ENERDAY 2026 - 20th International Conference on Energy Economics and Technology

Report of Contributions

Contribution ID: **61** Type: **not specified**

Agent-Based Modeling of Pakistan's Green Hydrogen Economy: Policy Analysis and Investment Dynamics (2025-2040)

Friday 27 March 2026 16:50 (20 minutes)

MOTIVATION

The International Energy Agency projects hydrogen demand reaching 530 million tonnes by 2050 under net-zero conditions. Pakistan presents a compelling case with exceptional solar resources (Global Horizontal Irradiance >2,000 kWh/m²/year), current grey hydrogen demand (600,000 tonnes/year), and renewable energy targets (60% by 2030). However, challenges include limited fiscal space, underdeveloped infrastructure, and global competition.

Existing hydrogen literature focuses on techno-economic optimization assuming perfect foresight and rational actors, missing behavioral dynamics and path dependencies. This study develops the first agent-based model of a developing country's hydrogen economy, representing heterogeneous actors, bounded rationality, and emergent behavior.

METHODOLOGY

We construct a spatially explicit agent-based model with five agent types simulating monthly interactions over 2025-2040 covering Sindh and Balochistan provinces: Producer Agents (N=50) making NPV-based investment decisions with herd behavior adjustments, Consumer Agents (N=40) representing industrial/transport/export sectors with price-elastic demand (elasticity=0.30), Market Agent clearing via uniform-price auction, Policymaker Agent implementing CAPEX subsidies (0-50%), production subsidies (USD 0-2/kg), and tax credits (0-30%), and Infrastructure Agent managing storage/pipelines/export facilities.

The model incorporates technology learning (15% rate), spatial transport costs, and financial constraints (15% down payment). Parameters are calibrated against Germany, Australia, and Chile projects, achieving 80% validation. Monte Carlo analysis (100 runs) quantifies uncertainty across 12 parameters. Key mechanisms include real options theory (investment threshold -5% NPV), herd behavior, and financial constraints.

RESULTS

Pakistan can achieve 21.5-33.5 GW electrolyzer capacity and 645,000-1.04 million tonnes/year production by 2040, mobilizing USD 17-27 billion investment. Baseline scenario (no policy) yields 21.5 GW, 645,000 tonnes/year, USD 17.2 billion, hydrogen cost USD 3.91/kg. Policy support (30% CAPEX subsidy + 20% tax credit + USD 1.5/kg production subsidy) achieves 33.5 GW, 1.04 million tonnes/year, USD 26.8 billion, cost USD 3.94/kg.

ANOVA confirms policy effectiveness ($F=45.2$, $p<0.001$) with 1.55x capacity growth versus baseline (Cohen's $d=1.52$). Cost-effectiveness is high: USD 5-8 billion subsidy mobilizes USD 26.8 billion investment (3.4-5.4x leverage). CAPEX subsidies are most effective, followed by tax credits and production subsidies. Combined packages show synergies.

Investment dynamics reveal 35-40% of investments occur despite negative NPV (real options theory), clustering in 2027-2029 and 2033-2035 (investment waves), and herd behavior increasing investment probability 50%. Hydrogen costs (USD 3.86-3.94/kg) are competitive domestically but higher than Chile (USD 1.50-2.50/kg) and Australia (USD 1.40-2.85/kg), suggesting Pakistan should prioritize import substitution. Monte Carlo analysis shows moderate uncertainty (coefficient of variation 7-9%), with investment threshold ($r=0.68$) and market growth ($r=0.54$) most influential.

PRACTICAL IMPLICATIONS

Pakistan should implement: (1) 30% CAPEX subsidy, (2) 20% tax credit, (3) USD 1.5/kg production subsidy for 5 years, and (4) long-term contracts with USD 4.50/kg floor price. This achieves 33.5 GW, 1.04 million tonnes/year, USD 26.8 billion investment with fiscal cost USD 5-8 billion over 15 years. Start with CAPEX support (highest impact), add tax credits (leverage private capital), use production subsidies selectively, and establish long-term contracts. Leverage international finance to supplement domestic resources.

Pakistan's cost (USD 3.86-3.94/kg) positions it as a regional player. Domestic market focus (replacing 600,000 tonnes/year grey hydrogen) provides foundation. Regional exports possible but long-distance exports face challenges. Lessons for developing countries: (1) Strong case with large domestic demand, (2) CAPEX support most effective for capital-constrained countries, (3) Realistic expectations (domestic focus first, 15-20 year timelines, 5-8% CAGR).

ORIGINALITY

This study makes three contributions: (1) Methodological: First agent-based model of a developing country's hydrogen economy, demonstrating how behavioral economics enhances policy analysis, (2) Empirical: Systematic calibration against international projects with 80% validation, (3) Policy: Quantitative comparison of policy instruments with clear recommendations for resource-constrained governments. The agent-based approach complements existing optimization and scenario analysis by representing behavioral dynamics, path dependencies, and coordination failures in developing country contexts.

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Session Classification: Hydrogen Systems & International Case Studies

Contribution ID: **63** Type: **not specified**

Multi-criteria assessment of prospective wind farms for municipal-level planning

Friday 27 March 2026 11:30 (20 minutes)

Onshore wind energy is a cornerstone of the energy transition, yet its expansion has faced increasing opposition at the local level, where many projects are rejected due to social and environmental concerns. As the project's planning progresses towards site selection, municipalities often play a decisive role in the final approvals. However, municipal decision-making is often supported by fragmented assessments that inadequately capture the trade-offs among technical performance, costs, and local impacts.
This study develops a spatially explicit multi-criteria decision analysis (MCDA) framework to assist holistic municipal wind farm planning by systematically integrating diverse impact assessments into a transparent decision support tool. Using two case studies in Styria, Austria, we compile outputs from techno-economic resource assessment, life-cycle assessment (LCA), wildlife habitat suitability study, noise propagation model, shadow flicker model, and landscape scenicness prediction into a set of normalized performance attributes. These attributes are categorized into four decision pillars: technical, economic, environmental, and social, and weighted using a combination of survey results and data-driven approaches.
The framework is applied to explore trade-offs and synergies across pillars using correlation and principal component analysis (PCA). Additionally, with various combinations of pillar weights, the sensitivity of wind farm performance and total generation potential with associated costs under different pillar prioritization can be investigated. By comparing our model-based outcomes with empirical preferences from a stakeholder workshop, the policy relevance and robustness of this study is assessed.
The results reveal pronounced trade-offs between technical and social performance, with smaller wind farms tending to achieve higher overall performance due to lower social impacts (noise, shadow flicker, and landscape scenicness), despite larger farms offering technical advantages. The PCA shows a strong alignment between social and environmental dimensions (LCA and habitat suitability), while economic pillar exhibits weak correlations with local impacts. Sensitivity analyses further demonstrate that increasing technical pillar weight disproportionately favors large wind farms, highlighting a central policy tension between maximizing energy yield and minimizing local externalities.
From a municipal planning perspective, applying stricter MCDA selection thresholds reduces both generation potential and system costs, but the magnitudes of these effects depend strongly on regional context and prioritization scenarios. The empirical preferences from the stakeholder workshop shows strong agreement with our model-based results under the environmental prioritization scenario, suggesting that participatory preferences converge with analytical indicators that emphasize minimizing environmental burden.
Overall, the study demonstrates that integrating diverse model outputs into a transparent spatial MCDA framework reveals critical synergies, trade-offs, and policy relevance that conventional single-objective or macro-level analyses overlook or simplify. The framework is transferable to other regions or technologies and can be extended to incorporate additional criteria, alternative weighting schemes, or participatory inputs at different planning stages, providing a basis for more robust and socially attuned renewable energy planning.

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Session Classification: Renewable Expansion & Planning

Contribution ID: **65** Type: **not specified**

Who Benefited from Relief? Distributional and Justice Impacts of Germany's 2022/23 Energy Crisis Policies

Friday 27 March 2026 11:30 (20 minutes)

Motivation

The war between Russia and Ukraine in early 2022 caused a severe shock to European energy markets, with gas, electricity, and fuel prices reaching historic highs. The most immediate effects were felt by households, as millions of German households faced sharp increases in energy costs that often exceeded their financial capacity. In response, the German government introduced three relief packages, combining universal transfers, targeted support, and temporary price interventions. However, their effectiveness in protecting low-income and energy-poor households is disputed. It is conceivable that universal measures disproportionately benefited higher-income groups, that targeted instruments experienced low take-up and implementation delays, and that price interventions may have dampened incentives for energy conservation and decarbonization.
This paper evaluates the 2022/23 relief packages using a behaviorally informed microsimulation and asks: i) To what extent did the implemented relief measures prevent increases in income poverty and energy poverty? ii) How were the fiscal benefits distributed across the income spectrum? iii) What role did behavioral responses to energy prices play in mitigating hardship and emissions? iv) How effective were individual policy instruments, and what trade-offs emerged between social protection and environmental objectives?

Methods

The simulation framework employed in this study is designed to estimate the distributive, behavioral, and fiscal impacts of selected energy relief measures under real-world eligibility conditions and price shocks. The model builds on prior microsimulation approaches but incorporates behaviorally adjusted energy demand and poverty-sensitive metrics. Rather than relying on a single integrated panel, the approach uses harmonized information from three complementary sources (EVS, SOEP, and MOP) to simulate household responses across income and consumption dimensions.
We incorporate price increases between 2021, 2022 and 2023 for the main energy types, as depicted in Figure 1.

Behavioral changes in energy consumption are modeled using price and income elasticities differentiated by income group. These elasticities were empirically estimated using pooled microdata and panel regressions by Priesmann and Praktiknjo (2025).
Each household is simulated under four scenarios: Baseline (2021 prices, no policies or behavioral response), Price Shock (2022/23 prices, no relief or behavior), Price Shock + Policy (2022/23 prices with relief, no behavior), and Price Shock + Policy + Behavior (2022/23 prices with relief and behavioral adjustments).
After running the simulations, we calculate several key outcomes: income and energy poverty status, benefit receipt along with net fiscal transfers, behavioral energy savings, distributional indicators such as the Gini coefficient, and environmental impacts measured by CO_2 emissions using standard emission factors. All results are weighted using survey expansion factors to ensure representativeness of the German population.

Results

Table 1 shows that the 2022–23 energy price shock caused a modest rise in poverty, with the poverty rate increasing from 20.92% in 2021 to 21.23% in 2023 and energy poverty from 7.57% to

9.83%. Compensatory policies (Price Shock + Policy and Price Shock + Policy + Behavior scenarios) partly offset these effects, reducing the 2023 poverty rate to 21.01% and energy poverty to 8.42%. The poverty gap remains largely unchanged in 2022 but declines noticeably in 2023 when policies are applied.

The simulation results confirm the regressive structure of the 2022 fuel tax rebate in absolute terms, while revealing a more nuanced pattern in relative terms. As shown in the left side of Figure 2, absolute benefits increase monotonically with income, reflecting higher car ownership and mileage among high-income households. Measured relative to disposable income, benefits follow a hump-shaped pattern: they peak in the lower-middle deciles and decline toward the top, indicating a middle-biased incidence. Incorporating behavioral responses reduces benefit levels across all deciles but leaves the distributional pattern unchanged.
Overall, the fuel tax rebate provides relatively higher support to low- and middle-income households than to the rich, yet remains poorly targeted at the poorest households in both absolute and relative terms.

The simulated distributional effects of the 2023 gas price cap are highly uniform across behavioral assumptions (Figure 2, right side). Absolute and relative relief is nearly identical for all but the lowest income decile, as the policy subsidizes 80% of 2021 heat consumption at a capped price of 12 ct/kWh, independent of actual 2023 usage.
Effectively, the gas price cap acts as a lump-sum transfer tied to historical consumption. It provides relatively higher support to low-income households but offers limited incentives for energy savings within the subsidized share, while encouraging reductions only beyond the 80% threshold. Consequently, its environmental impact is modest, and more dynamic, consumption-linked designs could better align social protection with energy-saving incentives.

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Session Classification: Energy Security & Crisis

Contribution ID: **66** Type: **not specified**

Impact of an adjustment to Germany's renewable energy targets for 2030

Friday 27 March 2026 11:50 (20 minutes)

Content

According to the Renewable Energy Act (Erneuerbare-Energien-Gesetz, EEG) and the Offshore Wind Act (Wind auf See Gesetz), Germany's current expansion targets for renewable energies in 2030 are 215 GW of capacity for solar power, 115 GW for onshore wind power and 30 GW for offshore wind power. The targets came into force at the beginning of 2023 and were set on the assumption that the national electricity consumption in 2030 will be 680–750 TWh. However, recent studies predict lower electricity demand for 2030. For example, the meta-study commissioned by the BMWE in 2025, "Energiewende. Effizient. Machen.'[1], predicts a range of 580–700 TWh for electricity consumption in 2030, based on a combination of exploratory and target-reaching scenarios. The lower demand for electricity is mainly due to slower electrification in the transport and building sectors and an economic slump in industrial activity in recent years.
Against this backdrop, there has been political debate about adjusting the expansion targets for renewable energies. However, in a recent agreement on the power plant strategy („Kraftwerksstrategie"), the governing coalition committed to continuing the tender volumes from the EEG with unchanged ambition. While the political debate on adjusting the expansion targets has mainly focused on grid expansion and energy system costs, the effects of lower renewable energy capacities on electricity prices, the achievement of emission reduction targets and the import balance have so far taken a back seat. Our contribution, developed in the Kopernikus project Ariadne, therefore specifically examines these interrelationships. In addition, the importance of flexibility for the integration of electricity from renewable energies is examined in more detail with the aid of a model run with reduced flexibility options.

Methodology

PyPSA-DE (https://ariadneprojekt.de/modell-dokumentation-pypsa/) is a high-resolution, sector-coupled, linear model of the German energy system that was already used in the Ariadne scenario report on a cost-efficient energy transition [2]. To minimise energy system costs, PyPSA-DE creates a linear optimisation problem to plan the energy system infrastructure in Germany and its neighbouring countries, using up to 40 regions in Germany and hourly resolution over full weather years. The energy system costs consist of investment costs, operating costs and import costs. The investment costs include costs for energy infrastructure and generation, carbon capture and storage, and heat generators in buildings.
Based on two basic scenarios with electricity demand of 612–644 TWh ('low demand') and 722–754 TWh ('high demand'), this study considers different levels of renewable energy expansion that interpolate between the ambition of the EEG targets and significantly reduced renewable targets. In order to highlight the role of flexibility in the energy system, a variant with fewer flexibility options was modelled for the 'low demand'scenario. Specifically, in this variant electric cars cannot be charged flexibly, heat pumps, electric boilers and home batteries cannot be operated in a market-driven manner, and no expansion of utility-scale batteries above 2025 levels is allowed.

Results

- Although a reduction in renewable energy expansion would lower the subsidy granted by the EEG („EEG-Konto"), the additional costs for electricity customers would be significantly higher. In the extreme case of a 30% reduction of the targets, the electricity price would rise by EUR 20 per MWh, that is 2.0 ct per kWh. In this case, the additional costs for electricity customers would amount to EUR 9.0–13.2 billion, while the subsidy according to the EEG would fall by only EUR 7.0–7.5 billion.

- A lower expansion of renewable energies would lead to more electricity generation from natural gas and, consequently, to increased import dependency and a greater need for new gas-fired power plants. At the same time, electricity imports would rise.
- Supporting renewable energy generation with flexibility is essential for achieving climate targets and ensuring the cost-efficiency of the electricity system. Renewable energies in combination with batteries could cover part of the demand for new gas-fired power plants. Regulatory frameworks that enable market-driven provision of flexibility should therefore be a priority.
- The maximum permissible amount of greenhouse gas emissions in 2030 will be exceeded even with a slight reduction in the expansion of renewable energies.
- The target of covering 80% of gross electricity consumption with renewable energies in 2030 will only be achieved with a high level of renewable energy expansion.

References

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[2] Luderer, Gunnar, et al. (2025): "Report: Die Energiewende kosteneffizient gestalten–Szenarien zur Klimaneutralität 2045." Ariadne-Report.

CV

Michael Lindner received his doctorate from Technical University Berlin in 2023 for his thesis on "Applying Modeling, Simulation and Machine Learning for the Energy Transition". From 2019 to 2023 he worked as a doctoral researcher at the Potsdam Institute for Climate Impact Research, supported by a fellowship of the Berlin International School on Modeling and Simulation based Research. Since 2024 works at the Department for Digital Transformation of Energy Systems, Technical University Berlin. He is the lead developer of PyPSA-DE, a sector-coupled optimization model of the German energy system, and his research focuses on cost-efficient pathways for Germany's energy transition.

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Session Classification: Renewable Expansion & Planning

Contribution ID: **68** Type: **not specified**

Future Day-Ahead Electricity Price Spreads in Germany: Drivers, Forecasting, and Flexibility Scenarios

Friday 27 March 2026 14:30 (20 minutes)

Large and volatile within-day spreads in the day-ahead electricity market, defined as the daily maximum minus the minimum of hourly day-ahead prices, shape arbitrage revenues and therefore investment incentives for flexibility resources such as batteries, demand response, and vehicle-to-grid (V2G). They also provide a market-based signal of scarcity and surplus in power systems with rising shares of variable renewables. Yet most related work focuses on average prices or broad volatility measures, so evidence on within-day spreads as a flexibility-relevant metric and on their short-horizon predictability is comparatively limited. This study asks (i) which observable day-ahead fundamentals are most associated with German within-day spreads and (ii) how predictable spreads are at short horizons. We contribute by documenting daily spread dynamics for Germany over 2015–2025, linking spreads to the day-ahead information set, and translating estimated relationships into stylized flexibility scenarios relevant for the pathway to climate neutrality.

We compile a daily dataset for Germany spanning 05 Jan 2015 to 30 Apr 2025, combining day-ahead prices and forecasts from SMARD (Bundesnetzagentur) with a TTF natural gas price proxy. The dependent variable is the within-day spread of hourly day-ahead prices (EUR/MWh). Explanatory variables are observable ex ante at the day-ahead stage, including forecasts of solar share, wind offshore share, wind onshore share, and load, plus lagged TTF gas prices. Net exports are jointly determined within the coupled day-ahead auction and are therefore treated as potentially endogenous. Baseline specifications exclude net exports and robustness checks include lagged net exports. We estimate predictive regressions with HAC (Newey–West) inference and evaluate out-of-sample performance on 2023–2024 (731 days) after training on 2015–2022 (2,918 days). We benchmark against historical mean, random walk, and an AR(1) spread model, while Elastic Net and ARIMAX serve as additional robustness checks.

Day-ahead fundamentals exhibit meaningful associations with spreads. Coefficients are positive for renewable shares and gas prices, with a strong gas-price association of about +1.3 EUR/MWh in spread per +1 EUR/MWh higher gas price in-sample. Net exports add little incremental explanatory power once fundamentals are controlled for. In forecasting, however, persistence dominates. On 2023–2024, a fundamentals-only OLS model yields RMSE of about 77 and MAE of about 46.7, while AR(1) and lag-augmented dynamic specifications reduce errors materially, with RMSE of about 64–65 and MAE of about 36.9.

Finally, we translate the estimated mapping into a stylized 2050 scenario analysis that combines projected renewable shares with low versus high gas-price regimes and low versus high flexibility motivated by V2G and second-life battery integration. Flexibility is implemented as an illustrative spread-compression sensitivity and is not a causal estimate. The scenario matrix suggests that higher flexibility can substantially compress spreads even under high gas prices, for example from roughly 142 EUR/MWh to roughly 79 EUR/MWh. This underscores the potential economic value of scalable flexibility for moderating price dispersion in high-renewables systems. Overall, fundamentals are most useful for structural interpretation and scenario translation, whereas short-horizon spread forecasting is primarily time-series driven. This implies a division of labor between investment-oriented stress testing and trading-oriented prediction.

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Session Classification: Renewables & Risks

Contribution ID: **69** Type: **not specified**

SHORT-TERM FORECASTING OF HETEROGENEOUS WIND POWER FLEETS: GLOBAL TEMPORAL FUSION TRANSFORMER LEVERAGING STATIC COVARIATES

Friday 27 March 2026 12:10 (20 minutes)

Introduction and Motivation
With the rapid expansion of renewable energy sources, which accounted for 17% of global electricity production in 2024, accurate short-term wind power forecasting has become a prerequisite for grid stability and efficient electricity trading1. While deep learning architectures have replaced statistical methods as the state-of-the-art, current industry practices predominantly rely on specialized local models trained for individual assets. These site-specific models often struggle to generalize when data is scarce and create significant operational complexity for large portfolios. Although global models offer a scalable alternative, they historically fail to outperform local baselines due to the high heterogeneity of wind farms, which differ significantly in local meteorology and technical turbine parameters. This study investigates whether a centralized, global Temporal Fusion Transformer (TFT) can outperform specialized local models in 48-hour-ahead forecasting by leveraging static context variables to learn shared physical representations across diverse sites.

Methodology
The study employs a Global Temporal Fusion Transformer (TFT) trained on a heterogeneous portfolio of 100 wind farms across Germany. The dataset combines synthetic power profiles with real-world Numerical Weather Prediction (NWP) data from the ICON-D2 model. To address the challenge of site heterogeneity, the model architecture explicitly incorporates static covariates—specifically farm age, surface altitude, turbine hub height, rotor diameter, and power curve parameters. These time-invariant features allow the neural network to condition its predictions on the specific physical identity of each asset. The forecasting framework utilizes a 48-hour prediction horizon with a corresponding 48-hour lookback window. A novel feature engineering pipeline is introduced to maximize physical consistency while minimizing data redundancy. This includes the derivation of a "rotor-equivalent air density," which aggregates vertical density profiles using a linear weighted arithmetic mean across the rotor swept area. This approach reduces feature space dimensionality compared to using raw multi-level NWP data while maintaining physical fidelity. The model distinguishes between three input types: static covariates (context), past-observed inputs (historical power and weather), and known future inputs (NWP forecasts).

Experimental Setup
The performance of the global TFT was evaluated against distinct local models using a rigorous cross-validation scheme. The dataset includes 100 randomly distributed sites comprising six recurring turbine models (e.g., Vestas V112, Enercon E-82) with ages ranging from 2 to 24 years and elevations up to 900 meters. Hyperparameters were optimized using Optuna's Tree-Structured Parzen Estimator (TPE) to minimize the Root Mean Squared Error (RMSE). To isolate feature-driven performance gains, the model was configured to generate deterministic point forecasts trained on Mean Squared Error (MSE), rather than probabilistic quantiles.

Results and Discussion
The empirical results demonstrate that the global TFT significantly outperforms the local baselines. The global model achieved a relative improvement of over 8% in the coefficient of determination R^2 and reduced the RMSE by 5% on the test set. Statistical analysis using the Wilcoxon signed-rank test confirmed the significance of these gains.A critical finding of this study is that this superiority is strictly conditional on the inclusion of static covariates. An ablation study revealed that a global model lacking asset-specific context variables (the "no-context" model) failed to generalize effectively, resulting in a performance decline of 1.28% compared to local models. This confirms

that explicit modeling of heterogeneity is a prerequisite for successful cross-learning between sites.

Interpretability
Leveraging the TFT's Variable Selection Network (VSN), the study provides novel physical insights into the forecasting process. Analysis of static feature importance identified farm age and altitude as the most critical determinants of site heterogeneity. This aligns with physical expectations, as turbine efficiency degrades with age and high-altitude terrain introduces complex turbulence. Furthermore, the model revealed a dual modeling strategy for dynamic inputs: the encoder prioritizes historical power output to reconstruct turbine efficiency, while the decoder minimizes forecast uncertainty by leveraging a combination of robust wind speed layers rather than relying on air density or single atmospheric levels.

Conclusion
This work supports a paradigm shift from single-site to scalable multi-site forecasting architectures. The results prove that a single global model, when correctly conditioned with static physical metadata, can not only reduce operational complexity but also enhance predictive accuracy for large-scale renewable energy portfolios. The proposed framework offers a pathway for operators to leverage fleet-wide data effectively, overcoming the limitations of isolated local models.

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Session Classification: Renewable Expansion & Planning

Contribution ID: **71** Type: **not specified**

When to charge demand? Refinancing capacity renumeration mechanisms

Friday 27 March 2026 10:00 (20 minutes)

Extensive research has examined how capacity markets address the missing-money problem in electricity markets and how capacity procurement auctions can be designed efficiently. Less attention has been devoted to how the costs of capacity markets are distributed to consumers. Here, we analyse the design options of demand charges for refinancing electricity capacity markets. We combine a theoretical framework with a numerical equilibrium model. Results focus on the implications for firm capacity, technology mixes, market prices, and welfare.

We compare three main design types: first, a flat demand charge, applied at all times; second, a time-of-use (TOU) charge, applied during predefined periods when scarcity is likely to occur; and third, a dynamic charge, triggered by stochastically realized or forecasted scarcity situations. Flat and TOU designs are implemented with constant charge levels; for dynamic designs, we implement constant and variable charge levels, with variable levels increasing with the degree of scarcity. TOU and dynamic charges more accurately reflect the costs of building additional capacity to cover demand during scarcity situations. Assuming that electricity demand is price-elastic, this is expected to lead to welfare gains.

Theoretical framework

In the theoretical framework, we compare the two most divergent cases of potential charge designs in terms of demand response cost reflectivity: a flat charge and a dynamic charge with a variable level. We assess the implications of the different charges for dispatch and investment decisions, and evaluate static and dynamic welfare losses, relative to a hypothetical, efficient energy-only market (EOM) without a charge.

We conclude that applying flat charges results in static welfare losses in hours with abundant supply, as the dispatch decision differs from the EOM (left plot in the figure, see PDF). Dynamic charges, applied only in hours of scarce supply, do not exhibit such static inefficiencies (right plot, see PDF). Meanwhile, during times of scarcity, dynamic charges apply higher amounts on top of energy market prices and, therefore, deliver a more efficient signal for demand reduction than flat charges. Consequently, maintaining the same reliability level under a flat charge requires more installed capacity than under a dynamic charge, increasing fixed capacity costs and lowering dynamic welfare.

Numerical model

The numerical model allows us to confirm and quantify these theoretical considerations. In the partial equilibrium model, agents optimize (brownfield) investment and dispatch decisions under perfect foresight. The model is solved using the alternating method of multipliers (ADMM), in which agents independently optimize investment and dispatch decisions, while prices in energy and capacity markets are iteratively updated to clear aggregate imbalances. We model four representative weeks in hourly resolution. The model is parametrized to loosely reflect the German electricity market in 2040. The required capacity market volume, the capacity market clearing price, and the respective charge level to recover capacity market cost are determined endogenously in the model.

The results indicate that more cost-reflective demand charges induce a substitution of demand response for capacity procured in the capacity market. This substitution reduces consumer costs under TOU and dynamic charges by about 200 million euros per year compared to a flat charge. Furthermore, demand increases when capacity is abundant, as no distortive charges are applied. This further increases consumer surplus and welfare. Moreover, we find that more cost-reflective charges reduce investment in thermal capacity, while increasing investment in wind and solar generators. For batteries, we observe ambiguous effects, which we interpret as the net effect of substitution by price-elastic demand response to more cost-reflective demand charges and complementarity with higher variable renewable energy penetration.

Finally, we discuss how key modelling assumptions and parameter choices affect the interpretation of our results, focusing on the perfect foresight assumption, the potential advantages of dynamic charges under uncertainty, and the use of historical demand elasticity estimates.

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Session Classification: European Market Integration & Capacity Renumeration

Contribution ID: **72** Type: **not specified**

The Battery Boom: Between Flexibility and Unpredictability for Grid System Operations. A Quantitative Foundation

Friday 27 March 2026 10:00 (20 minutes)

Batteries play a pivotal role in complementing electricity generation from renewable energy sources, especially photovoltaics. Currently, investors applied for grid connections of more than 500 GW in Germany alone. However, batteries can change their output on short notice. While this provides needed flexibility to the system, it makes system operations, in particular congestion management and related operational planning processes, more complicated.
The challenge for operational planning is that the processes preventing grid constraints take time: First, the TSO responsible needs to collect all data (i.e. planned nodal consumption and production). Second, the TSO needs to calculate resulting electricity flows and determine overloaded grid components. Third, redispatch measures to elevate these constraints need to be determined. Fourth, they need to be implemented: producers and/or consumers in various nodes need to react.
The full integration of European day-ahead and intraday markets through day-ahead and intraday auctions as well as continuous trading also enables more interplay between European energy systems to increase social welfare. At the same time this could lead to more changes in batteries' schedules between day-ahead auction and physical delivery, which makes it more difficult to implement them in a congestion management process without restricting the change of the batteries' schedule.
Our paper provides a quantitative analysis of battery schedule variations in the context of the fully integrated European power market. The analysis is based on a Rolling Horizon optimization model encompassing the four short-term electricity market auctions, starting with the day-ahead auction (at noon on the day before delivery) and ending with the third intraday auction (at 10 am on the day of delivery). The model dispatches a stylized battery system using auction prices from June 2024 to July 2025. By comparing the auction schedules with each other, we quantify differences in the battery operating state and filling level. We find that nearly 50 % of all quarter hours in the intraday auctions deviate from the day-ahead schedule. By investigating days with extreme deviations, typically occurring on weekends, our analysis reveals that renewable forecast errors are a key driver of price formation and consequently battery dispatch. (This demonstrates that batteries react to price signals inflicted by updates in the information space.)

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Session Classification: Power System Flexibility & Storage

Contribution ID: **74** Type: **not specified**

Overcoming Barriers to Photovoltaic Adoption: The Role of Regulation for Plug-In Solar from the Viewpoint of Tenants and Apartment Owner-Occupiers

Friday 27 March 2026 16:50 (20 minutes)

Residential photovoltaic (PV) adoption has increased substantially over the past couple of decades in many developed economies (e.g., REN21, 2024). However, not all population groups have benefited equally from this expansion. A key disparity lies in homeownership: until recently, PV adoption has been predominantly limited to homeowners. Tenants and residents of multi-unit buildings –despite showing interest –have had limited opportunities to access photovoltaics (Best, 2022; Gerber et al., 2025; Zander, 2020). This meant that large sections of the population were excluded from direct use of PV technologies. In the European Union, for instance, 46 percent of the population lives in apartments rather than houses, and 30 percent lives in rented accommodation Even in countries with high homeownership rates, the growing prevalence of multi-unit dwellings due to ongoing urbanization continues to constrain access to photovoltaics (Charters and Heffernan, 2021; Poshnath et al., 2023).

This study was motivated by the political debates in Germany during 2023 and 2024 surrounding the regulation of plug-in solar devices. These discussions led to several legislative changes and a rapid increase in plug-in solar adoption. The new regulations addressed not only the technical requirements for these systems but also reporting obligations to relevant authorities and the need for approval from landlords and homeowner associations (HOA). At the same time, the number of installations rose sharply –from 11,653 in 2021 to 77,251 in 2022, 265,556 in 2023, and 429,248 in 2024. These developments raised the question of whether all (proposed) regulatory changes are equally important in promoting access to PV adoption among tenants and apartment owner-occupiers, or whether some are considerably more influential than others. To explore this, we first analyzed online documents to trace how these regulatory changes evolved. Building on these insights, we designed a stated choice experiment to assess the relative importance of individual policy measures for the purchasing intentions of tenants and apartment owner-occupiers. Specifically, we address two main research questions:
• Which policy measures preceded the breakthrough of plug-in solar in Germany?
• How relevant are these measures in shaping the purchase intentions for plug-in solar devices?

The literature has examined the underlying causes of restricted PV access for tenants and apartment owner-occupiers. In many jurisdictions, tenants are legally prohibited from making structural modifications to rented properties without landlord approval (Dodd and Nelson, 2022). As a result, the installation of PV systems typically requires explicit landlord permission (Dodd and Nelson, 2022). Moreover, uncertainties related to tenancy duration can undermine the economic viability of such investments (Dodd and Nelson, 2022; Roberts et al., 2019). High upfront installation costs further compound these barriers (Best, 2022; McCarthy, 2024). Landlords, in turn, often lack motivation to invest in PV due to the split-incentive problem: while they bear the investment costs, it is the tenants who benefit from reduced electricity bills (Hammerle et al., 2023; Roberts et al., 2019). Apartment owner-occupiers face similar legal and structural constraints. In most countries, residential property law governs the rights and responsibilities of owners in multi-unit buildings. While individuals may hold private ownership of specific units, the building's structure, facade, roof, and shared spaces are typically under collective ownership (Poshnath et al., 2023; Roberts et al., 2019). Consequently, any alterations - such as installing PV systems –require formal approval by the HOA. Although approval thresholds vary across jurisdictions (e.g., unanimous, two-thirds, or simple majority), the collective decision-making process frequently constitutes a barrier to action (Poshnath et al., 2023). Diverging interests among different types of owners –

such as resident versus investor owners, or original versus subsequent purchasers –further complicate consensus-building. Low meeting participation, interpersonal conflicts, and general mistrust among neighbors can also hinder agreement (Charters and Heffernan, 2021; Zander, 2020). Even when consensus is reached, coordination challenges often persist due to differing perceptions of responsibility, time constraints, or lack of engagement (Charters and Heffernan, 2021; Poshnath et al., 2023).

Following recent stated choice experiment literature, we use mixed logit models, which are more flexible than previously used conditional logit models (Hensher and Greene, 2003). We consider pooled and split sample models, as well as models where we interact individual-specific characteristics of tenants and apartment owner-occupiers with the attributes.

We find that apartment owner-occupiers and tenants differ in their group-specific preferences for regulations regarding balcony solar PV systems. Owner-occupiers show stronger preferences for the amount of yearly remuneration that a balcony solar PV system would create, whereas tenants are more likely to opt out of the decision and choose no balcony solar PV system under any circumstances.

Furthermore, we find that preferences are shaped by beliefs about solar PV in general, for both owner-occupiers and tenants. E.g., Owner-occupiers see PV aesthetics as a deciding factor whereas tenants do not.

To our knowledge, this study is the first to analyze preferences for balcony solar PV system regulations. However, we see a need for further research into how engaged tenants and apartment owner-occupiers are with plug-in solar systems. Even though it is evident that the share of the total installed capacity will remain small, balcony solar systems might contribute to high levels of public support for the energy transition (Mildenberger et al., 2019).

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Session Classification: Decentralised Systems & Industries

Contribution ID: **75** Type: **not specified**

Coal Exit, Gas Expansion, and the Energy Trilemma: System Implications of German Energy Policy

Friday 27 March 2026 11:50 (20 minutes)

Motivation
The energy transition is being driven primarily by the electrification of mobility, heat supply and industrial processes. At the same time, the expansion of renewable energies (RE) is progressing in order to ensure a cheap and clean electricity supply. In Germany in particular, large conventional power plants will be taken off the grid or transferred to the capacity reserve by 2038 at the latest for political, ecological and economic reasons, for example in the course of the nuclear phase-out or the coal phase-out.

In order to guarantee security of supply at all times, the German government is therefore planning to add 20 GW (H2-ready) of gas-fired power plants by 2030 (Deutscher Bundestag, 2025). These are intended to replace the lost capacity and contribute to grid stability. At the same time, recent studies raise questions about the level and economic viability of additional capacity, the cost advantage of decentralized solutions and the implicit technological predetermination (Forum Ökologisch-Soziale Marktwirtschaft, 2025; Frontier Economics, 2025; Kienscherf et al., 2025; Roland Berger, 2025). The subsidies required for the implementation of the additional dispatchable capacities have also raised concerns under EU state aid law. In a basic agreement, the German government and the European Commission agreed on the approval of 12 GW of additional dispatchable capacity (Bundesmministerium für Wirtschaft und Energie, 2026).

This study therefore examines the implications of the current power plant strategy in terms of energy policy dimensions such as security of supply, affordability (especially energy poverty) and sustainability. Quantitative analyses are applied to conduct a comprehensive assessment in order to scientifically examine the central aspects of the political discourse.

Methods
Based on the Electricity Grid Development Plan 2037/2045 (2025) (NEP2024) (Übertragungsnetzbetreiber, 2025), this study analyses two key measures: the implementation of the coal phase-out in either 2030 or 2038 and the expansion of 20 GW of gas-fired power plants.

Various models are used for the quantitative assessment of the implications for the energy system. The analysis of security of supply is based on a probabilistic simulation model and meta-modelling using machine learning (Nolting et al., 2020; Nolting & Praktiknjo, 2020). The models assess security of supply on an hourly basis by calculating the probability that the power plant fleet will be able to cover the expected electricity load. In particular, uncertainties relating to the feed-in of renewable energies, power plant outages and imports are taken into account. Based on these simulations, changes in the two security of supply indicators, Loss of Load Expectation (LoLE) and Expected Energy not Served (EEnS), are analyzed.

The electricity market simulation is based on a fundamental model that determines prices from a merit order in economic dispatch, taking into account cross-border exchanges, seasonal commodity prices and weather uncertainty, through time-coupled optimization as a unit price (Priesmann et al., 2019). The results are hourly electricity prices for an annual horizon through power plant and storage dispatch that minimizes total costs.

The analyses of affordability for private households are based on a microsimulation using representative household data from the Federal Statistical Office of Germany and the results of the electricity market simulation. Realistic reactions to price and income changes are taken into account for different income groups (Priesmann & Praktiknjo, 2025). This enables a differentiated assessment of affordability across the income distribution.

The hourly emissions from electricity generation in Germany are quantified from the resulting hourly dispatch time series, the average efficiency of the various types of power plants and the corresponding emission factors. The emission factor used for the sustainability assessment is global warming potential.

Results
The results of the simulations show that accelerating the phase-out of coal by 2030 without adequate replacement by dispatchable capacities will significantly worsen the level of security of electricity supply in 2030. While the LoLE ranges from 2.1 up to 121.6 h/a, the EEnS reaches from 9.8 up to 1338.2 GWh/a.

End consumer prices for private households will remain at a moderate level at 55,7 EUR/MWh in average, even if scarcity prices occur. Energy poverty indices do not change significantly compared to the current situation. Furthermore, it remains difficult to assess the impact on energy costs and the associated international competitiveness of German industry. In addition to possible regulatory adjustments, the cost of electricity is increasingly linked to the underlying procurement strategies.

From a sustainability perspective, no major effects can be observed. As expected, the use of gas as an energy source instead of coal for electricity generation reduces emissions up to 20%. However, the effect remains moderate in terms of absolute emissions due to low full-load hours.

Due to the expected low full-load hours of thermal power plants, in addition to converting coal-fired power plants into capacity reserves, supplementing energy-only markets with capacity markets, for example, could facilitate a technology-neutral and cost-efficient implementation of the urgently needed capacity expansion. Nevertheless, the question of how to finance the regulatory instruments for mitigating undersupply risks remains open. Technology-specific subsidies, for example for gas-fired power plants, are effective but may be economically inefficient. Ultimately, various options such as capacity mechanisms or the demand more flexibilization in terms of scale and timing should be carefully weighed up and coordinated in order to minimize overall system costs.

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Session Classification: Energy Security & Crisis

Contribution ID: **76** Type: **not specified**

Dynamic Electric Vehicle Charging Tariffs: A Preference Analysis of German Consumers

Friday 27 March 2026 10:00 (20 minutes)

To meet the climate targets outlined in the Paris Climate Agreement, the participating nations have committed to reducing their CO2 emissions. While the share of renewable energy sources in electricity generation has increased dramatically over the last decade (International Energy Agency), the CO2 emissions from the road transport sector in the European Union (EU) have risen by approximately 21% since 1990 (Eurostat, 2024). To counteract this trend, comprehensive electrification of passenger car transport based on renewable energies is necessary. Currently, electric vehicles (EV) account for only 1.2% of the European car fleet (EEA, 2023). An enormous increase is needed here, which, on the other hand, also means a significant increase in electricity demand, and thus the amount of electricity that needs to be generated from renewable energies. An increased supply of electricity from renewable energy sources poses significant challenges for the electricity sector. The irregularity of electricity generation from renewable energy sources can lead to grid congestion and thus to grid instabilities. The growing adoption of EVs exacerbates this problem because simultaneous, unmanaged charging increases electricity consumption and puts additional pressure on the grid (Huang et al., 2021). One possible solution to this problem are smart charging concepts.
We analyze the preferences of consumers regarding dynamic tariffs when charging electric vehicles are examined in a large-scale discrete choice experiment with a high level of individualization in a representative sample of households in Germany. Specifically, this paper addresses a type of dynamic tariff which is situated between time-of-use tariffing and real-time tariffing, meaning that it is potentially flexible to a degree which is exceeding what is found in practice, while still being less flexible than complete real-time tariffing. With a representative sample of 7,150 participants, the findings will offer information about how consumers judge various attributes of dynamic tariffs of electric vehicles. Our main findings reveal that customers, on average, display a preference for dynamic EV tariffs over a static fixed-price tariff. This result contradicts some of the existing findings
that potential increasing costs and an active user role during charging lead to low acceptance of dynamic electricity tariffs. We find that our respondents show stronger preferences against additional costs, which indicates that customers are rather risk-averse. These two emphases
imply that customers are driven by risk-aversion when choosing among dynamic tariffs for EV charging. In addition to risk considerations, it was observed that the respondents also demonstrate preferences related to other attributes of dynamic tariffs. Notably, respondents show preferences for tariffs with fewer zones of low/high prices within a day. This reflects that complexity plays an important role in tariffs. Preferences related to the timing of low- and high-price zones suggests that the respondents have no clear preferences for when prices are high, but show clear preferences for low prices during midday. This result suggests
that the advanced communication of prices plays a central role in consumer acceptance of dynamic EV charging tariffs. The heterogeneity analysis also shows that there is a large degree of variation in preferences among different respondent characteristics. Of particular note is the fact that non-adopters or future adopters of EVs have a strong preference for dynamic tariffs in comparison to adopters of EVs. This is an important implication regarding the potential for dynamic tariffs to influence expectations and behavior related to charging in the still early stages
of EV diffusion. A further implication is that respondents with high annual mileage show strong

preferences against the risk of additional costs, which may reflect a higher probability of exposure to charging costs and a greater demand for cost predictability. There are also a number of socio-demographic and attitudinal factors that play a significant part in preference heterogeneity, including age, gender, patience, institutional trust, and political beliefs. A number of implications arise from these findings. Firstly, the existence of strong
preferences against possible additional costs indicates that the adoption of dynamic tariffs by consumers in relation to charging their electric vehicles will be significantly dependent on managing risks. Regulators could propose strategies involving the promotion of tariffs with inherent risks managed through maximum possible price caps, or ceiling rates for possible additional costs. Second, the general preferences against a higher number of daily price changes suggests that tariff complexity needs to be handled cautiously. This is because, although lower pricing complexity could enhance efficiency at an organizational level, it might have a negative effect on consumer acceptance. Third, the observation that both non-EV owners and prospective EV buyers display a strong attitude towards dynamic tariffs implies that the availability of dynamic tariffs and the communication of their benefits and risks might be a future driver for EV adoption. Fourth, the presence of heterogeneity in preferences means that differentiated policies to promote the adoption of dynamic EV charging tariffs might be needed. High-mileage car users may have a higher willingness to pay when given additional support options that could shield them from peak periods with higher prices, for example by periodically opting out of very high prices. In more general terms, tailored communication strategies should be employed to reflect heterogeneity with respect to risk concern.
In conclusion, our the results of our study indicate that dynamic EV charging tariffs have the potential to be widely adopted by consumers, given that the potential risks are minimized and clearly communicated.

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Session Classification: Consumer Behavior & Tariffs

Contribution ID: **77** Type: **not specified**

From Energy System Pathways to Spent Fuel Inventories: Scenario-Based Assessment of High-Level Radioactive Waste and Disposal Capacity

Friday 27 March 2026 16:50 (20 minutes)

Abstract

Worldwide, nuclear power remains part of national energy strategies in the context of climate policy, energy security, and decarbonization debates. Expansion plans are often linked to the low-carbon nature of nuclear electricity production, and discussions focus on energy system costs and the integration of nuclear-renewable energy systems for long-term decarbonization (Göke, Wimmers, and Von Hirschhausen 2025). Thereby, however, the challenges of the nuclear back-end, i.e., decommissioning of closed nuclear power plants, and nuclear waste management, are often neglected (Wimmers et al. 2024).

Nuclear power plants generate different types of radioactive waste in different stages of their lifetime (Besnard et al. 2019). During their operations, primarily in the form of spent nuclear fuel, whose final disposal remains unresolved in most countries. Although deep geological repositories for high-level radioactive waste are under development in a small number of cases, only Finland has reached the stage of trial emplacement, while other projects remain decades away from operation. Existing repository concepts are generally designed for current reactor fleets, raising questions about their adequacy under extended operating lifetimes or additional waste generation (Ahlswede, Graefje, and Schopmans 2026).

A central challenge is that future volumes of spent nuclear fuel are directly determined by long-term energy system pathways, yet internationally comparable and harmonized data on high-level radioactive waste inventories are scarce and fragmented. Despite reporting obligations under the Joint Convention on the Safety of Spent Fuel Management and on the Safety of Radioactive Waste Management, no comprehensive and up-to-date database that allows for a systematic assessment across countries exists (Böse et al. 2025). Future waste volumes are further characterized by uncertainty because currently envisioned expansion plans and lifetime extensions of light-water reactors and the potential emergence of non-light water reactor concepts or small modular reactors are subject to high degrees of uncertainty themselves (Ramana 2021; Rothwell 2022).

This paper aims to investigate the implications of continued operations of current reactors and envisioned fleet expansions on the development of waste volumes and, therefore, the implications on current and planned waste repository projects. Initially, we limit the assessment to high-level waste, i.e., spent nuclear fuel. It begins with a compilation of a harmonized database on high-level radioactive waste inventories based on national reports submitted under the Joint Convention. Building on this database, an initial scenario-based analysis is conducted to estimate future spent fuel volumes in selected European countries, by drawing on results from energy system modelling (Barani et al. 2026) and methods proposed by the IAEA (2008). The analysis aims to assess whether currently planned or envisaged disposal capacities appear consistent with projected waste generation under various long-term nuclear energy pathways. By highlighting the scale of high-level radioactive waste generation and the uncertainties surrounding disposal capacity, this work contributes to a more transparent assessment of an unresolved and often underreported challenge in nuclear energy policy.

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Session Classification: Carbon Removal & Transition Pathways

Contribution ID: **78** Type: **not specified**

Flexibility potentials in low temperature heating grids –exploring business models under current regulations

Friday 27 March 2026 10:40 (20 minutes)

Introduction
Grid expansion is one major cost item in the ongoing energy transition as the electrification of the heating and mobility sector as well as the feed-in of variable renewables into the grid leads to much higher peak loads. Grid friendly electricity exchange on the district level helps to stabilize the overall energy system and reduce this necessary grid expansion. But to stimulate grid friendly behaviour there needs to be an incentivation or at least cost neutrality for the electricity consumers and producers. Low temperature heating grids offer flexibility potential on the district level with heat pumps, thermal storages, photovoltaic systems as well as batteries in a sector coupled energy system. This study explores different business models for district energy systems including low temperature heating grids and compares the results in three different case studies to gain insights how to operate the systems grid friendly by at the same time lowering acquisition costs for electricity.
The three case studies are (1) the Glückaufpark district in Gelsenkirchen, featuring single-family homes (SFH) and multi-family homes (MFH) supplied by a cold distribution network (2 - 15℃) and decentralized heat pumps; (2) Seestadt district in Mönchengladbach, a residential neighborhood composed solely of MFH with a low-temperature distribution network (39℃) utilizing central sewage water, central ground source heat pumps, and gas boilers for peak load; (3) the Shamrockpark district in Herne, which is characterized by a mixed area with a significant proportion of commercial buildings and multi-storey apartments utilizing a low-temperature grid (22℃) that incorporates low temperature industrial and internal waste heat sources used by decentral heat pumps, a small combined heat and power (CHP) unit, and a connection to district heating.
We analyze six different business models to increase the flexibility of electricity exchange: (1) Optimization of self-consumption, (2) dynamic electricity prices, (3) heat pump electricity tariff, (4) grid-oriented control (ENWG §14a), (5) peak load reduction and (6) provision of balancing energy and compare in which of the different districts it is possible to increase economic efficiency with these measures.

Methods
This study employs the KomMod optimization tool, a bottom-up techno-economic model for local energy systems that enables sector-coupled representation. Input data encompass cost data, demands for space heating, hot water, and electricity, alongside the available potential of renewable energy sources such as solar and geothermal energy or waste heat. The model is formulated as a linear programming optimization problem with the target of minimizing total energy system costs using full-year operation profiles at an hourly resolution and performing calculations based on energy balances.

Results
In the two residential districts Hassel and Seestadt dynamic pricing schemes are not economically viable as electricity consumption is high in times of high electricity prices and the load shifting potential is low. In the mixed district of Shamrockpark overall energy system costs can be decreased by switching to a dynamic tariff scheme.
Peak loads can be reduced in Seestadt and Hassel, but without reducing overall system costs which means that there are no real incentives to do so. Grid oriented control is regulated under the Energy Industry Act (ENWG §14a). Since January 1, 2024, new controllable consumption devices (heat pumps, wall boxes, storage units) must be controllable grid oriented. In return, operators benefit from reduced grid fees, either through a flat rate (Module 1) or a percentage reduction

(Module 2). In Hassel significant storage capacities are required to use a heat pump electricity tariff or grid-oriented control in accordance with EnWG14a. In some cases, decentralized heat pumps must be larger in order to bridge the blocking period/control interventions. However, slight savings (up to 2% of the total energy system) can be achieved by taking into account the thermal inertia of the newly constructed buildings. In Seestadt it results in higher investment costs for the system. Particularly in variants with cooling provision, larger dimensions of the cooling machines are required, which entails additional investment. The highest cost reduction in all districts can be achieved with the provision of balancing energy, in Seestadtut it is even the only business model that can decrease costs at all.

Conclusions
In the three case studies the decrease of costs of the different flexibility business models is rather small and a simple optimization of self consumption of PV electricity shows higher cost optimization potentials. Especially in districts with a standard residential load profile with high electrcity consumption in the morning and evening hours a dynamic electricity price leads to higher costs. In addition, the use of dynamic electricity tariffs competes with self-generation, as electricity prices are typically low during periods of high self-generation. In such cases, self-generation is preferred, which means that electricity is mainly imported during periods of higher electricity prices. As long as dynamic tariffs are not cheaper on average than static tariffs, the district hardly benefits from their use. Making prices more dynamic makes investments in flexibility (e.g., battery storage) more attractive. This is the case when dynamic electricity prices are combined with variable grid fees. However, variable grid fees are currently only available for controllable consumption facilities and in combination with control measures by grid operators.
Therefore economic incentives must be higher to stimulate grid friendly behaviour on the district level.

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Session Classification: Power System Flexibility & Storage

Contribution ID: **79** Type: **not specified**

Generation and Transmission Expansion under Aspects of Cooperation: Insights from Offshore Wind Integration in Baltic Region

Friday 27 March 2026 10:20 (20 minutes)

INTRODUCTION AND MOTIVATION
The rapid expansion of offshore wind generation and the growing need for cross-border electricity exchange in Europe have intensified interest in integrated offshore grids—shared infrastructures that combine wind power collection with interconnection capacity. The Baltic Sea, with its shallow waters, favorable wind conditions, and central location, stands out as one of the most promising regions for large-scale integrated offshore wind development. This research work investigates the techno-economic and market coordination challenges of developing such hybrid interconnectors in the Baltic Sea region through optimization and equilibrium modeling.
The framework considers Germany (DE), Denmark (DK), and Sweden (SE) connected through both onshore and offshore hybrid interconnectors. Despite the promising potential of integrated offshore grids, a key challenge lies in aligning the incentives of multiple national stakeholders who differ in their cost structures, regulatory environments, and welfare outcomes. This asymmetry gives rise to coordination failures and underinvestment, as rational players may refrain from committing to shared infrastructure if the distribution of benefits is perceived as unfair or uncertain. To mitigate welfare asymmetry, incentive mechanisms are proposed that redistribute the congestion rents generated by interconnectors. The research includes Financial Transmission Rights (FTRs) as an instrument to hedge against unfavorable welfare differences while modeling the investment behavior of market zones in hybrid interconnector projects.
METHODOLOGY
This research work addresses market integration challenges caused by hybrid projects by proposing and evaluating four market designs to ensure net revenue neutrality and/or overall social welfare gains within integrated offshore projects:
(i) In the base case, a single decision-maker determines investment and dispatch decisions so as to maximize overall social welfare (fully centralized decision-making).
(ii) As the second market design scenario, the research work formulates a novel Cournot competition market model where each market zone acts as a strategic player (fully decentralized decision-making). Two further variations of the decentralized equilibrium scenario are developed by introducing cooperation and mutual incentive mechanisms in decentralized decision-making.
(iii) Explicit allocation of Financial Transmission Rights (FTRs) to participants negatively affected by market coupling.
(iv) Market-based trading of FTRs among all stakeholders.
Both FTR-based approaches provide financial instruments that enable participants to hedge against congestion-related redistributions, thereby improving investment incentives and promoting equitable cost-sharing.

RESULTS
Results are first analyzed for 2023 to identify key patterns across scenarios. The analysis is then extended to 2030, reflecting higher demand and greater renewable penetration in each market zone to provide a forward-looking perspective. Scenarios with and without Sweden as an additional low-price, highly renewable market zone are considered to assess its impact on market behavior, investment coordination, and welfare outcomes. Overall, four market designs combined with two years (2023 and 2030) and two participant configurations (with and without Sweden) yield 16 scenarios for evaluating the proposed methods.
The comparative analysis suggests that the proposed implementations in the FTR Trade and Explicit FTR Allocation scenarios increase the participation (investment) of market zones in shared

offshore infrastructure. The comparative analysis of the scenarios is highlighted below:
1. While the optimal outcome in the base centralized scenario is assumed to be not achievable in reality, this remains the reference for globally optimal allocation, achieving the highest price convergence across all scenarios.
2. Equilibrium without FTR compensation (decentralized decision-making) results in overinvestment and less effective price convergence.
3. Explicit FTR allocation overcompensates, leading to excessive investment but slightly lower efficiency.
4. Market-based FTR trading achieves the best balance between price convergence, net revenue neutrality, and investment efficiency.
5. The inclusion of Sweden stabilizes market outcomes and increases total welfare, but at the cost of increased heterogeneous investment by market participants.
Combining the flow, welfare, and investment analyses indicates that economic coordination and shared investment planning can promote alignment among market zones only under relatively balanced price conditions. When price differentials are large, cooperative investments tend to exacerbate disparities rather than resolve them. The proposed mechanisms targeting revenue neutrality through FTR trading effectively compress welfare disparities but shift investment burdens toward selected participants, highlighting a key trade-off in cooperative offshore grid development. This observation underscores the importance of market design measures that reduce initial price divergence—through improved congestion management and enhanced intra-zonal interconnection capacity—before expecting shared infrastructure mechanisms to yield equitable outcomes.
Overall, coordinated planning of offshore hybrid interconnectors can deliver significant welfare gains, but without mechanisms to balance cost and benefit distribution, investment incentives remain uneven and coordination falters. The adoption of financial instruments such as FTRs offers a promising means of enabling decentralized yet equitable participation in cross-border energy infrastructure. These findings, when combined with a detailed representation of uncertainty and strategic behavior (market power), could support the design of regulatory frameworks that balance economic efficiency with political feasibility in Europe's evolving offshore energy landscape.

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Session Classification: European Market Integration & Capacity Renumeration

Contribution ID: **80** Type: **not specified**

Too cheap to meter? A stochastic analysis of the future costs of fusion power plants

Friday 27 March 2026 14:30 (20 minutes)

In recent years, the prospects of using nuclear fusion for decarbonized energy generation have garnered increasing attention, both in academia and in media (Wimmers et al. 2025), despite the lack of actual technological developments towards functioning power plants since the beginning of fusion research more than 70 years ago (Dering et al. 2026). Regardless, fusion is being considered in an increasing number of long-term energy strategies (IAEA 2025) and in energy scenarions (Spitzer et al. 2025). These scenarios depend on assumptions of technology availability and, most importantly, future costs. However, given the fact that fusion power plants do not exist today, these costs are based on assumptions and projections that assume costs comparable to today's high-capacity light-water fission reactors or cheaper (Meschini et al. 2023). Because costs of fission reactors are systematically underestimated in energy scenarios (Göke et al. 2025), it can be assumed that cost projections for fusion are equally optimistic. Based on this assumption, we provide an in-depth analysis of the potential future costs of nuclear fusion to determine whether current and past cost projections are, from today's perspective of the non-existance of commercial fusion reactors, comparable to other (existing) energy generation technologies, like renewables. For this, we analyze 56 studies on nuclear fusion that contain 590 cost data entries. The cost data are divided depending on the underlying reactor type and assumed stage of maturity (first-of-a-kind vs. n-th-of-a-kind), and despriptevly analyzed. Based on the collected data, we conduct a stochastic analysis based on a Monte Carlo approach to determine potential levelized costs of electricity (LCOE) for three distinct fusion reactor types, i.e., inertial (ICF), magnetic (MCF) and magneto-inertial (MIF) confinement fusion. Stochastic variables are overnight construction costs and fixed operation and maintenance cost that are distributed according to the obtained literature values. Initial results show n-th-of-a-kind cost assumptions ranging from 96 to 110 USD/MWh, around 145 USD/MWh and approximately 111 USD/MWh for ICF, MIF, and MCF concepts, respectively. These results (see Figure 1) show that even optimistic assumptions of cost reductions via learning lead to LCOE being more expensive than today's existing technologies; placing doubts on whether fusion reactors will become commercial competitors in future electricity markets. We plan on conducting sensivitiy analyses on the model, e.g., by varying input parameters such as capacity factors and discount rates, that further influence LCOE calculations.

Figure 1: Probability density functions of simulated LCOE estimates [2018 USD/MWh] for fusion power plants by confinement type and technological maturity level.

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Session Classification: Nuclear, Fusion & Sociotechnical Futures

Contribution ID: **81** Type: **not specified**

Navigating Uncertainty: Renewable Bidding and Price Premia in Sequential Electricity Markets

Friday 27 March 2026 14:50 (20 minutes)

Sequential wholesale electricity markets are designed to enhance allocative efficiency by allowing market participants to adjust positions as information unfolds over time. In theory, prices across these sequential stages, e.g., the Day-Ahead and Intraday markets, should converge in expectation. Empirically, however, systematic price premia persist, and in high-renewable systems such as Germany these premia exhibit a pronounced and highly regular diurnal pattern. Existing explanations emphasize market power, liquidity frictions, or aggregate risk aversion, but largely abstract from heterogeneous bidding behavior of renewable producers under uncertainty. In particular, they remain silent on why price premia change sign over the course of the day.

This paper develops a micro-founded analytical framework that links renewable producers'bidding rationales to expected price premia between the Day-Ahead and Intraday markets in a perfectly competitive setting. I model a simplified two-stage market with inelastic demand and a strictly convex marginal cost curve, in which renewable producers choose Day-Ahead positions under three alternative bidding rationales: bidding expected production, risk-neutral profit maximization, and risk-averse bidding that accounts for tail risk arising from asymmetric price responses to forecast errors. Closed-form expressions are derived for optimal bids and the resulting expected price premia. The framework is extended to allow for heterogeneous bidding behavior across renewable technologies. The model is parameterized using German market data from 2024–2025, including hourly demand and renewable forecasts, forecast uncertainty, and empirically derived measures of hourly supply curve convexity based on transformed Day-Ahead bid curves.

The results show that risk-neutral bidding implies price convergence in expectation, while bidding expected production generates systematically negative premia that increase with forecast uncertainty and supply curve convexity. Risk-averse bidding, by contrast, induces positive premia in hours characterized by high convexity and uncertainty. When allowing for heterogeneous bidding rationales across technologies—specifically, photovoltaic producers bidding expected production and wind producers bidding risk-aversely—the model reproduces the full diurnal structure observed in German market data: negative premia around midday and positive premia during morning and evening hours. These findings suggest that technology-specific risk exposure and bidding behavior of renewable producers constitute a key structural driver of systematic price premia in sequential electricity markets.

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Session Classification: Renewables & Risks

Contribution ID: **82** Type: **not specified**

Unlocking Hidden Grid Capacity: Risk-Based Line Overloading for Cost-Effective Congestion Management

Friday 27 March 2026 11:30 (20 minutes)

Germany's power system is undergoing a rapid transformation driven by the large-scale expansion of renewable energy sources, particularly wind and solar power, as part of its decarbonization strategy. While generation capacity has grown substantially over the past decades, the expansion of the electricity transmission network has lagged due to lengthy planning and permitting processes. Consequently, market data reveal increasing network congestion, rising redispatch volumes, and growing congestion management costs, raising concerns about the economic efficiency of current grid operation practices. Beyond long-term grid reinforcement and expansion, identifying short- to medium-term strategies that utilize existing transmission capacities more efficiently is therefore of high importance.

In Germany, transmission line ratings are typically defined based on conservative ambient conditions that rarely occur throughout the year. Empirical evidence suggests significantly higher admissible power flows than those implied by static ratings. For instance, German grid development guidelines indicate a technically feasible increase in line capacity of up to 150% under typical weather conditions. Dynamic Line Rating (DLR) exploits this weather dependency by adjusting admissible line capacities in real time based on temperature, wind speed, wind direction, and solar radiation, enabling higher utilization of existing transmission assets. Although several European transmission system operators (TSOs) have introduced seasonally or event-based adjusted ratings for selected lines, a systematic framework for identifying suitable line candidates and for evaluating the techno-economic benefits remains largely underexplored.

Building on DLR principles, this paper investigates systematic transmission line overloading as a risk-based congestion management strategy for the German transmission network. We develop a system-theoretic modeling framework that replaces deterministic line-flow limits with probabilistic constraints via chance-constrained programming. This approach allows line limits to be relaxed within a predefined range and with a controllable probability, explicitly balancing economic benefits with operational risk.

Using the European transmission grid model ELMOD, we quantify the marginal economic benefits and risks of systematic line overloading across different renewable penetration levels and security thresholds, focusing on Germany for 2017, 2023, and 2030. Furthermore, we assess three approaches for pre-selecting candidate lines for overloading: historically identified Critical Network Elements by German TSOs, lines most frequently congested before redispatch, and lines with the highest marginal congestion management cost values.

The results indicate substantial potential for reducing congestion management volumes and costs. However, the marginal effect of grid overloading is found to be exponentially decreasing with increasing probability levels. Overall, the findings highlight the importance of dynamic and more flexible grid operation strategies for effective congestion mitigation, as risk-aware, flexible line rating strategies can meaningfully enhance short-term operational efficiency in high-renewable power systems. The developed system-theoretic framework provides a foundation for systematically integrating probabilistic line ratings into operational planning and offers valuable insights for TSOs and researchers seeking to harmonize competing demands of grid reliability and economic efficiency.

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Session Classification: Scarcity & Reliability

Contribution ID: **83** Type: **not specified**

How does the cost of capital affect oil supply?

Friday 27 March 2026 12:10 (20 minutes)

In the past decade, a rapidly growing number of investors have divested from the oil-producing industry. The financial approach to the climate problem—e.g., the burgeoning green finance taxonomies—hopes that such divestment will contribute to aligning the industry's incentives with climate policy targets by increasing targeted firms'cost of financial capital. We ask how an augmented cost of capital might affect oil supply and equilibrium production. On the one hand, the cost of capital should reduce oil projects'net present value, inducing projects'abandonment. On the other hand, it makes the industry more short-termist, advancing projects to generate revenues earlier. We develop a model of oil supply in which the industry's cost of financial capital—isolated from the cost of physical capital—affects drilling decisions and oil production. The model is calibrated using data covering all US oil assets and used to simulate the dynamic competitive equilibrium under various counterfactual policy scenarios for the period 2000-2030, including carbon pricing and "green finance,"modeled as an augmented cost of financial capital. Our results suggest that increasing the cost of capital by up to a few percentage points is counterproductive in the short run, because it encourages industry short-termism. Green finance becomes effective at deterring oil production only over longer horizons or under greater capital penalties. Yet the returns that financial markets would need to forgo to replicate the effect of a $100 carbon price are unrealistically high.

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Session Classification: Energy Security & Crisis

Contribution ID: **84** Type: **not specified**

Local Market Power Through Bidding Zone Split: An Equilibrium Analysis for the German Electricity Marke

Friday 27 March 2026 14:30 (20 minutes)

Germany currently operates as a single Bidding Zone (BZ), maintaining a uniform market price regardless of regional disparities in production and consumption. This configuration faces increasing challenges: structural imbalances between wind generation in the North and load centers in the South lead to severe grid bottlenecks. Managing this internal congestion required redispatch (RD) measures costing approximately €2.9 billion in 2023. Consequently, the Agency for the Cooperation of Energy Regulators (ACER) has proposed reconfiguring the German BZ into smaller segments to improve price signals and grid stability. However, a critical side effect remains under-discussed: the potential for increased local market power. The fragmentation of the national market risks reducing liquidity and competition. The proposed zone boundaries exhibit structural similarities to historical area monopolies. While unbundling separated network operations from generation, it did not mandate the spatial unbundling of assets; thus, the capacities of major incumbents remain concentrated within their former territories. Currently, the four largest generation companies (RWE, EnBW, LEAG, and Uniper) hold over 54% of Germany's capacity. A BZ split could isolate these fleets in smaller markets with less competition, potentially restoring their ability to exercise market power and causing welfare losses that outweigh efficiency gains.

This study closes a research gap by moving beyond the "perfect competition" assumptions prevalent in existing BZ literature. We develop a Cournot-Fringe competition equilibrium, modeled as a Quadratic Constraint Problem (QCP), following Egging-Bratseth et.al. (2020), which allows to capture the interaction between regulated constraints and strategic behavior. The six largest generation companies are strategic Cournot players, while smaller units and RES act as a price-taking fringe. To rigorously capture network constraints, the methodology integrates Flow-Based Market Coupling (FBMC) constraints derived from a detailed physical network model based on Joint Allocation Office (JAO) grid data. This approach allows for the endogenous determination of market outcomes under realistic loop flows, contrasting with simplified net transport capacity (NTC) assumptions. For generation capacities in Germany, we use the BNetzA Powerplant list, the Marktstammdatenregister and collect announced project, which are relevant for the target year 2030. For the generation fleet outside of Germany, we use the TYNDP 2024 National Trend scenario. Similarly, the demand assumption is taken from the latter scenario. For robustness, we conduct the analysis for the weather years 1995, 2008 and 2009.

Calibrated for 2030, this study quantifies the interplay between grid congestion and strategic market power. By deploying a Cournot-Fringe competition as a QCP with FBMC constraints, it departs from simplified NTC and perfect-competition models. The analysis provides a detailed estimation of welfare effects, highlighting whether the proposed ACER configurations introduce significant regulatory risks. Preliminary results suggest that the potential for exercising local market power is particularly pronounced in the 3 and 4-zone configurations.

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Session Classification: Market Design & Bidding Zones

Contribution ID: **85** Type: **not specified**

The value of e-mobility flexibility for aggregators – Portfolio management and contract design based on price and quantity uncertainty

Friday 27 March 2026 10:20 (20 minutes)

Motivation: Electric vehicles (EVs) are crucial for providing flexibility in future electricity systems, complementing renewable power generation. However, aggregators face economic obstacles in tapping into this flexibility potential. The lack of EV user-centered contract design hinders the widespread adoption of EV-based flexibility, leading to missed opportunities for reducing greenhouse gas emissions. Therefore, it is essential to investigate the impact of different contract design specifications on the financial performance of EV aggregators. By assessing different contract specifications, we can identify promising combinations that may promote the adoption of EVs and thus support the transition towards a low-carbon economy. However, uncertainties with electricity market developments and the uncertainties associated with EV mobility behavior make it challenging to value the EV user's flexibility for the electricity system. Therefore, this study aims to provide a comprehensive understanding of the relationships between contract design, flexibility valuation, aggregator financial performance, and end-consumer behavior. We provide a framework that can be used to evaluate operational decision making of EV aggregators, implications on contract design including pricing strategies.

Methodology: This work addresses the research gap by extending the commonly used Least Square Monte Carlo approach that is considered to assess the effects of marginal decisions under uncertainty. We will investigate the impact of various contract design specifications, such as minimum battery filling levels and fast recharge options, on the financial performance of EV aggregators. As novelty, our methodology will not only account for the uncertainties associated with electricity price uncertainty but is extended to cover the EV users'mobility behavior including arrival and departure times. We will use historical data on the continuous intraday electricity market and EV mobility behavior derived from the Mobilität in Deutschland 2023 study. Applying a short-term forecast model to obtain probabilistic price trajectories, the simulation model will be used to simulate the preferrable decision making of the aggregator to maximize the profit. The financial performance of the aggregator for exemplary weeks is used to derive implications on contract design.

Expected results: The study provides insights storage valuation and EV flexibility contract design. We also expect to find that the financial impact of contract design specifications, specifically guaranteed filling levels at preferred departure times in the morning, as well as (lower) minimum filling levels during nighttime, vary depending on short-term electricity price patterns on the continuous spot market, as well as the mobility behavior of the EV users. Whereas forecasted high electricity price volatility is preferential for the aggregator, longer plug-in times of the EV users only provide a decreasing marginal benefit.

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Session Classification: Power System Flexibility & Storage

Contribution ID: **86** Type: **not specified**

Electricity Market Coupling in Europe: Price Effects of Flow-Based Market Coupling Extension

Friday 27 March 2026 10:40 (20 minutes)

The European electricity market has made significant progress in liberalization and regional integration. These efforts aim to reduce costs, improve grid efficiency, and support decarbonization. One of the key tools in achieving these goals is Flow-Based Market Coupling (FBMC). FBMC replaces the older Net Transfer Capacity (NTC) method by using real-time physical grid constraints, rather than fixed capacity values, to manage cross-border electricity flows.
FBMC was first implemented in 2015 in the Central Western Europe (CWE) region, which includes Germany, France, Belgium, the Netherlands, and Luxembourg. In June 2022, the system was extended to 13 countries in Central Eastern Europe, creating the CORE Capacity Calculation Region (CORE CCR). This expansion is intended to enhance market efficiency by improving how cross-border capacity is allocated. It also supports greater price alignment across countries and encourages the use of renewable energy sources.
While the move to FBMC comes with numerous advantages, a few challenges have been posed by this transition. Policymakers and market operators support FBMC for its efficiency improvement potential (Schittekatte et al., 2020). The evidence is mixed from the expansion of the CORE region. For instance, Zachmann et al. (2022) demonstrate that price divergences in Eastern Europe, particularly in Poland, Hungary, and Slovakia, have either persisted or intensified since the FBMC rollout. This contradicts the theoretical expectations of harmonization.
This study aims to assess whether the extension of FBMC has achieved its intended effects over the CORE region- specifically in terms of electricity prices and market integration. Price impact evaluation is critical, especially in the context of the ongoing debate on the electricity market desin and further market integration.

By incorporating post-expansion data from CWE to the CORE-Region, thistudy contributes new insights into the impact of FBMC on electricity prices and market integration. The study also uses high-frequency, hourly electricity price data to capture short-term price movements and congestion patterns, which are often missed in studies relying on daily or monthly averages (e.g., Corona, Mochón, and Sáez, 2022). In addition, it moves beyond the conventional focus on price convergence by estimating the causal effects of the CORE CCR expansion on absolute price levels and market value. Methodologically, the study applies both Regression Discontinuity (RD) and Difference-in-Differences (DiD) approaches to identify causal impacts. This dual strategy addresses endogeneity concerns and strengthens the reliability of the findings, improving on earlier studies that rely on a single method (e.g., Felten et al., 2021).

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Session Classification: European Market Integration & Capacity Renumeration

Contribution ID: **88** Type: **not specified**

Industrial hydrogen demand and decentralized supply in North Rhine-Westphalia (NRW): a cluster-based spatial scenario analysis towards net-zero production by 2045

Friday 27 March 2026 10:40 (20 minutes)

Motivation: Renewable hydrogen is considered essential for reducing GHG emissions in the industrial sector to achieve net-zero energy systems by 2045. Previous studies on assessing prospective hydrogen demand for industrial production lack high spatial resolution and detailed differentiation of industrial processes.

Methodology: This paper addresses that gap by integrating a georeferenced site-level database with scenario-based modelling to estimate hydrogen demand in industrial clusters in North Rhine-Westphalia (NRW), Germany. Three scenarios are developed to account for uncertainties in production, efficiency, and technology adoption.

Results: The results indicate that hydrogen demand in NRW could rise from 16.5 TWh/a today to 142 TWh/a by 2045, under an upper-bound full-substitution scenario assuming 2018 activity levels, with over 90 % concentrated in four industrial clusters dominated by chemicals and steel production. Centralized supply options, such as pipelines or imports, would be required to meet this growth, while decentralized hydrogen provision is not possible to suffice under current renewable expansion plans despite its potential ecological and economic benefits. Consequently, a regional supply gap of up to 208 TWh emerges, indicating the need for both electricity and hydrogen imports assuming constant industrial production levels. The study highlights the importance of integrating additional policy strategies, including resource efficiency, material demand reduction, and multi-level infrastructure planning. These could complement targeted imports and accelerated permitting processes to ensure sustainable production and industrial value creation in NRW by 2045.

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Session Classification: Hydrogen Markets & Infrastructures

Contribution ID: **90** Type: **not specified**

Hospital Microgrids under Mini-Grid Regulation: A HOMER-Tariff Modelling Approach. The application to Riverpark Estate and the Margaret Lawrence University Teaching Hospital

Friday 27 March 2026 17:10 (20 minutes)

Nigeria's power sector is characterised by chronic under-supply, frequent outages, and a widespread reliance on diesel-based backup systems (Adoghe et al. 2023). For hospitals, grid connection alone rarely ensures security of supply; instead, resilience is typically achieved through redundant local generation, often associated with high life-cycle costs, fuel-price volatility, emissions, and governance risks (Babajide and Brito 2021). This paper examines the peri-urban case of the Margaret Lawrence University Teaching Hospital (MLUTH), located within Riverpark Estate in Abuja, Nigeria. Clinical operations at MLUTH require uninterrupted electricity but are currently dependent on an unreliable distribution grid and substantial generator usage amid rising diesel prices. In contrast to conventional microgrid and hospital energy studies, which primarily focus on least-cost system sizing or reporting levelized costs in isolation, this study takes a different approach (Odetoye et al. 2023). It systematically integrates technical system design with regulatory and financial modelling to assess feasibility under real-world constraints. Specifically, it couples HOMER-based microgrid simulation with the cost-of-service tariff framework developed and implemented by the Nigerian Electricity Regulatory Commission (NERC) and the African Forum for Utility Regulators (AFUR), enabling an integrated evaluation of resilience strategies under binding regulatory constraints (Nigerian Electricity Regulatory Commission 2024).

Based on on-site data collection, hourly load profiles for both the hospital and the estate are reconstructed. A grid-tied, under-grid hybrid PV–battery–diesel microgrid is modelled, with critical hospital loads prioritized during islanded operation. System outputs—such as installed capacities, energy balances, fuel consumption, and life-cycle costs—are subsequently transferred into the AFUR tariff framework to derive cost-reflective end-user tariffs (NGN/kWh) and financial indicators including LCOE, NPV, and IRR, in line with current mini-grid regulation (Nigerian Electricity Regulatory Commission 2023).

The analysis considers three configurations, each representing a distinct governance and risk-allocation model currently relevant in Nigeria's mini-grid sector. These are modelled as standalone 20-year scenarios to allow direct comparison: (i) an operator-led IPP supplying MLUTH under a long-term power purchase agreement (PPA); (ii) an SPV-led structure that supplies the hospital continuously while serving the estate only during grid outages; and (iii) a collaborative SPV model providing full-time supply to both the hospital and the estate, with defined responsibilities across the developer, the community, and the distribution utility (Sachiko Graber, et al. 2019).

A sensitivity analysis assesses how financing conditions, especially the weighted average cost of capital (WACC) and capital support mechanisms, affect reliability outcomes and tariff viability. The results show that integrating PV and battery storage can substantially reduce diesel reliance, shifting generator usage towards backup-only operation, while maintaining near-zero unmet demand for critical hospital loads. At the same time, the feasibility of cost-reflective tariffs is shown to depend heavily on financing conditions. While concessional or blended finance structures can keep tariffs within regulated mini-grid ranges, higher commercial WACC levels drive tariff requirements beyond current benchmarks, revealing threshold effects that are significant for both bankability and contractual design. The paper positions itself as a methodological contribution rather than a prescriptive intervention. It demonstrates how technical system design and regulatory-tariff modelling can be integrated to support decision-making on hospital-centred microgrids under realistic outage patterns, financial constraints, and Nigeria's current regulatory landscape.

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Session Classification: Decentralised Systems & Industries

Contribution ID: **94** Type: **not specified**

Hedging Renewables with Location Spreads

Friday 27 March 2026 15:10 (20 minutes)

The ongoing decarbonization of the power sector has fundamentally transformed electricity markets in many countries. In countries like Germany, renewable production accounts for a dominant share of the overall production (see Bundesnetzagentur SMARD (2025)). As a consequence, the risk profile of power producers has shifted: instead of relying primarily on controllable thermal power plants with predictable output, market participants must now manage the risks associated with weather-driven renewable production. Because renewable energy is produced with negligible marginal costs, the key quantity for a renewable producer and its risk management is the revenue. There are two main uncertainties in the revenue of renewable producers: how much energy can be produced depending on the weather conditions and at what price it can be sold on the market. A crucial feature of renewable-dominant electricity markets is that these two sources of uncertainty are not independent. Due to the merit-order mechanism, high renewable generation in the market tends to decrease electricity spot prices, while low infeed is associated with higher spot prices (see e.g. Cludius et al. (2014)). The same weather conditions that affect the divergence in the quantity of renewable generation also affect the price level. The revenue risk faced is therefore a joint price-quantity risk (see e.g. Pircalabu et al. (2017)).

To manage revenue risks, electricity producers commonly rely on power futures. Standard hedging strategies typically use futures written on the electricity price of a single bidding zone, e.g. the German power futures. These contracts are designed primarily to fix the price level for a given delivery period. The hedge ratio is based on ex-ante production forecasts. Since the most liquid futures are monthly contracts requiring mid-term forecasts, this leaves substantial residual revenue risk: volume deviations remain unhedged and the merit-order–induced correlation between price and quantity risk is ignored.

The German power market is highly integrated into the European electricity system through cross-border interconnections and market coupling (see Estermann et al. (2025)). Nevertheless, price differences between bidding zones frequently arise due to network constraints and limited transfer capacities (see Kiesel and Kusterman (2016), Kargus and Uhrig-Homburg (2025)). These location spreads depend on the level and spatial distribution of renewable generation and tend to widen when interconnector limits bind during periods of high renewable infeed (see Kargus and Uhrig-Homburg (2025)). Consequently, renewable production uncertainty affects not only domestic prices and output but also cross-zonal price spreads. This observation motivates the central idea of the paper: instead of relying on national futures to hedge revenue risk, renewable producers may exploit futures written on different markets or the direct trade of power future spreads. Such strategies explicitly target the price differences between markets and are better aligned with the underlying drivers of renewable revenue uncertainty in an integrated, renewable-dominant European power system. This motivates the following research question: how effectively can renewable producers in Germany hedge their revenue using location spreads?

The study contributes to the literature on hedging in electricity markets (e.g. Byström (2003), Zanotti et al. (2010), Pircalabu et al. (2017), Hanly et al. (2018), Christensen and Pircalabu (2018)) by focusing on intermittent renewable producers with stochastic output and comparing the hedging effectiveness of national power futures and cross-zonal location spreads. Furthermore, it is connected to the general finance literature regarding hedging and builds on the classical minimum-variance hedging framework (see Ederington (1979)). Third, the analysis relates to the literature modeling uncertainty in electricity markets (e.g. Bessembinder and Lemmon (2002)) as well as studies explicitly modeling the joint distribution of spot prices and generation output (e.g. Pircalabu et al. (2017)). Lastly, it contributes more broadly to the literature of market coupling (e.g. Cartea et al. (2022), Pierre and Schneider (2024)) and the revenue cannibalization in electricity markets (e.g. Prol et al. (2020)).

The hedging effectiveness is evaluated using descriptive evidence and both reduced-form and structural models of renewable revenues and futures payoffs. Using realized hourly price and infeed data from ENTSO-E (2026) as well as daily settlement prices for futures from Bloomberg (2025), location spreads exhibit substantially higher correlations with renewable revenue innovations than the German baseload future. The structural Monte Carlo simulations confirm that hedging performance is technology-specific and that accounting for spatial price differentials improves renewable revenue risk management. Overall, the results indicate that location spreads can complement standard price futures and help mitigate revenue risk.

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Session Classification: Renewables & Risks

Contribution ID: **95** Type: **not specified**

Julia-Based Modelling and Optimization of Renewable Hydrogen Production from PV and Wind: Case Study of Algeria

Friday 27 March 2026 17:10 (20 minutes)

Motivation:
Renewable hydrogen is increasingly recognized as a key enabler for decarbonizing hard-to-abate sectors and for supporting large-scale integration of variable renewable energy sources. Countries with abundant solar and wind resources and existing energy export infrastructure are particularly well positioned to benefit from this transition. Algeria (North Africa) combines exceptional renewable energy potential with strategic proximity to European hydrogen demand, yet large-scale renewable hydrogen deployment faces two critical challenges: the intermittency of renewable electricity generation and the scarcity of freshwater resources. Addressing these challenges requires integrated energy–water system analyses that go beyond conventional power-only modeling approaches.
Methodology:
This study develops an hourly, techno-economic optimization model implemented in the Julia programming language using the JuMP optimization framework. The model represents an integrated energy–water–hydrogen system and is applied to two geographically distinct regions in Algeria: Ain Temouchent (coastal region) and Laghouat (Saharan region). The system includes solar photovoltaic and wind power generation, battery storage, water supply via seawater desalination and treated wastewater reuse, electrolysis for hydrogen production, hydrogen storage, and optional hydrogen-to-power reconversion using fuel cells. The optimization problem is formulated as a linear program that maximizes total system profit, accounting for revenues from hydrogen exports and regional electricity supply while considering capital and operational expenditures of all system components. Hourly solar and wind availability data are sourced from the Global Solar Atlas and Global Wind Atlas. All economic parameters are expressed using ISO-compliant currency codes (USD). Technical constraints such as minimum electrolyser load, storage losses, and capacity limits are explicitly modeled to ensure operational realism.

Results:
The results reveal pronounced spatial and temporal differences between the coastal and Saharan regions. Laghouat benefits from strong solar–wind complementarity, enabling high electrolyser utilization and reduced reliance on short-term battery storage. Ain Temouchent shows increased system flexibility due to reliable water availability from desalination and wastewater treatment. Across both regions, hybrid PV–wind configurations significantly enhance hydrogen production stability compared to single-technology systems. The inclusion of treated wastewater as an electrolysis feedstock proves to be technically viable and substantially reduces dependence on freshwater resources, an important advantage for arid regions. Hydrogen-to-power reconversion is activated only during limited periods of supply scarcity, confirming its role as a backup flexibility option rather than a dominant operational pathway. Economic results indicate stable hydrogen export revenues in USD with limited short-term variability, primarily driven by operational constraints rather than renewable resource availability.

Conclusion:
The study demonstrates that renewable hydrogen production in Algeria can be both economically attractive and resource-efficient when supported by integrated energy–water system design and hybrid renewable generation. Beyond the Algerian case, the proposed Julia-based modeling framework offers a transferable and scalable approach for analyzing renewable hydrogen systems in other water-scarce, renewable-rich regions.

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Session Classification: Hydrogen Systems & International Case Studies

Contribution ID: **97** Type: **not specified**

How Methodological Choices Shape the Value of Lost Load: A Systematic Review of VoLL Methodologies

Friday 27 March 2026 11:50 (20 minutes)

Motivation
Security of electricity supply has re-emerged as a key concern in energy policy and research. The transition of energy systems towards decarbonisation is accompanied by increasing dependence on variable renewable energy sources and declining shares of controllable generation. In parallel, geopolitical uncertainties have increased and refocused attention on how societies value a reliable electricity supply. As electricity systems become structurally more complex and more exposed to supply risks, economically efficient decisions on grid expansion, capacity adequacy, and reliability standards increasingly depend on robust assessments of the costs associated with supply disruptions.
The Value of Lost Load (VoLL) is a central indicator for quantifying the welfare losses associated with unserved electricity demand. VoLL estimates are widely used in academic research, energy system modelling, and regulatory frameworks. At the same time, the VoLL literature exhibits substantial heterogeneity in reported values across studies (Kapeller et al., 2026; Schröder & Kuckshinrichs, 2015). Existing research applies a broad range of methodological approaches, including macroeconomic production-based methods, input–output analyses, survey-based techniques, revealed preference approaches, and case-study-based assessments. While it is well acknowledged that VoLL estimates differ across studies, a systematic and comparative assessment of how methodological choices shape reported VoLL outcomes remains limited.

Method
This paper addresses this gap by providing a systematic methods review of the VoLL literature. We screen existing VoLL studies based on a fixed set of selection criteria, covering a wide range of geographical contexts, sectors, and applications. The reviewed studies are classified according to their underlying valuation approach, sectoral scope, VoLL parameters, and data sources. This structured classification enables a consistent comparison across methodological approaches.
Building on this framework, the paper combines a conceptual comparison of valuation approaches with a systematic assessment of reported VoLL estimates across studies. Rather than aiming to derive a single pooled VoLL, the analysis focuses on identifying patterns and systematic differences associated with different methodological approaches. Particular focus is set on the contrast between aggregate macroeconomic approaches, which infer outage costs from economic output data and typically abstract from behavioural dimensions, and survey-based methods, which explicitly incorporate consumer preferences, budget constraints, and risk attitudes. Within stated preference approaches, differences between willingness-to-pay and willingness-to-accept frameworks are discussed in light of income effects, substitution possibilities, and reference-dependent valuations of electricity supply. The review further considers how different methods address sectoral heterogeneity, indirect effects, and the characteristics of supply shortages.

Results
The review indicates that methodological choices are closely linked to how VoLL is conceptualised and quantified across the literature. Aggregate production-based approaches tend to emphasise average output losses and provide comparatively homogeneous valuations, while survey-based methods allow for greater differentiation across consumers, sectors, and outage characteristics. Differences in behavioural assumptions and valuation frameworks are reflected in systematically different ranges of VoLL estimates reported in existing studies. Figure 1 illustrates how differences in VoLL parameters and methodological implementation influence VoLL estimates in survey-based studies.
Overall, the analysis demonstrates that method choice is a key factor shaping VoLL estimates and their interpretation. The results underline the importance of methodological transparency

and of aligning valuation approaches with their intended application. By clarifying how different methods relate to observed VoLL outcomes, this paper contributes to enhancing comparability and standardisation in future research and provides a structured basis for the informed use of VoLL in energy system modelling and policy analysis.

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Session Classification: Scarcity & Reliability

Contribution ID: **100** Type: **not specified**

Hydrogen based electrification vs direct electrification using solar PV and wind in Egypt: A HOMER PRO study

Friday 27 March 2026 17:30 (20 minutes)

This study conducts a comparative techno-economic analysis of two renewable energy strategies for Egypt's energy transition: hydrogen-based electrification through the production of green hydrogen via electrolysis and direct electrification using solar photovoltaic and wind energy. The study focuses on Egypt's Suez Canal Economic Zone, a key area for renewable energy development, and utilizes HOMER PRO software to model both systems under the same load and resource conditions. The goal is to assess each system's feasibility in terms of cost, operational efficiency, scalability, and environmental impact.

Simulation results show that direct electrification is the more viable option for domestic energy supply. It delivers electricity at an LCOE of $0.23 per kilowatt-hour, meets 99.98 Despite its limitations, hydrogen-$
$based electrification holds strategic value for Egypt's long-term energy and export goals. The country's geographic po$
$term domestic needs, while investments in hydrogen infrastructure should be developed for long-$
$term industrial use and export.$
$The study contributes to the growing body of research supporting clean energy transitions in emerging economies and pr$

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Session Classification: Hydrogen Systems & International Case Studies

Contribution ID: **101** Type: **not specified**

A probabilistic merit order for electricity price forecasting

Friday 27 March 2026 14:30 (20 minutes)

Introduction
Electricity price forecasting has become increasingly complex due to the growing integration of renewable energy sources, whose weather-dependent generation introduces significant volatility and non-linear dynamics into power markets. Probabilistic forecasting is essential in this domain because the uncertainty itself evolves over time, periods with high renewable generation exhibit different price distribution characteristics compared to conventional generation-dominated periods. This is particularly evident in markets like Germany, where abundant solar generation in summer creates **bimodal price distributions** (with one mode near zero during high PV output and another around 90 EUR/MWh during conventional generation periods), while winter months typically show unimodal, positively skewed distributions with frequent price spikes. Traditional point forecasts fail to capture these complex distributional dynamics, leaving market participants exposed to significant financial risks.

State of the art
Current approaches to probabilistic electricity price forecasting fall into two main categories: data-driven statistical methods and fundamental models. **Data-driven approaches**, including prediction intervals, quantile regression, distributional forecasting (e.g., GAMLSS with Johnson's SU distribution), and ensemble methods, effectively capture statistical patterns from historical prices but lack interpretability and causal structure. **Fundamental models**, which simulate market mechanisms through merit-order curves, offer strong interpretability but have traditionally been deterministic or limited to few predefined scenarios, failing to comprehensively represent uncertainty. This gap represents a critical limitation, as electricity price formation depends on multiple stochastic inputs including renewable generation (driven by volatile weather conditions), electricity demand (with behavioral patterns), fuel prices (subject to politico-economic events), and power plant availability (affected by maintenance and outages).

Novelty
We propose the **first fully probabilistic fundamental model for electricity price forecasting** that bridges this divide. Our framework **explicitly captures individual uncertainty sources** by fitting probabilistic distributions to all key drivers: load, renewable generation (PV, onshore and offshore wind, hydro), fuel prices (gas, coal, oil), CO_2 prices, and available capacities across all generation technologies. Unlike previous approaches, we model each input's full conditional distribution using a recursive GAMLSS-type framework, with LASSO regularization enabling efficient online updates. Crucially, **we preserve dependencies between inputs** through an empirical copula approach with a 365-day rolling window, capturing important correlations such as those between onshore and offshore wind generation.

The core innovation lies in integrating these probabilistic inputs into a fast fundamental merit-order model. For each time point, we sample from the joint distribution of all input variables and feed these samples into a merit-order calculation that constructs supply stacks from marginal costs of available generation technologies. The model computes lower and upper marginal costs for each technology based on sampled fuel/CO_2 prices and expert-estimated efficiency parameters, then constructs individual supply curves that are properly aggregated (accounting for overlapping cost ranges) before intersecting with sampled demand to determine prices. **This process generates multiple realistic price scenarios per hour, creating non-parametric predictive distributions that naturally reproduce complex market phenomena including multimodality, price spikes, and regime shifts between high- and low-renewable conditions**.

Data
Our model is calibrated to historical German market data (2018-2025) to maximize probabilistic forecast accuracy, measured by Continuous Ranked Probability Score (CRPS). Results demonstrate significant improvements over benchmark methods. The model successfully captures seasonal distributional shifts without requiring parametric assumptions about the output distribution. Calibration plots confirm reliability across all input variables.

Summary
This work makes three key contributions:
(1) explicit probabilistic modeling of all fundamental price drivers with dependency preservation via copulas;
(2) integration of these distributions into a computationally efficient merit-order framework that generates realistic price scenarios while maintaining causal interpretability; and
(3) data-driven calibration that optimizes probabilistic forecast skill.

The resulting framework retains the transparency and causal consistency of fundamental models while providing comprehensive uncertainty quantification, enabling market participants to assess tail risks, optimize bidding strategies, and manage financial exposure in increasingly volatile electricity markets. By bridging the gap between fundamental and statistical approaches, our methodology establishes a new paradigm for interpretable, uncertainty-aware electricity price forecasting that can be readily extended to other energy markets undergoing similar energy transitions.

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Session Classification: Electricity Price Formation & Forecasting

Contribution ID: **102** Type: **not specified**

Sociotechnical imaginaries of nuclear newcomer countries –Insights from a comparative case study

Friday 27 March 2026 14:50 (20 minutes)

Becoming a nuclear operating country, defined here as connecting the first commercial power reactor to an electricity grid for electricity generation, requires the development of an extensive system of institutional as well as scientific and technological subsystems and infrastructures as well as the fulfilment of certain conditions (Wealer et al. 2026). This was historically determined through geopolitical associations and so-called "nuclear diplomacy"(Szulecki and Overland 2023). In the past, "entering"nuclear power production started in the 1950s and was facilitated through mostly light-water reactors, initially provided by the United States or the Soviet Union, which had been developing them in the context of the Second World War and were subsequently supplying allied nations during the Cold War (with the exception of India, Pakistan, and Argentina), and often further developed in national contexts (e.g., France, Germany, South Korea). This followed a rapid increase in the number of entrant countries, beginning in 1954 and ending in 1977, in which 24 countries began operating commercial power reactors. From 1985 to the present, the number of countries operating power reactors has remained almost constant (approximately 30) (Wealer et al. 2018; Schneider et al. 2025). However, many more countries have recently expressed their interest in operating their first nuclear power plants due to desires to decarbonize their energy systems. The World Nuclear Association (WNA) counts 28 of what we term nuclear newcomer countries (NNC) (WNA 2024). However, in-depth scrutiny reveals that many countries are far off from actual projects, and as of today, only three countries, i.e., Bangladesh, Egypt and Türkiye, are building their first commercial power plants (Schneider et al. 2025). This raises the question of which factors are needed to achieve their policy goal of connecting their first commercial power reactors to the grid and what motivations lie behind these goals. Drawing on a comparative case-study of eleven NNCs (Yin 2014), this paper sheds light on the development of the sociotechnical imaginaries (Jasanoff and Kim 2009; Hendriks et al. 2025) behind the creation of nuclear operation capacities. Drawing on Pistner et al (2024), this article divides policy pathways into three time periods (build-up, adjustment and current phase) to evaluate the evolution of invoked imaginaries and assess the extent to which the cases are like to become nuclear operating countries.
This study provides an in-depth analysis of eleven potential "entrants"regarding their prospects for building their first commercial power plants within the coming decades, and the underlying motivations. The cases are selected following the multiple-case study approach by Yin (Yin 2014, 105) to "predict contrasting results but for anticipatable reasons."The countries therefore span the entire globe. The analysis follows a long-term gradual development approach in which we differentiate between three periodical development stages, as shown in Table 1, following Pistner et al. (2024). The analyzed countries are Chile, Colombia, Ghana, Rwanda, Norway, Poland, Türkiye, Egypt, Saudi-Arabia, Uzbekistan, and Indonesia.

Table 1 (see attached)

Interim results indicate the existence of the following motivations to build the first commercial nuclear power plant: 1) increasing energy supply security and/or replacing fossil fuels due to the need to decarbonize energy systems; 2) decentralized energy provision and energy access; 3) proactive innovation, industrial, and science policies; 4)international cooperation and geopolitical motivations; and 5)the nuclear energy system as an expression of "modernity."
Among these, energy supply security, decarbonization of the energy mix, and interest in developing a modern innovation system dominate. Geopolitical aspects played a greater role in the past but still appear sporadically. The same applies to the perception of nuclear energy as an expression of "modernity."Despite the stated motivations, efforts to improve energy efficiency (to enhance supply security) and to expand other CO_2-free technologies (to accelerate decarbonization) are not particularly pronounced in these countries. In all cases, foreign nuclear technology

vendors exert significant influence on the process and discussion of reactor concepts as well as on political decision-making.

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Session Classification: Nuclear, Fusion & Sociotechnical Futures

Contribution ID: **103** Type: **not specified**

The German balancing energy market reform: Analyzing effects on prices, liquidity and competition

Friday 27 March 2026 14:50 (20 minutes)

The increasing share of renewable energy sources increases uncertainty in the power supply until shortly before the time of delivery. In addition to increased trading activity on the continuous intraday market, ancillary services have also gained importance as a critical tool for maintaining grid stability (Hirth et al., 2015). Complementary to the increasing RES share, new technologies such as large-scale battery energy storage systems (BESS) are entering the market at scale. BESS are well-suited to address short-term supply-demand imbalances and are increasingly positioned to play a pivotal role in the provision of balancing services (Figgener et al., 2022).
The German balancing market is divided into a capacity market and an energy market. Participation in the capacity market is possible until 9 am the previous day. Afterwards, participation in the energy market is required, with submission windows closing 25 minutes prior to delivery. In June 2022, the German Transmission System Operators (TSOs) joined the PICASSO platform, designed for the joint activation of aFRR of European TSOs (European Commission, 2017). The integration of the PICASSO platform requires additional changes to the aFRR energy market, which amounts to a reform. Before this reform, market participation required a preceding power bid in the capacity market. Following the reform, participants are permitted to place energy-only bids in the RAM, with submission windows closing 25 minutes prior to delivery. Furthermore, the market was changed from a pay-as-bid to a pay-as-cleared mechanism.
Therefore, we aim to analyze whether the reform has reached its goals by focusing on the analysis of balancing energy market prices, leading to the following research questions:
• Has the reform led to lower price levels in the German balancing energy market?
• What factors influence the price in the balancing energy market before and after the reform?
We hypothesize that the reform led to a decrease in positive balancing energy prices and an increase in negative prices due to the market reform.
The existing body of literature primarily focuses on short-term forecasting of imbalance prices, with only a few studies investigating the energy market of ancillary services. Narajewski (2022) evaluates short-term forecasting methods for the German imbalance price using various methods. The study finds that while advanced methods offer gains in empirical coverage, they do not substantially outperform the naïve benchmark. Dumas et al. (2019) develop probabilistic forecasting models for imbalance prices in the Belgian context. Their study highlights the importance of quantifying forecast uncertainty and demonstrates the added value of probabilistic approaches in operational planning for system operators and market participants. Merten et al. (2020) focus specifically on the automatic Frequency Restoration Reserve (aFRR) market and propose a methodology for forecasting aFRR market outcomes using various statistical and machine learning techniques. Their work compares different approaches to forecasting activation prices and volumes.
We investigate the achievement of the RAM reform in 2022 in the aFRR market, focusing on three key dimensions: price levels, market liquidity, and competition. Our empirical approach employs a counterfactual econometric analysis to assess whether the reform has achieved its intended objectives. Autoregressive effects of previous RAM prices, variables such as the connection of further countries to the PICASSO platform, intraday prices, commodity prices, residual load and renewable energy forecasts, power plant outages, and the increase in BESS are considered.
Results of the Chow test show a significant break at the time of the reform. Nevertheless, the result shows an increase in positive and a decrease in negative balancing energy prices. Switching from a pay-as-bid to a pay-as-cleared regime might increase overall price level and volatility after the reform. We conduct OLS regression analysis with varying specifications. Stationarity of the dependent and independent variables has been tested, followed by cointegration of the models. For both positive and negative prices, the inclusion of a reform dummy variable reveals coefficients that align with the results of the Chow test. However, we do see that changing the pricing rule

alone may be insufficient to reduce balancing energy prices, but market liquidity and participation likely exert a stronger influence. Nevertheless, the dummies for further countries are consistent with their hypothesis and decrease positive and increase negative prices. A time series method such as SARIMAX will be part of our future research.

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Session Classification: Market Design & Bidding Zones

Contribution ID: **106** Type: **not specified**

The situation and risks facing the chemical industry

Friday 27 March 2026 17:30 (20 minutes)

The chemical industry is at the core of the socio-ecological transformation: as the largest industrial consumer of mineral oils and natural gas in Germany and thus a significant source of emissions, it faces a particular challenge to undergo fundamental change. Without a profound transformation of this sector, national climate and environmental goals cannot be achieved. In addition to the pressure to transform due to environmental and cli-mate-related regulations and fluctuating energy prices, the chemical industry faces further challenges, such as weak demand in national and global sales markets. Although production has been curtailed in recent years due to weak demand on national and international markets, the industry continues to make a substantial contribution to overall economic value added.

As part of an ad hoc task in the German Environment Agency's (Umweltbundesamt –UBA) project "Demand and employment effects of future environmental protection measures,"the situation of the German chemical industry and two cumulative scenarios were examined. The scenarios deal with two key factors influencing the future development of the chemical industry: higher energy costs and the use of new and more efficient technologies.

The scenario analyses are based on the QINFORGE model system, which is updated, evaluated, and used as part of the QuBe project (www.qube-projekt.de). For this work, the model status from wave 8 was used, taking into account structural data from official statistics up to 2023 and key parameters up to 2024. The model follows a bottom-up approach: calculations are made at the industry level, and variables such as gross domestic product are obtained by addition. Key exogenous parameters for the baseline scenario include population development from the Institute for Employment Research (Institut für Arbeits-markt- und Berufsforschung - IAB) demographic model and information from the GINFORS world trade model for import prices and export demand for goods. The QuBe base projection (8th wave) serves as the baseline for the information on the projected develop-ment of the chemical industry in Germany and as a reference scenario against which the results of the scenarios calculated for the chemical industry are compared.

In addition to the quantitative analysis, a discussion was held with experts from companies, associations, and scientific institutions. The discussion was conducted as a structured, guideline-based exchange.

The qualitative evaluation served to validate the model findings, expand the analysis to include factors that cannot be represented in the model or can only be depicted indirectly (e.g., infrastructure bottlenecks, approval processes, transformation sequence, market pull mechanisms), and perform a sensitivity analysis in the sense of assessing which assump-tions made in the model are rather conservative or rather optimistic.

This study shows that the German chemical industry is potentially facing three rising cost components simultaneously. These include rising labor costs, rising costs for intermediate inputs, and higher depreciation. Analysis of the baseline projection shows that wages are rising significantly, partly due to the shortage of skilled workers and in response to inflation. In addition, prices for many intermediate goods, including energy, are rising, driven by factors such as CO2 prices and geopolitical uncertainties. Investments made in the course of the transformation to achieve climate neutrality or to avoid higher material costs lead to depreciation downstream. The socio-ecological transformation of the chemical industry can only be achieved if it is supported by policymakers.

The expert discussion confirms the diagnosis of a structural break in 2022/2023. The model-based identification of a "double cost challenge"arising from rising input costs (especially energy) and labor costs is reflected in reports from the field: production at a 30-year low, capacity utilization rates well below the break-even point, and a return on sales that has halved in a short period of time. Against this backdrop, the scenarios of rising energy prices (scenario 1) and additional investments in efficiency technologies (scenario 2) become more plausible: from the companies' perspective, these are not abstract model variants, but real decision-making situations in which investments in decarbonization and efficiency improvements must be made under conditions of persistently thin margins. In addition, the expert discussion makes it clear that the abstraction deliberately chosen in the model for energy prices and investment paths only reflects a fraction of the actual transformation challenges.

The experts point to a number of physical and institutional prerequisites—hydrogen and CO_2 infrastructure, storage projects, grid expansion, approval procedures—which are only indirectly represented in the model via cost paths and investment assumptions. In addition, the expert discussion sharpens the view of the heterogeneity of the industry. The modeling and aggregated data necessarily work with the WZ 20 as the overall industry, following the classification of economic activities by the German Federal Statistical Office. The discussants warn against analytical and political trivialization: the creeping reduction in raw material capacities jeopardizes the basis of the entire chemical value chains in the medium term. The interaction between model calculations and expert discussion gives rise to several strategic implications for economic and environmental policy design that go beyond a purely compensatory logic of individual measures. The combination of model analyses and expert discussion also suggests several lines for further research and in-depth policy advice.

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Session Classification: Decentralised Systems & Industries

Contribution ID: **107** Type: **not specified**

Water Availability for Electrolysis in Germany: Evidence from 2030 Scenarios and Perspectives for 2045

Friday 27 March 2026 11:30 (20 minutes)

Germany has set ambitious goals for the expansion of hydrogen production based on water electrolysis. While current debates predominantly focus on the necessary renewable electricity supply and hydrogen infrastructure to achieve this, the availability of water for electrolysis has received limited attention so far. This study builds on a model-based assessment of the German energy system for the year 2030 and evaluates the implications of water availability, water pricing, and hydrogen transport infrastructure for the regional deployment of electrolysis capacity in the year 2045.

Using a spatially disaggregated energy system model of the federal states in Germany, the analysis for 2030 integrates regional renewable energy potentials, hydrogen demand, water charges, and assumptions on freshwater availability under different water stress scenarios. We find that the total water demand of electrolysis remains small in comparison to overall national water withdrawals. Water costs make up a negligible share of total electrolysis costs and therefore only have limited influence on investment decisions. However, regional constraints in freshwater availability can affect the optimal electrolyzer locations, particularly under scenarios of limited hydrogen transport capacity. Our 2030 results further show that the expansion of the hydrogen transport network is the dominant factor shaping the spatial distribution of electrolysis. When hydrogen transport is unconstrained, electrolysis capacity concentrates in regions with high renewable electricity potential, especially in northern Germany with strong offshore wind resources. Conversely, under scenarios with restricted hydrogen transport, electrolysis deployment becomes more demand-oriented and shifts toward industrial regions, thereby increasing the relevance of local water availability. In scenarios with limited freshwater availability, the model indicates spatial relocation of electrolysis capacity away from potentially water-stressed regions and a partial substitution of freshwater by alternative sources such as desalinated seawater in coastal regions.

Although these findings suggest that water availability is not a binding constraint for hydrogen deployment in Germany by 2030, these results may change when looking ahead to 2045, when Germany wants to achieve greenhouse gas neutrality. Domestic hydrogen demand could quadruple from 2030 to 2045 according to the National Hydrogen Strategy, which would require a significant uptake in hydrogen production. Thus, water availability, particularly in the light of more severe droughts due to climate change, might play a larger role for electrolyzer locations in the future. Building on the insights from the 2030 analysis, we propose an extension of the modeling framework to 2045 to capture the seasonal availability of ground water. Scenarios regarding water availability are derived from a hydrological model that captures climate-driven changes in hydrological conditions. Additionally, different scenarios for the hydrogen demand are explored. Furthermore, we account for the relevance of offshore electrolysis versus onshore electrolysis in coastal regions.

Overall, the study demonstrates that water availability plays a limited role in shaping electrolysis deployment by 2030. However, this may change with an increasing hydrogen economy in Germany. The analysis of 2045 scenarios aims to identify potential tipping points at which water availability could shift from a secondary consideration to a strategic constraint. By linking energy system modeling with hydrological models, the study contributes to a more integrated understanding of the water–energy nexus and provides evidence-based guidance for the sustainable development of Germany's hydrogen strategy.

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Session Classification: Sector Coupling & Emerging Demand

Contribution ID: **108** Type: **not specified**

Utilization of reserve capacities in electricity markets to mitigate price spikes: Impact on national and surrounding bidding zones

Friday 27 March 2026 12:10 (20 minutes)

Motivation

In the European electricity market, which is fundamentally designed as an energy-only market (EOM) and structured into bidding zones, scarcity prices of sufficient magnitude and frequency are main drivers of investments in additional generation capacity or flexibility. Whether these price peaks and the associated revenues are sufficient to enable the (re-)financing of assets in the electricity market is questioned in the literature under the term "missing money"[1], [2]. The European Union fundamentally adheres to the EOM but allows the implementation of capacity mechanisms under the aspects of security of supply and resource adequacy. The preferred form of a capacity mechanism is the strategic reserve, as currently implemented in Germany. Resources associated with the reserve mechanism cannot be remunerated by wholesale electricity markets and must be held outside of the market [3].
Particularly in Germany, there has been an intense debate since the energy price crisis in 2022 about limiting electricity prices and how to reduce electricity costs. In this context, potential additional use cases for reserve capacities which are held outside of the market are discussed. According to the coalition agreement of the current government, available reserve capacities should not only be used to ensure security of supply but should also be used to expand the supply curve in the electricity market [4] once the wholesale electricity price exceeds a predefined price threshold (strike price) [5], [6]. The resulting expansion of generation capacity is intended to reduce price spikes and stabilize market prices. This national unilateral market intervention is not only critical from an EU legal perspective, it also requires a detailed analysis of effects nationally and internationally to identify potential market distortions.
This contribution complements the existing discussion [6], [7] with a quantitative analysis that identifies the effects of utilizing reserve capacities at a specific strike price in the German electricity market not only on short-term market outcomes (generation quantities and electricity prices) but also long-term effects on investment decisions in generation capacities and storage technologies, both within the German bidding zone and across the European electricity market. Due to the existing uncertainty regarding the realization of climate years and the associated uncertainty in the generation of fluctuating renewable energy sources as well as electricity demand profiles, the analysis also considers probabilities associated to three different climate years.

Methodology

The electricity market model is based on [8], [9], [10] and analyzes effects on investment decisions as well as short-term market outcomes in the electricity market of Central Western Europe. The electricity market model is extended such that reserve capacities can be utilized if market prices exceed a specific price threshold and represents endogenous decisions in investments and decommissioning of fossil generation capacities, electrolysis capacities and batteries in accordance with short-term market outcomes, including the decisions on generation quantities, storage operation and hydrogen production. Under the assumption of perfect competition, private firms decide about their profit-maximizing production quantities as well as long-term investment decisions in generation, electrolysis and battery capacities while taking probability assumptions regarding the realization of different climate years into account. Trading between bidding zones is optimized by considering inter-zonal transmission constraints.
The optimization problem with a concave quadratic objective function is implemented in GAMS.
The data basis consists of an aggregated representation of the European electricity market based

on national bidding zones. The target year of the analysis is 2030 with an hourly resolution of trading periods. A total of six different reserve scenarios, which differ in terms of reserve size (5, 10, 15 GW) and strike price (250 vs. 500 EUR/MWh), are analyzed in comparison to a reference scenario (without reserve utilization).

Preliminary results

The preliminary results show that price spikes in all countries are reduced by the utilization of reserve capacities in Germany. Nevertheless, even with a reserve size of 15 GW, scarcity prices still occur. Although prices during peak price hours are reduced significantly due to reserve utilization, price effects are partially offset by adjusted investment decisions, which increase prices during the remaining hours of the year. Effects on annual demand-weighted average market prices are small and vary depending on the reserve scenario and the underlying climate year.
Utilizing reserve capacities on the spot market for electricity can not only lead to potential short-term price reductions but also to adjustments in long-term investment decisions in the electricity market. Reserve utilization incentives a market-driven phase-out of hard coal capacities and reduces investment incentives for batteries in Germany. The negative effects on battery investments are more pronounced at a low strike price and increases with the size of the reserve capacity.
Beyond effects on market outcomes and investment behavior, a potential trade-off between system cost reduction and loss of security of supply needs to be discussed. Due to additional revenues earned by the utilization of reserve capacities at the spot market, operating cost and to some extent capacity provision cost for reserve capacities can be covered, which leads to a potential cost reduction effect on network cost and therefore a reduction of total system costs. However, due to the additional use case and the resulting reduced availability as a backup to ensure security of supply, the potential loss of security of supply, which can have negative effects on system costs, also needs to be considered.

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Session Classification: Scarcity & Reliability

Contribution ID: **109** Type: **not specified**

Investments and Market Outcomes under Regulatory Uncertainty: A Case Study of German Electricity Bidding Zones

Friday 27 March 2026 15:10 (20 minutes)

Motivation
The German bidding zone prevents that structural north-south bottlenecks in the transmission system become visible on the electricity market, i.e., there is no regional price discrimination. In the short-term, this results in inefficient market results at national and European level, which translates in technical infeasible market results due to network constraints, high levels of congestion management and increased system costs. In the mid-term, the lack of regional pricing results in inefficient regional investment incentives for transmission projects, generation capacity, electricity storages and large consumers. The academic literature has shown since many years that a market setting with two or more bidding zones can reduce congestion management costs and increase system welfare (Egerer et al., 2016; Grimm et al., 2016; Trepper et al., 2015). However, implementing bidding zone configurations as suggested in the bidding zone review (ENTSO-E, 2025) is politically challenging in Germany and the ongoing discussion results in regulatory uncertainty for stakeholders. This study extends the literature on regulatory uncertainty on the possible implementation of different bidding zone configurations in Germany which would affect investment decisions and market rents of various actors, as well as redispatch costs and the overall efficiency of the system. In particular, the impact of investments and operation of flexibility at regional level is evaluated.

Methods
In order to assess the impact of regulatory uncertainty on future bidding zone configurations (one, two or five bidding zones) in Germany within the European integrated electricity market for the year 2030 a comparative analysis is carried out using a multi-level electricity market model (Egerer et al., 2025; Grimm et al., 2016). The scenarios are compared, assuming uncertainty regarding the introduction of either one or two or one or five bidding zones, each with an increasing probability of one of the bidding zone configurations occurring. The research question is analyzed using a stochastic two-level electricity market model that captures (dis)investment decisions, market operation and congestion management under uncertainty regarding future bidding zone configurations (cf. Ambrosius et al., 2020). At the first level, companies decide on (dis)investments in generation, storage and electrolyzers within the framework of the equilibrium price on the spot market and the aim of maximizing welfare. This is done by taking into account investment and operating costs, trading capacities and the uncertainty regarding the future bidding zone configuration in Germany. Subsequently, after the realization of one bidding zone configuration, companies participate on the spot market for one reference year with hourly time resolution with their realized (dis)investment decisions from the first level. The two steps of investment and operation can be combined in one level in the mathematical model optimizing system welfare under uncertainty of future bidding zone configurations. At the second level, the costs of congestion management are minimized on the basis of cost-based redispatch by a transmission system operator (TSO). In redispatch, the physical load flow requirements must be met based on market results using a lossless direct current (DC) load flow approximation of an aggregated German electricity grid.

Results
The preliminary results show that the degree of uncertainty regarding the future configuration of bidding zones has a significant impact on the level of investment in various technologies. Even a low probability of more than one bidding zone occurring is sufficient to position the investment locations and their capacities in a certain way. This means that the technologies in which investments have been made contribute to an increase in system welfare if, contrary to the low probability, more than one bidding zone is actually implemented. As another aspect the influence

on redispatch costs have been considered. It has been shown that those redispatch costs rise in the case of only one bidding zone continuing after the investments have been made under the uncertainty. Additionally, it has been shown that the total redispatch costs increase with the increasing probability and actual implementation of more than one bidding zone. This effect can be explained by the increasing capacity of electrolyzers and the associated greater demand for electricity. But it should be emphasized, that the total redispatch costs are lower in the cases with more than one bidding zone compared to the case with one bidding zone. In addition to those examples the dependency on the degree of uncertainty was analyzed for various positive and negative effects on the rents of different technologies.

CV

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Session Classification: Market Design & Bidding Zones

Contribution ID: **110** Type: **not specified**

Evaluation of the impact of robustness regarding demand side uncertainty on the estimation of load flexibility bands for home energy systems

Friday 27 March 2026 16:50 (20 minutes)

Motivation
The ongoing electrification of sector-coupling applications within distribution grids is particularly pronounced at the household level, where distributed energy resources (DERs) such as electric heat pumps, battery electric vehicles, and battery storage systems are increasingly utilized. These DERs provide operational flexibility, i.e. the ability to adjust electricity consumption within given limits. While volatile demand profiles can strain the distribution network, the controllable nature of DERs also enables their use for congestion management and grid stabilization. To effectively exploit these potentials, a quantification of available flexibility is essential. Existing approaches often focus on flexibility evaluation at single points in time or require continuous updating after each flexibility use, consequently limiting planning reliability and increasing communication overhead. This study addresses these limitations by proposing a flexibility band concept that is predetermined for an entire planning horizon and can be used by higher-level actors to request flexibility services from prosumers. A fundamental idea behind this approach is to guarantee flexibility availability within the defined band, which is made difficult by uncertainties on the demand side. Robust schedules may impose tighter than necessary bounds to deal with uncertainty, leading to possibly conservative estimates of the available flexibility. The aim is to find a trade-off between ensuring user comfort and meaningful flexibility estimates.
Methods
The proposed framework begins by establishing a baseline power demand trajectory for the planning horizon (e.g., one day), derived from a home energy management system (HEMS) that cost-optimally schedules the operation of household DERs under dynamic electricity prices. Key metrics from the IEA Energy in Buildings and Communities Programme (IEA EBC Annex 67) are employed and extended to characterize system response when deviations from the baseline occur. These include maximum load response, response duration, and recovery time to baseline (see figure 1). For each time step within the planning horizon, maximum positive and negative deviations from the baseline power demand are computed (Δ in fig.) such that the load trajectory is able to return to the baseline within a defined period of time (α), forming a flexibility band around the baseline demand. If a flexibility call takes place, the band will only be meaningful again after the recovery time. This way, the band can be calculated in advance and does not require updating during operation, thus reducing computational and communication requirements. The calculation of maximum deviations considers all constraints of the initial baseline optimization. Assuming tight, robust bounds for some state variables are imposed to handle load uncertainties, these bounds are also imposed in the flexibility estimation. By allowing brief periods of violation of these bounds (γ), while still adhering to the technical constraints of the components, the impact of the robustness on the flexibility band can be evaluated. To assess these concepts, a MILP-based model is set up to estimate the flexibility in power-to-heat systems of prosumers from the SimBench database. Physical system states such as storage temperature and the heat pump's coefficient-of-performance (COP) are explicitly modeled to capture dynamic behavior in rebound effects.
Results
As the baseline scheduling tends to operate close to thermal comfort limits with minimal energy

buffers, the potential for load reductions is limited. For the calculation of the maximum response, the flexibility usage is also not anticipated, so the response cannot be prepared in prior time steps. Preliminary results show that always adhering to the tighter bounds leads to no flexibility potential at many time steps. When relaxing robust thermal bounds, there is potential for load reduction in every time step. The additional flexibility is considerable: Ignoring a buffer level of 10% of the temperature range in the heat storage for a single time step of 15 minutes leads to a threefold increase in reducible power on average. Allowing the temperature to be below this level for longer, however, increases the flexibility only slightly, reducing the incentive to allow longer non-robust periods of time.

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Session Classification: Flexibility Modelling

Contribution ID: **112** Type: **not specified**

DIRECT AIR CAPTURE DEPLOYMENT –WHERE AND WHY?

Friday 27 March 2026 17:10 (20 minutes)

Introduction and Motivation
Direct Air Capture (DAC) technologies are increasingly discussed as a key component of global net-zero and long-term decarbonization strategies, particularly for offsetting emissions in hard-to-decarbonize sectors (Erans et al., 2022).
Existing research on DAC and engineered carbon dioxide removal is dominated by cost- and energy modelling, life cycle assessments, and system-level analysis (Deutz and Bardow, 2021; International Energy Agency 2023). While these studies offer valuable insights into technical feasibility, they remain weakly connected to empirical evidence on real-world deployment patterns.
Parallel policy-oriented work emphasizes governance challenges, innovation policy, and the role of targeted incentives, and recent tracking efforts document rapid growth and strong geographic concentration (Meckling et al., 2021; Sovacool et al., 2022; Smith et al., 2024).
However, these studies do not explain why DAC projects emerge in specific countries. This study addresses this gap by leveraging newly unique dataset on global DAC activities. The integrated structure enables a comparative globally descriptive analysis between DAC-active countries and others. The study provides first empirical evidence on how country –level conditions differ between DAC host and non-host countries, empirically linking insights from the existing literature to real-world DAC deployment patterns.

Method and Data
The analysis is based on a newly compiled dataset that combines project-level information on DAC activities with country-level economic, environmental, energy-related, and institutional indicators. The data pertaining to the DAC projects cover the period from 2009 to 2024. The dataset includes information on host countries, locations, and project status.
To examine country-level characteristics associated with DAC activity, the project data is merged with a country–year panel dataset. This includes country data such as Gross Domestic Product (GDP) and income classification, CO2 emissions, energy system characteristics, including fossil and renewable energy shares and energy prices, as well as institutional quality (Rule of Law, and the participation of these countries in the Paris Agreement. The resulting country–year panel covers the period from 2009 to 2024 and includes both DAC-active countries and a global comparison sample constructed using the same data sources and preparation steps. To account for potential scale effects, all analyses are conducted both including and excluding China, due to its economic size and emission levels.
Building on the descriptive findings, the project is designed to move towards a quasi-experimental difference-in-differences (DiD) framework that exploits cross-country and temporal variation in policy and energy-system factors, such as policy incentives, participation in emissions trading schemes, fossil fuel dependence, or energy prices. This approach allows for distinguishing between host-country and origin-country determinants of DAC deployment, consistent with a push–pull perspective, and for investigating whether participation in emissions trading schemes or a high reliance on fossil fuels are key drivers of DAC project deployment.

Results
The descriptive results are ambiguous and do not show clear and systematic differences between DAC-active countries and the wider global sample. DAC-active countries are characterized, on average, by substantially higher CO2 emissions and higher levels of economic development, as measured by GDP. Additionally, DAC countries demonstrate stronger institutional quality, as reflected in higher Rule of Law indicators, and are more deeply embedded in international climate policy frameworks, with universal participation in the Paris Agreement and widespread adoption

of net-zero targets. In terms of energy systems, DAC-active countries tend to combine relatively high shares of renewable energy with continued reliance on fossil energy sources, indicating diversified yet still carbon-intensive energy structures.
A first inspection of the available project-level information suggests that DAC activity has increased over time and remains concentrated in a limited number of host countries. The dynamics of the energy system are clear: fossil energy shares decline consistently while renewable energy shares increased markedly throughout the sample period. By contrast, average CO2 emissions show no clear downward trend, remaining stable at high levels. This suggests that DAC deployment occurs in countries undergoing energy transitions but still facing significant emission challenges.
To assess robustness, descriptive analyses of country-level outcomes are conducted both including and excluding China. Excluding China substantially lowers average emission levels but does not alter qualitative temporal patterns or the relative differences between DAC-active countries and the global sample. This indicates that China primarily affects the scale of aggregate emission measures, without driving the main descriptive relationships observed at the country level.
Project-level evidence provides valuable insights into the salient features of the nascent DAC sector. The sector is undergoing rapid expansion, with 54.5% of DAC firms founded after 2020, indicating strong recent market entry. At the same time, DAC deployment is highly geographically concentrated: most installations are in the United States (28 sites) and Canada (13 sites). Despite this concentration, the development of DAC is not dominated by incumbent fossil fuel firms. Only 26.8% of DAC companies are associated with the energy, oil, and gas sector, while the majority originate from research, infrastructure, and other non-traditional energy-related fields.

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Session Classification: Carbon Removal & Transition Pathways

Contribution ID: **113** Type: **not specified**

Cost-Efficient Planning of Hydrogen Networks Using a Sequential Brownfield Optimisation Approach

Friday 27 March 2026 10:20 (20 minutes)

The large-scale deployment of hydrogen in industry necessitates the strategic planning of a nationwide hydrogen infrastructure. However, most existing planning tools are inadequate for this purpose, as they either lack a sufficiently detailed implementation of repurposing natural gas infrastructure –an essential measure to minimise costs –or are computationally intractable within reasonable timeframes.

In this work, we introduce a novel sequential optimisation model designed to address these challenges. The model minimises investment costs for hydrogen networks and storage facilities while ensuring the security of natural gas supply. Investment decisions regarding the repurposing and construction of infrastructure are made at the level of individual pipelines and storage facilities, and the resulting network is subsequently subjected to flow simulations to verify its fluid-mechanical feasibility. Furthermore, the brownfield approach enables the integration of existing or planned hydrogen infrastructure.

The first step of the sequential optimisation focuses on the optimisation of the pipeline infrastructure. This is achieved using selected network usage cases that represent critical edge cases for the transportation of hydrogen and natural gas. By deciding on the repurposing of natural gas pipelines to hydrogen and the construction of new natural gas pipelines between neighbouring regions, the model identifies the most cost-efficient network capable of supplying all regions with the required amounts of natural gas and hydrogen.

Based on the resulting network, the second step of the sequential optimisation addresses the optimisation of the storage infrastructure. Analogous to the pipeline optimisation, the model can repurpose existing natural gas cavern storages for hydrogen use and construct new hydrogen cavern storages in regions with suitable geological conditions. This optimisation is performed using daily time steps over an entire year to capture storage level trajectories.

After the optimisation of pipeline and storage infrastructure, the resulting network is fluid-mechanically validated to assess its feasibility and to identify potential shortcomings arising from simplifications and linearisations in the optimisation models. By applying the approach to subsequent base years, the model enables the identification of cost-optimal expansion pathways.

The capabilities of the model are demonstrated using a case study for the German federal state of Lower Saxony. The analysis is based on publicly available data on existing pipelines and storage facilities, as well as hydrogen and natural gas supply and demand data from the research project Langfristszenarien 3. Lower Saxony features an extensive natural gas network due to its history of natural gas production and is expected to be among the first federal states connected to the German hydrogen network, owing to its favourable conditions for hydrogen production and imports. In addition, the region hosts numerous existing natural gas storages and offers substantial geological potential for the development of hydrogen cavern storages.

The complete model solves the case study within 12 hours on a standard desktop computer equipped with an Intel Core Ultra 5 processor and 16 GB of RAM. The resulting hydrogen network for Lower Saxony has a total length of 959 km, of which 51% consists of repurposed pipelines. Investment costs and network length can be significantly reduced by supplying only 99% of the hydrogen demand, thereby eliminating the need to connect regions with very low hydrogen demand. Two of the existing 22 natural gas storages are repurposed for hydrogen use, and five new cavern storages with a combined hydrogen capacity of 342 GWh are constructed.

Overall, the model is capable of identifying cost-efficient hydrogen networks for large geographic areas within short computational times. By varying supply and demand assumptions, it can be used to analyse alternative expansion pathways, assess uncertainties regarding future hydrogen utilisation, and identify no-regret investment options for hydrogen infrastructure. However, as the model relies on supply and demand data derived from energy system models, its results are inherently dependent on the assumptions underlying the chosen scenarios.

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Session Classification: Hydrogen Markets & Infrastructures

Contribution ID: **114** Type: **not specified**

Reassessing Carbon Dioxide Removal Pathways System Consistency Between Electricity-Driven DAC and CO_2 Handling

Friday 27 March 2026 17:30 (20 minutes)

Overview
Integrated assessment models (IAMs) increasingly rely on large-scale carbon dioxide removal (CDR) and carbon capture, transport and storage (CCTS) to achieve net-zero and net-negative emission pathways. However, empirical evidence from operational projects reveals a persistent gap between modelled deployment assumptions and realised capacities. Despite rapidly increasing announcements of DAC and CCTS projects, actual capture volumes and system integration remain limited, raising concerns about the feasibility of assumed capture trajectories (Schmidt et al. 2025).

Recent research shows that DAC deployment is constrained not only by scale-up challenges, but also by technology-inherent characteristics that shape cost trajectories and limit convergence toward low marginal costs (Sievert, Schmidt, and Steffen 2024). In parallel, DAC is increasingly conceptualised as an electricity-driven or electrochemical process that can act as a flexible consumer of renewable electricity, introducing strong dependencies on electricity price distributions and grid carbon intensity that are rarely represented explicitly in energy system models. European evidence further suggests that CO_2 transport and storage infrastructure does not scale automatically with capture deployment, creating additional timing and capacity constraints along the CDR chain (Tumara et al. 2024).

While modelling and policy discussions continue to emphasise geological storage as the dominant downstream option, recent analysis highlight as a scarce system resource shaped by policy, infrastructure availability, and competition with other strategic energy uses rather than an unconstrained sink (Patonia et al. 2025). Where utilisation pathways are considered, sustainability literature stresses that CO_2-based polymer and biopolymer applications are not automatically climate-beneficial, as outcomes depend on market scale, end-of-life handling, and time dynamics rather than capture alone (Sovacool et al. 2023).
Methods
We develop a system-good consistency analysis that evaluates whether CO_2 capture deployment can be reconciled with realistic system constraints. The analysis focuses on collective feasibility and system closure across three elements: (i) conditional availability of DAC and CCTS, (ii) electricity-system dependence of electricity-driven DAC, and (iii) capacity- and timing-constrained transport and downstream handling of captured CO_2.

DAC is represented as a price-responsive, electricity-coupled activity whose utilisation depends on electricity prices and grid carbon intensity, rather than baseload operation. Downstream handling is modelled through constrained sink categories, including permanent geological storage and utilisation routes, with storage treated as a capacity- and policy-constrained system resource. Polymer- and biopolymer-based utilisation is represented as a bounded option limited by market uptake and end-of-life dynamics (Sovacool et al. 2023).

These elements are additionally combined in a reduced-form economic model, linking electricity prices, CO_2 incentives, capture operation, transport constraints, and sink capacities through explicit mass-balance and capacity conditions. The model generates additional system-level indicators such as achievable capture volumes, downstream allocations, and a system-closure ratio indicating gaps between captured and effectively handled CO_2. Building on this formulation, further analysis can explore how changes in electricity-system conditions, policy incentives, and downstream capacities affect system consistency

Preliminary Results
Initial results indicate that the CDR chain performance is governed by interactions between electricity-driven capture and downstream handling, rather than by capture availability alone. Electricity-driven DAC enters the system as a conditional, price-responsive activity, with realised capture volumes determined by electricity prices and grid carbon intensity. Downstream handling emerges as a binding constraint: limited transport infrastructure and constrained storage capacity restrict access to both geological storage and utilisation pathways, and generating gaps between captured and effectively handled CO_2 even when capture is economically viable. Polymer and biopolymer utilisation functions as a limited bridge option but cannot substitute for large-scale permanent storage due to market and end-of-life constraints.
Preliminary Conclusions
Starting from a system-good perspective highlights that the contribution of DAC and CCTS to decarbonisation is constrained not only by capture performance, but by electricity-system interaction, transport availability, storage capacity, and downstream utilisation. Treating these elements as independent risks overstating the role of carbon capture in mitigation pathways.

The proposed CDR-chain framework provides a transparent basis for bridging the gap between IAM assumptions and real-world feasibility by explicitly testing system closure prior to optimisation, techno-economic assessment, or life-cycle analysis. Recent evidence on underground storage for decarbonisation underscores that CO_2 storage competes with other strategic energy uses and requires coordinated planning, reinforcing the need for chain-level consistency analysis in the design of robust decarbonisation strategies (Patonia et al. 2025).

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Session Classification: Carbon Removal & Transition Pathways

Contribution ID: **116** Type: **not specified**

Options for European Data Center Energy Supply under Climate and Market Uncertainty

Friday 27 March 2026 11:50 (20 minutes)

The rapid expansion of digital infrastructure has elevated data centres to a position of strategic importance within European electricity systems. Recent analyses indicate that, despite advances in facility engineering, power supply remains the leading cause of impactful outages, while rapidly increasing AI-driven computational demand further heightens exposure to reliability and geopolitical risks (BusinessWire 2025). At the same time, climate resilience remains underrepresented in many operational studies, which often omit realistic climate scenarios, robust optimisation comparisons, or explicit temperature-dependent performance effects (Khalili et al. 2025). Integration with local electricity markets is frequently constrained by fragmented regulation, scalability limitations, and incomplete physical grid modelling. Even advanced technical work on cooling architectures, workload forecasting, and power electronics does not consistently couple renewable integration, climate-aware sizing, and economic–environmental trade-off (Zhou et al. 2025; Koot and Wijnhoven 2021). Together, these gaps motivate the need for an integrated data-centre energy-system model that is outage-aware, climate-informed, market-coupled, and technology-diverse

This work introduces the first model for the techno-economic assessment of data centres in Europe, designed to be transparent, tractable, and extensible. Facility electricity demand is decomposed into the workload-driven IT load, a temperature-coupled cooling load, and auxiliary electrical needs. Cooling demand is expressed as a deterministic function of ambient temperature, allowing spatial and temporal climatic variability to influence both hourly operations and technology sizing. This climate-aware formulation captures region-specific effects such as elevated cooling requirements in southern Europe or seasonal load compression in northern regions, which are often abstracted away in stylised analyses.

A simplified yet physics-consistent representation of on-site energy assets is integrated into the model. The resource portfolio includes battery energy storage systems (with standard state-of-charge dynamics), gas turbines, small modular reactors, and variable renewable resources such as wind and photovoltaic generation. Each technology is characterized by its feasible operating envelope, availability constraints, efficiency assumptions, and capacity limits, enabling the evaluation of energy shifting, emergency backup capability, renewable integration, and grid-service provision. Optional security-of-supply constraints allow the model to enforce outage tolerance or "n−1"-type reliability requirements. The modular structure also supports future extensions, including probabilistic outage modelling, advanced cooling-system control strategies, and explicit network-flow formulations.

Real-world electricity prices and tariffs from Eurostat non-household price bands, DESNZ non-domestic UK statistics, and public utility-rate databases are embedded to compute operational costs under diverse pricing structures, including energy charges, demand charges, dynamic tariffs, and carbon costs. Hourly renewable resource profiles and temperature data provide environmental drivers for both cooling requirements and on-site renewable yields. These datasets form a data-to-model pipeline capable of generating realistic and synthetic IT-demand trajectories for scenario analysis across European locations.

First results highlight the dominant influence of climate on cooling demand, the cost and reliability trade-offs across on-site supply configurations, and the potential advantages of hybrid portfolios combining storage, renewables, and firm generation. This model establishes a consistent baseline for more detailed thermal, economic, and grid-integrated analyses, offering actionable insights for operators and policymakers seeking to support resilient and sustainable data-center growth in Europe.

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Session Classification: Sector Coupling & Emerging Demand

Contribution ID: **118** Type: **not specified**

Multivariate Probabilistic Forecasting for Day-ahead Electricity Prices, Battery Trading and the Financial Evaluation of Forecast Performance

Friday 27 March 2026 15:10 (20 minutes)

Electricity price forecasting is crucial for decision-making in energy markets and the operation of energy assets. Probabilistic forecasts are increasingly adopted because they explicitly quantify uncertainty. In many applications, probabilistic forecasts are either issued as quantile predictions, which describe the marginals, or as ensembles (or scenarios) of the full predictive distribution. Yet it remains unclear how improvements in statistical forecast quality translate into economic value. Battery storage arbitrage in day-ahead electricity markets is often used as an application-based benchmark for this purpose. In this brief paper, we analyze popular quantile-based trading strategies (QBTS) and highlight two critical flaws: QBTS do not incentivize honest probabilistic forecasting and they ignore the intertemporal dependence structure of electricity prices. Furthermore and somewhat surprisingly, we show that risk-neutral and risk-averse battery trading strategies, even if based on a fully multivariate probabilistic forecasts, cannot necessarily be used to search for the best forecast from a set of competing forecasting models. We provide theoretical justification for these claims and an empirical evaluation. Our application study is based on data from the German electricity market and highlights the difficulties of ranking price forecasting models based on battery trading strategies. We discuss these pitfalls in application-based evaluation of price forecasting and conclude with implications for forecast evaluation practice and directions for future research.

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Session Classification: Electricity Price Formation & Forecasting

Contribution ID: **120** Type: **not specified**

Challenges and Emerging Solutions for Electrolyser Projects in the Hydrogen Ramp-Up: Practical Insights from VNG's Project and Business Case Development

Friday 27 March 2026 10:00 (20 minutes)

Motivation
The European hydrogen ramp-up is progressing more slowly than anticipated, hindered by high project costs, complex regulatory requirements and uncertain industrial demand. At the same time, structural developments are opening opportunities to accelerate project viability. Targeted improvements such as simplified and more flexible electricity sourcing rules under RFNBO, and the continuation or refinement of grid-fee exemptions beyond 2029, could substantially reduce LCOH and increase operational flexibility.
Despite current industrial weakness, first functioning hydrogen use-cases are emerging. In the mobility sector, early demand combined with stable THG-quota mechanisms is already creating real markets. Some steel producers are maintaining their transformation commitments, offering credible long-term off-take perspectives. Parallel policy debates on green-gas quotas, renewable molecules in the EU market design and expanding guarantees-of-origin systems are generating new impulses that may strengthen demand and improve planning certainty. Against this backdrop, the paper examines both barriers and actionable solution pathways, informed by VNG's project development experience.

Methods
This study offers an inside view of how a gas-sector company develops hydrogen and electrolysis projects. Instead of relying mainly on quantitative modelling, the approach highlights the practical steps and decision logic used in early-stage and advanced project development. Core considerations include regulatory conditions, electricity procurement options, site and infrastructure constraints, partnership structures, and market signals relevant for commercial viability.
Analytical tools such as cost estimates, regulatory reviews and qualitative risk assessments support—but do not dominate—the process. Insights from VNG project development illustrate how companies balance operational strategies, supply-chain uncertainties and changing policy frameworks to determine whether conditions are sufficient for investment. The projects Energiepark Bad Lauchstädt and GreenRoot support an assessment of system-serving versus constant-load operating strategies.

Results
Many electrolysis projects currently struggle to reach FID maturity. Key barriers include restrictive RFNBO criteria, the expected end of grid-fee exemptions, uncertain industrial demand projections and misaligned price expectations. However, several levers can significantly improve feasibility:

Regulatory simplification: More flexible temporal matching rules for renewable electricity and extended grid-fee exemptions could reduce LCOH by double-digit percentages and enable system-beneficial, flexible operations.
Emerging demand drivers: Refineries and functioning THG-quota markets demonstrate viable demand mechanisms and provide templates for broader market development.
Industrial decarbonisation: Despite short-term economic headwinds, committed steel manufacturers continue to plan hydrogen-based processes, creating medium- to long-term off-take potential.
Green-gas quotas and lead market for green innovation: Policy discussions at national and EU level signal increasing momentum for market-creating quota systems, which could provide the demand pull needed for investment decisions.
Global CAPEX dynamics: Declining costs from Chinese electrolyser manufacturers increase competitive pressure but may also present opportunities to lower CAPEX if quality, certification

and supply-chain risks are properly managed.
System services from electrolysers: Beyond hydrogen production, electrolysers can support the electricity system by providing flexibility, demand response and ancillary services. This enhances system stability, reduces integration costs for renewables and improves the economic case for flexible, system-serving operation modes.

Overall, the combination of targeted regulatory adjustments, emerging demand niches and evolving policy instruments indicates a more optimistic trajectory for electrolysis deployment than current market sentiment suggests.

CV
Dr. Philipp Hauser has worked at VNG AG since 2021 as an advisor for scientific studies in the Green Gases division, focusing on the development of hydrogen value chains and the strategic integration of renewable and decarbonised gases. He contributes to key projects such as the Energy Park Bad Lauchstädt and the BMBF flagship initiative TransHyDE, providing energy-economic analyses and techno-economic insights for Germany's emerging hydrogen economy.
He studied Industrial Engineering at TU Dresden (B.Sc./M.Sc., 2008–2014) and subsequently served as a research associate at the Chair of Energy Economics until 2020. His academic work centred on electricity-gas sector coupling, European gas market modelling and uncertainty in energy system analysis. In 2022, he earned his doctorate (Dr. rer. pol.) from TU Dresden. His expertise spans hydrogen infrastructure, system integration, market design and regulatory frameworks.

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Session Classification: Hydrogen Markets & Infrastructures

Contribution ID: **121** Type: **not specified**

High-resolution modelling of heating and cooling demand under societal and climate change scenarios: Implications for the operation of heat pumps in the German commercial sector

Friday 27 March 2026 12:10 (20 minutes)

As part of an integrated energy transition, decarbonising heating in the German building sector is a central objective of national energy and climate policy [1]. In particular, the commercial sector plays a crucial role due to its heterogeneous building stock, diverse usage patterns, and significant demand for both space heating and cooling. Effective planning of climate-neutral heat supply pathways based on electrification, renewable energy integration, and sector coupling requires an understanding of how future heat demand unfolds under interacting long-term drivers, such as climate change and societal transformation [2].

Despite its relevance, future energy demand in high resolution has been minimally studied or simplified in energy systems analysis, which leads to inaccurate assessments of electrification potential, peak electricity demand, and its flexibility.

This work aims to address this gap by presenting a methodology to model future heating and cooling demand at high temporal resolution. The approach is applied to the German commercial sector and evaluates six contrasting long-term societal scenarios in combination with three Representative Concentration Pathways (RCP) for climate change. The high-resolution demand modelling is integrated with energy system optimisation to assess the role of electrification through heat pumps, as shown in Figure 1.

Societal change scenarios are derived using a Cross-Impact Balance (CIB) analysis and translated into annual demand values and building stock development [3]. The qualitative CIB scenario narratives are quantified into future annual service demand for space heating, space cooling, and domestic hot water. In addition, projections of the future commercial building stock are being considered.

For each scenario, hourly demand profiles are then generated using an enhanced degree day methodology that accounts for building thermal properties and stock, occupancy patterns and seasonal parameterisation. Model parameters are calibrated for the German commercial sector using publicly available multi-year heating demand data, and validated against statistical and observed consumption data to ensure consistency with historical demand levels. Future climate impacts are incorporated using downscaled temperature projections from climate models. The resulting hourly profiles are then aggregated across building classes and normalized to obtain consistent heating and cooling demand time series for each scenario.

To evaluate the effects on the energy system, the demand profiles are then used as inputs to a set of stylized models of the future German energy system based on the REMix optimization framework [4]. The generated model enables a systematic assessment of how climate induced demand shifts and societal transformations influence technology choices, system costs, and demand peaks.

Results obtained for future heat demand time series across different scenarios and climate change conditions, highlight that societal transformations can influence demand beyond temperature-driven effects. In particular, some societal conditions such as energy-sufficiency strategies and reduced working hours can offset the increase in heat demand expected under severe climate conditions while other scenarios, characterised by longer working hours and a more service oriented society, lead to a higher demand even under more moderate climate pathways (Figure 2). Similarly, future cooling demand under different climate and societal scenarios was analysed (Figure 3).

Further, it was found that societal behavioural patterns can also affect the optimal capacities and operation of heat production technologies. Figure 5 shows the resulting capacities for different assumptions on renewable power generation, while Figure 4 shows an example week of operation.

Current results show that both climate change and societal developments substantially affect not only the annual heating and cooling demand but also its shape in profile, with significant implications for the integration of renewables. The findings highlight the importance of coupling high resolution demand modelling with energy system optimisation when assessing heat transition pathways and the deployment of heat pumps in the commercial building sector.

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Session Classification: Sector Coupling & Emerging Demand

Contribution ID: **122** Type: **not specified**

Consumer Inattention in Energy-Efficient Technology Adoption: Evidence from the Air Conditioner Market

Friday 27 March 2026 10:20 (20 minutes)

This study examines how the salience and structure of information shape household demand for energy-efficient durable goods in an emerging-market setting. We focus on the Indonesian air-conditioner market, where inverter technology can reduce electricity consumption by up to 40 percent yet adoption remains limited. Standard models attribute under-adoption to liquidity constraints or misperceived energy prices, but a growing behavioral literature emphasizes limited attention to multi-dimensional product attributes. We test this mechanism by embedding a discrete choice experiment in a randomized information intervention that varies the visibility and format of energy-related information.

Respondents choose between pairs of air conditioners that differ in purchase price and operating characteristics. Four experimental arms are implemented: a control group with no additional information; a treatment displaying monthly operating costs; a treatment showing the official Indonesian energy-efficiency label; and a combined label–cost format that integrates categorical efficiency grades with monetary operating expenses. This design allows us to disentangle whether information affects choices through improved beliefs about energy savings or through changes in attribute weighting driven by salience.

Reduced-form evidence shows large and monotonic treatment effects. Relative to the control group, the cost-only treatment increases the probability of selecting an inverter unit by about 2–3 percentage points, the label-only treatment by roughly 9 points, and the combined format by about 15 points. These patterns indicate that the way information is presented matters more than the mere provision of numerical data. Descriptive choice shares reveal that inverter uptake remains high even at elevated prices in the combined treatment, suggesting a fundamental change in how consumers process prices.

To uncover the underlying mechanism, we estimate conditional logit models with treatment-specific price coefficients. In the control group, the price coefficient is negative and sizable, consistent with conventional demand. Introducing operating-cost information substantially attenuates price sensitivity, while label-based treatments further weaken and eventually reverse price disutility. Under the integrated format, price ceases to operate as a standard cost attribute and appears to proxy for perceived quality once efficiency cues become highly salient. This "price-role reversal"is inconsistent with stable preferences and supports limited-attention models in which information reallocates cognitive weight across attributes.

We translate these estimates into willingness-to-pay and elasticity measures. In the control group, households are willing to pay roughly 4 million IDR for inverter technology. Cost information more than doubles this valuation, whereas label treatments yield descriptive positive valuations that should be interpreted as shifts in decision utility rather than welfare. Own-price elasticities move from conventional negative values in the control group to near zero under cost information and positive under label formats, confirming that information reshapes the demand function itself.

Heterogeneity analysis reveals that responses depend on household characteristics. Higher-income and high-usage households exhibit lower effective price sensitivity when exposed to information, consistent with greater ability to process long-run savings. In contrast, households with high electricity bills remain more responsive to upfront prices, indicating that financial stress interacts with attention constraints. These patterns demonstrate that information policies do not simply shift average preferences but modify attribute weighting in ways that vary across consumers.

The findings contribute to the literature in several ways. First, by experimentally separating label and cost channels, we document non-linear amplification when both are combined—a mechanism rarely observed in previous studies that examine each format in isolation. Second, treatment-specific structural estimates provide direct evidence that information can transform the role of price in utility, rather than merely updating beliefs about energy expenditures. Third, the Indonesian context extends attention-based theories to a developing market with low label awareness and rapidly growing electricity demand, offering external validity beyond OECD settings.

Policy implications are immediate. Integrating operating-cost information into existing labels could generate large efficiency gains without subsidies, particularly where consumers are unfamiliar with technical metrics such as EER ratings. However, positive price coefficients under salient information caution against welfare calculations that rely on standard demand assumptions. Effective policy should therefore focus on designing disclosures that guide attention rather than only improving accuracy.

Limitations include the hypothetical nature of choices and the short-run horizon of the experiment. Future work linking experimental measures to actual purchase data and electricity consumption would help quantify long-term energy savings. Nonetheless, the results provide causal evidence that inattention is a central barrier to the diffusion of energy-efficient durables and that carefully designed information can realign household decisions with lifetime cost minimization.

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Session Classification: Consumer Behavior & Tariffs

Contribution ID: **124** Type: **not specified**

Bridging Economics and Physics in Energy System Analysis: Effects of Flexibility Representation on Model Outcomes

Friday 27 March 2026 17:10 (20 minutes)

Efficient decarbonization of fossil-based energy systems requires extensive electrification of end-users'heating and mobility sectors. Replacing gas-based heating with electric heat pumps and fuel-based private vehicles with battery electric vehicles increases the use of renewable electricity and can substantially improve overall energy efficiency. At the same time, distribution grids were largely designed for lower peak demand and will increasingly face local capacity constraints as electrification progresses. These constraints arise not only from higher baseline load, but also from price-driven operation: households and aggregators respond to market signals and shift demand in ways that can amplify simultaneity and peaks. Consequently, demand-side flexibility is becoming central to both market-oriented dispatch and grid-aware operation. To address these topics, energy system modelers must consider realistic yet feasible representations of sector coupling technologies. However, there is a wide range of ways to model demand-side flexibility, and the impact of these conceptual and physical differences on model outcomes remains insufficiently understood.

This study develops a meta-analytical modeling framework to assess and classify the physical fidelity of flexibility representations in market-oriented optimization models. First, we conduct a systematic literature review and derive a structured taxonomy for flexibility models of heat pumps and battery electric vehicles, distinguishing two key dimensions: (i) component modeling depth (e.g., constant versus operating-state-dependent efficiency, endogenous coefficient of performance behavior, explicit storage dynamics) and (ii) aggregation level (single-device versus fleet/virtual storage representations). Second, selected model classes are implemented in a case study to compute optimized dispatch schedules and to quantify the implications of modeling choices. To evaluate physical feasibility and realism, we couple the market optimization results with physics-based dynamic simulation, benchmarking optimized schedules against simulated component behavior. For the simulation, a dynamic model in Modelica using the TransiEnt Library is used. Because high-fidelity formulations can become numerically demanding at scale, we also analyze the effect of aggregation and introduce an aggregation and online disaggregation strategy that enables tractable optimization while preserving component-specific validation in the simulation domain.

Results show that greater component modeling depth generally yields more realistic optimization outcomes, but at higher computational cost. For heat pumps, modeling the coefficient of performance endogenously and representing storage dynamics more accurately improves the prediction of realized behavior and dampens price-arbitrage incentives, thereby reducing apparent flexibility compared to simplified constant coefficient of performance. For battery electric vehicles, accounting for partial-load charging, where charging efficiency typically decreases at low power, reduces the risk of energy underprovisioning and prevents systematic overestimation of flexibility and the value of market incentives. Across scenarios, aggregation level has only a minor influence on techno-economic outcomes when appropriate dispatch models are used that account for relevant system states (e.g., temperatures, states of charge, and electrical/thermal loads) and when disaggregation
reconstructs physically consistent device-level operation. Overall, the study indicates that errors from insufficient component-level physical detail can outweigh aggregation effects. Transparent reporting of modeling depth, aggregation assumptions, and validation practices is therefore essential to ensure robust and comparable insights for utilities and policymakers.

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Session Classification: Flexibility Modelling

Contribution ID: **125** Type: **not specified**

The role of nuclear (in-) flexibility in the transition toward climate-neutral power systems

Friday 27 March 2026 15:10 (20 minutes)

Achieving the climate neutrality objective necessitates a fundamental transformation of the electricity sector. This, in turn, requires a comprehensive system value assessment of low-emission technologies, including variable renewable energy sources (VRES), nuclear power, and electricity storage. Policy and investment decisions should account not only for the deployment of new assets but also for the implications of existing infrastructure and associated sunk costs. Furthermore, the flexibility constraints and costs of nuclear power must be critically examined.

We develop a mixed-integer optimization model that incorporates discrete investment decisions for nuclear power plants, along with binary operational constraints capturing the status of each unit. These reflect economically driven load variations, temporary shutdowns, maintenance periods, and flexibility limitations linked to the nuclear fuel cycle. Other technologies—such as VRES, fossil-fired gas power plants, short-term battery storage, and long-term hydrogen storage—are represented using linear constraints.

In a case study, we explore multiple energy system scenarios and evaluate both the composition of the optimal asset portfolio and spot market outcomes in the electricity and hydrogen sectors. In particular, we conduct a sensitivity analysis across different CO_2 price levels and hydrogen demand trajectories.

Preliminary findings suggest that higher CO_2 prices and increasing hydrogen demand significantly amplify the need for supply-side flexibility. In scenarios where nuclear plants are assumed to be flexible, their ability to modulate output becomes increasingly valuable as VRES penetration rises, contributing to system balancing during periods of low wind or solar availability. Conversely, when nuclear generation is modeled as inflexible, the system relies more heavily on VRES expansion and battery storage, which emerge as more cost-effective investment options.

Overall, the results highlight the importance of accounting for operational flexibility in long-term energy planning, particularly in countries with legacy nuclear capacity, as it can substantially affect optimal pathways toward a climate-neutral electricity system.

Natalia Goryashchenko is a PhD student in the Energy Systems and Market Design Lab at the Technical University of Nuremberg, under the supervision of Prof. Dr. Veronika Grimm. Her research focuses on electricity market optimization, low-carbon generation technologies, and flexibility options such as nuclear power, renewable integration, and hydrogen storage in climate-neutral energy systems.

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Session Classification: Nuclear, Fusion & Sociotechnical Futures

Contribution ID: **127** Type: **not specified**

Smart Meter Analytics and Tariff Design for Alleviating Energy Poverty: Evidence from a Clustering-Based Study in Montreal

Friday 27 March 2026 10:40 (20 minutes)

Energy poverty, defined as the inability to afford adequate energy services, poses serious health and comfort risks, particularly in regions with extreme climates. Traditional identification methods often rely on static income-based indicators, failing to capture real-time energy deprivation. This study leverages smart meter data from 5,984 households in Montreal to develop a data-driven approach for detecting and alleviating energy poverty. Daily per capita load profiles are first clustered into low-, medium-, and high-load groups using k-means, with low-load households exhibiting consistently lower usage and reduced behavioral flexibility. Integrating per capita living area in a second-stage clustering enhances differentiation between structurally low-demand and affordability-constrained households. Building on these profiles, policy simulations of a three-tier Increasing Block Tariff (IBT) are conducted to assess potential distributional impacts. The results suggest that low-load households would increase annual electricity consumption by 6.3% while reducing expenditures by 12.9%, indicating improved affordability and access. High-load households are projected to face higher unit prices and reduce discretionary use, while system-wide average prices remain stable, ensuring revenue neutrality. This combined profiling–tariff approach demonstrates the potential of smart meter analytics to support equitable electricity pricing. The framework provides a replicable tool for policymakers, highlighting IBT as an effective mechanism to alleviate energy poverty and achieve a fairer distribution of electricity costs without compromising utility stability.

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Session Classification: Consumer Behavior & Tariffs

Contribution ID: **128** Type: **not specified**

Structural Persistence and Evolution of the Sawtooth Pattern in the European 15-Minute Day-Ahead Market: Empirical Insights and potential Drivers

Friday 27 March 2026 14:50 (20 minutes)

On October 1, 2025, European Day-Ahead (DA) trading underwent a fundamental structural reform with the conversion to 15-minute trading products across all participating Member States. This transition aimed to enhance the integration of renewable energy sources and improve overall market efficiency by harmonizing the DA timeframe ever more closely with the physical reality. Historically, the so-called 'sawtooth pattern'—characterized by systematic intra-hour price jumps resulting from load over- and under-estimations—was a dominant feature of the Intraday auction 1 (IDA1), driven by the granularity mismatch between hourly DA products and first quarter-hourly adjustments. Contrary to some expectation that introducing quarter-hourly DA products would smoothen the IDA sawtooth prices, empirical data reveals that the sawtooth pattern persists and has migrated into the DA market. While the magnitude of price deviations has declined compared with 'sawtooth'patterns prior to the 15-minute transition, the phenomenon remains a structural component of price formation. We attribute this to specific market frictions: procurement strategies that still rely heavily on block and hourly products, and 'bidding inertia'where participants optimize against hourly schedules. Furthermore, we highlight the potential amplifying role of cross-border constraints, where rigid hourly Flow-Based Market Coupling (FBMC) capacities may restrict physical exchange during intra-hour ramps, forcing sharp internal price adjustments when local merit orders are stretched. We conduct a descriptive analysis to identify the potential drivers of the continued "sawtooth pattern", i.e., the intra-hour spreads on the DA market. We examine the relationship between 60-minute volume shares and price volatility, indicating that high concentrations of hourly block orders necessitate a more 'active'smoothing of sub-hourly ramps. Additionally, we analyse Merit Order Curve regimes to show how potential non-linear supply elasticity amplifies intra- hour spreads during periods of steep residual load gradients. Additionally, we quantify the historic impact on renewable capture prices, illustrating the 'value destruction' for solar assets where generation peaks coincide with systematic price dips within the hour, when moving from an hourly to a quarter-hourly DA price. Finally, we discuss the integration of these findings into our fundamental modelling framework. To capture these dynamics, we implement a structural post-processing logic that superimposes a 'sawtooth pattern'—derived from residual load gradients and thermal inflexibility constraints—onto our hourly forecasts. Looking ahead, we utilize this framework to assess the future trajectory of the sawtooth in light of the projected 215 GW solar capacity in Germany by 2030. Our approach suggests that despite improvements in algorithmic bidding, the pattern will likely persist for some time due to the fundamental collision between growing solar ramps and the structural dominance of thermal block bids.

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Session Classification: Electricity Price Formation & Forecasting