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– Sustainable energy security, ready for the future –

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INTRODUCTION:

CURRENT AND FUTURE CHELLENGES TO ENERGY SECURITY

– Sustainable energy security, ready for the future –

This edition addressed emerging security challenges and opportunities resulting from global efforts to lower CO_2 emissions by reducing consumption of high-carbon energy sources, it focussed on the impact of climate change on the global energy system considering both mitigation and adaptation actions and their possible impacts on the transition roadmap toward a decarbonisation system.

There is a strong link between energy policy and national security and the forthcoming dangers of climate change focused the attention on the international and national dimensions of the future of energy-security nexus. Various interest groups, intergovernmental organizations, industry leaders, and security experts debate on energy security and although there is a wide consensus regarding the need to a net zero emission society, the points of view regarding the path of this transition are not always the same.

This 2025 edition had a special significance: ten years have passed since the ratification of the Paris Agreement, a historic agreement that has profoundly changed the policies of various countries. Climate change is now a reality which our governments must face in their economic, environmental and social development prospects, to avoid putting at risk the future generations.

A boosting development of renewable energy sources is necessary to contrast the climate change, that together with the actions to accelerate the improvements in energy efficiency are two fundamental pillars of a win-win strategy to reduce energy bills, dependence on imported fuels and speed up reductions in greenhouse gas emissions. At the same time this will support the economy and the industrial sectors, with the creation of new job opportunities and a national industrial supply chain.

However, there are also many critical challenges, including the energy crisis, inflationary pressures, availability of some critical raw materials.

The AIEE Symposium is always an opportunity to discuss all these issues, to bring together prominent academic voices as well as experienced practitioners and policymakers, offering an opportunity to "bridge the gap" between these sectors.

Participants in the conference are challenged to identify critical issues and to explore new and existing trends proposing creative solutions of new technologies, in the context of the emergence of new market conditions and new market operators.

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Matteo Di Castelnuovo, Conference General Chair, Associate Professor of Practice of Sustainability, Director of the Master in Sustainability Management, SDA Bocconi, Italy

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Abstracts

Magdalena Zajączkowska

RETHINKING ENERGY SECURITY IN THE EUROPEAN UNION AFTER 2022: FROM SUPPLY DIVERSIFICATION TO SYSTEMIC RESILIENCE

Magdalena Zajączkowska,
Krakow Univeristy of Economics, Rakowicka 27, 31 510 Kraków, Poland
Email: zajaczkm@uek.krakow.pl

Overview

The Russian invasion of Ukraine in 2022 marked a critical juncture in the European Union's energy policy, exposing the limitations of long-standing strategies focused predominantly on supply diversification. In response, EU energy security discourse has begun to evolve toward a more systemic and resilience-oriented paradigm, reflecting the complex interplay between infrastructure, markets, governance structures, and geopolitical risk. This study critically re-evaluates the conceptual foundations of EU energy security and argues for the adoption of a systemic resilience framework—one that transcends traditional metrics such as import dependency or source diversification. By integrating absorptive, adaptive, and transformative capacities, the paper develops a novel analytical lens to assess how EU and national-level responses—such as REPowerEU, cross-border interconnections, and critical infrastructure planning—contribute to the robustness and flexibility of the European energy system under conditions of prolonged volatility and systemic stress.

Methods

This research employs a multi-method approach integrating conceptual analysis, comparative case study, and composite index development to evaluate the evolution of energy security frameworks in the European Union post-2022.

Conceptual analysis: A critical review of the academic literature and policy documents is conducted to trace the evolution of the "energy security" concept and to position the notion of "systemic resilience" within interdisciplinary discourses on infrastructure, governance, and risk. Key sources include peer-reviewed journals, European Commission strategies (e.g., REPowerEU), and relevant technical reports.

Comparative case study design: The study applies a structured, focused comparison across three EU member states—Poland, Germany, and the Nordic States—selected based on variation in energy system configuration, institutional readiness, and exposure to external supply shocks. Country-specific data on energy infrastructure, policy instruments, and market integration are systematically analyzed to assess national-level resilience trajectories.

Composite Index Construction: A novel Energy Systemic Resilience Index (ESRI) is developed to quantify energy system robustness across three dimensions:

- absorptive capacity: ability to buffer shocks via storage, diversification, and redundancy mechanisms,
- adaptive capacity: responsiveness of regulatory frameworks, interconnectivity, and market flexibility,
- transformative capacity: long-term structural change via investments in renewable energy, grid modernization, and critical material security.

The index is calibrated using harmonized indicators from Eurostat, ENTSO-E, IEA, and national statistical offices, enabling cross-national and temporal comparison.

Results

The application of the Energy Systemic Resilience Index (ESRI) reveals pronounced disparities in the resilience architecture of EU member states. Poland demonstrates significant progress in absorptive capacity, particularly through the expansion of LNG import infrastructure and strategic gas storage.

However, deficiencies are observed in adaptive and transformative capacities, notably due to regulatory inflexibility, limited decentralization, and underinvestment in critical infrastructure protection.
Conversely, Germany and the Nordic states exhibit more balanced resilience profiles, characterized by advanced grid integration, diversified renewable energy portfolios, and mature institutional mechanisms for crisis coordination. The Nordic States, while vulnerable in absolute terms, show high relative gains in interconnectivity and regional cooperation mechanisms.
At the EU level, policy instruments such as REPowerEU, the strategic energy reserves, and proposed joint stockpiling of critical raw materials contribute positively to systemic resilience. Nevertheless, the analysis identifies persistent coordination asymmetries and institutional fragmentation, particularly in the operationalization of cross-border solidarity and crisis-response governance.

Conclusions

This study demonstrates that traditional supply-centric metrics are insufficient to capture the complexity of energy security in a post-2022 geopolitical and infrastructural landscape. The proposed systemic resilience framework offers a more comprehensive, multi-dimensional perspective that encompasses infrastructural robustness, regulatory agility, and long-term system transformation.
Key conclusions include:
Systemic resilience should become the central organizing principle of EU energy security policy, requiring the integration of absorptive, adaptive, and transformative elements across all governance levels.
National energy strategies must be context-sensitive and aligned with transnational resilience objectives to reduce systemic vulnerabilities arising from fragmentation and asymmetry.
The development and institutionalization of resilience-based indicators, such as the ESRI, can enhance strategic planning, enable performance benchmarking, and inform investment prioritization.
Future research should extend this framework to include cross-sectoral interdependencies (e.g., water–energy– cyber nexus) and apply dynamic modeling to test policy interventions under high-uncertainty scenarios.

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Maciej Skuza

ENERGY RESILIENCE OF THE EUROPEAN UNION

Maciej Skuza, Maria Curie-Sklodowska University in Lublin,
Poland Institute of Political Sciences and Administration, Doctoral School of Social Sciences
Email: maciej.skuza@mail.umcs.pl

Overview

Resilience is a topic gaining particular importance due to the increasing complexity and unpredictability of modern threats, which test the ability of states to protect their citizens and maintain stability. The state's resilience system appears to be an existential issue in the upcoming uncertain future for Europe. The concept of energy security necessitates redefinition and a new approach through energy resilience, which has gained particular significance due to the ongoing Russian aggression against Ukraine, the COVID-19 pandemic, and the period of widespread geopolitical turbulence and climate crisis. Energy resilience is a proposal for a concept on how to describe energy security and the ability to counter new threats to a state's ability to supply energy.
In this presentation, the author will present the main assumptions and research results related to the ongoing research in the discipline of international relations/political science. The analysis is designed to define the concept, specifics, key determinants, normative foundations, and implementation of energy resilience. Understanding the EU's energy resilience will help facilitate a proactive approach to energy policymaking, helping to achieve a sustainable and secure energy system, enabling it to respond more effectively to crises, adapt to changing conditions, and minimize the impact of risks.

Methods

The resolution of the research problem was based on the selection of appropriate theoretical and methodological assumptions. The methodological framework of the research included methods appropriate to the science of international relations and political and administrative sciences. This project proposes using the following research methods: factor analysis, comparative analysis, and predictive analysis. Research techniques include document analysis, statistical analysis of available and collected data, literature review, case study analysis, and conducting interviews. Referring to existing scientific research findings on the concept of levels of analysis, the level of the European Union as an international organization being a sui generis entity in the international environment, and the level of selected Member States as the fundamental subjects of international relations will be considered, taking into account their energy resilience policies.

Results and conclusions

1. Energy resilience is a multidimensional concept. The evolution of energy resilience and the prospects for development in this dimension are largely influenced by relationships in the global energy market, conditioned by a range of geopolitical, economic, ecological, and infrastructural factors that differ between Member States. The conceptual complexity and multifaceted nature require a coordinated and multi-level approach to ensure energy resilience.
2. The actions of the European Union in the field of energy resilience stem from its multi-level nature in both the subjective and objective dimensions. The bifurcation of the subjective dimension in the EU energy market and the dynamics of its development in various sectors cause the reality in this area to 'complicate faster than it matures.' Global geopolitical changes and the turbulence/instability of international energy markets are major determinants of the European Union's energy resilience.
3. The European Union's past actions to ensure energy resilience have been mainly reactive, accelerated mainly by energy crises and other forms of imbalances in energy markets. This was due to the unpredictable nature of the global energy market and internal difficulties at the decision-making level in the EU. The multi-level decision- making structure in the European Union and the diverging interests of individual Member States complicate the challenges of harmonizing and implementing an effective energy resilience policy strategy.

Lars Nickel

ENERGY RESILIENCE AND ENERGY IMPORT DEPENDENCY IN THE EU

Lars Nickel, Technical University Munich, Email:lars.nickel@tum.de

Overview

As Europe seeks to reduce its dependence on energy imports, especially from non-EU countries, the role of renewable energy in achieving energy sovereignty has become a focal point. This study utilizes the PyPSA-Eur model to simulate the European energy grid under different renewable energy penetration scenarios, aiming to assess how renewable energy integration influences the EU's energy import dependency. Our results indicate that higher shares of renewable electricity generation are associated with a reduction in energy import dependence, but significant challenges related to grid integration, storage, and cross-border electricity trade remain. The findings provide crucial insights for policymakers striving to achieve a more energy-independent Europe.

Methodology

This study uses the PyPSA-Eur model to simulate the European electricity grid, focusing on the impact of renewable energy integration on energy import dependency. The model optimizes generation, transmission, and storage for 32 EU countries, incorporating data on renewable energy generation (wind, solar), electricity demand, and cross-border transmission capacities. To assess the outcome, various scenarios have been developed reflecting different levels of renewable energy penetration and grid flexibility. These scenarios consider increasing renewable energy shares, along with enhanced storage, grid infrastructure, and cross-border trade to accommodate the variability of renewable generation. The model aims to minimize total system costs while ensuring grid stability and reducing energy import dependency.

Results

The simulation results demonstrate a clear relationship between the increasing share of renewable energy and the reduction in energy import dependency. As the proportion of renewable energy in the grid rises, the need for imports from non-EU countries decreases, primarily due to the displacement of fossil fuel-based generation. The results also highlight the critical role of grid flexibility, with storage and cross-border electricity trade helping to mitigate the variability of renewable generation. While higher renewable penetration reduces energy imports, it also introduces challenges related to grid stability.

Conclusion

This simulation study highlights the potential of renewable energy to drive significant emissions reductions in Europe, while also underlining the challenges of grid stability and economic feasibility at high levels of renewable penetration. The simulation provides a valuable tool for policymakers to simulate future energy scenarios and assess the trade-offs between cost, independence, and sustainability. Further research is needed to refine these models, incorporate additional flexibility mechanisms, and evaluate the impacts of sector coupling, such as the integration of power, heating, and transport systems.

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Marie-Joëlle Kodjovi and Pierre-Henri Bombenger

UNLOCKING SUCCESS: CRITERIA FOR EFFECTIVE ECONOMIC COORDINATION IN RENEWABLE ENERGY FACILITIES. INSIGHTS FROM A COMPARATIVE PERSPECTIVE

Marie-Joëlle Kodjovi: Institute of Tourism, University of Applied Sciences and Arts Western Switzerland Valais Wallis, , Professor Dr. Rue de la Plaine 2, 3960 Sierre, Switzerland
Email: marie-joelle.kodjovi@hevs.ch
Pierre-Henri Bombenger: Institute of Territorial Engineering (insit), School of Engineering and Management Vaud, University of Applied Sciences and Arts Western Switzerland,
Professor Dr. Rte de Cheseaux 1, 1400 Yverdon-les-Bains, Switzerland
Email: pierre-henri.bombenger@hes-so.ch

Overview

The decarbonization of the energy system is only possible if a sufficient number of local renewable energy projects (REPs) are implemented. However, REP projects often face implementation challenges due to various poorly coordinated sectoral policies. This research identifies the key economic conditions required for the successful implementation of renewable energy production facilities.

Methods

Methodologically, the research project is based on a comparative study of twelve local renewable energy production projects employing four different technologies: ground-mounted photovoltaics, deep geothermal energy, agricultural biomass, and wind power. The studied REP projects are distributed across three countries: Switzerland, France, and Canada. They are either operational, under development, or abandoned, which allows us to cover a range of cases of success or failure. Each project is examined in relation to economic coordination, which characterizes the practices of distributing economic gains and losses associated with a REP and evaluating the fairness of treatment among the parties involved. The comparison of the twelve studied REP projects has allowed us to identify coordination gaps among stakeholders and the economic success factors for project implementation. The obtained results enable the formulation of a series of recommendations for decision-makers.

Results

From an economic perspective, the sharing of operating income from projects, usually guaranteed by public funds, is limited. The local benefits of these energy projects remain constrained, even though the exploited natural resource is deeply rooted in the local context. This results in an asymmetry between the economic gains generated by the REP and the losses caused by the environmental and situational impacts of the REP on local residents and users of the site. Ultimately, there is a lack of coordination between, on the one hand, economic subsidy and public guarantee mechanisms for REP implementation, primarily driven by national actors, and, on the other hand, environmental and spatial authorization mechanisms, which are mainly managed at the regional and municipal levels.

In successful projects, various sector-specific public aids supporting REP development are coordinated with mechanisms for selecting the most appropriate sites. Different approaches can be used to achieve this objective, such as involving an intermediary actor who is not capable of developing the project themselves. Another option is the selection of sites through competitive bidding for operating concessions. These types of mechanisms allow leveraging the advantages of offers made by market actors (thus maximizing production yields and minimizing operating costs) while integrating planning criteria imposed by environmental and territorial regulatory authorities. These approaches, developed notably in France, enable reliance on the technical and economic expertise of developers while explicitly incorporating legal requirements, such as consistency with environmental protection measures and consideration of the expectations of the local stakeholders concerned. This latter dimension could be accompanied by a consultative voting procedure on the REP involving the local population.

Public aid is then granted only to projects that simultaneously satisfy spatial optimization criteria for site selection and ensure high production efficiency at the lowest cost. In successful REP projects, greater transparency regarding financial structures and the distribution of costs and dividends would contribute to building stronger trust among the actors involved.

Conclusion

In terms of recommendations for policymakers, it can notably be mentioned that the economic gains from projects, which often benefit from public support, should be less opaque and redistributed, even if only to a minor extent, more equitably among local actors, especially to compensate for environmental losses. Moreover, the mobilization of public land for the implementation of REP projects and the operation of REPs by a public entity are better suited to maximizing the collective public benefits of the energy transition, notwithstanding the organization of public bidding processes for operating concessions.

Honorata Nyga-Łukaszewska

ENERGY SECURITY AND INTERNATIONAL COMPETITIVENESS OF HIGH-INCOME COUNTRIES

Honorata Nyga-Łukaszewska, SGH Warsaw School of Economics,
Email: hlukas@sgh.waw.pl

Overview

Energy security is an important topic from the perspective of economic theory and practice, but still it is a theoretically underestimated phenomenon (Van de Graaf T. et al. 2016). Existing energy security analyses, in most cases, are vocal about the perspective of energy importers but remain rather silent on the perspective of exporters (e.g.: Dike, 2013; Karatayev, Hall, 2020; Novikau, 2022). Rare studies showing the latter optic mostly cover the group of developing/transition/emerging countries while omitting developed countries perspective in the natural gas market, as pointed out by Antoniadis (2017), Bollino, Galkin (2021), Karatayev and Hall (2020).

Additionally, accordingly to the data the group of highly developed countries from the Organization for Economic Cooperation and Development (OECD) has increased its share of liquefied natural gas (LNG) exports (only) from less than 10% in 2000 to 40% in 2021 (BP, 2022). This trend is expected to continue or perhaps even strengthen in the future

Reckognizing the above arguments, countries' sample used in the study included the world's leading industrialized natural gas exporters. I selected developed countries from the group of high-income OECD economies. As a result, the group of countries included: Australia, Canada, the Netherlands, Norway and the US. The period of analysis covered the first two decades of the 21st century.

Methods

The goal of this study was to check if energy demand security influenced the comparative advantage of highly developed (net) natural gas exporting countries. In the study, I verified the thesis that at the beginning of the 21st century, on the one hand, there is a growing importance of analyses about exporters' security in scientific research, and on the other hand, that exporters' security determined the comparative advantage of high-income gas-exporting countries.

I tested the thesis using various research methods. First, I used a critical review of the literature enriched with elements of a systematic review (scoping review), which aimed to examine and organize the current state of research on exporters' energy security. Second, I used the econometric modelling. The quantitative study was based on the Amoroso et. al. (2011) model, in which I verified the thesis of the formation of countries' comparative advantages under the Heckscher-Ohlin and Ricard hypotheses. In the study, I tested whether Norway's pattern of comparative advantages relative to other developed, leading gas exporters was related to differences in factor endowments or differences in labor productivity. The use of this approach was prompted by the fact that there is a growing body of evidence (Leamer, 1995; Harrigan, 1997; Chor, 2010; Morrow, 2010) suggesting that countries' patterns of specialization (regardless of their income) are shaped simultaneously by differences in factor endowment and differences in labor productivity. Therefore, the final model specification was a combination of the Heckscher-Ohlin and Ricard hypotheses.

Results

Within the theoretical goal, literature review proves that energy security studies, and energy demand security, in particular, is on the rise in scientific research in the 21st century. Even though, the absolute numbers of scientific investigations in energy demand security are still moderate, their growth dynamics are significant. Results show dominant position of Asian or North American institutions and meager role of European universities in energy security studies.
The results of the empirical study proved that Norway's comparative advantage compared to other high-income gas- exporting countries was related to both differences in labor productivity and factor endowment, which at the same time confirmed previous suggestions from the literature (Leamer, 1995; Harrigan, 1997; Chor, 2010; Morrow, 2010).

The comparative advantage in this group of countries was not associated with natural gas export revenues, fuel exports and the quality of institutions - variables that are theoretical references to the exporters' concept of energy security. The only statistically significant energy variable was supply security index, which proved that even for energy exporters, concerns about energy supply security interacted with comparative advantage.

Conclusions

As long as part of the hypothesis on increased relevance of energy demand security phenomenon in the 21st century, can be confirmed by the theoretical conclusions; its importance for international competitiveness of high income OECD nations is questioned. Theoretical considerations support claim that since the beginning of 2000s there is a growing number of research in energy demand security studies. Empirical model, within its specification, confirms rather the importance of supply, not demand security, for high income OECD net natural gas exporters. This claim has three implications for future research. Firstly, from the theoretical point of view, this conclusion may speak in favor of analysing energy supply and demand security together as mirroring concepts, building together energy security idea. Secondly, from the empirical point of view, the above argument, suggests that even when looking at the net energy exporters, it might be essential to include the energy imports' perspective. One may expect, that the smaller is the energy exports over imports surplus, or the more price-volatile are energy imports over exports; the greater might be possible influence of supply security concerns over international competitiveness through established comparative advantage. Thirdly, study proves, what has been already acknowledged for supply security research, that demand security is highly contextual phenomenon. It means that energy demand security meaning might be different for various regions or countries depending on their individual economic and energy situation.
This research, as any other, has its limitations. They result from: conceptual approach, sample choice, methodological constraints and data limitations.

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Claudio Meroni, Vincenzo Maria D'Ascanio, Alice Cozzi

A POSSIBLE STEP FORWARD TO GREEN HYDROGEN USE EXPANSION

Claudio Meroni, Tiemes srl – Via R. Galli 9 Milano, Email:claudio.meroni@tiemes.it
Vincenzo Maria D'Ascanio, Tiemes srl – Via R. Galli 9 Milano, Email: vincenzo.dascanio@tiemes.it
Alice Cozzi, Tiemes Srl– Via R. Galli 9 Milano, Email: alice.cozzi@tiemes.it

Overview

In order to limit average Earth temperature change in 2050 to 1.5°C with respect to pre-industrial times, as per Paris Agreement 2015, electrification by renewable energy of carbon emitting activities plays a major role. However, electrification is difficult in some processes of the so-called "Hard-to-Abate" (HTA) sectors and hydrogen is a suitable energy carrier for many applications and is expected to provide 12% contribution to the decarbonization needed, which seems today very hard to achieve. Although various initiatives have been taken or announced, their execution is in doubt, mainly because of high costs.

Method

This paper evaluates various tools, mainly technical (eg. fossil fuel replacement rates), economic (eg. diffusion and learning curve), environmental (eg. GHG impact), some alternatives and analyze the one(s) likely to start before 2030.

Results

The analysis shows that green hydrogen production near HTA industries is an opportunity to do something which has to be done in any case, it allows some synergies, with affordable incentives, as for other sectors in the early stages of development and generates a large enough market to initiate a positive learning curve.

Conclusions

Replacement of fossil fuels in HTA industrial plants, particularly EAF steel plants, with locally produced hydrogen is a possible next step to extend the use of hydrogen, to facilitate technical improvements and economies of scale to make hydrogen less expensive and, therefore, to extend its use to other sectors.

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Mauro Giorgianni, Agatino Nicita, Gaetano Maggio

HYDROGEN-OXYGEN CO-PRODUCTION PLANT IN HOSPITALS: BUSINESS MODEL AND ECONOMIC ANALYSIS

Mauro Giorgianni, Researcher CNR – ITAE, Email: mauro.giorgianni@itae.cnr.it
Agatino Nicita, Technologist CNR – ITAE, Email: agatino.nicita@itae.cnr.it
Gaetano Maggio, Researcher CNR – ITAE, Phone: Email: gaetano.maggio@itae.cnr.it

Overview

The present work sets out a methodology for the evaluation of the application of a sustainable technology facility.The objective of this study is to assess the economic feasibility and organisational structure of a company using a business model structure. The Business Model Canvas (BMC) tool was used to analyse the new activity of a hospital using a Renewable Energy Sources-based water electrolysis plant for oxygen production in hospitals to self-produce the amount of oxygen they need and sell the surplus. The size of the hospital is around 350 beds, the plant's size is able to cover a consumption of oxygen equivalent to a 500 bed hospital. By considerimg a selling/market price of H2 and O2 of 3 €/kg, the results show the economic feasibility and what changes the hospital needs to gain a competitive advantage by using the green hydrogen and oxygen production system.

Methods

The BMC is able to define a clear vision of how the business model works for managers, employees and stakeholders in general. It is used to gain an in-depth understanding of the current business model and to facilitate the creation of new ones, thereby supporting decision-making processes. The components (or blocks) of BMC are the following: 1. key partners; 2. key activities; 3. value proposition; 4. customer relationship; 5. customer
segments; 6. key resources; 7. channels; 8. cost structure; 9. revenue streams.

The case study here analysed is based on literature data [1, 2]. In particular, it refers to the design of a Renewable Energy Sources (RES)-based (photovoltaic) water electrolysis (alkaline electrolysis) plant for oxygen production in hospitals, to produce the amount of oxygen they need themselves. The novelty, respect our previous works, is the selling of the oxygen surplus. The plant in question therefore has the function not only of storing hydrogen energy, but also of producing medically usable oxygen. From 1 kg of H2 produced by water electrolysis, we produce about 8 kg of oxygen, which is normally vented to the atmosphere, but in this case study we store it, use it, and sell the surplus [3]. In this specific case, the capacity of the electrolyser should be about 4 MW and the size of PV plant is 5 MW.
To evaluate the economic feasibility of the project, the net present value (NPV) has been calculated as follows:

$$NPV = -CAPEX + (1 - TR) \sum_{n=1}^{N} \frac{REV_n - OPEX_n}{(1+r)^n}$$

where CAPEX is the initial investment cost, REVn the revenues (annual incomes) at time n, OPEXn the operative expenditure (fixed and variable O&M costs) at time n, r is the discount rate, N is the number of periods, and TR the tax rate on earnings. In particular, the revenues are those related to the selling of hydrogen, the avoided purchase of self-produced oxygen and the selling of surplus oxygen.

Results

The results of this study can be divided into two types. One concerns the analysis of the business and the creation of the BMC, the other concerns the analysis of the economic profitability and return on investment.

Therefore, a BMC has been created, including a further block of analysis that overcomes one of the limitations of the conventional BMC model, i.e. a block related to environmental benefits. The following section presents the results of the analysis of the hospital's new activity, specifically showcasing a selection of the five most significant blocks – out of a total of ten that have been analyzed

- **KEY PARTNERS:** These are the companies that can strategically facilitate and enrich the value proposition through partnerships. Since the hydrogen and oxygen are high-barrier-to-entry markets, to accelerate business start-up procedures and overcome these challenges, it is fundamental to have partners who are already established in the markets and hold the requisite permits and experience.

- **VALUE PROPOSITION**: The fundamental value proposition proffered by the company to its clientele is predicated on the provision of an ecologically sustainable product. Moreover, a critical and quantifiable benefit for the customer is evident in the form of competitive pricing structures coupled with expedited delivery timelines.

- **COST STRUCTURE**: The cost structure is divided into CAPEX (with great impact on total costs) and OPEX. CAPEX relates to the installation of electrolyzer, PV (when not already owned), compression and storage systems. OPEX mainly relates to the salaries of the staff involved in selling the products and in the supervision, operation and maintenance of the above-mentioned installations and contracts signed with the company's external transport service provider.

- **REVENUE STREAMS**: Focusing only on the secondary activity (distinct from the core activities of healthcare and patient care), the main financial benefits can be divided into two categories: increased revenues and avoided costs. The increased revenues are due to the conclusion of service and supply contracts for oxygen produced in excess of the hospital's requirements, and the selling of hydrogen. The avoided costs relate to the self-consumption of oxygen produced.

- **ENVIRONMENTAL BENEFITS:** The installation of an electrolysis plant for the production of oxygen and hydrogen using renewable energy has, as its main consequence, the reduction of greenhouse gas emissions.

In order to assess the profitability and payback time of the investment, a sensitivity analysis was carried out which refers to a scenario with a proprietary PV plant. It can be seen that in the present case study, in the least favorable scenario, i.e. with an O2 market cost of 1 €/kg, the break-even point (BEP) is not reached in 20 years, whereas in the most favorable case, with an O2 cost of 7 €/kg, the break-even point is reached in nearly 4 years, resulting in an economic return of about 34,000 k€ at the end of 20 years. Considering the average price of wholesale oxygen, it can be seen that with a selling price of H2 at 3 €/kg and a market price of O2 at 3 €/kg, it is possible to be competitive on the market and reach the break-even point in about 12 years.

Conclusions

Business analysis, through the construction of the BMC, has provided a clear picture of the organisation that the company (hospital) will need to adopt by changing its service portfolio. It shows the changes it will face by focusing not only on the "conventional" nine blocks, but also on the environmental benefits. The technical, economic and financial analysis gives a positive figure for the feasibility of the plant. By setting the H2 sales cost at 3 €/kg and the O2 price at 3 €/kg, the break-even point is reached in 12 years, according to the forecast of the net present value (NPV) calculation. From this study, it can be concluded that the production of green hydrogen can be an economically viable route using the technology available today, thanks to the self-consumption and sale of the oxygen resulting from the production process. In this way, an economic return can be achieved in the medium term.

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JunHyung Kim and Deokjoo Lee

OPTIMAL INVESTMENT STRATEGIES FOR HYDROGEN REFUELING STATIONS CONSIDERING ON-SITE CONVERSION OPTION

JunHyung Kim: Lab. of Engineering Economic SystemsAnalysis, Seoul National University
Gwanak-ro, Gwanak-gu Seoul 08826, Republic of Korea
E-Mail: junkim95@snu.ac.kr
DeokJoo Lee: Lab. of Engineering Economic Systems Analysis, Seoul NationalUniversity
Gwanak-ro, Gwanak-gu Seoul 08826, Republic of Korea
E-Mail: leedj@snu.ac.kr

Overview

Rapid growth in hydrogen-fuel-cell vehicle adoption in Seoul has outpaced infrastructure development, creating a critical shortage of refueling stations. Despite extensive research on hydrogen refueling infrastructure, existing studies have generally treated site selection, investment timing, and strategic interactions as separate problems. In this work, we develop a comprehensive framework that concurrently integrates (1) objective multi-criteria analysis (CRITIC–TOPSIS) to pinpoint optimal locations for new stations, (2) a two-stage compound real-option model to determine the value and timing of off-site construction versus on-site conversion under uncertainty, and
(3) a game-theoretic network module that captures how neighboring stations' conversion choices create spatial externalities and influence each other's investment incentives. By unifying these three methodological strands, our approach delivers a more realistic and robust guide for investors and policymakers aiming to expand hydrogen refueling capacity in Seoul.

Method

First, we applied an objective multi-criteria evaluation using CRITIC weighting and TOPSIS ranking to identify the five most suitable administrative districts for new hydrogen refueling stations in Seoul, based on safety, population density, existing demand, and land cost. Next, we formulated a two-stage compound real-option model to value (1) off-site station construction and (2) subsequent on-site conversion under uncertainty in hydrogen price and demand. To incorporate strategic interactions, we embedded a network game in which each potential investor's payoff depends not only on their own conversion choice but also on the proportion of neighboring stations choosing on-site production. We solved for Nash equilibria via iterative best-response dynamics and calibrated network externality parameters through Monte Carlo simulation

Results

Accounting for network effects raises the expected real-option value of conversion by an average of 18 % compared to isolated decision models, and alters the optimal on-site conversion horizon by up to three years across candidate sites. We identify a critical neighbor-conversion threshold above which the incentive to switch on-site diminishes, leading to equilibrium clusters of mixed station types. Sensitivity analysis shows that stronger network externalities accelerate collective conversion but also amplify the downside risk when hydrogen price growth is weak.

Conclusions

Integrating game-theoretic network effects into site selection and investment timing models provides deeper insights into how spatially correlated investor behaviors shape hydrogen infrastructure development. Policymakers and private investors should account for these strategic interdependencies to design subsidy schemes and investment incentives that foster coordinated growth. Future research may extend this framework to dynamic network topologies and explore regulatory mechanisms to steer equilibrium outcomes.

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Julian Keutz, Jan Kopp

THE COST OF SECURITY: ANALYZING STRATEGIES TO HEDGE HYDROGEN IMPORT DISRUPTION UNDER STOCHASTIC REPRESENTATION OF WEATHER

Julian Keutz: Senior Research Associate at the Institute of Energy Economics at the University of Cologne, +
Email: julian.keutz@ewi.uni-koeln.de
Jan Kopp: Senior Research Associate at the Institute of Energy Economics at the University of Cologne,
Email: jan.kopp@ewi.uni-koeln.de

Overview

The EU's goal of achieving climate neutrality by 2050 requires a fundamental shift in energy sourcing, with an increasing role for green energy. Imported green hydrogen is seen as a key element in this strategy. However, reliance on imported energy brings risks, such as supply disruptions and price volatility, as demonstrated by the 2022 gas crisis. As the international hydrogen market develops, it may face similar supply concentration risks as early natural gas markets. Nonetheless, security risks in emerging hydrogen markets remain underexplored.
Additionally, a significant challenge for green hydrogen production is its dependence on weather, particularly electrolysis powered by renewable energy sources. Cost estimations often rely on single weather years, which can lead to inaccurate projections. Similarly, long-term infrastructure planning in Europe often uses deterministic models that fail to fully account for weather variability. Given the long time horizons involved, better integration of uncertainty is needed to create a more resilient energy system.
Against this background, this work conducts a stochastic optimization of European electricity and hydrogen assets together with an optimization of non-European hydrogen imports. In addition, we explore hedging strategies, such as diversification and import reduction, to lower the exposure to potential disruptions in imports and assess the economic benefits of these hedging strategies within a case study.

Methods

We develop a linear two-stage stochastic model that minimizes total system costs of European electricity and hydrogen assets, including electrolysis, storage, and hydrogen-fired power plants. We cluster a set of 27 weather years into five weather years, which we use inputs to our investment decision.
Moreover, we account for hydrogen imports from non-European origins, which are represented via LTCs. The price for hydrogen LTCs is based on the levelized cost of hydrogen and vary by exporter. The optimization of the asset configuration in the exporter's country, too, is done using a stochastic approach.

Results

Our analysis reveals that the stochastic nature of our model reduces system costs by one-third compared to a deterministic solution that assumes average weather conditions in system planning. We also identify the need for a substantial expansion of hydrogen storage capacity, considerably exceeding previous estimates, to manage fluctuations in both domestic and imported supply. A pure cost minimization of imports results in a significant market concentration, with only three exporters being contracted. By evaluating strategies to mitigate import disruption risk, we find that diversification and import reduction strategies incur higher costs in the investment stage, which can be economically justified by averted disruption costs, while complete energy independence proves inefficient. Intuitively, the degree to which a mitigation strategy is efficient is highly dependent on the likelihood and implications of an import disruption.

Conclusions

Our findings point to the need for European infrastructure planning (e.g. TYNDP) to include stochastic approaches to account for weather variability, as we find severe benefits over deterministic approaches. With regard to hydrogen import security, we give a first intuition on the magnitude of additional costs that come with a diversified import market. Also, we find that European self-sufficiency is not beneficial in any of our scenarios, pointing to the need to foster energy partnerships outside Europe.

Erasto Mathias Saganda

FACTORS INFLUENCING USE AND ADOPTION OF CLEAN COOKING TECHNOLOGIES IN RURAL HOUSEHOLDS: A CASE STUDY OF MOROGORO REGION, TANZANIA.

Erasto Mathias Saganda, Makerere University Business School, student and researcher
Plot 21A Port bell Road, Nakawa, P.O. Box 1337, Kampala,
Email: erastosaganda148@gmail.com

Overview

Access to modern energy is a drive towards clean energy. However, until present, about 4 billion people globally do not have access to clean cooking energy, and in sub–Saharan Africa more than a third of the people do not have access to clean cooking energy. There is a global effort toward reducing or eliminating dirty fuels and technologies for cooking due to their severe health, environmental and economic implications. The use of inefficient biomass pyrolysis stoves is a major driver of the degradation of biomass energy resources. As a mitigation measure, the use of improved cookstoves has been promoted.

Methods

The objective of this study was to analyze the factors influencing the use and adoption of clean cooking technologies in rural households in the Morogoro region. The specific objectives were to establish the types of cooking energy and technologies used by households. Determine the influence of household characteristics and social interactions on the use and adoption of the technologies and determine how the policy and institutional set-up influences the use and adoption of the technologies by households in the Morogoro region. The study's theoretical framework and design were based on the Technology Acceptance Model, using a mixed methods approach. Quantitative data was obtained through household survey questionnaires. Qualitative data were obtained from the literature review.

Results

The study reviled that, only 11.5% of households in the Morogoro region use improved cookstoves. The main type of cooking energy used by households in the study area was found to be firewood (75%). The households predominantly used the traditional three stones cookstoves for cooking (75%). The results of a binomial logistic regression analysis showed that: age, income, and the household's awareness of a business entity engaged in the sale and repair of improved cookstoves, significantly influenced the use of improved cookstoves in the study area. Policies on biomass energy and cooking technologies are domiciled in different Government ministries. This has given rise to incoherent coordination of their implementation. There is however no policy in place at the Morogoro region level that addresses biomass energy and clean cooking technologies. Even though private enterprises and Non-Governmental Organizations are engaging in the promotion of clean cooking technologies, institutional involvement in the promotion of clean cooking technologies is weak.

Conclusions

This study recommends the creation of more awareness of the benefits of using clean cooking energy and technologies, and that private businesses be incentivized to engage in the production, dissemination, and maintenance of clean cooking technologies. That a Morogoro region-level policy on biomass energy and household cooking technologies be formulated to facilitate the implementation of national policies and guarantee funding for the promotion of clean cooking technologies. In conclusion, only 15% of the households were using improved cookstoves. This is attributable to the low level of awareness of the benefits of clean cooking technologies, low incomes, and weak involvement of institutions in promoting clean cooking technologies in the Morogoro region.

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Chocoroua Omar, Fumiaki Inagaki

EXAMINING ENERGY ACCESS IN RESOURCE-RICH DEVELOPING COUNTRIES: THE CASE OF MOZAMBIQUE

Chocoroua Omar: Akita University, Graduate School of International Resource Sciences, Akita University, 1-1 Tegata-gakuencho, Akita City, 0108502, Japan, Email: axinene@live.com
Fumiaki Inagaki: Akita University, Graduate School of International Resource Sciences
1-1 Tegata-gakuencho, Akita City 0108502, Japan,
Email: fumiaki.inagaki@gipc.akita-u.ac.jp

Overview

Energy access is a global concern, addressed in the UN's 2030 Agenda, a challenge particularly significant in developing nations such as Mozambique. A significant amount of natural gas deposits (5 tcf onshore and 100 tcf offshore) have been discovered, yet less than 20% (of onshore) is being allocated to the domestic market.
Conversely, a significant majority (96%) of its population continues to depend on solid biomass for cooking, resulting in health risks and reduced productivity. Although 2030 targets may seem ambitious, increasing in domestic gas allocation and investing in energy systems will improve access. It is also crucial for the government to properly implement energy policies (such as a price adjustment mechanism) to allow competitiveness in the domestic market.

Methods

We used a mixed-methods approach to evaluate domestic energy access through survey analysis conducted in Inhambane and Maputo, Southern Mozambique. A binary and multinomial logistic model was employed to analyze the responses. Energy access refers to the ability of households to have reliable and affordable access to clean cooking and electricity. As energy access is impacted by many factors, we extended our analysis by exploring energy policy implementation, foreign direct investment (FDI) inflows, energy systems, and existing research on energy access and poverty.

Results

The study showed that gas is the favored cooking fuel in Inhambane and Maputo, owing to its lower cost and improved efficiency compared to alternatives. Consumption habits and a lack of maintenance for gas distribution systems were the primary causes of widespread fuel stacking (96% solid biomass), particularly in rural and peri- urban settings. In 2021, FDI in oil and gas reached US$4.7 billion historical levels, representing 91% of total coun- try FDI. Nevertheless, this was export-oriented and electricity generation-focused. Despite having energy policies in place, there are challenges in their full implementation, especially regarding pricing adjustment mechanisms.

Conclusions

Further growth in energy industry investment is anticipated, driven by developments in offshore gas. Achieving energy access goals by 2030 continues to pose a significant hurdle, even in developing countries rich in energy resources. Effective government policies and strategies are needed to increase access to clean cooking fuel; this includes expanding domestic gas allocation (due to household preference) and using price adjustment mechanisms to boost competition in the cooking fuel market.

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Dong Hanmin, Zhang Lin, Liu Yishuang,

THE IMPACT OF NEW ENERGY BASE CONSTRUCTION IN CHINA'S DESERT, GOBI, AND DESERTIFIED (SHAGEHUANG) AREAS ON SOIL ORGANIC CARBON

Dong Hanmin, CCNU, Email: donghanmin@ccnu.edu.cn
Zhang Lin, CityU, Email: l.zhang@cityu.edu.hk
Liu Yishuang, WHU, Email: vanavampire@whu.edu.cn

Overview

To accelerate progress toward its carbon neutrality targets, China has strategically developed large-scale renewable energy bases in desert, Gobi, and desertified areas — collectively known as Shagehuang regions. While these projects help reduce fossil fuel dependence, their ecological side effects, particularly on terrestrial carbon dynamics, remain understudied. Soil organic carbon (SOC) plays a critical role in carbon sequestration and is a key indicator of soil quality and ecosystem functioning. This study evaluates how the construction and operation of new energy bases (solar, wind, and hybrid) affect SOC levels in Shagehuang regions, combining econometric modeling with spatial data analytics.

Methods

This research employs a quasi-experimental framework using panel data of 2005–2022 across counties in western China. We use a difference-in-differences (DID) approach to estimate the causal impact of new energy base construction on SOC, exploiting temporal and spatial variation in project rollout. To strengthen causal inference:

- Propensity score matching (PSM) is used to construct a control group with similar pre-treatment characteristics.
- Event study models assess the dynamic treatment effects and test the parallel trends assumption.
- Remote sensing data (e.g., MODIS NDVI, surface albedo, and LST) and national ecological surveys are used to derive SOC proxies with high spatial and temporal resolution.
- Heterogeneity analyses are conducted based on vegetation cover, aridity index, and energy project type (solar vs. wind vs. hybrid).

Results

Our analysis shows that the construction of new energy bases leads to significant medium-term increases in SOC, especially in solar-dominant areas. SOC gains are attributed to reduced wind erosion, enhanced microclimate conditions beneath solar panels, and land restoration efforts associated with project design. However, short-term declines in SOC are observed during the construction phase due to land disturbance. The treatment effect follows a U-shaped trajectory over time. The effects are most prominent in areas with moderate vegetation cover and policy-supported ecological restoration.

Conclusions

This study provides robust evidence that large-scale renewable energy infrastructure, when properly integrated with ecological planning, can generate co-benefits for land carbon sinks in arid and semi-arid regions. Findings support a land-sensitive clean energy strategy, highlighting the need for standardized environmental design guidelines and long-term ecological monitoring. As renewable energy continues to scale up globally, our work underscores the importance of aligning climate mitigation with terrestrial ecosystem resilience.

Lorenzo Monga

MILAN 2050: A DATA-DRIVEN VISION FOR URBAN ENERGY DECARBONIZATION

Lorenzo Monga, A2A, Email: Lorenzo.monga@a2a.it

Overview

Cities play a crucial role in achieving climate neutrality by 2050, with one of the main challenges being the development of low-CO_2 solutions for heating and cooling urban areas. This evolving scenario presents both opportunities and challenges for grid operators. A2A – a multi-utility company primarily active in northern Italy has developed a data-driven model to forecast urban energy consumption, distributed photovoltaic (PV) generation, and CO_2 emission trends.
The model accounts for historical data and socio-economic factors to predict fluctuations and peak demand, enabling efficient resource allocation as well as planning and management of network expansions. The European and Italian energy transition targets serve as the main drivers for shaping energy trends and determining the investment strategies needed to meet those goals.

Method

The simulation analyzes annual energy consumption and distributed generation for heat, electricity, and natural gas in Milan, projecting their evolution through 2050. The model explores various scenarios based on changes in energy demand of domestic, non-domestic and industrial users, including heating, cooling, transportation, and PV production. Key drivers include habits and population evolution, building renovation and heat pump adoption rates, influenced by European and National regulations like the Energy Performance of Building Directive (EPBD) and Energy Efficiency Directive (EED), as well as other incentive programs.
Data used to analyze future trends include both internal and public sources, the most relevant ones are historical consumption data of the energy distributed by A2A Group, building energy efficiency (CENED – Building Energy Registry of Lombardia Region), heat generation systems (CURIT – Thermal System Registry of Lombardia Region), circulating vehicle fleet (ACI – Italian Fleet Register).

To improve the understanding of how future energy demand trends could impact specific portions of the electrical grid, in addition to the city-level energy analysis the forecasting model was further applied to subdivide the city of Milan into Primary Substation influence areas. An accurate peak load forecast on primary substations, which are the boundary nodes between transmission and distribution networks, where High Voltage level is stepped down to Medium Voltage, is essential to plan efficient investments and enable a reliable energy transition.

Key Results and Insights

The model's scenarios forecast an overall reduction in energy demand of approximately **-25% – 30% by 2050**, driven largely by the adoption of energy-efficient building solutions and the deployment of low-carbon technologies such as heat pumps, electric vehicles, and district heating systems. The main insights from the analysis are as follows:

1. ***Electrification of Energy Demand***
   A major shift in energy vector usage is expected, with electricity consumption projected to increase by about **35% – 40%,** while gas consumption (natural gas and biomethane) could decrease by nearly **40% – 60%**. This reflects the growing electrification of heating, cooling, and mobility systems in urban areas.

2. ***Impact on Primary Electrical Substations***
   The electrification of urban energy demand is expected to put significant pressure on the electric grid and Distribution System Operators (DSOs) must be able to tackle new challenges, such as higher and more variable loads. Granular forecasting and geographical analysis enable the identification of localized congestions across the load areas, highlighting the points that may

require reinforcements or upgrades in the coming decades. By analyzing the location of the additional electricity demand in relation to projected urban development and demographic trends, it is possible to determine more accurate details about the timing and location of future infrastructure investments needs.

3. ***Flexibility market impact***
   One of the DSOs of the A2A Group is part of a demonstration project, promoted by the The Italian Energy Regulatory Agency, to assess and demonstrate the potential and feasibility of local flexibility services at DSOs level. The pilot project, enables the direct participation of distributed resources (e.g.,charging stations, PV systems, combined heat and power units) in the Local Flexibility Market, through a market auction from which the selected participants obtain a fixed payment for capacity availability and a variable one for the energy actually exchanged. As a result of the auction, the selected resources have to increase energy production or reduce energy consumption when it is needed by the electrical grid, allowing the DSO to provide real-time services, thus improving peak management.

4. ***Role of District Heating and Cooling (DHC) in Decarbonization***
   District heating will be a critical enabler of urban decarbonization, especially in a dense city like Milan, in particular for historical buildings where the electrification of heat production poses several heritage and spatial constraints. Furthermore, in compliance with the European EED Directive, it is expected that more than **90% of the distributed energy of DHC by 2050** is waste heat recovered from data centers, industrial processes or from renewable energy sources, located in the area surrounding the city.

Conclusions

The transition toward climate neutrality by 2050 presents both significant opportunities and complex challenges, particularly for urban areas where energy demand is concentrated and heterogeneous, serving different categories of end users. The modeling and forecasting work carried out by A2A provides strategic understanding into how cities like Milan can evolve toward a more sustainable and decarbonized energy system. Key findings highlight the central role of electrification, the importance of flexibility markets, and the strategic value of district heating and cooling in reducing CO_2 emissions. The forecasting model applied with a geographical granularity at primary substations level, offers a crucial tool for anticipating infrastructure needs and guiding targeted investments. Furthermore, the decarbonization of the industrial sector through technological integration and cleaner energy sources underlines the systemic nature of this transition. Together, these elements form a comprehensive roadmap that supports data-driven decision-making and enables urban energy systems to meet the ambitious targets set at both national and European levels.

Damiano Alessi,Kavita Surana, Behnam Zakeri

TIMELINES AND DELAYS IN EUROPEAN GRID EXPANSION

Damiano Alessi, WU (Vienna University of Economics and Business), Email: damiano.alessi@wu.ac.at
Kavita Surana, WU (Vienna University of Economics and Business), Email: kavita.surana@wu.ac.at
Behnam Zakeri, WU (Vienna University of Economics and Business), Email: behnam.zakeri@wu.ac.at

Overview

As Europe pursues its ambitious climate targets and shifts toward a low-carbon economy, the expansion and modernization of the electricity grid have become critical to ensuring both the integration of renewable energy and the security of supply. To support long-term electricity infrastructure planning, the European Network of Transmission System Operators for Electricity (ENTSO-E) publishes the Ten-Year Network Development Plan (TYNDP). The TYNDP, published biennially, primarily includes large-scale transmission investments of pan- European significance, most of which are Projects of Common or Mutual interest (PCI/PMI), typically high- voltage lines above 110kV. However, despite coordinated planning under the TYNDP, numerous projects face delays, often linked to complex permitting processes, environmental constraints, and evolving policy priorities. Yet, comprehensive evidence and long-term analysis at the European scale to understand the length of the building process and patterns of delays is still missing. This research systematically examines (a) how long does it take to build a transmission line in Europe; (b) which factors mostly impact the overall duration from planning to commissioning, and (c) how often projects are delayed and why.

Methods

We developed and analyzed an original dataset by systematically matching projects and harmonizing varying reporting structures across TYNDP editions from 2010 to 2024. The dataset captures more than 900 unique investments, detailing their evolution from initial proposal through planning, permitting, construction, and final commissioning. For each investment we extract project characteristics, such as, onshore vs. offshore linkage, voltage level, involved country(ies), project type (new vs. existing), the role of the Transmission System Operator (TSO) in investment, the expected commissioning year, the line type (direct or alternating current), the line length, and, for projects reported after 2016, the estimated capital expenditure (CAPEX). Our initial analysis uses clustering algorithms and natural language processing to analyze and study the reasons reported for the delay in each investment during its lifetime.
We plan to further use this dataset for a two-pronged empirical analysis. First, we will apply survival models to estimate how project characteristics such as voltage, length, cross-border scope, social, and regulatory context influence the time until commissioning, while explicitly accounting for right-censoring. Second, we will model how project characteristics impact the presence and length of delays using regression approaches that account for skewed distributions.

Results

We identify more than 900 investments grouped into around 300 projects involving 43 countries. Over 50% of these projects are cross-border transmission projects involving more than one country, and approximately 50 of these involve more than two countries. The country most represented in the TYNDP reports is Germany, followed by Italy; however, in recent years, the Baltic countries have seen significant transmission capacity investments due to their planned integration into the European electricity system.
Initial results indicate that grid investments require approximately 9.5 years, on average, from the proposal and study phase to full commissioning. Of the analyzed investments, almost one-third experienced delays, with an average delay exceeding 4 years, and 25% of these investments with delays longer than 6 years. The preliminary analysis suggests that most of these delays happened during the permitting processes, and almost two-thirds of the investments face delays due to environmental issues.

Throughout the investment lifecycle, 185 investments were rescheduled, of which more than 80% were due to changes or delays in the commissioning of the production plant needed to be connected to the grid.

Conclusions

By analyzing more than a decade of transmission projects spanning the European continent, we find that the average implementation period for grid investments is nearly 10 years, with frequent multi-year delays and significant bottlenecks. These delays are underlying persistent problems with the long permitting process, environmental constraints, and coordination issues with generation plants. Given Europe's ambitious 2050 climate and energy targets, this implies that only two full development cycles remain to plan and build the transmission infrastructure needed. Our results provide empirical evidence on why projects face delays and sheds light on why certain investments are more difficult to implement.

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Maria Teresa Vespucci, Giovanni Micheli, Gianluigi Migliavacca and Dario Siface

TSO–DSO COORDINATION AND MARKET POWER IN SEQUENTIAL ELECTRICITY AND ANCILLARY SERVICES MARKETS: EQUILIBRIUM MODELS UNDER LOAD AND RENEWABLE GENERATION UNCERTAINTY

Maria Teresa Vespucci, University of Bergamo, Department of Management, Information and Production Engineering,Viale Marconi 5 – 24044 Dalmine (BG), Italy, Email: maria-teresa.vespucci@unibg.it
Giovanni Micheli, University of Bergamo, Department of Management, Information and Production Engineering, Viale Marconi 5 – 24044 Dalmine (BG), Italy, Email: giovanni.micheli@unibg.it
Gianluigi Migliavacca, RSE S.p.A, Via Rubattino 54 – 20134 Milano (MI), Italy, Email: gianluigi.migliavacca@rse-web.it
Dario Siface, RSE S.p.AVia Rubattino 54 – 20134 Milano (MI), Italy, Email: dario.siface@rse-web.it

Overview

The European Union's decarbonization targets and the effort to reduce fossil fuel dependence are accelerating the integration of non-dispatchable renewable energy sources and the deployment of Distributed Energy Resources (DERs) at the distribution level. While DERs increase the demand for system flexibility, they also offer new opportunities to provide ancillary services. In response, many countries are adapting regulatory frameworks to facilitate DER participation in electricity and ancillary services markets. However, the oligopolistic structure of electricity markets, the hierarchical configuration of the grid, and the sequential nature of market clearing can enable dominant players to exert market power, distort prices, and increase overall system costs. This study aims to investigate how alternative coordination schemes between the Transmission System Operator (TSO) and Distribution System Operators (DSOs) influence market power dynamics in electricity and ancillary services markets under uncertainty in load and renewable generation.

Methods

We develop a two-stage stochastic game-theoretic model of electricity markets with strategic participants and sequential market clearing. The model features a day-ahead market followed by a balancing market, with market participants acting as profit-maximizing leaders and a central operator acting as the follower. The resulting interaction is formulated as a multi-leader, common-follower game under uncertainty, leading to an Equilibrium Problem with Equilibrium Constraints (EPEC). Each participant's problem is represented as a Mathematical Program with Equilibrium Constraints (MPEC), using the KKT conditions of the market-clearing problem. An iterative algorithm is implemented to compute the equilibrium. We compare three TSO–DSO coordination schemes: (A) unified market with integrated TSO–DSO management, (B) independent local distribution markets, and (C) separated markets with the possibility of reallocating unused DER capacity to the transmission system.

Results

The model is applied to a test system comprising a transmission network and three distribution grids, with 24 flexible resources managed by 9 strategic players. Simulations are conducted under various stochastic scenarios for load and renewable output. Results show that while the day-ahead dispatch remains identical across coordination schemes, significant differences emerge in the balancing market. In schemes A and C, DERs strategically increase their bid prices during congestion events to exploit arbitrage opportunities. In contrast, Scheme B limits such strategic behavior by restricting DERs to local balancing markets, resulting in lower total system costs. On average, Scheme B yields the lowest expected cost, with Scheme A being 5.13% more expensive and Scheme C 23.06% more expensive.

Conclusions

Our findings demonstrate that TSO–DSO coordination design can significantly influence market power dynamics and total system costs.

Counterintuitively, more restrictive DER access to transmission-level balancing markets (as in Scheme B) may lead to more efficient outcomes under strategic behavior. This highlights the need for carefully designed market structures that account for gaming incentives. The proposed modeling framework provides regulators and system planners with a quantitative tool to assess the efficiency and robustness of different coordination strategies in the evolving context of high DER penetration

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Joachim Geske, Boris Ortega, Laura Andolfi, Rawan Akkouch

THE DUCK CURVE BITES BACK: WHEN FLEXIBLE DEMAND OVERLOADS THE GRID

Joachim Geske, Boris Ortega, Laura Andolfi, Rawan Akkouch
Email: joachim.geske@uni.lu, Email: boris.ortega@uni.lu,
Email: laura.andolfi@uni.lu, Email: rawan.akkouch@uni.lu
Digital Financial Services and Cross-Organisational Digital Transformations Research Group Interdisciplinary
Centre for Security, Reliability and Trust (SnT), University of Luxembourg,
29 Av. John F. Kennedy, 1855 Kirchberg, Luxembourg

Overview

The decarbonisation of the energy sector and the electrification of heating and mobility are reshaping the electricity landscape in Luxembourg and across the European Union. In this context, residential consumers are increasingly expected to act not only as passive users but also as active flexibility providers, capable of adjusting consumption and generation patterns in response to price signals. This paper investigates whether such flexibility, particularly under wholesale market-based tariffs, contributes to a more efficient and secure electricity system or exacerbates stress on distribution grid infrastructure. The analysis focuses on household electricity consumption and flexibility supply at the transformer level, aiming to assess the operational and investment implications of various future flexibility scenarios. As a use case, we analyse the Luxembourgish distribution grid.

Methods

To examine the role of household flexibility, we simulate the electricity consumption of 166 representative households connected to low-voltage transformers in rural and semi-urban Luxembourg. Electricity demand is derived from synthetic load profiles, mobility patterns, and weather-dependent factors, while price signals are based on the ACER Ten-Year Network Development Plan for a representative weather year. Transformer load, overload durations, and thermal stress are tracked to determine infrastructure reinforcement needs.

We develop a linear optimisation model to capture the behaviour of both flexible and inflexible households over an entire year, under scenarios for 2030 and 2040. These scenarios include varying shares of technological equipment and behavioural flexibility, as well as grid tariff, curtailment, and market-based interventions. Flexible households are assumed to respond to dynamic electricity prices by optimising the use of electric vehicles, battery storage, photovoltaic generation, and thermal energy systems (space and water heating) in order to minimise costs. The model incorporates technical constraints, comfort conditions, and degradation limits.

One of the challenges was to assess the impact of grid tariff design on grid stress. To address this, we implemented a two-way dynamic grid tariff that extends Luxembourg's 2025 reform. The tariff includes a household-specific capacity threshold k, with penalties applied to both imports and exports exceeding this limit. Households face a trade-off between higher fixed charges for a larger threshold and variable penalties for exceedances. In the optimisation model, flexible households minimise total electricity costs by adjusting consumption, storage, and threshold choice in response to hourly prices.

Results

The simulations demonstrate that household flexibility, while beneficial in reducing energy bills and peak evening loads, can also introduce severe local congestion under high technology adoption rates. In the 2040 scenario with full flexibility, all seven transformers require reinforcement due to overload and thermal stress. The analysis reveals that the phenomenon of "ping-pong flexibility" emerges at high flexibility levels, whereby households synchronously import during low-price hours and export during high-price periods. This results in the inversion of the classical "duck curve," with demand peaking during midday and excessive injections in the evening.

Grid tariffs based on capacity thresholds are effective in reducing this effect, limiting overload hours and reducing the number of transformers requiring reinforcement. In contrast, curtailment strategies targeting critical hours have a more limited and localised impact.

Conclusions

As households become more technologically equipped and responsive to dynamic tariffs, their collective behaviour increasingly shapes grid conditions. This study finds that, under unregulated flexibility provision, local grid bottlenecks emerge despite overall system benefits. Effective grid operation will depend on a combination of infrastructure planning, dynamic pricing structures, and well-targeted regulatory instruments. Tariff reform, particularly two-way capacity-based pricing, shows promise in mitigating overloads without undermining the economic rationale for flexibility. However, at high penetration rates of energy technologies, additional interventions such as demand coordination, direct load control, or locational market signals may be necessary. The findings highlight the need for DSOs to anticipate flexibility-driven load patterns and adopt adaptive, forward-looking strategies for grid development. Without such measures, the economic value of household flexibility may be offset by costly reinforcements and operational risks.

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Jaesung Choi

UNLOCKING THE GRID: INSTITUTIONALIZING POWER SYSTEM IMPACT ASSESSMENT FOR INTEGRATED SOC-ELECTRICITY INFRASTRUCTURE IN SOUTH KOREA

Jaesung Choi, Korea Research Institute for Human Settlements (KRIHS),
Room 621, 5 Gukchaek Yeonguwon-ro, Sejong, 30147, Republic of Korea,
Email: jaesung.choi@krihs.re.kr

Overview

In late 2025, South Korea is scheduled to implement its first-ever "National Backbone Power Grid Expansion Act," setting the stage for a transformative shift in electricity infrastructure planning. One might ask: Why now? And why focus on road and rail corridors? The answers lie in an emerging dilemma—how to build more transmission lines in a nation with shrinking available land and growing citizen resistance. Based on field observations and institutional consultations conducted between 2024 and 2025, this research proposes the formalization of a Power System Impact Assessment (PSIA) as a pre-project mechanism embedded within national transport infrastructure planning.

Interestingly, this proposal is not merely an engineering refinement, but a legal- institutional innovation inspired by the paradox that while energy demand is spiking, the grid remains spatially constrained.

Methods

Drawing upon empirical interviews with utility planners, infrastructure ministries, and legal experts, as well as a policy review of international cases (USA, EU, Japan), the study identifies regulatory blind spots and proposes procedural remedies. The methodology blends qualitative policy analysis with legal design modeling. Particular attention was given to the South Korean case of the Gyeongnam Gunbuk-Gaya highway co-installation with a 154kV underground line—a rare but instructive exception.

Geographic information systems (GIS) and infrastructure overlays were used to assess corridor synergies.

Results

The analysis reveals three critical bottlenecks in the current system:

1. Lack of Early-Stage Coordination: Electricity planning occurs downstream from SOC planning, often requiring retrospective and politically sensitive adjustments.
2. Inefficiencies in Land Use: Separate approvals for SOC and transmission lines generate avoidable duplication in land compensation and excavation.
3. Social Conflict Escalation: Grid installations are perceived as 'nuisance facilities', unlike highways or rail, leading to fierce opposition and permitting delays exceeding one year in dense areas like Seoul's southeast.

By institutionalizing PSIA at the pre-feasibility stage, government agencies can align transmission planning with SOC corridors (highways, railroads) and avoid costly redesigns and community resistance. The proposed framework mirrors elements from U.S. states like Wisconsin (Act 89), where existing corridors are legally prioritized for utility lines.

Conclusions

From an infrastructural logic, co-locating transmission with transport networks seems obvious. Yet policy inertia and fragmented governance have prevented this logic from materializing—until now. As of July 2025, the Korean government has initiated legislative steps to embed PSIA within national planning law, supported by multi- stakeholder forums and new incentive mechanisms. The implications go beyond South Korea. In densely populated countries, where land scarcity and public opposition are pronounced, PSIA can serve as a tool to merge energy transition with land efficiency and procedural justice. Future work should examine how AI-driven load forecasting and participatory GIS tools could be integrated to further enhance PSIA's predictive and deliberative capacity.

Keywords: *Power system impact assessment, transmission planning, infrastructure integration, energy security, South Korea, SOC corridors, legal reform, grid expansion*

Belinda Ravaz, Pierre-Henri Bombenger

REDEVELOPMENT TRAJECTORIES OF NUCLEAR SITES. AN EUROPEAN COMPARISON

Belinda Ravaz, School of Engineering and Management Vaud, HES-SO University of Applied Sciences and Arts Western Switzerland, Email: Belinda.ravaz@heig-vd.ch
Pierre-Henri Bombenger, School of Engineering and Management Vaud, HES-SO University of Applied Sciences and Arts Western Switzerland, Email: Pierre-henri.bombenger@heig-vd.ch

Overview

Although nuclear power is undergoing a revival as part of the energy transition and the goal of carbon neutrality, it remains true that production infrastructures have a limited lifespan, generally estimated at around forty years (WNISR, 2023). The possibility of extending the lifespan of certain nuclear power plants is currently being considered. However, hundreds of reactors around the world have already closed (Schneider et al., 2024). And many nuclear power plants will reach the end of their life in the coming decades. In this context, the literature on the future of these sites, and more specifically on their territorial impact, is still in its early stages (Greco & Yamamoto, 2019; Meyer, 2021; Yamamoto et al., 2020; Yamamoto & Greco, 2022). Indeed, the nuclear industry marks its territory in different ways and over long periods (Meyer, 2018). The intensity of the debates, the decommissioning processes and the proposed redevelopment projects vary considerably from one plant to another (Meyer, 2018; Ravaz, 2024).
This paper examines the development trajectories of sites and territories guided by the objectives and strategies of actors. To this end, our paper proposes a comparative analysis of redevelopment trajectories based on four European cases: Brunsbüttel (Germany), Fessenheim (France), Santa María de Garoña (Spain) and Wylfa (Wales).

Methods

Our methodology includes:

- Press analysis (n=5105)
- Grey literature: analysis of territorial development strategies and policies (n=56)
- Semi-structured interviews with key stakeholders (n=28)

Results

These four nuclear power stations have all been shut down in the last decade. However, the strategies implemented vary considerably from one site to another. This has enabled us to develop a typology of closure trajectories.
In Brunsbüttel, we can observe a strategy that can be described as a gradual erasure of nuclear power: the closure has not given rise to any strong mobilization or structuring project, and the plant is fading symbolically and physically from the local landscape. On the other hand, Fessenheim and Wylfa are struggling to break with their nuclear past. These two areas, marked by a high level of socio-economic dependence on the power station, are thinking about redevelopment in terms of technological continuity (SMR projects, radioactive materials recycling plant, desire to relaunch a power station). Santa María de Garoña, on the other hand, is adopting a more adaptive strategy, taking account of local constraints. Its trajectory is neither a radical break nor a direct extension of the nuclear model, but an attempt at gradual recomposition on a local scale. This diversity of approaches reveals the variability of redevelopment trajectories. These depend on specific spatial, institutional, political and cultural configurations, which influence the ability of areas to innovate or reconfigure.

Conclusion

The research contributes to theoretical debates on territorial resilience and energy transition by demonstrating how local contexts shape redevelopment trajectories. It also provides practical insights for territories facing similar challenges.

The findings have significant implications for European energy transition policies, suggesting the need for better integration between decommissioning strategies and territorial development planning. They also emphasize the importance of supporting local stakeholder capacity and cross-scale coordination in managing successful territorial redevelopment.

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Sophia A. E. Spitzer, Katja Pelzer, Anton Bauer, Maximilian J. Blaschke

IS FUSION TOO LATE? HOW INVESTORS VALUE ITS ROLE IN A DECARBONIZED EUROPE

Sophia A. E. Spitzer,TUM School of Management, Technical University of Munich, Germany
Marvel Fusion GmbH, Munich, Germany
Katja Pelzer, TUM School of Management, Technical University of Munich, Germany
Anton Bauer, TUM School of Management, Technical University of Munich, Germany
Maximilian J. Blaschke, TUM School of Management, Technical University of Munich, Germany
and Center for Energy and Environmental Policy Research, MIT, USA
Email: maximilian.blaschke@tum.de

Overview

Fusion energy promises to deliver clean, firm, and geographically flexible electricity, making it a potentially transformative technology for the decarbonization of Europe's power system. However, its uncertain commercialization timeline - often seen as perpetually distant - raises critical questions about whether fusion will arrive in time to contribute meaningfully to Europe’s net-zero targets. This paper examines the alignment between fusion’s long-term system value and current investment levels. Specifically, it addresses two central questions:
(a) What is the potential value of fusion energy within an already fully decarbonized European energy system? and (b) To what extent do current public and private investment levels reflect confidence in fusion’s eventual commercialization?

Methodology

We incorporate fusion energy into the open-source PyPSA-Eur energy system model, simulating Europe’s transition to net zero under varying assumptions for fusion's commercialization year, capital costs, and deployment constraints. The model captures hourly system dynamics and spatial heterogeneity across European regions between 2030 and 2100. Using scenario analysis, we evaluate fusion’s cost-saving potential across multiple configurations. We introduce a probabilistic valuation framework that links system savings with historical and projected fusion investments (starting in 2010) via an „Anticipated Commercialization Probability“. This metric quantifies the commercialization likelihood implicitly assumed by today’s investors.

Results

Model results show that fusion could supply up to 43% of installed capacity and reduce total energy system costs by as much as €2 trillion by 2100 in optimistic scenarios with early commercialization and low capital costs. However, when comparing this potential value to actual investments, the implied commercialization probabilities remain below 20% across most cases. The benefits of fusion diminish substantially when commercialization is delayed until 2050. Early deployment and rapid industrial scale-up are therefore essential to capture fusion’s full system value.

Conclusion

Fusion energy has the potential to play a transformative role in Europe’s low-carbon energy mix by reducing the need for renewables overcapacity, long-duration storage, and grid expansion. Yet, current investment levels remain modest relative to fusion’s estimated system value, likely reflecting investor skepticism about commercialization success. This underinvestment may reinforce a self-fulfilling cycle of delayed progress and lost potential. To unlock fusion’s system benefits, policymakers should consider milestone-based funding mechanisms, harmonized safety regulations, and accelerated deployment pathways. A more deliberate and coordinated policy response could help bridge the gap between fusion’s long-term promise and short-term financial commitment.

Olivier Paltenghi, Massimiliano Capezzali and Pierre-Henri Bombenger

PROSPECTIVE ANALYSIS OF SPATIAL AND ECONOMIC IMPACTS OF SMALL MODULAR REACTOR DEPLOYMENT IN SWITZERLAND

Olivier Paltenghi: University of Applied Sciences and Arts Western Switzerland, Av. de Provence 6, 1007 Lausanne, Switzerland, Email: olivier.paltenghi@master.hes-so.ch
Massimiliano Capezzali: Institut of Energies, School of Engineering and Management Vaud, University of Applied Sciences and Arts Western Switzerland, Rte de Cheseaux 1, 1400 Yverdon-les-Bains, SwitzerlandEnergy and environment Av. de Provence 6, 1007 Lausanne, Switzerland
Email: massimiliano.capezzali@heig-vd.ch
Pierre-Henri Bombenger: Institute of Territorial Engineering (insit), School of Engineering and Management Vaud, University of Applied Sciences and Arts Western Switzerland,
Rte de Cheseaux 1, 1400 Yverdon-les-Bains, Switzerland
Email: pierre-henri.bombenger@hes-so.ch

Overview

In Switzerland, electricity demand is projected to rise sharply, while the progressive phase-out of nuclear power threatens to exacerbate supply risks. Renewable energy sources, particularly photovoltaics, are currently struggling to meet this growing demand. The "Stop Blackout" initiative, launched in 2024, has rekindled the national debate on nuclear energy and opened the possibility of revising existing bans. In this context, Small Modular Reactors (SMRs) are emerging as a low-carbon and flexible energy solution. Their smaller scale and modular design offer new integration possibilities, but they also introduce significant technical, economic, and regulatory challenges. This research investigates the potential spatial and economic impacts of SMR deployment in Switzerland, with the objective of supporting energy sector stakeholders in strategic decision-making. The analysis is based on four main categories of criteria: technological, cognitive, spatial, and economic.

Methods

A comprehensive review of the existing scientific literature indicates a marked increase in publications on SMRs in recent years, particularly regarding technical, energy-related, and economic aspects. However, the territorial integration of SMRs remains relatively underexplored. This study combines an extensive literature review with a series of semi-structured interviews conducted with key stakeholders in the Swiss energy sector. Interview participants include representatives from industry, energy producers and distributors, policymakers and regulators, experts and researchers, as well as civil society and non-governmental organizations. This mixed-methods approach allows for a multidimensional understanding of the challenges and opportunities associated with SMR deployment.

Results

The study's findings are organized into three sequences, each reflecting a set of conditions necessary for the potential implementation of Small Modular Reactors (SMRs) in Switzerland.
The first sequence concerns prerequisites. Political acceptance emerges as a central yet fragile factor, shaped by concerns over supply security but weakened by fears related to nuclear waste, decommissioning, and potential accidents. Moreover, the technological maturity of SMRs must be demonstrated, ideally through operational feedback from pilot projects in Western countries.
The second sequence addresses concrete regulatory, organizational, and economic conditions. The regulatory framework must be adapted to reflect the specific characteristics of SMRs, which could require international harmonization. In Switzerland, the current ban on constructing new nuclear power plants would first need to be lifted, and the regulatory status of SMRs clarified. Ensuring a reliable supply of HALEU (High-Assay Low-Enriched Uranium) is essential. Economic viability depends on standardization, investment costs, and financing mechanisms compatible with existing renewable energy subsidies.

The third sequence highlights territorial conditions. Repurposing former nuclear sites could help reduce costs but might limit opportunities for industrial heat use. Local acceptance, generally higher around existing nuclear power plants, will be crucial for successful deployment. Projects will also need to secure the necessary territorial authorizations, including building permits and environmental impact assessments.

Conclusion

The deployment of SMRs is contingent upon addressing a complex array of technological, regulatory, economic, and territorial challenges. Comprehensive stakeholder engagement and adaptive regulatory frameworks will be essential tofacilitate the integration of SMRs into the Swiss energy landscape. These findings provide a strategic foundation for policymakers and industry stakeholders considering the role of SMRs in Switzerland's future energy transition.

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Cristina Moscatiello, Riccardo Loggia, Luigi Martirano

MICROGRID CONFIGURATIONS FOR ENERGY COMMUNITIES: THE POWER SHARING MODEL

Cristina Moscatiello, Dept. of Astronautics, Electrical and Energetic Engineering Sapienza University, Rome, Italy, Email: cristina.moscatiello@uniroma1.it
Riccardo Loggia, Dept. of Astronautics, Electrical and Energetic Engineering Sapienza University Rome, Italy, Email: riccardo.loggia@uniroma1.it
Luigi Martirano, Dept. of Astronautics, Electrical and Energetic Engineering Sapienza University Rome,Italy, Email: luigi.martirano@uniroma1.it

Overview

Energy communities offer an effective model for facilitating renewable energy sharing and enhancing self- consumption within distributed systems. While traditional regulations accommodate virtual microgrids, they often lack fair and clear criteria for distributing shared energy and governing control. This study proposes an innovative Power Sharing Model (PSM). It includes a comparative analysis of physical and virtual microgrids, presents the PSM's implementation, and reports on the first results obtained from the LAMBDA microgrid project.

Methods

The methodology includes comparison between physical and virtual microgrids; definition of the Power Sharing Model; implementation of a physical LVDC microgrid at LAMBDA; simulation and experimental validation using real consumption profiles and PV generation.

Results

Results confirm limitations of current virtual sharing models and demonstrate improved fairness, self-consumption, load-shifting, and stability using PSM. Physical tests at LAMBDA validate increased renewable utilization and effective real-time user engagement through Power Alert devices.

Conclusions

The proposed PSM overcomes regulatory limitations of virtual communities, enabling fair energy allocation and increased renewable integration. Future work includes predictive models, scalability studies, and integration with EV charging strategies.

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Daniele Menniti, Nicola Sorrentino, Giovanni Brusco, Giuseppe Barone, Angel Oswaldo Ocana Guevara

VALUE CREATION IN RENEWABLE ENERGY COMMUNITIES INCREASING SELF CONSUMPTION BY OPERATION MANAGEMENT PLATFORM: A REAL LIFE CASE

Daniele Menniti, Università della Calabria, Email: daniele.menniti@unical.it
Nicola Sorrentino, Università della Calabria, Email: nicola.sorrentinounical.it
Giovanni Brusco, Università della Calabria, Email: giovanni.brusco@unical.it
Giuseppe Barone, Creta Energie Speciali S.r.l, Email: giuseppe.barone@cretaes.com
Angel Oswaldo Ocana Guevara, Creta Energie Speciali S.r.l., Email: angel.ocana.guevara@cretaes.com

Overview

Renewable Energy Communities (RECs) represent one of the main instruments to engage citizens in the energy transition and promote decarbonization. However, the operation phase still suffers from the lack of integrated digital tools capable of coordinating energy exchanges and managing the economic allocation of shared benefits.
This paper introduces a multi-level operation management platform that enables real-time control of distributed resources and storage systems within a REC. The platform integrates technical, economic, and behavioural dimensions through a hierarchical, cloud-based architecture that enhances transparency, active participation, and collective self-consumption.
The system connects forecasting, optimization, and control functions, fostering cooperation among members and supporting the evolution of RECs toward the provision of flexibility services and participation in energy markets.

Method

The proposed methodology is based on a hierarchical structure articulated into five levels: Network Manager, REC Manager, Config Manager, Cluster Manager, and Members.
The platform operates on two temporal horizons (day-ahead and real-time), integrating forecasting, optimization, and control modules for distributed storage systems.
Behavioural models are implemented for community members to encourage cooperation and voluntary load shifting within specific time ranges.
Multi-level performance indicators evaluate energy, economic, and participatory performance, providing continuous and dynamic feedback to community operators and users.

Results

The model was validated in a real-life Italian REC composed of 62 members — consumers, prosumers, and producers — equipped with photovoltaic systems and hybrid inverters with storage.
Experimental tests demonstrated a significant increase in collective self-consumption and a reduction in energy exchanges outside the community.
The comparison among three simulation scenarios (baseline, individual optimization, and community optimization) confirmed that coordinated control improves technical efficiency and ensures fair redistribution of economic benefits, while enhancing transparency and active participation among members.

Conclusions

The proposed platform enables RECs to evolve from simple energy-sharing groups into active and cooperative actors within the power system.
The integration of predictive control, real-time management, and behavioural participation fosters collective value creation, economic sustainability, and social engagement.

The model represents a concrete step toward more resilient and scalable local energy systems capable of providing flexibility services to the grid and participating in energy markets.
Future developments will focus on extending the framework to interoperable multi-REC networks and on promoting cooperative behaviours through dynamic incentive mechanisms.

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Tommaso Ferrucci, Davide Fioriti and Davide Poli

FAIR REWARD ALLOCATIONS FOR ENERGY COMMUNITIES: BRIDGING THE GAP BETWEEN GAME-THEORY AND PRACTICAL ALLOCATIONS

Tommaso Ferrucci, DESTEC – University of Pisa, Email: tommaso.ferrucci@phd.unipi.it
Davide Fioriti, DESTEC – University of Pisa, Email: davide.fioriti@unipi.it
Davide Poli, DESTEC – University of Pisa, Email: davide.poli@unipi.it

Overview

Energy Communities (ECs) are pivotal for the energy transition, enabling collective citizen investment in renewables [1,2]. Their success, however, hinges on fair internal reward allocation to ensure member retention and coalition stability. While Cooperative Game Theory (CGT) provides methods like the Shapley Value and the Core to guarantee fairness, their computational complexity renders them impractical for real-world ECs beyond 20 members [3]. This work bridges this gap by integrating a computationally efficient CGT method, the Variance Least Core (VLC) [4], with a cooperative optimization framework. We test this approach across 32 scenarios, varying community size, prosumer penetration, and user heterogeneity. Our results demonstrate that VLC, deployed via a row-generation algorithm, replicates theoretical fairness with minimal computational overhead, providing a scalable and practical solution for EC reward allocation.

Methods

Our methodology, implemented using the EnergyCommunity.jl Julia package [5], consists of two stages: 1) Techno- Economic Optimization: we model both a Non-Cooperative (NC) baseline, where users maximize their own Net Present Value (NPV), and a Cooperative (CO) case where an aggregator maximizes the social welfare (total NPV) of the community. The CO model includes a collective reward which is the hourly minimum of total community generation and consumption, following Italian regulations. The value v(J) of a coalition J is defined as the difference in NPV between the CO and NC cases [3]. 2) Fair Reward Allocation: The total value v(I) of the grand coalition I is allocated among members using the VLC [4]. The VLC finds the unique allocation in the Least Core that minimizes the variance from a uniform distribution, ensuring fairness and stability (i.e., no sub-coalition has an incentive to leave). To overcome the combinatorial explosion of constraints, we employ a row-generation algorithm that iteratively solves a Master Problem and a Separation Problem, adding only the most violated constraints [5]. The analysis spans 32 scenarios with communities of 10, 30, and 50 members, prosumer penetration rates from 20% to 100%, and both heterogeneous ("Mixed") and homogeneous ("Identical") user configurations.

Results

CO optimization significantly boosts the community NPV compared to the NC baseline (Fig. 1). The benefit increases with community size and prosumer penetration, reaching up to around 0.5 M€ (total lifetime) for a large 50-user community with 100% prosumers. This confirms the synergy effects of energy sharing.

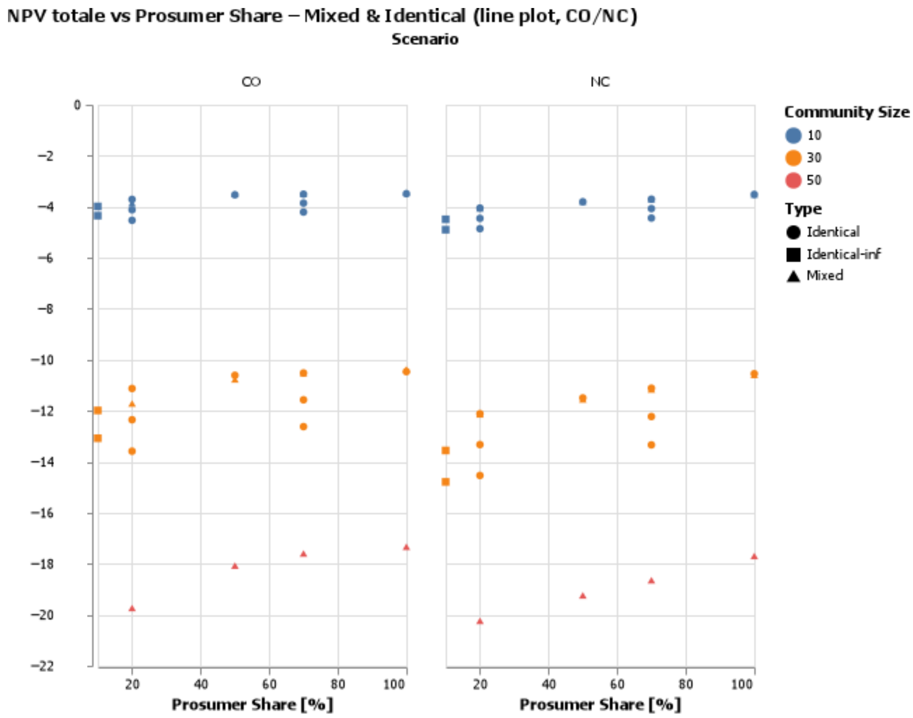

Fig 1. - NPV for the community - All scenarios

The VLC method successfully produced stable allocations ($\Theta_{LC} > 0$) for all viable coalitions. This means that no subset of users was economically tempted to break away from the community, ensuring long-term stability. Furthermore, the row-generation algorithm was crucial for scalability. While the number of required iterations increased with community size and heterogeneity, it remained computationally feasible (typically <20 iterations for 50 users), a stark contrast to the intractable combinatorial nature of the full problem [2, 3].
The analysis of the allocated rewards ΔNPV reveals two key patterns. In smaller communities (10 users), rewards are more concentrated, reflecting the higher marginal impact of individual users. In larger communities, the distribution flattens. Prosumers receive significantly larger allocations than pure consumers, as their assets and consumption patterns directly enable energy sharing and create the collective value v(I).

Conclusions

This study presents a framework for fair reward allocation in Energy Communities that successfully bridges theoretical game-theoretic principles with computational practicality. By coupling cooperative MILP optimization with the Variance Least Core and a row-generation algorithm, we achieve fair, stable, and unique allocations for communities of up to 50 users.

The key conclusion is that fairness is best achieved through energy- and investment-based metrics. Allocations proportional to members' contribution to the shared energy (a measurable quantity) naturally align with CGT principles, unlike uniform or demand-based splits. This provides a blueprint for designing EC business models that are both economically efficient and equitable. Future work will explore other parameters in schemes on optimal allocation mechanisms.

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Adnan Shihab-Eldin

EVALUATING NET-ZERO PATHWAYS THROUGH A MULTI-CRITERIA SUSTAINABILITY LENS: TRADE-OFFS IN EMISSIONS, ECONOMICS, AND ENERGY SECURITY

Adnan Shihab-Eldin, Senior Visiting Research Fellow, Oxford Institute for Energy Studies, Oxford, UK
Email: adnan.shihabeldin@oxfordenergy.org

Overview

As countries increasingly reassess their net-zero emissions (NZE) targets and strategies, policymakers must make difficult choices between competing energy pathways-each with distinct implications for environmental sustainability, economic cost, and energy security. Existing decision frameworks often emphasize emissions reduction while underweighting the trade-offs in affordability and resilience. This paper presents a structured framework to evaluate NZE strategies across three interlinked sustainability pillars: emissions, economics, and energy security.

Methods

The paper adopts a mixed-method approach, synthesizing insights from integrated assessment models (IAMs), techno-economic assessments (TEAs), and energy systems modeling. It categorizes leading NZE strategies-including renewables-dominant pathways, nuclear energy (large and SMRs), fossil fuels with CCS, hydrogen systems, and demand-side measures-against key criteria derived from recent scenario literature, including IEA/IPCC frameworks and the OPEC 2025 World Oil Outlook reference case. A comparative matrix is used to evaluate trade-offs across sustainability dimensions. The analysis incorporates system integration needs, geopolitical risks, lifecycle emissions, and investment profiles. Selected global and regional case studies are used to illustrate pathway variability.

Results

The evaluation reveals that while renewables offer strong emissions performance, they require substantial investment in storage and grid integration, posing reliability challenges. Nuclear energy delivers high base-load security but faces financial and social barriers. Fossil-based pathways with CCS reduce emissions but carry leakage and cost uncertainties. Hydrogen and bioenergy pathways offer flexibility but depend heavily on sustainable feedstocks and infrastructure readiness. Demand-side and behavioral interventions emerge as cost-effective enablers but require strong policy frameworks. The OPEC 2025 World Oil Outlook reference case highlights the continued role of oil in supporting development-driven energy demand growth in non-OECD economies. This scenario, while high in implied emissions, reflects real-world socioeconomic constraints and the need for transitional flexibility. The analysis shows that no single pathway satisfies all sustainability goals equally; hybrid strategies and coordinated sequencing are often more robust.

Conclusions

The paper underscores the importance of a multi-criteria framework for guiding NZE decisions, especially in contexts where decarbonization must align with economic development and energy access. It identifies three key research needs: (1) improving the modeling of energy security under transition risk scenarios; (2) expanding region-specific assessments for developing economies; and (3) incorporating just transition and equity considerations into systems models. By adopting a holistic sustainability lens, governments and institutions can better navigate the complex trade-offs and synergies inherent in NZE transitions.

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Agnieszka Iwan, Krzysztof A. Bogdanowicz and Witalis Pellowski

A GLOBAL VIEW OF ENERGY SECURITY FROM DUAL USE PERSPECTIVE: SOLAR CHARGERS, SCINTILLATORS AND UNMANNED PLATFORMS FOR MEDICINE, NUCLEAR AND MILITARY SECURITY AND SPACE EXPLORATION

Agnieszka Iwan: Military Institute of Engineer Technology, Obornicka 136, 50-961 Wrocław, Poland.
Email: iwan@witi.wroc.pl
Krzysztof A. Bogdanowicz: Military Institute of Engineer Technology, Obornicka 136, 50-961 Wrocław, Poland.
Email:bogdanowicz@witi.wroc.pl
Witalis Pellowski: Faculty of Security and Safety Research, General Tadeusz Kosciuszko Military University of Land Forces, Czajkowskiego 109, 51-147 Wrocław, Poland.
Email:witalis.pellowski@awl.edu.pl

Overview

Energy security is defined as the state of the economy that allows for meeting the prospective demand of recipients for fuels and energy, in a technically and economically justified manner, while maintaining the requirements of environmental protection. Perovskite-based scintillators are considered a new generation of luminescent materials used in the detection of ionising radiation, which could allow energy harvesting from sources other than light. Moreover, drones are playing an increasingly important role in ensuring energy security. They are used to inspect infrastructure, monitor threats and respond quickly to failures. Furthermore, drones can effectively and efficiently manage the energy grid, which translates into a higher level of security and reliability of energy supplies.

Method

The work carried out is aimed at developing new guidelines, methodologies, functional and utility requirements, as well as the construction of new/innovative devices or components for applications in safety engineering. The solution of these issues is supported by basic research concerning in-depth analysis of phenomena and processes occurring in the device, as well as application research using appropriate engineering/construction conditions and achieving a high level of technological readiness. The activities carried out include work on solar chargers, drones, and scintillators, as an overview of requirements, concepts, and their possible implementation.

Results

The three main pillars of this study focus on (i) solar charges, (ii) scintillators and (iii) advancements in drones. We construct solar chargers based on new materials and technologies, including organic and inorganic solar cells and energy storage devices (lithium-ion and sodium-ion batteries, supercapacitors). The work carried out includes both miniaturisation of devices and construction of large-sized solar chargers, as well as construction of flexible solar devices and solar cells with a reduced radar signature. Currently, more and more innovative solutions for devices for obtaining and storing energy from the sun are appearing. The most widely used are energy storage devices based on batteries (electrochemical cells) and hybrid systems, where supercapacitors are additionally used as a high-current source buffer. The electrical solutions of the storage determine the receivers. Hence, newer developments of highly specialised storage devices for specific purposes are appearing. This is also the subject of our innovative solutions in the field of solar chargers. We design solar chargers with TRL = 9 based on new materials/component devices also equipped with a microprocessor measurement system that improves measurement efficiency. This is a nod towards the digital transformation of AI (Artificial Intelligence) measurement processes, bringing immeasurable benefits in terms of time savings and minimizing errors made during tedious measurements.

We construct scintillators using silicon solar cells. From comparative studies between amorphous and monocrystalline silicon cells, amorphous cells proved to be less sensitive to direct gamma radiation. Using a scintillator-solar cell coupled system, it is possible to generate current from processed gamma radiation.

The possibility of converting penetrating gamma radiation enables the use of multilayer scintillator-solar cell tandem systems with up to three layers. Five postulates were proposed to convert photons of light generated by radiatively induced photoluminescence into electrical energy in photovoltaic cells. The new generation of perovskite-based scintillators still needs to solve many problems, e.g. stability and toxicity, but the obtained light efficiency results show promising prospects. Perovskite scintillators are a promising alternative to classical materials, offering higher light efficiency, shorter decay time and potentially lower production cost. They exhibit very high light efficiency, often exceeding 50,000 photons/MeV, with shorter decay times, which increases the detection speed. They can be produced at low temperatures using low-cost methods (e.g. thin-film printing). They have great potential in space applications, in imaging medicine and miniaturised detectors for satellite missions. The vision of the future is to produce a perovskite for X-ray detection (~20 keV). To implement it, a perovskite with Eg ~3 eV, e.g. $CsPbCl_3$, should be used. In addition, it is also beneficial to dope Eu^{3+} to introduce intermediate states for red light emission. As well as to create a 2D/3D heterostructure to improve the long-term stability of perovskites. In addition, future research directions should include work on: (i) two-phase perovskites to combine with plastic scintillators to obtain materials with better mechanical resistance, (ii) hybrid scintillators to integrate with photonic crystals to enhance light emission, (iii) artificial intelligence and machine learning in the design of perovskite materials with optimized chemical composition in terms of dedicated properties.
We design operational-reconnaissance, combat, and support drones in cooperation with an industrial partner. Drones of small and giant sizes for use in the air, on land and in the water. We also design drones equipped with flexible solar cells and modern energy storage devices based on sodium-ion batteries. We propose the following technological solutions to minimize the limitations related to the integration of solar cells with drones: (i) the use of flexible solar cells to reduce weight and better integrate with the drone's body, (ii) hybrid power systems (This application will solve the problems with too fast battery discharge, because solar cells will maintain the battery charge during favorable weather conditions, thus extending the drone's operating time.), (iii) intelligent energy management, and (iv) mission planning.

Conclusions

Solar chargers based on solar cells and energy storage devices, drones for various applications, also with flexible solar cells, and scintillators based on perovskites are the three key topics addressed in this paper in the aspect of energy security. The vision of the future in the field of energy security is multidimensional and includes both social and technological factors. Innovation is an inherent element of energy security, which was demonstrated in this work. Implementation of new materials into existing devices allows for their modification and improvement of operational parameters, and the modularity of the proposed solutions is based on the 6R principles, promoting sustainable development and responsible resource management.

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Vlad Duboviks, Roberta Galli, Steve Pedder, Rafael Ledesma

NAVIGATING THE ENERGY TRANSITION: PATHWAYS TO NET ZERO IN ITALY

Roberta Galli – GE Vernova – Executive Enterprise Commercial Development, Email: roberta.galli@gevernova.com
Vlad Duboviks, GE Vernova, Consulting Services Europe, UK, Email: vlad.duboviks@gevernova.com
Rafael Ledesma – GE Vernova – Nuclear Europe Commercial Director, Email: rafael.ledesma@gevernova.com
Steve Pedder, Technical Director with GE Energy Consulting

Overview

The European Green Deal followed by the "Fit for 55" package, sets binding Greenhouse Gas (GHG) emissions reduction targets for each Member State of the European Union (EU) to achieve climate neutrality by 2050. This is further reinforced by the European Climate Law which sets a legally binding target of net zero emissions by 2050. Consequently, Italy defined its recent National Energy and Climate Plan (NECP) that includes a set of planned measures to reduce CO_2 emissions in the power sector by 58-66%, aligning with the EU's 62% reduction target for 2030. This is expected to be accomplished by setting a target of at least 53% of renewable electricity consumption by 2030. Beyond 2030, the proposed 90% GHG reduction target for 2040 sets another interim goal.
In the presence of these ambitious emission reduction and renewables penetration goals alongside a projected 70% growth in demand by 2050, the need is to explore credible pathways to achieve net zero in Italy. These pathways should investigate the role of various no or low carbon electricity generation technologies as well as of the electricity grid to efficiently enable this complex transition of the Italian power sector.
This paper explores alternative decarbonization pathways for Italy's power sector, considering the economic implications of different electricity generation technologies, capacity expansion strategies, and network infrastructure requirements to reach net zero in 2050. The paper provides insights into the challenges and opportunities to inform policymakers, industry stakeholders, and investors to support informed decision-making and effective planning for a sustainable and resilient future power system in Italy.

Method

The salient features of the Italian power sector captured in this paper include CO_2 emissions reduction trajectory, growth in demand and its variability, renewables resource potential, cross border interconnection as well as inter-zonal transmission constraints. To address the uncertainty in future renewables penetration, we have analysed two alternative scenarios:
– **Renewable Ambition** - assuming renewable additions align with Italy's NECP targets, and
– **Business As Usual** - assuming a more gradual renewables increase in line with recent trends.
In both scenarios, the least-cost expansion approach is applied to determine the optimal portfolio of generating technologies to deliver net zero by 2050. However, only the Renewable Ambition scenario will achieve 2030 Renewable Energy Directive (RED) based targets for renewable capacity as outlined in the NECP. In the Business As Usual scenario, the 2030 RED targets for wind and solar additions in Italy are assumed to be missed, while an earlier introduction and a higher utilisation of the CCS technology combined with additional Hydrogen-capable gas plants can keep Italy on the 2050 net zero trajectory.

Results

Our analysis demonstrates that **Italy can achieve its net zero goals** through a successful transition to clean energy by significantly accelerating renewables deployment – with total solar and wind capacity reaching 100 GW by 2030 (i.e. more than a two-fold growth from the 2024 level), investing in flexible thermal resource (CCS and Hydrogen capability) and equally importantly through timely reinforcing the transmission grid. Key insights from our analysis are:

- **Maintaining system reliability will need a high level of flexibility resource in the system:** In order to maintain system reliability at current levels with a significantly larger penetration of renewables (solar and wind), a significant volume of flexibility resource will be required in the system. We quantified that by 2050, at least 40 GW of battery energy storage system (BESS) capacity will be needed alongside existing 29 GW hydropower capacity, 16-18 GW of CCGTs with carbon capture and sequestration (CCS) and 8 GW of nuclear (potentially Small Modular Reactors, SMRs). Our analysis also specifies that around 4 GW of Hydrogen-capable units would be cost-effective in compensating a relatively constrained renewable growth (Business as Usual scenario). Demand side response can also contribute to flexibility provision.
- **Accelerating transmission upgrades and further reinforcements in the south of Italy:** We concluded that transmission upgrades are essential and a cost-efficient way of integrating the required quantum of renewable energy. Energy curtailment could reach 82 TWh (circ. 16% of electricity demand) by 2050 even with all currently planned investments in the Hypergrid projects. Timely completion of these upgrades will save over €11 billion in system and redispatch costs by 2050[1]. Zones with high renewable capacity, lower demand and limited flexible generation will be more vulnerable to curtailment, such as in the south of Italy. Without additional transmission upgrades these zones will face significant curtailment, resulting in a loss of renewable energy and financial inefficiencies.
- **Risky reliance on solar and required mitigation options:** On economics and resource potential basis, solar (PV) capacity is the largest single source of capacity additions. However, significant challenges will need to be overcome for both solar and wind integration that include standardisation and streamlining of the authorisation of connection procedures, adequate grid infrastructure to evacuate power from lower demand zones hence managing price risks, alignment of incentives for power producers and consumers (consumers pay a single national electricity price while generators receive zonal price), and reconsidering the ban on Contracts for Difference (CfD) for ground-mounted solar-PV in agricultural areas. With a significant part of solar PV poised to be curtailed by 2050, programmes incentivising smaller PV+BESS hybrid projects should be rolled out as soon as possible, in addition to the utility-scale energy storage support mechanism (MACSE).
- **Implications of 2030 renewables targets:** In case of missing the NECP 2030 Renewables targets (i.e., the Business As Usual scenario), emissions to 2030 will be relatively high due to increased use of thermal generation. However, Italy can still achieve its 2050 target with significantly more dependence on CCS, Nuclear and Hydrogen technologies (which are yet to commercialise and are associated with cost uncertainties), and electricity imports from its neighbouring countries.
- **Cost implications:** The total system costs (excluding imports) between the high renewables (Renewable Ambition) and relatively low renewables (Business As Usual) scenarios are comparable. In the Renewable Ambition scenario, the capital expenditure will be greater, while Business As Usual scenario being more reliant on natural gas and Hydrogen will lead to higher fuel (operational) costs. Additionally, in the Business As Usual scenario, Italy will rely more on imported power, increasing the cost to consumers in Italy.

Conclusions

In conclusion, Italy's efficient transition to a reliable and resilient net zero electricity system by 2050 is achievable but it will be significantly dependent on ensuring adequate flexibility resource in the system and timely augmentation of the electricity network infrastructure. Terna's Hypergrid projects represent a vital investment for delivering net zero, however these will be realised between 2035-2040 period and therefore will not address energy curtailment in earlier years besides being inadequate for efficiently integrating the required volume of new generation by 2050.

[1] While zonal prices lead to relatively low compensation payment for curtailed energy, Hypergrid benefits can be estimated at over €80bn if curtailed energy is values at National Single Price (PUN).

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Alessio Vai, Matteo Nicoli, Valeria Di Cosmo, Daniele Mosso, Laura Savoldii

THE POTENTIAL ROLE OF ALTERNATIVE FUELS IN DECARBONIZING HARD-TO-ABATE TRANSPORT SECTOR

Alessio Vai, University of Turin Lungo Dora, Siena 100, Torino TO, Italy
Matteo Nicoli: Research Fellow, University of Turin Lungo Dora, Siena 100, Torino TO, Italy,Email: matteo.nicoli@polito.it
Valeria Di Cosmo: Associate Professor in Applied Economics, University of Turin, Lungo Dora Siena 100, Torino TO, Italy, Email: valeria.dicosmo@unito.it
Daniele Mosso Politecnico di TorinoCorso Duca Degli Abruzzi 24, Torino TO, Italy, Email: daniele.mosso@polito.it
Laura Savoldi: Full Professor in Nuclear Power Plants, Politecnico di TorinoCorso Duca Degli Abruzzi 24, Torino TO, Italy, Email: laura.savoldi@polito.it

Overview

research, conducted by the Department of Economics and Statistics at Università degli Studi di Torino in the MOST project, addresses the critical challenge of decarbonizing hard-to-abate transport sectors. These sectors, which include heavy industry (cement, steel, and chemical manufacturing) and heavy-duty transport (heavy-trucks, shipping, and aviation), are particularly difficult to decarbonize due to a lack of mature technologies and prohibitive costs. Collectively, they account for approximately a quarter of the world's energy consumption (100 EJ/year) and a fifth of total CO_2 emissions (7.6 Gt). The primary aim of this activity is to evaluate how alternative fuels may support the decarbonization of the energy system, specifically focusing on their consumption within the transport sector.

Methods

The study utilized TEMOA-Italy, an Energy System Optimization Model (ESOM), to model the Italian energy system. This model is designed to cover all energy sectors within a single region, providing medium-to-long term analysis up to 2050, with outcomes related to activity and capacity. A central aspect of the methodology involved modeling the biofuel supply chain, including primary energy resources and refinery processes. The research distinguished between two generations of sustainable alternative fuels:

- 1st Generation: These fuels are produced using standardized processes from food crops. Examples include vegetable oil from rapeseed via crushing, biodiesel through transesterification of vegetable oil, bioethanol from starch or sugar crops, ETBE from bioethanol and isobutylene, and hydrotreated vegetable oil.
- 2nd Generation: These involve emerging processes that utilize non-food crops. This category includes the production of biodiesel, bioethanol, and biokerosene from grassy crops.

Two distinct scenarios were analyzed to assess the impact of decarbonization efforts:

- Business As Usual (BAU): This scenario operates free from any CO_2 emission constraints.
- Net Zero Emission (NZE): This scenario incorporates specific constraints designed to limit CO_2 emissions.

Results

The analysis presented the projected fuel consumption under both the BAU and NZE scenarios, illustrating trends for crops, refinery processes, and final fuels across the period up to 2050. For aviation fuels consumption, the NZE scenario consistently shows a different trajectory compared to the BAU scenario, underscoring the influence of decarbonization constraints on this sector. Similarly, when examining heavy truck fuels consumption, the study revealed distinct patterns between the BAU and NZE scenarios over the period, indicating the necessary shifts in fuel mixes to achieve decarbonization goals for heavy-duty road transport.

Conclusions

The study concludes that sustainable alternative fuels represent a valuable alternative for achieving decarbonization. It highlights that the decarbonization of the hard-to-abate transport sector can be effectively supported with these alternative fuels. This suggests a need for diversification of fuels and the application of different fuels for different specific uses within the transport sector. Future perspectives for this research include investigating the potential CO_2 mitigation trade-off that might arise from increased biofuel production and analyzing how dedicated policies could effectively incentivize the consumption of sustainable alternative fuels.

Aastha Bindra, Thushara Addanki, Thomas Hamacher

DECARBONIZING THE U.S. GRID: AN OPTIMIZATION-BASED STUDY

Aastha Bindra, School of Engineering and Design, Technical University of Munich, Email: aastha.bindra@tum.de
Thushara Addanki, M.Sc. Chair of Renewable and Sustainable Energy Systems, Technical University of Munich, Email: thushara.addanki@tum.de
Thomas Hamacher, Chair of Renewable and Sustainable Energy Systems, Technical University of Munich

Overview

Decarbonizing the U.S. electricity grid is central to achieving long-term climate goals, yet faces substantial uncertainty due to volatile political dynamics and rapid technological change. This study presents a comprehensive optimization- based framework to simulate and assess the evolution of the U.S. electricity system through 2050. Using the linear programming model urbs, hourly operations across nine predefined U.S. regions are optimized under various cost, demand, and policy scenarios. The model integrates key technologies such as solar PV, onshore/offshore wind, fossil fuels, carbon capture and storage (CCS), hydrogen, and energy storage systems.
Special emphasis is placed on emerging decarbonization technologies, CO_2 restrictions, policy reversals (e.g., “Trump scenario”), and the role of consistent policy in shaping investment pathways. A novel contribution of this work is the integrated treatment of hydrogen, explicitly modeling production via both SMR and electrolysis, with downstream impacts on electricity demand and emissions.

Methods

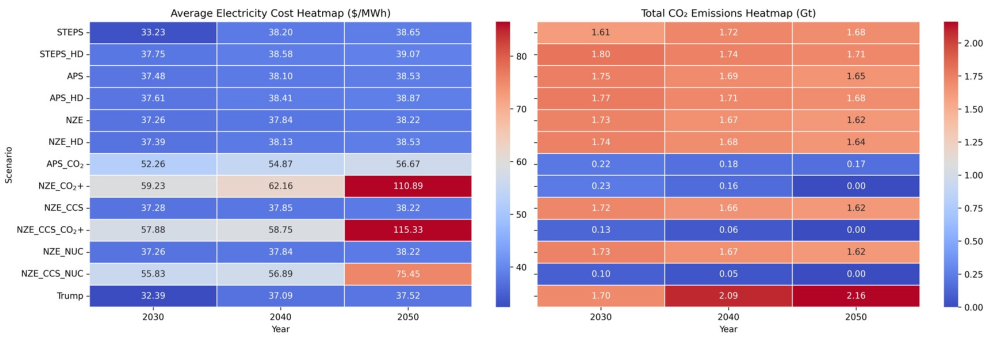
The model simulates U.S. electricity and hydrogen systems using urbs, configured for cost minimization and validated for the base year 2022 and optimized for 2030, 2040 and 2050 under different pathways. It includes electricity- only and integrated electricity-hydrogen models, operating on hourly resolution. Demand is projected via top-down regression using GDP per capita and historical electricity usage data, with separate modules for EVs and hydrogen. Supply-side technologies include fossil fuels (coal, gas), nuclear, solar PV, onshore/offshore wind, hydro, geothermal, biomass, and storage systems (batteries, PHS, hydrogen).
A wide range of scenario combinations were defined (STEPS, APS, NZE), with cost projections drawn from IEA and NREL sources. CCS is modeled as retrofit and new-build options, subject to 45Q incentives. Hydrogen is modeled with two pathways: SMR (limited to 2022) and green electrolysis, segregated by power source. Scenarios include CO_2 pricing, emission caps, and shifts in policy ambition (e.g., policy rollback under Trump scenario)

Scenario	Cost Type	Demand	CO_2 Pricing	CO_2 Limit	Nuclear Expansion	CCS Implementation	Hydrogen Integration
STEPS	STEPS	Reference					
STEPS_HD	STEPS	High					
APS	APS	Reference					
APS_HD	APS	High					
NZE	NZE	Reference					
NZE_HD	NZE	High					
APS_CO_2	APS	Reference	✓				
NZE_CO_2+	NZE	Reference	✓	✓			
NZE_CCS	NZE	Reference				✓	
NZE_CCS_CO_2+	NZE	Reference	✓	✓		✓	
NZE_NUC	NZE	Reference			✓		
NZE_CCS_NUC	NZE	Reference	✓	✓	✓	✓	
NZE_HYD	NZE	Reference					✓
NZE_HYD_CO_2+	NZE	Reference	✓	✓			✓

Scenario Assumptions Matrix

Results

Across all scenarios, solar PV and onshore wind dominate new capacity due to low costs and favorable load profiles. Without CO_2 pricing, fossil fuel usage remains robust; under strong climate policy (NZE CO_2+), coal and natural gas decline significantly, replaced by renewables, battery storage, and CCS where economically viable. However, the impact of CCS remains modest, hindered by high costs and competition from renewables.
In scenarios where nuclear capacity was allowed to expand, the optimization results clearly showcased its potential as a low-cost, firm, and low-emission energy source that significantly reduces dependency on fossil-based baseload. The following figure presents the evaluated electricity cost and CO_2 emissions across all scenarios underlining the aforemntioned argument.



Conclusions

This study highlights that decarbonizing the U.S. electricity grid is technically feasible but hinges on consistent and ambitious policy support. Solar PV and onshore wind are economically optimal in nearly all scenarios, with hydrogen and storage offering additional flexibility. CCS, while technologically mature, remains cost-constrained and sensitive to CO_2 pricing mechanisms. Policy volatility, especially between contrasting administrations, poses a significant risk to long-term investment and planning.
Integrated modeling of electricity and hydrogen, combined with high-resolution demand and scenario analysis, proves essential for understanding the complex dynamics of the future grid. Transitioning to a net-zero electricity system by 2050 will require a balanced approach, leveraging low-cost renewables, firm decarbonization technologies, and robust policy frameworks that ensure both affordability and environmental integrity.

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Hanna F. Scholta, Benedikt Lechl, Gero Sutmann,

THE SPATIAL RESOLUTION OF GREEN ELECTRICITY CLAIMS: INSIGHTS ON LOCATIONAL MATCHING AND MARKET LIQUIDITY FROM GERMANY

Hanna F. Scholta, Technical University of Munich, Chair of Management Accounting, Arcisstrasse 21, 80333 Munich, Germany, Email: hanna.scholta@tum.de
Benedikt Lechl, Technical University of Munich, Chair of Management Accounting, Arcisstrasse 21, 80333 Munich, Germany
Gero Sutmann, Technical University of Munich, Chair of Management Accounting, Arcisstrasse 21, 80333 Munich, Germany

Overview

The liberalization of power markets has enabled consumers to advocate for green electricity, with demand steadily increasing in recent years. The labeling of electricity as green relies on Energy Attribute Certificates (EACs), which are typically canceled on an annual volumetric basis to account for renewable electricity consumption. However, this annual accounting system has drawn sustained criticism for its limited effectiveness and transparency. Increasingly, stakeholders are calling for more granular accounting to better align electricity consumption with renewable generation in time and location. While prior research has focused on the environmental impact of stricter accounting rules, little attention has been paid to the trade-offs with market functionality. In Europe, the integrated EAC market currently allows for cross-border trading, providing flexibility in certificate sourcing. Stricter locational matching rules would introduce new restrictions, limiting this flexibility.
Our study addresses this gap through a case study of Germany, empirically analyzing the implications of stricter locational matching rules for EAC usage in Europe. We assess how past EAC flows align with physical electricity flows and evaluate how different spatial constraints would affect market liquidity. As the largest net importer of EACs in Europe, Germany offers a critical context for examining the potential consequences of such policy shifts. Aiming to enhance the credibility and effectiveness of green electricity claims, our research offers practical insights for policy frameworks that balance transparency with market functionality.

Methods

Our study seeks to answer two key research questions:

1. How do electricity and EAC flows interact under current accounting practices?
2. How would different spatial resolution constraints have affected market liquidity in past EAC transactions?

To answer these questions, we conduct a case study of Germany, the largest net importer of EACs in Europe. Spanning the years 2016-2024, our analysis combines physical electricity flow data from the German electricity market data platform SMARD with EAC cancellation data provided by the German Federal Environment Agency (UBA).

To assess Research Question 1, we calculate the monthly balance between physical electricity imports and canceled EACs to evaluate the degree of alignment between green electricity claims and actual electricity flows in Germany. To address Research Question 2, we conduct counterfactual simulations to examine the liquidity effects of four increasingly restrictive spatial matching scenarios:

- **Scenario A**: Allowing only EACs from countries that also physically exported electricity to Germany in the given month.
- **Scenario B:** Restricting EAC imports to countries from which Germany was a net importer over the month.
- **Scenario C:** Limiting EAC trade to interconnection capacity between Germany and its trading partners.
- **Scenario D**: Allowing only domestically issued EACs.

For each scenario, we assess changes in total EAC availability and supplier-level liquidity to identify potential disruptions to corporate procurement.

Results

The analysis confirms a persistent misalignment between EAC usage and physical electricity imports in Germany, with a considerable proportion of canceled certificates originating from countries without corresponding physical energy flows.
Simulations of stricter locational matching scenarios reveal notable reductions in EAC availability. Under Scenario A (Electricity Trading Countries Only), monthly volumes would have decreased by more than 50% in most months prior to autumn 2020, and by approximately 25% thereafter. Scenario B (Net Import Countries Only) exhibits a comparable trend, albeit with slightly lower availability and more pronounced reductions in several months – exceeding two-thirds. These patterns coincide with the commissioning of a direct electricity interconnection between Germany and Norway in late 2020. By contrast, Scenario C (Interconnection Capacity Limit) results in more stable but constrained availability, fluctuating around one-third of actual cancellations. Scenario D (Domestic Certificates Only) yields the most restrictive outcome, with volumes consistently below one-fifth of historical cancellation levels. The analysis also reveals substantial differences in suppliers' current procurement strategies, with only a small subset of suppliers able to maintain sufficient certificate volumes under stricter locational matching scenarios.

Conclusions

This case study of Germany highlights a consistent misalignment between EAC usage and physical electricity flows under current accounting rules. Simulations show that stricter locational matching could enhance the spatial soundness of green electricity claims but would also lead to significant reductions in certificate availability, with only a small subset of suppliers currently holding procurement strategies compatible with such constraints. These findings underscore the risk that stricter spatial alignment rules could severely constrain market liquidity and hinder the ability of consumers to engage in green electricity procurement.
While based on historical data and not accounting for future market adjustments, our analysis enables a better understanding of the structural effects of locational matching reforms. The findings highlight the need for policy frameworks that not only strengthen spatial soundness but also preserve market functionality and cross-border efficiency.

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Adonis Yatchew, Frederik Dufour, Michael Scafe,
INCENTIVE REGULATION AND PRODUCTIVITY ANALYSIS OF ONTARIO ELECTRICITY DISTRIBUTORS

Adonis Yatchew, University of Toronto, Email: adonis.yatchew@utoronto.ca
Frederik Dufour, University of Toronto, Email: frederik.dufour@mail.utoronto.ca
Michael Scafe, University of Toronto, Email: michael.scafe@mail.utoronto.ca

Overview

Ontario electricity distributors have been under incentive regulation for about 25 years. The regulator (the Ontario Energy Board) uses data-driven methods to evaluate their performance and to set rates. However, the energy transition has complicated the data analysis process as the roles and responsibilities of distributors have evolved over time. This paper analyzes a comprehensive dataset on Ontario distributors and reveals substantial variation in their measured efficiency. The paper proposes alternatives for the next generation of incentive regulation in Ontario.

Methods

The data consist of a panel on over 50 electricity distributors of widely varying size over the periods 2002-2012 and 2013-2024. We apply two methodologies to assess productivity: Total Cost Benchmarking (TCB) and Total Factor Productivity (TFP). The TCB implementation incorporates up to four output variables (number of customers, distribution capacity, electricity deliveries and network line length). Input variables include factor prices (OM&A and capital) and utility specific factors (such as customer density, underground v. overhead wires). The TFP implementation does not account for covariates. It follows the usual approach of comparing aggregate output and input indexes.

Results

The previous regulatory modelling relied upon data for the 2002-2013 period. Estimated productivity growth was negative. Our analysis, which covers the period 2014–2023, yields a modest positive productivity growth. This suggests that the incentive regulation scheme which the OEB implemented in 2014 has had a beneficial effect. The earlier negative productivity estimates may stem from modeling limitations due to insufficient data on the evolving roles and responsibilities of utilities. The current modelling attempts to include variables related to the energy transition such as EV and distributed energy resources (DER) penetration.

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Younoussa Abdoulhazis Oumarou, Camille Massié Gamard

HOW HAS COVID-19 AFFECTED THE FRENCH ELECTRICITY LOAD CURVE?

Younoussa Abdoulhazis Oumarou, Université de Pau et des Pays de l'Adour,
Email: younoussa.abdoulhazis-oumarou@univ-pau.fr
Camille Massié Gamard, Université de Pau et des Pays de l'Adour, Email: camille.massie@univ-pau.fr

Overview

Amid heightened geopolitical tensions and market volatility, the resilience of national energy systems to external shocks has become a major concern. The COVID-19 crisis has acted as an unprecedented stress test, forcing radical and immediate changes in consumption patterns. This emergency requires a precise understanding of how lockdown measures, widespread teleworking, and disruption to economic activity are affecting electricity demand at the national level. It is crucial to analyze these dynamics to enable network managers and policy makers to ensure energy security and adapt infrastructure to future crises (e.g., health, geopolitical) or structural social changes. Although the impact of COVID-19 on energy consumption is a relatively well-documented topic at the international level, this research aims to make a significant contribution by empirically assessing the causal impact of restrictions in the specific unstudied case of France and, above all, by detailing the effect on its daily electricity load curve.

Methods

We use a rigorous difference-in-differences approach, comparing days subject to restrictions (in 2020 and 2021) with their historical equivalents without restrictions (between 2015 and 2019), in order isolate the effect attributable to government measures. We employ national half-hourly electricity consumption figures provided by RTE France and the Oxford University Government Response Severity Index (Oxford COVID-19 Government Response Tracker - OxCGRT). The analysis is conducted on the electricity load curve to capture the heterogeneity of effects according to the time of day and type of day (weekday versus weekend).

Results

Sectoral analyses show that the positive effect observed in the residential sector (due to teleworking and staying at home) was not sufficient to offset the widespread negative effects in industry, the tertiary sector, agriculture, and transport, resulting in an overall net decline in French electricity consumption during lockdowns. This negative effect was almost entirely concentrated on weekdays and hours of economic activity, with the sharpest declines occurring between 7 a.m. and 12 p.m., and again between 2:30 p.m. and 9 p.m. In contrast, the weekend pattern differs markedly: the effect on the load curve was insignificant at night and in the early morning (until 8:30 a.m.), negative, then insignificant again between 12:30 p.m. and 2 p.m., before turning negative once more, though systematically weaker than during weekdays. Above all, Sundays showed virtually no significant effect on the load curve, with the negative impact observed for aggregated weekends being almost entirely attributable to Saturdays. This lack of a significant effect on Sundays may suggest that, during lockdowns, the traditional distinction between weekdays and weekends largely disappeared, as restrictions and widespread teleworking made daily patterns of electricity consumption more homogeneous across the week. Overall, these results provide preliminary evidence that COVID-19 lockdowns affected not only the level but also the shape of the daily load curve in French electricity consumption.

Conclusions

This study contributes to the rich stream of literature on the effects of the COVID-19 pandemic on energy systems, with a distinctive and unique contribution stemming from its focus on France, which has so far remained unstudied. Indeed, we demonstrate that lockdown measures caused a profound and heterogeneous change in French electricity demand, revealing a vulnerability and sensitivity to shocks concentrated on days and hours of economic activity. These periods were profoundly disrupted during lockdowns, as mandatory teleworking may have altered working hours within both the day and the week. COVID-19 therefore represented a major consumption shock for the French energy system. As this study highlights patterns that can be generalized to other types of shocks, prioritizing strategies such as incentive tariffs to smooth the load curve in the middle of the week could help strengthen resilience and ensure the robustness of the energy system in the face of future geopolitical shocks, which are at the core of energy security.

Hendrik Diers

EVALUATING THE IMPACTS OF THE EU METHANE REGULATION ON NATURAL GAS IMPORTS

Hendrik Diers, Institute of Energy economics at the University of Cologne
Vogelsangerstraße 321a, 50827 Cologne Phone: +4922165074528, Email: Hendrik.diers@ewi.uni-koeln.de

Overview

The European Union has introduced the Methane Emission Regulation (MER), a landmark initiative aimed at drastically reducing methane emissions from the fossil fuel sector. The regulation addresses both domestic operators and global supply chains. It applies to imports of crude oil, coal, low-carbon hydrogen, and natural gas. Given that the security of supply for natural gas is of particular concern to policymakers, it is the focus of this paper.
Similar to the Carbon Border Adjustment Mechanism (CBAM), this EU climate policy extends decarbonization efforts to imported fossil energy, placing global producers under pressure to meet EU environmental standards. Beginning January 1, 2027, importers must demonstrate that all supply contracts signed or renewed after August 3, 2024, comply with equivalent monitoring, reporting, and verification requirements at the production level.
Relevant to this paper, the regulation also sets the stage for mandatory methane intensity standards for imports starting in 2030. These standards will impose maximum thresholds tailored by fuel type and production method. The regulation aims to differentiate between onshore and offshore production, as well as between conventional and unconventional production techniques. Failure to comply will result in penalties, effectively creating a form of emissions pricing.
This regulation has the potential to reshape the global natural gas market by influencing the merit order of suppliers and redefining purchasing decisions based on methane intensity. However, it increases the risk of canceling long-term contracts (LTCs) that exceed methane thresholds, thereby endangering energy security.
Despite the broad implications of the MER, current literature offers limited insight into its economic effects. Olczak (2024) suggests that the LNG market could split into “low emission gases” for the EU and “high emission gases” for the rest of the world. Rystad (2023) finds small markups for consumers; however, the analysis does not incorporate ex-ante methane pricing. Academic work on emissions pricing in the gas sector remains scarce. Aside from Heal and Schlenker (2019), which analyze oil and gas combined, existing literature such as Asker et al. (2019, 2023) focuses mainly on oil emissions pricing. To the best of my knowledge, no research applies methane pricing in partial equilibrium models. Moreover, methane is a potent greenhouse gas, and leakages during transport (via pipeline, liquefaction, and regasification) are a serious concern. Spatial effects, however, are not considered in the current literature.

Methods

This paper applies methane pricing within a spatial Cournot-fringe competition framework, following Salant (1980). The model is formulated as a mixed complementarity problem (MCP) and uses detailed micro-level data on upstream methane emissions from Rystad (2025), covering over 28,000 assets globally. Additional asset-level information on historical production, CAPEX, OPEX, reserves, LTCs, and upstream and liquefaction emissions is obtained from Rystad Energy (2025). Emissions from pipeline leakage, shipping, and abatement costs are sourced from the IEA (2025).
Producer behavior is modeled following Asker et al. (2019), using marginal costs that vary across production technologies (conventional, unconventional, offshore), lifecycle stages (brownfield, greenfield), and abatement options. Greenfield costs reflect break-even prices, including CAPEX, under the assumption of perfect foresight. Abatement costs are added directly to marginal costs. Investments in clean production capacities and abatement technologies are endogenous. Production is constrained by a maximum extraction rate: the sum of abated and unabated output per class must not exceed reserves. As the MER targets producers individually, splitting production into abated and unabated segments within a class is considered valid.

Trade is modeled via two flows. A “dirty” flow is supplied by units above the methane threshold and is subject to EU penalties. A “clean” flow is supplied by units below the threshold. Both are perfect substitutes in the market clearing condition, but only dirty imports face penalties, capturing the MER’s impact on trade and compliance behavior.

Results

The paper finds that the MER will induce significant investments in abatement, as the cost of abatement is very low. Even higher thresholds and lower penalties will still trigger investments. Furthermore, producer rents decrease more sharply when the EU is the only viable market, as is the case for North African countries.
Nevertheless, global emissions will decrease only marginally, as trade flows adjust accordingly.

Conclusion

The Methane Emission Regulation (MER) will drive significant investments in abatement technologies, particularly for producers targeting the EU market, leading to a reduction in producer rents and altered trade flows. However, the global reduction in methane emissions will be modest, as adjustments in trade dynamics mitigate the broader environmental impact. This paper contributes by applying methane pricing within a spatial Cournot-fringe competition model, offering a novel approach to assessing the economic effects of methane emissions pricing in the natural gas sector, and expanding the literature by incorporating spatial effects in pricing of externalities.

Thorsten Fischer

THE ECONOMICS OF CARBON CAPTURE AND STORAGE: LEARNINGS FROM POLICYMAKING AND INVESTMENT ANALYSIS

Thorsten Fischer, Saudi Aramco, Dhahran, Saudi Arabia; Email: thorsten.fischer@aramco.com

Overview

The objective of the presentation is to increase the quality of investment analysis for CCUS projects. In order to achieve this objective, the approach employs three prongs. This presentation will show (1) how to improve the forecast of global carbon prices by using output from policymakers, namely the Social Cost of Carbon (SCC), as an input into the capital budgeting model for CCUS projects; (2) how to identify and treat systematic risk on one side and non-systematic or diversifiable risk on the other side when conducting Discounted Cash Flow (DCF) analysis; and (3) how to extract value through flexibility, i.e. to use options embedded in the CCUS project, such as the option to delay, expand or abandon the project, and how to quantify the value through real options.

Methods

We apply a standard Net Present Value (NPV) model, as is commonly used in capital budgeting, to a generic CCUS project in a representative jurisdiction. The model will show the typical structure, that is initial capital outflows and subsequent operating expenses. Within the model we demonstrate how to forecast revenues, how to treat systematic risk, how to model diversifiable risk and how to perform real option valuation.

Revenue forecasts

Revenue forecast depend critically on assumptions regarding the price of carbon. Often this will take the form of opportunity costs, as the benefits from CCUS are avoided expenditures in jurisdiction where a price of carbon has been established whether through a carbon tax or a cap-and trade system. While the forecast of the price of carbon credits is difficult, guidance can be provided by SCC.
The SCC measures the marginal economic cost of emitting one additional ton of carbon. It is often measured in US dollars per ton of CO_2-equivalent. A carbon price based on the SCC can be seen as an empirical estimate for a Pigouvian tax. In theory SCC is an ideal candidate for an estimate for the price of carbon in our model. In practice the exercise is much more difficult, as estimates of the SCC are notoriously unreliable and highly contested
We choose the output from the Dynamic Integrated Model of Climate and the Economy (DICE) model by Barrage and Nordhaus because of the outstanding reputation of the model (Nordhaus was awarded the economics Nobel in 2018 for his work on "long-term economic growth and its relation to climate change.") and the fact that it results in estimates of the SCC in the mid-range of all estimates.

Systematic risk

Systematic risk will be incorporated into the discount rate. For the cost of equity, the Capital Asset Pricing Model (CAPM) will be used. As for any asset pricing model the cost of equity depends on systematic risk, here as measured by covariance of returns of the asset with the market portfolio. We consider two cases:

Case 1: Full exposure to carbon prices through carbon trading. Investing in CCUS is an alternative to buying credits. The value of emission abatement will dependent on carbon prices. Here we use a peer group that has similar exposure to commodity prices, most notably oil and gas. The estimated beta for these cyclical industries is 1.1.

Case 2: Government contract with contract-for-differences. Very stable cash flows, minimum cash flow risk. Here we select peer companies from regulated and stable cash flow companies. Beta: 0.4.

In Case 1 we assume project financing of 30% and a cost of debt of 5.5% to obtain a WACC of 11%, unchanged from the unlevered cost of equity; and in the second case we assume 70% debt financing resulting in a WACC of approximately 7%.

Diversifiable risk

Diversifiable risk will be treated by an adjustment in the cash flows. This will show the range of possible outcomes, but will not affect the pricing of risk itself, i.e. an additional dollar of future cash flows will be discounted at the same rate. Thus, the trade-off between a safe dollar today and a risky dollar tomorrow remains unaffected. This is what asset pricing theory demands.

The approach enables decision makers to rely on much richer data than mere deterministic analysis. Risks can be quantified and measured, rather than assessed merely qualitatively. Stochastic analysis is also an effective way to overcome optimism bias. Diversifiable risk will be modeled using Monte Carlo simulation.

Valuing flexibility (real options valuation)

In addition to assessing the value of the investment in CCUS, which is achieved by committing the full capital expenditure today, we can also examine how a more flexible approach towards deciding when and how much to invest can generate higher economic value. Having secured the physical infrastructure for the carbon storage the CCUS project can be viewed as a series of investment decisions over time to determine how to maximize value.

A suitable project can be modelled as a (series) of real option(s), where an investment decision can either reveal a cash flow or another real option. In the latter case we speak of compound options. For our example we limited the analysis to a simple option without any loss of generality.

Results

Based on our assumptions (not part of this abstract), we find an NPV of negative $1.0 billion in Case 1 and negative $300 million in Case 2.

In addition, the simulation results for Case 1 show that in 10% of all cases losses will exceed $1.38 billion, while the probability that NPV will be positive is only 1.6%. For Case 2 Value-at-Risk at 10% is $1.1 billion and the probability of a positive NPV is 38%, even as the mean and median of the NPV are still negative.

Based on our assumptions for the real option, we calculate an option value of $21 million. Thus, even though the project has a negative NPV of more than one billion, the ability to limit the downside risk by exercising the option in stages carries a positive value. As long as our exploratory drilling costs are no more than $21 million, we should proceed.

Conclusions

We have outlined best practices in evaluating future CCUS projects, focusing on forecasting the price of carbon; treatment of systematic and diversifiable risk; and the proper valuation of options embedded in the CCUS project.

While a key distinction has to be drawn between the investor's task who evaluates the economic merit of a CCUS investment and the task of the policymaker who designs the optimal policy, it turns out the latter can inform the former as follows: The output of the policymaker's analysis, namely an estimate of the SCC may guide the choice of a central input into the investor's analysis, i.e. the value of a ton of carbon abated.

The advantages of linking expectations of future carbon prices to the SCC are that they describe an optimum based on social cost benefit analysis; that they are invariant with respect to whether a carbon tax or cap-and-trade is in place: and that since GHG emissions represent a global externality there is no need to distinguish carbon prices for different jurisdictions.

Other parallels are also instructive such as the analogy between the CAPM for companies evaluating systematic risk and the more general Consumption CAPM used by policy makers and academics who seek to calculate the SCC. The distinctions between systematic risk and diversifiable risk remains important for both approaches, opening the prospect for synergies in modelling and evaluation.

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Haiying Jia, Roar Adland

REDRAWING THE ENERGY MAP: A MARITIME DATA PERSPECTIVE ON POST-UKRAINE WAR PETROLEUM TRADE

Haiying Jia, Norwegian School of Economics

Abstract

This study provides a maritime big data analysis based on real-time vessel tracking Automatic Identification System (AIS). Seaborne petroleum trade flows are investigated following the voyages taken by ocean-going tanker vessels. The trade flows are identified based on origin- destination routes. Prior to the war, Russia was a major petroleum supplier to European countries. Following the invasion that began in February 2022, a group of European nations, along with global allies implemented systematic reductions in Russian petroleum imports. This geopolitical event has caused a significant shift in petroleum trade flows.

The import volume shift in 2023 compared to the base-line level in 2021 is presented in *Fig.* 1 below. In addition, we also identify import volume shifts at the national level.

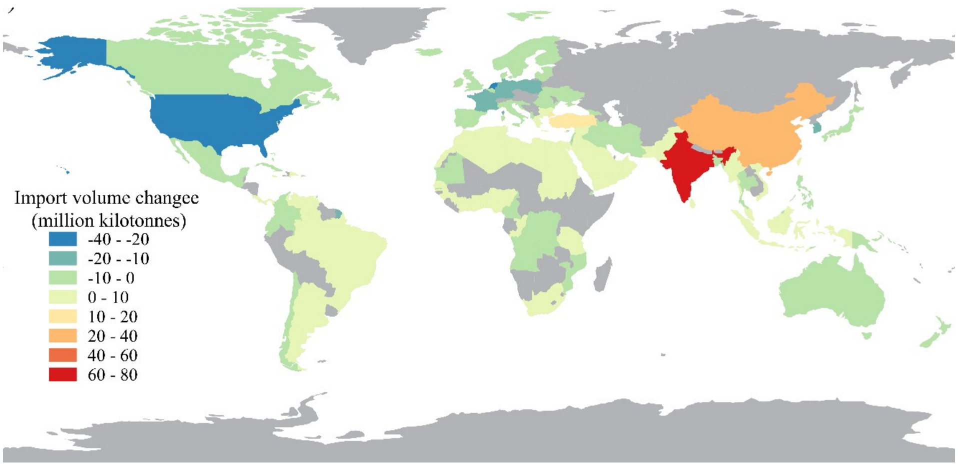

Figure 1. Global import volume changes in 2023 vs. 2021 for seaborne Russian petroleum trades

The findings in the study suggest the ongoing change in global petroleum trade routes and trading partners. The dynamic in trade flow shows certain level of resilience in terms of volume at the global scale. However, regional differences may raise concerns over long-term energy security and market dependence. The findings have implications for business operations, risk management and policy makings.

***Key words**: Trade flow, Ukraine-Russia war, energy security, maritime, AIS*

Emran Hakeem, Mohammed Hakeem, Rozina Shaheen

UNDERSTANDING ENERGY POVERTY IN THE GLOBAL NORTH: A PANEL DATA INVESTIGATION

Emran Hakeem, PhD Student, Effat University, Jeddah, Saudi Arabia, Email: eohakeem@effat.edu.sa
Mohammed Hakeem, PhD Student, Effat University, Jeddah, Saudi Arabia, Email: mohakeem@effat.edu.sa
Rozina Shaheen, Associate Professor, Effat University, Jeddah, Saudi Arabia,
Email: roshaheen@effatuniversity.edu.sa

Abstract

Despite its traditional association with developing nations, energy poverty is increasingly recognized as a structural concern in advanced economies, driven by escalating energy costs, inefficient and aging housing infrastructure, and heightened vulnerability to climate-related risks.

This study investigates the macroeconomic and structural determinants of energy poverty in high-income countries. Utilizing a panel dataset comprising eight developed economies, such as Australia, Canada, France, Germany, Italy, Mexico, the United Kingdom, and the United States, for the period 1990 to 2023, the analysis explores whether reduced energy use reflects constrained access to essential energy services. The dependent variable, residential energy consumption per capita, is examined in relation to electricity prices, GDP per capita, heating degree days, urbanization, and residential energy intensity. Fixed-effects and panel- corrected standard error estimators are employed to control for country-specific and temporal heterogeneity. Preliminary results indicate that elevated electricity prices and low levels of energy efficiency are significantly associated with lower residential energy consumption, suggesting the presence of structural energy deprivation even within affluent contexts.

The findings contribute to the academic discourse on energy poverty in the Global North and offer policy-relevant insights for designing equitable energy transition strategies that enhance affordability, resilience, and sustainability.

Keywords: *Energy Poverty, Consumption, Efficiency, Developed Countries, Panel Data*

Liu Yishuang, Dong Hanmin

THE IMPACT OF CHINA'S OUTWARD INVESTMENT ON ENERGY POVERTY IN AFRICA

Liu Yishuang, WHU, Email: vanavampire@whu.edu.cn
Dong Hanmin, CCNU, Email: donghanmin@ccnu.edu.cn

Overview

Energy poverty, defined as the lack of access to reliable, affordable, and clean energy, remains a significant obstacle to sustainable development across sub-Saharan Africa. Despite ongoing efforts by multilateral institutions and domestic governments, progress toward universal electrification remains slow. Over the past two decades, China has become a major investor in African energy infrastructure, financing power generation, grid expansion, and off-grid solutions through its Belt and Road Initiative (BRI) and other bilateral platforms. While Chinese investment is often viewed as a critical external resource to alleviate Africa's infrastructure gaps, its actual contribution to reducing energy poverty is still underexplored.

This study aims to fill this gap by empirically evaluating whether and to what extent China's outward foreign direct investment (OFDI) in the energy sector contributes to alleviating energy poverty in African countries. Focusing on the period from 2006 to 2022, we integrate macro-level energy access indicators with geospatial satellite data and project-level Chinese investment records to provide a comprehensive causal analysis.

Methods

We construct a panel dataset of 49 African countries using data from the World Bank, International Energy Agency (IEA), and the China Global Investment Tracker (CGIT), complemented by satellite-derived night-time light (NTL) data to proxy for local electrification. The identification strategy relies on a difference-in-differences (DID) design that exploits the variation in timing and location of Chinese energy investment projects. To improve comparability between treated and untreated units, we apply propensity score matching (PSM) based on pre-treatment characteristics such as GDP per capita, population density, energy investment needs, and governance indicators.

Additionally, an event study framework is employed to assess dynamic effects over time and to test the parallel trends assumption. We also explore heterogeneity in treatment effects by disaggregating projects by energy type (renewable vs. fossil fuel), grid connectivity (centralized vs. off-grid), and geographic location (urban vs. rural).

Results

The empirical findings show that Chinese energy investment leads to a statistically significant reduction in energy poverty indicators. Countries and regions receiving Chinese energy infrastructure investment exhibit:
A 6–12 percentage point increase in electricity access within 3–5 years after project implementation;
Noticeable improvements in night-time luminosity, particularly in rural areas where electrification baselines were low;
Enhanced household energy consumption and connectivity as captured in household surveys.
The effects are more pronounced in renewable and off-grid energy projects, which offer quicker deployment and broader coverage in dispersed populations. In contrast, large-scale grid-connected projects tend to have delayed but longer-lasting impacts.

Conclusions

This study provides robust causal evidence that Chinese OFDI plays a meaningful role in addressing energy poverty in Africa. Beyond increasing electricity supply, these investments contribute to socio-economic improvements, especially when tailored to local conditions and complemented by institutional support.

Our findings carry important policy implications. First, they underscore the potential for South–South cooperation to serve as an effective mechanism for delivering Sustainable Development Goal 7 (Affordable and Clean Energy). Second, they highlight the need for African governments to strengthen investment governance and integration planning to maximize the local benefits of foreign-funded energy projects. Lastly, the research encourages international stakeholders to support hybrid financing models that combine Chinese capital with local or multilateral resources to expand and sustain energy access in underserved areas.

Yishuang Liu
Recipient of the Hubei Provincial "Boshi Xin" (Outstanding Postdoctoral Researchers) Program and the Wuhan University Excellent Postdoctoral Fellowship. Dr. Liu's research focuses on interdisciplinary issues related to global economic imbalances and the green, low-carbon economic transition. She has published nearly 20 articles in CSSCI, SSCI, and SCI journals, including three ESI Highly Cited Papers. She has led several research projects, including the China Postdoctoral Science Foundation General Program and fundamental research projects supported by central universities. Dr. Liu also serves as a Guest Editor for the International Review of Financial Analysis and a Youth Editorial Board Member of Carbon Footprints.

Emna Kanzari, Stefano Fricano, Gioacchino Fazio

FOREIGN DIRECT INVESTMENT AND ENERGY POVERTY IN AFRICA: THE ROLE OF INTERNATIONAL PARTNERSHIPS

Emna Kanzari, University of Palermo, Department of Economics, Business and Statistics,
Email: emna.kanzari@unipa.it
Stefano Fricano, University of Palermo, Department of Economics, Business and Statistics,
Email: stefano.fricano@unipa.it
Gioacchino Fazio, University of Palermo, Department of Economics, Business and Statistics,
Email: gioacchino.fazio@unipa.it

Overview

Despite the technological advances that our societies are witnessing and the efforts to accelerate the energy transition towards environmentally friendly forms, a significant number of people worldwide, especially in Africa, still live in energy poverty. This is due to several challenges, including the poor infrastructure and limited investments in national electricity grids. On the other hand, the African continent has recently received foreign investments from international investors in different sectors that may potentially influence energy access. This paper examines the channels through which Foreign Direct Investment (FDI) can influence energy poverty in Africa, with a particular focus on FDI from China.

Methods

To empirically explore this complex nexus, we rely on one of the structural equations modelling (SEM) methods for panel data. The analysis uses a dataset covering African countries from 2003 to 2020, integrating variables related to energy access, socioeconomic development, and foreign investment. The use of this method allows for the assessment of both direct and indirect effects of FDI on energy access.

Results

The empirical results reveal that FDI has played an important role in improving electricity access in African countries through different channels. The effect operates through several channels, including infrastructure development, technology transfer and economic growth. While Chinese FDI shows strong and significant impacts, similar positive effects are also observed from other international partners.

Conclusion

The study tries to understand the relationship between foreign investments and the mitigation of energy poverty in African countries and how it is crucial for driving sustainable energy progress. Foreign investments, especially directed toward electricity infrastructure, can provide access to clean and reliable energy sources, which in turn can boost economic growth and improve standards of living. Finally, the paper concludes by underscoring the need to foster international cooperation and boost regional and global partnerships to address development challenges, including energy poverty.

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Corinne Chaton, Thierry Kamionka, Mila Marsot

HOW HAS COVID-19 INFLUENCED THE DYNAMICS OF FUEL POVERTY IN MAINLAND FRANCE?

Corinne Chaton, CREST - FiME, Email: corinne.chaton@ensae.fr
Thierry Kamionka, CREST, Email: thierry.kamionka@ensae.fr
Mila Marsot, ENSAE, Email: mila.marsot@ensaze.fr

Overview

According to Eurostat, in France, more than one in nine households (11.8%) were unable to keep their home adequately warm in 2024, compared with 12.1% in 2023. The causes of this inability are living in energy-inefficient housing, low income, and/or high energy prices. These are also the three main causes of fuel poverty. This inability to heat one's home adequately was the first definition of fuel poverty (Bradshaw and Hutton [1983]). In France, there are fewer households with arrears on utility bills (7.5% in 2023) than households reporting difficulties in keeping their homes adequately heated. During the winter of 2023- 2024, 30% of French people reported suffering from the cold (4 percentage points more than the previous winter), 41% of them for financial reasons [ONPE 2023, 2024]. Since the winter of 2019-2020, more and more people have found themselves in this situation. According to the latest national housing survey conducted between October 2019 and April 2022, in mainland France, the percentage of households that suffered from cold during the previous winter is 10.2% [Driant, 2024].

It is a fact that the proportion of households in fuel poverty according to the perceived cold indicator has been rising for several years. But are there households that have been able to escape fuel poverty? What is the dynamic of energy poverty? Between 2009 and 2011, fuel poverty in mainland France was ``*mostly a transitory (i.e., temporary) state. Nevertheless, it must not be forgotten that 38\% are stayers in a fuel poverty state and 33% are stayers in a severe fuel poverty state. Additionally, the proportion of individuals who are vulnerable to fuel poverty is approximately 15%.*" [Chaton and Lacroix, 2018]. The emergence of COVID-19 has led to major economic disruption, including job losses, lower incomes and increased household energy expenditure due to prolonged lockdown. However, the resumption of travel has led to a decline in household consumption and fuel consumption, leaving more savings for energy expenditure on heating homes.

In this paper, we examine how COVID-19 has affected household stability across different levels of energy poverty in mainland France between 2017 and 2021.

Methods

Some authors have already studied the impact of the COVID-19 pandemic and the measures taken to eradicate it on fuel poverty. Burlinson et al. [2021], using the longitudinal Understanding Society (UKHLS, Wave 10, January 2018– February 2020), studied the link between fuel poverty and financial difficulties before and during the first wave of the COVID-19 pandemic in the United Kingdom. Before and during the COVID-19 pandemic, fuel poverty increased the risk of late bill payments and financial hardship. Carfora et al. [2022] quantify the effects of the pandemic on energy discomfort in European households. According to these authors, the increase in the number of households experiencing fuel poverty due to the COVID-19 pandemic and the measures put in place to slow it down (e.g. lockdown) is expected to be absorbed slowly and unevenly across countries.[2]

[2] Articles by Mastropietro et al. [2020], Ambrose et al. [2021], Siksnelyte-Butkiene [2021], Shao [2023], Mayr and Agnolucci [2024] may also be cited

However, these articles do not answer the question we are investigating. It is true that few studies examine the dynamics of energy poverty in the European context, and to our knowledge, none cover the period 2017–2021.[3] Our study complements the literature on this subject, firstly by examining, like Chaton and Lacroix [2018], the probabilities of transition between different states, and secondly by looking at the impact of Covid-19 on these transitions.

We use waves 2017 to 2021 of the French Statistics on income and living conditions (SRCV) survey. The samples consist of households that responded to the survey for three consecutive years, allowing for a longitudinal analysis of transitions between different states of fuel poverty. The fuel poverty index used in this study is based on responses to two questions in the SRCV questionnaire: 1. Do you have the financial means to keep your home at a comfortable temperature? 2. How does your household manage to make ends meet at the end of the month?

Based on the two previous questions, we define three states in which a household may find itself: severe poverty (SFP), fuel poverty (FP), and non-fuel poverty (NFP). To determine whether fuel poverty is an absorbing state, we use a mover-stayer model. The mover-stayer model is an extension of the Markov chain model. It is a discrete-time process with a discrete state space (see Frydman [1984], Fougère and Kamionka [1992], Chaton and Lacroix [2018].

Results

The fuel-poor accounted for between 18% and 28% of the sample examined. The proportion of FP shows a slight fluctuation around 16%, with a slight decrease in 2021 (14.66%). This could indicate that households experiencing fuel poverty have benefited from an improvement in their energy conditions, particularly after the COVID period. The proportions of SFPs are the lowest, remaining stable at around 4% with a slight decrease in 2018 (3.45%) and relative stability in the following years.

The NFP proportions are relatively stable, at around 80%, between 2017 and 2021. This indicates that the majority of households that are not in fuel poverty remain in this situation year after year. A slight increase is observed in 2021 (81.40%), suggesting an improvement or stabilisation of the situation after COVID-19.

The probabilities of transition from one state to another for each individual (household) over two periods: 2017-2019 and 2019-2021, which includes the COVID year, have been calculated. The aim here is to obtain an initial analysis of the changes between these two periods in order to determine the impact of the global pandemic on energy poverty in France. The proportion of NFP households remaining in this situation increased slightly, from 87.51% to 88.83% between the two periods. There was a significant increase in the proportion of FP households becoming NFP, from 60.55% to 68%, suggesting an improvement in the energy conditions of vulnerable households during the first period (2019-2021). The proportion of SFP households becoming NFP increased from 43.96% to 50.69%, suggesting a notable improvement in the conditions of households in severe precarious situations during the first period.

During the period 2019-2021, a higher percentage of households managed to escape fuel poverty or avoid falling into severe fuel poverty. This improvement can be attributed to various energy and financial support measures put in place during the COVID-19 period, as well as to a possible increase in awareness of fuel poverty issues.

Over the period 2017–2019, almost 50% of the non-fuel-poor will not fall into fuel poverty; 75% of the fuel-poor will remain precarious; and 85% of the severely fuel-poor will remain in that state. Over the period 2019–2021, this percentage decreases for those who are not in fuel poverty and increases for the others. Consequently, fuel poverty and severe fuel poverty are mainly irreversible situations, as more than three-quarters of people in fuel poverty or in severe fuel poverty remain in the same situation throughout the observation period. This trap is more significant during COVID period.

[3] Phimister et al. [2015] studies the dynamics of fuel poverty in Spain, Roberts et al. [2015] in the United Kingdom, Chaton and Lacroix [2018], Cadoret and Thelen [2022] in France, Kearns et al. [2019] in Glasgow, Karpinska and Smiech [2021] in Poland, Drescher and Janzen [2021] in Germany

The stability of movers in the NFP state increased, which is a positive sign of increased resilience among households not affected by fuel poverty. Stability for movers in the FP state decreased slightly, and transitions to the NFP state increased, suggesting that more households are successfully moving out of energy insecurity. Stability in the SFP state remained low and constant, indicating persistent severe vulnerability for these households. A general trend towards improvement is observed with more transitions from FP to NFP and from SFP to NFP. However, low stability in the SFP state and significant transitions from NFP to FP show that households remain vulnerable to fuel poverty.

Conclusions

Fuel poverty in mainland France seems mainly to be a trap. Governments should move towards long-term policies such as subsidies for energy renovation. However, in order to better target these policies, it is necessary to understand the characteristics of both stayers and movers. We therefore also analyse the effects of individual characteristics on the probability of transition between the three states (SFP, FP and NFP).

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Aviv Steren, Yehuda Slater, Ofir Rubin, Aliza Fleischer, Iddo Kan

TOWARD SUSTAINABLE PRACTICES IN PHOTOVOLTAIC AND AGRICULTURAL GREENHOUSE SYSTEMS: AN ECOSYSTEM SERVICES FRAMEWORK

Aviv Steren, Electric Vehicle Research Center, University of California at Davis, Davis, CA, USA,
Email: asteren@ucdavis.edu
Yehuda Slater, Department of Environmental Economics and Management, Robert H. Smith Faculty of Agriculture, Food and Environment, Hebrew University of Jerusalem, Israel,
Email: yehuda.slater@mail.huji.ac.il
Ofir D. Rubin, Department of Public Policy & Management, The Guilford Glazer Faculty of Business and Management, Ben-Gurion University of the Negev, Israel,
Email: orubin@bgu.ac.il
Aliza Fleischer, Department of Environmental Economics and Management, Robert H. Smith Faculty of Agriculture, Food and Environment, Hebrew University of Jerusalem, Israel,
Email: aliza.f@mail.huji.ac.il
Iddo Kan, Department of Environmental Economics and Management,
Robert H. Smith Faculty of Agriculture, Food and Environment, Hebrew University of Jerusalem, Israel,
Email: iddo.kan@mail.huji.ac.il

Overview

Renewable energy targets often clash with the need to preserve farmland and protect environmental quality. Agrivoltaics, integrating photovoltaic systems into agricultural land, offers a potential solution, yet its sustainability depends on economic viability and ecosystem service impacts. This study investigates the integration of transparent solar panels (TSP) into greenhouses in Israel, a context where land scarcity and regulatory controls over agricultural land use present unique challenges.

By applying an ecosystem services (ESS) framework, the study quantifies the benefits of introducing TSP in terms of food and energy production (provisioning services), greenhouse gas (GHG) emission reductions (regulating services), and landscape aesthetics (cultural services). The analysis assesses both the narrow perspective of farmers who focus mainly on direct revenues and the broader societal perspective that internalizes non-provisioning ESS via taxes and subsidies. The study asks how incorporating ESS valuations into policy decisions could guide optimal land allocation and enhance sustainable energy transition without undermining agricultural productivity.

Methods

The research combines economic modeling and simulation using VALUE, a partial equilibrium mathematical programming model representing Israel's vegetative agriculture across 18 regions.

Three scenarios were compared:
- Scenario 0 (baseline): PVGs are prohibited; farmers allocate land solely for agricultural profit. This scenario is used to calibrate of the model.
- Scenario 1: Farmers install TSP and consider only the direct profits from agriculture and electricity (provisioning ESS).
- Scenario 2: Non-provisioning ESS are internalized through Pigouvian taxes and subsidies, reflecting GHG emission reductions and landscape impacts.

To value GHG impacts, the study estimates per-hectare emissions for open-field, greenhouse, and orchard crops, alongside CO_2 savings from renewable energy replacing fossil fuels. Landscape value loss from increasing greenhouse coverage is quantified using a discrete choice experiment with 508 respondents, yielding an average willingness to accept (WTA) compensation of $2.6 per household annually per lost hectare TSP installation assumptions include 35% greenhouse roof coverage, 5% panel efficiency, and a feed-in tariff of $0.06 per kWh, based on local solar radiation data.

The model simulates farmer behavior under profit maximization, subject to resource constraints (land, water, labor), trade regulations, and demand elasticities, allowing land reallocation between open-field and covered crops.

Results

The adoption of TSP-equipped PVGs significantly increases total vegetative agriculture ecosystem services (VAESS). Under Scenario 2, the annual VAESS per hectare rises by $864. This net gain comes primarily from $812 generated through electricity production, complemented by $259 resulting from reduced greenhouse gas emissions and an additional $277 in consumer surplus linked to agricultural products.

These benefits are partially offset by a $441 decline in the value of agricultural output and a $43 reduction in landscape value.

The model projects that about 1.3% of Israel's cultivable land would shift to covered crops, producing 5.5 TWh of electricity, around 7% of national power generation. Farming profits per hectare increase by $605, driven by electricity revenues and subsidies for environmental benefits.

Sensitivity analyses show results are more responsive to changes in TSP efficiency (3–7%) than to variations in feed-in tariff rates. Higher efficiency increases electricity production and overall welfare significantly, while lower tariffs have a moderate negative impact.

Notably, internalizing non-provisioning ESS shifts new greenhouses to less densely populated regions, reducing visual landscape impact and decentralizing energy production, which may enhance energy security.

Conclusions

Integrating TSP into greenhouse farming emerges as economically viable and sustainable, especially when policies account for broader ESS impacts. The study highlights:

- TSP-equipped PVGs can help meet renewable energy goals with minimal farmland loss.
- Including non-provisioning ESS in policy design (via taxes and subsidies) increases overall welfare and directs land use toward socially preferred outcomes.
- Policies focusing solely on direct profits risk overlooking broader environmental and cultural costs.
- Decentralized solar energy through agrivoltaics can support climate mitigation, landscape preservation, and local economic gains.

This ESS-based framework offers a replicable model for other regions aiming to harmonize renewable energy development with agricultural and environmental sustainability.

Massimo Filippini, Samuel Schenk

THE ROLE OF BOARD DIVERSITY ON THE COST OF HYDROPOWER COMPANIES

Massimo Filippini, ETH Zurich & USI, Email: mfilippini@ethz.ch
Samuel Schenk, ETH Zurich, Zu¨richbergstrasse 18, CH-8092 Zurich, Email: samuel.schenk@mtec.ethz.ch

Overview

The reform of the electricity sector carried out in Europe over the past two decades has created competitive markets for the purchase and sale of electricity and introduced new methods of regulation in the transportation and distribution of electricity. The introduction of competition in the production and sale of electricity has compelled companies to adopt strategies that reduce production costs and enhance corporate governance. Among these strategies, we also find rethinking the composition of boards of directors, particularly in public companies, which are often dominated by rather political logics rather than expertise and gender diversity. In this study, we aim to analyze the factors influencing the production costs of a sample of Swiss hydropower companies using econometric methods. We are particularly interested in analyzing the cost impact of the presence of women on the boards of directors of hydropower companies. Having women on a board brings diverse perspectives that enhance decision-making and innovation. Further, this strategic decision also reflects a commitment to equity and inclusion.

This study examines the impact of female representation on the boards of directors of hydropower companies, em- ploying econometric methods. To achieve this goal, we specify a translog total cost function and estimate it using panel data from a sample of 51 hydropower companies in Switzerland observed over the period 2010-2019.

Methods

We estimate a translog total cost function where total cost (TC) is modeled as a function of input prices, output, and a dummy for board gender composition

$$TC = f\,(Y,\ P,\ X,\ Gender,\ T\,),$$

where TC is total cost, Y denotes output (e.g., electricity produced in kWh), P is a vector of input prices (labor, electricity, capital, water), X is a vector of company characteristics such as number of plants run by the company, run-of-river plant, storage or pump storage plant, load factor and public ownership status, *Gender* is a binary variable equal to 1 if at least one woman sits on the board and T is a time trend capturing technologicalchange.

We employ a translog functional form to permit flexible substitution patterns among inputs and nonlinear scale ef- fects. The specifications includes interaction and squared terms to capture curvature and interactions between inputs and outputs. From an econometric perspective, we employ a fixed-effects model (FE), a random-effects model (RE), and a random-effects model with the Mundlak adjustment (RE-MU). This adjustment tries to mitigate the potential bias of the coefficients due to the presence of time-invariant unobserved heterogeneity. One of the advantages of the random effects model with Mundlak adjustment over the fixed effects model is that it helps to reduce the mul- ticollinearity problem that can occur when using a translog model specification, which includes square terms of the explanatory variables. The estimation of a fixed effects model is based on the within variation of the variables. While the random-effects model exploits both within- and between-variation of variables, it is less susceptible to the effects of multicollinearity.

Results

The preliminary empirical results suggest that the presence of women on the board of directors is associated with a modest but statistically significant reduction in total costs. This result is confirmed in all three econometric models used in the analysis (FE, RE, RE-MU).

The estimation results obtained with the RE and RE-MU models also indicate the presence of economies of scale. For instance if we consider of the RE-MU model and apply the following formula for the computation of the economies of scale

$$ES = \frac{1}{\frac{\partial lnTC}{\partial lnY}}$$

the value of the economies of scale at the point of approximation is 4.255. As can be seen in the table below the first order coefficient of the FE model for output is negative and not significant. This counterintuitive result is due to the presence of a multicollinearity problem, highlighting the importance of Mundlak adjustments

Regression results first order coefficients:

	RE no Mundlak (1)	FE (2)	RE-MU (3)
ln Y	0.650*** (0.0265)	-0.0509 (0.0381)	0.235*** (0.0330)
Gender	-0.0204** (0.0094)	-0.0325*** (0.0072)	-0.0203** (0.0081)
ln P_l	0.153*** (0.0166)	0.104*** (0.0131)	0.117*** (0.0148)
ln P_w	0.217*** (0.0143)	0.239*** (0.0113)	0.236*** (0.0128)
ln P_k	0.621*** (0.0103)	0.642*** (0.0080)	0.636*** (0.0091)
ln N	0.281*** (0.0471)	-	0.253*** (0.0406)
F	-0.863*** (0.0327)	0.145** (0.0657)	-0.330*** (0.0415)
DS	0.123*** (0.0377)	-	0.0736** (0.0316)
DP	0.233*** (0.0683)	-	0.310*** (0.0608)
T	-0.00140** (0.0006)	-0.000396 (0.0005)	-0.000834 (0.0006)
ln $Y_m adj$	-	-	0.575*** (0.0359)
ln $P_l adj$	-	-	0.0642 (0.1150)
ln $P_w adj$	-	-	-0.277*** (0.0350)
ln $P_k adj$	-	-	-0.239*** (0.0288)
Public	0.0731*** (0.0199)	0.0750*** (0.0195)	0.0872*** (0.0167)
Constant	17.22*** (0.0397)	16.55*** (0.0669)	16.63*** (0.0475)
Interactions	Yes	Yes	Yes
Observations		836	

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Conclusions

This study contributes to the literature on corporate governance and production efficiency by quantifying the cost effects of board gender diversity in a capital-intensive and strategically important sector. The findings suggest that the inclusion of women on boards may lead to more effective oversight and decision-making processes, resulting in lower operational costs. For policymakers and shareholders, the results support initiatives aimed at enhancing board diversity not only for equity reasons but also for performance improvements. Of course, this empirical analysis provides only suggestive evidence of the role of gender diversity on cost performance.

Therefore, the next step in the analysis is to estimate the cost function using an instrumental variable approach to provide causal evidence.

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Maurizio Gargiulo, Alessandro Chiodi, Tommaso Pillon

HYDROGEN TRADE PROSPECTS AND TRANSPORT MODELLING WITH TIMES-GEO GLOBAL MODEL

Maurizio Gargiulo, Alessandro Chiodi, Tommaso Pillon.
E4SMA Srl, Via Livorno 60, Turin, Italy

Abbstract

This study explores the role of hydrogen in the global energy transition, emphasizing the importance of hydrogen trade in modern energy economy and energy markets. As low-carbon hydrogen production scales up, international trade is expected to represent 20–30% of total output, creating a landscape of exporting and importing countries. Using the TIMES-GEO[4] energy model, the research identifies strategic global trade routes and assesses large-scale hydrogen transport options by sea and pipeline. The model results indicate that the United States, Australia, and Latin America are likely to emerge as key global exporters of hydrogen, supplying high-demand regions such as Japan, South Korea, and China.

The global energy transition, driven by the urgent need to mitigate climate change, aims to achieve net-zero greenhouse gas emissions by mid-century. This shift entails a profound transformation of energy systems worldwide, prioritizing the deployment of low-carbon technologies, renewable energy sources, and sustainable fuels. In this context, international energy trade plays a critical role in ensuring the efficient allocation of energy resources across regions with varying production capacities and demand levels. Facilitating cross-border flows of clean energy carriers, such as hydrogen, is essential to enable countries to meet their decarbonization targets while maintaining energy security and economic competitiveness. Within the continuously evolving global energy landscape, hydrogen holds significant potential due to its remarkable versatility. While its primary applications are expected in hard-to-abate sectors, such as heavy industry, aviation, and shipping, hydrogen also serves as a crucial feedstock for the synthesis of widely used chemicals, including ammonia and methanol.

In 2023, global hydrogen production reached 97 million tonnes [5] (Mt), of which only about 1% was produced using low-carbon methods. Hydrogen is classified as "grey" when produced from fossil fuels (e.g., coal, methane), "blue" when produced similarly but combined with carbon capture and storage (CCS), and "green" when generated using renewable energy sources. The combination of green and blue hydrogen constitutes the category of low-carbon hydrogen. Currently, its production is approximately 1 Mt, but it is expected to become the dominant method, surpassing 400 Mt annually by 2050[6], to meet growing demand and contribute to the decarbonization of the global energy system. However, hydrogen production is highly energy-intensive and often economically unfeasible for countries without access to low-cost energy resources. As a result, a global division is expected between hydrogen-exporting and hydrogen-importing countries, with geopolitical relationships and strategic supply agreements shaping an international hydrogen trade projected to represent more than 20% of total global low-carbon hydrogen production[2].

This work focuses on the definition and characterization of potential global routes for the hydrogen trade. Key regions for the production, export and import are identified, based on the predictions and targets outlined by each country's national strategy or roadmap for the technological integration of hydrogen.

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[4] The model was developed in the framework of project Chimera (Multi-model innovations in Integrated Assessment Modelling of Global, Chinese, and Irish energy-economy-environment-climate systems investigating deep decarbonisation pathways from the Paris Agreement to the United Nations sustainable development goals in 2018-2022 funded by the Science Foundation Ireland and National Science Foundation of China. Reference to the project: https://www.marei.ie/project/chimera/. Reference to Github repository: https://github.com/MaREI-EPMG/TIMES-GEO

[5] IEA (2024), *Global Hydrogen Review 2024*, IEA, Paris https://www.iea.org/reports/global-hydrogen-review-2024, Licence: CC BY 4.0

[6] IEA (2024), World Energy Outlook 2024, IEA, Paris https://www.iea.org/reports/world-energy-outlook-2024, Licence: CC BY 4.0 (report); CC BY NC SA 4.0 (Annex A)

Countries abundant in fossil fuel sources or renewable energy are expected to become the main hydrogen producers, exporting to technologically advanced countries with high demand but limited domestic production. The analysis employs the TIMES-GEO, an integrated energy system model built on the TIMES modelling framework, designed to explore long-term global energy dynamics. TIMES-GEO covers the entire energy system across 31 regions, comprising 16 individual countries and 15 regional aggregates, and generates least cost scenario pathways. These scenarios provide insights into future energy flows, fuel mixes, investment patterns, and greenhouse gas emissions up to the year 2100. Its wide geographical coverage makes it a strategical tool for assessing medium to long-term energy transition scenarios and for supporting the development of robust energy policies. An example of the model output is presented in Figure 1, which illustrates the projected evolution of low-carbon hydrogen production in selected key regions up to 2050. Starting from a very limited level of clean hydrogen production in the early years of the simulation, production volumes increase substantially from 2035 onward and continue to grow in the subsequent decades, primarily driven by the United States (USA) and Europe (EUW).

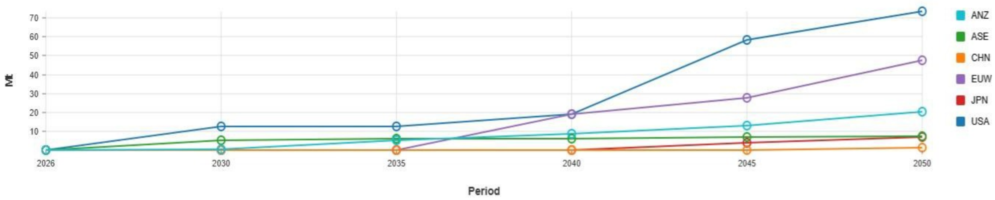

Figure 1 - Low-Carbon Hydrogen production evolution in selected geographical areas

The aim of this study is to geographically and economically define the primary large-scale hydrogen transport solutions by sea and via pipeline.

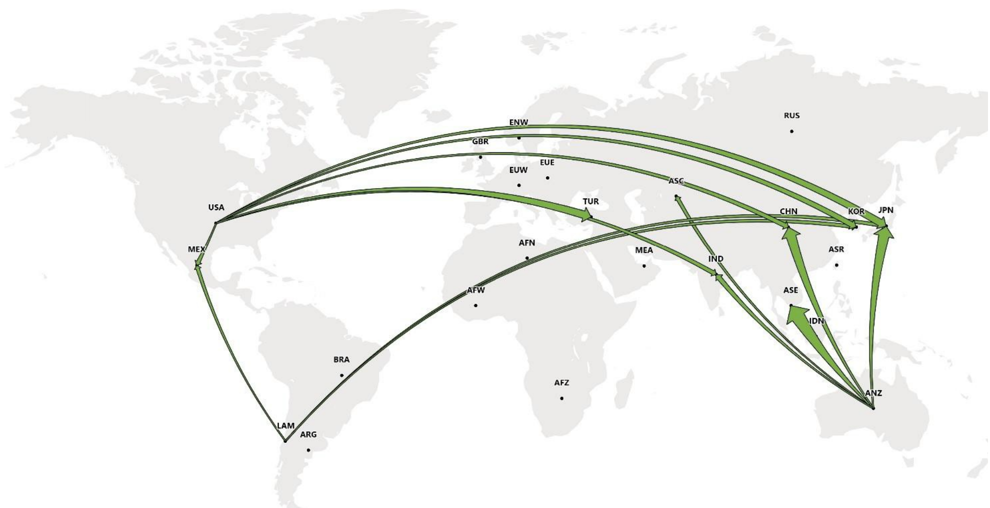

Figure 2 -Main Hydrogen and Hydrogen products trade routes in 2050

Pipeline transport may occur through dedicated hydrogen pipelines or via retrofitted natural gas pipelines, carrying hydrogen either in pure form or as a blend with natural gas. The TIMES-GEO model incorporates both existing pure hydrogen pipeline routes and those currently under development, including their transport capacities and capital investment costs.

Existing international natural gas infrastructure is assumed to be suitable for hydrogen transport, provided that appropriate retrofitting is undertaken. Pipeline transport costs vary depending on the nature of the pipeline (new construction vs. retrofitting), the pipeline length, and the hydrogen volumes transported.
By sea, hydrogen can be transported via ship after being either liquefied or converted into derivative products (e.g., ammonia, methanol) that are more suitable for maritime shipping. In the near future, with the anticipated growth in hydrogen consumption, the traded volumes of ammonia and methanol are expected to increase, not only to meet their specific industrial demand, but also as hydrogen carriers. Although there is currently no well-developed hydrogen shipping network, liquefaction remains a viable alternative. The costs associated with maritime hydrogen transport depend largely on the choice of carrier and the length of the commercial shipping route.

The main trade routes for hydrogen and hydrogen-related products, as provided by TIMES-GEO, are reported in figure 2 for the time-period 2050. Important producers, such as the United States (USA) and Australia (ANZ), are also projected to become the principal exporters of hydrogen. East Asia is expected to emerge as one of the main importing regions, owing to the high hydrogen demand in countries such as Japan (JPN), South Korea (KOR), and China (CHN). Furthermore, Latin America (LAM) is likely to play a significant role in global hydrogen trade, supported by the region's vast renewable energy potential and the strong political commitment of key countries, notably Chile.
In conclusion, this study highlights the growing importance of international hydrogen trade, driven by the anticipated surge in global demand. Various trade pathways, including pipeline transport and maritime shipping of different hydrogen carriers, are examined from both technical and economic perspectives. The implementation of the TIMES-GEO model enables a comprehensive analysis of the future development of hydrogen production and provides insights into the emerging global hydrogen trade network, including major trade routes and projected trade volumes

Massimo Filippini

SPECIAL SESSION: TEACHING ENERGY ECONOMICS AND POLICY – REflECTIONS AND A NEW OPEN-ACCESS TEXTBOOK

Massimo Filippini, Professor ETH Zürich and Università della Svizzera Italiana, Switzerland

At most scientific conferences, the focus is naturally placed on presenting and discussing new research findings. However, for a professional association like the International Association for Energy Economics (IAEE), which brings together academics, policy experts, and practitioners, it is equally important to reflect on how we teach energy economics and policy. This includes the tools, methods, and materials we use to train the next generation of energy economists. After all, quality teaching is essential to ensuring that research, knowledge, and insights are effectively transferred to students, policymakers, and professionals.

The goal of this special session is to initiate a discussion on best practices in teaching energy economics and policy, while also showcasing a new classroom resource. A central focus will be the recently published open-access textbook "**An Introduction to Energy Economics and Policy**" by **Massimo Filippini** and **Suchita Srinivasan**, published by Cambridge University Press. The book is freely available online and offers a structured, accessible introduction to key concepts in energy economics, combining theory with real-world case studies. In this session, Professor Filippini will present the objectives, content, structure, and pedagogical innovations of the book, highlighting how it can be used in both undergraduate and graduate teaching.
To broaden the discussion, distinguished scholars will share their personal experiences and strategies for teaching energy economics and policy. They will reflect on the design of their courses, the materials and textbooks they use, and how they engage students in this dynamic and interdisciplinary field.

The session will conclude with an open discussion, chaired by Professor Filippini, allowing the audience to exchange views, ask questions, and contribute ideas on how to enhance teaching practices and curriculum development in energy economics.
To achieve the session's objectives, the structure is as follows:

1. Book Presentation (30 minutes) – Professor Massimo Filippini will present the textbook, outlining its motivation, structure, content, key themes, and pedagogical innovations.

2. Initial Discussion (10 minutes) – A short Q&A and initial discussion with the audience will follow the presentation.

3. Teaching Experiences (2 × 15 minutes) – Professors Andrea Bollino and Valeria Di Cosmo, both experienced educators in energy economics, will present their respective teaching approaches, course structures, materials, and the textbooks they use.

4. General Discussion (30 minutes) – The session will conclude with a broader discussion chaired by Professor Filippini, inviting the audience to share their experiences, ask questions, and explore how teaching methods and materials can be improved or adapted to new academic and policy contexts.

By creating a space for dialogue between textbook authors, experienced instructors, and the broader academic community, this session contributes to the development of high-quality, accessible, and relevant energy economics education. It also reflects the IAEE's commitment to fostering excellence not only in research but also in teaching and professional development.

Shivani Taneja and Filip Mandys

DIGITAL TRANSFORMATION AND INDUSTRIAL SUSTAINABILITY

Shivani Taneja, University of Kent, United Kingdom, Email: s.taneja@kent.ac.uk
Filip Mandys, University of Cambridge, United Kingdom, Email: fm619@cam.ac.uk

Overview

The use of digital technologies in the global industrial sectors has substantially increased since the beginning of the 21st century. Although the expansion of these sectors is important for global economic growth, industries also contribute to about 23% of global greenhouse gas emissions (Energy and Climate Intelligence Unit, 2021). Thus, the carbon footprint of industries cannot be ignored, and it is important for policymakers worldwide to balance economic growth and sustainability. Adoption of digital technologies can help balance this, and therefore, it is crucial to understand the net effect of greater ICT capital investments on industrial energy use. From one point of view, modern ICTs are more energy efficient and consequently reduce relative demand for energy (Taneja and Mandys, 2022). However, with the expansion of ICTs and greater number of systems, overall carbon footprint is also increasing. Thus, we address the following research questions: First, does digitalisation reduce net electricity use across industries? And second, how does digital transformation impact electricity use in OECD countries?

Methods

We construct a dataset by combining information from four specific sources: 1. EU KLEMS & INTANprod Data,

2. Groningen Growth and Development Centre (GGDC) Productivity Level Database, 3. International Energy Agency (IEA) Energy Prices Data, and 4. IEA Extended World Energy Balances. Using a translog cost function, we estimate the share of electricity in industrial variable cost (equation 1) for 14 sectors within 16 countries from 1995 to 2020, and apply the fixed effects method

$$S_E = \beta_0 + \beta_1 \text{ In } \left(\frac{P_E}{P_L}\right) + \beta_1 \text{ In } \left(\frac{P_{NE}}{P_L}\right) + \beta_3 \text{ In } \left(\frac{K_{ICT}}{Y}\right) + \beta_4 \text{ In } \left(\frac{K_N}{Y}\right) + \beta_5 \text{ In } Y + \delta t \qquad (1)$$

In the above equation, SE is share of electricity in variable cost, PE is price of electricity, PNE is price of non-electric energy, PL price of labour, $KICT$ is ICT capital use, KN is non-ICT capital use, Y is output (value added), and t represents time. Demand elasticities are then estimated, i.e., percentage change in electricity use after a 1% rise in ICT capital. In the previous literature, mixed results have been found (Taneja and Mandys, 2022; Saidi et al. 2017; Schulte et al., 2016), and ultimately, it is an empirical question as to whether digitalisation has a positive or negative effect on industrial electricity use in the current digital era.

Results

Our results revealed that digital transformation contributes to industrial sustainability. The average elasticity of electricity demand with respect to ICTs for all sectors is -0.078, suggesting that a 1% increase in ICT capital reduces electricity demand by 7.8%. This implies that digital technologies have the potential of reducing electricity use for all sectors. A stronger effect is seen within the manufacturing sector than services. Furthermore, we analyse cross-country differences to understand the role of digitalisation in the decarbonisation of European countries, and find that a 1% increase in ICT capital reduces electricity demand the most in Germany, by almost 27%, followed by the UK (20%). On the other hand, France is the only European country with a positive impact of 5.3%, suggesting that ICTs increase energy demand.

Conclusions

Understanding the association between ICTs and electricity consumption is crucial, as it sheds light on the profound impact of digitalisation on advancing environmental sustainability efforts. We find that digitalisation boosts the decarbonisation of industrial sectors.

The ongoing improvements in technology are associated with a reduction in relative electricity use. We also showcased that greater digitalisation supports European decarbonisation efforts, revealing that industrial sectors in Germany and the UK reap the greatest benefits from the net energy-saving effects of ICTs. Therefore, businesses can benefit from digital transformation by achieving operational efficiency and higher productivity, as well as reducing their carbon footprint to help the environment.

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Johannes Bösch

SELECTIVE TARGET REPORTING? ASSESSING CORPORATE SCOPE 2 EMISSION DISCLOSURE

Johannes Bösch, Technical University Munich, Email: johannes.boesch@tum.de

Overview

Electricity consumption is a major driver of global greenhouse gas emissions, with corporate electricity use accounting for over 70% of total consumption. Under current Scope 2 reporting guidelines (GHG Protocol and Science-Based Targets initiative, SBTi), companies can report emissions using either a market-based or location-based method. While dual reporting is formally required, companies are allowed to select one method
for target setting and performance tracking. Prior literature (e.g., Bjorn et al., 2022; Ma and Duan, 2024; Paris et al., 2024) has raised concerns that this flexibility may lead to misleading emission disclosures and double counting. Given the ongoing revision of both the GHG Protocol Scope 2 guidelines and SBTi standards, this study is timely and policy-relevant. This paper investigates how firms in practice use these reporting options. It addresses two main research questions: (a) Do companies selectively choose the accounting method that results in lower reported emissions? and (b) To what extent does the current framework allow for double counting of Scope 2 emissions?

Methodology

Methodologically, the analysis draws on CDP data covering over 800 European firms, including site-level emission data and the reported Scope 2 accounting method. I first assess whether firms systematically favor the reporting method that presents lower emissions. Second, I adjust location-based emissions using country-level residual mix factors—reflecting the subtraction of electricity attribute certificates already claimed under the market-based method—to estimate the extent of potential double counting.

Results

Results indicate, first, that a significant majority of companies systematically select the accounting method that minimizes reported emissions, suggesting strategic use of reporting flexibility. Second, adjusting location-based disclosures with residual mix data increases aggregate emissions by up to 50%, highlighting substantial
double-counting risk.

Conclusion

These findings suggest that the current Scope 2 framework enables inconsistent and potentially misleading emissions reporting, undermining the credibility of corporate climate targets. To improve consistency and reliability, either the dual approach must be retained with a correction to location-based methods, or a single standardized method should be mandated. The results contribute new quantitative evidence to the debate and may support policymakers and standard-setters in revising corporate carbon accounting rules.

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Victoria Fohrer

TOO COMPLEX TO CONTROL? HOW FIRMS NAVIGATE SCOPE 3 GOVERNANCE UNDER STRATEGIC AND INSTITUTIONAL UNCERTAINTY

Victoria Fohrer, Chair of Management Accounting, TUM School of Management,
Technical University of Munich, Arcisstraße 21, 80333 München, Email: Victoria.fohrer@tum.de

Overview

Scope 3 emissions account for the largest share of corporate carbon footprints in many sectors, placing increasing pressure on firms to address emissions beyond their direct control. However, the governance of Scope 3 emissions remains complex due to fragmented standards, limited data availability, and unclear accountability especially in downstream categories. While companies are setting increasingly ambitious climate targets, it remains unclear how they operationally engage with Scope 3 emissions in practice.

Method

This study employs a qualitative case study design across 20+ large German firms operating in Scope 3-intensive industries such as automotive. Cases were selected using a polar sampling approach to capture a range of governance maturity levels. Data collection involved semi-structured interviews with strategic and operational sustainability stakeholders, supported by internal documents and external disclosures. Thematic coding was used for analysis, drawing on stakeholder theory, neo-institutional theory, and the natural resource-based view.

Results

The study identifies four strategic response mechanisms accept, improve, explore, and avoid which firms apply differently depending on the Scope 3 category (upstream vs. downstream), governance capacity, and stakeholder expectations. Based on these mechanisms, we develop a typology of corporate strategies:

- *Symbolic full-spectrum*: Broad public commitments without deep integration
- *Substantive upstream*: Targeted action and control over upstream emissions
- *Explorative hybrid*: Co-development initiatives with suppliers and data partners
- *Downstream avoiders*: Limited engagement due to lack of influence or data Across cases, many firms expressed critical views on the adequacy of the current Scope 3 framework, citing its limitations for strategic steering, accountability, and comparability.

Conclusions

This study extends existing literature on strategic responses to institutional complexity by integrating organizational capabilities and stakeholder collaboration into the analysis of Scope 3 governance. While upstream categories are increasingly addressed through KPIs, SBTi targets, and supplier programs, downstream engagement remains underdeveloped. Policymakers and ESG leaders should focus on improving standardization, clarifying expectations, and fostering implementation capacity to close the governance gap especially in light of new regulatory requirements under CSRD and SFDR.

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Maylis Peyret, Frédéric Gonand

SUSTAINABILITY OF THE GLOBAL BALANCE BETWEEN SUPPLY AND DEMAND FOR METALS IN THE LONG TERM – ACCOUNTING FOR SECONDARY SUPPLY

Maylis Peyret, Email: maylis.peyret@dauphine.psl.eu
Frédéric Gonand, Email: frederic.gonand@gmail.com
LEDa, Université Paris-Dauphine–PSL, Place du Maréchal de Lattre de Tassigny, 75116 Paris, France

Overview

The accelerating demand for metals driven by the energy transition, digitalization, and industrial development raises concerns about long-term supply security and price volatility (IEA, 2021; Boer et al., 2021). While most analytical frameworks in resource economics focus on primary supply under depletion constraints (Dasgupta & Heal, 1979; Krautkraemer, 1998; Tilton, 2018), and circularity is often examined through material flow or stock-based approaches (Reck & Graedel, 2012; Elshkaki et al., 2016), few models capture both dynamics in a unified, forward- looking macroeconomic framework.

This paper develops a novel theoretical model of metals markets where primary and secondary supply channels co- evolve, and where the expansion of recycling capacity is modeled as a discrete Markov process that reflects technological maturity and system development. This allows for a rigorous exploration of how secondary supply introduces regime-dependent elasticities, memory effects, hysteresis, and potential price segmentation, all of which are observed empirically in markets such as copper and nickel (Vidal et al., 2021; Sverdrup et al., 2014). The model formalizes, for the first time, the analytical interaction between logistic depletion and state-dependent recycling responsiveness.

Methods

We model demand using a CES function with imperfect substitution between primary and secondary metal. The demand for metal at time t is expressed as

$$Q_{d,t} = B(t) \cdot P_{primmary,t}^{\sigma-1} + B'(t) \cdot P_{secondary,t}^{\rho-1}$$

where *B(t)* and *B'(t)* are time-varying scaling parameters representing baseline demand, $P_{primary,t}$ are the prices of copper at time *t* on the primary and secondary market, respectively, and σ and ρ are parameters representing demand price elasticity and material substituability.

Primary supply follows a logistic depletion dynamic derived from the cumulative availability curve (Tilton, 2018; and Castillo & Eggert, 2020). The inverse CAC function, denoted $C_{max}(P)$ provides the total recoverable quantity of copper at different price levels

$$C_{max}(P) = \frac{L}{1 + e^{-\propto(P-P_m)}}$$

where L is the asymptotic maximum level of cumulative availability, α controls the steepness of the sigmoid curve, and *Pm* is the midpoint price at which availability increases most rapidly. The annual primary supply is then given by a logistic depletion function

$$Q_{s,t} = \frac{C_{max}(P_t)}{1 + \exp\left[\gamma\left(\frac{c_t}{C_{\max}(P_t)} - \theta\right)\right]}$$

where γ is the steepness parameter, θ is the inflection point of the logistic curve,and ct represents cumulative extraction at time *t*

Secondary supply is modelled as a function of the primary price and a regime variable which evolves stochastically over time through a Markov chain:

$$Q_{s,,t}^{secondary} = \eta \cdot P_{primmary,t}^{\delta} \cdot S_{t-1}$$

where S_{t-1} is a state variable from the previous period, capturing factors like the available scrap stock, technological improvements, and macroeconomic conditions that influence recycling rates, η is a parameter reflecting recycling efficiency, and δ is the price responsiveness of recycling.

Results

The analytical derivations reveal the following features:

- **Endogenous moderation of price pressures**: secondary supply acts as a stabilizer whose influence grows as the recycling regime matures;
- **State-dependent market resilience**: the model captures hysteresis and memory effects through the Markovian evolution of recycling capacity, extending insights from circular economy dynamics into an analytical, more streamlined framework (Reck & Graedel, 2012; Boer et al., 2021);
- **Absence of price convergenc**e: depending on substitution elasticity and regime state, dual pricing may persist–a phenomenon observed in empirical market structures (Vidal et al., 2021);
- **Time varying demand elasticity:** as secondary supply increases in relative weight, aggregate price responsiveness shifts structurally;
- **Potential for multiple equilibri**a: under certain conditions, the system may exhibit locally stable price- quantity pairs or transitions between regimesn consistent with dynamic instability noted in system models of resource depletion (Sverdrup et al., 2014).

This paper contributes an original analytical framework that bridges classical resource depletion theory with the economics of secondary supply, advancing the macroeconomic modeling of circularity in metal markets. In contrast to numerical system dynamics or empirical stock-flow simulations, this model enables formal analysis of long-run sustainability, price stability, and regime transitions. This model lays the groundwork for empirical calibration and policy analysis, with preliminary simulations expected to be available at the time of presentation.

Conclusion

This model provides a novel theoretical contribution to the economics of metal markets by integrating resource depletion dynamics with the evolving capacity of secondary supply. It advances the literature by offering closed- form derivations that clarify how market stability, price elasticity, and supply responsiveness are shaped not only by geological limits but also by the state-dependent expansion of recycling infrastructure. In doing so, it bridges the gap between traditional Hotelling-style models and circular economy frameworks.

By analytically capturing regime transitions, memory effects, and endogenous price moderation, the model highlights how long-term sustainability hinges on the strategic development of secondary supply systems. These insights have implications for both policy design — e.g., incentivizing early recycling infrastructure — and for forecasting price trajectories in markets undergoing technological and institutional transformation.

Preliminary numerical simulations and empirical testing, to be presented at the conference, will further explore how this framework can inform debates on resource scarcity and resilience in the context of the low-carbon transition.

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Diyun Huang, Geert Deconinck

THE FINANCIAL TRANSMISSION RIGHT TRILEMMA IN THE EUROPEAN CROSS-BORDER LONG-TERM MARKET:FLOW-BASED MARKET COUPLING, REVENUE ADEQUACY AND ECONOMIC EFFICIENCY

Diyun Huang, KULeuven, Email: Diyun.huang@esat.kuleuven.be
Geert Deconinck, KULeuven, Email: Geert.deconinck@kuleuven.be

Overview

The flow-based market coupling (FBMC) mechanism is the target model for the cross-border capacity calculation in European internal electricity market. While widely adopted in the day-ahead timeframe, its application is expanding to intraday markets, and the Forward Capacity Allocation Network Code mandates its implementation in the forward timeframe. At the time of writing, financial transmission rights (FTRs) are expected to be allocated in a yearly auction. Regulation (EU) 2024/1747 further proposes possible changes to the maturities of long-term transmission rights, in particular maturities extended up to at least three years.

Unlike the U.S. electricity markets, where FTRs and locational marginal pricing (LMP) are foundational elements of the standard market design, the European cross-border market operates under a fundamentally different structure: zonal pricing with the separation of network and market operation. This divergence prompts the research question: can the FTRs be effectively implemented under the European zonal pricing with the FBMC mechanism?

This paper addresses the inherent trilemma arising from the simultaneous pursuit of zonal pricing, economic efficiency, and revenue adequacy in FTR implementation. We explore how the governance structure under zonal pricing and grid modelling under FBMC mechanism impact FTRs, specifically concerning cross-border coordination and economic efficiency. Revenue adequacy of FTRs plays an essential role in facilitating a seamless European cross-border market. Its absences implies that the cost gap will be allocated across-borders based on administratively made rules, instead of market signals. The economic efficiency encompasses both the ability of FTR to support efficient cross-border dispatch and effectiveness in providing hedging incentives. Therefore, we investigate the impact of zonal grid parameters on achieving two criteria for FTR implementation following a case study approach: 1) revenue adequacy; 2) economic efficiencies in the case where revenue adequacy is achieved.

Methods

The revenue adequacy requires the cleared FTRs in the long-term auction to be physically feasible in the day-ahead market. The case study analysis highlights the direction of feasible region shift from the long-term to day-ahead market is essential in achieving revenue adequacy. The load flow constraints under nodal pricing that define the feasible region are only relevant to the grid typology and network capacity limit, which makes the feasible region of long-term and day-ahead identical when these two parameters stay constant. However, the separation of network and market operation for the European electricity market leads to information asymmetry for network operator at the zonal grid modelling stage. The load flow constraints under zonal pricing are linked to predictive zonal grid parameters such as generation demand shift key (GDSK) and base cases. In particular, base case is related to generation, load forecast and the installed generation capacity, load levels that are subject to high uncertainties 3-5 years ahead of operation. The high uncertainties in getting accurate long-term base case implies high uncertainties to achieve revenue adequacy.

Revenue adequacy is assessed in the case studies by comparing the congestion rent with the FTR payback in day-ahead market. Comparison of feasible regions from long-term to day-ahead together with the load flow constraints are made to explain the cause for revenue inadequacies, whether it is the application of different base cases or GDSK metrics that shifts the feasible regions in undesirable directions between the timeframes.

In the cases where the revenue adequacy is achieved with methods adopted to mitigate grid modelling uncertainties, we compare the long-term FTR auction outcomes under zonal pricing with those of nodal pricing.

The total amount of allocated FTRs, the interconnection utilization and the payback price formulation of FTRs are analysed to explain the sources of economic inefficiencies as more restrictive grid parameters are applied to improve revenue adequacy.

Results

The first group of case studies show that the currently implemented GDSK methodologies do not include mechanism to guarantee revenue adequacy. The second group of case studies demonstrate that high uncertainties in base case for long-term grid modelling impose challenges for FTR revenue adequacy. As a result of salient uncertainties in the long-term and decreased uncertainties in the day-ahead grid modeling, the application of base case with distinct injection and withdrawal patterns in these two timeframes might shift the feasible regions in directions that can make FTR clearing point infeasible for day-ahead grid model. The third group of case studies investigate the effect of adopting multiple base case methodology required by regulation to mitigate the uncertainties for long- term grid modelling. Implementing the multiple base cases shrinks feasible regions in the long-term grid model by combining the more restrictive constraints of the applied base cases that represent the typical grid operation scenarios.

The first case study in the group demonstrates that the multiple base case method improves revenue adequacy when the system does not experience capacity change from generation to load. The resulting feasible region from combining more restrictive constraints makes the long-term grid model more restrictive compared to day-ahead and thus helps to achieve FTR revenue adequacy. However, the shrunk feasible region in long-term also restricts the capability for efficient utilization of the grid and dispatch of resources across the system. Compared with nodal pricing, lower amount of total allocated and cross-border FTRs, as well as lower interconnection utilization is observed with multiple base case approach under zonal pricing.

In the case where intra-zonal congestion occurs as a result of day-ahead clearing, redispatch costs are incurred for market players that hold FTRs for cross-border transactions. The cross-zonal FTRs by design can not hedge against the redispatch costs associated with intra-zonal congestion. Furthermore, when the intra-zonal congestion occurs in the FTR withdrawal zone, the merit order might select marginal generator that has the lowest cost to match the load level while ignoring intra-zonal congestion. This implies that the zonal price determined by the marginal generator may become artificially low in day-ahead market and potentially affect the payback price of FTRs and thus hedging effectiveness of the instrument.

Our case study also shows that the multiple base case approach is not robust to unexpected change of capacities in the system. Unforeseen generation capacity changes or load evolution results in new injection and withdrawal patterns outside of the boundaries defined by the multiple base cases selected from historical data or TSO scenario making process. When these capacity changes take place between long-term and day-ahead timeframe, the day-ahead grid model might get more restrictive feasible region, which makes the long-term FTR infeasible in day-ahead grid. We argue that in the era of accelerated electrification and fast evolving landscape of generation/storage, it is extremely challenging to reliably forecast the capacity changes in the system three to five years prior to operation, if ever possible.

Conclusions

This paper demonstrates that flow-based market coupling, high economic efficiency and revenue adequacy represent a trilemma for implementing FTRs in the European cross-border electricity market. We argue that long-term FTR auction exacerbates the uncertainties arising from information asymmetry for zonal grid modelling. High operational and investment uncertainties in the long-term zonal grid model, coupled with the requirement imposed by revenue adequacy, makes it exceptional challenging for accurate zonal grid parameterization. While methods to mitigate the long-term grid uncertainties exist, such as the multiple base case approach analysed in the case study, they inherently present a trade- off between the revenue adequacy and economic efficiency under flow-based market coupling.

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Thomas Schöb, Theresa Klütz, Toni Busch, Jochen Linssen, Jann Michael Weinand

PEAKS AND LULLS IN SECTOR INTEGRATED ENERGY SYSTEMS – A RISK FOR SECURITY OF SUPPLY?

Thomas Schöb: Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems, Jülich Systems Analysis, 52425 Jülich, Germany; Email: t.schoeb@fz-juelich.de
Theresa Klütz: Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems, JülichSystems Analysis, 52425 Jülich, Germany
Toni Busch: Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems, Jülich Systems Analysis, 52425 Jülich, Germany & RWTH Aachen University, Chair for Fuel Cells, Facultyof Mechanical Engineering,52062 Aachen, Germany
Jochen Linssen: Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems, Jülich Systems Analysis, 52425 Jülich, Germany Jann
Michael Weinand: Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems, Jülich Systems Analysis, 52425 Jülich, Germany

Overview

In ongoing efforts to reduce greenhouse gas emissions, countries around the world are transforming their energy systems from fossil fuel-based systems to renewable energy-based systems. The European Union has set the goal to become greenhouse gas neutral by 2050 [1], while Germany has legally pledged to reach this target already by 2045 [2]. Future energy system designs which achieve ambitious emission targets will likely be based on volatile renewable sources such as wind and solar power and feature electrification of the end-use sectors to reduce emissions [3]. This electrification is enabled by sector coupling technologies such as electrolyzers, heat pumps and battery electric vehicles. Due to the intermittent nature of wind and solar power, sector-integrated energy systems need operational strategies to keep energy supply and demand in balance. Of special relevance are peaks of electricity demand and dark lulls, where renewable sources supply only minimal electricity to the energy systems. In this study, we address the following questions: Are these peaks and lulls a risk to the security of supply in sector- integrated energy systems, and what are the optimal operational strategies for dealing with these situations? We address these questions by using the future German energy system as a case study.

Methods

We use the sector integrated optimization model ETHOS.Infrastructure [4,5] to determine the minimum-cost design of electricity, gas, hydrogen and heating infrastructure in Germany. The optimization is performed as a linear program for a single year at hourly resolution for the year 2045, in which Germany will have to achieve greenhouse gas neutrality. The modelled components include renewable energy sources, conversion processes, transmission technologies, and storage technologies. In addition, the model can import commodities from outside the model boundaries, e.g. hydrogen and electricity from neighboring countries. The model optimizes the sizing and operation of the given options, considering technical and environmental constraints, to always meet the demand profiles in all modeled regions. For this optimization the energy system can benefit from numerous flexibility options: The modeled options include short- and long-term storage that is charged when renewable energy feed-in is high and discharged when renewable energy feed-in lags demand. Instead of storing electricity directly, it can also be converted into other commodities which can be directly used or stored. In combination with storage options, the demand can be met flexibly although the conversion processes are geared to electricity supply. These options include power-to-gas conversions, e.g. hydrogen production via water electrolysis, and power-to- heat conversions, e.g. electric boilers. The options can be combined with hydrogen and heat storage to meet demand at later time steps. Furthermore, the model can decide to curtail the feed-in of renewable energies instead of dimensioning flexibility options to the maximum feed-in. To obtain a robust system design, a cold and dark lull was introduced for two consecutive weeks in January. In this period, renewable energy supply was reduced to 10% of the original generation potential. Additionally, the heating demand was increased by 25% for these two weeks.

Results

Our results show that in the year 2045 the German electricity supply is dominated by renewable energy sources photovoltaic and wind energy with a total installed generation capacity of 700 GW. These supply 90% of the electricity demand of 1330 TWh, from which about 50% originate from flexible sector coupling technologies like electrolyzers and heat pumps. The peak load of the electricity system in 2045 is 375 GW and occurs at noon on March 27th when favorable weather conditions lead to high electricity generation by wind turbines and photovoltaics. In this situation, the flexible sector coupling technologies and storage options increase their electricity demand to harvest as much renewable electricity as possible. Thus, this situation is not critical for security of supply but instead helps to decarbonize other sectors of the energy system. Additionally, the peak load is driven by the supply side and not by the demand side which contrasts with fossil-based energy systems today. As shown, the concept of peak load is not suitable anymore for assessing security of supply in renewable-based sector-integrated energy systems. Therefore, we introduce the new concept of resilience peak load which is defined as the maximum inflexible residual load which must be covered by flexible power plants. The inflexible residual load itself is calculated by subtracting the volatile renewable electricity supply from the inflexible electricity demand which excludes flexible sector coupling options. This resilience peak load occurs during the cold dark lull in January with 139 GW at 5 PM on January 14th. In this situation hydrogen gas turbines need to provide 64 GW of electricity, biomass combined heat and powerplants 32 GW, and energy storage 48 GW. On the other side of the energy balance, the electricity load is reduced as much as possible by shutting down electrolyzers and power- to-heat applications as well as reducing the load of heat pumps. Thus, the required flexible power plant capacity of 139 GW in the year 2045 is determined by this inflexible electricity demand at the resilience peak load. Consequently, dark lulls are critical for security of supply in sector-integrated energy systems and must be considered for planning flexible generation and energy storage capacities.

Conclusions

Our optimization results for the future German energy system show that in sector integrated, renewable energy systems, the electricity load must adjust to the volatile renewable electricity supply. Thus, the flexibility of sector coupling technologies to adjust their demand is a key aspect of optimal operation strategies of such energy systems and should be incentivized by policymakers and system planners.

Furthermore, we show that peaks of electricity demand are not critical for security of supply but help to decarbonize the energy system. In contrast, dark lulls are critical situations for the security of supply and must be bridged by flexible power plants and energy storage. Thus, future energy systems need to ensure that dimensioning of flexible power plant capacities and planning of long-term energy storage take dark lulls into account during the planning phase.

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Marina Bertolini, Pierdomenico Duttilo, Francesco Lis

NETWORK INFRASTRUCTURES AND DAY-AHEAD VOLATILITY: A CASE FROM THE ITALIAN MARKET

Marina Bertolini, Dipartimento di Scienze Statistiche e Centro Levi Cases, Università degli Studi di Padova, Italy, Email: Marina.bertolini@unipd.it
Pierdomenico Duttilo, Dipartimento di Scienze Statistiche e Centro Levi Cases, Università degli Studi di Padova, Email: Pierdomenico.duttilo@unipd.it
Francesco Lisi, Dipartimento di Scienze Statistiche e Centro Levi Cases, Università degli Studi di Padova, Italy. Email: Francesco.lisi@unipd.it

Overview

The energy transition process requires the transformation of energy markets and huge infrastructural investments: in the electricity markets, in particular, infrastructures can modify market performances. In this paper, we analyze the effects of the introduction, within the Italian electricity grid, on May 2016, of the so-called "Sorgente-Rizziconi" cable, which increased the power interconnection between Sicily and the mainland. In particular, we focus on the effects of the cable on the zonal price volatility of the Italian day-ahead electricity market. We model prices and volatility using two different heteroscedastic models: a semi-parametric additive model and a fully non-parametric additive model.
The results of both models point out that i) the cable directly affected only the Sicily zone; ii) it did not make the price level decreasing but iii) it increased the base-level of the price volatility. We interpret the last result as an increase in the market competitiveness.

Methods

To describe the dynamics of price and volatility in each market zone, we resort to a heteroscedastic additive regression model already used in this context (the methodological approach starts from the work of Bernardi and Lisi, 2020). In this context, likewise for prices in financial markets, the definition of volatility refers to the conditional variance of the residuals from the conditional mean. As for the conditional variance, in this work we consider two different specifications. The first one is a parametric GARCH(1,1) with and additive intervention function. The second one is non-parametric, meaning that we do not impose any specific functional form but leave the data to shape the effect.
The dataset we used is provided by GME (Gestore dei Mercati Energetici): we used the data on day ahead electricity prices in the market zone of Sicily between 2015 and 2018 and we modelled daily series for each load period.

Results

Results show that the effect of the infrastructure is an increase in price volatility in the day ahead market. As in the literature, an increasing of price volatility is often associated with an increased market competitiveness, and we believe that the impact we found is consistent with the economic theory.

Conclusions

Infrastructure heavily affect the performance of electricity markets. Since the European policy – as many policies in the world - encourages the creation of local electricity markets (Agostini et al., 2021), it is important to understand the impacts that innovations, in this case structural ones, have on market prices and on the economic environment in general: price volatility has always been linked to the evaluation of investments and the associated risk (Bertolini et al., 2018), and different level of this risk might lead to e.g. different diffusion of renewable production plant and the associated industries. This has also an impact also on several socio-economic parameters, like energy access and welfare.

Studying islanded market is strategic to understand this kind of dynamics, because the effects can be more identifiable: the more a market is connected, the harder is to identify what contributes to its functioning.

Our work analysed the effect that an infrastructural change had on a specific local market, from the perspective of price volatility. The analyses conducted on the introduction of the Sorgente-Rizziconi cable show that the impact on price volatility is evident and clearly recognizable. This result is consistent with the economic theory and can be interpreted as an increased competitiveness of the market (Sapio and Spagnolo, 2016; Acemoglu et al., 2017)
This type of analysis allows us to take a step forward in the field of strategic investment evaluation for infrastructures, especially by providing a new perspective for network development plans.
Future work will focus on the possibility of transferring the results of one analysis to other contexts and on extending the methodology to other markets where real-time prices are even more significant, such as ancillary services and balancing markets

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Zhe-Yi Chen, Lu-Tao Zhao

HOW DOES CHINA RESPOND TO THE CARBON BORDER ADJUSTMENT MECHANISM? AN APPROACH OF GLOBAL TRADE ANALYSIS

Zhe-Yi Chen, Centre for Energy and Environmental Policy Research, School of Management, Beijing Institute of Technology, Beijing, China, Email, zheyichen@bit.edu.cn
Lu-Tao Zhao, Centre for Energy and Environmental Policy Research, School of Management, Beijing Institute of Technology, Beijing, China Email, ltzhao@bit.edu.cn

Overview

The EU's Carbon Border Adjustment Mechanism (CBAM) has sparked widespread debate recently, as a major trading partner of the EU, China may be significantly affected by CBAM. Based on the computable general equilibrium framework, we evaluate the environmental and economic consequences of CBAM from a global trade perspective, with a particular focus on its impact on China. Furthermore, we explore a potential response policy by considering whether the adverse impacts of CBAM can be offset through enhanced international cooperation and exchange in low-carbon technologies.

Methods

This study employs the GTAP-E model, calibrated to the latest GTAP-11 database, to evaluate the environmental and economic impacts of policy interventions. The modelling framework incorporates accounting of embedded emissions, construction of a dynamic baseline, simulation of CBAM implementation with phased-out free allowances in EU-ETS, and the inclusion of endogenous technology spillovers. We simulate three scenarios: (1) a baseline without CBAM; (2) implementation of the CBAM; and (3) a cooperative scenario featuring enhanced Sino-EU technology exchange.

Results

Simulation results show that while the CBAM reduces global carbon leakage by 8.4 percentage points and achieves a global emissions reduction of 30 Mt CO_2 (−0.1%), it imposes uneven economic burdens. China experiences a welfare loss of 231 million USD for a reduction of 4.39 Mt CO_2—resulting in an abatement cost of 53 USD/ton, exceeding its domestic carbon price. These costs are primarily driven by trade disadvantages and inefficient resource reallocation. In contrast, a cooperative scenario featuring Sino-EU technological exchange achieves greater emissions reduction (6.19 Mt for China; 32.8 Mt globally), improves China's welfare by 621 million USD, and lowers the global cost per ton of abatement by nearly 50%. Furthermore, the emissions reduction is driven by enhanced energy efficiency, not passive output cuts—indicating a more sustainable path for China's low-carbon transition.

Conclusions

While CBAM aligns with the EU's climate objectives, its asymmetric economic impacts may undermine global equity principles. For China, it imposes disproportionately high costs for relatively limited emissions reductions. In contrast, enhanced climate cooperation through technology exchange yields greater emissions mitigation and welfare gains, while reducing both global abatement costs and carbon leakage risks. These findings suggest that multilateral strategies based on reciprocity and technology diffusion are more effective and equitable than unilateral approaches.

Holger Schlör, Sandra Venghaus

SUSTAINABLE WELFARE ECONOMICS – AN EXAMPLE OF WEST AFRICA

Holger Schlör. Forschungszentrum Jülich, 52428 Jülich, Germany, Email: h.schloer@fz-juelich.de
Sandra Venghaus RWTH Aachen, 52072 Aachen, Germany, Email:venghaus@socecon.rwth-aachen.de

Overview

The current challenges (population growth, agricultural production, inflation, debts, hunger, climate change, political instability) facing Niger pose significant risks to the well-being of its population, particularly in rural areas [1-4]. In order to address these challenges a solar-water plant was planned in a small rural village. This plant will provide the village with clean water and electricity, and it will enable the irrigation of fields, thereby improving food production. The solar-water plant will be analysed by a sustainable welfare economics approach based on the ethical value concept of sustainability, as expressed in the UN SDGs and available technological systems.

Methods

Against the backdrop of the aforementioned challenges and the UN SDG targets [5], a household survey was conducted to evaluate the socioeconomic and environmental conditions of the small village. The household survey collected data on agricultural production structures, energy and water consumption, and the effects of climate change on living conditions. A holistic picture of rural development is provided by this household survey, with Niger serving as an example.
Based on these household data, the welfare economics approach presented here measures the difference between the positive economics approach of 'what is' and the normative economics concept of 'what ought to be' [6-8], as expressed in the UN SDGs. The aim of sustainable welfare economics is to determine the optimal level of household welfare. Therefore, the Marshallian demand function and the utility function are used to estimate the change in welfare resulting from the new solar-water system.

> The concept of the Marshallian demand function was first proposed by Alfred Marshall and subsequently interpreted by Edgeworth [9-12]. The Marshallian demand function is defined as the demand for goods as a function of prices and income [13]. Marshallian functions satisfy the adding-up conditions [14], whereby an increase in income is allocated for the purchase of new goods. A further condition is that the Marshallian demand functions are homogeneous of degree zero [9], that is to say, a proportional change in prices and of the income leaves the demand of the households unchanged [13]. Marshallian demand functions serve to operationalise the normative 'what ought to be'.
>
> The household assesses how useful the available goods are for its benefit. The household has the possibility to order the goods according to its own preferences and needs [13]. Ordinal utility theory - based on the philosophical-ethical concept of utilitarianism, which was systematically developed by Jeremy Bentham (1748-1832) and John Stuart Mill (1806-1873) [15, 16] - assumes a preference order for each individual, which through a constant, strictly monotonically increasing transformation enables to determine consumer's direct utility function [10, 13]. Hence, the utility function can be derived from the preference order of the household, when the preference order is complete, reflexive, transitive, monotone, consistence, and strictly convex [10, 13].

Additionally, the question of whether the new plant can be considered a 'merit good' will be discussed. The term 'merit good' (or 'merit want') was first introduced by Richard Musgrave [17-19]. He used the concept of merit goods to describe the urgent welfare needs of society and the problem of providing for them, since the market system does not supply goods at the socially desired level [19]. The paper aims to evaluate the impact that the merit-good nature of the plant will have on the well-being of the village and the financing of the new solar-powered water system.

Results

The analysis showed that the normative welfare economics approach can determine whether planned policies, such as the introduction of new solar energy systems in rural West Africa, will have a positive effect on welfare.

The socio-economic success of investing in a decentralised solar power system hinges on the price of electricity for local households. The social question can be answered: What costs the electricity price needs to cover and what electricity price households can afford to pay to make the solar power plant a local success story. The welfare economic analysis showed who would be better or worse off, and under which socio-economic conditions investment in a solar energy system could help to bridge the rural-urban divide in West Africa. The presented welfare analysis enables to operationalise the concept of 'what ought to be' - a better energy system for rural Niger -, and enables to determine the optimal level of welfare for households and consumers [20, 21].

Conclusions

The analysis has shown the great usefulness of household surveys in rural West Africa for conducting a comprehensive socio-economic analysis. The analysis has also shown that a socio-economic assessment of an investment requires an analysis of social and individual welfare in order to determine its benefits. The welfare analysis reveals which political measures households would prefer in order to cope with the aforementioned challenges.

The welfare analysis shows that the extent to which financial measures are needed to implement solar energy investment projects depends on the investment's utility goal and the electricity price that local households can afford. So that, the extent of economic measures defines the level of sustainability that can be achieved in rural Niger. The sustainable welfare economics approach can be applied to other developing countries that are facing similar challenges to those in Niger.

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Lovindu Wijesinghe, Jann Michael Weinand, Noor Titan Putri Hartono, Detlef Stolten, Jochen Linßen

IDENTIFYING FLEXIBILITY IN AUTONOMOUS MUNICIPAL ENERGY SYSTEMS USING MODELING TO GENERATE ALTERNATIVES

Lovindu Wijesinghe, Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems (ICE), Juelich Systems Analysis (ICE-2), 52425, Jülich, Germany. Email: l .wijesinghe@fz-juelich.de
Jann Michael Weinand, Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems (ICE), Juelich Systems Analysis (ICE-2), 52425, Jülich, Germany. Email: j .weinand@fz-juelich.de
Noor Titan Putri Hartono, Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems (ICE), Juelich Systems Analysis (ICE-2), 52425, Jülich, Germany. Email: t .hartono@fz-juelich.de
Detlef Stolten, Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems (ICE), Juelich Systems Analysis (ICE-2), 52425, Jülich, Germany
Jochen Linßen, Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems (ICE), Juelich SystemsAnalysis (ICE-2), 52425, Jülich, Germany. Email: j.linssen@fz-juelich.de

Overview

As the global energy landscape shifts toward decentralization and sustainability, municipalities are increasingly exploring self-sufficient, autonomous energy systems to improve resilience, reduce environmental impacts, and achieve carbon neutrality targets [1]. In Germany, where climate neutrality by 2045 is mandated [2], understanding how flexible municipal energy systems can be is vital for effective planning. However, energy system designs are subject to significant uncertainty in demand, policy, and technology pathways [3]. This study aims to identify the range of technically and economically feasible system configurations that municipalities can adopt under such uncertainties. To do so, we employ modeling to generate alternatives (MGA) approach, enabling the systematic exploration of near- optimal energy system designs for selected municipalities previously identified as fully autonomous [4].

Methods

ETHOS.FINE is a Python-based, open-source tool for techno-economic optimization of regional energy systems [5]. The study builds upon the ETHOS.FINE energy system modeling framework and applies the random vector MGA method (e.g., Ref [6]) to five German municipalities: Neuschoo, Ilmenau, Müden (Mosel), Urmitz, and Kahl am Main. Each municipality's energy system includes renewable sources (wind, rooftop PV, open-field PV, biomass, etc.), storage technologies, and conversion components for electricity, heat, hydrogen, and industrial process heat. Demand is modeled using fixed hourly profiles for the year 2045, scaled to municipal levels. MGA is used to identify near- optimal configurations that remain within a 10% cost margin from the optimal solution. The harmonic mean of squared Euclidean distances (HMSED) [7] is used to select maximally distinct alternatives, with iterations stopped when the relative diversity of solutions falls below a 1% threshold.

Results

The number and diversity of near-optimal alternatives varied significantly among municipalities. Neuschoo and Ilmenau (low-cost autonomy cases) showed the highest flexibility, with 42 and 36 distinct MGA solutions, respectively. In these cases, renewable technology capacities—especially open-field PV and wind could vary widely without exceeding the 10% cost margin, indicating a robust and substitutable system structure. In contrast, high-cost municipalities like Urmitz and Kahl am Main exhibited only 13 and 6 viable MGA alternatives, respectively, with minimal variation in technology capacities due to spatial constraints and limited renewable potential. Flexibility in low-temperature heat and industrial process heat supply was also observed in some cases, particularly through varied use of heat pumps and electric furnaces. However, high-cost municipalities showed rigid dependence on expensive technologies like large-scale batteries and heat pumps, which constrained system adaptability.

Neuschoo and Ilmenau show minimal variability in specific system costs across 42 and 36 MGA solutions, respectively, indicating stable and robust autonomy pathways. Müden (medium-cost autonomous municipality), despite higher overall costs, also exhibits low-cost variance, suggesting consistent outcomes despite land constraints.

In contrast, Urmitz displays high variability among its 13 MGA solutions, highlighting sensitivity to local constraints and reduced planning reliability. Kahl am Main's narrow, costly solution space (only six alternatives) reflects the structural difficulty of achieving affordable autonomy under severe spatial and technological limitations.

Conclusions

This study demonstrates that MGA can effectively quantify the flexibility and robustness of autonomous municipal energy systems under uncertainty. Municipalities with higher renewable resource availability and larger land areas can support multiple viable configurations with minimal cost increases, offering greater decision-making flexibility. The stability of MGA solutions in Neuschoo, Ilmenau, and Müden indicates that some municipalities can plan for autonomy with confidence despite varying configurations. However, in municipalities like Urmitz and Kahl am Main, the limited or volatile solution space reveals critical constraints that challenge the reliability and affordability of energy autonomy. These findings emphasize the need for flexible strategies tailored to local conditions. MGA thus not only uncovers alternatives but also reveals the depth of structural limitations in planning decentralized energy systems.

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Anna Carozzani, Chiara D'Alpaos, Verena Hagspiel-Janssen, Michele Moretto

THE FATE OF AGING HYDROPOWER PLANTS: REINVESTMENT OR UPGRADING?

Anna Carozzani, Department of Civil, Environmental and Architectural Engineering - University of Padova, via Venezia 1 – 35131 Padova, Email: anna.carozzani@phd.unipd.it
Chiara D'Alpaos, Department of Civil, Environmental and Architectural Engineering - University of Padova and Interdepartmental Centre "Giorgio Levi Cases" for Energy Economics and Technology, via Venezia 1 – 35131 Padova, Email: chiara.dalpaos@unipd.it
Verena Hagspiel-Janssen, Department of Industrial Economics and Technology Management - Norwegian University of Science and Technology, Alfred Getz vei 3 – Sentralbygg 1 Gløshaugen Campus Trondheim, Email: verena.hagspiel@ntnu.no
Michele Moretto, Department of Economics and Management - University of Padova and Interdepartmental Centre "Giorgio Levi Cases for Energy Economics and Technology, via del Santo 33 – 35123 Padova, Email: michele.moretto@unipd.it

Overview

Hydropower remains the largest source of renewable electricity generation globally and plays a critical role in ensuring grid stability and long-term storage capacity (IEA, 2024). However, the sector is at a turning point: many large-scale hydropower plants (HP) built in the mid-20th century are now reaching the end of their design life. According to the International Energy Agency, over 40% of the installed global capacity was commissioned before 1980, and a large share of facilities requires modernization, refurbishment, or repowering. In parallel, the European regulatory landscape is highly fragmented. The institutional and legal frameworks governing large hydropower concessions vary significantly across countries, especially in terms of the legal instrument used (authorizations vs concessions) and the presence or absence of competitive tendering procedures for water use rights. In Italy, for instance, more than 80% of concessions are set to expire by 2029, prompting a national debate over whether to adopt open competition or alternative renewal mechanisms.
Against this backdrop, the choice between preserving or expanding capacity, as well as the nature of the investor - incumbent (i.e., the current licensee or concessionaire) or new entrant - can significantly affect the public value of concessions. These factors shape not only the rhythm of decarbonisation, but also the distribution of benefits from hydropower resources and the credibility of the allocation process.

Methods

We develop a real options model to evaluate two mutually exclusive investment strategies for aging hydropower plants at the end of their concession: (i) reinvestment, which preserves current production, and (ii) upgrading, which expands generation capacity. The model accounts for electricity price uncertainty, with future cash flows based on the incremental output and investment costs assumed proportional to the added production. Timing flexibility differs by investor type: new entrants can invest only at concession expiry, while incumbents may act earlier. To reflect this asymmetry, we estimate the option value under both timing regimes and include potential losses from early investment due to the residual value of the existing concession. The model is calibrated using historical data from Norway, and option values are expressed per unit of additional energy to ensure a consistent comparison between reinvestment and upgrading.

Results

The analysis reveals how investment timing and scale critically affect the value of hydropower concession renewal. At low unit investment costs, postponing the decision until the license expiry is optimal: in these cases, the European option (waiting) dominates, as early investment would imply a significant loss of residual concession value. As costs increase or the expansion potential becomes substantial, early investment becomes economically justified: the corrected American option, which accounts for revenue losses from early exercise, begins to dominate, highlighting the growing importance of timing flexibility.

To ensure consistent comparisons between reinvestment and upgrading choice, all option values are normalized per unit of additional energy output. The results show that upgrading becomes preferable for unit costs above 150 NOK/MWh and production increases of at least 30% (i.e., KU ≥ 1.3 MWh). In this region, the combined benefits of scale and flexibility outweigh the higher investment costs and the lost revenues from the existing concession.
We also simulate a bidding scenario in which an incumbent and a new entrant compete under three possible regulatory settings: (i) reinvestment only, (ii) mandatory upgrading, and (iii) free choice between reinvestment and upgrading. We assume that the incumbent, unlike the new entrant, can invest before the concession expires, gaining a strategic edge in the bidding process. The results show that this early move advantage translates into a structural economic benefit: when both options are available, the incumbent achieves the highest normalized value by choosing early upgrading, a strategy unavailable to the new entrant. This confirms that timing flexibility, when permitted, can significantly influence bidding outcomes and affect the competitiveness of concession allocation processes.

Conclusions

Investment decisions at the end of hydropower concessions involve a fundamental trade-off between maintaining existing capacity at lower cost and pursuing higher returns through capacity expansion. In the proposed model, this choice is shaped by investment costs, incremental production potential, and regulatory constraints. The results show that upgrading gains in value under conditions of higher investment costs and when the option to invest early is available. Regulatory frameworks that account for these dynamics, while ensuring transparency and fair access, can help accelerate the renewal of aging infrastructure and align investment decisions with long-term energy policy goals. This finding has important regulatory implications, particularly in countries that aim to promote open competition while ensuring investment efficiency and timely modernization of hydropower assets

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Andrea Paolacci, Maria Carmen Falvo e Flavio Andreoli

TECHNO-ECONOMIC ANALYSIS OF SIMPLE PRODUCTION AND CONSUMPTION SYSTEM FOR HYDRO POWER PLANTS: A CASE STUDY

Andrea Paolacci, Department of Astronautical, Electrical and Energy Engineering (DIAEE)
Via Eudossiana 18, Rome, Italy, Email: andrea.paolacci@uniroma1.it
Maria Carmen Falvo, Department of Astronautical, Electrical and Energy Engineering (DIAEE),
Via Eudossiana 18, Rome, Italy Email: mariacarmen.falvo@uniroma1.it
Flavio Andreoli, Epico Viale degli Ammiragli 67, Rome, Italy, Email: flavioandreoli@epico.green

Overview

Over the last years, European policies aim to avoid indiscriminate incentives for the energy efficiency in building and the integration of renewables power plants. The recent directives subsidise the grow of new renewable power capacity, under the constraint to aggregate power plants and consumption unit within well-defined perimeters. In particular, Renewable Energy Directive II 2018/2001 (RED II) introduced new concepts and measures to promote self- consumption. Among these, Energy Communities are certainly the most popular innovation. The goal is to encourage local self-consumption and enable a more efficient energy management and distribution grids management, by limiting reverse power flows and cascade effects. Moreover, this approach aims to get citizens more involved in the energy transition, giving them more autonomy and responsibility. Despite these mechanisms are designed to boost consumer participation, in practice they are seeing limited uptake and a negligible effect on the power system. One of the main reason for this inefficiency is due to the fact that currently the players capable to influence the energy sector with the required capital are large investors, typically the energy production companies, rather than individual citizens or small consumers. Additionally, it is necessary to consider that innovations, such as Energy Communities, are tied exclusively to the new renewable capacity neglecting the existing one already in operation.
However, the Legislative Decree 210/21, with which Italy implemented part of RED II, introduced a new definition for Simple Production and Consumption System (SSPC), which represent a concrete opportunity for the energy production companies. This new definition can enable physical self-consumption, ensuring economic sustainability for renewable power plants that are no longer supported by previous incentive schemes. Moreover, it offers benefits to distribution grids through a more efficient energy flows management and provides implicit incentives to both producers (owners of the renewable plants) and consumers.

Method

To evaluate the implementation of a Simple Production and Consumption system (SSPC) between a producer and an end-user, we conducted a technical-economic analysis on a specific case study.
The first step is to evaluate the distance between the two units that have to be connected. This is a key factor because the cost of the connection infrastructure significantly affects the project economic viability and represents one of the main obstacles to its realization. Another essential step is to analyse the features of both the production and consumption units. For this purpose, historical production and consumption data from the past year were collected. These data were used to build the production and consumption curves and to assess their suitability to be coupled.
Production and consumption curves showed a good match, so we proceeded to estimate monthly and annual self- consumption. These data represent the foundation to the economic analysis, which includes the assessment of the current tariff applied to the end user for the withdrawals from the grid. Based on the estimated physical self- consumption and on the economic tariff conditions, a supply tariff can be developed for the energy exchanged under the SSPC configuration. The goal is to ensure economic benefits for both producer and end-user. Finally, it is necessary to design the electrical connection and it should include all necessary measures, to ensure safe operation and accurate energy flows measurement within the system.

Results

The model used to implement the Simple Production and Consumption System (SSPC) allows assessing all the key aspects, ensuring both technical reliability and economic sustainability.
Access to historical production and consumption data of both units and the analysis of the avoided costs related to additional components on the bill, allowed calculating accurately the savings resulting from SSPC configuration. These savings are redistributed between the consumer and the producer, owner of the power plant, to mitigate the impact of energy price fluctuations given by the current uncertainties in energy markets. From a technical point of view, the better electrical connection was identified. It allows safe system operation and it always ensures to inject into the grid the produced energy regardless of consumer needs.

Conclusions

SSPCs are solutions to ensure the economic sustainability of renewable power plants and they are able to provide some benefits for all power system actors. Producers can improve the economic value of the energy produced through an implicit form of incentive, while consumers can save money by exploiting energy directly on-site. The grid itself improves its operational efficiency thanks to the SSPCs influence on the end-user behaviour. In fact, in order to maximize economic saving, end-users will tend to shift their consumption to times when local energy is available. This reduces energy flows to higher voltage grid levels helping to avoid additional costs for distribution grid upgrades.
European governments should adopt strategies to promote the development of these systems and the aggregation of renewable power plant already in operation. Thanks to these configurations public support could be provided at a much lower cost due to the presence of an existing implicit form of incentive.

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Thierry Kamionka

DOES NEIGHBOURHOOD MATTER? THE IMPACT OF PROXIMITY TO (DIS)AMENITIES ON HOME PRICE

Thierry Kamionka, CNRS, CREST and Institut Polytechnique de Paris,
Email: kamionka@ensae.fr

Overview

We model apartment transaction prices in Paris using geocoded administrative data. We enrich these transactions using information on (dis)amenities. These amenities include information on energy efficiency label (EPC), on the level of noise (road, train, plane), information on train and subway stations, information on proximity of educational establishments, information on delinquency. It is important to include the characteristics of the apartment being sold in the model specification. It is also important to consider the presence of any omitted heterogeneity. We model these housing prices using hedonic models (see Rosen 1974) with fixed effects. We consider also a mixture of hedonic models in such a way that the distribution of unobserved heterogeneity can be specific to the neighborhood and propose a simulated EM algorithm to estimate this specification. We estimate these models using data from the DVF administrative data base for the years 2018 to 2024. The empirical results show that physical characteristics of the apartments matters as well as the ones of the (dis)amenities located in the neighborhood like the noise level. Importantly, the energy efficiency label is an important characteristic of the price. We obtained the precise impact of the energy performance level on the selling price. This information is important because it shows how much a homeowner can gain from investing in energy-efficient renovations and can be compared with the cost of such renovations. We can also compare the effects on the sale price of an apartment of an energy label (EPC) based on the apartment's energy characteristics and those of an energy label based on energy expenditure. Results testify that the impact of train and subway stations can vary according to the proximity and the quality of the transportation offer. Interestingly, the effect of the proximity to the terminal may indicate that these stations generate jointly a positive externality (transport accessibility) and a negative externality (crime, inconveniences associated to the crowd).

Method

We model the log of the transaction price using conditional hedonic models. Unobserved heterogeneity is modelled using fixed effects models and mixture of hedonic models to study the robustness of the results. These models are estimated using administrative data on transactions on the housing market. Energy efficient labels (EPC) are obtained from administrative data. Both data sets are geocoded.

Results

The energy label is based on seven levels, ranging from A for apartments with the best energy performance to G for those with the worst. Each energy performance level has a significant effect compared to the reference performance level (level D). The best apartments in terms of energy performance (EPC equal to A or B), achieve a gain of 27.1% compared with those classified with a D label. The least energy-efficient apartments (those rated G) are sold, all other things being equal, for 3.4% less than those rated D. There is some information to suggest that the relatively low-price differentials estimated between energy efficiency labels D and G are the result of relatively strong demand for apartments in Paris. A change in the methods used to calculate the energy efficiency label has been introduced for July 2021. Before this date, energy efficiency was calculated based on energy bills. From this date onwards, energy efficiency was determined based on the technical characteristics of the dwelling. As the data covers the period 2018 to 2024, we have estimated the effects on prices of the two energy label systems (EPC). The results show that the estimated effects of the energy label when defined based on energy consumption are biased by the presence of apartments that are not occupied all year round. These results show the importance for public policy of the method used to establish the energy label (EPC). We also estimate the effects of other apartment characteristics on transaction prices.

Conclusions

In this paper, we model transaction prices on the housing market in Paris using hedonic models and mixture of hedonic models. We use administrative data enriched by additional information on (dis)amenities such as the energy efficiency label (EPC), the level of noise (road, rail, air corridors), the proximity and the quality of educational establishments, the proximity and quality of train and subway stations, delinquency. The results show that if the physical characteristics of the apartments are important, like the number of rooms or the surface, those of theneighborhood have a significant effect on the transaction price of housing. Amenities are characterized both by the distance from the accommodation and their intensity. For example, the effect on the transaction price of high schools will depend on the distance to the high school and its quality.

Interestingly, the effects of the energy label (EPC) on the transaction price of apartments in Paris are significant and relatively large. Apartments with the best energy characteristics (labels A or B) are sold for an average of 27.1% more than those with the most frequent label (label D). Apartments with the lowest energy efficiency are sold for 3.4% less than those with an intermediate label (an EPC equal to D).
These results are important for apartment owners who want to determine whether it is economically worthwhile to renovate their apartment. They are also important for public policy, in the face of both rising energy costs and climate change.

Our results also show that in terms of public policy, the criteria used to determine the energy efficiency of buildings are important.

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Sophie Charlotte Westphal

CHARGING SMART: EVALUATING EMISSION AND COSTS OF SAEV CHARGING STRATEGIES IN A EUROPEAN POWER SYSTEM

Sophie Westphal, Chair of Management Accounting, TUM School of Management Technical University Munich, Arcisstrasse 21 80333 Munich, Germany, Email: Sophie.westphal@tum.de

Overview

The transition to electric vehicles has disrupted mobility patterns. However, further disruption is imminent with autonomous driving technology, expected to operate primarily within shared fleets (e.g., Waymo or Moia). This paper defines "shared" to include both ride-hailing and ride-sharing systems, forming Shared Autonomous Electric Vehicle Fleets. These fleets represent a fundamental shift in vehicle utilization, charging, and control. While the transition to EVs stresses the electric power system—due to increased demand and peak loads—SAEVs could reduce charging demand by increasing vehicle occupancy and enhancing charging flexibility through centralized fleet management. However, their environmental impact depends on fleet size and therefore adoption levels, operations, and charging strategies. While fleet operators seek to minimize charging costs, it is unclear how this relates to minimizing charging emissions. This study seeks to answer the following research question: How do emissions and cost trade-offs vary across different SAEV electricity demand scenarios? We use empirical mobility data from Germany and integrate it with real-world electricity grid data using the open-source European Energy System Optimization Moel PyPSA-Eur. While (Li et al., 2022), (Zhang & Chen, 2020) and (Estandia et al., 2021) provide valuable insights into the benefits of smart charging and SAEV-grid interactions in U.S.-based contexts, these studies primarily focus on operational efficiency or emissions in isolation, often neglecting real-world power system constraints; moreover, their findings lack generalizability to the German context due to differing grid structures and travel patterns. Results show that charging inverse to netload is the most cost-effective and most emission-efficient strategy.

Methods

This study simulates SAEV charging demand profiles using empirical mobility data from Germany (Mobilität in Deutschland, 2017) and integrating these profiles with hourly real-world electricity grid data. Further it is distinguished between SAEV fleet charging strategies and private EV strategies. The SAEV strategies considered are Charging Inverse to Netload, Charging Inverse to Travel Demand, and Uniform Charging. For private EVs, Home Overnight Charging, Daytime Workplace Charging, and Daytime Public Charging (Li et al., 2022; Märtz et al., 2022) are analyzed. To simulate the operation of power plants in response to electricity demand, the open- source European Energy System Optimization Moel PyPSA-Eur, an economic dispatch optimization model. While this study is focused on the SAEV fleet within cities in Germany, the power system is substantially more interconnected. Therefore, we simulate the operation of the entire European power system, to capture the import and export of electricity across different balancing zones. The model co-optimizes the charging scheduling (under smart charging strategy) along with economic dispatch of generators and renewable capacity expansion, to find the minimal cost combination to obtain a supply–demand balance in the power system. The simulation is run on an hourly basis, for each day from, from 2026 through 2040. Base, medium, and high SAEV adoption levels correspond to 8%, 17%, and 24% of the current travel demand market size by 2035 respectively. We examine two different introduction years (2025 and 2030) and assume a linear growth in the market adoption from 0% in introduction year to 2040.

Results

Simulation results demonstrate that charging strategies have significant effects on both emissions and system costs under varying SAEV adoption levels. Charging Inverse to Netload emerges as the most cost-effective and emission-efficient strategy. By aligning charging activity with periods of high renewable generation, this strategy reduces CO_2 emissions and alleviates grid stress.

In contrast, Uniform Charging creates a constant base load but fails to capitalize on temporal fluctuations in renewable availability, offering limited emission benefits. Charging Inverse to Travel Demand reduces peak load congestion but often shifts charging into hours with lower renewable penetration, leading to higher emissions.
Private EV charging strategies—especially home overnight and workplace daytime charging—result in up to 25% higher emissions than SAEV-specific strategies. This is primarily due to their fixed temporal patterns, which coincide with fossil-based generation peaks and lead to higher marginal generation costs. Consequently, charging costs for private EV strategies are approximately 10% higher than those for smart SAEV strategies.

A cost-emission trade-off analysis reveals that the Charging Inverse to Netload strategy dominates on both fronts, minimizing emissions without incurring higher costs. The findings suggest that grid-aligned smart charging strategies can simultaneously improve economic feasibility and environmental performance.
From a policy perspective, dynamic electricity pricing emerges as a key enabler to incentivize renewable- aligned SAEV charging. Policymakers can promote this through time-of-use tariffs, carbon pricing, or dedicated SAEV charging infrastructure. For fleet operators, the results underline the strategic importance of flexible, renewable-sensitive charging schedules to optimize both costs and sustainability.

Conclusions

Under the European power grid, SAEVs can be less carbon-intensive than private EVs, when operated under optimized charging strategies. SAEV-specific charging strategies not only improve grid efficiency and cost but also provide substantial emissions reductions, highlighting the environmental benefits of optimizing charging behavior based on renewable energy availability and fleet operation rather than mimicking private EV strategies.. CO_2 emissions from SAEVs increase with fleet expansion, but total emissions are inversely correlated with occupancy rates, meaning higher occupancy leads to more efficient environmental outcomes. This study contributes to the literature by examining the role of SAEVs in decarbonizing transportation, focusing on their impact on grid efficiency, cost and emissions reduction. The findings emphasize the necessity of SAEVs alongside private EVs and highlight the need for policies that support renewable-aligned charging strategies, such as carbon taxes or dedicated charging stations. For SAEV fleet operators, the study shows that aligning charging strategies with renewable energy generation not only enhances operational efficiency but also improves grid stability. For researchers, the study provides a foundation for further exploration into the impact of SAEVs on the German power market, using derived charging profile as inputs for power system models.

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Francesco Castellani, Maria Carmen Falvo, Federico Santi

EFFICIENCY AND DECARBONIZATION THROUGH ELECTRIFICATION IN NON-RESIDENTIAL CIVIL SECTOR: CHALLENGES, POTENTIAL AND MAIN OBSTACLES

Francesco Castellani, Studio Santi Via Latina 57 - 00058 Santa Marinella (RM) - Italy and Sapienza University of Rome, Email: francesco.castellani@studiosanti.eu
Maria Carmen Falvo, Sapienza University of Rome, Italy
Federico Santi, Studio Santi Via Latina 57 - 00058 Santa Marinella (RM) and Sapienza University of Rome, Italy Email: prof.federico.santi@gmail.com

Decarbonization, nowadays, is maybe the main goal of the entire humanity since it is the key to arrest the Climate Change and its consequences on the environment and on human health and activities. This thesis describes the role and explores the potential contribution of non-residential civil buildings in this process. The research, conducted between 2022 and 2025, focuses on elaborating a consistent methodology to analyse large non-residential civil users, in order to assess their carbon footprint (energy related), energy needs, electricity consumption and, above all, to define a feasible and reliable "decarbonization through electrification" path that can habilitate these users to access to the electricity market.

After an overview of the current policies for the decarbonisation of the civil sector, led by the Fit-for-55 EU program, the research focuses on electrification of large non-residential civil users, defining the boundaries of this research, demonstrating the feasibility of this solution, explaining the main efficiency (electric heat pumps, above all) and renewable energy production (especially photovoltaic) technologies. This work gives an overview of the possibilities, for decarbonized and electrified buildings, to access to the electricity market both to sell demand response services and to buy/sell renewable energy in optimized modern configurations ("prosumers"), and also shows the simulation methodologies used to analyse the case studies of the research. These models are based on current available standards, especially EN 16247 and UNI/TS 11300, and on literature review.

The research provides details on the four case studies object of this study, selected according to their common characteristics (tertiary sector, public entities, Rome metropolitan area), in order to start the definition of a representative sample to be used in following researches. The first case study is an Italian museum in historic building, the National Gallery of Modern and Contemporary Art in Rome. This museum underwent a decarbonization through electrification process and real measured data were collected and analysed, to demonstrate the reliability and feasibility of the decarbonization through electrification. The second case study is a European research centre, ESA ESRIN in Rome; the third case study is an Italian research centre, whose identity cannot be published since this research contains sensitive data for a tender that will be announced in the next months; the fourth and last case study is the headquarter of an Italian public administration, hosted in an historic building, that has a very strong security policy and has not given the permission to report its sensitive data.

These last three case studies are related to efficiency and decarbonization proposals that demonstrate the potential goals achievable through this process.

Amir Ashour Novirdoust

EQUILIBRIUM POWER MARKET INVESTMENTS - INVESTIGATING EQUILIBRIA OF CAPACITY PAYMENTS

Amir Ashour Novirdoust, Hendrik Diers, Pia Willers Institute of Energy Economics at the University of Cologne, Vogelsanger Str. 321a, 50827 Cologne, Germany

Overview

There are various reasons for a lack of security of supply in the power system, including missing money for investments in firm capacity and risk-averse investors operating under high uncertainty. Accordingly, the issues of resource adequacy and capacity mechanisms are under intense debate. Germany and France have declared their willingness to jointly develop capacity mechanisms to address resource adequacy and security of supply (*Bundesregierung 2025*). The literature on capacity mechanisms highlights that uncoordinated policies can create redundancies, cross-border distortions, and ineefcient reliability outcomes (*Bhagwat et al. 2017; Cepeda 2018*). A related strand of research incorporates risk aversion and market incompleteness into equilibrium models, showing that these frictions distort investment and reduce welfare (*Dimanchev et al. 2023; Munoz et al. 2017; de Maere d'Aertrycke et al. 2017*). We investigate how different capacity mechanisms affect investment, dispatch and welfare in coupled European electricity markets, focusing on how introducing a mechanism in one country changes the need for capacity mechanisms in neighbouring countries and which equilibria between countries result.

Methodology

We build on a stochastic investment and dispatch model by *Dimanchev et al. (2023)*, formulated as a mixed complementarity problem (MCP), in which independent system operators (ISO) minimise costs and risk-averse investors decide based on expected value under conditional value-at-risk (CVaR) preferences. We extend the model to capture multiple coupled markets and cross-border fl ows, reflecting the European electricity system. There is one investor per country and technology, purely profit-maximising. Price caps limit scarcity rents, creating potential missing-money problems that can induce underinvestment and load not served. We therefore introduce various capacity-mechanism designs. For example, country-specific reliability standards can endogenously allow higher scarcity rents. If such standards exist in more than one market, the resulting scarcity-rent mark-ups establish an equilibrium across coupled markets, as they mutually affect one another. The model captures demand, fuel and weather uncertainties as well as existing grid and generation capacities. It allows a comparison of integrated (one mechanism for all markets combined) versus non-integrated (one mechanism per market) settings. Using a primal–dual formulation (ISO + investors), we analyse strategic coordination (or its absence) between countries and the resulting firm capacity and battery investments, trade flows and welfare effects.

Results

Preliminary results show that capacity mechanisms tend to reduce energy not served. However, in coupled markets they generate two opposing effects. On the one hand, they increase security of supply, which can reduce the need for capacity payments in coupled markets. On the other hand, they depress scarcity-time prices, which can increase the need for capacity payments when reliability standards must be met. As investors anticipate lower revenues and invest less, security of supply can decline, or scarcity-rent mark-ups may rise in coupled markets. These opposing forces, and the equilibria they imply, are at the core of our analysis. Furthermore, as expected, integrated, coordinated capacity mechanisms increase welfare compared to fragmented solutions. The application to the Central Western European power system quantities these trade-offs, provides evidence for the benefits of coordinated capacity mechanisms in Europe's coupled electricity markets, and offers guidance on how to concretely design capacity mechanisms in coupled electricity markets.

Conclusion

Capacity mechanisms are well-studied instruments to address resource adequacy. Yet their effects on coupled markets remain under-investigated from theoretical, empirical and numerical perspectives. Our research aims to shed light on the cross-border effects of capacity mechanisms from an equilibrium-model perspective.

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Giuseppe Dell'Olio

LEVELIZED COST OF ELECTRICITY: CAN ITS ACCURACY BE IMPROVED?

Giuseppe Dell'Olio, GSE S.p.A, Email: gidellolio@gmail.com

Overview

The Levelized Cost of Electricity (LCOE) is widely used when estimating the costs and the revenue of a planned electricity production plant. Several definitions are available for it; while they somehow differ as to the calculation conditions, virtually all of them involve the notion of interest rate, applied both to money income and to electricity production. It is therefore worth assessing whether a more precise estimate of the interest rate is beneficial. In particular, the introduction of different interest rates for money and, respectively, for electricity seems to improve the accuracy of financial forecasts.

Methods

A literature survey has been performed, and several definitions of Levelized Cost of Electricity (LCOE), each in its own calculation conditions, have been compared. For each definition, it has been evaluated whether, and in which way, the concept of discount rate is involved. The discount rate turned out to be typically applied to electricity, as well as to money.
The sensitivity of LCOE to discount rate has also been assessed.

Results

A significant influence of the discount rate on the LCOE has been found. This warrants a deeper analysis, in order to evaluate the most appropriate values for interest rates (in particular, the one associated with electricity production) to be used in association with LCOE. Main definitions of LCOE have therefore been analyzed for this purpose.

Conclusions

It has been concluded that the introduction of different interest rates for money income and, respectively, for electricity production significantly increases the accuracy of LCOE and hence the whole financial forecast.

Peiwen Zhan, Markus Blesl

IMPACT OF COORDINATED INFRASTRUCTURE DEVELOPMENT TOWARD CLIMATE NEUTRALITY UNDER EU REGULATIONS FROM AN ENERGY SYSTEM PERSPECTIVE

Peiwen Zhang, Institute of Energy Economics and Rational Energy Use, University of Stuttgart, Heßbrühlstraße 49a, 70565 Stuttgart, Germany Phone: +49 711 685 87827, Email: peiwen.zhang@ier.uni-stuttgart.de
Markus Blesl, Institute of Energy Economics and Rational Energy Use, University of Stuttgart, Heßbrühlstraße 49a, 70565 Stuttgart, Germany Phone: +49 711 685 87865, Email: markus.blesl@ier.uni-stuttgart.de

Overview

With the introduction of many EU policies, including the fit-for-55 package[1], green deal[2] and clean industrial deal[3], EU is aiming itself for reaching climate neutrality at 2050. In order to reach its goal, the energy system transition hinges on coordinated infrastructure development. To date, no extant energy system model has modelled the synergy of multiple infrastructures on a large time horizon for the whole European continent due to extensive computational effort. The objective of this study is therefore set as follows: 1) the development of a methodology that converts physical parameters from existing infrastructures into capacity units, which serves to reduce calculation effort and ensure implementation in linear programming optimization; 2) the development of an evaluation tool that interprets the results from an energy-economic perspective such as energy carrier prices. The analysis of the development of electricity, gas and hydrogen infrastructure within the 27 EU member states as well as UK, Norway and Switzerland from 2020 to 2050 is facilitated by the utilization of the TIMES PanEU energy system model and the implementation of the methodologies. Insight into the interaction of different infrastructures along with the pathway of reaching climate neutrality is given under the current regulations including the 15% interconnection target for the electricity grid at 2030 from the clean industrial deal[3], the 2040 climate target[4] and the ETS-2 regulation[5].

Methods

This study is methodically divided into two parts to address the methodological challenges. The first part uses an analytical approach to translate real-world infrastructure data into insights that can be implemented within the energy system model. The 15% interconnection target at 2030, which applies exclusively to the electricity grid, is implemented in the model. Furthermore, the expansion of gas and hydrogen infrastructure is modelled within the TIMES PanEU framework[6] based on ENTSO-G's Ten-Year Network Development Plan (TYNDP)[7]. As the model uses a 'one node per country' modelling approach, infrastructure is represented in terms of capacity values rather than actual physical parameters. Physical infrastructure metrics, such as transmission line or pipeline lengths, are systematically converted into energy capacity values using technical parameters, including capacity per unit length, efficiency factors and carrier-specific characteristics. Moreover, the second part develops a methodology to interpret infrastructure results by converting them into monetary values to reflect carrier-specific costs, with energy flows interpreted as annual import and export quantities.

Results

Under the existing EU climate regulations such as 15% interconnection target for the electricity grid at 2030 from the clean industrial deal[3], the 2040 climate target[4] and the ETS-2 regulation[5], this study sets out and analyses two scenarios: the first is a "business-as-usual" scenario, with a low electricity interconnection target of 2040; the second is an "electrification" scenario, with a high electricity interconnection target for 2040. Results show that a higher degree of electrification leads to improved integration of renewable energy sources and a reduced reliance on fossil-fuel-based backup powerplants, resulting in lower curtailment as surplus renewable electricity can be shared more effectively across borders. Additionally, the need for newly-built gas infrastructure decreases, with much of the existing network being retrofitted into hydrogen grids to support power-to-X applications.

Enhanced interconnection also strengthens energy security by reducing national dependence on domestic generation portfolios. From an energy economic perspective, the study finds that electricity prices are influenced by both infrastructure investment costs and the costs of renewable energy deployment.

Conclusions

Modelling multiple infrastructures at the EU level makes it possible to systematically assess the impact of infrastructure development toward the climate neutrality goal. By implementing the methodology introduced in this study as well as the further development of the energy system model TIMES PanEU, this study provides valuable insights into the synergy of multiple infrastructures and the effectiveness and feasibility of current regulatory frameworks in guiding the EU to transit towards climate neutrality from an energy economic perspective.

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Cédric Clastres, Alexandre de Cannière, Kriti Baruah

TARIFF STRUCTURE FOR DISTRIBUTION NETWORKS: A CASE STUDY FOR EUROPEAN PROSUMERS AND STAKEHOLDERS

Cedric Clastres, Univ. Grenoble-Alpes, CNRS, INRAE, Grenoble INP, GAEL, 38000 Grenoble, France
Economic Climate Chair, Palais Brongniard, 28 place de la bourse, 75002 Paris -
Corresponding author: Email: cedric.clastres@univ-grenoble-alpes.fr
Alexandre De Canniere, Elia Transmission Belgium, Boulevard de l'Empereur 20 • 1000 Bruxelles, Belgium
Kriti Baruah, Univ. Grenoble-Alpes, CNRS, INRAE, Grenoble INP, GAEL, 38000 Grenoble, France

The energy transition is leading to an increase in self-consumption through the deployment of distributed energy resources (DER) along with decentralized energy markets in renewable energy communities (EC) across Europe. The increasing adoption of DERs with the conventional grid tariff structures can lead to Utility Death Spiral due to reduced revenues for utilities. A model is developed to test the impact of self-consumption on the network topology and network costs. It was found that self-consumption results in lower network costs but does not impact network topology. We then assess the cost of the network and try to find an optimal way to share the costs among the participants. Cooperative game theoretic approaches such as the core and Shapley value are used to test network tariff allocations. An optimization program is added to the model to test whether there exists a solution consisting of a three-part tariff structure for participants such that the incentive to stay in the community could be maximized to obtain an even more stable solution. The paper concludes with policy implications based on our research work for tariff structures for renewable ECs that fulfil cost-reflectiveness, cost-recovery and fairness which can prevent Utility Death Spiral in the long run.

Keywords: *Distribution system operator, Tariff structures, Cooperative game theory, Optimization, Utility Death Spiral, Energy Community.*

1. Introduction

In the European electricity sector, the focus on analyzing the economics of power distribution has been relatively limited compared to power generation and transportation. In the last three decades, power distribution issues have been implicitly presented as minor matters in public policy debates (Perico E Santos and Massol, 2022). However, at least two factors suggest that this traditional view no longer holds. First, the widespread deployment and affordability of distributed energy technologies, such as rooftop solar panels, demand response, and energy storage, are causing a radical transformation in the market environment for Distribution System Operators (DSOs), who are responsible for local low voltage networks. These smart energy technologies empower network users, reshape their interactions with the distribution grid, and introduce greater complexity. Second, there has been a shift in public policy goals assigned to regulatory authorities, which now include not only promoting competition and market integration but also rapidly decarbonizing European economies. By nature, these distributed energy technologies have a low-carbon nature and now provide credible options. Organizing their cost- efficient integration within the existing energy system is thus crucial. However, the regulatory framework applied to DSOs and the rate structure they charge largely predates these developments and one can wonder whether they are still adapted. Indeed, in case of a poorly adapted pricing, a DSO can stimulate the users' migration to off-grid solutions and initiate the so-called "Utility Death Spiral" whereby the large fixed costs has to be recouped from a shrinking number of users (Cambini and Soroush 2019; Perico E Santos and Massol, 2022).

Indeed, electricity trades could now be made at the local level, considering the development of prosumers, self-consumers or Energy Communities (EC). However, these stakeholders are often connected to the distribution network to balance their electricity flows due to their intermittency (Botelho et al., 2022). Some ECs could be autonomous but we do not see it widely yet because of investment costs in storage systems, that remain costly and unprofitable in some countries (Clastres et al., 2021). According to the new definition of EC, where members could be connected via the distribution network to make trades, DSOs need to contract with them (Johansson, 2020).

Moreover, the DSO also fosters the transmission of information between each EC member connected to its network (Iazzolino et al., 2022). Hence, we see the important role of DSOs in this new environment of decentralization of energy market trades. When it comes to Utility Death Spiral, Castaneda et al. (2017) argues that the reality is more complex than the simple narrative of the growth of DERs being the only contributing factor as there are other underlying factors such as consumer behaviour, policies incentivizing DER adoptions and so on. However, it is known that Utility Death Spiral threatens and, even though it could have only but a small impact in the short run, the forecasted increase of decentralized energy trades makes it worth of interest to study (Clastres et al., 2019). This issue makes concerns as policymakers must keep two objectives in mind: 1) to continue to incentivize self-consumption and EC deployment and 2) to minimize cross- subsidies between "on-grid" and "off-grid" stakeholders to avoid by-pass strategies

The purpose of this paper is thus to examine whether the different tariff structures implemented by European DSOs are adapted to the current and upcoming business environment of DSOs. More specifically, this paper examines: (i) whether these rate structures can recoup the cost to build and operate the distribution infrastructure, and (ii) whether the associated cost-sharing is compatible with the continuing participation of users.

The paper begins with a summarized policy background of our study followed by our contribution to existing the literature. Then we show the methods used to build our model and the data used for our case study and then discuss our main results. Finally, we conclude with policy implications, our main intuition and further research or developments.

2. Our contribution

Some of the main papers on this topic are those of Abada et al. (2020a, 2020b). They study, using cooperative game theory models, trades in EC and show some insights on the stability of coalitions and on the significance of modifying network tariffs to internalize the "Utility Death Spiral" effect. In their work, they theoretically show conditions to obtain stable coalitions with non-empty core and optimal allocation values (Shapley and MinVar values) in the core (Abada et al., 2020a). However, they could not conclude that the core is always non-empty because of the lack of convexity of the optimization problem. They obtain empirical results that show a non- empty core with the optimality of the two previous allocation values. In case of heavy coordination costs, the grand coalition is not viable. They propose to split consumers into several smaller coalitions which are stable because of lower coordination costs. In the first paper, they do not introduce network tariffs. In the second paper (Abada et al., 2020b), they study the "Utility Death Spiral" but they called it the "snowball effect". They show that a per-capita network tariff is the best tariff to create stable coalitions and higher welfare. They compared the per-capita network tariff with a capacity-based or volumetric-based network tariff. All these tariffs must increase to deal with the financial equilibrium constraint of the DSO, but only per-capita tariffs are efficient (except for high coordination costs inside coalitions where volume-based tariffs are more efficient because of the smaller size of stable coalitions). However, unlike in Abada et al. (2020a and 2020b), our assumptions that will be discussed in the later sections lead us to results where we analyze the different ways of sharing the costs of the network between the different participants and we realize that charging the same value to consumers, as in Abada et al (2020b), is not always efficient. The non-discrimination clause must be changed in our new decentralized energy environment. Indeed, simple tariffs do not achieve allocations in the core. However, we sense that more complex pricing (three-part tariffs) could be suitable (CEER, 2017). Particularly, a DSO could charge these consumers different distribution tariffs considering their features (households or firms, self-consumers or not). Indeed, since Boiteux's works (1949), we know it could be efficient to differentiate tariffs between consumers to develop network industries. Non-discriminatory rules hold if consumers are in the same context, but not for all consumers. As such multi-part tariffs are complex, according to ACER (2023) it has to meet the need of all stakeholders by having requirements such as cost reflectivity so that the tariff reflects the actual cost of the service, maintaining and upgrading the network infrastructure, fairness which makes a balance between the interests of different stakeholders such as consumers, network operators and regulators and incentives for network operators to invest in the network's future and to operate the network efficiently. Schittekatte and Meeus (2018) also elaborate on the principles and theories of distribution network tariff design. This paper thus builds upon existing studies and proposes the use of more sophisticated pricing mechanisms to optimize cost allocation. The paper contributes to the understanding of DSOs' role in decentralized energy market trades and offers policy insights into the evolving energy landscape. They have discussed the ideas of cost reflectivity, cost recovery and fairness of distribution tariffs briefly. In Table 1, we have summarized the previous literature studies on tariff structures and cost allocation of distribution networks used in our study

Author	Focus of study	Methodology	Findings
Abada et al. (2020a)	Cooperative Game theory	Use of Shapley and MinVar to allocate optimate values to allocate costs that lie in the core	There exists a core but is not always non-empty
Abada et al. (2020b)	Snowball effect (Utility death spiral)	Comparison a per-capita tariff with traditional tariffs	Although per-capita tariff is efficient, more complex tariffs should be considered
Schittekatte and Meeus, 2018)	Network tariffs, energy communities	Literature studies ,case studies	DSO's role and pricing behaviours in energy market trades

Table 1: Summary of main literature

3. Methodology

The initial approach to achieve our objectives is to develop a quantitative model which determines a cost-efficient power distribution infrastructure for a set of network participants. The motivation to use this approach comes from the study by Abada et al. (2020a, 2020b). Contrary to their literature, we assume several different consumers, households and firms, are connected with the distribution grid at different locations. At first by construction, our engineering model provides an appropriate representation of the cost structure of a DSO. Then, we combine that model with a cooperative game theoretic approach to study the associated cost-sharing problem among network users. The "core" is used as the solution consisting of possible tariff allocations that allow cost- sharing among network users and prevent withdrawal from the community network which has the possibility of leading to the UDS. Using the core as a solution concept, we show that this representation makes it possible to test whether a given rate structure is capable to prevent UDS. With the optimal topology and the cost associated with it, we use different repartition methods (volume-based pricing, power capacity-based pricing, Shapley-value and standalone) to check whether a method can lie in the core of the problem. This allows us to discuss the different strategies that could be present in the problem and to compare the temptation to secede in the case where self-consumption is integrated into the model. We further test and analyze a three-part tariff structure by executing an optimization to maximize the incentive received by the community to achieve cost allocations that result in a more stable core. The following subsections describe the concepts used to build our quantitative model.

3.1 Network Infrastructure

In this empirical paper, we use an Integer Program (IP) to determine the optimal network for a set of given participants. In this model, we assume a tree network configuration as it is often the case in distribution grids. We also assume that all the energy flow comes from the "source" node (i.e. which can be interpreted as a link to a transmission network). The problem we want to solve is then a minimum spanning tree problem. The IP-formulation of the program can be found in Golari (2015). The constraints are there to make sure we have N-1 edges in the tree and that we have no cycle in the tree. The variable x defines whether or not an edge belongs to the tree.

The cost function i.e, cost (D,P,n) has been defined as having two parts as shown in *Equation 2*. The first one is linked to the initial investment cost and is a function of the total length of the network which we refer it as the Capital Expenditures (CAPEX). The second one is linked to the losses in lines and is a function of the length between each consumer and the source node which we refer to as the Operational Expenditures (OPEX).

$$\text{Minimize cost (D,P,n)} \qquad (1)$$

$$\text{Subject to } \sum_{i,j\in E}^{|s|} x_{ij} = n-1$$

$$\sum_{i,j\in E; i\in S, j\in S}^{|s|} x_{ij} \leq |S| - 1 \; \forall \, S \sqsubseteq V$$

$$x_{ij} \in \{0,1\} \; \forall i,j \in E$$

We model the costs of the establishment of a low voltage island network. The network will be represented by edges belonging to E and will be charged to link participants represented by nodes belonging to the set V. The source node is called v0 and the index “0” will refer to this source. Each participant “i” is characterized by a demand pi and each edge eij is characterized by a length dij. “j” could be another consumer or the source node v0. Indeed, as distribution networks are considered as radial networks, a consumer could be connected to another consumer (connected again to another consumer or at node v0) or directly at the v0 node.

The costs of establishing the network will be modeled by an investment term (I) and a loss term (L). The loss term is considered to be linearly proportional to the power demand and the length of the network. It is discounted over the lifetime of the infrastructure by a discount rate “r”. Thus, the cost of the network could be written as follow:

$$\text{cost (D, P, n)} = \text{I(D)} + \sum_{i=0}^{n} \frac{L(D,P)}{(1+r)^i} = \text{K} * \sum_{i=1}^{|V|} d_{0,i} + \sum_{i=0}^{n} \frac{k * \sum_{i=1}^{|V|} \left[d_{0,1} * p_j\right]}{(1+r)^i} \qquad (2)$$

With,

- D is the sum of the lengths of the selected edges (= the total length of the network).
- P is the sum of the yearly loads on each node.
- n is the lifespan of the investment. Its value is set as 40 years.
- r is the discount rate, fixed at 5%.
- K is the full infrastructure installation cost per km. We set it as 100 000€/km (Verderi, 2022).
- k is the cost of the losses per km-kWh-year.

Regarding our work, we could add additional hypotheses at this stage. The infrastructure is built “ex nihilo”. Indeed, we start from a set of consumers and we want to compute the total cost of an optimal network to connect them. This is the case in some rural zones or in isolated networks. The investment only allows to influence the losses by the choice of the topology.
There exists no possibility to choose between different cable technologies. Only one could be and is used to build the network. The demands are fixed for the network lifespan. We do not integrate at this stage the opportunity of an increase or a decrease in electricity demand, linked with some energy or environmental policies. Finally, we assume losses are linearly proportional to the demand and the distance.

In the context of an isolated grid, the cost associated with the losses will not depend on the wholesale electricity price but on the cost of the oversizing required due to these losses. The oversizing will only influence the production facility due to the fact that we are only considering a single cable technology.

The price at which the losses will be valorized will then be the LCOE of the production facility (since we are in an isolated market) and considered here at 0.1€/kWh, an estimation of solar panels LCOE computed in Pawel (2014). The losses applied to each participant are then computed as:

$$k_i = LCOE \cdot \frac{p_i}{d_{0,i}} \cdot \alpha \qquad (3)$$

With α a loss factor taken as 6% (average value computed with data from distributed network operator). k_i is the cost of the losses per km-kWh-year for each consumer, pi is the yearly load of each consumer and $d_{0,i}$ is the length of the edge of the network connceting each consumer.

Therefore after we find the network costs of all possible coalitions of network participants (sub-coalitions), the gametheoretic concepts of shapley and core is used (Peters, 2015). Then we try tariff allocation methods such as volume-based pricing, capacity-based pricing and shapley- based pricing. The idea is to test if these allocation methods lie in the core. If it does it means it would successfully recover the network costs and will stay in the grand coalition of the 4 community network. The results obtained are discussed in section 5.1. However, we further try to introduce incentives to obtain a more stable core. This is done by building an optimisation model

3.2 Mathematical representation of the optimisation model

A maximization program is developed and added to the model to determine a solution recovering the costs of the network i.e. cost (D,P,n) while lying, as much as possible, in the core. The solution to recover the grid costs is a solution such that the sum of all the fees required from all the network participants equals the total cost of the grid construction. A solution is in the core if the sum of the fees paid by the participant of all the potential collaborations or sub-coalitions (noted as Inv(s), with s referring to a sub-coalition) is always smaller than the cost of a subgrid optimally built for that coalition (noted as C(s), which is equal to the previously expressed cost (D,P,n) for a subcoalition 's')

The optimisation problem to be solved is formulated as:

$$\begin{aligned} &\text{Maximize } e \qquad (4) \\ &\text{Subject to } C(s) - Inv(s) \geq e \\ &C(N) = \text{total grid cost} \end{aligned}$$

If e > 0 the incentive received by a sub-coalition is to stay in the grand coalition and the solution remains in the core until when e < 0. To obtain a solution which is more stable, we have then to maximize e. In order to find the tariff that will maximize e, we test an invoice function Inv(s). The invoice function is taken to be a three part tariff

$$\begin{aligned} \text{Inv}(s) = \sum_{i=1}^{|S|} x_1 * V^{si} + x_2 * \text{P}^{si} + x_3 \\ x1 \geq 0 \\ x2 \geq 0 \\ x3 \geq 0 \end{aligned}$$

In this function, V^{si} refers to the volume of electricity consumed by i in the coalition s, and P^{si} refers to the power requested by i in the coalition s. The decision variables of the optimisation program are x1, x2 and x3 which are the coefficient of the tariff paid by each participant i of a coalition s for volume based pricing, power capacity based and fixed costs.

4. Our case study

The data used for our case study is discussed in this section. Consumers 1 and 2 stand for small and big firms respectively, 3 for households at a flat rate and 4 for households with Time of Use Tariffs (TOU). It is assumed that one residential neighborhood consists of 50 households to avoid the size effect in our analysis. The network topology considering all stakeholders is represented in *Fig 1 & 2.*

The first one with only "classical" consumers (further referred to as the base case) and the second one with a mix of classical and self-consuming parties (further referred to as the mixed case). The locations of the nodes, standing for each consumer or self-consumer, have been selected randomly. Self-consumption is introduced for consumers 2 and 4 for our case study. The consumers that self-consumer are selected in such a way that it represents half of the total consumers. However, this could have different possibilities of choosing which consumers to self–consume. Therefore we later test our results for the validity of our results with all possibilities in section 5

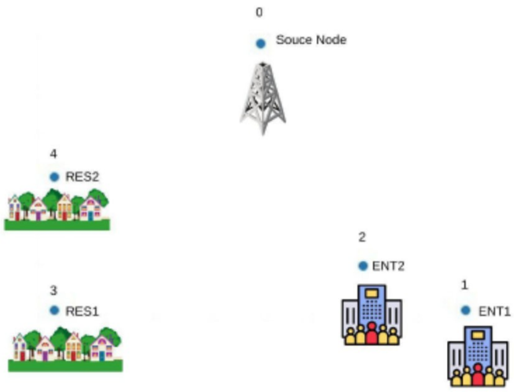


Figure 1- Network topology in the base case

The volume of electricity and power profiles for each type of participant is obtained from Clastres et al. (2021) for both cases. The consumer profiles are calculated for one year and are shown in *Table 2.* The consumption data comes from the sample provided by CRE to calculate the TURPE 5.

The subscribed power for classical and self-consumers are assessed from the maximal power demand for the time step with a margin for occasional spikes. The consumption by time range corresponds to average consumption for ENT1, ENT2, RES1 and RES2 with subscribed power (kW) of 74 kW for ENT1, 450 kW for ENT2 and 6 kW for one household. Therefore, for 50 households as it is not rational for all the households to be at their maximum capacity at the same time, we take the maximum power capacity to be 20% less which is 240kW. Similarly, the estimated maximum power capacity for self-consumers was estimated to be 120kW for RES2AC (3 kW for one household) and 364kW for ENT2AC

For the requested volumes (kWh/year), we find the total volume requested for one year for every consumer. One household is multiplied by 50 to obtain the profiles for the residence neighborhood. For the requested volume for the self-consumers in the mixed case, the self- consumption profiles are subtracted from the total consumption profile for the self-consumers ENT2AC and RES2AC.

	Base Case				**Mixed Case**			
Node	1	2	3	4	1	2	3	4
Consumption Profile	ENT1	ENT2	RES1	RES2	ENT1	ENT2AC	RES1	RES2AC
Requested volumes (kWh/year)	160579	2013939	150350	284550	160579	1659805	150350	203150
Subscribed Power(kW)	74	450	240	240	74	364	240	120

Table - Consumer profiles

5. Results and Discussion

5.1 Impact of self-consumption

In order to assess the impact of self-consumption on the optimal topology of the network, we tested both base and mixed cases. Interestingly, we observe that in both cases the optimal topology obtained with our optimization program stays the same (*Fig 2*). Thus, the network topology remains stable under the introduction of self-consumption.

This phenomenon comes from the fact that the costs linked to the establishment of the grid (CAPEX) represent a far greater percentage (around 90%) of the total cost of the grid compared to the costs linked to the electrical losses on the lines over the asset lifecycle (OPEX). In consequence, the topology of the network we obtain with our optimization program is not impacted by the self-consumption.
The results also remain the same for the all possible combinations of self-consumers that could be chosen which implies it is independent of which consumers chosen to self-consume in the network.

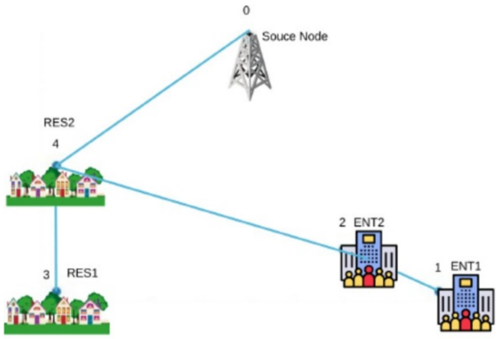


Figure 2- Optimal Topology for the network-base and mixed case

The *Figures 3&4* provides information about both use cases. The prices correspond to the yearly fees that the firms/neighborhoods (of 50 households) have to pay for the grid connection

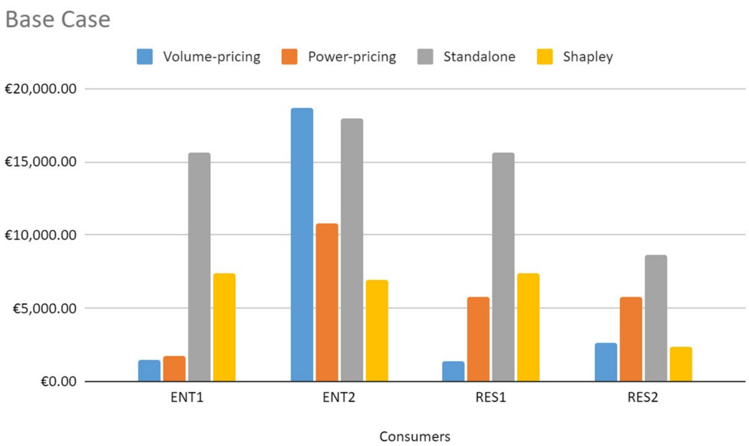


Figure 3: Cost-sharing methods-base case

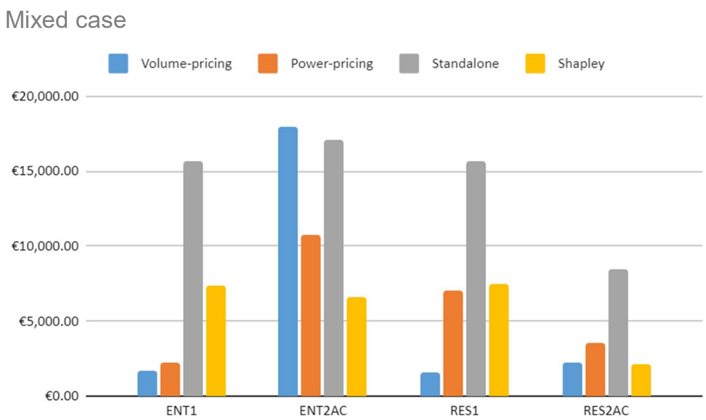


Figure 4: Cost-sharing methods-mixed case

If we compare both use cases, we observe that a cross-subsidy occurs between the classical and the self-consuming stakeholders for the volume and power-based tariffs. Indeed, the self- consuming participants will pay less in the “mixed case” than they would have paid in the “base case”. These reductions are partially compensated by the reduction of the losses on the grid (and thus by the discount on the total cost of the network), but not entirely and we observe an increase in the fees paid by the “classical” consuming stakeholders. This increase is around 15% for the volume-based tariff, and around 20% for the power-based tariff. Note that due to the way these tariffs are computed, the increase rates are the same for all the participants. These augmentations of the fees for the classical consumers might explain the small degradation of the proximity to the core for the mixed case compared to the base case (*Table 3*). Finally, it should be noted that the Shapley-based tariff does not allow these cross-subsidies and only reallocate given the grid structure. The rationale behind that might be linked with the discrimination process included in the Shapley value. Each consumer will pay a network tariff including its impact on the network. Thus, additional cost are allocated considering this rule; the increase for each consumer reflects it. As in the literature, we also show that, in both cases, a core exists (i.e. an allocation of network costs between coalition members exists such that there is no sub-coalition that would have an incentive to build the network for themselves). Sharing the cost and paying the network tariff is always profitable considering each stand-alone cost. However, simple network tariffs only based on a capacity or a volumetric methodology are not lying at the core of our problems. Indeed, as shown in *Table 4*, a large number of coalitions of consumers have incentives to leave the coalition to invest by themselves. We observe that the tariff based on the Shapley values is at the core in the mixed case. Contrary to the capacity or volume-based tariffs, using the Shapley values allows for discrimination in the function of the position of the node. For instance, node 4 which is quite close to the source and allows all the others to reuse its connection has a clear advantage in this system in both cases. On the other hand, node 3 which has the same consumption profile (for both cases) but which needs to build a line only for him will pay much more. Coalitions outside the core in the Shapley allocation are those in which one of the residential self-consumer is outside the coalition. *Table 3* shows the « proximity » to the core for the different allocations. The average percentage of exceeding costs should be understood as the average percentage of the exceeding costs for the coalitions that have an incentive to leave the great coalition.

	Coalitions with incentive to secede	Avg % of exceeding costs
Base Case		
Volume based pricing	5	11.6%
Power capacity based pricing	2	8.15%
Shapley based pricing	1	0.007%
Mixed Case		
Volume based pricing	5	10.6%
Power capacity based pricing	1	7.5%
Shapley based pricing	0	0

Table 3 - Core Analysis

We observe that shapley allocation for the mixed case lies in the core. The introduction of self-consumption has indeed increased the proximity to the core.

However, we also observe that contrary to the literature of Abada et al. (2020a, 2020b), the existence of households and firms in our model could introduce incentives for high electricity- consuming stakeholders to leave the coalition because of lower stand-alone costs. According to these results, and contrary to the literature, we could conclude that simple pricing is not sufficient and must evolve towards multi-part network tariffs (a capacity, a volumetric and a fixed part for instance). Thus, this result, added to the analysis of the Shapley value, shows it could be optimal to differentiate network tariffs between network users.

This section reports and discusses the results obtained while executing the optimization program for a three-part (volumetric, capacity based and fixed costs) network tariff structure. We take the mixed case where there is self-consumption introduced and test if the model has a non- empty core and whether there exist tariffs when there are incentives to stay in the grand coalition. We found that we obtain a non-empty core and then test if the obtained optimal tariffs recover the total network cost. The distribution of the three-part tariff for a range of optimal e-values is obtained. The maximum value of incentive (e_{max}) is when we obtain the most stable core. Although we obtain solution for e_{max} we perform a sensitivity analysis by obtaining the set of solutions when e is increasing between 0e e_{max} as shown in *Figure 5*, at first the distribution of tariffs is such that the decrease in the volumetric tariff is compensated by the increase in fixed costs and then there is an increase in the capacity tariff which results in a decrease in the fixed term

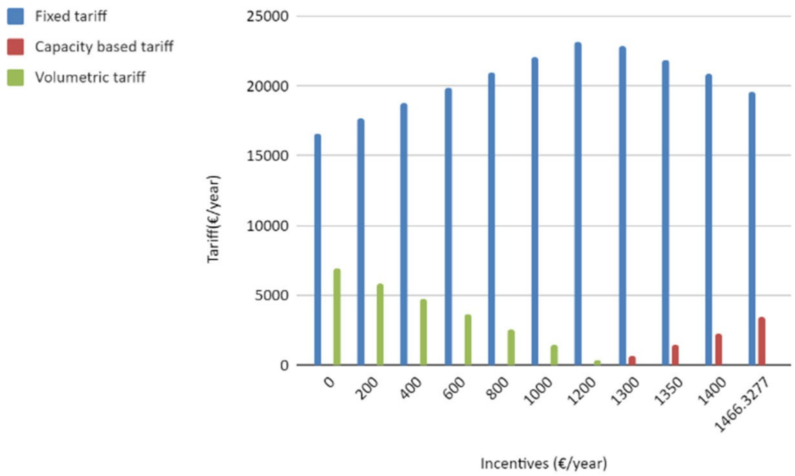


Figure 5 - Three part tariff for all participants

Figure 6 shows the total Invoice(Inv(s)) for each participant and their contribution to recover the total network costs along with their Shapley allocation. Hence, it is true that there exists a non- empty core with various distributions of invoices consisting of a three-part tariff structure that recovers the total cost of the network. It is understood that when the invoice depends mainly on the fixed costs, there is no differentiation of the total invoice paid by each consumer and every participant pays the same. When there is a variable term such as capacity or volumetric tariff, there is a differentiation in the invoice paid by each participant. *Fig 6* indicates that with the increase in the variable part of the tariff (volumetric/capacity), the invoice paid by ENT2AC increases while ENT1, RES1 and RES2AC decrease. The invoice when e is smaller could be termed as the fairest as it reflects the energy consumption profiles of each participant *(Table 2)*. The only way consumers could increase the incentives would be by reducing the variable part of their invoices. Therefore, using a uniform tariff for all consumers have a volumetric, capacity and a fixed term. We see that a two-part tariff (variable terms) is efficient in recovering the DSO's network costs and creating incentives to stay in the coalition. The flexible part of the tariff (variable terms) differs according to the stability of the core. If the stability is weak for only the volumetric term, it is replaced by the capacity term to make the stability stronger as it is less volatile. However, to stay in the core, the pricing must always be a function of consumption or capacity contracted. Indeed,the weakness of our solution in the core (e=0) introduces incentives to differentiate tariffs with a more volatile part between consumers, the volumetric part. Charging an additional fixed fee is for the recovery of fixed costs. As the solutions in the core become stronger, the fixed and less differentiated part of the tariff (capacity part) is more efficient to avoid incentives to withdraw from the grand coalition, recovering all fixed costs. In *Figure 6* we also see the comparison of the multi-part tariff with the Shapley allocation. The difference is that in Shapley allocation RES1 pays higher due to its higher fixed costs, RES2 pays lower and so on and it does not depend on their consumption or capacity contracted.

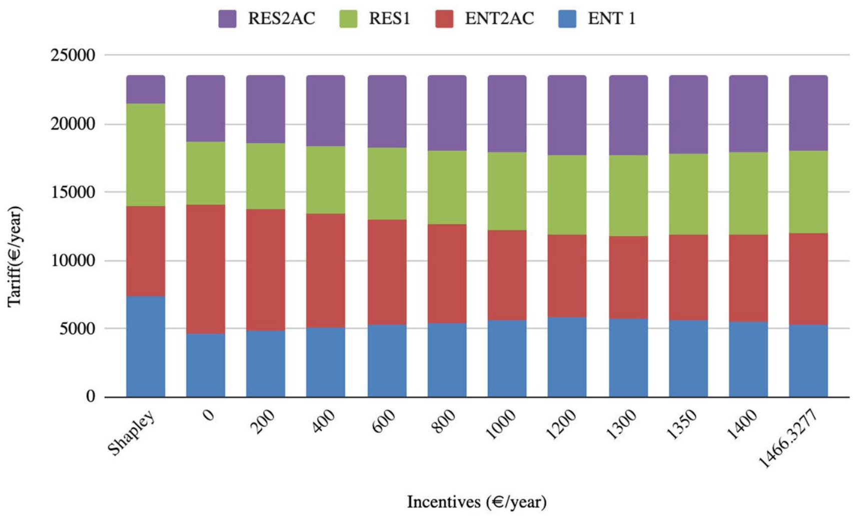


Figure 6 - Invoice of participants

However, this distribution is when the coefficient of the tariffs (x1, x2 and x3) are considered to be uniform for all participants. It is therefore interesting to test if there exists a more optimal way for the distribution of invoices of the participants when the tariffs are differentiated based on the type of participant. In the following 2 cases, the optimisation is executed when tariffs are differentiated based on two criterias: Case 1-Firms or Households, Case 2-Self consumers and classical consumers.

Case 1: Tariff differentiation between firms and households

In this case, we see that there does not exist a volumetric tariff when e > 0. The invoices are dependent on the capacity tariff for households and (capacity + fixed) for firms as shown in *Fig 7*. The invoices in *Fig 8* show that with the increase of the variable part of the invoice, RES 1, RES 2 and ENT 1 pay more while ENT2AC pay less which is when e is smaller. The invoices of RES1 and RES2 reflect their power profiles in *(Table 2)* as they only have a capacity tariff. So here again we could understand that with a small value of e, we could have a fair tariff distribution. Again, this also means to receive higher incentives the participants need to reduce the variable part of their invoices. It is however interesting to observe that the maximum incentive that can be received to stay in the grand coalition is higher in this case as compared to when the tariffs are uniform.

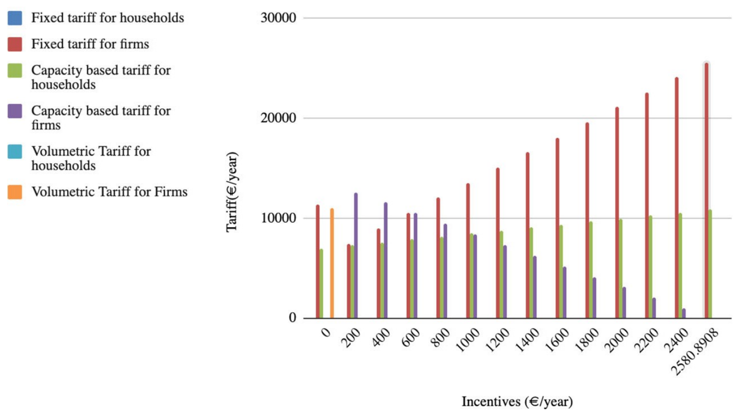


Figure 7 - Three part tariff for all participants-case

These results imply that differentiating tariffs between firms and residences results in fair tariff invoices with a larger incentive to stay in the grand coalition. The comparison with the Shapley allocation again implies that multi-part tariff is more reflective of the consumer profiles while Shapley allocation only depends on the fixed costs.

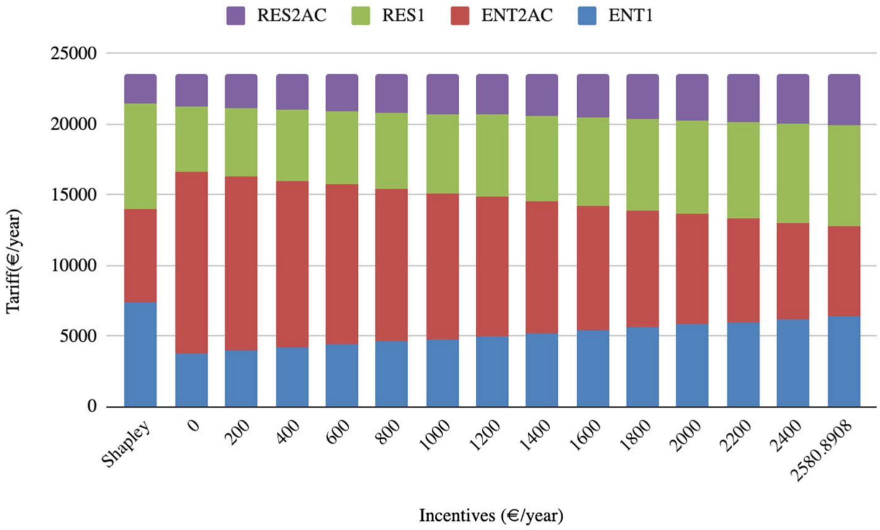


Figure 8 - Invoice of participants for case 1

<u>Case 2: Tariff differentiation between classical and self-consumers</u>

This case differentiates the tariff between classical and self-consumers. There exists a volumetric and fixed tariffs for self-consumers and only volumetric tariffs for classical consumers as shown in *Fig 9*. There does exist a capacity tariff in this case. The invoices for these tariffs in *Fig 10* show similar patterns as in the previous case which is with the increase of the variable part of the invoice, RES 1, RES 2 and ENT 1 pay more while ENT2AC pay less which is when e is smaller. They could increase their incentives in a fair way when self-consumers reduce the volumetric part of their invoices. The maximum incentive that can be received to stay in the Grand coalition is higher in this case as compared to when the tariffs are uniform but is lower than in Case 1. Similar to the previous case, here again, we see the difference between the Shapley allocation and the multi-part tariff as Shapley only depends on the fixed costs and not the consumption or capacity contracted by the consumers.

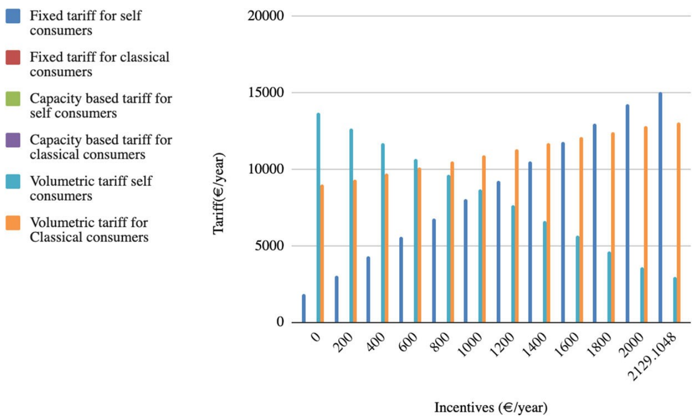


Figure - Three part tariff for all participants-case 2

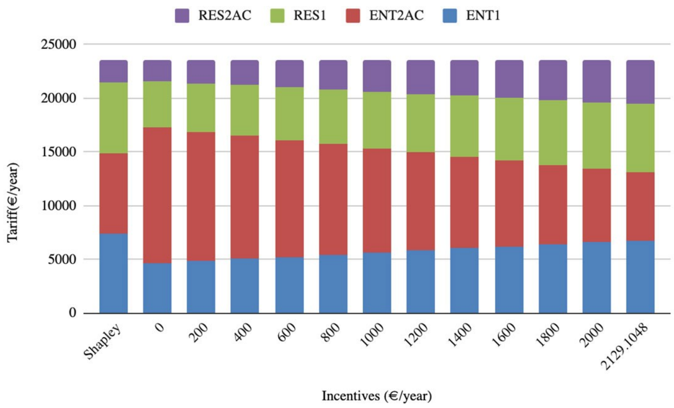


Figure10 - Invoice of participants for case 2

6. Conclusions and policy implications

This section discusses the fairness of a tariff allocation for a group of network participants. ACER (2023) has made it a requirement for a distribution tariff to be fair. Therefore, we mention a few criteria which could be used to measure this fairness.

Fairness could be measured by considering the needs and characteristics of different consumer groups. The tariffs should be designed taking into account the different types of consumers such as households, commercial or industrial (CCP, 2018). This ensures fairness as their energy usage patterns are not similar to each other, their tariff rates should be different.
The tariff should also take into account vulnerable consumers such as including a social tariff providing discounts and benefits to low-income households (ACER, 2023). This would be considered fairness in the social context by protecting vulnerable consumer groups.
Finally, a fair tariff should be easy to understand and transparent (CCP, 2018). Consumers can make informed choices by knowing about the pricing structures and controlling their energy usage and costs. There should be communication between stakeholders in the community to ensure transparency.

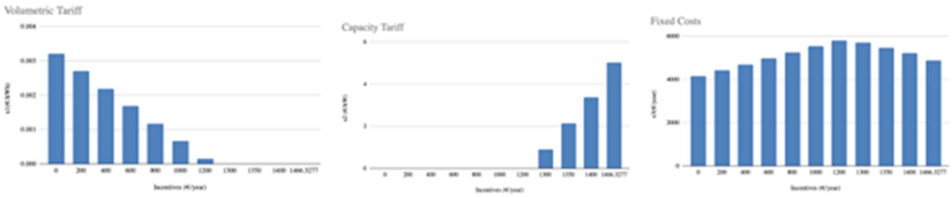
In Europe, the debate on self-consumption and energy communities, as well as tariff structures, is gaining momentum. This study presents a quantitative tool to evaluate the relevance of a specific tariff structure for a community that needs to establish its own infrastructure. By utilizing cooperative game theory concepts such as the core, we demonstrate that optimal distribution of network costs among coalition members is possible. Our analysis shows that self- consumption has a lesser impact on the optimal network topology compared to the influence of capital expenditure (CAPEX). However, we acknowledge the significance of the "Utility Death Spiral" and propose that new network allocation costs should account for it. Simple allocations are insufficient, and a multi-component network tariff approach, rather than focusing on a single aspect like capacity, seems promising. Consequently, we examined a three-part network tariff and achieved a fair distribution of uniform and differentiated tariffs among network participants. This suggests the potential for differentiated tariffs not only between consumers (households and businesses) but also between traditional and self-consumers, as observed in France. Our results, for both uniform and differentiated tariffs, indicate a fair invoice allocation without cross-subsidies when the incentive is lower, primarily influenced by the variable part of the invoice rather than the fixed cost. However, introducing tariff differentiation increases incentives. The recent decision by the French regulator to establish special network tariffs for self-consumers within the TURPE 6 scheme aligns with this direction and could enhance network cost recovery. Nevertheless, suboptimal tariff design could worsen the situation or reduce incentives for self-consumption.

Higher network costs for self-consumers incentivize investment in off-grid solutions, provided they remain profitable compared to the disparity between traditional and self-consumer network costs. This, in turn, escalates the "death spiral." If the difference in network costs is too small, self-consumption investments become unprofitable, diminishing its attractiveness and potentially impacting renewable energy development and network management. Therefore, continuous research in this area holds significant value for the future. Although we have gotten our desired results for our case study, it would indeed be interesting to test our model with a network consisting of more participants with different types of loads. Another prospect of future research would be to further evaluate the fairness of the tariff allocation methods implemented, especially the multi-part tariff structure when it is differentiated.

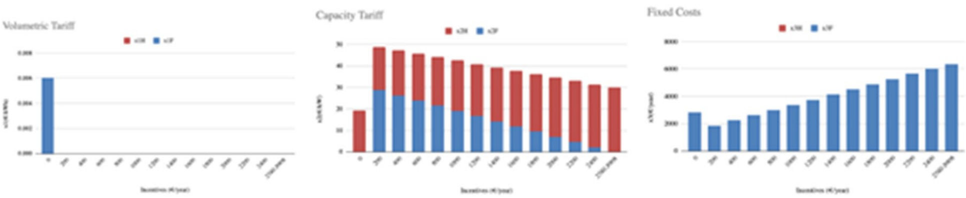
Apendix

The figures below show the unit Tariffs for each participant for all cases:

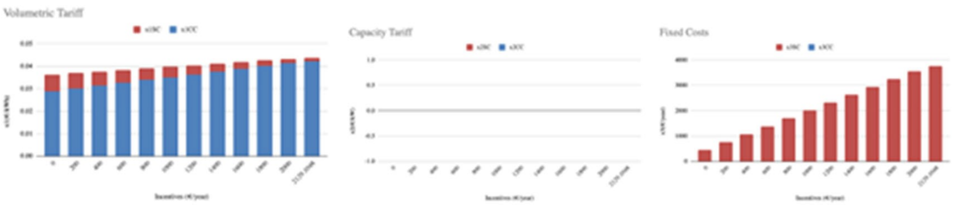
Uniform tariff:



Case 1:



Case 2:



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Olalekan Omoyele, Titan Hartono, Jann Michael Weinand, and Jochen Linßen

ETHOS.TISED: A PYTHON PACKAGE FOR TEMPORAL DOWNSCALING OF SOLAR IRRADIANCE

Olalekan Omoyele, Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems – Jülich Systems Analysis (ICE-2),52425 Jülich, Germany, Email: o.omoyele@fz-juelich.de
Titan Hartono, Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems – Jülich Systems Analysis (ICE-2), 52425 Jülich, Germany, Email: t.hartono@fz-juelich.de
Jann Michael Weinand, Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems –Jülich Systems Analysis (ICE-2), 52425 Jülich, Germany, Email: j.weinand@fz-juelich.de
Jochen Linßen, Forschungszentrum Jülich GmbH, Institute of Climate and Energy Systems –Jülich Systems Analysis (ICE-2),52425 Jülich, Germany, Email: j.linssen@fz-juelich.de

Overview

Accurate modeling of solar energy systems often requires high temporal resolution irradiance data. However, such data are not available globally. This study introduces a tool, ETHOS.TISED, to convert coarse-resolution hourly Global Horizontal Irradiance (GHI) data into high-resolution 1-minute data. The approach entails a non- dimensional irradiance representation and statistically matched parameters derived from historical high-frequency observations. The framework is designed to be scalable and location-independent, making it ideal for renewable energy simulations, grid integration studies, and system design applications.

Method

The methodology of the tool under consideration begins with the non-dimensionalization of solar irradiance and time into a high-resolution profile. This is achieved by normalizing GHI values with its extraterrestrial irradiance and the time between sunrise and sunset. Key daily parameters are extracted from reference minute-resolution datasets across diverse locations, with enhancement made to cover the entire range of Köppen-Geiger weather classification. These parameters include the clearness index, variability index, distribution, normalized variability index, and integrated complementary cumulative distribution function. The daily parameters are equally derived from the hourly resolution data to be downscaled and are then matched to the key daily parameters of the high- resolution profile using k-nearest neighbor machine learning algorithm. The corresponding synthetic high- resolution profiles that are consistent with both the diurnal cycle and intra-hour dynamics are obtained. The method has been implemented and is undergoing constant development in Python, with open access on GitHub (https://github.com/FZJ-IEK3-VSA/ETHOS.TISED) and has been validated using data from diverse climate zones.

Results

The model demonstrates strong performance across various geographic locations with diverse years. When evaluated against reference ground-truth minute-resolution data, the synthesized time series achieves a normalized Root Mean Square Error between 5 and 7% and a Kolmogorov–Smirnov integral between 0.1 and 0.7, indicating good agreement in distributional characteristics. Energy system case study of a self-sufficient building shows significant improvements in the cost accuracy of the system and the components sizing when using the high- resolution synthetic data compared to the original hourly data.

Conclusions

This study presents a robust and global downscaling tool for solar irradiance, offering an efficient alternative to physics-based or satellite-driven approaches. Its capacity to generate realistic minute-level GHI from hourly data— with minimal computational overhead—makes it particularly valuable for researchers and practitioners in energy modeling, system optimization, and renewable integration planning.

The framework is publicly available and designed to be extensible to other variables such as direct normal irradiance or diffuse horizontal irradiance. The outlook can generate data at varying temporal resolution between one hour and one minute resolution for all locations and weather classe.

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Marco Cappellari, Giovanni Cappena, Arturo Lorenzoni

EXPLORING THE ROLE OF OFFSHORE WIND IN ITALY'S 2050 ENERGY MIX: A SCENARIO-BASED ANALYSIS USING ENERGYSCOPE TDS

Marco Cappellari, Department of Industrial Engineering at University of Padua,
Email: marco.cappellari.2@phd.unipd.it
Giovanni Cappena, Department of Industrial Engineering at University of Padua,
Email: giovanni.cappena@unipd.it
Arturo Lorenzoni, Department of Industrial Engineering at University of Padua,
Email: arturo.lorenzoni@unipd.it

Overview

The transition to a carbon-neutral energy system requires strategic deployment of renewable technologies. In Italy, the offshore wind sector—particularly floating offshore wind—has significant untapped potential due to the country's deep coastal waters. This study investigates the techno-economic implications of including offshore wind in the Italian energy mix by 2050, using the EnergyScope TD open-source model. The aim is to assess how this technology could affect the overall system configuration, emissions, and investment costs.

Methods

Two snapshot scenarios for the year 2050 were modelled using EnergyScope TD, a bottom-up, techno-economic optimization tool. In Scenario 1, offshore wind is excluded from the system, while in Scenario 2, up to 15 GW of floating offshore wind is deployed, representing the estimated technical potential.
The model minimizes total system costs while meeting hourly energy demands and ensuring sectoral coupling (electricity, heating, mobility). Inputs include technology-specific CAPEX, OPEX, efficiency, lifetime, and CO_2 intensity, aligned with projections for 2050. Emissions constraints were applied to both scenarios to reflect EU decarbonization targets.

Results

The analysis performed using EnergyScope TD will compare the two modelled future scenarios, in particular regarding the final energy mix and its impacts on environment and economy.
This study will provide as outcome:
- CO_2 emissions decrease passing from one case to the other;
- System cost analysis (CAPEX and OPEX) comparison;
- Energy generation mix for Italy in 2050, with or without offshore wind.

Conclusions

Including floating offshore wind in Italy's 2050 energy mix has clear benefits in terms of emissions reduction and diversification, with only a modest cost increase. It enhances the system's resilience and supports decarbonization while reducing dependency on land-intensive renewables. Policymakers should consider offshore wind as a core component in long-term national energy planning.

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Federico Parolin, Andrea Capitali, Stefano Campanari, Paolo Colbertaldo,

THE IMPACT OF DISTRIBUTED POWER GENERATION ON STORAGE AND INFRASTRUCTURE IN NET-ZERO SCENARIOS

Federico Parolin, Department of Energy, Politecnico di Milano, Email: federico.parolin@polimi.it
Andrea Capitali, Department of Energy, Politecnico di Milano, Email: andrea.capitali@mail.polimi.it
Stefano Campanari, Department of Energy, Politecnico di Milano, Email: stefano.campanari@polimi.it
Paolo Colbertaldo, Department of Energy, Politecnico di Milano, Email: paolo.colbertaldo@polimi.it

Overview

The pathway to decarbonisation is strongly based on the increased penetration of renewable energy sources in the energy systems. The main actors are solar photovoltaic (PV) and wind power plants, featuring the largest potential for installation. Their power output can be delivered to end uses in the form of direct electrification or via conversion into clean energy vectors (hydrogen, e-fuels, …). Several studies have developed or adopted energy system models to investigate the need for generation and storage capacities to supply the expected demands, with increasing complexity in terms of spatial and temporal resolutions as well as range of sectors included. A common feature of energy system models is the copper plate assumption, i.e., the absence of grid constraints or congestion issues within each spatial node. This corresponds to neglecting the interaction of transmission and distribution networks, which is instead receiving increasing attention by grid operators as growing local congestions and larger upward energy flows (i.e., transfer of electricity from low- to high-voltage lines) are observed. To address this topic, we have developed a multi-layer formulation to model the electricity network and we have implemented it in an energy system model to assess the impact on capacity distribution among layers and on inter-layer exchanges.

Methods

This work adopts OMNI-ES (Optimisation Model for Network-Integrated Energy Systems) [1], a bottom-up integrated energy system model with multi-vector and multi-sector description, which enables the investigation of cost-optimal, emission-constrained scenarios at country scale. The model features hourly temporal resolution and regional spatial resolution, with perfect-foresight approach, and the objective function is minimum total annual cost.

In this study, the linear programming formulation in OMNI-ES is extended to improve the accuracy in modelling the electricity network. This is done by introducing three layers in cascade in the electricity network, which reflect the voltage levels of real-world grids (high, medium, low voltage – HV, MV, LV), though the energy balances refer to active power and there is no aim for optimal power flows. The goal is to assess, with a relatively simple model applied on a complex integrated energy system, the behaviour of the system in terms of upward and downward energy flows as well as the changes in installed capacities.

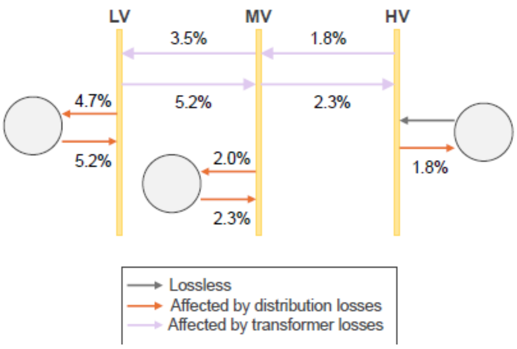

Figure 1 - Graphical description of the interactions between electric network layers and generation/demand nodes, with indication of the assumed losses (values from [3]).

The analysis looks at the Italian energy system, in a 2050 full-decarbonisation scenario, comprising the use of electricity, methane (biogenic or residual fossil), hydrogen, and liquid fuels (either bio- or e-fuels), with exogeneous final demands representing the residential, tertiary, industrial, and transport sectors. Techno-economic assumptions reflect expected costs of technologies by 2050. The three-layer level of the electricity network is schematised in *Figure 1,* with the indication of energy losses, which are allocated to transformers (orange) and/or lines (purple).

Traditionally, electric grids have been designed for electricity delivery from higher to lower voltage levels. To account for the unconventional operation of the electric grid, a cost is associated to the electric energy flowing from a lower to a higher voltage through a transformer. This uplift cost (ULC) is assumed equal for low-to-medium and medium-to-high flows and is subject to sensitivity. The associated expenditure is included in the objective function.

Results

The analysis considers the Italian energy system, constrained to net-zero CO_2 emissions (direct and supply chain- related). Main indicators are the distribution of renewables and storage units, as well as the upward electricity flows.

Figure 2 shows that electricity exchanges from MV to HV are more relevant than LV-MV flows, which are very small even for a null uplift cost (<2 TWhe/y, less than 0.3% of total electricity consumption). This reflects the larger share of electric loads in the MV layer and the lower installation costs in this segment.

The upward flows rapidly decrease as soon as a positive uplift cost is introduced. Even with a minimal economic penalty (the first data entry on x-axis is 10 €/MWhe, in line with current average transport fee in Italy), electricity transit on HV-MV exchanges drop from 10% to 1-2% of the total electricity consumption. A plateau occurs when the uplift cost exceeds 90 €/MWhe (order of magnitude of the electricity market price), essentially removing all upwards exchanges and stabilizing the system configuration (invariant TAC). The impact of upward flow constraints on TAC is minimal, estimated in a 1% increase from null uplift costs to the plateau.

In terms of capacity distribution, the main variations at increasing uplift cost affect flexibility systems, with a 30- 50% reduction of battery and electrolysis capacities in the HV layer, balanced by growth in the MV layer. A slight reduction of PV installations in the LV layers is balanced by an increased presence of wind plants in the HV layer, redirecting the system towards conventional downward operation. Impact on curtailment and import is minimal.

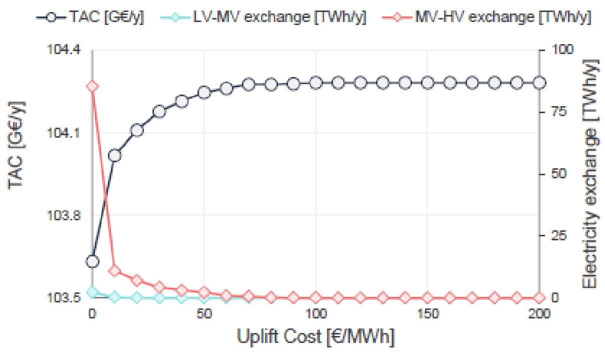

Figure 2 - Impact of the uplift cost on TAC (blue line, left y-axis) and on upward electricity exchanges (right y-axis).

Conclusions

This analysis highlights the relevance of tracking the multi-layer structure of energy networks (here focusing on the electric grid, possibly relevant also for gaseous energy vectors) and shows that accounting for this complexity imposes constraints that may affect the investment effectiveness and the infrastructural needs. Overall, this kind of results offers insights to decision makers to evaluate suitable solutions, balancing trade-offs between costs, technology adoption, social acceptance, and other priorities, in order to account for the needs of the multiplicity of stakeholders involved in the energy transition towards decarbonisation.

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Federico Rossi, Carlo Zanchetta

SEMANTIC DATA EXCHANGE IN BIM TO BEM WORKFLOWS USING IFC AND SQL-BASED MAPPING

Federico Rossi, University of Padua, Email: federico.rossi.7@phd.unipd.it
Carlo Zanchetta, University of Padua, Email: carlo.zanchetta@unipd.it

Overview

The construction sector high energy footprint makes it necessary to optimise the thermal behaviour of buildings by promoting efficient design solutions. This can be achieved by using energy analysis tools from the earliest design stages. Building Information Modelling (BIM), a digital methodology for creating and managing building information models, supports this process. The BIM-to-BEM (Building Energy Modelling) methodology is becoming increasingly popular as an innovative way to automate the flow of information between the BIM architectural model and the BEM energy model. The latter constitutes an analytical representation of a building, aimed at calculating its energy performance. (Andriamamonjy et al., 2019).
However, despite the methodology significant potential, interoperability between BIM and BEM remains challenging due to differences in the languages and building representation methods adopted in their respective domains (Gao et al., 2019). It is therefore essential to analyse existing information standards and develop an interoperable toolchain to connect the two domains.

Methods

In the BIM to BEM methodology, two main critical issues regarding interoperability arise: first, the reconstruction of the building geometry within the energy model (Nektarios Lilis et al., 2021); and second, the transmission of alphanumeric information, i.e. metadata describing the physical and performance characteristics of building elements (Miller et al., 2025).
This paper focuses on the latter challenge by proposing a new framework for the semantic transfer of data from BIM to BEM. The entire methodology is based on the Industry Foundation Classes (IFC) data model, which is an open information standard for representing data in the construction industry.
Performance calculations in energy simulation software are often structured on relational databases, which are built in accordance with the main energy calculation standards, and access to these databases provides an understanding of the logical data structure. This enables consistent mapping between BEM and BIM.
In parallel, the IFC file can contain the information required for the calculation, subject to the availability of the standard. In this sense, the methodology proposed by Bock and Eder for translating the IFC data model into the SQL language enables the creation of interoperable interfaces between BIM models and simulation environments (Bock & Eder, 2021/2025).
These assumptions ensure that an automated, semantically consistent transfer of energy data to the BEM model can be implemented. This starts with reorganising the alphanumeric information contained in the IFC model according to the logic of the BEM domain.

Results

Defining a standardised workflow for information exchange between BIM and BEM has multiple positive implications. Firstly, adopting neutral protocols increases interoperability between the two domains, overcoming current fragmentation. The proposed methodology, based on the IFC data model, guarantees the automatic transfer of data and the preservation of its technical meaning within the energy model.
Consequently, information already present in the BIM model can be effectively reused, reducing the need for manual intervention by designers and limiting the risk of errors. Automating data transmission optimises the BIM-to-BEM process, making the design workflow more efficient and accelerating the energy simulation phases.

From a business perspective, scalability and reusability of the process also become key factors. The proposed framework can indeed be replicated on different projects and easily adapted to heterogeneous contexts. This approach enables the BIM-to-BEM workflow to be permanently integrated into operational processes.

Conclusions

The highlighted results demonstrate the potential of an interoperable Building Information Modelling (BIM) to Building Energy Modelling (BEM) methodology in the building energy efficiency process. While the increase in interoperability leads to significant improvements in the design workflow, the challenge is far from over. In fact, despite the potential offered by the IFC standard, its current level of development does not permit complete coverage of the energy domain; hence the necessity to extend the data model.

Looking to the future, extending the information exchange in both directions (including the return of BEM results within the BIM model) will allow all information to be centralised in a single location. This integration ensures effective data sharing in subsequent design phases, such as plant dimensioning.

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Adonis Yatchew

NARRATIVES AND THE INTERDISCIPLINARY NATURE OF ENERGY

Adonis Yatchew, University of Toronto, Email: adonis.yatchew@utoronto.ca
Editor-in-Chief Emeritus, The Energy Journal, 2006-2023

Overview

Energy challenges and policies cannot be understood in isolation from the narratives that shape technological, political, and social evolution. This paper explores three historical and cultural narratives — advances in sailing and navigation, Victor Hugo's Les Misérables and its framing of state–individual relations, and the modern 'resource curse' exemplified by Russia — to illustrate how energy is embedded in broader human stories. By examining these episodes, the paper highlights the role of innovation, governance, and institutions in shaping energy outcomes across civilizations.

Methods

The approach is interdisciplinary, weaving together historical accounts, literary analysis, and political economy. Each narrative is treated as a case study to uncover the mechanisms through which energy and resources interact with societal structures. Comparative methods are used to connect disparate episodes — the Bernoulli principle and sailing innovation, debates on market versus government responsibility, and the influence of oil and gas wealth on democratization — under the unifying theme of how narratives frame energy and institutional development.

Results

The analysis reveals three central insights. First, technological narratives (such as sailing innovations) demonstrate how scientific principles underpin shifts in global trade and geopolitics. Second, literary narratives (such as Les Misérables) anticipate debates on state authority, market failures, and regulation, which became pivotal in the 20th century's energy economy. Third, resource narratives (as in Russia's oil and gas wealth) highlight how energy abundance can hinder democratization, strengthen authoritarianism, and shape alliances. Across these domains, energy emerges as both an enabler of progress and a driver of conflict.

Conclusions

Narratives are essential tools for understanding the energy landscape: they embed technical, political, and social elements in accessible and enduring forms. By tracing these stories, we see that energy policy must be contextualized within long arcs of history and institutions. Such an approach underscores that innovation and sustainability are not solely technological but also political and social. The paper argues that engaging with narratives enhances our understanding of energy transitions, governance, and the prospects for sustainable and democratic futures.

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Fakhri Hasanov, Naser Odeh, Carlo Andrea Bollino, Heyran Aliyeva, Majed Almozaini

ASSESSING THE ECONOMIC AND SECTORAL IMPACTS OF CARBON CAPTURE AND STORAGE INTEGRATION IN KGEMM

Fakhri Hasanov, Energy Macro & Microeconomics Department, KAPSARC, Riyadh, Saudi Arabia
Naser Odeh, Energy Macro & Microeconomics Department, KAPSARC, Riyadh, Saudi Arabia
Carlo Andrea Bollino, Visiting Fellow, KAPSARC, Riyadh, Saudi Arabia, 3 University G. Marconi, Rome, University of Perugia, and LUISS University, Rome
Heyran Aliyeva, Energy Macro & Microeconomics Department, KAPSARC, Riyadh, Saudi Arabia
Email: heyran.aliyeva@kapsarc.org
Majed Almozaini, Energy Macro & Microeconomics Department, KAPSARC, Riyadh, Saudi Arabia

Introduction

As a developing and oil-exporting country, two aspects are crucial for Saudi Arabia: maintaining economic growth and transitioning to a more sustainable, low-carbon economy. Recognising its role in global climate efforts, the Kingdom has significantly expanded its environmental and climate policy initiatives in recent years. These include the Circular Carbon Economy (CCE), Saudi Green Initiative (SGI), the Middle East Green Initiative (MGI) in 2021, and the net-zero emission goal by 2060.

Saudi Arabia has set a headline CCS target of 44 million tons of CO_2 emissions by 2035 as a pillar of the Kingdom's long-term climate strategy. This goal was first announced under the Saudi Green Initiative during COP27 and is already being translated into concrete projects. A flagship CCS hub in Jubail Industrial City, developed by Aramco with Linde and SLB, is scheduled to begin operations in 2027 and aims to capture up to 9 million tons of CO_2 per year in its first phase by 2028. Additional hubs are also planned for Yanbu and other industrial clusters.[7]

From a policy perspective, this target serves several purposes. It operationalizes the Kingdom's "Circular Carbon Economy" framework and its net-zero-by-2060 pledge, signaling that large-scale carbon management is Saudi Arabia's preferred decarbonization pathway. The scale of the commitment, as one of the world's largest national CCS ambitions, also positions Saudi Arabia to market low-carbon hydrogen, ammonia, and petrochemicals while retaining its role in global energy supply, setting a regional benchmark, and raising the bar for peer exporters.[8]

This policy target is the best option for scenario analysis to practically implement the CCS framework developed in this study. Additionally, this would provide understanding and insights into sectoral and macroeconomic implications of the announced target, which would be useful for policy decision-making, as it would bring together environmental and economic dimensions.

To support both environmental goals and economic development, it is essential to view CCS not in isolation, but as part of the overall economic system. While reducing greenhouse gas emissions, carbon capture and storage (CCS)-related activities, particularly demand for goods and services from domestic economic activities, may bring economic benefits. Moreover, financing CCS projects may crowd out other public- or private-sector investment, depending on who bears the cost. It is therefore helpful for decision-makers to have a better understanding of the economic implications of CCS deployment.

Methodology

The present study develops a CCS module in the KAPSARC Global Energy Macroeconometric Model (KGEMM) to assess macroeconomic and sectoral impacts of CCS deployment in Saudi Arabia. Then it takes the official announcement of capturing 44 million tonnes of CO_2 by 2035 as a policy-relevant case study and quantifies its macro-sectoral and emissions reduction effects. To be more useful for decision-making, three scenarios are designed in terms of the financing mechanism of the announced CCS in addition to business as usual (BaU). In the first scenario, it is assumed that Saudi Arabia's foreign reserves will finance all the associated costs of the announced CCS.

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[7] https://www.arabnews.com/node/2197841/business-economy; https://ccushub.ogci.com/saudi-arabia-plans-one-of-the-largest-ccs-hubs-in-the-world/

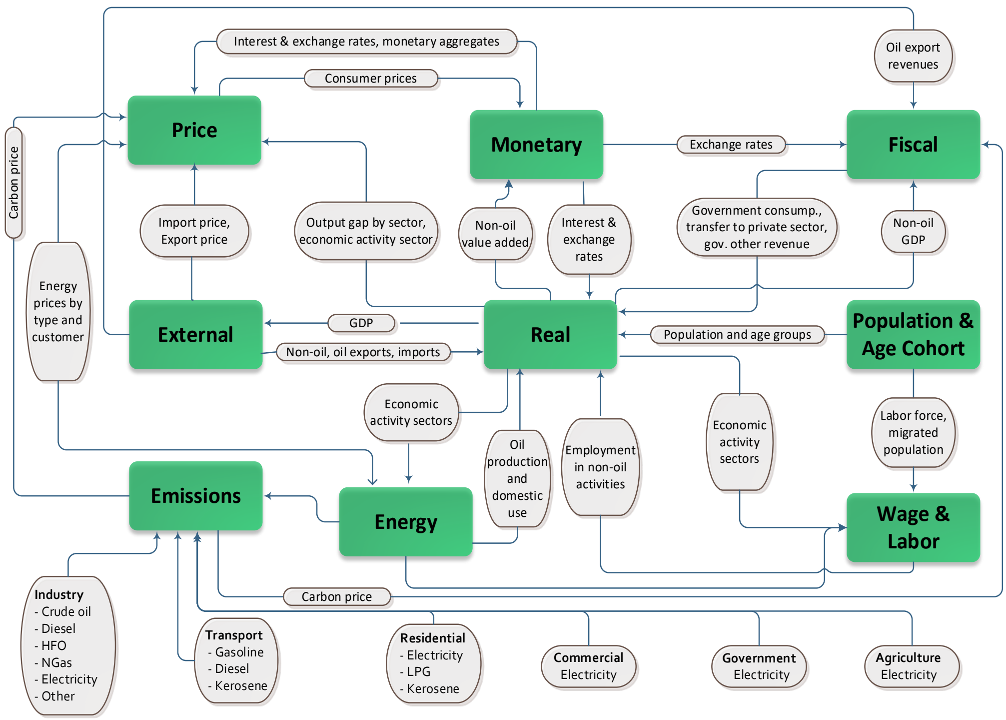
[8] https://www.globalccsinstitute.com/resources/insights/saudiarabiaccsefforts/

The second scenario assumes that the government budget will finance half of the total cost by cutting the same amount from its investment spending. Lastly, the third scenario assumes that the government and private sector will bear the total cost by reducing their investment spending.

A brief description of KGEMM. The KGEMM is a macro-sectoral econometric model designed to evaluate how domestic decisions and global shocks affect Saudi Arabia's economic, energy, and environmental relationships, both at the aggregate and sectoral levels (Hasanov et al., 2023).

It is a macroeconometric model augmented with energy and environmental sectors. This is a hybrid model, as it incorporates intermediate and final demand representations of the input-output model (IOM) into the macroeconometric framework. The IOM elements give the KGEMM sectoral granularity because, unlike standard macroeconometric models, it can examine demand at the level of sectoral economic activities. KGEMM covers 14 economic activity sectors. The model is also semi-structural, as it brings together theory-based and data-based approaches rather than being fully structural or purely data-driven as two extremes (e.g., Pagan 2003a; Hendry, 2018). The KGEMM represents the economic, energy, and environmental linkages in Saudi Arabia through nine blocks, as *Figure 1* illustrates.

Figure 1 - Schematic illustration of KGEMM.



Source: Modified from Hasanov et al. (2023).

The KGEMM structure follows the system of the national accounting framework, where economic activities are aggregated into 14 sectors (see SNA, 2008; Hasanov et al., 2023). To map these seven economic activities into the KGEMM framework, they are aggregated into three sectors, namely services, manufacturing, and construction, named demand for domestic economic activities, where all five service activities are combined into services. Following the aggregate classification of the merchandise imports from the World Bank's World Integrated Trade Solution database[9], the imports are broken into three components in KGEMM: capital goods, intermediate goods, and final

[9] https://wits.worldbank.org/

consumption goods. KGEMM also has imports of services. The seven activities related to CCS deployment are allocated among imports of services, capital goods, and intermediate goods. [10]

Results.

The main finding from the scenario analysis is that there is a slight benefit from the deployment of the announced CCS. The benefit is relatively larger in the first scenario, and scenarios two and three follow. Numerically, on average, from 2026 to 2035 across scenarios, GDP, non-oil GDP, and non-oil employment rise by 0.6%, 0.8%, and 0.3% relative to BaU, respectively. Non-oil budget revenues, domestic demand, and broad money increased by 0.2%, 1%, and 0.3% respectively, while the price level remained stagnant. At the sectoral level, value added in industry and services increases by 0.6% and 0.5% while agriculture is less than 0.1% compared to BaU. Employment in these sectors grew by 1%, 0.8%, and 0.7% respectively. The implementation of the announced CCS would lower industry and utility emissions by 7% and 0.7%, respectively, compared to BaU. Emissions from the transport sector may increase by 0.4% if a slight expansion in economic growth meets its energy demand by using fossil fuels. Resultantly, total emissions would reduce by about 3%.

Conclusion

The designed financing options with their respective macro-sectoral outcomes are useful in informing the decision-making process for the announced and other CCS deployments. These findings reflect the strategic viability of the announced CCS deployment and indicate that even if it is financed by the government and private sector, there will still be a slight economic gain. The study highlights the need for targeted policies, timely infrastructure rollout, and clear sectoral prioritization to maximize the role of CCS in achieving Saudi Arabia’s long-term net-zero goals while providing economic benefits.
Three policy insights should be pointed out. *The first* one is related to the financing option. Paying for the CCS hubs from foreign-exchange reserves produces the strongest stimulus and avoids crowding out public or private projects. Should fiscal resources be required, the government should prioritise projects with lower growth pay-offs for deferment and safeguard spending on human capital, digital infrastructure, and renewables that deliver larger multipliers. *The second* one is about maximising domestic spill-overs. Tying CCS procurement to the domestic supply chain could amplify the industrial and employment gains highlighted by the model and strengthen supply-chain resilience. *Third*, complement capture with transport abatement. The modest rise in the transport sector CO_2 suggests that vehicle-efficiency standards, accelerated electric- or hybrid-vehicle deployments, and freight-logistics improvements are needed to preserve the net-emission benefit of CCS.

Given a broad coverage of the developed CCS module and already existing capabilities of KGEMM, the following directions for future research naturally emerge. The present analysis only focused on CCS. One direction of future work should be simulating integrated policy portfolios in KGEMM that combine CCS with carbon pricing and large-scale renewable deployment to identify least-cost pathways to the Kingdom’s 2060 net-zero target with associated sectoral and macroeconomic implications. Another direction would be the consideration of carbon pricing to finance the associated cost of CCS deployment as one of the financing options. The other financing option to be considered in future research would be using loans from the financial markets to finance CCS-related costs. Finally, simulating KGEMM with various levels of learning rate, capture rate, penetration rate, levelized costs of capture, as well as transport and storage, would be another useful research direction. For example, carbon capture can be determined endogenously based on climate policy interventions and technological developments. Then, the total cost required for such capture and its allocation across economic activities, as well as the breakdown between domestic and foreign suppliers, can be calculated, and associated sectoral and nationwide effects can be simulated. This would allow a comparison with alternative options, with their cost and benefits.

[10] We do not consider imports of final consumption goods as the CCS buld up mostly involves capital and intermediate goods and serives.

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Federico Di Palma, Mohtana Aljassem, Alessio Rufa, Rosario Cammarata
EVALUATION OF PDIV IN LOW-GWP GASES

Federico Di Palma, Sapienza University of Rome, Italy, Email: Federicodipalma04@gmail.com
Mohtana Aljassem, Sapienza University of Rome, Italy
Alessio Rufa, Sapienza University of Rome, Italy
Rosario Cammarata, Sapienza University of Rome, Italy

Abstract

The study aims to evaluate the phenomenon of partial discharges in gases with low GWP and ODP, with the objective of contributing to the research of an alternative gas to SF_6. Using a sealed cell and a step-up transformer, the partial discharge inception voltages were recorded for humid air, helium, nitrogen, carbon dioxide, and nitrogen-based mixtures.

Marco Kunz, Joëlle Clot, Corinne Schwaller, Oliver Woll,
LOCAL ENERGY COMMUNITIES FOR AN INCLUSIVE ENERGY TRANSITION

Marco Kunz, Lucerne University of Applied Sciences andArts, Email: marco.kunz@hslu.ch
Joëlle Clot, Lucerne University of Applied Sciences andArts, Email: joelle.clot@hslu.ch
Corinne Schwaller, Lucerne University of Applied Sciences and Arts, Email: corinne.schwaller@hslu.ch
Oliver Woll, Lucerne University of Applied Sciences andArts, Email: oliver.woll@hslu.ch

Overview

The large-scale deployment of decentralised renewable generation, particularly rooftop photovoltaics, is central to the Swiss Energieperspektiven 2050+. This transformation places growing stress on distribution networks while creating new opportunities for collective models of energy use. Local energy communities (LECs), including Swiss-specific models such as local electricity communities and virtual self-consumption associations, offer a pathway to manage decentralised electricity flows and enhance citizen participation. Beyond technical benefits, LECs can extend access to renewable energy to tenants and low-income households. Thereby they address issues of equity and social justice as well as the availability of affordable electricity prices within the energy transition. However, implementing such inclusive community models requires integrated insights into techno-economic feasibility, governance structures, and socio-cultural dynamics.

Methods

The study applies a transdisciplinary approach, combining methods from social sciences and humanities (SSH) and techno- economic analysis. The techno-economic analysis assesses the viability of business models for local electricity sharing, simulation profitability, scalability, and system impacts across diverse household types, including those without generation assets. Special attention is given to the perspectives of tenants and households with low incomes, examining barriers such as upfront costs, access restrictions, and informational asymmetries. By integrating these two dimensions, the project generates holistic scenarios for the design of socially inclusive energy communities.

Results

The findings highlight that LEC can deliver both technical and social benefits if designed with equity as a central principle. Simulation scenarios demonstrate that local matching of production and demand reduces grid congestion and enhances energy security. Comparative analysis of different LEC configurations identifies the conditions under which they are most effective and how design choices influence outcomes. Economic assessments show that inclusive models are viable when complemented by dynamic tariff structures, collective investment mechanisms, and transparent governance rules. On the social dimension, results indicate that low-income and tenant households face significant structural barriers to participation, but targeted measures such as reduced grid fees for local sharing, cooperative ownership models or reduced electricity tariffs can improve access. Moreover, participatory governance frameworks strengthen trust, foster user engagement, and enhance perceived fairness, which are critical for long-term sustainability of LECs.

Conclusions

Local energy communities represent more than a technical innovation; they embody a social and institutional shift in the organisation of energy systems. By integrating vulnerable groups into decentralised electricity markets, LECs can contribute to both decarbonization and social inclusion. Key levers such as dynamic tariffs and cooperative ownership models are particularly effective in aligning technical efficiency with fairness. Embedding equity into their design ensures that the energy transition is not only efficient and resilient, but also just and participatory. The outcomes provide a basis for future research on scaling socially inclusive, community-based energy systems.

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Saeed Khorrami, Maria Carmen Falvo, Pablo García Fernández, Ángel Navarro Rodríguez, Carlos Gómez-Aleixandre, Tiemblo, Mahmoud Rashad Ahmed

RULE-BASED AC ENERGY EXCHANGE FOR URBAN PROSUMERS TO ENHANCE LOCAL ENERGY PERFORMANCE

Saeed Khorrami, Sapienza University of Rome, Italy, Email: saeed.khorrami@uniroma1.it
Maria Carmen Falvo, Sapienza University of Rome, Italy, Email: mariacarmen.falvo@uniroma1.it
Pablo García Fernández, University of Oviedo, Spain, Email: garciafpablo@uniovi.es
Ángel Navarro Rodríguez, University of Oviedo, Spain, Email: navarroangel@uniovi.es
Carlos Gómez-Aleixandre Tiemblo, University of Oviedo, Spain, Email:gomeztcarlos@uniovi.es
Mahmoud Rashad Ahmed, University of Oviedo, Plexigrid, Spain, Email: mahmoud.rashad@plexigrid.com

Overview

Urban energy communities increasingly face PV–load temporal mismatch and peak demand stress, leading to unnecessary grid imports despite nearby renewable generation (Mehta and Tiefenbeck, 2022). While market-based or optimization schemes exist, many communities need a simple, transparent way to share energy that remains power- flow feasible on actual feeders (Guerrero, Chapman and Verbič, 2018), (Khorrami, Falvo and Pompili, 2025). This study explores a rule-based exchange strategy for local AC energy exchange between adjacent prosumers, aiming to enhance local energy performance and reduce reliance on the grid without complex forecasting or optimization.

Method

The study was conducted by modeling and simulating a two-prosumer subset of a modified IEEE 13-node distribution feeder for a 24-hour test case, with cross-validation in OpenDSS (power-flow feasibility) and Python (control logic and Key Performance Indicators (KPIs) computation).
The dispatch rule was designed to prioritize meeting a neighbor's deficit before importing from the grid, while respecting feeder operational limits and battery State-of-Charge (SoC) constraints. This principle is similar to local energy sharing heuristics in recent smart grid studies (Anoh *et al.*, 2019), (Gebremariam *et al.*, 2024).
In this study, each building's PV system employs Maximum Power Point Tracking (MPPT) with a bidirectional DC/DC converter and bidirectional inverter, enabling efficient PV generation utilization, and battery charging/discharging. Building loads are first supplied directly by local PV generation; surplus PV energy then charges the battery within its capacity and power limits, respecting SoC constraints and efficiencies. During load deficits, battery discharge supplements demand before importing energy. If local resources are insufficient, surplus energy is requested from the adjacent building in the two-prosumer setup. Only if neighbor surplus is unavailable does the system import remaining energy from the external grid.
OpenDSS was used to validate voltages and system losses, while Python implemented the control logic and computed KPIs: self-consumption (SC), self-sufficiency (SS), and grid import (GI). SC measures the fraction of generated PV energy consumed locally within the community. SS represents the proportion of total community demand met by local generation and exchanges, without relying on external imports. GI quantifies the total energy drawn from the external grid to meet residual demand after local resources and exchanges. All performance changes are expressed relative to a no-exchange baseline (S1), with results compared against the neighbor-first exchange case (S2).
Two residential prosumer buildings are connected to a modified IEEE 13-node radial feeder that serves as the minimal community (Schneider *et al.*, 2017). Building 1 (B1), located at Bus 645.2, has an annual load of 5,937 kWh with a peak demand of 1.6 kW (hourly peak), a PV system producing 7,700 kWh annually (peak 4.3 kW), and a battery of 15 kWh capacity with 5 kW maximum charge/discharge rating, initialized at 7.5 kWh (50% SoC). Building 2 (B2), at Bus 646.3, has a larger annual load of 7,721 kWh and peak demand of 2.1 kW (hourly peak), with PV generation of 10,096 kWh annually (peak 5.8 kW) and a 5 kWh battery with 5 kW (maximum charge/discharge rating), initialized at 2.5 kWh (50% SoC).
Hourly (1-h resolution) load and PV profiles were used, along with a standard battery SoC model over a 24-hour test day.

Results

In the base-case scenario (S1, no exchange), feeder voltages remained within the range of 0.999–1.000 pu, with total system losses of 2.14 kWh and SC of 74.3%. Building 2's GI was 11.36 kWh, while Building 1 did not require any GI. Overall system SS was 77.7%.
Under the neighbor-first exchange scenario (S2), 7.74 kWh of energy was exchanged from B1 to B2 over the 24-hour test period. This reduced second building's GI to 3.63 kWh and increased first building's GI to 2.86 kWh.

The SS improved to 87.3% (+9.6 percentage points), and SC increased to 78.5%. Total system losses, including battery operation and exchanged energy, were 2.58 kWh. Feeder voltages remained within 0.9996–1.0001 pu, confirming voltage compliance.
At an energy price of 0.25 €/kWh, the daily electricity cost for B2 decreased from €2.84 in S1 to €0.91 in S2, yielding a saving of €1.93/day. The total daily electricity cost decreased from €2.84 to €1.62, resulting in a saving of €1.22/day.

Conclusions

The study demonstrates that a lightweight, rule-based AC energy exchange between neighboring prosumers is technically feasible and effective in improving local energy performance. In the two-building, 24-hour test case, the neighbor-first exchange approach delivered 7.74 kWh from B1 to B2, reduced second building's GI by 68%, and improved SS from 77.7% to 87.3%. The SC also increased from 74.3% to 78.5%, with total system losses remaining low at 2.58 kWh.
These results indicate that even minimal, local coordination without advanced forecasting or optimization can significantly enhance local energy performance in urban prosumer communities. The findings provide a foundation for future work on multi-building, year-long simulations and demand-side management strategies aimed at further enhancing grid stability and efficiency in urban energy communities.

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Muhammad Javid

ENERGY DEMAND FOR DESALINATED WATER IN SAUDI ARABIA

Muhammad Javid, King Abdullah Petroleum Studies and Research Center,
Email: muhammad.javid@kapsarc.org

Overview

Saudi Arabia is an arid country characterized by a scarcity of freshwater resources, with water demand escalating due to population growth, urbanization, and rapid economic development. To meet its water needs, the Kingdom relies heavily on desalination, which has been facilitated by the unique combination of water scarcity and abundant energy resources. This dynamic has driven the adoption of modern desalination technologies. However, the reliance on desalination to meet growing water demand requires significant energy, not only for the desalination process itself but also for transporting water across the supply chain from sources to end users. These two critical resources—water and energy—are closely interlinked and essential for the country's sustainable development. As such, the water-energy nexus is a vital issue that warrants special attention in Saudi Arabia. This relationship is expected to become even more prominent in the coming years due to initiatives such as the Saudi Green Initiative—which includes plans to plant 10 billion trees by 2030—and efforts to position the Kingdom as a major global tourist destination.

Saudi Arabia is the world's largest producer of desalinated water and the third-largest consumer of water per capita globally (U.S.-Saudi Business Council, 2022). According to the Ministry of Environment, Water, and Agriculture (MEWA), the total water demand in Saudi Arabia was 16 billion cubic meters in 2023. Meeting this demand has required significant energy input.

With limited surface water and depleting groundwater reserves, Saudi Arabia depends significantly on expensive, energy-intensive desalination, which burdens public finances and contributes to carbon emissions (The Arab Gulf States Institute in Washington, 2025)[11]. Water scarcity jeopardizes both energy and economic security, while energy-intensive water strategies impose sustainability constraints. This highlights why the water-energy nexus is central to Saudi Arabia's resource policy debate. With this background, the main objective of this paper is to:

- Project the energy requirement for desalinated water in Saudi Arabia.
- To assess the impact of water use efficiency on future water demand and the energy requirement for desalinated water.

For Saudi Arabia, where water resources are limited and water demand is escalating due to population growth, urbanization, and rapid economic development, understanding the interdependency between water and energy, as well as the role of water use efficiency, is essential for the effective and integrated planning and management of these two critical resources.

Methods

The main objective of this paper is twofold. First, we aim to project the domestic sector's demand for desalinated water in Saudi Arabia using regression analysis. We subsequently estimate the associated energy requirements for desalination based on these water demand projections. In the second stage, we integrate a water-use efficiency strategy into the analysis, assessing how efficiency improvements influence future water demand and the corresponding energy needs for desalination. This approach provides a more accurate forecast of resource requirements and highlights the potential benefits of efficiency measures in reducing pressure on the energy–water nexus.

[11] AGSIW | Saudi Arabia's Water Future: Addressing Scarcity and Ensuring Sustainability

Results

We project energy demand for desalinated water production under three demand scenarios: baseline, moderate, and optimistic. Three scenarios reflecting varying levels of water loss reduction are considered for energy projection. In the baseline scenario (Energy_S0), where no improvements are made and current water losses (36%) persist, energy demand is projected to rise significantly from 23.42 TWh in 2025 to 36.17 TWh by 2050. The moderate efficiency scenario (Energy_S1) assumes a reduction in water losses to 21% by 2031, resulting in a lower projected energy from 22.7 TWh in 2025 to 18.1 TWh in 2031 due to a reduction in water losses. However, after 2031, energy demand for desalinated water began to rise, reaching a demand of 28.58TWh by 2050. In the optimistic scenario (Energy_S2), where water losses are eliminated by 2031, energy demand will decline to 14.64 TWh by 2031 and then increase only marginally to 23.1 TWh by 2050. The results highlight the critical role of water loss reduction strategies in shaping the long-term energy footprint of desalination. These findings support the need for integrated water–energy planning and underscore the importance of aligning desalination policy with national sustainability goals, such as those articulated in Saudi Vision 2030.

Conclusions

The results emphasize the economic and energy consequences of Saudi Arabia's future water demand. Our analysis shows the strong water-energy connection by calculating the amount of desalinated water needed to meet expected demand and the electricity required to produce this water. This is important for national planning: as desalination capacity increases, it will rely heavily on energy resources, which have both financial costs and environmental impacts. The study's cost-recovery assessment objectively evaluates the fiscal sustainability of existing water supply practices. The findings likely indicate that, given current tariff levels, government subsidies would need to rise significantly to offset the increasing water production costs.

By highlighting these factors, the study offers a timely, policy-relevant contribution. It not only measures the scale of the upcoming water challenge in Saudi Arabia but also shapes the conversation on how to tackle this challenge sustainably. The findings can assist national stakeholders, including government ministries, regulators, and utility companies, make informed decisions about infrastructure investments, water pricing, and conservation initiatives. Ensuring an adequate water supply for Saudi Arabia's growing population, while balancing economic and ecological concerns, is a key priority. This research provides practical insights to support this goal. Ultimately, its significance lies in offering evidence-based guidance for policymaking that can help secure water resources for future generations in the Kingdom.

Gabriel Navarro Tilloca, Giacomo Marzi, Angelo Facchini

ENERGY AND TRANSPORT POVERTY IN THE EUROPEAN UNION AND UK: A BIBLIOMETRIC AND SYSTEMATIC LITERATURE REVIEW. A NON "AUTOBIOGRAPHY OF NO ENERGY EMANCIPATED HOUSEHOLDS IN UE AND IN HIS ISLANDS"

Gabriel Navarro Tilloca, IMT School for Advanced studies Lucca; Università di Firenze, Email: gabriel.navarrotilloca@unifi.it
Giacomo Marzi, MT School for Advanced studies Lucca; Email: giacomo.marzi@imtlucca.it
Angelo Facchini, MT School for Advanced studies Lucca; Email: 4.facchini@gmail.com

Abstract

Social challenges such as Energy poverty (EP) and Transport poverty (TP) highlight the complexity of achieving a more equitable society, particularly in regions that are struggling to adapt to the energy transition policies.
Over the past 15 years, research on the impact of EP and TP on households adopted a multidimensional and multidisciplinary approach, expanding considerably. Studies often combine insights from different disciplines - such as economics, engineering, health sciences, anthropology, politics and psychology - to address these issues. However, research examining both EP and TP together remains limited, especially in less studied geographies greater islands and inner areas.

In this work we map the intellectual structure of EP and TP research in the European Union with the aim to provide a better integration of the current knowledge between the two topics. We focus on the main articles published between 2011 and 2024, following a set of well-structured methodological guidelines for the bibliometric and the systematic literature analysis. The application of rigorous ten-step processes, utilising tools such as Bibliometrix and VOSviewer, ensures the work's reproducibility and robustness.

Our analysis makes it possible to underscore two main findings. On one hand, it highlights the gap in the literature covering the geographical area of the Mediterranean Sea and its major islands (Sardinia, Corsica, Balearic Islands). We observe that quantitative or qualitative research on EP and TP needs to be better developed and expanded. Moreover, an additional analysis of non-academic literature comprising national and regional legislation and policies from three islands reveals discrepancies with the academic literature. These discrepancies are often attributed to a lack of in-depth studies and research in inner areas and regions. Furthermore, the implementation of policy recommendations aimed at improving the situation is challenging in regions that differ from those where most case studies are concentrated. On the other hand, the concept of 'local welfare' has emerged as a subject of academic discourse, with scholars expressing strong conviction in the necessity of a 'local energy welfare' that empowers individuals to meet their fundamental needs.

The results of the bibliocouplig analysis indicate that studies on energy poverty mainly aggregate into five clusters, Similarly, transport poverty research is divided into four clusters. In both cases we can reveal a strong multidisciplinary nature of research for each cluster. Papers that simultaneously explore both social issues often occupy the edge of the clusters to which it belongs, a phenomenon attributable to the novelty of the study.

Alessio Lovarelli, Lucia Visconti Parisio

MEASURING MARGINALITY: THE EVOLUTION OF COMPETITIVENESS IN THE ITALIAN ELECTRICITY MARKET

Alessio Lovarelli, University of Milano-Bicocca, Email: alessio.lovarelli@unimib.it
Lucia Visconti Parisio, University of Milano-Bicocca, Email: lucia.parisio@unimib.it

Overview

Despite the drastic changes in the production technologies, the generous public funding and incentives, and the penetration of renewables, electricity prices in Italy remain higher if compared to EU markets counterparts. We address the question of going to the roots of this phenomenon that can be attributed to Electricity Market design, to strategic bidding of producers, or to the structure of the generation industry. Different explanations emerging from the analysis justify different policy prescriptions for the regulatory authority.

The current market structure allows a few firms to exert considerable market power that hinders the transmission of cost efficiency of innovative technologies to market price. According to the current market design, the equilibrium price is determined by the highest accepted bid, after arranging all received bid price-quantity pairs in increasing order according to their offer. This feature might significantly dampen the positive effect on prices due to the low marginal cost of production of renewable plants. Indeed, the most relevant interactions for price determination are those that take place around the equilibrium point where supply and demand meet. To study this issue, we introduce and measure the notion of marginality of a plant, i.e. how close a plant is to being the marginal producer. The idea of marginality is to assess the importance of a production unit in price determination or closeness to marginality, measured by the frequency of the event. The second step is to analyse the unit ownership and technology: the first point helps us to detect possible portfolio bidding by firms while the second point allows us to calculate the degree of dependence of the system from gas as productive input.

Methods

To investigate the evolution of competitiveness and marginality of firms and technologies, we use disaggregated plant-level data of daily bids in the Italian day-ahead market from 2015 to 2023. Our large dataset contains information regarding bids submitted every hour of the by each plant in the day ahead market and bilateral contract, matched with their status (accepted, partially accepted or rejected), and the price awarded to each one. Since the market is hourly, we mainly focus on four hours (03,09,13,20) which are meant to capture the most representative peak and off-peak phases of the market and ease the computation. The determination of the marginal unit requires an ad hoc procedure. Given that we only know plants IDs, bids and outcome, we can restrict our attention to those accepted and look at the Merit Order (MO) established by the System Operator (SO). In the analysis we consider the plant with the highest MO number, and also the zonal configuration, since the market splits according to macro- regions of the Italian territory, whenever transmission constraints are present. Indeed, market splits quite often, though there are clear indications of a decreasing trend. When such separation happens, we pick the marginal plant of the market to which the northern zone belongs to. We, then, proceed to study the bidding behaviour of such pivotal plants to capture the evolution over time of the impact of natural gas, carbon pricing and ownership of such plants.

Results

For every hourly market considered, we identify the marginal plant, which allows us to retrieve the specific producer and technology, as can be seen in the figures, for the H20 market of 2023 and for the top 30 most marginal plants of the period 2015-2023. Despite the significant change in market structure and the substantial increase of renewable plants, natural gas remains by far the most likely marginal technology and the role of the dominant firms is still unchallenged.

We proceed to identify the plants that are most likely to be marginal for each year and find that throughout the period such tail plants (that we set to 20 for simplicity) make the price around 45-50% of the time, showing no significant evolution over the 9 years. We find that the role of natural gas in determining the bids has changed over time, showing a similar dynamic across the hours and apparently decreasing during the 2021-2022 crisis. Next, we control whether the injection of renewables and bilateral contracts has changed the marginal bids, finding that the impact has been close to nothing. We examine the fixed effects relating the production unit to the Producer (firms who owns the plants), which show that smaller producers appear to charge more with respect to the larger ones. Lastly, we investigate the bidding behaviour of the hydroelectric plants and we find that their bids are strongly correlated to the price of natural gas, imitating the bidding behaviour of non-RES plants.

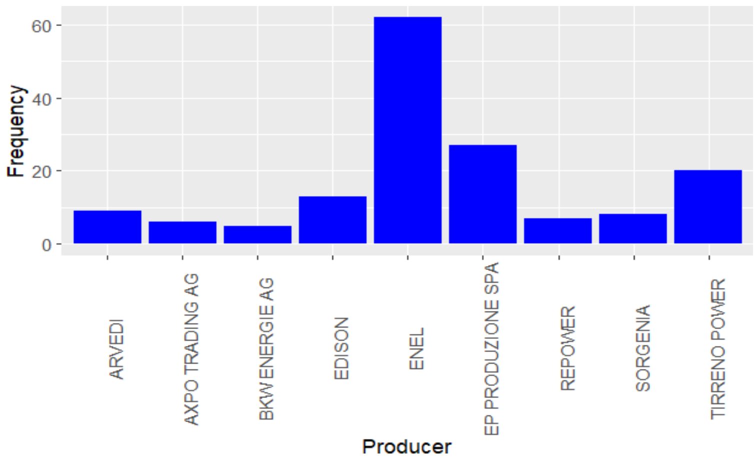

Figure.1 -Top 30 marginal producer for 2023

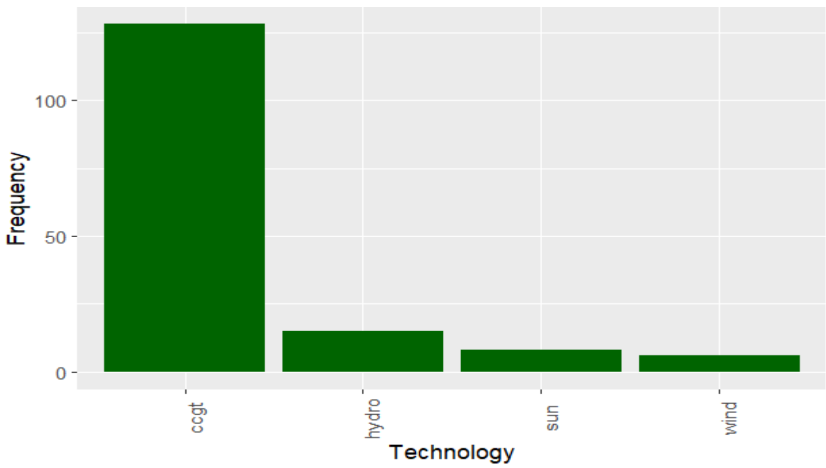

Figure 2 - Top 30 marginal technology 2023

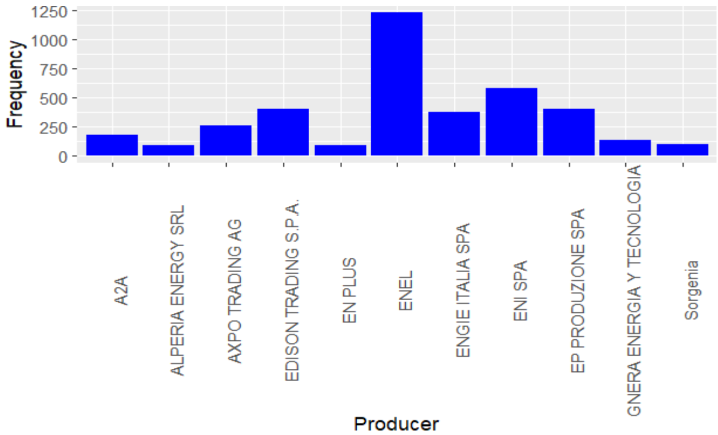

Figure 3 - Top 30 marginal producer 2015-2023

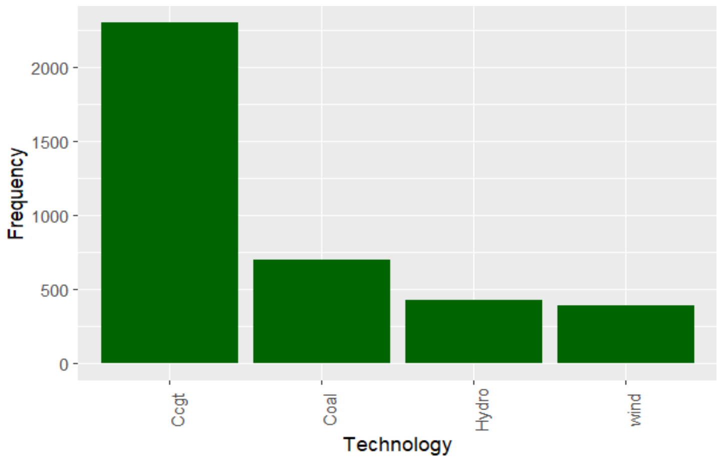

Figure.4 - Top 30 marginal technology 2015-2023

Conclusions

Using a large dataset containing disaggregated plant-level information, we investigate the changes occurred over the last 9 years in the final segment of the supply curve of the Italian (day-ahead) electricity market. Although a sharp increase in renewable production and in the composition of the production technology profile, renewables have still a hard time challenging the predominant role of natural gas as marginal technology and represent no threat to traditional plants. As confirmed by our analysis, though some minor changes occurred, a few dominant producers dominate the price-making activity and the introduction of more renewable sources, especially when the investment is realized by the same dominant operators, is unlikely to change the situation since the bidding strategy is determined at corporate group level. The current market design is highly manipulable and often delivers a suboptimal outcome by letting more efficient plants imitating the less efficient pricing strategies of non-RES plants by following the natural gas price dynamics.

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Théotime Coudra, Sandrine Michel

FLEXIBILITY AS A DRIVER OF STRUCTURAL DECENTRALIZATION: A MULTI-REGIONAL POWER SYSTEM MODEL

Théotime Coudray, Université de Montpellier, UMR 5281 ART-Dev, France
Corresponding author: coudray.theotime@gmail.com
Sandrine Michel, Université de Montpellier, UMR 5281 ART-Dev, France

Overview

The global drive to secure affordable, low-carbon electricity is colliding with the rapid rise of Variable and Renewable Energies (VRE). Conventional, nationally coordinated dispatch is struggling to provide the flexibility required to integrate intermittent generation within the electricity system without jeopardizing its reliability or inflating costs. We argue that flexibility is not merely an operational attribute but a transformative feature of the energy transition. According to the direction taken in the recent energy economics literature, flexibility can be understood as the coordination of dispatchable production units, storage, demand response (DR) and inter-regional exchanges to meet a given Residual Load (RL). Thus, flexibility can i) limit congestion on high-voltage corridors and ii) valorize local renewable surpluses, thereby strengthening resilience to fuel-price shocks and climate-driven extremes.Using mainland France as a case study, we ask:

> *Does harnessing flexibility at the regional level catalyze a structural decentralization of power-system governance while simultaneously enhancing energy security?*

This paper bridges the gap between micro-grid studies and purely national models by modeling four contiguous French regions in a single co-optimization framework.

***Keywords**: power-system flexibility • decentralization • regional optimization • energy security demand response • storage*

Methods

We develop RegionalFlex, a Python-based Mixed-Integer Linear Program that jointly optimizes generation dispatch, unit commitment, battery/pumped-hydro operation, DR activation and power flows across a high-voltage backbone.

- **Decision space:** 12 000 binary unit-commitment variables and 280 000 continuous variables over 17 520 half-hourly steps.
- **Objective:** minimize total system cost (fuel, start-up, storage cycling, DR activation, exchange tariffs, slack and curtailment penalties). **Data:** 2022 demand and VRE profiles from ODRÉ; techno-economic parameters from RTE and Enedis planning reports; four regions—Auvergne–Rhône–Alpes, Nouvelle-Aquitaine, Occitanie, Provence–Alpes–Côte d'Azur.
- **Scenarios implemented:**
  (i) regional operational coordination (regulatory dispatch) versus
  (ii) price-based nodal market (LP relaxation),

  plus DR-allowance sensitivities.

Results

- **Hydro-driven resilience. Almost three-quarters of delivered energy comes from hydro, keeping** thermal gas below 1 % and lowering carbon intensity by several orders of magnitude compared to the current EU average.
- **Demand response eclipses storage.** DR is dispatched before storage whenever its activation cost undercuts the full marginal cycling cost of storage:

$$c_{DR} = 120 \text{ e /MWh} < c_{stor,eff} = p_{ch} + (c_{ch} + c_{dis}) \gtrsim 125 \text{ e/MWh}.$$

Consequently DR delivers 2.4 TWh, covering ≈ 99 % of the flexibility that storage discharge might otherwise supply.

- **Limited but valuable regional trading.** Although exchanges account for only 7.8 % of total energy, they unlock € 479 million in revenue for the network operators, notably by smoothing hydro surpluses from Auvergne–Rhône–Alpes toward Provence and Nouvelle-Aquitaine.

- **Cost vs. price gap.** With nodal prices λ derived from the LP relaxation, market revenues λ load exceed operational costs by ~ € 54 billion, reflecting congestion and flexibility rents that should in principle finance future investments.

Conclusions

Regional coordination of flexibility resources simultaneously:

1. Enhances reliability by balancing supply–demand locally before stressing inter-regional ties;
2. Reduces system costs and redistributes congestion rents toward consumers and DSOs;
3. Enables higher VRE shares without costly over-build of transmission, supporting Paris-aligned decarbonization trajectories.

Policy insight: A multi-level governance model (for instance, a local optimization nested in a cooperative regional layer and overseen by a national security coordinator) offers a promising pathway for Europe's Energy Security and Carbon Neutrality targets for 2050. Instruments such as DSO-led cost-sharing mechanisms could operationalize these theoretical gains.

Matteo Nicoli, Valeria Di Cosmo, Laura Savoldi

MODELING TO GENERATE NEAR-PARETO-OPTIMAL ALTERNATIVES (MGPA) FOR LONG-TERM ENERGY PLANNING

Matteo Nicoli: Research Fellow, University of Turin
Lungo Dora Siena 100, Torino TO, Italy
Email: matteo.nicoli@polito.it
Valeria Di Cosmo: Associate Professor in Applied Economics, University of Turin,
Lungo Dora Siena 100, Torino TO, Italy
Email: valeria.dicosmo@unito.it
Laura Savoldi: Full Professor in Nuclear Power Plants, Politecnico di Torino,
Corso Duca Degli Abruzzi 24, Torino TO, Italy
Email: laura.savoldi@polito.it

Overview

This work presents the implementation of the Modeling to Generate near-Pareto-optimal Alternatives (MGPA) methodology [1] within the open-source energy system model TEMOA [2]. MGPA integrates multi-objective optimization (MOO) [3] with modeling to generate alternatives (MGA) [4] and explores near-Pareto-optimal trade-offs between two objective functions. This approach enables a comprehensive analysis of long-term capacity expansion pathways for future energy systems, providing decision-makers with a richer understanding of trade-offs beyond the single deterministic solutions and assessing the robustness and flexibility of energy system pathways under competing objectives.

Methods

The MGPA methodology, previously developed and validated for smaller scale modeling frameworks [1], has been adapted and implemented in TEMOA. The implementation enables exploring Pareto fronts between pairs of key objective functions: system costs, greenhouse gas emissions, material supply risk, and energy supply risk [3]. The approach uses iterative optimization to systematically identify alternative solutions close to the Pareto front. The MGPA implementation in TEMOA is designed with high flexibility to accommodate diverse user needs in exploring near-Pareto-optimal solutions. Beside selecting the objective functions to be considered, users can customize the number of points on the Pareto front, allowing control over the resolution and granularity of the multi-objective trade-off analysis. Additionally, users can define MGA slacks, which control the allowable deviation from optimality in generating alternative solutions, and specify the number of MGA iterations, balancing computational effort and solution diversity. These parameters are set through user-defined configuration files, providing a straightforward interface for scenario customization without modifying the core model code. This modular approach facilitates systematic sensitivity analyses and policy comparisons.

Results

We demonstrate the application of MGPA in TEMOA by generating and analyzing the Pareto front between system costs and emissions under different energy policy scenarios for Europe, employing the TEMOA-Europe model instance [5]. The results reveal a spectrum of near-optimal solutions illustrating the trade-offs between economic and environmental objectives. Additionally, preliminary analyses involving material and energy supply risks highlight the potential of MGPA to identify pathways that improve system security while maintaining cost and emissions performance. By varying policy assumptions, such as carbon pricing, technology availability, or resource constraints, the methodology reveals how these policies influence trade-offs between costs, emissions, and supply risks.

Conclusions

The successful integration of MGPA into TEMOA enables enhanced multi-objective exploration of energy system pathways, moving beyond single-solution optimization towards a richer understanding of trade-offs and uncertainties. This capability supports more informed decision-making by highlighting near-Pareto-optimal alternatives that balance costs, emissions, and supply risks. Future work will extend the methodology to additional objectives and larger scenario sets, further advancing the analysis of sustainable and resilient energy systems.

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Silvia Canevese and Antonio Gatti

AN ASSESSMENT OF BALANCING RESOURCES IN THE ITALIAN POWER SYSTEM

Silvia Canevese, Energy Systems Development Department, Ricerca sul Sistema Energetico – RSE S.p.A., Via Rubattino 54, 20134, Milan, Italy, Email: silviamaria.canevese@rse-web.it
Antonio Gatti, Energy Systems Development Department, Ricerca sul Sistema Energetico – RSE S.p.A., Via Rubattino 54, 20134, Milan, Italy, Email: antonio.gatti@rse-web.it

Overview

The prosecution of decarbonization objectives implies a strong increase in generation from Non-Programmable Renewable Energy Sources (NPRES), thus a reduction of the operating hours of relevant (i.e. with size 10 MW at least) thermoelectric and hydroelectric Generating Units (GUs). In Italy, these GUs are traditionally the ones supplying resources for power system regulation, in particular active power margins for frequency control, which are procured on the Ancillary Service Market (ASM).
To highlight possible risks for power system secure operation, it is therefore useful to assess the evolution of the margins still available over the years from conventional GUs. Starting from public data, estimates are made here of the overall power margins available in particular for secondary frequency regulation (i.e. automatic Frequency Restoration Reserve – aFRR) and tertiary frequency regulation (i.e, manual Frequency Restoration Reserve – mFRR and Replacement Reserve – RR), for the years 2015-2022, from GUs eligible for participation in the ASM.

Method

The power margins, i.e. the reserves, available in the whole Italian power system, in each hour of each considered year of operation, are the sum of the margins available from each GU enabled to the considered frequency regulations. To estimate the margins for each GU, the following steps are taken:

i) identifying the set of Italian GUs, in terms of installed power, energy source and technology;
ii) estimating, from the Italian electricity market outcomes, the subset of GUs enabled to aFRR, mFRR and RR, and also estimating, according to the Italian Grid Code requirements, the subset of GUs enabled to supply Frequency Containment Reserve (FCR), with their minimum Half-Band (HB) required for FCR;
iii) for each GU in each hour h, estimating, from the market outcomes, the operating point on market m, indicated as $P_{GU,m}(h)$ [MW]: it is the average power deriving from the algebraic sum of the GU upward (UP) and downward (DN) energy exchanges, in hour h, related to its accepted UP and DN bids, respectively, on the "market chain" up to market m. The overall chain is composed of the Day-Ahead Market (DAM), the IntraDay Market (IM) – also including the new continuous Cross-Border IntraDay (XBID) session, – the *ex ante* ASM and the *ex post* ASM or Balancing Market (BM);
iv) for each GU online in each hour, assessing the minimum HB for FCR ($HB1,GU$ [MW]), the maximum power ($P_{max,GU}$ [MW]) and the minimum power ($P_{min,GU}$ [MW]); $P_{max,GU}$ and $P_{min,GU}$ are defined, respectively, as the maximum power output minus $HB_{1,GU}$ and the technical minimum power output plus $HB_{1,GU}$ (each GU enabled to FCR and online must have its primary half-band, UP and DN, available);
v) the UP and DN power margins available from a GU downstream of the execution of each market m are, respectively, $P_{max,GU} - P_{GU,m}(h)$ [MW] and $PGU,m(h) - P_{min,GU}$ [MW].

Results

The annual boxplots and duration curves of the available hourly DN and UP margins are here analyzed, for years 2015-2022, with reference to three possible operating points, for comparison: downstream of XBID, i.e. of the Energy Market (EM), downstream of the *ex ante* ASM and downstream of the BM.

Overall, on the three markets and on the whole 8-year period, DN margins vary from minimum values around 2-4 GW to maximum values around 25-31 GW, with median values around 9-12 GW, 25th percentile values around 6-9 GW and 75th percentile values around 13-16 GW. The 25th and 75th percentile on the *ex ante* ASM are quite similar to those on XBID or slightly lower, while those on the BM, compared to the other two markets, tend to be lower up to 2020 and slightly lower in 2021, while in 2022 they are quite similar to those on XBID. Similar remarks hold for the median values. As for the UP margins, overall they vary from around 3-6 GW to around 20-25 GW, with median values around 10-13 GW, 25th percentile values around 8-11 GW and 75th percentile values around 12-15 GW. The 25th and 75th percentile on the *ex ante* ASM are quite similar to those on XBID or slightly higher, while those on the BM tend to be higher than on the other two markets up to 2020, while in 2021 and 2022 they begin to decrease, reversing the trend compared to previous years and therefore being quite in line or slightly lower than those on the *ex ante* ASM and those on XBID. Similar remarks hold for the median values. The duration curves for each market, both UP and DN, despite exhibiting some differences along the years, form as a whole a fairly compact "bundle", in line with the small variability of boxplots along the years, especially in the DN case (in the UP case, variability is greater, so the bundle is less compact, especially on the BM).

An indication of a shortage of regulating resources, i.e. of possible critical operating conditions for the power system, is the number of hours of the year with low margins, e.g. with margins below a threshold. For the aggregate of market zones labelled as NCC (after the National Control Center) and covering the continental part of Italy (i.e. the CNOR, CSUD, NORD, SUD and CALA market zones, and also SICI when connected synchronously to the peninsula, but this is neglected here), a reasonable threshold, both UP and DN, could be 3.5 GW, which is around the maximum of the average values reported by Terna for 2020-2021 for the total FRR and RR requirement (Terna reports the average values aggregated by hour of the day and month for January, April, July and October). In 2022, for the DN margin downstream XBID/*ex ante* ASM/BM, the possibly critical hours are 250/375/344, distributed over 85/97/97 days, especially in November (18/17/16 days, 74/73/54 hours in total), December (12/12/10 days, 44/40/44 hours), April (11/14/13 days, 43/55/68 hours), May (9/11/12 days, 48/50/70 hours) and October (9/11/11 days, 40/40/57 hours); the days are mainly Sundays (31/34/34 days, 185/198/232 hours), Saturdays (20/24/23 days, 80/90/110 hours) and Mondays (12/15/14 days, 32/37/48 hours). Overall, the hours of the day (from 1 to 24) with shortage of DN margin most often cover the range from 1 or 2 to 18 from April to June, from 2 to 16 or 17 from August to December. As for the UP margin, instead, in total there are only 8 hours below the threshold (7 on Saturdays and 1 on a Sunday) after XBID, 4 after the *ex ante* ASM (all on Saturdays), and 6 after the BM (half on Saturdays and half on Sundays). Overall, these hours fall on a Saturday in January, on a Saturday and a Sunday in April, a Saturday in March, one in November, and a Sunday in August, and are always distributed in the first half of the day, between hours 1 and 11, but with a prevalence in the first quarter of the day (up to about hour 6 or 7).

Finally, the hourly margins are computed for 2022 in each market zone by aggregating the regulating GUs by technology and energy source: coal, fuel oil, or natural gas Steam Turbines (STs); natural gas combined-cycle gas turbines (CCGTs); natural gas cogeneration CCGTs; natural gas or diesel oil GTs; syngas Integrated Gasification Combined Cycles (IGCCs); as to hydroelectric GUs, reservoir, pondage and Pumped Storage Hydropower (PSH) GUs. Results are quite similar for the three considered markets, so they are now reported for the *ex ante* ASM only.
As to the median values of the margins, the most significant contributions are from natural gas CCGTs and PSH GUs in the NORD zone, both DN (4.09 GW and 1.20 GW respectively) and UP (2.97 GW and 1.59 GW respectively). A significant UP contribution comes also from reservoir GUs in the NORD zone (0.90 GW). Significant DN median contributions (each between 0.22 GW and 0.64 GW) come from natural gas CCGTs in the other zones except for SARD, coal-fired STs in the CSUD and SUD zones, and reservoir GUs in the NORD zone. Significant UP median contributions (each between 0.30 GW and 0.59 GW) come from natural gas-fired CCGTs in the other zones except for SARD and CNOR, pondage GUs in the NORD and CSUD zones, and coal-fired STs in CSUD and SUD.

The only technology with significant margin in both directions throughout 2022 is the CCGT in the NORD zone: the other GUs mentioned above about median margins have minimum margins that are almost always zero, therefore they have no flexibility for a number of hours during the year, ranging from a few hours (after the *ex ante* ASM, 88 hours DN for coal-fired STs in the SARD zone, 19 hours UP for reservoir GUs in the NORD zone) up to thousands of hours.

Conclusions

Results obtained for 2022 suggest that DN power margin availability for the Italian power system could be critical (in that it is below a 3.5-GW threshold) for a few hundred hours along the year, which are mainly in the central part of Sundays or Saturdays, when demand is low and NPRES generation, especially PV generation, is high, so there are few conventional GUs online. Similar results could be expected for the other years analyzed, since the margin duration curves are quite similar to those for 2022. For the non-critical hours, instead, the similarity of the results downstream different markets (the EM, the *ex ante* ASM and the BM) suggests that the TSO can count on flexible resources that are still quite abundant, or at least adequate, and that do not require critical actions for their exploitation (e.g., simple adjustments of their operating point are often enough).

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Papers

A POSSIBLE STEP FORWARD TO GREEN HYDROGEN USE EXPANSION

Caudio Meroni
Tiemes srl – Via R. Galli 9 Milano, Italy, Email: claudio.meroni@tiemes.it

Vincenzo Maria D'Ascanio
Tiemes srl – Via R. Galli 9 Milano, Italy, Email: vincenzo.dascanio@tiemes.it

Alice Cozzi
Tiemes Srl– Via R. Galli 9 Milano, Italy, Email: alice.cozzi@tiemes.it

Abstract

In order to limit average Earth temperature change in 2050 to 1.5°C with respect to pre-industrial times, as per Paris Agreement 2015, electrification by renewable energy of carbon emitting activities plays a major role.
However, electrification is difficult in some processes of the so-called "Hard-to-Abate" (HTA) sectors and hydrogen is a suitable energy carrier for many applications and is expected to provide 12% contribution to the decarbonization needed, which seems today very hard to achieve. Although various initiatives have been taken and many projects have been announced, their execution may be in doubt, also because there are several alternatives and many links among them.
This paper evaluates various tools, mainly technical (eg. fossil fuel replacement rates), economic (eg. diffusion and learning curve), environmental (eg. GHG impact), some alternatives and analyze in detail the one(s) likely to start before 2030.
The analysis shows that green hydrogen production near HTA industries is an opportunity to do something which has to be done in any case, it allows some synergies, with affordable incentives, as for other sectors in the early stages of development and generates a large enough market to initiate a positive learning curve.
Replacement of fossil fuels in HTA industrial plants, particularly EAF steel plants, with locally produced hydrogen is a possible next step to extend the use of hydrogen, to facilitate technical improvements and economies of scale to make hydrogen less expensive and, therefore, to extend its use to other sectors.

1. Introduction

To combat climate change, IEA roadmap [63] calls for an increase of renewable energy (32% of total GreenHouse Gases, GHG, emissions reduction needed in 2050), electrification (20%), efficiency (12%) and other levers, emphasizing the use of renewable electricity, which is developing fast [64].

However, electrification is challenging in some processes.

In these cases GHG emissions can be reduced, further to efficiency and other measures, either by capturing and using/storing carbon dioxide or by replacing fossil fuels with hydrogen.

Direct use of electricity is generally more efficient than burning hydrogen, which retains only about 50% of the electricity spent producing it.

According to Ref. [63], hydrogen is expected to provide a global 12% contribution to the decarbonization effort.

Achieving this level of diffusion is challenging, as shown in Ref. [1] [2] [3] [4] [5] [60] . Despite various initiatives and announced projects, execution remains uncertain, also because there are several alternatives and current studies and policies tend to address more the global evolution of hydrogen technology and markets, rather than immediate initiatives to make hydrogen more viable.

Hydrogen can be produced by different methods, associated with different specific atmospheric emissions:

- Gray, produced by Steam Methane Reforming, without Carbon Capture,
- Blue, produced by Steam Methane Reforming, with Carbon Capture, Utilization and Storage (CCUS)
- Turquoise, produced by Methane Pyrolysis,
- Green, produced by Water Electrolysis, using wind or solar electricity,
- Pink, produced by Water Electrolysis, using nuclear electricity

In 2024, Green Hydrogen was about 5 times more expensive than Gray Hydrogen, whose kWh has already been substantially more expensive than the kWh from natural gas. Blue hydrogen is also advocated [66] but involves CCUS which requires high investment and storage availability.

The figure below, from Ref. [5], reports current hydrogen production of 117 Mt/y, with less than 0.3 Mt/y being “Green”. This low share is likely due to high costs, making investors hesitant to proceed with announced projects.
As detailed below, [10] reports over 700 projects for over 200 GW from Concept-stage to Final Investment Decision/Construction-stage, but only 10% have reached the final stage.
To achieve 95% carbon neutrality by 2050, Ref. [6] consider that green hydrogen production must grow to 27,6 Mt/y (117,4 GW) in 2030 and to 164 Mt/y (373 GW) in 2050, covering all uses, industrial (mainly steel, petrochemicals, glass), transportation (airplanes, ships, trucks, cars), buildings etc

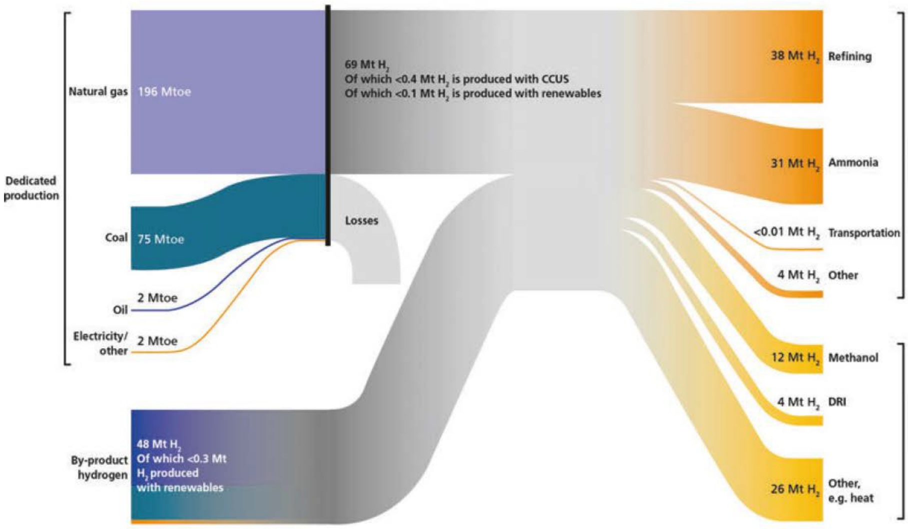


Figure 1- Hydrogen production 2023 *Source [6]*

2. Previous experiences

To effectively fight climate change by reducing the cost of green hydrogen, it is beneficial to learn from previous experiences. These experiences have shown that increasing cumulative capacity leads to substantial cost savings, particularly with photovoltaic (PV) plants and Lithium Ferrum Phosphates (LFP) batteries.

In 2009, when PV power production was almost a pioneering technology, our company built a 33 kW rooftop-integrated PV in central Italy for € 150.000, which equates to 4.5 €/W.
The owner received a feed-in tariff of 0.45 €/kWh for a production of 40 MWh/y, resulting in a payback of 8.3 years.
By 2024 a similar PV plant was installed for € 35.000, or 1,1 €/W, without a feed-in tariff. At the average 2024 grid rate of 0.1 €/kWh the payback time was 8.8 years.

This direct experience aligns with U.S. National Renewable Energy Laboratory [7] reporting:

- for residential 7-8 kW PV systems, costs were 7.53 $/W in 2010 and 2,51 in 2020,
- for commercial 200 kW systems, costs were 5,57 $/W in 2010 and 1,72 in 2020.

By the end of 2024 global PV capacity is estimated to be around 2000 GW, up from 1 GW end of 2000, 60 GW end of 2010, 300 GW end of 2015, as shown in the figure below.

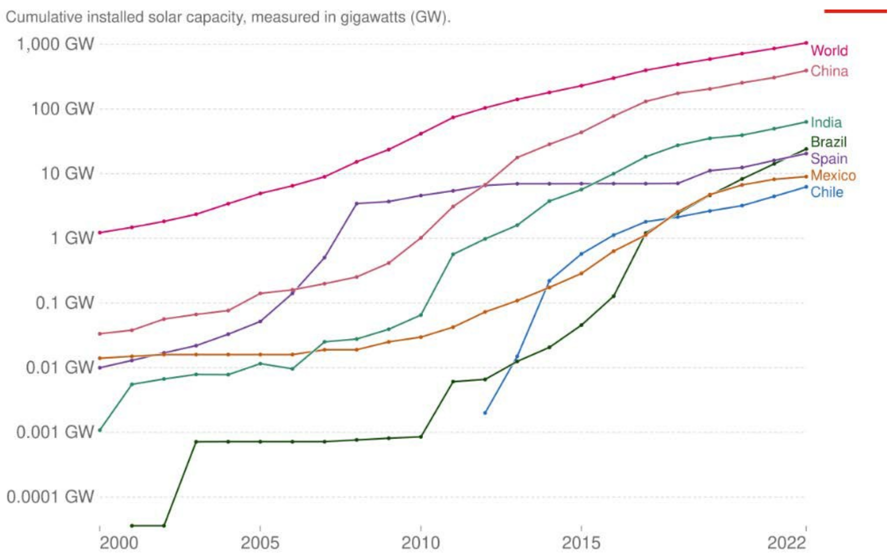


Figure 2 - Cumulative installed solar capacity *Source [7]*

Similarly, for LFP-Battery Energy Storage Systems (BESS), in 2015, we designed a 15 MWh LFP-BESS, inside a CCGT plant, which was built for 12 M€, with 800 €/kWh, with expected remuneration of 0.1 €/kWh for 10 GWh/y, resulting in a payout time of 10 years.
A similar design in 2024 estimated costs of 6 M€, or 400 €/kWh, with expected remuneration of € 8.000/MWh/y, resulting in a payout time of 10 years.
This direct experience aligns with Bloomberg New Energy Finance [8] reporting, for LFP packs only, costs declining from 345 $/kWh in 2015 to 115 $/kWh in 2024, with the worldwide market growing from 50 GWh to 1200 GWh in the same time frame.

These examples show how cost reductions are achievable with increasing market size, although in these cases helped by market conditions and technical advances, such as increasing efficiency in PV and better energy density in LFP batteries.
This can be translated into a learning curve, which shows that, as cumulative production increases, the time or cost per unit decreases, due to increased efficiency and experience. Learning curves for PV plants and LFP batteries suggest that by doubling installed capacity the cost is reduced by around 60% of the last year's considered slope.
This may also be achievable for electrolyzers to produce green hydrogen and facilitate their diffusion: should this not be as immediate as for PV and LFP batteries, a stepwise approach may be a wise choice.

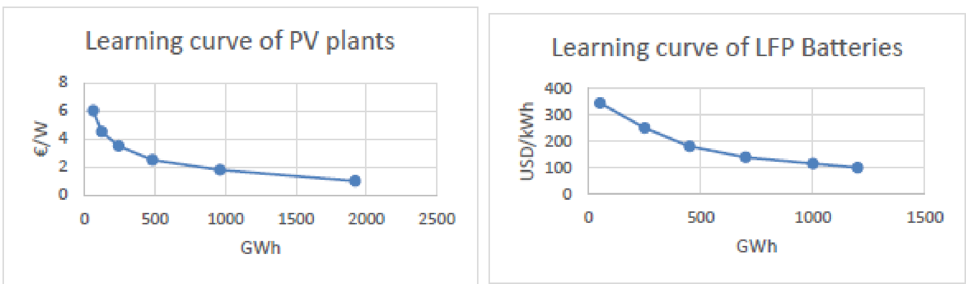


Figure 3 - Learning curves experienced for photovoltaic plants and LFP batteries
Source: own elaboration from BNEF data

3. Green Hydrogen facilities

It is well known [9] [14] that green hydrogen can be obtained by water electrolysis, using two main commercial systems:

- AEL (Alkaline Electrolysis), with alkaline electrolytes (typically potassium hydroxide or sodium hydroxide) cells, where hydrogen is produced at the cathode (negative electrode) through the reduction of water molecules.
- PEMEL (Proton Exchange Membrane Electrolysis), using a solid polymer electrolyte membrane to facilitate proton movement between the anode and cathode, generating hydrogen at the cathode and oxygen at the anode

Both systems arrange sequences of cells in stacks.
AEL has been the most established and cheapest method but requires longer times than PEMEL to adapt to fluctuating electricity supply, as obtained from renewable sources, and therefore requires larger energy storage.
As shown in the graph below, in recent years PEMEL has approached the cost of AEL, to the point that major suppliers offer it at around 1 €/W, including electrolysis stack and most Balance of Plant, ie. water and gas purification, power supply (PSU), instrument air, cooling and chilling facilities: including installation and indirect costs, the total installed cost is likely to be 1,1-1,2 €/W.

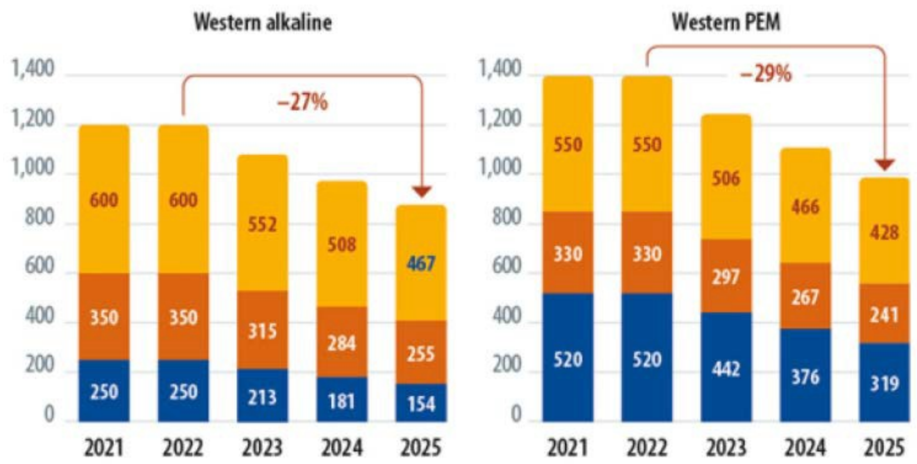


Figure 4 - USD/kW evolution in Europe/USA (stack in blue, then BOP, EPC) of AEL and PEMEL

Assuming an economy-of-scale profile like PV and LFP-BESS for a 5 MW PEMEL, with 2024 installed capacity of 120 MW at unit cost of 1 €/W, it can be estimated that, with a few thousands MW installed capacity, as shown in the figure below, electrolyzer cost could be reduced to close to 0.3 €/W. Meanwhile, PV cost is estimated to be reduced to 0.2 €/Wp.

IEA estimates updated to Mar.5, 2025 [10] shows green hydrogen projects with Final Investment Decision globally at 20,000 MW, of which 9,700 MW are in China, 4,500 MW in Europe, 2,200 MW in South Africa, 1,300 MW in India and 1,100 MW in the USA.

Even the lower estimate of Figure 5 will allow the cost of green hydrogen to be more aligned with the current cost of gray hydrogen and obtain a cost of hydrogen-kWh close to current natural gas-kWh cost. However, there have been many estimates of the future costs of green hydrogen, all linked to its diffusion in several sectors, according to policies and projects that have been announced. [12], [13], [14],[15], [16], [17], which have been subsequently reviewed according to perceived market trends [4]. Many sources estimate annual hydrogen requirements between 20 and 100 Mt in 2030 and between 90 and 1,200 Mt in 2050; such ranges are very high, showing how hard it is to predict the demand.

The purpose of this paper is to try to figure out means by which electrolyzers can be applied sooner in a context where they are likely to be needed in the long term and can be used with not too difficult changes in the application.

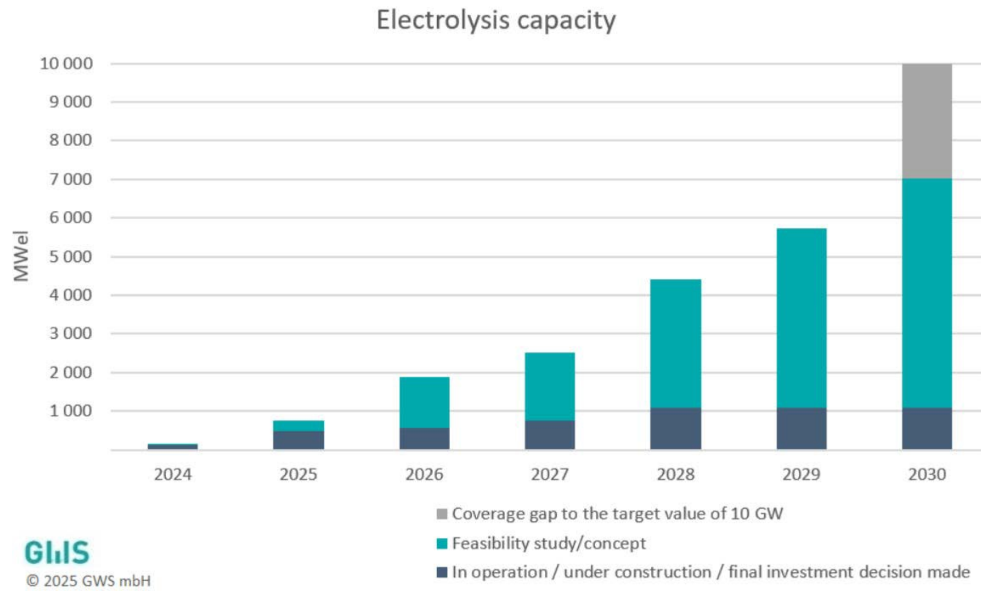


Figure 5 - Global evolution of electrolysis capacity expected Jan.2025 *Source: [11]*

4. Sectors for Green Hydrogen application

Generally, it is considered that demand for hydrogen will come from the following sectors:

- Heavy industry, such as steel, cement, chemicals, oil refining, glass, paper, mostly to replace fossil fuels or feedstocks,
- Passenger cars, Trucks, Buses and Rail, equipped with Fuel Cells, to replace gasoline end gasoil,
- Ships, to replace bunker oil,
- Airplanes, to replace jet fuel
- Buildings, to replace fossil fuels for heating/cooling

Heavy industry is a significant focus because it accounts for over a third of global energy use and a quarter of greenhouse gas emissions [18]. Other sectors, such as passenger cars and buildings, can be decarbonized through direct electrification, considering that in 2024 renewable electricity accounted for more than 40% of world power consumption [19] and this share is expected to continue growing. Aviation and shipping decarbonization, although important, is quantitatively less effective than heavy industry decarbonization.

Heavy Industries are particulalry challenging to decarbonize, due to technical and economic factors, such as product heterogeneity, equipment longevity, cost sensitivity and trade exposure [20]. They are often described as Hard-To-Abate (HTA) due to their energy- and carbon-intensive nature. In these industries, process heating is a significant contributor to industrial energy consumption and a major part of it is supplied at temperatures above 100°C, making it difficult to find market-ready alternatives to fossil fuels.

5. Decarbonize Hard-To-Abate Manufacturing Sectors

The literature on decarbonization options in HTA manufacturing industry focuses on specific technologies, such as hydrogen production [21], electrification [22], demand-side management [23], carbon capture, utilizazion and storage (CCUS) [24], or on specific sectors, like chemical and petrochemical [25], iron and steel [26], paper [27], cement [28], and glass [29], or on specific measures to improve energy efficiency [30].

Ref. [20] proposes a methodology to evaluate different decarbonization alternatives, Ref. [33] analyses decarbonization measures for HTA sectors according to their Technology Readiness Level and their potential for GHG reduction, Ref. [32] proposes a roadmap for heavy industry decarbonization.

The following is a brief analysis of main decarbonization routes, better illustrated in the references.

As is known, Scope 1 emissions refer to the industry direct emissions, Scope 2 to emissions from energy supply, Scope 3 to emissions in the value chain (purchased materials, use and disposal of sold products); data are taken from [35], [36], [37], [38].

In the steel sector (year 2023: 2,8 Gt/y GHG Scope 1+Scope 2 emissions, 8,1% of global CO_2), the main source of emission is the blast furnace. Decarbonization options, further to efficiency, include replacing it with low-emissions Electric Arc Furnace, which can only take place if scrap feed, whose availability is limited, is integrated with Direct Reduced Iron, from the treatment of iron ore with hydrogen (or natural gas). Emissions also come from product reheat, often with natural gas (replaceable by hydrogen), before secondary treatment. [39] [40]

In the cement sector (2,4 Gt/y, 7,7%), CO_2 emissions come from raw material calcination and fossil fuel heat supply. These cannot be easily changed with electricity or hydrogen supply, making CCUS probably the most viable alternative for decarbonization. [47] [48]

In the chemical sector (1,4 Gt/y, 4,5%), the main emissions source is process heat. Decarbonization options include, further to efficiency, electrification (for low temperatures) and green hydrogen, for combustion and as feedstock for ammonia and methanol synthesis.

Production of these may increase to obtain suitable hydrogen carriers to be transported overseas and split before hydrogen end-uses.[41] [42] [43]

In the refining sector (1.3 Gt/y, 4%), fossil fuels result from the operations and cannot be easily replaced with zero GHG heating. Therefore, together with efficiency improvements, CCUS is likely to be the most viable alternative for decarbonization. Hydrogen is widely used in refining, eg. in hydrotreating for sulfur removal and in hydrocracking, to improve value of heavy fractions; most refineries requirements of hydrogen are provided by naphtha catalytic reforming to make motor gasoline.[49] [50]

In the paper sector (0.4 Gt/y, 2%), emissions are mainly generated by steam production and can be reduced by cogeneration and/or electrification, with limited scope for using hydrogen or CCUS.[51] [52]

In the glass sector (0.1 Gt/y, 0,3%), emissions are mainly generated to melt the solid feed and can be reduced, further to better recycling and process changes, by use of oxygen instead of combusting air or by electrification (as in a few plants in Europe), with limited scope for use of hydrogen or CCUS. [37] [38] [42] [43] [44]

As it turns out from the above brief analysis, the steel industry is probably an interesting sector where, together with other measures [62], electrolyzers for hydrogen production are likely to be needed in the long term and can be used with not too difficult changes in the application, leading to the economies of scale which can make them more affordable also for other sectors.

This analysis offers suggestions for green hydrogen adoption in the steel industry, considering economic, political and environmental implications.

6. Steel industry

Steel is produced by two main classes of plants, shown in the figure below for Europe: the integrated blast furnace-basic oxygen furnace (BF-BOF) (red) and the electric arc furnace (EAF) (blue).

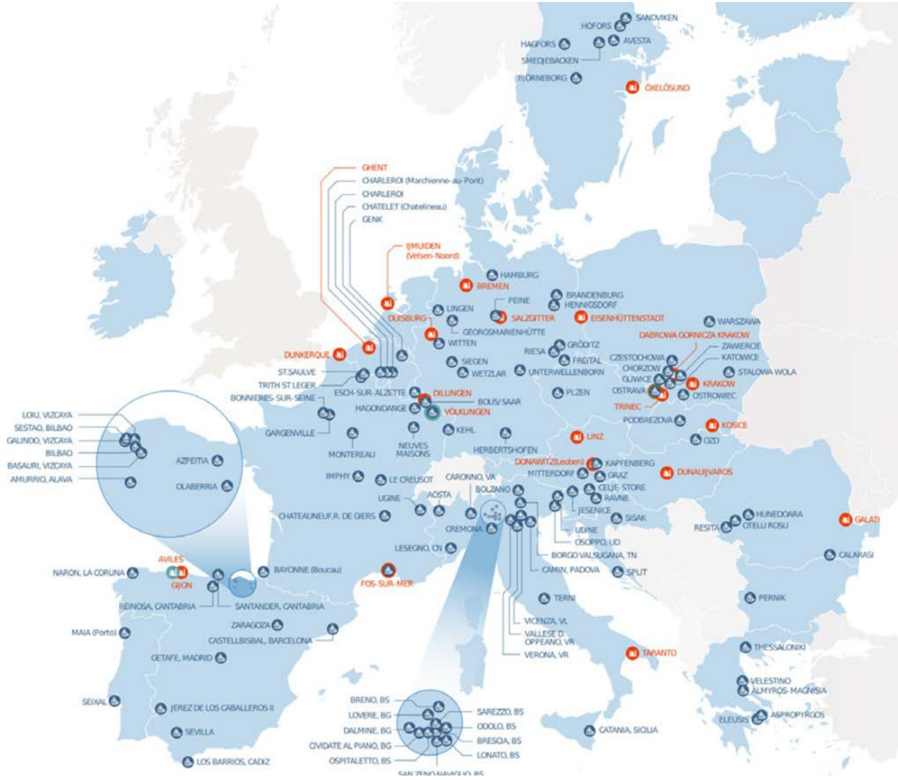


Figure 6 – Map of steel plants in Europe *Source [40}*

BF-BOF Route: Also known as the "integrated route," it is the most common method for producing new or "virgin" steel. It involves the use of a blast furnace to extract iron from iron ore using coke, followed by a basic oxygen furnace to refine the resulting molten iron into steel. The raw materials include iron ore, coal, limestone, and recycled steel. This route accounts for approximately 70% of global steel production.

EAF Route: It primarily recycle steel scrap. It involves melting steel scrap in an EAF and can also use Direct Reduced Iron (DRI) or hot metal, to supplement scrap availability. The raw materials mainly include recycled steel and electricity. This route accounts for about 30% of global steel production.

Both routes produce billets or slabs, which are finished either by cold rolling or through a reheat furnace, into plates, pipes or coils.

Steel production through EAF plays an increasingly important role in modern steelworks concepts [61]. In some countries, such as Italy and Spain, EAF steel production is significantly higher than BF-BOF steel production.

In the modern EAF, chemical energy contributes 25-45% of the total energy required for scrap smelting and refining. Natural Gas (NG) burners provide 40-80 kWh/t of steel [39], meaning that producing 100 tons of steel requires the combustion of 370-750 Nm3 of NG with CO_2 emission of 0.75-1.5 tons.

Due to limited availability of suitable scrap, expanding EAF requires reducing iron mineral to feed it to an EAF, similarly to the initial stages of the BF-BOF route.

This can be accomplished by Direct Reduction of Iron, which involves subtracting oxygen from minerals by burning it with natural gas or hydrogen. As of the end of 2024, there were over 100 such plants operating worldwide.

Current actions to decarbonize the industry include the following:

- Designing and realizing burners that can work with NG/H2 mixture, up to 100% hydrogen, tracking the performance of hydrogen burner in replacement of methane and evaluating H2 effect on steel quality, as ongoing by CELSA (Spain) and FERRIERE NORD (Italy).
- Designing facilities for safe storage, transport and injection of hydrogen, enriched by Life Cycle Assessment (LCA) analysis.
- Evaluating DRI+EAF and other decarbonization routes for further diffusion [62]

7. Case study

7.1 Application case

To appreciate the implications of green hydrogen introduction in an EAF-steelmaking plant, the rather common case of a facility with annual production capacity of 450.000 tons can be evaluated. This plant operates with a 90 tons net steel batch size, 1 hour cycle time (tap-to-tap) and works 48 weeks/y from Monday 6:00 to Friday 22:00 with 0.94 service factor.
There are about 100 such facilities in the EU (and over 150 in North America), with 60 located in France, Germany, Italy and Spain. These plants consume on average 2.8 GJ of thermal energy per ton of steel, ie 28,3 Mm3/year of natural gas.

7.2 Green Hydrogen for the case

It is known that EAF burners can accommodate a 20% replacement of natural gas with green hydrogen, without significant modifications.
For this case, hydrogen annual requirement will be 1,600 tons, which can be produced by three 5 MW PEMEL, fed by 80 GWh electricity annually.
PEMEL is chosen for its adaptability to renewable power fluctuations, although improvements are needed (and are ongoing) to ensure the assumed lifetime of 10 years.
Figure 7 shows in yellow the facilities included in a typical 5 MW electrolyzer package.
The Balance Of Plant (BOP) for this case includes hydrogen compression and storage, power station with electrical and control facilities and civil works.

7.3 Economics

In this case study, it is suggested that steelmakers plan, justify and get authorizations for green hydrogen production within their assets.

Incentives should be provided by the relevant authority to ensure a sufficient return on investment, assumed to be 6%.

If the Renewable Energy (RE) feed is solely photovoltaic, with an average capacity factor of 0.14 at 45°N latitude, a capacity of 66 MW on about 60-hectare surface is required. Alternatively, other RE sources may be used or bilateral Power Purchase Agreements (PPA) with RE producer(s) may be used, following the additionality principle. defined by EU Renewable Energy Directive II (RED II).

To expand PEMEL opportunities and achieve economies of scale, it may be beneficial to consider the cancellation, limitation or deferral of this requirement as part of the authorization process.

Table 1 shows economics for two scenarios, with the same BOP:

- Own RE supply, where RE generation constitutes two-thirds of the investment.
- External RE supply at 1Q2025 prices, where RE supply accounts for two-thirds of the running cost.

Both scenarios achieve hydrogen costs around 6 €/kg.

For the first scenario, if grid connection is insufficient, additional investment in batteries may be evaluated, considering that:

- PEMEL is rather flexible for fluctuating power supply,
- RE generation is sized to supply 20% of steel plant's heat requirements annually,
- in emergencies hydrogen supply can be reduced or power can be sourced from the grid.

7.4 System effects

To ensure a 6% return on investment, as shown in the table below, steelmakers require an incentive of 10,4 M€/y for 10 Mt/y CO_2 saving, ie. about 1 €/t CO_2 saved.

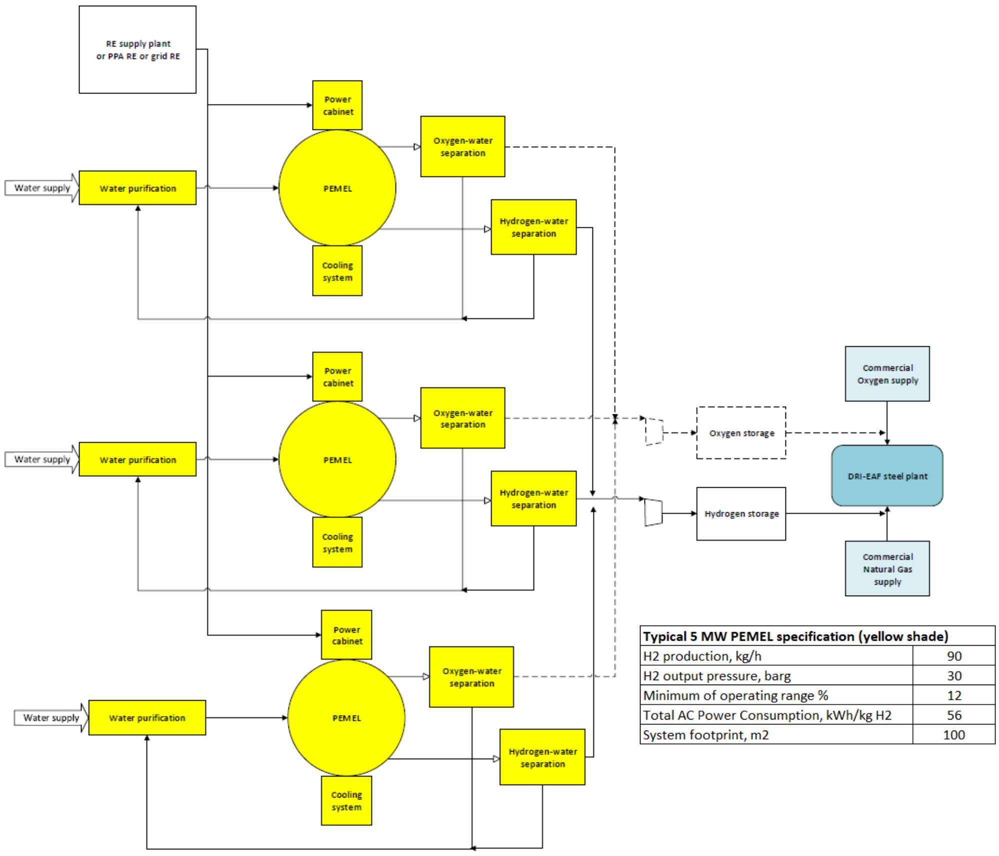
Thanks to economies of scale assumed in par.3 above, incentives will diminish, as the green hydrogen price drops to around 2-3 €/kg, aligning with the cost of natural gas.

It must be noted that the 3 electrolyzers require about 14.000 m3 of water to replace with hydrogen 20% of natural gas consumption by the steel plants. This quantity will be recycled by the combustion of hydrogen and can be sourced from salt water, if necessary, as discussed later in this paper.

Since scrap volumes are not sufficient to feed all EAF's, some mineral ore must be used and chemically reduced by removing oxygen via Direct Reduction of Iron (DRI), using natural gas or hydrogen, which will increase the required incentive.

However, for the purpose of this work, comparing the cost of scrap-fed EAF incentives with learning rate results and life cycle effects is sufficient.

Assuming one-third of EAF plants adopt in 10 years the 20/80 hydrogen/natural gas blend, this will require around 1200 MW of new PEMEL capacity. If a 20% learning rate occurs, similar to PV, hydrogen cost will drop below 2€/kg, potentially eliminating the need for incentives. Initial incentives will be similar to the budget allocated for EU Fuel Cells and Hydrogen (FCH) and Fuel Cells and Hydrogen 2 (FCH 2) Joint Undertakings (JUs), with no immediate result in emissions reduction.



Typical 5 MW PEMEL specification (yellow shade)	
H2 production, kg/h	90
H2 output pressure, barg	30
Minimum of operating range %	12
Total AC Power Consumption, kWh/kg H2	56
System footprint, m2	100

Figure 7 – 500 kt/y DRI-EAF with 3x5 MW PEMEL flow diagram and specification

Table 1 – Economics of Green Hydrogen Production with Own vs. External RE supply

Hydrogen production, kt/y	1.6											
Power requirements, GWh	80											
	2025						**2035**					
PEMEL investment, Eur/W	1						0.3					
PV investment, Eur/Wp	0.7						0.2					
RE PPA power price, Eur/kWh	0.06						0.02					
	Own RE supply			***External RE supply***			***Own RE supply***			***External RE supply***		
Green Hydrogen Investment	units	Meur/un	Meur	units	Meur/un	Meur	units	Meur/un	Meur	units	Meur/un	Meur
Electrolyzers	3	5	15	3	5	15	3	1.5	4.4	3	1.5	4.4
PV plant, MW	66	0.7	46				66	0.2	13			
BOP+H2 compression & storage			10			10			6			6
Total investment			71			25			24			10
Green Hydrogen Production Cost												
Oxygen credit, t O2/t H2	8	-0.04	-0.3	8	-0.04	-0.3	8	0.0	-0.3	8	-0.04	-0.3
Power supply+transport&overhead, GWh				80	0.08	6.4				80	0.04	3.2
Water supply + O&M, 2% investment			1.4			0.5			0.5			0.2
Depreciation 10y PEMEL, 20y BOP			4.3			2.0			1.4			0.7
ROI 6%			4.3			1.5			1.4			0.6
Hydrogen cost, eur/kg			6.1			6.3			1.9			2.8
Eur/kWh from Hydrogen			0.18			0.19			0.06			0.08

Note: The 3 electrolyzers of this case produce 1,6 kt H_2/y (and 13 kt/O2, about 50% of EAF requirements) leading to a unit cost of 6 €/kg, ie. 0,18 €/kWh vs. 0,05 from natural gas; incentive for a 6% ROI is therefore (0,18-0,05) €/kWh x 80.000.000 kWh = €. In 10 years, with economies of scale assumed in par.3, H_2-kWh cost will be close to natural-gas-kWh.

7.5 Assumptions and sensitivities

EAF and PEMEL standards have been used in the simulation, as outlined above.
Lifetime is assumed 10 years for PEMEL and 20 years for BOP.
Required ROI is assumed 6%.
2035 RE PPA price is assumed 0.02 €/kWh (+0,02 transport & overhead)

The following sensitivities can be calculated:

- Sensitivity to a 3 years shorter lifetime for both leads to 2035 external RE supply H_2 cost of € 2,9/kg
- Sensitivity to 10% leads to 2035 external RE supply H_2 cost of € 3,1/kg
- Sensitivity to 0,03 €/kWh leads to 2035 external RE supply H_2 cost of € 3,3/kg

Although these H2 costs are not competitive with 2024 natural gas prices, they represent a significant improvement and would have been competitive in other timeframes, such as year 2022.

7.6 Risks Mitigation

The proposed approach considers some risks, and their mitigation, as follows:

- Power price volatility: Incentives should compensate for the extra cost of H_2-kWh vs. fossil-kWh
- Technical reliability and performance shall be included in EPC contracts guarantees
- Social acceptance shall be seeked as required by local standards and habits, trading off extra cost with lower pollution and higher security

8. Life Cycle Assessment of PEMEL for EAF steel plants

A Life Cycle Assessment (LCA) must provide the main environmental indicators for the use of green hydrogen in current EAF steelmaking worldwide.
A comprehensive review of hydrogen production LCA for mobility in Germany under different energy scenarios [53] cites previous studies mostly addressing the GHG component:

- Electrolysis with wind power supply emits 0,97 kg CO_2 per kg H_2
- Electrolysis with PV power supply emits 2,4 kg CO_2 per kg H_2
- Steam Methane Reforming emits 11,9 kg CO_2 per kg H_2, or 3,3 with Carbon Capture and Sequestration

and states that electrolysis GHG impact is due to over 90% to electricity supply.

It analyzes the years 2017 (34% RE) and 2050 (60% RE), with an option to limit electrolysis to 3000 h to benefit of 100% RE). On top of GHG emissions (defined as Climate Change or CC), it considers six other impact categories: Ozone depletion (OD), Terrestrial acidification (TA), Human toxicity (HT), Particulate oxidant formation (POF), Particulate matter formation (PM) and Metal depletion (MD).
The Life Cycle Inventory (LCI) considers stack technology evolution with substantial reduction and recycling of expensive components and BOP including 0,1 TWh pump storage and 0.5 TWh hydrogen storage.

The results show that:

- PEMEL is a viable alternative to conventional steam methane reforming production and is flexible enough to fit into hours with volatile electricity production having very high shares of renewables, contributing to a significant reduction of greenhouse gas,
- The composition of the electricity mix mainly determines the impacts on Climate Change,
- Influence of system components plays a minor role, but critical materials are relevant,
- Results are subject to the restriction of using existing databases, not including increases of efficiency in energy production technologies (e.g. solar panels materials, emission factors etc.)

Another study [54}, although relevant to all green powerfuels (ie. hydrocarbon-based renewable energy carriers and feedstocks) and not following ISO 14044 standard, is worth considering, for the analysis of other components, such as biodiversity loss, land-system change, freshwater use and hydrogen leakage.

Also relevant is Ref. [59], which, through a Multi Criteria Decision Making technique, compares AEL and PEMEL, showing an economic advantage for AEL, offset by the better flexibility of PEMEL.

For the purpose of this paper, it is interesting to evaluate different components to understand whether the selection of EAF steelmaking to achieve economies of scale is appropriate from an economic and environmental perspective.
Compared to other HTA sectors, as previously discussed, steelmaking is the highest contributor to GHG and therefore initiatives to decarbonize it are probably a priority.
The LCA made using LCA Calculator (https://pro.lcacalculator.com/) shows that the suggestion of this paper has few drawbacks:

- PEMEL requires critical materials: use minimization is a major R&D effort by all manufacturers, recycling has yet to be started but will represent a major effort too.
- PV power supply, although in a less LCA impacting agrivoltaics form, requires too much land and may lead to a phasing of PEMEL modules investment according to the power availability, or be complemented with other sources of power, through PPA or, if additionality criteria can be waived, through other existing renewable sources.
- Safety standards must be imported and adapted to new uses from what has been learnt in current uses, such as petrochemical.

Water sourcing, also according to other literature [55], is unlikely to be a big problem.

As water is obtained from hydrogen combustion in the end-uses, its use for hydrogen production is unlikely to waste much of this precious resource.

However, seawater can also be considered, either with appropriate membranes [56] or by purification systems (eg. Reverse Osmosis) with integrated dehydration of brine to produce salt in replacement of current marine or mining facilities; but in this case, saltwater feed must be transported to the PEMEL-EAF facilities, which is difficult for many cases.

Each case can be studied by Proposers and submitted to environmental impact assessments, provided that a support policy as outlined above is planned, including particularly the possibility of waiving Renewable Energy (RE) additionality of RED II, if enough power cannot be supplied through own investment or PPA, eventually phased.

This is not different from what has been done in the last 20 years for other RE projects.

9. Conclusions

a. To fight climate change, electrification with use of Renewable Energy (RE), who has reached 40% of global power generation in 2024, is not applicable to some sectors requiring high temperature heat, difficult to provide by electrification, known as Hard-To-Abate (HTA).

b. For these sectors, emissions must either be captured or avoided by burning hydrogen generated from water electrolysis with RE, resulting in non-carbon emissions (so-called "green"), but with current kWh cost much higher than kWh from fossil fuels.

c. To reduce green hydrogen kWh cost, economies of scale are desirable, as experienced in the photovoltaic (PV) and LFP battery industries in recent decades. Therefore, it may be useful to find an HTA sector in which to concentrate available resources, along with ongoing long-range planning and R&D efforts.

d. The steel industry appears a priority, due to its economic and environmental importance, and to the numerous Electric Arc Furnace (EAF) plants, which allow hydrogen application, also for the integration of Direct Iron Reduction to supplement limited scrap steel availability. Other HTA sectors are probably more interested in other forms of decarbonization. For the steel case:

   - To limit technical complications in the end-use, hydrogen may be used in 20% blend with natural gas.
   - A project proposal can be made by each steelmaker, including Proton Exchange Membrane ELectrolyzers (PEMEL), RE supply, water sourcing and hydrogen storage. If it is authorized after examination by competent Authorities, it obtains subsidies allowing the steelmaker a satisfactory return on investment.
   - It is challenging to provide for the whole RE needs of the projects, so waiver to EU RED II additionality or phasing of investments (and subsidy) to Power Purchase Agreement availability to the Proposer must be considered.
   - Life Cycle Assessment (LCA) of the suggested prioritization suggests also the need to continue working on PEMEL improvements, particularly in increasing current density (which decreases weights and cost) and reducing/recycling critical materials, which represent the major LCA impact after power production.

As closure, it has to be noted that low impact hydrogen diffusion is difficult and there have been some false start in the past; many studies and pilot projects have been financed, from industrial to transport uses, piping networks and international trade have been explored, giving rise to a multitude of options which make decisions on investments more complex.

This paper tries to show some of the difficulties related to a specific application, the steel industry. Perhaps, as it is suggested by some [56] [57] [58], they may be better tackled if, instead of waiting for the harmonization of plans for the whole picture of green hydrogen diffusion, it is left to interested industrialists to make their own business plan, including assets design, power supply decisions, etc., to be submitted for authorization, as for other RE facilities.

After authorization, Public Authorities may accord financial support and adaptation of RE supply. This will allow the electrolyzers market to expand, which, together with PV cost reduction, should reduce the need for public support to green hydrogen end uses to the cases where specific investments are required, such as process modifications, e.g. for using 100% hydrogen.

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DECARBONIZING THE U.S. GRID: AN OPTIMIZATION-BASED STUDY

Aastha Bindra
M.Sc. School of Engineering and Design, Technical University of Munich
Email: aasthabindra25081999@gmail.com

Thushara Addanki
M.Sc. Chair of Renewable and Sustainable Energy Systems, Technical University of Munich
Email: thushara.addanki@tum.de

Thomas Hamacher
Chair of Renewable and Sustainable Energy Systems, Technical University of Munich

Abstract

Decarbonizing the United States electricity grid is essential to meeting long-term climate goals. This thesis investigates the future development of the United States electricity grid using a lin- ear optimization model that simulates hourly operations across nine defined regions from 2022 to 2050. The study takes into consideration a wide range of scenarios covering demand variation, technology costs under different policy landscapes, and new decarbonization technology deploy- ments. Core components include renewable energy technologies, fossil fuel capacity, battery and hydrogen storage, carbon capture systems, and CO_2 pricing.
Results show that solar PV and onshore wind dominate capacity additions in all scenarios owing to their low costs. Without CO_2 restrictions, fossil fuel use remains high through 2050. Scenarios that introduce carbon pricing or emissions caps show a faster decline in coal and natural gas, with a corresponding increase in clean technologies. Carbon capture is included in the model but has a limited impact overall, due to high investment costs and the fast growth of competitive renewable energy sources. These results indicate that decarbonizing the electricity grid requires consistent policy support, careful system planning, and technological progress, all balanced with a policy framework that ensures consumer affordability.

1. Introduction

Optimizing the electricity grid for the United States of America is a growing necessity, and it is a challenge to achieve this while maintaining system reliability and affordability. The electric- ity sector remains one of the largest contributors to national greenhouse gas emissions, despite increasing deployment of renewable energy technologies. While wind and solar capacity have expanded rapidly over the past decade, fossil fuels, particularly coal and natural gas, continue to dominate electricity generation. This persistence reflects not only legacy infrastructure but also policy uncertainty and regional heterogeneity across the United States.
Recent federal policy efforts, such as the Inflation Reduction Act, have aimed to accelerate the deployment of clean energy through subsidies, tax credits, and support for emerging technologies. At the same time, sharp political contrasts between administrations have created uncertainty for long-term investment planning. Changes in regulatory priorities, carbon pricing mechanisms, and clean energy incentives directly influence technology choices and system evolution. This policy volatility complicates efforts to design robust decarbonization pathways for a system as large and interconnected as the U.S. electricity grid.
In parallel, emerging technologies such as carbon capture and storage (CCS) and clean hydrogen have gained attention. Carbon capture is often proposed as a means to reduce emissions from existing fossil-based generation, while hydrogen offers flexibility as an energy carrier and storage medium. However, the economic competitiveness and system-level impacts of these technolo- gies remain uncertain, particularly when compared with the rapidly declining costs of renewable generation and battery storage.
This paper presents a comprehensive optimization-based analysis of the future U.S. electricity system through 2050. The study employs a linear programming framework to assess cost-optimal investment and dispatch decisions across a diverse range of demand, cost, and policy scenarios. The analysis focuses on identifying dominant technology pathways, assessing the role of policy instruments such as CO_2 pricing and emission caps, and assessing the system-level contribution of CCS, hydrogen, and nuclear energy.

2. Overview of the U.S. Electricity System

The United States electricity grid is characterized by its large geographic scale, regional diver- sity, and fragmented governance structure. The system is broadly divided into three synchronous interconnections: the Eastern Interconnection, the Western Interconnection, and the Texas Inter-connection. Within these interconnections, electricity generation and transmission are managed by numerous balancing authorities and utilities, resulting in a complex and decentralized system.
For modeling purposes, the national grid is aggregated into nine regions shown in *Figure 1*. This regional configuration is based on a combination of electricity consumption patterns and trans-mission planning areas, ensuring alignment with available data while maintaining computational tractability. These regions form the spatial basis for all simulations conducted in this study.

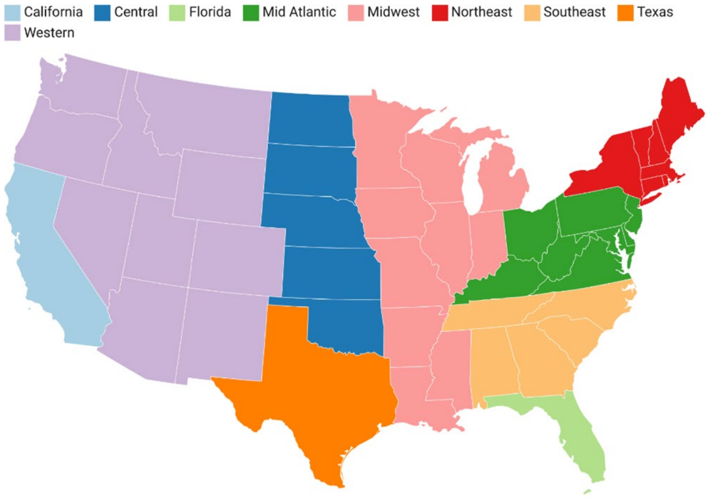

Figure 1 - Final Regional Grid Configuration

In 2022, the U.S. electricity mix remained heavily reliant on fossil fuels, refer to Figure 2. Natural gas and coal together accounted for the majority of generation, while nuclear power provided a stable share of baseload electricity. Renewable energy sources, primarily wind and solar, contributed a growing but still limited fraction of total generation. Hydropower and geothermal resources played a minor role at the national level, with significant regional variation.

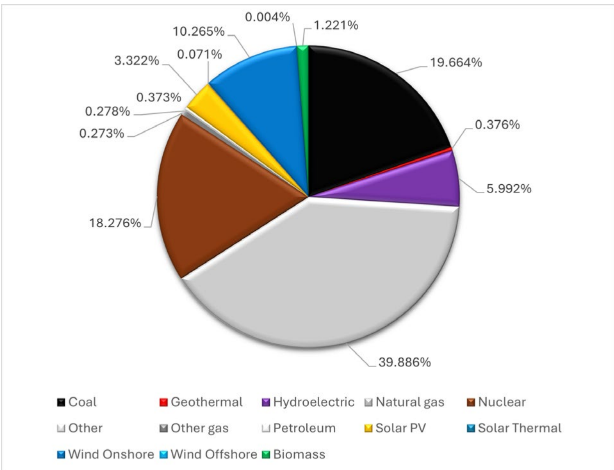

Figure 2 - Electricity Distribution by Source in 2022

Installed capacities shown in *Figure 3* reflects similar patterns. Fossil fuel technologies dominate capacity in most regions, although wind capacity is substantial in the Midwest and Central regions, and solar capacity is concentrated in California and the Western United States. These existing infrastructure patterns strongly influence near-term system behavior and investment decisions.

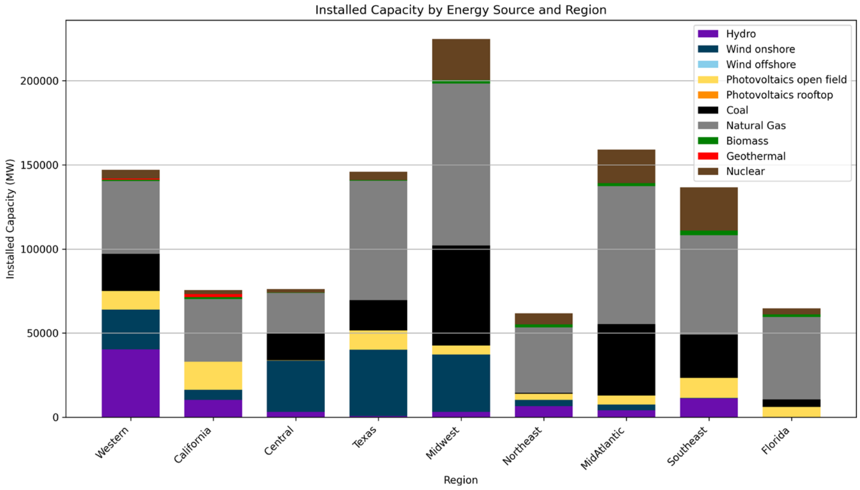

Figure 3 - Installed Capacity by Technology in 2022

3. Renewable Energy Resources and Decarbonization Technologie

The renewable energy potential of the United States is substantial and geographically diverse shown in *Figure 4*. Using spatial resource assessment tools, this study identifies significant po- tential for solar photovoltaic and onshore wind deployment across most regions. Solar potential is particularly high in the Western and Southwestern regions, while onshore wind resources are strongest in the Central and Midwest regions. Offshore wind potential exists primarily along the Atlantic coast but is constrained by higher costs and siting challenges.

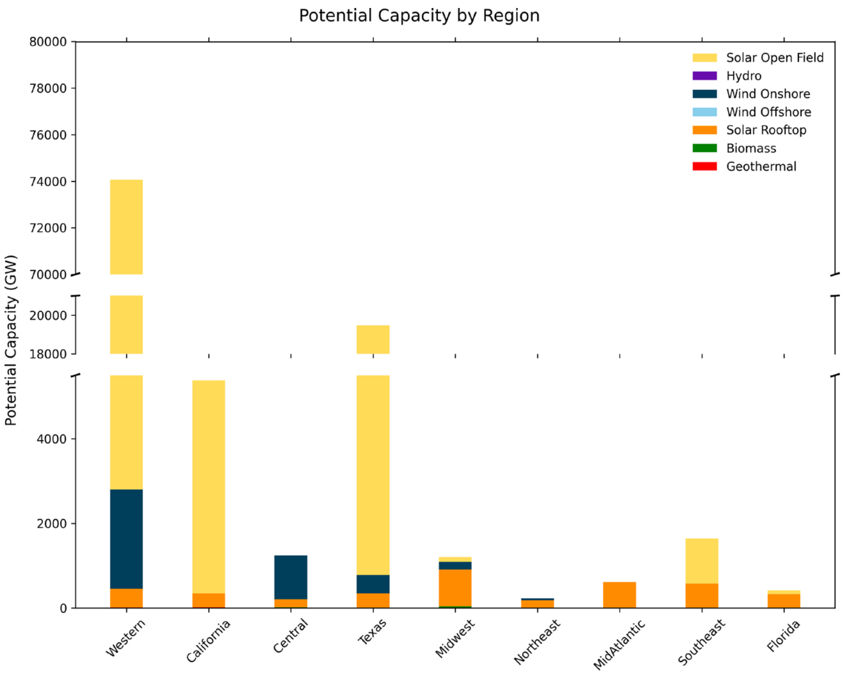

Figure 4 - Potential Capacity of Renewable Technologies

Hydropower provides stable generation in selected regions but offers limited expansion potential due to geographic and environmental constraints. Geothermal resources are regionally concen- trated and remain a niche contributor under most scenarios. Biomass is included as a dispatchable renewable option, though its contribution is limited by fuel availability and emissions considera- tions.
Carbon capture and storage is modeled as both a retrofit option for existing coal and natural gas plants and as an integrated component of new fossil generation. CCS retrofits are designed to capture a large fraction of CO_2 emissions while imposing an energy penalty on electricity out- put. Although the United States has significant geological storage capacity, CCS deployment is constrained in the model primarily by cost rather than storage availability.
Hydrogen is incorporated as final energy demand within the system. Existing hydrogen production is assumed to be supplied by steam methane reforming in the base year. Future capacity expan- sion is restricted to water electrolysis, reflecting decarbonization objectives. Electricity inputs to electrolysis are tracked by source to evaluate emissions impacts.

4. Methodology

4.1 Modeling Framework

The analysis is conducted using the linear optimization model *urbs*, developed at the Technical University of Munich. The model minimizes total system cost subject to meeting electricity and hydrogen demand, technology constraints, and policy conditions. It operates at an hourly temporal resolution, allowing detailed representation of variable renewable generation and storage behavior.
The model is validated for the year 2022 using historical data on electricity generation, demand, and capacity. Subsequent optimizations are performed for 2030, 2040, and 2050 using a myopic approach, where results from each period are carried forward as inputs for the next. This structure captures gradual system evolution while maintaining computational feasibility.

4.2 Demand Modeling

Electricity demand is projected using a top-down regression approach linking electricity consump- tion per capita to GDP per capita. Historical data from 1997 to 2022 is used to estimate income elasticity parameters for each region. A power-law function is used,

$$E = aY^b,$$

where E is electricity consumption per capita, Y is GDP per capita, a is a regression constant, and b is the income elasticity of electricity demand. Demand is disaggregated into residential, commercial, and industrial components. Electric vehicle demand is modeled separately using adoption projections from national energy outlooks and ap- plied load profiles to distribute charging demand over time. Demand projections have been shown in *Figure 5*.

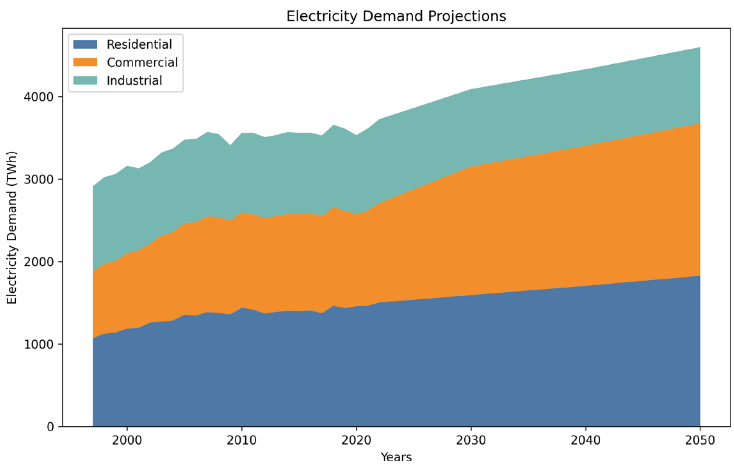

Figure 5 -Projected Electricity Demand Across Sectors

Hydrogen demand is derived from global net-zero scenarios and allocated regionally based on industrial economic activity and are shown in *Figure 6.*

4.3 Cost Assumptions and Scenarios

Technology investment costs, fuel costs, and CO_2 prices are drawn primarily from the International Energy Agency and the National Renewable Energy Laboratory. Three policy cost pathways are considered: Stated Policies (STEPS), Announced Pledges (APS), and Net Zero Emissions (NZE). These pathways reflect differing levels of climate ambition and technology advancements.
The assumed scenarios except the policy-rollback scenario have been shown in *Figure 7*

Scenario	Cost Type	Demand	CO_2 Pricing	CO_2 Limit	Nuclear Expansion	CCS Implementation	Hydrogen Integration
STEPS	STEPS	Reference					
STEPS_HD	STEPS	High					
APS	APS	Reference					
APS_HD	APS	High					
NZE	NZE	Reference					
NZE_HD	NZE	High					
APS_CO₂	APS	Reference	✓				
NZE_CO₂+	NZE	Reference	✓	✓			
NZE_CCS	NZE	Reference				✓	
NZE_CCS_CO₂+	NZE	Reference	✓	✓		✓	
NZE_NUC	NZE	Reference			✓		
NZE_CCS_NUC	NZE	Reference	✓	✓	✓	✓	
NZE_HYD	NZE	Reference					✓
NZE_HYD_CO₂+	NZE	Reference	✓	✓			✓

Figure 7 - Scenario Assumptions Matrix

Scenario variations include demand sensitivity cases, CO_2 pricing and emission caps, nuclear expansion, CCS availability, hydrogen integration, and a policy rollback case reflecting reduced support for clean energy technologies. Emission caps are set to reach net-zero electricity sector emissions by 2050 in relevant scenarios.

5. Results

5.1 Baseline Cost and Demand Sensitivities

Figure 8 shows the results across baseline scenarios without explicit CO_2 constraints, the electricity system evolves toward higher shares of renewable generation, driven primarily by cost declines in solar PV and onshore wind. Open-field solar PV emerges as the dominant capacity addition in all regions, with cumulative capacity exceeding several hundred gigawatts by 2050. Onshore wind also expands steadily, though to a lesser extent.

Despite this growth, fossil fuel generation remains significant in the absence of emissions constraints. Natural gas continues to provide dispatchable generation, while coal declines slowly but does not fully exit the system. Differences between reference and high-demand cases are limited, indicating that increased electrification does not fundamentally alter the optimal technology mix.

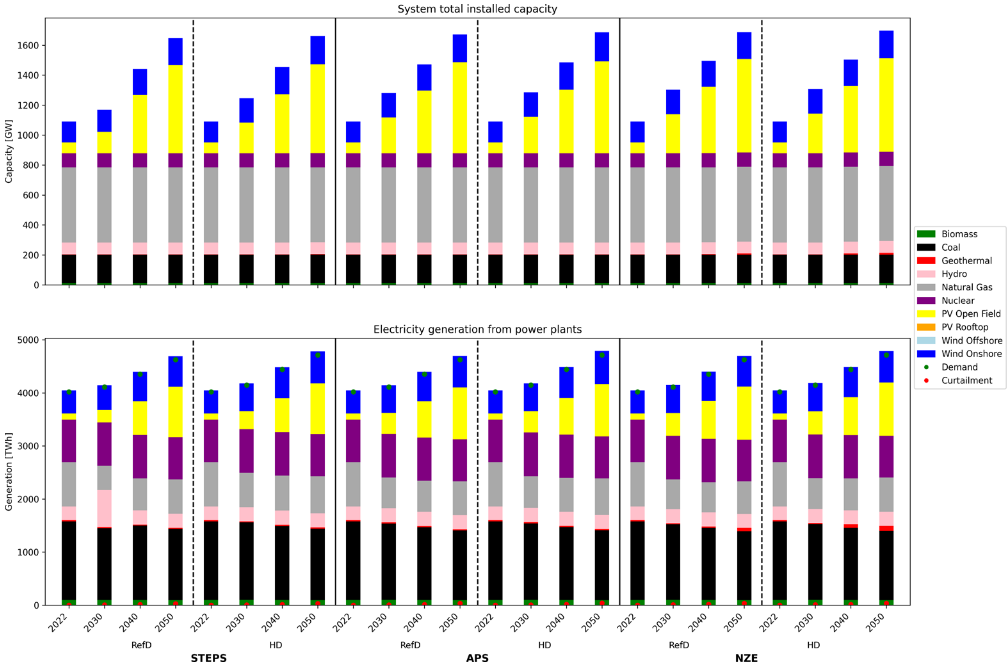

Figure 8 - Electricity Mix across Scenarios

5.2 Impact of CO_2 Pricing and Emissions Caps

Introducing CO_2 pricing or binding emissions caps leads to a rapid reduction in fossil fuel generation. The results for scenarios APS_CO_2 and NZE_CO_2+ are shown in *Figure 9*. Coal is phased out first, followed by declining natural gas generation toward mid-century. Renewable generation and battery storage expand to meet demand and balance variability.
Electricity system costs increase modestly under these constraints but remain within a narrow range across scenarios. The cost impact is driven primarily by accelerated investment rather than operational penalties, highlighting the affordability of deep decarbonization under current cost trends.

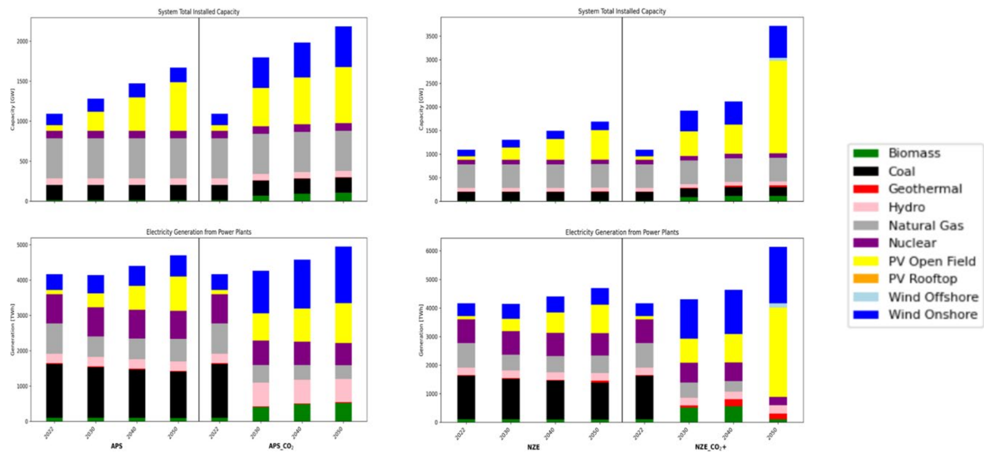

Figure 9 - Electricity Mix for APS_CO_2 and NZE_CO_2+

5.3. Role of Carbon Capture and Storage

The deployment of carbon capture and storage remains limited across most modeled scenarios. While CCS is available both as a retrofit option for existing coal and natural gas plants and as a component of new fossil-based generation, it is consistently outcompeted by renewable technolo- gies and storage on a cost basis. The energy penalty associated with capture, combined with high capital costs, reduces the net electricity output of CCS-equipped plants and increases system costs.

Under scenarios with no CO_2 restrictions, existing fossil units continue to operate without retrofits, as the additional cost of CCS outweighs avoided emissions costs. Only under strong climate policy conditions, characterized by high CO_2 prices or binding emissions caps, does CCS enter the opti- mal solution. Even in these cases, deployment remains modest and concentrated in regions with existing fossil infrastructure and relatively high residual demand for firm generation. *Figure 10* show the results for scenario NZE_CCS_CO_2.

The results indicate that CCS does not function as a primary decarbonization pathway within the electricity sector. Instead, it serves as a marginal compliance option under stringent policy constraints, filling small gaps where renewable expansion or storage deployment is insufficient or economically unfavorable

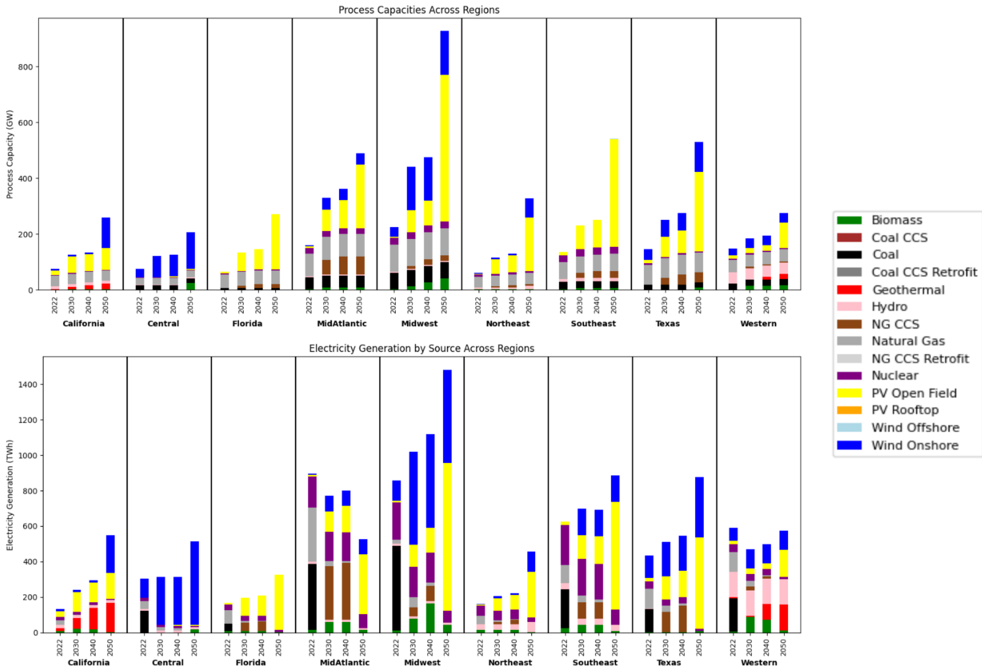

Figure 10 - Electricity Mix for NZE_CCS_CO_2

5.4 Nuclear Expansion

Figure 11 shows the electricity mix for scenarios NZE_NUC and NZE_CCS_ NUC.

In the NUC scenario, no CO_2 limits or costs are applied, so the system largely retains the existing fossil-heavy capacity mix and relies on already-built infrastructure. New investments are limited to onshore wind and PV open field, added only to meet incremental demand. Nuclear capacity remains unchanged, as it is not economically competitive without carbon penalties.

By contrast, the CCS_NUC case applies both a CO_2 price and a cumulative CO_2 limit, forcing a gradual phase-out of fossil fuels. Under these constraints, nuclear becomes economically at- tractive, with significant deployment before 2040. By 2050, nuclear supplies nearly 50% of total electricity generation, replacing fossil capacity and complementing wind and solar. This transition is driven by fossil emission penalties and nuclear’s lower LCOE under carbon pricing.

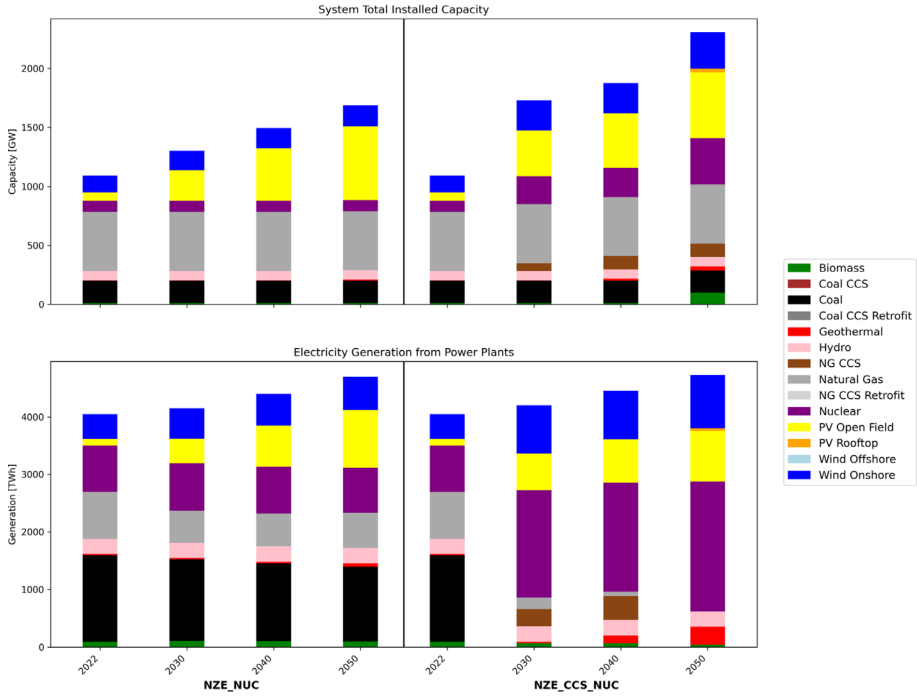

Figure 11 - Electricity Mix for NUC & CCS_NUC

5.5 Policy Rollback Scenario

The policy rollback scenario reflects reduced support for clean energy technologies through higher investment costs for renewables and storage (*Figure 12*).

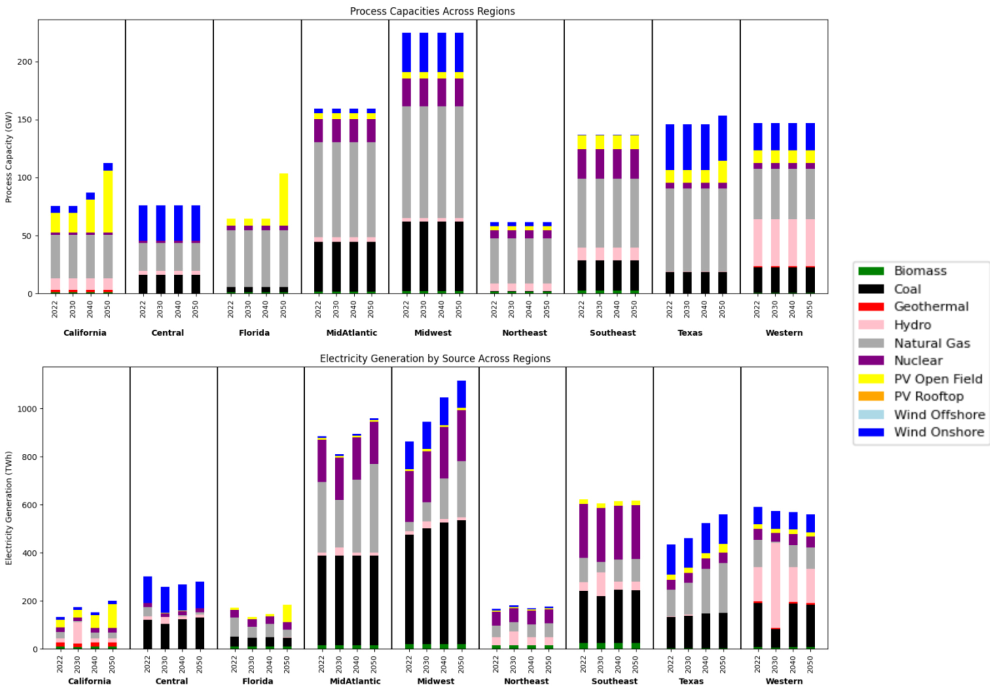

Figure 12 - Electricity Mix for policy-rollback scenario

Under these conditions, deployment of solar PV, wind, and batteries slows relative to other scenarios. Fossil fuel generation, particularly natural gas, retains a larger share of the electricity mix for a longer period.
The delayed transition results in higher long-term emissions despite similar near-term system costs, underscoring the importance of early and consistent policy intervention.

5.6 Hydrogen Integration

Integration of hydrogen does not fundamentally alter the electricity generation mix. Its primary impact lies in increasing overall demand while reinforcing the dominance of low-cost renewable technologies. As shown from the results in *Figure 13* the introduction of CO_2 pricing and emis- sions constraints accelerates the phase-out of fossil fuels, with coal nearly eliminated and natural gas significantly reduced. Renewable energy expands rapidly, driven by higher electricity demand from electrolysis and stricter environmental limits. However, the 2050 model becomes infeasible, revealing a structural limitation: electricity supply is insufficient to support both full decarboniza- tion and large-scale hydrogen production. Despite substantial renewable growth, generation cannot meet combined direct electricity demand and electrolysis requirements, constraining the system's ability to achieve carbon neutrality.

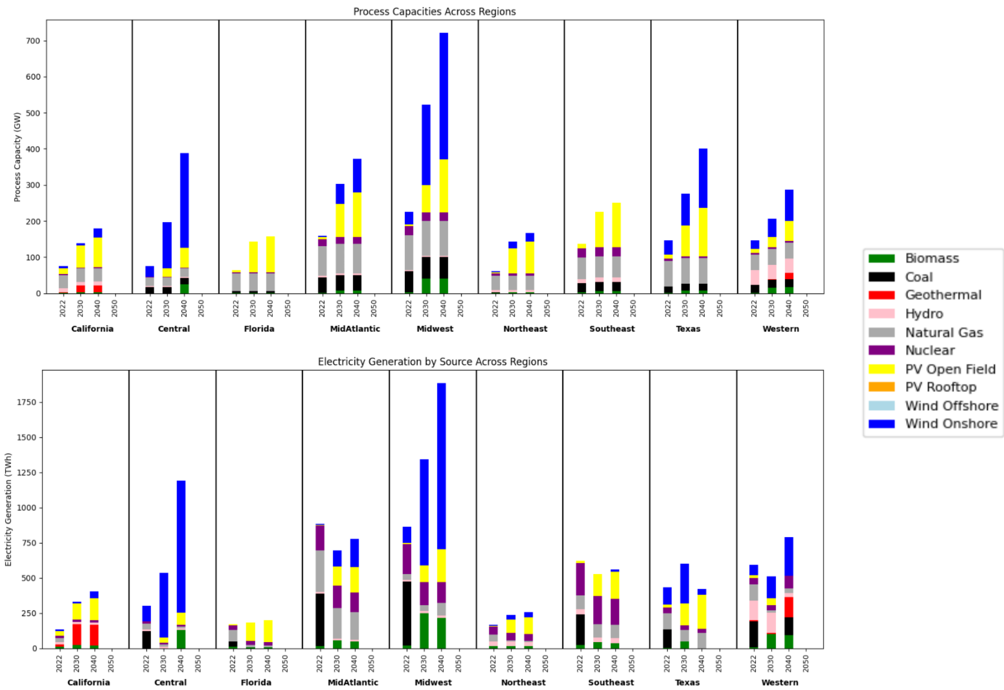

Figure 13 - Electricity Mix for HYD_CO_2+

5.7 System Cost and Emissions Outcomes

Figure 14 shows the electricity cost and total carbon emission projections across all scenarios for the years 2030, 2040 and 2050.

Electricity cost projections for 2030-2050 show clear differences across policy scenarios. Moderate pathways such as STEPS and APS maintain relatively stable costs, indicating limited affordability impacts. In contrast, aggressive decarbonization scenarios with high CO_2 pricing (APS_CO_2, NZE_CO_2+, and CCS_CO_2+) experience substantial cost increases by 2050, in some cases nearly doubling, raising concerns about long-term affordability.

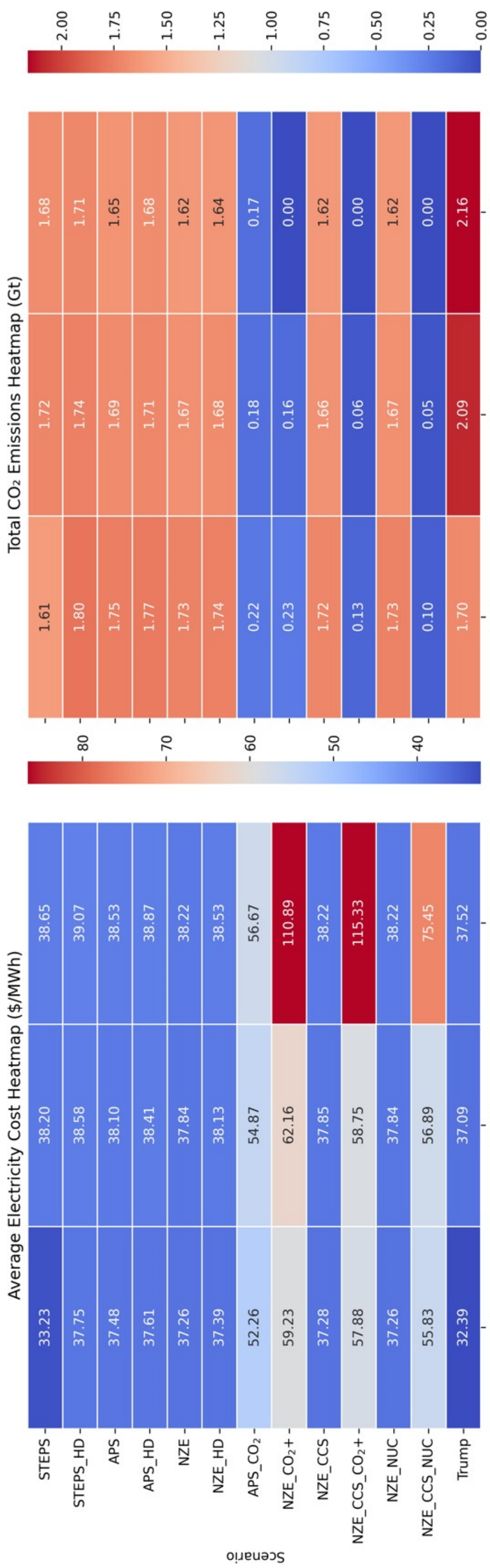

Figure 14 - Electricity cost and System Emissions Heatmaps

Nuclear energy plays a key role in moderating these increases. While CCS-only scenarios un- der strict emissions pricing show sharp cost escalation, the CCS_NUC scenario maintains a more gradual cost trajectory, suggesting that nuclear integration can stabilize electricity prices while supporting emissions reductions.
Overall, the results highlight the need for balanced energy policies that achieve climate goals without undermining economic feasibility.

6. Conclusion and Discussion

This study demonstrates that decarbonizing the U.S. electricity grid by 2050 is technically feasi- ble and economically viable. The modeling results show that declining renewable costs are the dominant driver of system transformation. Solar PV and onshore wind form the core of the future electricity system across all scenarios, supported by storage and limited firm generation, reflecting sustained cost reductions across most regions of the United States.
Policy instruments such as CO_2 pricing and emissions caps primarily influence the speed and completeness of fossil fuel phaseout rather than the underlying direction of technological change. In scenarios without emissions constraints, fossil fuels remain in the system for longer periods, resulting in higher cumulative emissions. Under strong climate policy, coal exits earlier and natural gas generation declines steadily toward mid-century, indicating that policy intervention remains essential for timely emissions reductions.
Carbon capture plays a constrained role due to cost and efficiency penalties. Although CCS is technically available, it is consistently outcompeted by renewable generation combined with storage and enters the system only under stringent policy conditions. CCS therefore functions as a complementary option to address residual emissions rather than a central decarbonization pathway.
Hydrogen integration increases electricity demand through electrolysis while providing additional system flexibility. Hydrogen production is largely driven by low-cost renewable generation and does not fundamentally alter investment decisions in electricity supply. Nuclear expansion offers a pathway to reduce reliance on fossil baseload and lower system costs under net-zero conditions, though its deployment depends on factors beyond the scope of the model.
Policy uncertainty remains a key risk for long-term system planning. Delayed or inconsistent policy action increases cumulative emissions despite relatively small differences in average system costs. Overall, the results show that cost-effective pathways to a low-emission U.S. electricity system exist, but their realization depends on sustained policy support.

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TECHNO-ECONOMIC ANALYSIS OF SIMPLE PRODUCTION AND CONSUMPTION SYSTEM FOR HYDRO POWER PLANTS: A CASE STUDY

Andrea Paolacci
Department of Astronautical, Electrical and Energy Engineering (DIAEE) Via Eudossiana 18, Rome, Italy
Email: andrea.paolacci@uniroma1.it

Maria Carmen Falvo
Department of Astronautical, Electrical and Energy Engineering (DIAEE), Via Eudossiana 18, Rome, Italy
Email: mariacarmen.falvo@uniroma1.it

Flavio Andreoli
Epico, Viale degli Ammiragli 67, Rome, Italy, Email: flavioandreoli@epico.green

Overview

Over the past two decades, the European Union adopted a complex set of measures and actions aimed at promoting energy efficiency and the use of renewable energy sources (RES). The common goal of these measures is to lead the transition to a decarbonised and more sustainable energy system. With these directives, the EU has set binding targets in terms of reducing greenhouse gas emissions and increasing the share of renewable energy in the EU gross final energy consumption, combining these targets with tools, strategies, and economic sources aimed at achieving them. One of the most recent measures is the RePower EU, adopted in 2022 to react to the energy crisis caused by the Russian-Ukrainian conflict. The main goal of the RePower EU is the reduction of the Union's dependence on imports of external energy sources, through diversification of supplies and a strong acceleration in the development of renewable power plants. For this reason, RePowerEU has raised the renewable share target on EU gross final consumption to 42.5% by 2030, compared to the previous target of 32% set by the RED II Directive (Directive 2018/2001/EU), has allocated new financial sources to supporting investments in the renewable sector.
Already the first EU actions allocated economic sources to promote the use of renewable energy favouring the introduction, in each Member State, of incentive mechanisms designed to stimulate investments in renewable power plants. These state grants, being highly profitable, allowed a rapid growth of renewable installed capacity in Europe. Currently, around 47% of the electricity produced in EU comes from RES, mainly from photovoltaic and wind power plants. Also in Italy energy policies and incentive mechanisms led to a growth in renewable installed capacity. In particular, from 2009 to 2013, there was a rapid increase in RES installed capacity thanks to the introduction of advantageous and easily accessible support schemes, such as “Conto Energia”, “Tariffa Omnicomprensiva” and “Certificati Verdi”. In the following years, however, with the reducing of incentive mechanisms, due to the rationalization and optimization of the financial sources, the development of renewable power plants decreased and the growth of RES installed capacity slowed to a plateau.

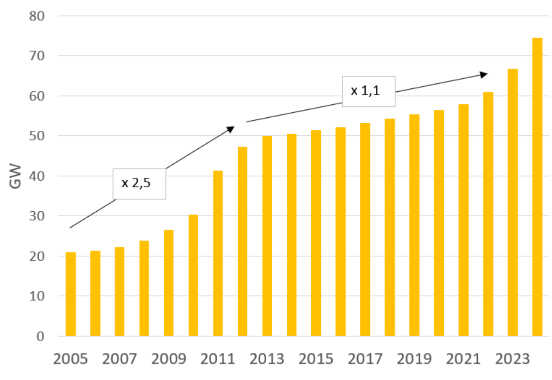

Figure 1 - Renewable energy installed capacity in Italy.

The growth of distributed generation, characterized by small and medium sized renewable power plants connected directly to the distribution grids, contributed to improving the energy sector environmental performance and, more generally, it helped the spread of more aware and actively involved end users. However, distributed generation significantly changed the architecture of the power system, accelerating the transition from a centralized and unidirectional model to a decentralized and bidirectional model. This change introduced new critical issues and poses several technical challenges including: local congestion, reverse power flows in LV/MV cabins, and voltage regulation issues. These aspects must be adequately faced to ensure efficient and reliable management of distribution grids. The EU has progressively recognized the need to address the development of distributed generation through more selective support mechanisms based on the real needs of the grid. The aim is to avoid to promote the widespread development of new renewable power plants and projects that do not guarantee an adequate return in terms of benefits, but which on the contrary risk to accentuate the critical issues precedently discussed, especially on local distribution grids.
In this context, the RED II gives a central role to self-consumption and to energy self-sufficiency introducing the concepts of virtual self-consumption and renewable energy communities. Virtual self-consumption refers to a sharing model in which the energy produced by a plant is shared with one or more consumption units located remotely, but however within a specific grid perimeter. In this model the energy is virtually self-consumed thanks to the use of the public distribution grid. Unlike direct self-consumption, therefore, spatial coincidence between production unit and consumption point is not required, as well as the private connection between the power plant and the consumption unit.
In Italy, the RED II Directive was implemented mainly through two legislative decrees: Legislative Decree 199/21 and Legislative Decree 210/21, both of which are relevant to the evolution of the regulation related to self-consumption of electricity. Legislative Decree 199/21 defines the rules to regulate virtual self-consumption and identifies the eligible configurations admitted to support schemes, including Renewable Energy Communities (REC). The support mechanism assigns an economic incentive to virtually self-consumed energy that is produced by new renewable power plants inserted in the configuration. The mechanism promotes a better alignment between production and consumption, so it promotes local energy management and consequently it contributes to the reduction of congestion, reverse power flows and grid losses. Despite the excellent purposes, the spread of virtual self-consumption configurations today is still limited and the overall impact on the power system is still marginal. This is probably also due to the requirements that limit the access to citizens, entities, small and medium sized business, leaving out operators with large investment capital, such as the big power producer companies, reducing the potential contribution of large-scale initiatives.
However, Legislative Decree 210/2021, although less well-known, addresses the regulation of direct self-consumption by introducing a new definition of a Simple Production and Consumption System (SPCS). This new definition enables physical self-consumption without power limits and without the access restrictions that characterize the virtual self-consumption configurations, making SPCSs potentially relevant also for industrial operators and companies active in power generation.
Within this context, this work aims to illustrate the features and the potential of an SPCS. The aim is to understand if these systems could be a concrete opportunity to ensure the economic sustainability of investments in new renewable power plants and, at the same time, if they could offer an alternative remuneration method for plants reaching the end of the incentive period. For this purpose, the paper shows a techno-economic analysis of a specific case study, discussing the essential steps for assessing the viability of deploying a SPCS.

The new definition of SPCS:

The new definition of a Simple Production and Consumption System (SPCS) describes a configuration in which a private power line connects one or more production units, owned by a subject as producer, to a consumption unit owned by a single end-user. To realize the system, the areas where the power plant and the consumption unit are located must be owned by at least one of the subjects belonging to the system; however, the private power connection may also cross areas not owned by the subjects, such as roads, waterstreams, or interposed territories.
The general and wide description allow to include within SPCSs all the configurations previously related to to direct self-consumption, in this way there is no longer any difference between the different direct self-consumption configurations that can be implemented. The definition contained in Legislative Decree 210/2021 simplifies and promotes homogeneity in the self-consumption regulation, making these systems more competitive.

Based on the new definition, the essential elements of an SPCS can be divided into:

- A private power line
- One or more production units
- A consumption unit
- A power producer
- A single end-user

The power producer and the end-user may coincide in the same subject. In this case, it will be a prosumer and self-consumption on site will therefore be managed spontaneously by the subject. This case represents the simplest Simple Production and Consumption System scheme. More interesting, also in relation to the case study analyzed in this work, are the systems in which the power producer is different from the end-user. In this particular case, the energy supplied via the private connection by the power producer is used locally by the end-user, reducing his energy withdrawals from the public grid.

Current regulations allow the separated management of energy withdrawal and energy injection contracts: the end-user maintains the supply contract for the energy withdrawn from the grid, while the power producer manages the contract relating to the energy fed into the grid according to the applicable market schemes. In such a configuration, it is therefore needed to establish a private agreement between the two parties governing the share of energy supplied and self-consumed within the SPCS. In practice, the agreement between producer and end-user may take the form of an economic tariff for the energy supplied on site. This tariff is generally defined to be competitive with the overall cost of energy purchased from the grid, considering the avoided costs on the bill and the sharing of benefits between the parties. Unlike virtual self-consumption configurations, for which an explicit incentive related to shared energy is provided, the economic benefit of SPCSs depends mainly on the avoided costs associated with energy direct self-consumption.

The SPCS economic benefit comes from some avoided cost components, such as system charges and grid charges, applied to the energy share withdrawn from the grid, while self-consumptiom energy via a private connection is not subject to these charges and reduces grid energy withdrawals. It follows that, given the same energy consumption, an increase in the share of direct self-consumption is associated with an increase in overall economic savings for the end-user. In support of the analysis, Table 1 reports the main cost components applied to the energy withdrawn from the grid. The first column shows the macro-categories in which the different cost components are distinguished: Grid Charges, System Charges and Supplier commercial tariffs. In the second column we find all the different cost components. In the third column we find the entity who fixed the value to assign to the component, while in the fourth column we find the typical update frequency related to the specific component.

	Bill charges	**Set by**	**Update frequency**
Grid Charges	Dispatching (PD)	ARERA	Quarterly
	Distribution (DS)	ARERA	Annual
	Transmission (TRAS)	ARERA	Annual
System Charges	UC3/UC6	ARERA	Quarterly
	System charge (Asos)	ARERA	Quarterly
	System charge (Arim)	ARERA	Quarterly
Supplier commercial tariffs	Capacity Market Charge (CMC)	Supplier	Variable
	Retailer's Spread	Supplier	Quarterly

Table 1 – Cost components applied on the bill

Methodology

In order to evaluate the feasibility of developing a SPCS, was used a methodology that can be divided into a series of steps:

1. Preliminary evaluation.
2. Energy flows analysis.
3. Estimation of avoided costs.
4. Definition of Economic Benefit parameter.
5. Definition of the economic tariff.
6. Estimation of overall economic benefit: end-user savings and additional producer margin.

Preliminary evaluation:

The case study analyzes the coupling between a hydropower plant owned by an Independent Power Producer and a consumer unit represented by a pumping station that operates a water distribution network in a region of central Italy. The production unit is a hydropower plant with a nominal power of 720 kW and an average annual production of approximately 2.5 GWh/y. The plant has reached the end of the incentive mechanism called "Tariffa Omnicomprensiva", resulting in a reduction in its economic revenues; In this context, the implementation of an SSPC represents a possible solution to increase the value of the energy produced through direct on-site supply. The consumption unit, instead, consists of hydro pumps with a total nominal power of 605 kW, and an average annual consumption of approximately 4 GWh/y.

The distance between the two units is a key factor because the cost of the electrical connection depends on the length of the power line and significantly impacts the initial investment cost. Likely, in this case, the distance between the two units is less than 200 m, a condition that reduces the cost of the connection and promotes its feasibility. Moreover, since this configuration involves a power producer different from the end-user, the definition of a bilateral agreement and of a supply tariff for the energy self-consumed on site is required.

The preliminary evaluations highlight:

- comparable nominal powers;
- limited distance, therefore potentially limited initial investment;
- annual demand exceeding production, that is a favorable condition for maximizing self-consumption and fully valorizing the energy generated by the power plant.

Energy flows analysis:

To evaluate the suitability of the SSPC, it is necessary to assess the energy flows that characterize the SPCS. Specifically, it is necessary to estimate the share of energy self-consumption, the share of energy withdrawn from the grid, and the share of energy fed into the grid. These quantities are estimated by simulating the operation of the SPCS over a time interval of 1 year. For this purpose, it is necessary to have acces to the production and consumption data of the two units, in order to build the production and consumption curves, to overlay them and to estimate the energy shares. In this case study, the analysis is conducted using historical 2024 production and consumption data, recorded every 15 minutes. These measures are available on the Distribution System Operator (DSO) web portal or in Italy via the so called "Portale Consumi" provided by the Italian energy authority (ARERA). The adopted time resolution allows to compare the produced and consumed energy measures assuming instantaneous self-consumption with a negligible computational error.

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To evaluate energy shares, it is necessary to introduce some mathematical definitions:

- C_j is the amount of energy consumed by the end-user.
- P_j is the amount of energy produced by the hydro power plant.
- S_j is the amount of direct self-consumed energy within the SPCS.
- F_j is the amount of energy fed into the grid through the end-user's POD.
- W_j is the amount of energy withdrawn from the grid.
- j is an index that varies from 1 to 35040 and corresponds to the number of quarter-hour intervals contained in a year.

It is possible to determine the amount of energy self-consumption in the 15-minute interval j, as the minimum between the energy consumption and the energy production:

$$S_j = \min\ [C_j\ ;\ P_j]$$

(Eq. 1)

By summing over j we obtain the total amount of annual energy self-consumption (S_{tot}) :

$$S_{tot} = \sum_{j=1}^{35040} S_j$$

(Eq. 2)

To determine the amount of energy withdrawn from the grid, it must be considered that W_j is different from zero only if $C_j > P_j$. Indeed, the end-user user will withdraw energy from the grid only if the energy produced by the hydropower plant should be not sufficient to meet the required end-user's needs.

So if $C_j > P_j$, we can express the amount of energy withdrawn from the grid with the following equation:

$$W_j = (C_j - P_j)$$

(Eq. 3)

By summing over j we obtain the amount of annual withdrawn energy (W_{tot}) :

$$W_{tot} = \sum_{j=1}^{35040} (C_j - P_j)\ ,\ if\ C_j > P_j$$

(Eq. 4)

In the same way, to estimate the energy fed into the grid, it must be considered that F_j is different from zero only if the energy produced by the hydropower plant is greater than the needs required by the end- user.

So, if $C_j < P_j$ we can quantify the amount of energy fed into the grid with the following equation:

$$F_j = (P_j - C_j)$$

(Eq. 5)

By summing over j we obtain the amount of annual injected energy (F_{tot}) :

$$F_{tot} = \sum_{j=1}^{35040} (P_j - C_j)\ ,\ if\ C_j < P_j$$

(Eq. 6)

Once all the energy flows have been estimated, it is possible to define two important indexes, useful for providing an evaluation of the expected performance of the system: the Self-Consumption index and the Self-Sufficiency index.

The Self-Consumption index (SC_i) is the ratio between the total energy self-consumption and the total energy produced by the hydropower plant:

$$SC_i = \frac{S_{tot}}{P_{tot}}$$

(Eq. 7)

While the Self-Sufficiency index (SC_i) is the ratio between total the total energy self-consumption and the overall end-user's energy needs:

$$SS_i = \frac{S_{tot}}{C_{tot}}$$

(Eq. 8)

In *Figure 2*, it is possible to observe the graphic representation of the overlaying of the consumption and production curves related to 2024. As can be seen, the production curve is almost always below the consumption curve and furthermore both curves are characterised by a flat trend during the year. These two features, easily observable from the graphical representation, already demonstrate the excellent coupling that can be achieved between these two units.

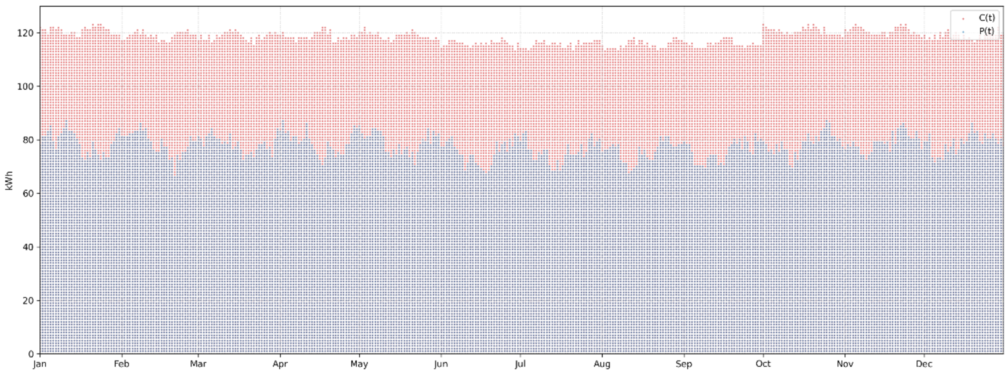

Figure 2 - Quarter-hourly Production (P(j)) and Consumption (C(j)) over the entire year.

Table 2 instead shows the results obtained by applying the equations previously illustrated and the annual values related to the hydropower plant overall energy production and the overall end-user's energy needs. All data are related to 2024.

	HYDROPOWER PLANT P2024	CONSUMPTION UNIT (C_{2024})	SELF-CONSUMPTION (ENERGY)	INJECTED ENERGY F_{2024}	WITHDRAWN ENERGY W_{2024}	SELF-SUFFICIENCY SS_i	SELF-CONSUMPTION SC_i
	[MWh]	[MWh]	[MWh]	[MWh]	[MWh]	%	%
ANNUAL AMOUNT	2.637	3.948	2.636	1	1.312	66,8%	99%

Table 2 – SPCS annual energy flows and indexes (reference year: 2024)

Now it is necessary to associate an economic value to the energy flows in order to calculate the economic revenues related to the SPCS.

Estimation of avoided costs:

As already said, the economic advantage related to a SPCS is in the avoided costs on the bill. In particular, the energy self-consumption within the SPCS is not subject to grid charges, system charges and other charges set by the energy supplier. Therefore, the final consumer, who no longer withdraws all the energy from the grid, benefits from economic savings equal to the avoided charges do not apply to the self-consumption energy. In this case, economic savings are quantified by taking into account especially grid and system charges. In fact, eletrical energy price will still have to be paid by the end-user to the power producer and so it is a costant if it is assumed that the supplier and the power producer apply the same price without further price spreads.

The value of the grid and system charges on the bill, applied to the energy withdrawals, are related to the unit consumption type and power. In order to assign an accurate value to each one of the cost components, the characteristics and type of the end-user were considered and all the values assumed by the components during 2024 were collected. Components data are shown in *Table 3* where the last line shows the average annual value assumed by each component.

Quarter (2024)	Dispatching (PD)	Distribution (DS)	Transmission (TRAS)	UC3	System charge (Asos)	System charge (Arim)	Capacity Market Charge (CMC)	Supplier's Spread
	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]	[€/MWh]
Q1	7,5	0,48	9,89	6,3	35,34	4,086	2,5	4,54
Q2	6,87	0,48	9,89	6,3	41,13	4,77	2,5	4,54
Q3	6,38	0,48	9,89	6,3	41,13	4,77	2,5	4,54
Q4	8,22	0,48	9,89	6,3	41,13	4,77	2,5	4,54
AVERAGE	7,2	0,48	9,89	6,	39,68	4,6	2,5	4,54

Table 3 – Grid and System charge componentson the bill in 2024 (€/MWh)
and their corresponding annual average

Definition of Economic Benefit parameter:

In order to assign an economic value (€/MWh) to self-consumed energy, it was chosen to define a parameter called Economic Benefit (EB). EB is the sum of all avoided grid and system charges and therefore it is expressed by the equation:

$$EB = PD + DS + TRAS + UC3 + CMC + A_{SOS} + A_{RIM}$$

(Eq. 9)

The Economic Benefit parameter for 2024 can be estimated using a mathematical formulation similar to the previous one, but related to the average values assumed in 2024:

$$\overline{EB}_{2024} = \overline{PD}_{2024} + \overline{DS}_{2024} + \overline{TRAS}_{2024} + \overline{UC3}_{2024} + \overline{CMC}_{2024} + \overline{A_{SOS}}_{2024} + \overline{A_{RIM}}_{2024}$$

(Eq. 10)

EB is a key parameter because it represents the end-user 's economic savings per unit of self-consumed energy. Whereas, for the power producer it can be seen as an implicit form of incentive, indeed if the end-user paid to the power producer the same price as he pays on the bill he would receive an additional revenue to the mere sale of energy. As will be seen later the EB will be shared between producer and end-user in such a way that both can enjoy the economic advantage generated by the implementation of the SPCS.Using the average value of the 2024 charges, shown in Table 2, in the equation *(Eq. 4)* it is possible to estimate the EB parameter in about 75 €/MWh.

Definition of the economic tariff:

As already shown, a direct supply of energy from the power plant to the end-user is realized within the SPCS. When the power producer is different from the end-user, the first will apply a price to the energy supplied and self-consumed under the SPCS. It is therefore necessary to set a private agreement between the parties and define an economic tariff to regulate only the energy self-consumption.

In this case study, the price (TP) applied to energy supplied by the power producer and self-consumed by the end-user is set by the following economic tariff:

$$TP = \left[\frac{Q_{F1} \cdot PUN_{F1} + Q_{F2} \cdot PUN_{F2} + Q_{F3} \cdot PUN_{F3}}{Q} \cdot (1 + F_{LOSS}) \right] + [(EB \cdot R_{\%}]$$

(Eq. 11)

In which:

- Q_{Fi} is the amount of energy consumed in the corresponding band (F1, F2, F3)
- Q is the overall energy consumed
- PUN_{Fi} is the energy price on spot energy markets
- F_{LOSS} is the power loss factor
- EB is the economic benefit
- $R_{\%}$ is a coefficient that depends on the price of energy on spot markets

For this case study a specific economic tariff was chosen to allow to allocate the Economic Benefit between the power producer and the end-user. The sharing of the EC is carried out through the $R_{\%}$ coefficient, defining the portion of the economic savings that will be attributed to the producer ($EB \cdot R_{\%}$).

The $R_{\%}$ coefficient is very important, because it does not assume a constant value but varies depending on energy price on the spot markets. The relationship between $R_{\%}$ and the energy price is inversely proportional. When the price of energy on the markets increases $R_{\%}$ decreases, while if the price of energy decreases $R_{\%}$ increases. Linking the $R_{\%}$ parameter to energy price on spot markets allows us to create a sort of insurance scheme:

- the producer is protected when energy prices are low
- the end-user is protected when energy prices are high

Observing equation 3 *(Eq. 3)*, when energy prices PUN_{Fi} are low, and thus the producer's investment is put at risk, he can benefit from a larger share of the EB. On the other hand, the end-user, who is already enjoying a low energy price, can easier waive the economic savings generated by the SPCS.
Otherwise, when energy prices are high and the producer already earns good revenues from the energy supply, he can easier waive the economic savings, protecting the end end-user that is exposed to high energy costs.

Estimation of economic benefit:

We now have all the elements to evaluate revenues and savings generated in 2024 by the SPCS under examination. First of all, it is necessary to indicate the relationship between $R_{\%}$ and the energy price on the spot markets. To simplify the analysis, in this study we chose to use a stepwise trend for $R_{\%}$, with $R_{\%}$ constant for each PUN variation of 20 €/MWh, starting from $R_{\%}$ = 1 for $PUN \leq 50$.

Now it is possible to calculate for each range of the PUN the part of EB that remains with the power producer and the corresponding ((EB · (1- $R_{\%}$)) which instead represents the part of economic benefit that remains with the end-user in the form of economic savings. Based on the end-user's unit savings ((EB · (1- $R_{\%}$)), it is possible to calculate the difference between the price he would pay with his energy supplier, and the price he would pay for the energy supply within the SPCS.
Finally, we can obtain the annual savings of the end-user that is calculated as the product between the unit economic savings ((EB · (1- $R_{\%}$)) and the annual energy self-consumption (S_{tot}).

Instead, the product between the producer's share of EB and the annual energy self-consumption energy (S tot) represents the additional revenues for the power producer.
The results obtained for each PUN Range are reported in *Table 4.*

PUN annual average	$R_{\%}$	*Power Producer's benefit share* ($EB \cdot R_{\%}$)	*End-user's benefit share* *(EB · (1- $R_{\%}$))*	*Tariff Price (TP)*	**Supplier' tariff**	**Δ price**	**End-user annual savings**	**Power producer additional revenue**
PUNm < 50	100%	75,0 €	0 €	< 127 €	< 127 €	0 €	0 €	< 197.700€
50,01 < PUNm < 70	90%	67,5 €	7,5 €	≃ 130 €	≃ 137 €	7,5 €	19.770 €	≃ 177.930 €
70,01 < PUNm < 90	80%	60,0 €	15,0 €	≃ 143 €	≃ 158 €	≃ 15,0 €	≃ 39.540 €	≃ 158.160 €
90,01 < PUNm < 110	70%	52,5 €	22,5 €	≃ 156 €	≃ 179 €	≃ 22,5 €	≃ 59.310 €	≃ 138.390 €
110,01 < PUNm < 140	60%	45,0 €	30,0 €	≃ 170 €	≃ 200 €	≃ 30,0 €	≃ 79.080 €	≃ 118.620 €
140,01 < PUNm < 150	50%	37,5 €	37,5 €	≃ 183 €	≃ 220 €	≃ 37,5 €	≃ 98.850 €	≃ 98.850 €
150,01 < PUNm < 170	40%	30,0 €	45,0 €	≃ 196 €	≃ 241 €	≃ 45,0 €	≃ 118.620 €	≃ 79.080 €
170,01 < PUNm < 190	30%	22,5 €	52,5 €	≃ 209 €	≃ 262 €	≃ 52,5 €	≃ 138.390 €	≃ 59.310 €
190,01 < PUNm < 210	20%	15,0 €	60,0 €	≃ 223 €	≃ 283 €	≃ 60,0 €	≃ 158.160 €	≃ 39.540 €
210,01 < PUNm < 220	10%	7,5 €	67,5 €	≃ 236 €	≃ 303 €	≃ 67,5 €	≃ 177.930 €	≃ 19.770 €
PUNm > 220,01	0%	0 €	75 €	≃ 239 €	≃ 314 €	≃ 75,0 €	≃ 197.700 €	= 0 €

Table 4 – SPCS annual economic outcomes across different PUN ranges under the proposed supply tariff structure

Results

Based on the analysis conducted, a Self-Consumption Index (SC_i) of 99% can be observed, which means that approximately all the energy generated by the hydroelectric plant will be self-consumed on site and therefore valued through the economic tariff of supply to the end-user. While the Self – Sufficiency index is 66%, this means that much more than half of the overall annual energy demand required by end-user users can be satisfied on-site thanks to the the SPCS, the remaining demand will have to be withdrawn from the grid as already happens. Finally, it can be observed that approximately 1 MWh of energy produced by the hydro power plant will be fed into the grid and can be economically exploited through market sales.

In the analysis a complex economic tariff was implemented, but capable of guaranteeing benefits to both entities that constitute the SPCS. The results vary with the price of energy on the wholesale market (PUN) and on the charges applied on the bill; however, in the scenario analyzed, the configuration is economically viable for both parties.

The use of historical production and consumption data, with a 15-minute resolution allows a highly accurate estimate of the energy flows, reducing the error associated with the results.

Assuming the values of the tariff components recorded in 2024 and a scenario with an average annual PUN of 110 €/MWh (a value compatible with recent price scenarios) and applying the EB parameter previously presented, the following annual economic results are obtained:

- expected revenues for the power producer equal to 138.390 €, additional to the revenues associated with the sale of energy.
- End-user annual savings equal to 59.310 €.

Finally, the cost difference between energy purchased through a supplier and the cost of energy supplied in the SPCS is positive and tends to increase as the PUN increases, highlighting the convenience of the configuration, particularly in high-price scenarios.

Conclusions

In conclusion, the analysis shows how SPCSs can represent an effective solution for both power producers and end-users, as they allow to increase the economic value of the energy produced through direct self-consumption and the sharing of economic benefits between the parties through dedicated contractual agreements. The most recent regulatory framework has helped to simplify the qualification and the deployment of such configurations, making them a concrete alternative to explicit support mechanisms that, in many cases, require technical and stringent requirements. SPCSs are particularly attractive for renewable power plants that have completed their incentive period and no longer benefit from direct subsidies. This scenario is expected to become frequent, due to the numerous power plants that entered into operation in the early stages of RES installed capacity expansion and now are reaching the end of incentive schemes. In this context, the implementation of an SPCS can constitute an alternative strategy compared to revamping or repowering interventions, contributing to improving the economic performance of the power plants.

The results presented in this work also demonstrate the importance of conducting an accurate techno-economic analysis in the preliminary design phase. In the absence of favorable conditions, such as poor matching between curves or high connection costs, it may be appropriate to evaluate virtual self-consumption configurations or other alternative solutions. Moreover, we were able to examine how SPCSs can ensure significant economic performance and how they can be useful in mitigating the impact of energy price volatility in energy markets.

Although it was not explored in detail in this work, it is also worth underlining that local self-consumption associated with SPCSs can also generate benefits to the power distribution grids, reducing congestion and grid losses, limiting reverse power flows, and helping to contain the need upgrades in distribution grids. In general, we can say that the development of these systems can help to make the management of distribution grids more reliable, secure and efficient.

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SEMANTIC DATA EXCHANGE IN BIM TO BEM WORKFLOWS USING IFC AND SQL-BASED MAPPING

Federico Rossi
University of Padua, Email: federico.rossi.7@phd.unipd.it

Carlo Zanchetta
University of Padua, Email: carlo.zanchetta@unipd.it

Abstract

Optimising the energy performance of buildings requires integrated design strategies to reduce energy consumption and improve efficiency. The Building Energy Model (BEM) is a fundamental tool for the analytical assessment of energy performance, but its generation is often disconnected from the design phase and requires significant manual intervention, limiting the efficiency of the process.

In recent years, the BIM-to-BEM methodology has established itself as an approach to automate the transfer of information from the Building Information Model (BIM) to the energy model, leveraging data already present in the digital building model. However, differences in languages and representations between the two domains, as well as variability in information, pose significant interoperability challenges. The adoption of open and neutral formats, such as Industry Foundation Classes (IFC) and Green Building Extensible Markup Language (gbXML), is a key strategy for facilitating communication between domains, but it does not completely solve the problems related to semantic consistency and data completeness.

This study proposes a new methodology for BIM-to-BEM information exchange based on the IFC data model and enhanced by conversion to SQL language. This strategy allows the analysis, reorganisation and integration of BIM model information into a relational structure compatible with energy simulation software, improving semantic consistency and data exchange. The methodology involves detailed mapping between BIM entities and properties and the corresponding BEM energy variables, drastically reducing the need for manual intervention and enabling the automated generation of energy models.

Keywords: *BIM, BEM, IFC, SQL, data exchange*

Overview

The construction sector is characterised by a high energy footprint, making the optimisation of buildings thermal behaviour a strategic priority for reducing both operational and embodied energy use. As building systems grow more complex and energy-efficiency requirements become increasingly stringent, advanced methods capable of supporting performance assessment throughout the entire building life cycle are needed. In this framework, the adoption of reliable energy analysis tools from the earliest design stages plays a fundamental role in supporting informed decision-making and promoting more sustainable design solutions. BIM, the digital methodology for generating and managing building data, provides a solid foundation for these evaluations (Pinheiro et al., 2018).

The BIM-to-BEM methodology is becoming increasingly popular as an innovative way to automate the flow of information between the BIM architectural model and the BEM energy model. The latter constitutes an analytical representation of a building, aimed at calculating its energy performance (Andriamamonjy et al., 2019). Its adoption enables design teams to assess the energy and environmental impacts of different solutions. In fact, the BEM outputs building loads and energy consumption support the definition of the building and system energy characteristics as well as the peak loads needed for HVAC system sizing (United States General Services Administration (GSA), 2015).

This methodology, also known as BIM-based BEM, relies on a simplified BIM model, containing architectural data, material properties, internal loads, and HVAC system information, to generate the input for the simulation environment. At the same time, it offers the possibility of making BEM development a faster and more cost-effective process (Gao et al., 2019).

Information exchange between modelling and simulation environments is enabled through standardised data schemas. In this context, the main data models are gbXML and IFC (Dong et al., 2007). The former was created specifically for the energy simulation domain, which limits its ability to represent information from other domains. Conversely, IFC was designed to meet the broader needs of the construction sector, though it does not fully cover the informational requirements of the energy and HVAC domains (Cheng et al., 2014).

Yet, despite being extensively studied, significant challenges persist when attempting to generate a BEM directly from the architectural BIM model (S. Chen et al., 2018). These issues manifest in multiple forms, such as semantic ambiguities, inconsistent levels of detail, missing or misinterpreted attributes, and difficulties in translating geometric and non-geometric information into a simulation-ready format. As a result, the BIM-to-BEM transition is often labour-intensive, error-prone, and requires substantial manual intervention (Cormier et al., 2011).

Within the BIM-to-BEM workflow, two main interoperability issues arise: first, reconstructing building geometry within the energy model (Nektarios Lilis et al., 2021); and second, transferring alphanumeric information, such as metadata describing the physical and performance characteristics of building elements (Miller et al., 2025). However, despite the methodology significant potential, interoperability between BIM and BEM remains challenging due to differences in the languages and building representation methods adopted in their respective domains (Gao et al., 2019).

Several recent studies have addressed BIM-to-BEM, highlighting both advantages and limitations while proposing solutions to integrate the two domains. Choi et al. (2019) proposed an integrated method that exploits an automated geometry extraction module to generate the simulation model. Their experiments showed that the automated module produces more accurate geometric data than manual modelling, increasing the reliability of simulation outputs and reducing the time required to manually create building geometry.

From an informational perspective, El Asmi et al. (2015) developed a methodology to automatically transform the IFC data model into the COMETH energy simulation environment, based on an XML structure compliant with French energy standards. The authors stated that IFC files derived from architectural models lack many of the inputs required for simulation, particularly HVAC configuration and climate data. After integrating the missing information, the IFC structure must be converted into the simulation input format through a mapping between IFC data and the energy model requirements. The outcome is an XML file generated directly from IFC and ready for import into the simulation environment.

Other studies have shown that the use of open formats such as IFC and gbXML is often limited to geometric reconstruction, neglecting essential information such as HVAC systems and internal loads. Sun et al. (2020) addressed this limitation by defining a detailed mapping between ASHRAE baseline HVAC data in the EnergyPlus IDF model and gbXML. Despite interoperability issues, including missing components, overlapping elements, and complex mapping rules, the revised mapping enabled correct encoding of ASHRAE VAV system specifications in gbXML and their successful import into the BEM environment.

To enhance interoperability, W. Chen et al. (2021) proposed extending IFC4 through new entities, attributes, and relationships to incorporate key concepts from energy simulation data models. Using a converter from the extended IFC to the simulation input model validated the overall approach.

Despite several efforts to improve information exchange between the two domains, the literature consistently reports limitations in the correct implementation of the BIM-to-BEM methodology (Gourlis & Kovacic, 2017). This highlights the need to develop an interoperable tool chain capable of connecting the two environments, as effective information exchange between BIM and BEM has been shown to reduce the time and costs otherwise required for model creation and data input (Bastos Porsani et al., 2021).

These limitations become even more critical when the BEM is used not only during design but also as a digital counterpart during operation, supporting the validation of actual building behaviour and contributing to performance optimisation strategies (Osadcha et al., 2024). To fully exploit BIM and BEM as complementary tools throughout the building life cycle, it is therefore essential to establish interoperable, semantically consistent information flows that preserve the meaning and structure of data exchanged between the two domains.

Interoperability thus emerges as a key factor in improving building energy performance (J. Choi et al., 2016). It requires transparent workflows, structured datasets, and shared standards ensuring that information generated in BIM can be correctly interpreted and reused within BEM without loss or distortion.

In response to these needs, this study proposes a novel BIM-to-BEM methodology based on the open Industry Foundation Classes (IFC) standard and enhanced through mapping strategies based on Structured Query Language (SQL). The approach ensures a consistent and semantically robust transfer of architectural and energy-related information from BIM environments to building energy simulation tools. By leveraging open schemas and database-driven mapping rules, the methodology improves data accessibility, minimises translation errors, and supports the automated, reliable generation of Building Energy Models.

Method

This research proposes a new framework for the semantic transfer of data from BIM to BEM. The methodology is entirely based on the IFC data model, an open standard for representing construction-sector information. The IFC standard, compliant with ISO 16739, establishes the data structure, semantic definitions, and interoperability rules necessary to enable consistent and reliable information exchange among stakeholders and software applications.
The framework was applied to EdilClima EC700, an Italian energy simulation software that incorporates a calculation engine compliant with UNI/TS 11300 (*EdilClima EC700*, n.d.). Recent versions of the simulation environment allow the import of IFC files to automatically generate the building envelope, enabling the transfer of the 3D geometry of spaces and the bounding envelope elements.
In the traditional workflow, the IFC file containing the envelope characterised by its stratigraphy and space definitions, is imported into the software to generate the BEM according to the BIM-to-BEM methodology. However, as with many energy simulation tools, EC700 exhibits interoperability limitations: only part of the information contained in the IFC file is read and interpreted, requiring manual user intervention to complete or correct the imported data (
Figure *1*). In a professional context, these shortcomings translate into operational inefficiencies and increased time required for energy modelling.

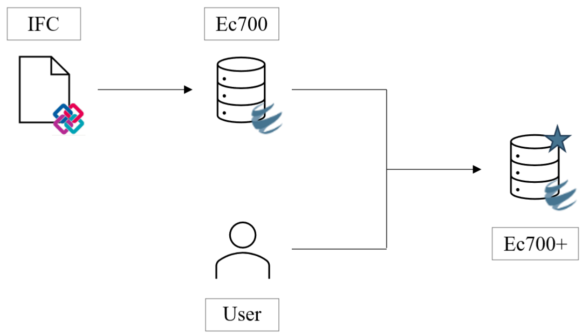

Figure 1 - Conventional BIM-to-BEM workflow with manual data handling

The approach proposed here was developed to build on the limitations of the traditional BIM-to-BEM methodology and enhance interoperability between the two domains. As with many energy simulation tools, EdilClima EC700 is based on a relational data model whose analysis reveals the actual structure of the data, organised into a set of interconnected tables. These tables constitute the information core on which the entire energy calculation process is based. The most relevant ones are:

- *Table 1*-StrOpache, containing opaque building envelope components (walls, floors and roofs);
- *Table 1*-StrStrati, storing the thermophysical properties of the material layers of each opaque element;
- *Table 1*-StrTelai, describing the geometric and thermal properties of window frames;
- *Table 1*-StrTrasp, listing the geometric and performance properties of transparent components;
- *Table 1*-StrVetriT, containing the characteristics of glazing associated with each transparent element;
- *Table 3*-Locali, defining the list of rooms (spaces) with their geometric and thermal properties;
- *Table 3*-ZoneRisc, reporting heated thermal zones and their main energy characteristics.

The existence of a procedure for translating the IFC model into a relational database, known as ifcSQL, enables a semantic link to be created between the BIM and BEM domains. The methodology adopts this IFC-to-SQL translation procedure (Bock & Eder, 2021/2025).
Operationally, the methodology is organised into a dual workflow:

- Traditional import of the IFC file into EdilClima, which automatically populates part of the tables in its internal database.
- Parallel translation of the same IFC file into SQL using ifcSQL, enabling the information to be reorganised and integrated according to EdilClima's relational structure.

This second pathway is essential because not all information contained in the IFC file is automatically interpreted by the software. Through SQL translation, IFC data are mapped to the corresponding tables of the EdilClima database, ensuring full coverage of geometric and energy-related properties.

Once reorganised and integrated, these data can be re-imported into the software, filling the gaps of the traditional BIM-to-BEM workflow and enabling the generation of a more consistent, semantically enriched energy model (**Errore. L'origine riferimento non è stata trovata.**).

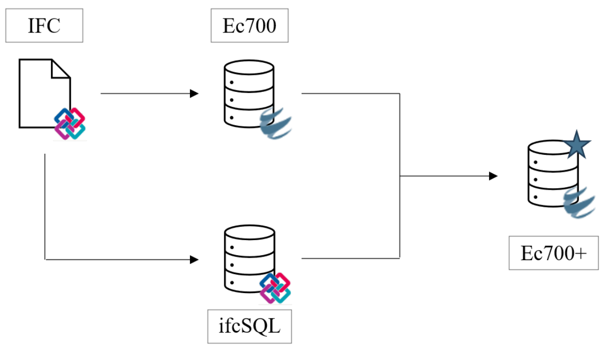

Figure 2 - Enhanced BIM-to-BEM workflow with semantic data exchange

It is important to emphasise that the research was developed in alignment with the informational structure and current capabilities of the IFC standard, limiting the use of proprietary property sets. While the first workflow follows the traditional approach, based on the direct import of the IFC file into the simulation software, the second workflow is structured into four modules, each corresponding to a specific phase of the BIM-to-BEM process (Figure 3). These modules, essential for ensuring the correct transfer of information from the IFC model to the BEM model, are listed below:
- BIM layer;
- Conversion layer;
- Data processing and integration layer;
- BEM layer.

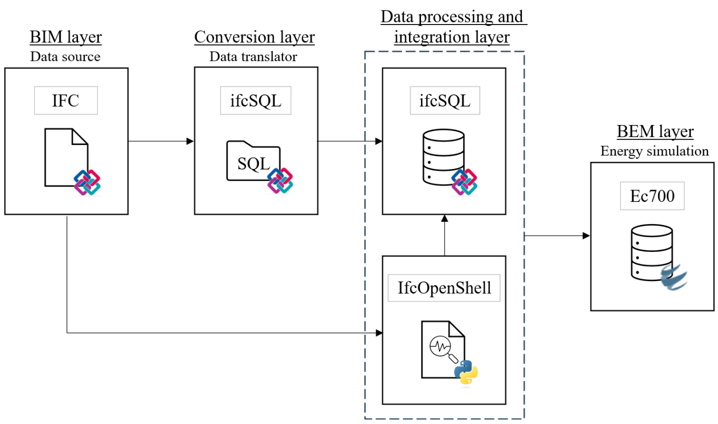

Figure 3 - Conceptual overview of the four modules of the proposed BIM-to-BEM framework

BIM layer

The first module corresponds to the initial step of the methodology, which consists in creating the BIM model. This model provides the geometric and informational basis from which the BEM will be generated. Autodesk Revit was used as the BIM authoring software.

Model development must follow specific rules to ensure workflow efficiency and proper interoperability between the two environments. A crucial aspect is the simplification of geometries, required because energy exchange calculations rely primarily on two-dimensional surfaces (Guízar Dena et al., 2024). Unlike architectural models, rich in construction and formal details, the energy domain focuses on surfaces describing thermal exchanges between spaces. Geometric simplification is therefore essential to minimise errors during the import and interpretation of geometries within the simulation software.

In addition, the stratigraphy of the building envelope elements must be fully defined, including material descriptions and their thermophysical properties. The BIM model must also include rooms and zones characterised by key energy parameters (such as design temperature and humidity), enabling a consistent transfer of information to the BEM.

Once the model is created, it is exported in IFC format, using the IFC4x3 schema. This choice resulted from a series of import tests performed in EdilClima EC700 to identify the most stable and compatible configuration for the proposed workflow. The tests confirmed that the software, which supports direct IFC import, handles IFC4x3 models more reliably, ensuring a consistent reconstruction of the building envelope and significantly reducing geometric errors or data loss. This choice is further supported by the fact that IFC4x3 is the most up-to-date official version of the IFC standard.

Conversion layer

The conversion module is responsible for translating the IFC file into a relational database by adopting the procedure developed by Bock and Eder, which imports the IFC file into the ifcSQL database and reorganises the model information into tables consistent with a relational schema. As previously noted, this operation is useful because energy simulation software extensively relies on relational databases, making it possible to analyse their structure and understand their functioning. Many BEM tools adopt relational databases both for managing input data and for storing output results. A relevant example is EdilClima EC700, which automatically generates an SQLite database during the IFC import process; this database is progressively enriched as the user integrates or modifies project data

Data processing and integration layer

Once the IFC file has been translated into a relational format, the data can be reorganised in accordance with the table structures and relationships of the BEM domain. This phase is a crucial step in the process, as it enables the translation of information from the IFC model into a format fully compatible with the energy simulation environment. Moreover, this approach establishes a direct information bridge between the two domains, ensuring traceability and semantic consistency throughout the transfer process.

This procedure requires an initial analysis and understanding of the energy database structure, which allows the logical organisation of the data within the ifcSQL model to be reconstructed. It is evident that this process demands a detailed mapping of the information structures of both BIM and BEM domains, as well as a clear understanding of the correspondences between IFC entities and the energy variables used in simulation software. Accurate mapping of IFC properties to the corresponding EdilClima database properties is essential to precisely locate each piece of data within the energy tables. This semantic mapping is fundamental for maintaining data consistency and traceability across the entire BIM-BEM interoperability workflow. Consequently, this step goes beyond mere format conversion and requires the definition of correspondences between IFC entities and energy variables.

Reorganising BIM information according to the energy software structure involves creating a dedicated database, called EdilClimaSQL, specifically designed to avoid direct modification of the ifcSQL database generated by the procedure proposed by Bock and Eder. Within this database, various tables are created to reorganise the data extracted from the BIM model in compliance with the information structure adopted by the energy software.

Some information in the IFC model cannot be directly processed within the ifcSQL database because it belongs to the geometric-derivative domain and is not explicitly described in the data model. A notable example is the calculation of the dispersive perimeter of a ground floor slab, which requires geometric processing based on spatial relationships between elements, as well as the identification of thermal bridges.

To extract and process such information, which is present in the model only implicitly through entity and geometric relationships, the IfcOpenShell library is employed. This allows more advanced access and manipulation of the geometry than traditional data query tools.

The results from this analysis phase are then imported into the EdilClimaSQL database, where the data are reorganised and integrated according to the structure of the energy simulation database.

BEM layer

Finally, by executing a Python script, the data are transferred from the EdilClimaSQL database to the SQLite database of EC700. This step completes the interoperability process, enabling the integration of energy information within the simulation environment.

The operation automatically generates a new *.E0001 file, marked with the suffix "_modified", which represents the updated and enriched version of the original model. This file is fully populated with the integrated energy information and is fully compatible with EdilClima EC700, allowing the direct execution of subsequent thermal analysis and calculation phases.

Application of the proposed methodology

To illustrate the overall methodology, the study presents two application cases: the association between rooms and thermal zones, and the management of window components. The procedure was also applied to additional informational elements related to the use of spaces and zones (such as indoor climatic conditions and internal loads), which are not included in this paper due to space constraints.

Association between rooms and thermal zones

When a user imports an IFC model into EdilClima, the software requires the specification of both the room typology and the corresponding thermal zone. The program can recognize any IfcSpace and IfcZone entities defined during the modelling phase; however, it cannot automatically determine the typology associated with each room.

In this context, the term typology refers both to the presence or absence of heating and to the geometric position of the room (for example, whether it is adjacent to the ground). In the absence of explicit information, EdilClima assumes by default that all rooms are heated and not in contact with the ground.

Once the room typology and the thermal zone have been correctly assigned, the software allows the export of an XML file containing the association between rooms and thermal zones, which can be used for future updates of the BEM model. The proposed methodology aims to generate this XML file directly from the information contained in the IFC model, thus avoiding manual input of data that are already available and ensuring an interoperable workflow between the two environments.

The XML file has a specific structure. The input information, such as room typology and the associated thermal zone, must be provided. As previously noted, the room typology depends on two additional pieces of information:

- the presence or absence of heating;
- the geometric position of the room.

In order to extract this information from the IFC model, the corresponding properties defined by the IFC standard must first be identified. The heating regime is specified by the boolean property DiscontinuedHeating, associated with IfcSpace within the Pset_SpaceHVACDesign. FALSE indicates a heated space, while TRUE corresponds to a non-conditioned space. The geometric position of the room is determined based on the PredefinedType attribute of IfcSlab, which can assume two relevant values:

- BASESLAB, representing slabs in contact with the ground;
- FLOOR, representing generic floor slabs.

Based on these properties, a mapping matrix between the IFC data structure and the room typologies defined in EdilClima is established (*Table 1*). It is worth noting that the IFC data model does not allow the explicit representation of spaces such as SolarGreenHouse. However, these spaces account for only a minor portion of the overall dataset.

Table 1 - Mapping matrix between IFC data structure and EdilClima room typologies

EdilClima data model	IFC data model	
RoomType: Climatized	DiscontinuedHeating: FALSE	PredefinedType: FLOOR
RoomType: NotClimatized	DiscontinuedHeating: TRUE	PredefinedType: FLOOR
RoomType: UndergroundClimatized	DiscontinuedHeating: FALSE	PredefinedType: BASESLAB
RoomType: UndergroundNotClimatized	DiscontinuedHeating: TRUE	PredefinedType: BASESLAB
RoomType: SolarGreenHouse	-	PredefinedType: FLOOR
RoomType: UndergroundSolarGreenHouse	-	PredefinedType: BASESLAB

However, due to the intrinsic differences between IFC and BEM models, building elements are identified and represented in different ways. An IfcSlab may be shared by multiple IfcSpace entities, depending on how it has been modelled in the BIM authoring software, whereas in a BEM model each building component is subdivided into multiple parts according to the type of energy transmission involved.

This situation typically occurs when a single element acts as a slab between spaces characterized by different conditioning regimes, such as a heated space and an unheated one. In this specific case, the energy model splits the slab into two distinct portions in order to account for the different amounts of heat transfer associated with each space.

For this reason, it is necessary to introduce the concept of the space boundary. Within the IFC standard, a space boundary defines the physical or virtual limits of a space through the IfcRelSpaceBoundary relationship with the surrounding building elements. This relationship manages the association between a construction element and the space it bounds (*Figure 4*). The use of IfcRelSpaceBoundary, rather than a direct reference to IfcSlab entities, allows building elements to be represented according to their energy transmission role, in a manner that is more consistent with the space-delimitation logic typically adopted in BEM models.

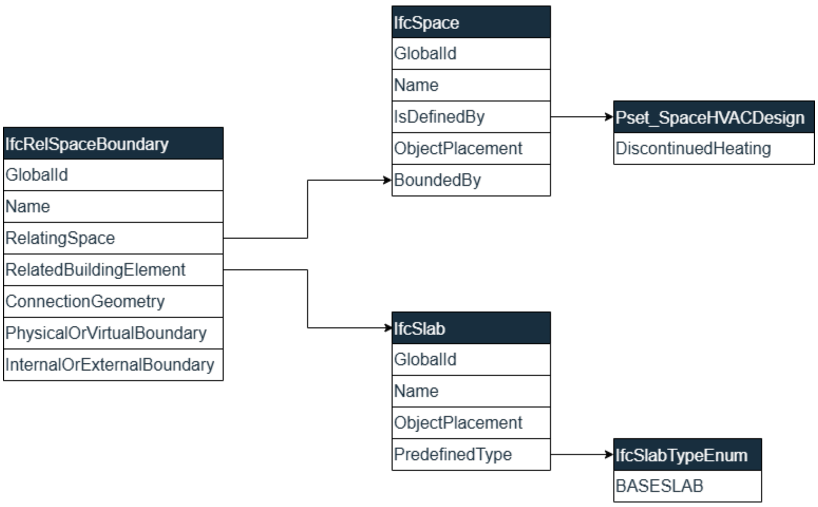

Figure 4 - Conceptual scheme for the identification of IfcSpace room types via IfcRelSpaceBoundary relationships

From a practical standpoint, the proposed methodology involves extracting the boolean value associated with the DiscontinuedHeating parameter for each IfcSpace in order to determine its conditioning regime, as well as retrieving all related IfcRelSpaceBoundary relationships whose RelatedBuildingElement is an IfcSlab. If at least one of the IfcSlab elements bounding the IfcSpace under analysis is characterized by a PredefinedType equal to BASESLAB, the corresponding IfcSpace is classified as Underground.

The combination of these two properties determines the room type associated with each IfcSpace, according to the classification defined in *Table 1*. The procedure is implemented through SQL queries, which generate two separate tables:

- ZoneXML, containing the list of IfcZone entities;
- SpaceXML, containing the list of IfcSpace entities together with the associated room type and thermal zone.

The information stored in these tables is used to generate the room-zone association XML, which can be imported into the EC700 software to automatically assign both the room typology and the corresponding thermal zone.

Window components

Windows represent one of the elements with the lowest level of interoperability between the BIM modelling environment and the energy simulation environment. Although the IFC data model contains a wide range of energy-related information, none of these properties are transferred to energy analysis software. The only attributes typically recognized by such tools are basic geometric properties, such as the height and width of the window component.
However, in order to perform accurate energy simulations, the UNI/TS 11300 standards require that window components be characterized from an energetic perspective as well. This involves defining specific geometric and energetic properties for both the opaque and transparent parts of the window, which are necessary for calculating the overall heat transfer coefficient U_w (*Equation 1*).

$$U_w = \frac{U_g A_g + U_f A_f + \psi_g L_g}{A_g + A_f} \quad (1)$$

Where:
- U_g is the thermal transmittance of the glazing;
- A_g is the area of the glazed element;
- U_f is the thermal transmittance of the frame;
- A_f is the area of the frame;
- Ψ_g is the linear thermal transmittance of the glazing-frame junction;
- L_g is the perimeter of the glazing-frame junction.

The limited interoperability between the BIM and BEM domains necessitates the manual re-entry of data already present in the model but not correctly recognized or interpreted in the energy simulation environment, thus reducing process efficiency.
Considering these limitations, the application of the methodology proposed in this study becomes essential to bridge the information gap and improve the workflow between modelling and energy simulation.
To make the methodology operational, a mapping between the information required by the energy simulation software and the data available in the IFC standard is necessary. This step is crucial to ensure proper information binding and, consequently, the success of the entire process.
In the IFC data model, a window is represented by the IfcWindow class, to which several property sets can be associated to describe its geometric and performance characteristics. Among these, three information groups are particularly relevant for energy purposes:

- Pset_WindowCommon, containing general information, including the thermal transmittance of the window component;
- Pset_DoorWindowGlazingType, related to the glazing system, with properties such as the number of panes, thicknesses, and energetic characteristics of the glazing system;
- Pset_WindowLiningProperties, which collects geometric information regarding the opaque parts of the frame.

Material properties are managed within the IfcMaterialConstituentSet class, linked to IfcWindow through the IfcRelAssociatesMaterial relationship. The IfcMaterialConstituentSet represents the set of materials composing the different parts of the window, and each IfcMaterialConstituent describes a single portion of the window made of a homogeneous IfcMaterial.
In contrast, the EdilClima data model features a dedicated information structure, organized into three main tables:

- Table 1-StrTrasp, containing general information about the window component;
- Table 1-StrVetriT, related to the glazing system;
- Table 1-StrTelai, which collects data regarding the frame.

The result of the mapping activity is shown in *Figure 5*. Most of the information required by the energy simulation software finds a direct correspondence in the IFC model. Other properties, however, require the combination of multiple IFC parameters (such as those related to the presence of mullions and transoms). Finally, some highly specific information is not currently supported by the standard, such as the spacer conductivity or the cavity resistance.

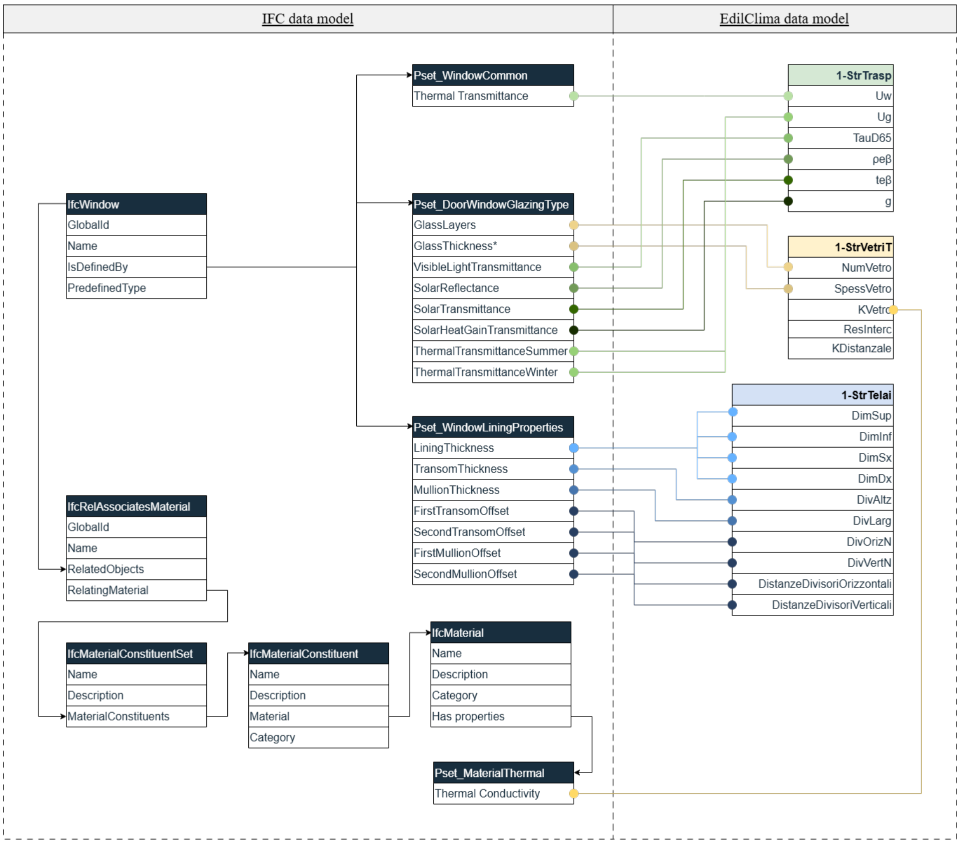

Figure 5 - Mapping of window properties between the IFC and EdilClima data models

Tabella: 1-StrVetriT

	Codice	NumTelaio	NumVetro	SpessVetro	KVetro	ResInterc	KDistanziale
	Filtro	Filtro	Filtro	Filtro	Filtro	Filtro	Filtro
1	1	1	1	5.0	1.0	0.0	NULL
2	2	1	1	6.0	1.0	0.0	NULL
3	3	1	1	6.0	1.0	0.0	NULL
4	4	1	1	6.0	1.0	0.0	NULL
5	4	1	2	7.0	1.0	NULL	NULL
6	3	1	2	8.0	1.0	NULL	NULL
7	1	1	2	6.0	1.0	NULL	NULL
8	2	1	2	7.0	1.0	NULL	NULL
9	4	1	3	8.0	1.0	NULL	NULL
10	1	1	3	7.0	1.0	NULL	NULL

Figure 6 - EdilClima database - 1-StrVetriT table populated through SQL-based IFC data mapping

In the early stages of testing, validation of the data transfer is based on comparing the information in the EdilClimaSQL database with that in the EC700 database *(Figure 6*) and with the information displayed in the user interface *(Figure 7*). The outcome of the mapping process is the transfer of semantically correct data from IFC to the EdilClima format.

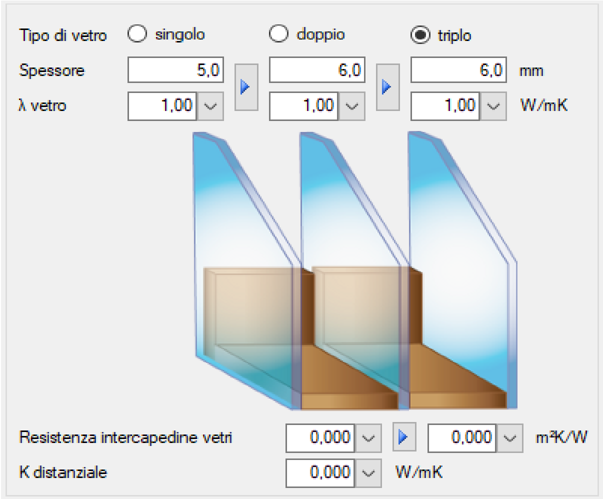

Figure 7 - EdilClima user interface - Glazing data populated through SQL-based IFC data mapping

It should be noted that the same methodology has been applied to ground floors, for which current regulations require the calculation of both the heat-loss area and perimeter, as well as to rooms and thermal zones. This enables the correct association of properties related to indoor climatic conditions and the possible presence of internal loads for both individual spaces and thermal zones.

Results

Defining a standardised workflow for information exchange between BIM and BEM has multiple positive implications. Firstly, adopting neutral protocols increases interoperability between the two domains, overcoming current fragmentation. The proposed methodology, based on the IFC data model, guarantees the automatic transfer of data and the preservation of its technical meaning within the energy model.

Consequently, information already present in the BIM model can be effectively reused, reducing the need for manual intervention by designers and limiting the risk of errors. Automating data transmission optimises the BIM-to-BEM process, making the design workflow more efficient and accelerating the energy simulation phases.

From a business perspective, scalability and reusability of the process also become key factors. The proposed framework can indeed be replicated on different projects and easily adapted to heterogeneous contexts. This approach enables the BIM-to-BEM workflow to be permanently integrated into operational processes.

Conclusions

The highlighted results demonstrate the potential of an interoperable BIM-to-BEM methodology in supporting building energy efficiency processes. While increasing interoperability leads to significant improvements in the design workflow, the challenge is far from resolved. Indeed, despite the potential offered by the IFC standard, its current level of development does not allow for full coverage of the energy domain, thus necessitating extensions to the data model.

With the introduction of new versions of the standard, the energy domain can be expanded to include additional concepts, entities, and properties, enabling a more comprehensive representation of energy-related information within the IFC model. In the current situation, one possible solution is the creation of custom property sets to accommodate missing properties. This approach can be effective in a structured corporate environment where the entire BIM-to-BEM workflow - from developing the information model to performing energy simulations - is managed in-house, ensuring consistent and controlled data.

However, when the two domains are handled separately, this approach loses effectiveness, as it does not rely on a universal standard like IFC. The loss of interoperability arises from the absence of a common and neutral language that would enable automated information exchange. For this reason, the present study has focused exclusively on properties contained within the IFC standard, avoiding the introduction of unofficial extensions or customizations.

Looking ahead, two main research directions can be identified. First, although advantageous, the translation into ifcSQL requires a precise definition of mapping rules between IFC entities and SQL tables, which may vary depending on the energy simulation software employed. The development of standardized interoperability schemes between IFC and energy databases represents a key area for future work, as it would enable greater automation and universality of the process.

Second, the creation of a dedicated user interface would facilitate a more intuitive and accessible application of the methodology, encouraging adoption by a wider range of professionals and deeper integration into the design process. Furthermore, extending the information exchange to include the return of BEM results to the BIM model would allow all data to be centralised in one location. Such integration ensures effective data sharing in subsequent design phases, including plant and system dimensioning.

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RULE-BASED AC ENERGY EXCHANGE FOR URBAN PROSUMERS TO ENHANCE LOCAL ENERGY PERFORMANCE

Saeed Khorrami
Sapienza University of Rome, Italy, *(corresponding author*), Email:saeed.khorrami@uniroma1.it

Maria Carmen Falvo
Sapienza University of Rome, Italy, Email: mariacarmen.falvo@uniroma1.it

Pablo García Fernández
University of Oviedo, Spain, Email: garciafpablo@uniovi.es

Ángel Navarro Rodríguez
University of Oviedo, Spain, Email: navarroangel@uniovi.es

Carlos Gómez-Aleixandre Tiemblo
University of Oviedo, Spain, Email: gomeztcarlos@uniovi.es

Mahmoud Rashad Ahmed
University of Oviedo, Plexigrid, Spain, Email:mahmoud.rashad@plexigrid.com

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Abstract

Urban energy communities face a well-known temporal mismatch, with photovoltaic (PV) generation peaking at midday and electricity demand peaking in the evening. This misalignment leads to avoidable grid imports and exports, even when surplus renewable energy is available locally. We propose a rule-based, neighbor-first AC energy exchange mechanism that allows adjacent prosumers to share surplus PV before importing from the grid. A minimal two- building test case was developed on a modified IEEE 13-node feeder, with control logic and key performance indicators (KPIs) implemented in Python and power-flow validation performed in OpenDSS. Each building was equipped with PV generation, battery storage, residential loads, and two scenarios (S) were evaluated: (S1) no exchange and (S2) neighbor-first exchange. Results show that in S2, 7.74 kWh was exchanged from Building 1 to Building 2 over 24 hours, reducing Building 2's grid imports by 68% (from 11.36 kWh to 3.63 kWh) while increasing Building 1's imports to 2.86 kWh. Overall community self-sufficiency improved from 77.7% to 87.3%, and self- consumption improved from 74.3% to 78.5%. System losses remained low (2.58 kWh), and feeder voltages were maintained within operational limits. At a flat electricity price of 0.25 €/kWh, daily costs decreased by €1.93 for Building 2 and €1.22 for the system. These findings demonstrate rule-based coordination enables technically feasible and economically beneficial local energy exchange and establish a foundation for future multi-building and year-long studies enhancing local energy performance in urban energy communities.

Keywords: *Energy communities, energy exchange, IEEE 13-node feeder, rule-based control, prosumers.*

Nomenclature

Symbol	Description	Unit
$G_i(t)$	PV generation of prosumer i	$[kW]$
$L_i(t)$	Load demand of prosumer i	$[kW]$
$\Delta_i(t)$	Net power balance	$[kW]$
$SoC_i(t)$	Battery state of charge	$[kWh]$
C_i	Battery capacity	$[kWh]$
Pmax	Inverter charge/discharge limit	$[kW]$
$P^{ch}(t)$	Battery charging power	$[kW]$
$P^{dis}(t)$	Battery discharging power	$[kW]$
$X_{i\rightarrow j}(t)$	Power exchanged between prosumers	$[kW]$
$I_i(t)$	Grid import	$[kW]$
$E_i(t)$	Grid export	$[kW]$
p	Electricity tariff	$[€/kWh]$
ηc , ηd	Charge/discharge efficiency	-
ηx	Line exchange efficienc	-

1. Introduction

The increasing penetration of renewable energy sources (RES), especially photovoltaic (PV) systems, in urban distribution networks has introduced challenges related to temporal mismatch between local demand and renewable availability, bidirectional power flow, and grid stability (Mehta and Tiefenbeck, 2022), (Khorrami, Falvo and Pompili, 2025). Even when surplus PV exists nearby, prosumers often continue to rely on grid imports due to the lack of simple exchange mechanisms. Such inefficiencies reduce local self-sufficiency and impose additional stress on distribution network (Guerrero, Chapman and Verbič, 2018).

To address these issues, research on peer-to-peer (P2P) energy exchange and community energy sharing has gained significant attention in recent years (Malik *et al.*, 2022). Existing approaches often rely on optimization, forecasting, or market-based trading, which may be computationally intensive or complex for small-scale communities (Islam, 2024). In this context, rule-based local exchange mechanisms provide a practical alternative by enabling neighboring prosumers to share surplus renewable energy without relying on forecasting or optimization (Heendeniya, 2021). These methods can be implemented with existing control devices, respect AC system limits, and offer transparency and low computational requirements that are suitable for real-time residential control.
This paper proposes a rule-based AC neighbor-first energy exchange strategy that enables local prosumers to share energy effectively without advanced forecasting or optimization. The approach is validated on a modified IEEE 13- node feeder with two prosumer buildings equipped with PV and storage. The structure of the paper is as follows: Section 2 reviews related work; Section 3 describes the method and performance indicators; Section 4 gives the simulation setup; Section 5 presents results; Section 6 discusses them; Section 7 concludes and indicates future work.

2. Literature Review

Recent studies have explored community energy exchange mechanisms. Market-based trading approaches allow dynamic pricing and P2P negotiations (Tushar *et al.*, 2021), while optimization-based frameworks employ game theory and rolling horizon control for coordinated dispatch (Paudel *et al.*, 2018), (Gebremariam *et al.*, 2024). However, such approaches typically require forecasting, communication infrastructure, and centralized algorithms, which may be impractical for small-scale communities (Duvignau *et al.*, 2020).
Alternative rule-based or heuristic strategies have been investigated to reduce computational and implementation burden. For example, self-consumption maximization strategies prioritize PV use within local demand (Schram, Lampropoulos and van Sark, 2018), while time-of-use (TOU) tariff strategies exploit price differentials to reduce costs (Khorrami *et al.*, 2025). Despite this progress, there remains limited work on AC-feasible and feeder-validated exchange rules that can be applied directly in urban distribution networks without optimization. Integrated simulation approaches also support building energy optimization toward zero-energy targets (Khazaee *et al.*, 2024). This gap motivates the present study, which introduces a simple yet effective neighbor-first exchange rule and validates it through full AC power flow simulations.

3. Method

3.1 Test system model

The study employs the modified IEEE 13-node radial distribution feeder (Schneider *et al.*, 2017) as the testbed for validating the proposed rule-based neighbor-first exchange control. Two residential prosumer buildings, each equipped with photovoltaic (PV) generation, battery storage, and household load profiles, are modeled; their specifications are summarized in *Table 1*.
The feeder includes a distribution line segment connecting Building 1 (Bus 645.2) and Building 2 (Bus 646.3), as shown in Figure 1. This 300 ft line (91.44 m) configured line segment results in a line impedance of $Z = 1.32 + j1.36\ \Omega$, based on the `mtx603` line code implemented in the OpenDSS model. This configuration provides a realistic distribution level connection for assessing inter-building AC energy exchange within the simulated feeder environment.

Table 1 - Technical specifications of the two-prosumer test system on the modified IEEE 13-node feeder for the 24- hour simulation study.

Parameter	**Building 1 (Bus 645.2)**		**Building 2 (Bus 646.3)**		**Unit**
	Annual	**Peak**	**Annual**	**Peak**	
Load	5,937	1.6	7,721	2.1	kWh / kW
PV Generation	7,700	4.3	10,096	5.8	kWh / kW
Battery Capacity (C_i)	15.0		5.0		kWh
Max Charge/Discharge Power (P^{max})	5.0		5.0		kW
Initial SoC (SoC_0)	7.5 (50%)		2.5 (50%)		kWh
Battery Efficiency (η_c / η_d)	0.95 / 0.95		0.95 / 0.95		—

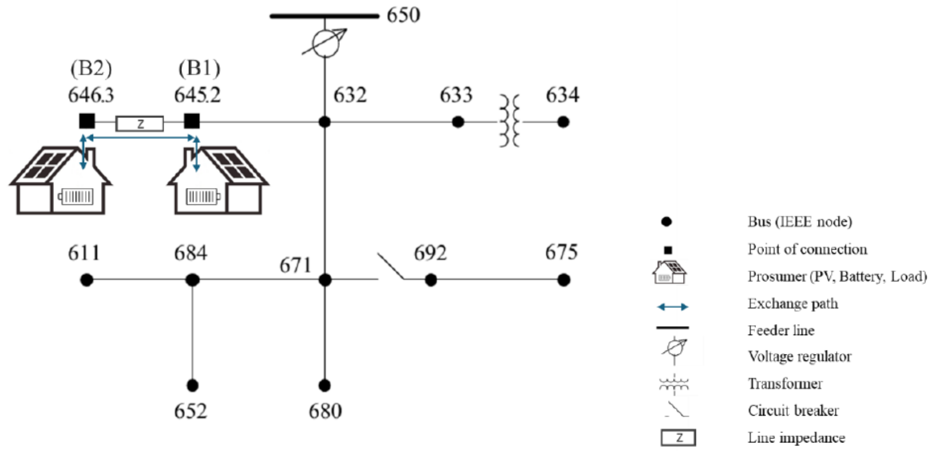


Figure 1 - Single-line diagram of the modified IEEE 13-node feeder showing buses, line impedances, transformer, and the locations of Building 1 (Bus 645.2) and Building 2 (Bus 646.3).

3.2 Operation strategies

Two operational scenarios were evaluated within the Python and OpenDSS co-simulation framework illustrated in Figure 2. In Scenario S1 (baseline with no energy exchange between buildings), each building operates independently under a Maximum Self-Consumption (MSC) strategy (Schram, Lampropoulos and van Sark, 2018), and PV generation first supplies local demand; any surplus charges the local battery within its SoC and power limits, and any remaining surplus is exported to the grid. During demand deficits, the battery discharges to support the load before importing power from the grid. No inter-building exchange occurs in this configuration.

Scenario S2 (Neighbor-First Energy Exchange), two prosumer buildings operate cooperatively through a rule-based neighbor-first control strategy. When one building exhibits PV surplus beyond its own demand and charging requirement, the excess energy is shared with the neighboring building experiencing a deficit before any grid import. Exchange takes place via the linking Buses 645.2 and 646.3, line efficiency $\eta_x = 0.99$ is determined from the line impedance $Z = 1.32 + j1.36\ \Omega$ and typical power levels. At each hourly step, the Python control layer determines available surplus and requested deficit while enforcing inverter power ratings, SoC boundaries, and line-capacity constraints. The shared power flow is solved in OpenDSS to verify voltage compliance and compute resistive losses. Data exchange between Python and OpenDSS is performed iteratively at each time step: Python sends control decisions to OpenDSS, which returns updated voltages, currents, and losses to close the simulation loop. Energy transfer proceeds until the supporter's discharge limit, the receiver's charging limit, or the line constraint is reached. Any remaining demand is supplied by grid imports, ensuring energy balance at each timestep.

This cooperative rule increases local utilization of renewable energy by reducing grid dependence and aligning surplus and deficit within the same feeder. The algorithm maintains all technical limits, allowing feeder-validated assessment of real-time AC energy sharing among urban prosumers.

3.3 Simulation Framework

The simulation framework integrates a Python-based control layer with an OpenDSS power-flow solver to represent the operational behavior of the two-prosumer system, as a flowchart illustrated in Figure 3. The co-simulation executes an hourly time-series analysis ($\Delta t = 1h$) for a 24−hour test horizon and can be extended to year−long datasets for future studies. Input data include hourly photovoltaic generation $G_i(t)$ and load demand $L_i(t)$ for each prosumer with $i \in \{1,2\}$, battery parameters such as capacity C_i, initial state of charge $SoC_{0,i}$, maximum charge/discharge power P_i^{max}, and inverter limits. The electrical coupling between the two buildings is represented through the corresponding line impedance between Buses 645.2 and 646.3 ($Z = 1.32 + j1.36\,\Omega$). A flat electricity tariff of 0.25€/kWh is assumed for the economic assessment. The exchange efficiency η_x = 0.99 represents an averaged efficiency parameter accounting for I^2R losses in the 300-ft distribution line (R = 1.32 Ω); instantaneous losses vary with power flow but average to approximately 1% of transferred energy over the test day, as validated through detailed OpenDSS power-flow calculations. This approximation enables computationally efficient real-time control while maintaining acceptable physical accuracy (validated error < 2%).

The Python control layer computes the net power balance for each building as $\Delta_i(t) = G_i(t) - L_i(t)$, and applies the selected operation strategy (MSC or Neighbor-First). Battery charging and discharging are updated while respecting SoC limits, power ratings, and efficiencies (η_c=η_d=0.95). When Neighbor-First is active, requested exchange is sent from Python to OpenDSS; it returns voltages and losses, closing the loop. Any residual unmet demand is supplied by grid imports, and any residual surplus is exported. The framework enforces feeder limits (0.95–1.05 pu) and produces hourly and aggregated KPIs (self-consumption, self-sufficiency, grid imports, system losses, and dail y costs).

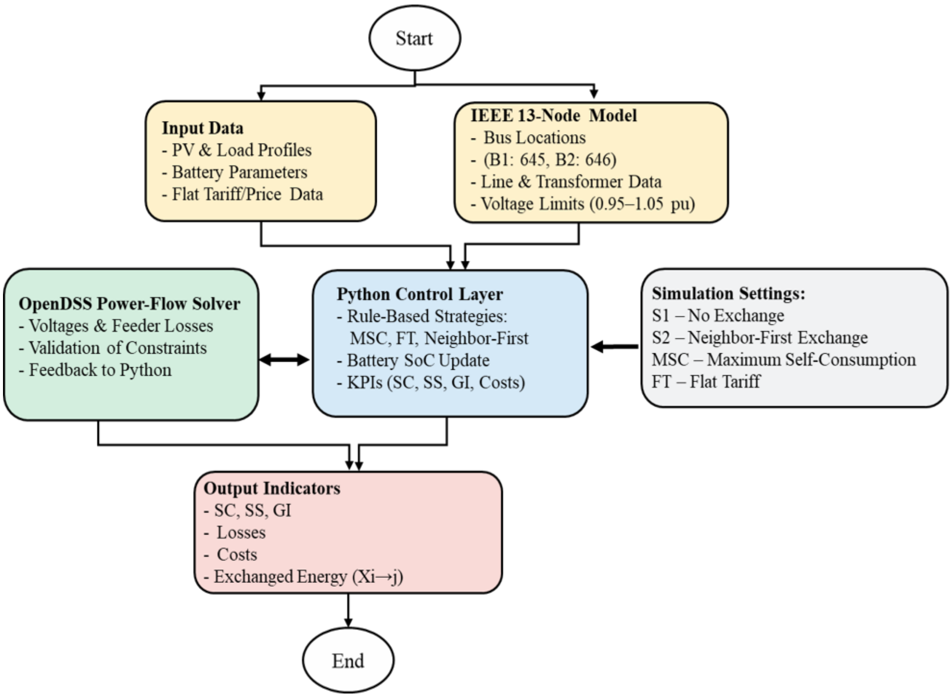


Figure 2 - Simulation framework integrating Python-based control and OpenDSS power-flow validation for rule-based energy exchange analysis

3.4 Neighbor first exchange rule

The energy balance of each prosumer $i \in \{1,2\}$, at hour t, is first determined by the difference between its PV generation $G_i(t)$ and load demand $L_i(t)$. This defines a positive $\Delta_i(t)$ indicates a surplus of PV, while a negative value indicates a deficit as expressed in equation (1):

$$\Delta_i(t) = G_i(t) - L_i(t) \qquad (1)$$

The battery state-of-charge (SoC) evolves depending on charging and discharging decisions. Equation (2) represents the SoC update:

$$SoC_i(t+1) = SoC_i(t) + \eta_c P_i^{ch}(t) - \frac{1}{\eta_d} P_i^{dis}(t) \qquad (2)$$

Where η_c and η_d are charge and discharge efficiencies, $P_i^{ch}(t)$ and $P_i^{dis}(t)$ are charging and discharging power, subject to the operational limits (3) with C_i the battery capacity and P^{max} the inverter charge/discharge rating:

$$0 \leq SoC_i(t) \leq C_{i,0} \leq P_i^{ch}(t), P_i^{dis}(t) \leq P^{max} \qquad (3)$$

When Building 2 (B2) faces a residual deficit after its own storage operation, the neighbor-first rule allows Building 1 (B1) to supply part of this deficit, constrained by its available SoC and inverter rating. The exchanged power is defined in equation (4), where η_x is the exchange efficiency, accounting for line losses:

$$X_{1\to2}(t) = min(\Delta_2^-(t), P^{max}, \eta_d \cdot SoC_1(t)) \cdot \eta_x \qquad (4)$$

The line efficiency $\eta_x = 0.99$ is determined from the line impedance Z = 1.32 + j1.36 Ω and typical exchange power levels. For the 300 ft line segment and hourly exchange magnitudes of 0–2 kW, I^2R losses average approximately 1% of transferred energy, as validated through OpenDSS power-flow calculations.

Finally, imports and exports from the external grid are determined by the residual surplus or deficit once battery and exchange actions are applied. These are expressed in equations (5) and (6), where I_i (t) and E_i (t) represent grid imports and exports of building i, respectively:

$$I_i(t) = max(0, -\Delta_i(t) - P_i^{dis}(t) - X_j \to i(t)) \qquad (5)$$
$$E_i(t) = max(0, \Delta_i(t) - P_i^{ch}(t) - X_i \to j(t)) \qquad (6)$$

Here, $X_i \to j(t)$ denotes the power exchanged from prosumer i to its neighbor j. Conversely, $X_j \to i$ (t) represents the reciprocal flow. The proposed rule prioritizes local deficit fulfillment via neighbor surplus before importing from the grid. This neighbor-first rule prioritizes peer-to-peer energy sharing to minimize external grid dependence while satisfying SoC and inverter limits.

3.5 Performance indicators

The following Key Performance Indicators (KPIs) were defined based on simulation outputs and are computed from the hourly simulation output over the 24-hour horizon T $(time\ index\ t)$. Self-sufficiency (SS) represents the share of community load covered by local PV, storage, and exchange, without relying on external grid imports (7):

$$SS = 1 - \frac{\sum_{t \in T} \sum_{i=1}^{2} Ii(t)}{\sum_{t \in T} \sum_{i=1}^{2} Li(t)} \qquad (7)$$

Self-consumption (SC) is defined as the fraction of total PV generation that is consumed locally, either directly or via exchange, as given in equation (8):

$$SC = 1 - \frac{\sum_{t \in T} \sum_{i=1}^{2} Ei(t)}{\sum_{t \in T} \sum_{i=1}^{2} Gi(t)} \qquad (8)$$

The total exchanged energy between prosumers over the 24-hour horizon is expressed in equation (9):

$$X_{tot} = \sum_{t \in T} [X_{1\rightarrow 2}(t) + X_{2\rightarrow 1}(t)] \qquad (9)$$

System losses include both battery inefficiencies and line losses during exchanges, as defined in equation (10):

$$L_{tot} = \sum_{t \in T} [L_{batt}(t) + L_{ex}(t)] \qquad (10)$$

The daily electricity cost under a flat tariff p (€$/kWh$) is calculated in equation (11):

$$C_{sys} = p \sum_{t \in T} \sum_{i=1}^{2} Ii(t) \qquad (11)$$

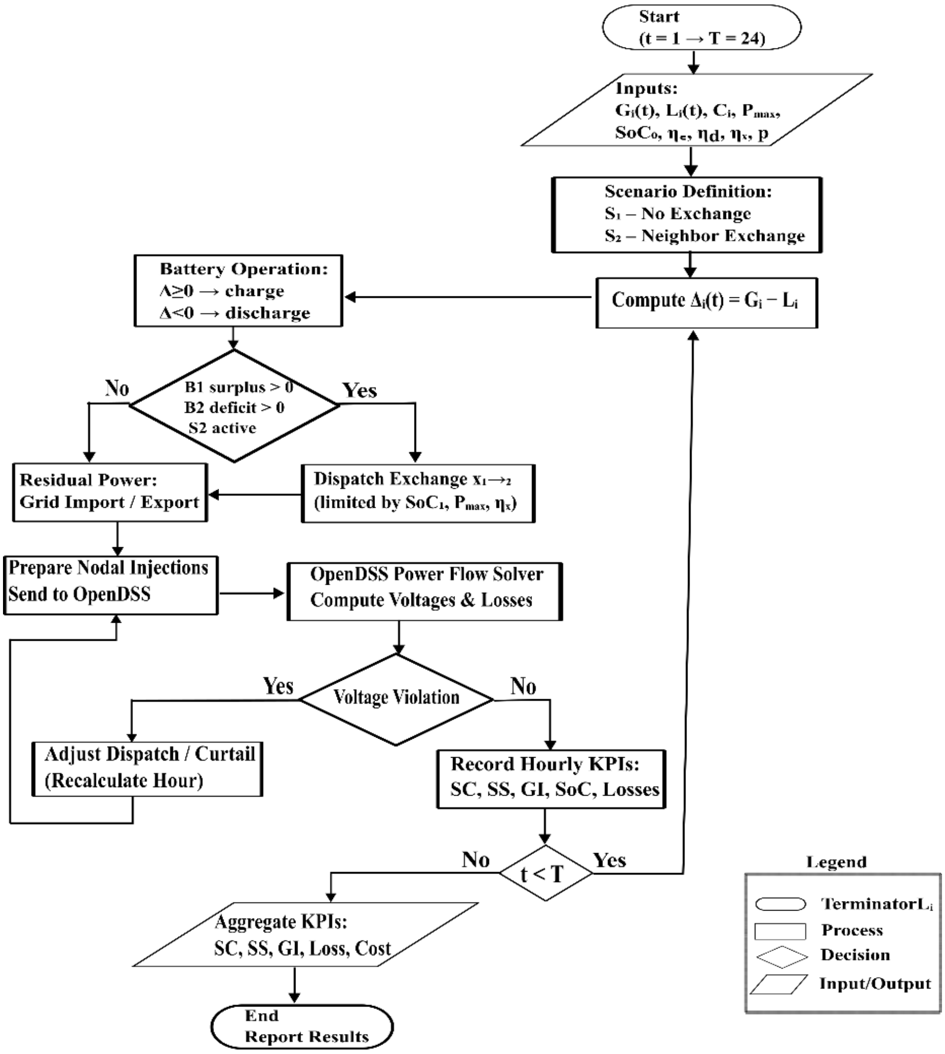


Figure 8 - Flowchart of the hourly simulation and control logic for rule-based AC energy exchange between two prosumers on the IEEE 13-node feeder

Figure 3 illustrates the hourly simulation and control logic applied to the rule-based AC energy exchange between the two prosumers on the IEEE 13-node feeder. For each hourly step, the model updates photovoltaic generation, demand, and battery SoC for both buildings. The controller then checks for surplus and deficit conditions if one building has excess energy and the other requires support; an exchange is triggered following the neighbor-first rule. The exchanged power is limited by available surplus, demand, and the exchange efficiency (η_x). After each transaction, feeder voltages and losses are recalculated to confirm network limits, and all variables are recorded before moving to the next hour.

4. Simulation setup

This section provides the complete simulation setup adopted for implementing and analyzing the AC control strategy. The configuration includes model parameters, input datasets for load and PV generation, storage characteristics, and operational constraints applied throughout the 24-hour simulation horizon.

4.1 Input profiles and parameters

Hourly load and PV profiles were used (resolution: 1 h). Battery models included round-trip efficiency, SoC bounds, and charge/discharge rates. The simulation employed a flat electricity tariff and identical time-step and horizon settings for both buildings. In this study, a flat electricity tariff of €0.25/kWh was assumed to isolate and evaluate the performance of the proposed energy exchange control algorithm under realistic power flow constraints. This simplification intentionally avoids the added complexity of dynamic pricing models, time-of-use tariffs, and smart contract mechanisms, which are outside the scope of the present technical validation. This work forms the basis of a broader research program, in which future studies will incorporate detailed economic modeling including variable pricing structures, peer-to-peer energy trading at intermediate prices (e.g., €0.18/kWh), and automated compensation schemes between prosumers using smart contracts. This phased approach enables a progressive evaluation of both technical feasibility and economic viability in real-world energy communities. Table 2 summarizes all input parameters used in the study

Table 2 - Simulation parameters case study

Parameter	Building 1	Building 2	Unit
Annual Load / PV	5,937 / 7,700	7,721 / 10,096	kWh
Peak Load / PV	1.6 / 4.3	2.1 / 5.8	kW
Battery (Capacity /Power / SoC_0)	15.0 / 5.0 / 7.5	5.0 / 5.0 / 2.5	kWh / kW / kWh
Efficiency (η_c / η_d / η_x)	0.95 / 0.95 / 0.99	0.95 / 0.95 / 0.99	—
Network (Bus)	645.2	646.3	—
Tariff / Δt / Horizon	0.25 / 1 / 24	0.25 / 1 / 24	€/kWh / h / h

5. Results

This section presents technical and economic outcomes for the two scenarios: S1 (no exchange) and S2 (neighbor-first exchange). The findings quantify how the proposed energy-sharing approach influences feeder performance, power losses, voltage quality, battery operation, and daily operating cost.

5.1 Technical performance

Figure 4 illustrates the hourly power exchange profile between the two buildings. Under scenario S2, a total of 7.74 kWh was transferred from B1 to B2 during the 24-hour period, following the typical pattern of daytime surplus at B1 and evening deficit at B2. This confirms that the control algorithm effectively reallocates excess PV energy within the feeder. In scenario S1, feeder voltages remained within 0.999–1.000 pu, and total system losses amounted to 2.14 kWh. When local exchange was enabled in S2, voltages stayed regulated at 0.9996–1.0001 pu, indicating that the additional power transfer did not cause any voltage deviation or violation of network constraints. Total system losses increased slightly to 2.58 kWh, representing a 0.44 kWh rise compared with S1.

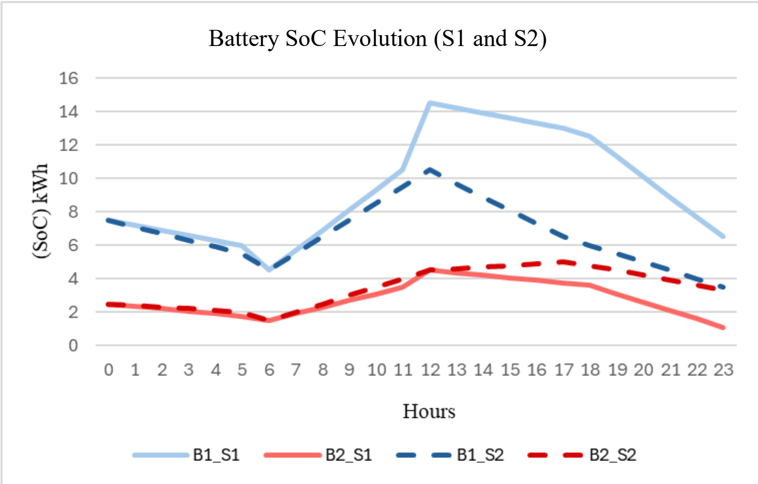


Figure 9 - Battery state-of-charge (SoC) evolution of Building 1 and Building 2 under scenarios S1 and S2.

A detailed loss decomposition shows that 0.077 kWh of this increase corresponded to line losses from the inter-building exchange, equivalent to an average line efficiency of about 99%. This validates the simplified efficiency parameter η_x used in the control algorithm and confirms the accuracy of the adopted network model.

The remaining 0.36 kWh was attributed to additional battery cycling: Figure 5 clearly shows that B1's state of charge decreased more frequently as it supplied B2, while B2's state of charge rose during exchange periods. The corresponding charging and discharging behavior is illustrated in Figure 6, where S2 resulted in higher discharge activity for B1 and increased charging for B2. These operational adjustments indicate effective energy cooperation between the two prosumers. No instability or excessive cycling was observed, confirming the robustness of the proposed control under practical feeder conditions.

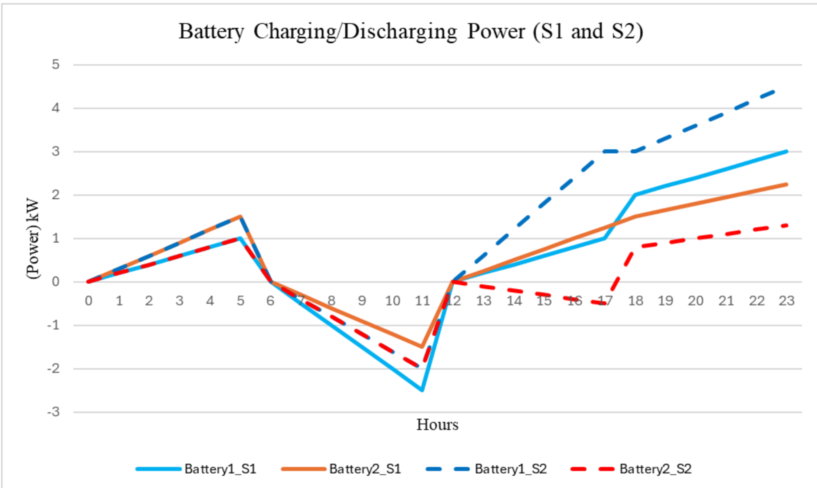


Figure 5 - Hourly battery charging and discharging power under scenario S1 and S2

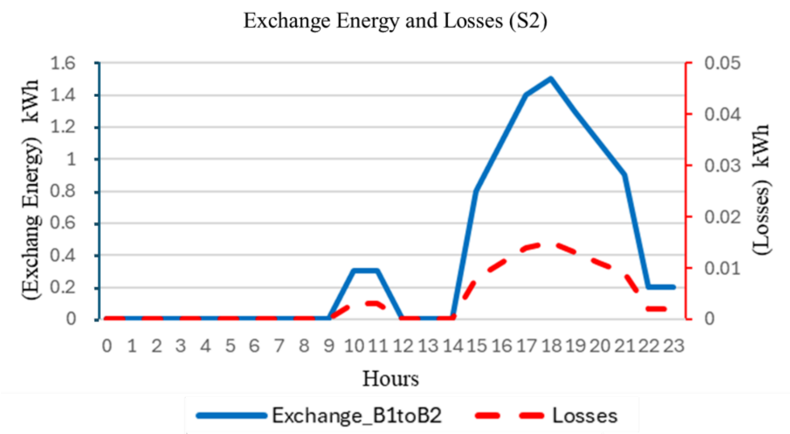
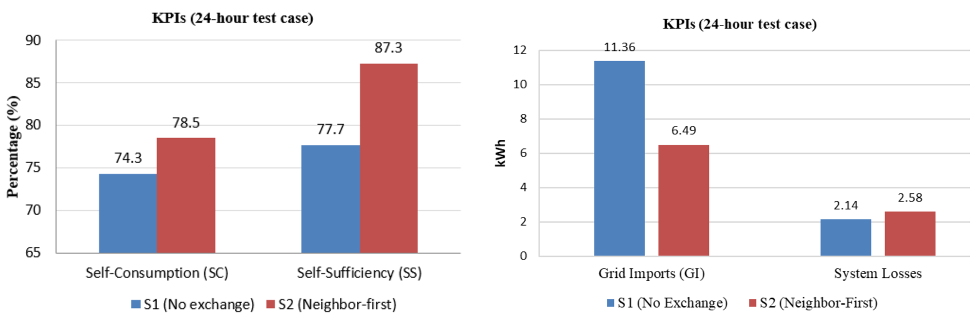


Figure 6 - Hourly profile of energy exchanged from B1 to B2
and associated losses under strategy S2

5.2 Economic Performance

The key performance indicators obtained from the simulations are summarized in Fig. 7. Self-consumption (SC) improved from 74.3 % to 78.5 %, and self-sufficiency (SS) increased from 77.7 % to 87.3 % when moving from S1 to S2 which is shown in Fig. 7(a). As presented in Fig. 7(b), grid imports (GI) decreased substantially, whereas total system losses exhibited only a modest rise. These results demonstrate that the neighbor-first exchange enhanced both local utilization of PV energy and overall feeder autonomy.

Economic evaluation was performed using a flat tariff of €0.25/kWh applied to each building's grid imports. The daily cost for B2 decreases markedly from €2.84 (S1) to €0.91 (S2), corresponding to a 68 % reduction. At the system level, total daily expenditure declined from €2.84 to €1.62, representing a 43 % overall saving. These results confirm that the neighbor-first exchange effectively translated technical improvements into monetary gains. Because the exchange markedly reduced grid imports for B2, despite a slight increase for B1, the overall grid import of the community decreased, and the small additional line and battery losses had only a minor effect on total cost. The 99 % average line efficiency ensured that nearly all shared energy retained its economic value within the local network. Operationally, B1 acted as the energy provider during high-generation hours, while B2 served as the primary receiver during demand peaks. This redistribution of operating effort and cost was therefore expected: B1 experienced slightly higher cycling and a small energy expense, whereas B2 benefited from substantial cost relief. A simple compensation or credit mechanism between the participants could balance these advantages, but detailed market design is beyond the present technical scope.



(a) (b)

Figure 10 - Comparison of key performance indicators for scenarios S1 (no exchange) and S2 (neighbor-first exchange). (a) Self-consumption and self-sufficiency (%).
(b) Grid imports and system losses (kWh)

6. Discussion

The simulation results confirmed that the rule-based neighbor-first exchange is technically feasible within existing low-voltage AC distribution infrastructure. All feeder voltages remained within the statutory limits (0.95-1.05 pu) throughout the 24-hour period, with maximum deviation less than 0.01 pu. This confirmed that energy exchange between adjacent prosumers can be operated safely when properly constrained by battery inverter ratings and line impedances.

The neighbor-first approach achieved an improvement of +9.6 percentage points in SS and +4.2 percentage points in SC compared with the no-exchange baseline scenario (S1). These values are consistent with prior studies on local energy sharing. The moderate SC increase reflects the already high PV self-utilization in S1 (74.3%), indicating that the main advantage of the proposed strategy lies in spatial redistribution of surplus energy rather than temporal shifting.

Total system losses increased from 2.14 kWh (S1) to 2.58 kWh (S2). Decomposition revealed that line losses contributed 0.077 kWh (3% of total loss increase), while battery losses increased by 0.36 kWh due to enhanced cycling. The resulting 99% line efficiency validated the simplified parameter ($\eta_{x)}$ and confirmed that short-distance exchanges are energetically sound.

Under the flat tariff, the system-wide economic benefit (€1.22/day) demonstrated the immediate financial viability. However, cost redistribution rose equity considerations: Building 1 shifted from zero cost to €0.72/day while enabling substantial savings for Building 2. Future studies should investigate equitable cost-sharing mechanisms that preserve economic incentives for all participants. This includes the integration of dynamic tariffs, intermediate exchange prices, and smart contract systems to automate and balance energy trade between prosumers.

7. Conclusions and Future Work

This paper proposed and validated a rule-based neighbor-first AC energy exchange strategy for urban prosumer communities. Applied to a two-building case study on the modified IEEE 13-node distribution feeder, the method increased self-sufficiency from 77.7% to 87.3%, improved self-consumption from 74.3% to 78.5%, and reduced the second Building's grid imports by 68%. The strategy delivered 7.74 kWh of exchanged energy over 24 hours while maintaining feeder voltages within operational limits and achieving total system losses of only 2.58 kWh. Economic analysis revealed daily saving of €1.22 for the overall system under a flat tariff of 0.25 €/kWh.

The proposed strategy is computationally lightweight, requiring no forecasting or optimization, and is therefore practical for small-scale urban energy communities. Future work will extend the framework to multi-building networks with diverse PV and demand profiles, perform year-long simulations under dynamic tariffs and peer-to-peer exchange pricing, and integrate demand-side management strategies. This will allow for more comprehensive assessments of both the technical and economic performance of community energy exchange system

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