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Strategizing for Carbon Neutrality: Policy-Driven Insights Using LEAP for Pakistan's Energy Sector Transformation

Friday, April 4, 2025 11:15 AM (25 minutes)

Pakistan's energy sector, heavily reliant on fossil fuels, facing rising emissions, energy insecurity, and affordability challenges. This study employs the Low Emissions Analysis Platform (LEAP) to model Pakistan's energy landscape, analysing energy demand, generation capacity, emissions, and costs under three scenarios: Reference (business-as-usual), With Existing Measures (WEM), and With Additional Measures (WAM). Using 2022 as the base year and projections until 2040, the results show a significant increase in electricity demand from 184 TWh to 820 TWh under the Reference scenario. The WEM scenario reduces greenhouse gas emissions by 16.3% through energy efficiency measures, while the WAM scenario achieves net-zero emissions with 80% renewable integration by 2040. Although initial costs in the WAM scenario rise to 73.6 billion USD, long-term benefits include improved energy security and equity. This study highlights the need for robust policy interventions, renewable investments, and technological advancements to achieve Pakistan's sustainable energy goals. The escalating challenges of climate change, marked by rising greenhouse gas emissions and global temperature increases, underscore the urgent need for actionable energy strategies. Pakistan, heavily reliant on fossil fuels, faces severe energy security risks, economic burdens, and environmental degradation. With its energy demand expected to quadruple by 2040, the country's current energy infrastructure is insufficient to sustain such growth. This study aims to address these pressing issues by exploring feasible pathways for achieving a low-carbon energy future, leveraging policy-driven interventions and advanced energy modeling techniques.

The Low Emissions Analysis Platform (LEAP) was selected for its robust capacity to model energy demand and supply dynamics, emissions, and economic implications across multiple scenarios. LEAP is highly adaptable, integrating energy system components and allowing for tailored scenario-based analysis. The methodology followed a structured approach, beginning with the development of a comprehensive national GHG inventory in accordance with the 2006 IPCC Guidelines. This inventory captured emissions across all energy generation activities, forming the foundation for modeling future projections.

Energy demand and supply modeling used LEAP's modules to project baseline data for 2022 and forecast scenarios to 2040. Scenarios included:

- The Reference scenario, which extrapolates current trends and policies.
- The WEM scenario, incorporating energy-efficient technologies and incremental policy measures.
- The WAM scenario, emphasizing renewable energy integration and targeting net-zero emissions.

Key data inputs included demographic growth, GDP, sectoral energy consumption, and technology-specific emission factors. The model's outputs provided projections for energy demand, generation capacity, GHG emissions, and associated costs. A comparative analysis assessed the environmental, economic, and security impacts of each scenario.

The results illustrate the transformative potential of policy-driven interventions:

Under the Reference scenario, GHG emissions are projected to rise from 78.7 million tons in 2022 to 345.3 million tons by 2040, primarily due to reliance on fossil fuel-based energy generation. The WEM scenario achieves a 16.29% reduction in emissions by 2040 through the deployment of energy-efficient technologies, while the WAM scenario realizes net-zero emissions by 2040. This is achieved by increasing renewable energy's share to 80% of the total energy mix, with significant contributions from solar (60.3 GW), wind (131 GW), and biomass (7.4 GW).

Electricity demand is projected to grow from 184 TWh in 2022 to 820 TWh by 2040 under the Reference scenario. Both the WEM and WAM scenarios mitigate this growth, with demand peaking at 692 TWh by incorporating energy efficiency measures. The diversification of the energy mix under WAM not only enhances energy security by reducing dependence on fossil fuels but also ensures resilience against supply disruptions.

Economic analysis reveals that the Reference scenario's projected electricity production cost of 66.3 billion USD is reduced to 55 billion USD in year 2040 under the WEM scenario, reflecting the cost-effectiveness of efficiency measures. The WAM scenario, though requiring higher upfront investments (73.6 billion USD), delivers long-term affordability through renewable integration, improving energy equity and reducing energy poverty. The higher initial capital costs are offset by lower operational expenses and greater energy access.

This study provides a comprehensive framework for evaluating the implications of different energy transition pathways in Pakistan. The findings emphasize the importance of integrating energy efficiency and renewable energy technologies. While the WEM scenario presents a cost-effective and achievable pathway, the WAM scenario offers the most sustainable long-term solution, with significant benefits for emissions reduction, energy equity, and energy security.

The results highlight the critical need for coordinated energy planning, policy coherence, and investment in renewables. These recommendations serve as a blueprint for aligning national energy policies with global climate goals, enabling Pakistan to transition to a sustainable and resilient energy future.

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Session Classification: Foreign market insights

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Economic Shadows of COVID-19: Electricity Trends in Tehran

Friday, April 4, 2025 12:05 PM (25 minutes)

The COVID-19 pandemic created unprecedented global health and economic challenges. Developing nations like Iran, which rely heavily on informal economic activities, faced unique hurdles in assessing and mitigating the pandemic's economic toll. Tehran, the economic hub of Iran, experienced significant disruptions, prompting a need for innovative approaches to quantify these impacts. Traditional metrics like GDP often fail to capture the nuances of economic activity in such contexts. Electricity consumption, a vital economic indicator, provides a promising alternative for real-time and sector-specific economic assessments. This study focuses on Tehran's commercial electricity consumption to estimate the pandemic's economic costs, contributing to informed policy-making and recovery planning.

The study employs a Difference-in-Differences (DID) methodology to measure the pandemic's impact on electricity consumption. Data from 14,638 commercial units in Tehran spanning 2019 (control group) and 2020 (treatment group) are analyzed. The DID model uses pre- and post-COVID-19 periods to estimate the causal effects of the pandemic on electricity usage. The model accounts for monthly and regional fixed effects to control for seasonality and unobservable heterogeneity. The DID framework ensures robust causal inferences by comparing trends in the control and treatment groups, isolating the pandemic's economic effects.

The results reveal a substantial decline in electricity consumption in the post-COVID-19 period, highlighting the pandemic's significant economic impact. Regression analyses show that the interaction term (treatment × post) is statistically significant and negative, indicating a marked reduction in electricity usage in 2020 compared to 2019. The treatment group experienced a prolonged decrease, with consumption levels failing to recover to pre-pandemic trends until two months after the initial outbreak. This finding underscores the pandemic's enduring impact on Tehran's commercial sector.

This study demonstrates the utility of electricity consumption as a proxy for economic activity, particularly during crises. By employing a robust counterfactual framework, it provides an innovative method to quantify the economic costs of COVID-19. The research offers actionable insights for policymakers, emphasizing the need for targeted support to affected sectors and the adoption of sustainable recovery strategies. The findings also contribute to broader discussions on the intersection of energy use and economic resilience, paving the way for future studies in similar contexts.

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Session Classification: Foreign market insights

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Economic Assessment of Negative Emissions from Sustainable Biomass in Europe

Friday, April 4, 2025 2:30 PM (25 minutes)

Biochar, produced by pyrolytic decomposition of biomass, offers stable carbon storage and potential for CO_2 removal. Biochar carbon removal (BCR) is an established technology that offers added value over gaseous CO_2 removal through sustainable by-products and ease of handling. There is a significant lack of techno-economic assessments of BCR, especially in the European context.

This study presents a mathematical model to assess the economics of BCR across supply chains. The aim is to determine the optimal carbon credit for the BCR supply chain, tha is a breakeven benefit at which a carbon removal project achieves a net present value (NPV) of zero. A mixed-integer nonlinear programming (MINLP) model is developed, along with its linear approximation. The model is applied to two case studies using all available paper sludge and sewage sludge from 32 European countries as input for a pyrolytic process known as Thermo-Catalytic Reforming (TCR®).

Results of case studies reveal that economic feasibility varies significantly depending on the type of feedstock and regional factors. Although paper sludge has a higher carbon sequestration potential per tonne compared to sewage sludge, the net present value is positive for sewage sludge with a carbon credit of over €29/t-CO_2, while for paper sludge it is positive up to €255/t-CO_2. Sewage sludge is economically more attractive as a large share of the costs can be offset by revenues from by-products. Optimal carbon credit could potentially drop to -132 €/t-CO_2 (sewage sludge) and 65 €/t-CO_2 (paper sludge), assuming that biochar is sold at a market price of 100 €/t. Additionally, this study explores the overall potential of BCR from the total sustainable potential of biogenic waste and residues in 42 European countries. According to our analysis, the total carbon sequestration through biochar can potentially range from 203 to 619 Mt CO_2 per year. Total potential of bio-oil as by-products is 126 TWh, which could increase to 619 TWh in an optimistic scenario. This biofuel can replace fossil diesel or serve as a feedstock for sustainable aviation fuel.

The study takes a conservative approach by giving priority to carbon removal through the disposal of biochar rather than its use as fertiliser. However, the technology would be more economically attractive if revenues could be generated from utilizations. The costs associated with BCR are primarily due to capital investments in conversion technology and energy requirements, and there is potential for reducing costs in these areas. Although the model is limited to a few case studies, it provides a basis for expanding BCR and designing sustainable carbon removal networks. BCR offers a sustainable alternative to waste management and improves the cost-benefit ratio by taking opportunity costs into account. Overall, regulations and certification frameworks are needed to incentivise carbon removal and reduce risks for stakeholders.

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Session Classification: Challenges of technological advances I

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Bridging Financing Gaps: Homeowners' Preferences for Solar PV Business Models

Friday, April 4, 2025 4:15 PM (25 minutes)

The purchase of a residential solar photovoltaic (PV) system necessitates a substantial initial investment and a certain degree of planning and administration. These obstacles may be overcome by implementing rental models. Furthermore, there is a growing discourse surrounding alternative business models that have the potential to address the utilization of PV electricity that is not utilized within a household. This issue is addressed by the concept of electricity clouds, which aim to stabilize the fluctuations in individual electricity demand and the availability of PV electricity. The study seeks to ascertain whether a customer segment can be identified for which these innovative energy services are perceived as attractive. Drivers of solar PV adoption decisions have been widely studied in the literature (e.g., Best et al., 2019; Best and Chareunsy, 2022; Groote et al., 2016; Zhang et al., 2023). We implement drivers, namely investment costs and self-sufficiency as well as barriers such as investment cost and amortization time, into a discrete choice experiment (DCE) to elicit homeowners'general preferences for these attributes.

Purchasing a solar PV system involves a large upfront investment and potential recurring maintenance costs over the life of the system. Thus, rental models can potentially enable homeowners to adopt solar PV who were previously unable to do so. However, it is unclear whether homeowners are willing to adopt rental models when they are presented in combination with "classic" direct purchase models. Some studies in the area of electric vehicle adoption decisions find that when given the option of leasing or purchasing an electric vehicle, people generally prefer to purchase, although these results are ambiguous and depend on the exact type of vehicle (Huang et al., 2021; Liao et al., 2019). Findings from studies in the area of energy retrofit decisions also suggest a preference for purchasing over renting. Schleich et al. (2021) study UK homeowners' preferences for purchase models for new heating systems and find that respondents have a positive willingness-to-pay (WTP) for direct purchase rather than a rental option. To explore these preferences in the real of residential solar PV systems, we differentiate between two purchase models: Respondents can choose to either ourtight purchase or rent their future solar PV system. In addition, empirical evidence demonstrates a prevalent preference among consumers for integrating their solar PV systems with batteries, thereby enhancing self-sufficiency (e.g., Priessner and Hampl, 2020; Uz and Mamkhezri, 2024). Thus, we also include the option to combine the purchased or rented solar PV system with a battery.

This paper presents the findings of the aforementioned DCE conducted among German homeowners to investigate their preferences regarding different purchase options for solar PV systems. To analyze the data, we employ flexible mixed logit models in preference space as well as in WTP space (Thiene and Scarpa, 2009; Train and Weeks, 2005). Furthermore, following, e.g., Ladenburg and Skotte (2022), Schleich et al. (2021), and Meyerhoff et al. (2019), we elicit heterogeneity in preferences by including interaction terms between the attributes and several individual-specific variables. For this study, to reduce hypothetical bias in our results, we limited our sample to homeowners who reported that they did not own a solar PV system and that installing one was at least a possibility. We did this by asking homeowners without a solar PV system about the likelihood of installing one in the next 5 years and excluding those who said it was very unlikely from the choice experiment. A total of 842 homeowners participated in the discrete choice experiment.

The results we find regarding innovative business models are ambiguous. First, our results suggest a general preference among homeowners for a direct purchase model when given the choice between it and a rent-to-own model. However, we find that this depends on household-specific characteristics, such as the age of the decision maker, the ability to invest 30.000 Euro and the ownership of electric vehicles. We find that homeowners who are older, who do not have the means to purchase a solar PV system outright, or who are less advanced in their decision making process regarding the adoption of solar PV, are less likely to invest in a solar PV system via direct purchase. With respect to rent-to-own models, we find that homeowners who are younger and less certain about their investment decisions are more likely to engage in this business model. A comparison of our hypothetical rent-to-own models with real-world examples showed that the choices in our experiment were made under favorable economic conditions for the rent-to-own model, with lower total prices compared to real-world examples. This suggests that the demand for rent-to-own models may be overstated in our models. Thus, our results suggest that rent-to-own models are potentially able to increase the solar PV adoption intentions of the aforementioned target groups, albeit to a small extent compared to the standard direct purchase business model. Regarding the concept of energy sharing, we find that there seems to be a general interest in these business models. However, we find differences in preferences between the two types of energy sharing as well as between household characteristics. In general, people prefer regional energy sharing compared to a "family and friends"type of energy sharing, where households choose the respective recipient of their surplus electricity. Examining heterogeneity in preferences, we find that prior ownership of electric vehicles positively affects the preferences for energy sharing options. Overall, our results suggest that rent-to-own and energy sharing models are likely to have a small impact on solar PV adoption among homeowners.

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On the preferences for electric vehicle energy tariffs with direct load control in Germany

Friday, April 4, 2025 3:20 PM (25 minutes)

In order to meet the climate goals of the Paris Climate Agreement, participating nations are committed to finding measures to reduce CO2 emissions in their country. Over the last decade, the share of renewable energy sources (RES) in the electricity generation has increased (IEA, International Energy Agency, 2021), but the amount of CO2 emitted by the road transport sector in the EU has also increased by about 21% from 1990 to today. In the EU, the total amount of emitted CO2 is about 740 million tons in 2022 (Eurostat, 2024). The electrification of the transport sector is a measure to reduce overall emissions, but leads to an increase in overall electricity demand. Despite strong growth in electric vehicle (EV) adoption in the EU in recent years, EVs account for only 1.2% of the Euroean car fleet and further growth is needed to meet the EU's goal of climate neutrality by 2050 (EEA, 2023; European Commission, 2024). Increased supply from renewable energy sources poses several challenges to the power sector, such as increased intermittency, which stresses the distribution grid and increases risk of grid congestion. The growing adoption of electric vehicles (EVs) exacerbates this problem, as simultaneous and unmanaged charging means significantly higher power consumption and additional stress on the distribution grid (Huang et al., 2021). This study aimed to explore preferences for electric vehicle (EV) energy tariffs with direct load control. We conducted a stated choice experiment of a representative sample of the German population (n=2,771) in which participants were offered different electric vehicle charging tariffs, all of which included the option for a third party (the grid operator) to intervene in the charging process of EVs. Both the choice scenario and the attribute levels were individualized based on the annual mileage and vehicle classification of respondents.

We elicit the preferences of car owners and participants who plan to purchase a car in the future for electric vehicle energy tariffs in Germany. The discrete choice experiment contains six choice sets for each participant. At the beginning of the choice experiment, all participants receive detailed and identical information about the hypothetical choice situation, with individualized information based on previous responses in the questionnaire. In the experiment, respondents are asked to choose between several hypothetical options for electric vehicle energy tariffs. Most of the attribute levels shown in the stated choice experiment were individualized based on previous responses in the questionnaire. We specifically asked for the annual mileage in the household and for the corresponding vehicle classification. Based on this information we calculated the current monthly charging duration per respondent. The attribute levels of the additional monthly charging duration and monthly remuneration were also individualized based on this information. The key dependent variable is the dummy variable "choice", which takes the value 1 if a respondent chooses a particular smart charging tariff in a choice situation and the value 0 otherwise. Our analysis of the discrete choice experiment relies on a mixed logit model, as it does not require the independence of irrelevant alternatives assumption (IIA) and it ensures efficient estimates even if respondents make sequential choices (Lancsar et al., 2017; Revelt andTrain, 1998).

First, the statistically significant positive estimated coefficient of the opt-out variable suggests that, on average, respondents have a general preference for choosing the opt-out or a "standard" charging tariff without any intervention or remuneration. Regarding the attributes of the charging tariffs with direct load control, we find that respondents prefer higher remuneration. Regarding the preferences for more additional charging hours due to the longer charging process, we find that respondents have preferences for fewer additional hours. On average, respondents are willing to give up €0.15 of monthly remuneration to reduce the additional monthly charging duration by 1 additional hour. However, this effect is only statistically significant at a 10% significance level. This result is somewhat surprising, given the fairly unanimous evidence from previous literature that people typically prefer fewer additional hours of charging time. The same is true for the maximum number of intervention days per month, where we also find a negative preference for a higher number of days, but only at a 10 % significance level. Here we find that, on average, respondents are willing to give up €0.30 of monthly remuneration for one less monthly intervention. Regarding the number of opt-outs available, Model 1 suggests a clear positive preference for more opt-outs, with an average willingness to accept of €1.38 for one additional opt-out. Regarding information provision, we find that respondents have a general preference for any of the given information provision options compared to receiving no information at all. Daily information about possible upcoming interventions appears to be the most preferred, with respondents willing to forgo €14.05 of monthly remuneration to receive it. For weekly information, respondents indicate that they are willing to give up €11.99 of their monthly remuneration. Finally, respondents show a fairly strong preference for hourly information, with an average willingness to accept of €8.34.

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Large-scale implementation of sector coupling in Europe - key concepts, barriers, and solution space

Friday, April 4, 2025 2:55 PM (25 minutes)

Overview
Sector coupling could be a cost-efficient supplement in addressing the European challenge of increasing electricity grid expansion costs. Its large-scale implementation could unlock significant electricity flexibility, storage and cross-sector synergy potential, thereby saving costs and increasing sustainability. Previous research in sector coupling concentrated on energy systems modelling and techno-economic assessments. Studies have proven the potential benefits of sector coupling, theoretically in system modelling and practically in pilot studies. However, in practice, it has not yet found large-scale implementation with studies citing different barriers. Recent literature reviews have focused on technologies and models or specific barrier categories but have not yet displayed a full picture of barriers. Therefore, this paper aims to provide a multi-perspective understanding of why sector coupling has been falling short of its potential with a focus on large-scale implementation barriers in the EU.

Methods
Using a systematic literature review methodology, an integrated and interdisciplinary understanding was gained applying a 3-step logic. 1) A 3-string search was used, consisting of "sector coupling"and used synonyms, a focus on business and economics perspective and a geographical focus on the EU. The resulting 70 search string combinations were used in the databases EBSCO host, Science Direct, Web of Science. 2) Papers were manually reviewed based on title and abstract. 3) Additions were made based on cross citations and further research. The final literature set included 150 publications The analysis consisted of a discussion of key concepts towards a clear definition of sector coupling, a collection and aggregation of implementation barriers into 6 categories and the synthesis of these towards 11 solution spaces to unlock the potential of sector coupling.

Results
Key concepts in sector coupling include power-to-mobility, power-to-heat/cooling and power-to-gas/liquid, and some authors also include power-to-power and power-to-negative emissions concepts. Definitions for sector coupling range from one-way energy conversion in specified end uses to a holistic cross-carrier energy system optimization. Relevant literature can be found within the terms sector coupling, smart energy, power-to-X, multi-energy systems, energy systems integration, and integrated energy systems. To capture the full body of research but also clearly delimitate the scope, a necessity for a clear definition emerges. This paper outlines a holistic definition of sector coupling to capture its full benefits.

The systematic literature review identified a total of 63 *barriers* for large-scale implementation of sector coupling in Europe, which were aggregated under 6 barrier categories:

1. Technical (203 mentions), e.g., technology development risks (top example, 28 mentions)
2. Regulatory (171), e.g., insufficient regulatory and policy frameworks (37)
3. Economic (157), e.g., high upfront investments for infrastructure and technology (43)
4. Market (149), e.g., unclear value chain and market design (28)
5. Social & environmental (106), e.g., consumer engagement and consumer behaviour (30)
6. Institutional & managerial (75), e.g., lack of coordination/ challenges in cross-company/ sector planning and operation (35).

These barriers across categories were further analysed and clustered based on similar root problems while accounting for dependencies between them. The result of this synthesis lead to the emergence of 11 *solution spaces* that provide a fertile ground for overcoming the large-scale implementation barriers of sector coupling:

1. Adapting to the frame conditions, referring to mentioned barriers that cannot be changed
2. Achieving technological progress to reduce technical constraints, risks, and eventually costs
3. Accelerating infrastructure expansion, e.g., grid expansion, charging points, heat pumps, or smart meters
4. Refining the political strategy, i.e., national implementation and detailing
5. Designing sector coupling markets, i.e., distribution of costs and benefits, and connection to energy markets
6. Standardizing and integrating regulation, from international, cross-sectoral, and cross-subsidy perspective
7. Unlocking financial investments, i.e., through targeted ramp up support and regulatory stability
8. Managing technical complexity, e.g., in modelling, technical coupling, operating, and cybersecurity
9. Integrating people to ensure social acceptance and steer consumer behaviour
10. Unlocking business innovation, i.e., through cross-stakeholder collaboration and business model creation
11. Prevailing against competition, i.e., increase competitiveness against fossil fuels and renewable alternatives.

Conclusions
This paper has looked at the state of research in sector coupling, summarizing the barriers that inhibit its large-scale implementation in the EU within 6 categories and suggesting 11 solution spaces to overcome them. While barriers from multiple sides hinder the implementation, the most severe barriers seem to be non-technological, thereby indicating it is not only technical but i.e. also regulatory, market, and social barriers hindering the implementation. Furthermore, it becomes evident how the development of sector coupling is dependent on technology adoption, e.g., the rollout of smart meters and heat pumps. Therefore, the large-scale implementation will have to be orchestrated with the overall energy system development. This also means, the potential of sector coupling to achieve immediate relief on energy transition costs seems rather limited. For the implementation, this suggests working within the solution spaces while accounting for interrelations, not only for the pace of the energy transition, but also between sectors, nations, energy carriers, and the barriers itself.

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Session Classification: Challenges of technological advances I

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Multi-Market Coupling Model: A Residual Demand Approach

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The growing share of intermittent renewable infeed calls for further interconnection of electricity markets. The European commission defined one coupled European electricity market as the target model and aims for an expansion of the interconnecting capacities to cover at least 15 % of the electricity produced in each connected country (European Commission (2015), European Commission (2024)). For Central Western Europe (CWE), we observe that the day-ahead prices are often identical and are influenced by transmission capacities implicitly allocated by the Flow-Based Market Coupling (FBMC) methodology. However, established electricity price models often do not consider market coupling and lack implementable solutions to integrate it. Existent coupling models often assume explicit capacity allocation not following the FBMC and do not account for more than two coupled bidding zones. Due to the expected growth of interconnecting capacities, an approach using structural information and the FBMC methodology is needed. With our multi-market coupling model we want to fill this gap and answer the following research question: How can we integrate FBMC in a residual demand framework to predict electricity day-ahead prices in a mid-term horizon?

The literature with regard to market coupling can be broadly divided into approaches that predict convergence states of coupled bidding zones and approaches that predict the prices or price spreads. Saez et al. (2019) and Corona et al. (2022) use decision trees and probit regressions to estimate the price convergence between two bidding zones. Pircalabu and Benth (2017) and Christensen and Benth (2020) use reduced-form models to predict price spreads between two bidding zones. Cartea and Gonzalez-Pedraz (2012) and Pierre and Schneider (2024) apply a reduced form model for the electricity prices of two price zones. Kiesel and Kustermann (2016), Füss et al. (2017), and Alasseur and Feron (2018) use fundamental models developed and tested for two connected bidding zones.

We take the general concept of Kiesel and Kustermann (2016), integrate the supply function methodology of He et al. (2013) and apply it to a residual demand approach. First, we estimate supply functions considering fuel prices of each price zone without interconnection. These supply functions are then adapted by the residual demand that is exchanged via interconnectors. Core of the model is the iterative optimization to find the optimal interconnector flows and the corresponding supply functions. Hence, we develop a proxy of the EUPHEMIA coupling algorithm and take the Remaining Available Margins (RAMs) of every interconnector as side restrictions. We obtain FBMC parameters from JAO (2025), take further electricity market data from ENTSO-E (2025), and fuel prices from Reuters (2025). Our model enables us to extend residual demand approaches (e.g., Wagner (2014), Hain et a. (2024)) into models covering multiple markets. By taking the interconnector capacities implicitly into consideration, our model enables us to determine the effect of additional interconnector capacities on the price dynamics, the most decisive interconnector, or the value of each interconnector. Empirical tests demonstrate that we can improve the in-sample performance of a residual demand model only considering one bidding zone.

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Session Classification: Energy security and market coupling

Contribution ID: **27** Type: **not specified**

On the status of energy communities'integration in existing energy markets

Friday, April 4, 2025 2:30 PM (25 minutes)

Energy communities, following the guidelines defined from the European Commission, gained in the last years an increasing attention in the research. In the European context, a regulatory framework for member States has been provided from the Clean Energy Package for all Europeans in 2019 (European Commission, 2019), where the Renewable Energy Directive REDII (European Commission, 2018) and the Electricity Market Directive (European Commission, 2019) paved guidelines for EU member states to implement renewable energy communities (REC) and citizen energy communities (CEC), respectively. In the Austrian regulatory framework, the RECs definition from REDII Directive has been transposed into the Renewable Energy Expansion Act (Bundesgesetz über den Ausbau von Energie aus erneuerbaren Quellen (Erneuerbaren-Ausbau-Gesetz –EAG)), whereas EMD guidelines are transposed into the Electricity Act (Bundesgesetz, mit dem die Organisation auf dem Gebiet der Elektrizitätswirtschaft neu geregelt wird (Elektrizitätswirtschafts- und –organisationsgesetz 2010 –EIWOG 2010)).

Although attractive for citizens, the prioritization of local benefits for local welfare could represent a challenge while embedding their participation within more active markets. Energy communities are already entitled to provide flexibility services through its members either individually or through aggregation. However, the data exchange between the involved actors result to be poorly regulated, especially between independent aggregators and energy suppliers (Perger, Kalt, Kabinger, Materazzi-Wagner, & Kaiser, 2024). On the technological side, smart energy management and IoT technologies need to achieve a sufficient rollout (Paiho, et al., 2021). Encouraging an active citizens participation to modify consumption/generation patterns plays a crucial role (Hampton, Foley, Del Rio, & Sovacool, 2022), but requires attention in the schedules planning phase. The analysis of such problematics and the proposal of new frameworks are therefore of primary importance to, first, unlock flexibility potential from each individual energy community, and second, foster their cooperation at a higher regional or national level. In this perspective, energy communities could be organized following a cellular structure, where each cell (in the form an energy community) is interconnected physically (grids), and virtually (platforms) (Lehmann, Huber, & Kießling, 2019).

To fill this gap, in this work different options concerning energy communities'integration in electricity markets are proposed, and potential barriers and opportunities discussed. Market opportunities have been identified using as reference the most promising and consolidated energy markets (day-ahead, intraday, balancing) in the current Austrian framework. Although future opportunities could come from the implementation of markets more at the local level, such as local energy markets, peer-to-peer trading, and local flexibility markets, such options are not considered due to their current lack of practical implementation (Capper, et al., 2022). However, lessons learnt could be transferred to any tasks concerning market design frameworks considering current or future trends. Both indirect (customers'reaction to input prices) and direct (central control from an aggregator) schemes concerning energy community's members market participation are investigated. Strategies to gather units'control over limited time slots over continuous control are considered more attractive in practice to gather participants interests, and later involve them within the planning of short-term flexibility provision. The provided analyses are discussed considering interests, opportunities, and barriers of all the stakeholders involved.

As a result, a potential towards market-friendly and grid-friendly behavior could be relatively easily unlocked through participants'indirect reaction to price tariffs. Indirect participation in day-ahead market, through prices sent from suppliers to each customer daily, is found to be relatively easy to implement according to current legislation. Similarly, grid-friendly behavior can be promoted if distribution grid operators are willing to send daily innovative grid charges to the participants, based on renewable sources forecasts. However, such options do not ensure a proper reaction from the participants, being the schedules not communicated, thus it is still task of suppliers and grid operators to anticipate the participants'behavior. On the other hand, higher potential can be retrieved through aggregation in balancing and intraday markets, where synergies between technical and commercial aggregator could foster flexibility activation driven from prices forecasts. Social preferences are crucial in this perspective, as the availability and flexibility from end-user components need to be properly anticipated before the trading. Bilateral communications in the form of requests and approval are assumed in place, in such a way households can negotiate in advance (e.g. day-ahead, hours ahead, etc.) the hours where a technical aggregator can take the control of components. However, the potential of the provision of flexibility through aggregation is limited from the rollout of smart technologies and IoT development. The potential of forecasts information sharing within the participants is also found to be beneficial. All the stakeholders would benefit form such data, as (i) energy suppliers could use such forecast to negotiate better price tariffs with the customers, (ii) grid operator can anticipate critical situation for the next day, (iii) aggregation operators could consider when to strategically schedule bids to have a lower impact on local energy sharing, and (iv) the energy communities and its participants can behave more community friendly and improve the exploitation of locally produced renewable energy.

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Session Classification: Utilization of flexibility potentials

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The Energy Playbook –An affordable strategy to net zero

Friday, April 4, 2025 11:40 AM (25 minutes)

The European energy transition is at a critical crossroads. Since the onset of the energy crisis in 2022, persistently high energy costs have placed significant strain on industries and households, raising concerns over the affordability of the transition. Simultaneously, the ambitious goal of achieving net zero emissions by 2050 requires unprecedented levels of investment. Over the next decade, an estimated EUR 6.6 trillion must be funnelled into the energy system to meet the objectives outlined in the EU Green Deal and REPowerEU plan (cf. European Commission, 2022). This implies that annual investments must more than double by 2030. The question of how to balance cost-efficiency, energy security, and sustainability has become increasingly pressing.

Beyond climate protection, Europe's reliance on fossil fuel imports, which account for 60% of its energy consumption and 30% of its system costs, presents an opportunity for transformation. A well-structured energy transition can mitigate these dependencies, enhance economic resilience, and drive domestic value creation. However, the current trajectory risks inefficiencies, as capital is allocated to expensive solutions with uncertain long-term viability.

The feasibility of reaching net zero has been demonstrated in numerous studies, particularly in the highly regarded IEA scenarios (cf. IEA 2024). However, the IEA's focus is global, rather than on Europe and Germany. Other European studies—such as the EU Impact Assessment (cf. European Commission, 2023), the Ten-Year Network Development Plan (cf. ENTSOG and ENTSO-E, 2024), the UBA (2019) study, and analyses from companies such as Shell (2023), Elia (2021) or EDF (2024) –primarily assess the technical feasibility of net zero, rather than its economic viability. This is precisely the gap that our study wants to fill. The Energy Playbook study develops an affordable, yet realistic scenario to net zero and compares it to the current EU targets to identify potential for optimisation.

The Energy Playbook scenario prioritises decarbonisation options based on abatement costs to achieve maximum emissions reductions per euro spent, while following a technology-neutral approach, allowing market mechanisms to determine the most effective solutions without favouring specific technologies. Based on a comprehensive and detailed modelling of the European energy system, we calculate the required energy-related investment and annual system costs in Europe. In addition, we quantify the alternative investment path and system costs of an EU Reference sensitivity, based on the current targets of the EU REPowerEU and Green Deal plan and the EU Impact Assessment. We find that, Europe can realise significant cost savings and economic benefits, including lower electricity prices, a flatter investment curve, and cumulative savings of approximately EUR 1.5 trillion in energy system costs by 2050 by following the Energy Playbook scenario instead of sticking to the REPowerEU and Green Deal pathway.

Based on the identified cost saving potentials, we conclude that a successful energy transition requires clear prioritisation of efforts. The current approach mandates simultaneous decarbonisation of power, heat, transport, and industry, which risks losing focus on key enablers. To ensure affordability and feasibility, the study identifies cost saving potential along three steps:
1. Prioritise electrification first: Electrification remains the most cost-effective pathway for 80% of the transition.
• However, electricity is currently overburdened with taxes and levies, making it less competitive. Reducing these costs will accelerate electrification and lower overall system expenditures.
• A timely grid expansion is critical to support the increasing share of renewable energy and the electrification of demand. Current non-competitive regulatory returns in the EU do not attract sufficient private capital, hindering the rapid scaling of Europe's electricity infrastructure.

• Integrating digital solutions can optimise energy consumption patterns, reducing the need for costly backup capacity and enabling system-wide efficiency gains.
2. Scale an affordable energy system: Europe needs to align the ramp-up of supply and demand. If these elements decouple, the energy system risks inefficiency, leading to over-subsidisation and stranded assets.
• Hydrogen will play a critical role in the long term, but it remains costly. A phased approach that aligns supply with demand will optimise resource allocation and defer unnecessary infrastructure investments, saving up to EUR 200 billion by 2030.
• Rescaling the system can cut the required renewable capacity expansion by 30% by 2030, cutting annual subsidies by EUR 20 billion.
• Strengthening cross-border grid interconnections can eliminate the need for 100 GW of additional backup capacity, reducing system costs and improving resilience.
3. Don't trip on the last mile: The final phase of decarbonisation –eliminating the last 10% of emissions –will be the most complex and costly in terms of abatement. To prepare for this challenge, Europe should:
• Invest in innovation: The affordability of the last mile will depend on breakthroughs in clean baseload power, cost-effective hydrogen production, and advanced carbon removal technologies.
• CCS and carbon offsets are key to net zero, often offering a cheaper alternative to hydrogen-based solutions. Their success depends on the timely development of regulatory frameworks and infrastructure.
Backed by in-depth analysis and modelling, the Energy Playbook identifies major cost-saving potential on the road to net zero. With concrete policy recommendations, it offers actionable insights for discussions and clear direction for policymakers.

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Session Classification: Energy market outlooks and transformation strategies

Contribution ID: **29** Type: **not specified**

A systematic approach to calculate future electricity load scenarios based on open-source geoinformation data: A case study for Berlin in the year 2045

Friday, April 4, 2025 10:25 AM (25 minutes)

The transition towards the decarbonization of energy systems means a significant shift towards electrification, which concurrently leads to increasing electricity demands and higher grid loads. On the other hand, in urban energy systems large installed capacities of PV systems on rooftops can lead to grid congestion during peak generation times, when generation exceeds local demand significantly. As a response, electricity grids must be strenghthened to handle these additional requirements. However, there are large uncertainties about the scale of investments needed to strengthen the infrastructure. Various factors, such as future developments in PV expansion, the share of central and decentralized heating systems, and the growing usage of electric vehicles, but also expected grid friendly behaviour of storage units or demand side management influence the resulting grid loads. All these uncertainty factors contribute to the complexity of estimating future loads. Furthermore, the resulting grid loads can vary significantly locally depending on structural differences. This study seeks to address the critical question: How do PV systems installed in urban areas influence load occurrences across different PV expansion scenarios in urban energy systems? For this purpose different scenarios w.r.t to critical development factors are calculated in a case study for the city of Berlin.

To explore this question, a systematic bottom-up approach for load estimation was developed utilizing open-source data. This data includes geoinformation data, e.g. the Berlin energy Atlas (Senatsverwaltung für Wirtschaft, Energie und Betriebe), municipal building records, standard load profiles, and projections on development factors based on existing studies as well as political targets. A Python toolchain was created to calculate hourly load profiles at the neighborhood level, based on projected annual demands for electricity, heating, and mobility to the year 2045. For this the following steps were undertaken: Previously conducted studies were used to project electrification shares in heating and mobility sectors (Bernd Hirschl et al., 2021; Reusswig et al., 2014; Senatsverwaltung für Umwelt, Mobilität, Verbraucher- und Klimaschutz, 2021; Stryi-Hipp et al., 2019). The distribution of residential, public, and various commercial users was subsequently used to generate resulting load profiles for each neighborhood. Individual building data, including roof area orientation and tilt, was used to generate PV generation profiles. Based on load and generation profiles resulting residual load profiles were calculated. The applied calculation scheme is summarized in Figure 1. A case study focusing on Berlin was conducted, in which load scenarios were developed by using a consistency assessment approach, clustering factors that lead to either higher or lower loads. These load scenarios were combined with various PV expansion scenarios considering different growth targets and market conditions for PV installations across diverse market segments, e.g. residential single-family homes, multi-family homes, commercial entities, and public buildings, as well as parking lot and balcony PV systems. Grid-friendly battery storage solutions were also considered.

The findings from the Berlin case study reveal a significant rise of grid load due to the electrification of the sectors mobility and heat. A substantial increase in peak loads on the power grid is expected, with an average peak load projected to be 2.9 to 3.6 times higher than current levels for the entire city. Also, when using the PV potential to a high extent, strong peak loads emerge, although this does depend on the various districts and their structures. Notable disparities were observed between central and surrounding suburban areas: in central locations with limited PV potential, load increases are primarily driven by population growth and the electrification of e-mobility and heating sectors. Conversely, in suburban areas with ample PV potential, even greater peak loads may arise from solar generation on middays during summer. Additionally in decentral areas higher peaks during winter months result from high shares of decentralized electric heating. The study concludes that PV expansion in central areas, where market conditions have previously hindered development, is essential. On the other hand, utilizing the PV potential to the maximum capacity in suburban neighborhoods can bring the risk of generating excess energy, that cannot be used locally, and exacerbate peak loads. Implementing grid-friendly battery storage solutions, that are not only used for enhancing self-consumption but also for mitigating peak loads, is recommended. These systems can alleviate excess generation during peak times and reduce wintertime load peaks caused by electric heating. Nonetheless, the widespread deployment of building-mounted PV systems may necessitate curtailment during peak hours to maintain grid stability. Figure 2 shows the estimated peak loads for the considered neighborhoods in Berlin for 2045 in the high load scenario with full utilization of PV potential as a fraction of 2023 peak loads. Blue colors indicate that peak loads occur in winter due to high demands, yellow indicates higher peak loads in summer due to solar generation.

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Session Classification: GIS-based analysis

Contribution ID: **30** Type: **not specified**

Rethinking N-1 Security: Balancing Reliability and Economy in Electricity Transmission –Applying chance-constrained congestion management optimization to evaluate the economic benefit of N-1 relaxation in the German high-voltage grid

Friday, April 4, 2025 11:15 AM (25 minutes)

The German power grid is undergoing a significant transformation driven by the increasing integration of renewable energy sources. While this shift supports decarbonization goals, it introduces substantial challenges for grid stability and congestion management. The variability of renewable generation, coupled with regional supply-demand imbalances, exacerbates flow bottlenecks and connected congestion management requirements. For example, total congestion management volumes have increased by more than 60% and associated cost more than twice over the past 5 years in Germany. The enforcement of the N-1 security criterion compounds these issues by reserving additional transmission capacity to account for potential component failures, such as the outage of a transmission line. This study addresses these challenges by introducing a chance constrained congestion management model to relax the N-1 criteria in the hours and for the lines where cost benefit of the relaxation is highest. The developed framework provides a viable alternative to the stringent N-1 security criterion, offering TSOs a more flexible and cost-effective approach to grid management.

Congestion arises primarily due to two factors: (1) nodal energy insufficiency, where local supply-demand imbalances create nodal deficits or surpluses, in conjunction with (2) insufficient transmission line capacities, which limit the ability to transfer power between nodes to resolve these imbalances in accordance with market-based dispatch outcomes. We simulate model-endogenous nodal power imbalance resulting from (zonal) market equilibria according to market practices as dependent random variables for 8760 hours of a year and considering historic parametric information from 2017.
Simulating single-line failures reveals that power distribution factors are centered around the mean but exhibit long tails. Nodal injections driven by market outcomes follow similar long tail pattern –resulting in significant outliers in line flow calculations and consequential costly congestion management measures. By analyzing these outlier events, we identify inherent low-probability, high-cost grid condition patterns that motivate the development of a chance-constrained optimization framework.

The aim of the developed method is to explore the potential of selective relaxation of the N-1 criterion during low-probability events that result in high redispatch volumes. Our proposed grid optimization model extends the ELMOD framework, a well-established tool for simulating electricity markets and congestion management in the German grid. To simulate N-1 contingencies, we develop a novel methodology based on contingency power transmission distribution factors (CPTDFs). These factors capture the maximum possible power flow on a given line resulting from nodal injections under simulated line failures. By combining CPTDFs with modelled nodal injection volumes, we determine line flows under contingency scenarios. These contingency flows, along with a controlled proportion of normal operating flows, are then integrated into the congestion optimization model. The model utilizes a mixed-integer program to optimize the relaxation of the N-1 security criterion by strategically switching between contingency and normal operating flows for specific lines and hours, aiming to minimize congestion management costs for pre-defined reliability values representing different N-1 security levels.

Simulations across a range of parametric settings suggest that the model can contribute to reductions in congestion management costs and volumes to varying degrees. For long-term (annual)

planning, we explore four methods to allocate relaxations across different time horizons. Methods that distribute relaxations on a daily basis indicate the potential for notable cost reductions, with estimated annual savings in the range of up to 26–30%, while hourly distributions appear to offer more moderate reductions of approximately 2–4%. However, these cost savings come at the expense of reduced system security, as relaxing N-1 constraints inherently increases the risk of unmanageable contingencies. On a daily resolution, we evaluate the model under three grid conditions: high positive and negative redispatch gaps, high renewable penetration, and high residual demand. We introduce two relaxation strategies: (1) Cumulative Time-Based Relaxation: Relaxing all lines for a given hour; and (2) Individual Line-Based Relaxation: Selectively relaxing specific lines over time.
The results show consistent cost and volume reductions across all scenarios, with the extent of savings varying by grid condition. For instance, scenarios with high renewable penetration exhibit moderate savings compared to those with high residual demand and high redispatch gaps. While cumulative time-based relaxations are computationally efficient, individual line-based relaxations offer greater cost and volume reductions.
Analyzing frequently relaxed lines and hours reveals optimal relaxation strategies. While restricting relaxations (e.g., limiting the number of relaxation hours per line) can diminish cost savings, it provides valuable insights into the trade-off between economic benefits and grid security.

The study highlights the potential of chance-constrained N-1 security relaxation for transmission lines to reduce congestion management costs and volumes. The findings underscore the importance of adaptive and more flexible grid management strategies for effective congestion mitigation. The developed system-theoretic framework offers a valuable insight for TSOs and researchers seeking to harmonize competing demands of grid reliability and economic efficiency. Its practical benefit regarding integration into transmission system operation planning and security concerns is yet to be explored.

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Session Classification: Energy security and market coupling

Contribution ID: **32** Type: **not specified**

Mandatory vs. Voluntary a priori Investment in Information Acquisition in Procurement Auctions

Friday, April 4, 2025 10:00 AM (25 minutes)

Procurement auctions play an essential role in securing goods or services at competitive prices. One of the key challenges, particularly prominent in renewable energy auctions, is the high uncertainty bidders face regarding future costs. To mitigate this risk, it is common practice to require certain prequalification measures prior to entering the auction (Kreiss et al., 2017). This requirement implies an investment in information acquisition. While mandatory investment enhances contract security, it imposes sunk costs on participants, resulting in reduced participation and lower competition levels, and may exclude interested bidders, leading to an inefficient outcome (Samuelson, 1985).

In response to these challenges, this paper compares two procurement auction settings in terms of participation, optimal reservation price, expected profit and efficiency (expected welfare): one with mandatory and another with voluntary investment in information acquisition. Although costly, the a priori investment serves to eliminate uncertainties about future costs. Our paper complements the existing literature on the voluntary setting and the comparison between mandatory and voluntary settings (see e.g. Bergemann and Välimäki, 2002; Jehiel and Lamy, 2015).

We consider a single-unit procurement auction with $N > 2$ firms (potential bidders) with a priori unknown private costs x_i. The firms will learn their own costs after an investment $c \geq 0$ in information acquisition. The auction is conducted as a second-price auction, where the auctioneer has a maximum willingness to pay of x_0 and sets a reserve price $r \leq x_0$.

In the mandatory setting, the auctioneer requires participants to invest c before participating in the auction. That is, all participants have already learned their true costs x_i when submitting their bids and c is sunk cost. They will bid truthfully in the auction if $x_i \leq r$ or will not bid if $x_i > r$.

In the voluntary setting, each participant can choose to invest c to learn the own costs x_i (investor), or not to invest and thus receive no additional information other the distribution of the costs (non-investor). The winner, however, has to invest c after the auction if the winner has not done it before the auction. In the auction, an investor will bid truthfully if $x_i \leq r$ or will not bid otherwise, while a non-investor will bid $\mathbb{E}[X_i] + c$ as a dominant strategy if $\mathbb{E}[X_i] + c \leq r$ or will not bid otherwise (Ehrhart et al., 2015).

Our analysis identifies five types of symmetric equilibria depending on c and r (see Figure 1: Equilibria depending on c and r in mandatory and voluntary model):

E_0: No participation
E_1^f: Full participation, all firms participate and invest c
E_1^r: Randomized participation, all firms participate and invest c with probability $q \in (0, 1)$
E_2: All firms participate without investment with probability $q' \in (0, 1]$
E_{mix}: All firms participate and invest c with probability $q_1 \in (0, 1)$ and participate without investment with $q_2 \in (0, 1)$, $q_1 + q_2 \leq 1$

Expected participation: The voluntary setting leads to higher expected participation than the mandatory setting.

Optimal reservation price: For each equilibrium, we determine different locally optimal reserve prices. Given c, the globally optimal reserve price is continuous and increasing in x_0 and takes the maximum of two locally optimal reserve prices after switching to another equilibrium.

Expected profit: Given the optimal reserve price: The participants expect a higher profit in the voluntary setting than in the mandatory setting, as long as c is high enough to exclude potential bidders, while the auctioneer's expected profit varies between the settings depending on c and x_0.

Expected welfare: A second price auction with $r = x_0$ implements the efficient auction. The voluntary setting always equals or exceeds the mandatory setting in terms of expected welfare.

The voluntary setting demonstrates clear advantages over the mandatory setting in terms of participation, participants'expected profit, and efficiency. Additionally, it can lead to higher expected profit for the auctioneer in certain settings.

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Session Classification: Procurement strategies

Contribution ID: **33** Type: **not specified**

Procurement strategies and margin obligations in energy sales: An analysis from the energy crisis to today

Friday, April 4, 2025 10:25 AM (25 minutes)

In 2022, energy producers and distributors ran into financial difficulties due to the exploding electricity and gas prices (Focus online, 2022). To mitigate price and volume risks, energy companies enter into long and short positions on the futures market (Wawer, 2022, p. 196). Margins must be deposited on the exchanges to hedge the default risk vis-à-vis the clearing house (ECC, 2022, p. 4f). While the associated liquidity risk was rather insignificant in phases of horizontal price movements, it gained focus from the second half of 2021 due to sharply rising prices.
The development of the variation margin (VM) of German energy producers for 2022 was already examined (Lehrbass et al., 2023, p. 3). In contrast, the potential impact of increased margin obligations on energy distributors remains largely unanalyzed. To quantify this, a new developed simulation model estimates daily and cumulative liquidity requirements based on futures prices and procurement strategies.
Framework assumptions of the simulation
- Period under review: 2018 to 2024
- Procurement takes place via long positions on the futures market; start at the earliest three years before the delivery year, annual volumes: 1 TWh natural gas and 0.5 TWh electricity, distributed over monthly tranches
- Procurement occurs via exchange or OTC, assuming full collateralization
- Purchase of calendar year products (EEX German Base Power and TTF Natural Gas Futures; data source: Montel, 2024)
- Calculation of the daily variation margin (VM):
VMt= Vt*(Pt-Pt-1) (Gabler, 2020; ECC, o.J.).
- It is approximated that the daily VMs are directly relevant for payment, without considering the initial margin.
- The cumulative VM since the start of the transaction determines the minimum liquidity requirement.
Procurement strategies examined
The choice of procurement strategy depends on the customer portfolio and the contract structures. Based on the composition of the customer portfolio in terms of customer loyalty and willingness to switch, three different procurement strategies were modeled (Tab. 1).
Discussion of the results
Fig. 1 illustrates an example of the volume development of a delivery year in the LaFri strategy. The procurement path is divided into three sub-portfolios according to the customer segments (Fig. 1, left). When procurement is completed and the delivery year begins, the contracts are successively closed and the customers are supplied, resulting in a typical sawtooth pattern (Fig. 1, right). The maximum procurement position and the average volume of procured futures contracts in the portfolio depends on the strategy.
The cumulative VM reflects the balance of the settlement account with the clearinghouse. The procurement of 0.5 TWh electricity while pursuing the LaFri strategy resulted in a maximum positive cumulative VM of around EUR 526 million. Simultaneous procurement of electricity (0.5 TWh) and gas (1 TWh) with the same strategy would have resulted in a positive VM of around EUR 900

million (Fig. 2, table below).

Negative cumulative VMs only occurred sporadically in gas procurement, while pandemic-related price declines in early and mid-2020 led to isolated liquidity outflows. Overall, the simulation shows that energy distribution companies did not experience any liquidity bottlenecks due to margin obligations during the crisis. On the contrary, long-term strategies led to high credit balances due to the long contracts in the portfolio with lower purchase prices. In contrast, energy producers that had sold electricity on the futures market had significant liquidity requirements due to the drastic rise in wholesale prices, as shown by Lehrbass (Lehrbass et al., 2023).

Development of average procurement costs

In addition to the expected cumulative VM, the average procurement costs per delivery year were determined (Fig. 3). The procurement of futures market contracts for the demand expected in the delivery year is completed at the beginning of the delivery year.

Until 2021, costs were similar across all strategies. In 2022, they doubled due to higher wholesale prices in 2021.

In terms of average procurement costs, the delivery year 2023 represents the extreme case. Due to the exploding wholesale prices in 2022, this particularly affected short-term procurement, resulting in the highest procurement costs for the delivery year 2023. This situation is also one reason for the drastic fall in tariffs for households and the insolvency of energy discounters, which mainly procured at short notice and were unable to pass on the extreme rise in costs to their customers (Focus online, 2022; Bundesjustizministerium, 2022).

Due to the decline in wholesale prices during the calendar year 2023, procurement costs for the delivery years 2024 and 2025 will also fall. For 2025 in particular, short-term procurement (KuFri) is the most cost-effective alternative, as companies with a longer-term procurement strategy still have tranches with higher procurement costs from 2022 and 2023 in their portfolio.

At the same time, it can be observed that the number of energy sales companies active on the market is increasing again. In addition, the rate at which households switched suppliers for gas and electricity rose again significantly in 2023 after a decline in 2022 (Bundesnetzagentur 2023, 2024).

Summary and conclusion

The analysis shows that, in contrast to energy producers, distribution companies had hardly any negative impact on liquidity during the energy crisis due to margin calls. Rather, there were financial hurdles due to the limited pass-through of the extremely high wholesale prices. Due to the drop in prices from 2023, it can currently be observed that energy discounters in particular (with short-term procurement) are increasingly active on the market and can pass on lower procurement costs to customers, while energy suppliers with long-term strategies still have procured shares with higher average prices.

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Session Classification: Procurement strategies

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Signals In, Reactions Out: Navigating Design and Modeling Challenges in Dynamic Grid Fees

Friday, April 4, 2025 2:30 PM (25 minutes)

Introduction
A major change in future energy systems is that, unlike before, demand will follow available capacities. In Europe, generation and demand are allocated in zonal markets, yielding one clearing price per zone. This zonal price does not reflect local grid restrictions—such as transmission limits and physical boundaries (line loading, voltage, power quality). Under the current market structure, grid enhancement is the main option to relieve these constraints. A local grid signal can also induce demand adjustments in specific areas, helping avoid congestion and ultimately reducing grid enhancements. This signal might be a price derived from load flow calculations of predicted load and generation. Currently, such signals see limited use in Europe, where flat grid fees don't reflect the load situation (ACER, 2023). If a price signal that varies in time and location is added to a flat grid fee, automated systems could optimize consumption to minimize costs—assuming perfect compliance—while promoting grid-friendly behavior.

Design options and difficulties
There are many design options for grid fees in general. A comprehensive assessment of criteria can be found in (Winzer, 2022) e.g. allocative efficiency, fairness and cost-reflectiveness, but also cost-recovery. For the implementation of a grid fee, transparency and simplicity are relevant criteria. It needs to be pointed out that one grid fee design cannot satisfy all possible criteria to the same extent. The theoretically most effective grid fee is dynamic, meaning that it changes as often as possible (e.g. 15min like the spot market price) with a high spatial granularity (e.g. low-voltage transformer) to in fact reflect the grid situation. The effectiveness of a dynamic grid fee has been shown for example in (Winzer, 2022; Vaughan 2023; Blume, 2022) and relevant stakeholders have expressed openness to the proposal (ACER 2023, E.DSO, 2024; CEER, 2020).

Most network operators recover their costs through a base price in combination with a capacity- and a volumetric tariff today (ACER, 2023) Developing a dynamic tariff component would increase cost reflectivity, i.e. consumption causing higher grid cost is more expensive (Winzer, 2022; E.DSO, 2024; VITO 2022). Some costs such as for metering infrastructure are time-independent and could therefore still be recovered through a flat base tariff. A combination of flat and dynamic components of the grid fee would therefore both be cost reflective and reduce the grid operators' risk of not recovering all cost.

To achieve its full impact, a dynamic grid fee has to cover all voltage levels. The signal can be derived from a load flow calculation of predicted load and generation patterns on every voltage level. Care must then be taken in the interrelation of the signals of different voltage levels. It remains a topic of research whether a top-down or a bottom-up approach is most efficient and whether a feedback loop needs to be included. In the former, TSOs first calculate a signal and transmit the signal to lower voltage levels ending with the signal that the local DSO needs to resolve congestion in the local grid. For the reverse direction, a proposal based on the cellular approach exists (Zapf, 2024). In any case control interventions by the grid operators will not be obsolete, however, reduced.

One disadvantage of tariffs is that in general they decrease economic welfare and distort the equilibrium of supply and demand. As in the current situation (e.g. Germany), where the Redispatch following zonal market clearing causes high cost and inefficiencies, a dynamic grid fee could potentially cause less distortions than the actual system. To let market actors react to grid restrictions, the signal should be fixed prior to market clearing of the day-ahead market. With more experience, an intraday adjustment of the dynamic grid tariff can solve problems due to forecast errors.
An important discussion to be held in all systems with large amounts of autonomous systems is

the so-called avalanche effect. When all Home-Energy-Systems and industrial consumers of a network optimize consumption based on a common signal, many of them could increase or decrease network use at the same time, aggravating congestion (Winzer, 2022).
In some European countries storage facilities, electrolysers and industrial consumers are exempt from grid charges. To unleash their full flexibility potential, every consumer should be exposed to the price signal in the long term. Attractive opt-in options for the exemptions mentioned could incentivize their participation in the short-term.

Outlook
The previous aspects are the basis for future research. Further study is needed for the details of the grid fee designs, the calculation of the price signal across voltage levels and the effects it causes. Of course, input assumptions regarding the willingness to pay for different consumers, the amount of flexibility on the consumer side and the chosen design influence modeling outcome. Executing many model runs with different parameter set and design options could foster our understanding of the outcomes. This understanding will enable us to study systems endogenous reactions without including an expected behavior in the model assumptions. This lays the foundation for DSOs to weigh the benefits of dynamic grid fees against their costs (such as metering infrastructure and digitization).

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Session Classification: Tariff designs

Contribution ID: **35** Type: **not specified**

May the tariff be with you –How effective tariff designs reduce DSO interventions

Friday, April 4, 2025 2:55 PM (25 minutes)

Flexible consumer electricity tariffs play a crucial role in coordinating demand and supply at the distribution grid level. However, as consumer electricity prices include both a retail and a grid component, potentially providing contradictory incentives, understanding their interdependencies is essential for ensuring efficiency. This study examines the interplay between dynamic grid tariffs and dynamic retail prices. It does so by focusing on electric vehicles (EVs) as a flexibility technology in comparison to inflexible demand at the distribution grid level. Specifically, I compare various time-of-use (ToU) and capacity-based grid charges with fixed, ToU, and real-time retail price rates.

For the analyses, various grid tariff designs are developed and applied in a bi-level problem. On the upper level, the distribution system operator (DSO) sets grid charges in anticipation of consumer demand while trying to recover costs. The retail charges are fixed. On the lower level, consumers react to the sum of the grid and retail charges. The bi-level program is transformed into a mathematical program with equilibrium constraints using Karush-Kuhn-Tucker conditions. The aim is to assess how frequently DSOs need to intervene to maintain grid stability under different grid tariff designs. The approach is applied to heterogeneous distribution grids, with grid constraints being approximated by transformer capacities only.

I expect to observe that the added value of more frequent tariff updates—e.g., yearly, seasonally, monthly, daily- and more granular tariffs decreases with increasing detail. Compared to a fixed network charge, I expect a ToU tariff, set once for an entire year, to reduce the necessity for DSO interventions more intensely than a more frequently updated ToU tariff, such as a monthly updated one. From a fairness perspective, I expect separate tariffs tailored to individual technologies to be most efficient. Regarding the integration of renewable resources, I expect to observe that more granular tariffs reduce the necessity to curtail excess production.

The findings provide insights into the effectiveness of different tariff structures in three key aspects: first, reducing the need for operator interventions; second, maintaining fairness between flexible and inflexible consumers; and third, enhancing the coordination between retail markets and distribution grids. All in all, the results contribute to the ongoing discussion on tariff design for the efficient integration of flexible generation and consumers in future power systems.

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Session Classification: Tariff designs

Contribution ID: **36** Type: **not specified**

How can electric two-wheeler concepts shape a sustainable mobility sector in Sub-Saharan Africa:Assessing the economic, social and environmental sustainability potential of a battery-swap motorbike business model in Kenya

Friday, April 4, 2025 11:40 AM (25 minutes)

The rapid urbanization, population growth, and increasing demand for affordable transportation in Sub-Saharan Africa present both challenges and opportunities for sustainable mobility. In Kenya, motorcycle taxis, commonly known as boda bodas, play a vital role in the transport sector, providing an estimated 3 million jobs and facilitating movement in areas where public transport infrastructure remains underdeveloped (Dankers, 2024). However, the widespread use of internal combustion engine (ICE) motorcycles has led to rising fuel costs, heavy reliance on imported petroleum, increased greenhouse gas emissions, and worsening urban air pollution. These challenges highlight an urgent need for a cleaner, cost-effective, and more sustainable alternative that aligns with Kenya's Vision 2030, its National Climate Change Action Plan (NCCAP), and global sustainability goals. Electric two-wheelers, coupled with an innovative battery-swapping model, offer a transformative solution to these challenges. By decoupling battery ownership from the vehicle, battery-swapping technology reduces the high upfront costs of EV adoption, minimizes downtime, and addresses the infrastructural limitations associated with conventional charging networks. This model ensures that riders can swap depleted batteries for fully charged ones in minutes, significantly improving operational efficiency and making electric motorcycles a viable alternative to traditional ICE boda bodas. Ampersand, a pioneer in electric mobility solutions, has introduced this model in Rwanda and Kenya, demonstrating its potential to lower operational costs by up to 40%, improve rider earnings, and contribute to a cleaner urban environment (Ampersand, n.d.). This study seeks to assess the economic, social, and environmental sustainability of battery-swapping for electric motorbikes in Kenya, using Ampersand as a focal case study. It will examine cost-effectiveness, user adoption, infrastructure readiness, environmental impact, and long-term feasibility. By analyzing the intersection of technology, policy, and market dynamics, this research aims to provide critical insights for policymakers, investors, and industry stakeholders on how electric two-wheelers can contribute to a resilient, low-carbon mobility sector in Sub-Saharan Africa. The findings will support evidence-based decision-making and contribute to the broader discourse on clean transportation solutions in emerging economies, reinforcing Kenya's role as a leader in Africa's transition toward sustainable mobility.

This study adopts a qualitative and deductive research design, integrating multiple analytical approaches to assess the feasibility and sustainability of a battery-swapping business model for electric two-wheelers in Kenya. The research synthesizes insights from an extensive literature review, stakeholder analysis, business model evaluation, and a Technology Innovation System (TIS) assessment to provide a comprehensive understanding of the sector's dynamics. To establish a benchmark for success, the study conducts comparative case analyses of well-established battery-swapping ecosystems in China, India, and Taiwan. These cases offer valuable lessons on key success factors, infrastructure requirements, policy frameworks, and market adoption strategies, enabling a contextualized evaluation of their applicability to the Kenyan market. The study employs the Triple Bottom Line (TBL) framework, with a specific focus on the Triple Layered Business Model Canvas (TLBMC) (Joyce & Paquin, 2016), to assess the economic, social, and environmental sustainability of the proposed model. This approach ensures a holistic evaluation of the business model's impact on key stakeholders, including boda boda riders, policymakers, investors, and consumers. The TIS analysis further identifies critical drivers, systemic challenges, and potential barriers to the widespread adoption of battery-swapping technology, informing strategic recommendations for industry stakeholders. The study leverages diverse data sources, including academic publications, industry reports, government policy documents, corporate communications, and expert interviews, ensuring a robust and evidence-based analysis. By integrating these methodologies, the research provides practical insights and strategic recommendations to support the transition toward sustainable electric mobility in Kenya and the broader Sub-Saharan African region.

The findings indicate that a battery-swapping model offers a cost-effective, socially beneficial, and environmentally sustainable alternative to traditional petrol motorcycles in Kenya's boda boda sector. Economically, it has the potential to reduce daily operating costs by up to 50%, easing financial burdens on riders (Cerulli, 2024). Socially, the model fosters employment opportunities in battery maintenance and station operations, enhances financial accessibility through pay-as-you-go systems, and contributes to overall community uplift (AFP, 2023). Environmentally, Ampersand's electric motorcycles produce 75% fewer lifecycle greenhouse gas emissions when using grid power and up to 97% less with renewable energy, while also reducing air pollution and improving urban air quality (Ampersand, n.d.; Dankers, 2024). However, successful implementation depends on overcoming key challenges, including scaling battery-swapping infrastructure, ensuring a reliable power supply, and securing regulatory support (Dahir, 2023; Nyabira, Muigai, & Onyango, 2023). The study underscores the crucial role of public–private partnerships, government incentives, and localized manufacturing in enabling the sustainable growth and adoption of battery-swapping technology in Kenya's transport sector.

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Session Classification: Foreign market insights

Contribution ID: **37** Type: **not specified**

Technological Dynamics in Direct Air Capture: A Statistical Analysis of Actors, Technologies, and Potential Contributions to CO2-Separation

Friday, April 4, 2025 3:20 PM (25 minutes)

Today, the collection of carbon plays an increasing role in the debate about climate change mitigation especially in future energy production. In recent years, fundamental research in carbon capture and storage (CCTS) technologies was particularly dynamic especially in direct air capture technologies (Renfrew, Starr, and Strasser 2020; Breyer et al. 2019). It is seen as a large-scale solution in many energy and climate scenarios, including those of the International Panel for Climate Change (IPCC)(Huppmann et al. 2019; Byers et al. 2022). However, in reality many of the pilot projects have provided heterogenous results, and challenges remain to scale these small pilots to large scale CCTS(Herold, Rüster, and Hirschhausen 2010; von Hirschhausen, Herold, and Oei 2012). This paper looks at over 100 of these pilote projects, and attempts a classification in terms of R&D dynamics, size, and other technical characteristics. This is useful to asses the potential of DAC, and also to establish the link to potential downstream activies, e.g. the use of CO2

We have collected a unique dataset on 104 pilot projects in Direct Air Capture (DAC) and potential applications (Direct Aircapture Coalition 2024), as well as data on the remaining gap for rolling out this technology at scale. We perform a technological assessment and a statistical analysis in respect to technologies, applications, companies, and financial indicators.

Detailed analysis of the data reveals a heterogenous picture (see figures) compared to predicted usage in IPCC –Scenarios. In terms of regional distribution, the US leads the pack by far, with 37 projects, of which 10 are operational (Canada: 14 projects, 2 operational, England: 9 projects, 2 operational) (Figure 1). In terms of technologies, low-temperature regeneration (46 projects) is outpacing electrochemical regeneration (17) and high-temperature regeneration (15). The average size of the capture projects is small. Until 2018, total capacities were negligible (below 1 Mt separated CO2), but it increasing rapidly since. In particular, from 2023 (7.4 Mt), total capacities increased to 44 Mt. The Technological Readiness Levels (TRL)
are very heterogeneous, the available data hints at average values of 4-6.

DAC is undergoing an impressive dynamic concerning pilot projects. This is mainly fundamental and some applied research on demonstrators. However, the step towards large-scale commercialization is yet to occur: 29 technologies are commercially available, but their impact on CO2 separation is still small. Further research should focus on these dynamics, i.e. from demonstration to large-scale diffusion.

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Session Classification: Challenges of technological advances I

Contribution ID: **38** Type: **not specified**

Optimizing Germany's Energy Transformation: Connecting Labor Markets, Training Strategies, and Migration Policies with energy system modelling

Friday, April 4, 2025 12:05 PM (25 minutes)

The transformation of Germany's energy system to renewable sources demands a diverse and expanding workforce specialized in wind and PV installations, infrastructure expansion (electricity, heating, hydrogen grids), and building renovations. This need arises as workers retire, leading to declining employment [1]. While literature highlights job gains from renewable energy, Germany faces the challenge of securing workforce amid labor shortages. Increasing workers in the energy sector is essential. Strategies include retraining, education, and recruiting foreign labor [2]. Prioritizing the energy transition involves incentivizing retraining programs, enhancing education in energy fields, and attracting international workers—representing the best-case scenario. However, geopolitical tensions and a right-leaning political landscape may divert resources, limiting personnel and funds for the energy transition. The growing right-wing climate may deter immigrants, making the best-case scenario challenging. In November 2023, members of the right-wing party AfD and radicals like the Identitarian Movement planned deporting individuals with a migration background [3]. Hence, Germany might not achieve the best-case scenario but instead face low immigration or even emigration and expulsion. To explore this, we conduct economic optimizations for Germany's energy transition under three scenarios: best-case, low-migration (limited immigration and fewer retraining opportunities), and worst-case (emigration and no retraining). We aim to answer: What impact does labor market development, influenced by training measures and migration policy, have on the energy system transformation and climate targets in these scenarios?

Our methods involve a literature review analyzing the required workforce for specific technologies and current and future employment trends in Germany. We develop scenarios projecting employment, considering the maximum workers suitable for the energy sector if prioritized in labor market policy, including evaluating right-wing expulsion plans for the worst-case scenario. We perform energy system modeling using GENeSYS-MOD, a linear techno-economic optimization model capable of comprehensive case studies with up to hourly resolution [4], [5], [6]. The model integrates a job module introduced by Hanto et al. [7], further developed to analyze different transformation paths based on training and migration policies.

Expected results indicate that in the best-case scenario, workforce growth through retraining, education, and immigration allows cost-effective energy system optimization without labor constraints. The value of immigration is highlighted by quantifying the number of foreign workers needed to fill domestic job gaps. In the low-migration and worst-case scenarios, a lack of skilled workforce is expected to hinder the energy transformation, illustrating the significant impact of migration and labor policies on climate goals. Comparing these scenarios underscores the importance of attracting international workers to facilitate the transition.

Conclusions suggest that additional efforts in labor market policies are necessary, potentially requiring the energy sector to be prioritized to enable timely transformation. Nationalist migration policies could jeopardize the energy transition's success, exacerbating the climate crisis. Therefore, more effort is needed to stabilize the political spectrum and enable worker migration to Germany. Efforts should extend beyond legal migration pathways to creating an environment that attracts people to work in the energy sector and other critical areas.

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Session Classification: Energy market outlooks and transformation strategies

Contribution ID: **39** Type: **not specified**

Multi-year storage or flexible imports for energy security under climate uncertainty?

Friday, April 4, 2025 12:05 PM (25 minutes)

Mitigating climate change while supplying the power sector and electrifying heating, transport, and industry requires weather-dependent energy sources, like wind, solar, and hydro. Weather-dependent supply adds to the already weather-sensitive demand and challenges future energy systems. Over short periods, supply and demand mismatches are manageable thanks to reliable weather forecasts and technical solutions, like short-term storage, particularly batteries, demand-side flexibility, and power grids. However, the longer the mismatch prevails, the harder it becomes to manage. The lack of accurate long-term weather forecasts raises uncertainty, and, as a technical solution, only long-term storage or flexible imports remain due to the growing magnitude of the energy deficit.

Last winter, European power systems were already under stress when the wind generation was low, and cold temperatures induced high demand, causing a multi-year deficit, also referred to as Dunkelflaute [1]. In the future, the growth of renewables and electrification will aggravate the problem, extending the potential duration of the deficit from a few days to multiple months or years. In South America, such multi-year energy draughts are already occurring since energy systems heavily depend on hydropower. Below-average rainfall in the last years depleted reservoirs, resulting in a severe energy crisis and frequent blackouts [2].

Fig. 1 exemplifies the challenge of multi-year storage and draughts. Here, the system can manage the most extreme year since storage levels are sufficient to compensate for low wind supply and high heat demand during winter. The following two years are less extreme, at least if considered separately, but in conjunction, they cause a severe shortage. In summer, below-average surpluses from hydro and PV prevent refilling the storage, and, as a result, the storage runs dry after two winters with adverse but not extreme weather.

Hedging against these fluctuations is a stochastic problem since the deficits during winter are uncertain, just like the available surplus for filling the storage during summer. Reliable weather forecasts are not possible months or years in advance. In addition, it is not a storage but a system problem since security depends on the distribution of deficits and surpluses. For instance, more PV will reduce year-to-year variations and uncertainty but increase seasonal imbalances since generation in winter is low. In the heat sector, electrification reduces total demand but increases uncertainty since winter deficits become more temperature-sensitive. Accordingly, in the example, the shortage could be prevented in three ways: extend the storage and avoid spillage, reduce the deficits during winter, or increase the surplus in summer.

In this work, we investigate how net-zero systems can be reliable and counter the risk of climate uncertainty, including multi-year draughts. As a first option, we consider multi-year storage with hydro reservoirs and hydrogen, methane, or methanol storage. Available sources for these fuels are domestic production and import contracts with limited flexibility. As an equivalent substitute, we consider decreasing climate vulnerability by adapting the composition of supply and demand. This adaptation includes the continued use of fossil fuels during deficit periods and offsetting emissions with direct air capture during surplus periods, as long as the expected greenhouse gas emissions are zero.

The analysis extends an existing energy planning model of the European system to a stochastic optimization under climate uncertainty with limited foresight [3]. We introduce a robust formulation for multi-year storage that implicitly considers thousands of weather years but keeps the problem size manageable. Since the resulting optimization problem remains massive, we solve it with a Benders decomposition algorithm refined for this problem.

As a data source, we extend an existing climate data set covering 35 years of PV, wind, and hydro generation with consistent heat demand and heat pump efficiency data [4]. Based on an autocorrelation analysis, we assume weather conditions in different months are stochastically independent. Therefore, we select a subset of representative months from the sample with an optimization-based clustering algorithm. Since the stochastic planning model implicitly considers all combinations of the representative months, a subsample of 36 months already covers up to 530'000 distinct weather years.

Preliminary results suggest that the European energy system requires significantly less backup for security against multi-year energy draughts than today's 2000 TWh of gas and oil reserves. The model chooses fuel storage for multi-year balancing since energy capacity is inexpensive and unconstrained. Hydro reservoirs provide seasonal balancing at cheaper costs, achieving a higher utilization of their scarce capacity . If the import of fossil fuels is permitted, the system has positive emissions in winter months with adverse weather conditions. Direct air capture offsets these emissions during surplus months, particularly in the summer. In conclusion, the developed method and results demonstrate how net-zero systems characterized by weather-dependent supply and demand can manage long-term fluctuations of renewables.

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Session Classification: Energy security and market coupling

Contribution ID: **41** Type: **not specified**

Hedging as a Match-Maker: Unlocking Industrial Demand Flexibility for Renewable Energy Integration

Friday, April 4, 2025 2:55 PM (25 minutes)

In this paper we analyze the design of hedging products for electricity to unlock industrial investments into load shifting capacity. Currently, most industrial consumers buy a large share of electricity in advance on forward and future markets, where the most liquid products are baseload contracts (EEX, 2025). However, using these contracts severely limits the direct exposure to price signals on the spot market, which diminishes the incentives for load shifting (Lund et al., 2015; Mays, 2021). To successfully integrate the growing share of renewable energy generation, however, it is essential to unlock the large untapped potential of industrial load shifting capacity (Howard et al., 2021). An alternative product for hedging could be a renewable energy profile (REP) hedge, which guarantees a fixed price for the amount of electricity supplied that is proportional to the generation profile of renewable energies. Features of the REP hedge can already be found in existing contract structures. For example, in long-term pay-as-produced power purchasing agreements (PPA), the consumer guarantees to buy all or a share of the generation of a renewable energy plant at a fixed price. As the generation from a single RE plant can be quite volatile, Neuhoff et al. (2023) propose a renewable energy pool (RE pool), through which the consumers'electricity demand is hedged by a portfolio of RE plants. We show that a REP hedge can, compared to the current market structure, positively impact firms'incentives to undertake flexibility investments.

We build a two-stage analytical model of investment under uncertainty. In the first stage, a representative industrial firm can invest into flexible production capacities. In the second stage, the firm can utilize this flexibility in the production process to react to realized levels of renewable energy supply and resulting electricity prices via the adjustment of its production level (load shifting). We compare the investment outcomes depending on the electricity procurement strategy of the firm: it is either hedged with a conventional baseload product, the REP hedge, or not hedged at all, thus being fully exposed to spot market prices. We explicitly take into account the notion of risk-averse decision making via the application of the conditional value at risk (Rockafellar & Uryasev, 2000). The core insight of our model is that when comparing risk-averse firms, the REP hedge is more successful at incentivizing investment into flexibility than the status quo of a baseload hedge and pure spot market procurement. Investment of the risk-averse REP firm is under any model configuration at least as big as those of baseload and spot firms. Further, we find that risk-averse firms under the baseload hedge and spot market procurement invest less than their risk-neutral counterpart. This result is driven by the adjustment to low price volatility in the spot market which is decreasing the relative benefit of flexibility investments. Contrary to that, the risk-averse REP firm will invest more than its risk-neutral counterpart when high volatility is a cost driver. This is best responded to with high investment levels.

Within numerical simulations, we further investigate several variations to the analytical base-model, such as effects of different compositions of the RE portfolio underlying the REP hedge and variations to the flexibility investment cost function. When cheap flexibility options are available, they are invested in regardless of the hedging design. However, in sectors in which flexibility is harder to unlock, incentives from the current hedging design are insufficient and only the REP hedge succeeds to unlock higher levels of flexibility investments. The REP hedge is thus a promising alternative to prevalent hedging instruments for fostering the development of flexibility.

We contribute to the literature in three ways: Firstly, to the best of our knowledge, we are the first to provide a detailed analysis of the potential of a REP hedge for unlocking flexibility. By that, we contribute to a literature of how electricity market design impacts incentives for demand side flexibility, necessary for the integration of intermittent renewable energies. Secondly, by building a model of flexibility investments under uncertainty, we expand the literature of flexibility investments which has mostly focused on implications for the supply side and its investments into generation capacity (Diaz et al., 2019; Möbius et al., 2023). Thirdly, those papers that do look at demand side investments mostly neglect the effect of risk aversion on such investments (e.g. Ambrosius et al., 2018). Hence, our core contribution is the analytical discussion of a hedge based on the renewable energy profile in the context of demand-sided investments into flexibilization, while accounting for risk aversion.

Our results show the potential of a REP hedge to unlock industrial flexibility potential. Regardless of this, such profile hedging has not yet been able to establish itself successfully on the futures market. To already jumpstart the usage of a REP hedge now, government support policies could be linked to it. An example in which this is already partially implemented are carbon contracts for difference (CCfDs) in Germany. They de-risk industrial investments into climate friendly production technologies by covering investment and operational cost differences relative to the conventional production method. Hereby, the operational cost component is designed as a composition of a baseload and REP hedge. Our model can be used to reveal the required balance of the two hedges needed to have a positive impact on flexibility investments.

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Session Classification: Utilization of flexibility potentials

Contribution ID: **42** Type: **not specified**

Why do they flock together? Analysing role of behavioural and socio-demographic factors in electricity consumption profiles of Norwegian households

Friday, April 4, 2025 4:40 PM (25 minutes)

Residential energy consumption has a significant share in the overall peak demand and energy related carbon emissions footprint of European nations (Torriti, 2014; Dubois, et al., 2019; Eurostat, 2024). Energy demand management within the avoid, shift and improve framework are considered as high potential climate change mitigation actions (Creutzig, et al., 2022; Jarre, Noussan, & Campisi, 2024). Digital innovations combined with occupant behaviours are believed to play important role in residential energy demand management and integration of variable renewables (Diao, Sun, Chen, & Chen, 2017; Schuitema, Ryan, & Aravena, 2017). Smart energy meters that measure, record and communicate energy consumption at frequent time intervals are being deployed at unprecedented scale and speed in many countries around the world with China, EU member states, USA and New Zealand as leading examples (ASSET Study, 2021; Sovacool, Hook, Sareen, & Geels, 2021). Availability of large scale granular electricity data for residential households has prompted a growing volume of empirical studies and renewed interests in residential profiles among researchers, industries and policymakers (Ramírez-Mendiola, Grünewald, & Eyre, 2017; Glasgo, Hendrickson, & Azevedo, 2017; Gellings, 1985). Further, it is expected that residential electricity profiles are likely to change in future due to enhanced use of solar photovoltaic cells, electrification, use of electric vehicles and demographic changes (Powells & Fell, 2019; Proedrou, 2021). A better and nuanced understanding of profile indicators is not only important in improving economic efficiency of energy systems but also vital for evidence-based climate change mitigation policies (Satre-Meloy, Diakonova, & Grünewald, 2020). However, in comparison to numerous studies based on aggregated monthly or annual residential energy consumption, empirical analysis of temporal dimensions of residential electricity demand remains limited, less understood and under researched (Ruokamo, Kopsakangas-Savolainen, Meriläinen, & Svento, 2019; Baker & Blundell, 1991; Grunewald & Diakonova, 2018).

In this study, we draw from and add to the growing volume of literature on residential energy profiles using a mix of survey responses and hourly electricity data from Norwegian households. In our two-part study, we first seek to identify subgroups that exhibit similar consumption profiles using cluster analysis while controlling for the price and weather effects. Next, we compare those identified residential subgroups based on their stated survey responses to behavioural, socioeconomic and demographic attributes using multinomial logit regression. Our study makes many novel contributions to the contemporary residential electricity profiles literature. Our analysis is based on longitudinal smart meter data explores temporal dimensions of residential energy consumption profile indicators that are different and cannot be captured using aggregated consumption volumes. By combining the hourly metered electricity data with survey responses on behavioural and socio-demographic attributes, we take forward the existing empirical literature on residential profiles that either use smart meter data alone or use it in combination with time of use activities. In line with our research objectives intended to explore the heterogeneity in household energy profiles, we control for the weather and price effects by choosing to use differences from average values of electricity consumption as the objective function in cluster analysis. By using cluster analysis, we reduce the dimensionality of high frequency data suitable for merging with one time survey responses on behavioural and socio-demographic attributes. Our choice of k-means clustering technique is guided by the objective to find explanatory factors that influence membership of households with similar energy consumption profiles at unique time intervals rather than the shape of the profiles or for projecting future demand. Finally, we are able to validate our analytical approach by predicting correctly more than two-thirds of cluster memberships based on our regression model and chosen variables.

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Session Classification: Residential energy systems

Contribution ID: **43** Type: **not specified**

Reducing industrial steam system temperatures to enable the utilisation of low-temperature heat sources –A review of the (Upper) Austrian industry

Friday, April 4, 2025 4:15 PM (25 minutes)

The decarbonisation of industrial process heat must be promoted in all industrial sectors, as it depicts a crucial role in the corporate transformation. Rosenow et al. (2024) emphasize the significant role of heat processing in industrial energy consumption, accounting for approximately 66 % of the total industrial energy demand within Europe. As up to 77 % of this energy is derived from non-renewable sources, the need for action to decarbonise the industrial heat supply is evident.
While companies from the energy-intensive industry (EII) (Iron and steel production, non-ferrous metals, non-metallic minerals, chemicals and petrochemical, paper, pulp and printing) face major challenges due to their affiliated high energy consumption, solutions have already been outlined in this field. Regarding Nurdiawati and Urban (2021) supply side measures (such as electrification, alternative energy carriers, carbon capture and utilisation (CCUS) or energy efficiency measures) and demand-side measures (reusing or recycling of products to lower overall material intensity) are considered viable methods of the upmost importance for the transition of EII companies. Next to technological solutions, proper energy management plans can contribute to energy efficiency savings of up to 6 % for companies from the EII and up to 13 % for entities belonging to the non-energy-intensive industries (NEII) (Thollander & Palm, 2015).
The non-energy-intensive industry (consisting of wood and wood products, construction, textile and leather, food, beverages and tobacco, machinery and transport equipment, as well as all other non-specified industrial branches) accounted for 36,7 % of the total final energy consumption in Europe in the year 2022 (eurostat, 2022). Smaller and medium entities (SME) of the NEII are characterised by a lower ratio of energy related costs (usually 1- 3 % of the production costs, whereas EII representatives can easily succeed a 10 % share) (European Commission, 2022). Businesses from the NEII are usually bound to limited economic and workforce-related flexibility, leading to a lower grade of defossilisation-related measures (König et al., 2020). Therefore, a novel approach to lower overall steam system temperatures of corporations from the NEII with the aim to lower overall fuel usage and allow for a higher share of low-emission technologies to supply heat demand is proposed.

The aim of the paper is, firstly, to show that decarbonisation of process heat, particularly within non-energy-intensive industries, is significantly hindered by the prevailing tendency to operate steam systems at temperatures higher than necessary. Secondly, to highlight that current corporate strategies indicate this issue is unlikely to change, and thirdly, to explain the necessity of implementing temperature reductions in a manner that aligns with exergy efficiency principles and non-fossil energy sources. To present the status quo, an empirical analysis was conducted on 20 production companies in Upper Austria between 2020 and 2022 as part of various research projects and proposals. These investigations focused on evaluating the feasibility of process heat supply through predominantly local, low-energy technologies.
To present the status quo, 20 Upper Austrian production companies were analysed in the years 2020-2022 as part of research projects or research proposals. Analyses were carried out to determine whether a process heat supply with (mainly local) low-energy technologies was possible.
Emphasizing the importance of lowering steam system temperatures to facilitate the integration of low-emission technologies in both NEII and EII sectors, one-quarter of the analysed companies belonged to the EII group. This underscores the significance of low- to medium-temperature heat demands within EIIs, where over 20 % of industrial heat consumption in the chemical and petrochemical industries, and more than 30 % in the paper, pulp, and print industries occurs at temperatures below 100 °C(Puschnigg et al., 2021).
Relevant company data from prior research projects and proposals were collected, focusing on

existing heat supply temperatures, current heat supply technologies, and (thermal) peak demand management. Due to confidentiality constraints, only the respective industrial sectors and descriptions of process heat systems can be disclosed.
By integrating generic research findings with company-specific insights, this study aims to provide conclusions for industry representatives and policymakers contributing to the effective design and implementation of future projects and funding schemes. Additionally, an evaluation of various approaches to lower steam temperatures - predominantly based on empirical data and supplemented by generic research findings - will be presented to support the increased adoption of low-carbon technologies.

Ultimately, despite the exploration of alternative supply options, two key observations can be made: (i) Gas boilers continue to be the standard choice for planned capacity expansions across all companies previously relying on gas-fired systems. Therefore, (ii) a reduction in process temperatures –and thus the precondition for enabling low-emission alternatives –does not appear to be a feasible approach for related entities. This cumulates in a lock-in effect, reinforcing the dependency on high process temperatures and fossil energy sources. Furthermore, the short-term focus of regulatory frameworks and the absence of targeted funding mechanisms for low-emission technologies intensifies this lock-in effect, limiting the adoption of critically important decarbonisation measures (Anderson et al., 2023).

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Session Classification: Challenges of technological advances II

Contribution ID: **44** Type: **not specified**

Gone with the wind? - Quantifying wake losses for offshore wind farms and a discussion of mitigation measures

Friday, April 4, 2025 10:00 AM (25 minutes)

Europe has set ambitious offshore wind energy targets, aiming for nearly 500 GW of capacity by 2050, with current installations at approximately 35 GW in 2024. Most wind farms are thus yet to be developed and countries with high energy demands but limited maritime space, may be forced to overexploit their domestic wind potential. Currently, some European wind farms exhibit peak power capacity densities exceeding 14 MW/km², while most fall within the 5-6 MW/km² range. Future projections suggest that high power densities will persist in regions with constrained offshore renewable energy potential.
This trend may result in inefficient spacing of wind farms, exacerbating the wake effect, a shading phenomenon which negatively impacts turbine efficiency and the economic viability of future investments. Long term system development studies are thus exposed to the uncertainty regarding future offshore wind capacity factors. The risk is to overestimate the energy yield for existing and future wind farms due to inadequate consideration of cross-border wake effects, potentially affecting turbine performance across jurisdictions.
This work aims to enhance understanding of offshore wake losses within the context of large-scale energy system planning by quantifying the potential generation loss and investigating possible mitigation measures. It argues that production efficiency challenges are interconnected with site identification and transmission corridor designation in heavily utilized maritime spaces. The focus is set on the North Sea, where about 30% of offshore capacity is expected to be concentrated in a single wind corridor by 2050.

This study utilizes the Kinetic Energy Budget of the Atmosphere (KEBA) model to analyze wake losses in offshore wind energy. KEBA is a simplified framework that replicates wind speed reductions by calculating effective wind speeds from sea level to the atmospheric boundary layer (700 m), considering energy inflows and outflows. It incorporates free-flow wind speeds, meteorological parameters, and turbine characteristics to predict wind speed reductions and electricity yields. This input-output approach is applied to three turbine clusters in the exclusive economic zones (EEZ) of the Netherlands, Germany, and Denmark. It thus assesses both domestic wake effects due to local shading as well as cross-border wake accumulation due to the long tail of wake behind a given wind farm. Three scenarios are analyzed: the "Base Case"estimates wake losses based on current plans, while scenario 2 spaces wind farms further apart, and scenario 3 shifts some capacity from Germany to Denmark. The scenarios are tailored to the current offshore development targets of the region for 2050, along with the spatial allocation of the capacity. The model resolution is one box per country EEZ with a temporal resolution of 8760 hours per year. To level out inter-annual weather variability ten representative historical climate years are modelled.
Since the shift in offshore wind generation capacity entails a maritime spatial planning dimension, a complementary GIS analysis is conducted. The purpose is to investigate how the connection corridors and lengths would change among the scenarios and to assess whether the potential gains in production efficiency with reduced wake losses are outweigh by the additional investment need for (longer) cable infrastructure. The GIS analysis employs a cost-minimizing routing algorithm to determine optimal connecting routes for offshore wind farms to shore and has been introduced and validated in previous works.

Wake losses significantly affect the effective wind velocity for downstream wind farms, leading to reductions in full-load hours (FLH) and annual electricity generation yield. They can be witnessed up to 100 km downstream of the wind farms. When comparing FLH under ideal conditions (no wake effects) with simulated wake conditions across three scenarios, the base case with current

planning towards 2050 shows an average reduction of 24% in the German Bight, with peaks reaching 30% in Germany. Denmark is affected as well, although it has much lower power densities. The reason is a cross-border accumulation of wake losses which can make up 50% of the total loss. To mitigate wake losses, spreading wind farms within each Exclusive Economic Zone (EEZ) can reduce power densities, achieving a theoretical limit of approximately 20% reduction in FLH and a potential yield increase of 42 TWh. However, further reductions require effective cross-border cooperation. The redistribution strategy, which involves relocating capacity from the German EEZ to Denmark, can reduce average FLH losses to 16%. Independent of the assessed mitigation scenario, it can be shown that the resulting energy yield saving is disproportionally larger for low wind periods. Since these periods are historically correlated with higher spot market prices compared to high wind periods, the economic efficiency of the wind farm generators would be positively impacted not only by more wind generation but also a higher marginal revenue during these periods. The GIS analysis results confirm for possible cable routes that for the shifting of wind farm capacity across the border slightly longer routes (+7%) would be required. In other words, some of the efficiency gains through a more efficient wind generation is offset by increased material investment costs. The net benefit is, however, still positive.
The chosen methodology proves to be sufficiently accurate when being compared to more complex atmospheric models. It establishes the basis for a possible integration in larger energy system analysis workflows or indeed a model coupling. Further research is identified with respect to an expansion of the analysis scope as well as alternative wake mitigation measures such as overplanting of wind power capacity compared to the grid connection capacity.

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Session Classification: GIS-based analysis

Contribution ID: **45** Type: **not specified**

Modified electricity price signals as a flexibility incentive for hydrogen production –the impact of hydrogen production profiles on costs and GHG emissions.

Friday, April 4, 2025 4:15 PM (25 minutes)

The increasing share of renewable energy has a direct impact on spot prices and electricity-related greenhouse gas (GHG) emissions. Low marginal costs for solar and wind reduce spot prices, especially in times with a high share of renewable electricity production. GHG emissions tend to decrease as the share of renewables increases throughout the year, again, particularly in times with a high share of renewable electricity.
Hydrogen production from grid electricity shows the potential to serve as a flexible consumer making use of low electricity and serving threefold: (1) supplying low-cost hydrogen for e.g. industrial processes (2) producing hydrogen leading to low GHG emissions and (3) serving the electricity system through a flexible demand.
A policy instrument with modified electricity price signals to stimulate flexible electricity demand from an electrolyzer has been presented (Schütte & Timmerberg, 2024). The modification consists of two parts: (1) the annual average is adjusted and (2) the hourly resolved electricity price is changed. The factor changes the amplitude of the price. It was analyzed which combinations of adjustments lead to a target price of €1.80/kg for hydrogen. Results show that higher price amplitudes lead to shorter electrolyzer operating times. This could be an incentive for flexibility on the consumer side.
This research examines how different hydrogen demand profiles affect costs and GHG emissions under the policy instrument, aiming for a target price. A demand profile is understood as a recurring, constant demand. Hydrogen production is considered in different time periods –per day, per week or per month –where the electrolyzer is operated at the least cost hours.

The methodology consists of (1) 'Modification of the electricity price signal', (2) 'Calculation of hydrogen production costs with different demand profiles'and (3) 'GHG accounting of hydrogen production'in order to find the best modifications for the electricity price to reach the H_2 target price and to answer the research question and its sub-questions.

–It is assumed that a modified electricity price signal is provided to companies interested in producing hydrogen electrolytically in response to this signal. This electricity price signal could, for example, be provided by a government agency or a government-commissioned company. It is based on the electricity exchange price adjusted by a calculation rule. This rule considers the average annual electricity price and the deviation of the exchange electricity price in an hour from this average.
–It is assumed that the hydrogen-producing company operates an electrolyzer flexibly, producing hydrogen when electricity is at low cost. The company's objective is to produce a fixed amount of hydrogen cost-effectively within a defined period, without considering specific pro-duction times. The company produces hydrogen based on its knowledge of the electricity price trend for the entire period under consideration (perfect foresight). Capital and operating costs are included.
–The GHG emissions assessment accounts for hourly variations in grid electricity emissions.

The modified electricity price signal $EP_{\text{mod},t}$ is derived from hourly electricity price values EP_t. The average annual electricity price EP_{mean} is calculated using equation (1). The modified hourly electricity price $EP_{\text{mod},t}$ results from an amplification factor F_a and a modified mean annual electricity price $EP_{\text{mean,set}}$ (equation (2)). For $F_a > 1$, the modified electricity price signal shows a greater deviation from the mean value than the original price signal.
1) $EP_{\text{mean}} = \frac{1}{N} \sum_{t=1}^{n} EP_t$

2) $EP_{\mathrm{mod},t} = (EP_t - EP_{\mathrm{mean}}) \cdot F_a + EP_{\mathrm{mean,set}}$
The modified electricity prices with equation (2) are sorted in ascending order, forming a series $EP_{\mathrm{mod},t}$. The sum of the electricity prices up to time t is related to the electrolyzer's full load hours (FLH), yielding a cumulative average electricity price for each timestep (equation (3)).
3) $EP_{\mathrm{mod,sort}} = \frac{\sum_{t=1}^{t} EP_{\mathrm{mod},t}}{\mathrm{FLH}}$
The hourly GHG emissions GHG_t in CO_2eq. of the German electricity mix are sorted alongside exchange electricity prices. The cumulative sum of hourly GHG emissions up to t is related to the FLH.
4) $THG_{\mathrm{EP,sort}} = \frac{\sum\limits_{t=1}^{n} THG_t}{FLH}$
To assess the GHG intensity of the hydrogen produced, the net calorific value of hydrogen LHV_{H_2} and the electrolyzer efficiency $\eta_{\mathrm{Ely,LHV}}$ are used:
5) $THG_{H_2} = \frac{THG_{\mathrm{EP,sort}}}{\eta_{\mathrm{Ely,LHV}}} \cdot \mathrm{LHV}_{H_2} \quad (2)$
Calculations are performed for various years and demand profiles. The data is resorted for each period. The additional costs and GHG emissions from different demand profiles compared to an annual design of the instrument are analyzed comparatively.

This scientific study analyzes which amplification factor F_a and average annual target electricity price $EP_{\mathrm{mean,set}}$ can be used to achieve a given production price for hydrogen.
The effect of various hydrogen demand profiles on costs and GHG emissions is also analyzed. For the use of the policy instrument at a predefined target price, the factor is expected to increase for shorter demand profiles. Shorter periods are expected to increase production costs if the factor remains unchanged.

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Session Classification: Hydrogen markets and infrastructure

Contribution ID: **46** Type: **not specified**

Analyzing the impact of the potential use of electrolyzer waste heat on the German energy transition

Friday, April 4, 2025 5:05 PM (25 minutes)

Germany's updated National Hydrogen Strategy aims to establish a strong hydrogen economy with 30 GW of electrolyzer capacity by 2030 and a comprehensive hydrogen transmission network [1]. This is crucial for energy storage, industrial decarbonization, and reducing energy import dependence—an increasingly important goal since Russia's invasion of Ukraine. However, renewable hydrogen production is energy-inefficient, losing over 20% of input energy as heat during electrolysis [2]. This waste heat has been largely overlooked but could significantly enhance efficiency if repurposed for heating. This paper analyzes the potential role of electrolyzer waste heat utilization on Germany's energy transition, focusing on its implications for electrolyzer placement and heating infrastructure.

This analysis employs the Global Energy System Model (GENeSYS-MOD), developed by Löffler et al. [3] based on the Open Source Energy Modelling System (OSeMOSYS). GENeSYS-MOD is a linear techno-economic optimization model, that aims to minimize system costs while accounting for long-term emission reduction pathways. Energy demands are provided exogenously for the electricity, buildings, industry, and transportation sectors. The model incorporates sector coupling, a wide range of technologies, and trade mechanisms to meet these demands effectively. Results are computed with hourly precision.

GENeSYS-MOD is applied to Germany, segmented into 18 regions (16 federal states and two offshore zones), with results calculated in five-year intervals from 2025 to 2050. The analysis incorporates key energy transition policies, such as expansion targets for wind, solar, and electrolyzer capacity as well as the phase-out of coal and nuclear power.
Electrolyzer waste heat is modeled as a secondary output of the electrolyzer technologies alongside hydrogen and can be converted into district heating for both industrial and residential use. Two scenarios are compared in order to analyze the effect of the utilization of waste heat: one incorporating electrolyzer waste heat utilization and one excluding it. Additionally, a comprehensive sensitivity analysis on the costs associated with waste heat recovery and transport is conducted.

The findings indicate that electrolyzer waste heat could supply nearly 30 TWh (6%) of Germany's low-temperature heat demand by 2040, with a particularly notable contribution in northern Germany, where in some states it could meet over 50% of district heating needs. By 2030, approximately 55% of the heat generated by electrolyzers is expected to be recovered, increasing to more than 90% in subsequent years. However, the overall composition of the heating sector remains largely unchanged.

Integration of electrolyzer waste heat utilization leads to a near-complete shift away from offshore hydrogen production, with Lower Saxony emerging as a key beneficiary. While hydrogen production remains concentrated in northern Germany, some southern states experience an earlier scale-up.
Utilizing waste heat improves energy efficiency, resulting in increased full-load hours for electrolyzers and boosting domestic hydrogen production. This reduces Germany's dependency on hydrogen imports, enhancing energy security. The Sensitivity analysis demonstrates that waste heat recovery remains economically viable even under substantially higher cost assumptions.
The use of electrolyzer waste heat provides significant support for Germany's heat supply and hydrogen economy. Its cost-effectiveness could make it a critical factor in future electrolyzer site selection and a meaningful contributor to the energy transition.

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Session Classification: Challenges of technological advances II

Contribution ID: **47** Type: **not specified**

When Compensation Backfires: Heterogeneity in Hydrogen Infrastructure Acceptance in Germany

Friday, April 4, 2025 4:40 PM (25 minutes)

The German government has an infrastructure plan to construct extensive hydrogen pipelines by 2032, marking a key step in advancing the sustainable energy transition. However, public knowledge and perceptions of such infrastructure projects can vary significantly, which in turn may influence individuals'willingness-to-accept (WTA) infrastructure development near their homes or properties. Compensation mechanisms can play a critical role in increasing WTA for such infrastructure projects among private households and communities. Previous research (van Wijk et al., 2021) indicates systematic differences in public acceptance between individual and municipal-level compensation measures. Furthermore, studies such as Vuichard et al. (2022) show that individuals have heterogenous preferences for compensation types, for example financial or non-financial.
A nuanced understanding of compensation mechanisms—both monetary and non-monetary—at the community and household levels could help optimizing infrastructure planning and implementation. To explore this perspective, we have designed and conducted a binary choice experiment. In a representative survey questionnaire for the population in Germany, we have collected data on technical knowledge and opinions about the hydrogen technology and (b) experimentally tested individuals'WTA private and community-level compensation. Preliminary results indicate that while high levels of private compensation increase the acceptance significantly, high level compensation at the community level statistically significantly lowers acceptance of infrastructure measures.

In a uniquely designed survey-based binary choice experiment, a dataset on private households, representative of the German population, was collected. While all survey participants responded to the survey questionnaire, experimental treatments—hypothetical scenarios involving compensation choices—were randomly allocated among participants. Using a binary choice experimental setup with a combination of between and within-subjects design, similar to Simora et al. (2018), the experimental segment of the survey presents hypothetical choice situations. In these scenarios, respondents are asked to take part in a referendum either in favor of or against (hypothetical) hydrogen pipeline infrastructure planning near their residence, influenced by varying forms (private and community) and levels of compensation (monetary and non-monetary).
Table 1 about here.

Preliminary findings suggest that lower levels of monetary compensation in our experimental setup do not significantly impact public acceptance of infrastructure projects. Acceptance levels among participants receiving low compensation are statistically indistinguishable from those in the control group, which received no compensation at all.
Figure 1 about here.
In contrast, high levels of monetary compensation at the individual (private) level are effective in increasing public acceptance. This suggests that when individuals receive direct and substantial financial benefits, their willingness to accept infrastructure development statistically significantly increases.
However, our results indicate that high monetary compensation at the community level significantly reduces acceptance. One possible explanation is that large-scale community compensation crowds out intrinsic motivation. When compensation is framed as a financial transaction at the community level, individuals may shift from evaluating the project based on its broader societal benefits to viewing it through a purely economic lens. This could reduce their willingness to support infrastructure that they might have otherwise accepted for reasons such as environmental sustainability, regional development, or collective progress.

Additionally, community-level compensation might be perceived as a signal that the project imposes significant negative externalities, leading to increased skepticism or resistance. It may also trigger concerns about fairness in how benefits are distributed, further eroding public support.

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Session Classification: Hydrogen markets and infrastructure

Contribution ID: **48** Type: **not specified**

Flexible trading of renewables - A Dutch case study

Friday, April 4, 2025 3:20 PM (25 minutes)

The rapid transition of European power systems is putting pressure on the revenues of renewable energy generators. The growing penetration of solar and wind generation has led to frequent periods with low electricity prices and a rising occurrence of negative prices in recent years. As the installed renewable capacity continues to expand across markets, price cannibalisation is expected to intensify. This will reduce the revenue and profitability of existing generators, especially during periods of high renewable energy generation. It will also pose significant challenges for new renewable energy projects to secure stable revenue streams and to mobilise the necessary investments to meet Europe's climate goals.

Simultaneously, the integration of intermittent renewables is driving higher demand for ancillary services. In the Netherlands, the procured capacity for automated Frequency Response Restoration (aFRR) services has increased by over 50% since 2021. The need for frequency response services is often high during periods of high renewable generation due to the inherent variability of renewables and the displacement of conventional generation, which traditionally provided grid stability.

This study analyses how solar and wind assets in the Netherlands can participate in ancillary markets to diversify their revenue streams, enhance profitability, and contribute to grid stability. The Netherlands is a particularly relevant case study due to the rapid expansion of renewable generation in recent years, which has led to high price cannibalisation and one of the highest occurrences of negative price hours in Europe. We assess the extent to which the current Dutch market design enables renewables to participate in balancing markets and identify market design adaptations that would improve the flexibility of renewable energy sources. We quantify the additional revenues for renewables from participation in Dutch ancillary markets, and comment on how these developments can support the continued expansion of renewable energy in the country.

This study uses Aurora's fundamental power market models to develop a comprehensive assessment of the potential of renewables to participate on balancing markets. Over 10 years, Aurora has built and developed a dedicated electricity market model to assess specific market developments and provide detailed analysis to clients and the wider energy community. Written in Python and GAMS, Aurora's model forecasts both 'capacity expansion', i.e. build decisions for all technologies available, and 'dispatch', i.e. plant-level generation subject to asset and market level constraints. An iterative loop between capacity expansion and dispatch then leads to a consistent and cost-minimising forecast for the evolution of the entire European power system. Aurora's model has recently been extended to include the Intraday and balancing markets, allowing it to resolve imbalances arising from forecasting errors after the Day-Ahead market closes.

Specific for this study we developed a "Flexible RES"dispatch module to quantify with which volumes renewables can participate on the different markets and how much revenue they can make under different market designs. The module considers the Day-Ahead, Intraday, aFRR energy and capacity markets and reactive balancing. The dispatch optimization approach, which works at quarter-hourly granularity, integrates forecasted and historical market prices and generation profiles, bid success rates, market-specific constraints and gate closure times to determine the arbitrage opportunities between the different markets.

To evaluate revenue potential and system flexibility contributions, we establish two flexible trading strategies that optimize dispatch decisions across markets. Our analysis includes both a backward-looking assessment, using historical prices from the past three years, and a forward-looking projection extending to beyond 2030.

Can additional revenues from balancing markets compensate the impact of price cannibalisation for renewables? Our analysis shows that, historically, solar and wind assets had the potential to generate significant revenues from balancing markets. In 2023, optimising imbalance positions could have increased revenues for solar and wind by up to 20%, while aFRR energy down could have offered 5-10% in additional revenues. The correlation between moments with high solar generation and high balancing prices, particularly for downward products, leads to a larger revenue increase for solar compared to wind. However, the actual participation of renewables has been limited, because of factors such as the duration of trading products on balancing markets and challenges in establishing a reliable baseline for flexibility.

Looking ahead, flexible dispatch strategies are expected to provide some additional revenue opportunities for solar and wind assets. We expect that solar and wind assets can make up to 6% additional revenues in 2025-2030. These earnings will not be sufficient to fully offset the impact of price cannibalisation. Despite this, we expect that revenue optimization strategies will become increasingly important for assets owners as renewable penetration increases.

Beyond 2030, we anticipate rising competition from batteries and other flexibility providers, which will likely suppress balancing market prices and reduce activation volumes. This will further limit the revenue potential for renewables. In this period, we expect the additional revenues to decrease to 1-3%.

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Session Classification: Utilization of flexibility potentials

Contribution ID: **49** Type: **not specified**

Public knowledge and public acceptance of nuclear energy in the Baltic States compared to other EU states

Friday, April 4, 2025 10:25 AM (25 minutes)

Objectives/ scope

This paper analyses the evolution of public attitudes and acceptance of nuclear energy in the Baltic States from 2009 to 2024, a period marked by deep geopolitical and technical changes. From this concrete example, it reflects on the significant problem in communicating complex issues related to energy and its infrastructure, energy policies and plans, and technological solutions to the public for education. It considers more particularly the role of scientists in this process, as, on the issue of nuclear energy, the public trusts scientists more than journalists, industry representatives or politicians.
The study compares data on knowledge about nuclear energy issues in the Baltic States to similar data in other states of the European Union.

Methods

The research utilized a combination of methods, including case studies of specific events and policies, analysis within socio-political and economic frameworks, data from Eurobarometer and other survey sources, reports from industry associations, rhetorical analysis of state leader's statements, and a review of theoretical literature to examine public acceptance of nuclear energy in the Baltic States. The scope of the study spans the period from 2009 to 2024.

Results, Observations, conclusions

The study shows increasingly positive attitudes toward nuclear energy, though the Baltic states do not produce nuclear energy.
Moreover, public acceptance has increased more rapidly since 2022, following the conflict in Ukraine. Until recently, public attitudes were still strongly influenced by the negative legacy of the Chernobyl and Fukushima disasters. However, the energy crisis following the closure of the Ignalina Nuclear Power Plant in Lithuania, required for the accession to the EU, has contributed to a shift toward greater acceptance of nuclear energy.
Preliminary results indicate significant differences in acceptance levels in Baltic States –with Estonia showing the highest support for new nuclear initiatives, while Latvia and Lithuania remains more sceptical.
The survey data also reveals that there is still a significant part of society in the Baltic States without opinion, or knowledge about nuclear energy. Indeed, in the Baltic States (10-13%) of people have no opinion on the effect of nuclear energy as energy production, when the EU average is 6%. For example, in Hungary 1%, in the Czech Republic 2%, in the Netherlands and Luxembourg 3%, and in the EU the record holder in nuclear energy production and export, France, - 4%, as well as in Sweden and Slovenia.
This observation interrogates the information provided to the Baltic population. In particular, it suggests more active and interactive dissemination of scientific and technical knowledge, in a way that is easier for the public to understand, leading to a deeper understanding of scientific topics.
Technical information about nuclear energy is not widespread in the Baltic states, as they do not currently produce nuclear energy anymore, following the EU request to close the Ignalina Nuclear Power plant in Lithuania. However, the construction of small modular reactors in the Baltic States is currently on the political agenda therefore it seems relevant to increase public information about this issue.
Finally, the transition to green energy and the EUs climate targets have influenced public acceptance of nuclear energy. In this respect, the issue of nuclear waste's environmental impact remains

a critical challenge.

How this paper will present novel or additive information (..) benefit to a practicing engineer

This research can provide valuable insights for planners of future engineering education, enabling them to identify trends in nuclear energy education, including the knowledge and workforce demands of the future. The study provides a recommendation - a new method for informing the public and monitoring opinions, using the principle of an e-Learning platform. Additionally, investors can utilize these insights to assess the market potential of the nuclear energy sector in the Baltic States.

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Session Classification: Reviewing nuclear power

Contribution ID: **50** Type: **not specified**

Ramping Up Low-Emission Hydrogen Imports to Europe: Case Studies and Transition Pathways

Friday, April 4, 2025 5:05 PM (25 minutes)

Overview
For the energy transition hydrogen and hydrogen carriers will become an important building block to defossilize many sectors such as energy, heating, industry and mobility. In light of the urgent global need to reduce greenhouse gas emissions and combat climate change, hydrogen emerges as a potent alternative to fossil fuels. According to the European Union the production target for hydrogen in 2030 is 10 million tons and additionally 10 million tons of hydrogen imports, of which Norway for example is predicted to be a significant part of. This study presents an analysis of the transition from natural gas to hydrogen (blue and green) as a pivotal move towards decarbonizing Europe's energy supply, with a specific case study focus on Norway and Algeria' s role as a primary energy exporter and as a suitable representative of further energy exporting countries. This research spans a significant timeframe, from 2025 to 2050, marking critical decades in the energy transition when the majority of Europe pledged to be carbon neutral. We assess the attractiveness of exporting low-carbon and renewable hydrogen in competition to natural gas to Europe through various possible transportation modes (by retrofitted natural gas pipelines, new purpose-built pipelines or ammonia as a hydrogen carrier) in this transition period. We analyze this transitioning from natural gas exports to hydrogen exports under different scenarios in a mixed-integer linear optimization model. Our results show, that this transition from an energy exporter perspective will take place under very different timeframes from natural gas to low-carbon or/and renewable hydrogen and that the switching times are heavily dependent on factors such as CO2 pricing, cost degressions and regional factors such as upstream emissions.
Methods
For the analysis in this research, we created a MIP model, solving with Gurobi. The objective function in this model is to minimize the total sum of annual system costs for the modeled country' s energy exports which includes the export of natural gas, blue hydrogen and green hydrogen over the whole timeframe from 2025 to 2050. The optimization model incorporates a variety of constraints, for example transport capacities and the inherent limitations in retrofitting existing natural gas pipelines for hydrogen transport. We also integrated a detailed sensitivity analysis to analyze the impact of pivotal parameters, including but not limited to, natural gas cost, CO2 pricing, upstream emission impact (which are influenced by CO2 pricing and region), and various capital costs. Generally, we presume a constant annual export of energy that can be composed of natural gas or hydrogen. Alternatively, to investigate the dynamics between low-carbon and renewable hydrogen only, an increasing hydrogen demand from 2025 to 2050 can be assumed. The composition of energy exports is calculated endogenously as well as all required capacities along the supply chain. The model is also applicable to further countries and hydrogen derivatives.
Results
Key results highlight the feasibility and economic viability of transitioning from natural gas to hydrogen, with a specific emphasis on Norway and Algeria in a case study. The analysis reveals that while the transition is feasible under a range of scenarios, it is particularly sensitive to fluctuations in natural gas cost, CO2 pricing, and the associated capital costs of electrolyzers and renewable electricity supply as well as upstream emissions. Moreover, the study discusses the concept of stranded investments and lock-in effects, particularly for low-carbon hydrogen production, pro-

viding insights into risks by investing into potentially short-lived low-carbon hydrogen plants. The results also underscore possible pathways to fully transition into renewable hydrogen exports with low-carbon hydrogen as a transitional means of hydrogen supply and the different onset of ramping up low-carbon or renewable hydrogen production depending on our scenario analysis. The results thus show, that depending on the scenario, different factors such as CO2 pricing may have to be more ambitious than usually projected for the transition to initiate earlier and reach a natural gas phase out earlier than 2050. The results also show different impacts on total emissions and system costs under certain shares between low-carbon and renewable hydrogen. In cases such as Norway a forced early phase-out of blue hydrogen or allowance of green hydrogen only, results in higher system costs and high abatement costs per ton of CO2.
Conclusions
The transition from fossil fuels such as natural gas to low-carbon hydrogen, presents a viable pathway for Europe to decarbonize various sectors, with Norway poised to play a pivotal role as a key exporter of low-carbon hydrogen in the medium-term and Algeria of renewable hydrogen depending on the upstream emissions of low-carbon hydrogen production. In our study, we outline viable pathways for natural gas exporters like Norway and Algeria to transition their export focus from natural gas to hydrogen. However, it is clear that for this shift to occur, there must be compelling incentives in place. The transition to exporting low-carbon or renewable hydrogen hinges significantly on economic factors. Primarily, this involves higher CO2 prices and a sufficient development of cost degressions, ensuring that the supply costs arising from hydrogen exports compete against those from natural gas. This shift is crucial in making hydrogen a more attractive export option. Nonetheless, it is important to recognize that such a transition is also capital-intensive. Substantial investments are necessary to develop and establish a hydrogen export supply chain. This includes the infrastructure for production, storage, and transportation of hydrogen. The study underscores the need for a well-structured financial and policy framework to accelerate this ramp-up of hydrogen exports.

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Session Classification: Hydrogen markets and infrastructure

Contribution ID: **51** Type: **not specified**

Scenarios for a Future EU Energy System Until and Beyond 2050 - Charting Energy Visions towards 2060

Friday, April 4, 2025 11:15 AM (25 minutes)

Motivation and central research question
The global energy transition requires a massive re-thinking of the ways we generate, consume, and transform energy. To achieve the set climate targets of the European Union of 100% emission reductions in 2045-2050 [1], heavy electrification, combined with a significant expansion of variable renewable energy sources (vRES) is required. However, the current unstable geopolitical landscape, both globally, but also with nationalistic trends emerging within Europe itself, poses several additional challenges to the already gargantuan task of the needed rapid decarbonization.

Methodology
To chart these uncertainties towards 2050 and beyond, the "European Energy Vision 2060"or EU-EnVis-2060 scenarios have been created. The scenario generation process included several workshops between experts from academia, industry and policy stakeholders, as well as need-owners from the CETP project "Man0EUvRE". The result of this process were four distinct qualitative storylines, mapping the major driving forces and key uncertainties facing the European energy transition (see Figure 1).

These qualitative storylines were then parametrized and translated into usable information for the use in energy system models. For this analysis, the Global Energy System Model (GENeSYS-MOD) [1] will be used to quantify the Pan-European pathways that result from the four developed scenarios. GENeSYS-MOD is a sector-coupled, open-source energy system model that includes the sectors electricity, buildings, industry, and transport, and performs a linear cost optimization of the energy system towards the future –in this case 2060 [3]. Main model results include investment trajectories, capacity expansion plans, the energy dispatches of the different energy carriers, as well as the flexibility and transmission requirements (see Figure 2).

Results and Conclusions
The expected results will show possible developments of the European energy system towards 2060 and possible solutions to achieve set climate targets while navigating the societal, geopolitical, and technological challenges that we face, including the uncertainty that exists around them. The GENeSYS-MOD outputs will display the necessary deployment and ramp-up of renewable energy sources and showcase no-regret options across the different storylines. Within the Man0EUvRE project, the Pan-European energy system results will then be passed on to regional and sectoral models in an iterative fashion –incorporating the findings from these models into the broader energy system model. The main goal of the project is to give detailed feedback to the National Energy and Climate Plans (NECPs) of the European member states to improve the planning for a sustainable, secure and robust energy system of the future.

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Session Classification: Energy market outlooks and transformation strategies

Contribution ID: **52** Type: **not specified**

Economics of the Early Nuclear Power Plants in the United States (1957-1987): Bandwagon or Negative Learning?

Friday, April 4, 2025 10:00 AM (25 minutes)

This paper examines the economics of the first generation of nuclear power plants in the United States between the 1950s and 1980s as acknowledged by Böse (In Press) with a focus costs during this formative period. The United States, the largest global producer of nuclear power, faced significant uncertainties in the early years of nuclear energy deployment, making the topic of particular importance. Contrary to initial expectations, the light-water reactor (LWR), despite being viewed as less promising compared to the breeder reactor with a fast neutron spectrum, became the dominant technology in the rollout of nuclear power plants.
We update earlier literature by Baade (1958), Münzinger (1960) and Cohn (1990) and provide a bottom up estimation of the cost of nuclear power. For example, costs of nuclear power plants of the 1950s (e.g. Shippingport and Yankee), of the 1960s (e.g., Oyster Creek and San Onofre-1) and the 1970s (e.g., Palisades) are analyzed. These costs are compared to those of competing energy sources, primarily coal, to assess the economic viability of nuclear power. Our preliminary findings reveal that the levelized costs of electricity (LCOE) for early nuclear plants increased significantly over time and thus not able to compete with coal. This trend contradicted the widespread expectation among utilities, reactor vendors, and the nuclear industry that nuclear power would eventually become more cost-effective.
Our analysis highlights the complexity of nuclear power's economic performance in its early stages and emphasizes the need for a more nuanced exploration of the interplay between economics, technology, and policy in the development of nuclear energy.

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Beyond Standard Load Profiles: Capturing Heterogeneity and Stochasticity in Residential Energy Demand

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Motivation
Residential energy usage accounts for 27% of the Swiss final energy demand and 15% of CO2 emissions. With the electrification of the heat and transport sectors, the characteristics of residential energy demand are changing. Understanding these changes is essential in light of the energy transition and the resulting decrease in supply-side flexibility from intermittent energy supply. Demand-side management is one option to introduce the required flexibility but relies on high-resolution residential load profiles to correctly assess flexibility needs and potentials.

Traditional standard load profiles fail to capture occupant behaviour, a critical driver for energy demand variability. Stochastic load profile models address this limitation but often focus on either heat or electricity demand. Another essential characteristic of demand is the heterogeneity of demand among different consumers. However, most models do not sufficiently differentiate between occupant types. To address these gaps, this study develops a novel stochastic load profile model that integrates heterogeneous occupant groups, activity-driven energy demand, and multiple end-use sectors, including appliances, heating, and electric vehicles (EV). This approach provides a more accurate and flexible representation of residential energy demand.

Methods
Using Swiss time use survey data, unique load profiles that introduce heterogeneity and stochasticity are created in a three-step process. First, to introduce heterogeneity, survey participants are grouped into eight occupant types by age (working, underage, retired), employment status (full-time, part-time, unemployed), and family status (children or no children). The survey data also enables the distinction between eight household activities, each one linked to distinct household and vehicle technologies with a unique use probability. Then, the occupancy behaviour of each group is modelled using a first-order inhomogeneous Markov Chain to generate stochastic probability distributions per activity and timestep. Finally, the resulting activity schedules for each occupant group are used to determine the technology use pattern, which in turn informs the load profiles. For this final prediction of the energy demands, the activity-technology mapping is complemented with technology-specific energy consumption values and use probabilities. The lighting model accounts for ambient irradiance, while the electric vehicle model incorporates commuting distance, vehicle efficiency, and charging speeds. The validation indicates that the modelled annual residential energy consumption and peak demand estimates match well with existing studies.

Results
Our results reveal distinct energy demand patterns across occupant groups. Figure 1 illustrates this for two household types: a 2-person household of retirees and a 2-person household with full-time employees. The retired household exhibits greater variability in demand, reflected in the wider uncertainty bands. In contrast, the full-time household has a much narrower range. The introduction of EV charging demands substantially increases peak loads across all occupant groups.

When aggregating the individual load profiles, they approximate the standard load profile as hundreds of households are combined. This suggests that these load profiles can be used to tailor load profiles to specific contexts, such as municipal energy systems, reflecting their unique demographic composition in distinct load profiles.

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Curtailment vs. Low-Capacity Credit –The Two Faces of Variable Renewable Energy Sources

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Poland is among the countries experiencing the highest growth dynamics in variable renewable energy sources (VRES). A country that not long ago relied almost entirely on coal-based energy is undergoing a profound transformation, with solar power plants and onshore wind farms playing a key role. Between 2020 and 2025, the installed capacity of wind power increased from 5.9 GW to more than 10 GW, while solar power grew from 1.6 GW to more than 21 GW. The peak demand in polish power system in 2024 exceeded 28 GW. By 2030 approx. 6 GW of offshore wind farms are planned for development, and after 2035, nuclear reactors are expected to be commissioned, with a total capacity reaching 6–9 GW by 2045. The current storage capacity, mainly in pumped storage power plants, amounts to 7.1 GW of discharge power. The total contracted capacity of new energy storage under the capacity market amounts to 4.4 GW, primarily consisting of storage systems based on electrochemical battery technology. The increasing share of VRES in energy systems leads to a growing number of hours with overproduction and negative residual load. On the other hand, VRES capacities are weather-dependent and characterized by low-capacity credits. Capacity credits quantify the contribution of a resource to overall system adequacy.

The ongoing process of electricity market coupling and the associated regulatory changes have led to the adoption of 15-minute settlement intervals. As a result, operational system data is now collected at this time resolution. Based on the gathered data, this study presents results on the occurrence of non-economic VRES redispatch from July 2024 onwards (frequency and magnitude). In the second part, historical data were used to calculate capacity credits for wind and solar power plants in the polish conditions. Two primary methods for calculating the capacity credit for renewable energy technologies were employed: the deterministic method and the probabilistic method. Additionally, periods when VRES operate with very low-capacity factors are identified.

The results indicate that due to low values of VRES capacity credit, in addition to energy storage solutions, flexible generation units must also be present in the system. These units must be capable of supplying electricity when unfavorable meteorological conditions persist for several days, preventing RES from charging depleted energy storage systems. Capacity credits for solar PV and onshore wind power plants for the years 2021–2023, ranged from 9.19% to 9.58% for onshore wind and from 2.12% to 4.10% for solar PV.

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