight of financial and social benefits against administrative and organizational burden. A well-functioning regulatory framework would promote such technologies and consumer and supplier behaviors that generates more social wealth than the cost of introduction and maintenance of the said policies. On the contrary, poorly designed regulatory framework can promote inefficient allocation of resources by either over-subsidizing certain activities or promoting private investment that depletes the investors' wealth.

Low energy costs

The cost of electricity consists of three main components – cost of resource (in Latvia, electricity price constitutes approximately 40 % of the total costs); cost of maintenance and development of the infrastructure necessary to transport electricity (in Latvia, grid services constitute approximately 30 % of the total energy cost); and taxes and levies (in Latvia value added tax and mandatory procurement component together constitute approximately 30 %).

While the long run marginal cost of producing electricity from renewable sources decreases over time due to technological advancements, the increase in intermittent and distributed generation as well as continuous increase in demand for electricity not only promotes volatility 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 [7] and percentage of residential consumers with rooftop solar panels reached 25 %. Such shift reduced electricity volumes consumed through distribution system but did not have considerable impact on the costs of the system, the volume-based distribution system tariffs increased by 112 % [8]. This illustrates that poorly designed or insufficiently flexible pricing strategy for system services can result in undesired consequences. With the emerging preference for electric transportation as well as electricity-based heating, ventilation and cooling systems, the demand for electricity has increased the tendency to cluster in high and low demand periods, which typically results in peak load demand outpacing overall increase in annual consumption. These trends continue to add further price pressures to the electricity and power system alike.

The potential of demand response

When considering alternative instruments for increasing system flexibility via climate and cost friendly solutions, one of the instruments is a product/service category broadly referred to as 'demand response'. According to the Federal Energy Regulatory Commission, demand response (DR) is defined as: "*Changes in electricity usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized*". DR can be broadly divided into two groups: implicit DR and explicit DR. Implicit DR ('price based' DR) refers to consumers choosing to be exposed to time-varying electricity prices and/or time-varying network tariffs that reflect the real cost of electricity at the time of use and allows the consumers to react to that price depending on their own preferences. Explicit DR refers to a program where demand competes directly with supply in the wholesale, balancing and ancillary services' markets directly or through the services of aggregators.

As discussed in [9]–[11], demand response is able to increase the system's adequacy and to substantially reduce the need for investment in grid development and peaking generation by shifting consumption away from times of high demand, as well as act as a cost-effective balancing resource for variable renewable generation. Adding stability to the system, it lowers the need for traditional and often ineffective sources of energy. It furthermore decreases the need for local network investments, as it shifts consumption away from peak hours in regions with tight network capacity [11]. DR delivers these benefits by providing consumers – residential, commercial, or industrial – with control signals and/or financial incentives to adjust their consumption at strategic times and by doing so promotes consumer engagement.

While there seems to be a consensus on the need for the energy sector to introduce and integrate DR in energy markets, the preferred choice of the market framework enjoys far less unambiguity both from policy makers' and industry representatives' point of view [12]–[19]. For example, in Austria the DR provider (incl. aggregator) has to agree bilaterally on data exchange and transfer pricing with the BRP before flexibly providing service to its customer; while in Switzerland the DR provider does not need such an agreement with the BRP, it has to compensate the BRP at transfer price determined by TSOs. Furthermore, in Ireland neither BRP nor aggregator is charged for the imbalance created [12], [13], [15]. Due to the increased role of DR and independent aggregator proposed in the European Commission "Clean Energy Package", the Member States have restarted discussion on the integration of DR in their respective energy markets with increased urgency. However, as mentioned above, when introducing new regulatory framework, considerable analysis is necessary to avoid loss of social wealth.

Hypothesis, objective and tasks of the Thesis

Hypothesis

By developing appropriate regulatory framework, the demand response services can provide a cost and energy efficient tool for improving system flexibility and mitigate resource price and system price volatility driven by increase in intermittent generation in the Baltic region.

Objective

To develop and assess an appropriate proposal for the main components of regulatory framework to facilitate the demand response service development and promote non-disruptive end-user engagement in energy transition.

Tasks

1. To develop compensation framework and determine roles and responsibilities between the demand response service provider and other market participants.
2. To develop methodology for estimating the volume of energy transferred in the event of demand response.

3. To evaluate and test the impact the demand response could have on electricity markets in the Baltics.
4. To evaluate and test potential financial benefits for the demand response asset holders' from engaging in explicit or implicit demand response.

Research methods and tools

Research studies presented in the Doctoral Thesis were performed employing various bespoke modelling tools and algorithms developed in-house at the RTU Institute of Power.

When modelling the different future scenarios (Chapters 2 and 3), MATLAB was employed to prepare the input data by scaling and adjusting the data according to the scenario assumptions. Furthermore, validation and analysis of the results obtained was performed in Excel. For solving optimization problem of the AOF parameter search tool presented in Chapter 3, MATLAB scripting environment and Global Optimization Toolbox was used to take advantage of its data processing abilities and solver *patternsearch.*

Monte Carlo simulation-based tool *DR Assess* tool employed in the case study presented in Chapter 4 was developed using the MATLAB scripting environment. To make it usable for any interested person, a stand-alone application was compiled, which can be deployed on a standard computer with the royalty-free MATLAB Runtime environment.

For testing and comparative analysis, data sets from NordPool, Elering AS, JSC "Augstsprieguma tīkls", SKM Market Predictor, and Latvian Environment, Geology and Meteorology Centre and specially obtained case study data were used.

Scientific novelty

To facilitate the demand response participation in any of the electricity markets, an algorithm for assessing the volume of electricity transferred is necessary. Considering the metering and market particularities in the Baltic region, alternative algorithms were tested on real metering data on randomly selected energy consumers based on three criteria – simplicity, accuracy, and robustness. From the four potential consumption baseline models analyzed the best performing model was identified. Furthermore, to tackle the issue of expected changes in imbalance settlement period (switching from hourly to 15-min periods), alternative interpolation methods on wind forecasting data were compared and the most precise one was identified. The results of the research assessing the volume of electricity transferred provide concrete assessment of the best performing algorithms in the context of Baltic energy markets.

Regarding compensation methodology a comprehensive overview of models employed in the European Union was reviewed and analyzed for their suitability for Latvian legal and market environment. The combination of integrated and centralized model was deemed to be the most appropriate. The proposal has been now partly introduced in national legislation.

To research how demand response would impact energy prices, two main markets were examined – the Baltic balancing market and the Baltic day-ahead market. For the needs of balancing market examination, the following assessments were made. Firstly, to facilitate optimal activation of balancing resources by the transmission system operator, a bespoke tool, AOF parameter search, has been developed. It includes a complex algorithm mimicking the activities of a TSO dispatch operator in ordering mFRR products to sustain the power system balance. For further assessment several mathematical models were used in order to assess the cost-benefit analysis. On the other hand, to assess the impact on the day-ahead market, multi-factor analysis of the day-ahead price determination was performed.

To evaluate the costs and benefits from demand side services for the asset owners, firstly, a demand response assessment tool has been developed. It is based on Monte-Carlo simulations to properly consider the uncertainties characteristic to electricity markets and provide probabilistic results on benefits the end-user can gain through provision of explicit DR to the market or via implementing implicit DR. While the tool has been tailored for the Latvian case, considering the existing common Baltic balancing market and Nord Pool day-ahead market frameworks, it could be easily applied also to other case studies with similar market setup. Furthermore, in 2020 the financial benefits from participation were tested in real-life environment based on heat-pump system. The alternative assessments provide a more transparent evaluation.

Practical significance of the research

Practical significance of the research studies carried out by the author during development of the Doctoral Thesis have contributed to several research and innovation projects. Listed below, they include not only national and international scientific projects but also contract work for a major industry stakeholder.

1. Research contract "Development of mathematical models for an economic assessment of demand-side flexibility resources and activation optimization of balancing reserves" (2017–2018), commissioned by "Augstsprieguma tīkls" JSC (the Latvian TSO).
2. Project "Management and Operation of an Intelligent Power System (I-POWER)" (2018–2021), funded by the Latvian Council of Science.
3. Project "Future-proof development of the Latvian power system in an integrated Europe (FutureProof)" (2018–2021), funded by the Ministry of Economics of the Republic of Latvia within the National Research Programme "Energy".

Author's personal contribution

During development of the Doctoral Thesis, the author participated in several collaborative projects implying tight cooperation with other staff members of the RTU Institute of Power Engineering. Namely, the AOF parameter search tool and DR Assess tool were developed by the author together with Researcher K. Baltputnis and Z. Broka under the supervision of Professor A. Sauhats. The author contributed to all stages of work and specifically in conceptualization and definition of the mathematical model, and performed the case studies and analysis of their results.

Approbation of the results

The research results included in the Doctoral Thesis have been discussed at six international scientific conferences.

Scientific paper related to Chapter 1 - Compensation methodology

1. **Sadovica L**., Marcina K., Lavrinovics V., Junghans G.; "*Facilitating energy system flexibility by Demand Response in the Baltics – choice of the market model*"; 58th International Scientific Conference on Power and Electrical Engineering of Riga Technical University, 2017 ISBN: 978-1-5386-3846-0; DOI 10.1109/RTUCON.2017.8124834.

Scientific papers related to Chapter 2 – Consumption baseline methodology

2. **Sadovica L**., Lavrinovics V., Sauhats A., Junghans G.; Lehtmets K.; *"Estimating the energy transferred in the event of demand response activation: baseline model comparison for the Baltic States"*; 15th International European Energy Market Conference, 2018; ISBN: 978-1-5386-1488-4; DOI: 10.1109/EEM.2018.8469796
3. **Kurevska L**., Sile T., Sauhats, A.; *"Developing an economically advantageous wind forecasting method for electricity market design with a 15-minute imbalance settlement period"*; 16th International European Energy Market Conference 2019; E-ISBN: 978-1-7281-3942-5 DOI: 10.1109/EEM.2019.8916574
4. **Kurevska L**., Lavrinovics V., Junghans G.; "*Harmonization of Imbalance Settlement Period Across Europe: the Curious Case of Baltic Energy Markets*", *60th International Scientific Conference on Power and Electrical Engineering of Riga Technical University*, 2019, e-ISBN: 978-1-7281-3942-5; DOI: 10.1109/EEM.2019.8916254.

Scientific papers related to Chapter 3 - Impact assessment on market prices

5. **Kurevska L**., Lavrinovics V., Junghans, G. Sauhats, A.; *"Measuring the impact of demand response services on electricity prices in Latvian electricity market"* 61st International Scientific Conference on Power and Electrical Engineering of Riga Technical University, 2020; e-ISBN: 978-1-7281-9510-0; DOI: 10.1109/RTUCON51174.2020.9316485
6. Broka Z., Baltputnis K., Sauhats A., Junghans G., **Sadovica, L**.; Lavrinovics V.; "*Towards optimal activation of balancing energy to minimize regulation from neighboring control areas"*; 15th International European Energy Market Conference 2018; e-ISBN: 978-1-5386-1488-4; DOI: 10.1109/EEM.2018.8469935
7. Silis A., Ertmanis K., **Kurevska (Sadovica) L**., Junghans G., Sauhats, A.; "*Benefits of regional balancing areas*"; 16th International European Energy Market 2019 Conference e-ISBN: 978-1-7281-1257-2 DOI: 10.1109/EEM.2019.8916254

Scientific papers related to Chapter 4 – Cost-benefit assessment for demand response asset holder

8. **Sadovica L**., Lavrinovics V., Sauhats, A., Junghans G., Baltputnis K., Broka Z.; *"Case study – assessing economic potential for demand response in Baltic balancing market"*; 59th International Scientific Conference on Power and Electrical Engineering of Riga Technical University, 2018.; ISBN: 978-1-5386-6903-7; DOI: 10.1109/RTUCON.2018.8659901
9. **Kurevska L**., *"Heat Pump Optimization Strategies for Participation in Price-Controlled Demand Response in the Latvian Electricity Market";* Latvian Journal of Physics and Technical Sciences, vol.58, no.3, 2021, pp.98-107. https://doi.org/10.2478/lpts-2021-0019
10. Broka, Z., Baltputnis, K., Sauhats, A., **Sadovica, L**., Junghāns, G.; *"Stochastic Model for Profitability Evaluation of Demand Response by Electric Thermal Storage"; 2018 IEEE 59th International Scientific Conference on Power and Electrical Engineering of Riga Technical University (RTUCON 2018),* Latvia, Riga, 12–14 November 2018. Piscataway, NJ: IEEE, 2018, pp.449–454. ISBN 978-1-5386-6904-4. e-ISBN 978-1- 5386-6903-7. doi:10.1109/RTUCON.2018.8659837.

Structure of the Thesis

Doctoral thesis is written in English. It consists of an introduction, four main chapters, conclusions, and bibliography. It contains 28 figures, 19 tables, 10 appendices. The total number of pages is 132, including appendices.

Chapter 1 provides an introduction on how far the demand response services and flexibility services in general have advanced in the European Union. Furthermore, the chapter proposes a taxonomy and decision-making algorithm based on which a policy maker can evaluate the best approach for market roles and responsibilities given the market conditions. The chapter concludes with the evaluation of alternative compensation model comparison and a proposal of combination of central settlement model and integrated model as the most appropriate for the current market conditions in the Baltics.

Chapter 2 provides an overview of the alternative methodologies to determine the energy consumption level that would have occurred in case the demand response activation would not have taken place. This calculated consumption is pivotal for explicit demand response service integration in any of the wholesale markets or allowing the demand response to provide ancillary services to system operators. The chapter includes a comparison of four consumption baseline calculation models (two are proposed by the author). The comparative analysis is based on robustness (using netted mean forecast errors) and accuracy (using absolute mean forecast error). For comparison, real metering data from 40 randomly selected medium to large Baltic consumers. As a result, consumption baseline model UK CBM was identified as the best performing both in terms of accuracy and robustness. Acknowledging that smart meters in Baltics are currently using hourly time resolution, while starting from 2025 (the latest), imbalance should be calculated based on 15-minute resolution, alternative interpolation algorithms are compared based on the case study for wind generation forecasts. The best performing interpolation algorithm based on the study is Spline (Order 5).

Chapter 3 deals with estimating and examining the role of demand response in the Baltic electricity markets. To understand the potential impact the demand response participation might have, the factors influencing the electricity day-ahead price are evaluated and quantified. The chapter looks at the following variables: gas price, wind production, emission costs and consumption changes. Based on the day-ahead market data of 2019, it is estimated that the reduction of consumption by 1 MWh/h results in a daily average price decrease of 0.025 EUR/MWh (and decreases total expenditure for electricity procurement by 500–700 EUR or 20–30 EUR/MWh for each 'unconsumed' MWh). This estimation is a valuable input when considering regulatory tools for introduction of demand response. Furthermore, the chapter includes an overview of two additional fields of study related to the demand response participation in electricity markets. One is the potential benefits for regional coordination in balancing market, the other is the examination of the system balancing procedures (activation optimization function). Findings from both indicate an increased potential for demand response regarding the provision of ancillary services as well as clear benefits for common regulatory framework.

Chapter 4 provides an overview of findings of two case studies related to the financial benefits the demand response asset holder might enjoy from participation in demand response. One case is related to implicit demand response where the benefits are tested in real-life environment using heat-pumps during Q1 2021. The other is related to explicit demand response and participation in balancing market. In case of the explicit demand response, an assessment using Monte Carlo simulation based on load profiles of multiple fridges is used. The results suggest that, while the benefits for implicit demand are quite modest, the potential benefits for participation in balancing market can provide motivation to consumers to participate and invest in the tools and processes necessary.

Conclusions of the Thesis provide a summary of main findings.

1. COMPENSATION METHODOLOGY

1.1. Motivation and background

The Paris Agreement under the United Nations Framework Convention on Climate Change, which as of April 2017, has been ratified by 145 countries (including the Baltics) [1] and the European Commission's "Clean Energy Package" published on 30 November 2016 [2] have once again shown that the global policy makers are determined to lead the world towards stronger reliance on renewable energy sources and improved energy efficiency. As a result of this fundamental paradigm shift in global legal framework, the energy sector has seen emergence of new products and services. One especially prominent category of such products has been broadly referred to as 'demand response'. According to the Federal Energy Regulatory Commission, demand response (DR) is defined as: "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized".

As discussed in [9]–[11], demand response is able to increase the system's adequacy and to substantially reduce the need for investment in grid development and peaking generation by shifting consumption away from times of high demand as well as act as a cost-effective balancing resource for variable renewable generation. Adding stability to the system, it lowers the need for traditional and often ineffective sources of energy. It furthermore decreases the need for local network investments, as it shifts consumption away from peak hours in regions with tight network capacity [11]. DR delivers these benefits by providing consumers – residential, commercial, or industrial – with control signals and/or financial incentives to adjust their consumption at strategic times and by doing so promotes consumer engagement.

While there seem to be a consensus on the need for the energy sector to introduce and integrate demand response in energy markets, the preferred choice of the market framework enjoys far less unambiguity both from policy makers' and industry representatives' point of view [12]–[19]. For example, in Austria the DR provider (incl. aggregator) has to agree bilaterally on data exchange and transfer pricing with balance responsible party (BRP) before flexibly providing the service to its customer; while in Switzerland the DR provider does not need such an agreement with BRP, it has to compensate the BRP at transfer price determined by the transmission system operator (TSO). Furthermore, in Ireland neither BRP nor aggregator is charged for the imbalance created [12], [13], [15]. Due to the increased role of DR and independent aggregator proposed in the European Commission "Clean Energy Package", the Member States have restarted discussion on the integration of DR in their respective energy markets with increased urgency. The objective of this section is to present an overview of market models to be considered by the Baltic policy makers. The main contribution of this section is to review and categorize the market models currently employed in the EU and determination of the preliminary qualitative assessment criteria for model evaluation in the context of balancing market in the Baltic region.

Despite the fact that the Energy Efficiency Directive (2012/27/EU) has urged the Member states of EU to introduce the DR in all the energy markets, the majority of Member States still need to fully adopt the directive in practice. According to the latest survey on the DR, as of 2017, only in six countries (Switzerland, France, Belgium, Finland, Great Britain, and Ireland) the DR products are actively participating in wide range of energy markets (Fig. 1.1) [12], [13], [15]. However, even in these countries there are still some market design and/or regulatory challenges.

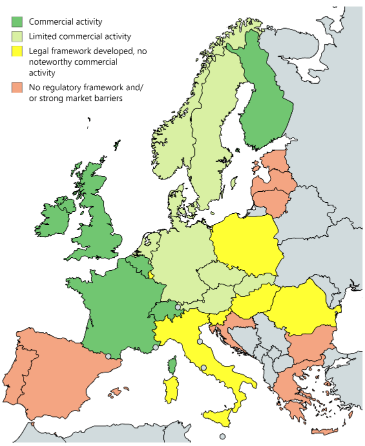

Fig. 1.1. Level of DR introduction in EU as of 2017 [13], [15]

When reviewing the countries with less substantial progress, three broad groups emerge. Countries where DR has been partly integrated; countries where the market models have been developed, but no noticeable commercial activity in the sector of DR has been observed, and lastly, countries where no regulatory framework has been introduced or very strong market barriers still persist.

The policy makers of Austria, Denmark, Germany, the Netherlands, Norway, Sweden, Czech Republic, and Slovakia have started working towards introduction, however, strong market barriers remain and the market growth is fairly limited. For example, Germany and the Nordic countries have started working towards introduction of independent aggregator, while Austria has been working to incrementally improve the bilateral agreement model currently employed. The policy makers of Slovenia, Italy, and Poland have been working towards initial introduction of DR in the energy markets and market activity is expected, while Romania, Hungry, and Luxemburg have developed regulatory framework but due to market barriers or energy system characteristics, have rendered those markets inactive. The policy makers of Spain, Portugal, Baltics, Greece, Croatia, and Bulgaria have yet to develop basic regulatory framework for DR or have to remove significant synthetic market barriers [12]–[14]. Overall, the situation in EU can be characterized as fairly heterogeneous.

1.1.1. The drivers for the DR in the Baltics

Increase in unpredictable generation

Similarly, to the trends in the Central and Southern Europe, the energy system in the Baltics becomes more reliant on the unpredictable distributed generation. Since 2010, the wind energy generation has increased more than three times, and currently the total wind capacity in the Baltics has reached almost 796 MW while solar capacity is 70 MW (Fig. 1.2). As of 2016, the installed capacity of unpredictable (distributed) generation (wind & solar) is more than 10 % of total generation capacity in the Baltics (Fig. 1.2). Furthermore, the trend is upwards sloping – the wind has already been one with the highest installed capacity increase rate, and it is expected to be further amplified by the upcoming oil shale production reduction in Estonia after 2020 due to facilitated lower CO_2 emissions.

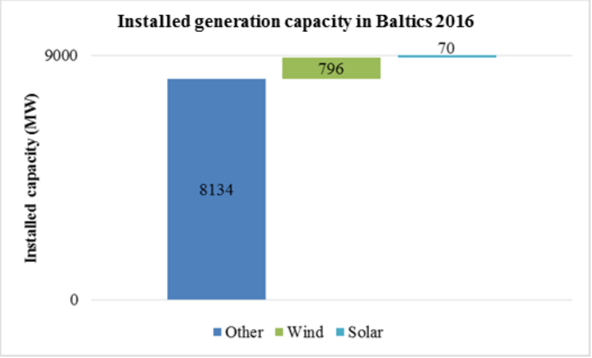

Fig. 1.2 Installed generation capacity in Baltics in 2016; data source: ENTSO-E

Higher balancing market liquidity

Currently in Latvia there is only one business entity participating in balancing market. While there has not yet been a situation where all submitted balancing bids are activated, having a single market participant is traditionally seen as suboptimal. Allowing new type of product (DR) would diversify the balancing market bid offer. Furthermore, the lack of demand side flexibility results in low energy price elasticity [20]. Increased demand side flexibility would have positive effect on market prices in all energy markets (including balancing market).

The legislative framework requirements

Both existing and upcoming requirements of the legislative framework designed by the European Commission have already emphasised that the Member States are to develop a market model where the demand response resource owners (both resident and non-resident) can freely participate in the respective energy markets. According to [12], [13], and [15], while none of the countries have special obstacles disallowing the demand response, the lack of appropriate framework for DR inclusion in different energy markets has made the DR inclusion virtually impossible. Furthermore, the "Clean Energy Package" originally published on 30 November 2016 continues to stipulate the requirements of the market model in a greater detail than before [2]. The precise requirements are reviewed in the following sections.

The desynchronization from the Integrated Unified Power System

The desynchronization from the Integrated Unified Power System (IPS/ UPS) is one of the priorities outlined in the EU Energy Strategy. While the exact date of the desynchronization has not yet been set, it is the common understanding of the Baltic TSOs that preparations for this task should be started already now. The following three scenarios have been suggested as the most feasible options for the desynchronization plan:

- Baltic States' synchronous operation with continental Europe (HVAC Lithuania-Poland interconnector), including soft coupling supported by existing HVDC links;
- Baltic States' synchronous operation with the Nordic countries (HVAC Estonia-Finland), including soft coupling supported by existing HVDC links;
- Baltic States' isolated island operation, including soft coupling supported by existing HVDC links.

While these approaches differ vastly in technical specification and costs, they all share the essential precondition for the Baltic States' energy system having higher flexibility [21].

When comparing the Baltics with other EU countries in regards to the main drivers behind the development of DR, it is clear that many aspects overlap. The increase in unpredictable generation to at least some extent is present in all EU countries. Similarly, the need for higher liquidity in balancing market is almost universal across the EU. Given that the Baltic region is in IPS/UPS and that the wind & solar energy penetration for the Baltics is still below Western Europe, it follows that the pressure to integrate DR in the energy markets is comparatively lower in the Baltics than in, for example, Ireland or Denmark. Furthermore, the EU policy/ regulatory requirements are the same for all EU countries, and this aspect, though important, also does not distinguish the Baltics among the other EU countries either. The most unique driver for DR in the Baltic region is the upcoming desynchronization from IPS/UPS. It is already known that when the Baltics do desynchronize, the market of DR must be already in place, especially for balancing and reserve markets. Based on experience in the EU, the length of time required for the DR market to become commercially active is five or even more years [13]. Accordingly, market regulations should be developed and implemented already now.

1.1.2. Review of legal requirements for the Baltics

Before the European Commission (EC) published the project for “Clean Energy Package” on 30 November 2016, the key EC regulation in regard to demand response and aggregation had been the Energy Efficiency Directive (2012/27/EU) [22]. The main requirements towards demand response under the Energy Efficiency Directive can be divided into four sections [15]:

- Demand response should be encouraged to participate alongside supply within the wholesale, balancing and ancillary services markets;
- TSOs and DSOs must treat the demand response providers, including aggregators, in a non-discriminatory manner and on the basis of their technical capabilities;
- national regulatory authorities should define technical modalities for the participation in these markets on the basis of participants’ capabilities;
- these specifications should include enabling aggregators.

The “Clean Energy Package” further includes more detailed and more concrete requirements for the Member States. The two regulations most discussed regarding DR are: Proposal for the Directive on the internal market for electricity and Proposal for the Directive on the internal market for electricity.

The draft proposal for the Directive on the internal market for electricity develops on the initial stance and provides Member States with further details (particularly Articles 13 and 15). The directive stipulates the importance of [2]:

- granting the demand side resources (private and professional) access to all markets (wholesale, balancing, ancillary services) at all timeframes and introducing a new obligation to remunerate customers for the flexibility;
- empowering the consumer to participate in DR (directly or through aggregation) without the consent of the supplier and to switch aggregation service provider without penalty;
- empowering independent aggregators by ensuring that they can enter the market without the consent from the supplier and can participate in the energy markets without compensating the supplier and/or generator.

The Directive on the internal market for electricity should have been fully transposed by the Member States by January 2021. All three Baltic countries are currently in process of including appropriate provisions in their national legislation.

1.2. Overview of alternative compensation models

The models presented in EU [11]–[19] can be broadly categorized into six main types. Within each of the architype, different variations of the model are possible. There are two main groups of the model architypes: models where the aggregator directly or indirectly compensates the supplier for the energy transferred (Supplier Settlement Model, Consumer Settlement Model, Central Settlement Model) and models where aggregators do not compensate either directly or indirectly the supplier for the energy transfer (Socialized Settlement Model, No Settlement model). The Integrated model does not have any energy transfer (and no compensation mechanism is necessary). Each of the groups has a subdivision. For the 'compensation group' the subdivision is determined by the party through which the compensation is granted to the supplier. For the 'no compensation group' the subdivision is determined by the group of customers who ultimately compensate the supplier (Fig. 1.3). The relationships between different market parties in each of the models are presented in Fig. 1.4.

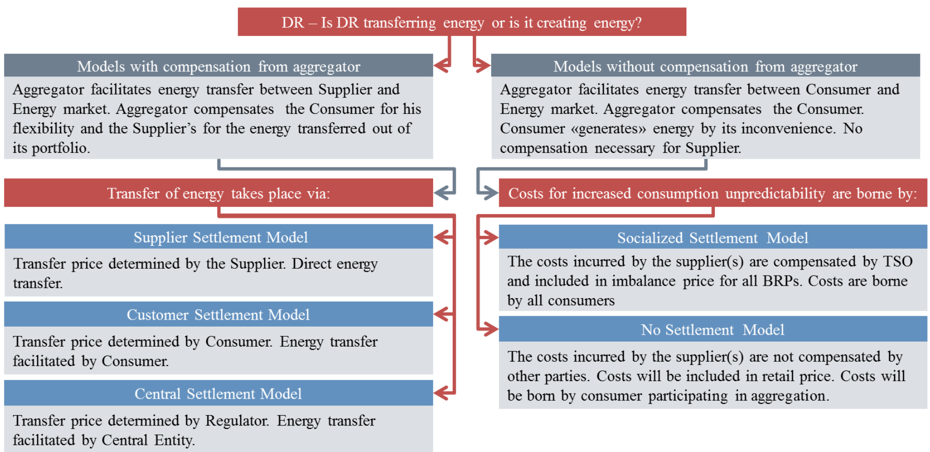

Fig. 1.3. Proposed market model taxonomy.

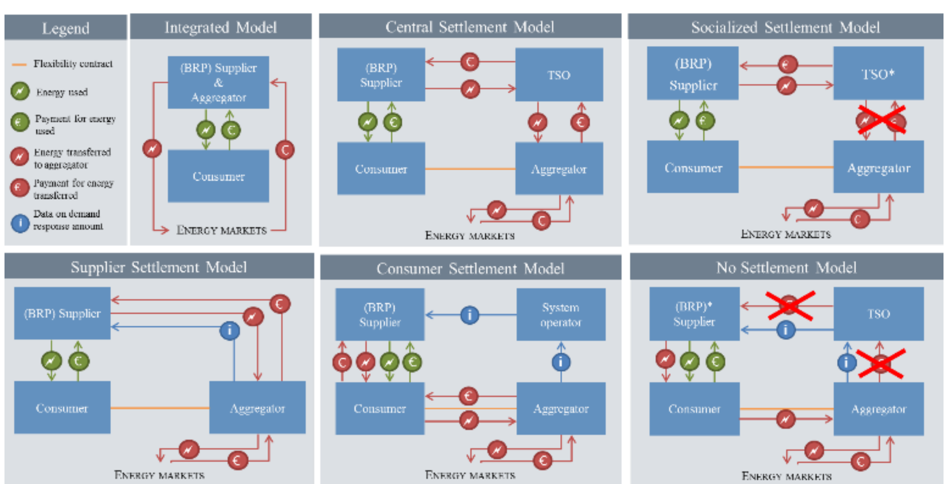

Fig. 1.4. Roles and responsibilities in different market models, adopted from [11], [14], [16-19].

Integrated Model

The bundled approach for supply and DR is the simplest way to implement DR and avoids interfering with other stakeholders. However, it does not allow Aggregators to operate independently from suppliers, which may prevent unlocking the full DR potential in some markets. There are two subtypes of the "Integrated model": "Price based integrated model" and "Supplier load control model". Within the "Price based integrated model" the consumer pays the supplier a variable supply price. The possible variations of the supply price are set contractually, and the consumer can adapt its consumption in response to price variations. This model represents a large share of existing DR in Europe, notably for small consumers equipped with smart meters. In Latvia and Estonia this model is already in place as a dynamic tariff package provided by the retailers. Within the "Supplier load control model" the supplier extends the offer for the consumer to not only provide energy, but also manage directly the consumption pattern and sharing the gains. Following the activation of DR the consumer curtails its load at a predefined volume. The "unconsumed energy" can then be used by BRP to take part in balancing markets, self-balance its portfolio or benefit from high market price situations. This type of integrated supply and flexibility typically targets industrial consumers [11].

The rest of the models deal with an "independent" Aggregator (as opposed to integrated Aggregator in Integrated Model). In case of independent Aggregator, the consumer has to have two contracts – electricity supply contract (with their supplier) and a "flexibility contract" with an Aggregator. The flexibility contract entails that the Aggregator has a direct control over consumers load at a pre-specified volume. In case of DR activation, the consumer is expected to curtail its consumption and the Aggregator can use the unconsumed energy to take part in the energy markets. The compensation or "settlement" mechanisms determine the process and roles how the Aggregator compensates the "unconsumed energy". As stated before, the models can be divided in two groups – with compensation from the Aggregator and with an alternative settlement mechanism (no compensation from the Aggregator).

Supplier Settlement Model

The supplier settlement model is a market design in which the independent Aggregator and the BRP source conclude a bilateral agreement to solve the issues regarding energy transfer. The economic efficiency of this model depends on the conditions in the contracts. If the BRP source/supplier refuses to sign bilateral agreements with independent Aggregators, or only at an excessive transfer price, it can exert a form of monopoly over flexibility.

Consumer Settlement Model

The Consumer Settlement Model requires that the energy sold on the market by the independent Aggregator is invoiced to the consumer by the supplier as if it had been consumed. This way, the transfer of energy is settled directly between the consumer and supplier at the contractual supply price. In case the Aggregator is not the consumer, compensation from the DR operator to the consumer is necessary, at least to cover the costs of the non-consumed invoiced energy. Such arrangements fall under the contractual relationship between the Aggregator and the consumer.

Central Settlement Model

The Central Settlement Model requires the transfer of energy to be performed by a neutral central entity. The central settlement model requires a wholesale settlement price between the independent Aggregator and the BRP source to settle the transfer of energy. This settlement price is a reference price that requires some form of regulatory approval.

Socialized Settlement Model

The Socialized Settlement Model is one option for the "no compensation" model. The model allows the consumer's BRP to sell the excess energy to TSO at the standard imbalance price. As transmission system operators are financially neutral institutions, the excess imbalance payment will increase the imbalance price. Within this model the costs of "unconsumed energy" are borne by all consumers.

No Settlement Model

The No settlement model requires the consumer's BRP schedule to be adjusted in accordance to the DR that was activated within the BRP's portfolio. Accordingly, the BRP is not able to sell the excess energy to the transmission operator. This model puts strong incentive on supplier to require the consumers participating directly or indirectly in aggregation to compensate the costs incurred.

1.3. Qualitative analysis

The overview presented in the previous sections sets up the basis for the evaluation of the models in the context of the Baltic region. The best practices along with the drivers for the DR integration in the Baltic energy market and the upcoming changes in the legislative framework suggest that a model should not only be in line with the current legislation but should also have the following characteristics:

- inclusive – meaning that the market model ensures there are no barriers of entry for the independent aggregator;
- fair – meaning that the market model treats the aggregators as energy transfer facilitators between market participants;
- simple – the market model is compatible with the existing data exchange processes and does not require significant investments in IT infrastructure/administrative processes for other market participants.

In the Figure 1.5. the summary of model comparison is presented.

Market model	Inclusive	Fair	Simple
Integrated	✗	✓	✓
Supplier settlement model	✗	✓	✓
Consumer settlement model	✓	✓	✗
Central settlement model	✓	✓	✓
Socialized settlement	✓	✗	✓
No settlement	✓	✗	✓

Fig. 1.5. Comparison of the market models

The preliminary qualitative comparison of the models suggests that the best approach for the integration of DR in the Baltic Balancing market is to combine two models:

- the integrated model is the most appropriate for suppliers who are interested in developing new products for their customer portfolio;
- the centralized settlement model is the most appropriate for independent business interested in providing aggregation service.

Such combination of models will provide the best opportunity for the existing and the potential market participants and ultimately will ensure that each and every customer has an option to participate in the balancing market. Further research should focus on the analysis of how the market model impacts the prices within energy wholesale and retail markets, as well as assessment of the most suitable market model or combination of market models for energy wholesale markets.

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2. CONSUMPTION BASELINE METHODOLOGY

2.1. Motivation and background

Demand response service (DR) is a temporal change in consumer's energy consumption due to a reaction to price signals or by other measures [23]. DR is associated with multiple benefits such as increased system flexibility, improved network congestion, cost-effective alternative to grid investments, and improved energy efficiency [24], [25].

DR can be broadly divided into two groups: implicit DR and explicit DR. Implicit DR ('price based' DR) refers to consumers choosing to be exposed to time-varying electricity prices and/or time-varying network tariffs that reflect the real cost of electricity at the time of use and allows the consumers to react to that price depending on their own preferences. Explicit DR refers to a program where demand competes directly with supply in the wholesale, balancing and ancillary services' markets directly or through the services of aggregators. This is achieved through the controlled changes in the load that are traded in the electricity markets, providing a comparable resource to generation, and receiving comparable prices [26], [27]. Currently, implicit DR in Latvia and Estonia is available to consumers via electricity supply contracts where retail price is linked to the spot price. Starting from late 2017, there is an ongoing DR aggregation pilot study in Estonia; however, the explicit DR is not commercially active there or anywhere else in the Baltics [28].

For explicit DR to become commercially active, a market framework describing the financial settlement among the market parties (such as consumers, aggregators, system operators and balance responsible parties) needs to be developed. Estimate of DR delivered also known as the electricity reduction amount (ERA) is a pivotal part of such a framework. ERA is the difference between the actual consumption that occurred and the forecasted consumption that would have occurred in the absence of DR activation event. This forecast is called a baseline, and a method for baseline estimation is called consumption baseline model (CBM) (Fig. 2.1) [29].

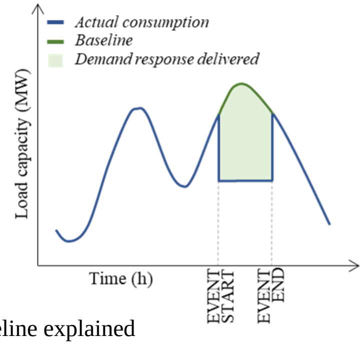

Fig. 2.1. Consumption baseline explained

As of now there is no universal consensus on the best performing CBM, and even in countries where the DR commercial activity is relatively high (e.g., UK, France, Belgium, USA) the choice of the model tends to be rather fluid and CBMs are regularly updated to reflect the reduced costs of data collection and processing as well as improved understanding of the underlying processes [24], [26], [27], [29]–[34]. Regional CBM compatibility studies have been performed in USA [29], [30], UK [35], Australia [36] and EU in general [26], [27] among others. When considering a CBM proposal for the Baltic region, we need to take into account the additional challenges regarding the data resolution. Traditionally, DR events for a single metering point can be shorter than 15 minutes. Currently the imbalance settlement period in the Baltics is 1 hour and the metering data that can be used for the financial settlement are collected at the same time resolution [28]. The mismatch between the length of a DR event and the time resolution of available metering data further complicates the development of acceptable CBM [33]. The main contribution of this section is testing of CBMs' accuracy and skewness on a lower resolution metering data (using the hourly data that are typically used in the Baltics instead of more popular 5-minute or 15-minute resolution usually used in the previous research). Such tests are important because the change in data resolution can have an impact on the relative performance of CBMs.

2.2. Overview of alternative consumption baseline models

A CBM is used to forecast the consumption in the absence of DR activation event. A well-designed CBM enables grid operators and utilities to measure the performance of DR resources and correctly attribute the imbalance caused. Such a CBM benefits all stakeholders by aligning the incentives, actions and interests of consumers, aggregators, utilities, and grid operators; however, not all CBMs can be considered well-designed [33]. A CBM that systematically over-estimates the forecasted consumption will over-value the contribution of the participating DR resource and result in overestimation of positive imbalance for the balance responsible party of the said resource. Conversely, a CBM that systematically underestimates the forecasted load will under-value the contribution of the participating DR resource and result in overestimation of negative imbalance for the balance responsible party [33].

Based on the literature review, CBMs are characterized by the following parameters: accuracy (low average expected error); robustness (absence of systematic error in either direction and lack of obvious data manipulation exploitation possibilities for opportunistic market participants); and transparency (market parties can apply the CBM and get the same results as the grid operator) [29], [36]. It is important to note that at times these characteristics are at odds with each other – very accurate models based on advanced data processing methodologies tend to be fairly complex and non-transparent, while very simplistic models tend to be fairly vulnerable to data manipulation [24], [33]. Accordingly, the choice of the CBM is ultimately dependent on the relative importance attributed to accuracy, robustness, and simplicity. This implies the necessity for tradeoffs when designing a CBM for a particular market and at least partly explains the exotic variety of CBMs already in place.

All CBMs can be broadly divided into two categories – a day-matching forecast and a regression forecast [34]. In the Baltics the concept of explicit DR is still fairly novel and the new market participants (such as independent aggregators) still face limited enthusiasm from the incumbent market participants. Based on the market maturity and the Baltics market participants' views presented in public consultation summary, it is obvious that a CBM relying on advanced statistic and data processing tools would currently not be feasible [24], [29], [36], [37]. Similar approach can be observed in the EU, where, as of now, only in France the balancing market has employed long-term statistics-based model, while all other EU states, where CBM is present, have opted for day-matching CBMs [26], [27], [33]. Furthermore, our position on regression-based models was further cemented by EnerNOC (2009) that stated that regression models have been rejected in the USA due to the lack of support from the market participants. Accordingly, the regression-based models are not reviewed in this section on the basis of not fulfilling the minimum requirements of simplicity parameter [33].

The day-matching CBMs can be further divided into two sub-categories – models using only the data from before the DR activation event and models using data from both before and after the DR activation event. In the EU, the CBMs using only ex-ante metering data seem to enjoy higher popularity [26], [27], which might be linked to the ex-ante/ex-post CBMs being more vulnerable to data manipulation exploits.

Baseline consumption methodology forecast models

We tested four day-matching CBMs – three of those only use metering data from before DR activation event and one uses the data from both before and after activation. Description of the CBMs tested is presented in Table 1.

1. EnerNOC CBM has been used and tested in North America (USA) and is one of the earlier baseline models tested in markets. EnerNOC original variation operates with a time resolution of 1 hour [33].
2. The UK model is adopted from the paper by Imperial College London (2014) and for some time had been used in the UK. The model originally operates with higher time resolution and has been adjusted to the use of hourly metering data [35].
3. Average CBM is the only model in our test that uses both before and after DR activation event data. The model broadly follows the concepts present in the CBM employed in Ireland [26], [27].
4. The daily profile CBM is loosely based on the methodology present in Belgium [26], [27]. Similar to the Daily profile, the Belgium model does not fully use day-matching approach, since only the data from the same day is employed in the CBM. Furthermore, Belgium uses 15 min time resolution.

Based on the paper presented by DNV KEMA (2013) on the basic CBM calculation type, a separate calculation can be applied to align the baseline with the observed conditions of the event day – baseline adjustment method. The CBM adjustment method can improve the performance of the model significantly. The factors used for adjustment rules may be based on, but are not limited to: temperature, humidity, calendar data, sunrise/sunset time, and/or event day operating conditions (the most widely used factor). There are two main types of baseline adjustment methods:

1. Additive, which adds a fixed amount to the provisional baseline load in each hour, such that the adjusted baseline will equal the observed load at a time shortly before the start of the event period.
2. Scalar, which multiplies the provisional baseline load at each hour by a fixed amount or scalar, such that the adjusted baseline will equal the observed load on average during a window of time shortly before the start of the event period [34].

In our analysis, additive adjustment is used in EnerNOC CBM, UK CBM and Average CBM, while scalar is used in Daily profile CBM (Table 2.1).

Table 2.1

Summary of Alternative Consumption Baseline Models

CBM	Short description
EnerNOC	Baseline is equal to the average consumption of 5 corresponding hours with the highest consumption within 10 last non-event days. Baseline is adjusted upwards by the average difference between the last two hours' actual consumption and their baseline. Formula: $b_t = \frac{c_1 + c_2 + c_3 + c_4 + c_5}{5} + \max[\frac{c_{t-1} - b_{t-1} + c_{t-2} - b_{t-2}}{2}; 0]$ (2.1)
UK	Baseline is equal to the average consumption of 5 corresponding hours within 5 days with the highest daily consumption (out of 10 last non-event days). Baseline is adjusted upwards and downwards by the difference between the last two hours' actual consumption and their baseline. Formula: $b_t = \frac{C_1 + C_2 + C_3 + C_4 + C_5}{5} + \frac{C_{t-1} - b_{t-1} + C_{t-2} - b_{t-2}}{2}$ (2.2)
Average	Baseline is equal to the average of consumption one hour before and one hour after the DR event. Formula: $b_t = \frac{c_{t-1} + c_{t+1}}{2}$ (2.3)
Daily profile	Baseline is equal to the consumption within preceding hour multiplied by the fraction of increase/decrease of consumption in the corresponding hours a day before the event. Formula: $b_t = \frac{c_{d,\,t-1} * c_{d-1,\,t}}{c_{d-1,t-1}}$ (2.4)

b_t – baseline at hour t;
c_1 – highest corresponding hourly consumption within 10 last non-event days;
C_1 – highest corresponding hourly consumption in a day with highest daily consumption within 10 last non-event days.

2.3. Quantitative analysis

2.3.1. Methodology

We used hourly metering data that represents annual consumption of 40 randomly selected medium to large electricity end-users from the Baltic region. The set of consumers included different consumption patterns with the hourly average consumption varying from 50 kWh to 3 MWh. In our analysis, we mainly focus on the medium and large consumers due to two reasons: such consumers usually are characterized by higher consumption pattern volatility, such consumers have higher DR potential.

To ensure that the sample is heterogeneous and represents different consumption patterns, correlation analysis was performed for all pattern pairs. The results of the correlation analysis indicated a well diverse sample and indicated that no pattern type is over-represented.

The total number of hours used in the analysis is 8760. Since each model requires different number of days or hours before the event, the number of hours with forecasted baseline differs among the models tested.

Analysis

Based on the literature review, all the analysed CBMs fulfil the simplicity parameter. Accordingly, the objective of the analysis was to quantify each model's accuracy and robustness.

For robustness comparison, we calculated netted mean forecast errors (NMFE), and for the accuracy measurement, we used absolute mean forecast error (AMFE). If NMFE is equal (close) to zero, it is expected that in the long term, inaccuracy will not have impact on total amounts of energy transferred – in other words, NMFE measure the extent to which the model is systematically skewed in either direction. AMFE measures the expected deviation in a single instance. As a benchmark for the AMFE we use the results from the study covering different CBMs in USA, where the model accuracy for models with adjustments ranged from 10–14 % [34].

The baseline error was calculated as follows:

$$Er_{BL} = E_F - E_A, \text{ where} \qquad (2.5)$$

Er_{BL} – baseline error, kWh;
E_F – baseline or forecasted energy consumption, kWh;
E_A – actual consumption, kWh.

Sample error at a trading interval (t) is calculated as follows:

$$Er_{\%_t} = \frac{\sum_{i=1}^{I} \frac{Er_{BL_{i,t}}}{Er_{A_{i,t}}}}{I}, \qquad (2.6)$$

where
$Er_{\%_t}$ – baseline error at a trading interval *t*;
I – number of consumption patterns in the testing sample;
i – consumption pattern.

Accordingly, if the baseline error is above 0, the baseline is overestimated, while if the baseline error is below 0, the baseline is underestimated.

NMFE is calculated as follows:

$$NMFE = \frac{\sum_{t=1}^{T} Er\%_t}{T}, \quad (2.7)$$

where
NMFE – netted mean forecast error for all trading periods within the sample;
t – trading interval;
T – all trading intervals in the sample.

AMFE is calculated as follows:

$$AMFE = \frac{\sum_{t=1}^{T} |Er\%_t|}{T}, \quad (2.8)$$

where AMFE is absolute mean forecast error for all trading periods within the sample.

To estimate the statistical significance of the average accuracy differences observed for both MNFE and AMFE, we ran F test for the difference in two variances for all CBM pairs at a significance level of 99 %. The results indicated that all CBMs' variances are significantly different from each other. We continued with *t*-test for differences in error means of CBMs. The results are presented in the next section.

2.3.2. Results and discussion

The descriptive statistics of NMFE and AMFE is presented in Tables 2.2 and 2.3.

Table 2.2

NMFE Descriptive Statistics

	EnerNOC CBM	**UK CBM**	**Average CBM**	**Daily prof. CBM**
SD	33.21 %	7.54 %	3.52 %	6.64 %
Variance	1103 $\%^2$	57 $\%^2$	12 $\%^2$	44 $\%^2$
Max	727 %	66 %	182 %	389 %
Mean	36.6 %	0.7 %	1.1 %	1.1 %
Min	1 %	–43 %	–23 %	–100 %
Sample	8312	5797	8759	8686

Table 2.3

AMFE Descriptive Statistics

	EnerNOC CBM	**UK CBM**	**Average CBM**	**Daily prof. CBM**
SD	33.15 %	6.24 %	3.27 %	6.49 %
Variance	1099 $\%^2$	39 $\%^2$	11 $\%^2$	42 $\%^2$
Mean	37.8 %	9.5 %	4.8 %	7.1 %
Sample	8312	5797	8759	8686

The density distribution for the forecast errors of the CBMs tested is presented in Fig 2.2.

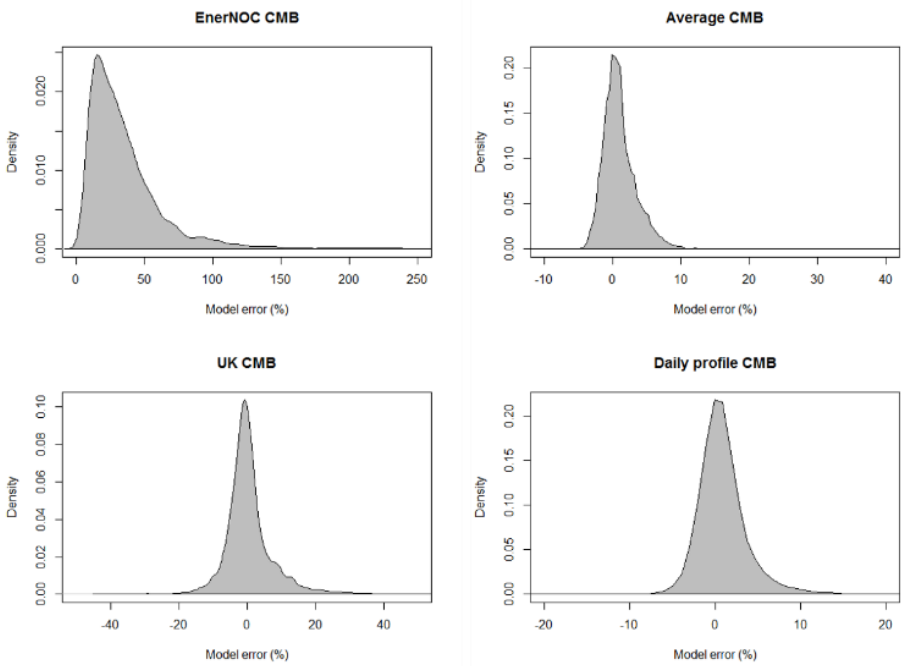

Fig. 2.2. Density distribution for the forecast errors of the CBMs tested

The results of the t-test for the mean difference for the model pairs for NMFE and AMFE values are presented in Tables 2.4. and 2.5, accordingly.

Table 2.4

NMFE t-test Results

t-value for differences of error means			
	UK CBM	**Average CBM**	**Daily prof. CBM**
EnerNOC CBM	95.280***	97.068***	95.691***
UK CBM		3.969***	3.677***
Average CBM			0.366

Significance: ***1 % level; ** 5 % level; *10 % level.

The results of the t-test for NMFE indicate that there is no significant difference between the NMFE of Average CBM and Daily profile CBM. All other differences are statistically significant at a significance level 1 %.

Table 2.5

AMFE t-test Results

t-value for differences of error means			
	UK CBM	**Average CBM**	**Daily prof. CBM**
EnerNOC CBM	72.895***	90.306***	83.059***
UK CBM		– 52.781***	–22.906***
Average CBM			–28.738***

Significance: ***1 % level; ** 5 % level; *10 % level.

The results of the t-test for AMFE indicate that the CBMs present significantly different AMFE at the 1 % significance level.

The UK CBM shows the lowest NMFE (0.7 %). The results indicate that if this model were applied, there would be no substantial long-term inaccuracy of ERA in either direction. The EnerNOC CBM shows the poorest results, which is associated with overestimation of ERA for more than one third of the total energy volume.

The analysis of AMFE indicates that all models, except for EnerNOC CBM, perform better than the benchmark value of 10–14 % and as such is considered to fulfill the minimum accuracy condition.

2.4. Comparison of alternative time resolution increase algorithms

2.4.1. Background and motivation

According to Article 53 of the European Union Electricity Balancing Guidelines, the transmission system operators (TSOs) should implement the 15-minute imbalance settlement period (ISP-15min) until 18 December 2020, with Article 62 indicating that the introduction can be postponed until up to 1 January 2025. Most smart-metering devices in the Baltics are capable only to support hourly time resolution for metering data. Similar issue can be observed in wind generation forecasting. To test alternatives transposing algorithms, a study based on the needs of wind forecasting in the context of 15-minute ISP, was performed.

Imbalance calculation and ISP

It is generally agreed that finer time resolution for imbalance settlement improves system forecast accuracy (Fig. 2.3) [38]–[40]. The longer the ISP, the more the deviations from the forecasted schedule are netted within the ISP and the lower imbalance amount is recorded. The netting effect is beneficial to market participants with volatile loads, but it hurts the other market participants. Regardless of netting, the system must be balanced at every moment, so the costs of balancing are still incurred and are translated into higher imbalance costs per MWh.

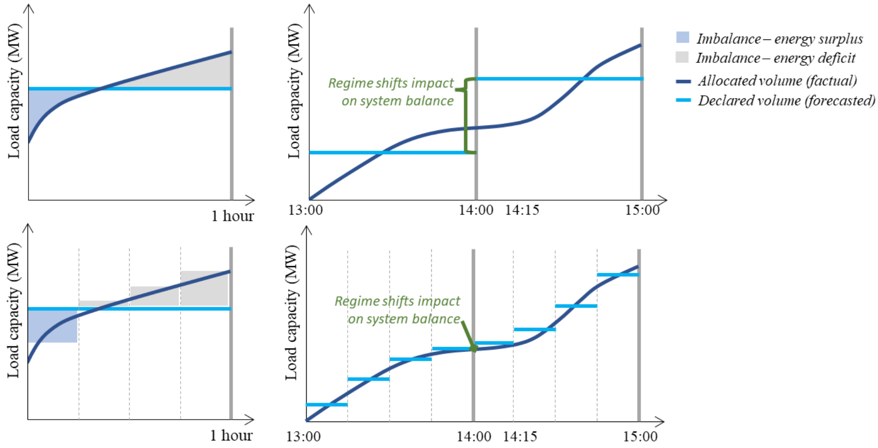

Fig. 2.3. Imbalance misattribution due to netting effect and regime change effect

Furthermore, the highest imbalance in the Baltic system is typically recorded at the beginning of the hour when the generation units change regimes. This is caused by the slow ramping rates of the conventional generation plants; by introducing shorter ISPs the ramping rates can be better acknowledged and more accurate system balance forecast could be created (Fig. 2.3).

Overall, it is expected that the cost allocation among market participants will better reflect cost creation. However, real benefits for system stability and balancing cost reduction can only be achieved if market participants adjust and improve their forecasting methodologies.

2.4.2. Methodology

Objective and scope

The typical time resolution of a mesoscale model output is 60 minutes. In order to get a qualitative improvement in load forecasting and consequently reduce imbalance costs, the 60-minute data must be translated into higher time resolution. The aim of the analysis is to explore the benefits of facilitation of this translation via interpolation and to test and compare the performance of the approaches. To exclude particularities outside of the scope of current research step, the author opted to interpolate data from a single model. To test the quality of the interpolation, the available wind observation data from 2018 with 10-minute time resolution was used. Accordingly, also the interpolation methods' performance is determined for 10-minute intervals. For the purpose of this study it is acceptable to assume that the method's performance at 10-minute resolution is a proxy for the method's performance at 15-minute resolution.

To provide a rough comparison of economic performance the authors also accounted for the differences between the imbalance cost of overestimation of wind speed and underestimation of wind speed and the used absolute (as opposed to netted) forecasting error.

Methodology

The Weather Research and Forecast model has been used to create a mesoscale model dataset. Although a 30-min model data are available, the data were down-sampled to the time resolution of one hour. In total the author tested 9 different interpolation methods. These approaches can be divided into three groups: 'the nearest neighbor', 'polynomial interpolation', and 'spline interpolation'.

- The nearest neighbor interpolation is the simplest method, as it substitutes the unknown value with the closest available value, namely, for all ISPs between 14:00 and 15:00 the available modeled value for 14:00 is used. 'The nearest neighbor' approach serves as a baseline approach to which the other eight methods are compared.
- Polynomial interpolations use a polynomial function to obtain the values between known points. Polynomial interpolation can have different orders, depending on the order of the function used. The author tested three polynomial interpolation approaches – a linear function, where a straight line is drawn between known points (first order), a quadratic function (second order), and a cubic function (third order).
- Spline interpolation is an approach where the interpolating function is required to have smoothness properties, by ensuring the continuity of derivatives. The author tested five approaches based on spline interpolation (order 1 to 5).

After obtaining the interpolated model data, the author converted both real observation and interpolated model data in energy generated by using a power curve of a small wind power station. The difference between energy calculations based on the forecasted and observed data is considered imbalance. Furthermore, the annual expected cost of imbalance was calculated based on a difference between average imbalance prices (both directions) and corresponding spot prices for 2018. Lastly, the relative performance of each interpolation approach was calculated assuming the 'nearest neighbor' method's performance as a reference.

Inputs

The author used the following data for the analysis:

- Model data was extracted from the mesoscale NEWA [41] dataset [42] for the nearest gridpoint and vertically logarithmically interpolated in each timestep to the observational height.
- For observational data, the available high mast measurements carried out using cellular communication masts for the station near Ventspils, Staldzene were used. Observational data are available for 10-minute intervals for one full year (2018) for the measurement height of 80 m [42].
- As a sample power curve for converting wind power in capacity, a power curve from Vestas V100/2000 (2MW) was used.
- For day-ahead price calculations the author used NordPool spot prices for 2018 (Baltic/Latvian bidding zone).
- For imbalance price calculations the author used the imbalance price data for 2018 of the Baltic TSOs (Baltic/ Latvian bidding zone).

2.4.3. Results and discussion

Overall deviations between observations and forecast are quite high (netted error is ~20%). The calculations also show that the error rates from the mesoscale model data is skewed in the direction of overestimation. 60% of modeled values suggested wind speed higher than the observed while 40% suggested wind speed lower than the observed. In other words, the modeled data when used for electricity generation scheduling would result in 60% ISPs with negative imbalance (imbalance energy bought by the power station operator) and 40% ISPs with positive imbalance (imbalance energy sold by the power station operator) (Table 2.6.). The authors do not detect statistically significant difference regarding systematic bias in one or the other direction among the interpolation methods tested.

Table 2.6.

Model comparison – imbalance costs (both directions)

Paramter	Standard approach	Polynomial interpolation			Spline inerpolations				
	Nearest neighbor	Linear	Quadratic	Cubic	Slinear	Spilne (order 2)	Spline (order 3)	Spline (order 4)	Spilne (order 5)
% of ISPs where imbalance energy is bought	60.05 %	60.59 %	60.61 %	60.64 %	60.59 %	60.49 %	60.78 %	60.58 %	60.57 %
Imbalance energy bought annually (MWh)	2 189.38	2 178.26	2 190.69	2 191.30	2 178.26	2 072.72	2 058.34	2 070.00	2 058.03
Price of underproduction (EUR/MWh)	8.22 €	8.22 €	8.22 €	8.22 €	8.22 €	8.22 €	8.22 €	8.22 €	8.22 €
Costs incurred in deficit hours (EUR)	18 002.09 €	17 910.63 €	18 012.88 €	18 017.86 €	17 910.63 €	17 042.82 €	16 924.60 €	17 020.52 €	16 922.04 €
% of ISPs where imbalance energy is sold	39.35 %	39.41 %	39.39 %	39.36 %	39.41 %	39.51 %	39.22 %	39.42%	39.43 %
Imbalance energy sold annually (MWh)	–965.31	–960.40	–966.15	–966.39	–960.40	–952.90	–953.84	–949.69	–952.54
Price of overproduction (EUR/MWh)	5.97 €	5.97 €	5.97 €	5.97 €	5.97 €	5.97 €	5.97 €	5.97 €	5.97 €
Costs incurred in overproduction hours (EUR)	5 764.13 €	5 734.81 €	5 769.15 €	5 770.54	5 734.81 €	5 690.00 €	5 695.64 €	5 670.82 €	5 687.83 €

While overall deviations between observed and modeled (forecasted) value is quite high, the overall costs of imbalance remain adequate (7% of electricity sales). That is related to favorable market conditions that rendered small price differences between imbalance price and spot price (8.22 EUR/MWh for deficit and 5.97 EUR/MWh for overproduction) [43].

While comparing interpolation approaches the best performing model is Spline (Order 5). Compared to the simplistic approach (assuming modeled hourly value is unchanged for all ISPs within an hour), Spline (Order 5) provides 5.1% reduction of imbalance costs against the Nearest neighbor. Similar level of reduced annual imbalance costs is associated with Spline (Order 3) (Table 2.7).

Table 2.7.

Model performance comparison

Method name	Expected annual imbalance costs	Performance against "nearest neighbor"
Nearest neighbor	23 766 .22 €	n/a
Linear	23 645 .44 €	-0 .51%
Quadratic	23 782 .04 €	0 .07%
Cubic	23 788 .40 €	0 .09%
slinear	23 645 .44 €	-0 .51%
spline (order 2)	22 732 .82 €	-4 .37%
spline (order 3)	22 620 .24 €	-5 .04%
spline (order 4)	22 691 .34 €	-4 .75%
spline (order 5)	22 609 .88 €	-5 .10%

3. IMPACT ASSESSMENT ON MARKET PRICES

3.1. Motivation and background

In the context of Baltic synchronization with Continental Europe synchronous area, the discussion on alternative sources for fast acting reserves (FCR and aFRR balancing products) has gained prominence. Demand response services has been considered as one of the less expensive technological options comparing it to storage facilities and conventional gas turbines [44, 45]. However, the main drawback for relying on demand response services as a significant contributor towards ancillary services, is the limited market interest shown in developing demand response services as a separate, self-sufficient market niche. Until recently, the only market demand response was allowed to participate in Baltic region was market for ancillary services. The balancing market volumes constitutes a fraction of the wholesale market volumes. According to data publicly available on Baltic Balancing market Dashboard, in 2019, the total amount of upwards balancing volume in Baltic balancing market was 28,2 GWh while average daily consumption in Latvia is approximately 20 GWh-30GWh.

To facilitate faster adoption of demand response role in Latvian electricity market, a new Cabinet of Ministers regulation has been developed for aggregators (in force from 24th of March 2020). This regulation allows demand response services to participate not only in providing ancillary services for system operators, but also to participate in wholesale electricity markets [46].

New type of market participant not only provides new opportunities to end-users but is also expected to have an impact on electricity prices. Latvian wholesale electricity market is particularly interesting research environment due to the fact that for the last four years Latvian market has had the highest and the most volatile prices in the region. The objective of this section is to perform factor analysis on Latvian wholesale electricity market prices to determine the effect of the introduction of demand response in day ahead market might have on electricity prices.

Supply-demand relationship in Baltic day-ahead electricity market

Due to the nature of electricity as a necessary good, the demand for electricity is naturally quite inelastic. Demand elasticity increases when consumers engage in either implicit (dynamic pricing) or explicit (active energy consumption management) demand response. Furthermore, overall electricity consumption in Latvia is fairly stable. For the last four years the year-over-year deviations for annual electricity demand has not exceeded 1.5%. According to report published by Latvian transmission system operator, electricity consumption is expected to grow by less than by 1% per annum (base scenario) [47]. The growth of consumption in a conservative scenario, (with average winter temperatures above -3.5 °C), is forecasted at ~0.5%. Similarly, the model developed by Skribans, V., & Balodis, M (2017) forecasts only slight increase (i.e. 10% within 10 years) of electrical consumption in Latvia [48]. From supply-demand perspective this means that lower prices for electricity can be achieved only by shifting demand from peak periods to, for instance, night hours, when electricity consumption in Latvia and the region is lowest [49].

On other hand, the supply of electricity depends on sale price on the market and their production short-term marginal costs. When bidding on Nord Pool exchange, producers with lower operational costs (and, thus, lower selling price) are followed by more expensive power producers, altogether forming merit order curve. Short-term marginal costs of wind, solar and hydro stations are comparatively low [44] while conventional stations have high operating costs both in absolute terms [45] and if compared to their share of capital costs (Fig. 3.1). Similarly, low marginal costs are expected to be associated with demand response services.

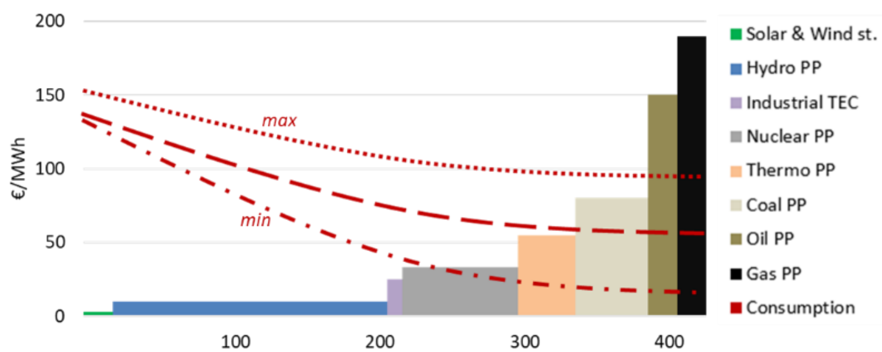

Fig. 3.1. Power supply merit order curve in the Nord Pool region by production type.
Source: adapted from Balodis M. (2016).

Day-ahead price characterization

Latvian electricity market operates under Nord Pool electricity exchange, which provides services for Nordic, Baltic region and Northern Europe (Germany, France, the United Kingdom, etc.). Nord Pool is the largest electricity exchange in Europe – in 2019 total of 494 TWh were traded on the exchange [50]. For comparison, Latvian total consumption of electricity in 2019 was 7.3 TWh, or 1.4% of traded on Nord Pool. Such traded amounts and large number of market participants (more than 400 entities) guarantee high competition and liquidity both for producers and consumers.

In 2019 average day-ahead price in Latvia was by 16% higher than in Sweden (zone 4), and by 5% higher than in Finland (Fig. 3.2). While prices in Latvia, Lithuania and Estonia are quite close to each other, they are significantly higher than prices in Nordics (especially Sweden and Norway). This difference becomes even more pronounced when accounting for electricity consumption profile. Consumption is considerably higher during the business hours, so demand in Nord Pool either cannot be covered by the relatively cheap renewable and nuclear energy. In these hours cheap energy is mainly consumed in the bidding zone, where it is produced. In other bidding zones, day-ahead closing prices are determined by more expensive producers.

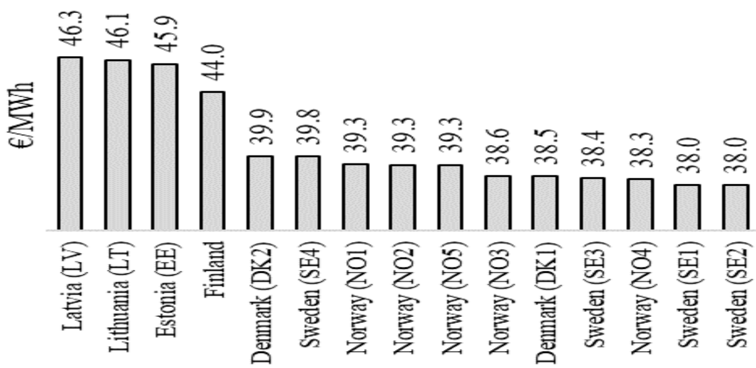

Fig. 3.2. Nord Pool day-ahead prices in 2019 (not profiled), source: Nord Pool (author's calculations).

Day-ahead prices in Latvia are not only the highest but also the most volatile when compared to other bidding zones. Fig 3.3 shows that Latvian prices vary from 12 €/MWh to 114.6€/MWh. In contrast, daily average prices in neighboring bidding zones never crossed 100 €/MWh level during the last 4 years from 2016 to 2019.

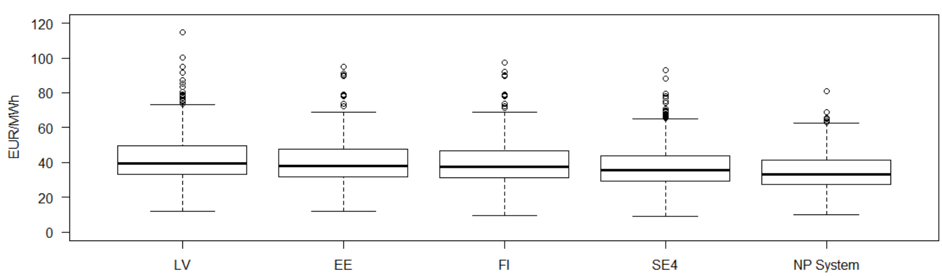

Fig. 3.3. Box plot of daily average day-ahead prices, 2016-2019, source: Nord Pool (authors calculations).

In Latvia, where only a couple of electricity retailers have their own production facilities, which can be used as a natural hedge against electricity price fluctuations, most traders are very sensitive to volatility of day-ahead prices. Introducing demand response services could provide additional hedging options for these traders.

3.2. Methodology

Framework

To determine the impact of demand response services on the prices of the day-ahead market, the day-ahead price factor analysis is performed. To do this, the author uses the time series methodology, which is the most widely used technique in studies focused on price determination [51]–[53]. The multiple linear regression model is employed to evaluate if the chosen set of *k* variables has a statistically significant impact on electricity prices (*Y*). The general form of multiple regression model is as follows:

$$Y_t = \beta_0 + \beta_1 x_{t,1} + \beta_2 x_{t,2} + \ldots + \beta_i x_{t,1k} + \varepsilon_t \,. \qquad (3.1)$$

The use of multiple regressions is associated with multicollinearity issues – the situation when two or more independent variables have high correlation, which may result in unstable solutions of regression models. According to [54], multicollinearity makes the regression coefficients unidentifiable. To minimize multicollinearity, the correlation matrix analysis is performed and regressions variables that have high mutual correlation are removed. Furthermore, for the regression model with the highest explanatory power (measured as adjusted *R*-squared) standard model diagnostic tests are performed.

Factors analyzed

To estimate the impact of consumption changes on the day-ahead electricity price, the author analyzes the relationships between fundamental factors and electricity prices in Latvia, such as oil, coal, natural gas. The CO_2 emission allowances have a statistically significant influence on day-ahead prices in Latvia, as the price of the fuels and CO_2 emission allowances constitute the biggest part of short-term marginal costs for generators [45]. Furthermore, the availability of renewable resources such as hydro and wind have a statistically significant influence on the day-ahead prices in Latvia because the short-term marginal costs of hydro and wind stations are negligible [55].

Factors considered in the analysis:

- Electricity spot price (€/MWh) – the Nord Pool traded day-ahead electricity price for a specific bidding zone (Nord Pool).
- Electricity consumption/production prognosis (MWh) – expected consumption/production volume according to the day-ahead Merit Order Curve result in a specific bidding zone (Nord Pool).
- Wind production prognosis (MWh) – expected wind production volume according to the day-ahead Merit Order Curve results in a specific bidding zone (Nord Pool).
- CO_2 emission allowance price (€/ 1000t) – CO2 daily closing price of continuously traded EUA future contract on ICE (SKM).
- Natural gas (TTF) price (€/MWh) – daily closing price of continuously traded future contracts on ICE (SKM).

The results of multicollinearity correlation matrix analysis are presented in Table 3.1.

Table 3.1

Correlation Matrix Based on Daily Data from 2016 to 2019 (inclusive)

Variable	[1]	[2]	[3]	[4]	[5]
Price LV [1]	100 %				
Consumpt. prog. LV [2]	24 %	100 %			
TTF price [3]	36 %	15 %	100 %		
CO_2 price [4]	51 %	1 %	5 %	100 %	
Wind prod. NordPool [5]	–10 %	26 %	14 %	27 %	100 %

3.3. Results and discussion

Analysis

The results of the regression with four independent variables (prognosis of electricity consumption in Latvia, forecasted electricity amount from wind stations at Nord Pool territory, CO_2 emission allowances and natural gas (TTF) future contract prices) indicate that all of them are statistically significant predictors of the day-ahead price in Latvia. The equation of the model is as follows:

$$Price_d = \beta_0 + \beta_1 Consumption\ prog_d + \beta_2 CO_2 price_{m-1} + \beta_3 TTFprice_{m-1} + \beta_4 + \varepsilon_d \qquad (3.2)$$

All variables are significant at 1 % level. The results suggest that higher forecasted consumption, CO_2 emission allowances, and natural gas prices result in higher day-ahead prices. In contrast, higher wind production is associated with lower day-ahead prices. The regression's adjusted *R*-squared is 61.35 % – more than half of the variance of the day-ahead prices is explained by the variance of these four independent variables. The variance inflator factor indicates no multicollinearity in the equation.

Table 3.2

Regression Analysis using the Consumption Prognosis, CO_2 Price, TTF Price, and Wind Production Prognosis in Nord Pool as Independent Variables

	Estimate	St. Err.	t-value
Intercept	1.601	1.590	1.007
Consumpt. progn. LV	0.025***	0.002	13.767
CO_2 price	0.805***	0.021	39.041
TTF price	0.960***	0.042	22.757
Wind prod. Nord Pool	–0.081***	0.004	–21.401
# of observations	1387		
Adj. R-squared	0.6135		
F-statistics	551		
p-value	$2.2e^{-16}$		

*Significance: *** 1 % level; ** 5 % level; * 10 % level*

Furthermore, the author uses Multivariate Adaptive Regression Splines (MARS) to model independent variable relationship with the day-ahead prices in Latvia. This allows to evaluate non-constant linear relationship between the predictor and response variable. The results of MARS are presented in Fig. 3.2.

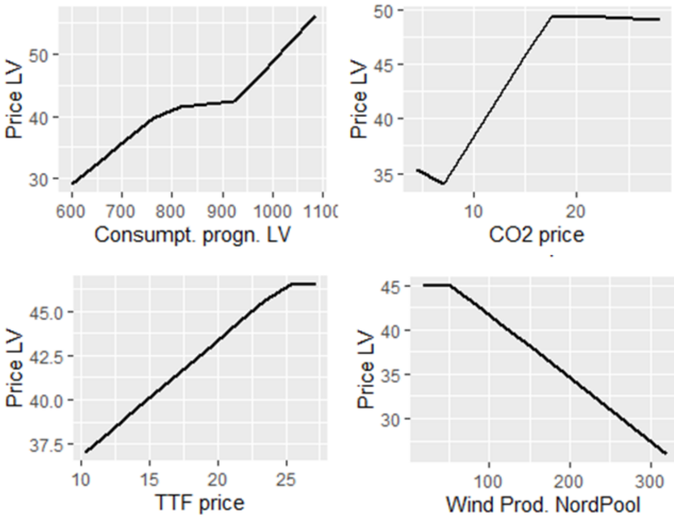

Fig. 3.2. Output of regression analysis using consumption prognosis, CO_2 price, TTF price, and wind production prognosis in Nord Pool as independent variables.

Estimated impact – changes in consumption

The results suggest that an additional 1 MWh/h of electricity consumed results on average in increase of 0.025 EUR/MWh in the day-ahead electricity price. Furthermore, the MARS analysis identifies that on days with average hourly consumption below 780 MWh or above 930 MWh, additional consumed electricity results in higher price response than on days with average hourly consumption between 780–930 MWh. This can be explained by nature of generating resources in the region. The costs of production remain quite flat when, with certain level of generation, producers are ready to sell electricity without major increase in prices in order not to stop the production by conventional stations. In contrast, when the consumption is growing and tends towards its peak levels, the producers face start-up costs of less efficient plants. This leads to a more pronounced electricity price response to increasing demands.

Estimated impact – other factors

CO_2 prices have significant impact on the electricity price in day-ahead market. CO_2 price increase by 1€ results in 0.81 €/MWh increase of day-ahead electricity prices in Latvia. Similar conclusion is reported by Bariss et al. (2016) who demonstrate that 1€ increase of CO_2 emissions would increase electricity prices in the Baltics by 0.67 €/MWh [53]. This finding identifies a clear need to hedge risks associated with volatility of CO_2 emission allowance prices. For example, the retailers can enter yearly or monthly forwards under the EUA scheme, thus, fixing the CO_2 price level. This effectively would result in lower financial risks from electricity price changes on the day-ahead market.

Natural gas prices significantly affect the day-ahead electricity prices in Latvia. Regression estimates suggest that, *ceteris paribus*, a 1€ increase of TTF forward prices translates in 0.96 €/MWh growth of the day-ahead electricity prices in Latvia. So, hedging via gas derivatives removes substantial price risks for traders.

Increased wind generation availability has negative impact on day-ahead prices. The estimates of all regressions show robust results – additional 1 MWh/h of electricity produced during the day from wind reduces Latvian day-ahead prices, on average, by 0.081 €/MWh. These findings are in line with the conclusions presented by Jonsson et al. (2012), who studied the relationship between electricity volumes generated by wind stations and Elspot prices in Western Danish price area [56]. Similarly, Fabra N. & Reguant M. (2014) report positive correlation between the wind speed and electricity prices in Spain [57].

3.4. Optimization of imbalance price

3.4.1. Motivation and background

While most commercial activity takes place in the day-ahead timeframe, a part of the electricity price in retail is related to imbalance costs. Accordingly, as additional field of study the potential opportunities for improving balancing costs were examined. Firstly, it was the regional coordination among the Baltic states based on the preliminary results of coordinated balancing area (CoBA). Secondly, the author participated in the development of improved balancing energy optimization with the goal to minimize the total cost of balancing (and therefore imbalance price).

Baltic coordinated balancing area

The Baltic area balancing mechanism was developed to establish a common balancing area starting from 2018. To achieve this, the TSOs established procedures for coordinated balance control, exchange of the balancing energy, imbalance netting, and balance settlement. The objective of harmonized Baltic balancing market was to increase the safe operation of the power system by promoting the availability of balancing resources and reducing the power system balancing costs. Establishing the Baltic balancing market involved harmonization of the balancing market framework and introduction of a common balancing IT platform.

One of the building blocks of the common balancing system is the Activation Optimization Function (AOF). As stipulated in guidelines [58] developed by ENTSO-E, the AOF determines the most efficient activation of the incoming balancing request while respecting some capacity and operational restrictions. The Baltic TSOs intend to implement the AOF as an automatic algorithm the main inputs to which are the available bids from the CMOL (considering transmission constraints) and activation volume proposal [59], the latter being the focus of this section. Specifically, it implies an algorithm for the suggestion of activation volume of balancing reserves along with a time schedule based on the historic ACE data with minute resolution and the current ACE forecast. It is meant to support the decision making by the human operator of the transmission system, and thus constitutes the first steps towards building a fully automatic system for the activation of balancing reserves. As of now, the decision to order the balancing energy is left solely to the human operator with a very short timeframe for decision-making. However, since the power system is a very complex structure with a large number of variable and uncertain parameters, an automated tool should provide a more optimal solution. Nevertheless, human operators usually have significant hands-on experience which is challenging and sometimes outright impossible to represent mathematically within an automated algorithm. Thus, one of the tasks of this study has been to investigate the pros and cons of automated vs manual regulation activation.

3.4.2. Results and discussion – regional coordination

To estimate the impact of coordinated procedures and harmonized regulation data sets from 2017 (year before CoBA operations) and 2018 (first year of CoBA operations) were compared regarding the following aspects: area control error (precision of regulation); balancing market liquidity (price efficiency of the market); and imbalance price. The results indicate that the common Baltic market performs better in all of the aspects.

Area control error

The analysis of the of historical data of the Baltic CoBA performance revealed that centralized balancing market approach led to significant decrease of the Baltic ACE. Average ACE decreased by 43 % from 42 MWh to 24 MWh per imbalance settlement period in 2018 compared to year 2017. Similarly, improved results on maintaining ACE close to 0 MWh were observed. In 2018, ACE was within 50 MWh range in 89 % of operational hours compared to 65 % in 2017 (Fig. 3.3).

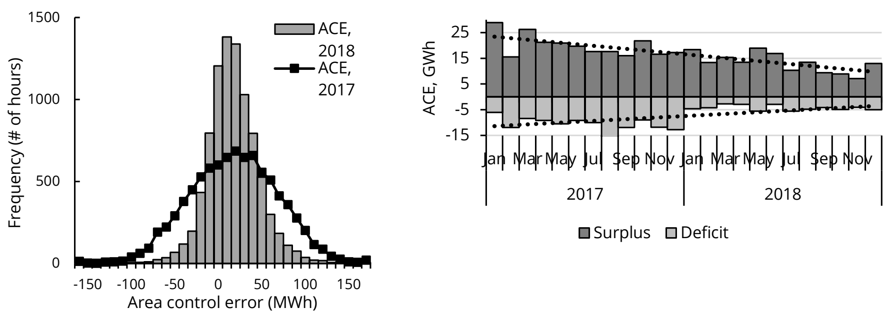

Fig. 3.3. Frequency and monthly trend in changes in area control error

Market liquidity

The reduced ACE was mostly achieved by improved and coordinated balancing. In 2018, the Baltic TSOs ordered mFRR products in 79 % of hours, which is twice as much as in 2017 (36 % of hours). This higher demand for balancing resources increased the balancing market liquidity and made it more attractive to local generation. Therefore, the amount of used balancing energy in 2018 tripled compared to 2017, while at the same time the share of local balancing resources stayed at the level of 66 % (Fig. 3.4).

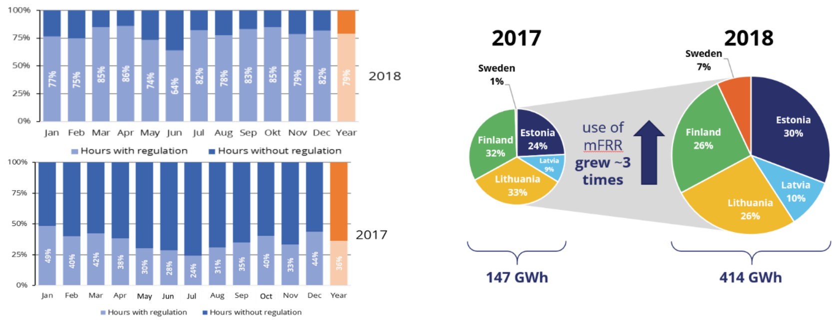

Fig. 3.4. Increase in balancing energy used after operation of CoBA

Imbalance costs

Changes in imbalance pricing system created more level playing field for pan-Baltic BRPs and BSPs. Total Baltic BRP balancing costs decreased from 19.9 M.EUR in 2017 to 15.1 M.EUR in 2018. To evaluate the impact of changes in imbalance pricing model on pan-Baltic BRP's imbalance costs, we simulated the BRP's portfolio.

Pan-Baltic BRP was created with average hourly planned consumption of 100 MWh in each country. Hourly consumption was profiled according to the Baltic weekly average consumption profile, and different imbalance scenarios (300) were simulated. As a result, the simulated BRP cost reduced significantly comparing 2017 to 2018 and the BRP can benefit from netting its imbalances between the Baltic countries, therefore reducing the cost of balancing (Fig. 3.5).

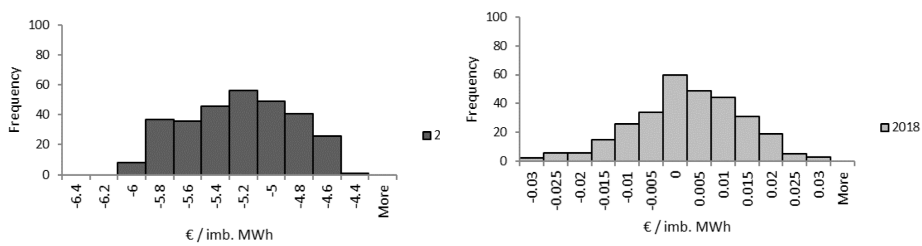

Fig. 3.5. Comparison of imbalance costs for simulated BRP

Overall, the introduction of Baltic CoBA created considerable benefits by reducing the reliance on open balance provider (reduced ACE), improving local generation asset participation in balancing market and reducing the imbalance costs for balance responsible parties. The increased demand for balancing resources provides more opportunities also for the demand response assets.

3.4.3. Results and discussion – improved activation optimization function

The objective of optimization is to minimize expected activation costs by considering both ACE and cost of bid activation. The author participated in the development of a software tool with an algorithm for deriving optimal activation parameters of mFRR for balancing of the Baltic power system. The algorithm operates under the assumption that the mFRR should be activated one or a few times within the given imbalance settlement period (in this case study, no more than five activations within an imbalance settlement period were considered). The algorithm itself is based on three main parameters: the time of activation (minutes from the beginning of each ISP), the percentage of the ACE forecast to be regulated against, and the ignorance level (the minimum value of the ACE forecast for regulation to be activated). Consequently, the time series of ACE forecast with minute resolution is provided as input data. Real-life historic data from 2016 provided by the TSO was used for numerical simulations.

After testing of the developed software, the following results were obtained when comparing the alternative frequency of regulation (Fig. 3.6).

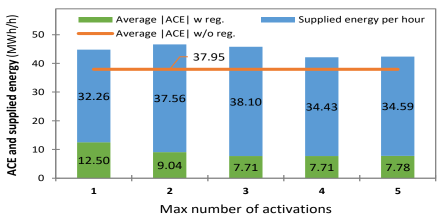

Fig. 3.6. Comparison of alternative activation frequencies.

Furthermore, the alternative scenarios were compared assuming the set balancing and ACE costs (Table 3.3).

Table 3.3

Comparison of Costs of Alternative Activation Frequencies

Max. number of activations	**1**	**2**	**3**	**4**	**5**
	Cost of ACE with local regulation (€)				
Energy bought @ 100 €/MWh	205 643.77	137 685.42	133 461.79	126 568.68	133 142.01
Surplus sold @ 5 €/MWh	–21 540.16	–16 118.70	–12 948.91	–13 285.65	–13 148.32
Cost of ACE	***184 103.60***	***121 566.72***	***120 512.88***	***113 283.03***	***119 993.69***
	Cost of supplied local regulation energy (€)				
Energy bought @ 50 €/MWh	188 740.31	246 043.25	238 190.36	194 939.63	194 561.59
Surplus sold @ 10 €/MWh	–126 444.67	–141 952.35	–146 298.99	–136 286.05	–137 142.43
Cost of supplied local energy	***62 295.64***	***104 090.90***	***91 891.37***	***58 653.58***	***57 419.15***
Total cost with local regulation	**246 399.25**	**225 657.63**	**212 404.26**	**171 936.61**	**177 412.84**
	Cost of ACE without local regulation (€)				
Energy bought @ 100 €/MWh	409 669.61				
Surplus sold @ 5 €/MWh	–76 089.76				
Total cost without local regulation	**333 579.85**				

Overall results suggest that the more precise and more frequent activation of balancing energy produces better results for the market. As demand response typically provides lower volume balancing bids, the shift towards more frequent balancing would provide potential future opportunities.

4. COST-BENEFIT ASSESSMENT FOR DEMAND RESPONSE ASSET HOLDER

4.1. Case study: Implicit demand response

4.1.1. Motivation and background

Traditionally the balance between demand and supply in a power system is maintained by adjusting centrally controlled supply to the largely inelastic demand. The increase in intermittent and distributed generation [60] as well as 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 [7] and the percentage of residential consumers with rooftop solar panels reached 25 %. Such shift reduced electricity volumes consumed through distribution system but did not have considerable impact on the costs of the system, the volume-based distribution system tariffs increased by 112 % [8].

With the emerging preference for electric transportation and heating the demand for electricity has even a greater tendency to cluster in high and low demand periods, which may result in peak load demands increasing faster than the total annual consumption, adding additional price pressures to the electricity as resource and power system alike. On the other hand, the technologies enabling demand response offer an opportunity to mitigate the volatility of energy consumption patterns, which could help the power system to adjust to the emerging and in some cases already established market requirements. The consideration that improving of system flexibility is a key factor in reducing the costs of integrating intermittent generation, has also been reinforced by recent studies [61]–[63]. For this reason, encouraging consumer engagement in demand response activities has become an increasingly important energy policy topic [61], [64]–[66]. While there might be consensus on whether facilitation of consumer engagement in electricity market is necessary, how to achieve it is a challenge with a less clear solution. The objective of this case study is to compare in alternative and easy to apply cost optimization scenarios for air-to-air heat-pump based heating system.

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 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. [..]" while 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” [67]. 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 are available to residential users [68].

Electricity market liberalization in Latvia started in 2007 when the option to freely choose electricity supplier was offered to business consumers with high consumption. Furthermore, they were joined by business consumers with medium consumption on April 1, 2012 and all other business consumers on November 1, 2012. The market was opened to residential consumers on January 1, 2015. While the electricity suppliers in Latvia are required to offer ‘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 % (three-fold increase from the end of 2017) of residential consumers and 42.8 % of business consumers (~30 % increase from the end of 2017) had chosen dynamic pricing type of contract (Figure 4.1. and 4.2.) [69]. Currently, most of electricity suppliers provide some type of dynamic price contracts (either time-of-use [70] or spot-price tied [71]) to both business and residential consumers.

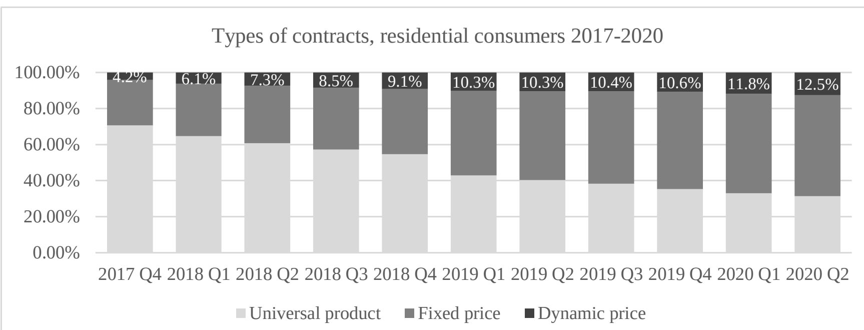

Fig. 4.1. Contract type structures for residential consumers in Latvia 2017-2020. Data source: [68].

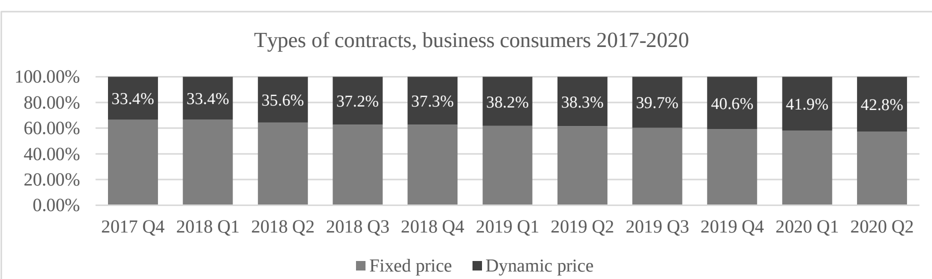

Fig. 4.2. Contract type structures for business consumers in Latvia 2017-2020. Data source: [68].

To look at overall consumption pattern trends in Latvia year 2020 is excluded due to considerable, but not easily measurable impact of the 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 – Table 4.1. [72]. While a positive trend and more research should be done to explore the drivers behind it, the data also shows high variations between peak and off-peak demand and potential for implicit demand response to facilitate it.

Table 4.1.

Comparative descriptive statistics for energy volumes sold on NordPool Day-ahead market on 2017 and 2019, Data source [71].

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%

Barriers for consumer engagement in demand response

Residential consumer’s engagement (or lack of it) can be divided into stages, each characterized by 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. 4.3.) [61], [73].

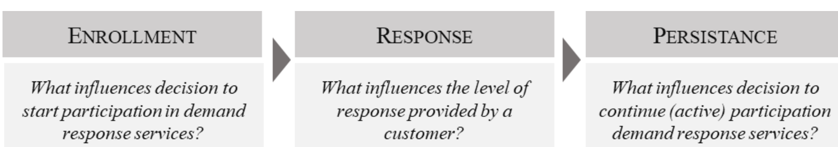

Fig. 4.3. Three stages of consumer engagement in demand response. Adapted from [8].

Understanding barriers and enablers 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 approach and assess the potential for demand side response participation in more precise manner.

In literature the following types of motivators were identified: financial, environmental and social. Based on multiple studies, the financial incentives are the most important [61], [74]-[80]. Financial incentives include reduced monthly bill, rewards for specific consumption patterns, free or reduced cost technology [61]. Environmental motivators are less studied and seem to play less important role as participation in demand response does not necessarily decrease the overall consumption [61], [81]. Social motivators include increased perceived control over energy consumption [74], [81], finding the experience novel and entertaining [74] or taking pride in being socially responsible or supportive to energy system [61], [82], [83].

These benefits or motivators are usually weighed against effort, time, convenience, and comfort [61], [84]-[86]. Based on the systemic review by [61], real financial benefits are necessary precondition for meaningful participation in implicit demand response activities.

4.1.2. Case study design

Heating, ventilation, and air conditioning systems (HVAC) have tendency in developed countries to become more prevalent over time [87]. The latest data for Latvia is from 2015, when 6% of residential buildings in Latvia had electricity-based heating and ~2% of residential buildings in Latvia had air conditioning [88]. Furthermore, HVAC tends to be one of the most energy intensive type of residential type 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 differ depending on climate, building and other appliances. On average it is considered that heating is responsible for up 50% of the monthly electricity consumption during the peak demand period [89].

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, the general approach for introducing deterministically controlled HVAC system is fairly simple and requires data collection, algorithm and load controller device [90]-[92]. The objective of this study is to evaluate in real data setting, the most appropriate algorithm for implementing automatic and cost-efficient HVAC system management that relies on publicly available data. To achieve that for 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. In Tables 4.2. and 4.3., present the environment and data description.

Table 4.2.

Description of the Case Study Environment

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

Table 4.3.

Description of the Data Used in the Case Study

Outside temperature	Factual hourly data from meteorological data from the Latvian Environment, Geology and Meteorological Centre (°C) [93]
Day-ahead prices	Factual hourly data from Nord Pool exchange (EUR/MWh) [72]
Heat pump load	Measured every minute (MW)

In the context of this study the following assumptions (simplifications) were made – firstly, the load is only shifted and there is no reduction of total consumption (rebound effect expected to be 100 %). The consumption from the hour where 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 observed also during the date change). The following optimization scenarios were devised (Table 4.4).

Table 4.4. Optimization scenarios used in the case study.

Scenario	Conditions	Objective
Selecting two hours in every given day when the HVAC is switched off based on the following criteria:		
2–1	The lowest temperature	Representation of the highest expected consumption [94]
2–2	The highest day-ahead price	Representation of the highest cost per MWh
2–3	The highest forecasted 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 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 forecasted cost savings from load shifting	Representation of the highest total gains from shifted consumption

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

$$C_{H0} = E_{H0} \times P_{H0} - E_{H0} \times \frac{P_{H1}+P_{H2}}{2}, \qquad (4.1)$$

where C_{H0} – expected cost 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 (EUR/MWh).

The expected volume E_{H0} shifted is calculated based on empirically obtained relationship for the particular HVAC system.

$$E_{H0} = 0.001288 - 0,00015\, T_{H0}, \qquad (4.2)$$

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

The empirical equation (Fig. 4.4.) was obtained by applying linear regression on the empirical consumption and factual temperature data from the case study.

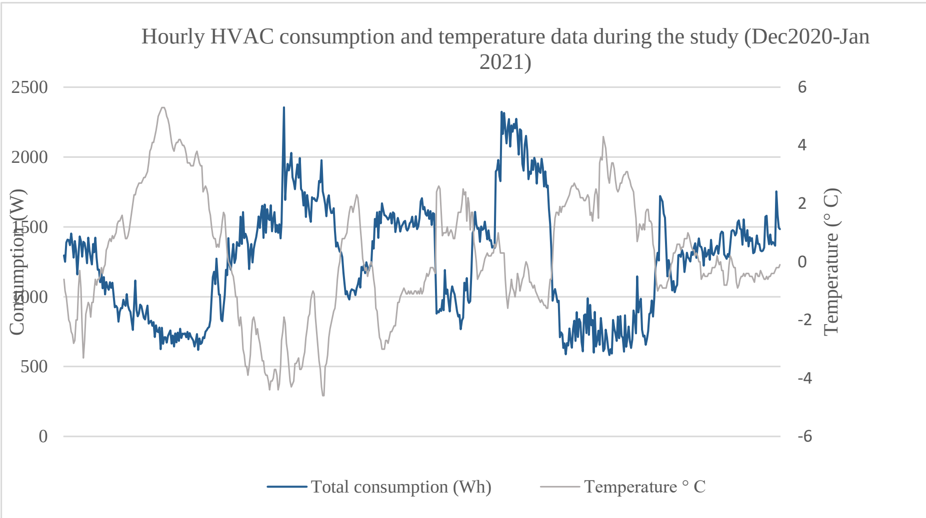

Fig. 4.4. Hourly HVAC consumption and temperature data during the study. Temperature data source [91].

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.

4.1.3. Results and discussion

During the observation period the following data was collected in regard to outdoor temperature, day-ahead price and actual HAVC consumption (Table 4.5.).

Table 4.5.

Descriptive Statistics of Temperature, Electricity Price, and HVAC Consumption During the case Study. Data sources: temperature [91], electricity prices [71]

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 previously described scenarios provide the outcomes shown in Table 4.6.

Table 4.6.

Comparison of Optimization Scenario Outputs

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 group. The highest load shift is observed in the scenario where the load is shifted away from the coldest hours (in two-hour scenario – 9.5 % of total load was selected, while in 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 night, when the electricity price dynamic is less pronounced. Scenarios 2–2 and 3–2 in both two-hour and three-hour group demonstrate the best performing similar relative performance in their respective scenario group, however, the best performing scenarios were 2–3 and 3–3 that considered both the expected difference in price as well as the expected loads. The improved economic performance in scenarios 2–2 and 2–3 is considerably higher than the increased load shift. This indicates that considering only the day-ahead prices and not considering the expected consumption level is the sub-optimal choice.

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 from residential consumers in implicit demand response activities are 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.

4.2. Case study: Explicit demand response

4.2.1. Motivation and background

The reliability of electric power system operation depends on the balance between power production and consumption [3]. To achieve this balance, every grid connection point needs to be accounted for [4]. Traditionally, this is managed by dividing the system in multiple imbalance areas each having a market participant, which is financially responsible for ensuring that all energy generated within the area is sold, and all energy consumed within the imbalance areas is bought. These market participants are called balance responsible parties (BRPs). BRPs ensure the balance by forecasting demand and supply of energy within their imbalance areas and ensuring according energy trades via day-ahead and intraday markets.

When BRPs fail to forecast demand and supply accurately, it can result in excess/ deficit energy in the power system. Forecasting errors are corrected in real time by transmission system operators (TSOs) via balancing market. Ensuring sufficient balancing energy reserves is pivotal to TSOs as without them the power system balance cannot be maintained, which, depending on the interconnections to other power systems, can result in costly procurement of balancing energy from other control areas or in adverse system frequency fluctuations.

The costs of power system balancing are covered by imbalance payments from those BRPs, whose actual consumption/ generation deviated from the forecast. Accordingly, the costlier balancing energy is, the more expensive penalty payments for forecasting errors are and consequently the costlier energy in retail markets becomes. The main driver for high balancing prices is balancing resource scarcity. Currently, in the Baltics, only electricity producers provide balancing resources. Furthermore, since the opening of the Common Baltic Balancing market and subsequent increased reliance on national balancing resources (instead of balancing energy resources from Russian TSO), we can observe preliminary indications of balancing resource scarcity [5].

Furthermore, according to the Baltic generation adequacy report, it is expected that during the next 10-15 years the capacity required for balancing reserves will increase due to rising intermittent generation and the planned Baltic power system desynchronization from UPS/ISP. At the same time, the generation from some of the sources typically used for balancing purposes in the Baltic states (thermal power plants in Estonia) will reduce by up to 50% due to lost competitiveness of oil-shale power plants caused by the increasing costs of SO_2 and NO_2 emissions [5]. The forecasted generation mix for the Baltic states is presented in Figure 4.5.

This gives us clear indications that additional sources for balancing reserves are needed. Demand response (DR) is a promising source of balancing energy to consider. DR integration in balancing energy markets can provide significant financial savings for grid operators and market participants and promote optimal resource allocation [6]. Some large consumers in the Baltic states have already expressed preliminary interest in providing services to the TSOs [6]. However, to facilitate DR participation in power system balancing, the service must provide economic gains for both the existing market participants and DR service providers.

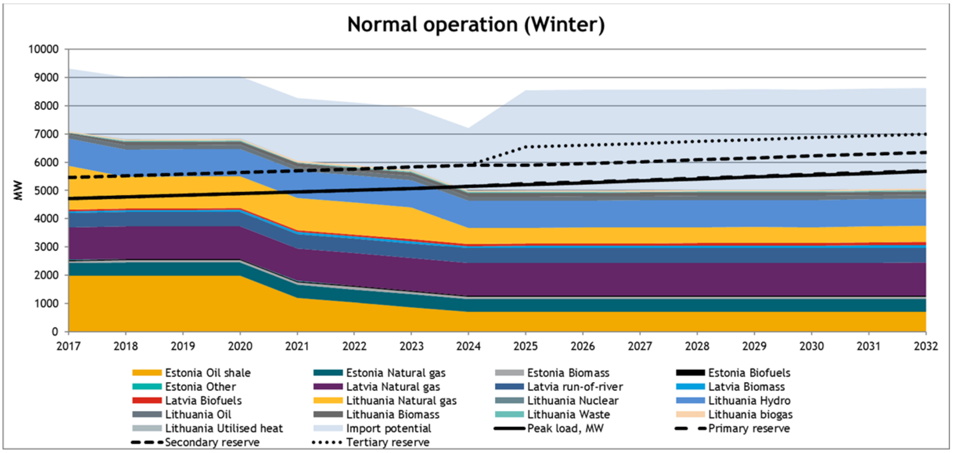

Fig. 4.5. Forecasted available electricity supply capacity in the Baltic region in winter [4]

Independent DR aggregation in balancing market

DR service is a temporal change in consumer's energy consumption due to a reaction to price signals or other measures [95]. DR is associated with multiple benefits, such as increased system flexibility, improved network congestion management, cost-effective deferral of grid investments and improved energy efficiency [96], [97]. DR can be broadly divided in two groups: implicit and explicit DR. Implicit (price-based) DR refers to consumers choosing to be exposed to time-varying electricity prices and/ or time-varying network tariffs that reflect the real cost of electricity at the time of use and allow the consumer to react to prices depending on their preferences. On the other hand, explicit DR refers to a program, where demand competes directly with supply in the wholesale, balancing and ancillary services markets directly or through the services of aggregators. This is achieved through controlled changes in the load that are traded in the electricity markets, providing a resource comparable to generation, and receiving a commensurate compensation [97], [98]. Based on the mFRR product specification, only explicit DR is applicable when considering balancing market [4].

Large industrial plants in Europe (e.g. in the Nordics, Poland, Croatia, the Netherlands, Germany) have been involved in DR provision for ancillary services for considerable time [97], [98]. These large consumers can participate in the market individually. In the Baltics, the energy intensive industry is not highly developed, accordingly the DR potential is locked in smaller consumers (i.e. SMB, residential). A rough estimate suggests that both for residential and commercial buildings (such as schools, hotels, retailers) approximately 50% of energy consumption stems from heating, cooling, ventilation and lighting [99]. This indicates substantial flexibility potential, however, given that the minimum bid size for mFRR product is 1 MW, these consumers can only participate in the balancing market, if their loads are aggregated and coordinated. Advancements in information technology render such aggregation and resource coordination feasible.

While it is an energy related product, DR aggregation requires different business processes in place compared to a typical energy supplier. To ensure that all consumers willing to participate in DR are allowed to, without switching their supplier, a new market participant – an independent aggregator – emerged. In essence, an independent aggregator is a DR aggregation service provider that delivers balancing energy sourced from end-users that are included in imbalance areas different to the aggregator [100]. There is no consensus on the best market framework for the integration of independent DR aggregators, since optimal choice of model differs by countries and types of electricity markets [97], [98]. The settlement model currently favored by the Baltic TSOs is a centralized model (Figure 4.6.) [100]. Detailed explanation of this model is provided in Chapter 1 of this Thesis.

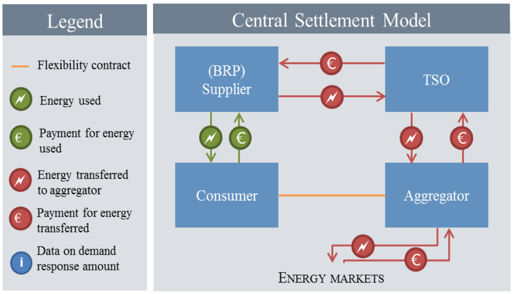

Fig. 4.6. Financial and data exchange relationships in central settlement model

4.2.2. Case study design

Assumptions for Energy Transfer

When DR activation takes place, it has the following impact on the consumption curve (Fig. 4.7.). When DR activation for upwards regulation (i.e., reduced consumption) takes place, the consumption is curtailed.

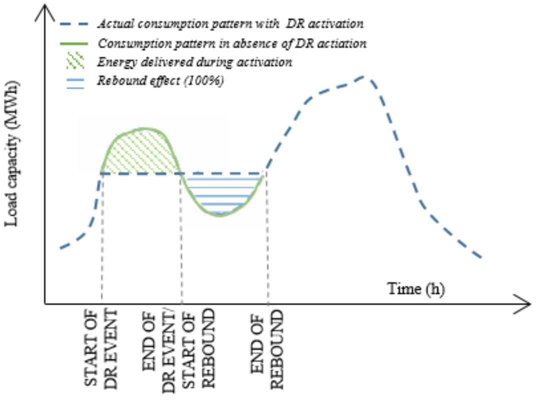

Fig. 4.7. DR activation explained

Depending on the resource type, the energy unconsumed during the activation will be consumed to some extent during one or few following hours. Based on the results of the pilot with fridges [3], the assumed recovery effect in our simulations is 100% and it takes place during the next hour. Within our simulation framework, it is assumed that the volumes of energy transferred can be determined without an error.

Assumptions for the Settlement Model (Cash-Flows)

Within the simulation, it is assumed that the following prices are equal:

- retail price is equal to the day-ahead price.
- balancing price is equal to the imbalance price.

In line with the centralized settlement model, the following trades for the energy delivered during activation take place:

1. Before an operational hour, the supplier/BRP buys energy in the day-ahead market at a day-ahead price (P_{DA}).
2. During the operational hour, the TSO orders balancing energy from aggregator at a balancing price (P_{bal}).
3. During the operational hour, the consumer does not consume the energy it would consume in the absence of the TSO's activation order.
4. During the settlement phase, the TSO makes an imbalance adjustment for the declared position of the impacted BRP.
5. During the settlement phase, the TSO pays to the BRP a compensation for the energy taken from its portfolio at a reference price (P_{ref}).
6. During the settlement phase, the TSO pays to the aggregator the difference between P_{bal} and P_{ref}.
7. During the settlement phase, the consumer does not pay for the energy unconsumed and may receive part of the profit generated by the difference between P_{bal} and P_{ref}.

The following trades for the consumption pattern deviation caused by the recovery effect take place:

8. During the settlement phase, the consumer pays to the BRP/Supplier a retail price (P_{ret}) of the recovery hour for the energy consumed due to the recovery effect.
9. During the settlement phase, the BRP pays the imbalance price (P_{bal}) of the recovery hour to the TSO for the energy consumed due to the recovery effect.

The simulation tool

The modelling for the case study was carried out using a Monte-Carlo simulations-based tool introduced and elaborated in [101]. The stochastic nature of the model requires the output to be probabilistic instead of deterministic. Consequently, most of the input settings concern the expected mean of a particular parameter across scenarios and the output is provided in the form of probability distributions.

The main modules of the tool are day-ahead price scenario generation, balancing liquidity and price scenario generation, balancing activation simulation and short-term and long-term economic assessment.

Input assumptions and DR resource characterization

The assumptions for day-ahead market were made based on the historical values from Nord Pool day-ahead market data for the Baltics in 2017. The assumptions are presented in Table 4.7.

Table 4.7.

Day-ahead Market Data Simulation Parameters

Price simulation parameters	Value (st. dev.)
Mean price for 99.5% of hours	34.02 €/MWh (10%)
Mean value for weekdays divided by mean value for weekends	1.23 (10%)
Mean value for day (06:00-22:00) divided by mean value of night (22:00-06:00)	1.38 (10%)
Minimum price	2.99 €/MWh (10%)
Maximum price for 99.5% of hours	75.34 €/MWh (10%)
Maximum price for 100% of hours	130.05 €/ MWh (10%)
Number of scenarios	300

The assumptions for the balancing market were made based on the historical values for the Baltic balancing market data for the first quarter of 2018. These reference values were chosen due to the significant market changes implemented on January 1, 2018. The assumptions are presented in Table 4.8.

Table 4.8.

Balancing Market Data Simulation Parameters

Price simulation parameters	Value
% of hours when regulation takes place	70%
% of regulation hours, where upwards regulation is required (load reduction)	45%
Balancing price for upwards regulation (expectation)	1.6 P_{DA}
Balancing price for downwards regulation (expectation)	0.6 P_{DA}
Number of scenarios	300

We based technical assumptions about the DR resource on the data presented in a pilot study by Lakshmanan et. al (2016) [3]. We set the total load capacity at 2.5 MW (25 fridges). The load profile for a typical day is depicted in Fig. 4.8.

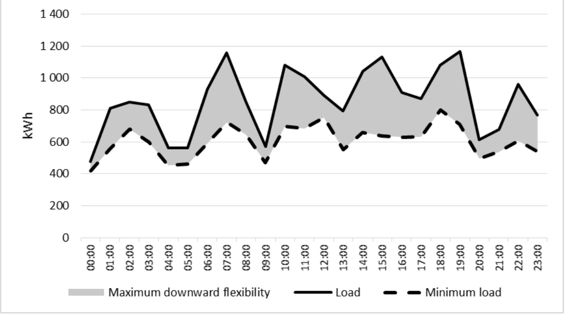

Fig. 4.8. Load profile of the DR resource simulated

DR activation parameters are presented in the Table 4.9. Minimum DR bid price is set at 45 €/MWh to limit events where DR activation causes losses due to price difference between day-ahead price and balancing price. Based on the historical data from 2017, day-ahead price in Baltic region was below 45 €/MWh 85% of times**.**

Table 4.9.

DR resource simulation parameters

DR resource simulation parameter	Value
Maximum number of events during 24 hours	6
Minimum time between the events	2 h
Maximum period before rebound	2 h
Rebound effect / DR energy delivery	100%
Minimum DR bid price	45 €/MWh
Discount rate used for NPV calculations	3%

It is assumed that the resource participates only in upwards regulation. Furthermore, it is assumed that participation in DR does not damage the resource and consequently does not add other additional costs.

4.3. Results and discussion

The portfolio's expected average annual income from participation in balancing market is 8 622.89 €. 85% of that is the revenue from balancing market payments and 15% stems from day-ahead price difference between the activation hour and recovery hour (Fig. 4.9.). There is no benefit from energy savings in this case study, since we assumed that all the curtailed consumption would be recovered later.

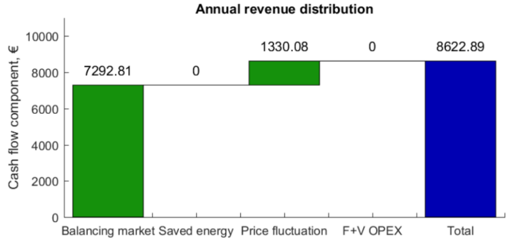

Fig. 4.9. Average annual revenue distribution

Assuming a 10-year asset service life and 3% discount rate, the expected net present value (NPV) of the simulation described in the previous section is 73 555.01 €. In other words, the project would be profitable, if the initial investment was below 73 555.01 € or below 2 942.20 € per fridge (Fig. 4.10.).

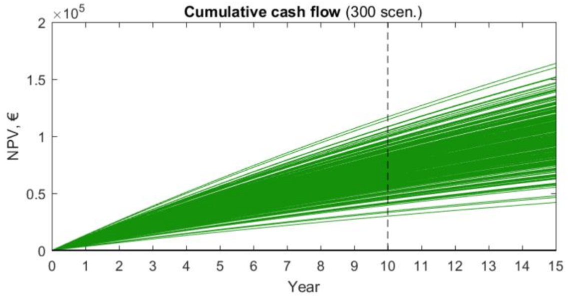

Fig. 4.10. Cumulative cash-flow for 15 years (all scenarios)

It is expected that on average the portfolio will annually deliver 326.24 MWh of balancing energy, by participating in 32% of all hours (1257 hours annually) when downwards regulation is used. Accordingly, on average, the portfolio earns 26.43 € per each MWh delivered to the balancing market (Fig. 4.11.).

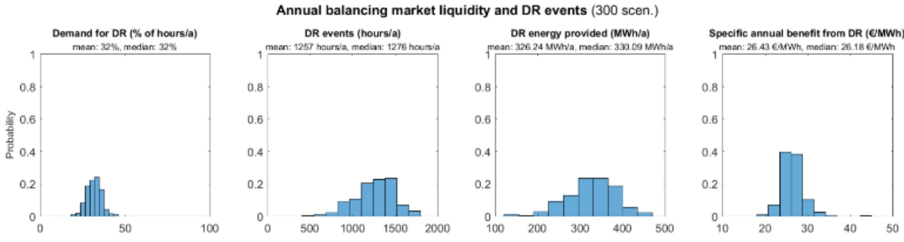

Fig. 4.11. Overview of simulated DR events and balancing market prices

The expected average annual cash inflow for the portfolio is equal to 19 661.18 €, while the expected average cash outflow for the portfolio is 11 038.29 € (Fig. 4.12).

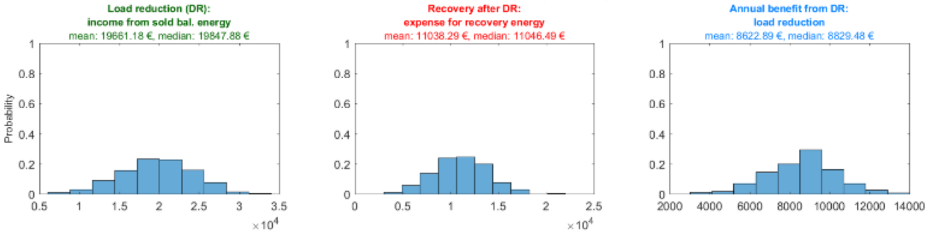

Fig. 4.12. Breakdown of DR asset owner's estimated annual profit.

CONCLUSIONS

1. The performed cost-benefit assessment tests performed confirm the hypothesis that by developing an appropriate regulatory framework the demand response services can provide a cost and energy efficient tool for improving the system flexibility and mitigate the resource price increase and regional price volatility driven by the increase in intermittent generation in the Baltic region.
2. The market framework proposed in this research (*centralized settlement model*) for allowing the demand response services to participate in the Baltic region ancillary services market avoids abnormal returns to any of the market participants and provides, inclusive, fair, and simple allocation of roles and responsibilities.
3. The algorithm proposed in this research (*UK CBM*) for estimating the volume of the demand response services (energy) delivered provides an easy-to-introduce method that offers reasonably robust and accurate results.
4. The interpolation algorithm proposed in this research (*Spline* (*Order 5*)) offers better results than the alternative eight models when considering transposing hourly metering data to 15-minute time resolution.
5. There are identifiable financial benefits from the demand response participation in providing ancillary services to both service providers and other market participants.
6. The algorithm proposed in this research for optimizing the heat-pump system for implicit demand response provides an affordable method that relies on publicly available data and can be used by any owner of the HVAC type of demand response asset. The proposed algorithm offers up to 5 cost reduction.
7. Based on historical data (2016–2019) on the Baltic electricity market and day-ahead price drivers, the financial benefits from introducing demand response services in the day-ahead market or from customers engaging in implicit demand response are quite modest. The existing market conditions do not suggest that additional regulatory stimuli for faster demand response uptake are currently necessary. The situation might change after synchronization with the Continental Europe Synchronous Area.

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APPENDICES

Facilitating energy system flexibility by Demand Response in the Baltics – choice of the market model

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***Abstract* — Flexibility is defined as the modification of generation injection or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. Integrating such resources into the electricity market increases security of supply, supports market competition and enables consumer empowerment, which are important objectives of the EU energy policy. To facilitate smooth integration of Demand Response resources in the balancing market, new market player role – "the Aggregator" comes into play. Currently, the main barrier for the Aggregators in Latvia is the lack of a regulatory framework defining the roles and responsibilities for the Aggregators and the compensation mechanisms between different energy system parties, when Demand Response activation takes place. Currently, there is no consensus on the best practice in regards of particular market framework. The aim of this paper is to examine and categorize the different market models observed in practice and assess the model feasibility in the context of the Baltic region.**

Keywords— aggregation; distributed energy resources; demand response; balancing markets

I. I. INTRODUCTION

The Paris Agreement from United Nations Framework Convention on Climate Change, which as of April 2017, has been ratified by 145 counties (including the Baltics) [1] and European Commission "Clean Energy Package" published on 30th of November 2016 [2] has once again shown that the global policy makers are determined to lead the world towards stronger reliance on renewable energy sources and improved energy efficiency. As a result of this fundamental paradigm shift in global legal framework, the energy sector has seen emergence of new products and services. One especially prominent category of such products has been broadly referred to as "Demand Response". According to Federal Energy Regulatory Commission, Demand Response (DR) is defined as: "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" (Fig. 1).

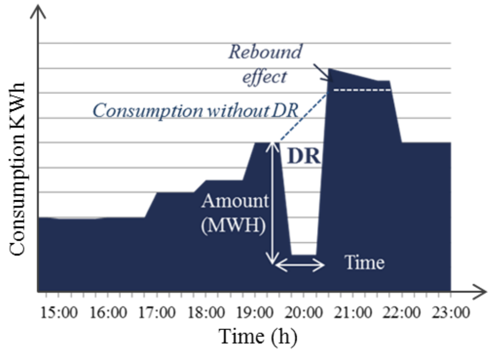

Fig. 1 Demand Response effect on consumption pattern

As discussed in [3], [4], [5] Demand Response is able to increase the system's adequacy and to substantially by reduce the need for investment in grid development and peaking generation by shifting consumption away from times of high demand as well as act as a cost effective balancing resource for variable renewable generation. Adding stability to the system, it lowers the need for traditional and often ineffective sources of energy. It furthermore decreases the need for local network investments, as it shifts consumption away from peak hours in regions with tight network capacity [5]. DR delivers these benefits by providing consumers – residential, commercial or industrial – with control signals and/or financial incentives to adjust their consumption at strategic times and by doing so promotes consumer engagement.

While there seem to be a consensus on the need for the energy sector to introduce and integrate Demand Response in energy markets, the preferred choice of the market framework enjoys far less unambiguity both from policy makers' and industry representatives' point of view [6], [7], [8], [9], [10], [11], [12], [13]. For example in Austria DR provider (Aggregator) has to agree bilaterally on data exchange and transfer pricing with Balance Responsible Party (BRP) before providing flexibly service to its customer; while in Switzerland DR provider does not need such an agreement with BRP, it has to compensate the BRP at transfer price determined by Transmission system operator (TSO). Furthermore, in Ireland neither BRP nor Aggregator is charged for the imbalance created [6], [7], [9]. Due to increased role of DR and independent Aggregator proposed in the European Commission

“Clean Energy Package”, the Member States have restarted discussion on the integration of DR in their respective energy markets with increased urgency. The objective of this paper is to present an overview of market models to be considered by Baltic policy makers. The main contribution of this paper is to review and categorize the market models currently employed in the EU and determination of the preliminary qualitative assessment criteria for model evaluation in the context of Balancing market in the Baltic region. The rest of the paper is organized in six parts: integration status in the EU; review of the market models; review of the main drivers behind DR in the Baltics, review of the legislative requirements; market model evaluation and conclusions.

II. II. DR INTEGRATION STATUS IN EU

Despite the Energy Efficiency Directive (2012/27/EU) has urged the Member states of EU to introduce the DR in all the energy markets, the majority of Member States still need to fully adopt the directive in practice According to the latest survey on the DR as of 2017, only in five countries (Switzerland, France, Belgium, Finland, Great Britain, and Ireland) DR products are actively participating in wide range of energy markets (Fig. 2*)* [6], [7], [9]. However, even in these countries, there are still some market design and/ or regulatory challenges.

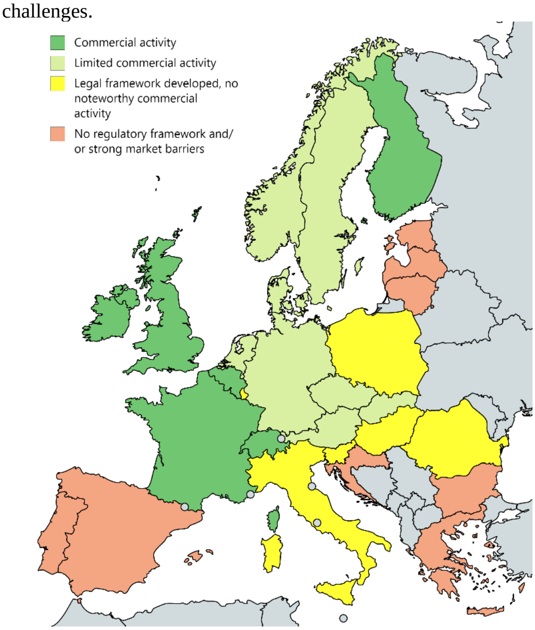

Fig. 2 Level of DR introduction in EU as of 2017. adopted from [7] [9]

When reviewing the countries with less substantial progress, three broad groups emerge. Countries where DR has been partly integrated; countries where the market models have been developed, but no noticeable commercial activity in the sector of DR has been observed and lastly countries where no regulatory framework has been introduced or very strong market barriers still persist.

The policy makers of Austria, Denmark, Germany, Netherlands, Norway, and Sweden, Czech Republic, Slovakia have started working towards introduction, however strong market barriers remain and the market growth is fairly limited. For example - Germany and the Nordic countries have started working towards introduction of independent Aggregator, while Austria has been working to incrementally improve bilateral agreement model currently employed. The policy makers of Slovenia, Italy and Poland have been working towards initial introduction of DR in the energy markets and market activity is expected, while Romania, Hungry and Luxemburg have developed regulatory framework but due to market barriers or energy system characteristics has rendered those markets inactive. The policy makers of Spain, Portugal, Baltics, Greece, Croatia, and Bulgaria has yet to develop basic regulatory framework for DR or have to remove significant synthetic market barriers. [6], [7], [8]. Overall, the situation in EU can be characterized as fairly heterogeneous.

III. III. THE REVIEW OF THE MARKET MODELS

The models presented in EU [5], [6], [7], [8], [9], [10], [11], [12], [13] can be broadly categorized in six architypes. Within each of the architype, different variations of the model are possible. There are two main groups of the model architypes: models where Aggregator directly or indirectly compensates the supplier for the energy transferred (Supplier Settlement Model, Consumer Settlement Model, Central Settlement Model) and models where Aggregators do not compensate neither directly nor indirectly the supplier for the energy transfer (Socialized Settlement Model, No Settlement model). The Integrated model does not have any energy transfer (and no compensation mechanism is necessary). Each of the groups has a subdivision. For the “compensation group” the subdivision is determined by the party through which the compensation is granted to the supplier. For the “no compensation group” the subdivision is determined by the group of customers who ultimately compensate the supplier (**Kļūda! Nav atrasts atsauces avots.**). The relationships between different market parties in each of the models are presented in (**Kļūda! Nav atrasts atsauces avots.**).

A. Integrated Model

The bundled approach for supply and DR is the simplest way to implement DR and avoids interfering with other stakeholders. However, it does not allow Aggregators to operate independently from suppliers, which may prevent unlocking the full DR potential in some markets. There are two subtypes of the “Integrated model”: “Price based integrated model” and “Supplier load control model”. Within the “Price based integrated model” the consumer pays the supplier a variable supply price. The possible variations of the supply price are set contractually, and the consumer can adapt its consumption in response to price variations. This model represents a large share of existing DR in Europe, notably for small consumers equipped with smart meters. In Latvia and Estonia this model is already in place as a dynamic tariff package provided by the retailers. Within the "Supplier load control model" the supplier extends the offer for the consumer to not only provide energy, but also manage directly the consumption pattern and sharing the gains. Following the activation of DR the consumer curtails its load at a predefined volume. The "unconsumed energy" can then be used by BRP to take part in balancing markets, self-balance its portfolio or benefit from high market price situations. This type of integrated supply and flexibility typically targets industrial consumers [5].

The rest of the models deal with an "independent" Aggregator (as opposed to integrated Aggregator in Integrated Model). In case of independent Aggregator, the consumer has to have two contracts – electricity supply contract (with their supplier) and a "flexibility contract" with an Aggregator. The flexibility contract entails that the Aggregator has a direct control over consumers load at a pre-specified volume. In case of DR activation, the consumer is expected to curtail its consumption and the Aggregator can use the unconsumed energy to take part in the energy markets. The compensation or "settlement" mechanisms determine the process and roles how the Aggregator compensates the "unconsumed energy". As stated before, the models can be divided in two groups – with compensation from the Aggregator and with an alternative settlement mechanism (no compensation from the Aggregator).

B. Supplier Settlement Model

The supplier settlement model is a market design in which the independent Aggregator and the BRP source conclude a bilateral agreement to solve the issues in regards to energy transfer. The economic efficiency of this model depends on the conditions in the contracts. If the BRP source/supplier refuses to sign bilateral agreements with independent Aggregators, or only at an excessive transfer price, it can exert a form of monopoly over flexibility.

C. Consumer Settlement Model

The Consumer Settlement Model requires that the energy sold on the market by the independent Aggregator is invoiced to the consumer by the supplier as if it had been consumed. This way, the transfer of energy is settled directly between the consumer and supplier at the contractual supply price. In case the Aggregator is not the consumer, compensation from the DR operator to the consumer is necessary, at least to cover the costs of the non-consumed invoiced energy. Such arrangements fall under the contractual relationship between the Aggregator and the consumer.

D. Central Settlement Model

The Central Settlement Model requires the transfer of energy to be performed by a neutral central entity. The central settlement model requires a wholesale settlement price between the independent Aggregator and the BRP source to settle the transfer of energy. This settlement price is a reference price that requires some form of regulatory approval.

E. Socialized Settlement Model

The Socialized Settlement Model is one option for the "no compensation" model. The model allows the consumer's BRP to sell the excess energy to TSO at the standard imbalance price. As transmission system operators are financially neutral institutions, the excess imbalance payment will increase the imbalance price. Within this model the costs of "unconsumed energy" are borne by all consumers.

F. No Settlement Model

The No settlement model requires the consumer's BRP schedule to be adjusted in accordance to the DR that was activated within the BRP's portfolio. Accordingly, the BRP is not able to sell the excess energy to the transmission operator. This model puts strong incentive on supplier to directly or indirectly require the consumers participating in aggregation to compensate the costs incurred.

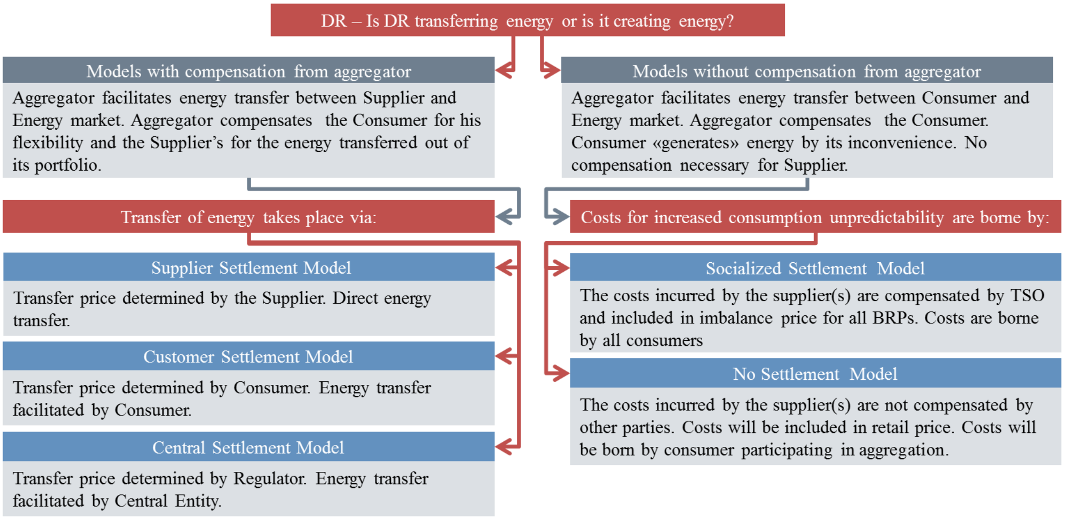

Fig. 3 Proposed market model taxonomy.

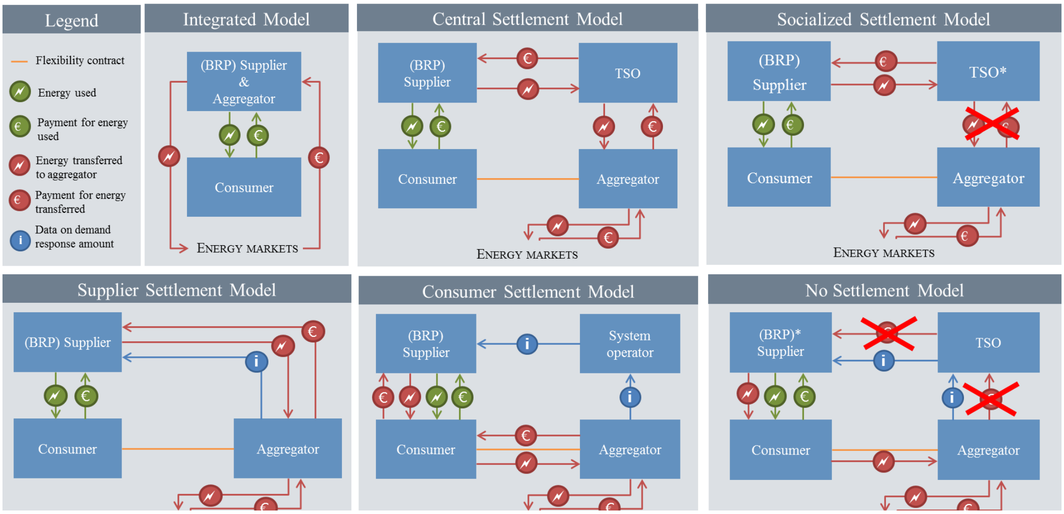

Fig. 4 Roles and responsibilities in different market models, adopted from [5], [8], [10], [11], [12], [13].

IV. IV. THE DRIVERS FOR THE DR IN THE BALTICS

A. Increase in unpredictable generation.

Similarly to the trends in the Central and Southern Europe, the energy system in the Baltics becomes more reliant on the unpredictable distributed generation. Since 2010 the wind energy generation has increased more than three times and currently the total wind capacity in the Baltics has reached almost 796 MW while solar capacity is 70 MW (**Kļūda! Nav atrasts atsauces avots.**). As of 2016 the installed capacity of unpredictable (distributed) generation (wind & solar) is more than 10% of total generation capacity in the Baltics (Fig. 5). Furthermore, the trend is upwards sloping – the wind has already been one with the highest installed capacity increase rate, and it is expected to be further amplified by the upcoming oil shale production reduction in Estonia after 2020 due to facilitated lower CO_2 emissions.

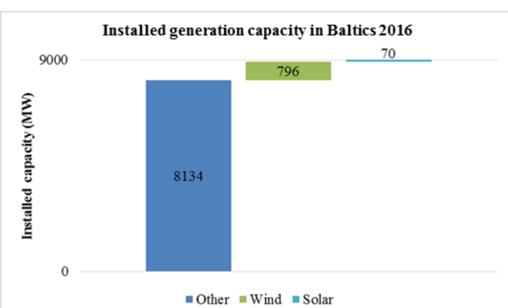

Fig. 5 Installed generation capacity in Baltics 2016, Data source: ENTSO-E

B. Higher balancing market liquidity.

Currently in Latvia there is only one business entity participating in balancing market. While there has not yet been situation where all submitted balancing bids are activated, having a single market participant is traditionally seen as suboptimal. Allowing new type of product (DR) would diversify the balancing market bid offer. Furthermore, the lack of demand side flexibility results in low energy price elasticity [14]. Increased demand side flexibility would have positive effect on market prices in all energy markets (including balancing market).

C. The legislative framework requirements

Both existing and upcoming requirements from the legislative framework designed by European Commission have already emphasised that the Member States are to develop a market model where Demand Response resource owners (both resident and non-resident) can freely participate in the respective energy markets. According to the [6], [7], [9] while none of the countries have special obstacles disallowing Demand Response, the lack of appropriate framework for DR inclusion in different energy markets has made DR inclusion virtually impossible. Furthermore, the "Clean Energy package" originally published on the 30th of November 2016 continues to stipulate the requirements of the market model in a greater detail than before [2]. The precise requirements are reviewed in the following sections.

D. The desynchronization from the Integrated Unified Power System

The desynchronization from the Integrated Unified Power System (IPS/ UPS) is one of the priorities outlined in EU Energy Strategy. While the exact date of the desynchronization has not yet been set, it is the common understanding of the Baltic TSOs that preparations for this task should be started already now. The following three scenarios have been suggested as the most feasible options for the desynchronization plan:

- Baltic States' synchronous operation with continental Europe (HVAC Lithuania-Poland interconnector), including soft coupling supported by existing HVDC links;
- Baltic States' synchronous operation with the Nordic countries (HVAC Estonia-Finland), including soft coupling supported by existing HVDC links;
- Baltic States' isolated island operation, including soft coupling supported by existing HVDC links.

While these approaches differ vastly in technical specification and costs, they all share the essential precondition for Baltic States' energy system having higher flexibility [15].

When comparing the Baltics with other EU countries in regards to the main drivers behind the development of DR, it is clear that many aspects overlap. The increase in unpredictable generation to at least some extent is present in all EU countries. Similarly, the need for higher liquidity in balancing market is almost universal across the EU. Given that the Baltic region is in IPS/ UPS and that the wind & solar energy penetration for the Baltics is still below Western Europe, it follows that the pressure to integrate DR in the energy markets are comparatively lower in the Baltics than in, for example, Ireland or Denmark. Furthermore, the EU policy/ regulatory requirements are the same for all - EU countries and this aspect, though important, also do not distinguish the Baltics among the other EU countries. The most unique driver for DR in the Baltic region is the upcoming desynchronization from IPS/ UPS. It is already known that when the Baltics do desynchronize, the market of DR must be already in place, especially for balancing and reserve markets. Based on experience in the EU the length of time required for DR market to become commercially active in five or even more years [7]. Accordingly, market regulations should be developed and implemented already now.

V. V. REVIEW OF LEGAL REQUIREMENTS FOR THE BALTICS

Before European Commission (EC) published the project for "Clean Energy Package" on 30th of November 2016, the key EC regulation in regards to Demand Response and aggregation had been Energy Efficiency Directive (2012/27/EU) [16]. The main requirements towards Demand Response from the Energy Efficiency Directive can be divided into four sections [9]:

- Demand Response should be encouraged to participate alongside supply within the wholesale, balancing and ancillary services markets;
- TSOs and DSOs must treat Demand Response providers, including Aggregators, in a non-discriminatory manner and on the basis of their technical capabilities;
- National regulatory authorities should define technical modalities for the participation in these markets on the basis of participants' capabilities;
- These specifications should include enabling Aggregators.

The "Clean Energy Package" further includes more detailed and more concrete requirements for the member states. The two regulations most discussed in regards to DR are: Proposal for Directive on the internal market for electricity and Proposal for Directive on the internal market for electricity.

The draft proposal for the Directive on the internal market for electricity develops on the initial stance and provides Member States with further details (particularly Articles 13 and 15). The directive stipulates importance of [2]:

- Granting demand side resources (private and professional) access to all markets (wholesale, balancing, ancillary services) at all timeframes and introducing a new obligation to remunerate customers for the flexibility;
- Empowering the consumer to participate in DR (directly or through aggregation) without the consent of the supplier and to switch aggregation service provider without penalty;
- Empowering independent Aggregators by ensuring that they can enter the market without the consent from the supplier and can participate in the energy markets without compensating the supplier and/ or generator.

VI. QUALITATIVE EVALUATION OF THE MARKET MODELS

The overview presented in the previous sections sets up the basis for the evaluation of the models in the context of the Baltic region. The best practices along with the drivers for the DR integration in the Baltic energy market and the upcoming changes in the legislative framework suggest that a model should not only be in line with the current legislation but should also have the following characteristics:

- Inclusive – meaning that the market model ensures there are no barriers of entry for the independent Aggregator;
- Fair – meaning the market model treats the Aggregators as energy transfer facilitators between market participants;
- Simple – the market model is compatible with the existing data exchange processes and does not require significant investments in IT infrastructure/ administrative processes for other market participants.

In the Fig. 6 the summary of model comparison is presented.

Market model	Inclusive	Fair	Simple
Integrated	✗	✓	✓
Supplier settlement model	✗	✓	✓
Consumer settlement model	✓	✓	✗
Centralized settlement model	✓	✓	✓
Socialized settlement	✓	✗	✓
No settlement	✓	✗	✓

Fig. 6 Comparison of the market models

The preliminary qualitative comparison of the models suggests that the best approach for the integration of DR in Baltic Balancing market is to combine two models:

- The Integrated model is the most appropriate for suppliers who are interested in developing new products for their customer portfolio;
- The Centralized settlement model is the most appropriate for independent business interested in providing aggregation service.

Such combination of models will provide the best opportunity for the existing and the potential market participants and ultimately will ensure that each and every customer has an option to participate in the balancing market. Further research should focus on the analysis of how the market model impacts the prices within energy wholesale and retail markets, as well as assessment of the most suitable market model or combination of market models for energy wholesale markets.

VI. V. CONCLUSIONS

There is a clear necessity both from business and regulatory side to implement and advance Demand Response inclusion in the balancing market of Baltic region.

The theoretical and practical market models observable in literature or practice can be divided into six different model types based on how the DR energy is treated and how the compensation of energy transfer is compensated.

The market model adopted in Baltics should facilitate barrier-free entry for the Aggregators as otherwise DR market will not develop to extent it provide sufficient support for the energy system.

The preliminary qualitative analysis of the models concludes that the most appropriate model for Baltic countries is combination of Integrated and Centralized settlement model.

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Estimating Energy Reduction Amount in the Event of Demand Response Activation: Baseline Model Comparison for the Baltic States

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***Abstract* — Demand response integration in energy markets can provide significant financial saving for grid operators and market participants and promote optimal resource allocation. An important step towards the integration is the introduction of methodology estimating energy transferred via demand response activation event. In essence, a consumption baseline model is a mathematical forecast of the energy consumption pattern that would have occurred in the absence of demand response event. These calculations are then used as the basis for the financial settlement among different market parties – consumers, aggregators, system operators and balance responsible parties. Currently there is no universal consensus on the best consumption baseline model and approaches used, differ wildly even among countries with relatively high demand response commercial activity. The objective of this paper is to compare different consumption baseline methodologies in terms of accuracy and robustness while taking into account the unique challenges within the Baltic region. For the comparative analysis we use hourly consumption patterns of one year for 40 different types of consumers. The analysis suggest that from the consumption baseline models reviewed, UK model performs the best in terms of accuracy and robustness.**

***Index Terms* — Demand response, balancing market, baseline calculations, system balancing, independent aggregation.**

I. INTRODUCTION

Demand response service (DR) is a temporal change in consumer's energy consumption due to a reaction to price signals or by other measures [1]. DR is associated with multiple benefits such as increased system flexibility, improved network congestion, cost-effective alternative to grid investments and improved energy efficiency [2], [3].

DR can be broadly divided in two groups: implicit DR and explicit DR. Implicit DR ("price based" DR) refers to consumers choosing to be exposed to time-varying electricity prices and/ or time-varying network tariffs that reflect the real cost of electricity at the time of use and allows the consumer to react to that price depending on their own preferences. Explicit DR refers to a program, where demand competes directly with supply in the wholesale, balancing and ancillary services' markets directly or through the services of aggregators. This is achieved through the controlled changes in the load that are traded in the electricity markets, providing a comparable resource to generation, and receiving comparable prices [4], [5]. Currently, implicit DR in Latvia and Estonia is available to consumers via electricity supply contracts where retail price is linked to the spot price. Starting from late 2017, there is an ongoing DR aggregation pilot study in Estonia, however the explicit DR is not commercially active there or anywhere else in the Baltics. [6]

For explicit DR to become commercially active, a market framework describing the financial settlement among the market parties (such as consumers, aggregators, system operators and balance responsible parties) needs to be developed. Estimate of DR delivered also known as the electricity reduction amount (ERA) is a pivotal part of such a framework. ERA is the difference between the actual consumption that occurred and the forecasted consumption that would have occurred in the absence of DR activation event. This forecast is called a baseline and a method for baseline estimation is called consumption baseline model (CBM) (Figure 1) [7].

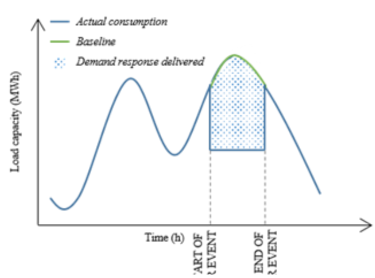

Figure 1. Descriptions of models reviewed

As of now there is no universal consensus on the best performing CBM and even in countries where the DR commercial activity is relatively high (e.g. UK, France, Belgium, USA) the choice of the model tends to be rather fluid, and CBMs are regularly updated to reflect the reduced costs of data collection and processing as well as improved understanding of the underlying processes [2], [4], [5], [7]-[12]. Regional CBM compatibility studies have been performed in USA [7], [10], UK [13], Australia [14] and EU in general [4], [5] among others. When considering a CBM proposal for the Baltic region, we need to take into account the additional challenges regarding the data resolution. Traditionally, DR events for a single metering point can be shorter than 15 minutes. Currently the imbalance settlement period in the Baltics is 1 hour and the metering data that can be used for the financial settlement are collected at the same time resolution [6]. The mismatch between the length of a DR event and the time resolution of available metering data further complicates development of acceptable CBM [11]. The main contribution of this paper is testing CBMs' accuracy and skewness on a lower resolution metering data (using the hourly data that are typically used in Baltics instead of more popular 5-minute or 15-minute resolution usually used in the previous research). Such tests are important because the change in data resolution can have an impact on the relative performance of CBMs.

The rest of the paper is organized as followed – overview of CBMs tested, CBM comparison analysis and Conclusions and further results.

I. OVERVIEW OF CBM

A. Characteristics of CBM

A CBM is used to forecast the consumption in the absence of DR activation event. A well-designed CBM enables grid operators and utilities to measure performance of DR resources and correctly attribute imbalance caused. Such CBM benefits all stakeholders by aligning the incentives, actions and interests of consumers, aggregators, utilities and grid operators, however, not all CBMs can be considered well-designed [11]. A CBM that systematically over-estimates the forecasted consumption will over-value the contribution of the participating DR resource and result in overestimation of positive imbalance for the balance responsible party of the said resource. Conversely, a CBM that systematically underestimates forecasted load will under-value the contribution of the participating DR resource and result in overestimation of negative imbalance for the balance responsible party [11].

Based on the literature review, CBMs are characterized by the following parameters: accuracy (low average expected error); robustness (absence of systematic error in either direction and lack of obvious data manipulation exploitation possibilities for opportunistic market participants) and transparency (market parties can apply the CBM and get the same results as the grid operator) [7], [14]. It is important to note that at times these characteristics are at odds with each other – a very accurate models based on advanced data processing methodologies tend to be fairly complex and non-transparent, while very simplistic models tend to be fairly vulnerable to data manipulation [2], [11]. Accordingly, the choice CBM is ultimately dependent on the relative importance attributed to accuracy, robustness and simplicity. This implied necessity for tradeoffs when designing a CBM for a particular market, at least partly explains the exotic variety of CBMs already in place.

All CBMs can be broadly divided in two categories – day-matching forecast and regression forecast [12]. In the Baltics the concept of explicit DR is still fairly novel and the new market participants (such as independent aggregators) still faces limited enthusiasm from the incumbent market participants. Based on the market maturity and the Baltics market participants' views presented in public consultation summary, it is obvious that a CBM relying on advanced statistic and data processing tools would currently not be feasible [2], [7], [14], [15]. Similar approach can be observed in the EU, where, as of now, only France balancing market has employed long-term statistics-based model, while all other EU states, where CBM is present, has opted for day-matching CBMs [4], [5], [11]. Furthermore, our position on regression based models were further cemented by EnerNOC (2009) that stated that regression models have been rejected in the USA due to the lack of support from the market participants. Accordingly, regression based models are not reviewed in this paper on the basis of not fulfilling the minimum requirements of simplicity parameter [11].

The day-matching CBMs can be further divided in two sub-categories – models using only data from before the DR activation event and models using data from both before and after the DR activation event. In the EU CBMs using only ex-ante metering data seem to enjoy higher popularity [4], [5], which might be linked to the ex-ante/ex-post CBMs being more vulnerable to data manipulation exploits.

B. Baseline methodology forecast models

We tested four day-matching CBMs – three of those only use metering data from before DR activation event and one uses data from both before and after activation. Description of the CBMs tested is presented in Table 1.

1. EnerNOC CBM has been used and tested in North America (USA) and is one of the earlier baseline models tested in markets. EnerNOC original variation operates with time resolution of 1 hour. [11]

2. UK model is adopted from the paper by Imperial College London (2014) and for a time was used in the UK. The model originally operates with higher time resolution and the model has been adjusted to the use of hourly metering data [13].

3. Average CBM is the only model in our test that uses both before and after DR activation event data. The model broadly follows concepts present in the CBM employed in Ireland [4], [5].

4. Daily profile CBM is loosely based on the methodology present in Belgium [4], [5]. Similarly, to the Daily profile, the Belgium model does not fully use day-matching approach since only the data from the same day is employed in the CBM. Furthermore, Belgium uses 15 min time resolution.

Based on the paper presented by DNV KEMA (2013) to the basic CBM calculation type, the separate calculation can be applied to align the baseline with the observed conditions of the event day – baseline adjustment method. CBM adjustment method can improve the performance of the model significantly. The factors used for adjustment rules may be based on, but are not limited to: temperature, humidity, calendar data, sunrise/sunset time and/or; event day operating conditions (most widely used factor). There are two main type of baseline adjustments methods:

1. Additive, which adds a fixed amount to the provisional baseline load in each hour, such that the adjusted baseline will equal the observed load at a time shortly before the start of the event period.
2. Scalar, which multiplies the provisional baseline load at each hour by a fixed amount or scalar, such that the adjusted baseline will equal the observed load on average during a window of time shortly before the start of the event period [12].

In our analysis, additive adjustment is used in EnerNOC CBM, UK CBM and Average CBM, while scalar is used in Daily profile CBM (see table I).

TABLE I. TABLE TYPE STYLES

CBM	Short description
EnerNOC	Baseline is equal to the average consumption of 5 corresponding hours with highest consumption within 10 last non-event days. Baseline is adjusted upwards by the average difference between last two hours' actual consumption and their baseline. $$\text{Formula: } b_t = \frac{c_1 + c_2 + c_3 + c_4 + c_5}{5} + \max[\frac{c_{t-1} - b_{t-1} + c_{t-2} - b_{t-2}}{2}; 0] \quad (1)$$
UK	Baseline is equal to the average consumption of 5 corresponding hours within 5 days with highest daily consumption (out of 10 last non-event days). Baseline is adjusted upwards and downwards by the difference between last two hours' actual consumption and their baseline. $$\text{Formula: } b_t = \frac{C_1 + C_2 + C_3 + C_4 + C_5}{5} + \frac{C_{t-1} - b_{t-1} + C_{t-2} - b_{t-2}}{2} \quad (2)$$
Average	Baseline is equal to the average of consumption one hour before and one hour after the DR event. $$\text{Formula: } b_t = \frac{c_{t-1} + c_{t+1}}{2} \quad (3)$$
Daily profile	Baseline is equal to the consumption within preceding hour multiplied by the fraction of increase/decrease of consumption in the corresponding hours a day before the event. $$\text{Formula: } b_t = \frac{c_{d,\,t-1} * c_{d-1,\,t}}{c_{d-1,t-1}} \quad (4)$$

b_t – baseline at hour t;

c_1 – highest corresponding hourly consumption within 10 last non-event days;

C_1 – highest corresponding hourly consumption in a day with highest daily consumption within 10 last non-event days.

II. CBM COMPARISON ANALYSIS

A. Data description

We used hourly metering data that represents annual consumption of 40 randomly selected medium to large electricity end-users from the Baltic region. The set of consumers included different consumption patterns with the hourly average consumption varying from 50 kWh to 3 MWh. In our analysis, we mainly focus on the medium and large consumers due to two reasons: such consumers usually are characterized with higher consumption pattern volatility, such consumers have higher DR potential.

To ensure that the sample is heterogeneous and represents different consumption patterns, correlation analysis was performed for all pattern pairs. The results of the correlation analysis indicated a well diverse sample and indicated that no pattern type is over-represented.

The total number of hours used in the analysis is 8760. Since each model requires different number of days or hours before the event, the number of hours with forecasted baseline differs among the models tested.

B. Analysis

Based on the literature review all CBMs analyzed fulfil the simplicity parameter. Accordingly, the objective of the analysis was to quantify each model's accuracy and robustness.

For robustness comparison, we calculated netted mean forecast errors (NMFE) and for the accuracy measurement we used absolute mean forecast error (AMFE). If NMFE is equal (close) to zero it is expected that in long term inaccuracy will not have impact on total amounts of energy transferred – in other words, NMFE measure the extent to which the model is systematically skewed in either direction. AMFE measures the expected deviation in a single instance. As a benchmark for the AMFE we use results from the study covering different CBMs in USA where the model accuracy for models with adjustments ranged from 10-14% [12].

The baseline error was calculated as follows:

$$Er_{BL} = E_F - E_A, \text{ where} \quad (5)$$

Er_{BL} – Baseline error (kWh),

E_F – Baseline or forecasted energy consumption (kWh),
E_A – actual consumption (kWh).

Sample error at a trading interval (t) is calculated as follows:

$$Er_{\%_t} = \frac{\sum_{i=1}^{I} \frac{Er_{BL\,i,t}}{Er_{A\,i,t}}}{I}, \text{ where} \quad (6)$$

$Er_{\%_t}$ - baseline error at a trading interval t,
I – number of consumption patterns in the testing sample,
i – consumption pattern.

Accordingly, if the baseline error is above 0 the baseline is overestimated while if the baseline error is below 0, the baseline is underestimated.

NMFE is calculated as follows:

$$NMFE = \frac{\sum_{t=1}^{T} Er\%_t}{T}, \text{ where} \qquad (7)$$

NMFE – netted mean forecast error for all trading periods within the sample,

t – trading interval,

T – all trading intervals in the sample.

AMFE is calculated as follows

$$AMFE = \frac{\sum_{t=1}^{T} |Er\%_t|}{T}, \text{ where} \qquad (8)$$

AMFE – absolute mean forecast error for all trading periods within the sample.

To estimate the statistical significance of the average accuracy differences observed for both MNFE and AMFE, we run F test for the difference in two variances for all CBM pairs at significance level of 99%. The results indicate that all CBMs' variances are significantly different from each other. We continue with t-test for differences in error means of CBMs. The results are presented in the next section.

C. Results

The descriptive statistics of NMFE and AMFE is presented in table II and table III.

TABLE II. NMFE DESCRIPTIVE STATISTICS

	EnerNOC CBM	**UK CBM**	**Average CBM**	**Daily prof. CBM**
SD	33.21%	7.54%	3.52%	6.64%
Variance	1103%^{2}	57%^{2}	12%^{2}	44%^{2}
Max	727%	66%	182%	389%
Mean	36.6%	0.7%	1.1%	1.1%
Min	1%	-43%	-23%	-100%
Sample	8312	5797	8759	8686

TABLE III. AMFE DESCRIPTIVE STATISTICS

	EnerNOC CBM	**UK CBM**	**Average CBM**	**Daily prof. CBM**
SD	33.15%	6.24%	3.27%	6.49%
Variance	1099%^{2}	39%^{2}	11%^{2}	42%^{2}
Mean	37.8%	9.5%	4.8%	7.1%
Sample	8312	5797	8759	8686

The density distribution for forecast errors of the CBMs tested is presented in Figure 2.

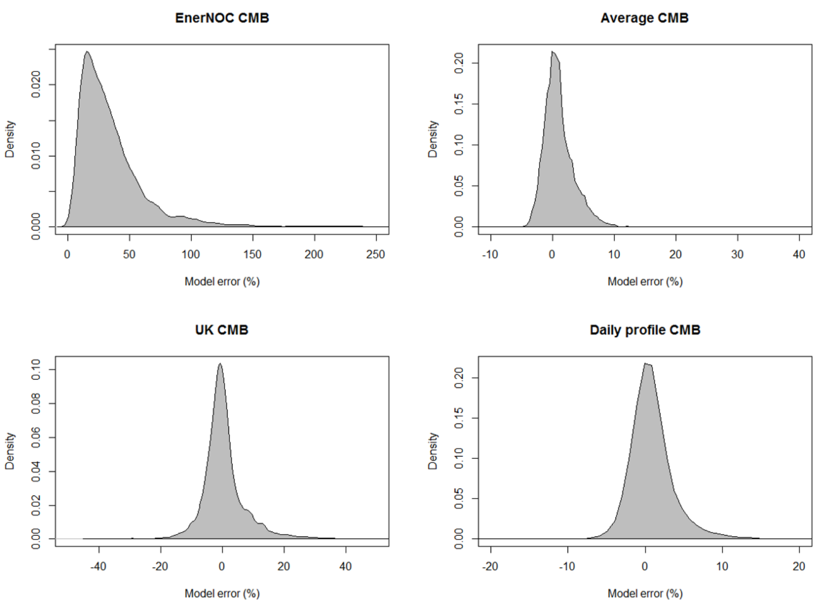

Figure 2. Density distribution for forecast errors of the CBMs tested

The results of the t-test for the mean difference for the model pairs for NMFE and AMFE values are presented in the table IV and table V accordingly.

TABLE IV. NMFE T-TEST RESULTS

t-value for differences of error means

	UK CBM	Average CBM	Daily prof. CBM
EnerNOC CBM	95.280***	97.068***	95.691***
UK CBM		3.969***	3.677***
Average CBM			0.366

Note: Significance: ***:1% level; **: 5% level; *:10% level.

The results for the t-test for NMFE indicate that there is no significant difference between NMFE of Average CBM and Daily profile CBM. All other differences are statistically significant at a significance level 1%.

TABLE V. AMFE T-TEST RESULTS

t-value for differences of error means			
	UK CBM	Average CBM	Daily prof. CBM
EnerNOC CBM	72.895***	90.306***	83.059***
UK CBM		-52.781***	-22.906***
Average CBM			-28.738***

Note: Significance: ***:1% level; **: 5% level; *:10% level.

The results for the t-test for AMFE indicate that the CBMs present significantly different AMFE at the 1% significance level.

UK CBM shows the lowest NMFE (0.7%). The results indicate that if this model were applied there would be no substantial long-term inaccuracy of ERA in either direction. The EnerNOC CBM shows the poorest results, which is associated with overestimation of ERA for more than one third of the total energy volume.

Analysis of AMFE indicates that all models expect for EnerNOC CBM perform better than the benchmark value of 10-14% and as such is considered to fulfill the minimum accuracy condition.

III. CONCLUSIONS AND FURTHER RESEARCH

DR is associated with multiple benefits such as increased system flexibility, improved network congestion, cost-effective alternative to grid investments and improved energy efficiency. These benefits can only be taken advantage of if the DR service delivered can be measured in an accurate and transparent way. In this paper, we attempted to identify the most promising CBM for the Baltic States based on the criteria of simplicity, accuracy and robustness. From the four potential CBMs analyzed the best performing CBM in terms of accuracy and robustness is UK model. The model could be further studied and improved by testing different baseline adjustment methods. Furthermore, CBMs could be tested for systematic biases in specific points of the consumption pattern such as peak/off-peak and ramp up/ ramp down periods.

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Developing an economically advantageous wind forecasting method for electricity market design with a 15-minute imbalance settlement period

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***Abstract* — According to legal framework developed by European Commission all EU Member States shall employ 15-minute time resolution for imbalance settlement no later than 18th of December 2020 (or 1st of January 2025 in case of derogation). For intermittent energy sources that are traditionally associated with less precise generation forecasts this might result in considerable increase in imbalance costs. This presents a unique challenge for wind power station operators as there is lack of adequate forecasting tools supporting 15-minute time-resolution. The objective of this paper is to test and provide comparative analysis of alternative data interpolation methods in order to determine approach associated with the lowest mid-term imbalance costs for wind power station operators. The results of this study support wind power station operators and grid operators in transition towards 15-minute imbalance settlement period.[1]**

***Index Terms* - imbalance optimization, imbalance settlement period, market design, wind forecasting, renewable energy integration**

I. INTRODUCTION

European Energy Union strives towards integrating EU national energy markets to support coordinated transition to a low-carbon, secure and competitive EU economy. Market integration is a complex endeavor as it requires coordinated development of infrastructure, harmonization of market designs and adoption of operational procedures that allows effective use of said infrastructure and market principles. One of initiatives aimed at market convergence and improved cross-border trade is the harmonization of time resolution used for imbalance settlement – imbalance settlement period (hereinafter – ISP) – among all EU states. In accordance with legal framework developed by European Commission all EU Member States shall employ 15-minute time resolution for imbalance settlement no later than 18th of December 2020 (or 1st of January 2025 in case of derogation). Currently most EU countries employ 60-minute ISP.

Balancing market design has an incompatibility between the time resolution of system balancing and imbalance accounting. While the system balancing ensures that the frequency is kept stable at any moment in time, the costs balancing is attributed based on market participant's net imbalance for certain period (60 min, 30 min, 15 min). Longer ISP allows more profound netting effect which is beneficial to market participants with volatile loads (e.g. intermittent generation) but results in unintended burden to other market participants due to resulting higher imbalance price. While the mechanism how the higher time resolution used for imbalance accounting will facilitate better cost allocation is self-evident, without improved operational planning both on system operator's and market participant's side, the resulting socio-economic benefits will remain limited.

One upcoming challenge faced by wind power station operators is the lack of adequate forecasting tools supporting 15-minute time-resolution. Currently, the typical time resolution of a mesoscale model output is 60-minutes. In order to get a qualitative improvement in load forecasting and lesser imbalance costs, the 60-minute data must be translated into 15-minute periods in a meaningful way. The objective of this paper is to test and provide comparative analysis of alternative data interpolation methods in order to determine approach associated with the lowest mid-term imbalance costs for wind power station operators. As the basis for analysis, the authors use wind speed observational data and imbalance price data from Latvia 2018. The results of this study will support wind power station operators and grid operators in transition towards 15-minute imbalance settlement period

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II. BACKGROUND

A. EU Legal requirements

European Union Treaty of Lisbon of 2007 [1] formalized the legal background for EU-wide solidarity in matters of energy supply and is considered the basis for EU Energy Union initiative. Energy Union is made up of five closely related and mutually reinforcing dimensions: security, solidarity and trust; a fully integrated internal energy market; energy efficiency; decarbonizing the economy; research, innovation and competitiveness [2]. As one of the tools to facilitate the objectives of the Energy Union, European Parliament delegated European Network of Transmission System Operators for Electricity (ENTSO-E) to develop network codes for grid connections, system operations and market design [3]. The codes list principles and guidelines all Member States should follow; however, the methodologies and implementation strategies are to be developed by competent authorities or grid operators. The requirement to harmonize imbalance settlement period is stated in Electricity Balancing guidelines (hereinafter – GLEB) [4]. According to GLEB Article 53 transmission system operators (hereinafter – TSOs) should implement 15-minute imbalance settlement period (hereinafter – ISP-15min) until 18th of December 2020 with Article 62 indicating that the introduction can be postponed until up to 1st of January 2025 (with the request for postponement to be submitted to National Regulatory Authority no later than 18.06.2020) [4]. Currently there three different time resolutions used for imbalance settlement in Europe: 60-minute ISP which is currently the most popular, 30-minute ISP which is employed only in UK, Ireland and France and 15-minute ISP which is set to be the new standard (see Figure 1) [5].

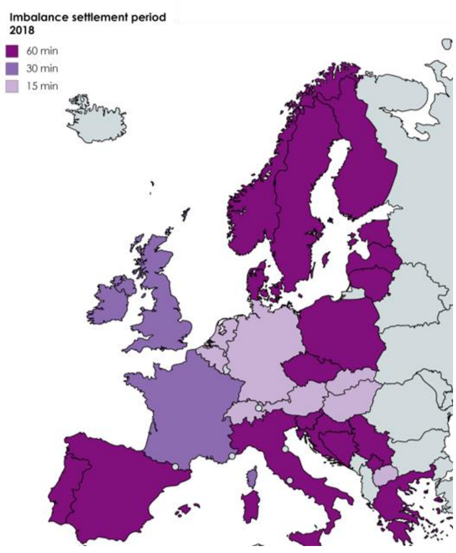

Figure 6 Overview of time resolution used for imbalance settlement in Europe [3].

B. Wind generation in Baltics

While traditionally Baltic states have mostly relied on electricity generation from natural gas and hydro resources, the introduction of more demanding climate requirements in EU combined with already exhausted opportunities for medium to large scale hydro power stations, wind generation has become the fastest growing type of electricity generation in terms of newly installed capacity. As of end of 2018, the total installed capacity of wind power stations in the Baltics is 815 MW - an 11% increase from 2017. The fastest growth has been observed in Lithuania (17%) (Figure 2). [6]

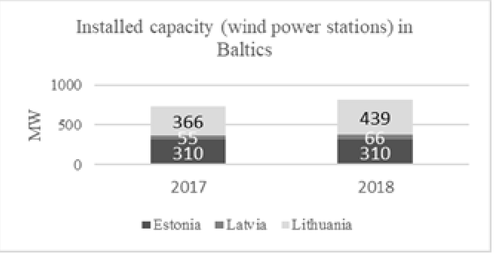

Figure 2 Installed capacity in the Baltics in MW.

Currently, wind generation constitutes up to 10% of total electricity generation mix. Due to considerable increase in installed capacity the growth in wind power generation has seen strong year-on-year growth with an exception of 2018, where all Baltic countries experienced abnormally dry and low wind weather during spring and summer (Figure 3) [6].

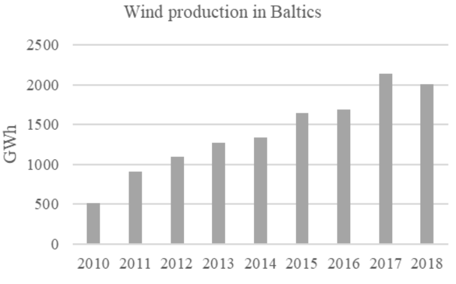

Figure 3 Baltic wind electricity generation trend 2010-2018 (GWh)

C. Baltic Balancing electricity market specifics and formation of imbalance price

Baltic energy systems are part of IPS/USP synchronous area, and the operational procedures are greatly influenced by conditions and requirements set out in BRELL agreement concluded among the Baltic states, Russia and Belorussia [7]. The agreement stipulates that the frequency in BRELL ring is maintained by Federal Grid Company of Russia while the Baltic states support it by ensuring area control error (hereinafter – ACE) of the systems within certain corridor. As of now, there is no market for FCR or aFRR type of balancing products required in the Baltics and only mFRR products are used. ACE is accounted for as unintended energy exchange and is measured on hourly basis. This unconventional setup does indicate a somewhat different balancing cost structure for Baltic States in comparison to rest of the EU. The situation will, however, change as soon as the Baltics join Continental Europe synchronous area and will be required to maintain stable frequency by the Baltic TSOs themselves [7].

As of January 2018 Baltic TSOs operate a common balancing market for exchange of mFRR standard products based on TSO-BSP model [4]. The balancing price is determined via marginal price methodology while imbalance price methodology implies single portfolio and single price mechanism. Costs (income) related to area control error (as well as other TSOs' costs related to balancing and not included in balancing price) are recovered via additional component (targeted component) in imbalance price [8].

D. Expected impact of 15-minute ISP on system operations

It is generally agreed that finer time resolution for imbalance settlement improves system forecast accuracy (Figure 4) [9-11]. The longer ISP, the more the deviations from the forecasted schedule are netted within the ISP and the lower imbalance amount is recorded. The netting effect is beneficial to market participants with volatile loads, but it hurts the other market participants. Regardless of netting, the system must be balanced at every moment, so the costs of balancing are still incurred and is translated into higher imbalance costs per MWh.

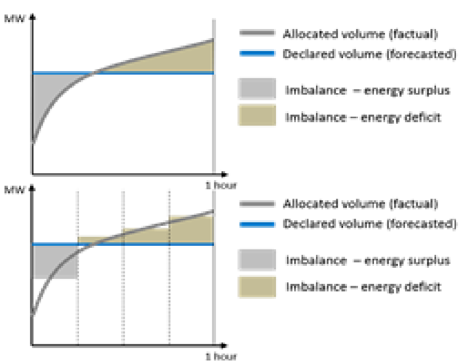

Figure 4 Imbalance settlement period, netting effect.

Furthermore, the highest imbalance in the Baltic system is typically recorded at the beginning of the hour when the generation units change regimes. This is caused by the slow ramping rates of the conventional generation plants by introducing shorter ISPs the ramping rates can be better acknowledge and more accurate system balance forecast could be created (Figure 5).

Overall, it is expected that the cost allocation among market participants will better reflect cost creation. However, real benefits for system stability and balancing cost reduction can only be achieved if market participants adjust and improve their forecasting methodologies.

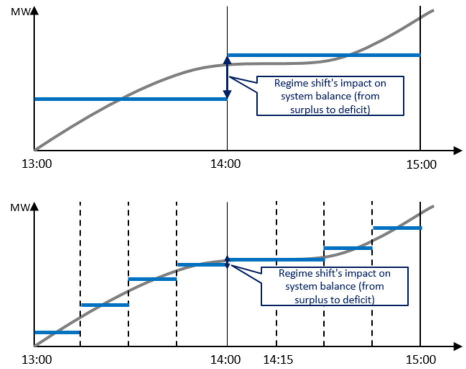

Figure 5 Imbalance caused by regime changes

III. ANALYSIS

A. Objective and scope

The typical time resolution of a mesoscale model output is 60-minutes. In order to get a qualitative improvement in load forecasting and consequently reduce imbalance costs, the 60-minute data must be translated into higher time resolution. The authors aim to explore benefits of facilitate this translation via interpolation an to test and compare the performance of the approaches. To exclude particularities outside of the scope of current research step, the authors opted to interpolate data from a single model. To test the quality of the interpolation, available wind observation data from 2018 with 10-minute time resolution was used. Accordingly, also the interpolation methods' performance is determined for 10-minute intervals. The authors are confident that for the purpose of this study it is acceptable to assume that the method's performance on 10-minute resolution is a proxy for the method's performance on 15-minute resolution.

To provide a rough comparison of economic performance the authors also accounted for the differences between imbalance cost of overestimation of wind speed and underestimation of wind speed and used absolute (as opposed to netted) forecasting error.

B. Methodology

Weather Research and Forecast model has been used to create a mesoscale model dataset. Although 30 min model data are available, the data were down-sampled to the time resolution of one hour. In total the authors tested 9 different interpolation methods. These approaches can be divided into three groups: "nearest neighbor", "polynomial interpolation" and "spline interpolation".

Nearest neighbor interpolation is the simplest method as it substitutes the unknown value with the closest available value, namely, for all ISPs between 14:00 and 15:00 the available modeled value for 14:00 is used. “Nearest neighbor” approach serves as a baseline approach to which the other eight methods are compared.

Polynomial interpolations use a polynomial function to obtain values between known points. Polynomial interpolation can have different orders, depending on the order of the function used. The authors tested three polynomial interpolation approaches – a linear function, where a straight line is drawn between known points (first order), a quadratic function (second order) and a cubic function (third order).

Spline interpolation is an approach where the interpolating function is required to have smoothness properties, by ensuring the continuity of derivatives. The authors tested five approaches based on spline interpolation (order 1 to 5).

After obtaining the interpolated model data the authors converted both real observation and interpolated model data in energy generated by using a power curve of a small wind power station. The difference between energy calculations based on the forecasted and observed data is considered imbalance. Furthermore, the annual expected cost of imbalance was calculated based on a difference between average imbalance prices (both directions) and corresponding spot prices for 2018. Lastly, the relative performance of each interpolation approach was calculated assuming the “nearest neighbor” method’s performance as a reference.

C. Inputs

The authors used the following data for the analysis:

- Model data was extracted from the mesoscale NEWA [13] dataset [14] for the nearest gridpoint, and vertically logarithmically interpolated in each timestep to the observational height.
- For observational data, available high mast measurements carried out using cellular communication masts for station near Ventspils, Staļdzene was used. Observational data are available for 10-minute intervals for one full year (2018) for the measurement height of 80 m [13].
- As a sample power curve for converting wind power in capacity, a power curve from Vestas V100/2000 (2MW) was used.
- For day ahead price calculations authors used NordPool spot prices for 2018 (Baltic/ Latvian bidding zone).
- For imbalance price calculations authors used Baltic TSOs imbalance price data for 2018 (Baltic/ Latvian bidding zone).

D. Results and discussion

Overall deviations between observations and forecast are quite high (netted error is ~20%). The calculations also show that the error rates from the mesoscale model data is skewed in the direction of overestimation. 60% of modeled values suggested wind speed higher than the observed while 40% suggested wind speed lower than the observed. In other words, the modeled data when used for electricity generation scheduling would result in 60% ISPs with negative imbalance (imbalance energy bought by the power station operator) and 40% ISPs with positive imbalance (imbalance energy sold by the power station operator) (Table 1). The authors do not detect statistically significant difference regarding systematic bias in one or the other direction among the interpolation methods tested.

Parameter	Standard approach	Polynomial interpolation			Spline interpolations				
	Nearest neighbor	**Linear**	**Quadratic**	**Cubic**	**Slinear**	**Spline (order 2)**	**Spline (order 3)**	**Spline (order 4)**	**Spline (order 5)**
% of ISPs where imbalance energy is bought	60 .65%	60 .59%	60 .61%	60 .64%	60 .59%	60 .49%	60 .78%	60 .58%	60 .57%
Imbalance energy bought annually (MWh)	2189 .38	2178 .26	2190 .69	2191 .30	2178 .26	2072 .72	2058 .34	2070 .00	2058 .03
Price of underproduction EUR/MWh	8 .22 €	8 .22 €	8 .22 €	8 .22 €	8 .22 €	8 .22 €	8 .22 €	8 .22 €	8 .22 €
Costs incurred in deficit hours (EUR)	18 002 .09 €	17 910 .63 €	18 012 .88 €	18 017 .86 €	17 910 .63 €	17 042 .82 €	16 924 .60 €	17 020 .52 €	16 922 .04 €
% of ISPs where imbalance energy is sold	39 .35%	39 .41%	39 .39%	39 .36%	39 .41%	39 .51%	39 .22%	39 .42%	39 .43%
Imbalance energy sold annually (MWh)	-965 .31	-960 .40	-966 .15	-966 .39	-960 .40	-952 .90	-953 .84	-949 .69	-952 .54
Price of overproduction EUR/MWh	5 .97 €	5 .97 €	5 .97 €	5 .97 €	5 .97 €	5 .97 €	5 .97 €	5 .97 €	5 .97 €
Costs incurred in overproduction hours (EUR)	5 764 .13 €	5 734 .81 €	5 769 .15 €	5 770 .54 €	5 734 .81 €	5 690 .00 €	5 695 .64 €	5 670 .82 €	5 687 .83 €

TABLE 1 MODEL COMPARISON – IMBALANCE COSTS (BOTH DIRECTIONS)

While overall deviations between observed and modeled (forecasted) value is quite high, the overall costs of imbalance remain adequate (7% of electricity sales). That is related to favorable market conditions that rendered small price differences between imbalance price and spot price (8.22 EUR/MWh for deficit and 5.97 EUR/MWh for overproduction) [6].

While comparing interpolation approaches the best performing model is Spline (Order 5). Compared to the simplistic approach (assuming modeled hourly value is unchanged for all ISPs within an hour), Spline (Order 5) provides 5.1% improvement for imbalance costs (Table 2).

Method name	**Expected annual imbalance costs**	**Performance against "nearest neighbor"**
Nearest neighbor	23 766 .22 €	n/a
Linear	23 645 .44 €	-0 .51%
Quadratic	23 782 .04 €	0 .07%
Cubic	23 788 .40 €	0 .09%
slinear	23 645 .44 €	-0 .51%
spline (order 2)	22 732 .82 €	-4 .37%
spline (order 3)	22 620 .24 €	-5 .04%
spline (order 4)	22 691 .34 €	-4 .75%
spline (order 5)	22 609 .88 €	-5 .10%

TABLE **2** MODEL PERFORMANCE COMPARISON

IV. CONCLUSIONS AND FURTHER RESEARCH

The objective of this paper is to test and assess performance of nine alternative data interpolation methods ("nearest neighbor", three polynomial and five spline) and to determine the method associated with the lowest mid-term imbalance costs for wind power station operators. According to the analysis, the best performing interpolation method for translating hourly model data into smaller time intervals is spline (Order 5). Spline (Order 5) compared to the simplistic "nearest neighbor" model offers 5.10% expected imbalance cost reduction. Similar level of reduced annual imbalance costs is associated with Spline (order 3). Based on these findings the authors consider that further analysis of the model performance should be carried out to compare the performance of Spline interpolation approach on other wind modeling tools and on other wind power turbines (including method's performance against metered generation outputs). While in-depth analysis would help to improve the interpolation approach, the initial assessment obtained in this study can already be applied as an interim support solution.

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Appendix IV

Harmonization of Imbalance Settlement Period Across Europe: the Curious Case of Baltic Energy Markets

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***Abstract*—In accordance with legal framework developed by European Commission all EU Member States shall employ 15-minute time resolution for imbalance settlement no later than 18th of December 2020 (or 1st of January 2025 in case of derogation). This presents a unique challenge for the Baltics, currently using 60-minute imbalance settlement period, as Baltics are synchronized with Integrated Power System/ Unified Power System of Russia (IPS/UPS) synchronous area where different legal framework applies. Based on these special conditions we, firstly, define parameters directly linked with imbalance settlement period and then analyze advantages and disadvantages of alternative approaches and propose implementation model to be used as an input for national policy makers.**

***Index Terms*—balancing markets, imbalance settlement period, market design, market integration**

I. INTRODUCTION

European Energy Union strives towards integrating EU national energy markets to support coordinated transition to a low-carbon, secure and competitive EU economy [1-2]. Market integration is a complex endeavor as it requires coordinated development of infrastructure, harmonization of market designs and adoption of operational procedures that allows effective use of said infrastructure and market principles. Due to the unique composition of existing energy system infrastructure, market practices and operational procedures, initiatives aimed and reaching the state of EU-wide convergence can, in practice, present widely different challenges for the Member States. Harmonization of time resolution used for imbalance settlement – imbalance settlement period (hereinafter – ISP) – among all EU states is no exception for that. There three different time resolutions used for imbalance settlement in Europe: 60-minute ISP which is currently the most popular, 30-minute ISP which is employed only in UK, Ireland and France and 15-minute ISP which is set to be the new standard (see Figure 1) [3]. While increasing granularity of time resolution will not be an easy task to any Member States currently employing 30 or 60-minute settlement periods, the situation for the Baltics might be somewhat more unconventional due to three main reasons:

- The Baltics are part of IPS/UPS synchronous area operated by the Federal Grid Company of Russia which is not subject to EU regulation and as of now has not proposed switching to a finer time resolution.
- The Baltics are operating a common Baltic Balancing market which means that not only Baltics need to harmonized not only ISP but also the approach of implementation (including treatment of meters not equipped with 15-minute time resolution capabilities).
- The Baltic Balancing market relies considerably on balancing energy from the Nordics via HVDC links. Having different imbalance settlement periods might hinder the energy exchange and further market integration.

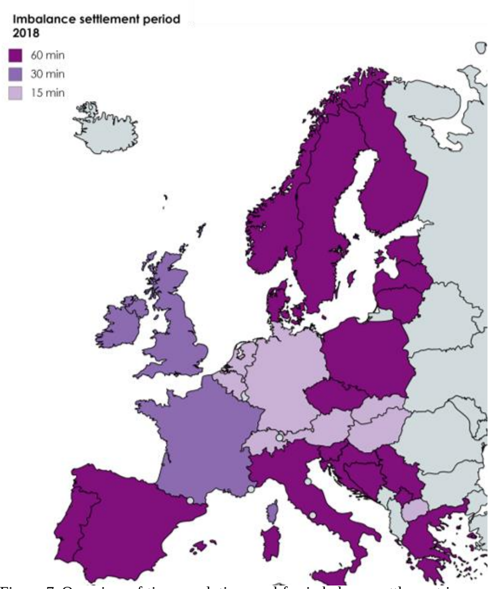


Figure 7 Overview of time resolution used for imbalance settlement in Europe [3].

This work has been supported by Latvian Council of Science, project: Management and Operation of an Intelligent Power System (I-POWER) (No. lzp-2018/1-0066).

This paper aims to review and analyze aspects to be considered while choosing the implementation model for adopting 15-minute ISP in Baltic balancing market. The main contribution of this paper is to structure the decision the policy maker must take into account while developing market framework as well as to propose changes necessary to the existing imbalance settlement practices. The aspects related to system planning (e.g. application of common grid model and cross-border capacity calculations for wholesale markets and security reasons are out of the scope.

The rest of the paper is organized as follows – Section II presents legal framework while Section III lists main expected benefits of the initiative. Section IV explains the particularities of Baltic Balancing market. Section V introduces the three implementation options, while Section VI compares the benefits and drawbacks. Finally, the conclusions are presented in Section VII.

II. LEGAL FRAMWORK

European Union Treaty of Lisbon of 2007 [1] formalized the legal background for EU-wide solidarity in matters of energy supply and is considered the basis for EU Energy Union initiative. Energy Union is made up of five closely related and mutually reinforcing dimensions: security, solidarity and trust; a fully integrated internal energy market; energy efficiency; decarbonizing the economy; research, innovation and competitiveness [2]. As one of the tools to facilitate the objectives of the Energy Union, European Parliament delegated European Network of Transmission System Operators for Electricity (ENTSO-E) to develop network codes for grid connections, system operations and market design [4]. The codes list principles and guidelines all Member States should follow; however, the methodologies or implementation strategies are to be developed by competent authorities or grid operators. The requirement to harmonize imbalance settlement period is stated in Electricity Balancing guidelines (hereinafter – GLEB) [5]. According to GLEB Article 53 transmission system operators (hereinafter – TSOs) should implement 15-minute imbalance settlement period (hereinafter – ISP-15min) until 18th of December 2020 with Article 62 indicating that the introduction can be postponed until up to 1st of January 2025 (with the request for postponement to be submitted to National Regulatory Authority no later than 18.06.2020) [5].

III. BENEFITS FOR ISP15

A. *Benefits of harmonized ISP*

The main benefits of ISP harmonization among Member States are more effective energy cross-border exchange. If two countries have different ISPs they will have different market time units (hereinafter - MTU) and that means that there will be segments of energy products the countries will not be able to exchange as hourly products cannot be put in the same common merit order as 15 minute products. Limited product exchange would result in market barriers and reduced optimal energy market liquidity, facilitating price differences that would harm fair competition for both electricity generators and energy-intensive industries. It is also important to note that harmonization of balancing market frameworks (including ISP) would allow more beneficial use of EU-wide balancing reserve market platforms that are currently being developed (e.g. MARI, PICASO) [5].

B. *Benefits of shorter ISP*

The main benefits for shorter ISP are the following [6-10]:

- Improved accuracy of balancing cost allocation;
- Improved profitability for flexible resources;
- Improved system balance forecasting.

The longer ISP the more the deviations from the forecasted schedule are netted within the ISP and the lower imbalance amount is recorded. The netting effect is beneficial to market participants with volatile loads, but it hurts the other market participants. Regardless of netting, the system requires to be balanced at every moment, so the costs of balancing are still there, and this results in higher imbalance costs per MWh. Finer time resolution for imbalance settlement improves accuracy (see Figure 2)

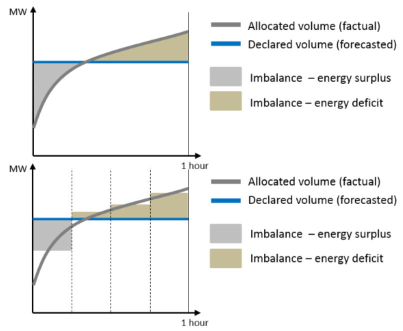
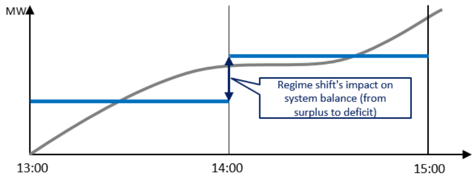


Figure 8 Imbalance settlement period, netting effect.

Improved cost allocation will result in higher profitability for flexible resources and more costs for the inflexible resources that causes imbalance. This should support higher investment in technologies supporting self-balancing portfolios for market participants [8,10].

When examining the system balance patterns it is clear that the highest imbalance is typically recorded at the beginning of the hour when the generation units' changes regimes. This is caused by the slow ramping rates of the conventional generation plants by introducing shorter ISPs the ramping rates could be considered and more accurate system balance forecast could be created (Figure 3).

Overall while implementation of finer time resolution is always related to investments it is important to keep in mind that in longer term it is expected to pay back due to reduce the total costs of balancing [6-7].



IV. ISP

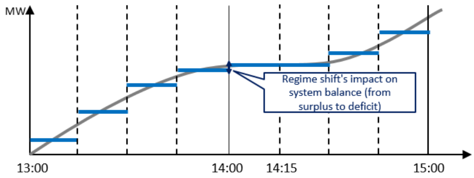


Figure 9 Imbalance caused by regime changes

IN BALTIC BALANCING MARKETS

When considering the implementation of 15-minute ISP in Baltics the following three special conditions must be taken into account:

- Baltics energy system is operating in IPS/UPS synchronous area;
- Baltic TSOs operate a common Balancing market;
- Baltic energy system relates to Nordic energy system.

C. IPS/USP synchronous area

Baltic energy systems are part of IPS/USP synchronous area and the operational procedures are greatly influenced by conditions and requirements set out in BRELL agreement [11] which states that frequency in BRELL ring is maintained by Federal Grid Company of Russia while Baltic states support it by ensuring area control error (hereinafter – ACE) of the systems within certain corridor. In essence it means that in Baltics as of now, there is no market for FCR or aFRR type of balancing products and only mFRR products are used. ACE is accounted for in MWh and is measured on hourly basis. This unconventional setup does indicate that somewhat different balancing cost structure for Baltic States in comparison to rest of the EU. The situation will, however, change as soon as Baltics join Continental Europe synchronous area as then the frequency will be maintained by Baltic TSOs themselves [11].

D. Characterization of Baltic Balancing market

As of January 2018 Baltic TSOs operate common balancing market for exchange of mFRR standard products based on TSO-BSP model [5] Balancing price is determined via marginal price methodology while imbalance price methodology implies single portfolio and single price mechanism. Costs (income) related to area control error (as well as other TSOs costs related to balancing and not included in balancing price) are recovered via additional component (targeted component) in imbalance price. Metering data collection is not harmonized among the Baltics. Smart meter rollouts are currently at different stages – in Estonia smart meter rollout is already finished, in Latvia approximately 40% of meters (covering ~60% of consumption, ~100% of generation) are switched and in Lithuania the rollout is just starting [12].

E. Cooperation with the Nordics

Currently Baltic systems are interconnected with the Nordic system via two HVDC links – ESTLINK between Finland and Estonia and NORDBALT between Sweden and Lithuania. The connections allow energy exchange in all market frameworks but is especially important for balancing as it constitutes up to 30% of all balancing energy used in the Baltics. According to Nordic regulatory authorities, Nordics will assume 15-minute ISP at the end of 2020 [13].

V. IMPLEMENTATION OPTIONS

A. Model parameters

To ensure compliance with legal requirements only three alternative models for implementation are available:

- Option I – full implementation that implies system balancing for minimum ACE for each 15-minute ISP (disregarding that the Federal Grid Company only considers hourly imbalance for settlement purposes);
- Option II – light implementation (to continue system balancing for minimum ace at the end of the hour, while formally introducing 15-minute ISP;
- Option III – postponement of implementation until 2025.

When considering alternative options, the following processes are considered:

- *Balancing objective* – what is the goal of TSOs dispatchers when balancing the system?
- *Balancing products* – should 15-minute or 60-minute products be used? Is there common merit order (hereinafter cMOL) for 15-minute ISP or for the 60-minute period.
- *Balancing price* – is there the same balancing price for 60-minute period or different balancing price for each 15-minute ISP?
- *Targeted component* – how is the ACE related costs/benefits shared among the market participants.
- *Imbalance price* – is there the same imbalance price for 60-minute period or different balancing price for each 15-minute ISP.
- *Positions* – in which time resolution balance responsible parties are required to provide their positions (60-minute or 15-minute)?
- *Metering data* – how to profile metering data that cannot be measured directly at 15-minute time resolution?

B. Current situation (60-minute ISP)/ Option III

Process	Application
Balancing Objective	Minimization of ACE for each 60-minute ISP
Balancing products	60-minute mFRR products. cMOL for each 60-minute ISP
Balancing price	Single price for 60-minute ISP
Targeted component	Total costs/ earnings divided by absolute imbalance
Imbalance price	Single price for 60-minute ISP
Positions	60-minute time resolution
Metering data	60-minute time resolution

TABLE 2 MARKET PROCESSES (CURRENT SITUATION/ OPTION III) [12]

C. Option I

Process	Application
Balancing Objective	Minimization of ACE for each 15-min ISP
Balancing products	15-minute mFRR products, individual cMOL for each 15-minute ISP.
Balancing price	Determined for each ISP.
Targeted component	Methodology for targeted component does not change.
Imbalance price	Determined for each 15-minute ISP.
Positions	Submitted for each 15-minute ISP.
Metering data	Direct metering for all meters that are technically capable combined with profiled metering for all meters that are with 60 min resolution or lower. Profiles are to be determined based on network border meters which are all capable of 15-min resolution.

TABLE 3 MARKET PROCESSES (OPTION I)

D. Option II

Process	Application
Balancing Objective	Minimization of ACE for each 60-minute ISP
Balancing products	15 and 60-minute mFRR products. cMOL for each 60-minute ISP
Balancing price	Same price for four 15-minute ISPs within the hour.
Targeted component	Total costs/ earnings divided by absolute imbalance
Imbalance price	Same price for four 15-minute ISPs within the hour.
Positions	Submitted at 60-minute time resolution, equally divided by TSO to allocate positions for 15-minute ISPs.
Metering data	60-minute metering data equally divided by TSO to allocate positions for 15-minute ISPs

TABLE 4 MARKET PROCESSES (OPTION II)

E. Linked processes

When considering implementation options, it is important to take into account that by choosing the balancing objective (either 15-minute optimization or 60-minute optimization) all other processes listed in Tables 2 and 3 are already set.

For example, if TSOs employ 60-minute balance optimization, but the imbalance is determined directly for each 15-min ISP. Such set-up would require investments both from grid operators (changes in metering data exchange) and market participants (changes in how the positions are submitted), but there would be no benefits. Since the price for the balancing is the same for all four ISPs there is no financial impact on submitting different positions within the same hour. On other hand – if 15-minute balance optimization is coupled with equal imbalance volume distribution within four 15-minute ISPs within the same hour, in case the real imbalance of market participant was netted within that hour (possible if real imbalance was in different direction within the same 60-minute period), the TSOs will experience cash-flow difference between balancing and imbalance settlement.

VI. RESULTS

In this section main advantages and disadvantages of the Options presented shall be reviewed. To compare the option, the following criteria are used:

- Cost of implementation;
- Harmonization options with the Nordic systems;
- Benefits from shorter ISP-15 min as listed in Section III.

A. Option I

The Option I is the most challenging to implement as it requires changes in grid operator's and market participant's information systems. Furthermore, it would require the balance service providers to adopt shorter balancing products before Baltics has joined common EU mFRR exchange platform. For some BSP's the requirements might be too difficult to implement so soon.

While this option is the most ambitious it also provides most benefits. Not only Option I allows full harmonization with the Nordic systems but it also allows the market to provide motivational price signals to market participants and supports more accurate cost allocation.

B. Option II

The Option II requires IT investments only on TSOs part while allowing to continue to exchange energy products with the Nordic energy systems. Option II, however, does not allow for motivational price signal that would engage the market participants to support system balance.

C. *Option III*

The Option III provides little to no advantage over Option II while disallowing energy exchange with Nordic energy systems (which would considerably increase system balancing costs and even pose risk to system security). Accordingly, Option III is considered inferior to Option I and II.

VII. CONCLUSIONS AND FURTHER RESEARCH

In accordance to legal framework developed by European Commission all EU Member States shall employ 15-minute time resolution for imbalance settlement no later than 18th of December 2020 (or 1st of January 2025 in case of derogation). This presents a unique challenge for Baltics currently using 60-minute imbalance settlement period, as Baltics are synchronized with IPS/UPS synchronous area where different legal framework applies. After developing and reviewing three possible options for implementing 15-minute ISP in Baltic balancing market we propose that full implementation (Option I) would be preferable if the costs related to the implementation until end of 2020 are proportionate to the benefits that could be gained from the improved cost sharing accuracy, while light implementation (Option II) would be preferable either in case it is not possible to implement Option I un end of 2020 or if the costs of implementation is considered not proportionate to the according benefits. The estimation of costs and benefits is a topic of further research.

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Appendix V

Measuring the impact of demand response services on electricity prices in Latvian electricity market

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***Abstract* - Improved end-user engagement is considered to be a key factor in decarbonization efforts towards climate neutral energy systems. While local implementations of implicit and explicit demand response solutions have been available to end consumers, energy consumption optimization is still in the stage of early adopters and no aggregator services have emerged. The new regulation allowing demand response to enter Day-ahead market is expected to have an impact on the electricity prices. The objective of this paper is to perform factor analysis on Latvian wholesale electricity market prices to determine the effect of the introduction of demand response in day ahead market might have on other market participants.**

***Index Terms* - demand response, electricity price, electricity markets**

I. INTRODUCTION

In the context of Baltic synchronization with Continental Europe synchronous area, the discussion on alternative sources for fast acting reserves (FCR and aFFR balancing products) has gained prominence. Demand response services has been considered as one of the less expensive technological options comparing it to storage facilities and conventional gas turbines [1, 2]. However, the main drawback for relying on demand response services as a significant contributor towards ancillary services, is the limited market interest shown in developing demand response services as a separate, self-sufficient market niche. Until recently, the only market demand response where allowed to participate in Baltic region was market for ancillary services. The balancing market volumes constitutes a fraction of the wholesale market volumes. According to data publicly available on Baltic Balancing market Dashboard, in 2019, the total amount of upwards balancing volume in Baltic balancing market was 28,2 GWh while average daily consumption in Latvia is approximately 20 GWh-30GWh.

To facilitate faster adoption of demand response role in Latvian electricity market, a new Cabinet of Ministers regulation has been developed for aggregators (in force from 24th of March 2020). This regulation allows demand response services to participate not only in providing ancillary services for system operators, but also to participate in wholesale electricity markets [3].

New type of market participant not only provides new opportunities to end-users but is also expected to have an impact on electricity prices. Latvian wholesale electricity market is particularly interesting research environment due to the fact that for the last four years Latvian market has had the highest and the most volatile prices in the region. The objective of this paper is to perform factor analysis on Latvian wholesale electricity market prices to determine the effect of the introduction of demand response in day ahead market might have on electricity prices.

II. LATVIAN ELECTRICITY MARKET

A. Supply-demand relationship in electricity market

Due to the nature of electricity as a necessary good, the demand for electricity is naturally quite inelastic. Demand elasticity increases when consumers engage in either implicit (dynamic pricing) or explicit (active energy consumption management). Furthermore, overall electricity consumption in Latvia is fairly stable. For the last four years the year-over-year deviations for annual electricity demand has not exceeded 1.5%. According to report published by Latvian transmission system operator, electricity consumption to grow less than by 1% per annum (base scenario) [4]. The growth of consumption in a conservative scenario, (with average winter temperatures above -3.5 °C), is forecasted at ~0.5%. Similarly, the model developed by Skribans, V., & Balodis, M (2017) forecasts only slight increase (i.e. 10% within 10 years) of electrical consumption in Latvia [5]. From supply-demand perspective this means that lower prices for electricity can be achieved only by shifting demand from peak periods to, for instance, night hours, when electricity consumption in Latvia and the region is lowest [6].

On other hand, the supply of electricity depends on sale price on the market and their production short-term marginal costs. When bidding on Nord Pool exchange, producers with lower operational costs (and, thus, lower selling price) are followed by more expensive power producers, altogether forming merit order curve. Short-term marginal costs of wind, solar and hydro stations are comparatively low [1] while conventional stations

This work has been supported by Latvian Council of Science, project: Management and Operation of an Intelligent Power System (I-POWER) (No. lzp-2018/1-0066).

have high operating costs both in absolute terms [2] and if compared to their share of capital costs (Figure 1). Similarly, low marginal costs are expected to be associated with demand response services.

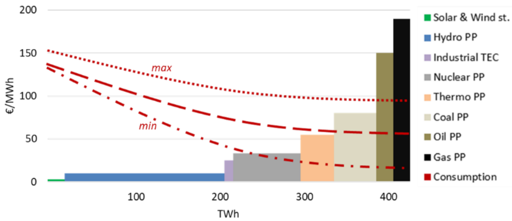
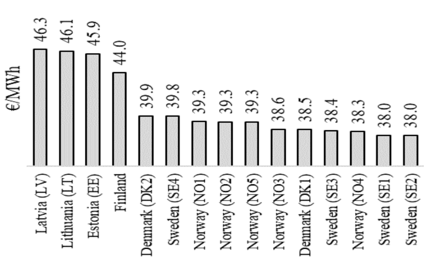


Figure 1. Power supply merit order curve in the Nord Pool region by production type. Source: adapted from Balodis M. (2016).

B. *Day-ahead price characterization*

Latvian electricity market operates under Nord Pool electricity exchange, which provides services for Nordic, Baltic region and Northern Europe (Germany, France, the United Kingdom, etc.). Nord Pool is the largest electricity exchange in Europe – in 2019 total of 494 TWh were traded on the exchange [7]. For comparison, Latvian total consumption of electricity in 2019 was 7.3 TWh, or 1.4% of traded on Nord Pool. Such traded amounts and large number of market participants (more than 400 entities) guarantee high competition and liquidity both for producers and consumers.

In 2019 average day-ahead price in Latvia was by 16% higher than in Sweden (zone 4), and by 5% higher than in Finland (Figure 2). While prices in Latvia, Lithuania and Estonia are quite close to each other, they are significantly higher than prices in Nordics (especially Sweden and Norway). This difference becomes even more pronounced when accounting for electricity consumption profile. Consumption is considerably higher during the business hours, so demand in Nord Pool either cannot be covered by the relatively cheap renewable and nuclear energy. In these hours cheap energy is mainly consumed in the bidding zone, there it is produced. In other bidding zones, day-ahead closing prices are determined by more expensive producers.



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114.6 €/MWh. In contrast, daily average prices in neighboring

Figure 2. Nord Pool day-ahead prices in 2019 (not profiled). Source: Nord Pool (authors calculations).

bidding zones never crossed 100 €/MWh level during last 4 years from 2016 to 2019.

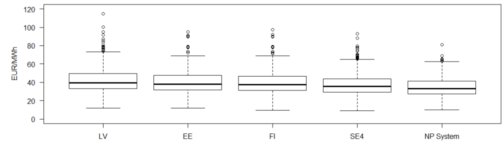

Figure 3. Box plot of daily average day-ahead prices, 2016-2019, Source: Nord Pool (authors calculations).

In Latvia, where only a couple of electricity retailers have their own production facilities, which can be used as a natural hedge against electricity price fluctuations, most traders are very sensitive to volatility of day-ahead prices. Introducing demand response services could provide additional hedging options for these traders.

III. METHODOLOGY AND DATA SET

A. *Methodology*

To determine the impact of demand response services on the prices of the day-ahead market, day-ahead price factor analysis is performed. To do this the Authors use time series methodology, which is the most widely used technique in studies focused on price determination [8, 9, 10]. Multiple linear regression model is employed to evaluate, if chosen set of *k* variables have statistically significant impact on electricity prices (*Y*). The general form of multiple regression model is (1):

$$Y_t = \beta_0 + \beta_1 x_{t,1} + \beta_2 x_{t,2} + \ldots + \beta_i x_{t,1k} + \varepsilon_t \quad (1)$$

The use of multiple regressions is associated with multicollinearity issues – the situation when two or more independent variable have high correlation, which may result in unstable solutions of regression models. According to [11], multicollinearity makes the regression coefficients unidentifiable. To minimize multicollinearity correlation matrix analysis is performed and regressions variables which have high mutual correlation is removed. Furthermore, regression model with highest explanatory power (measured as adjusted R-squared) standard model diagnostics is performed.

B. *Factors analysed*

To estimate the impact of consumption changes on the Day-ahead electricity price, the authors analyze the relationships between fundamental factors and electricity prices in Latvia such as oil, coal, natural gas and CO2 emission allowances have statistically significant influence on day-ahead prices in Latvia as the price of the fuels and CO2 emission allowances constitute biggest part of short-term marginal costs for generators [2]. Furthermore, the availability of renewable resources such as hydro and wind have statistically significant influence on day-ahead prices in Latvia because short-term marginal costs of hydro and wind stations are negligible [12].

Variable uses in analysis

- Electricity spot price (€/MWh) - Nord Pool traded day-ahead electricity price for a specific bidding zone (Nord Pool)
- Electricity consumption/ production prognosis (MWh) - Expected consumption/ production volume according to day-ahead Merit Order Curve result in a specific bidding zone (Nord Pool).
- Wind production prognosis (MWh) - expected wind production volume according to day-ahead Merit Order Curve results in a specific bidding zone (Nord Pool).
- CO_2 emission allowance price (€/ 1000t) -CO2 Daily Closing price of continuously traded EUA future contract on ICE (SKM).
- Natural gas (TTF) price (€/MWh) -Daily Closing price of continuously traded future contracts on ICE (SKM).

The results of multicollinearity correlation matrix analysis is presented in Figure 4.

Variable	[1]	[2]	[3]	[4]	[5]
Price LV [1]	100%				
Consumpt. prog. LV [2]	24%	100%			
TTF price [3]	36%	15%	100%		
CO_2 price [4]	51%	1%	5%	100%	
Wind prod. NordPool [5]	-10%	26%	14%	27%	100%

Figure 4. Correlation matrix based on daily data from 2016 to 2019 (inclusive). (calculated by the author).

IV. DISCUSSION OF THE RESULTS

A. Analysis

The results of the regression with four independent variables (prognosis of electricity consumption in Latvia, forecasted electricity amount from wind stations at Nord Pool territory, CO_2 emission allowances and natural gas (TTF) future contract prices) indicate that all of them are statistically significant predictors of day-ahead price in Latvia. The equation of the model is as followed (2):

$$Price_d = \beta_0 + \beta_1 Consumption\ prog_d + \beta_2 CO_2 price_{m-1} + \beta_3 TTFprice_{m-1} + \beta_4 + \varepsilon_d \quad (2)$$

All variables are significant at 1% level. The results suggest that higher forecasted consumption, CO_2 emission allowances and natural gas prices result in higher day-ahead prices. In contrast, higher wind production is associated with lower day-ahead prices. The regression's adjusted R-squared is 61.35% – more than half of variance of day-ahead prices is explained by variance of these four independent variables. Variance inflator factor indicates no multicollinearity in the equation.

	Estimate	St. Err.	t-value
Intercept	1.601	1.590	1.007
Consumpt. progn. LV	0.025***	0.002	13.767
CO2 price	0.805***	0.021	39.041
TTF price	0.960***	0.042	22.757
Wind prod. NordPool	-0.081***	0.004	-21.401
# of observations	1387		
Adj. R-squared	0.6135		
F-statistics	551		
p-value	2.2e-16		

*Note: significance ***: 1% level; **: 5% level; *: 10% level.*

Figure 1. Output of regression analysis with consumption prognosis, CO2 price, TTF price, wind production prognosis in Nord Pool as independent variables.

Furthermore, the Authors use Multivariate Adaptive Regression Splines (MARS) to model independent variable relationship with day-ahead prices in Latvia. This allows to evaluate non-constant linear relationship between predictor and response variable. The results of MARS are presented in Figure 6.

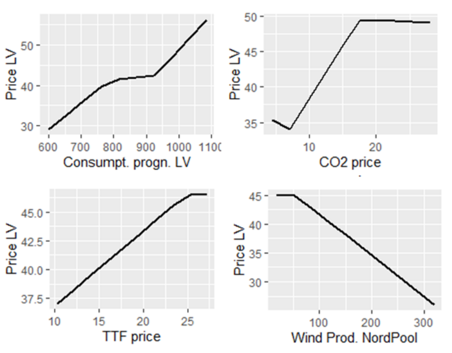

Figure 6. Output of regression analysis with consumption prognosis, CO2 price, TTF price, wind production prognosis in Nord Pool as independent variables.

B. *Estimated impact – other factors*

CO_2 prices have significant impact on electricity price in day-ahead market. CO_2 price increase by 1€ results in 0.81 €/MWh increase of day-ahead electricity prices in Latvia. Similar conclusion is reported by Bariss et al (2016), who demonstrate that 1€ increase of CO_2 emissions would increase electricity prices in Baltics by 0.67 €/MWh [10]. This finding identifies the clear need to hedge risks associated with volatility of CO_2 emission allowance prices. For example, the retailers can enter yearly or monthly forwards under EUA scheme, thus, fixing CO_2 price level. This effectively would result in lower financial risks from electricity price changes on day-ahead market.

Natural gas prices significantly affect day-ahead electricity prices in Latvia. Regression estimates suggest that, *ceteris paribus*, 1€ increase of TTF forward prices translates in 0.96 €/MWh growth of day-ahead electricity prices in Latvia. So, hedging via gas derivatives removes substantial price risks for traders.

Increased wind generation availability has negative impact on day ahead prices. The estimates of all regressions show robust results – additional 1 MWh/h of electricity produced during the day from wind reduces Latvian day-ahead prices, on average, by 0.081 €/MWh. These findings are in line with conclusions presented by Jonsson et al (2012), who studied relationship between electricity volumes generated by wind stations and Elspot prices in Western Danish price area [13]. Similarly, Fabra N. & Reguant M. (2014) report positive correlation between wind speed and electricity prices in Spain [14].

C. *Estimated impact – chagnes in consumption*

Th results suggest that an additional 1 MWh/h of electricity consumed results on average in increase of 0.025 EUR/MWh in day ahead electricity price. Furthermore, MARS analysis identifies that in days with average consumption below 780 MWh or above 930 MWh additional consumed electricity results in higher price response than in days with average hourly consumption between 780 – 930 MWh. This can be explained by nature of generating resources in the region. Costs of production remain quite flat when with certain level of generation; producers are ready to sell electricity without major increase in prices in order not to stop production by conventional stations. In contrast, when consumption is growing and tends towards its peak levels, producers face start-up costs of less efficient plants. This leads to more pronounced electricity price response to increasing demands.

V. CONCLUSIONS AND FURTHER RESEARCH

Introducing demand response in the electricity wholesale market can result in gains for the market. Depending on the volume that is traded within the bidding zone and the demand and supply elasticity at the clearing point, the effect of reducing the consumption can be highly disproportionate. Assuming that the average daily consumption in Latvia is between 20 000 to 30 000 MWh and reduction of consumption by 1 MWh/h results in daily average price decrease of 0,025 EUR/MWh (and decrease total expenditure for electricity procurement by 500-700 EUR or 20-30 EUR/MWh "unconsumed"). Such conclusion can be a valuable input for analysis on necessity for compensation between aggregators and balance responsible parties or basis for further analysis for policy makers when considering necessity for state support to accelerate introduction of the service.

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Towards optimal activation of balancing energy bids to minimize regulation from neighboring control areas

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***Abstract*—The paper presents practical research based on a real-life case study of the Baltic power system for optimal activation of manual frequency restoration reserves. A software tool for suggestion of the activation volume and time schedule is developed to facilitate the decision-making process of the transmission system operator in balancing the power system within a coordinated balancing area in light of the ongoing integration of balancing markets in Europe and the subsequent need to develop an activation optimization function. As of now, regular balancing needs of the Baltic countries are covered by the neighboring Russian power system. The aim is to substitute that with local regulation as much as possible for economic and energy dependence related reasons. The optimized activation parameters exhibit overall very good results during numerical simulation. Thus, this study forms one of the first steps in creating a fully automated balancing system.**

***Index Terms*--balancing, frequency restoration reserves, optimization, power system control.**

I. INTRODUCTION

The European Commission draft regulation on electricity balancing aims to foster formation of efficient and integrated balancing markets to enable cost-efficient and reliable exchange of balancing services among the European countries [1]. To enable this, relevant ICT tools need to be developed, as until now the balancing of power systems is largely human operator dependent. Balancing bids for activation should be selected from common merit order lists (CMOLs) containing bids of standardized balancing products. This paper is focused on the current endeavors of Latvian, Lithuanian and Estonian transmission system operators (TSOs) in implementing a Baltic balancing market with the final target to develop a common Nordic-Baltic balancing market for manually activated frequency restoration reserves (mFRR) [2].

The Baltic power system has some distinct characteristics due to its synchronous operation with the IPS/UPS system of Russia and Belarus. The Russian power system provides primary power reserves for frequency regulation and secure system operation within the BRELL (Belarus, Russia, Estonia, Latvia and Lithuania) ring [3]. As of 2016, the TSOs of Latvia, Estonia and Lithuania (Augstsprieguma tīkls, Elering and Litgrid) have established the Baltic coordinated balancing area (Baltic CoBA) within which the three TSOs share balancing energy. However, the remaining not netted imbalance is settled by an Open Balance Provider (OBP) which supplies balancing energy from the Russian power system (Fig. 1). The imbalance settlement period (ISP) currently is one hour, and the not netted imbalance with the OBP is defined as the total Baltic Area Control Error (ACE), or system imbalance. It is calculated as the difference between the planned and the actual power flow each minute, integrated over the whole ISP to obtain the final ACE in MWh. Thus, the payment for the Baltic ACE covers the cost of the Russian frequency control service [4].

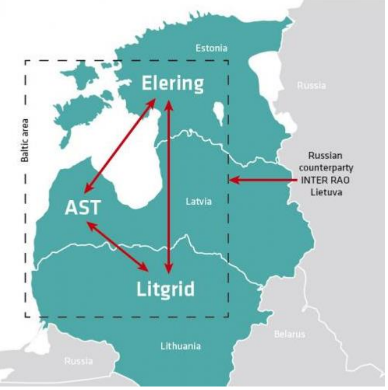

Figure 2. Imbalance netting of the Baltic TSOs under the Open Balance Agreement [4]

Formally, the three Baltic countries are required to keep their imbalance within certain limits (± 30 MWh/h for Estonia and Latvia each and ± 50 MWh/h for Lithuania [2]). In practice, minor imbalances are currently handled by the imports from Russia on a regular basis while local activations are used to cover larger imbalances on relatively rare occasions. As a result, the ACE energy forms a major part of the Baltic balancing energy and its costs constitute a significant share of balancing costs in the Baltic markets (e.g., some 40% of total balancing costs in Latvia in 2014 [4]). Handling ACE with energy from Russia is costly due to the specific pricing policy of the OBP (sell price of about 5 €/MWh and buy price about 100 €/MWh) [4].

The aforementioned considerations along with the political decision to desynchronize from Russia by 2025 [5] have encouraged the Baltic TSOs to develop a Baltic balancing IT system with the primary function to ensure sustainable physical cross-border balancing. This system shall be adopted starting from 2018. It implies sharing balancing energy among the three countries with the aim to mostly rely on mFRR provided by local producers, the bids of which will be included in a CMOL. It should reduce the overall balancing costs incurred by the three Baltic TSOs, while contributing to the energy independence of Latvia, Estonia and Lithuania. Consequently, a goal is envisioned to minimize the ACE of each hour which is now being covered almost exclusively by the FRR from Russia.

One of the building blocks of the common balancing system is the Activation Optimization Function (AOF). As stipulated in guidelines [1] developed by ENTSO-E, the AOF determines the most efficient activation of the incoming balancing request while respecting some capacity and operational restrictions. The Baltic TSOs intend to implement the AOF as an automatic algorithm the main inputs to which are the available bids from the CMOL (considering transmission constraints) and activation volume proposal [2], the latter being the focus of this paper. Specifically, it implies an algorithm for suggestion of activation volume of balancing reserves along with a time schedule based on the historic ACE data with minute resolution and the current ACE forecast. It is meant to support the decision making by the human operator of the transmission system, and thus constitutes the first steps towards building a fully automatic system for the activation of balancing reserves. As of now, the decision to order the balancing energy is left solely to the human operator with a very short timeframe for decision-making. However, since the power system is a very complex structure with a large number of variable and uncertain parameters, an automated tool should provide a more optimal solution. Nevertheless, human operators usually have significant hands-on experience which is challenging and sometimes outright impossible to represent mathematically within an automated algorithm. Thus, one of the tasks of this study has been to investigate the pros and cons of automated vs manual regulation activation.

Until now, only a few scientific papers refer to the AOF introduced in the recently developed guidelines on electricity balancing [1]. One of the studies [6] proposes balancing optimization based on stochastic unit commitment principles using imbalance forecast scenarios. The objective of optimization is to minimize expected activation costs, which is demonstrated using Norwegian imbalance and market data. As a result, bid activation schedules are proposed. The imbalance forecasts are generated from probability distributions of historical data series, and balancing activation bids are created based on prices and volumes in the Norwegian balancing energy market. Utilization of both mFRR and aFRR is considered.

Case studies of optimal scheduling of ancillary services (AS) for the Czech Republic are presented in [7] and [8]. In [7], five different types of AS used by the Czech TSO are considered to minimize the cost of balancing. Power imbalances and the resulting ACE is obtained from Monte-Carlo simulations to imitate the random behavior of the power system, while the AS prices are assumed as estimated by experts due to the complexities related to modelling the entire AS market. In [8], an evolutionary algorithm for cost-optimal dispatch of AS is used and regulation reserves are modeled for a 6-hour horizon. Comparison of the historical vs optimized activations shows that the ACE and regulation energy costs decrease in the latter case.

II. METHOD

We have developed a software tool with an algorithm for deriving optimal activation parameters of mFRR for balancing of the Baltic power system. The algorithm operates under the assumption that the mFRR should be activated one or a few times within the given ISP (in our case study, we assume no more than five activations within an ISP of one hour). It calculates the amount of up or down regulating power which ought to be activated based on three main parameters: *the time of activation* (minutes from the beginning of each ISP), *the percentage of the ACE forecast* to be regulated against and *the ignorance level* (the minimum value of the ACE forecast for regulation to be activated). Consequently, time series of ACE forecast with minute resolution is provided as input data. Real-life historic data from 2016 provided by the TSO was used for numerical simulations. Since forecasting per se was out of scope of this study, we used an already existing naïve forecasting approach of the ACE:

$$ACE_{\text{forec.}}^{m} = P_{\text{actual}}^{m} \cdot \frac{60-m}{60} + \int_{1}^{m-1} P_{\text{actual}}\,dt - \int_{1}^{60} P_{\text{plan}}\,dt \quad , \tag{1}$$

where $ACE_{\text{forec.}}^{m}$ is the forecast of the hourly ACE (MWh/h) at minute m, P_{actual}^{m} is the actual power flow measured at minute m, and the two integrals include the actual power flow P_{actual} until the previous minute, $m-1$, and the planned power flow, P_{plan}, for the whole hour. The power flows here refer to the total scheduled Baltic power flow balance after the Nord Pool day-ahead and intraday trading and the actual Baltic balance. The results of the case study presented further on demonstrate an overall good applicability of this ACE forecasting approach. Nevertheless, it is also one of the possible directions for improvement of the AOF algorithm in the future work. Some of the approaches for a more sophisticated forecasting of system imbalance volumes are provided in [9] and [10].

In general, there can be two distinctive possible applications of the activation volume suggestion algorithm the main difference of which is the nature of ACE forecast input data. In *real-time* application, the ACE forecast is recalculated each minute based on the measured power flows in the system since the beginning of the current ISP. Alternatively, an *offline* application of the algorithm can be envisioned the main purpose of which is to identify close to optimal parameters (time of activation, percentage, ignorance level) for a particular dataset and evaluate the performance of the algorithm with the computationally or arbitrarily selected parameters. In this case, the dataset can be either a historical record of ACE forecasts or simulated time series created for testing purposes. This study concerns the offline application to determine the (close to) optimum activation parameters based on the historic data. However, real-time usage can be based on the same logic.

A. Overall Structure of the Algorithm

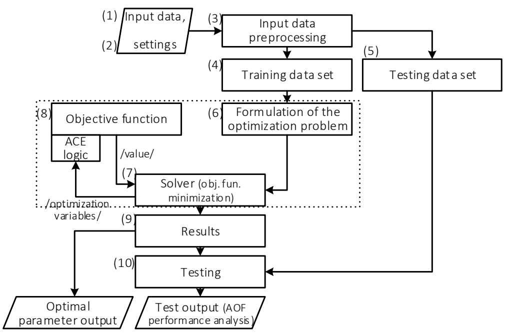

Figure 3. Structure of the algorithm.

The overall structure of the algorithm for offline implementation of the AOF is explained in Fig. 2. The optimization problem is formulated and solved in MATLAB to take advantage of its data processing abilities and solvers. MS Excel is used for input and output in a user-friendly manner. Additionally, analysis of the results obtained by the optimizer is carried out in Excel. Consequently, the most important blocks of the algorithm are as follows.

Reading minutely ACE forecast statistics for the timeframe under study (1) and algorithm settings (2), such as assumed preparation time from the decision to activate mFRR to the beginning of ramping, ramping rate, ISP size in minutes, number of starting points for the global optimization solver and various constraints, particularly, minimum interval in minutes between sequential mFRR activations, maximum number of activations within a single ISP and lower and upper bounds on the optimization variables (*the times of activation*, *the percentages of ACE forecast* to be balanced and *the ignorance levels*). For this study, the preparation time was set to 2 min and the ramping rate to 20 MW/min. The maximum number of activations was varied from 1 to 5, the bounds for variables were set as minute [5; 45], [0; 100] % and [10; 500] MWh/h.

After the input data series are read, they are preprocessed (3), i.e., separated in training and testing subsets (2/3 and 1/3 respectively) and passed through a filter to remove hours with odd behavior which might negatively influence the overall performance of the parameters found by the solver. In this study, we abstained from including such hours in the training (4) and testing (5) subsets which exhibited abrupt changes in the ACE forecast of the order of at least 50 MWh/h within a timeframe of 5 minutes or less. The first 10 minutes of the hour were excluded from filtering as large structural imbalances may occur at hour shifts [11] after which the power flow fluctuates less and becomes more predictable. The main reason for removing the outlying hours was the lack of full data about actual regulations carried out by the Baltic TSOs with minute resolution. Thus, the intention was to exclude such hours from optimization. This concludes the preprocessing stage.

Finally, the processed data and constraints are used to formulate an optimization problem (6) to be passed to a solver (7) which evaluates the objective function (8) by moving though the search space. The objective function contains within its evaluation the entirety of the logical instructions the AOF follows based on the parameters and the training dataset fed to it. Thus, the optimization problem can be characterized as non-smooth and its convexity cannot be established analytically for a general case. Thereby, the use of gradient-based solvers is not recommended and rather global search techniques have to be employed. For this study, we have chosen to adapt the MATLAB *pattern search* [12] algorithm with 50 randomly selected initial points. A note should be made that the results obtained are not guaranteed to indeed be the global minima, but they can reasonably be expected to be sufficiently close to it and generally better than any arbitrarily selected sets of AOF parameters.

Once the solver has found resulting close to optimum parameters for the AOF (9), they are once more passed to the ACE logical instructions, but now with the testing dataset in order to evaluate the performance (10) of the AOF algorithm with these particular parameters under the conditions of new, "unseen" ACE data.

B. Regulation Simulation Logic and Objective Function

The set of instructions simulating regulation activities during evaluations of the objective function has a fairly complex structure. Broadly speaking, it consists of the following main steps (note that the ACE forecast dataset is passed to these instructions one ISP at a time and during each ISP there can be 1 to 5 times of activation).

1. Select the ACE forecast value for the current time of activation.
2. Check whether the ACE forecast ignorance level is met; if it is, go to 3; if it is not, select the next time of activation and return to 1.
3. Check if there are any active regulation operations in effect; if there are, go to 4; else go to 7.
4. Obtain and analyze the state of currently active regulation operations (still ramping or ordered power achieved; is it possible to fully cancel the active regulations by the end of the ISP; current regulating power and expected supplied energy by the end of ISP).
5. If cancellation of previous regulations is necessary, do it fully or partially in a chronological order to achieve the necessary amount of canceled regulation energy if possible; if not possible, fully cancel all regulations.
6. Update the ACE forecast and once again compare it to the ignorance level; if it is met, go to 7; else select the next time of activation and return to 1.

7. Calculate the balancing power that should be activated; check if it can be ramped to in time; if affirmative, simulate its activation; else, simulate the activation of the maximum possible regulating power in the remaining timespan.
8. Update the ACE forecast; if this was the last time of activation, go to next ISP; else, select the next time of activation and return to 1.

Throughout the objective function evaluations, the algorithm keeps track of the ACE at the end of each ISP, sum of the supplied regulation energy and sum of the balancing power orders during each ISP. The objective function value is calculated by the following expression:

$$w_{1a} \cdot \sum_{n=1}^{N} ACE_{+}^{n} + w_{1b} \cdot \sum_{n=1}^{N} \left|ACE_{-}^{n}\right| + w_{2} \cdot \sum_{n=1}^{N} \left|E_{\text{suppl.}}^{n}\right| + w_{3} \cdot \sum_{n=1}^{N} \left|P_{\text{ord.}}^{n}\right| , \quad (2)$$

where w_{1a}, w_{1b}, w_2, w_3 – weight coefficients for the multi-objective function; ACE_{+}^{n} – positive ACE, or balancing energy exported to Russia (MWh/h) during the ISP n; ACE_{-}^{n} – negative ACE, or regulation energy imported from Russia (MWh/h) during the ISP n; $E_{\text{suppl.}}^{n}$ – total supplied regulation energy (MWh) during the ISP n; $P_{\text{ord.}}^{n}$ – sum of the ordered regulation power (MW) during the ISP n; n, N – index and set of the ISPs in the training dataset.

The purpose of the weight coefficients is to give an option to adjust the focus on ACE minimization (positive and/or negative) versus utilized balancing energy and ordered power. Sensitivity analysis on the influence of these coefficients is out of scope for this paper but will be provided in future publications. For this study, the weight coefficients had fixed values of 1000, 1000, 10 and 1 that were chosen after a series of experiments.

The operation of the activation logic can be better explained by referring to visual representations of ACE dynamics in particular hours in Fig. 3–4. The examples displayed refer to a scenario where the maximum number of activations is equal to three and the optimized regulation parameters are the same as for the case study below (Table I).

For the example in Fig. 3, in the first activation time (minute 22), no balancing is ordered as the module of the ACE forecast (–3.9 MWh/h) is lower than the corresponding ignorance level (33.0 MWh/h), but during the second time (minute 34), the forecast (33.3 MWh/h) does trigger the threshold (27.5 MWh/h) and thus regulation equal to 81.9 % of the forecasted ACE is desired (–27.3 MWh). The balancing market is organized by power bids though, thus an order equal to –70.5 MW is activated. Similarly, also in the last activation time (minute 45), the forecasted ACE (12.6 MWh/h) is greater than the ignorance level (10.0 MWh/h), thus an activation volume of 98.5% corresponding to –12.4 MWh or –59.7 MW is simulated. The resulting ACE after regulation is 14.1 MWh, which is an improvement of 381.6% compared to the ACE without regulation (53.8 MWh).

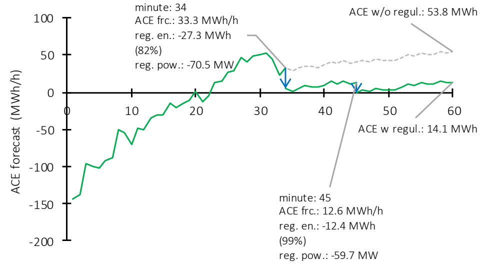

Figure 4. ACE dynamics and simulated regulations (06.09.2016 hour 22)

The example in Fig. 4 illustrates an hour when a previously activated order has to be canceled (red arrow) and a new order in the opposite direction has to be activated. At minute 22, the ACE forecast (–45.7 MWh/h) exceeds the first ignorance level and subsequently a 65.9 % regulation volume (30.1 MWh) corresponding to a 50.6 MW upwards bid is activated. At the second activation time (minute 34) no action is necessary, but at the last activation time (minute 45) the ACE forecast (31.6 MWh/h) once again exceeds the threshold (10.0 MWh/h), but in this case downwards regulation is required. Thus, the first order is fully canceled resulting in 10.7 MWh of previously expected regulation energy to not be supplied. The consequently updated ACE forecast (20.9 MWh/h) is still higher than the ignorance level, thus a downwards bid of –109.6 MW is activated. In this case, the resulting ACE (6.0 MWh) is close to that without any regulation (7.2 MWh) while 40 MWh of regulating energy has been used. This indicates a rather rare case of redundant regulations. Meanwhile, it cannot be avoided given the dynamics of the ACE and its direction change (from negative to positive).

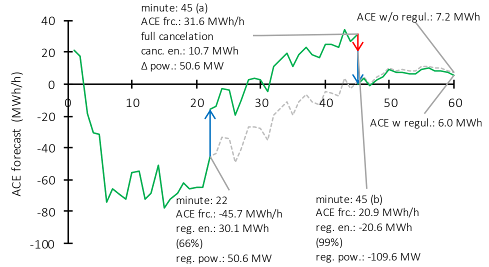

Figure 5. ACE dynamics and simulated regulations (04.09.2016 hour 21)

III. RESULTS AND DISCUSSION

This section presents some of the initial results for suggestion of activation volume. To obtain (close to) optimum activation parameters, the optimization procedure was applied to historical data of the year 2016 provided by the TSO which was divided into training and testing subsets. Data series of the ACE forecast (eq. 1) and the actual ACE with minute resolution was split into three-month periods to capture seasonality or any other possible time-variable trends. This approach also reflects the intended use of the algorithm by the TSOs, namely, its application on historic data of one or a few months to obtain activation parameters which are then used to assist the operators in balancing the power system for some time ahead (e.g., one or a few months). Regulation parameters were optimized on the training data set comprising the first 2/3 of the whole preprocessed set. To test the performance of the optimized regulation schedule, the estimated parameters where applied on the testing data set (i.e., the remaining 1/3) to simulate all activities of regulation. Consequently, the results presented show the performance of regulation only for the testing set and allow us to evaluate the generalization ability of the optimization procedure.

The optimized activation parameters and resulting ACE for one of the data sets (July–September 2016) are shown in Table I. As mentioned before, the hours with detected large ACE fluctuations were removed during data pre-processing.

The resulting ACE after simulating the regulation activities according to the optimized schedule is shown in Fig. 5. The ACE is noticeably reduced (up to 4.9 times) from 37.95 MWh/h to 7.7–12.5 MWh/h. The stacked charts allow to assess the efficiency of regulation in terms of supplied regulation energy and improvement of the ACE. The sum of the ACE after regulation and supplied energy is always more than the ACE without any regulation because of the ACE uncertainty which sometimes causes redundant orders (leading to cancellation or overregulation) or, in very rare cases, increase of the final ACE. In the data period shown in Fig. 5, the most efficient regulation happens when the max number of activations is 4 or 5. Then, cancellation is needed for only 1.4% or 1.7% of the ordered energy. Also, less balancing energy is used to reduce the ACE compared to cases with 2 or 3 activations. It is important to note that the average absolute error of ACE forecast at the minute 45 was 6.34 MWh/h in Jul–Sep 2016. This is very close to the lowest average ACE value achieved (7.71 MWh/h) which again demonstrates the efficiency of the proposed activation parameters when applied on the testing set.

In all the cases with 2 to 5 max activations the last selected activation minute is 45, which is the upper bound imposed during the optimization. This is due to the initially highly uncertain nature of the ACE forecast the accuracy of which significantly increases towards the end of each hour (Fig. 6). Since premature activation can lead to redundant orders for regulation and the subsequent cancellation of regulations that happen to be in the opposite direction, the algorithm evidently tends to postpone activations as long as possible.

Fig. 7 shows a histogram of ACE without regulation for all the hours in July–September, whereas Fig. 8–9 present frequency distribution of the hourly ACE without and with regulation applied to the testing subset of Jul–Sep 2016 dataset (509 hours in total). The ACE without regulation is moderately skewed to the right with an average value of +11.4 MWh/h (Fig. 7). This can be explained by the behavior of balance responsible parties (BRP) who tend to be long rather than short given the potential for ‘short’ prices be more extreme than ‘long’ prices [4]. As a result, the Baltic countries in general sell more energy to Russia than they buy.

After applying the optimized regulation parameters to the test set of Jul–Sep 2016, the average ACE decreases from +21.9 MWh/h (Fig. 8) to +2.5 MWh/h (Fig. 9). Thus, the noticeable positive bias of the ACE is almost eliminated. This clearly demonstrates not only a good performance of regulation with the optimized parameters but also the generalizability of the obtained parameters when applied to the testing data.

TABLE I REGULATION PARAMETERS OPTIMIZED FOR JUL–SEP 2016

Reg. parameters						
max number of activations		***1***	***2***	***3***	***4***	***5***
activation minutes		35	23 - 45	22 - 34 - 45	15 - 25 - 35 - 45	5 - 15 - 25 - 35 - 45
volume of activation relative to ACE forecast	%	90.5	75.4 - 97.4	65.9 - 81.9 - 98.5	50.1 - 50.7 - 80.6 - 93.7	31.1 - 31.1 - 31.1 - 76.7 - 94.3
ignorance level	MWh	10.0	22.1 - 10.0	33.0 - 27.5 - 10.0	192.0 - 107.0 - 31.0 - 10.0	182.0 - 137.5 - 81.8 - 33.0 - 10.0
Average |ACE| w/o reg.	MWh/h	**37.95**				
Average ACE w/o reg.	MWh/h	21.85				
Sum |ACE| w/o reg.	MWh	19 315				
Sum pos. ACE w/o reg.	MWh	15 218				
Sum neg. ACE w/o reg.	MWh	–4 097				
Average |ACE| w reg.	MWh/h	**12.50**	**9.04**	**7.71**	**7.71**	**7.78**
Average ACE w reg.	MWh/h	4.42	3.63	2.47	2.73	2.55
Sum |ACE| w reg.	MWh	6 364	4 601	3 924	3 923	3 961
Sum pos. ACE w reg.	MWh	4 308	3 224	2 590	2 657	2 630
Sum neg. ACE w reg.	MWh	–2 056	–1 377	–1 335	–1 266	–1 331
|ACE forec. error| @ last activ.	MWh/h	10.67	6.34	6.34	6.34	6.34
Supplied energy	GWh	**16.419**	**19.116**	**19.394**	**17.527**	**17.605**
regulation up	GWh	3.775	4.921	4.764	3.899	3.891
regulation down	GWh	12.644	14.195	14.630	13.629	13.714

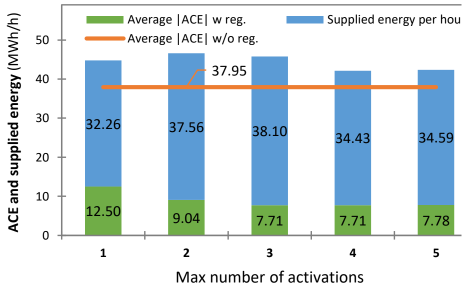

Figure 6. ACE w/o and with reg. + supplied reg. energy: Jul–Sep 2016

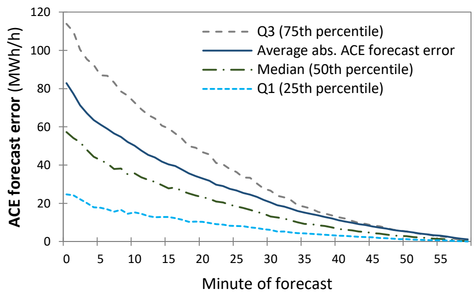

Figure 7. Average absolute ACE forecast error depending on the minute of forecasting (Jul–Sep 2016)

Though cost minimization of regulation activation was not performed at this stage, it is useful to quantify the economic benefits of common Baltic balancing operations compared to sole reliance on the neighboring Russian power system for balancing needs. If we assume that the OBP buys excess energy at 5 €/MWh and sells upwards regulation at 100 €/MWh [4], then for the test dataset of 509 hours the cost of fully depending on the OBP (cost of ACE without regulation) would be equal to 333.58 thousand € (76.09 thousand € income from sold energy and 409.67 thousand € expense for purchased energy). However, when local balancing activations are performed in accordance with the optimized parameters as presented before, the overall cost decreases notably. The balancing expense structure depending on the selected maximum number of activations within an hour is summarized in Table II. For simplicity's sake, the prices of local balancing bids are assumed to be always cleared at 50 €/MWh for upwards and 10 €/MWh for downwards regulation and perfect liquidity is implied.

In all cases with local balancing operations, the total imbalance costs are diminished by a factor of 1.35 to 1.94 (depending on the selected max. number of activations) compared to the case with no local regulation. The lowest cost is achieved with 4 and 5 activations (171.9 and 177.4 thousand € respectively). However, if we look particularly on the cost of ACE (paid to the OBP), the decrease is in the range of 1.81 to 2.94.

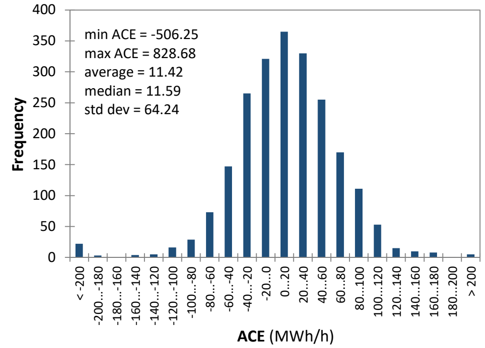

Figure 8. ACE histogram without regulation (Jul–Sep 2016)

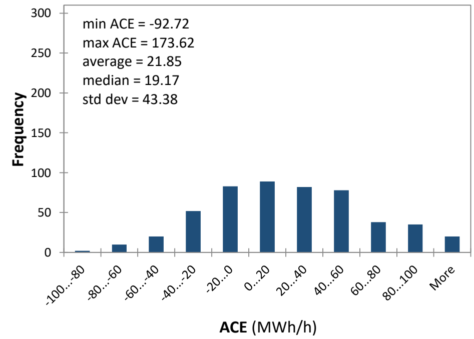

Figure 9. ACE histogram without regulation (Jul–Sep 2016, testing dataset)

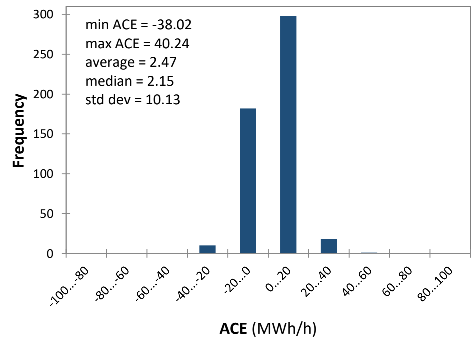

Figure 10. ACE histogram with regulation based on the optimized activation parameters (Jul–Sep 2016, 3 max activations, testing dataset)

TABLE II ESTIMATED COST OF REGULATION ENERGY

Max. number of activations	1	2	3	4	5
	Cost of ACE with local regulation (€)				
Energy bought @ 100 €/MWh	205 643.77	137 685.42	133 461.79	126 568.68	133 142.01
Surplus sold @ 5 €/MWh	–21 540.16	–16 118.70	–12 948.91	–13 285.65	–13 148.32
Cost of ACE	***184 103.60***	***121 566.72***	***120 512.88***	***113 283.03***	***119 993.69***
	Cost of supplied local regulation energy (€)				
Energy bought @ 50 €/MWh	188 740.31	246 043.25	238 190.36	194 939.63	194 561.59
Surplus sold @ 10 €/MWh	–126 444.67	–141 952.35	–146 298.99	–136 286.05	–137 142.43
Cost of supplied local energy	***62 295.64***	***104 090.90***	***91 891.37***	***58 653.58***	***57 419.15***
Total cost with local regulation	**246 399.25**	**225 657.63**	**212 404.26**	**171 936.61**	**177 412.84**
	Cost of ACE without local regulation (€)				
Energy bought @ 100 €/MWh	409 669.61				
Surplus sold @ 5 €/MWh	–76 089.76				
Total cost without local regulation	**333 579.85**				

IV. CONCLUSIONS

The simulations of balancing activations based on parameters found using historical time series affirmed the generalizability of the results, since in most of the cases the average absolute ACE was close to the forecast error. Additionally, this confirms improved ACE forecasting techniques as a promising avenue for further research as any enhancements there can be expected to notably improve the efficiency of balancing operations. Furthermore, as currently the balancing parameter optimization tool has a tendency to postpone regulation to later in the hour when forecasts are more trustworthy, perfected early prediction abilities would allow for more even balancing operations throughout the ISP.

For the dataset considered in this study, 4 and 5 were identified as the maximum number of activations during the ISP equal to one hour that can provide the most efficient balancing. While the case with 3 maximum activations did provide a small overall ACE, the aforementioned cases were superior in terms of the utilized balancing energy and estimated cost.

While our tool has yet to be expanded to incorporate the merit order of balancing bids, the initial simplified economic calculations already point to benefits of active local balancing in the Baltic power system with less reliance on regulation from Russia, especially with its current balancing energy pricing policy.

However, even if the present pricing practices by the OBP were made more transparent and reasonable, the overall movement towards a common and more active Baltic balancing market is well underway. Similar trends are ongoing throughout Europe as the TSOs strive to adapt the recently developed ENTSO-E guidelines on electricity balancing and devise their AOF. The work the beginning of which is presented in this paper proves to be of significant relevance in light of the changing balancing market landscape in Europe. The initial results of this study will inform some of the decisions of the Baltic TSOs in the evolution of their common balancing market. Moreover, this is also important as the Baltic countries strive to desynchronize from the BRELL ring.

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Benefits of regional balancing areas

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Abstract*—The European power system is transforming rapidly to integrate more renewables, develop flexibility and enable consumers to play a more central role. For electricity markets, this transition means that trading needs to move closer to real time while respecting system security. As the system is changing, the more efficient balancing of the power system also needs to be developed. This paper provides an analysis of operation of common balancing area based on a case study of the Baltic common balancing energy market model which was launched as from 1st of January 2018. The objectives of development of the common Baltic balancing market were to increase balancing efficiency, to increase availability of balancing resources and to reduce the costs of power system balancing. Establishing the common Baltic balancing market required harmonization of balancing market frameworks of the three Baltic States including the settlement rules between market parties, introduction of a coordinated balance control on a regional level and introduction of common balancing IT platform. This paper analyses operational indicators assessing the performance of the new balancing system, including changes in area control error, changes in market liquidity and diversity, changes in balancing costs for market participants. Paper also analyses changes in balancing energy price dynamics in the Baltic States, including price volatility and price correlation to understand how imbalance prices could motivate balance steering of the balance responsible parties. Proposals for further balancing market model development are also provided in the paper.[2]

***Index Terms*-- Power system, electricity balancing, electricity market.**

I. INTRODUCTION

Work on the Baltic integration into the European electricity balancing market started in 2009 with the approval of the Baltic Energy Market Interconnection Plan (hereinafter – Plan) [1]. The aim of the initiative was to provide a comprehensive guideline for establishing Baltic cross-border interconnections and facilitating market integration in the Baltic Sea Region. One of the main tasks listed in the Plan was to work jointly towards opening, liberalizing and harmonizing electricity market as well as creation of a common balancing market and harmonized imbalance settlement and imbalance pricing. The European power system, similarly, to the Baltic region faces challenges regarding organizing processes for ensuring permanent balance between consumption and production of electric power in the grid system. Increasing share of intermittent generation resources is steadily growing and it requests development of the flexibility. This transition means that electricity markets move to the next level of development, where trading needs to move closer to real time, while continuously ensuring system security. As the system is changing, the efficient balancing of the power system also needs to be developed. The promoter and initiator for defining the balancing framework is the Commission Regulation (EU) 2017/2195 of 23 November 2017. It lays down detailed rules for the integration of balancing energy markets in Europe, with the objectives of fostering effective competition, non-discrimination, transparency and integration in electricity balancing markets, and by doing so, enhancing the efficiency of the European balancing system as well as security of supply.

This paper provides an analysis of common Baltic area balancing mechanism which was developed to establish coordinated balancing area (hereinafter - CoBA). tarting from 2018. To achieve this, the TSOs established procedures for coordinated balance control, exchange of the balancing energy, imbalance netting and balance settlement. The objective of harmonized Baltic balancing market was to increase the safe operation of the power system by promoting the availability of balancing resources and reducing power system balancing costs. Establishing the Baltic balancing market involved harmonization of balancing market framework and introduction of a common balancing IT platform.

This paper analysis several indicators to assess performance of the new balancing system, which include changes in area control error (quality of balance management), changes in market liquidity and diversity, changes in balancing costs for market participants. This paper also analysis changes in imbalance energy price dynamics in the Baltic States, including price volatility and correlation.

We use data from 2017 and 2018, a full year with the new model in operation. This already allows comparing the performance between the old and the new approach. allows capturing the trends created by the introduction of Common

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Baltic Balancing market and highlight possible improvement for the next operating periods and experience for other regions.

II. CREATING COBA

Goal for common Baltic balancing market is to increase transmission system operation reliability, to foster availability of balancing resources and to reduce costs of system balancing. Common balancing market creates competition between balancing service providers that respectively reduces costs of balance responsible parties.

Main objectives for Common Baltic balancing market are:

- Increased reliance on local balancing resources and improve balancing market liquidity;
- Leveling playing field and establishing incentivizing price signals that promote BRPs self-balancing;
- Harmonized settlement procedures to remove market entry barriers;
- Improved data transparency.

The following features were introduced with Baltic CoBA:

- Common balancing towards Russia;
- TSO-TSO imbalance netting;
- Common centralized mFRR activation model with shared merit order list;
- Nordic-Baltic mFRR exchange;
- Harmonized BRP balance management model and imbalance pricing methodology.

III. RESULTS OF ANALYSIS OF OPERATIONAL INDICATORS

From the first year there is visible significant impact on main balancing market performance characteristics:

A. Area control error (ACE)

Baltic's Area Control Error (hereinafter - ACE) means the Baltic's not netted imbalance towards Russia.

Successful cooperation models among TSOs for balance control and imbalance netting has been in place for some time, and one of successful examples is Grid Control Cooperation (GCC) between German TSOs [2], that has grown to pan-European imbalance netting project involving 24 countries. Introducing similar principles to common Baltic balancing area enables optimization of balancing effort. As each country is not balanced separately it is possible to avoid counter-activation by netting *"long"* and *"short"* positions and as a result there is higher availability of mFRR reserves for minimization of Baltic's Area Control Error (ACE).

Advantages and challenges for imbalance netting are widely discussed; [3] emphasizes importance of TSO-TSO settlement to maintain financial neutrality, thus all TSOs benefit from imbalance netting.

The analysis of the of historical data of Baltic CoBA performance revealed that centralized balancing market approach led to significant decrease of Baltic ACE. Average ACE decreased by 43% from 42 MWh to 24 MWh per imbalance settlement period (ISP) in 2018 compared to year 2017. Similarly, improved results on maintaining ACE close to 0 MWh was observed. In 2018 ACE was within 50 MWh range 89% of operational hours compared to 65% in 2017.

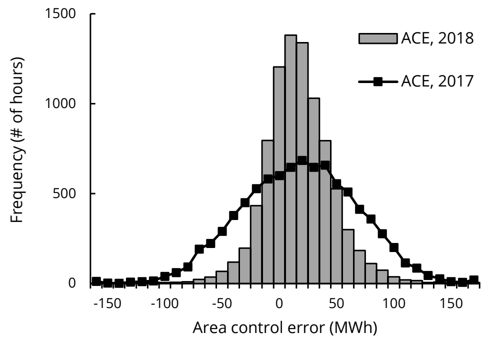

Fig. 1. Baltic Area control error (ACE)

Trend of monthly acumulated ACE "Fig.2" indicates that ACE could continue decrease even further from gaining experience in choosing and ordering optimal amount of balancing energy. Improvements in ACE forecasting will also add to reduction of ACE.

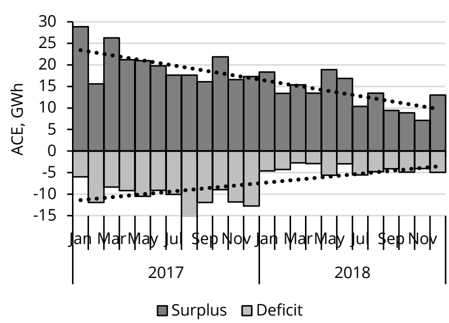

Fig.2. Monthly acumulated ACE

B. Market liquidity

More active balancing of CoBA with the goal to minimize Baltic ACE increased frequency of use of balancing energy bids. In 2018 Baltic TSOs ordered mFRR products in 79% of hours, which is twice as much as in 2017 (36% of hours), "Fig.3".

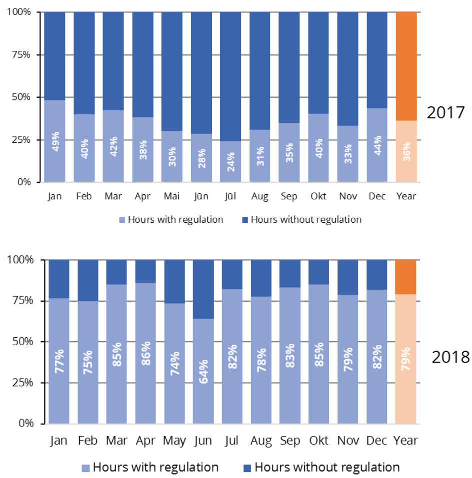

Fig. 3. Share of hours with regulation

This higher demand for balancing resources, increased balancing market liquidity and made it more attractive to local generation. Therefore, amount of used balancing energy in 2018 tripled compared to 2017 "Fig. 4", while at the same time share of local balancing resources stayed at the level of 66%.

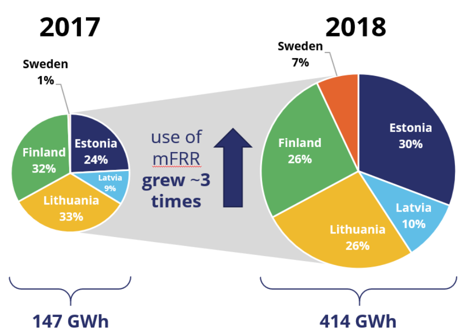

Fig.4. Use of balancing energy

C. Imbalance pricing

Major change is seen not only by balancing service providers, but also for balance responsible parties – introduction of single pricing for BRPs regardless of their imbalance position. Until 2018 settlement procedures were country based, imbalance prices included country specific components. Harmonization of settlement procedure and introduction of single imbalance price model (previously – dual price model) led to almost full convergence of imbalance prices in Baltic counties in 2018. Hourly imbalance prices were equal "Fig.5" in Latvia, Estonia and Lithuania in 97% of hours in 2018.

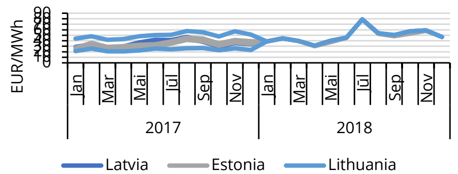

Fig .5. Imbalance price

Imbalance price in 2018 compared to the day-ahead market for Baltic countries show that 43% of hours has higher imbalance price than day-ahead price. In addition to that there are continuous periods of up to 88 hours long with imbalance price difference in one direction (smaller or larger) compared to day ahead price. Long periods of price difference in one direction may create motivation for BRPs to plan for intended imbalance with "long" or "short" position. This effect should be further monitored and analyzed to understand if it does not create counterproductive behavior at the system level.

Changes in imbalance pricing system created more level playing field for pan-Baltic BRPs and BSPs. Total Baltic BRP balancing costs decreased from 19,9 M.EUR in 2017 to 15,1 M.EUR in 2018. To evaluate the impact of changes in imbalance pricing model on pan-Baltic BRP's imbalance costs, we simulated BRP's portfolio.

Pan-Baltic BRP was created with average hourly planned consumption 100 MWh in each country. Hourly consumption was profiled according to Baltic weekly average consumption profile. To create multiple scenarios with randomized imbalances towards planned schedule actual position was randomly generated for each hour from planned value. Randomization was made with normal distribution and standard deviation of 5 MW to get on average 4% imbalance (no leaning towards surplus or deficit). In result calculated cost/profit from bought/sold imbalance volume. Average yearly cost/profit of imbalance MWh (300 scenarios) shown in "Fig.6 and 7.". In result is visible that for simulated BRP cost reduced significantly comparing 2017 to 2018 and that BRP can benefit from netting its imbalances between Baltic countries therefore reducing cost of balancing.

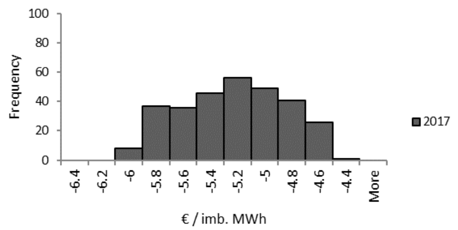

Fig.6. BRP imbalance costs

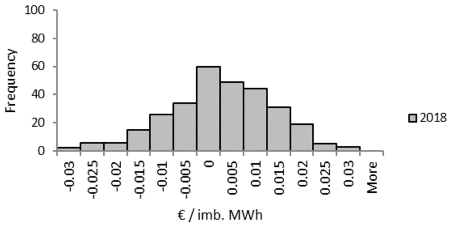

Fig.7. BRP imbalance costs

D. Transparency

Transparency issue is one of the top questions in energy market and the balancing market is not an exception. The Baltic CoBA has solved the transparency issue and created balancing dashboard where all data is available in one place - common Baltic data platform. After the end of an imbalance settlement period (hereinafter – ISP) all Baltic TSOs ensure that all information regarding activation orders is completed and publicly available on Baltic balancing market dashboard and/or Baltic TSOs websites as well as on the central ENTSO-E information transparency platform based on EU regulation. Data items like the balancing prices, imbalance volumes and BSP offers are published 1 hour after operational hour. In addition to that, monthly balancing reports are created by transmission system operators (TSOs).

Until creation of CoBA dashboard individual country data were stored on each TSO's webpage, balancing prices were published only at the beginning of the next month and there was no information (volume and price) on BSP bids in market.

IV. CHALENGES IN FUTURE

Despite the good results of Baltic coordinated balancing area there are several challenges that lay ahead. There is still need for more mFRR resources and more active BSPs bid offering as there is not always sufficient volume of offered balancing bids available in six-month period from February 2018 were TSOs observed that in 12% of hours offered mFRR volumes was not sufficient. To improve this characteristic it is possible to add demand response (DR) to mFRR market [4]-[5]. Based on above mentioned at the end of the year 2017 Baltic transmission system operators held a common public consultation [6] on TSOs' position paper “Demand Response through Aggregation – a Harmonized Approach in the Baltic Region” [7].Key finding after public consultation [were made - stakeholders recognize the need for DR integration in all Baltic countries. Furthermore, stakeholders see benefits for having a common demand response framework in the Baltic electricity markets and express strong overall support and willingness to participate in the DR market pilot studies.

Other challenges are the transition from 1h ISP to 15-minute ISP as well as further balancing market integration in Europe, joining MARI mFRR platform.

V. CONCLUSIONS

Analysis of performance indicators of the Baltic balancing system indicate clear benefits of common balancing areas and coordinated balance management. Market players including balancing service providers and balance responsible parties benefited from introduction of single price and single portfolio model. Considering that in 2018 97% of hours imbalance prices were similar in all three Baltic States, balance responsible parties are able to exercise imbalance netting and substantially reduce balancing costs that are passed onto end-users.

Analysis show that introduction of common balancing area and centralized balance management at a regional level has improved efficiency of system balancing, reduced ACE, improved availability of balancing resources and thus improved security of supply.

The model which is presented in this paper is not yet ready to ensure active real time balancing from BRP side, because imbalance and balancing prices are published after real time and that is issue which requires further study.

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Case study – Assessing Economic Potential for Demand Response in Baltic Balancing Market

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***Abstract* - Demand response integration in balancing energy markets can provide significant financial savings for grid operators and market participants and promote optimal resource allocation. To facilitate demand response participation in power system balancing, the service must not only provide economic gains for the existing market participants, but it also has to present a viable business case for demand response service providers. Currently, in the Baltic states, there is no demand side participation in balancing markets. To support balancing market development, we analysed the economic potential of demand response for service providers. To forecast market conditions, we employed stochastic simulations for energy market prices and balancing product activation. Furthermore, to calculate the economic gains of a service provider, we used technical parameters of fridges obtained in a demand response pilot study and the demand response aggregation settlement model proposed by the Baltic TSOs and Finnish TSO. The preliminary results suggest sufficient financial incentives for future investments.**

Keywords— aggregation, balancing market, demand response, economic analysis, mFRR.

I. INTRODUCTION

The reliability of electric power system operation depends on the balance between power production and consumption [1]. To achieve this balance, every grid connection point needs to be accounted for [2]. Traditionally, this is managed by dividing the system in multiple imbalance areas each having a market participant, which is financially responsible for ensuring that all energy generated within the area is sold, and all energy consumed within the imbalance areas is bought. These market participants are called balance responsible parties (BRPs). BRPs ensure the balance by forecasting demand and supply of energy within their imbalance areas and ensuring according energy trades via day-ahead and intraday markets.

When BRPs fail to forecast demand and supply accurately, it can result in excess/ deficit energy in the power system. Forecasting errors are corrected in real time by transmission system operators (TSOs) via balancing market. Ensuring sufficient balancing energy reserves is pivotal to TSOs as without them the power system balance cannot be maintained, which, depending on the interconnections to other power systems, can result in costly procurement of balancing energy from other control areas or in adverse system frequency fluctuations.

The costs of power system balancing are covered by imbalance payments from those BRPs, whose actual consumption/ generation deviated from the forecast. Accordingly, the costlier balancing energy is, the more expensive penalty payments for forecasting errors are and consequently the costlier energy in retail markets becomes. The main driver for high balancing prices is balancing resource scarcity. Currently, in the Baltics, only electricity producers provide balancing resources. Furthermore, since the opening of the Common Baltic Balancing market and subsequent increased reliance on national balancing resources (instead of balancing energy resources from Russian TSO), we can observe preliminary indications of balancing resource scarcity [3].

Furthermore, according to the Baltic generation adequacy report, it is expected that during the next 10-15 years the capacity required for balancing reserves will increase due to rising intermittent generation and the planned Baltic power system desynchronization from UPS/ISP. At the same time, the generation from some of the sources typically used for balancing purposes in the Baltic states (thermal power plants in Estonia) will reduce by up to 50% due to lost competitiveness of oil-shale power plants caused by the increasing costs of SO_2 and NO_2 emissions [3]. The forecasted generation mix for the Baltic states is presented in Fig. 1.

This gives us clear indications that additional sources for balancing reserves are needed. Demand response (DR) is a promising source of balancing energy to consider. DR integration in balancing energy markets can provide significant financial savings for grid operators and market participants and promote optimal resource allocation [4]. Some large consumers in the Baltic states have already expressed preliminary interest in providing services to the TSOs [5]. However, to facilitate DR participation in power system balancing, the service must provide economic gains for both the existing market participants and DR service providers. The main contribution of this paper lies in estimations of the financial potential of DR for a service provider in the context of the Common Baltic balancing market and DR settlement model proposed by Baltic TSOs [6].

The rest of the paper is organized as follows. Section II presents an overview of the relevant market framework. Data used for simulations and the model setup is explained in Section III. Section IV summarizes the results and, finally, the conclusions are drawn in Section VI.

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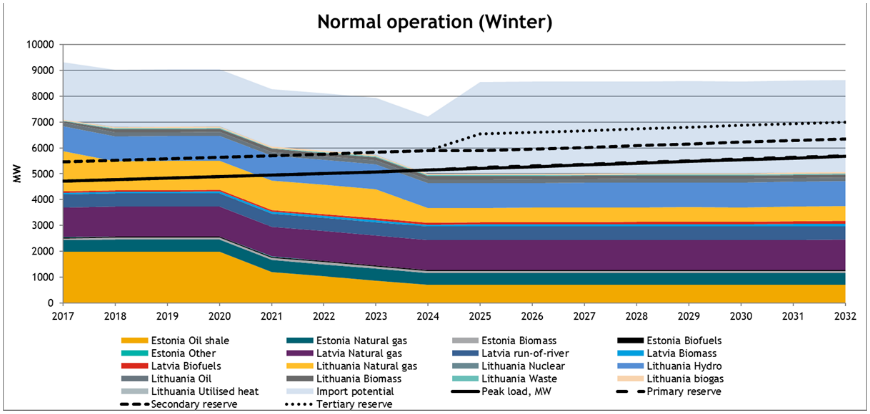

Fig. 1. Forecasted available electricity supply capacity in the Baltic region in winter [2]

II. INDEPENDENT DR AGGREGATION IN BALANCING MARKET

DR service is a temporal change in consumer's energy consumption due to a reaction to price signals or other measures [7]. DR is associated with multiple benefits, such as increased system flexibility, improved network congestion management, cost-effective deferral of grid investments and improved energy efficiency [8], [9]. DR can be broadly divided in two groups: implicit and explicit DR. Implicit (price-based) DR refers to consumers choosing to be exposed to time-varying electricity prices and/ or time-varying network tariffs that reflect the real cost of electricity at the time of use and allow the consumer to react to prices depending on their preferences. On the other hand, explicit DR refers to a program, where demand competes directly with supply in the wholesale, balancing and ancillary services markets directly or through the services of aggregators. This is achieved through controlled changes in the load that are traded in the electricity markets, providing a resource comparable to generation, and receiving a commensurate compensation [9], [10]. Based on the mFRR product specification, only explicit DR is applicable when considering balancing market [2].

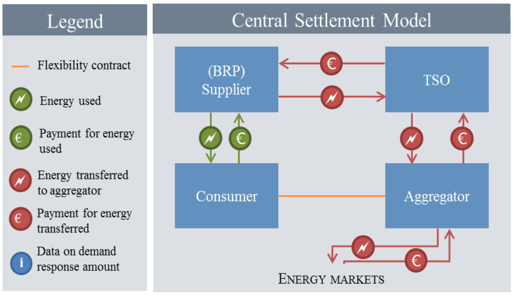

Fig. 2. Central settlement model

Large industrial plants in Europe (e.g. in the Nordics, Poland, Croatia, the Netherlands, Germany) have been involved in DR provision for ancillary services for considerable time [9], [10]. These large consumers can participate in the market individually. In the Baltics, the energy intensive industry is not highly developed, accordingly the DR potential is locked in smaller consumers (i.e. SMB, residential). A rough estimate suggests that both for residential and commercial buildings (such as schools, hotels, retailers) approximately 50% of energy consumption stems from heating, cooling, ventilation and lighting [11]. This indicates substantial flexibility potential, however, given that the minimum bid size for mFRR product is 1 MW, these consumers can only participate in the balancing market, if their loads are aggregated and coordinated. Advancements in information technology renders such aggregation and resource coordination feasible.

While it is an energy related product, DR aggregation requires different business processes in place compared to a typical energy supplier. To ensure that all consumers willing to participate in DR are allowed to, without switching their supplier, a new market participant – an independent aggregator – emerged. In essence, an independent aggregator is a DR aggregation service provider that delivers balancing energy sourced from end-users that are included in imbalance areas different to the aggregator [6]. There is no consensus on the best market framework for the integration of independent DR aggregators, since effect models differ by countries and types of electricity markets [9], [10]. The settlement model currently favored by the Baltic TSOs is a Centralized model (Fig. 2) [6].

III. CHARACTERIZATION OF THE SIMULATION SET-UP

A. *Assumptions for Energy Transfer*

When DR activation takes place, it has the following impact on the consumption curve (Fig. 3). When DR activation for upwards regulation (i.e. reduced consumption) takes place, the consumption is curtailed.

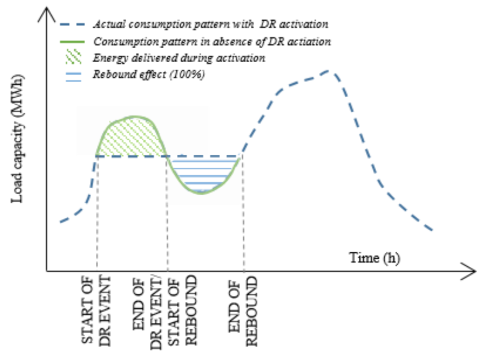

Fig.3. DR activation explained

Depending on the resource type, the energy unconsumed during the activation will be consumed to some extent during one or few following hours. Based on the results of the pilot with fridges [1], the assumed recovery effect in our simulations is 100% and it takes place during the next hour. Within our simulation framework, it is assumed that the volumes of energy transferred can be determined without an error.

B. *Assumptions for the Settlement Model (Cash-Flows)*

Within the simulation, it is assumed that the following prices are equal:

- Retail price is equal to the day-ahead price.
- Balancing price is equal to the imbalance price.

In line with the Centralized settlement model, the following trades for the energy delivered during activation take place:

1) Before an operational hour, Supplier/ BRP buys energy in day ahead market at day-ahead price (P_{DA}).
2) During the operational hour, TSO orders balancing energy from aggregator at balancing price (P_{bal}).
3) During the operational hour, consumer does not consume the energy it would consume in the absence of TSO's activation order.
4) During a settlement phase, TSO makes an imbalance adjustment for the declared position of the impacted BRP.
5) During the settlement phase, TSO pays BRP compensation for the energy taken from its portfolio at reference price (P_{ref}).
6) During the settlement phase, TSO pays Aggregator the difference between P_{bal} and P_{ref}.
7) During the settlement phase consumer does not pay for the energy unconsumed and may receive part of the profit generated by the difference between P_{bal} and P_{ref}.

The following trades for the consumption pattern deviation caused by the recovery effect take place:

1) During the settlement phase, consumer pays BRP/ Supplier retail price (P_{ret}) of the recovery hour for the energy consumed due to the recovery effect.
2) During the settlement phase, the BRP pays imbalance price (P_{bal}) of the recovery hour to the TSO for the energy consumed due to the recovery effect.

C. *The Simulation Tool*

The modelling for the case study is carried out using a Monte-Carlo simulations-based tool introduced and elaborated in [12]. The stochastic nature of the model requires the output to be probabilistic instead of deterministic. Consequently, most of the input settings concern the expected mean of a particular parameter across scenarios and the output is provided in the form of probability distributions.

The main modules of the tool are day-ahead price scenario generation, balancing liquidity and price scenario generation, balancing activation simulation, short-term and long-term economic assessment.

D. *Input Assumptions and DR Resource Characterization*

The assumptions for day-ahead market were made based on the historical values from Nord Pool day-ahead market data for the Baltics in 2017. The assumptions are presented in Table I.

The assumptions for the balancing market were made based on the historical values for the Baltic balancing market data for the first quarter of 2018. These reference values were chosen due to the significant market changes implemented on January 1, 2018. The assumptions are presented in Table II.

We based technical assumptions about the DR resource on the data presented in a pilot study by Lakshmanan et. al (2016) [1]. We set the total load capacity at 2.5 MW (25 fridges). The load profile for a typical day is depicted in Fig. 4.

DR activation parameters are presented in the Table III. Minimum DR bid price is set at 45 €/MWh to limit events where DR activation causes losses due to price difference between day-ahead price and balancing price. Based on the historical data from 2017, day-ahead price in Baltic region was below 45 €/MWh 85% of times.

We assume that the resource participates only in upwards regulation. Furthermore, it is assumed that participation in DR does not damage the resource and consequently does not add other additional costs.

TABLE I DAY-AHEAD MARKET DATA SIMULATION PARAMETERS

Price simulation parameters	Value (st. dev.)
Mean price for 99.5% of hours	34.02 €/MWh (10%)
Mean value for weekdays divided by mean value for weekends	1.23 (10%)
Mean value for day (06:00-22:00) divided by mean value of night (22:00-06:00)	1.38 (10%)
Minimum price	2.99 €/MWh (10%)
Maximum price for 99.5% of hours	75.34 €/MWh (10%)
Maximum price for 100% of hours	130.05 €/ MWh (10%)
Number of scenarios	300

TABLE II BALANCING MARKET DATA SIMULATION PARAMETERS

Price simulation parameters	Value
% of hours when regulation takes place	70%
% of regulation hours, where upwards regulation is required (load reduction)	45%
Balancing price for upwards regulation (expectation)	1.6 P_{DA}
Balancing price for downwards regulation (expectation)	0.6 P_{DA}
Number of scenarios	300

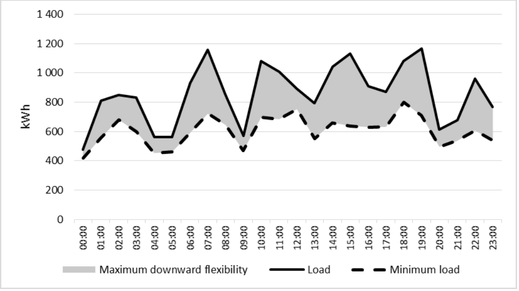

Fig.4. Load profile of the DR resource simulated

TABLE III DR RESOURCE SIMULATION PARAMETERS

DR resource simulation parameter	Value
Maximum number of events during 24 hours	6
Minimum time between the events	2 h
Maximum period before rebound	2 h
Rebound effect / DR energy delivery	100%
Minimum DR bid price	45 €/MWh
Discount rate used for NPV calculations	3%

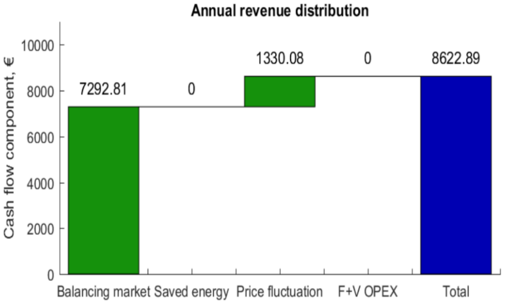

Fig. 5. Average annual revenue distribution

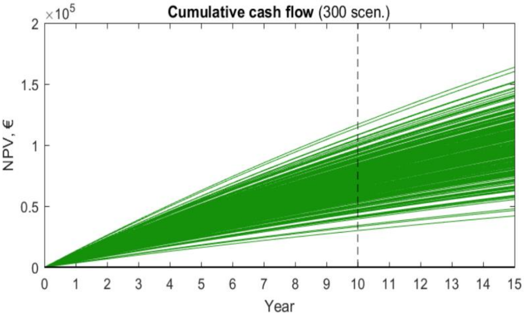

Fig.6. Cumulative cash-flow for 15 years (all scenarios)

IV. RESULTS

The portfolio's expected average annual income from participation in balancing market is 8 622.89 €. 85% of that is the revenue from balancing market payments and 15% stems from day-ahead price difference between the activation hour and recovery hour (Fig. 5). There is no benefit from energy savings in this case study, since we assumed that all the curtailed consumption would be recovered later.

Assuming a 10-year asset service life and 3% discount rate, the expected net present value (NPV) of the simulation described in the previous section is 73 555.01 €. In other words, the project would be profitable, if the initial investment was below 73 555.01 € or below 2 942.20 € per fridge (Fig. 6).

It is expected that on average the portfolio will annually deliver 326.24 MWh of balancing energy, by participating in 32% of all hours (1257 hours annually) when downwards regulation is used. Accordingly, on average, the portfolio earns 26.43 € per each MWh delivered to the balancing market (Fig. 7).

The expected average annual cash inflow for the portfolio is equal to 19 661.18 €, while the expected average cash outflow for the portfolio is 11 038.29 € (Fig. 8).

V. CONCLUSIONS

DR is associated with multiple benefits, such as increased system flexibility, improved network congestion managment, cost-effective deferral of grid investments and improved energy efficiency. However, to ensure that these benefits can be achieved, market needs a non-discriminatory framework that not only protects all the market participants from undue burdens but also facilitates business opportunities for DR aggregators. The preliminary assessment of expected economic gains from the small DR resource aggregation within the Baltic Balancing market employing Central Settlement model for aggregator integration seems promising. It suggests that there is existing balancing reserve potential in the Baltics.

For further research, we suggest reviewing more DR resource types, and, if possible, comparison of modelled expected benefits and the actual gains should be piloted to further verify the accuracy of the simulations. Furthermore, the simulation tool could be used to determine the optimal reference (compensation) price by assessing financial impacts not only on the aggregator but also on BRPs.

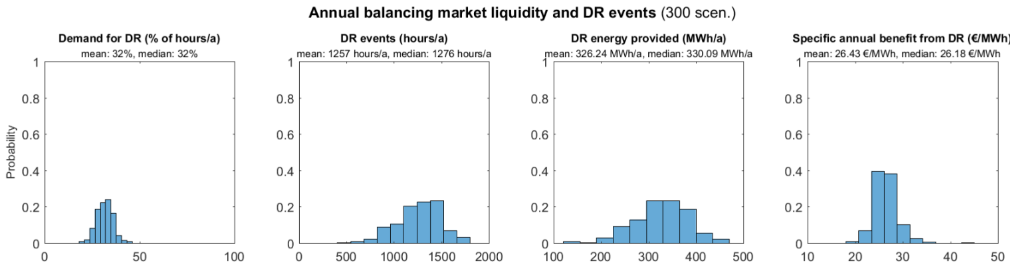

Fig.7. Overview of simulated DR events and balancing market prices

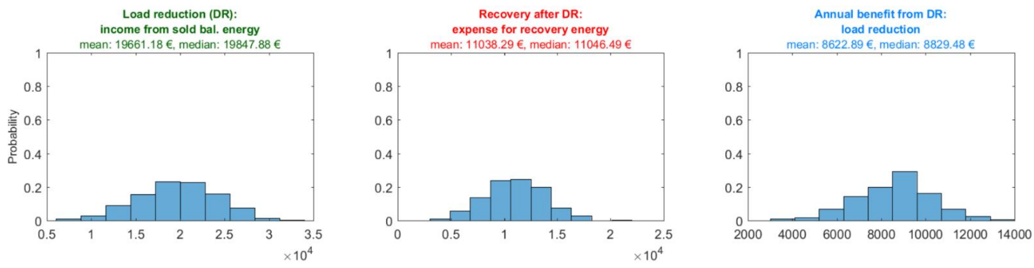

Fig. 8. Breakdown of DR owner's annual profit

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Heat-pump optimization strategies for participation in price-controlled demand response in 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 behavior can only be achieved if the financial benefits are well established and presented.

The author sets out estimate the economic performance of engaging in provision of demand response services using air-to-air heat pumps as the underlying technology. The results of the paper help to evaluate in a real data setting, whether the existing market framework provides sufficient incentives to facilitate end-user participation in demand response service.

Keywords: demand response, heat pumps, electricity price, electricity markets

1. INTRODUCTION

Traditionally the balance between demand and supply in a power system is maintained by adjusting centrally controlled supply to the largely inelastic demand. The increase in intermittent and distributed generation [1] as well as continuous increase in demand for electricity not only promotes volatility electricity prices, but also creates new challenges for the power system infrastructure. An aspect if this is illustrated by the case of South Queensland (Australia) where during 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 shift reduced electricity volumes consumed through 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 offers an opportunity to mitigate the volatility of energy consumption patterns which could help the power system to 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 concuss on whether facilitation of consumer engagement in electricity market is necessary, how to achieve that is a challenge with a less clear solution. The objective of this paper is to compare in alternative and easy to apply cost optimization scenarios for air-to-air heat-pump based heating system. The rest of the paper is organized as followed: in Section 2, market background and legal framework for Latvian electricity market is presented. In Section 3 is devoted to examination of enablers 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 the results of the case study and conclusions are presented.

2. BACKGROUND AND LEGAL FRAMEWORK

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 the 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. [..]" while 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 are available to residential users. [11].

Electricity market liberalization in Latvia started in 2007 when the option to freely choose electricity supplier was offered to business consumers with high consumption. Furthermore, they were joined by business consumers with medium consumption on April 1 2012 and all other business consumers on November 1 2012. The market was opened to residential consumers on January 1 2015. While the electricity suppliers in Latvia are required to offer "universal product" to residential consumers, Latvian legal framework does not require electricity suppliers to offer dynamic electricity price contracts. According to the data published by Public Utilities Commission of Latvia, 12.5% (three-fold increase from the end of 2017) of residential consumers and 42,8% of business consumers (~30% increase from the end of 2017) had chosen dynamic pricing type of contract (Figure 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.

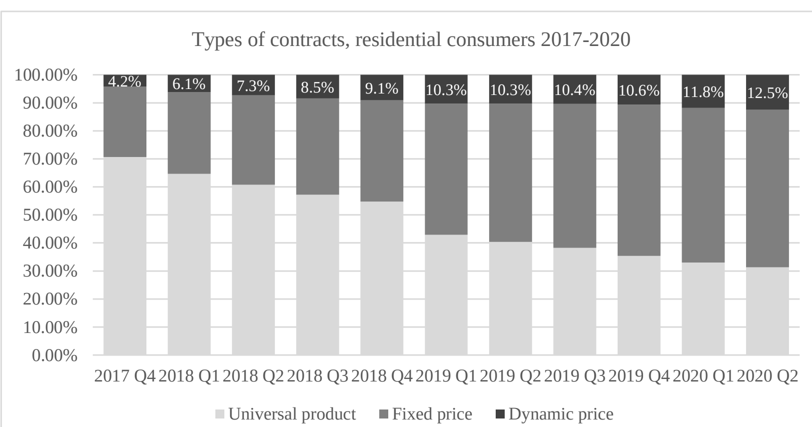

Fig. 10 Contract type structures for residential consumers in Latvia 2017-2020. Data source: [11].

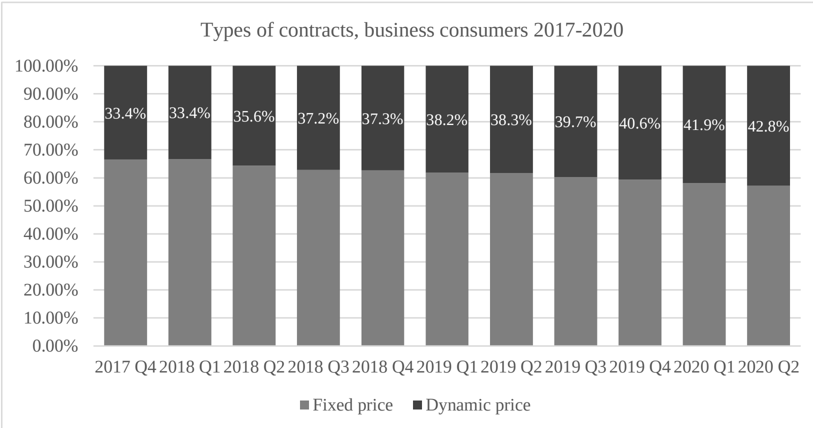

Fig. 11 Contract type structures for business consumers in Latvia 2017-2020. Data source: [11].

To look at overall consumption pattern trends in Latvia year 2020 is excluded due to 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 – Table 1 [15]. While a positive trend and more research should be done to explore the drivers behind it, the data also shows high variations between peak and off-peak demand and potential for implicit demand response to facilitate it.

Table 5

Comparative descriptive statistics for energy volumes sold on NordPool Day-ahead market on 2017 and 2019, Data source [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's engagement (or lack of it) can be divided stages, each characterized 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 (Figure 3) [4], [16].

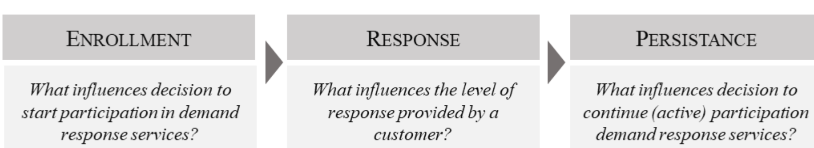

Fig. 12 Three stages of consumer engagement in demand response. Adapted from [3].

Understanding barriers and enablers 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 approach and assess the potential for demand side response participation in 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 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 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 as necessary precondition for meaningful participation in implicit demand response activities.

4. CASE STUDY DESIGN

Heating, ventilation, and air conditioning systems (HVAC) have tendency in developed countries to become more prevalent over time [30]. The latest data for Latvia is from 2015, when 6% of residential buildings in Latvia had electricity-based heating and ~2% of residential buildings in Latvia had air conditioning [31]. Furthermore, HVAC tends to be one of the most energy intensive type of residential type 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 50% of the monthly electricity consumption during 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, the general approach for introducing deterministically controlled HVAC system is fairly simple and requires data collection, algorithm and load controller device [33]-[36]. The objective of this study is to evaluate in real data setting, the most appropriate algorithm for implementing automatic and cost-efficient HVAC system management that relays on publicly available data. To achieve that for 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. In Table 2 and 3, presents environment and data description.

Table 6

Description of the case study environment.

HVAC systems used	One Toshiba Premium air-air type of heat pumps (RAS-25PAVPG-ND), with heating capacity 0.7-6.70 kW and three Toshiba Optimum (RAS-25PKVSG-ND) 1.00 - 6.50 kW was chosen.
Area	Two isolated rooms 26 m^2 (set indoor temperature of 17° C) and 23 m^2 set indoor temperature of 17° C and large hall 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 7

Description of the data used in the case study.

Outside temperature	Factual hourly data from metrological data from Latvian Environment, Geology and Meteorology Centre (° C) [37]
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 following assumptions (simplifications) were made – firstly the load is only shifted and there is no reduction of total consumption (rebound effect expected to be 100%). The consumption from the hour where 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 then once every two hours (the condition is observed also during date change).

The following optimization scenarios was devised (Table 4).

Table 8

Optimization scenarios used in the case study.

Scenario	Conditions	Objective
Selecting two hours in every given day, when the HVAC is switched off based on the following criteria:		
2-1	Lowest temperature	Representation of highest expected consumption [38]
2-2	Highest day-ahead price.	Representation of the highest cost per MWh
2-3	Highest forecasted 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 based on the following criteria:		
3-1	Lowest temperature	Representation of highest expected consumption
3-2	Highest day-ahead price.	Representation of the highest cost per MWh
3-3	Highest forecasted cost savings from load shifting	Representation of the highest total gains from shifted consumption

The highest forecasted costs savings (C_{H0}) from load shifting was calculated as followed:

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

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 (EUR/MWh).

The expected volume E_{H0} shifted is calculated based on empirically obtained relationship for the 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 (Figure 4) was obtained by applying linear regression on the empirical consumption and factual temperature data from the case study.

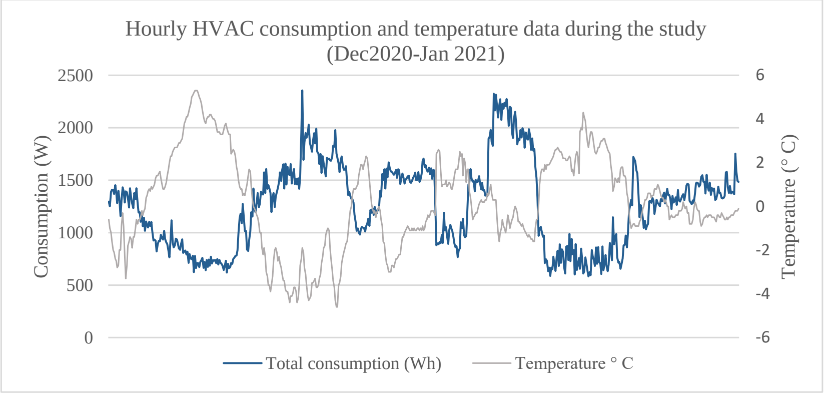

Fig. 13 Hourly HVAC consumption and temperature data during the study. Temperature data source [35].

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 was collected in regard to outdoor temperature, day-ahead price and actual HAVC consumption (Table 5).

Table 9

Descriptive statistics of temperature, electricity price and HVAC consumption during the case study. Data sources – temperature [35], 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 10

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 group. The highest load shift is observed in scenario where the load is shifted away from the coldest hours (in two-hour scenario – 9,5% of total load was selected while in three-hour scenario 14.0% of load was shifted). However, neither scenario 2-1 more 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 night, when the electricity price dynamic is less pronounced. Scenarios 2-2 and 3-2 in both two-hour and three-hour group demonstrates the best performing similar relative performance in their according scenario group, however, the best performing scenario was 2-3 and 3-3 that considered both the expected difference in price as well as 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 only considering day-ahead prices and not taking into account the expected consumption level, is sub-optimal choice.

Overall, results of the case study suggests that the immediate benefits from load-shifting is modest. Taking this into account, if the energy policy maker considers and identifies that active engagement from residential consumers in implicit demand response activities are 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.

ACKNOWLEDGEMENTS

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Stochastic Model for Profitability Evaluation of Demand Response by Electric Thermal Storage

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***Abstract*—In this paper, a tool for the economic assessment of a potential demand response asset used for power system balancing is presented. The model tackles uncertainties in electricity market prices and system imbalance by employing Monte Carlo simulations. While the model provides vast customizability options, the potential demand response benefits for a particular type of consumer, smart electric thermal storage, are the focus of the case study. It is found that such type of operations can be economically feasible for the asset owner, but on the condition that sufficient proportion of the balancing renumeration is shared with the owner by the aggregator.**

***Keywords*—aggregation; balancing; demand response; Monte Carlo.**

I. INTRODUCTION

Demand response (DR) is an increasingly enticing means the power system operators can employ in system control and management. There are several benefits DR can bring to the system, e.g., provision of ancillary services, contingency management, price volatility reduction, investment cost deferral etc. [1]. In principle, two main types of DR programs can be distinguished – price based (implicit), where the load follows some external price signal, and incentive based (explicit), where the DR asset owner is remunerated in either a classic direct control/interruptible load program or from an ancillary service/ capacity market [1].

To improve the energy independence and diversify the flexibility resources offered on the Baltic balancing market, the transmission system operators (TSOs) of the three Baltic states are planning to commence employment of DR assets for system balancing in the near future [2]. However, small loads do not have much influence on the overall system frequency, hence their control has to be aggregated to reach the required minimum balancing power bid size. This is usually done by an aggregator which is an entity that pools together the flexibility resources of several consumers and offers them to a marketplace or an operator directly [3].

On the one hand, for electricity end-users to become interested in DR provision, they need to be aware of the potential benefit they can gain. On the other hand, proper incentives need to be introduced for customers to participate in DR programs. However, the modeling of DR operation required for economic feasibility evaluation is quite complicated. An important issue which should not be neglected is load recovery when consumers change their consumption patterns in the hours following a DR event [4]. Another peculiarity arises when modeling the flexibility potential of a consumer and uncertainties related to it [5]. Uncertainty is also a factor concerning the stochastic behavior of prices in electricity markets and system imbalances. To that end, Monte Carlo based simulations have proven to be an effective approach to handle modeling uncertainties [6].

In this study, Monte Carlo simulations are utilized in developing a software tool for DR economic potential that has been created in close collaboration with the national TSO. In essence, the tool establishes the potential economic benefit the owners of controllable load assets might achieve should they agree to participate in an explicit DR program, particularly, by having their load remotely reduced or increased to meet system balancing needs. The software has been developed using the MATLAB scripting environment [7].

This paper also provides a case study to evaluate the DR potential of a consumer who uses smart electric thermal storage devices for heating their dwelling [8].

II. METHODOLOGY

As stated previously, the main computational principle of this software lies in a Monte Carlo simulation-based approach for modeling the activations of DR and the related cash flows within a full year of the asset's operation. Consequently, the output of the model is in the form of probability distributions instead of one deterministic result as implying absolute certainty would be unreasonable when considering future processes. The tool is implemented via a number of software modules which are described in more detail in the following subsections.

A. Input Module

The overall setup of the model is based on the expected market conditions for DR operation in the Baltic states, since as of mid-2018 it is still under development. The input settings necessary to run the developed assessment model are primarily divided in four categories.

This work is part of the RealValue project. This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 646116.

Firstly, the parameters which provide economic description of the DR asset and contractual conditions of its owner:

- asset service life (years);
- capital expenditure (CAPEX) to enable participation in system balancing (€), e.g., remote control hardware or software;
- annual fixed operating expenditure (F-OPEX) to maintain the DR provision ability (€), e.g., additional bandwidth maintenance, related service fees etc.;
- variable operating expenditure (V-OPEX) arising from DR operations. This parameter can be modeled in three distinct ways – €/DR activation, €/DR affected load or €/unrecovered load;
- minimum balancing price for consumption reduction and maximum balancing price for consumption increase (either fixed €/MWh or % from hourly day-ahead price) – parameters to establish the bid price limits of the DR asset's participation in the balancing market;
- a binary variable to establish if the owner of the DR asset itself is a balance responsible party (BRP) or not, which significantly changes how the cash flows are modeled;
- an option to select how the energy purchase price is modeled (only day-ahead Π_{da}^{t}, day–ahead with markup in the form $k_1 \cdot \Pi_{\mathrm{da}}^{t} + k_2$, fixed price derived from the simulated day-ahead price or scenario-independent general fixed price) (€/MWh);
- share of the TSO payment for load reduction which is passed on to the DR asset owner (%); implying that the rest of the renumeration is received by the aggregator, BRP or other unspecified party.

Secondly, a technical description of the DR asset's hourly load and its flexibility has to be provided. This can be done either for a typical day or a typical week if applicable and with up to four distinct profiles to capture seasonality (i.e., the modeled year can be divided in four three-month periods).

As the DR activations are modeled with an hourly resolution, the most important parameters here are the maximum permitted number of DR events in a day or week, minimum time distance between any two DR events (hours), load flexibility direction for balancing (reduce, increase, both), minimum and maximum duration of a DR event (hours), maximum duration before load recovery (hours), load recovery factor (coefficient, where 1 implies that all the load reduced/increased during a DR event has to be recouped (increased/reduced) in the following hours. The meaning of these settings is better explained in Fig. 1, where green colors denote a DR event and red – the recovery.

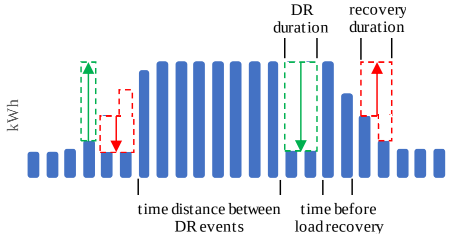

Figure 1. Explanation of some of the DR modeling terms used

Note that the distance between two events is the time between the end of last recovery and beginning of the next DR activation. The area ratio between the green and red figures depends on the recovery factor, which can be selected different for the load increase and load reduction DR events. The hourly load profile with hourly upwards and downwards flexibility concludes the full technical description of the DR asset.

Thirdly, there are settings concerning the generation of day-ahead price scenarios – expected mean price (€/MWh) for the normally distributed hours, expected maximum price (€/MWh) for the normally distributed hours, expected ratio between the mean weekday and holiday price, expected ratio between the mean day and night price (night defined as 22:00–6:00), expected minimum price (€/MWh). For each scenario these parameters are drawn from a normal distribution. Two more parameters ensure that the resulting price distributions more closely follow the skewness with right tail traditionally observed in electricity wholesale spot prices – percentage of hours where peaks outside the normal distribution occur and the expected maximum (€/MWh) of such peaks. All the parameters described in this paragraph additionally have individually selectable standard deviations to ensure better controllability of the price scenario generation mechanism.

Finally, certain input parameters are needed to model the balancing market scenarios – expected balancing market liquidity (% of hours when the TSO has imbalance it could cover with DR), upper and lower bounds of this parameter to ensure that in none of the scenarios the liquidity is drawn from outside this range, ratio of negative imbalance hours from all the hours with system balancing. The balancing price is drawn from the previously generated day-ahead price scenarios. The settings controlling this are – the expected ratio of hourly balancing price vs day-ahead price separately for negative and positive system imbalance, probability of extraordinarily high balancing price peaks and the maximum ceiling for the extraordinary balancing price (€/MWh).

B. *Day-Ahead Price Scenario Generation*

The input parameters described in the previous subsection are used to generate a pre-selected number of day-ahead price scenarios for a whole year with hourly resolution. The day-ahead price generation algorithm proceeds as follows.

1. From a normal distribution, draw price generation settings for each particular scenario (mean, min, max, ratios etc) using the expected values and standard deviations read from the input parameters.
2. For each scenario s, ensure that the drawn mean, min and max settings are not contradictory.
3. For each hour category within each scenario, calculate a coefficient necessary to enforce the weekday/holiday and day/night ratios as in (1) for weekday nights, (2) for weekday daytime, (3) for holiday nights and (4) for holiday daytime:

$$k_{\mathrm{w,n}}^{s} = \left(R_{\mathrm{w/h}}^{s} \cdot \Pi_{\mathrm{da}}^{s,\mathrm{avg}} / \left(2/7 + 5/7 \cdot R_{\mathrm{w/h}}^{s} \right) \right) / \left(1/3 + 2/3 \cdot R_{\mathrm{d/n}}^{s} \right); \quad (1)$$

$$k_{\mathrm{w,d}}^{s} = R_{\mathrm{d/n}}^{s} \cdot \left(R_{\mathrm{w/h}}^{s} \cdot \Pi_{\mathrm{da}}^{s,\mathrm{avg}} / \left(\tfrac{2}{7} + \tfrac{5}{7} \cdot R_{\mathrm{w/h}}^{s} \right) \right) / \left(\tfrac{1}{3} + \tfrac{2}{3} \cdot R_{\mathrm{d/n}}^{s} \right); \quad (2)$$

$$k_{\mathrm{h,n}}^{s} = \left(\Pi_{\mathrm{da}}^{s,\mathrm{avg}} / \left(2/7+5/7\cdot R_{\mathrm{w/h}}^{s}\right)\right)/\left(1/3+2/3\cdot R_{\mathrm{d/n}}^{s}\right); \quad (3)$$

$$k_{\mathrm{h,d}}^{s} = R_{\mathrm{d/n}}^{s}\cdot\left(\Pi_{\mathrm{da}}^{s,\mathrm{avg}} / \left(2/7+5/7\cdot R_{\mathrm{w/h}}^{s}\right)\right)/\left(1/3+2/3\cdot R_{\mathrm{d/n}}^{s}\right). \quad (4)$$

4. For each hour t in each scenario s, generate day-ahead price as in (5) and (6), while ensuring they do not violate scenario minimum and maximum restrictions:

$$\Pi_{\mathrm{da}}^{s,t} = \max\left[N\left(k_{t}^{s},\left(\Pi_{\mathrm{da}}^{s,\mathrm{avg}}-\Pi_{\mathrm{da}}^{s,\mathrm{min}}\right)/3\right),\Pi_{\mathrm{da}}^{s,\mathrm{min}}\right]; \quad (5)$$

$$\Pi_{\mathrm{da}}^{s,t} = \min\left[\Pi_{\mathrm{da}}^{s,t},\Pi_{\mathrm{da}}^{s,\mathrm{norm\,max}}\right]. \quad (6)$$

5. Smoothen the generated time series with a moving average filter with a span of five elements.
6. Enforce the expected mean on the smoothened price:

$$\Pi_{\mathrm{da}}^{s,t} = \Pi_{\mathrm{da}}^{s,t}\cdot\Pi_{\mathrm{da}}^{\mathrm{exp,avg}}\Big/\sum_{s=1}^{S}\left(\sum_{t=1}^{T}\Pi_{\mathrm{da}}^{s,t}/\left(S\cdot T\right)\right). \quad (7)$$

7. Finally, in each scenario, for $k_{\mathrm{extra\,peak}}^{s}$ % of hours add an increased price event:

$$\Pi_{\mathrm{da}}^{s,t} = \Pi_{\mathrm{da}}^{s,t}+\Pi_{\mathrm{da}}^{\mathrm{s,extra\,max}}-\Pi_{\mathrm{da}}^{s,\mathrm{norm\,max}}. \quad (8)$$

C. Balancing Liquidity and Price Scenario Generation

The balancing liquidity and price scenarios are generated as follows.

1. For each scenario, draw the balancing liquidity (% of hours where TSO might request DR) parameter from a normal distribution.
2. Ensure that the drawn values respect the upper and lower bounds; if they do not, replace the value with the violated bound.
3. Since the model runs with hourly resolution, each hour with balancing liquidity has to be assigned either direction – upwards or downwards balancing.
4. Generate upwards and downwards balancing prices for each hour in each scenario:

$$\Pi_{\mathrm{bal,\,up}}^{s,t} = \Pi_{\mathrm{da}}^{s,t}\cdot\min\left(1,N\left(R_{\mathrm{up/da}},\left(R_{\mathrm{up/all}}-1\right)/3\right)\right); \quad (9)$$

$$\Pi_{\mathrm{bal,\,dwn}}^{s,t} = \Pi_{\mathrm{da}}^{s,t}\cdot\max\left(1,N\left(R_{\mathrm{dwn/da}},\left(1-R_{\mathrm{dwn/all}}\right)/3\right)\right). \quad (10)$$

5. Combine the two timeseries for each scenario as per the hourly imbalance direction to obtain one balancing timeseries per scenario.

D. Balancing Activation Simulation

When all day-ahead electricity price and balancing scenarios have been generated, they can be paired, and the balancing activations can finally be estimated.

The purpose of this module is identifying the hours when the modeled DR asset can participate in balancing and when the energy recovery post-DR takes place. The program goes through each scenario sequentially checking each hour to test if activation conditions are met. The overall DR activation simulation algorithm is summarized in Fig. 2.

In the first conditional test block, all of these conditions have to be met:

- the minimum time distance since the previous DR activation is respected;
- the number of DR activations in the current day/week does not exceed the limit;
- there is demand for balancing in the system coinciding with the direction the DR asset owner is willing to provide services in (load reduction/increase);
- the DR asset has flexibility in the particular direction during the particular hour;
- the balancing price falls within the DR asset's bid limits;
- there is enough flexibility in the next hours for DR energy recovery respecting the max duration before load recovery constraint (relevant if the load recovery factor is nonzero).

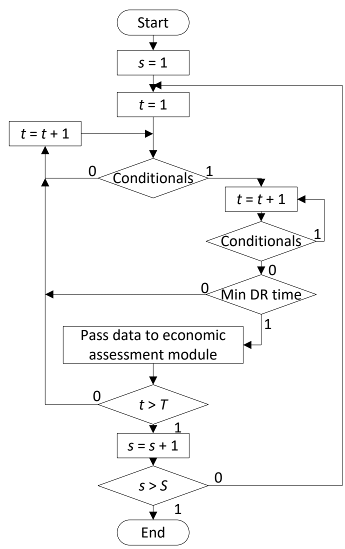

Figure 2. Simplified viusalization of the DR activation simulation algorithm

During the subloop with the second conditional block, it is tested if the duration of the DR event can be increased (the same conditions are checked with an additional test against the max duration of a DR event variable). Finally, it is checked whether the potential DR event duration meets the minimum limit.

Afterwards, if a DR event has been identified, information about it is passed on to the economic assessment module.

E. Short-Term Economic Assessment

The formulae (11)–(14) are used to calculate the cash flows associated with a simulated DR event. They depend on the direction of the DR induced load change and the balance responsibility status of the DR asset owner. The benefit is derived by contrasting the cash flows with and without DR. Beforehand, however, the energy purchase price timeseries are produced as mentioned in section A.

Variable tDR denotes the set of hours when the DR event takes place and, consequently, $trec$ denotes the set of hours when the recovery takes place. Since, theoretically, the DR event and recovery can span multiple hours, the multiplications in the following equations are implied to be matrix operations.

Benefit from load reduction if DR asset owner is BRP is composed from the income from the sold balancing energy (at balancing prices) and expenditure for recovery energy (at balancing prices):

$$B_{\mathrm{BRP}}^{\mathrm{red.}} = E_{\mathrm{DR}}^{s,tDR} \times \Pi_{\mathrm{bal}}^{s,tDR} - E_{\mathrm{rec}}^{s,trec} \times \Pi_{\mathrm{bal}}^{s,trec} . \tag{11}$$

Benefit from load increase for a BRP depends on the expense for procured balancing energy during the DR event and income from sold balancing energy during the recovery:

$$B_{\mathrm{BRP}}^{\mathrm{incr.}} = -E_{\mathrm{DR}}^{s,tDR} \times \Pi_{\mathrm{bal}}^{s,tDR} + E_{\mathrm{rec}}^{s,trec} \times \Pi_{\mathrm{bal}}^{s,trec} . \tag{12}$$

For a DR asset owner who is not balance responsible, the benefit from load reduction derives from the income from sold balancing energy, savings from load reduction during the DR event (at retail purchase price since, unlike BRP, the owner has no obligation to balance their portfolio) and expense for recovery energy (at purchase price):

$$B_{\mathrm{nonBRP}}^{\mathrm{red.}} = E_{\mathrm{DR}}^{s,tDR} \times \left(\Pi_{\mathrm{bal}}^{s,tDR} + \Pi_{\mathrm{pp}}^{s,tDR} \right) - E_{\mathrm{rec}}^{s,trec} \times \Pi_{\mathrm{pp}}^{s,trec} . \tag{13}$$

Finally, for a non-BRP, the load increase cash flow components are the expense for procured balancing energy (at balancing price) and the savings from load reduction in the recovery phase (at purchase price):

$$B_{\mathrm{nonBRP}}^{\mathrm{incr.}} = -E_{\mathrm{DR}}^{s,tDR} \times \Pi_{\mathrm{bal}}^{s,tDR} + E_{\mathrm{rec}}^{s,trec} \times \Pi_{\mathrm{pp}}^{s,trec} . \tag{14}$$

The benefit from load reduction and/or increase is contrasted to the fixed and variable OPEX to find the overall benefit from participation in DR in each scenario throughout the whole year.

F. Long-Term Economic Assessment

The modeling outcome from the one-year run is extrapolated to further years for the whole service life of the DR asset by applying the previously selected discount rate. Several widely used investment assessment metrics are now calculated, such as net present value (NPV), internal rate of return (IRR) and payback period (PP). Once the long-term assessment is finalized, the calculation results are summarized and output to figures and data tables.

III. CASE STUDY

A. Assumptions

The case study aims to apply our developed software tool for economic assessment of smart electric thermal storage (SETS) participation in DR. The subject of the study is a hypothetical household having five SETS devices at their disposal with 2.2 kW input power and 15.4 kWh storage capacity each. The owner is not balance responsible and is willing to participate in both upward and downward DR (which requires the SETS equipment to never be disconnected from the outlet and the gateway). We assume the asset service life to be 15 years, discount rate – 3%, CAPEX – 200 € (to cover gateway costs) and annual F-OPEX – 20 € (service and other related costs). For simplicity sake, it is implied for now the householder purchases electricity at wholesale price. It is also assumed that the aggregator passes on to the DR asset owner all of the TSO payments for load reduction (however, the effect of this assumption will be explicitly addressed).

In regards to the load profile and flexibility, we set a maximum number of 14 DR activations per week, but do not restrict the time between them. In this study, we do not allow for multi-hour DR events. Maximum duration before load recovery is set to 12 hours and the recovery factor is set to 0.9 both for load reduction and increase (this implies some energy savings in case of load reduction and some wasted energy in case of increase).

The seasonal heating demand data is derived from the model of [9], where it was seen that the overall heating demand in summer, spring and autumn is approximately 10%, 50% and 20% of the winter demand respectively. Consequently, we assume that, in summer, there is one SETS unit that charges 2..5 hours a day, can be disconnected anytime during the charging and another unit can be turned on whenever necessary.

In autumn, one SETS unit charges for the full seven hours, but can be disconnected at request; the other remaining units can be switched to charging when necessary. In winter, four units are in full operation; in spring – two, in either case the operational units can be switched off and any idle units – set to charging.

The day-ahead price scenario generation settings are derived from an analysis of the Nord Pool Latvian bidding area prices during the period of 01.06.2017–31.05.2018. Expected mean price for 99.5% of hours is 37.75 €/MWh, expected maximum price for 99.5% of hours – 119.5 €/MWh, expected ratio between mean weekday and holiday prices – 1.25, expected ratio between mean daytime and nighttime prices – 1.44, expected minimum price – 1.59 €/MWh, expected rare maximum – 255 €/MWh. A total of 1000 price scenarios are generated.

The balancing scenario settings are derived from the common Baltic balancing market launched on 01.01.2018. The expected balancing market liquidity is 64.97%, ratio of negative vs positive imbalance hours – 0.44, expected balancing price during positive system imbalance – 0.58 pu from the day-ahead price, expected balancing price during negative system imbalance – 1.49 pu from the day-ahead price. Zero extraordinary balancing price events are assumed.

The generated hourly day-ahead market and balancing prices across the thousand scenarios are summarized in Fig. 3.

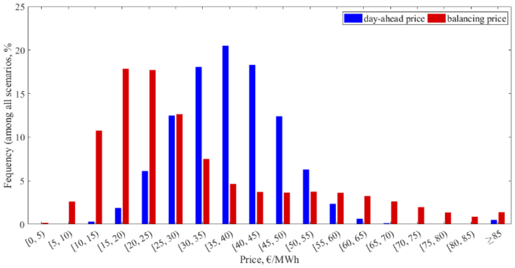

Figure 3. Day-ahead (blue) and balancing (red) price histograms

B. Results

Though the simulation results imply there have been much more DR activations for load increase than for load reduction (on average, 452 times for increase and 199 for reduction), Fig. 4 suggests that the reduction operations have been overall more economically beneficial (scenario average of 46.50 € vs 12.71 €). This is also reflected in the specific benefit per DR activation (mere 3.92 €/MWh average for increase, but 49.80 €/MWh for reduction). This can primarily be explained by two factors, the additional positive cash flow component in case of load reduction (see Fig. 4) and the initially assumed load recovery factor 0.9 for both directions, which implied that load increase DR is slightly wasteful in terms of energy consumption.

The average NPV is at 268.10 €, however, Fig. 5 and Fig. 6 show that there are some scenarios (3.6%) where the NPV is still negative at the end of the selected service life. The average IRR is 17.56%. The average payback period is thus 7.23 years while the median is 6 years, which signals that the outlier scenarios are likely skewing the mean. Indeed, Fig. 5 shows that some of the outlier scenarios have not reached payback even by year 20.

Nevertheless, while an expectable 268.10 € benefit accumulated during a 15-year period is not necessarily very enticing for a whole household to allow remote control of their heating equipment, this result does serve as valuable first insights in the assessment of the economical potential of participation in explicit DR on a dwelling level.

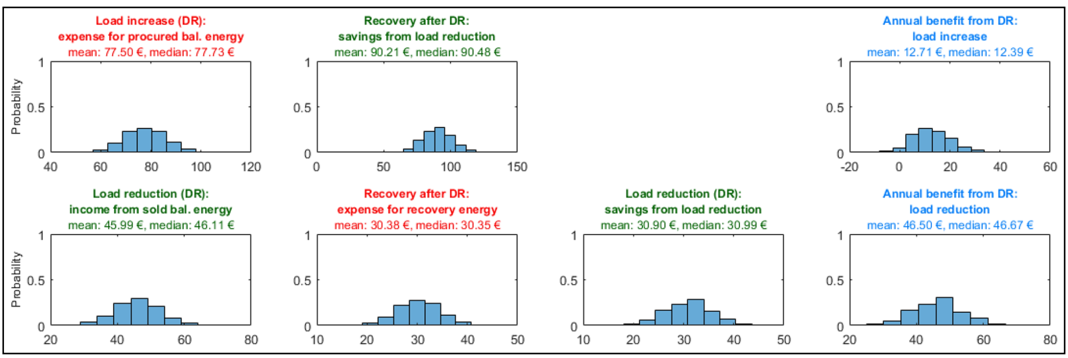

Figure 4. Economic assessment for a single modeled year

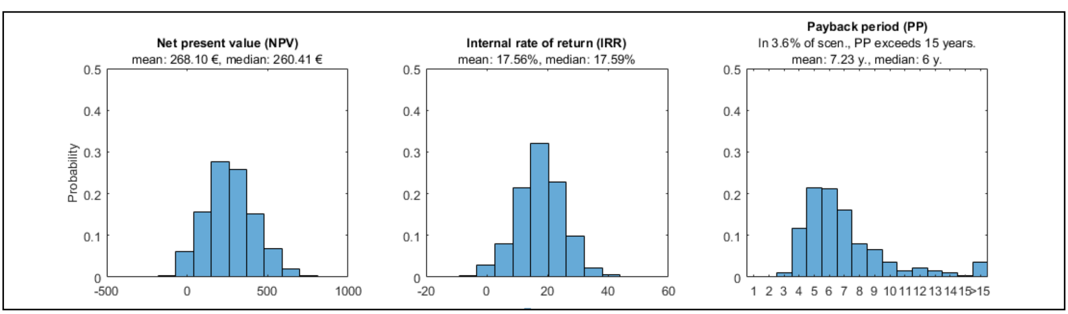

Figure 5. Long-term economic assessment for the asset service life (15 years)

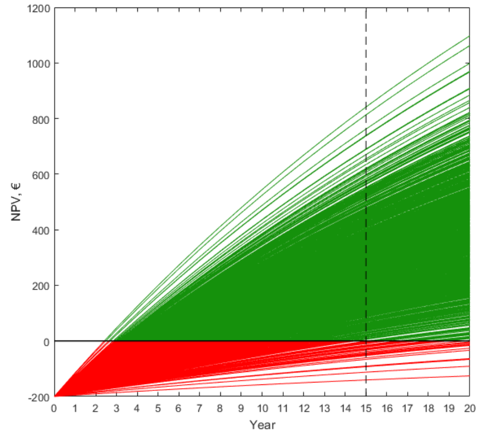

Figure 6. The cumulative cash flows in the simulated scenarios

A note should be made, however, that the initial assumption of a household in Latvia exclusively heated by SETS devices is not strictly realistic since even conventional electric heating which could be replaced is not currently widespread in Latvia and SETS is on a significantly higher price range than conventional heaters. If the SETS device costs where also included in DR CAPEX calculations, payback would not be possible.

C. Impact of the Payment Sharing on SETS DR Feasibility

Additionally, the assumption that 100% of the TSO payment for load reduction is received by the DR asset owner is objectionable. To alleviate this limitation of the study, we completed several additional model runs with all the same input data only varying the share coefficient. The results from the repeated runs are summarized in the following table. Evidently, the share of TSO payment the DR asset owner receives has to be higher than 50% for the participation in an explicit DR program to be economically meaningful.

TABLE I. EFFECT OF BENEFIT SHARING ON DR FEASIBILITY

TSO payment share passed to the DR asset owner	**Long-term assessment parameter**			
	NPV, €	***IRR, %***	***PP, years mean / med.***	***% of scenarios where PP impossible***
100%	268.10	17.56	7.23 / 6	0.0
90%	209.37	14.57	8.51 / 7	0.0
80%	149.28	11.32	11.17 / 8	0.0
70%	101.08	8.57	15.06 / 10	0.7
60%	35.43	4.37	22.92 / 13	2.0
50%	-6.85	1.47	29.99 / 16	3.4

IV. CONCLUSIONS

The developed Monte Carlo simulation-based DR economic assessment tool has proven to be useful in providing preliminary evaluation of the potential benefits controllable load asset owner might gain by participating in the power system balancing via an explicit DR program. However, the model employed requires quite detailed knowledge of the technical characteristics of the DR asset, especially in regard to its available flexibility with an hourly resolution. In general, the results are assumption-sensitive, thus any output should not be viewed independently of the input.

The preliminary results signal that electric thermal storage devices can recoup the additional investments necessary to make them DR-ready, but only if more than 50% of the load reduction renumeration is passed on to the asset owner. In fact, the stochastic output of the model shows that even at 100% renumeration, there is a small probability that the payback period could exceed the asset service life. Realistically, however, such a full payment sharing is unlikely as the aggregation service provider also needs incentives for its operation.

In conclusion, a more accurate DR economic feasibility assessment would require near perfect beforehand knowledge of the contractual setup between the DR asset owner, aggregator, BRP, TSO and other potentially linked parties. However, the current version of the tool already allows modeling a variety of different setups which enables studies on finding the most suitable business case for a particular application. Nevertheless, further improvements of the tool and subsequent more rigorous validation are in the plans.

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